PROJECT 13-01 | NOVEMBER 2014

CRN

Cooperative Research Network

Electric Distribution System Losses

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for

Cooperative Research Network
National Rural Electric Cooperative Association
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PREVIEW VIEW

The National Rural Electric Cooperative Association

NRECA is the national service organization for more than 900 not-for-profit rural electric cooperatives and public power districts providing retail electric service to more than 42 million consumers in 47 states and whose retail sales account for approximately 12 percent of total electricity sales in the United States.

NRECA's members include consumer-owned local distribution systems—the vast majority—and 66 generation and transmission (G&T) cooperatives that supply wholesale power to their distribution cooperative owner-members. Distribution and G&T cooperatives share an obligation to serve their members by providing safe, reliable, and affordable electric service.

About CRN

NRECA's Cooperative Research Network™ (CRN) manages an extensive network of organizations and partners in order to conduct collaborative research for electric cooperatives. CRN is a catalyst for innovative and practical technology solutions for emerging industry issues by leading and facilitating collaborative research with co-ops, industry, universities, labs, and federal agencies.

CRN fosters and communicates technical advances and business improvements to help electric cooperatives control costs, increase productivity, and enhance service to their consumer-members. CRN products, services, and technology surveillance address strategic issues in the areas:

- Cyber Security
- Consumer Energy Solutions
- Generation & Environment
- Grid Analytics
- Next Generation Networks
- Renewables
- Resiliency
- Smart Grid

CRN research is directed by member advisors drawn from the more than 900 private, not-for-profit, consumer-owned cooperatives which are members of NRECA.

Electric Distribution System Losses

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Questions

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PREVIOUS VIEW

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Mr. Inan is a Sr. Project Manager in the Smart Grid Solutions section of Leidos Engineering, where he is the project manager and technical lead for smart grid demonstration projects. He has 17 years of national and international experience in the energy sector, including smart grid technologies and T&D control systems. Mr. Inan has expertise in distribution automation (DA), power system planning and engineering, as well as extensive knowledge of electric utility and independent system operator/regional transmission organization operations. He leads projects focused on power systems planning, analysis, modeling and simulation, and control; protective relaying; DA systems; energy storage integration; microgrids; electric wholesale markets; and transmission congestion management. Mr. Inan has an M.B.A. in General Management, an M.S. in Power Systems Engineering, and a B.S. in Electrical and Electronics Engineering, and is a certified Engineer in Training (EIT). Mr. Inan is also a Ph.D. Candidate in Power Systems Engineering at West Virginia University. He is a registered member of the IEEE Power and Energy Society, the DOE-facilitated Microgrid Exchange Committee, and the NIST Smart Grid Interoperability Panel. Mr. Inan has presented at the 2014 TechAdvantage Conference, 2012 TechAdvantage Conference, 2009 Smart Grid America Forum, 2009 International Microgrid Symposium, and the 2007 Renewable Expo.

Sridhar Chouhan

Mr. Chouhan is a power systems engineer in the Smart Grid Solutions section of Leidos Engineering. He has more than seven years of experience in the power sector in transmission and distribution operations and advanced technology research. He has been involved in various smart-grid-related projects, such as distribution automation, volt/var control, renewable energy integration, energy storage systems, and microgrids. He specializes in modeling and simulation of distribution systems, transmission systems, and power markets through various software packages. He received a Master's degree in Power Systems Engineering from West Virginia University and currently is pursuing a Ph.D. in Power Systems Engineering with a research focus on multiagent grid management systems, microgrid controls, and distributed energy resource optimization. He was a member of the DOE National Energy Technology Laboratory's Modern Grid Strategy team. Mr. Chouhan is a member of the IEEE Power and Energy Society, and is a certified Engineer in Training.

Trishia Swayne

Ms. Swayne is a registered professional engineer with 10 years of experience in electric utility system planning. She obtained a B.S. in Engineering Physics and a Master's Degree in Business Administration at Murray State University in Kentucky. Ms. Swayne specializes in a variety of electric system analysis programs, developing models and performing load flow studies, capital improvement plans, arc-flash, distributed generation impact, voltage optimization, sectionalizing, system loss, capacitor placement, and reliability studies. She also helps clients with load forecasting and prioritization of recommended system improvements for transmission, substation, and distribution facilities.

Continued

K.C. Fagen

Mr. Fagen has 23 years of experience in the planning and design of distribution and transmission systems, gained working for Leidos Engineering, as well as two years with Austin Energy at the City of Austin. Mr. Fagen was the project manager for the Northwest Energy Efficiency Alliance's Distribution Efficiency Initiative four-year research project, which measured the relationship of energy consumption and applied voltage. He has been working with Bonneville Power Administration on its Energy Smart Utility Efficiency Program, and has consulted on EPRI's Green Circuit program and developed procedures for performing a distribution loss study for EPRI. Mr. Fagen led the Leidos team in developing requirements and technical specifications ("System of Systems") as part of Guam's Smart Grid initiative, which included a distribution management system, a load control management system, distribution automation, substation automation, and a volt/var system.

Craig Rizzo

Mr. Rizzo is the Director of Microgrid Solutions for Leidos. He has 21 years of experience implementing and leading systems engineering and analysis projects for the energy and defense industries. He currently manages energy projects that include the analysis, design, and deployment of microgrid, smart grid, and distributed energy resource solutions with advanced monitoring, control, and analytics for electric utilities, commercial/industrial clients, and regional transmission organizations in North America. Prior to joining Leidos in 2004, he served eight years as an Air Force Officer, where he managed strategic planning efforts for combat aircraft, space, and missile systems and developed validation methodologies for electronic warfare modeling systems. Mr. Rizzo has M.S. and B.S. degrees in Operations Research from the Air Force Institute of Technology and the U.S. Air Force Academy, respectively.

Joni Batson

A registered professional engineer, Ms. Batson has 36 years of project management experience working both as a consultant and directly for utilities. For cooperative utilities nationwide, Ms. Batson develops long-range and construction work plans and evaluates the energy, capacity, efficiency, and reliability capabilities of transmission and distribution systems, including evaluating the impacts from loss reduction programs, demand response, smart grid applications, renewables, and distributed generation. Her system planning guides focus on utilities' need for transmission, substation, and distribution facilities under normal, projected, and contingency conditions. Utilities rely on these guides to evaluate the costs and benefits of alternative upgrades and to develop and implement capital requirement programs for budgeting, financing, and rate analysis.

Navid Nowakhtar

Mr. Nowakhtar is an economic consultant providing business consulting services to energy markets. He advises on utility infrastructure and helps clients with resource planning, load forecasting, financing, economic evaluations, and policy studies. Mr. Nowakhtar serves client planning needs through the application of sophisticated econometric models in support of power supply, policy, and strategic planning. He brings 16 years of experience in load forecasting and econometric modeling and has assisted large electric cooperatives, municipal electric authorities, and joint-action agencies in the development of energy sales, peak demand, and uncertainty forecasting efforts. As a Leadership in Energy and Environmental Design (LEED) Green Associate, Mr. Nowakhtar fuses the skills and experience from a vast body of work in the statistical and data management fields with the appropriate universe of knowledge and concepts within the energy efficiency and sustainability fields to provide relevant and in-depth analytical services. Mr. Nowakhtar led development of Leidos' proprietary energy efficiency and demand-side management business decision tool.

1 Introduction

The purpose of this report is to provide guidelines regarding operational, engineering, and financial management strategies for calculating, identifying, and reducing electric cooperative system losses.

The electric grid itself is by far the largest electric power consumer in the U.S. Every year, six to eight percent of electrical energy generated is lost in our transmission and distribution (T&D) infrastructure, according to data available from the Energy Information Administration (EIA). Figure 1.1 illustrates the most recent five-year loss data available from EIA.

> The largest electric consumer is the electric grid itself, consuming 6–8 percent of energy generated every year.

T&D losses are a significant cost to society. It is calculated that T&D losses are costing the U.S. approximately nine billion dollars each year. **Appendix B** provides details of this calculation using the EIA data. It is important to note that the EIA database does not have any data to breakdown T&D losses into transmission and distribution losses.

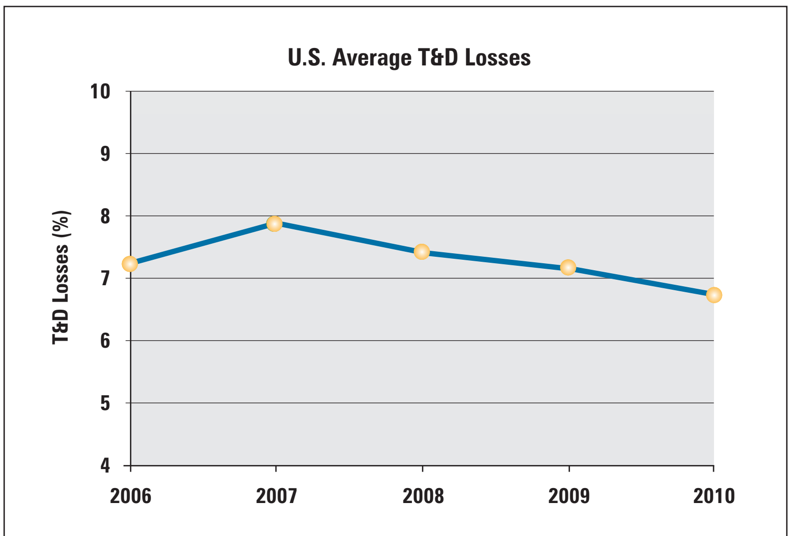

FIGURE 1.1: U.S. Average T&D Losses (%) from 2006 to 2010

Every year, cooperative utilities (co-ops) that borrow through the Rural Utilities Service (RUS) and National Rural Utilities Cooperative Finance Corporation (CFC) are required to report their losses to NRECA, along with other system and performance information. Loss percentage calculations are based on Equation 1.1.

Equation 1.1

$$\textit{Losses \%} = \left(1 - \frac{\textit{Total kWh Sales} + \textit{kWh Own Use}}{\textit{kWh Purchased} + \textit{kWh Generated} + \textit{kWh Interchange}}\right) \times 100$$

Roughly 97 percent of distribution co-ops report their losses every year using this formula. **Figure 1.2** shows the average annual co-op losses reported between 2007 and 2012. According to this figure, annual co-op losses are in the range of five to six percent.

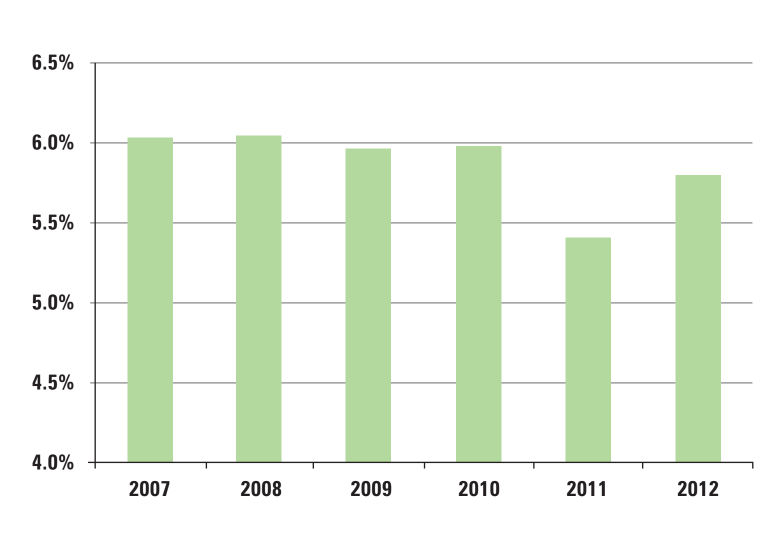

FIGURE 1.2: Average Co-op Distribution Losses

Although energy losses are inherent to grid operations, studies have shown that there is room for improvement in most cases. Losses cannot be avoided, but they can be minimized by combining advanced technologies with improved operational procedures and effective policies and regulations.

Given the significance of losses, utilities always face pressure—either through competitive or regulatory forces—to operate their systems as efficiently as possible. Increasing distribution system efficiency through loss reduction will optimize existing capacity and defer major capital investments in new generation, transmission, and distribution infrastructure. The net result will be a decrease in energy-generation and delivery costs and a reduced environmental impact.

> Average distribution co-op losses are 5–6 percent.

This report provides information on:

- Industry practices and methods used by cooperatives to calculate losses in electric T&D systems,
- Processes to determine where losses occur,
- Measures and techniques to reduce system losses,
- Methods for performing economic evaluation of loss-reduction strategies,
- The effect of emerging technologies on electric system losses, and
- Two case studies of effective cooperative loss analysis and reduction programs.

Analyzing distribution system losses requires analytical tools. In addition to the report, three spreadsheet tools were developed to help co-op staff analyze losses and evaluate loss-reduction techniques. The tools are a Loss Evaluation Tool, a Cost-Benefit Tool, and a Decision Matrix. The functionality of each tool is described in **Section 8**.

2 Management Guidelines

In This Section:

- **Develop a Loss-Reduction Plan**
- **Quantify and Locate Your Losses**
- **Evaluate Technological Loss-Reduction Techniques**
- **Consider Business Process Changes to Reduce Losses**
- **Evaluate Economics of Losses**
- **Embrace Smart Grid Technologies**
- **Summary**

This section details important steps to help co-ops improve their system efficiency by reducing power system losses. Electrical energy lost in the distribution system is a significant expense for many co-ops; therefore, reducing losses can improve a co-op's bottom line.

One of the challenges with loss reduction is that there is no single methodology adopted by co-ops to analyze losses and select appropriate loss-reduction techniques. In the absence of a standard methodology, this section provides general guidelines for co-ops to identify and minimize electric distribution losses.

Develop a Loss-Reduction Plan

The most effective way to demonstrate a commitment to minimize distribution system losses to your customers is to develop a loss-reduction plan that identifies the source and magnitude of losses and recommends a loss-reduction program in line with their estimated financial impact. This will require studies that identify technical losses along with unbilled revenue losses and losses due to customer theft. Technical programs and business process changes can then be designed for each loss type, based on a business case assessment. For example, using a formal process to QA/QC metered data and training staff to identify theft can improve nontechnical loss issues.

The strategic plan should engage your stakeholders in participating in loss-reduction initiatives. Ideally, the plan shall be updated annually, based on performance in the previous year.

Empower your staff with the tools and training they need. System-level loss analysis is fairly straightforward. However, as you attempt to allocate losses to various distribution system components, the need for analytical tools increases. Distribution analysis software can effectively support loss analysis. If possible, send your staff to training workshops that focus on distribution system analysis.

Quantify and Locate Your Losses

Assessing the amount of losses in your current system is a crucial first step. It determines how much room you may have for improvement so you can evaluate different loss-reduction options. It can also serve as a performance baseline, providing valuable insight on how effective your loss-reduction programs are.

Identifying the most cost-effective technique requires that you locate the losses on your current system. In general, distribution system analysis software is used to analytically calculate line losses; equipment and customer load data are used to estimate losses in other equipment.

Evaluate Technological Loss-Reduction Techniques

There are multiple loss-reduction techniques which will be described in detail in the following sections. The benefit of any loss-reduction technique depends heavily on distribution system characteristics. It is important to thoroughly understand these techniques and study their impact on your system.

The spreadsheet tools that are part of this study can be used to evaluate potential loss-reduction techniques for your system. These tools require co-op personnel to use modeling software and run power flows in the distribution system to calculate values to be input into the spreadsheet tools.

The co-op also can model a proposed system improvement and determine the reduction in system losses compared with the existing system. Economic analysis can be applied to determine the cost-effectiveness of each loss-reduction technique.

There has been great advancement in the smart grid domain this past decade and it is expected that the trend will continue. This report provides a list of loss-reduction techniques that are considered to be viable as of the time this report was written. It is recommended that co-op personnel keep a loss-reduction techniques list up-to-date as new smart-grid technologies and new regulatory structures emerge.

CONSIDER TIME-OF-USE RATES OR DEMAND RESPONSE TO RESHAPE LOAD CURVES

Time-of-use rates and demand response programs can be effective tools to reshape load curves. In general, these programs are implemented by utilities to reduce or shift peak demand. In some cases, total energy consumed over a period of time may also be reduced. Due to the I2×R effect, distribution system losses will be reduced by reducing peak load even though total energy consumed stays the same.

DE-ENERGIZE UNLOADED TRANSFORMERS

No-load losses do not change as the transformer load varies and are present even when there is no load on the transformer. Thus, transformers that no longer have load on them should be removed or de-energized from the system to reduce no-load losses. If it is not cost-efficient to remove these transformers, they can be de-energized so that they do not consume energy.

STUDY YOUR LOAD GROWTH CAREFULLY WHEN SIZING NEW TRANSFORMERS

Transformers that are lightly loaded operate inefficiently because of no-load losses. Likewise, when transformers are operated above the nameplate rating the majority of the time, operating efficiency is reduced due to load losses. Therefore, sizing new transformers is very critical in managing distribution transformer losses.

Initial sizing of distribution transformers is challenging because the electrical infrastructure is installed before customer facilities are built. The co-op has to develop an understanding of customer end-use loads and timing of load growth to properly size transformers for new construction.

KEEP AN EYE ON REACTIVE POWER FLOWS

As reactive power flow in your system increases, line currents increase, which causes energy losses to increase. Therefore, minimizing reactive power flows in your system will reduce losses.

In general, co-ops try to maintain a constant power factor at the substation, which is always a good practice. However, cap banks at substations do not reduce reactive power flows on the distribution system itself. Ideally, cap banks should be located as close as possible to loads so that reactive power flows are minimized. Distribution system analysis software can be used to calculate reactive power flows on each line segment and an optimal capacitor placement plan can be developed. Most current tools offer this feature.

Some cooperatives have programs to enforce a power factor to commercial or industrial customers. Methods used by co-ops include a power factor penalty and a contract that requires the customer power factor to stay above a certain threshold as a condition of service.

Consider Business Process Changes to Reduce Losses

PERIODICALLY EVALUATE YOUR PLANNING AND DESIGN STANDARDS

Distribution system losses can be economically reduced over time by changing the planning and design standards of the utility. Actual loss reductions are highly dependent on existing electrical system performance, existing and past utility design and planning practices, and the way a utility operates the distribution system. Therefore, these plans and standards should be periodically revisited and updated when necessary.

INCLUDE LOSSES IN BID EVALUATIONS

The cost of losses can be incorporated into bid evaluations for transformers and voltage regulators and when choosing conductor sizes. Using life-cycle cost analysis will determine the least-cost implementation of loss-reduction upgrades and programs. Benefit-to-cost ratios will vary due to the value placed on electrical losses, growth rates, and capital construction and carrying costs.

Utilities may need to change planning and design standards and purchasing criteria in order to realize the least cost over the life-cycle of the electrical infrastructure. This may include providing for installation of larger conductors, more efficient transformers, shorter secondary conductors, and more efficient utilization of equipment.

CONSIDER LOSS SAVINGS IN YOUR CAPITAL EXPENDITURE PLANS

Co-ops develop capital expenditure (cap-ex) plans in light of their current system conditions, load projections, and current asset conditions. In some cases, loss savings can provide substantial benefits; therefore, it is good practice to account for them when evaluating capital projects. A co-op interview we conducted for this study demonstrated a good example of this.

The San Isabel Electric Association, headquartered in Pueblo West, Colorado, was trying to justify new substation construction in a heavily loaded area. Co-op engineers simulated distribution system losses before and after the substation addition and conducted cost-benefit analysis with these results. Through simply calculating the loss savings, they learned that a new substation would pay for itself within 10 years. Co-op staff obtained required approvals easily with the help of this analysis.

MANAGE YOUR TRANSFORMER INVENTORY

The economic benefits of loss-control programs, such as optimal transformer sizing and loading, must be balanced with other strategies, such as inventory management. Limiting the number of transformer sizes in stock or on the truck may not always provide the appropriate size for optimal loss reduction, resulting in oversized transformers.

Management and engineering may need to analyze the costs and benefits of expanding inventory versus incurring additional transformer losses. Also, line workers and field personnel should be trained on the importance and value of installing the correct size transformer for long-term loss benefits, although this may not always be possible, especially during outage situations.

ESTABLISH PROGRAMS TO CALIBRATE METERS PERIODICALLY

Improper meter calibration is a potential source of losses and could adversely affect revenues. Proactive programs to routinely check the calibration of every meter can reduce losses. Some cooperatives that have replaced meters as part of AMR/AMI programs have noted significant loss savings due to improved meter accuracy.

LEVERAGE DATA BEING COLLECTED

Advanced metering infrastructure (AMI) and smart grid deployments are key to collecting additional information needed to perform more accurate studies. Detailed analysis of the supplementary data from these sources will enhance loss calculations, meaning that lower losses can be achieved at minimal costs.

Evaluate Economics of Losses

An economic analysis is commonly performed by utilities when evaluating system improvements to reduce electric system losses. As the name suggests, the analysis considers the annual costs of system improvements (including financing costs, if applicable) and the benefits—in the form of annual cost savings or additional revenue—to achieve the desired goals. Annualized costs and benefits are projected over the selected study period to determine annual net cash flows. The net present value (NPV) of the annual net cash flows (also referred to as Net System Benefits) is used to evaluate life-cycle costs for each system improvement alternative the co-op is considering.

In addition to simple NPV analysis, there are several industry standard cost-benefit ratios that can be computed, given a complete cataloguing of all project costs and benefits. Several of those ratios are discussed in **Section 5**.

For a complete cost-benefit analysis, cooperatives need to quantify the full costs and benefits associated with capital projects and the reduction of demand and energy requirements. The capital cost of the released capacity does not necessarily appear as a direct immediate cost benefit to the utility. However, the kilowatt reductions on a utility system may offset growth and postpone the need for capital investment.

When comparing loss-mitigation strategies with other system improvements, a base case needs to be established on current utility practices, and each considered alternative compared to the base case. It is critical to have as precise an understanding as possible of system losses under baseline conditions, so that loss improvements can be estimated given the system loss percentage that is expected from the project improvements. Furthermore, longitudinal analysis over a carefully selected study period can ensure that the impacts of future load growth, which may increase benefits associated with the project over time, can be captured.

The value of peak kilowatt reduction is highly dependent on the cost of generating the next kilowatt and the cost of the total plant required to generate and deliver the peak kilowatt and associated losses. The value of kilowatt-hour reductions are more directly coupled with the cost of generating the next kilowatt-hour (such as fuel costs and other costs associated with the marginal generating unit, or, in the case of distribution cooperatives, tariff or power purchase agreement energy charges) and the associated cumulative line losses from the point where the energy reduction occurs back to the source.

For a cooperative that is a wholesale buyer of power, the value of reducing peak kilowatt and kilowatt-hour is equal to the cost of purchased power. Wholesale utilities may have a tiered energy rate and a monthly or ratchet demand rate. In some cases, a wholesale utility may have a reactive power rate or penalty charge to be considered.

Electric losses can be reduced by system improvements on both the transmission and distribution systems. Generic or case-specific cost-benefit analysis is required to justify necessary expenditures for these system improvements. As noted above, **Section 5** in this report is dedicated to providing an overview of the cost-benefit analysis framework and associated techniques.

Embrace Smart Grid Technologies

U.S. utilities have made significant investments in smart grid technologies in the past decade and this trend is expected to grow in the future. Advancements in communication, sensor, control, metering, and distributed generation technologies have made smart grid technologies viable for distribution utilities. Most of the smart grid technologies—such as distribution automation, voltage optimization, distribution management system, and distributed generation—provide energy-efficiency benefits by reducing T&D losses and total demand.

Summary

In summary, the goal of this manual is to evaluate current industry practices, develop guidelines for performing a loss study on a distribution system, and account for the reduction in losses that would result from proposed system improvements. Loss reduction can provide benefits in system planning, energy conservation, accounting, and the financial health of electric utilities. Understanding how the electric system is performing and identifying areas that will maximize capital investments will allow utilities to operate systems as efficiently as possible.

PREVIOUS VIEW

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3 Loss Analysis

In This Section:

- Understanding Total System Losses
- Considerations for Calculating Losses
- Calculating Losses by Distribution System Components

Each utility accounts for and calculates losses differently based on a number of factors, including tariffs, regulations, and accounting practices. For instance, the ancillary power required to operate a substation may be considered an operational cost and not counted as an electric system loss.

Most co-ops calculate system losses on an annual basis. In general, substation transformer losses are included in the system losses that co-ops calculate. Even though the metering is sometimes located at the low side of the substation transformer, losses are calculated including the transformer losses.

Understanding Total System Losses

Total system losses can be calculated by subtracting total megawatt-hour sales (including unmetered sales and own usage) from total megawatt-hours purchased. Purchases should include both wholesale purchases and the purchases from the distributed generation units in the co-op territory and also the kilowatt-hour exchange. Equation 1.1 is the formula to calculate system-wide losses.

Losses in distribution systems may be different between cooperatives due to physical and operating differences, such as different voltage levels, feeder lengths, loading patterns, and conductor sizing. Therefore, a co-op with a lower loss percentage may have more room for improvement compared to a co-op with a higher loss percentage. Co-ops should study their system in detail to identify the potential savings.

Since the total system loss calculation is based on the energy purchased and energy sold, it includes both technical and nontechnical losses.

TECHNICAL LOSSES

Technical losses are associated with the loss of energy due to energization of equipment (fixed losses) and current flowing through electrical devices (variable losses), which by nature have a resistive quality. To further break down technical losses, they are made up of two components: fixed (no-load) and variable (load) losses.

Fixed Losses

Fixed losses are defined as energy required by the system to energize equipment and keep the system ready, even when no load is being serviced. Fixed losses are generally constant, so the magnitude of the fixed losses (kilowatt) multiplied by time (hours) will give energy losses (kilowatt-hours).

Variable Losses

Variable losses are the losses that are incurred as load is added to the system and change in proportion to the load. These include the losses due to current flowing through resistive electrical components.

Figure 3.1 shows the change in fixed and variable losses with transformer loading on a 150-kVA liquid-filled three-phase pad-mounted transformer.[1] This illustration clearly shows the quadratic increase of load-losses with the increase in transformer loading.

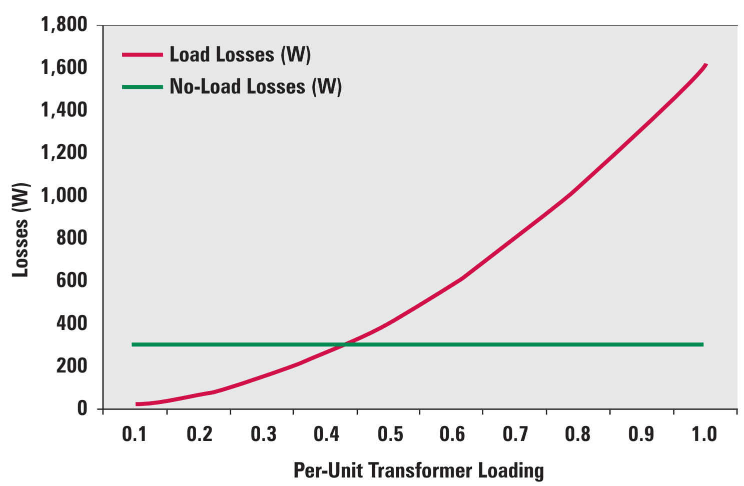

FIGURE 3.1: Transformer No-Load and Load Losses Example

NONTECHNICAL LOSSES

Nontechnical losses can result from problems with meter reading and related accounting. Electric power theft indirectly causes system losses to increase through the accounting of losses (i.e., no sales to offset purchases or power supply).

Each utility must estimate what percentage of total system load is associated with nontechnical loads attributed to theft. This is typically estimated based on the difference between total system losses and quantifiable technical losses and other assumed nontechnical losses that have been identified.

Unmetered loads, such as street lighting and station service, consume energy in the form of end-use load and losses. End-use load is not included in losses, but rather as part of the system load. The energy consumed by these components would be a mixture of fixed and variable loads. In many cases, losses incurred by unmetered loads are categorized in an "unaccounted for" category that consists of losses not specifically calculated in a technical loss category.

When the information is available or can be calculated, there is value in identifying these losses in a separate category for unmetered loads. By doing this, system improvements can be made to target possible high-loss components. Manufacturer specification data for substation auxiliaries, lighting across the system, transformer fans, and battery chargers are typically needed to calculate auxiliary consumption.

Considerations for Calculating Losses

METERING VS. ANALYTICAL CALCULATIONS

Although co-ops may calculate system-wide losses easily, it is more complicated to break down these losses into sections of the distribution system. This breakdown can be accomplished using two methods: metering and analytical calculations.

Metering is the process of installing energy meters at various points on the distribution system and comparing the energy data over a period of time. With metering, the utility must be concerned with the accuracy of the sensors and meters, as well as the timing or coincidence of the meter reads. In addition, unmetered loads still need to be estimated.

Analytical calculation is the process of calculating energy losses by using system characteristic information and available load data. Power system modeling software is generally used for analytical calculations due to the large number of system components involved and the complexity of power flow calculations. With analytical calculations, the utility needs to have thorough knowledge of all system configurations and must consider the accuracy of the data. Utilities typically have not recorded the loss parameters for

[1] "Eaton Consulting Application Guide," Table 17.0-10.

distribution transformers nor the actual load passing through each transformer.

The type and frequency of data that each utility maintains will determine the specific technique that can be used in calculating losses. Hourly data will allow more detailed studies and calculations to be performed, resulting in more accurate results. Annual data will require more assumptions and the use of system-average data, which can lead to less accurate results. If detailed information is not available, utilities can use sampling techniques to determine losses for each category based on a percentage of the system, and the information can then be used to expand the sampling to reflect total electric system losses.

Because detailed information is not always available, utilities commonly use sampling techniques to determine losses for each loss category. The preferred sample size depends on the size of the system. There are more than likely a number of atypical feeders that should be evaluated individually. For the remaining feeders, a representative sample from each voltage class can be selected that are similar enough to others on the system to provide reasonable extrapolated results.

MODELING AND SIMULATION

Use of modeling software to analyze power flows in the distribution system is an effective way to evaluate losses. It is important to model your system with software that can simulate a three-phase distribution system. Figure 3.2 shows a screenshot of a CYMEDist distribution model. Some of the tools that are widely used among co-ops include Milsoft, SynerGee, CYMEDist, and OpenDSS.

The results from the power flow analysis can establish the baseline for the distribution system for the existing configuration, including planned system upgrades. Additional modeling of system improvements can easily be performed to determine the potential reduction in system losses. Economic analysis can be applied to determine the cost-effectiveness of each loss-reduction technique.

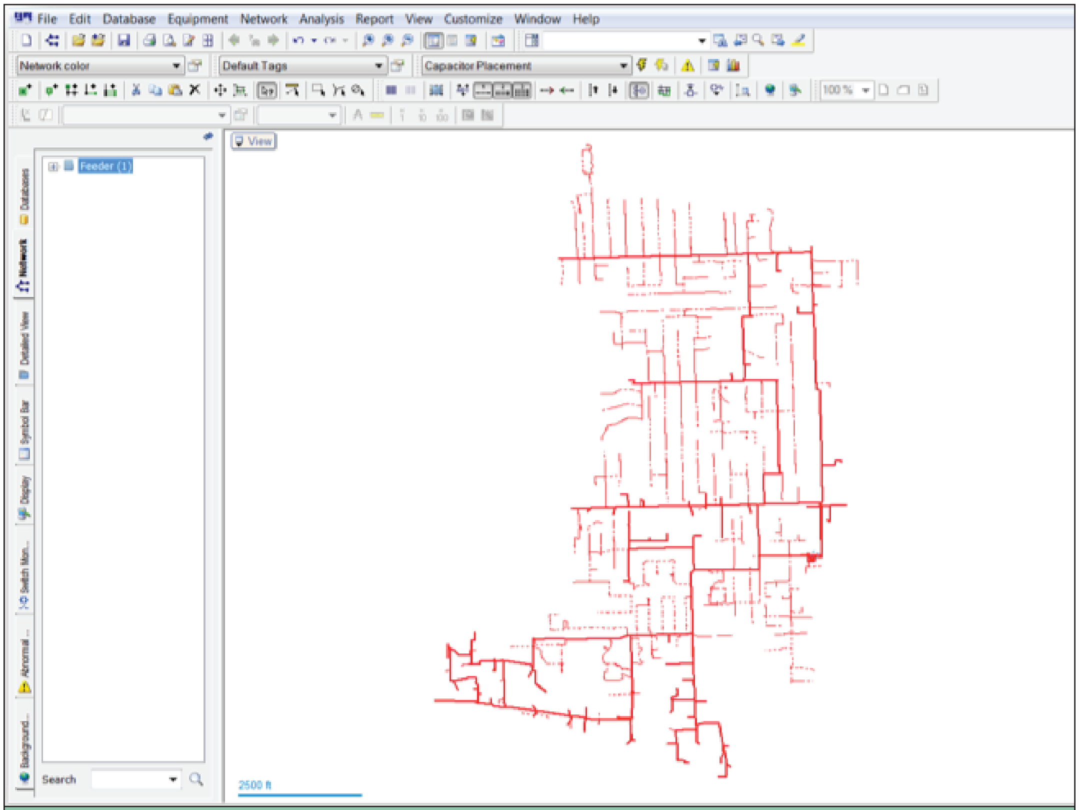

FIGURE 3.2: Snapshot of a CYMEDist Distribution Model

It is important to note that the accuracy of load flow results is totally dependent on the data and assumptions used in developing the models. Loss analysis is particularly sensitive to customer load types and bus voltage. For instance, a constant current load will generate the same losses regardless of voltage, but losses from constant impedance and constant power loads will vary with voltage. This phenomenon is illustrated in **Case Study 2** [Fort Loudoun Electric Cooperative (FLEC)].

By using distribution system modeling software, the utility engineer can change or add conductors or transformers, move load around, place capacitors, balance load, and monitor how each improvement affects system losses. While the distribution model can be used with power flow analysis software to analyze nearly any loss-reduction improvement, additional calculations may be needed to capture loss-reduction improvements that are not included in the computer model, such as secondary conductors, metering equipment, substation and distribution equipment, and distribution transformers.

CALCULATING PEAK LOSSES VS. ANNUAL ENERGY LOSSES

Analysis using distribution system models typically evaluates one loading scenario at a time and will calculate losses associated with that run. In general, a peak-loading scenario is studied by utility engineers because it is when most of the overloading and under-voltage incidents occur in their system. However, losses are present in the system throughout the year. While system losses are greatest at peak loads, approximately 70 percent of energy losses occur during off-peak times. It is important to know the load profile of the areas being analyzed in order to determine the complete loss picture in a system.

Seasonal load effects and variations in load distribution should be reviewed to better understand where losses occur in the system. If the analysis is performed at peak load, the contribution of the transformer no-load losses may appear to be minimal; however, if the system generally operates in a lightly loaded condition (lower load factor), the no-load losses may be a major deciding factor when selecting improvements.

Losses at peak are typically calculated using coincident load for each component at system peak. Energy losses are generally calculated in one of two ways.

1. Use hourly data to calculate losses for each hour of the time period. This is the most data-intensive approach.
2. Calculate energy losses based on the peak loss of the equipment or at the feeder level multiplied by the loss factor for the equipment or feeder. It is common to use annual data, but monthly data could offer increased precision. Monthly data would increase the cost and complexity of the analysis, but may add additional insight into seasonal variation, as well as accuracy for loads with atypical load shapes. Because hourly data is not typically available to calculate losses for each hour, the most common practice is to calculate peak load losses and use a loss factor to develop an annual energy loss value.

Losses calculated for each system component are then normalized based on metering data. Using metering data, total system losses can be determined by using the difference between power purchased and power delivered, while accounting for unmetered loads.

When available, hourly data will allow more detailed studies and calculations to be performed, resulting in increased granularity of results. Using annual data will require more assumptions and the use of system average data, which can lead to less precise results. Hour-by-hour analysis requires detailed data collection and modeling. Such detailed modeling allows analysis of how losses vary with time and may allow modeling of Volt/VAR control systems.

LOAD AND LOSS FACTORS

Electric system losses are highest during peak conditions. However, the majority of energy losses occur off-peak. Therefore, factors that represent the relationship between peak losses and average losses are helpful in determining electric system losses. The loss factor and load factor are similar in that they both describe the relationship between average and peak conditions. The load factor is calculated by dividing the average load by the peak load, while the average load is determined by dividing the energy over a period of time by that period of time. See Equation 3.1.

The loss factor is defined as the ratio of average power loss to peak power loss or, in other words, kilowatt-hour losses divided by the hours over the study period, divided by peak kilowatt losses. Energy losses are typically not directly calculated and the loss factor is used to calculate energy losses over a period of time based on peak loading loss studies for that same period.

The loss factor can be calculated using data that is commonly available. Loss factors are generally calculated system-wide, but, if data is available, it can be calculated for types of equipment and voltage class. For example, distribution transformers would have a different loss factor than the primary or secondary conductors due to differences in loss characteristics. The loss factor can be calculated as in Equation 3.2.

Equation 3.2 requires hourly load data for the duration of the study period, which may not be available. Another way to calculate the loss factor is by using the load factor. Loss factor is then calculated as in Equation 3.3.

DEMAND ADJUSTMENT FACTOR

To annualize demand losses, a demand adjustment factor can be calculated that accounts for variations in system monthly peaks. Evaluating multiple years of monthly peaks improves accuracy of the demand factor, but a single year is acceptable if that is what is readily available. The factor is calculated by determining the percent of annual peak for every month of the year. An average should be used if multiple years are utilized in the calculation. Each "percent of peak" value is squared, and the values are summed up to reflect a demand adjustment factor.

When peak demand for any given distribution system component is identified, an annual demand can be calculated by multiplying the demand adjustment factor by the demand loss calculated at peak.

Equation 3.1

$$LDF = \frac{kWh}{kW_{Pk}}\left(\frac{1}{T}\right)$$

Where:

- LDF = Load Factor
- kWh = Energy in kilowatt-hours for a given study period
- kW_{Pk} = Peak load that occurs within the study period
- T = Duration of study period, usually 8,760 hours (one year)

Equation 3.2

$$LSF = \frac{\sum_{n=1}^{T} kW(n)^2}{kW_{Pk}^2}\left(\frac{1}{T}\right)$$

Where:

- LSF = Loss Factor
- kW = Demand for each hour
- kW_{Pk} = Peak demand that occurred during the study period
- T = Duration of study period, usually 8,760 hours (one year)

Equation 3.3

$$LSF = (LDF^2 \times K) + (LDF \times [1 - K])$$

Where:

- LSF = Loss Factor
- LDF = Load Factor
- K = Ranges between 1 and 0.7 [1]
  For distribution transformers, $K = 0.85$ [2]
  For residential feeders, $K = 0.9$ [3]

Note that the Loss Factor and Load Factor are dimensionless.

(1) "Distribution Systems," ABB (formerly Westinghouse), 1964, page 128.

(2) M. Monasinghe and W. Scott, "Energy Efficiency: Optimization of Electric Power Distribution System Losses," Paper No. 6, World Bank Energy Department, Washington, D.C., July 1982.

(3) *Ibid.*

POWER FACTOR

Apparent power (kVA) consists of two components: real power (kW) and reactive power (kvar). In an AC circuit, this is calculated by the product of the rms voltage and rms current. Real power is the actual working power that is supplied to the load. Real power is also termed as actual power, true power, watt-full power, useful power, and active power.

Reactive power is the power that continuously bounces back and forth between source and load. Reactive power is needed by loads for magnetizing elements such as motor windings. Reactive power is also termed as use-less power and watt-less power. The phasor sum of real and reactive power gives the apparent power. The relationship of real, reactive, and apparent power can be shown in Figure 3.3.

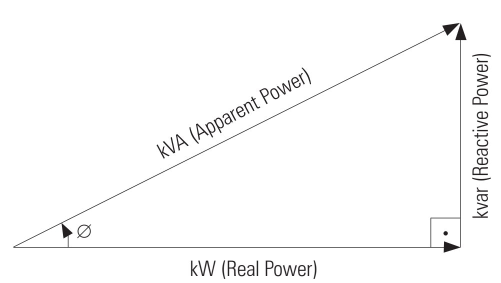

FIGURE 3.3: Power Triangle Diagram

In Figure 3.3, ∅ is the electrical angle (phase angle) between the current and the voltage. The power triangle gives the relationships found in Equations 3.4 through 3.6.

Equation 3.4

$$kVA = \sqrt{kW^2 + kvar^2}$$

Equation 3.5

$$Cos\ \varnothing = \frac{kW}{kVA}$$

Equation 3.6

$$Sin\ \varnothing = \frac{kvar}{kVA}$$

Power Factor—the ratio of the useful power in kilowatts to the apparent power in kVA or cosine of electrical angle (phase angle) ∅—is expressed by the formula in Equation 3.7.

Equation 3.7

$$Power\ Factor = Cos\ \varnothing = \frac{Real\ Power\ (kW)}{Apparent\ Power\ (kVA)} = \frac{kW}{\sqrt{kW^2 + kvar^2}}$$

Some end-use loads and the distribution system are inductive by nature, causing a lagging power factor and requiring the electric grid to supply reactive power to the distribution circuits. The addition of the reactive power (var) increases the total line current, which contributes to additional losses in the system.

The benefits for cooperatives in improving power factor by reducing reactive power include:

- **Loss Reduction**, resulting from lowering current flow and $I^2 \times R$ losses.
- **Capacity Release**, resulting from reduced reactive power flows. For example, a 12/16/20-MVA transformer loaded to 18.2 MW at a 90 percent power factor would be loaded above the top nameplate rating (18.2 MW ÷ 90% = 20.2 MVA). However, at an equivalent demand with a 95 percent power factor, it would be only 96 percent loaded (18.2 MW ÷ 95% = 19.2 MVA).
- **Voltage Improvement**, resulting from lowering current flow.
- **Cost Savings**, resulting from reduced energy purchases or generation due to fewer losses. The loss reduction results in economic savings based on the annual cost of losses.

As can be followed from these examples, low power factor reduces the capacity of the electric distribution by increasing the current flow, which causes energy losses to increase. The more reactive power that customers use, the more energy the system loses. Some utilities charge an additional fee to large commercial and industrial customers with a power factor less than 0.95 to compensate for energy losses and encourage these customers to take corrective action to improve their power factor.

A detailed discussion on power factor correction and its impact on distribution losses is included in the **Power Factor Correction** section of this report.

Calculating Losses by Distribution System Components

Total system losses can be calculated easily by **Equation 1.1**. However, this number alone does not provide actionable information to reduce losses. In order to address and reduce losses, knowledge of where losses are occurring on the electric system is needed. This can be achieved by categorizing losses into individual distribution system components. Typical categories include:

- Substation transformer losses,
- Distribution line losses,
- Capacitor and voltage regulator losses,
- Distribution transformer losses,
- Equipment and meter losses, and
- Secondary losses.

The breakdown of losses by component can differ from one co-op to another due to system characteristics. Figure 3.4 summarizes an EPRI study of 42 circuits that used detailed system models. In some cases, the system model extended to each customer meter. Losses were calculated using hourly resolution metered data.

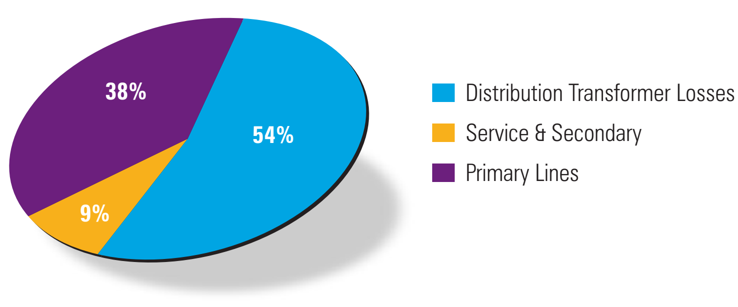

FIGURE 3.4: Breakdown of Distribution Losses

SUBSTATION TRANSFORMER LOSSES

Substation transformer losses can be determined by either metering or analytical calculations. Substation transformer losses are sometimes not considered part of distribution system losses, depending on location of ownership for the electric cooperative. If power delivery is received on the high side of the substation, substation transformer losses should be accounted for as part of the cooperative's system losses. To do this, there are three methods commonly used to determine the associated losses:

1. The difference between the coincident metered demand on the high side of the transformer and the low side of the transformer represents the losses. Sometimes, the metering on the low-side bus of the transformer is not in place.
2. If metering is not in place, then calculating losses based on measured peak load and transformer nameplate data is an option. See the example in Table 3.1.

TABLE 3.1: Example of Substation Transformer Loss Calculations

Transformer base rating (kVA)	10,000
Transformer percent impedance (%Z)	6.00%
Noncoincident peak load (kW)	5,000
Annual substation load factor (1)	56.60%
Transformer no-load losses (kW) (2)	25.58
Annual no-load demand losses (kW) (3)	306.96
Calculated transformer load losses (kW) (4)	70.36
Annual load demand losses (kW) (5)	158.15

(1) Annual Substation Load Factor can be calculated as shown in the load factor equation, **Equation 3.1**, if data is available. If measured demand and energy values are not available, then using system level load factor is a generally accepted practice.

(2) Transformer no-load losses from nameplate and/or test reports. Another option is to use a reference such as the *Westinghouse Transmission and Distribution Book,* which includes typical no-load losses for a range of transformer sizes.

(3) Transformer no-load losses times a factor of 12 to calculate annual no-load losses.

(4) Using peak load, voltage, and transformer impedance known, calculate load losses.

(5) Multiplying the demand adjustment factor, as discussed previously in this section, by the calculated transformer load losses derives the total annual demand losses.

3. A final option is to model substation transformers in engineering modeling software and calculate losses at peak load flow conditions, including no-load losses.

Additional information on the specific equations and formulas used to calculate substation transformer losses are included in **Appendix C**.

DISTRIBUTION LINE LOSSES

Computer simulation is the recommended method to calculate losses in primary lines. Conductor sizes and lengths can be obtained from system maps or field reconnaissance. Feeder peak load is typically provided by metering or SCADA.

There are two basic methods of allocating the feeder load to the feeder line sections: (1) by connected kVA, or (2) by customer-metered kilowatt-hours (energy delivered to the customer from metered data). Both methods have advantages and disadvantages.

Allocation by connected kVA requires knowing where the transformers are located on the system and the size of those transformers. This data can also be generally obtained from system maps or via field reconnaissance. The connected-kVA method assumes that transformers are loaded to the same level.

Allocation by customer-metered kilowatt-hour requires a data link between the utility's billing data and the location of the customer in the computer model, typically through the distribution transformer. The customer-metered kilowatt-hour method assumes customer monthly demand is proportional to monthly consumption and may not accurately represent peak conditions.

As data from advanced metering infrastructure (AMI) becomes integrated in the utility's infrastructure, the load data can be directly assigned to the computer simulation model. This way, errors due to load allocation can be eliminated in loss calculations.

For underground systems, dielectric losses occur, but are very small compared to $I^2 \times R$ losses and can be ignored for most loss calculations. This report uses this assumption and ignores dielectric losses.

An alternative method for calculating primary line losses is by analyzing representative circuits and determining the percent losses (peak and energy) for each circuit type. These circuits need to be chosen to include different voltage levels and customer type (i.e., primarily residential customers, commercial customers, industrial feeders, overhead, underground, and a combination of different feeder configurations, including urban and rural). Load placement should also be considered. If a feeder is chosen with the bulk of its distributed load near the front, it will illustrate different loss characteristics than one that has a fairly evenly distributed load or a heavy load at the end, such as a primarily residential feeder that supplies a strip mall at the end.

The greater the number of representative circuits per voltage and customer class, the greater the accuracy of the primary loss model. Losses can then be calculated for each circuit type by multiplying the percent peak and energy losses by the total peak and energy for that circuit type.

Additional information on the specific equations and formulas used to calculate primary distribution line losses are included in **Appendix C**.

CAPACITOR AND VOLTAGE REGULATOR LOSSES

Though capacitors can experience minor losses due to their dielectric properties, they are not considered loss-increasing equipment. On the contrary, they are used to improve power factor and line voltage, ultimately reducing losses. Capacitors, placed accurately on the electric system, can supply the reactive power (kvar) required by some customers. This lowers line and transformer currents, which reduces losses.

Voltage regulators both reduce and contribute to system losses. They reduce losses by improving and maintaining feeder voltage, which lowers line current and may lead to loss reduction. Voltage regulators also contribute to losses. The magnitude of the losses is based on regulator type and design. There are multiple types of voltage regulators:

- Substation Regulators
  - Regulators on the distribution bus serving multiple feeders
  - Regulators for each distribution feeder
- Line Regulators
  - Single-phase
  - Boosters

PREVIOUS VIEW

Although voltage regulator losses are generally not accounted for when assessing system losses by component, when feeders have multiple line regulators, the losses can be substantial enough to consider.

Substation regulator losses are computed in a similar fashion to substation transformer losses, as explained in **that section**. Line regulator losses can be computed in a similar fashion to that of distribution transformer losses, as explained in the next section.

Additional information on the specific equations and formulas used to calculate line equipment losses are included in **Appendix C**.

DISTRIBUTION TRANSFORMER LOSSES

In general, distribution transformers account for a large portion of total losses in an electric system. As it is for primary distribution losses, computer simulation is a good way to calculate distribution transformer losses. Utilities now are more frequently using detailed models that include distribution transformers. Setting transformer impedance and loss parameters in the modeling software, then running peak load flow analysis, will calculate peak demand losses.

Simulation-based analysis requires detailed distribution transformer load data. Utilities typically gather monthly peak data at the substation transformer level, but do not gather peak data at the distribution transformer level, except for some commercial and industrial loads that have energy and demand data available from metering. When this specific information on distribution transformers and a detailed engineering model are not available, a widely used approach for determining the peak and annual energy losses for distribution transformers is described below:

1. Calculate the total distribution peak load compared to total available distribution transformer kVA, by voltage class, to provide the ratio of peak load to connected load. This can be performed for each feeder as in the example presented below:
   a. Peak feeder load = 3,500 kVA
      Sum of distribution transformer name plate = 6,200 kVA
      Connected load ratio = 3,500/6,200 = 0.5645
   b. Total annual energy delivered by feeder = 15,000 MWh
      Load factor = 15,000,000/8,760/3,500 = 0.489 [See **Equation 3.1**.]
   c. Loss factor = $(0.4892^2 \times 0.85)$ + (0.489×0.15) = 0.277 [See **Equation 3.3**.]

2. A transformer database can provide the number of distribution transformers by voltage class. There also are numerous industry resources available with manufacturer test report data for each transformer size, by voltage level, that can be used to calculate peak load and no-load losses. If available, utility-specific manufacturer test report data would provide more precision in this estimating technique, especially where newer and more efficient transformers have been installed over the years. Many available resources include average impedance data for older transformer styles. See **Table 3.2** for a continuation of the example.

3. Use the calculated load factors and system loss factors from Step 1 to calculate annual energy losses. See **Table 3.3**.

Some co-ops use a transformer load management (TLM) system to keep track of transformer sizes and ages. Nameplate loss data typically is not retained for individual distribution transformers unless it was entered into a TLM. Loss data can be obtained on transformers of similar age for each size from either the manufacturer, from various published documents, or from test reports that have been retained by the utility. Transformers can be grouped by age and/or type if the utility has changed practices over time, such as switching to more efficient transformers or adding loss requirements in their transformer purchasing practices.

A significant challenge in calculating losses for distribution transformers is determining the system coincident peak load on the transformer. Three methods for determining loading can be used.

1. **A Detailed Computer Model.** A computer simulation model can assist in providing estimates, depending on how much detail was used in the development of the computer

TABLE 3.2: Example Transformer Data for a Feeder

Transformer Size (kVA)	Quantity	Total Connected kVA	Connected kVA Ratio[1]	Load Losses (kW)[2]	No-Load Losses (kW)[3]
15	40	600	0.565	0.179	0.076
25	76	1,900	0.565	0.295	0.109
50	28	1,400	0.565	0.505	0.166
75	20	1,500	0.565	0.663	0.274
100	8	800	0.565	0.881	0.319
TOTAL	172	6,200	—	—	—

[1] Connected kVA ratio = Feeder Peak Demand/Total Feeder Connected kVA
[2] Load Losses can be obtained from the transformer test reports
[3] No-Load Losses can be obtained from the transformer test reports

TABLE 3.3: Distribution Transformer Calculated Annual Energy Losses Example

Transformer Size (kVA)	Quantity	Total Connected kVA	Connected kVA Ratio	Load Losses (kW)	No-Load Losses (kW)	Loss Factor	Total Calculated Losses at Peak (kW)[1]	Total Annual Energy Losses (kWh)[2]
15	40	600	0.565	0.179	0.076	0.277	5	32,177
25	76	1,900	0.565	0.295	0.109	0.277	15	89,935
50	28	1,400	0.565	0.505	0.166	0.277	9	51,669
75	20	1,500	0.565	0.663	0.274	0.277	10	58,276
100	8	800	0.565	0.881	0.319	0.277	5	27,815
TOTAL	172	6,200	—	—	—	—	44	259,872

[1] Calculated Losses at Peak = (((Load Losses × (Transformer Size × Connected kVA ratio)^2) / (Transformer Size)^2) + No-Load Losses) × (Quantity)
[2] Annual Energy Losses (kWh) = [(((Load Losses × (Transformer Size × Connected kVA ratio)^2) / (Transformer Size)^2) × Loss Factor) + (No-Load Losses)] × (Quantity) × (8,760)

model. A detailed computer model may have each individual transformer modeled with the corresponding billing information. The computer model would then provide the peak losses—including for distribution transformers—by allocating the feeder load coincident with system peak, proportional to each customer's billing.

Detailed load data could be supplied by advanced metering infrastructure (AMI), indicating each customer's load at the time of the system peak to provide additional load information for use in load allocation.

2. **Feeder-Level Analysis.** The coincident peak transformer loading can be calculated by using the ratio of connected transformers to the coincident feeder peaks and applying the load ratio to the transformer loss data. The transformer groupings—by size, type, and age—would be summarized for each feeder in the utility.
3. **Data Sampling.** Sampling of transformer percent loading at system peak can be used in lieu of the detailed computer model and/or AMI data. Each type of transformer configuration or grouping should have sufficient sampling to provide meaningful results.

Additional information on the specific equations and formulas used to calculate distribution transformer losses are included in **Appendix C**.

SECONDARY LOSSES

Secondary lines and service drops to electric utility customers are not typically modeled in engineering analysis load-flow software. A small percentage of U.S. utilities have detailed models down to the consumer level, including secondary and service lines. Although these source-to-customer models could offer more precise calculations, there are alternatives.

A widely used approach leverages spreadsheet analysis where some known system information is included and a variety of different approximations are made. **Table 3.4** provides an example of a common approach used to estimate secondary and service drop losses. In some cases, customer class load factors are not readily available. In the example, system load factor is used to calculate annual energy losses.

Additional information on the specific equations and formulas used to calculate secondary losses are included in **Appendix C**.

EQUIPMENT AND METER LOSSES

Equipment losses that occur on the utility's side of the meter can be included in distribution losses. This equipment can be itemized separately for substation and distribution systems and includes equipment such as potential transformers, communication equipment, relays, surge arrestors, shunt reactors, rectifiers, meters, line regulators, network protectors, and capacitor equipment.

Losses for each equipment type can be calculated by using the nameplate data. Station service—the electricity required to operate the distribution substation—may or may not be included as part of system losses, depending on the rules that the co-op is following.

Revenue meters have two types of losses that should be accounted for: first, the losses due to inaccuracy, and second, the internal losses required for operations. Revenue metering inaccuracy is variable; it depends on the average percentage registration of the meter and on the energy throughput. The internal losses are fixed losses and vary depending on the type of meter, i.e., electromechanical or electronic.

Additional information on the specific equations and formulas used to calculate metering losses are included in **Appendix C**.

TABLE 3.4: Example of Secondary/Service Drop Loss Calculations													
Customer Class	**# of Customers**	**Total Transformer kVA**	**Annual Energy Usage (kWh)**	**Annual System Load Factor**	**Calculated Peak Demand (kW)**	**Average Length per Service (ft)**	**Type of Secondary/ Service Drop**	**Ohms Per Foot**	**Service Voltage (kV)**	**Average Peak Demand Per Customer (kW)**	**Average Annual Demand Loss Per Service (Watts)**	**Annual Demand Loss (kW)**	**Annual Energy Losses (kWh)**
Residential	22,276	78,437	154,736,000	74.07%	23,848	100	#2 TPX	0.000266	0.240	1.07	61.33	1,366.10	643,497
Commercial	4,673	40,077	79,085,000	74.07%	12,188	100	#1/0 TPX	0.000167	0.480	2.61	57.28	267.66	126,080
Large Power	561	75,440	148,850,000	74.07%	22,940	100	#1/0 TPX	0.000167	0.480	40.89	14,078.60	7,898.09	3,720,386
Primary Service	32	45,177	89,124,000	74.07%	13,736	—	—	—	—	—	—	0	0
Security Lights	4,827	2,586	5,096,000	74.07%	785	200	#2 TPX	0.000266	0.120	0.16	11.33	54.70	25,768
TOTAL	32,369	241,716	476,891,000		73,497							9,586.55	4,515,730

Notes:

1. Text in blue is input from utility records and manufacturer specifications (in the case of conductor resistance values).
2. Calculated Peak Demand is calculated from annual system load factor (column 5), annual energy usage per customer class (column 4), and 8,760 hours (one year).
3. Average Peak Demand Per Customer is calculated from the calculated peak demand (column 6) and number of customers (column 2).
4. Average Annual Demand Loss Per Service is calculated from the average peak demand per customer (column 11), the demand factor ($\sum$((Monthly Peak)/(Annual System Peak))^2), service voltage (column 10), ohms per foot (column 9), and average length per service (column 7).
   Use the formula: (((average peak demand per customer × demand factor)/service voltage)^2) × (ohms per foot × average length per service).
5. Annual Demand Loss is calculated from the average annual demand loss per service (column 12) and the number of customers (column 2).
   Use the formula: (average annual demand loss per service × # of customers).
6. Annual Energy Losses are calculated from annual demand loss (column 13). Use the formula: (annual demand loss/demand factor) × 8,760 × ((0.16 × load factor) + (0.84 × (load factor^2))).

PREVIOUS VIEW

4 Loss-Reduction Techniques

In This Section:

- **Operational Approaches**
- **New Programs and Asset Improvements**

In this section, loss-reduction techniques (listed in **Table 4.1**) will be described. The techniques are grouped in two categories: operational approaches and new programs and asset improvements.

Operational Approaches

LOAD BALANCING AND MULTIPHASING

Phase balancing is balancing phase currents along three-phase circuits, which is one of the most cost-effective improvements that can be made to reduce losses in a distribution system. According to the industry research,[2] reducing phase imbalance from 25 percent to below 10 percent can reduce primary line losses by 10 to 15 percent.

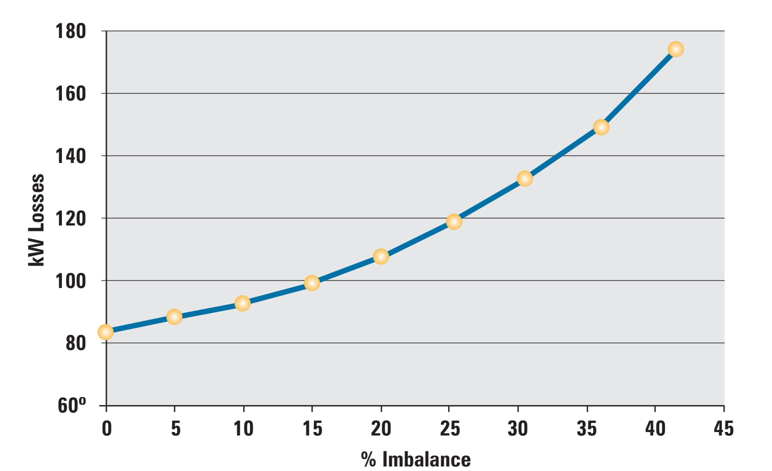

FIGURE 4.1: Impact of Phase Imbalance on Losses

Figure 4.1 shows the results of a power-flow analysis on a typical distribution feeder. Loads were allocated as balanced and then reallocated as unbalanced in five-percent increments, and line losses were determined. As shown, the percentage of line losses increases as the percentage of phase imbalance increases.

Phase balancing reduces average losses in phase conductors by balancing the loads (amperage) among phases. Due to the exponential loss of $I^2 \times R$, the sum of losses in the three balanced phases will always be less than any combination of unbalanced loading scenarios. A balanced system avoids zero-sequence currents, eliminating the neutral losses.

Balancing phase loads at the substation does not guarantee the phase balance along the feeder path due to the single-phase nature of many feeder taps. Therefore, evaluating phase load balance at multiple points along the feeder is a recommended practice. Also, studying different loading conditions is important as phase

[2] Northwest Energy Efficiency Alliance and SAIC, Inc., "Distribution Efficiency Initiative," December 2007.

TABLE 4.1: Loss-Reduction Techniques		
#	Loss-Reduction Technique	Description
OPERATIONAL APPROACHES		
1	Loads Balancing and Multiphasing	Balancing phase currents along three-phase circuits can reduce line losses.
2	Distribution Feeder Reconfiguration	Balancing loads among adjacent feeders using distribution feeder reconfiguration can reduce line losses.
3	Condition-Based Maintenance	Condition-based maintenance of distribution equipment can make them more efficient and potentially decrease losses.
4	Closed-Loop Operation of Distribution Feeders	Proper looped operation of feeders might reduce line losses as it divides system load between looped feeders.
NEW PROGRAMS AND ASSET IMPROVEMENTS		
5	Voltage Optimization	Optimizing voltage on distribution systems reduces the system demand and can reduce line losses, dependent on the load type.
6	Power Factor Correction	Improving the power factor of the system by installing fixed/switched capacitor banks can reduce line losses.
7	Increasing Primary Conductor Size	Increasing the feeder primary conductor size reduces losses due to the reduced conductor resistance.
8	Adding a (Parallel) Feeder	Adding an additional parallel feeder to the existing feeder can reduce the net line losses of the system.
9	Upsizing Conductors or Reconfiguring Secondary Networks	Upsizing secondary conductors and/or reconfiguring localized secondary networks can reduce secondary losses.
10	Changing Out a Distribution Transformer	Changing out the distribution transformers that are under/over loaded can reduce distribution transformer losses.
11	Using Amorphous Core Transformers	Amorphous core transformers have higher efficiencies and very low no-load losses, up to 60–70 percent less than conventional transformers. Replacing conventional transformers with amorphous core transformers decreases transformer losses.
12	Voltage Conversion	Upgrading the voltage class of the distribution system decreases the line currents carried by the feeder circuits for the same amount of feeder load and, thus, reduces line losses.
13	Updating Substation Auxiliary Equipment	Upgrading to efficient substation auxiliary equipment can reduce losses.
14	Adding Substation Transformers	Adding an additional substation transformer to balance the load between transformers decreases transformer losses.
15	Upgrading Metering Technology	Upgrading to efficient electronic metering technologies can reduce losses.
16	Updating Street Lighting Technology	Upgrading street lighting to advanced technologies—such as high-intensity discharge (HID) or light-emitting diodes (LED)—can reduce the load and, thus, decrease losses.

balance varies according to varying loading scenarios.

Distribution analysis software may be used to aid in identifying corrective actions for phase unbalances, such as moving loads from one phase to another. Co-op engineers may run simulations for different scenarios to assess the loss reduction achieved by such actions.

Recommendations from computer simulations are typically filtered by field personnel before they are implemented.

DISTRIBUTION FEEDER RECONFIGURATION

Distribution feeder reconfiguration is altering the distribution circuit configuration by changing the open/closed states of the sectionalizing and tie-switches. Altering circuit configurations from time to time, based on system conditions, can help to maintain balanced loading among feeders and can greatly improve the operating conditions of the system.

The distribution feeder reconfiguration transfers loads from heavily loaded feeders to (relatively) less loaded feeders. This action can reduce line losses and also improve the voltage profile of the reconfigured system. It is recommended that, before performing any load transfer, computer simulations are run to assess the loss reduction achievable.

Transferring load between feeders may be as simple as operating or installing manual or motor-operated switches. Often, more extensive construction may be required, such as multi-phasing a single-phase tie or building new three-phase sections of a tie line, adding significant cost and complexity. This technique should particularly be considered by co-ops that already have distribution automation (automated switches) in place.

CONDITION-BASED MAINTENANCE (CBM)

Condition-based maintenance (CBM) is the process of maintaining system components based on the condition of system equipment. CBM is a recommended practice that provides improved reliability and efficiency benefits by reducing equipment failures and extending the lifetime of system components.

Traditionally, utilities maintain system components according to time-based maintenance schedules. Modern measuring techniques provide opportunities for power distribution networks to implement real-time online monitoring. The key equipment in distribution networks—i.e., substation transformers, circuit breakers, capacitor banks, voltage regulators, and power cable—may be monitored by embedded sensors. The resulting data can be utilized to diagnose the condition of equipment and reduce excess losses resulting from its improper operation.

CLOSED-LOOP OPERATION OF DISTRIBUTION FEEDERS

The majority of distribution feeders are operated in open loop (radial) with a normally open switch between feeders. In general, radial system operation is preferred due to its simplicity; power flow can be kept under control easily by utility personnel. However, in radial operation, line losses are not always optimized because it is hard to ensure that distribution feeders are loaded evenly.

Closed-looped operation is the process of connecting multiple feeders without any normally open switches between them. The major advantage of this configuration is increased reliability. Looped feeders are common in urban areas, particularly commercial and business districts where reliability is critical, such as downtown Manhattan, New York. In general, loop-feeder operation decreases line losses, improves voltage profiles, and relieves congested feeder segments. According to a technical paper,[3] it is also possible that loop operation may increase line losses under specific power flow conditions.

Although looped-feeder configuration provides operational benefits, it is usually not desired due to the following challenges that it introduces:

- Complex protection and coordination design,
- Expensive protection and feeder construction,
- Complex fault location, and
- Complex voltage control.

[3] Saradarzadeh, M., et al. “The Benefits of Looping a Radial Distribution System with a Power Flow Controller.” *2010 IEEE International Conference on Power and Energy (PECon)*. IEEE, 2010.

New Programs and Asset Improvements

VOLTAGE OPTIMIZATION

Voltage optimization is sometimes an effective loss-reduction technique that can be implemented in either simple or sophisticated forms. Optimizing the voltage profile on the distribution system can generate energy-efficiency benefits by reducing the demand and usage as well as reducing line losses.

Conservation Voltage Reduction (CVR) is the concept that, by making a reduction in distribution system primary voltage, a corresponding reduction in demand and energy will occur that may also reduce the line losses. The amount of energy reduction will vary depending on end-use load type. The change is measured using a CVR factor (CVRf) which is defined as the ratio of percent change in energy over percent change in voltage ($\%\Delta E/\%\Delta V$), and can range from zero to a theoretical maximum of 2.

On a 120-Volt base, ANSI C84.1-2011 allows a secondary delivery voltage range between 114 and 126 Volts for secondary metered customers, and a distribution primary voltage range between 117 and 126 Volts for primary metered customers. The goal is to operate the distribution system in the lower portion of these acceptable ranges without providing voltage lower than the applicable limit for each customer's meter.

Historically, many utilities operated in the higher voltage range in order to prevent low voltage to customers when under peak loading conditions. However, utilities can use a moderately low voltage set point and utilize line drop compensation to raise the voltage only under times of higher loading. The concept of operating at a lower annual average voltage profile is illustrated in Figure 4.2, whereby just lowering the voltage settings and applying line drop compensation can reduce voltage levels.

Voltage Optimization (VO) is the concept of tuning the circuit to achieve a flattened voltage profile before implementing CVR in order to produce greater savings than CVR alone. Voltage profile of a typical feeder with VO is shown in **Figure 4.3**. System improvements are made—such as balancing the load between phases, power factor correction, and reconductoring undersized wire—in an effort to reduce the difference in voltage drop between phases of the same line section, as well as reduce the overall voltage drop on the feeder. This optimization allows a greater reduction in voltage than CVR alone, due to the flattened profile, allowing more clearance to the bottom of the ANSI voltage range.

Electric load can be characterized from three load types: constant current (I), constant power (PQ), and constant impedance (Z). System losses for constant current load are not impacted by voltage, system losses for constant power loads will increase as the voltage decreases, and system losses for constant impedance loads will decrease as the voltage decreases. Many electric loads can be characterized by a combination of three load types, referred to as *ZIP* or *IPQZ* load models.

The process of modeling loss reduction due to voltage optimization is complex. It requires the knowledge of end-use load types (electric

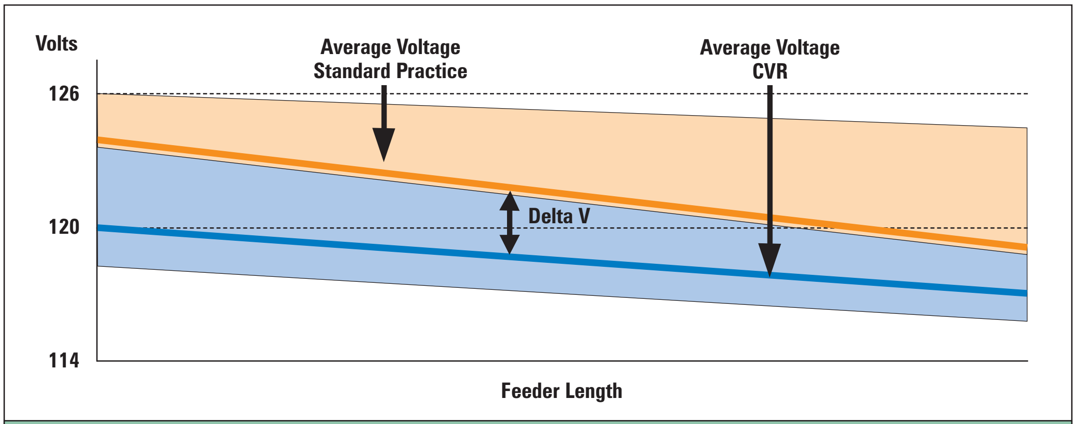

FIGURE 4.2: Feeder Voltage Profile with CVR

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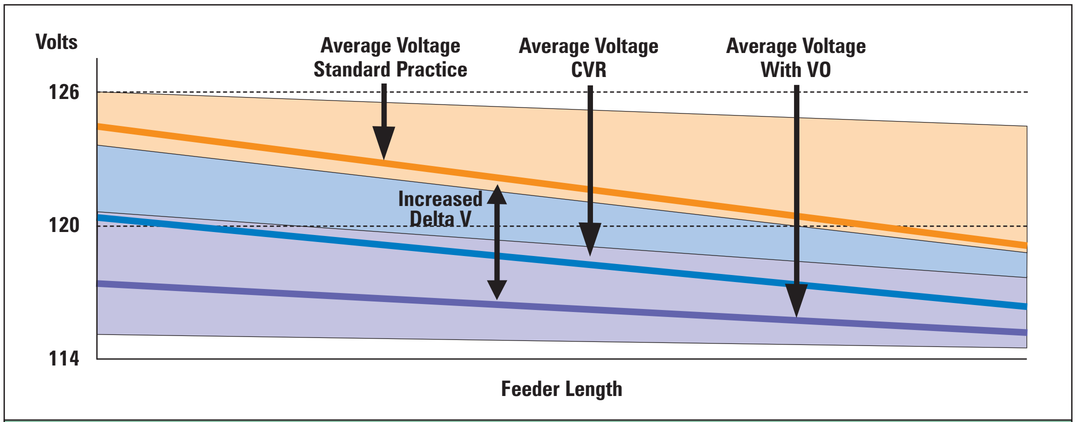

FIGURE 4.3: Feeder Voltage Profile with VO

space or hot water heating, gas space or hot water heating, heat pump, or air conditioning), their ZIP coefficients, and the voltage reduction. End-use load is the best predictor of CVR factors, as determined from the NEEA Distribution Efficiency Initiative study completed in 2007. The electric heating loads (shown as blue bars in Figure 4.4) have the lowest CVR factors, where the non-electric loads (shown in purple bars in Figure 4.4) have higher CVR factors.

An example of the possible benefits from voltage optimization can be seen in a study performed by Leidos. Bonneville Power Administration (BPA) developed the Energy Smart Utility Efficiency (ESUE) Voltage Optimization (VO) program. This program incentivizes utilities to improve the efficiency of the distribution system in order to help utilities meet regional goals established by the Northwest Power and Conservation Council's (NWPCC) Sixth Northwest Power Plan. The NWPCC goals for energy efficiency included potential distribution efficiency savings based on the Northwest Energy Efficiency Alliance's (NEEA) Distribution Efficiency Initiative research project completed by Leidos in 2007.[4]

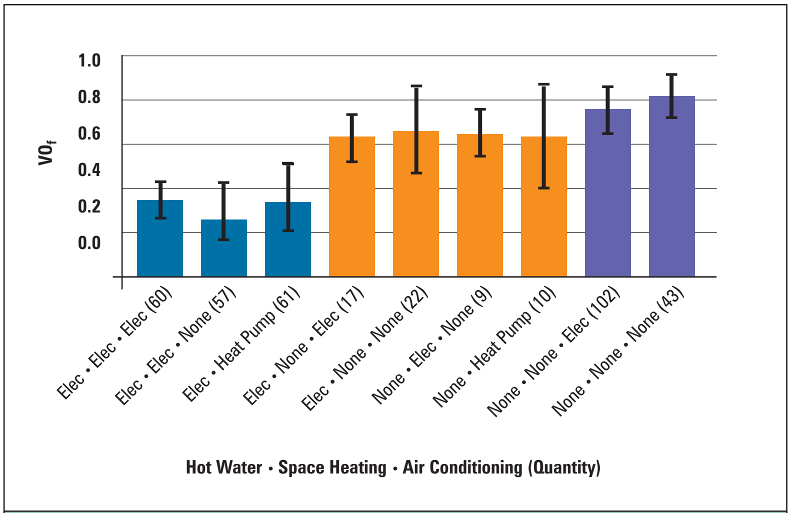

FIGURE 4.4: Energy Reduction Response to Applied Voltage (%ΔE/%ΔV p.u.)

Leidos has performed ESUE studies for seven utilities that included 21 substations and 70 distribution feeders. The results of the ESUE studies show that the majority of substations and associated feeders analyzed could be made more efficient by implementing cost-effective system improvements and operating the voltage level in the lower acceptable voltage range. In most cases, more than just adjusting voltage bandwidth was required to achieve energy savings.

Total energy savings were estimated at 1.3 percent and 19,837 MWh/year, where 11.3 percent of the savings were from system loss reductions and 88.7 percent from end-use customer load. The total benefit-to-cost ratio for the project was 1.10. This assumes there is a benefit for the reduction of customer load and does not consider the reduction in revenue based on the ESUE program policy.

[4] Northwest Energy Efficiency Alliance and SAIC, Inc., *Op. cit.*

Additional analysis was performed that excluded some of the worst-performing feeders/substations that had individual benefit-to-cost ratios less than 1.0. Total energy savings were estimated at 1.21 percent and 14,534 MWh/year, where 5.2 percent of the savings were from system loss reductions and 94.8 percent from end-use customer load. The total benefit-to-cost ratio for the subset of projects was 4.32.

POWER FACTOR CORRECTION

Power factor correction by capacitor placement is a beneficial loss-reduction technique for many co-ops. Certain customer inductive loads, distribution lines, and transformers require reactive power to be supplied by the electric grid. This addition of reactive power (var) increases total line current, which contributes to additional losses in the system.

Power factor is expressed as in Equation 4.1.

Equation 4.1

$$\text{Power Factor} = \cos\varphi = \frac{P_{real}}{\sqrt{3} \times V_L \times I_L}$$

Where:

V_L = Line voltage (phase-phase)
I_L = Line current
$\cos\varphi$ = Power Factor

From Equation 4.1, it is evident that, as the power factor decreases, current increases, while real power and voltage remain constant.

Figure 4.5 shows the increase in current and losses that occurs as power factor decreases, based on Equation 4.1. For example, a decrease in power factor from 100 percent to 90 percent causes the distribution line current to increase by approximately 11 percent, which causes line losses to go up by approximately 23.5 percent. Improving the power factor decreases the line current, which decreases distribution losses.

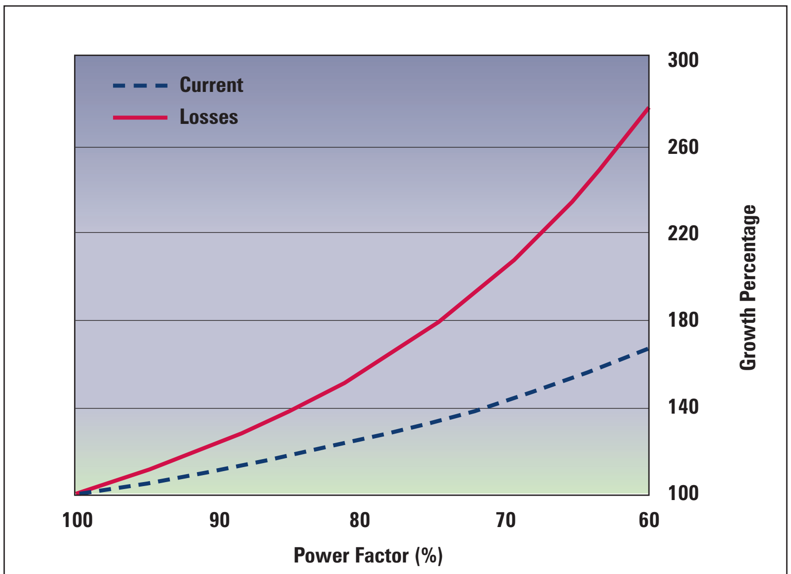

FIGURE 4.5: Current and Losses Versus Power Factor

Some utilities require that large customers maintain a minimum power factor. This may be applied as a condition of service or, in some cases, there may be a penalty for not complying with power factor requirements. For these customers, the power-factor correction (for example, installing capacitors) is commonly performed on the customer's side of the meter. Corrections made on the customer's side of the meter have the additional benefit to the utility of reducing system losses in the distribution transformer.

According to an article,[5] there is a common practice called the "two-thirds rule," or some variant, for distribution capacitor placement. It suggests installing a capacitor with var capacity equal to two-thirds of the total feeder peak inductive var at a distance of two-thirds of the overall feeder length from the substation. This rule is applicable for a feeder with constant load that is uniformly distributed along the feeder.

Reactive power also varies by time, similar to real power. Using fixed capacitors alone on a feeder may over-compensate reactive power during light feeder loading conditions and under-compensate during peak loading conditions. This can cause an increase in line current and, hence, increase the losses and degrade the voltage profile along the feeder.

This problem can be solved by using switched capacitor banks, along with fixed capacitors, to better track reactive power demand. This combination proves to be effective

[5] Steve Eckles, *Utility Automation & Engineering T&D,* April, 2007.

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in reducing losses. Fixed capacitor banks are commonly sized to average annual minimum var requirements; the switched capacitor banks are sized to meet the difference between total peak feeder var requirements and minimum var requirements.

Most distribution analysis software can perform power factor analysis to determine the var requirements of a system and the optimal size/location of fixed and switched capacitor banks. The co-op's planning engineer should perform this analysis at various loading levels and conditions for optimized results.

INCREASING PRIMARY CONDUCTOR SIZE

Increasing the primary conductor size of a distribution circuit will reduce line losses because, when the area of a conductor is increased, resistance of the conductor is reduced. Upgrading the conductor size has advantages beyond line loss savings. Larger size conductors have higher thermal capacity, which can provide the capability to serve more customers. Also, due to reduced resistance, there will be less voltage drop in the system.

Although the benefit of loss reduction alone may not be sufficient to justify reconductoring

Example

POWER FACTOR CORRECTION AT THE DISTRIBUTION TRANSFORMER SECONDARY

Adams-Columbia Electric Cooperative (ACEC) is a rural electric distribution cooperative serving approximately 36,000 member/owners in parts of 12 Central Wisconsin counties from 29 distribution substations. As part of a pilot project, ACEC has deployed Varentec's distributed volt/var regulation units.

ACEC was highly interested in expanding demand management on its distribution grid. Energy conservation is a very high priority for ACEC and peak demand charges are an operational cost that the co-op believes can be reduced using volt/var Control technology. ACEC is in the process of testing conventional volt/var control using LTCs, regulators, and cap banks. In addition, ACEC also became interested in the Varentec ENGO solution due to the potential to address the secondary side of the equation.

Varentec's ENGO volt/var regulator units are low-voltage (240-V) cap banks that can easily be connected in 15 minutes to distribution transformer secondaries and inject reactive power dynamically based on local voltage measurements. ENGO provides secure, cloud-based software to view the data coming off the ENGO units and to configure a set point on a single screen, which requires no training by the user.

Adams-Columbia is expecting a four percent peak demand reduction (reducing peak events by four percent using volt/var control). As the co-op has a $15/kW per month peak demand charge, on a 1-MW circuit, the co-op calculated that the demand reduction can save more than $7,000 per year. Applying the technology to 50 feeders, the cost savings may exceed $250,000 per year. Additional benefits include line loss reductions, improved power factor, improved voltage compliance to the end customer, and greater visibility to voltage across a network.

The pilot program was a great learning experience for both ACEC and Varentec. The two groups collaborated on reviewing the feeder model in Milsoft, for identification of optimal placement of the ENGO units. The original installation process went quickly; the entire feeder was completed in a few weeks. However, one challenge facing the project was establishing communications with all ENGO units in a rural environment, which required a reconfiguration of the communications of some units.

The ability of ENGO units to perform secondary-side volt/var regulation was demonstrated, and field data continues to be assessed. In the near future, the Peak Demand Reduction technique will be implemented and measured to determine the amount of energy reduction achieved.

existing distribution circuits to a larger conductor size, this improvement option may be more desirable when combined with other benefits. An economic analysis—in which the annual savings in losses are balanced against the fixed charges of the cost of construction—will help determine the economical conductor size for new construction and for replacing conductors on an existing distribution circuit.

An IEEE paper[6] indicates that the selection of conductors for upgrading a distribution system is a complex process. Several factors—such as conductor cost, energy lost cost, and voltage regulation—are considered in the conductor-size decision process.

ADDING A (PARALLEL) FEEDER

Adding feeders is a cost-intensive technique for reducing line losses. Power loss is expressed as $I^2 \times R$, which reveals that a reduction in peak current (or load) results in reducing peak demand losses proportional to the square of the reduced load. Thus, total losses can be reduced by splitting the load carried out by a single feeder to two feeders. Additional reduction in net loading losses may be realized in substation transformers if the new feeder is served from a different transformer.

It is typically cost-prohibitive to add feeders for line loss reduction alone. Many other factors need to be considered when justifying additional distribution feeders, including cost analysis, reliability issues, growth estimates, and load diversity. Co-op engineers can make use of distribution analysis software to precisely assess the loss reduction achieved by adding proposed additional feeders. Economic analysis and cost-benefit tools should be utilized to assess the economic viability of this kind of infrastructure-related projects.

UPSIZING CONDUCTORS AND/OR RECONFIGURING SECONDARY NETWORKS

Upsizing secondary conductors or reconfiguring localized secondary networks can reduce secondary losses. This can also improve service quality to customers by reducing the impact of voltage flicker.

Upgrading or reconfiguring a localized secondary system may include distribution transformer additions, primary line extensions, installation of additional secondary runs, and upgrades of secondary conductor sizes.

Although upgrading the overhead secondary system is straightforward, upgrading the underground secondary system may be challenging and impractical because of direct buried cable or because the conduit size limits the size of secondary wire.

CHANGING OUT A DISTRIBUTION TRANSFORMER

In general, transformers have two loss components: fixed losses (no-load losses) and variable losses (load losses). Load losses vary with the load and are expressed as $P_{loss} = I^2 \times R$. Fixed losses are constant, determined by core material and design.

Transformer change-out projects require comprehensive cost-benefit studies that apply detailed knowledge of transformer loading, the benefits in reducing losses, and the cost to replace the transformer. The type of equipment is also typically considered, such as overhead versus pad-mounted transformers. Peak, average, and minimum loading on the transformers each play a role in determining whether a transformer change-out is practical.

According to a technical paper,[7] the economic loading of distribution transformers is typically between 80 and 100 percent of nameplate rating for the initial peak loading (sometimes called first-year peak loading). Transformer loading at or around lower peak values (e.g., 80 percent) is appropriate for places where a higher rate of growth is expected. Areas that have relatively low growth rates may target higher loading for the initial peak.

Due to power characteristics, transformers operate efficiently at or around full load capacity. Over-loaded transformers above nominal

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6 Mandal, S., A. Pahwa, "Optimal Selection of Conductors for Distribution Feeders," *IEEE Transactions on Power Systems,* Vol. 17, No. 1, pp. 192–197, February 2002. DOI: 10.1109/59.982213.

7 Spangler, Allen R., "The Economical Loading of Distribution Transformers," *IEEE Transactions on Industry Applications,* Vol. IA-13, No. 2, pp.120–124, March 1977. DOI: 10.1109/TIA.1977.4503374.

capacity tend to operate inefficiently due to excess copper losses. Transformers that are lightly loaded operate inefficiently because of the no-load losses. It is a good practice to remove or de-energize transformers that no longer have load on them to reduce unnecessary no-load core losses.

The initial sizing of distribution transformers is very critical in keeping distribution transformer losses at reasonable rates. However, this is a complex problem because the electrical infrastructure is typically installed before customer facilities are constructed. Co-ops need to have a good understanding of end-user loads, load profiles, and load growth patterns to properly size distribution transformers.

Using higher efficiency, amorphous-core transformers for new transformer installations or transformer change-out projects may be economically viable when including the cost of loss savings. Fixed losses depend on the transformer core design and steel lamination molecular structure. Core losses have been shown to be reduced with improved manufacturing of steel cores and the introduction of amorphous metals (such as metallic glass).

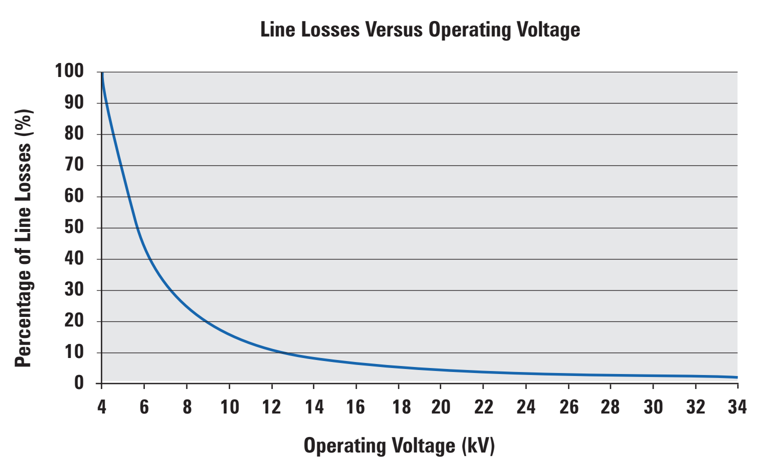

FIGURE 4.6: Decreasing Line Losses as Primary Operating Voltage Increases

USING AMORPHOUS CORE TRANSFORMERS

An amorphous core transformer (AMT) uses amorphous metal alloy strips for its magnetic circuit. This allows building transformers with very low no-load losses (up to 70 percent less than conventional types). Because of the flexible structure of the core, the capacity of amorphous core transformers is currently limited to 10 MVA. Amorphous core transformers are five to 20 percent heavier than conventional transformers of the same capacity.

According to a white paper,[8] distribution transformers are considered to be efficient (90 to 99 percent efficient) compared to other electrical equipment of the distribution system. However, considering that they work in continuous operation and have a long life span—typically 30 to 40 years—a small efficiency increase can add up to significant energy savings over the lifetime of a transformer.

VOLTAGE CONVERSION

Apparent power (VA) is expressed as $VA = V \times I$, where V is voltage and I is current. For a given amount of apparent power, doubling the voltage would reduce the current by half. Line losses can be reduced by reducing current, as evident by the resistive power loss equation $P_{loss} = I^2 \times R$, which indicates that the losses will be reduced quadratically by reducing the current. Therefore, line losses can be effectively reduced through current reduction by increasing the operating voltage of the feeder.

Thus, doubling the voltage reduces the line loss to 25 percent that of the original voltage using the same feeder conductor and length. This relationship of line losses to the feeder operating voltage is depicted in Figure 4.6. For a fixed feeder with the same feeder conductor, the line losses are reduced by 89 percent when the distribution voltage class is upgraded from 4.2 kV to 12.47 kV.

The rated feeder capacity also doubles when doubling the feeder primary voltage. Increasing the voltage class of the feeder results in im-

[8] Ferreira, Sergio, "Energy Efficient Distribution Transformers," Leonardo Energy, May 19, 2009.

proved voltage regulation and enables serving more customers on long feeders with less line losses and percentage voltage drop.

However, upgrading the primary voltage of the distribution feeder involves upgrading the voltage class of distribution equipment along the feeder, which can be costly. Many co-ops have portions of older 4.16-kV distribution systems in their service territories. Upgrading these feeders to higher voltage is an expensive task, which is often not economically viable based on only loss-reduction savings.

If these feeders are in a high load growth area or the existing feeders are aged and in bad condition, then new feeder investments are generally considered. In these cases, it is recommended to consider conversion to a higher voltage class and run a cost-benefit analysis to determine the cost-effectiveness of voltage conversion.

UPDATING SUBSTATION AUXILIARY EQUIPMENT

Many approaches exist to reduce energy consumption in substation installations, including making efficiency improvements in control rooms and buildings and using higher-efficiency electrical auxiliary equipment, such as transformer fans, pumps, light and power transformers, heaters, and so on. Examples of non-electrical efficiency measures include improving insulation and weatherization of substation control buildings and installing higher-efficiency HVAC systems to keep equipment at normal temperatures.

ADDING SUBSTATION TRANSFORMERS

Adding new substation transformers to balance the load between the transformers at existing substations or at a new substation location is another way of mitigating losses. Similar to distribution transformer change-out projects, they require comprehensive cost-benefit studies that apply detailed knowledge of transformer and feeder loading, the benefits in reducing losses, and the cost to add the transformer and associated equipment. Both load and no-load losses must be considered—as well as feeder loads and losses—if a new substation location is contemplated.

This method is considered to be expensive due to the high upfront capital cost of a substation transformer. In general, adding a substation transformer for the sole reason of reducing

Example

JUSTIFYING A NEW SUBSTATION PROJECT WITH THE HELP OF LOSS REDUCTION

The San Isabel Electric Association (SIEA), headquartered in Pueblo West, Colorado, is one of 22 electric cooperatives in the state of Colorado. SIEA was facing excessive loading of feeders and reliability issues in its heavily loaded suburban service area. There were three existing substations about 10 miles apart that fed this area. Due to excessive loading and long feeder lines, SIEA experienced heavy line losses in this area.

SIEA personnel planned for a new substation right in the middle of the suburban Pueblo West service area that would help solve the problems. But co-op personnel were having difficulty obtaining approvals for the build out.

To support their case, SIEA engineers decided to simulate the distribution system losses before and after the substation addition and conduct a cost-benefit analysis with these results. At the end of this study, they found that line losses in this area were reduced by 50 percent with the new installations.

These results were as expected due to the reduced feeder load and reduced circuit miles per feeder for the existing peripheral substations. As an added benefit, the new substation would also improve the service reliability of the area.

The cost-benefit analysis revealed that the new substation would pay for itself within 10 years by line loss savings alone. This exercise of cost-benefit analysis helped co-op personnel to obtain the required approvals easily and the planned construction has started.

losses might not be economically viable. Other factors—such as existing substation and feeder capacity limits, load growth, and voltage improvements—may make adding substation transformers a viable option.

Some co-ops perform a transformer economic evaluation when considering purchases of new transformers. Economic evaluations take into account the initial capital costs as well as the operating costs for the equipment, including load and no-load losses. With the additional transformers, operating costs will go up, as O&M costs are directly proportional to the number of transformer units. Several transformers from different manufacturers are typically compared to determine the optimal transformer choice by evaluating life-cycle costs.

UPDATING METERING TECHNOLOGY

New electronic metering requires about 25 percent of the power required by older electronic equipment and 15 percent of the power required by electromechanical equipment. With this potential for loss reduction, changing metering equipment may make sense to a utility, especially if it can be rolled into another program such as an advanced metering infrastructure (AMI) program or a demand-management program. Performing a cost-benefit analysis can help determine the cost-effectiveness of changing metering equipment.

UPDATING STREET LIGHTING TECHNOLOGY

Street lighting is an area where co-ops can take certain measures and reduce losses. Losses can be mitigated either by updating the existing street lighting technology or by modifying the co-op's lighting standards to require the use of more efficient lighting technologies in the installation of new street lights.

Street lighting in the United States evolved from oil and gas lamps in the 17th and 18th centuries to electric lamps in the late 19th century. Electric lamps have since progressed from incandescent to fluorescent and then to mercury vapor. Today, high-intensity discharge (HID) lamps dominate street lighting installations. Two HID lamp types predominate: high-pressure sodium (HPS), noted for its yellow/orange light, and metal halide (MH) that emits a bright, white light.

Replacing mercury vapor lamps in existing streetlights with HPS lamps will result in significant reduction in energy consumption for street-lighting load. HPS streetlights rated at 100 Watts are available that produce the same lumen output as 175-W mercury lamps. Similarly, new energy-efficient lighting—such as light-emitting diodes (LED)—can significantly reduce load and, thereby, reduce losses. According to university research,[9] it is estimated that LED-based street lighting can save about 70 percent in energy and maintenance costs compared to legacy lighting technologies.

Upgrading the voltage level or adopting a higher voltage level for new street lighting installations can also reduce losses in the street lighting infrastructure. There are many voltage options available in today's street lighting selections. Selecting a 240-V lamp over a 120-V lamp will cut secondary line losses by a factor of four.

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[9] *LED Street Light Research Project,* Remaking Cities Institute, Carnegie Mellon University, Pittsburgh, Pa., September 2011.

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5 Economic Evaluation of Losses

In This Section:

- **Identify General Financial Assumptions**
- **Parameterize Loss Improvement Investment Costs**
- **Develop Projected Loads and Baseline System Loss Percentages**
- **Estimate Loss Savings**
- **Estimate Avoided Costs of Investment**
- **Compute Net System Benefits and Benefit-Cost Ratios**
- **Sensitivity Analysis/Levers**
- **Cost-Benefit Tools**
- **Results Presentation**

Improvements that result in lower distribution line losses can be evaluated from an economic perspective that compares the cost of losses to the costs associated with equipment or system modifications intended to reduce losses. These evaluations are best done prior to project deployment in order to determine whether anticipated project savings (benefits) outpace project costs. Such economic evaluations are predicated on the comparison of all-in project costs with a valuation of the incremental amount of losses that will be avoided, the latter of which is valued based on the cost to otherwise incur such losses.

The process graphic in Figure 5.1 summarizes the key components of economic analysis.

Such evaluations can be done at a monthly or annual level of granularity. Annual or monthly analyses, in general, will provide a utility with enough information to determine whether loss percentage improvements are cost-effective. However, the discussions that follow can also be applied to hourly analysis based on the discretion of the utility and size and scope of the investment in question.

This section provides a chronological description of the steps involved in conducting economic evaluations. This discussion is followed

FIGURE 5.1: Summary of Economic Analysis Procedure

by a sensitivity analysis overview that may be valuable for understanding the overall economic picture. A brief overview of the cost-benefit model developed by Leidos is provided and is also discussed further in a stand-alone Excel section of this report.

Finally, some graphical examples of results and notes communicating the outcomes of an economic evaluation are provided. For a description of the technical calculations required to estimate peak demand and energy-related loss reductions, please refer to **Section 3** and **Appendix C** of this report

Identify General Financial Assumptions

Before engaging in an economic analysis, it is critical to identify certain key assumptions that underpin how costs will escalate into the future, and how the dollars estimated in a given future period are calculated in today's dollars. Furthermore, it is imperative to set a time horizon for the analysis that carefully balances utility priorities. The key elements of preliminary financial assumptions are:

1. The inflation rate,
2. The discount rate, and
3. The time horizon for the cost-benefit analysis.

Inflation is a measure of change in the price level for a representative set of goods and services, some of which are embedded in certain cost categories relevant to the costs and avoided costs (benefits) of a given project. Inflation is used to estimate the escalation of costs in the absence of a direct projection, as well as the cost of any ongoing administrative efforts associated with a project. There are several sources for inflationary assumptions, most notably the Consumer Price Index (CPI) as made available by the United States Bureau of Labor Statistics. In order to provide medium- to long-term inflation rates, the Blue Chip Economic Indicators report, which measures the consensus view among several prominent economic sources, can be used as a primary source. To the extent market conditions or inflation expectations change, adjustments to this value may be necessary over the course of a particular economic evaluation. When there is no other escalation rate provided for certain downstream inputs, inflation can be used as an escalation factor in the analysis.[10]

The discount rate is used to "discount" or convert future dollars to present day dollars as part of the calculation of the net present value ("NPV," see details below) of net system benefits, which is defined as the difference between a given project's total avoided costs (benefits) and the intrinsic cost of the project (i.e., the costs involved in either executing or administering the project or program). It is important to use a discount rate that is consistent with the utility's power supply planning assumptions for traditional supply-side power assets or other demand-side management programs in order to avoid "apples and oranges" comparisons.

Various sources exist for alternative discount rates. The discount rate assumption may warrant adjustment as market conditions change, most notably if interest rates fluctuate.[11]

The time horizon of the economic evaluation (or n = # of years) is typically chosen based on a given utility's tolerance for the payback period of a given investment, as well as their tolerance for recovery of investment costs over a longer time frame. In order for an investment to be economically sensible, it must return a positive NPV over a reasonable time horizon, wherein initial investment costs are gradually recovered in the form of savings/benefits.

The exact choice of the horizon for the analysis is somewhat subjective. However, in most cases, a line-loss savings project should be evaluated with a horizon that is in the same general range as the useful life of the project and/or the economic evaluation period for the marginal generating unit that would otherwise have to generate energy to meet losses that are not avoided if the project is not implemented. Tolerances for payback periods typically range from $n=5$ to $n=20$ years.

[10] For an alternative source for projected inflation, refer to **www.bls.gov/cpi/**.

[11] For potential discount rate assumptions, see **www.federalreserve.gov/releases/h15/data.htm**.

Parameterize Loss Improvement Investment Costs

Once the general financial assumptions are in place, it is important to understand and catalogue the anticipated costs of the investment. Project cost elements can be developed using detailed engineering information and other internal utility costs as summarized in a capital plan for distribution system planning.

Typically, utility capital plans contain raw equipment costs that can be used as a starting point for estimating overall investment costs. The development of a more detailed cost itemization can help to better communicate the overall cost-benefit picture for a given deployment. The main project cost categories are as follows.

- **Capital Outlay.** This includes the raw, fully burdened cost of equipment, as well as staffing and specialized labor or contractors.
- **Taxes.** Any taxes associated with procurement or ownership.
- **Insurance.** Any changes to insurance costs or policies associated with a significant equipment investment, if applicable.
- **Ongoing Operation and Maintenance (O&M) and Administrative and General (A&G) Costs.** This cost component is often ignored in cost-benefit analysis. For loss-reduction projects, ongoing O&M and A&G costs may be minimal, but should be included, if available. Allocation of additional O&M and A&G during the period of time that the project is being completed should be considered, if feasible, in terms of extracting such costs from a utility's overall budget.
- **Intraperiod Improvements.** To the extent that the project is complete and does not require any further intervention over the study period, then such intervention costs are zero and this category does not apply. However, to the extent that improvements or engineering quality-control related costs occur after the initial capital outlay, such costs should be included in the analysis.

Note that certain costs associated with other types of system improvements or incentive-based projects—such as marketing costs or participant discounts—will generally not apply to loss savings projects that are entirely a function of engineering investments in the distribution system.

Develop Projected Loads and Baseline System Loss Percentages

Generating a reliable energy and peak demand forecast over the study horizon is critical to understanding:

- How avoided *energy* losses will grow over time, which may bode well for a program that, through a reduction in loss percentage, helps avoid an increasing amount of energy to be otherwise served over time, and
- How avoided *peak demand* losses will grow over time, which may bode well for a program that improves peak demand losses and helps the utility save money on costly demand-related charges or capacity costs.

Load forecasts are typically available for most utilities as a matter of course in terms of resource planning. Statistically derived load forecasts that represent an industry-standard utility methodology are preferable.

In order to value the change in losses associated with the project, it is necessary to understand the baseline, or existing loss percentages. This can be done by analyzing the historical gross energy for load, or the total energy needed to meet load, inclusive of losses, and the associated total retail sales for that same historical period (which would be *net* of losses). The difference in these two values is equal to the historical loss percentage.

Historical data of this nature is generally readily available as part of a utility's internal database. Alternatively, such estimates can be determined at a much higher level, but the utility must recognize the error that will trickle through to the cost-benefit analysis if a good handle on baseline losses is not available.

Historical or "baseline" loss percentages can be computed as shown in Equation 5.1.

Equation 5.1

$$\begin{aligned}\textit{Baseline Loss Percentage} &\\ &= [\textit{Historical Net Energy for Load (Total Electrons)}\\ &- \textstyle\sum \textit{Historical Retail Sales}]\\ &\div \textit{Historical Net Energy for Load (Total Electrons)}\end{aligned}$$

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Estimate Loss Savings

Estimating the loss savings associated with a given project is predicated upon engineering estimates and is covered in in **Section 3** and **Appendix C** of this report. This section assumes that a reasonable baseline of historical losses is computed as shown in Equation 5.1, and that a reliable estimate of the loss percentage after the project is executed is available.

The formulas in Equations 5.2 and 5.3 can be used to compute estimated loss-related energy and peak demand savings associated with the project. (Note: Savings should increase over time, assuming a modest amount of long-term load growth.)

The calculations in Equations 5.2 and 5.3 capture the losses that are "saved" as a result of program implementation. They consider what losses would otherwise have been relative to retail sales, and then compute the difference between that total gross energy and the alternative amount of gross energy required to serve the same level of retail sales given an improved loss percentage. This differential approach underscores the importance of understanding baseline loss percentages, so the utility can assign a precise value to anticipated project savings.

Equation 5.2

$$\begin{aligned}&\textit{Loss-Related Energy Savings (MWh)}\\&\quad= [\textit{Projected Retail Sales (MWh)} \times (1 + \textit{Baseline Loss Percentage})]\\&\quad- [\textit{Projected Retail Sales (MWh)} \times (1 + \textit{Post-Project Loss Percentage})]\end{aligned}$$

Equation 5.3

$$\begin{aligned}&\textit{Loss-Related Peak Demand Savings (MW)}\\&\quad= [\textit{Projected Peak Demand (MW)} \times (1 + \textit{Baseline Loss Percentage})]\\&\quad- [\textit{Projected Peak Demand (MW)} \times (1 + \textit{Post-Project Loss Percentage})]\end{aligned}$$

Estimate Avoided Costs of Investment

The graphic in Figure 5.2 depicts the key components of the avoided costs (or benefits) associated with a given project.

The key components of the avoided costs (or benefits) of a given project that improves distribution line losses over a prespecified time horizon, some of which may not necessarily apply to every project, include:

- Avoided or Delayed Generation or Purchased Power Capacity Additions (demand savings);
- Avoided Costs of Energy Production;
- Avoided Transmission and Distribution costs (including avoided capital expenditures), and the associated avoided ongoing O&M costs; and
- The value of potential power market sales from resources that are free to serve the external market in place of the energy generation/losses that are avoided as a result of the program.

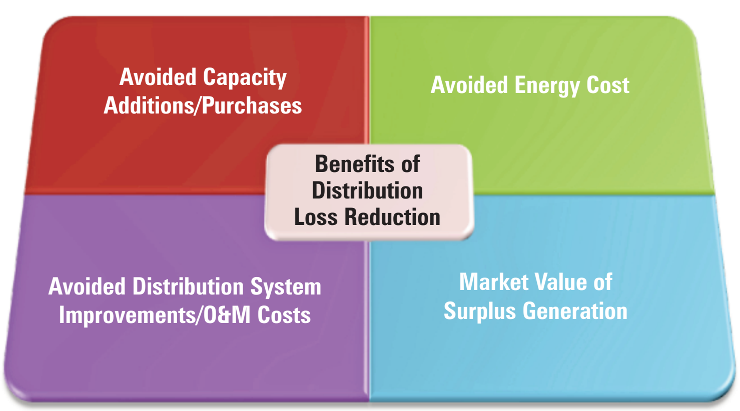

FIGURE 5.2: Summary of Basic Benefits of Distribution Loss Reduction

From an avoided-cost perspective, the bulk of benefits associated with the project will arise from avoided demand and energy costs. Avoided or delayed capacity additions may also be significant, depending on the utility.

In addition to deferred or avoided investment costs, capacity savings can also include a reduction in the cost of running high-cost peaking generation, which may be reflected in a demand tariff. Energy savings represent both immediate and ongoing cumulative benefits associated with the reduction in generation fuel and operating costs as well as losses.

Depending on the utility, there are typically two key marginal capacity and energy situations that are likely to be encountered, specifically:

1. The utility has avoided costly operation of existing peaking units, or
2. The utility buys marginal capacity and energy from the market or is a participating member of a G&T, whereby avoided costs can be mapped to an existing demand or energy rate.

In the former case, it is critical to identify the avoided marginal generating resource, either by selecting from a list of predefined generic marginal units (e.g., large natural gas combined-cycle unit, small gas peaking unit, etc.) with performance characteristics that are representative of the regional market, or to define the operating characteristics of a specific marginal unit (which could also represent a contract, tariff rate, or market purchase).

To capture avoided demand costs, it is necessary to collect information on marginal generating unit capital and fixed O&M costs to estimate potential capacity savings. Incremental capacity costs are then applied, if applicable, to the estimated loss savings at the time of the system peak to determine capacity benefits.

To develop projections of avoided and incurred marginal energy costs, the heat rates of the assumed marginal generating resources (generic or member-defined) are typically multiplied by a cooperative-defined forecast of fuel prices plus variable O&M and emission allowance costs (again, either pre-defined or co-op-defined) for the marginal unit to derive a total per-unit ($/MWh) marginal average energy cost for these resources. These average per-unit costs would then be multiplied by the projected avoided energy of the project (adjusted for marginal losses) to derive total energy costs.

In the absence of such detailed information, existing contracts, tariffs, etc., as entered into by a given co-op, can be reviewed to determine the most appropriate energy and demand rates to input into the evaluation.

Avoided O&M costs associated with the transmission and distribution system should be a function of engineering estimates. Note that the cost of the outlay itself is not the same as the avoided maintenance costs that would otherwise be incurred as a result of a lack of upgrades or other new equipment that would proactively avoid costly downstream costs.

Finally, in some cases, as a result of the reduction in losses, a utility may be able to market its surplus energy in a liquid and efficient power market, either through bilateral transactions or power purchase agreements. The energy that would previously be dispatched and "lost" (i.e., the energy was not a function of billings captured through a utility's retail customer base) can still be generated by a utility's existing resources and sold. This only applies to utilities that own generating resources and have the capability to market additional generating capacity.

> A utility may be able to market its surplus energy in a liquid and efficient power market.

The Energy Information Administration (EIA) *Annual Energy Outlook* can be used to construct a valuation of the market price of energy that is regionally representative of what can be anticipated for energy pricing over the time period of evaluation.

To the extent other elements of avoided cost are relevant to a specific utility, such estimates can be included as secondary benefits in an economic evaluation, so as to provide a fair and objective evaluation of potential program benefits. Other examples of secondary benefits include, but are not limited to:

- The monetized value of avoided carbon emissions associated with avoided energy, using externally derived projections of future carbon costs or internal shadow values associated with carbon avoidance;
- The monetized value of jobs created from the project or other short-term economic benefits associated with project implementation, and
- The downstream economic benefits associated with energy and demand savings that represent an additional amount of disposable consumer income in the general economy.

Care should be taken when developing assumptions for secondary benefits. Secondary sources of carbon projections, such as those produced by Synapse Energy Economics, Inc., can provide a guideline for an appropriate valuation of carbon emissions. Downstream analyses of economic impacts should only be performed if the project is sufficiently large to warrant the inclusion of such benefits. In some cases, the cost associated with such evaluations may outweigh or swamp the benefits to be monetized.

Compute Net System Benefits and Benefit-Cost Ratios

After the benefits and costs have been estimated, the next step is the presentation of results in a simple format. The two most common summary measures used are the NPV of Net System Benefits and the Benefit-Cost Ratio (BCR). A calculation that supports such metrics is the discounted payback period (DPP).

The NPV is calculated by summing the dollar-valued benefits and then subtracting the dollar-valued costs, with discounting applied to both benefits and costs as appropriate. The BCR is the ratio of total benefits to total costs, both discounted as appropriate. The DPP is used to calculate the length of time to recoup an investment based on the investment's discounted cash flows. By discounting each individual cash flow, the discounted payback period formula takes into consideration the time value of money.

The formulas in Equations 5.4 and 5.5 summarize these calculations.

Equation 5.4

$$NPV = \sum_{t=0}^{n} \frac{(Benefits - Costs)^t}{(1 + r)^t}$$

Where:

r = Discount rate chosen (see above)

t = Year

n = The time horizon for the cost-benefit analysis

Equation 5.5

$$BCR = \frac{PV\ Benefits}{PV\ Costs}$$

$$DPP = n \text{ when } NPV = 0$$

The DPP formula is used in capital budgeting to compare a project against the cost of the investment. The simple payback period formula can be used as a quick measurement. However, discounting each cash flow can provide a more accurate picture of the investment.

As a simple example, suppose that an initial cost of a project is $5,000 and each cash flow is $1,000 per year. The simple payback period formula would be five years: the initial investment divided by the cash flow each period. However, the discounted payback period would look at each of those $1,000 cash flows based on its present value. Assuming the rate is 10 percent, the present value of the first cash flow would be $909.09, which is $1,000 divided by 1+r. Each individual cash flow would then be discounted to its present value until it is determined how long it would take to recoup the original $5,000.

Interpretation of success metrics by co-ops and other stakeholders should be fairly simple by design. The avoided costs of the project that are relevant are typically subtracted from the total project intrinsic costs in each year. These Net System Benefits are then discounted back to today's dollars and added to compute the NPV of Net System Benefits. In a year in which costs outweigh benefits, the BCR will be less than 1.0. This ratio should be above or equal to 1.0 as the study horizon extends.

In general, a project that has a positive NPV of Net System Benefits should be implemented, because the benefits outweigh the costs in the long run. If a project has a negative NPV of Net System Benefits, project parameters may need to be reexamined or sensitivity analysis developed. In some cases, it may be that the project is simply too expensive relative to the expected demand and energy reductions.

Devising a consistent framework for evaluating success in advance of deployment can help a utility determine the reasonableness of the investment required to achieve a certain amount of distribution loss savings. As payback period tolerances differ among utilities, care should be taken when interpreting these results. In order for the NPV of Net Benefits to be positive over the horizon of the analysis, the investment must pay itself back over that same period.

Understanding success for a given project depends on utilizing the best available estimate of costs combined with the best available estimate of avoided costs. While there are numerous approaches to economic analysis of benefits, there are several industry-standard benefit-cost ratios, which can be defined as follows:

- **Utility Cost Test (UCT).** A measure of whether the benefits of avoided utility costs are greater than the costs incurred by a utility to implement the project.
- **Rate Impact Measure (RIM) Test.** A measure of whether utility ratepayers that do not participate in a project would see an increase in retail rates as a result of other customers participating in a utility-sponsored project.
- **Total Resource Cost (TRC) Test.** A measure of whether the combined benefits of the utility and customers participating in the project are greater than the combined costs to implement the project.
- **Societal Cost Test (SCT).** A measure that is identical to the TRC but also includes estimates of environmental and other non-energy benefits that are currently not valued by the market (i.e., have no direct monetized value).

The components of each of these ratios are summarized in the **sidebar** on the following page. Note that such descriptions are generic in nature and the exact applicability to a specific project will differ depending upon the nature of the measures deployed. Some costs may well be negligible for a significant number of projects.

From the perspective of a given co-op, metrics that may be easier to communicate to stakeholders, such as the NPV of Net System Benefits, may be used to complement the above cost-benefit analyses. In most cases, the TRC can be made to be equivalent to the benefit-cost ratio that reflects Net System Benefits, so long as the costs and benefits have been parameterized appropriately to capture the correct utility perspective.

Comparison of project alternatives can easily be made based on one or more of the above metrics. The example in Table 5.1 summarizes some sample calculations of a select number of benefit-cost ratios.

As evidenced by the comparison in Table 5.1, it is possible that various BCRs will result in different outcomes. It is generally the discretion of the utility that determines whether projects will move forward. In this example, each measure fails the RIM test, which is a metric that a fair number of utilities utilize to determine whether to deploy a particular project.

According to literature published by the National Action Plan for Energy Efficiency,[12] there is no single best test for evaluating the cost-effectiveness of a project. Each cost-effectiveness ratio provides different information regarding the impacts of a project from different vantage points. Historically, reliance upon the RIM test has limited investment, as it is the most restrictive metric. However, given that distribution loss improvements do not typically involve one group of ratepayer participants versus another, a project that passes the TRC test should be considered for implementation.

TABLE 5.1: Example Comparison of Benefit-Cost Ratios

Metric	UCT	RIM	TRC
Measure A	10.6	0.9	0.4
Measure B	2.2	0.7	1.9
Measure C	8.3	0.9	1.4
Measure D	3.8	0.8	3.3

[12] National Action Plan for Energy Efficiency (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers*. Energy and Environmental Economics, Inc., and Regulatory Assistance project. www.epa.gov/eeactionplan.

INDUSTRY-STANDARD BENEFIT-COST RATIOS

Utility Cost Test (UCT)	Rate Impact Measure (RIM) Test	Total Resource Cost (TRC) Test	Societal Cost Test (SCT)
BENEFITS = Avoided Energy Supply Costs (net generation level decreases × marginal energy costs) + Avoided Capital Supply Costs (net generation level decreases × incremental capital costs) + Avoided O&M Supply Costs (net generation or distribution level decreases × marginal O&M costs) + Participation Charges	**BENEFITS =** Avoided Energy Supply Costs (net generation level decreases × marginal energy costs) + Avoided Capital Supply Costs (net generation level decreases × incremental capital costs) + Avoided O&M Supply Costs (net generation or distribution level decreases × marginal O&M costs) + Revenue Gains (net meter level increases × retail rates) + Participation Charges	**BENEFITS =** Avoided Energy Supply Costs (net generation level decreases × marginal energy costs) + Avoided Capital Supply Costs (net generation level decreases × incremental capital costs) + Avoided O&M Supply Costs (net generation or distribution level decreases × marginal O&M costs) + Avoided Participant Costs (avoided capital, O&M, etc.) + Tax Credits	**BENEFITS =** Avoided Energy Supply Costs (net generation level decreases × marginal energy costs) + Avoided Capital Supply Costs (net generation level decreases × incremental capital costs) + Avoided O&M Supply Costs (net generation or distribution level decreases × marginal O&M costs) + Avoided Participant Costs (avoided capital, O&M, etc.) + Tax Credits + Environmental Benefits (monetized value of avoided emissions) + Additional Resource Savings (e.g., gas or water if utility is electric) + Non-Energy Related Benefits (e.g., economic impact)
COSTS = Increased Energy Supply Costs (net generation level increases × marginal energy costs) + Increased Capital Supply Costs (net generation level increases × incremental capital costs) + Increased O&M Supply Costs (net generation or distribution level increases × marginal O&M costs) + Utility program costs (administrative costs) + Incentives (utility incentives, rebates, etc.)	**COSTS =** Increased Energy Supply Costs (net generation level increases × marginal energy costs) + Increased Capital Supply Costs (net generation level increases × incremental capital costs) + Increased O&M Supply Costs (net generation or distribution level increases × marginal O&M costs) + Revenue Losses (net meter level decreases × retail rates) + Utility program costs (administrative costs) + Incentives (utility incentives, rebates, etc.)	**COSTS =** Increased Energy Supply Costs (net generation level increases × marginal energy costs) + Increased Capital Supply Costs (net generation level increases × incremental capital costs) + Increased O&M Supply Costs (net generation or distribution level increases × marginal O&M costs) + Incremental Participant Costs (capital costs, O&M, etc.) + Utility Project A&G Costs	**COSTS =** Increased Energy Supply Costs (net generation level increases × marginal energy costs) + Increased Capital Supply Costs (net generation level increases × incremental capital costs) + Increased O&M Supply Costs (net generation or distribution level increases × marginal O&M costs) + Incremental Participant Costs (capital costs, O&M, etc.) + Utility Project A&G Costs

The computations of such ratios should reflect the incurred incremental costs and avoided incremental costs (benefits) that are applicable to the measure in question. Only benefits and costs that apply to a specific project should be included in the analysis.

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Sensitivity Analysis/Levers

The uncertainty and volatility of the restructured electric market makes power loss prediction very difficult. In order to better understand a range of possible futures and foster the selection of the most effective power loss management plan, sensitivity analyses must be completed to understand how the cost-benefit picture may (or may not) change as a result of varying levels of key assumptions.

A typical sensitivity analysis examines several different future scenarios, with each scenario defined by selected values of key variables. Appropriate selection of the range used for variables is essential to a meaningful result. Such analyses typically begin by creating a listing of all variables. A likely range of values for each variable is then assigned and the modeling constructs are recomputed to compare the outcomes against the "base case" assumptions.

As the time horizon for implementation has already been determined above, each scenario should be evaluated over that same time horizon in order for the results of the comparisons among scenarios to be meaningful. For distribution line losses, the following is a recommended minimum set of variables to be examined for purposes of creating sensitivities.

- **Load Variation (High/Low).** Lower or higher levels of load growth over the time horizon of evaluation can impact the discounted payback period (or the time until the initial capital outlay is recovered by the project), as well as the NPV and BCR, as a higher amount of load growth may imply that the project has more of a benefit and vice versa. Load variations can be derived from the utility's base case load forecast as a function of the following key variables:
  - Weather volatility,
  - Economic uncertainty,
  - Discrete load additions or load losses that are known or anticipated to occur in the future,
  - Estimated improvements in energy efficiency across the utility service territory,
  - Deployment of specific levels of demand response programs or other behaviorally based programs that seek to reduce future load on peak or with respect to total energy consumption, and
  - Probabilistic simulations of future load levels (that capture uncertainty in load driven from a variety of variables).
- **Energy Price Variation.** The cost of otherwise avoided losses is dependent upon the accuracy of estimated future energy prices, which are subject to significant uncertainty. Energy price sensitivities or goal-seek techniques can be used to determine the minimum energy price at which the BCR for a given project becomes greater than 1.0. Alternatively, third party projections of energy prices—or publically available sources of energy price projections, such as the EIA *Annual Energy Outlook*—can be used to better understand how variable the energy-related benefit is expected to be relative to the base case.
- **Capacity Price Variation.** Variation in the demand charge that is anticipated to be incurred—either as a pass-through from a wholesale provider or as a function of internal capacity cost estimates—should also be varied in order to understand the influence that such variation may have on the project NPV.
- **Capital Expenditure Variation.** Engineering estimates of equipment costs and deployment costs can be subject to significant uncertainty. Ranges of scenarios around such costs should be carefully coordinated with the engineering and contracting staff who are developing the cost estimates in order to understand the variability in cost components (both in a positive and negative direction). As the initial capital outlay represents the vast majority of upfront investment, a significant increase in actual capital cost can significantly impact the NPV and BCR of the potential project.

Sensitivity analysis should be crafted with due consideration to a given utility's strategic objectives. Consulting with utility stakeholders to devise alternative scenarios will provide multiple perspectives to the economic evaluation.

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Cost-Benefit Tools

A consistent framework for evaluating the economics of projects can be developed using a cost-benefit tool. Such a tool—developed by Leidos for this study—allows stakeholders to determine the cost-effectiveness of a particular project. The tool is based on the TRC framework and can also be used to compare one project with another in both graphical and tabular formats. A pro forma financial projection over a selected forecast horizon that summarizes the costs and benefits in a top-down, easily understood structure also is included. Refer to **Section 8** of this report for a more detailed description of the input-output structure of the tool.

Results Presentation

Figures 5.3 through 5.5 show options for presenting results. These are included in the cost-benefit tool that's part of this report.

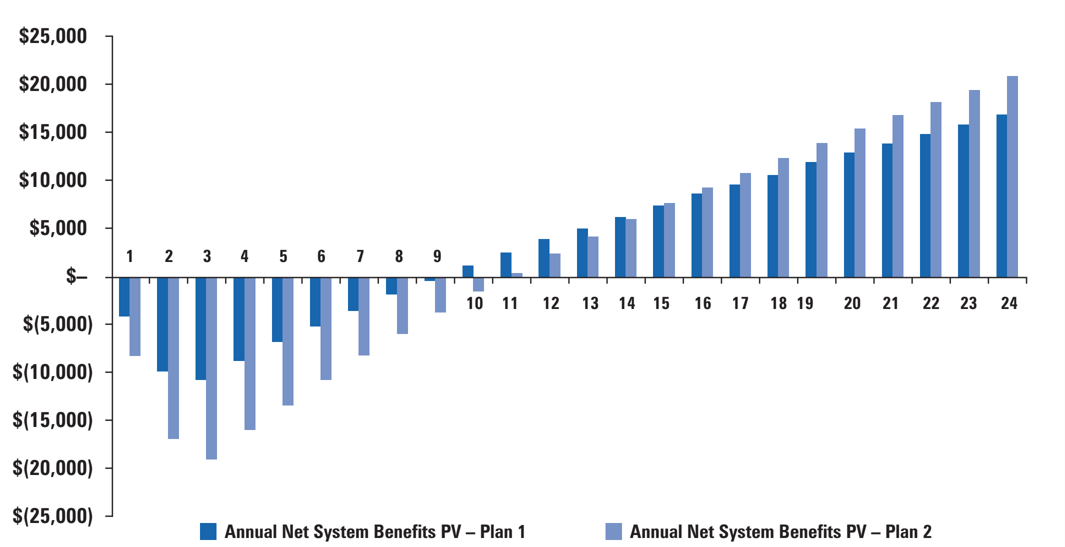
It is important to note that communication of results to stakeholders may require the creation of specific presentation materials that use the raw financial details and assumptions that underpin the cost-benefit tool. Additional exhibits can be created as a function of the input-output structure and the tabularization of final evaluation results.

Figure 5.3 compares present value (PV) of the net system benefits of two loss-mitigation projects by year over an example study period. Upfront net benefits are negative as a result of the investment but, over time, as the marginal cost of energy abated increases and the upfront investment amortization period ends, there is significant benefit.

Figure 5.4 depicts a comparison of annual energy losses under the "base case," or business as usual, as compared to the estimated annual energy losses associated with the improvements made in a given project. The horizontal axis reflects the years in the evaluation period.

Figure 5.5 represents the estimated total cost associated with two different potential projects on a cumulative basis. In this example, the accumulation of costs is similar. However, Plan 2 has a higher cumulative cost over the study period than Plan 1.

The presentation of results should be guided



Net Present Value (NPV) – Plan 1 **$91,600**
Net Present Value (NPV) – Plan 2 **$54,700**

FIGURE 5.3: Annual Net System Benefits PV Comparison

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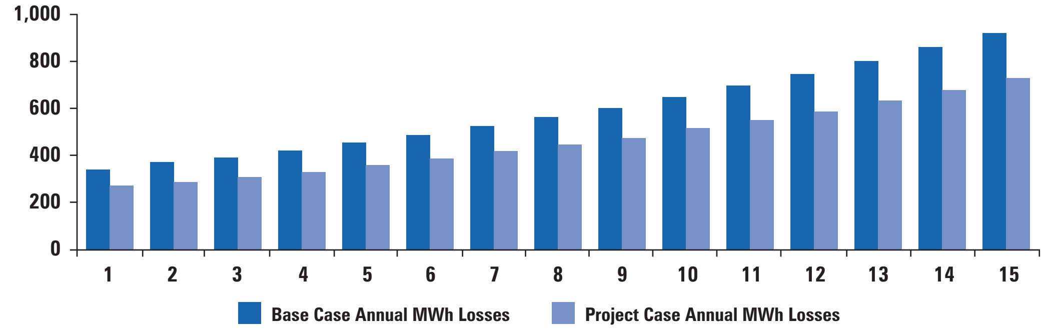

FIGURE 5.4: Annual Energy Losses (MWh) Comparison

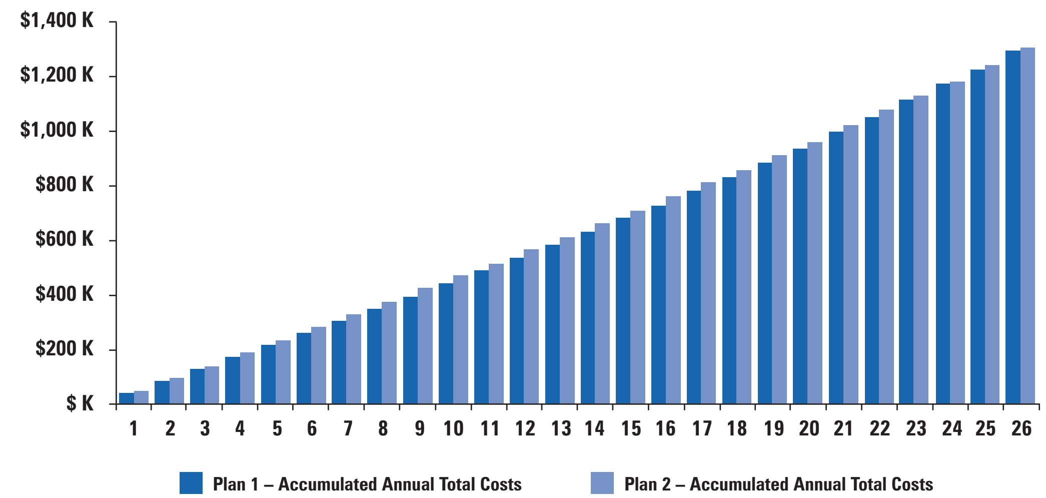

FIGURE 5.5: Annual Total (Capital and Loss) Costs Comparison

by feedback from a broad cross-section of utility stakeholders to refine outputs in terms of both aesthetics and priorities related to financial metrics. The Leidos cost-benefit tool outputs have been designed to be easily understood by a wide range of stakeholders. Given a robust cataloguing of the appropriate costs and benefits of a given project, calculation of alternative BCRs or a repurposing of the structure of a given output can be accomplished by combining the appropriate cost and avoided cost (benefit) elements together directly from the model.

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6 Impact of Smart Grid Technologies on Losses

In This Section:

The increase in grid awareness provided by smart sensors and data collection and management systems will play a significant role in the future of loss management. The following section describes the impact that new technologies could have on transmission and distribution system losses.

Advanced Metering Infrastructure

Advanced Metering Infrastructure (AMI) is a widely deployed smart grid technology that measures customer electrical consumption and other relevant data (such as voltage) and periodically sends this information back to the utility for monitoring and billing purposes. AMI systems provide major benefits in billing accuracy and meter reading. However, the data collected by these systems may enable other smart applications and help co-ops to operate their systems more reliably and efficiently. For example, the last-gasp (loss-of-voltage) messages from AMI meters following an outage can help operators locate faults more quickly. Additional operational benefits may include: improved situational awareness, improved distribution system planning, determination of voltage violations, rate profiling, and remote connect/disconnect.

AMI data can greatly improve the loss analysis process. As interval data from AMI becomes integrated into the cooperative back-office systems at both the feeder/substation and customer levels, the load data can be directly assigned to computer simulation models. This will improve system models to a great extent, resulting in more accurate simulation results. This approach to loss computation improves accuracy by eliminating the assumptions made in the load allocation and providing added granularity to the results.

Another advantage of AMI is the use of interval voltage data to improve the effectiveness of Conservation Voltage Reduction (CVR) programs. CVR is a Voltage Optimization technique in which the reduction in voltage results in reduced energy consumption and losses. Electric utilities have relied on computer-simulated models or limited measurement points along their feeders to operate CVR programs and avoid violating voltage limits for end-of-the-line customers. Due to the lack of exact voltage information, operators could not effectively perform CVR on their systems. Incorporating AMI data as feedback into the

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CVR programs allows further reductions in feeder voltage without impacting end-of-the-line customer voltage. This would allow co-ops to further reduce their peak demands and, hence, reduce line losses.

Figure 6.1 illustrates how voltage can be lowered with AMI data.[13] Voltage control without AMI feedback (see left side of figure) results in higher voltages and increased losses, while voltage control with AMI feedback (right side of figure) yields a tighter range and lower losses.

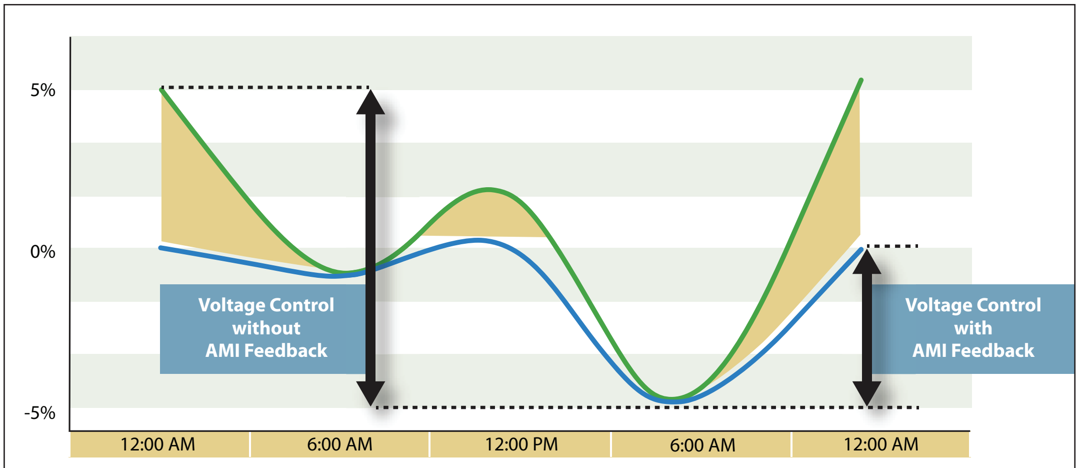

FIGURE 6.1: Improving Voltage Reduction with AMI Data

Volt/Var Control

Volt/var control is an important smart grid technique that allows utilities to operate their systems more efficiently by minimizing reactive power flows (var) and flattening voltage profiles. Volt/var control solutions may include capacitor banks, load tap changers (LTC), voltage regulators, and hardware or software controllers.

There are multiple design alternatives for volt/var solutions and each alternative has to be evaluated for a specific co-op system. For example, voltage control and var control can be operated independently or in an integrated manner. As another example, volt/var control can be implemented as centralized or distributed control architecture. Although distributed controllers at LTC transformers, voltage regulators, and capacitor banks can provide volt/var control, they can only make decisions based on local information. This distributed control solution is simple to implement. However, control actions may not be optimal because distributed control lacks the greater view of the electric grid.

Control actions taken locally will impact other grid sections; therefore, a centralized solution should be selected to ensure optimal control. Distribution Management System (DMS) volt/var modules usually satisfy this requirement.

DMS provides a central monitoring and control platform to support volt/var systems. DMS products allow system operators to model the entire distribution system and run real-time power flows and volt/var optimization algorithms based on different objective functions. These algorithms calculate the optimal set points for local controllers (LTC, regulator, cap banks, etc.) in order to achieve the objective function.

The impact of volt/var systems on losses is covered in more detail as potential loss-reduction techniques in **Section 4** of this report.

[13] Wambaugh, Joseph O., "The Value of AMI: It's So Much More Than Billing," *Electric Energy T&D Magazine,* September/October 2013. **www.electricenergyonline.com/show_article.php?mag=90&article=727**.

Distribution Automation

Distribution Automation (DA) is a smart grid technology that provides monitoring and control for distribution equipment that is outside of the utility substation fence. By providing distribution system visibility, DA systems allow co-ops to operate their systems more efficiently. For example, co-ops can identify phase unbalances along a distribution feeder and take action if telemetered data is available from various points on the feeder.

Distribution Management Systems are an important component of DA solutions, providing a central monitoring and control platform to support distribution operations. DMS software products include many model-based analytical applications that provide actionable information to system operators. In general, DA deployments require three main components to be tightly integrated:

1. **Monitoring, Control, and Analytics Software.** DMS or SCADA software.
2. **Communication System.** Fiber, cellular, Worldwide Interoperability for Microwave Access (WiMAX), Wi-Fi, 900 MHz, broadband over power lines (BPL), licensed frequencies, etc.
3. **Hardware.** Automation hardware—such as Remote Terminal Units (RTUs), Programmable Logic Controllers (PLCs), IEDs, controllers—and power system hardware such as reclosers, switches, capacitor banks, and regulators.

Monitoring, control, and analytics software products typically offer a wide variety of features, including optimization algorithms, to reduce line losses. For example, restoration plans, switching plans, and volt/var optimization plans can be run with the goal of loss reduction.

Distributed Generation

Technology advancements, changes in fuel costs, regulatory changes, and other drivers have spurred an increase in distributed generation (DG) resource deployments, including solar, wind, combined heat and power, and small hydro. The numbers of installations and penetration levels are approaching the point where distribution operations at many electric utilities could be impacted.

The integration of DG into existing power infrastructure can provide multiple benefits, including peak shaving, energy-efficiency improvements, congestion support, line-loss reduction, reduced greenhouse gas emissions, voltage support, and deferred investments of future capital projects. Customers may also benefit from improved power quality and a reduced cost of supply. Analyzing the loss-reduction and financial benefits of DG could be a challenging task due to the numerous characteristics of various DG technologies.

Multiple research studies have concluded that DG will usually reduce system losses provided that they are placed at the right location and dispatched at the correct level to meet system loads. Commonly suggested practices are to place DG in close proximity to a load center and to disperse them throughout the network; the more dispersed the DG units are, the greater their impact on loss reduction.

Although all DG technologies can help reduce losses, wind turbines typically have a lower impact on losses compared to other technologies due to their intermittency and general mismatch between output and feeder load patterns.[14] PV generation, although it also experiences intermittent output, typically aligns closer with average feeder load profiles.

Control of DG reactive power plays a vital role in line-loss management. More sophisticated voltage and reactive power control will impact losses to a greater extent.

[14] Quezada, V.H. Méndez, J. Rivier Abbad, and T. Gomez San Roman. "Assessment of Energy Distribution Losses for Increasing Penetration of Distributed Generation." *IEEE Transactions on Power Systems,* Vol. 21, No. 2, pp. 533-540, May 2006. DOI: 10.1109/TPWRS.2006.873115.

Energy Storage Systems

Energy storage technologies have been used extensively in different products, such as automobiles, portable computers, smart phones, and other consumer devices. With recent advancements in storage technology, the number of utility-scale energy storage systems is steadily increasing. These systems are commonly used to defer T&D investments, improve reliability, stabilize renewable energy output, regulate frequency, improve power quality, and implement energy arbitrage (purchasing/storing energy when electricity prices are low and selling/discharging energy when electricity prices are high). Regardless of the size or type energy storage deployed, it may have a large impact on distribution system efficiency.

Appendix D presents a case study that evaluates the cost-effectiveness of a distributed energy-storage system designed to help utilities reduce peak-energy consumption for air-conditioned buildings. The system uses thermally efficient, off-peak power to produce and store energy for use by air conditioners the next day, using a fraction of the peak energy required by conventional systems. It creates and stores cooling energy at night by freezing water in an insulated storage tank. The utility can dispatch it to cool during the day by circulating chilled refrigerant from that tank to the conventional air-conditioning system, eliminating the need to run the energy-intensive compressor during peak daytime hours.

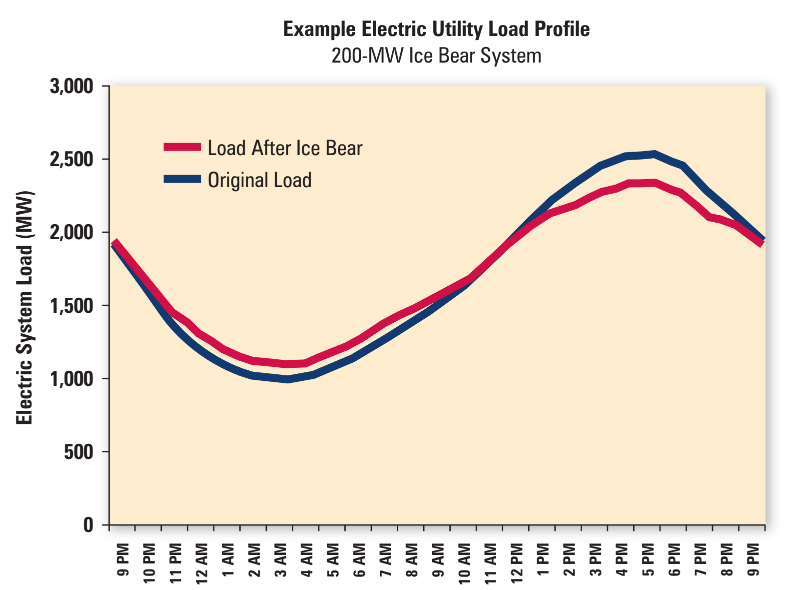

FIGURE 6.2: Load Shift Due to Ice Bear Cooling System

The results showed loss reductions, improvements in voltage, capacity release, and improvements in power factor. Improvements in peak loss ranged from eight to 20 percent per feeder, with analysis of a set number of cooling units placed. From a sensitivity analysis evaluating saturation levels, improvements in peak load loss ranged between five and 43 percent. The total reduction in peak load ranged between two and 23 percent. Figure 6.2 shows how the load is shifted from peak to off-peak, reducing system losses.

Plug-in hybrid electric vehicles (PHEVs) are also an important energy-storage technology that will have a significant impact on electric grid operations. Due to technological advancements, the cost of PHEVs has come down significantly. PHEVs can be used in grid-to-vehicle (G2V) or vehicle-to-grid (V2G) modes of operation. In G2V mode, the energy storage will be charged from the electric grid; whereas, in V2G mode, the stored energy in the battery will be discharged to the grid. Currently, most PHEV applications support the G2V model, but it is expected that V2G will become viable in the near-term as well.

Distribution system losses will be impacted and likely be increased due to the addition of PHEV loads onto the system. However, advanced control systems can coordinate the charge/discharge cycles of various PHEVs and minimize the overall impact.

Demand Management

Demand management is a smart-grid technique widely implemented among electric utilities and continuing to grow in popularity. Demand management is a broad term that encompasses many ways to reduce peak loading and energy requirements. It involves direct load control, price-responsive demand control, and time-of-use rate programs.

> Demand management… involves direct load control, price-responsive demand control, and time-of-use rate programs.

In addition, demand management may include energy-efficiency programs to utilize more efficient products, such as compact fluorescent lighting, higher-efficiency motors and appliances, efficient heating and cooling systems, or increased home insulation.

Demand management affects electric system infrastructure by reducing system peak load and energy requirements. Decreased current flow would result in reduced $I^2 \times R$ losses due to a reduction in end-use load. Demand management is also widely used to reduce peak load. The benefits of demand management reach beyond loss reduction. By reducing peak loading, some capital improvement projects could be eliminated or delayed, and the demand costs for peak generation or power acquisition lowered.

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7 Case Studies

In This Section:

Case Study 1 Distribution System Loss Evaluation

MVEC Engineers Conduct Time-Series Simulations to Evaluate Distribution System Losses Using OpenDSS Software

Maquoketa Valley Electric Cooperative (MVEC) engineers analyzed their distribution system losses by running time-series power flows using OpenDSS software and AMI data.

CO-OP OVERVIEW

Maquoketa Valley Electric Cooperative is a member of the generation and transmission cooperative Central Iowa Power Cooperative (CIPCO), located in Cedar Rapids, Iowa. Established in 1935, MVEC provides power to more than 14,000 members across 3,100 miles of line from 37 distribution substations. The customer base is approximately 95 percent rural, mostly consisting of residential and agricultural customers.

As shown in Figure 7.1, MVEC is headquartered in Anamosa, Iowa. The cooperative's membership region includes Delaware, Dubuque, Jackson, and Jones counties, as well as portions of Buchanan, Cedar, Clayton, Clinton, and Linn counties.

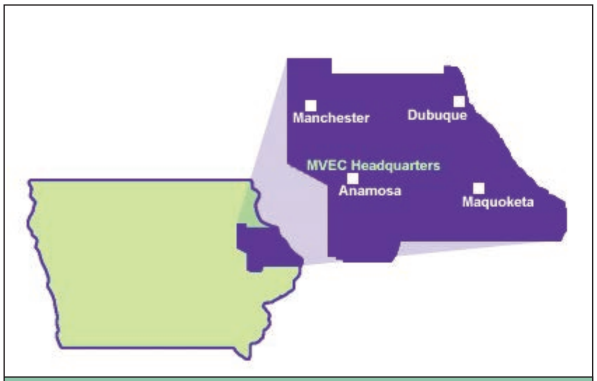


FIGURE 7.1: MVEC Service Territory

Between 2008 and 2009, MVEC switched from a member self-read billing system to a fully implemented Automatic Metering Infrastructure (AMI). They have a robust SCADA system in place as well, which is tied to the distribution substations.

HISTORICAL DISTRIBUTION LOSSES AT MVEC

MVEC is metered by CIPCO on the low-side of each distribution substation transformer and calculates losses as the difference between electricity purchases and sales. Substation transformer losses are accounted for by adjusting the substation purchases with a loss factor for each substation power transformer. MVEC system losses over the past five years are shown in Table 7.1.

TABLE 7.1: MVEC System Losses Over Five Years

Year	% Losses
2008	5.59%
2009	4.13%
2010	6.37%
2011	6.22%
2012	6.32%

While it appears in Table 7.1 that losses varied greatly in 2008 and 2009 from the following years, the values reflect a change in the time of month the meter reading was conducted and a "catch-up" period of 10 extra days of billing collected to match the CIPCO billing cycle during AMI implementation. According to MVEC, losses prior to 2008 were also in the six percent range.

While AMI didn't reduce losses, using AMI data in the WindMil engineering model has helped to detect weak areas of the distribution system where losses are higher. The benefit comes from using AMI data (near-real-time simulation) versus the typical monthly kilowatt-hour allocation approach.

While MVEC has not completed an in-depth report on various nontechnical losses (such as theft or unaccounted-for losses), they did investigate metering accuracy and found an accuracy range of ±0.5 percent on 98.6 percent of their electronic meters. The co-op also found that only 78.5 percent of their old mechanical meters fall into that same accuracy range. By switching to AMI and electronic meters, overall meter accuracy improved, increasing revenue by more than $120,000 annually.

TIME-SERIES SIMULATIONS FOR LOSS ANALYSIS

MVEC engineers evaluated their system losses by implementing power flow simulation. Their initial analysis looked only at a peak-loading scenario that returned annualized losses based on engineering approximations. After the initial analyses failed to provide the needed accuracy, engineers decided to run time-series simulations for the entire year. SCADA data and 15-minute AMI data for an entire year provided much of the data needed for the time-series simulation. The only missing piece was the software tool that would enable their analysis. They decided to use OpenDSS after learning about the tool at an industry conference.

OpenDSS, now an EPRI tool, is an electric power Distribution System Simulator (DSS) used to analyze distribution systems over multiple time intervals. It's a multipurpose tool that provides very fast analysis for a large amount of data, such as performing hourly or 15-minute load interval simulations.

MVEC performed loss analysis on four different distribution substations to get a representative system sample. After AMI data was integrated into the analysis, MVEC applied OpenDSS to evaluate the source of their losses and methods to reduce them. Engineers determined that the majority of losses came from large, older distribution transformers with higher impedance values and also from many unloaded, energized transformers on the system.

MODELING AND SIMULATION PROCESS

For the four substations studied, MVEC used AMI data to develop load shapes for several different customer types. SCADA by-feeder/by-phase values were used for the annual hourly simulation. Distribution transformers were modeled, and impedance and loss characteristics (as defined in IEEE documentation) were included —by age of transformer—to calculate load and no-load losses. With some minor code writing, MVEC was able to include details from the WindMil model in the OpenDSS model. Secondary level distribution details were not included, but primary distribution, distribution transformers, and customers were all modeled.

Building the model took approximately two months, and analysis time was in addition to that. Currently, OpenDSS does not have a geographic user interface or a straightforward tool to export an engineering model to the software. This made the process more time-consuming. However, MVEC feels that it was worth the effort and helped them gain a better understanding of their energy losses.

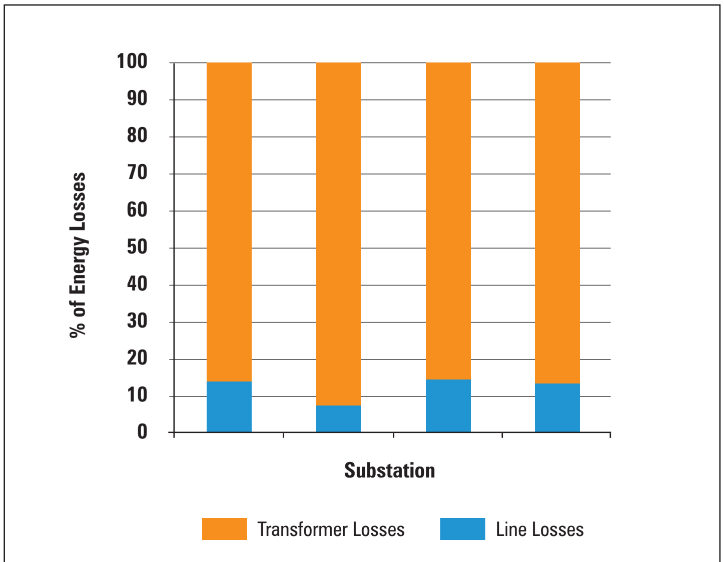


FIGURE 7.2: Comparison of Line Losses and Transformer Losses

The analysis showed that transformer no-load and load losses accounted for 87 percent of annual losses for the four substations studied, while line losses accounted for 13 percent of the total losses calculated in the model. Figure 7.2 presents the percentages for line losses versus transformer losses at each evaluated substation.

In comparison, by spot checking certain time stamps, WindMil calculated lines losses very close to the values calculated in OpenDSS. However, MVEC found more accuracy in transformer losses in the OpenDSS tool than in the WindMil model.

COST-BENEFIT ANALYSIS

MVEC used the analysis results to perform an economic evaluation of replacing distribution transformers to reduce losses. The analysis showed the following:

- Replacing all 2,139 distribution transformers on the four substations studied with lower loss units would not allow the co-op to break even in the foreseeable future;
- Downsizing all under-utilized transformers at four substations, 30 in total, would provide a 20-year payback under a 35-year loan; and
- Downsizing all under-utilized transformers larger than 37.5 kVA on the system, 251 in total, would provide a 23.5-year payback under a 35-year loan.

From this analysis, MVEC determined it would not be economical to replace every old transformer with a new, lower loss unit all at once. MVEC plans to gradually replace those transformers, going forward as dictated by age, capacity, or condition.

LOSS-REDUCTION TECHNIQUES AT MVEC

MVEC does implement various loss-reduction techniques on their system, including conservation voltage reduction, reviewing fixed capacitor placement every two years, using SCADA to keep feeders and phasing balanced on a regular basis, installing more efficient transformers as needed, and reconductoring primary and secondary lines. Also, the cost of losses is evaluated when purchasing new transformers.

While MVEC operates near unity power factor, the co-op did investigate the benefit of using switched capacitors and found it would generate a small amount of savings. However, the savings calculated would not justify the cost and communications required for the switched capacitors.

MVEC also investigated a technology from Varentec: a capacitor placed on the secondary side of the distribution transformer. This dynamic technology injects small quantities of var as needed, versus larger banks that can't respond as quickly to var needs. However, the return on investment was questionable at the time of this report.

FUTURE PLANS

In the future, MVEC will continue to monitor losses and replace transformers on the system with lower loss units as needed. The co-op will continue to investigate loss-reduction strategies, including emerging technologies, to make economically sound decisions that could reduce its system losses.

Case Study 2 Voltage Optimization

Fort Loudoun Electric Cooperative (FLEC) Voltage Optimization Study Shows Significant Peak Demand and Energy Conservation Savings

The FLEC voltage optimization study shows that the co-op can reduce peak demand by 2.4 percent, which equates to $244,000 in demand savings per year. The study also shows that, while total energy consumed decreases, line losses may increase as a result of voltage reduction events.

CO-OP OVERVIEW

Fort Loudoun Electric Cooperative serves portions of a three-county area in East Tennessee, with the main office in Vonore, Tennessee. Formed in 1940, FLEC currently provides power to 32,000 customers, with more than 3,100 miles of distribution lines operated at 12.5/7.2 kV. FLEC purchases power from Tennessee Valley Authority (TVA) at 161 kV and distributes power throughout its service territory through eight substations.

As shown in Figure 7.3, FLEC provides service to parts of three counties—Blount, Loudon, and Monroe.

PURPOSE AND BACKGROUND

To align with Smart Grid initiative goals as part of the TVA Virtual Power Plant program, FLEC recently funded a study to analyze the effects of voltage optimization on its distribution system in order to lower peak demand and conserve energy. The study investigated potential energy and demand reduction savings due to a combination of optimizing circuit properties, such as equipment loading, feeder voltage, and var flow and the implementation of conservation voltage reduction (CVR). This combined process is known as Voltage Optimization (VO).

FIGURE 7.3: FLEC Service Territory

ANALYSIS PROCESS

Analysis was performed using the FLEC engineering model in WindMil. Metered by-phase amps and power factor for each feeder were used to allocate load in the model, based on actual billing data for each customer. A summer and winter analysis was performed. For the purpose of this case study, only the summer case will be presented.

To perform the study and help define parameters, FLEC began with defining the following voltage optimization goals:

- Optimize system performance,
- Reduce peak demand,
- Improve system power factor, and
- Maintain customer voltage.

Various other criteria were established regarding sizing and placement of capacitors, placement and settings of voltage regulators, and power factor limits.

Prior to the analysis, CVR factors (CVRf) were established for each substation transformer load tap changer (LTC) zone. CVR factors define end-use load types such as constant impedance (Z), constant current (I), and constant power (P), known as ZIP values. To better understand the classifications of load mixes, see the information in **Figure 7.4** from the IEEE Standard 399-1980—*Recommended Practice for Industrial and Commercial Power System Analysis.*

PREVIOUS VIEW

The calculated positive or negative impact on calculated system demand and energy will depend highly on the consumer load mixes defined as ZIP values. The impact for each load type is as follows.[15]

- **Constant Impedance.** A fixed percentage of the connected load is described as "constant impedance" (%Z) load. With %Z load, the effect of reducing voltage would be decreases in both power delivered and line loss proportional to the square of voltage decrease.
- **Constant Current.** A fixed percentage of the connected load is described as "constant current" (%I) load. With %I load, the effect of reducing voltage would be a decrease in power delivered proportional to the voltage decrease, with line loss remaining the same because current is constant.
- **Constant Power.** A fixed percentage of the connected load is described as "constant power" (%PQ) load. With %PQ load, the effect of reducing voltage would be that power delivered remains constant and line losses increase due to the increase in current required to maintain constant power delivery.

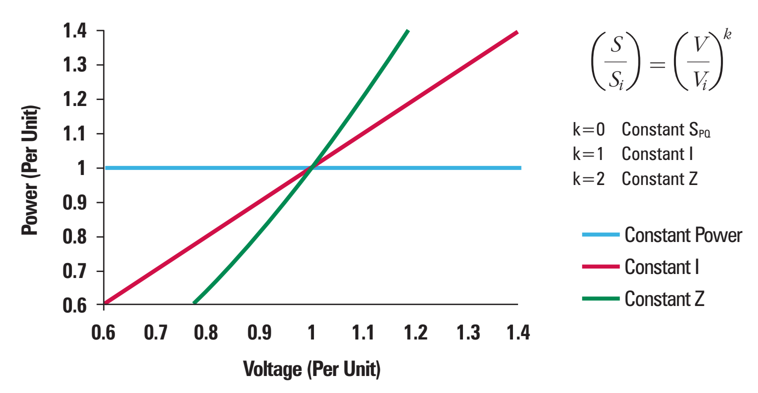


FIGURE 7.4: Classification of Load Mixes

While developing CVR factors can be very complicated, CVR factors for the FLEC study were determined based on:

- SCADA readings from actual voltage reduction events occurring in the summer for each substation, and
- Metered substation load before and after each event, used within a trending methodology to estimate the % Demand Reduction.

CVR factors for each substation transformer were developed by using Equation 7.1 and the variables discussed above.

Equation 7.1
CVRf = % Demand Reduction/% Voltage Reduction

Based on a standard chart of available ZIP values for any given CVRf, ZIP values were selected for each substation transformer to reflect the load mixes of all customers served from each source. For each customer meter in the model, the load mix or ZIP values were defined prior to analysis.

To flatten the voltage profile along each feeder, in preparation to lower the voltage at each voltage regulation point, a series of incremental solutions were evaluated in the following stepped approach:

1. **Phase Balancing.** Base phase-change selections on loss savings.
2. **Var Management.** Correct power factor to between 99 and 100 percent; only use current inventory of FLEC capacitors.
3. **Voltage Regulator Management.** Identify key locations for voltage monitoring and use voltage regulators to help boost the voltage in sensitive areas.
4. **Voltage Optimization.** Reduce the voltage in regulation zones, including LTCs and voltage regulators, while maintaining a voltage on the primary distribution system above 117 Volts, on a 120-V base.

[15] Fagen, K.C., K. O'Conner, "Efficiencies in Distribution Design and Operating Practices," *Rural Electric Power Conference, 2005,* pp. B3/1–B3/8, May 8–10, 2005. DOI: 10.1109/REPCON.2005.1436309.

PREVIOUS VIEW

RESULTS

Table 7.2 shows the results for three scenarios. In these scenarios, "system improvements" refers to phase balancing, var management, voltage regulator management, and voltage optimization as described above. Pre-VO and Post-VO refer to conditions before and after implementing a voltage reduction (CVR) event.

The following study results show that the voltage optimization solutions implemented pre-VO help in reducing summer peak system losses. However, a reduction in voltage for the CVR event or post-VO slightly increases the losses. This is a result of the type of loads on the FLEC distribution system. Determining CVR factors at the beginning of the study showed that the FLEC loads are a mix of primarily constant power and constant current, with a minor percentage of constant impedance loads. With larger percentages of constant power and constant current load mixes, demand reduction and loss increases can be expected from a voltage reduction event.

CONCLUSION

While CVR didn't decrease overall losses for FLEC in the study performed, for the summer case evaluated, an average 2.8 percent voltage reduction was accomplished, which led to a 2.4 percent reduction in demand. FLEC has identified a yearly demand savings of roughly $244,000 from voltage reduction events. Even with a slight increase in losses for a few hours a year when voltage reduction events are likely to occur, it's expected that savings in demand costs should outweigh the increase in losses for FLEC.

TABLE 7.2: Voltage Optimization Study Results

	kW Demand	kW Losses	% Losses
Summer, No VO, No System Improvements	145,528	4,617	3.17%
Summer, Pre-VO, With System Improvements	145,697	4,402	3.02%
Summer, Post-VO, With System Improvements	142,219	4,421	3.11%

8 Loss Evaluation, Cost-Benefit, and Decision Tree Tools

In This Section: Loss Evaluation Tool · Cost-Benefit Tool · Decision Matrix Tool

Leidos has developed three Excel-based tools to help cooperatives evaluate losses, analyze costs and benefits, and identify potential loss-mitigation techniques. Figure 8.1 illustrates a likely process flow for applying the loss analysis tools. Detailed functionality of these tools is described in this section.

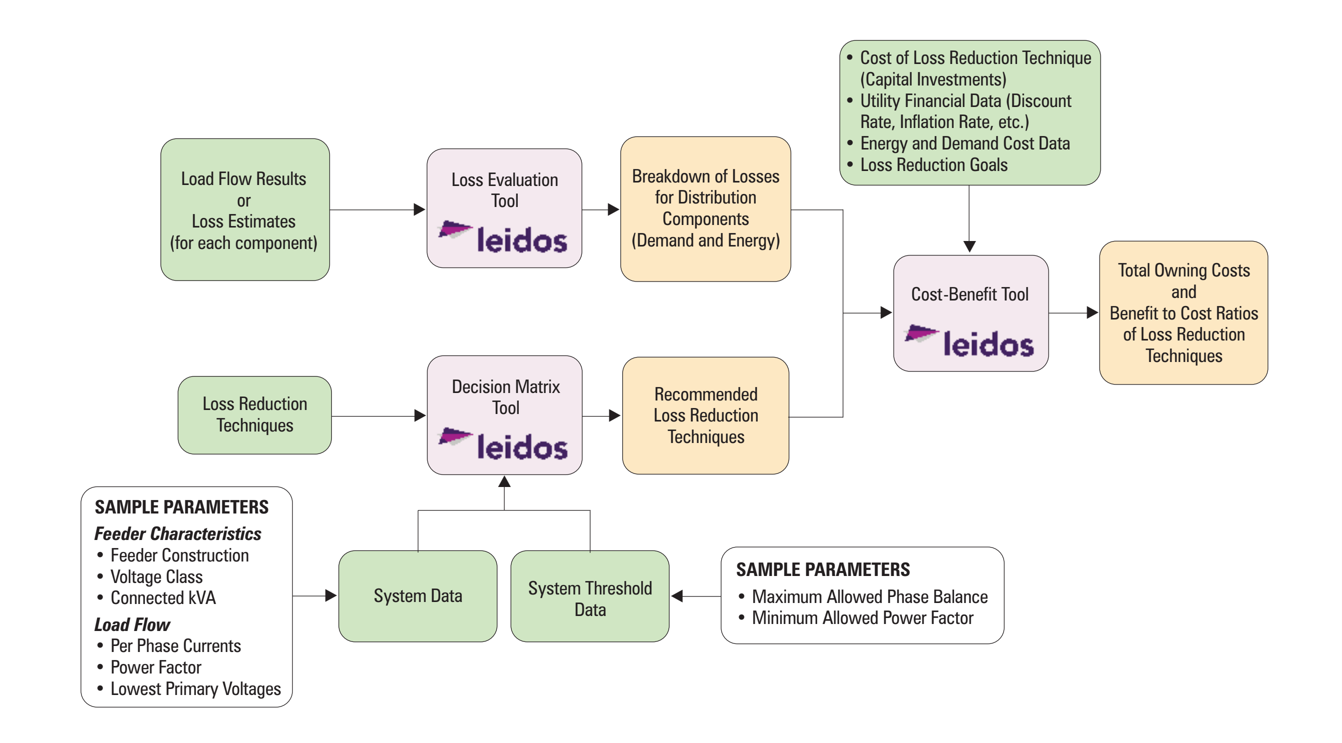


FIGURE 8.1: Process Flow of the Tools

PREVIOUS VIEW

Loss Evaluation Tool

The first step in reducing distribution system demand and energy losses is to account for all electric power being used by the system. The Loss Evaluation Tool will help electric cooperatives identify and account for all sources of electric load in a uniform way. Once losses are identified, steps can be taken to reduce their magnitude.

This tool itemizes calculations to help engineers identify equipment classes that are the largest contributors to overall losses. Formulas applied in the tool are based on those presented in **Section 3** of this report.

Sample data provided in the tool helps users understand operation of the tool. The bulk of the user's effort will reside in data collection and performing intermediate calculations to align data with appropriate fields in the tool, especially data for secondary and service lines.

The tool requires users to input loss estimations or calculations for each distribution system component, by category. Also, users must input system peak and average load data for load factor and loss factor calculations. If hourly load data is available, load and loss factors can be computed by the Load and Loss Factor Calculator. A general list of data required for a loss study is provided below.

DATA

The following list describes the data and information that may be needed to perform a loss study.

- **System Data.** Historical system peak data, and purchased and sold energy.
- **Substation Transformer.** Characteristics including metered peak loads, quantity, size, no-load iron (Fe) core losses, load, copper (Cu) coil impedance, and voltage levels.
- **Substation Equipment.** Characteristics including quantity, size, no-load iron (Fe) core losses, load, copper (Cu) coil impedance, voltage levels for voltage regulators, current transformer (CT) and potential transformer (PT) instrumentation, meters, capacitors, auxiliary equipment, and bus losses.
- **Distribution Primary.** Conductor sizes and impedance definitions, lengths, loadings, representative feeders for each voltage class, customer type, and feeder type (urban or rural).
- **Distribution Transformer.** Characteristics including estimated loading, quantity, size, no-load iron (Fe) core losses, load, copper (Cu) coil impedance, and voltage levels.
- **Distribution Secondary.** Standard conductor sizes and impedance definitions, as well as lengths and loading.
- **Distribution Equipment Data.** Size, types, locations, and loss data of other distribution equipment such as regulators, capacitors, and street lights.
- **Load Data.** Load profile, power delivered at different times throughout the period.

There are detailed instructions within the Loss Evaluation Tool that describe the input parameters for each worksheet and general tool guidelines. After successful entry of the required data, the tool will evaluate the overall system peak and energy losses in a summary view. **Figure 8.2** shows the summary view of distribution losses from the tool.

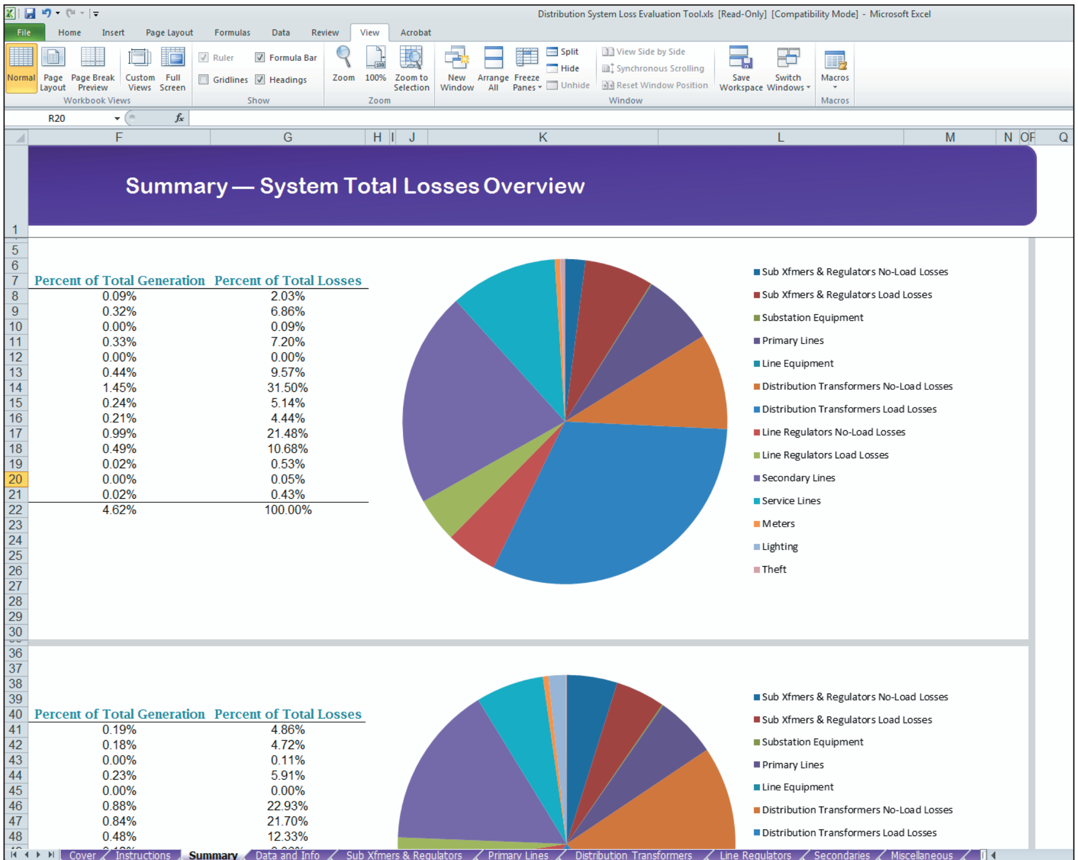


FIGURE 8.2: Summary View of Peak and Energy Losses in the Loss Evaluation Tool

Cost-Benefit Tool

The Distribution System Losses Cost-Benefit Tool was developed to assist cooperatives in performing a cost-benefit analysis of distribution system loss mitigation projects. The tool consists of two modules: the "Loss Cost Savings Tool" and the "Project Comparison Tool." The Loss Cost Savings Tool determines the avoided cost of losses resulting from a loss mitigation project. The Project Comparison Tool helps to identify which of two distribution system loss mitigation projects is the most cost-effective. It does this by comparing the capital costs and system benefits (distribution loss cost savings) of each project. This tool is comprised of the following tabs.

INSTRUCTIONS

This tab provides an explanation of what can be entered into the User Input cells in the "Input," "Loss Cost Savings Tool IO," and "Project Comparison Tool IO" tabs. This will guide the user in making the key decisions that will render meaningful model results. A summary of the key output charts in the "Loss Cost Savings Tool IO" and "Project Comparison Tool IO" tabs are also provided at the end of the "Instructions" tab to aid in interpreting model outcomes.

INPUT

This tab is intended for users to input the key parameters required to perform the cost-benefit analysis. These parameters are common for both the "Loss Cost Savings Tool" and "Project Comparison Tool" modules. All the input cells have default values that should be altered by the user to reflect their actual requirements for the intended analysis. In general, black text with purple cell shading indicates that the cell is an input cell that needs to be altered/completed by the user to perform the cost-benefit analysis.

PREVIOUS VIEW

LOSS COST SAVINGS TOOL IO

This tab houses both input and output sections specific to the Loss Cost Savings Tool. The user should enter the key parameters in the User Input section. The tool will then use this data—combined with the parameters from the "Input" tab—to perform the cost-benefit analysis. The Output section will display the present value of loss cost savings (avoided cost of losses) and key output charts, including the Accumulated Annual Loss Cost Savings, Annual Peak Losses Comparison, and Annual Energy Losses Comparison charts. Figure 8.3 shows a screenshot of the Loss Cost Savings Tool IO tab of the tool.

PROJECT COMPARISON TOOL IO

This tab houses both input and output sections specific to the Project Comparison Tool. The user should enter the key parameters in the User Input section. The tool will then utilize this data—combined with the parameters from the "Input" tab—to perform the cost-benefit analysis. The Output section will display the project cost-benefit ratios and key output charts, including the Accumulated Annual Total (Capital and Loss) Costs Comparison, Annual Peak Losses Comparison, Annual Energy Losses Comparison, Accumulated Annual Capital Costs Comparison, and Accumulated Annual Loss Costs Comparison charts. **Figure 8.4** shows a screenshot of the Project Comparison Tool IO tab.

LOSS COST SAVINGS CALCULATIONS

This tab illustrates data calculated by the Loss Cost Savings Tool. Data entered into the "Input" and "Loss Cost Savings Tool IO" tabs are copied to this tab for present value calculations. Data in the chart tables at the bottom are used to create the charts shown in the "Loss Cost Savings Tool IO" tab. Users can apply the calculation results to create customized outputs, if needed.

PROJECT COMPARISON TOOL CALCULATIONS

This tab illustrates data calculated by the Project Comparison Tool. Data entered into the "Input" and "Project Comparison Tool IO" tabs are copied to this tab for present value calculations. Data in the tables at the bottom are used to create the charts shown in the "Project Comparison Tool IO" tab. Users can apply the calculation results to create customized outputs, if needed.

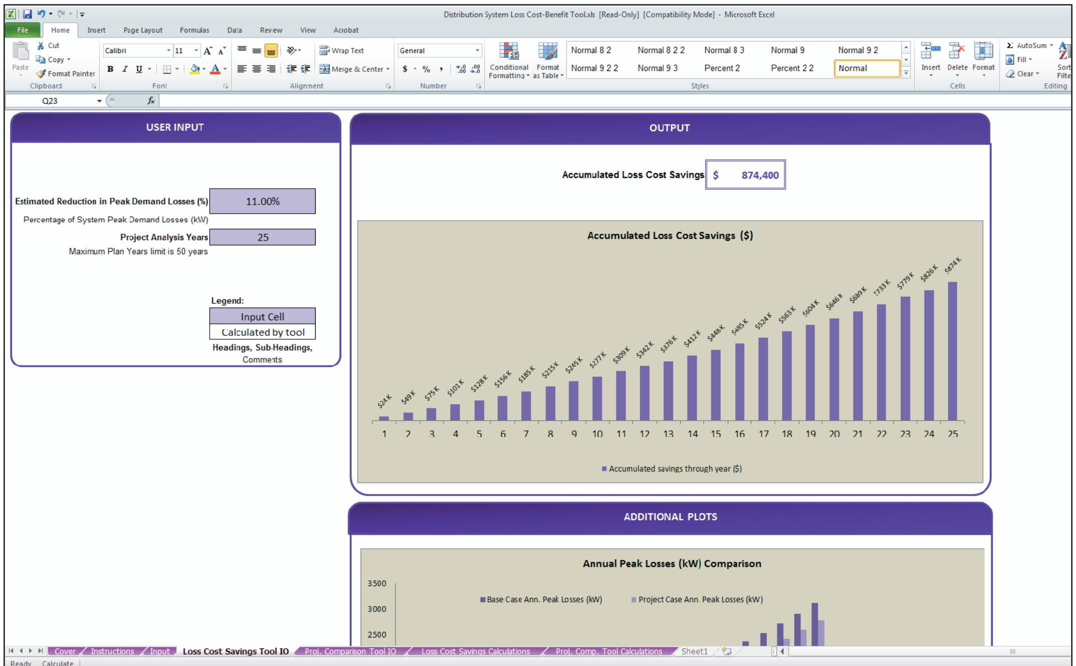


FIGURE 8.3: Screenshot of Loss Cost Savings Tool IO Tab

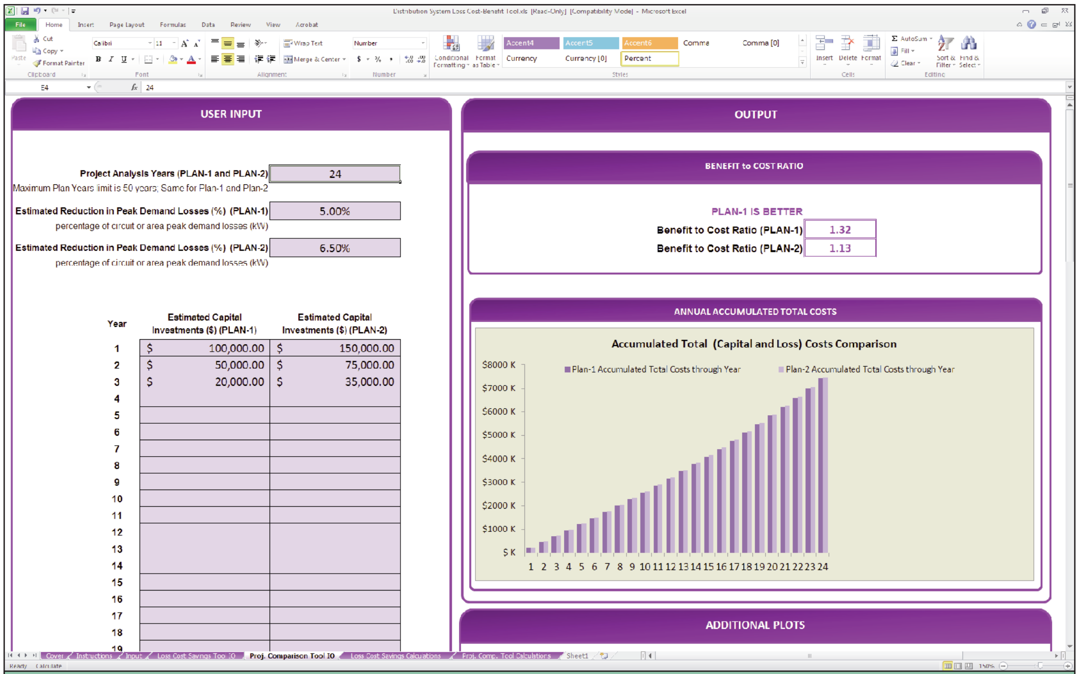


FIGURE 8.4: Screenshot of Project Comparison Tool IO Tab

Decision Matrix Tool

The Decision Matrix tool assists cooperatives in the selection of mitigation techniques that can reduce distribution system losses. The tool requires user data to be entered into the System Inputs and Planning Criteria Inputs worksheets. This tool evaluates one substation with up to 15 feeders at a time. Co-ops can start with this potential list of techniques and perform further cost-benefit studies outside of this tool to identify the most beneficial approach for their system. This workbook consists of the following six worksheets, excluding the “Cover” tab. It is recommended that each user read the Instructions worksheet before starting work with this tool.

INSTRUCTIONS

This tab provides an overview of each worksheet in the tool. It is recommended that users read these instructions carefully when initially working with the tool. Proper entry of information in the correct units of measure is crucial to obtaining accurate results. It may be beneficial to print out these instructions prior to using the tool for the first time. No calculations are performed in this tab. Note: It is very possible to generate theoretically untenable outcomes as a result of erroneous data entry. It is ultimately the responsibility of the user to carefully review his/her input data and ensure that it correctly reflects the system parameters being modeled.

LOOK-UP

This worksheet houses reference tables that are used in the “System Inputs” worksheet to create the data lists.

SYSTEM INPUTS

Users should input their system parameters into this worksheet. All the input cells are color-coded with black text and purple cell shading. Users can enter information for up to 15 substation feeders. A few cells in this worksheet have sample data and the user should alter this data to represent the system being modeled. **Figure 8.5** shows a screenshot of the System Inputs worksheet of the tool.

PLANNING CRITERIA INPUTS

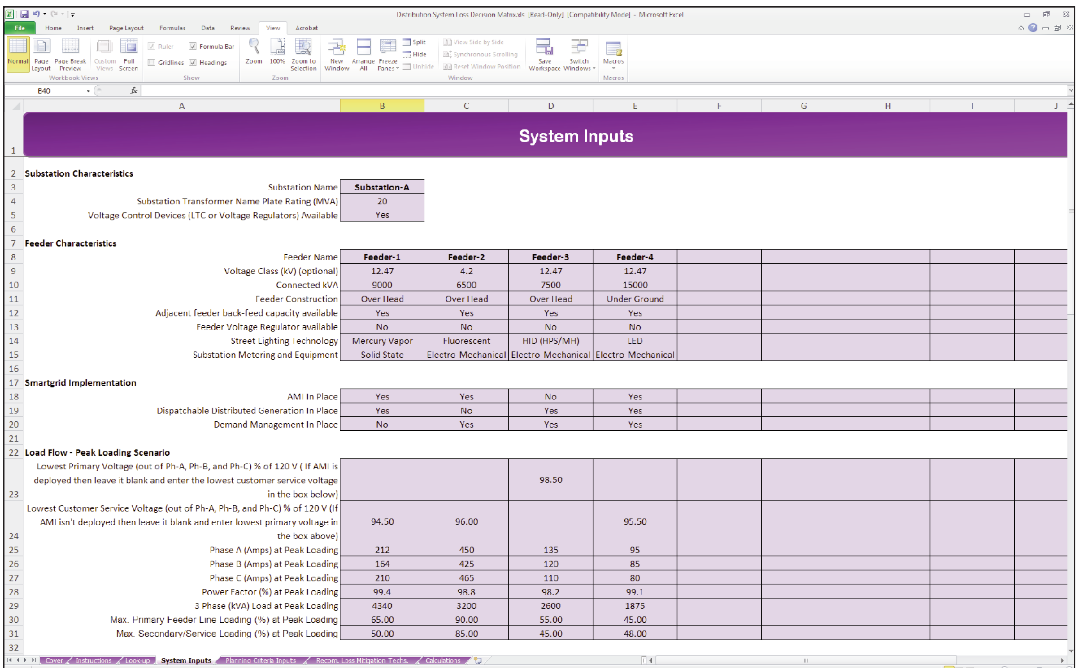
Users should input their system planning criteria parameters in this worksheet. The parameters in the "System Inputs" worksheet are compared against the planning criteria entries to identify potential mitigation techniques based on the logic described in **Appendix E**. Therefore, these entries are very important and need to be completed by a user who is knowledgeable about the system being modeled. All the input cells are color-coded with black text and purple cell shading. Each input parameter is described in detail below. All cells of this worksheet have sample data and the user should alter this data to fill in the data that represents the system being modeled.

RECOMMENDED LOSS MITIGATION TECHNIQUES

This worksheet lists all the potential mitigation techniques applicable for each feeder for which the data is entered in the "System Inputs" worksheet. It is up to the user to perform further cost-benefit studies on the recommended techniques to identify the most beneficial mitigation techniques. **Figure 8.6** shows a screenshot of the "Recommended Distribution Loss Mitigation Techniques" worksheet.

CALCULATIONS

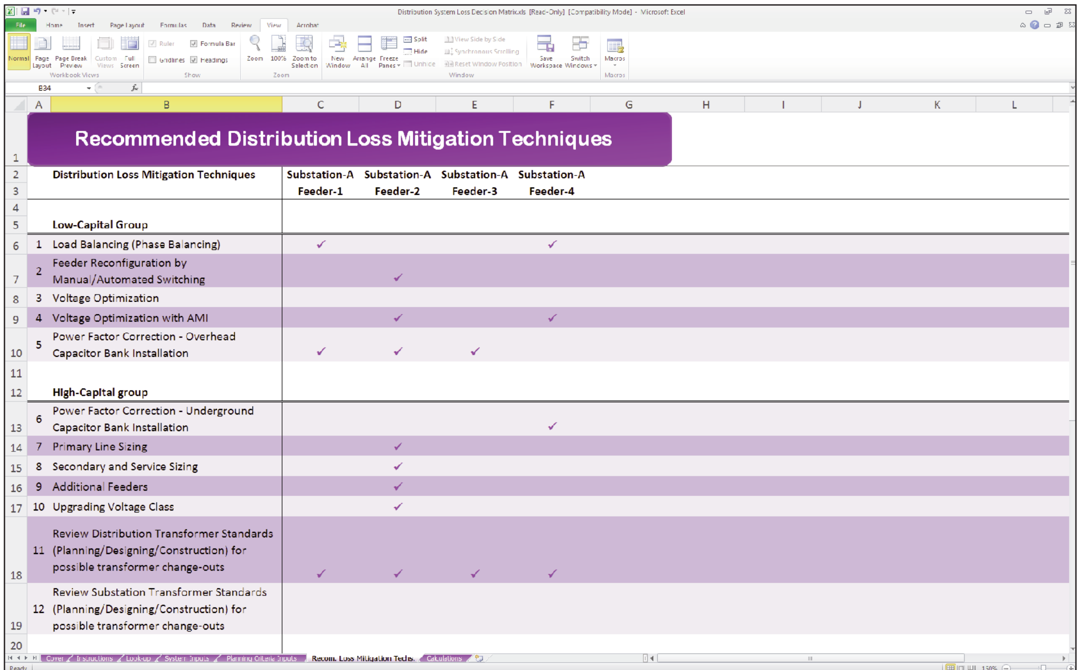
This worksheet houses all data calculated by the tool to demonstrate the applicable mitigation techniques.



	A	B	C	D	E
1	System Inputs				
2	**Substation Characteristics**				
3	Substation Name	**Substation-A**			
4	Substation Transformer Name Plate Rating (MVA)	20			
5	Voltage Control Devices (LTC or Voltage Regulators) Available	Yes			
6					
7	**Feeder Characteristics**				
8	Feeder Name	**Feeder-1**	**Feeder-2**	**Feeder-3**	**Feeder-4**
9	Voltage Class (kV) (optional)	12.47	4.2	12.47	12.47
10	Connected kVA	9000	6500	7500	15000
11	Feeder Construction	Over Head	Over Head	Over Head	Under Ground
12	Adjacent feeder back-feed capacity available	Yes	Yes	Yes	Yes
13	Feeder Voltage Regulator available	No	No	No	No
14	Street Lighting Technology	Mercury Vapor	Fluorescent	HID (HPS/MH)	LED
15	Substation Metering and Equipment	Solid State	Electro Mechanical	Electro Mechanical	Electro Mechanical
16					
17	**Smartgrid Implementation**				
18	AMI In Place	Yes	Yes	No	Yes
19	Dispatchable Distributed Generation In Place	Yes	No	Yes	Yes
20	Demand Management In Place	No	Yes	Yes	Yes
21					
22	**Load Flow - Peak Loading Scenario**				
23	Lowest Primary Voltage (out of Ph-A, Ph-B, and Ph-C) % of 120 V (If AMI is deployed then leave it blank and enter the lowest customer service voltage in the box below)			98.50	
24	Lowest Customer Service Voltage (out of Ph-A, Ph-B, and Ph-C) % of 120 V (If AMI isn't deployed then leave it blank and enter lowest primary voltage in the box above)	94.50	96.00		95.50
25	Phase A (Amps) at Peak Loading	212	450	135	95
26	Phase B (Amps) at Peak Loading	164	425	120	85
27	Phase C (Amps) at Peak Loading	210	465	110	80
28	Power Factor (%) at Peak Loading	99.4	98.8	98.2	99.1
29	3 Phase (kVA) Load at Peak Loading	4340	3200	2600	1875
30	Max. Primary Feeder Line Loading (%) at Peak Loading	65.00	90.00	55.00	45.00
31	Max. Secondary/Service Loading (%) at Peak Loading	50.00	85.00	45.00	48.00
32					

FIGURE 8.5: Screenshot of System Inputs Worksheet

PREVIOUS VIEW



Recommended Distribution Loss Mitigation Techniques

	Distribution Loss Mitigation Techniques	Substation-A Feeder-1	Substation-A Feeder-2	Substation-A Feeder-3	Substation-A Feeder-4
	Low-Capital Group				
1	Load Balancing (Phase Balancing)	✓			✓
2	Feeder Reconfiguration by Manual/Automated Switching		✓		
3	Voltage Optimization				
4	Voltage Optimization with AMI		✓		✓
5	Power Factor Correction - Overhead Capacitor Bank Installation	✓	✓	✓	
	High-Capital group				
6	Power Factor Correction - Underground Capacitor Bank Installation				✓
7	Primary Line Sizing		✓		
8	Secondary and Service Sizing		✓		
9	Additional Feeders		✓		
10	Upgrading Voltage Class		✓		
11	Review Distribution Transformer Standards (Planning/Designing/Construction) for possible transformer change-outs	✓	✓	✓	✓
12	Review Substation Transformer Standards (Planning/Designing/Construction) for possible transformer change-outs				

FIGURE 8.6: Screenshot of Recommended Loss Mitigation Techniques Worksheet

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A Summary of Co-op Questionnaire Responses

In This Section:

- Overview
- Five-Year Historical Losses
- Loss Mitigation Techniques
- Challenges

Overview

Leidos interviewed six co-ops to learn about their system losses and to understand various measures taken to mitigate those losses. This appendix provides a general summary of the responses received from these co-ops:

- Adams Electric Cooperative (AEC), Gettysburg, Pennsylvania
- Brunswick Electric Member Cooperation (BEMC), Shallotte, North Carolina
- Dakota Electric Association (DEA), Farmington, Minnesota
- Maquoketa Valley Electric Cooperative (MVEC), Anamosa, Iowa
- Sulphur Springs Valley Electric Cooperative (SSVEC), Willcox, Arizona
- Withlacoochee River Electric Cooperative (WREC), Dade City, Florida

Five-Year Historical Losses

Table A.1 and **Figure A.1** show the five-year historical distribution losses reported by co-ops that responded to the questionnaire.

TABLE A.1: Annual Co-op Distribution Losses (%)

	AEC	BEMC	DEA	MVEC	SSVEC	WREC
2008	4.42%	5.16%	3.03%	5.59%	6.75%	4.10%
2009	4.57%	5.64%	2.71%	4.13%	7.67%	3.90%
2010	4.49%	7.91%	1.81%	6.37%	6.84%	3.80%
2011	4.73%	3.48%	3.57%	6.22%	8.08%	3.80%
2012	4.85%	6.60%	2.75%	6.32%	7.23%	4.10%

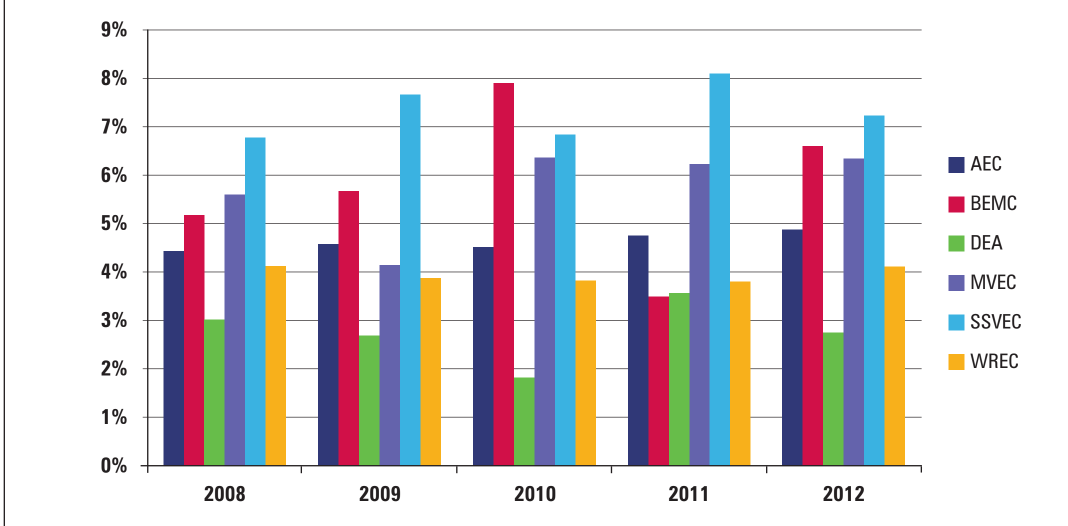

FIGURE A.1: Annual Co-op Distribution Losses (%)

Loss Mitigation Techniques

Table A.2 shows the loss mitigation techniques implemented by each co-op.

TABLE A.2: Loss Mitigation Techniques Implemented per Co-op

	AEC	BEMC	DEA	MVEC	SSVEC	WREC
Distribution Capacitor Installation	•	•	•	•	•	•
Conservation Voltage Reduction (CVR)	•		•	•	•	
Phase Balancing	•	•	•	•	•	
Upgrading the Voltage Class		•			•	•
Installing More Efficient Transformers	•	•	•	•		•
Reconductoring of Primary or Secondary Conductors	•	•	•	•	•	
Multiphasing of Single-Phase Primary Lines		•	•		•	
AMI	•	•			•	
Demand Response	•		•		•	

Challenges

The six cooperatives responded with the following challenges they face in regards to losses at executive, finance, and engineering levels of their organizations.

- Co-op personnel tend to oversize distribution transformers, leading to higher losses. This happens because lineworkers only want to carry one size of distribution transformers on their trucks.
- Most losses occur in distribution transformers and it is hard to cost-justify any mass transformer change out based on kilowatt-hour savings after factoring in the labor costs to perform the changes.
- Finding and developing better ways to narrow down where distribution losses occur would help to implement specific strategies to mitigate the losses that are predominant.
- Power supply is going to be a more energy-based (kilowatt-hour) rate, with the demand rate (kilowatt) being very low. Many charges are becoming fixed, not kilowatt-hour or kilowatt based.
- Future transmission availability and costs are not usually included in loss analysis.
- Projecting or forecasting future costs is difficult.
- The ability to analyze energy (kilowatt-hour) losses is almost non-existent. All analysis programs are built on a certain demand level and don't allow time-series analysis needed for energy.
- Most field devices and SCADA are designed for kilowatt/Amp metering and not for energy/kilowatt-hour metering.

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B U.S. Average T&D Losses Calculation

This section reviews the calculations performed to compute U.S. average T&D losses and the cost of U.S. average T&D losses using Energy Information Administration (EIA) data.

U.S. Average T&D Losses

The chart shown previously in **Figure 1.1** is created using data from the "State Electricity Profiles" report by EIA released on January 2012.[16] This report presents a summary of key state electricity statistics for the year 2000, and years 2004 through 2010. Data for years 2006 to 2010 have been used. The required data are in "Table 10: Supply and Disposition of Electricity" of each Profile. To view this data, scroll down each Profile page to find Table 10 and see the row for Estimated Losses in the Table.

T&D losses as a percentage are calculated by dividing Estimated Losses by the result of Total Disposition minus Direct Use.[17] Direct Use electricity is electricity that is generated at facilities that is not put onto the electricity transmission and distribution grid and, therefore, does not contribute to T&D losses.

Cost of U.S. Average T&D Losses

The cost of U.S. average T&D losses can be calculated as in Equation B.1.

Equation B.1

$$\begin{aligned} \textit{T\&D Losses Cost} &= \textit{U.S. Average T\&D Losses (MWh)} \times \textit{Avg. Generation Rate (\$/MWh)} \\ &= 273{,}852{,}600 \times \$34.40 \\ &= \$\ 9.5\ \textit{Billion} \end{aligned}$$

Where:

U.S. Average T&D Losses (MWh) = the five-year average losses from 2006 to 2010

Average Generation Rate ($/MWh) = the average on-peak wholesale (spot) price for the year 2012 [(1)]

(1) "2012 Brief: Average Wholesale Electricity Prices Down Compared to Last Year." January 9, 2013. *Today in Energy,* U.S. Energy Information Administration. **www.eia.gov/todayinenergy/detail.cfm?id=9510**.

16 "State Electricity Profiles 2010." January 2012. U.S. Energy Information Administration, U.S. Department of Energy. **www.eia.gov/electricity/state/pdf/sep2010.pdf**.

17 "Frequently Asked Questions: How Much Electricity is Lost in Transmission and Distribution in the United States?" U.S. Energy Information Administration. **www.eia.gov/tools/faqs/faq.cfm?id=105&t=3**.

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C Distribution Loss Calculations and Equations[18]

In This Section:

- **Substation Transformers**
- **Primary Lines**
- **Line Equipment**
- **Distribution Transformers**
- **Secondary and Services**
- **Meters and Other Equipment**

Substation Transformers

No-load losses (NLL) should be calculated using the manufacturer's data for each transformer rather than by sampling substation transformers. Impedance values typically range greatly between transformers, even those of comparable size ratings and of the same manufacture and vintage. Utilities will generally have the transformer test data for each unit. In addition, the average voltage versus the nameplate voltage $(V_{Nameplate})$ should be taken into account because no-load losses are a function of the applied voltage $(V_{Applied})$ squared.

Equation C.1

$$NLL = \frac{NLL_{Xfmr} \times kV_{Applied}{}^2}{kV_{Nameplate}{}^2} \text{ (kW)}$$

Where:

NLL = No-load loss for the transformer

NLL_{Xfmr} = No-load loss of transformer from certified test reports

$kV_{Applied}$ = Average voltage applied to transformer

$kV_{Nameplate}$ = Rated voltage of transformer

Load losses for each unit should be obtained when possible due to wide ranging characteristics between transformers of the same size and voltage class. Load losses at system peak can be calculated as in Equation C.2.

Equation C.2

$$LL_{Pk} = \frac{LL_{Xfmr} \times kW_{Pk}{}^2}{kW_{Nameplate}{}^2} \text{ (kW)}$$

Where:

LL_{Pk} = Peak load loss of transformer at system coincident peak

LL_{Xfmr} = Load loss of transformer from certified test reports

kW_{Pk} = Load of transformer at system coincident peak

$kW_{Nameplate}$ = Base rating of transformer

Total peak losses are calculated by adding no-load loss and load losses for the coincident transformer load at the system peak using Equations C.1 and C.2, as shown in **Equation C.3.**

[18] Short, Tom (EPRI), Trishia Swayne (SAIC), "Assessment of Transmission and Distribution Losses in New York State." Final Report for the New York State Energy Research and Development Authority (NYSERDA). November 2012.

Equation C.3

$$LS_{Pk} = \sum_{n=1}^{N} (LL_{Pk}(n) + NLL(n)) \ \textbf{(kW)}$$

Where:

- LL_{Pk} = Peak load loss of transformer at system coincident peak (see **Eq. C.2**)
- NLL = No-load loss for the transformer (see **Eq. C.1**)
- LS_{Pk} = Total peak losses for transformer at system coincident peak
- n = Each transformer

Total energy losses can be calculated using hourly load data (Equation C.4) or using peak losses multiplied by the loss factor, adding no-load loss and load losses peak multiplied by the loss factor, and multiplying by the time using **Equations C.1 and C.2**, where the peak load is the noncoincident load or annual peak of the transformer (Equation C.5).

Equation C.4

$$LS_{Energy} = \sum_{n=1}^{N} \sum_{h=1}^{T} (LL_{HrLd}(h)(n) + NLL(n)) \times T \ \textbf{(kWh)}$$

Where:

- LS_{Energy} = Total energy losses for transformers
- LL_{HrLd} = Load losses for each hour of the transformer load
- h = Each hour
- n = Each transformer
- T = Hours of study period, usually 8,760 hours (one year)

Or

Equation C.5

$$LS_{Energy} = \sum_{n=1}^{N} (LL_{Pk}(n) \times LSF_{Xfmr}(n) + NLL(n)) \times T \ \textbf{(kWh)}$$

Where:

- LS_{Energy} = Total energy losses for transformers
- LL_{Pk} = Peak load loss of transformer at system noncoincident peak
- LSF = Loss factor for each transformer (see **Section 3**)
- NLL = No-load loss for each transformer (see **Eq. C.1**)
- T = Hours of study period, usually 8,760 hours (one year)
- n = Each transformer

Primary Lines

Demand and energy losses, per feeder, for primary distribution lines can be calculated using the following equations, which require output from computer simulations.

Equation C.6

$$LS_{Pk} = \sum_{n=1}^{N} LnLS(n) \ \ \textbf{(kW)}$$

Where:

LS_{Pk} = Losses for a feeder at the feeder load during system peak (coincident load)

$LnLS(n)$ = Line Losses ($I^2 \times R$ losses) for segment n from power flow analysis

n = Each feeder

The energy losses for the primary lines can be calculated by running power flow analysis using hourly load data (Equation C.7) or at the feeder peak and multiplying by the loss factor for the feeder and then summing each feeder to get total primary line losses (Equation C.8).

Equation C.7

$$LS_{Energy} = \sum_{n=1}^{N} \sum_{h=1}^{T} LnLS_{HrLd}(h)(n) \ \ \textbf{(kWh)}$$

Where:

LS_{Energy} = Energy losses for feeders

$LnLS_{HrLd}$ = Line losses for each hour of the feeder load

h = Each hour

n = Number of feeders

T = Hours of study period, usually 8,760 hours (one year)

Or

Equation C.8

$$LS_{Energy} = \left(\sum_{n=1}^{N} LnLS_{Pk}(n) \times LSF(n) \right) \times T \ \ \textbf{(kWh)}$$

Where:

LS_{Energy} = Energy losses for feeders

$LnLS_{Pk}$ = Line losses at feeder noncoincident peak

n = Number of feeders

T = Number of hours, usually 8,670

Line Equipment

Line equipment includes voltage regulators and surge arrestors for a distribution system. Losses for voltage regulators are calculated the same as for substation transformers (see **Equations C.1 through C.5**).

The losses for a metal oxide varistor (MOV) surge arrestor can be calculated for each voltage class. Typical leakage current is less than 1 mA and ranges from 0.5 mA to 0.7 mA. The losses are constant, regardless of loading.

Equation C.9

$$Losses = \sum_{n=1}^{N} kV\,ln_n \times 0.0006 \times Qty_n \times T \ \ \textbf{(kWh)}$$

Where:

n = Each voltage class

$kV\,ln$ = Kilovolts line to neutral

0.0006 = Leakage current of MOV arrestors

Qty = Quantity of arrestors

T = Duration of study period, 8,760 hours for annual analysis

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Distribution Transformers

No-load losses can be calculated simply by multiplying the quantity of each type of transformer by the no-load losses and by time. Equation C.10 is similar to **Equation C.1** but, rather than using specific loss data for each transformer, average values are used for each transformer classification or grouping.

Equation C.10

$$NLL = \left(\frac{NLL_{Xfmr} \times kV_{Applied}{}^2}{kV_{Nameplate}{}^2}\right) \textbf{(kW)}$$

Where:

- NLL = No-load losses for distribution transformer
- NLL_{Xfmr} = Average no-load losses for classification/grouping of distribution transformer
- $kV_{Applied}$ = Average voltage that is applied to the distribution transformer
- $kV_{Nameplate}$ = Nameplate voltage rating of the distribution transformer

Load losses can be determined by grouping the transformer sizes with customer class and customer quantity typically assigned to transformers of each size studied. Average transformer loading at system peak could be determined by customer data and then applied to the distribution transformer loss model. Load losses at peak system load could then be approximated with Equation C.11.

Equation C.11

$$LL_{Pk} = \frac{LL_{Xfmr} \times kW_{Pk}{}^2}{kW_{Nameplate}{}^2} \textbf{(kW)}$$

Where:

- LL_{Pk} = Peak load loss of transformer at system coincident peak
- LL_{Xfmr} = Average load loss for classification/grouping of distribution transformer
- kW_{Pk} = Coincident load of transformer at system peak
- $kW_{Nameplate}$ = Base rating of transformer

Total peak losses are calculated by adding no-load loss and load losses for the coincident transformer load at the system peak using Equations C.10 and C.11.

Equation C.12

$$LS_{Pk} = \sum_{n=1}^{N} (LL_{Pk}(n) + NLL(n)) \times Qty(n) \;\; \textbf{(kW)}$$

Where:

- LS_{Pk} = Total Peak losses for transformer at system coincident peak
- LL_{Pk} = Peak load loss of transformer at system coincident peak (see Eq. C.11)
- NLL = No-load loss for the transformer (see Eq. C.10)
- n = Each transformer or classification/grouping
- Qty = Number of transformers for each classification/grouping (If calculating losses by individual transformers, Qty = 1)

Total energy losses for transformers can be calculated using hourly load data (**Equation C.13**) or using peak losses multiplied by the loss factor and adding no-load loss then multiplying by time (**Equation C.14**). The loss factor can be determined using equations from **Section 3**, where the peak load is the noncoincident load or annual peak of the transformer.

Equation C.13

$$LS_{Energy} = \sum_{n=1}^{N} \left(\sum_{h=1}^{T} (LL_{HrLd}(h)(n) + NLL(n)) \times T \right) \times Qty(n) \quad \textbf{(kWh)}$$

Where:

- LS_{Energy} = Total energy losses for transformers
- LL_{HrLd} = Load losses for each hour of the transformer load
- h = Each hour
- n = Each transformer or transformer classification/grouping
- T = Hours of study period, usually 8,760 hours (one year)
- Qty = Number of transformers for each classification/grouping (If calculating losses by individual transformers, Qty = 1)

Or

Equation C.14

$$LS_{Energy} = \sum_{n=1}^{N} (LL_{Pk}(n) \times LSF_{Xfmr}(n) + NLL(n)) \times T \times Qty(n) \quad \textbf{(kWh)}$$

Where:

- LS_{Energy} = Total energy losses for transformers
- LL_{Pk} = Peak load loss of transformer at system noncoincident peak
- LSF = Loss factor for each transformer (see **Section 3**)
- T = Hours of study period, usually 8,760 hours (one year)
- n = Each transformer or transformer classification/grouping
- Qty = Number of transformers for each classification/grouping (If calculating losses by individual transformers Qty = 1)

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Secondary Systems and Services

The loss calculation methodology will depend on the data that is available for a particular co-op. In general, secondary systems can be grouped together based on similar categories related to calculating losses. These categories may include conductor size, age of installation, customer class, overhead, underground, and voltage levels. Historical records or sampling of secondary systems can be used to determine electrical characteristics, including conductor sizes (resistance), loads (magnitude, load factors, and imbalance), loss factors, coincidence factors, and diversity factors. Losses then could be approximated using Equations C.15 and C.16.

Equation C.15

$$LS_{Energy} = \sum_{n=1}^{N} \left(\frac{kW_{Pk}(n) \times Cf}{V(n) \times 1000} \right)^2 \times imbF \times Lavg(n) \times R \times DF(n) \times Qty(n) \quad \textbf{(kW)}$$

Equation C.16

$$LS_{Energy} = \sum_{n=1}^{N} \left(\frac{kW_{Pk}(n)}{V(n) \times 1000} \right)^2 \times imbF \times LSF \times Lavg(n) \times R \times DF(n) \times T \times Qty(n) \quad \textbf{(kWh)}$$

Where:

- n = Grouping category
- kW_{Pk} = Average peak demand
- Cf = Coincident factor to convert average peak demand to demand during system peak
- V = Voltage level line to line in volts; for three phase, V(n) = V(n)LL×1.7321
- $imbF$ = Imbalance factor for phase imbalance (for a balanced secondary imbF = 1, value increases as the phase imbalance increases)
- LSF = Loss Factor (see **Section 3**)
- $Lavg$ = Average conductor length in feet
- R = Resistance of conductor per foot
- DF = Diversity factor or coincidence factor and is dependent on the number of customers served by the conductor:

Number of Customers	DF
1	1.00
2	0.90
3	0.83
4	0.78
5	0.75
>10	0.70

- Qty = Quantity of systems matching the grouping category
- T = Hours of study period, usually 8,760 hours (one year)

Meters and Other Equipment

Losses for most types of metering equipment are considered fixed and, therefore, the calculations are straightforward. Losses for energy are the equipment losses multiplied by time.

Equation C.17

$$Losses = \sum_{n=1}^{N} EquipmentLosses(n) \times T \quad \textbf{(kWh)}$$

Where:

n = Each type of equipment

T = Duration of study period, usually 8,760 hours (one year)

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D

Distributed Generation Emerging Trends Case Study[19]

In January 2009, SAIC, Inc., finalized the "Distributed Renewable Energy Operating Impacts and Valuation Study" for Arizona Public Service (APS). The study evaluated the value of solar distribution energy (DE) technologies on the APS transmission and distribution system. Locating solar DE generation near the demand benefits the electric system primarily in two ways:

- It reduces the line losses across the electric system because less energy needs to be transmitted from large central station generation to the location of the demand.
- It reduces the burden on the electric system at peak demands, possibly allowing deferral of transmission and distribution investments.

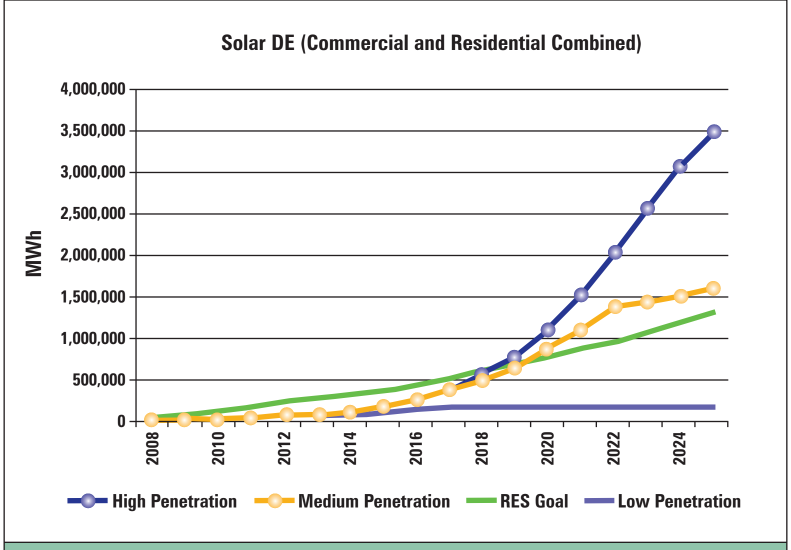

FIGURE D.1: Solar Distribution Energy Penetration and Energy Savings

APS estimates that losses account for eight percent of energy purchased and generated. Discounting for no-load losses, theft, and company use that are not affected by load reduction, transmission and distribution "series" losses or "load" losses are estimated at six percent. Energy loss savings will occur every hour of every year and increase as solar deployment increases.

The study shows that solar DE brings value to APS in both the near term and, increasingly, over the long term. One of the key aspects of the study reflects the fact that solar adoption will likely follow economic attractiveness. Alternative funding mechanisms, such as third-party leasing, may alter the economic drivers for individual adoption decisions.

In the absence of such alternatives, payback period is the primary driver for most technology adoptions, which applies to solar DE adoption as well. As electric rates increase and technology costs decease, the payback period will shorten and deployment will accelerate. The resulting traditional technology "S-shaped" curve for adoption has significant impact on near-term value calculations, particularly in the 2010 and 2015 timeframes. Figure D.1 shows how the solar DE adoption is anticipated to accelerate in the future and the annual energy savings.

Using the adoption cases and characterizing the solar DE production, the study developed the capacity impacts on APS. For the distribution system, the market adoption scenarios (low, medium, and high penetration cases) created no real value. This is because the need

[19] Short/Swayne, "Assessment of T&D Losses in New York State."

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to meet peak customer load when solar DE is unavailable eliminates most of the potential benefits. However, value for the distribution system can be derived when sufficient solar DE is deployed on a specific feeder. Such deployment can potentially defer distribution upgrade investments, but these solar installations must be located on a specific feeder to reduce a specific overloaded condition. The associated annual savings, which include the impact from carrying costs, are represented in Table D.1.

TABLE D.1: Capital Reductions at Distribution Level (2008 $000)

	Distribution System	Carrying Charge (%)	Associated Annual Savings
Target Scenario			
2010	$345	12.06%	$42
2015	$3,335	12.06%	$402
2025	$64,860	12.06%	$7,822
Single-Axis Sensitivity			
2010	$345	12.06%	$42
2015	$3,450	12.06%	$416
2025	$67,045	12.06%	$8,086

TABLE D.2: Capital Reductions at Transmission Level (2008 $000)

	Transmission System	Carrying Charge (%)	Associated Annual Savings
High-Penetration Case			
2010	$0	11.84%	$0
2015	$0	11.84%	$0
2025	$110,000	11.84%	$13,024

TABLE D.3: Capital Reductions at Generation Level (2008 $000)

	Generation System	Carrying Charge (%)	Associated Annual Savings
Medium-Penetration Case			
2010	$0	11.79%	$0
2015	$0	11.79%	$0
2025	$184,581	11.79%	$21,762
High-Penetration Case			
2010	$0	11.79%	$0
2015	$0	11.79%	$0
2025	$299,002	11.79%	$35,252

Unlike the distribution system, the specific location of the solar DE was not an impediment to obtaining value for the transmission system. However, there are several other issues that were determined to affect value.

First, the long-term planning requirements for transmission facilities made opportunities in 2010 and 2015 unlikely. Initially, a specific load pocket was targeted for transmission relief through solar DE, but the near-term need for additional transmission capacity in that area eliminated this targeted value opportunity.

Second, transmission improvements are "lumpy" in nature. A significant number of solar DE installations would be required to aggregate sufficient capacity demand reduction to avoid or defer investments in transmission systems. Therefore, the calculated transmission capacity savings occur only in the last target year (2025) and for the high-penetration case. The carrying costs are represented in the annual savings shown in Table D.2.

Solar DE value for the generation system was similar to the transmission system in that the specific location of solar DE was not an impediment to determining capacity savings. Also, similar to the transmission system, capacity cost reductions for the generation system require a significant aggregation of solar DE installations, and benefits occur only in the later years of the study period. However, unlike the transmission system, reductions in generation capital cost were determined to exist for both the medium- and high-penetration cases, as shown in Table D.3 (which incorporates the impacts from the associated carrying costs).

Much of the potential annual savings from solar DE results from APS avoiding the energy produced from solar DE systems. This reduced energy requirement decreases fuel and purchased power requirements and brings associated reductions in line losses and annual fixed O&M costs. Generally, these energy savings were found to exist for all deployment cases, with the exception of reduction in fixed O&M costs for the low-penetration case. Additionally, the specific location of the deployment of solar DE was not a determinant for these value characteristics.

The values determined for the annual energy savings are shown below and are a direct result of the output from the solar DE installations. As more solar DE technology is installed, these savings values will directly increase. Reductions in fixed O&M costs related to the reduction in demand for the dependable generating capacity. The target scenario results (not shown below) are identical to the high-penetration case (as the target scenario is focused on specific locations of solar DE on the distribution system, which impacts the capacity savings but not the energy savings). The single-axis sensitivity shows a slightly higher energy savings resulting from increased production from these units.

The results reveal another significant finding of this study: the "law of diminishing returns" applies to solar DE installations. In other words, the more solar DE installed, the less incremental value of each additional solar DE installation. This is illustrated in Table D.4 in the decreased average value of loss reduction between the low-, medium-, and high-penetration cases in the year 2025; the high-penetration case, with the most solar DE installed in 2025, has the lowest loss savings per solar generated (MWh) at 11.2 percent, compared to 11.8 percent for the low-penetration case.

In addition to savings in energy losses, there is also a benefit of avoided losses on capacity, or the ability to defer distribution, transmission, or generation investment. For transmission, the loss savings at the 90 percent confidence interval was 22 percent of the dependable capacity, as calculated in the study.

TABLE D.4: Annual Energy and Fixed O&M Savings (2008 $000)

	Solar DE Deployed (MWh)	Annual Energy Loss Savings (MWh)	MWh Savings in Losses/ MWh Solar Generated	Reduction in Losses	Reduction in Fuel/Purchased Power	Reduction in Fixed O&M Costs	Total Energy-Related and Fixed-O&M Savings
Low-Penetration Case							
2010	15,019	1,829	12.2%	$102	$834	$0	$936
2015	94,782	11,290	11.9%	$501	$5,105	$659	$6,266
2025	157,454	18,607	11.8%	$701	$7,847	$3,728	$12,276
Medium-Penetration Case							
2010	15,798	1,929	12.2%	$108	$872	$0	$980
2015	161,377	19,467	12.1%	$1,034	$9,066	$1,351	$11,450
2025	1,599,924	188,907	11.8%	$8,659	$87,936	$18,946	$115,542
High-Penetration Case							
2010	15,798	1,929	12.2%	$108	$872	$0	$980
2015	161,377	19,467	12.1%	$1,034	$9,066	$1,351	$11,450
2025	3,472,412	390,248	11.2%	$14,529	$167,480	$20,965	$202,974
Single-Axis Sensitivity							
2010	16,608	2,031	12.2%	$114	$918	$0	$1,031
2015	167,804	20,262	12.1%	$1,074	$9,504	$1,546	$12,124
2025	3,638,634	407,170	11.2%	$14,925	$173,921	$21,444	$210,290

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E Decision Matrix Tool Logic

TABLE E.1: Decision Matrix Tool Logic				
#	**Techniques**	**Required Inputs**	**Calculated Inputs**	**Logic**
		Low-Capital Group		
1	Load Balancing (Phase Balancing)	• Phase-A, Phase-B, and Phase-C currents (Amps) at substation at peak loading • Phase-A, Phase-B, and Phase-C currents (Amps) at substation at average loading • Allowed maximum phase unbalance (%)	• Phase unbalance (%) for peak loading • Phase unbalance (%) for average loading	Technique is applicable if: • Calculated phase unbalances for peak is greater than allowed maximum phase unbalance **(OR)** • Calculated phase unbalances for average is greater than allowed maximum phase unbalance
2	Feeder Reconfiguration by Manual/Automated Switching	• Maximum primary line loading at peak (%) • Allowed maximum primary line loading at peak (%) • Adjacent feeder back-feed capacity available (Yes/No)		Technique is applicable if: • Maximum primary line loading at peak (%) is greater than allowed maximum primary line loading at peak (%) **(AND)** • Adjacent feeder back-feed capacity available input is "Yes"
3	Voltage Optimization	• Lowest primary voltage (out of Phase-A, Phase-B, and Phase-C) % of 120 V at peak • Maximum secondary voltage drop (%) • Allowed minimum customer service voltage (V) • Voltage control devices (LTC or voltage regulators) available (Yes/No) • Feeder voltage regulators available (Yes/No)	Allowed Min. Primary Voltage % of 120V	Technique is applicable if: • Lowest primary voltage (%) is greater than the calculated allowed minimum primary voltage (%) **(AND)** • Voltage control devices (LTC or voltage regulators) available input is "Yes" and feeder voltage regulators available input is "Yes"

Continued

TABLE E.1: Decision Matrix Tool Logic (cont.)

#	Techniques	Required Inputs	Calculated Inputs	Logic
Low-Capital Group (cont.)				
4	Voltage Optimization with AMI	• Lowest customer service voltage (out of Phase-A, Phase-B, and Phase-C) % of 120 V at peak • Allowed minimum customer service voltage (V) • Voltage control devices (LTC or Voltage Regulators) available (Yes/No) • AMI is in place (Yes/No) • Feeder voltage regulators available (Yes/No)	Allowed Minimum Customer Voltage (%)	Technique is applicable if: • Lowest customer service voltage (%) is greater than the allowed minimum customer voltage (%) **(AND)** • Voltage control devices (LTC or voltage regulators) available input is "Yes" and feeder voltage regulators available input is "Yes" **(AND)** • AMI is in place input is "Yes"
5	Power-Factor Correction Overhead Capacitor Bank Installation	• Power factor at peak (%) • Allowed minimum power factor at peak (%) • Feeder construction (overhead or underground)		Technique is applicable if: • Power factor at peak (%) is less than allowed min. power factor at peak (%) **(AND)** • Feeder construction is overhead
High-Capital Group				
6	Power-Factor Correction Underground Capacitor Bank Installation	• Power factor at peak (%) • Allowed minimum power factor at peak (%) • Feeder construction (overhead or underground)		Technique is applicable if: • Power factor at peak (%) is less than allowed minimum power factor at peak (%) **(AND)** • Feeder construction is underground
7	Primary Conductor Sizing	• Maximum primary line loading at peak (%) • Allowed maximum primary line loading at peak (%)		Technique is applicable if: • Maximum primary line loading at peak (%) is greater than allowed maximum primary line loading at peak (%)
8	Secondary and Service Sizing	• Maximum secondary/service line loading at peak (%) • Allowed maximum secondary/service line loading at peak (%)		Technique is applicable if: • Maximum secondary/service line loading at peak (%) is greater than allowed maximum secondary/service line loading at peak (%)
9	Additional Feeders	• Maximum primary line loading at peak (%) • Allowed maximum primary line loading at peak (%)		Technique is applicable if: • Maximum primary line loading at peak (%) is greater than allowed maximum primary line loading at peak (%)

Continued

TABLE E.1: Decision Matrix Tool Logic (cont.)				
#	**Techniques**	**Required Inputs**	**Calculated Inputs**	**Logic**
		High-Capital Group (cont.)		
10	Review Distribution Transformer Standards (Planning/Designing/ Construction) for Potential Transformer Change-Out	• Connected kVA • 3-phase (kVA) load • Allowed minimum ratio of connected kVA to actual kVA loading	Ratio of connected kVA to actual kVA loading	Technique is applicable if: • Ratio of connected kVA to actual kVA loading is less than allowed minimum ratio of connected kVA to actual kVA loading
11	Review Substation Transformer Standards (Planning/Designing/ Construction) for Potential Transformer Change-Out	• 3-phase (kVA) Load • Substation transformer name plate rating (MVA) • Allowed maximum substation transformer loading (%) at peak	Substation transformer loading (%) at peak	Technique is applicable if: • Substation transformer loading (%) at peak is greater than allowed substation transformer loading (%) at peak
12	Upgrading Voltage Class	• Max. Primary line loading at peak (%) • Allowed maximum primary line loading at peak (%)		Technique is applicable if: • Maximum primary line loading at peak (%) is greater than allowed maximum primary line loading at peak (%)
		Smart Grid Group		
13	Demand Management	Demand management program in place (Yes/No)		Technique is applicable if: • Demand management program is in place input is "Yes"
14	Distributed Generation	Dispatchable distribution generation available (Yes/No)		Technique is applicable if: • Dispatchable distribution generation is in place input is "Yes"
		Miscellaneous		
15	Street Lighting	Street lighting technology (incandescent, fluorescent, mercury vapor, HID [HPS/MH], LED)		Technique is applicable if: • Street lighting technology is other than HID (HPS/MH) or LED
16	Metering	Metering technology (electromechanical, solid state)		Technique is applicable if: • Metering technology is other than solid state

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F Abbreviations

%Z	Constant Impedance
AC	Alternating Current
ACEC	Adams-Columbia Electric Cooperative
A&G	Administrative and General
AMI	Advanced Metering Infrastructure
AMT	Amorphous Core Transformer
ANSI	American National Standards Institute
APS	Arizona Public Service
BCR	Benefit-Cost Ratio
BPA	Bonneville Power Administration
BPL	Broadband Over Power Lines
CBM	Condition-Based Maintenance
CFC	National Rural Utilities Cooperative Finance Corporation
CIPCO	Central Iowa Power Cooperative
CPI	Consumer Price Index
Cu	Copper
CT	Current Transformer
CVR	Conservation Voltage Reduction
CVRf	Conservation Voltage Reduction Factor
DA	Distribution Automation
DG	Distributed Generation
DMS	Distribution Management System
DPP	Discounted Payback Period
DSS	Distribution System Simulator
EIA	Energy Information Administration
ESUE	Energy Smart Utility Efficiency
Fe	Iron
FLEC	Fort Loudoun Electric Cooperative
G2V	Grid-to-Vehicle
HID	High-Intensity Discharge
HPS	High-Pressure Sodium
HVAC	Heating, Ventilation, and Air Conditioning
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
kVA	Kilovolt-Ampere
kvar	Kilovolt-Ampere Reactive
kW	Kilowatt
kWh	Kilowatt-Hour
LED	Light-Emitting Diode
LTC	Load Tap Changer
MH	Metal Halide
MOV	Metal Oxide Varistor
MVA	Megavolt Ampere
MVEC	Maquoketa Valley Electric Cooperative
NEEA	Northwest Energy Efficiency Alliance
NLL	No-Load Losses
NPV	Net Present Value
NWPCC	Northwest Power and Conservation Council

O&M Operation and Maintenance

PHEV Plug-In Hybrid Electric Vehicle
PLC Programmable Logic Controller
PT Potential Transformer
PV Present Value

QA/QC Quality Assurance/Quality Control

RIM Rate Impact Measure
rms Root Mean Square
RTU Remote Terminal Unit
RUS Rural Utilities Service

SAIC Science Applications International Corporation, Inc.
SCADA Supervisory Control and Data Acquisition
SCT Societal Cost Test
SIEA San Isabel Electric Association

T&D Transmission and Distribution
TLM Transformer Load Management System
TRC Total Resource Cost
TVA Tennessee Valley Authority

UCT Utility Cost Test

V2G Vehicle-to-Grid
VA Volt-Ampere
var Volt-Ampere Reactive
VO Voltage Optimization

W Watt
Wi-Fi Wireless Local Area Network
WiMAX Worldwide Interoperability for Microwave Access

ZIP Constant Impedance (Z), Constant Current (I), and Constant Power (P)