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Distribution System Losses Evaluation

Reduction: Technical and Economic Assessment

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PRODUCT DESCRIPTION

Constructing new infrastructure increases system capacity, but can be costly compared to other alternatives. In addition, required investment on generation, transmission, and distribution infrastructure will place a significant financial burden on ratepayers.

As a result, utilities face pressure, either through competitive or regulatory forces, to operate systems as efficiently as possible. Increasing the efficiency of distribution systems may create sufficient capacity to avoid or at least defer major capital investments in new generation, transmission, and distribution infrastructure. One area where the efficiency of electrical infrastructure could be improved is the area of electric system losses.

Currently, there is not an industry standard on how utilities calculate and account for electrical losses and reductions in electric system losses. Computer models used to analyze power flows typically only include the primary components of the distribution system infrastructure. More detailed electric system models can benefit utilities by providing more accurate loss calculations as well as benefits for system planning and engineering. The utility industry could benefit from having a consistent and uniform way to measure, compare, and evaluate distribution system losses.

This report identifies current industry practices, develops a methodology for best practices in determining system losses, and provides guidelines for utilities to use in accounting for system efficiencies for reducing system losses.

Results and Findings

Distribution system losses can be reduced by 5% to 10% over the next 10 to 15 years by performing system upgrades, optimizing voltage levels, and changing the planning and design standards of the utility [1, 12, 13, 15]. Some loss reduction techniques are cost effective to retrofit existing infrastructure such as phase balancing and reactive power management, while other techniques are typically economical when implemented at initial construction. Actual loss reductions are highly dependent on existing electrical system performance, existing and past utility design and planning practices, the way a utility operates the distribution system, and the value a utility assigns to loss reduction. Using life-cycle cost analysis to determine the least-cost implementation of new infrastructure provides the best benefit/cost ratio. Table 1 provides ranges for percent loading based on initial annual peak that will provide the least life-cycle cost including electric system losses for utilities. Ranges are provided due to the sensitively of the results to the value placed on electrical losses, growth rates, and capital construction costs. The least cost loading ranges are lower than typically used by most utilities today. Utilities will need to change planning and design standards and purchasing criteria in order to position themselves for using least-cost over the life-cycle of the electrical infrastructure. This would include providing for installation of larger conductors, more efficient transformers, shorter secondary conductors, and more efficient utilization of equipment.

Table 1
Economic Equipment Loading for Lowest Life-Cycle Cost [1, 5, 12, 15]

Distribution Infrastructure	Economic Loading at Initial Peak (% of Nameplate Rating of Thermal Limit)
Substation Transformer	70% to 85%
Primary Conductors	15% to 30%
Distribution Transformers	80% to 100%
Secondary Conductors	10% to 15%

Replacing existing electrical infrastructure will reduce electric system losses, but at higher initial investment than when constructing new facilities. Loss-reduction techniques that can be performed on existing infrastructure and have a high rate of return for the investment are listed below. These loss-reduction techniques are listed in order of highest to lowest benefit-to-cost ratio for typical distribution circuits [13]. Utilities will need to evaluate which loss-reduction techniques are applicable on a circuit by circuit basis. For example, if the circuit power factor is 99 percent, then power factor correction may not produce a high benefit-to-cost ratio.

- Phase balancing,
- Power factor correction,
- Load balancing between feeders/substations,
- Removal of energized transformers that do not serve load, and
- Voltage optimization.

On the other hand, reconductoring, adding new substation transformers and feeders, replacing existing distribution transformers with more efficient transformers, and increasing the voltage class will all reduce distribution losses, but have a higher capital investment.

Detailed analysis needs to be performed at the substation and feeder level in order to ascertain the magnitude of losses, the location where losses are occurring, and which loss reduction techniques can be cost-justified. In many cases other factors, such as reliability or replacement aging infrastructure, play a larger role in determining if infrastructure should be upgraded, while loss reduction analysis can help determine the least-cost design.

Challenges and Objectives

This report targets regulatory commissions, utility managers, distribution system planning engineers, and conservation and energy efficiency departments. Planning, designing, and operating a distribution system efficiently can reduce electric system losses by 5% to 10% over the next 10 to 15 years [1, 12, 13, 15]. Some loss reduction techniques are cost effective to retrofit existing infrastructure such as phase balancing and reactive power management, while other techniques are typically economical when implemented at initial construction. Operating a distribution system more efficiently can further reduce energy requirements and peak demand by 2% to 3% [13], where the majority of the energy reduction is achieved by reducing the customer's energy consumption. More work is needed to refine methodologies and provide more accurate loss values. In preparing this report we reviewed existing practices and developed guidelines for calculating and accounting for loss reduction based on common industry practices. However, many unknowns still exist and assumptions are being used to determine distribution system losses. With additional research, these unknowns and assumptions can be better understood and the loss calculation methodology can be refined, which will provide guidance in determining how specific the loss calculations need to be to provide realistic loss values. Advanced metering infrastructure (AMI) and Smart Grid deployments are the key to collecting additional information needed to perform more detailed analysis. With this additional information, detailed analysis can be performed which will allow the loss calculation methodologies to be optimized so that the best results can be achieved at minimal costs.

Applications, Values, and Use

EPRI's Green Circuits initiative will be performing detailed analysis for several distribution substations and feeders using 15-minute feeder data and, for the feeders that have AMI, 15-minute customer data. With the 15-minute customer data, analysis can be performed that will allow a better understanding of primary line and distribution transformer losses. In addition, optimization of the distribution system losses will be studied and the benefits and costs will be developed based on detailed realistic computer models.

A trend in the electric industry is to integrate system mapping and computer analysis software applications. Updating of electric system information occurs in one location and is typically required for operational issues. Leveraging the mapping information 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.

EPRI Perspective

This report provides important steps to help utilities improve their electrical efficiency and reduce their carbon footprint. Utilities have always done loss studies, but there is a wide range of approaches and inconsistencies. This report will help provide a better framework for loss evaluations and help standardize approaches. As utilities evaluate loss improvements, the loss-improvement accounting guidelines provided here will allow them to confidently choose the most cost-effective options.

Approach

The approach used for the Distribution System Losses Assessment was to review existing rules and regulations regarding distribution system losses, loss studies performed by utilities, and to studies and literature on the subject of calculating losses and distribution efficiency. Seven utilities answered a survey, eight regulatory jurisdictions were reviewed, 19 loss studies by 11 utilities were analyzed, and several reports and studies were included as part of the loss assessment.

The goal was to establish consistent and uniform guidelines for best practices on how to calculate distribution system losses so the utility would have a way to measure, compare, and evaluate distribution system losses. Eight categories were identified for distribution losses and methodologies and formulas were established to guide utilities in determining the losses for each of the categories. Guidelines were then established in each of the eight categories to help utilities determine what changes can be cost-effectively implemented and to account for the reduction in system losses.

Keywords
Conversation voltage regulation
Distribution losses
Distribution efficiency
Loss calculations
Loss guidelines
Optimizing losses
Voltage optimization
VAR management

EXECUTIVE SUMMARY

All electric distribution systems incur energy losses. Losses are defined as the difference between the energy put into the system and the energy that is utilized by the end users. Most energy losses result from energizing the equipment and sending electric current through the system; some losses also result from theft and unmetered loads.

While electric utilities are under increasing pressure to operate their systems as efficiently as possible, the industry lacks a standard method to determine electrical losses. Computer models, where they exist, are helpful, but most models do not include the distribution transformers and secondary system, which account for 40% of the total distribution system losses at peak and 36% for energy as calculated from the results in Table 3-1. Having a consistent and uniform way to evaluate distribution system losses would help provide confidence for regulators that proper allocations are being provided to utilities, help utilities target cost-effective approaches to reducing system losses, and allow utilities to document energy savings so they can be properly credited for energy efficiency claims.

Distribution system losses can be reduced by 5% to 10% over the next 10 to 15 years by performing system upgrades, optimizing voltage levels, and changing the planning and design standards of the utility [1, 12, 13, 15]. Some loss reduction techniques are cost effective to retrofit existing infrastructure such as phase balancing and reactive power management, while other techniques are typically economical when implemented at initial construction. Actual loss reductions are highly dependent on existing electrical system performance, existing and past utility design and planning practices, the way a utility operates the distribution system, and the value a utility assigns to loss reduction.

Detailed analysis needs to be performed at the substation and feeder level in order to ascertain the magnitude of losses, the location where losses are occurring, and which loss reduction techniques can be cost-justified. In many cases other factors, such as reliability or replacement of aging infrastructure, play a larger role in determining if infrastructure should be upgraded, while loss reduction analysis can help determine the least-cost design.

This report evaluates current industry practices and provides guidelines that utilities can use to perform a loss study on a distribution system and to account for the reduction in losses that would result from proposed system improvements. In conducting this study, the researchers reviewed regulatory requirements currently in place in typical jurisdictions. The researchers also collected information from 19 utilities to evaluate the way they perform system loss studies.

Existing Regulations

A survey sent to participating EPRI utilities provided little information on regulatory requirements for loss studies. As a result, the researchers performed a literature search which showed most regulations that mention energy losses focus on wholesale power providers and not on the electric distribution system. Regulations focused on utilities seemed to be intentionally vague and are not particularly demanding, so that utilities could evaluate losses using whatever information they currently possess.

Current Loss Study Methodologies

Sixteen EPRI member utilities and two other non-member utilities provided recent loss studies and background information on the methods and purposes of those studies. This review revealed a variety of approaches to the evaluation and, thus, a wide range of measured loss statistics.

The peak losses for the distribution system ranged from 2.79% to 6.04% and averaged 3.83%. Energy losses ranged from 1.71% to 7.96% and averaged 3.69%. The standard deviation for both peak and energy losses is relatively high, indicating a large variation in reported data. The percent increase in losses at peak compared to energy was only 3.9%, which is much lower than expected. (Note that this is a comparison of reported losses, and no attempt was made to normalize results from the various utilities to account for differences in methods.)

Guidelines for Calculating System Losses

This report provides guidelines that a utility can use to categorize losses, determine which electrical components should be included in the loss study, and calculate the losses for each electrical component.

Electric system losses can be technical losses, meaning losses due to energizing equipment and current flowing through electrical devices, or non-technical losses, which are typically defined as theft and unmetered loads. Technical losses can be further categorized as fixed losses and variable losses. Fixed losses are the energy required by the system to energize equipment and keep the system ready, even when no load is being serviced. These losses, also known as “no-load” losses, remain constant regardless of the system load. Variable losses, which result from current flowing through the equipment, change in proportion to the load.

Each utility needs to determine how to categorize its equipment and which equipment to include in the loss study. Tariffs or regulations may dictate which equipment can be included in electric system loss recovery. For example, the tariff for street lighting may be a fixed fee that already includes losses. As another example, ancillary power required to operate a substation may be considered an operational cost and not counted as an electric system loss.

The type and frequency of data that each utility maintains will determine the techniques that can be used in calculating losses. Hourly data results in more accurate results. Annual data can be used instead, but can lead to less accurate results. If detailed information is not available, utilities should use sampling techniques to determine losses for each category. Utilities may use metering or calculations to calculate losses, and should report both peak load and total energy losses.

The loss study should include the losses of each component in the distribution system, from the customer meter up to and including the substation transformer. Typical categories for distribution system losses include:

- Substation transformer
- Substation equipment
- Primary lines
- Line equipment
- Distribution transformers
- Secondary and service lines
- Meters
- Unmetered load (streetlights and theft)

The two components that make up a large portion of the losses are the substation and distribution transformers. Utilities typically have monthly data at the substation transformer level, but little data at the distribution transformer level. The data needed to calculate losses for each system component will vary based on the tools and models used by the utility.

Two important components of the loss study are the loss factor and the load factor. While electric system losses are highest during peak conditions, approximately 70% of the energy losses occur off peak [13, post final report analysis of hourly data using power flow software for three distribution feeders]. Therefore, factors that represent the relation between peak losses and average losses are helpful in determining electric system losses.

Guidelines for Accounting for Loss Reductions

As utilities make improvements to their systems to reduce losses, they need a consistent way to account for those loss reductions. The two main areas utilities focus on to reduce losses are (1) replacing existing infrastructure and (2) changing design and planning criteria for future infrastructure investments to ensure they are efficient. Utilities should use life-cycle cost analyses to determine that they are implementing infrastructure improvements in the most economical manner.

The simplest and most cost-effective way to analyze proposed loss improvement projects is to use modeling software to analyze power flows in the distribution system. The utility 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.

This report provides guidelines for determining losses and then applying economic analysis to determine the life-cycle cost savings of the following improvements:

- Balancing loads
- Correcting power factor
- Increasing primary conductor size
- Adding an additional (parallel) feeder
- Changing out a distribution transformer
- Upsizing conductors or reconfiguring secondary network
- Adding substation transformers
- Updating street lighting technology
- Upgrading metering technology
- Implementing demand management
- Optimizing voltages

The methodologies developed in this report are based on sound engineering principles and commonly accepted industry practices. However, in order to provide methodologies that are more universal in nature to address the needs of a wide range of utilities, certain assumptions and estimates were employed to simplify the process. Many unknowns still exist and assumptions are being used to determine distribution system losses. With additional research, these unknowns and assumptions can be better understood and the loss calculation methodologies can be refined. Advanced metering infrastructure (AMI) and Smart Grid deployments are the key to collecting additional information needed to perform more detailed analysis. With this additional information, detailed analysis can be performed which will allow the loss calculation methodologies to be optimized so that the best results can be achieved at minimal costs.

A trend in the electric industry is to integrate system mapping and computer analysis software applications. Updating of electric system information occurs in one location and is typically required for operational issues. Leveraging the mapping information 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 including identifying and reducing electrical system losses.

CONTENTS

LIST OF TABLES

1 INTRODUCTION

Electric utilities are under increasing pressure to deliver quality energy to their customers as efficiently as possible. This pressure comes from competition and from new regulations requiring increasing levels of renewable energy sources for which reducing energy losses are included.

Evaluating system losses is a vital way that utilities determine whether they are running their systems as efficiently as possible. Reducing losses can create additional capacity that may eliminate or at least defer the need for major capital investments in new generation, transmission, and distribution infrastructure.

In a typical distribution system there may be many ways to cost-effectively reduce losses. The best examples would be phase balancing and var management, which can reduce losses significantly with minor investment and will have a return of $10 to $15 for each dollar spent [12]. Another common means is to evaluate transformer sizing, which can lead to such actions as swapping transformers or replacing some transformers with higher efficiency models. These types of actions can often delay or eliminate the need for new substations.

Today the utility industry lacks a standard method to determine electrical losses. At best, computer models used to analyze power flows typically include only the primary components of the distribution system infrastructure and do not include the distribution transformers and secondary system. The utility industry could benefit from having a consistent and uniform way to measure, compare, and evaluate distribution system losses. This will help provide confidence for regulators that proper allocations are being provided to utilities, provide utilities ways to target cost-effective approaches to reducing system losses, and allow utilities to document energy savings so they can be properly credited for energy efficiency claims.

The purpose of this paper 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. In conducting this study, the researchers reviewed regulatory requirements that are currently in place in typical jurisdictions. The researchers also collected information from 18 utilities to evaluate the way they perform system loss studies.

2
REGULATORY REVIEW

This section summarizes information available on regulatory requirements of various agencies in regards to establishing, updating, and reporting distribution loss factors (DLF) for distribution service providers.

A survey was sent to participating EPRI utilities that included questions regarding why a loss study is performed by each utility. Little information came back in terms of regulatory requirements for their study or the purpose of each study with the exception of the following:

- "Loss factors are needed for regulatory purposes and by the Rate Department for rate calculations and cogeneration rate adjustments."
- "For compensation of electrical system losses that occur as part of the delivery process," and "To assess any significant impact on losses with major improvements."
- "The purpose of this study is to quantify the cost of losses by system equipment type and rate class."

The regulatory statutes were generally at a higher level and are intended to provide mechanisms to balance the exchange of power for Independent System Operator companies, generating companies, and retail providers. The reviews did not find any references or goals for levels of electric system losses or what components should or should not be included when determining system losses. Some guidelines exist for methodologies defining acceptable techniques that can be used, but these guidelines were purposefully vague in nature to allow each utility to tailor the specifics to how the utility currently operates.

The purpose of the regulatory review is to identify requirements currently affecting utilities, and to illustrate what requirements might be developed in the future. Requirements of ERCOT are listed first as it is an example of present adopted regulatory requirements in the United States. The development of requirements of the California Energy Commission, and proposed methodology to adhere to the requirements by PG&E, SCE, and SDG&E, are listed next as examples of developing requirements. Regulatory requirements for the Republic of the Philippines and Australia are listed at the end as examples of developed regulatory language. In addition, reviews were made of Indiana, New York, and Florida but are not summarized in this report.

ERCOT

From ERCOT Nodal Protocols, Section 13: Transmission and Distribution Losses, Updated August 1st 2007, sub section 13.1.1 (3 and 4)

ERCOT shall forecast Settlement Interval Distribution Loss Factors (DLFs) and post them to the MIS Public Area by 0600 of the Day Ahead period. ERCOT shall forecast the Settlement Interval DLFs as a percentage of load for each Settlement Interval of the Operating Day. On the day following the Operating Day, ERCOT shall also calculate Settlement Interval DLFs using actual system Load for that Settlement Interval and post the resulting deemed actual Settlement Interval DLFs to the settlement system and the MIS Public Area.

Distribution loss coefficients, and the calculation methodology from which they are derived, will be subject to audit by ERCOT for accurate and consistent application. Non-Opt-in Entities (NOIE) with Interval Data Recorders at the settlement point of delivery are not required to provide Distribution loss coefficients and calculation methodology.

California Energy Commission

DLF Criteria and Methodologies: There were no updates found to the information listed below:

In the RSIF sub-committee sessions held during July and August, 1997, parties supported the development of interim, implementable methods for DLFs as of 1/1/98. These interim methods could be utilized for up to one year while the parties study enhancements to the various DLF calculation formulae currently under consideration. These enhancements could then be incorporated into the calculation process and information flow.

DLF Design Criteria

Parties reached consensus on the criteria for DLF estimation Methodology

The calculations should be based upon hourly UDC system loads.

The calculations should vary by service voltage levels (i.e., subtransmission as appropriate, primary and secondary).

The calculations can vary by UDC as long as the output is provided in a consistent manner (e.g., communication protocols and data formats).

The calculations can be based solely on either engineering-modeled distribution line losses, or on historical distribution system losses which also include meter error and energy theft estimates.

The DLFs should be available prior to the trading day for use as day-ahead scheduling tools.

The DLFs based on the day ahead UDC system load forecast will be used for settlement purposes and may be used for scheduling purposes as well.

Base DLFs on the UDC forecasted system load. The UDCs agreed to reevaluate this decision during the overall review of the DLF methodologies prior to 1/1/99.

PG&E

From Cal. PUC Decision 07-03-0444 Filed October 2, 2007:

> DLFs will be calculated by PG&E based on the forecast hourly PG&E Service Area Load (Direct Access, Community Choice Aggregation, plus Bundled Service) per Decisions 97-08-056 and 04-12-046. The hourly DLFs will be broken out by service voltage level and made available each day to market. PG&E will calculate the hourly DLFs based on samples of hourly service area load by applying the approach approved in Decisions 92-12-057, and 04-12-046.

SCE

From Cal. PUC Decision 04-12-046 Filed February 14th 2005:

> Distribution Line Loss Adjustment Factors shall be calculated on an hourly basis for each service voltage. The day-ahead hourly forecast of total system load in megawatts (Loadh), as determined by SCE, shall be used in the calculation of the Distribution Line Loss Adjustment Factors:

- Service metered and delivered at voltages greater than 50 kV:
  - Loss Factor = 1 + [(14.3 / Loadh)+ (0.000000495* Loadh) + 0.00497]
- Service metered and delivered at voltages between 2kV and 50kV:
  - Loss Factor = 1 + [(20.3 / Loadh) + (0.00000267 * Loadh) + 0.00979]
- Service metered and delivered at voltages below 2kV:
  - Loss Factor = 1 + [(87.4 / Loadh) + (0.00000452 * Loadh) + 0.00642]

SDG&E

From Filing of SDG&E (U 902-E) on Distribution Loss Factors, October 31st, 1997

> Distribution Loss Factors (DLFs)
>
> The DLFTLL for each voltage level includes a factor for lost and unaccounted for energy. DLFTLL will be calculated by the utility based on the forecast hourly SDG&E UDC Service Area Load (Direct Access, plus UDC customers, including the Hourly EECC Rate Option Service) per Decision 97-08-056, as modified by Decision 97-11-026. The hourly DLFTLL will be broken out by service voltage level and made available each day to market participants during the day-ahead market. The utility will calculate the hourly DLFTLL by applying the following formulae:
>
> a. Secondary Voltage Class Customers
>
> DLFDLL = 1 + [Losses/Load]
> DLFTLL = 1.0065 x DLFDLL
> Where: Losses = [0.0000090935 × (SysLoad)2] + 27.21
> Load = -[0.00000804463 ×(SysLoad)2]+[0.8586372 ×SysLoad] -24.0524567

SysLoad = SDG&E system load during hourly period in MW.

b. Primary Voltage Class Customers

DLFDLL = 1 + (Losses/Load)
DLFTLL = 1.0065 x DLFDLL
Where: Losses = [0.0000001523524 × (SysLoad)2] + 0.427367656
Load = -[0.000001181634 × (SysLoad)2] + [0.12612 × SysLoad] - 3.533
SysLoad = SDG&E system load during hourly period in MW.

c. Primary at Substation Voltage Class Customers

DLFDLL = 1 + (Losses/Load)
DLFTLL = 1.0065 x DLFDLL
Where: Losses = [0.000000000009798 x (SysLoad)2] + 0.007089
Load = -[0.0000000196 x (SysLoad)2] + [0.002092 x SysLoad] - .0586
SysLoad = SDG&E system load during hourly period in MW.

d. Transmission Voltage Class Customers

DLFDLL = 1 + (Losses/Load) = 1
DLFTLL = 1.0065 x DLFDLL = 1.0065

Republic of the Philippines

In the Philippines, the Energy Regulatory Commission issued guidelines for the automatic adjustment of generation rates and system loss rates by distribution utilities. Once a month, distribution utilities are required to calculate new System Loss Rates as

$$\textit{System Loss Rate} = (GR * U) + (ATR * U) \qquad \textbf{Eq. 2-1}$$

where

GR = Generation Rate calculated in accordance with Article III,

ATR = Average Transmission Rate based on the most recent unbundling decision in Peso per kWh, computed as Transmission Costs per unbundling divided by the Annualized Sales in kWh per unbundling,

U = Gross Up Factor = *%SystemLoss* / (1 – *%SystemLoss*).

The *% System Loss* is based on the actual system loss or the system loss cap, whichever is lower, plus actual company use or the company use cap of 1%, whichever is lower. The actual system loss and company use are based on the previous month figures to be submitted by the Distribution Utility. Actual System Loss can be calculated on an individual customer class level if the Distribution Utility has the requisite information to support customer class level System Loss Rates.

Energy Australia

Distribution Loss Factors must be calculated in accordance with a methodology under the National Electricity Rules. Each distribution network service provider must determine a methodology or must use the jurisdictional regulators' methodology, if available. The methodology must be developed, maintained, and published in accordance with clause 3.6.3 of the National Electric Rules.

Clause 3.6.3 calls out for assignment of connection points in system. These would be site-specific metered points such as at a substation transformer, or non-site-specific, such as streetlight loading. The total of all these connection points would then match the total losses of the distribution system.

3
REVIEW OF DISTRIBUTION LOSS STUDIES

This section summarizes the methodologies described in the loss studies provided by participating utilities. EPRI member utilities were surveyed and asked to provide recent loss models, components studied, methods used, results, suggestions for best practices, reasons for study, the type of losses investigated, and improvement ideas. In addition to EPRI member surveys, two other loss studies were reviewed for the same information.

As expected, the percent losses of total distribution power requirements varied between utilities. The likely causes of the wide variations are the differences in the age of facilities and voltage classes, and inconsistencies in the methodologies used to calculate losses. Variations in methodologies included:

- Some utilities used computer models to calculate primary losses, while others used average loading for each size of conductor.
- Some included secondary and meter loss, while others did not.
- Some included substation equipment, while others did not.
- Some included substation transformers losses as transmission losses, while others considered those to be distribution losses.

Loss statistics were calculated for the peak and energy losses as reported by the participating utilities (see Table 3-1). The peak losses for the distribution system ranged from 2.79% to 6.04% and averaged 3.83%. Energy losses ranged from 1.71% to 7.96% and averaged 3.69%. The standard deviation for both peak and energy losses is relatively high, indicating a large variation in reported data. The percent increase in losses at peak compared to energy was only 3.9%. This is much lower than expected.

Table 3-1
Statistics from Loss Studies Reviewed

Electric System Losses (Peak Demand)				
	Transmission	**Distribution**	**Secondary**	**Total Distribution**
Average	3.69%	2.34%	1.50%	3.83%
Standard Deviation	1.53%	0.73%	0.81%	0.98%
Electric System Losses (Energy)				
	Transmission	**Distribution**	**Secondary**	**Total Distribution**
Average	2.60%	2.36%	1.33%	3.69%
Standard Deviation	1.14%	1.57%	0.89%	1.71%

Table 3-2 shows that of the six utilities that reported both peak and energy losses, one utility had higher percent losses for energy than at peak; and for a second utility, there is only a 5.9% increase in peak losses over energy losses. It would be expected that the percent losses at peak would be much higher than for energy due to the $I^2 \times R$ relationship. The relationship between peak load and average load is between 40% and 60% (known as the load factor), while the relationship between losses at peak and average losses is between 20% and 40% (known as the loss factor).

Table 3-2
Increase in Peak Losses Over Energy Losses

Utility	Increase
F	–1.4%
G	13.0%
H	63.2%
I	31.6%
J	16.4%
P	5.9%

Table 3-3 summarizes the reported losses for the distribution system as well as the reported losses for the transmission system.

Table 3-3
Summary of Loss Studies Reviewed

	Electric System Losses (Peak Demand)				Electric System Losses (Energy)				
Utility	**Transmission**	**Distribution**	**Secondary**	**Total Distribution**	**Transmission**	**Distribution**	**Secondary**	**Total Distribution**	**Year**
A	N/A	3.92%	1.05%	4.97%					2005
B					0.62%	2.73%	3.75%	6.49%	2002
C					N/A	1.91%	0.92%	2.84%	2007
D					2.53%	1.79%	0.89%	2.68%	2004
E					3.71%	2.40%	0.35%	2.76%	
F	2.83%	2.10%	1.44%	3.54%	2.25%	1.84%	1.75%	3.59%	2006
G	5.41%	2.12%	1.54%	3.66%	3.76%	1.53%	1.71%	3.24%	2005
H	5.15%	1.68%	1.11%	2.79%	4.20%	0.82%	0.89%	1.71%	2006
I	5.19%	1.98%	1.23%	3.21%	3.51%	1.20%	1.24%	2.44%	2005
J	4.38%	1.64%	1.34%	2.98%	3.70%	1.28%	1.28%	2.56%	2006
K					1.10%	6.40%	1.56%	7.96%	
L	N/A	2.97%	0.82%	3.79%					
M	3.03%	2.84%	0.91%	3.75%					2004
N	1.57%	2.41%	3.63%	6.04%					2005
O(1)					1.80%	3.67%	0.38%	4.05%	2005
P	1.98%	1.68%	1.90%	3.58%	1.38%	1.58%	1.80%	3.38%	2007
Q					2.53%	1.14%	1.83%	2.96%	2004
R					2.69%	4.69%	0.30%	4.99%	

Note: Losses reported as provided in reports. No attempt was made to normalize losses due to the differences in the way each utility categorized and reported losses.

(1) 2.37% loss for Loose Hardware, Corona or Other Mechanical Abnormalities and Metering Inaccuracies are not included.

While all the participating utilities who responded provided useful information on what was looked into and the results of the study, very little information was revealed in terms of why they performed the study, improvement suggestions, and ideas for a development of best practices to be applied to a standardized loss study. Table 3-4 highlights some of variations in methodology used to calculate primary line and secondary system losses. Appendix A provides a summary overview for side-by-side comparisons between participating utilities for each loss category for each utility.

Table 3-4
Sample of Various Loss Methodologies

Calculation of Primary Losses	
Utility C and D	% of system analyzed is not given. 5 - 4.16kV, 31 - 15kV, 3 - 23.9kV, and 2 - 34.5kV circuits analyzed. Modeled results account for PF and Load Imbalance.
Utility E	Demand losses: a representative feeder conductor was used for each distribution voltage. Average feeder load determined by total load divided by # of feeders. Feeder losses=3*I^2*R*Avg length
Utility F, G, H, I, and J	Line loading and loss characteristics of “Representative Primary Circuits” used. Losses calculated using power flow software.
Utility L	Line losses estimated by feeder efficiency at peak load, loss factor, and power delivered.
Utility M	Power flow on feeder sampling at peak loading. Analysis again performed at different levels by scaling peak load to 100%, 80%, 60% and 40%.
Utility Q	Primary lines losses calculated at 4kV and 15kV classes. Approximately 600 circuits in system and modeled using PSS/ADEPT.
Calculation of Service and Secondary Losses	
Utility A	Calculate secondary line losses on various conductors; uses sizing charts and assumptions with voltage flicker as driver for sizing. Assume 50% residential OH.
Utility B	Secondary: Used 3 typical size aluminum, and 3 typical size copper and evaluated typical average current, then calculated losses through the conductor characteristics.
Utility C and D	Twelve different service configurations provided. Assumed phase imbalance.
Utility E	No commercial customers considered for evaluation of secondary system; Secondary losses determined by average length and typical conductor to serve residential customers.
Utility L	Not Evaluated
Utility P	Used spot loads of each type OH service conductors representing expected load diversity for an OH residential distribution system configured with 16 houses per transformer.

Detailed worksheets were provided by with some of the loss studies, while other utilities provide just the reports. Where a loss model could be ascertained by reading a utility’s loss study, the loss model is summarized in this section. A loss model consists of the tools used to calculate, summarize, and report losses. Each section also summarizes the key items each utility evaluates in its loss study for the major system components.

Utility A

The loss model for Utility A is made up of a series of workbooks that calculate primary line losses, distribution transformer losses, and losses in secondary and service drops.

- Primary Losses:
  - Sampled 12% of distribution system at peak and extrapolated to system
  - Used loss factors to calculate energy losses
  - Analysis software: CYMDIST
- Distribution Transformer Losses:
  - Used GIS to import size and types of transformers.
  - Used average transformer loss data
  - Analyzed at average peak provided from internal data sources
  - Scrubbed data for nonstandard sizes and errors
- Service and Secondary Losses:
  - Used current design guidelines for conductor size and lengths
  - Used design criteria determining conductor sizes and lengths
  - Assume 50% of residential services are overhead
- Distribution Substation Transformers:
  - Did not include in loss evaluation (Loss factors were shown in loss factor development summary, but no calculations or method of derivation were included.)
- Meter:
  - Did not include in evaluation

Utility B

Utility B's system loss report provided a detailed methodology and provided information regarding the types of losses that were calculated, and how losses were calculated for each component. However, a loss model using the methodology and summarizing overall loss findings was not included.

- Primary Losses:
  - Used sum of substation loads by area, number of feeders from each substation by area, and average feeder load.
  - Incorporated typical feeder characteristics and averaged load to calculate losses.
- Distribution Transformer Losses:
  - Evaluated for average no-load losses (total of certified test report losses * 8,760).

- Evaluated for

$$Average\ Load\ Losses = No.\ of\ Units \times Avg.\ Load\ Loss \times Loss\ Factor \times Avg.\ Peak\ Load^2$$

where

load loss comes from certified test reports,

$$Loss\ Factor = \left(\sum\left(Hourly\ Demand\ Load^2\right) / System\ Peak\ Load^2\right) / 8760$$

- Service and Secondary Losses:
  - Secondary: used three typical size aluminum and three typical size copper and evaluated typical average current; then calculated losses based on the conductor characteristics.
  - Services: for both OH and UG, used 55.8% of normal cable loading to determine current; then calculated losses based on the conductor characteristics.
- Distribution Substation Transformers:
  - Evaluated for average no-load losses (Total of certified test report losses * 8,760)
  - Evaluated for *Average Load Losses = No. of Units * Avg Load Loss * Loss Factor * Avg Peak Load*^{2}), where load loss comes from certified test reports and loss factor = (∑(*Hourly Demand Load*^{2}) / *System Peak Load*^{2})/8760
- Meters:
  - Evaluated based on number of each type and losses for each type of meter.
  - Metering devices included energy meters, demand meters, relays, and recorders.

Utilities C, D, E

Loss model includes sample distribution circuit loss analysis, projected losses for all 4.16-, 15-, 23.9-, and 34.5-kV circuits based on sampled analysis and actual feeder loading, distribution transformer analysis based on kVA and quantity. No loss summary was given or calibration of losses to total system losses.

- Primary Losses:
  - The percentage of the system analyzed was not given.
  - Circuits analyzed consisted of five 4.16-kV circuits, thirty-one 15-kV circuits, three 23.9-kV circuits, and two 34.5-kV circuits.
  - Load losses calculated using results from power flow model that reflected actual power factor and load imbalance
  - Analysis software: Siemens PTI PSS/Edept
- Distribution Transformer Losses:
  - Calculate load and no-load losses
  - Loading based on average non-coincident load of 66% rating
  - Demand loss determined for each size- then calculated on quantity per size

  - No-load demand loss determined by no-load demand impedance per size * number of each size
- Service and Secondary Losses:
  - Twelve different service configurations provided
  - Voltage imbalance assumed 55%/45% loading on legs of single phase 120/240
- Distribution Substation Transformers:
  - Calculate load and no-load losses.
  - Peak loads used to calculate load losses
  - Typical transformer no-load losses used to calculate no-load losses
  - Average peak loading of the transformers with historical information used
- Meters:
  - Calculated on standard meter requirement of 0.8 W/hr and electronic meters on 0.2 W/hr
  - Assumed 70% mechanical
  - Assumed 30% electronic

Utilities F, G, H, I, J

The loss model is workbook with a series of worksheets that have been customized for the utilities. Model is made up of a three worksheets. The main worksheet contains calculations for primary and secondary losses, summaries of transformer losses, and loss outputs. Transformer worksheet contains data input and loss calculations for each major transformer and by type for smaller distribution transformers. Conductor worksheet contains a summary of data voltages for circuit miles, loading assumptions, and demand and energy loss calculations.

Distribution System Components evaluated in loss study

- Primary Losses:
  - Line loading and loss characteristics of "Representative Primary Circuits" used
  - Losses then based on kW loss per MW of load
- Distribution Transformer Losses:
  - Losses based on typical transformer size for service group, and # customers per transformer.
- Service and Secondary Losses:
  - Estimated the conductor size and length, and loadings for each secondary customer type
  - Estimated maximum demands and used loss factors to obtain kWh losses
- Distribution Substation Transformers:
  - Load and no-load losses calculated for each substation transformer

- Meters:
  - Did not include in evaluation

Utility K

The loss model was developed using a workbook format to calculate losses of each component and summarize results. The system has two unique service areas with both being accounted for in separate worksheets of the same model.

- Primary Losses:
  - Line losses calculated using computerized distribution model
  - Software used: Windmil
- Distribution Transformer Losses:
  - No-load and load losses calculated through computer model.
  - Software used: Windmil
- Service and Secondary Losses:
  - Estimated based on average lengths, size, and type and average peak load for each customer class
  - Used a load factor per customer class
- Distribution Substation Transformers:
  - No-load losses provided by utility from test reports
  - Load losses calculated from computer model using peak load flows
  - Software used: Windmil
- Meters:
  - Did not include in evaluation, however metering inaccuracies were included as part of general category that included loose hardware, Corona and other mechanical abnormalities, and security lights

Utility L

The study that was provided was a guide to reduce losses through distribution system improvements. An actual loss study was not provided. The guide did include some loss values on system to evaluate proposed improvements.

- Primary line losses:
  - Line Losses estimated using peak loads at ~2.98%, a 0.40 loss factor, and 55,673,000 MWh delivered
- Distribution transformer losses:

  - No-load losses were calculated using typical no-load losses per transformer * number of transformers
  - Load losses were estimated by transformer size, load profile, and number of transformers
- Secondary losses:
  - Did not include in evaluation
- Distribution substation transformers:
  - No-Load Losses were calculated on load data loses estimated at 1kW per MVA
  - Load Losses were calculated on load data loses estimated at 4kW per MVA, and a loss factor of 0.40
- Meters:
  - Did not include in evaluation

Utility M

- Primary losses:
  - Used power flow analysis on selected groups of feeders of each voltage level
  - Power flow analysis performed at system peak loading
  - Load was allocated based on connected kVA
  - Analysis performed at different levels by scaling peak load to 100%, 80%, 60% and 40%
- Distribution transformer losses:
  - Load and no-load losses determined for 22 different kVA sizes using test report data for 0–100% of rated kVA
- Service losses:
  - Not updated since previous study in 1993 due to no real significant changes in system. The 1993 loss factors were estimated at 2% at peak for small general secondary customers and 0.75% for large.
- Distribution substation transformers:
  - No-load losses were obtained directly from manufacturers test reports
  - Load losses calculated on percentage of coincident peak, which was system peak.
  - Used test data to determine on all transformers with hourly data (Test KVA adjusted for actual hourly data)
- Meters:
  - Did not include in evaluation

Utility N

Load model includes evaluation of summer and winter peaks. Losses are developed for each component by taking percentage of peak. Total energy losses are then evaluated by the percentage of time in study period that the system was in each load range, this study used 10% increments.

The loss model consisted of calculations for fixed and variable losses using

- Primary losses:
  - Peak losses calculated using Primary Loss Program that calculates average “Loss Ratio” or “Unit Value”, which indicates the fraction of power losses that are delivered at peak.
  - Peak losses are converted to any load level through a conversion equation
- Distribution transformer losses:
  - No-load losses calculated by multiplying quantity for each size by corresponding manufacturers loss data
  - Load losses determined using transformer load monitored computer (TLM) for 13.8kV =0.0205 p.u. and for 4.3kV = 0.0310 p.u.
  - Peak losses are converted to any load level through a conversion equation
- Secondary and Service losses:
  - Assumed 10% of services underground and 90% overhead.
  - Assumed 50% of overhead used #4 service wire and 50% used 1/0 wire
  - Historical installation data used to determine average length
  - Underground conductor was estimated at 50% 1/0 wire and 50% 3/0 wire
  - Peak losses are converted to any load level through a conversion equation
- Distribution Substation Transformers:
  - Included in Transmission/Sub Transmission Analysis
- Meters:
  - Incorporated loss data from meter groups to more accurately account for meter losses in loss model

Utility O

The loss model uses worksheets to calculate losses of each component and summarize results. The system has two unique service areas with both being accounted for in separate sheets of the same model.

- Primary losses:
  - Line losses calculated through combined models provided by SGS Witter

- Distribution transformer losses:
  - Load and no-load data obtained from test reports
  - Loading based on average load/kWh
- Service and secondary losses:
  - Estimated Based on average conductor lengths, size, and type, and used average peak load.
  - Used a load factor per customer class
- Distribution substation transformers:
  - No-load losses provided by utility from testing
  - Load factors for substation transformers obtained from previous studies and remained unchanged
- Meters:
  - Not evaluated. however metering inaccuracies were included as part of general category that included loose hardware, Corona and other mechanical abnormalities
  - Security lights included as a loss category

Utility P

Distribution system loss model was based on a series of workbooks and a conversion tool to convert peak kW demand to annual kWh losses.

- Primary Losses:
  - Asset planning documented the feeder demand kW losses at peak.
  - Used average losses at peak loads to determine percent demand loss.
  - Converted demand loss to annual kW losses using in-house conversion tool
- Distribution transformer losses:
  - Uses average of 50% nameplate rating at peak loads to calculate kWh losses with certified test data on transformer.
  - Has loss data on test data on each transformer
- Service and secondary losses:
  - Model run with spot loads on each of the OH service conductors that represent the expected load diversity for an OH residential distribution system configured with 16 houses per transformer
- Distribution substation transformers:
  - Included no-load losses
  - Load losses for 118 actual substation transformer installations serving retail load.

- Average demand or kW losses were:
- Average % kW load losses = 0.49%
- Average % kW no-load losses = 0.17%
- Average % total kW losses = 0.66%

- Meters:
  - Did not include in evaluation

Utility Q

- Primary Losses:
  - Used about 600 feeders are maintained database at 4kV and 15kV service levels. A sample of ten representative circuits chosen for study.
  - Primary circuit losses determined using Siemens PTI distribution computer model, PSS/ADEPT
- Distribution transformer losses:
  - Used 54% Utilization based on transformer inventory, and load research on non-coincident demands for secondary customers with 1.2% diversity factor
  - Load and no-load impedances obtained from historical data
- Service and secondary losses:
  - Uses distribution standards to model ten different types of residential service and two commercial. A 10% unbalance was assumed on 240/120 services
- Distribution substation transformers:
  - Used actual transformer test data on all transformers in which available, estimated remainder
  - Uses peak measured values at each sub station transformer to calculate losses
- Meters:
  - Calculated on standard single phase mechanical meter requirement of 0.8 W/hr, thee phase mechanical of 1 W/hr and electronic meters on 0.25 W/hr

Utility R

Distribution system loss model was based on

- Primary Losses:
  - Primary losses studied using a sampling of circuits on each distribution voltage level
  - Past Loss studies performed using Distribution Analysis Package (DSAP), however recent studies include increasing amount of circuit sampling as more circuits are getting modeled.

- Distribution transformer losses:
  - Included with secondary losses and looked at typical losses at various load levels between 40% and 100% of peak
  - Average 25 kVA transformer used in system, losses studied using 25 kVA supplying secondary and six services
- Service and secondary losses:
  - Service and secondary losses included with distribution transformer loss analysis
- Distribution substation transformers:
  - Included in transmission loss analysis
- Meters:
  - Did not include in evaluation

4
LOSS CALCULATION GUIDELINES

The reviews of regulatory information found only high-level considerations for how to calculate electric system losses; in most regulations, the main objective in calculating electric system losses was for the exchange in power between the parties in the electric grid. No goals or incentives were found in the regulations that help utilities achieve a more efficient and less costly electric system. The reviews of the utility loss studies provided a plurality of ways to determine losses in the electric system, but there were many inconsistencies among utilities and some utilities did not account for electric losses in electrical components, such as secondary conductors, that can be found in all utilities. This section of the report attempts to provide guidelines for categorizing losses, determining what electrical components should be included in the loss study, and calculating the losses for each electrical component. The methods explored in this section are a culmination of the researchers' professional experience, reviews of research by others, reviews of existing regulatory statutes, and reviews of loss studies from 19 utilities.

Overview

All electrical distribution systems incur losses. Losses are defined as the difference between the energy put into the system and the energy that is utilized by the end users. Electric system losses can be technical losses, meaning losses due to energizing equipment and to current flowing through electrical devices, or non-technical, which are typically defined as theft and unmetered loads. This report provides information and guidelines for technical losses and the more common types of unmetered load.

Technical losses in an electric system are made up of two components, fixed losses and variable 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. These losses, such as iron losses in transformers, are also known as "no-load" losses. Conductors in the system that supply transformers also experience fixed losses as they carry the magnetizing current to energize the transformers, but typically these losses are included in the variable losses. Fixed losses also occur in equipment such as meters and voltage regulators. Fixed losses are generally constant, so the magnitude of the fixed losses (kW) multiplied by time (hours) will give energy losses (kWh).

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 transformer windings, primary and secondary conductors, and equipment such as line regulators.

There can be contributors that should be accounted for in loss studies including street lighting load, station service, theft, and other unmetered load. The energy consumed by these components would be a mixture of fixed and variable losses.

Many factors affect the way each utility calculates and accounts for losses. Tariffs or regulations may list requirements for what can be included in electric system loss recovery. For example, the tariff for street lighting may be a fixed fee that estimates the total energy required for the street lighting system (including losses) and not just the wattage of the lights multiplied by the number of hours of operation. The ancillary power required to operate a substation may be considered an operational cost and not counted as an electric system loss.

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 should use sampling techniques to determine losses for each category. Typically, a sample size of 15% will provide a good base to use to determine total system losses. However, if representative sampling is used, it is highly recommended that a sample design be developed by personnel experienced in statistical analyses. The sample design will provide a specific sample size for a given relative precision and could reduce the percentage of the system that needs to be included in the analysis. This information can then be used with system-wide information to determine total electric system losses.

Two basic methods can be used to calculate distribution system losses: metering and calculations. Both methods have limitations. With metering, the utility must be concerned with the accuracy of the sensors and meters, as well as the timing of the meter reads. In addition, unmetered loads still need to be estimated. When calculating distribution system losses, the utility must have thorough knowledge of the system configurations and must consider the accuracy of the data. For example, utilities typically have not recorded the loss parameters for distribution transformers nor the actual load passing through each transformer.

System Losses Reporting

Generally a distribution system loss study should include the losses of each component in a distribution system, from the customer meter up to and including the substation transformer. Losses should be reported for both peak load and total energy losses. Losses at peak should be calculated using coincident load for each component at system peak. Energy losses should be calculated one of two ways.

1. Use hourly data to calculate losses for each hour of the time period, or
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. This preferred method is to use monthly data, but as a fallback, annual data can also be used.

Losses calculated for each system component should be normalized based on metering data. Using metering data, the total system losses can be determined by using the difference between power purchased and power delivered and accounting for unmetered loads. Typical categories for distribution system losses include:

- Substation transformer
- Substation equipment
- Primary lines
- Line equipment
- Distribution transformers
- Secondary and service lines
- Meters
- Unmetered load
  - Streetlights
  - Theft

Data Requirements

The data available varies significantly for each utility. In general, the two components that make up a large portion of the losses are the substation and distribution transformers. Utilities typically have monthly data at the substation transformer level, but little data at the distribution transformer level except for some commercial and industrial loads that have energy and demand data available from metering. The data needed to calculate losses for each system component will vary based on the tools and models used by the utility.

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

- **System Data:** System peak data and purchased and sold energy.
- **Substation Transformer:** Characteristics including quantity, size, losses (no-load, load, and impedance), and voltage levels.
- **Substation Equipment:** Characteristics including quantity, size, losses (no-load, load, and impedance), and voltage levels for voltage regulators, CT and PT instrumentation, meters, capacitors, and bus losses.
- **Distribution Primary:** Conductor sizes, lengths, loadings, representative feeders for each voltage class, customer type, and feeder type urban or rural.
- **Distribution Transformer:** Characteristics including quantity, size, losses (no-load, load, and impedance), and voltage levels.
- **Distribution Equipment Data:** Size, types, locations and loss data of other distribution equipment such as regulators and capacitors.
- **Load Data:** Load profile, kW delivered at different times throughout the period.

- **Customer Data:** Number and type of customers for each voltage level served.
- **Development of Loss Model:** Incorporates supply, customer, and load data to calculate fixed and variable load losses for peak and average loading on system. Breaks down losses to detailed components then calibrates so total sum of components equals total system losses. Total system losses equal difference between power delivered to system or substation and total metered energy delivered to end users.

Load and Loss Factors

Electric system losses are highest during peak conditions. However, approximately 70% of the energy losses occur off peak. [13, post final report analysis of hourly data using power flow software for three distribution feeders] Therefore, factors that represent the relation 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 by the time of the period.

$$LDF = \frac{kWh}{kW_{peak}}\left(\frac{1}{T}\right) \qquad \textbf{Eq. 4-1}$$

where

LDF = Load Factor,

kWh = Energy in kilowatt-hours for a given study period,

kW_{peak} = Peak load that occurs within the study period,

T = Duration of study period, usually 8,760 hours.

The loss factor is defined as the ratio of the average power loss to the peak power loss, or in other words, kWh losses divided by the hours over study period, divided by the peak kW losses. However, 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 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

$$LSF = \frac{\sum_{n=1}^{T} kW(n)^2}{kWpk^2}\left(\frac{1}{T}\right) \qquad \textbf{Eq. 4-2}$$

where

LSF = Loss Factor,

kW = Demand for each hour,

$kWpk$ = Peak demand that occurred during the study period,

T = Duration of study period, usually 8,760 hours.

Eq. 4-2 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

$$LSF = \left(LDF^2 \times K\right) + \left(LDF \times \left[1 - K\right]\right), \text{ [6, 12]} \qquad \textbf{Eq. 4-3}$$

where

LSF = Loss Factor,

LDF = Load Factor,

K = ranges between 1 and 0.7, [6]
Distribution transformers K = 0.85, [12]
Residential feeders K = 0.9. [12]

Note that the Loss Factor and Load Factor are dimensionless.

Substation Transformers

Some participating utilities studied substation transformers as part of their distribution losses while others accounted for these losses as part of their sub-transmission losses. Because some utilities do not have sub-transmission systems but all utilities calculating distribution system losses have distribution infrastructure, it is recommended that the power transformers in the substations be included as a subcategory in the distribution system loss calculations.

No-load losses (NLL) should be calculated using 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.

$$NLL = \frac{NLL_{Xfmr} \times V_{Applied}^{\;2}}{V_{Nameplate}^{\;2}} \quad \textbf{(kW)} \qquad \textbf{Eq. 4-4}$$

where

NLL = No-load loss for the transformer,

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

$V_{Applied}$ = Average voltage applied to transformer,

$V_{Nameplate}$ = 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 follows:

$$LL_{Pk} = \frac{LL_{Xfmr} \times kW_{Pk}^{2}}{kW_{Nameplate}^{2}} \text{ (kW)} \qquad \textbf{Eq. 4-5}$$

where

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

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

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 eq. 4-4 and eq. 4-5.

$$LS_{Pk} = \sum_{n=1}^{N} \left(LL_{Pk}(n) + NLL(n)\right) \text{ (kW)} \qquad \textbf{Eq. 4-6}$$

where

LL_{Pk} = Peak load loss of transformer at system coincident peak, see eq. 4-5,

NLL = No-load loss for the transformer, see eq. 4-4,

LS_{Pk} = Total Peak losses for transformer at system coincident peak,

N = Each transformer.

Total energy losses can be calculated using hourly load data or using peak losses multiplied by the loss factory adding no-load loss and load losses peak multiplied by the loss factor and multiplying by the time using eq. 4-4 and eq. 4-5, where the peak load is the non-coincident load or annual peak of the transformer.

$$LS_{Energy} = \sum_{n=1}^{N} \sum_{h=1}^{T} LL_{HrLd}(h)(n) + NLL(n) \times T \text{ (kWh)} \qquad \textbf{Eq. 4-7}$$

where

LS_{Energy} = Total energy losses for transformers,

LL_{HrLd} = Load losses for each hour of the transformer load,

LS_{UGC} = Underground cable dielectric losses (specific for each cable size and type),

h = Each hour,

N = Each transformer,

T = Hours of study period, usually 8,760 hours;

or

$$LS_{Energy} = \sum_{n=1}^{N} \left(LL_{Pk}(n) \times LSF_{Xfmr}(n) + NLL(n) \right) \times T \text{ (kWh)} \qquad \textbf{Eq. 4-8}$$

where

LS_{Energy} = Total energy losses for transformers,

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

LSF = Loss factor for each transformer, see eq. 4-2 and eq. 4-3,

T = Hours of study period, usually 8,760 hours,

N = Each transformer.

Primary Lines

Computer simulation is one of the best ways to economically calculate losses in the primary lines. While obtaining conductor sizes and lengths is relatively easy from system maps or field reconnaissance, allocation of the loads is a little more complex. The two basic methods of load allocation are by connected kVA or by connected kWh (energy delivered to the customer from metered data). Allocation by connected kVA requires knowing where the transformers are located on the system and the size of the transformer. Again this data can be generally obtained from system maps or via field reconnaissance.

Allocation by connected kWh requires a connection between the utility's billing data and the location of the customer in the computer model. Both methods have advantages and disadvantages. The connected kVA method assumes the transformers are loaded to the same level and the connected kWh method assumes an average demand and may not accurately represent peak conditions incurred by seasonal load customers.

As data from advanced metering becomes integrated in the utility's infrastructure, the load data can be directly assigned to the computer simulation model. In addition, hourly data, including kW and kvar, can be used to calculate distribution energy and peak system losses. This method can produce more accurate results by eliminating errors due to load allocation.

Computer simulations should be performed on circuits at the feeders' load at the system peak load (coincident load) and at the feeder peak load (non-coincident load). Losses at system peak are calculated by performing power flow analysis for each feeder for the feeder load at the system peak (coincident loading). Energy losses can be calculated by determining losses for the feeder load at each hour or by using the feeder non-coincident load multiplied by the loss factor of the feeder.

For underground systems, the dielectric losses should be included. Power flow computer simulations typically only include $I^2 \times R$ losses, therefore the dielectric losses should be added to the results.

$$LS_{Pk} = \sum_{n=1}^{N} LnLS(n) + LS_{UGC}(n) \text{ (kW)} \qquad \text{Eq. 4-9}$$

where

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

LS_{UGC} = Underground cable dielectric losses (specific for each cable size and type),

N = Each feeder.

The energy losses for the primary lines can be calculated by running power flow analysis using hourly load data 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.

$$LS_{Energy} = \sum_{n=1}^{N} \sum_{h=1}^{T} LnLS_{HrLd}(h)(n) + LS_{UGC}(n) \times T \text{ (kWh)} \qquad \text{Eq. 4-10}$$

where

LS_{Energy} = Energy Losses for feeders,

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

LS_{UGC} = Underground cable dielectric losses (specific for each cable size and type),

h = Each hour,

n = Number of feeders,

T = Hours of study period, usually 8,760 hours.

or

$$LS_{Energy} = \left(\sum_{n=1}^{N} LnLS_{Peak}(n) \times LSF(n) + LS_{UGC}(n) \right) \times T \text{ (kWh)} \qquad \text{Eq. 4-11}$$

where

LS_{Energy} = Energy Losses for feeders,

$LnLS_{Peak}$ = Line losses at feeder non-coincident peak,

LS_{UGC} = Underground cable dielectric losses (specific for each cable size and type),

n = Number of feeders,

T = Number of hours, usually 8,670.

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 (see "Overview," page 4-1). 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 service types including urban and rural). Load placement should also be considered. If a feeder is chosen with a 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.

Line Equipment

Line equipment is considered to be voltage regulators and surge arrestors for a distribution system. Losses for voltage regulators are calculated the same as for substation transformers, see eq. 4-4 through eq. 4-8.

The losses for a metal oxide varistor (MOV) surge arrestor should 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 the same for energy and peak.

$$Losses = \sum_{n=1}^{n} V_{\ln}(n) \times 0.0006 \times Qty(n) \times T \quad \textbf{(kWh)} \qquad \textbf{Eq. 4-12}$$

where

n = Voltage class,

V_{ln} = Volts line to ground,

0.0006 = Leakage current of MOV arrestors,

Qty = Quantity of arrestors,

T = Duration of study period, usually 8,760 hours.

Distribution Transformers

Utilities should have an inventory of installed distribution transformers that contains information on sizing and age. In the ideal situation, the utility would have a transformer load management (TLM) system that include inventories which can be used to develop a list of common transformer sizes and average age per size. Nameplate loss data typically is not retained for individual distribution transformer unless it was entered into the TLM. Loss data can be obtained on transformers of similar age for each size from manufacturers, from various published documents, or from test reports that have been retained by the utility. Transformers may have to 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 the purchasing of transformer.

Another significant challenge in calculating losses for distribution transformers is determining the power that is flowing through the transformer. For larger commercial and industrial transformers this data is typically available and the analysis should be performed for each of the larger transformers, typically transformers of sizes 300 kVA and larger. However, load data is rarely available for the smaller transformers serving residential and small commercial loads. For these smaller transformers 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 model. The ideal case is for the computer model to have each individual transformer modeled with the corresponding billing information. This ideal case would require detailed load data that could easily be supplied by advanced metering infrastructure (AMI) as well as a link between the customer load and the transformer. The computer model would then provide the peak losses.
2. Feeder level analysis. The peak transformer loading can be calculated by using the ratio of connected transformers to the coincident and non-coincident feeder peaks. The transformer groupings would be summarized for each feeder in the utility.
3. Data Sampling. Sampling methods could be used in lieu of the detail computer model and AMI data. Each type of transformer configuration or grouping should have sufficient sampling to provide meaningful results (see "Overview," page 4-1).

No-load losses can then be calculated simply by multiplying the quantity of each type of transformer by the no-load losses and by time. Eq. 4-13 is similar to eq. 4-4, but rather than using specific loss data for each transformer, average values are used for each transformer classification or grouping.

$$NLL = \left(\frac{NLL_{Xfmr} \times V_{Applied}^{2}}{V_{Nameplate}^{2}} \right) \textbf{(kW)} \qquad \textbf{Eq. 4-13}$$

where

NLL = No-load losses for distribution transformer,

NLL_{Xfmr} = Average no-load losses for classification/grouping of distribution transformer,

$V_{Applied}$ = Average voltage that the is applied to the distribution transformer,

$V_{Nameplate}$ = 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 the following equation:

$$LL_{Pk} = \frac{LL_{Xfmr} \times kW_{Pk}^{2}}{kW_{Nameplate}^{2}} \textbf{ (kW)} \qquad \textbf{Eq. 4-14}$$

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 eq. 4-13 and eq. 4-14.

$$LS_{Pk} = \sum_{n=1}^{N} \left(LL_{Pk}(n) + NLL(n)\right) \times Qty(n) \quad \textbf{(kW)} \qquad \textbf{Eq. 4-15}$$

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. 4-14,

NLL = No-load loss for the transformer, see eq. 4-13,

N = Each transformer or classification/grouping,

Qty = Number transformer for each classification/grouping. (If calculating losses by individual transformers, Qty = 1.)

Total energy losses can be calculated using hourly load data or using peak losses multiplied by the loss factor and adding no-load loss then multiplying by time. The loss factor can be determined using eq. 4-2 or eq. 4-3, where the peak load is the non-coincident load or annual peak of the transformer.

$$LS_{Energy} = \sum_{n=1}^{N} \left(\sum_{h=1}^{T} LL_{HrLd}(h)(n) + NLL(n) \times T \right) \times Qty(n) \quad \textbf{(kWh)} \qquad \textbf{Eq. 4-16}$$

where

LS_{Energy} = Total energy losses for transformers,

LL_{HrLd} = Load losses for each hour of the transformer load,

LS_{UGC} = Underground cable dielectric losses (specific for each cable size and type),

h = Each hour,

N = Each transformer or transformer classification/grouping,

T = Hours of study period, usually 8,760 hours,

Qty = Number transformer for each classification/grouping. (If calculating losses by individual transformers, Qty = 1.);

or

$$LS_{Energy} = \sum_{n=1}^{N} \left(LL_{Pk}(n) \times LSF_{Xfmr}(n) + NLL(n)\right) \times T \times Qty(n) \quad \textbf{(kWh)} \qquad \textbf{Eq. 4-17}$$

where

LS_{Energy} = Total energy losses for transformers,

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

LSF = Loss factor for each transformer, see eq. 4-2 and eq. 4-3,

T = Hours of study period, usually 8,760 hours,

N = Each transformer or transformer classification/grouping,

Qty = Number transformer for each classification/grouping. (If calculating losses by individual transformers, Qty = 1.)

Secondary and Services

For the purpose of the loss calculations, the secondary system is considered to be the portion of low-voltage conductor that serves more than one customer and the service system is defined as the low-voltage conductors that serve only one customer. Ideally, secondary and service losses should be calculated using a power flow computer model in conjunction with the calculation of primary line and transformer losses. However, because most utilities do not have secondary and service systems modeled, the methodology for calculating these losses will likely include the use of sampling, design criteria, and load research data.

The exact methodology will depend on the data that is available for a particular utility. In general, secondary systems should 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 the electrical characteristics, including conductor sizes (resistance), loads (magnitude, load factors, and imbalance), loss factors, and diversity factors. Losses then could be approximated with the following equations:

$$LS_{Pk} = \sum_{n=1}^{n} \frac{kW_{Pk}(n)}{V(n)} \times imbF \times C_f \times Lavg(n) \times R \times DF(n) \times Qty(n) \text{ (kW)} \qquad \textbf{Eq. 4-18}$$

$$LS_{Energy} = \sum_{n=1}^{n} \frac{kW_{Pk}(n)}{V(n)} \times imbF \times LsF \times Lavg(n) \times R \times DF(n) \times Qty(n) \text{ (kWh)} \qquad \textbf{Eq. 4-19}$$

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; for three phase, V(n) = V(n)LL*1.7321;

$imbF$ = Imbalance factor for phase imbalance (balanced secondary $imbF$ = 1, value increases as the phase imbalance increases)

LsF = Loss Factor (see eq. 4-2 and eq. 4-3);

Lavg = average conductor length in feet;

R = resistance of conductor per foot;

DF = diversity factor or coincidence factor and is dependant on the number of customers served by the conductor;

Number of Customers	*DF*
1	0.00
2	0.90
3	0.83
4	0.78
5	0.75
>10	0.70.

Qty = quantity of systems matching the grouping category.

Meters and Other Equipment

Equipment losses that occur on the utility's side of the meter should be included in the distribution losses. This equipment should 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 found on nameplate data or can be obtained from manufacturers. 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 utility 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.

The losses for most types of equipment are considered fixed and therefore the calculations are straightforward. The losses for energy are the peak losses multiplied by time.

$$Losses = \sum_{n=1}^{N} EquipmentLosses(n) \times T \quad \textbf{(kWh)} \qquad \textbf{Eq. 4-20}$$

where

N = each type of equipment,

T = duration of study period, usually 8,760 hours.

Unmetered Loads

Unmetered load typically includes streetlights, traffic lights, security lights, and theft. The energy used by the equipment and for theft should be considered as load. Losses due to dedicated conductors and transformers should also be considered as load. Tariffs and regulations should be reviewed as they may provide information regarding the inclusion of unmetered load in rates, in which case these loads would not be included as losses. If metering of incoming and outgoing energy is used to reconcile loss calculations, then unmetered loads need to be accounted for as load in the reconciliation calculations.

Streetlights

Utilities range widely in the way that streetlights are accounted for. For example, some utilities have an agreement with another agency or with private owners that accounts for all of the energy consumption and losses for streetlights, while other utilities provide street lighting. Each utility needs to determine if streetlight consumption and losses for streetlights are to be included as losses. Generally these loads can be included as fixed loads during the lighting hours and would be included as energy loads. Street lighting loads would only be included in the peak loss calculations if the system peak occurred after dark when the streetlights would be energized.

Theft

Each utility should determine what percent of total system load is associated with non-technical loads attributed to theft.

5
LOSS REDUCTION ACCOUNTING GUIDELINES

As utilities make improvements to their systems to reduce losses, they need a consistent way to account for those loss reductions.

The two main areas utilities focus on to reduce losses are (1) replacing existing infrastructure and (2) changing design and planning criteria for future infrastructure investments to ensure they are efficient. The incremental cost to change out existing infrastructure can be high compared to the cost savings through loss reduction. However, the incremental cost to build efficiencies into planned capital projects could be low compared to efficiency gains.

This section provides guidelines for determining loss reduction and describes how the utility can use life-cycle cost analyses to determine that they are implementing infrastructure improvements in the most economical manner. The methodologies provided in Section 4 should be used in calculating the reduction in electric losses.

Distribution Model

Use of distribution system modeling software to analyzing power flows in the distribution system is the simplest and most cost effective way to analyze proposed loss improvement projects. 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 reduction in system losses that can be achieved. Economic analysis can be applied to determine the cost effectiveness of each loss reduction technique.

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.

Analysis using computer models typically evaluates one loading scenario at a time and will give losses associated with that run. It is important to know the load profile of the areas being analyzed in order to determine the complete loss picture in a system. While system losses are greatest at peak loads, approximately 70% of the energy losses occur during off-peak times [13, post final report analysis of hourly data using power flow software for three distribution feeders].

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.

Load Balancing

Phase balancing in a distribution system is probably the number one improvement that should be made to reduce distribution system losses. Improving phase imbalance from 25% to below 10% can reduce primary line losses by 1.5% to 2% based on research performed as part of the Northwest Energy Efficiency Alliances Distribution Efficiency Initiative [13]. This generally has one of the greatest benefit/cost ratios of all the reduction measures. Balancing load between phases will reduce average losses in the phase conductors by lowering current in one or more conductors. Due to the exponential loss of $I^2 \times R$, the sum of losses in the three balanced conductors will always be less than any combination of loading scenarios. A balanced system will also reduce neutral return current to zero, eliminating all neutral losses in the return path.

Load balancing analysis should evaluate the load at the feeder source and at multiple points along the feeder, as well as the load imbalance at different loading conditions. Phase balancing should be performed starting at the metering point furthest from the end of the circuit, such that each metering point achieves phase balancing around 5% to 10%. Even though the line current is highest during peak loads, peak loading only occurs for about one percent of year. Phase balancing should be considered at average load levels as well.

Evaluation of loss reductions for phase balancing is typically done using a system model and power flow analysis. Most distribution load flow analysis applications contain an option to assist the utility engineer in determining which load can be switched to balance load. A summary of taps or transformers that need to be moved to balance the system at the modeled load levels can be generated. For overhead distribution systems this can be straightforward, while underground systems may prove challenging depending on the system configuration. The recommendations from the computer simulations should be field-verified before they are implemented.

In addition to phase balancing, load balancing between feeders can reduce distribution system losses. Feeder balancing is achieved when the losses on each circuit included in the analysis are equal. Feeder balancing can be performed by transferring load between feeders. Transferring load between feeders may require operating or installing manual or motor-operated switches. On the other hand, where switches are not feasible or possible, more extensive construction may be required, such as multi-phasing a single-phase tap or building new three-phase sections of line.

The life expectancy of feeder or phase balancing is highly dependent on the load growth and configuration of the circuit. Typical balancing has a life expectancy of around 5 years at a higher load growth rate of 2.5% per year, or 10 years at a load growth rate of 1.5% per year.

The following verification method can be used to account for the loss reduction due to phase balancing:

1. Determine and record phase balancing at feeder source and at select points along the distribution feeder being considered for phase balancing.

   a. At least one mid-feeder location should be included, preferably two or more locations. Line current recording can be used at the mid-feeder locations.

   b. Peak, average, and seasonal load conditions should be monitored to determine average annual phase imbalance for each monitoring location.

   c. Data should be recorded and documented for 7 contiguous days or longer to establish a base line. Recorded data should include reactive power and power factor at a minimum.

2. Calculate annual losses using existing phase imbalance for peak and energy losses. Computer simulation models can quickly determine losses for varying load condition and levels. See equations in Section 4, Primary Lines.
3. Determine corrective actions to improve phase imbalance. Field verification should be performed using spot measurements to make sure corrective action is reasonable.
4. Determine new phase balance.
5. Calculate losses with new phase balance. Use same loss model as used in step 2.
6. Calculate loss reduction by subtracting the step 5 results from the step 2 results.
7. Implement corrective actions.
8. Document phase balancing at feeder source and at selected points along the distribution feeder using process from step 1.

   a. Data should be recorded and documented for 7 contiguous days or longer to establish the corrected values.

   b. Phase balancing documentation at the feeder source should be performed for each year of the life of the loss reduction.

9. Make adjustments to loss reduction calculation step 8 using recorded phase balance from step 8.

The following verification method can be used to account for the loss reduction due to feeder balancing:

1. Determine and record loads at each feeder source and at select points along each distribution feeder being considered for the feeder balancing. The mid-feeder meter data will provide more accurate load allocation and provide more accurate results when switching load between feeders.

   a. At least one mid-feeder location should be included, preferably two or more locations. Line current recording can be used at the mid-feeder locations. Data should be recorded for 7 contiguous days or longer to establish a base line.

   b. Peak, average, and seasonal load conditions should be monitored to determine peak and energy losses for each feeder.

   c. Monthly peak and energy readings for the past year should be recorded.

2. Calculate annual losses using existing feeder configurations for peak and energy losses. Computer simulation models can quickly determine losses for varying load condition and levels. See equations in Section 4, Primary Lines.

   a. If the feeders involved in the load balancing are not connected to the same substation transformer then the transformer losses should also be included. See equations in Section 4, Substation Transformers.

3. Determine corrective actions to provide for load switch to occur. Field verification should be performed using spot measurements to make sure corrective action is reasonable.
4. Determine new loads for each of the feeders.
5. Calculate losses with new feeder configurations. Use same loss model as used in step 2.
6. Calculate loss reduction by subtracting the step 5 results from the step 2 results.
7. Implement corrective actions.
8. Document new feeder loads at the feeder source and at selected points along the distribution feeder as performed in step 1.

   a. Data should be recorded for 7 contiguous days or longer to establish a base line.

   b. Load documentation at the feeder source should be performed for each year of the life of the loss reduction by recording monthly peak and energy readings.

9. Make adjustments to loss reduction calculation step 8 using recorded feeder loads from step 8.

Power Factor Correction

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. Power factor correction at or near the load to eliminate or reduce the lagging power factor will result in a reduction in system losses in the primary lines and substation transformers by reducing the line current. Corrections on the customers' side of the meter will have the additional benefit to the utility in reducing system losses in the distribution transformer. The reduction in kW losses is proportional to the square of the reduction in line current.

The combined effect of inductive loads from all customers on the distribution circuit increases primary line losses. Power factor correction to 98% lagging at peak load conditions can reduce primary line losses and losses in the substation transformer. For many large customers the responsibility of power factor correction is placed on the customer. For these large customers, the power factor correction should be performed on the customer's side of the meter.

A power factor analysis should be performed to determine the amount of reactive support needed in a system, whether it should be switched to prevent leading power factor, and the proper placement of the reactive support. Power factor analysis is generally performed at the feeder level, but the effect on the substation transformer should also be considered. Power factor analysis can be done using a computerized system model and power flow analysis. Most distribution power flow analysis software contains a module that can assist the planning engineer to optimize the placement and size of capacitors. The planning engineer needs to evaluate capacitor sizing and switching at various loading levels and conditions.

The key to placement and sizing of capacitor banks is to understand where the var load center is located on the feeder and the maximum and minimum var requirements. Fixed capacitor bank should be sized to the average annual minimum var requirements. If the difference between the maximum and minimum var requirements is large enough, then additional switched capacitor banks should be used. If the var load center is not known, then the tradition rule of placing the capacitor bank at two-thirds of the distance out from the substation works well and sizing the capacitor bank at two-thirds of the average annual maximum var load.

Capacitor banks have a life expectancy of 10 to 15 years. In addition, operations and maintenance costs will increase due to annual inspections and occasional replacement of fuses.

The following verification method can be used to account for the loss reduction due to power factor correction:

1. Determine and record loads at the feeder source and at select points along each distribution feeder being considered for the power factor correction. The mid-feeder meter data will provide more accurate load allocation and provide more accurate results by providing data as to where along the feeder the var load center is located.

    a. At least one mid-feeder location should be included, preferably two or more locations.

    b. Reactive power flow and power factor data is required at feeder source and mid-feeder metering locations. Hourly data should be recorded over a month for kW and kvar. Varh data over long periods, up to a year, at the feeder source would be a good way to be able to measure and verify savings.

    c. Peak, average, and seasonal load conditions should be monitored to determine peak and energy losses for each feeder.

2. Determine loads on substation power transformer.

3. Calculate annual losses using existing feeder configurations for peak and energy losses. Computer simulation models can quickly determine losses for varying load condition and levels. See equations in Section 4, Primary Lines.
4. Calculate losses in substation transformer. See equations in Section 4, Substation Transformers.
5. Determine capacitor size so that the minimum var requirement is reduced to zero or slightly negative (leading power factor). Add switched capacitor banks to achieve a 96% to 98% power factor at peak loads.
6. Determine new loads for the feeder with the power factor corrections.
7. Determine new loads for the substation power transformer with the power factor corrections.
8. Calculate losses with power factor corrections. Use same loss model as used in steps 2 and 3. If switched capacitor banks are planned, multiple load levels will need to be analyzed to determine losses.
9. Calculate loss reduction by subtracting the step 5 results from the step 2 and 3 results.
10. Implement corrective actions.
11. Document new feeder loads at feeder source and at selected points along the distribution feeder as performed in step 1.

    a. Hourly data should be recorded over a month for kW and kvar at each of the metering points.

    b. Annual load documentation at the feeder source should be performed for each year of the life of the loss reduction. Varh data over long periods, up to a year, at the feeder source would be a good way to be able to measure and verify savings.
12. Make adjustments to loss reduction calculations steps 8 and 9 using recorded loads from step 11.

Primary Conductor Sizing

Increasing the primary conductor size will reduce primary line losses by reducing the resistance in the line. Changing primary sizing may have substantial impacts beyond loss evaluation as it may reduce voltage drop to acceptable levels without other more expensive improvements. This measure should also increase maximum operating capacity, allowing for more switching options under contingent conditions, leading to a possible increase in system reliability.

For new construction, the cost of selecting a larger conductor can be economically justified. While loss reduction alone may not be sufficient to justify reconductoring existing distribution circuits to a larger conductor size, a combination of other benefits may make this improvement option more desirable. An economic analysis, in which the annual savings in the losses are balanced against the fixed charges on the cost of construction, will help determine the economical conductor size for new construction and for replacing conductors for an existing distribution circuit. Economic analysis shows that the initial peak loading of a conductor should be around 15% to 30% [12] of the conductor rating and reconductoring can be cost-justified when the existing conductors are loaded as low as 50% to 60% during peak loads, depending on the expected growth rate for the feeder load and load factor.

Primary conductors have a life expectancy exceeding 30 years. Operations and maintenance costs should initially decrease because of the newer facility.

The following verification method can be used to account for the loss reduction due to changing primary conductors:

1. Determine and record loads at the feeder source and at select points along each distribution feeder being considered for changing the primary conductor. The mid-feeder meter data will provide more accurate load allocation and provide more accurate results.

    a. At least one mid-feeder location should be included, preferably two or more locations. Real and reactive data should be recorded at the mid-feeder locations.

    b. Peak, average, and seasonal load conditions should be monitored to determine peak and energy losses for each feeder.

    c. Collected month data for peak and energy for the past 12 months to provide a base case for loads.

2. Calculate annual losses for peak and energy losses. Computer simulation models can quickly determine losses for varying load condition and levels. See equations in Section 4, Primary Lines.

    a. If the feeder exists, calculate losses for the sections of line to be reconductored.

    b. If the feeder is a new feeder calculate the losses based on the utility's current practices for conductor sizing. Included the losses from all feeders that are affected by the new electrical infrastructure. Losses in the substation power transformer should be included if the new feeder is connected to a new or different substation power transformer. See equations in Section 4, Substation Transformers.

    c. Collected month data for peak and energy for the past 12 months to provide a base case of loads.

3. Determine new conductor size based on life-cycle cost methods and loss reduction goals.
4. Determine new loads for each of the feeders if new feeders are being added.
5. Calculate losses with new conductors and if applicable the new feeder and existing feeders. Use same loss model as used in step 2.
6. Calculate loss reduction by subtracting the step 5 results from the step 2 results.
7. Implement corrective actions.
8. Document feeder loads at feeder source for each feeder as performed in step 1. Feeder source data is sufficient to determine the actual loss reductions.

   a. Collected and document hourly load data for a month.

   b. Annual load documentation at the feeder source for peak and energy should be collected for each year of the life of the loss reduction.

9. Make adjustments to loss reduction calculations steps 5 and 6 using recorded feeder loads from step 8.

Parallel Feeders

Adding an additional feeder can reduce loading losses in two ways. First, the current and the resistance in the existing feeder could effectively be cut in half, resulting in an $I^2 \times R$ loss reduction. Second, there could be a net loss reduction in the substation transformers. For example, if the parallel feeder is fed from another substation transformer and the transformer losses serving the parallel feeder do not increase more than the loss reduction in the original transformer, then there should be a loss reduction.

In general, adding feeders cannot be cost-justified by loss reductions alone. Many factors need to be considered when adding distribution feeders, including cost analysis, reliability issues, growth estimates, and load diversity. Losses should be calculated for the existing configuration and for the new parallel feeder configuration including planned system improvements for both configurations. The difference in losses will be the amount of the loss reduction.

Feeder additions have a life expectancy exceeding 30 years. Operations and maintenance costs will increase slightly with the additional feeders, but should be less than the system average cost per mile because the feeder is new.

The following verification method can be used to account for the loss reduction due to adding parallel feeders:

1. Determine and record loads at the feeder source and at select points along each distribution feeder affected by the addition of the parallel feeder. The mid-feeder meter data will provide more accurate load allocation and provide more accurate results.

   a. At least one mid-feeder location should be included, preferably two or more locations. Real and reactive data should be recorded at the mid-feeder locations.

   b. Peak, average, and seasonal load conditions should be monitored to determine peak and energy losses for each feeder.

2. Calculate annual losses for peak and energy losses. Computer simulation models can quickly determine losses for varying load condition and levels. See equations in Section 4, Primary Lines.

   a. If the feeder exists, calculate losses for the sections of line to be reconductored.

  b. If the feeder is a new feeder calculate the losses based on the utility's current practices for conductor sizing. Include the losses from all feeders that are affected by the new electrical infrastructure. Losses in the substation power transformer should be included if the new feeder is connected to a new or different substation power transformer. See equations in Section 4, Substation Transformers.

3. Determine new conductor size based on life-cycle cost methods and loss reduction goals.
4. Determine new loads for each of the feeders if new feeders are being added.
5. Calculate losses with new conductors and if applicable the new feeder and existing feeders. Use same loss model as used in step 2.
6. Calculate loss reduction by subtracting the step 5 results from the step 2 results.
7. Implement corrective actions.
8. Document feeder loads at feeder source for each feeder as performed in step 1. Feeder source data is sufficient to determine the actual loss reductions.

   a. Collected month data for peak and energy for the first year.

   b. Load documentation should be performed for each year of the life of the loss reduction.

9. Make adjustments to loss reduction calculations steps 5 and 6 using recorded feeder loads from step 8.

Distribution Transformers

Distribution transformers typically operate around 95% efficient if the initial transformer sizing was reasonably selected. The economic loading of distribution transformers is from 80% to 100% of nameplate rating for the initial peak loading (sometimes called first year peak loading) [12]. The 80 percent initial peak loading would be applicable to areas with high growth rates, whereas areas that had relatively low growth rates should target 100 percent loading for the initial peak. In addition to growth rates affecting the percent loading for the initial peak, the type of equipment needs to also be considered. For example, an overhead verses an underground transformer. Loss reduction can be used to justify replacement distribution transformers if the transformers were improperly sized or if the load has significantly changed over time. Transformers that are lightly loaded operate inefficiently because of the 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. In addition, transformers that no longer have a load on them should be removed or de-energized from the system to reduce unnecessary no-load losses.

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

To justify a transformer change-out requires a clear understanding of the transformer loading, the benefits in reducing losses, and the cost to replace the transformer. Peak, average, and minimum loading on the transformers all play a role in determining if a transformer change-out is practical. Pole-top distribution transformers can operate at 150% of nameplate rating and pad-mount transformers can operate at 115% of nameplate rating without adverse impacts due to overloading, provided that the average loading is below nameplate. A transformer may be at capacity during peak load but spend the majority of the time lightly loaded. In this case, the no-load losses of an additional transformer will probably result in an increase in total losses. If it makes sense to change out a distribution transformer, then this should be done in conjunction with evaluation of secondary conductors to see if secondary length can be reduced or increased in size to further reduce system losses.

Existing transformer sizing standards and guidelines should also be reviewed due to increases in transformer efficiencies. Because of the higher emphasis placed on the cost of losses, purchasing higher efficiency transformers can be economical when including the cost of losses and the capital costs.

Distribution transformers have a life expectancy exceeding 30 years. Operations and maintenance costs should not change.

The following verification method can be used to account for the loss reduction due to replacing existing distribution transformers with more efficient transformers and by installing higher efficiency transformers for new construction:

Replacing existing distribution transformers:

1. Determine and record loads for the distribution transformer that is considered for change-out.

    a. Monthly data should be documented for the past 12 months. For loads that have only energy meters, the peak demand can be estimated using typical load factors. Monthly demand and energy data should be recorded for the past 12 months loads that have demand and energy meters.

    b. Loss factors can be calculated for each month.

2. Determine existing transformer losses using one of the following methods,

    a. Actual loss data for the transformer.

    b. Loss data from similar transformers – age, size, manufacturer, and purchasing requirements. Data can be from utility records or from manufacturer records.

    c. Sampling of several similar transformers. Sample size should be selected so the error bars for the average values is less than the difference between the average losses and the losses of the new transformer.

3. Calculate no-load and load losses for the existing transformers based on transformer loss data for peak load data and using loss factors for each of the past 12 months and annualize.

4. Calculate no-load and load losses for the new transformers based on estimated or guaranteed transformer nameplate and no-load and load losses data for peak load data and loss factors for each of the past 12 months and annualize.

    a. For the case where a transformer is added, calculate no-load and load losses for the existing and the new transformers based on the load division between the affected transformers and the new transformer.

5. Calculate loss savings by subtracting the step 4 results from the step 3 results.
6. Implement corrective actions.
7. Document corrective actions and new secondary systems with upside conductors. No load document is needed for verification.

Secondary and Service Sizing

Secondary losses can be reduced by either upsizing conductors or reconfiguring the localized secondary network to reduce secondary loading and length. Upgrading or reconfiguring a localized secondary network may include distribution transformer sizing, primary line extensions, installation of additional secondary runs, and upgrades of secondary conductor sizes. For overhead secondary systems, changing the secondary system is straightforward, but for underground systems this may be impractical due to direct-buried cable or because the conduit size limits the size of secondary wire.

The economical operating range for secondary conductor is from 10% to 15% of the conductor capacity at peak loads [12]. Depending on the load factor and the number of customers connected to the localized secondary network, it can be economical to upsize or reconfigure the secondary system when peak loading reaches 50% to 60% of the cable capacity. In addition to the reduction of secondary losses, another benefit to reworking the secondary system is that it will improve power quality by reducing the impact of voltage flicker.

Secondary conductors have a life expectancy exceeding 30 years. Operations and maintenance costs should not change.

The following verification method can be used to account for the loss reduction due to changing the secondary systems:

1. Determine and record loads for the secondary system.

    a. Monthly data should be included, typically energy for residential and small commercial loads, and peak demand and energy for larger loads.

    b. Peak, average, and seasonal load conditions should be monitored to determine peak and energy losses for the secondary system.

    c. For new secondary systems calculated expected loads and existing criteria for secondary conductor sizing.

2. Calculate annual losses for peak and energy losses using monthly data. See Section 4, Secondary and Services.

    a. Use monthly data and typical loss factors for residential loads.

    b. For loads that have peak and energy data, the loss factor can be calculated.

3. Determine new conductor size and or secondary configuration based on life-cycle cost methods and loss reduction goals.
4. Determine new load for secondary conductors if the secondary system was reconfigured.
5. Calculate losses with new secondary conductors or reconfiguration. Use same loss model as used in step 2.
6. Calculate loss reduction by subtracting the step 5 results from the step 2 results.
7. Implement corrective actions.
8. Document corrective actions and new secondary systems with upside conductors. No load document is needed for verification.

Substation Transformer

Adding substation transformers can be a way to reduce distribution system losses. As a transformer load is increased, the $I^2 \times R$ losses increase exponentially. Load losses at capacity could be four times greater than running a transformer at half capacity.

When adding substation transformer capacity the utility should consider such factors as cost, reliability, growth estimates, and load diversity. Due to the high capital cost to install an additional substation transformer, it may not be economical to add transformers for the sole purpose of reducing losses. In addition, the new transformer would add no-load losses to the system. If substation transformers are operated in parallel, the utility should consider providing control systems to de-energize one transformer when it becomes more economical to serve all load from only one of the transformers.

Substation transformer additions have a life expectancy exceeding 30 years. Operations and maintenance costs will increase, as these costs are based on the number of transformers.

The following verification method can be used to account for the loss reduction due to changing the substation transformer or adding substation transformers:

1. Determine and record loads for the substation transformer that is considered for change out or for which load will be affected the addition of a substation transformer.

    a. Monthly peak and energy data should be documented for the past 12 months.

    b. Loss factors can be calculated for each month.

2. Calculate no-load and load losses for the existing transformers based on transformer nameplate and test data based on peak load data and loss factors for each month and annualize.
3. Calculate no-load and load losses for the new transformers based on estimated or guaranteed transformer nameplate and no-load and load losses data for peak load data and loss factors for each of the past 12 months and annualize.

    a. For the case where a substation transformer is added, calculate no-load and load losses for the existing and the new transformers based on transformer nameplate and test data based on peak load data and loss factors for each month and annualize.
4. Calculate loss savings by subtracting the step 3 results from the step 2 results.
5. Implement corrective actions.
6. Document monthly peak and energy data each year of the life of the loss reduction.
7. Make adjustments to loss reduction calculations steps 5 and 6 using recorded feeder loads from step 8.

Street Lighting

There are many ways to reduce losses due to streetlights by updating streetlight technology in existing systems, and by changing standards to call for use of new technology in installation of new streetlights.

Replacing mercury lamps in existing streetlights with high-pressure sodium (HPS) will result in significant reduction in energy consumption for street lighting load. HPS streetlights rated at 100 W are available that produce the same lumen output of 175-W mercury lamps.

Upgrading the voltage level or changing the voltage level for new street lighting installations will 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 4. If 480-V three-phase is available in the immediate area, line losses could be reduced further.

The utility could evaluate street lighting efficiency improvements by evaluating the existing makeup of the streetlight system. Some utilities have an inventory of the streetlight system in a database that includes such details as secondary lengths, lamp types, voltages, and in-service dates, while other utilities have no information at all. In the latter case, the utility could sample a few random areas, looking for fixture type, secondary length, and voltages—obviously, the larger the sample, the more accurate the estimate of existing system requirements. Generic data on older mercury vapor lighting can be used, while for newer lamps manufacturer data should be available. Since street lighting is either on or off and power requirements are constant when the lamps are on, calculating kWh savings is straightforward. Taking the sum of energy used by existing lamps, and line losses associated with existing secondary and lamps voltages and then subtracting energy consumption and line losses after improvements, a kW reduction can be obtained. This reduction, multiplied by the number of hours the streetlight is on in the evaluation period, will give kWh saved.

The following verification method can be used to account for the loss reduction due to changes to the street lighting system:

1. Calculate the existing load for the street lighting system using the following formula:

$$kW\ existing = \left(ELW + ESW + DTL\right)\ \text{(kW)}$$

   where

   ELW = Existing lamp wattage,

   ESW = Existing secondary losses,

   DTL = Distribution transformer losses,

2. Calculate the new load for the street lighting system using the following fomula:

$$kW\ new = \left(NLW + NSL + NDTL\right)\ \text{(kW)}$$

   where

   $NDTL$ = New primary line losses,

   NLW = New lamp wattage,

   NSL = New secondary losses,

   T = Hours of streetlight operation in evaluation period.

3. Calculate loss savings by subtracting the step 2 results from the step 1 results.
4. Implement corrective actions.
5. Provide documentation that the improvements for the street lighting system were implemented.

Metering and Equipment

Advances in metering equipment, relay equipment, control devices, and other substation equipment have generally resulted in reductions in associated losses. To determine what kind of loss savings would be associated with changing out certain equipment the utility would need to (1) determine which model makes up the majority of each type of that device in the system, (2) investigate the loss characteristics of that device, and (3) compare that equipment with the new devices that are now available.

New electronic metering requires about 25% of the power required by older electronic equipment and 15% of the power required by electromechanical equipment. With this indication in loss reduction, changing metering equipment may make sense to a utility, especially if it can be rolled into another program such as an AMI program or a demand management program.

Life expectancy of microprocessor-based metering and relay equipment is greater than 30 years. Operation and maintenance costs would decrease as compared to older electromechanical styles.

The following verification method can be used to account for the loss reduction due to changing metering and other types of equipment:

1. Determine and document power requirements of existing equipment.
    a. Manufacturer data can be used or the power requirements of the equipment can be directly measured.
2. Calculate losses for the existing equipment by multiplying the power requirement of each equipment type.
3. Calculate losses for the new equipment using manufacturer data.
4. Calculate loss savings by subtracting the step 3 results from the step 2 results.
5. Implement corrected actions.
6. Document number of equipment replacements and calculate annual savings by multiplying the number of replacements by the loss reduction.

Demand Management

Demand management is a very broad term and can consist of many ways to reduce peak loading and energy requirements. Demand management involves working with end-use customers, typically larger customers, to curtail electrical usage on demand and to provide a network of smart devices, meters, and monitoring to reduce electric load for air conditioners, water heaters, or other large-demand equipment that are on at any given time. In addition, utilities have participated in energy efficiency programs focused on compact fluorescent lighting, higher efficiency motors and appliances, efficient heating and cooling systems, or increased home insulation.

Demand management affects the distribution infrastructure by reducing system peak load and energy requirements. Distribution losses would be reduced due to $I^2 \times R$ losses because of a reduction in end-use load. Determining the loss reduction caused by demand management efforts can be challenging because many of the demand management programs are not deployed by the utility, but rather through the marketplace (for example, the location where compact fluorescent light bulbs are used is not tracked, but there is an impact on overall 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 power acquisition will be lowered.

The loss reduction attributed to demand management can be calculated by the following process:

1. Determine the percent reduction in load for a particular distribution system.
2. Determine the load and losses for a particular distribution system and calculate the percent of losses. See Section 4 for how to calculate losses for the distribution system.
3. The percent reduction in system losses for a particular distribution system will be the square of the percent in load reduction.
4. Multiply the percent reduction in system losses by the losses for the particular distribution system.

Voltage Optimization

Electric load can be characterized from three load types: constant current, constant load, and constant impedance also known as IPQZ loads. The electric load is semi-dependant on the applied voltage, where power is the product of voltage multiplied by the current. Similarly, electric system losses are semi-dependant on the operating voltage of the distribution system and the load characteristics. For example, the no-load losses in transformers and the internal losses of electric motors are proportional to the voltage squared. System losses for constant current load are not impacted by voltage, system losses for constant power loads will decrease as the voltage increases, and system losses for constant impedance loads will increase as the voltage increases.

The relationship between the changes in electric power to the change in voltage reduction is known as the CVR factor and is expressed as $\%\Delta E/\%\Delta V$ p.u., where E can represent demand, energy or vars and V is per unit, i.e., for a 1% reduction in voltage. The net effect of electric losses on a distribution feeder is dependent on the system CVR factor where a CVR factor below approximately 0.5 could cause the electric losses to increase and a CVR factor above 0.5 will reduce losses. The line losses will increase at CVR factors below 0.8 and decrease for a CVR factor above 0.8, whereas the total distribution transformer losses will decrease with any reduction in voltage [13, results from software tools developed as part of the Northwest Energy Efficiency Distribution Efficiency Initiative].

The process of determining loss reduction due to voltage optimization is complex. It requires the knowledge of end-use load types (i.e. electric space or hot water heating, gas space or hot water heating, heat pump, or air conditioning) and the voltage reduction. End-uses load are the best predictors of CVR factors. Performing system improvements as listed above as well as balancing voltage levels can significantly improve the performance of voltage optimization.

The following verification method can be used to account for the loss reduction due to reducing the voltage level:

This analysis is best performed using computer simulation models. These software packages have modules to analysis the loss impact due to voltage reduction. Additional analysis will need to be performed to account for loss reduction for distribution transformers.

1. Determine the data for all feeders served by the voltage control device, typically load tap changers or voltage regulators.

    a. Determine monthly energy, power factor, and peak load for each feeder for the past 12 months and total data by the four seasons, winter, spring, summer and fall.

    b. Determine the percent of load by customer class, residential, light commercial, commercial and industrial for each of the four seasons.

    c. Measure and record the voltage levels at the substation and end of feeder. End of feeder is determined by area with most voltage drop for each of the four seasons.

    d. Determine the lowest voltage level that the primary voltage can set to. This can be done by adding the voltage drop of the secondary system and distribution transformer to the minimum voltage level at the customer meter. For example, 114V + 3V for secondary + 2V for transformer = 119V for minimum primary voltage (on a 120V base).

    e. Determine number, type, and sizes for distribution transformers for each section of the feeder and no-load losses for each classification of distribution transformers. No-load losses are calculated by $V^2_{original}/V^2_{nameplate}$ multiplied by the name plate no-load losses.

2. Calculate losses on the distribution feeders using past 12 months of load data for each of the four seasons.

    a. Determine average voltage levels for each section of the feeder.

3. Calculate energy weighted CVR factors using the following end-use CVR factors for each of the four seasons.

    a. Residential load with all electric heating – 0.55

    b. Residential loads will all heating by energy source other than electric – 0.9

    c. Residential loads with heat pumps/AC – 0.6

    d. Residential load with AC – 0.7

    e. Small commercial loads – 0.85

    f. Commercial and Industrial loads – 0.9

4. Determine reduced voltage levels for each line section on the feeder.

5. Calculate loss reduction for distribution transformers based on $V^2_{new}/V^2_{original}$ multiplied by the no-load losses calculated in step 1.e.
6. Calculate load reduction.
    a. Multiply the load by the weighted average CVR factor and by the percent voltage reduction. This is the energy savings.
    b. Subtract the calculated energy savings in step 5.a. and the reduction in transformer losses in step 5 from the total recorded energy.
7. Calculate losses on the distribution feeders using past 12 months of load data for each of the four seasons less the load reduction calculated in step 6.b.
8. Calculate the loss reduction by subtracting the step 7 results from the step 2 results and adding the step 5 results.
9. Document average annual voltage levels for each year of the life of the loss reduction.

Economic Analysis

An economic analysis should be performed when evaluating system improvements to reduce electric system losses and should consider the costs of system improvements as well as the benefits to achieve the desired goals. An economic analysis that will generate net present value (NPV) should be performed to evaluate each of the system improvement alternatives including the life-cycle cost. When comparing the alternative, a base case needs to be established based on current utility practices, and each alternative considered should be compared to the base case. Some of the factors:

- The cost to the utility for the next kW purchased (avoided cost)
- The cost to the utility for energy
- The duration of the benefit/cost analysis, for example 20 years
- The initial investment
- Future investments
- Changes in operation and maintenance costs
- Remaining life at the end of the analysis term
- Load growth rate
- Inflation rate
- Discount rate
- Energy savings
- kW demand reduction
- kvar demand reduction

- Deferred capital investment
- Renewable energy
- CO_2 impacts

The NPV analysis takes into account the time value of money for costs and benefits, taking into account inflation and discount rates. Costs and benefits can be a single payment or a series of payments (annuity). Different formulas are used in each case. To determine the future value for today's dollar for a one-time investment, the future value equation is used.

$$FV = PV \times (1+i)^n$$

where

FV = future value due to annually compounding interest,

PV = present value in today's dollars,

i = interest rate,

n = number of years.

To determine current worth of a future sum of money for a one-time investment, the present value formula is used.

$$PV = FV \times (1+i)^{-n}$$

where

i = discount rate.

To determine the future value for today's dollar for a series of equal investments, the future value equation is used.

$$FV_{Ordinary\ Annuity} = \frac{C \times (1+i)^n - 1}{i}$$

where

C = investment for each period,

i = interest rate,

n = number of periods.

To determine the current worth of a future sum of money for a series of equal investments, the present value formula is used.

$$PV_{Ordinary\ Annuity} = \frac{C \times (1 - [1 + i]^{-n})}{i}$$

where

C = Investment for each period,

i = discount rate,

n = number of periods.

The NPV analysis would account for the initial investment and the future value of costs and benefits and discount the future benefits and costs back to present dollars.

6 CONCLUSIONS

Conclusions

Planning, designing, and operating a distribution system efficiently can reduce system losses by 5% to 10% over the next 10 to 15 years [1, 12, 13, 15]. Some loss reduction techniques are cost effective to retrofit existing infrastructure such as phase balancing and reactive power management, while other techniques are typically economical when implemented at initial construction. Operating a distribution system more efficiently can further reduce energy requirements and peak demand by 2% to 3% [13], where the majority of the energy reduction is achieved by reducing the customer's energy consumption. To achieve a more efficient electrical network, a better understanding of how the electric system is performing, and where cost effective changes can be implemented, needs to be accomplished. One area that could benefit from the additional knowledge is electric system losses. Reducing electric system losses is a significant area that can have a profound reduction in energy requirements for the electric network.

This study establishes sound methodologies for utilities to use for calculating electric distribution system losses at the system peak and for energy losses, and provides guidelines to account for the reduction in electrical losses. By establishing a consistent baseline, utilities and regulatory bodies will better understand where system losses are occurring and solutions can be developed to cost effectively reduce peak and energy requirements. Regulatory bodies can make more informed decisions in providing targeted incentives for utilities to reduce energy requirements and provide mechanisms for recovery of the additional costs and loss of revenue that utilities will be faced with.

The methodologies developed in this report are based on sound engineering principles and commonly accepted industry practices. However, in order to provide methodologies that are more universal in nature to address the needs of a wide range of utilities, certain assumptions and estimates were employed to simplify the process. More work is needed to refine methodologies and provide more accurate electric distribution loss values.

Next Steps

In preparing this report, existing practices were reviewed to channel the development of the guidelines for calculating and accounting for loss reduction. However, many unknowns still exist and assumptions are being used to determine distribution system losses. With additional research, these unknowns and assumptions can be better understood and the loss calculation methodology can be refined, which will provide guidance in determining how specific the loss calculations need to be to provide realistic loss values. Advanced metering infrastructure (AMI) and Smart Grid deployments are the key to collecting additional information needed to perform more detailed analysis. With this additional information, detailed analysis can be performed which will allow the loss calculation methodologies to be optimized so that the best results can be achieved at minimal costs.

EPRI's Green Circuits initiative will be performing detailed analysis for several distribution substations and feeders using 15-minute feeder data and, for the feeders that have AMI, 15-minute customer data. With the 15-minute customer data, analysis can be performed that will allow a better understanding of primary line and distribution transformer losses. In addition, optimization of the distribution system losses will be studied and the benefits and costs will be developed based on detailed realistic computer models.

A trend in the electric industry is to integrate system mapping and computer analysis software applications. Updating of electric system information occurs in one location and is typically required for operational issues. Leveraging the mapping information 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.

A

COMPARISON OF LOSS STUDY METHODS FOR SURVEYED UTILITIES

Table A-1
Evaluation Comparison

Utility	Primary Losses	Distribution Transformer Losses	Service and Secondary Losses	Distribution Substation Transformers	Meters	Comments
Utility A	Used 12% Sample of dist system at peak Analysis software: CYMDIST	Used GIS to import size and types of transformers. Analyzed at average peak – scrub data for non standard sizes and errors. Uses average transformer loss data	Calculate secondary line losses on various conductors- uses sizing charts and assumptions with voltage flicker as driver for sizing. Assume 50% residential OH	Not Evaluated	Not Evaluated	2005
Utility B	Includes cable dielectric losses and copper losses	Categorized as Distribution equipment, which includes transformers, voltage regulators, primary capacitors, and shunt reactors	Secondary- Used 3 typical size Aluminum, and 3 typical size copper and evaluated typical average current then calculated losses through the conductor characteristics Services- for both OH and UG 55.8% of normal cable loading was used to determine current then calculated losses through the conductor characteristics	Load and No-load Losses of substation transformers and equipment	Evaluated based on number of each type and multiplying factor. Metering devices also included i.e. Demand meters, relays, and recorders	2002

Utility	Primary Losses	Distribution Transformer Losses	Service and Secondary Losses	Distribution Substation Transformers	Meters	Comments
Utility C and D	% of System analyzed is not given- 5-4.16kV, 31-15kV, 3-23.9kV, and 2-34.5kV circuits analyzed. Calculate Load Losses- Modeled results account for PF and Load Imbalance Analysis software: Siemens PTI PSS/Edept	Calculate load and No-load Losses Loading based on average non-coincident load of 66% rating Demand loss determined for each size- then calculated on # per size No-Load demand loss determined by no-load demand impedance per size * of size	Twelve different service configurations provided Voltage imbalance assumed 55/45 on legs of single phase 120/240	Calculate load and No-load Losses. Peak Loads used to calculate load losses Typical Transformer no-load losses used to calculate no-load losses Average peak loading of all transformers with historical information used	Calculated on standard meter requirement of 0.8 W/hr and electronic meters on 0.2 W/hr Assumed 70% Mechanical Assumed 30% Electronic	2007
Utility E	Demand losses- a representative feeder conductor was used for each distribution voltage- Average feeder load determined by total load divided by # of feeders. Feeder losses=3*I^2*R*Avg length Energy losses- Distribution primary calculated by demand loss*hours in year*Loss factor	Calculate load and No-load Losses	No commercial customers considered for evaluation of secondary system- Secondary losses determine by average length and typical conductor to serve residential customers. Services were evaluated by using single conductor size and length per residential customer and a single conductor and size for a commercial customer	Calculate load and No-load Losses	Not Evaluated	2006

Utility	Primary Losses	Distribution Transformer Losses	Service and Secondary Losses	Distribution Substation Transformers	Meters	Comments
Utility F, G, H, I, and J	Line loading and loss characteristics of “Representative Primary Circuits” used. Losses then based on kW loss per MW of load	Losses based on typical transformer size for service group, and # customers per transformer.	Estimated for each secondary customer for size, length and loadings. Also looked at for Maximum demands to obtain kWh losses.	Load and No-Load Losses Calculated for Each Substation Transformer	Estimated for each customer and incorporated into losses	2005- 2006
Utility K	Line Losses calculated through distribution model Software used: Windmil	No-Load and Load losses calculated through distribution model. Software used: Windmil	Estimated Based on average lengths, size, and type and average peak load. Used a load factor per customer class	No-Load losses provided by utility from testing Load losses calculated from model with 2007 peak load flows Software used: Windmil	Not evaluated- however metering inaccuracies accounted for in Category for loose hardware, Corona, or other Abnormalities, and metering inaccuracies	From 2007 Used RUS Forms
Utility L	Line Losses estimated by feeder efficiency at peak load, loss factor, and power delivered	Load Losses calculated per transformer type Load Losses estimated by transformer size, and number of transformers	Not Evaluated	No-Load Losses- estimated at 1kW per MVA Load Losses- Calculated on load data loses estimated at 4kW per MVA, and a loss factor of 0.40	Not Evaluated	Loss study provided was a how to guide to improve losses and evaluate loss proposed loss reduction measures

Utility	Primary Losses	Distribution Transformer Losses	Service and Secondary Losses	Distribution Substation Transformers	Meters	Comments
Utility M	Power flow on feeder sampling at peak loading. Analysis again performed at different levels by scaling peak load to 100%, 80%, 60% and 40%.	Load and No-load losses determined for all sizes. Used test report data for 0-100% of rated kVA	Not updated used previous study values due to no significant changes in system.	No-load losses directly from manufacturers test reports Load losses calculated on percentage of coincident peak- which was system peak. Used test data to determine on all transformers with hourly data (Test KVA adjusted for actual hourly data)	Not Evaluated	From 2004
Utility N	Calculated peak losses on each feeder through a ratio and convert to various load levels through equation	Calculates Load and no-load losses at peak and converts to any load level through equation	Secondary evaluated on assumptions of type of conductor and percentage of use in system for OH and UG Secondary line losses calculated from voltage drop over average section	Included in Transmission / Sub-trans5mission Analysis	Meters evaluated using data from metering group	From 2005 Loss model takes losses at different levels and uses duration at each level to compute total losses

Utility	Primary Losses	Distribution Transformer Losses	Service and Secondary Losses	Distribution Substation Transformers	Meters	Comments
Utility O	Combined distribution models used to estimate losses	Included Load and no-Load losses at Transmission substation and distribution substation levels	Estimated Based on average lengths, size, and type and average peak load. Used a load factor per customer class	Includes Load and no-Load losses at for line transformers	Not evaluated- however metering inaccuracies accounted for in Category for loose hardware, Corona, or other Abnormalities, and metering inaccuracies	From 2005 Other- Security Lights accounted for and Regulators accounted for. Used RUS Forms
Utility P	Used feeder demand kW losses at peak. Used average losses at peak loads to determine percent demand loss. Converted demand loss to annual kW losses	Included no-load losses Load Losses for 118 actual substation transformer installations serving NPPD Retail load.	Used spot loads of each type OH service conductors representing expected load diversity for an OH residential distribution system configured with 16 houses per transformer	Load and No-load losses from test data on each transformer.	Not Evaluated	From 2007 Large customers served directly from substation were excluded since billed kWh included losses
Utility Q	Primary lines losses calculated at 4kV and 15kV classes. Approximately 600 circuits in system and modeled using PSS/ADEPT	Uses peak measured values at each sub station transformer to calculate losses based on transformer data	Estimated Based on average lengths, size, and type and average peak load. Used a load factor per customer class	Load and No-load losses from test data on each transformer. Used a 54% Utilization based on actual kVA inventory	Evaluated based on number of each type and multiplying factor.	From 2004
Utility R	Uses computer modeling of sampled circuit at each voltage level. Working towards increasing sample size as more circuits modeled	Evaluated with Secondary using average size and average secondary and number of services	Evaluated with distribution transformer using average size and average secondary and number of services	Evaluated as part of transmission analysis	Not Evaluated	From 1989

B
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