MICHIGAN ELECTRIC COOPERATIVE ASSOCIATION
2859 W. Jolly Rd.
Okemos, MI 48864
517-351-MECA (6322)
FAX 517-351-6396
meca.coop

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Following is the Michigan Electric Cooperative Association's (MECA) response to Energy Efficiency question 15:

"How have energy efficiency programs in Michigan or other jurisdictions addressed non-traditional proposals for energy efficiency (e.g. digital metering, grid management technologies, or improvement on the utility side of the meter?"

We have discussed our response with other industry leaders and organizations and we have concurred that our response needs careful and thoughtful consideration for Michigan's clean, renewable, and efficient energy future.

MECA created the MECA EO Collaborative in 2008 to administer the design, implementation, evaluation, and regulatory compliance and reporting for the Energy Optimization Programs specified in PA-295 which represents a commitment of nearly $40,000,000.00 in expenditures by our Collaborative members through 2015. The Collaborative has contracted with the Wisconsin Energy Conservation Corporation (WECC) for the implementation of the Energy Optimization Programs in addition to contracting with KEMA for the independent 3rd party evaluation of the EO programs. Both of these organizations are nationally recognized and highly respected.

The following twelve Michigan rural electric cooperatives and municipals comprise the MECA EO Collaborative:

- Alger Delta Cooperative Electric Association
- Cloverland Electric Cooperative
- City of Escanaba
- Great Lakes Energy Cooperative
- HomeWorks Tri-County Electric Cooperative
- Marquette Board of Light & Power
- Midwest Energy Cooperative
- Newberry Water and Light Board
- Ontonagon County Rural Electrification Association
- Presque Isle Electric & Gas Co-Op
- City of Stephenson
- Thumb Electric Cooperative

MECA generally supports Consumers Energy and DTE's industry responses to the Energy Efficiency questions.

Executive summary

1. Arkansas, Florida, Iowa, Massachusetts, Maryland, Minnesota, New York, and Vermont include transmission and distribution savings to count towards their Energy Efficiency Resource Standards (EERS).

2. Electricity is lost through resistive heat loss in transmission lines, hysteresis loss in transformer cores, and various other processes. The result is that electric utilities typically lose anywhere from 2% to 15% or more of their purchased or generated electricity to transmission and distribution losses. This represents a substantial cost to utilities, leading to higher retail costs[1].

3. System losses are typically divided into two categories; "**load losses**" which result from **resistive loss** over power lines and other wires, and "**no load losses**", which are losses that occur as a result of simply creating a voltage on the system. The physics associated with resistive losses give rise to the concept of "**marginal loss**". Marginal loss is the loss associated with the next kW of added load at any given load level. Marginal losses increase as the system load rises – a kW added at times of low load may only have a 5% loss associated with that kW, but a kW added at peak demand may have a 20% or higher loss.

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1. **Arkansas, Florida, Iowa, Massachusetts, Maryland, Minnesota, New York, and Vermont include transmission and distribution savings to count towards their Energy Efficiency Resource Standards (EERS).**

   These states have recognized that energy efficiency goes beyond the customer's side of the meter and in many cases, the opportunity for energy efficiency improvements are greater on the utility's side of the meter and the value of a kWh saved during system peaks on the utility side can be provide 25% more value than the kWh saved on the customer's side of the meter during the same peak period.

2. **Electricity is lost through resistive heat loss in transmission lines, hysteresis loss in transformer cores, and various other processes. The result is that electric utilities typically lose anywhere from 2% to 15% or more of their purchased or generated electricity to transmission and distribution losses. This represents a substantial cost to utilities leading to higher retail costs.**

   Utilities can combat no-load and resistive losses with a number of specific technical tools, including voltage upgrades, new transformers, upgraded conductors, power factor correction, and optimization of load balancing. However, a utility that wants to maximize the effectiveness of specific remedies to combat losses will want to consider the following questions:

   a. How do system losses change over the load range? In particular what are system losses at times of peak demand?
   b. Where do losses originate in the system – transmission lines, distribution lines, substations, distribution transformers? What is the percent breakdown for each component? How does the breakdown change with load?
   c. How do losses vary from substation to substation, and from feeder to feeder?
   d. How do these answers affect the utility? What cost-effective steps are available to reduce the impact of losses?

[1] National Rural Electric Cooperative Association, Cooperative Research Network, "Marginal Line Losses", August 2012

3. **System losses are typically divided into two categories; "load losses" which result from resistive loss over power lines and other wires, and "no load losses", which are losses that occur as a result of simply creating a voltage on the system. The physics associated with resistive losses give rise to the concept of "marginal loss". Marginal loss is the loss associated with the next kW of added load at any given load level. Marginal losses increase a s the system load rises – a kW added at times of low load may only have a 5% loss associated with that kW, but a kW added at peak demand may have a 20% or higher loss.**

   Accurate calculation of marginal losses can drastically change the cost/benefit analyses of demand response and energy efficiency programs. These programs may appear to be marginal break-even or slight losers for utilities to implement, but may be quite profitable after the marginal loss calculation are applied. This analysis cannot be performed unless losses are analyzed beyond the annual figure.

   Load losses typically account for around 70% - 75% of the system-wide lines losses, with no-load losses making up around 25% - 30% of total system losses. However, this industry-wide figure is not necessarily applicable to a typical cooperative, especially a rural cooperative with low customer densities. A rural cooperative may have no-load losses that equal 50% or more of total system losses, at least during times of low and average load.

   Energy Efficiency Resource Standards that include efficiency savings on the utility side of the meter provides for:

   - New technology available today that offers distribution transformers that are 98% - 99% efficient, capable of reducing no-load losses by 30% or more.
   - Reducing marginal line losses at times of high peak providing numerous financial and environment benefits including:
     - Avoided reserves
     - Deemed savings of energy efficiency programs
     - Postponement or avoidance of generation/market purchases
     - Postponement or avoidance of T&D investments
     - The creation of energy credits

NRECA CRN™ COOPERATIVE RESEARCH NETWORK

AUGUST 2012

Marginal Line Losses

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AUGUST 2012

Marginal Line Losses

Prepared by
Chris Ivanov
Power System Engineering, Inc.
1532 W. Broadway
Madison, WI 53713
www. powersystem.org

for

Cooperative Research Network
National Rural Electric Cooperative Association
4301 Wilson Boulevard
Arlington, Virginia 22203-1860

PREVIOUS VIEW

The National Rural Electric Cooperative Association

The National Rural Electric Cooperative Association (NRECA), founded in 1942, is the national service organization supporting more than 900 electric cooperatives and public power districts in 47 states. Electric cooperatives own and operate more than 42 percent of the distribution lines in the nation and provide power to 40 million people (12 percent of the population).

NRECA's Cooperative Research Network (CRN) harnesses research and development to benefit its electric co-op members in four key ways:

- Improve productivity,
- Control costs,
- Increase service excellence, and
- Keep pace with emerging technologies.

CRN strives to deliver new products and services best suited to the particular needs of electric co-ops. CRN communicates with its members through its Web site (**www.cooperative.com/crn**), online and printed reports, newsletters, Web conferences, and seminars.

In addition, CRN staff present at several annual events, including NRECA's TechAdvantage Conference & Expo, the NRECA/Touchstone Energy "Connect" marketing conference, and Touchstone Energy's New & Emerging Technologies (NET) Conference. For more information about these events and CRN's participation, visit the Conferences & Training section of **www.cooperative.com**. For questions about CRN, call 703.907.5843.

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Questions

Maurice Martin, Program Manager
maurice.martin@nreca.coop

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1 Introduction: Electrical System Losses

In This Section:

- Calculating System-Wide Annual Losses: Historical Approach
- Cooperative Loss Statistics
- Limitation of the "Annual Losses" Figure
- Benefits of Examining Losses
- Load Losses vs. No-Load Losses

Electricity losses are a cost of doing business for all electric utilities. At every stage of the generation, transmission, and distribution supply chain, the laws of physics conspire to slowly bleed electricity from the system. Electricity is lost through resistive heat loss in transmission lines, hysteresis loss in transformer cores, and various other processes. The result is that electric utilities typically lose anywhere from 2% to 15% or more of their purchased or generated electricity to transmission and distribution losses. This represents a substantial cost to utilities, leading to higher retail costs.

System losses are typically divided into two categories: **load losses**, which result from **resistive loss** over power lines and other wires, and **"no-load" losses**, which are losses that occur as a result of simply creating a voltage on the system. Although utilities sometimes refer to their total system losses as "line losses," it is more accurate to say that line losses are just one component of total system losses, along with other resistive losses and no-load losses.

The physics associated with resistive losses give rise to the concept of "**marginal loss**," which is the focus of this paper. Marginal loss is the loss associated with the next kW of added load at any given load level. Marginal losses increase as the system load rises—a kW added at times of low load may only have a 5% loss associated with that kW, but a kW added at peak demand may have a 20% or higher loss.

> Marginal loss is the loss associated with the next kW of added load at any given load level.

In order to fully understand the concept of marginal losses, one must first examine how resistive losses and no-load losses differ. The reason marginal losses increase with added load is that resistive losses increase exponentially as the current rises. No-load losses, on the other hand, remain constant with varying current. The relationship between load and losses will be examined in more detail throughout the paper.

Utilities can combat no-load and resistive losses with a number of specific technical tools, including voltage upgrades, new transformers, upgraded conductors, power factor correction, and optimization of load balancing. However, a co-op that wants to maximize the effectiveness of specific remedies to combat losses will want to consider the following questions.

1. How do system losses change over our load range? In particular, what are system losses at times of peak demand? Again, this paper will focus on the marginal losses, which increase as demand rises.
2. Where do losses originate in the system—transmission lines, distribution lines, substations, distribution transformers? What is the % breakdown for each component? How does this breakdown change with load?
3. How do losses vary from substation to substation, and from feeder to feeder?
4. How do the answers to the above questions affect my utility? What cost-effective steps are available to reduce the impact of losses?

The answers to some of these questions might look quite different for electric cooperatives than for investor-owned utilities or municipal electric utilities. Cooperatives often have unique circumstances that affect how their losses will vary with load.

This paper will show cooperatives how to assess their current system-wide losses at various load levels. The extent to which cooperatives will be able to analyze marginal loss data will depend in part on their current state of technology. However, even cooperatives with legacy systems can learn about their systems losses to the extent possible. Such data can have dramatic impacts on other areas of a utility's practice.

For example, accurate calculation of marginal losses can drastically change the cost/benefit analyses of demand response ("DR") and energy efficiency ("EE") programs. A DR program that appears to be break-even or a slight "loser" for a cooperative and its members may in actuality be quite profitable after the marginal loss calculations are applied. This analysis cannot be performed unless losses are analyzed beyond the average annual figure. More detailed calculations, in turn, affect the value of DR and EE programs; this application will be examined in **Section 4**.

Calculating System-Wide Annual Losses: Historical Approach

Electric utilities have historically calculated system-wide losses using a straightforward approach, with numbers taken from annual reports. All utilities use the same basic approach. System losses for the year are calculated from year-end forms, such as RUS Form & or FERC Form 1, as follows:

$$\text{Losses} = \frac{(\text{kWh purchased} + \text{kWh generated}) - (\text{kWh sold} + \text{kWh own use})}{(\text{kWh purchased} + \text{kWh generated})}$$ [1]

An example with concrete numbers would be Oklahoma Gas & Electric's ("OG&E") 2010 FERC Form 1.[2] For 2010, OG&E's "sources" of electricity, including generation, power exchanges, purchases, and transmission for other of energy, totaled 30,303,712 MWh.[3] Excluding losses, OG&E's disposition of energy, including sales to customers, sales for resale, own use, and energy furnished with no charge, totaled 28,273,494 MWh. The difference between the total sources of energy and the measured disposition of energy constitutes OG&E's 2010 losses: 2,030,218 MWh, or around 6.7% of total sources.

It is important to note that OG&E did not *measure* the losses (using instruments) to be 2,030,218 MWh. It *calculated* the losses as the difference between sources of energy and disposition of energy. It would be impractical to try to actually measure the heat released by the various physical processes, such as resistive losses

[1] This paper does not address theft of electricity, but that figure is often included in losses as well, unless it is discovered and tracked separately. If it is tracked separately, the numerator in the equation above would change to: (kWh purchased + kWh generated) – (kWh sold + kWh own use + **kWh lost to theft**)

[2] OG&E was picked at random for illustrative purposes.

[3] See OG&E's 2010 FERC Form 1, filed 4/11/2011, p. 401a.

along transmission lines. It would be less impractical, but still quite onerous, to take voltage and current measurements before and after every component of the system, and then add up each component loss to arrive at a total. What utilities do instead is take the total of its sources (a figure which is readily measured), and subtract the total of its sales and other uses (also readily measured). Whatever is left *must* be losses.

FACTORS THAT AFFECT SYSTEM LOSSES

The total amount of system losses depend on many factors, including:

- Miles of transmission line
- Miles of distribution line
- Customers per mile of distribution line
- Type of distribution line
- Voltage levels
- Number, size, efficiency, and age of transformers, regulators, etc.
- New service and line extension practices (i.e. location of meter, size and length of secondary service wires, etc.)
- Ambient air temperatures
- Load shapes
- Load levels of substations and distribution transformers (as a % of capacity)
- Load factors
- Average number of customers per transformer

One of the most evident differences between cooperatives and other electric utilities is that cooperatives have, on average, lower customer density.[4]

With all other things being equal, one would expect a transmission and distribution utility with a higher ratio of customers per mile of line to have lower total losses than a utility with **fewer** customers per mile of line. And, on average, T&D utilities with condensed service areas do have lower losses. As previously shown, OG&E's total losses in 2010 were around 6.7%. OG&E had a "customers per mile of distribution line" figure of around 20 (this figure is relatively low for an IOU).

Compare OG&E's total 2010 losses to that of Atlantic City Electric Co. ("Atlantic") in New Jersey, which is a T&D IOU with a "customers per mile of distribution line" figure of over 50. Atlantic's total losses for 2010 were around 4.6%.[5] Of course, OG&E and Atlantic vary in any number of ways, but all other factors being equal, higher customer density results in lower losses.

For cooperatives, the "customers per mile of distribution line" ratio is often below 10—sometimes as low as 2 or 3. Thus, all other things being equal, one might expect cooperatives to have higher system losses than an "average" utility. However, it depends on the method of calculation. If you calculate the cooperative and national averages, cooperative losses are actually below the U.S. system as a whole. The U.S. system as a whole has losses of around 6.5% in 2009, and 6.3% in 2010.6 Cooperative losses are around 6.0%. This comparison is not particularly informative, however. The "cooperative average" and the national average are calculated in two different ways. **See Footnote 8**. Furthermore, for large systems made up of a network of utilities, system losses are higher than losses for one component utility of the system.

Comparing cooperatives to IOUs, however, is not always illuminating, as all other factors are rarely equal. For example, cooperative substations and feeder layouts are often more carefully planned than those of IOUs. IOUs, on the other hand, tend to operate their equipment closer to its load limits, which can greatly affect losses (more on this later). Therefore, comparisons between the two kinds of utilities can be misleading.

The next section will examine how the 6% figure for average cooperative losses was calculated, and look at the loss statistics of U.S. electric cooperatives in more detail.

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[4] For example, Platts' *UDI Directory of Electric Power Producers and Distributors* typically lists the number of customers and the total distribution line miles for each utility.

[5] Atlantic had 637,282 MWh of total losses, and 13,768,570 MWh of total sources of energy. See Atlantic's 2010 FERC Form 1, filed 4/18/2011, p. 401a.

[6] See www.eia.gov/electricity/state/unitedstates/index.cfm (click on "Table 10") for national data from the U.S. Energy Information Administration. The EIA national system losses were calculated by summing the total energy sources and summing the losses, and dividing the latter into the former. For example, for 2009, losses were 260,581 gigawatt-hours, out of 4,002,522 gigawatt-hours produced.

Cooperative Loss Statistics

The following chart was created from using 2010 cooperative statistics found on SNL Energy, an information service focusing on the energy industry.[7] The chart below shows the loss ranges for the cooperatives. Out of 906 cooperatives listed on SNL, 41 cooperatives were not used for Figure 1.1, because their data was incomplete (e.g., losses were listed as zero, data was missing, etc.). The average 2010 system-wide loss for the 865 remaining cooperatives was 6.04%.[8] This fits in with nationwide cooperative losses as reported by NRECA in the past.

The data can also be broken down by cooperative type. For example, one would expect cooperatives engaged in transmission and distribution to have higher losses than cooperatives engaged solely in distribution, because there is an extra level of losses associated with the transmission facilities. The three sub-groups of cooperatives presented here are as follows:

1. **Distribution cooperatives with no transmission facilities.** This includes: distribution-only cooperatives; distribution and generation cooperatives.
2. **Distribution cooperatives with transmission facilities.** This includes: distribution and transmission cooperatives; distribution, generation and transmission cooperatives.
3. **Cooperatives that do not distribute electricity to customers.** This includes: generation-only cooperatives; transmission-only cooperatives; generation and transmission cooperatives.

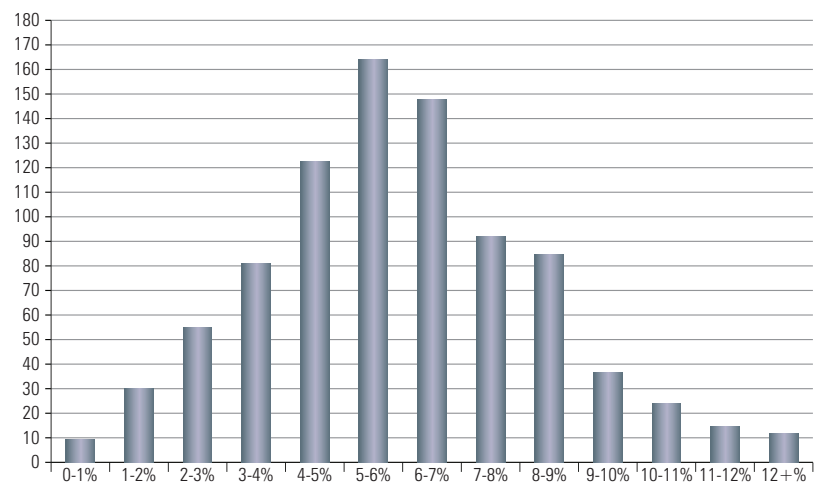


FIGURE 1.1: National Cooperative Loss Distribution

The losses for these three sub-groups are shown in **Figure 1.2**, **Figure 1.3**, and **Figure 1.4**.

Figure 1.2 shows the data for distribution-only cooperatives and distribution and generation cooperatives. Again, these were sorted using SNL data, which came from FERC forms and EIA.[9] There were 519 of these cooperatives, and the average losses were 5.8% (using the "average of the averages" approach).

In Figure 1.3, losses for distribution and transmission cooperatives and distribution, generation and transmission cooperatives are shown. There were 304 of

[7] SNL Energy ("SNL") is a for-profit site that requires a subscription. SNL cited its data as coming from FERC Form 1, p. 401a; and from EIA Form 861.

[8] There are two ways to state the losses for cooperatives as a whole. One is to calculate the losses for each cooperative in terms of averages, and then average the averages. This is how losses for groups of utilities are determined in this paper.

A second way is to sum the energy inputs for the 865 cooperatives, sum the losses, and treat all the cooperatives as if they were one big cooperative. This is the method used for the EIA national losses, as stated in Footnote 6. On this method, the 865 cooperatives total to 822,647,899 MWh, and losses total 37,500,238 MWh, for "average" losses of 4.56%. However, this method of calculating "average" cooperative loss is not often used, as the larger cooperatives skew the data.

It should be noted that the "average" losses of the cooperative industry as a whole can be either higher or lower than the national "average," depending on how the two averages are calculated. The national average is not typically calculated by the "average of the averages" method, as this would involve averaging all of the IOUs, cooperatives, and municipal utilities.

[9] Cooperatives typically file RUS forms, not FERC forms. This paper simply conveys SNL's stated sources for loss statistics.

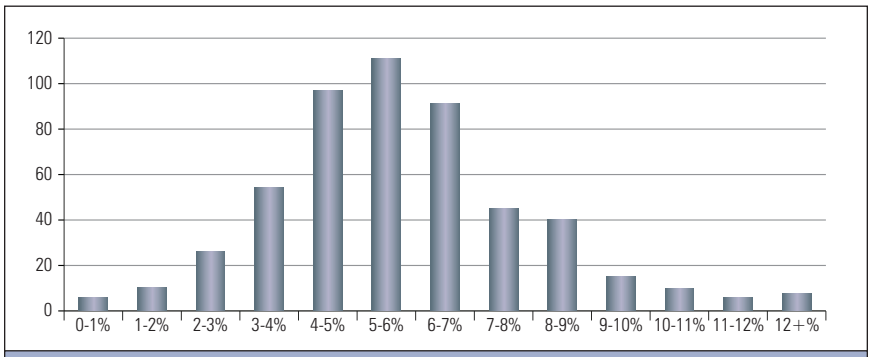


FIGURE 1.2: Distribution-only Cooperatives

these cooperatives, and the average losses were 6.8%. These cooperatives had higher losses on average than those in Figure 1.2, which makes sense: adding a transmission system into the mix will, on average, increase losses.

Cooperatives that do not distribute electricity to customers are shown in Figure 1.4 below. There were 40 cooperatives in this sample. The average losses for these cooperatives were only 2.9%.

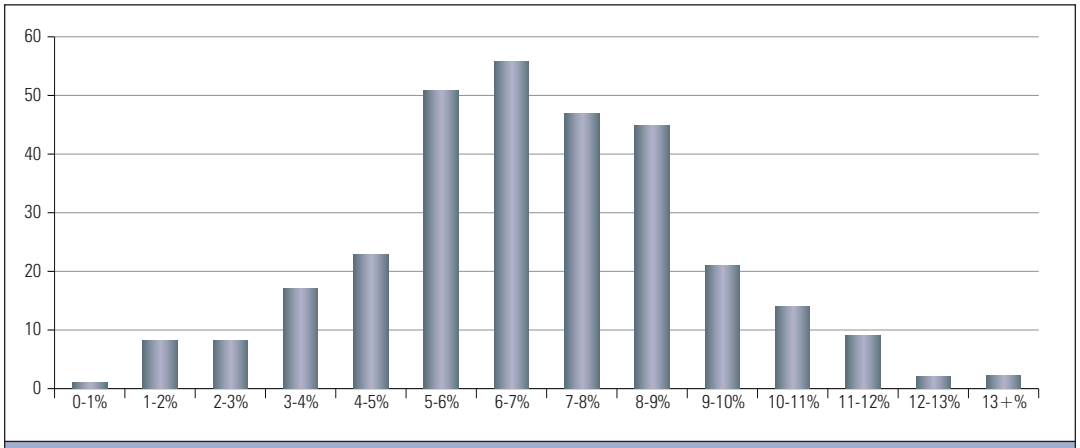


FIGURE 1.3: Distribution and Transmission Cooperatives

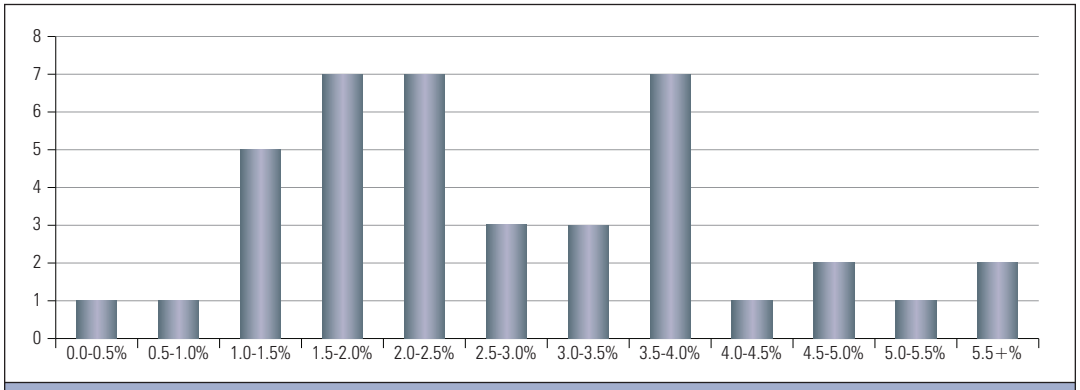


FIGURE 1.4: Generation and Transmission Cooperatives

Limitation of the "Annual Losses" Figure

BREAKDOWN BY COMPONENT

One way in which the annual loss figure falls short is that it does not provide the breakdown by component of where the losses originate. For example, it would be useful to know exactly how much transmission line loss occurs on a system. The more miles of line a cooperative had on its system, the more interested it would be in measuring line losses accurately. The total amount of line losses could be broken down further by determining losses specific to each gauge/type of transmission line (e.g., high voltage lines vs. lower voltage service conductors). In addition to line loss breakdowns, it would also be useful to know what losses occur at each substation and transformer.

> Proper transformer sizing can reduce losses.

It should be noted that proper transformer sizing can reduce losses. If transformers are larger or more numerous than the load requires, the system will have more "no-load" losses than is necessary. As this paper will show below, this is because the no-load losses result from simply creating a voltage on the system, and are not dependent on the load level.

> An annual loss figure does not indicate the marginal loss for a range of load levels.

A detailed study by component may also identify losses that are unanticipated. For example, it may be that lightning arrestors are leaking current to the ground. Regulators can have losses that are higher than expected. Or it could be that three-phase current (if present) is suffering losses on the returning current neutral. The losses for these components can only be discovered if a utility goes beyond the "annual losses" figure.

These more specific loss measurements can be determined two ways. If a utility has modern "smart grid" equipment, such as Advanced Metering Infrastructure ("AMI") and Geographic Information System ("GIS"), a breakdown by component is possible (See **Case Study #3: Otsego Electric Cooperative** in Section 2). Without smart grid technologies, to get component-specific loss figures, utilities would be left with calculating losses using more basic engineering models and load data, rules of thumb, and estimations using industry-accepted approaches. But these models and calculations are often rough estimations, and without smart grid technology, the utility would be unable to confirm its calculations.

BREAKDOWN BY LOAD

Another way that the annual loss figure falls short is that it does not indicate how system losses will change with load. More importantly, an annual loss figure does not indicate the **marginal loss** for a range of load levels. Without this information, utilities cannot properly evaluate programs that reduce load at peak times.

The basic engineering models mentioned in the previous section are typically run with peak load inputs for planning purposes. However, utilities often do not run these models at a variety of load levels, and so marginal losses are not readily available. Even if the utility runs the engineering models with a variety of load inputs, basic models have the following limitations:

1. Basic engineering models do not include all components of the system; particularly, distribution transformer, service conductors and short primary line taps are often not included in a basic model.
2. Accuracy cannot always be confirmed by real-world data. This is because the engineering model typically uses assumptions common to the industry, such as load allocations during various times, and the type of load mix across the system.
3. Estimates of energy losses are particularly suspect.
4. The precision at the component level may not be sufficient for cost-benefit analyses.

Benefits of Examining Losses

Even though losses are inevitable, cooperatives may want to pay close attention to them for three main reasons.

First, **although a certain level of loss is unavoidable, the exact amount of losses can be reduced through strategic planning.** A drop in annual system-wide losses from (for example) 7% to 6% will save a distribution utility 1% on its wholesale bill—and the wholesale savings can be even more if a higher proportion of losses are avoided during coincident peak times, when wholesale demand charges are incurred.

Second, if average losses can be broken down by component level, utilities can make more informed choices about component selection, T&D planning, and other related issues. At the component level, the capability to make detailed measurements of losses could assist a cooperative in many ways:

- More accurate cost/benefit analyses when determining the purchase of new equipment,
- Determining whether Brand X Transformer meets its manufacturer's claims about the unit's losses at various loads.
- Measuring the transformer's performance deterioration over time.
- More detailed analyses of feeder and distribution line layouts.
- Improved standards for designing new service extensions

Third, **a utility can track system and component losses against load, and thus gain information about the value of programs and technologies that help reduce peak loads**. This third point is the focus of the present paper. While typical utility losses might average between 5 to 10% annually, at times of peak load line losses may approach or even exceed 20%. Thus, any program that reduces peak demand, such as direct load control of air conditioners, avoids more losses than previously thought. And as mentioned earlier, reducing losses and energy purchased at peak demand time can avoid both wholesale energy and demand charges.

> Reducing losses and energy purchased at peak demand time can avoid both wholesale energy and demand charges.

For example, consider a system where average losses are 7%, and losses at peak load are 20%. One kW saved at the meter at peak time doesn't just save the utility 1 kW at the point of generation or purchase. Losses must be taken into account. Most utilities just use the average annual loss figure:

$$1.075 \text{ kW at purchase} - (0.07 \times 1.075 \text{ kW}) \approx 1.0 \text{ kW at meter}$$

However, a kW saved at peak saves more than just 1.075 kW, because losses at peak are 20%. The kW saved at the meter saves 1.25 kW at purchase:

$$1.25 \text{ kW at purchase} - (0.20 \times 1.25 \text{ kW}) = 1.0 \text{ kW at meter}$$

Often, cooperatives do not calculate system losses with any specificity past the "average for the year" figure. Sometimes the annual figure is broken down by month, which begins to give an idea of how load can affect the system losses.

However, for planning purposes and accurate cost/benefit analyses, a cooperative needs to know its marginal losses at system peak. How else can a cooperative value a Demand Response (DR) program, such as a dynamic pricing program, that reduces peak demand? If the marginal losses at peak are 20%, as in the example above, the DR program will be much more valuable than previously thought.

Load Losses vs. No-Load Losses

Before the concept of marginal losses is explored further, a breakdown of system losses by sub-type is required. Overall losses are made up of two main types: **load losses** (also called resistive losses) and **no-load losses**. Although some utilities refer to the overall system losses (no-load and resistive) as "line losses," this paper uses the term "line loss" to refer only to one type of resistive loss—loss that occurs in transmission and distribution lines and service conductors. This distinction is needed, because some resistive losses also occur in transformer windings (more on this later).

Another possible source of inaccuracy occurs when the term "no-load loss" is used synonymously with "transformer losses." This is inaccurate because transformers and regulators incur both load losses and no-load losses. Thus, when performing cost/benefit analyses that go beyond total system losses, cooperatives need to break down losses into load and no-load categories.

> When performing cost/benefit analyses that go beyond total system losses, cooperatives need to break down losses into load and no-load categories.

> Resistive losses increase significantly in high load periods, due to the exponential "I-squared" relationship.

LOAD LOSSES (AKA RESISTIVE LOSSES)

Resistive loss, also known as **load loss**, occurs any time an electric current flows through a conductor. As the flowing electrons collide with the atoms of the conductor, they transfer kinetic energy to the conductor atoms, which in turn gain kinetic energy. The kinetic energy gained in the conductor material is released as heat. Resistance in a conductor is sometimes paralleled with the concept of mechanical friction: the higher the resistance of a conductor, the more the electrons are "slowed down" by releasing some of their kinetic energy.[10]

Resistive losses are calculated as follows: Resistive loss = I^2R, where I = current and R = resistance. Once a specific conductor is selected (e.g. #2 ACSR), resistance for that segment is simply a function of the conductor material. Resistance is then constant over that segment.[11] The current, however, varies with load. Thus, resistive losses increase

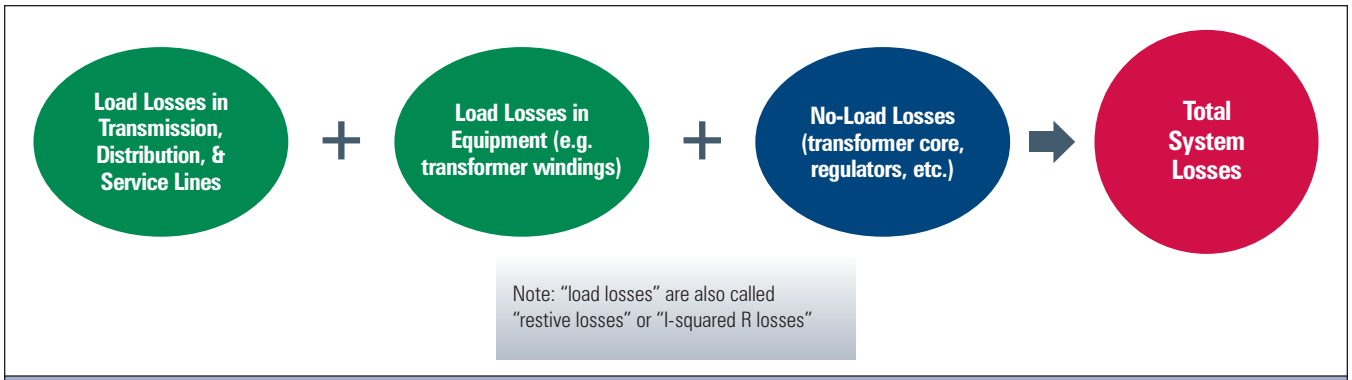


FIGURE 1.5: Total System Losses

[10] The electrons actually lose energy rather than velocity.

[11] This assumes a constant temperature. Note that some changes in resistance occur with temperature changes.

significantly in high load periods, due to the exponential "I-squared" relationship.

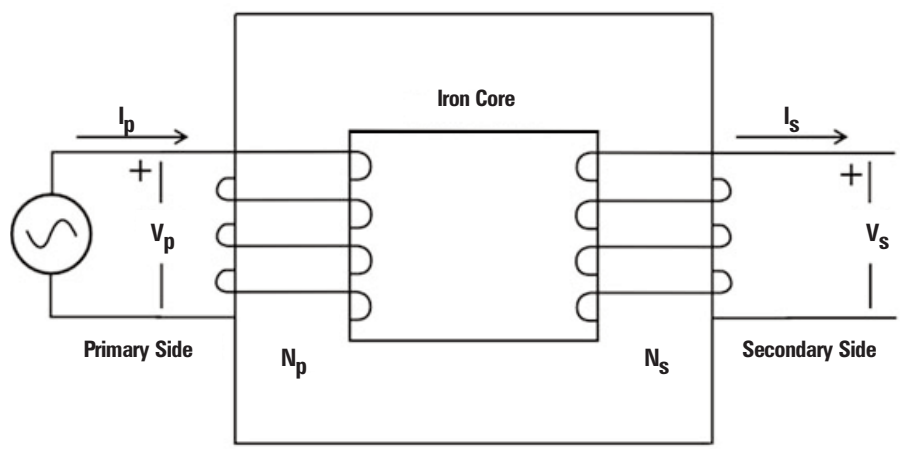
For the electric industry as a whole, load losses typically account for around 70-75% of the system-wide line losses, with no-load losses thus making up around 25-30% of total system losses.[12] However, this industry-wide figure is not necessarily applicable to a typical cooperative, especially a rural cooperative with low customer densities. A rural cooperative may have no-load losses that equal 50% or more of total system losses, at least during times of low and average load. However, the ratio of load to no-load losses will be highly variable between cooperatives, and even between different substations within the same cooperative. The impact of load losses vs. no-load losses will be discussed further in **Section 2**.

NO-LOAD LOSSES

No-load losses are losses that occur when a system is energized, regardless of load. These losses occur mostly in transformers and regulators, although other components may also have no-load losses. These losses are constant over the load range[13] For the electric industry as a whole, no-load losses typically account for around 25-30% of the system-wide line losses.[14] As stated above, however, no-load losses for cooperatives may easily reach 50% or higher.

The term "no-load loss" sometimes refers to losses that occur in a transformer, as opposed to in transmission lines. At other times, the term is used to refer to any losses on a system that are not resistive losses. The latter definition is the one used for this paper.

Consider the makeup of a transformer. In a basic transformer, voltage is changed by use of "turns" of a conductive wire wrapped around a core in a "winding" configuration. (See Figure 1.6.)[15] Thus, a transformer has some resistive losses associated with it, as the turns are composed of "lines" that are subject to the same I^2R losses that affect transmission and distribution



$$\frac{V_p}{V_s} = \frac{N_p}{N_s} = \frac{I_s}{I_p}$$

FIGURE 1.6: Basic Transformer

[12] Jim Lazar and Xavier Baldwin, "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements," August 2011 (Regulatory Assistance Project paper), pp. 3-4.

[13] Note that no-load losses do vary with voltage to some degree. Higher voltages, as compared to the nameplate voltage of the transformer, lead to higher no-load losses.

[14] Lazar and Baldwin, pp. 3-4.

[15] Image in Figure 1.6 from http://drstienecker.com/tech-261-material/15-transformers-chapter-12/.

lines. This is why it is not accurate to divide losses into "resistive losses" and "transformer losses."

In addition to the resistive losses in the turns of the windings, transformers have core losses, which consist primarily of **hysteresis losses** and **eddy losses**. Hysteresis losses are caused by molecules in the core laminations resisting being magnetized and demagnetized by the alternating magnetic field. This resistance causes friction, which results in heat.[16] Eddy loss occurs when "eddies" of electric currents form within the core itself—eddies that flow in a direction other than the direction of the intended magnetic flux. These eddies dissipate energy, so that less current is generated in the secondary windings.

Although hysteresis losses and eddy losses make up the majority of losses in a transformer, there are also other losses, such as eddy losses in non-core components (such as clamps) and dialectic losses. Out of all these, hysteresis contributes the most losses.

Therefore, some losses in a transformer vary with load (the resistive losses in the turns), and some do not (the core losses). Ideally, a cooperative will be able to take the total loss associated with a transformer and break it into resistive losses and core losses. For newer transformers, these breakdowns will be available from the manufacturer specifications. For older transformers, such breakdowns may not be available.

[16] See, e.g., *The Authoritative Dictionary of IEEE Standard Terms*, 7th ed., IEEE, 2000: "The energy loss in magnetic material that results from an alternating magnetic field as the elementary magnets within the material seek to align themselves with the reversing magnetic field."

2 Marginal Losses

In This Section:

- **Case Study #1: Hypothetical Feeders One and Two**
- **Case Study #2: Hypothetical Feeder Three**
- **Case Study #3: Otsego Electric Cooperative**
- **Case Study #4: CRN Data (Pedernales)**
- **Lessons**

The resistive loss equation results in **marginal line losses** (also called simply **"marginal losses"**), which are the losses associated with the next increment of load at a given point in time. The increment is arbitrary—it could be an additional kW or MW of load. The important concept is that the added increment will be composed of two components: useful load (delivered to the end point) and system losses. So, if the system in question has (for example) 5% marginal losses at 100 kW of load, this means that the next kW added will be 0.95 kW of useful load and 0.05 kW of loss.

> The added increment (of load) will be composed of two components: useful load…and system losses."

Because resistive losses vary with the square of the current, the line loss associated with one kW of additional load at high load levels is much greater than the line loss from one kW of additional load at low load levels. So, for example, if the peak summer load is *twice* the average load, the resistive loss at peak is *four times* the loss during the average load. The more of a "needle peak" a utility or specific substation has, the worse the line losses will be at peak times (assuming similar loads at low load levels).

Consider a hypothetical system that typically varies from 4 MW of load to 12 MW. A MW added at low load times (from 4 MW to 5 MW) may only have 60 kW of resistive loss (6% of the added MW). At a much higher load level, adding one more MW of load in that same system (from 11 MW to 12 MW) may add 160 kW of resistive loss (16% of the added MW).

The marginal loss is the % loss associated with the added increment. So, in this example, the MW added at 11 MW consisted of 160 kW of loss and 840 kW of "useful" load at the point of delivery. This increase in the marginal loss from low load to high load is driven by the "I-squared" component of the line loss equation.

The marginal loss concept illustrates the disproportionate impact that high demand times can have on a utility's overall system loss metrics. It also provides an opportunity for cooperatives to lower line losses significantly—*if* peak demand can be lowered.

Case Study #1: Hypothetical Feeders One and Two

To get a clearer understanding of marginal line losses, one needs to calculate it for a range of different loads. Consider a system (here, a feeder) that typically ranges from 100 to 400 kW of demand at the meter. (See Table 2.1.) Assume that when the feeder is at 100 kW, it has 3 kW of resistive loss and 3 kW of no-load loss. Thus, the total losses at a load of 100 kW are 6%.

If the load goes up to 110 kW, the no-load losses will remain constant. However, the additional resistive loss for that 10 kW increment varies with the square of the current, and will be 0.63 kW:

$$\left(\left(\frac{110\ kW}{100\ kW}\right)^2 \times 3\ kW\right) - 3\ kW = 0.63\ kW$$

The total losses for the system are now 6.63 kW, which is 6.027% of the total load of 110 kW. The extra 10 kW of load added 0.63 kW of loss. Therefore, the marginal line loss—the loss on the added 10 kW—was 6.3%.

Looking at the situation from the perspective of the meter, if the feeder is at 100 kW of load, and the load is reduced by 1 kW at the meter, the utility will save around 1.064 kW at the point of purchase:

1.064 kW at purchase – (.06)(1.064 kW)
≈ 1 kW at meter

If instead the load is at 110 kW, and the load is reduced at the meter by one kW to 109 kW, the total losses are 6.3%, and the utility will save around **1.067 kW** at the point of purchase.[17] Since this is still on the low end of the system's kW range, the effect of the marginal line loss is not very pronounced. However, consider what happens at the high end, where the marginal losses are much higher. At 400 kW, the marginal loss percentage is 23.7%. At a load of 400 kW, one kW saved at the meter saves over **1.3 kW** at the point of purchase:

1.311 kW at purchase – (.237)(1.311 kW)
≈ 1 kW at meter

TABLE 2.1: Marginal Losses on Hypothetical Feeder #1

Load (kW)	Resistive Losses (kW)	No-Load Losses (kW)	Total System Losses (kW)	Total Loss in %	Amount of Loss in the 10 kW Increment (kW)	Marginal Loss
100	3.00	3	6.00	6.000%		
110	3.63	3	6.63	6.027%	0.63	6.3%
120	4.32	3	7.32	6.100%	0.69	6.9%
200	12.00	3	15.00	7.500%	1.17	11.7%
210	13.23	3	16.23	7.729%	1.23	12.3%
220	14.52	3	17.52	7.964%	1.29	12.9%
300	27.00	3	30.00	10.000%	1.77	17.7%
310	28.83	3	31.83	10.268%	1.83	18.3%
320	30.72	3	33.72	10.538%	1.89	18.9%
400	48.00	3	51.00	12.750%	2.37	23.7%

[17] 1.067 kW at purchase – (.063)(1.067 kW) ≈ 1 kW at meter.

Another thing to note about Table 2.1 is that the marginal losses depend only on the magnitude of the initial resistive losses. Changing the magnitude of the initial no-load losses does not change the marginal loss percentage, as shown in Table 2.2 below. The initial magnitude of the no-load losses has been changed from 3 kW to 1.5 kW, but the marginal loss percentage at each added 10 kW increment stay the same.

This is because resistive losses increase with the square of the current, but no-load losses stay the same. So, the added 10 kW increment of load will add zero no-load losses, but it will add 0.63 kW of resistive loss (the same as in Table 2.1):

$$\left(\left(\frac{110\ kW}{100\ kW}\right)^2 \times 3\ kW\right) - 3\ kW = 0.63\ kW$$

Therefore, the marginal loss of the added 10 kW—the percentage of that 10 kW that was loss—is 6.3%. This 6.3% is the same whether the initial no-load loss is 3 kW or 1.5 kW.

> Changing the magnitude of the initial no-load losses does not change the marginal loss percentage.

TABLE 2.2: Marginal Losses on Hypothetical Feeder #2

Load (kW)	Resistive Losses (kW)	No-Load Losses (kW)	Total System Losses (kW)	Total Loss in %	Amount of Loss in the 10 kW Increment (kW)	Marginal Loss
100	3.00	1.5	4.50	4.500%		
110	3.63	1.5	5.13	4.664%	0.63	6.3%
120	4.32	1.5	5.82	4.850%	0.69	6.9%
...						
200	12.00	1.5	13.50	6.750%	1.17	11.7%
210	13.23	1.5	14.73	7.014%	1.23	12.3%
220	14.52	1.5	16.02	7.282%	1.29	12.9%
...						
300	27.00	1.5	28.50	9.500%	1.77	17.7%
310	28.83	1.5	30.33	9.784%	1.83	18.3%
320	30.72	1.5	32.22	10.069%	1.89	18.9%
...						
400	48.00	1.5	49.50	12.375%	2.37	23.7%

Case Study #2: Hypothetical Feeder Three

Table 2.1 assumed that resistive losses and no-load losses were three kW each when the system was at its low load (100kW). Note that in both Table 2.1 and Table 2.2, the total system losses rose as the load rose. However, this is not always the case. In some cases, additional load will actually cause the total system losses in **percent terms** to decrease. The total system losses in kW terms, obviously, will still be increasing.

For example, consider a case where at the bottom end of the load range, the resistive losses are 1.5 kW, and the no-load losses are 4.5 kW. This scenario is depicted in **Table 2.3**.

TABLE 2.3: Marginal Losses on Hypothetical Feeder #3						
Load (kW)	Resistive Losses (kW)	No-Load Losses (kW)	Total System Losses (kW)	Total Loss in %	Amount of Loss in the 10 kW Increment (kW)	Marginal Loss
100	1.5	4.5	6	6.000%		
110	1.815	4.5	6.315	5.741%	0.32	3.2%
120	2.16	4.5	6.66	5.550%	0.35	3.5%
...						
200	6	4.5	10.5	5.250%	0.59	5.9%
210	6.615	4.5	11.115	5.293%	0.62	6.2%
220	7.26	4.5	11.76	5.345%	0.65	6.5%
...						
300	13.5	4.5	18	6.000%	0.88	8.8%
310	14.415	4.5	18.915	6.102%	0.92	9.2%
320	15.36	4.5	19.86	6.206%	0.95	9.5%
...						
400	24	4.5	28.5	7.125%	1.19	11.9%

Note that in Table 2.3, as the total load goes from 100 to 110 kW, the total system losses actually *decrease* in percentage terms, from 6% to 5.741% (although obviously in absolute terms the total losses increase, from 6 to 6.315 kW). This is because the initial amount of resistive losses was low, relative to no-load losses. The total % losses don't start increasing until the marginal losses in percentage terms equal the total % losses. And even after the total % losses begin increasing again, the total loss figure doesn't reach 6% again until 300 kW.

Note also that although the total losses initially decrease in Table 2.3 as one moves from 100 kW upward, the marginal losses rise steadily. At 300 kW of load, the marginal losses have risen to 8.8%—much lower than the 17.7% marginal losses at 300 kW in **Table 2.1**, but still much higher than the initial Table 2.3 marginal losses of 3.2%. At 400 kW in Table 2.3, the marginal loss is 11.9%, and so one kW saved at that load saves 1.135 kW at purchase.

> The total % losses don't start increasing until the marginal losses in percentage terms equal the total % losses.

Table 2.3 demonstrates a crucial point: **when comparing two systems (or areas of the same system), the rate at which overall system losses change with load depends on the initial ratio of no-load losses to resistive losses**.

The "initial" ratio refers to the ratio at the low end of the load range. So, in Table 2.1, the total losses at 100 kW were 6%, and this 6% was broken down into 3 kW of no-load losses and 3 kW of resistive losses. However, in Table 2.3, the initial losses consisted of 4.5 kW no-load losses and 1.5 kW resistive losses.

If the initial ratio of resistive losses to no-load losses is 1.0 or higher, the system loss percentage will increase from the very first added increment (as in Table 2.1). If the initial ratio is below 1.0, the total system loss percentage will decrease at first as load is added, but will eventually match and surpass the initial total system losses (as in Table 2.3).

The second crucial point from these tables is that **a kW of load reduction is "worth" more on**

systems (or areas of the same system) with a higher initial ratio of resistive losses. Again, the "initial" ratio here refers to the ratio of resistive to no-load losses at the low end of the load range.

Consider the hypothetical feeders in **Table 2.1** and **Table 2.3**. On the first system, a saved kW at 401 kW to 400 kW is worth 1.311 kW at purchase; in the second, 1.135 kW. This fact has obvious implications for Demand Response (DR) and Energy Efficiency (EE) programs. For now, simply note that if two feeders had the properties as described in those figures, and had identical end-use appliances and load distribution, the first substation would be a better candidate for DR and EE programs.

The next section addresses an actual case study—one where the marginal losses were measured, as opposed to simply calculated in a spreadsheet.

Case Study #3: Otsego Electric Cooperative

For an example of how losses can be measured by system component, consider a case study of a cooperative involving a single substation, its two feeder lines, and its distribution transformers.[18] Otsego Electric Cooperative ("Otsego") took hourly load data for this substation from a 125-hour period, and broke down system losses at various load levels.

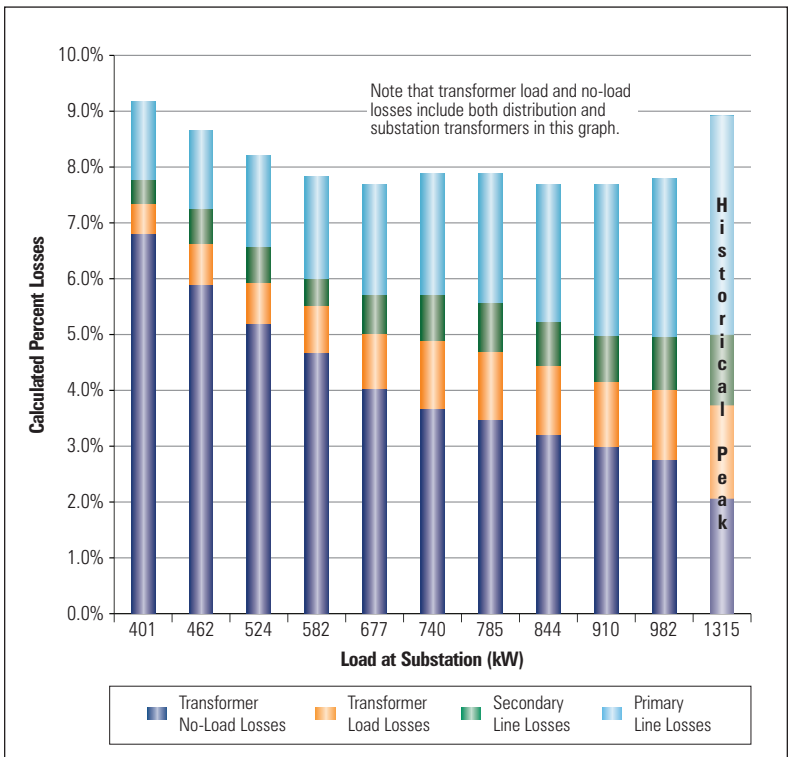


FIGURE 2.1: Otsego Substation—Total Losses as a Function of Load

Otsego is located in the eastern part of central upstate New York. At the time of the study, Otsego had AMI and GIS systems fully deployed for the substation service area. The system consisted of one substation, two feeders, and a variety of distribution transformers, from 5 kVA to 50 kVA. There were 459 customer accounts on the substation's feeders (mainly residential).

AMI load data was collected every hour over a 125-hour period. For the entire period, total losses were around 7.9%. Total system losses were calculated by subtracting total sales and own-use from purchases. Otsego then calculated component losses using the following procedure:

- Use customer load data to calculate I^2R losses for all secondary lines
- Calculate distribution transformer losses using load data
- Calculate substation transformer and regulator losses using load data
- The remaining loss must be primary distribution line losses:
  Total losses = (secondary line losses + distribution transformer losses + substation losses + primary line losses)

This was done for each hour of the 125-hour period. Otsego then graphed the total system losses by the load at the substation, with results as shown below in Figure 2.1.[19]

The total losses at each kW increment are also broken down into the source of the loss: transformer no-load losses, transformer load

[18] This section summarizes a case study as presented in the following paper: "Evaluating Distribution System Losses Using Data from Deployed AMI and GIS Systems," Jeff Triplett, Stephen Rinell, and Jim Foote, 2010 IEEE 10.1109/REPCON.2010.5476204.

[19] Triplett et al, p. 7.

losses, secondary line losses, and primary line losses. At 401 kW, the ratio of no-load losses to load losses was about 3:1 (6.8% to 2.3%). This ratio at the low end of the load range is similar to that used in **Table 2.3**.

Indeed, the results from the Otsego case parallel Table 2.3 closely. In Table 2.3, the total system loss percentage decreased for the first few added increments, and only reached 6% at 300 kW, or three times the load system minimum. Similarly, the total system loss percentage for Otsego decreased as the load moved from 401 kW to 677 kW, from 9.1% to 7.7%, only approaching 9.0% again when the system reached around three times the low load.[20]

Case Study #4: CRN Data (Pedernales)

In cooperation with the CRN, Pedernales Electric Cooperative (Texas) supplied data from four feeders, resulting in a "real-world" test of marginal line losses. For each of the four feeders ("Feeder A" through "Feeder D"), marginal losses were calculated at low loads and at peak loads. The data is provided below. While this test provides useful insights into the losses for different feeder types, it should be noted that more extensive testing would need to be conducted to support general conclusions. Losses are influenced by a wide number of factors, and with only four feeders, it is difficult to isolate all of the relevant factors. A more thorough analysis would require a study of twenty or thirty feeders, so each possible factor could be tested, with other factors screened out.

In the four Pedernales feeders described below, only primary distribution line losses were measured. Thus, no-load losses and other resistive losses (e.g., transformer winding losses) did not come into play. For each feeder, the primary distribution line characteristics are listed: voltage, miles of line, type of conductor, and consumer density.

Each feeder has a summary table that describes losses at each measured level of load. Total load and total system losses (in kW and percentage terms) are displayed. The measured marginal line losses are shown, and compared to the "expected" marginal losses. The "expected" marginal losses take the losses from the lowest load level and calculate what they "should" be for the higher load levels, using the "I-Squared R" formula. For example, consider this expanded table excerpt for Pedernales Feeder A (Table 2.4).

Feeder A had 0.20 kW of total losses at 217 kW of load. The next level of load measured is 345 kW, for a 127.3 kW increment.[21] If one applies the "I-squared R" formula, the R (resistance) stays constant, and so the losses for the added 127.3 kW of increment will vary with the square of the current—i.e. the square of the load. So the expected losses in the 127.3 kW increment will be:

$$\left(\left(\frac{345\ kW}{217\ kW}\right)^2\right) \times 0.20\ kW = 0.50\ kW$$

TABLE 2.4: Expanded Table Excerpt for Pedernales Feeder A

Total Load	Primary Distribution Line Losses		Load Increment kW	Measured Losses		Expected Losses Using "I-squared" Method		
kW	kW	Percent %		Loss in the Increment kW	Marginal Loss %	Loss Expected (kW)	Incremental Loss Expected (kW)	Marginal Loss % Expected
217	0.20	0.09%	n/a	n/a	n/a	0.20	n/a	n/a
345	0.52	0.15%	127.3	0.32	0.25%	0.50	0.30	0.24%
471	1.04	0.22%	126.0	0.52	0.41%	0.94	0.44	0.35%

[20] The historical peak values were estimated/extrapolated, not measured.

[21] Some amounts will be more or less precise due to rounding.

TABLE 2.5: Pedernales Feeder A Characteristics	
Perdernales Feeder A Summary	
Voltage	24.9/14.4 kV
Maximum Length (from substation, in miles)	18.5
Total Lines Miles	115.8
Prevalent 3PH Conductor	795 MCM ACSR
Prevalent 1PH Conductors	#4 ACSR - 336 MCM ACSR
Consumers	253
Consumers/Mile	2.2
Characteristic	Low Load Factor
Average kW Load	453

This 0.50 kW of expected loss is composed of the original 0.20 kW of loss and an additional 0.30 kW of expected loss in the 127.3 kW increment. The 0.30 kW represents 0.24% of the 127.3 kW increment. Therefore, 0.24% is the expected marginal loss as this feeder moves from 217 kW to 345 kW. The calculated marginal loss was 0.32 kW, or 0.25%. For the next increment (from 345 kW to 471 kW), the expected marginal loss percentage was 0.35%, while the actual marginal loss percentage was 0.41%. The characteristics of Feeder A are shown in Table 2.5.

Feeder A was characterized as a "low load factor" feeder by Pedernales, although as discussed below, it is best not to draw conclusions regarding load factor and marginal losses without further study. Feeder A is not densely populated, with only 2.2 consumers per line mile. The calculated and expected marginal losses for Feeder A are shown in Table 2.6.

The calculated marginal losses are moderately higher than the expected marginal losses. At the last increment (from 1361 to 1488 kW), the calculated marginal loss percentage was 1.68%, or about 1.39 times higher than the expected marginal losses of 1.21%. Further research would be required, on a much larger sample of feeders, to determine what characteristics of this feeder system caused the calculated marginal losses to be higher than the expected marginal losses.

Feeder B, described in **Tables 2.7** and **2.8**, is characterized as having a high load factor. It should also be noted that Feeder B has a much

TABLE 2.6: Calculated and Expected Line Losses for Pedernales Feeder A

Total Load	Primary Distribution Line Losses (total)			Expected Losses Using "I-squared" Method		
kW	kW	Percent %	Calculated Marginal Loss %	Total Loss Expected (kW)	Incremental Loss Expected (kW)	Marginal Loss % Expected
217	0.20	0.09%	n/a	0.20	n/a	n/a
345	0.52	0.15%	0.25%	0.50	0.30	0.24%
471	1.04	0.22%	0.41%	0.94	0.44	0.35%
597	1.78	0.30%	0.59%	1.51	0.57	0.45%
723	2.72	0.37%	0.74%	2.22	0.71	0.56%
851	3.53	0.41%	0.63%	3.07	0.85	0.67%
978	4.76	0.48%	0.97%	4.05	0.98	0.77%
1,104	6.21	0.56%	1.14%	5.17	1.12	0.88%
1,232	7.89	0.64%	1.32%	6.43	1.26	0.99%
1,361	9.81	0.72%	1.49%	7.85	1.42	1.10%
1,488	11.95	0.80%	1.68%	9.39	1.54	1.21%

TABLE 2.7: Pedernales Feeder B Characteristics	
Perdernales Feeder B Summary	
Voltage	24.9/14.4 kV
Maximum Length (from substation, in miles)	3.9
Total Lines Miles	34.4
Prevalent 3PH Conductor	OH: 795 MCM ACSR
	UG: 1/0 & 1000 MCM AL
Prevalent 1PH Conductors	#4 ACSR - 336 MCM ACSR
	UG: 1/0 AL, 2/0 CU
Consumers	2,334
Consumers/Mile	67.8
Characteristic	High Load Factor
Average kW Load	5,497

higher customer density than Feeder A (67.8 customers per primary line mile, vs. 2.2 for Feeder A).

Feeder B has marginal loss percentages a little lower than expected: at 12,401 kW, it was calculated at 1.35%, or about 0.86 times the expected 1.57%. As stated before, the fact that Feeder B has lower marginal line losses than expected cannot necessarily be attributed to load factor, or to any other one factor in particular. Feeder B's losses could also be affected by outside temperatures, age and type of primary conductor, voltage variations, and many other factors.

Nor does a high or low customer density necessarily result in drastically different marginal losses: Feeder A and Feeder B, despite having customer densities of 2.2 and 67.8 customers per line mile, respectively, had marginal loss percentages that

Lower marginal line losses than expected cannot necessarily be attributed to load factor, or to any other one factor in particular.

TABLE 2.8: Calculated and Expected Line Losses for Pedernales Feeder B

Total Load	Primary Distribution Line Losses (total)			Expected Losses Using "I-squared" Method		
kW	kW	Percent %	Calculated Marginal Loss %	Total Loss Expected (kW)	Incremental Loss Expected (kW)	Marginal Loss % Expected
1,714	1.93	0.11%	n/a	1.93	n/a	n/a
2,678	4.05	0.15%	0.22%	4.71	2.78	0.29%
3,642	7.24	0.20%	0.33%	8.71	4.00	0.42%
4,607	11.50	0.25%	0.44%	13.94	5.23	0.54%
5,585	16.91	0.30%	0.55%	20.49	6.55	0.67%
6,552	23.35	0.36%	0.67%	28.21	7.71	0.80%
7,521	30.88	0.41%	0.78%	37.16	8.95	0.92%
8,502	39.63	0.46%	0.89%	47.49	10.33	1.05%
9,472	49.39	0.52%	1.01%	58.94	11.45	1.18%
10,443	60.26	0.57%	1.12%	71.65	12.70	1.31%
11,428	72.43	0.63%	1.24%	85.79	14.14	1.44%
12,401	85.58	0.69%	1.35%	101.02	15.23	1.57%

are not drastically different. Pedernales Feeder C *does* have significantly higher marginal loss percentages. Its characteristics and loss data are shown in Tables 2.9 and 2.10.

The marginal losses percentages for Feeder C are quite high. One major difference between Feeder C and the other three Pedernales feeders is that Feeder C has some 12.47/7.2 kV lines, whereas the other three feeders only had 24.9/14.4 kV lines. In order to transmit the same power as the 24.9/14.4 kV lines, the 12.47/7.2 kV lines must carry twice the current, which in turn increases losses by a factor of four. This is probably one of the biggest factors in Feeder C's higher losses, although it bears repeating that there are many factors involved. For example, Feeder C also had the highest total line miles and the longest maximum length from the substation of any of the four feeders. Other factors, such as feeder capacity and voltage variations, would also need to be studied.

Feeder D has the lowest marginal loss percentages of any of the four feeders. Its marginal loss percentages as calculated were close to the expected marginal loss percentages. Feeder D had a high customer density relative to the other feeders (81.6 per line mile), and a low number of total line miles. It also had the shortest maximum line length from the substation. (See **Tables 2.11 and 2.12**.)

TABLE 2.9: Pedernales Feeder C Characteristics

Perdernales Feeder C Summary	
Voltage	24.9/14.4 kV, 12.47/7.2 kV
Maximum Length (from substation, in miles)	33.6
Total Lines Miles	504
Prevalent 3PH Conductor	795 MCM ACSR & #2 ACSR
Prevalent 1PH Conductors	#4 ACSR - 336 MCM ACSR
Consumers	912
Consumers/Mile	1.8
Characteristic	Low Density
Average kW Load	764

TABLE 2.10: Calculated and Expected Line Losses for Pedernales Feeder C

Total Load	Primary Distribution Line Losses (total)			Expected Losses Using "I-squared" Method		
kW	Total Losses kW	Percent %	Calculated Marginal Loss %	Total Loss Expected (kW)	Incremental Loss Expected (kW)	Marginal Loss % Expected
397	6.59	1.63%	n/a	6.59	n/a	n/a
512	8.83	1.70%	2.0%	10.94	4.35	3.8%
627	12.00	1.88%	2.7%	16.46	5.52	4.8%
746	16.19	2.12%	3.5%	23.26	6.80	5.7%
864	21.33	2.41%	4.4%	31.19	7.92	6.7%
982	27.48	2.72%	5.2%	40.36	9.17	7.7%
1,102	34.68	3.05%	6.0%	50.81	10.45	8.7%
1,223	42.96	3.39%	6.8%	62.56	11.76	9.7%
1,345	52.38	3.75%	7.7%	75.68	13.11	10.7%
1,407	63.16	4.12%	8.6%	90.39	14.71	11.8%
1,595	75.05	4.49%	9.5%	106.35	15.96	12.8%
1,721	88.24	4.88%	10.5%	123.80	17.45	13.9%

TABLE 2.11 Pedernales Feeder D Characteristics	
Perdernales Feeder D Summary	
Voltage	24.9/14.4 kV
Maximum Length (from substation, in miles)	3
Total Lines Miles	31.1
Prevalent 3PH Conductor	OH: 795, 336 MCM
	UG: 1000 MCM AL
Prevalent 1PH Conductors	#4 & 1/0 ACSR
	UG: 1/0 AL/CU, 2/0 CU
Consumers	2,539
Consumers/Mile	81.6
Characteristic	High Density
Average kW Load	5,689

The Pedernales feeders reinforce the lesson learned above, which is that many factors contribute to line loss and to system losses in general. For example, while it is true, all other factors being equal, higher customer density will lead to lower line losses, this rule is only a very rough guide, because all other things are rarely equal. Feeder A and Feeder B, for example, had dramatically different customer densities, but marginal loss percentages that were similar. Feeder C had a low customer density, similar to that of Feeder A, but had much higher loss percentages.

The bottom line is that cooperatives would get much more "bang for the buck" on programs that reduce peak load on feeders that are similar to Feeder C than they would for those same programs on other feeders similar to Feeder A. Cooperatives need to identify their high-loss feeders in order to make optimal decisions.

TABLE 2.12 Calculated and Expected Line Losses for Pedernales Feeder D

Total Load	Primary Distribution Line Losses (total)			Expected Losses Using "I-squared" Method		
kW	kW	Percent %	Calculated Marginal Loss %	Total Loss Expected (kW)	Incremental Loss Expected (kW)	Marginal Loss % Expected
2,088	1.24	0.06%	n/a	1.24	n/a	n/a
3,161	2.84	0.09%	0.15%	2.81	1.60	0.15%
4,234	5.13	0.12%	0.21%	5.10	2.26	0.21%
5,322	8.15	0.15%	0.28%	8.06	2.96	0.27%
6,397	11.83	0.18%	0.34%	11.64	3.58	0.33%
7,472	16.20	0.22%	0.41%	15.88	4.24	0.39%
8,548	21.27	0.25%	0.47%	20.78	4.90	0.46%
9,639	27.12	0.28%	0.54%	26.43	5.64	0.52%
10,717	33.61	0.31%	0.60%	32.67	6.24	0.58%
11,795	40.80	0.34%	0.67%	39.57	6.90	0.64%
12,888	48.81	0.38%	0.73%	47.24	7.67	0.70%
13,968	57.43	0.41%	0.80%	55.49	8.25	0.76%

Lessons

There are several lessons to be learned from the case studies. To know how system losses and marginal loses will vary with load, one needs to know the initial ratio of resistive losses to no-load losses.

1. If the ratio of initial resistive losses to no-load losses is **one or greater**, total losses will increase in percentage terms across all added load increments. This is what happened in **Table 2.1** and **Table 2.2**.
2. If the ratio of initial resistive losses to no-load losses is **less than one**, total system losses will initially **decrease** in percentage terms. Of course, total system losses in kW will increase even as the losses in percentage terms are decreasing. This is what happened in **Table 2.3**. The decrease in percent losses will continue until total resistive losses equal total no-load losses. At that point, the total system losses (in percentage terms) will start to rise.
3. In all systems, regardless of the starting ratio of resistive losses to no-load losses, marginal losses will always rise. This is because the no-load losses remain constant.
4. The marginal loss in percentage terms will depend solely on the initial resistive losses. In Table 2.1 and Table 2.2, the marginal losses were the same despite the different initial no-load losses.
5. The marginal loss will grow at the same **rate**, regardless of the resistive losses or the no-load losses. For example using the increment 10 kW, the marginal losses at 320 kW will always be three times the marginal losses at 110 kW. In Table 2.1, these values were 18.9% and 6.3%. In Table 2.3, these values were 9.45% and 3.15%.
6. Although there are some rules of thumb that help to predict losses from substation or feeder characteristics, these rules should not be used on their own. For example, it is true that low customer-density feeders should have higher losses in general than high-density feeders. In practice, however, many factors are in play, as was shown with the Pedernales feeders. It is crucial for cooperatives to learn the characteristics of their individual substations and feeders.

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3 Technology Needed to Measure Line Losses

To measure *annual* system-wide line losses, no particular technology is needed, other than the ability to measure purchases and total sales. Care must be taken to make sure the billing/metering reading cycles match up with the purchase period. Once the cycles are matched up, total annual losses are easy to calculate:

$$\text{Annual System Losses} = \frac{(\text{kWh purchased} + \text{kWh generated}) - (\text{kWh sold} + \text{kWh own use})}{(\text{kWh purchased} + \text{kWh generated})}$$

Monthly losses can be measured the same way, again assuming that the purchase cycle and metering/billing cycles match up. However, many times the cycles do not match up, and so many cooperatives do not calculate system loss by month.

Even if monthly losses are not calculated, many cooperatives do attempt to calculate their losses at times of peak demand. If detailed AMI data is not present, losses at peak demand are typically calculated by creating an engineering model of the system. This model is often fairly basic, and may not provide details about losses at the individual component level.

With the advent of smart grid technologies, however, the measurement of losses becomes easier. As the Otsego example above showed, the three main systems that facilitate detailed measurement of lines losses are Advanced Metering Infrastructure (AMI), GIS, and supervisory control and data acquisition systems ("SCADA"). These three systems admittedly have overlap, so that at times it is difficult to determine whether a particular component belongs to one system or the other, or whether another component is a necessary feature of a particular system. However, certain features are critical for measuring losses as a function of load.

1. **AMI**. The crucial pieces of information supplied by AMI systems are the hourly load intervals for each meter. Thus, the meters on the system must all be two-way or "smart" meters. The system needs to be able to communicate this information to a central location, manage it, and store it. Software that can handle and process this information is also required.

   It should be noted that to obtain accurate loss measurements, all load data must be accounted for. If even 1% or 2% of meters are malfunctioning, this would throw off loss estimates significantly. Ideally, an AMI system would be able to automatically esti-

It should be noted that to obtain accurate loss measurements, all load data must be accounted for.

mate the appropriate load data for any meters that are not accounted for, by using data from load periods similar to the period in question. Similarly, unrecorded load data (own use, street lighting, etc.) must be accounted for.

2. **GIS**. The term "geographical information systems" covers a broad range of systems. Generally speaking, a GIS is a tool for understanding the geographic layout of a utility. For example, maps of transmission lines, substations, feeder lines, meters, in addition to details on their specifications would constitute a GIS. For the purposes of measuring system losses, the most important information required of a GIS is detailed specifications regarding:

   - Number and locations of meters
   - Number and location of unmetered usage, such as street lights
   - Length and type of secondary conductors (distribution transformer to meter), with resistance specifications
   - Number, size, and location of distribution transformers, with manufacturer loss estimates by load
   - Length and type of primary conductors, with resistance specifications and phasing information
   - Substation components
   - Transmission line information (if applicable)

   This information will allow the cooperative to create engineering models of segments of the system. These models are used to (for example) estimate secondary distribution lines losses, as was done in the Otsego study mentioned above.

3. **SCADA**. At times, it is difficult to determine whether a system component belongs in the AMI category or the SCADA category. For purposes of measuring line losses, however, a utility has a sufficient SCADA system if it is able to collect, manage, and process the data from meters, substations, and other relevant sources.

These three technologies are what will allow a utility to produce the data shown in **Table 2.1** and **Figure 2.1**. This, in turn, will allow utilities to more effectively install and administer Demand Side Management (DSM) programs (such as dynamic pricing and direct load control), which take advantage of the marginal line loss concept. "Smart grid" technologies also assist cooperatives in measuring and verifying the amount of, and the source of, reductions in resistive losses.

4 Re-Evaluating the Benefits of Demand Response and Energy Efficiency Programs

The effect of marginal line losses on demand response ("DR") and energy efficiency ("EE") can be quite dramatic. This means that if a cooperative is not using marginal losses to run cost/benefit tests for demand response programs, it may be drastically underestimating the value of those programs. The same conclusion is true for energy efficiency programs. Energy efficiency programs that reduce load at peak times should be also analyzed using the marginal losses instead of the average annual losses. Of course, the coincidence factor of a given EE improvement needs to be taken into account. This will be discussed below.

The following are issues that cooperatives need to be aware of when it comes to marginal line loss and DR/EE programs.

1. **Programs that reduce peak loads are more valuable due to the marginal loss concept.** This should be factored in to any cost/benefit analysis. Consider a system with average losses of 6%, and marginal losses (at times of peak load) of 15%. At peak load, the value of a kW of load saved at the meter is worth more than just 1 kW at purchase—losses must be taken into account.

   If the average loss figure of 6% is used, the kW at the meter saves 1.064 kW at point of purchase. However, if the marginal losses are used instead, 1.176 kW are saved at point of purchase—10% higher than if average losses were used. Thus, program benefits are increased by 10% when the more accurate marginal losses are used in cost-benefit calculations.

2. **More accurate projections of DR and EE programs can affect all areas of a cooperative's operations. Investments in generation or volatile reserve purchases can be deferred.** T&D and other system planning elements can be improved with the revised projections.

3. **DR and EE programs may also reduce the reserve margin requirement.** This means that at the point of generation, 10-15% more could be saved. The 1.176 kW saved at purchase (mentioned above) would become 1.294 kW (at 10% reserves) or 1.352 kW (at 15% reserves). If the reserve requirement applies, this can make DR/EE programs even **more** valuable to cooperatives and the G&T utilities serving them.

> If a cooperative is not using marginal losses to run cost/benefit tests for demand response programs (and energy efficiency programs), it may be drastically underestimating the value of those programs.

PREVIOUS VIEW

4. **Cooperatives need to know losses by substation/feeder** in order to maximize the value of their DR and EE programs. A DR program would be much more valuable (relatively speaking) on the feeder shown in **Table 2.1** than on the feeder shown in **Table 2.3**.
5. **On systems with high marginal line losses, EE programs with high coincidence factors become relatively more valuable** than those with low coincidence factors. If a cooperative has high marginal line losses, it may want to consider stressing EE programs that have high coincidence factors, like rebates for energy efficient air conditioners (assuming a summer peak).
6. **DR and EE programs are more valuable on feeders/substations with high marginal losses.** If a cooperative has feeders and substations that vary greatly with respect to their marginal losses, it may want to target its DR and EE programs accordingly. For example, assume Cooperative ABC has four feeders like the system in Table 2.3, and one substation ("Number 5") like the system in Table 2.1. ABC would be best served by focusing its DR efforts on feeder Number 5 (assuming similar consumer end-use loads).

   Suppose ABC wanted to install a peak-time rebate program ("PTR"), in which customers are offered rebates for lower demand during peak periods. In a world with no concerns about customer equality, ABC could consider making the rebate higher for customers on feeder Number 5. The PTR program on that feeder would have a much higher return on investment for ABC. In actuality, ABC would probably not want to set different PTR rates for different feeders. However, one thing ABC *can* do is step up its marketing efforts for the PTR program in Number 5's area, even if the same program and same rebates are also offered to feeders Number 1–4.

These issues will significantly influence the cost-benefit analysis of a given DSM program. Incorporating the marginal loss concept will impact the benefits realized by distribution cooperatives and their power suppliers.

5 Conclusion and Recommendations

Reducing marginal line losses at times of high peak load will have numerous financial benefits for cooperatives. The immediate savings will come from the fact that 1 kW saved at the meter in times of peak demand could save 1.25 kW or more of generation capacity. However, there are other financial benefits, including:

- Avoided reserves,
- Deemed savings of energy efficiency programs,
- Postponement or avoidance of generation/market purchases,
- Postponement or avoidance of T&D investments,
- The creation of energy credits (used to satisfy state/federal mandates), and
- The possibility of extra salable DR assets in RTO/ISO markets.

Cooperatives that currently have programs that will influence demand (or are considering such programs) may want to thoroughly examine the marginal losses on their systems. This examination may impact many aspects of the program. Cost-benefit analyses will become more accurate. Marketing strategies may change. Current or future feeder line locations may be altered. All of these actions require knowledge of line losses that go far beyond the "total system loss" figure.

The Pedernales data shows that cooperatives must learn the loss characteristics of their individual substations and feeders in order to minimize system losses. It is not enough to go by simple guidelines such as "low customer density means higher losses." Recall that Pedernales Feeders A and C each had customer densities of around 2 customers per line mile, but had marginal loss percentages at high load that were dramatically different: 1.68% vs. 10.5%. A peak-shaving program, such as direct load-control, would provide a much higher return-on-investment on Feeder C than it would on most other feeders.

Although specific loss reductions plans will vary from cooperative to cooperative, there are some general steps that every cooperative can take.

1. **Identify subsystem annual losses.** All cooperatives probably already calculate annual system losses for their system as a whole. This is a simple calculation based on annual purchases, generation, own-use, and sales. However, if a cooperative has multiple points of purchase for completely separate substation systems, the annual losses should be calculated for each independent sub-system. This should be simple even for cooperatives with no AMI/Meter Data Management Systems (MDMS), as all that is required is some way to separate sales and own-use by sub-system. A cooperative will then calculate the annual loss figures on each of its independent sub-systems.
2. **Breakdown of subsystem losses with AMI data.** Subsystems with high annual losses should be targeted for loss reduction mea-

sures. The next step is to determine: (A) how those losses vary with load, and (B) how those losses are broken down by system component. This step is easier for those cooperatives with full AMI and MDMS coverage. For those cooperatives, a procedure like the one briefly described in Section 2 (**Study #3: Otsego Electric Cooperative**) should be followed. This will allow a cooperative to chart losses vs. load, and also to determine how losses are broken down into load and no-load components.

3. **Breakdown of subsystem losses without AMI data.** If a cooperative does not have AMI/MDMS, it will be somewhat more difficult to break down subsystem losses according to load levels, or by component. However, cooperatives may want to consider making the effort, especially if the subsystem has high annual losses. In this case, an engineering model could be created; this will give at least a rough idea of the component losses at peak load. Although an engineering model may not be as precise as using AMI data, it should at least help identify substations or feeders with high losses and where those losses may be coming from.
4. **Target high-loss components.** Once the high-loss areas of the system are identified, they can be targeted for loss reduction as needed. The appropriate solution will vary from system to system. If no-load losses are high, perhaps a transformer change is required, or even a new T&D layout. Other systems might require a transmission line upgrade, VAR control, or other solution.
5. **Plan demand-response and energy efficiency programs accordingly.** If a cooperative is planning an AMI or DSM pilot program, for example, a high-loss substation or feeder should be used. The effects of the program will be more dramatic, thus ensuring buy-in at both the cooperative and customer level. Large C&I customers on high-loss subsystems can be targeted with special programs. The value of any program that reduces load at peak times will be more valuable on these systems.

In sum, when a cooperative learns about how its system-wide losses are broken down, it can use that knowledge to install a number of upgrades and programs that will reduce costs and increase reliability. The concept of marginal losses, in particular, enables a cooperative to get more from their DSM programs. Cooperatives cannot afford to miss these opportunities.