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Determination Analysis of Energy Conservation Standards for Distribution Transformers

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POWER SYSTEMS TECHNOLOGY PROGRAM

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DETERMINATION ANALYSIS OF ENERGY CONSERVATION STANDARDS FOR DISTRIBUTION TRANSFORMERS

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ABBREVIATIONS, ACRONYMS, AND INITIALISMS

A	ampere
ac	alternating current
APPA	American Public Power Association
BOE	band of equivalence
C&I	commercial and industrial
CDA	Copper Development Association
CSA	cross-sectional area
DOE	U.S. Department of Energy
DSM	demand-side management
EEI	Edison Electric Institute
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act of 1992
EPRI	Electric Power Research Institute
GE	General Electric Company
I^2R	resistive heating (current squared times resistance)
kV	kilovolt
kVA	kilovolt-ampere
kWh	kilowatt-hour
lb	pound
mil	0.001 in. (2.54×10^{-5} m)
MVA	megavolt-ampere
NEMA	National Electric Manufacturers Association
O&M	operation and maintenance
OEM	original equipment manufacturer
ORNL	Oak Ridge National Laboratory
PCB	polychlorinated biphenyl
T&D	transmission and distribution
TOC	total owning cost
V	volt
Vac	volt, alternating current
W	watt

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The authors convey a special thanks to the organizations, task force committees, associations, and individuals that served on the ORNL Distribution Transformer Review Group (see Appendix A for the list of members). The many comments and helpful suggestions provided by the review group are gratefully acknowledged.

FOREWORD

Subtitle C, Sect. 124 of the Energy Policy Act of 1992 (Pub. L. 102-486, Oct. 24, 1992) contains an amendment to Sect. 346 of the Energy Policy and Conservation Act (42 U.S.C. Sect. 6317). A portion of that amendment is provided below:

> *Sec. 346 (a) (1) The Secretary shall, within 30 months after the date of the enactment of the Energy Policy Act of 1992, prescribe testing requirements for those high-intensity discharge lamps and distribution transformers for which the Secretary makes a determination that energy conservation standards would be technologically feasible and economically justified, and would result in significant energy savings.*
>
> *(2) The Secretary shall, within 18 months after the date on which testing requirements are prescribed by the Secretary pursuant to paragraph (1), prescribe, by rule, energy conservation standards for those high-intensity discharge lamps and distribution transformers for which the Secretary prescribed testing requirements under paragraph (1).*

This report contains information to assist the U.S. Department of Energy in making a determination on the feasibility and significance of energy conservation for distribution transformers as required by par. (a)(1) above. The potential energy savings presented in this document are preliminary estimates appropriate for a determination study. Subsequent studies on this topic will involve more exact, detailed analysis on the effects of energy conservation standards for distribution transformers.

ABSTRACT

The report contains information for the U.S. Department of Energy to use in making a determination on proposing energy conservation standards for distribution transformers as required by the Energy Policy Act of 1992. The potential for saving energy with more efficient liquid-immersed and dry-type distribution transformers could be significant because these transformers account for an estimated 140 billion kWh of the annual energy lost in the delivery of electricity. The objective of this study was to determine whether energy conservation standards for distribution transformers would have the potential for significant energy savings, be technically feasible, and be economically justified from a national perspective. It was found that energy conservation for distribution transformers would be technically and economically feasible. Based on the energy conservation options analyzed, 3.6–13.7 quads of energy could be saved from 2000 to 2030.

EXECUTIVE SUMMARY

Subtitle C, Sect. 124 of the Energy Policy Act of 1992, Pub. L. 102-486, Oct. 24, 1992, contains an amendment to Sect. 346 of the Energy Policy and Conservation Act (42 U.S.C. Sect. 6317) requiring that the U.S. Department of Energy (DOE) assess the feasibility of energy conservation standards for distribution transformers. The objective of this study was to determine whether energy conservation standards for distribution transformers would have the potential for significant energy savings, be technically feasible, and be economically justified from a national perspective.

Distribution transformers are used to deliver electric power as part of the electrical distribution system. Electrical energy is delivered to consumers by utility power transmission and distribution systems. The transmission network delivers power at high voltages (69–765 kV) from power plants to local distribution systems. Transmission voltages are used to transmit high levels of power over long distances. The high-transmission voltages require lower currents, which reduce line losses, conductor material, and costs. Once the electrical power has reached the distribution system, it is transformed to lower primary distribution voltages (ranging from 4 to 35 kV) that are more economical for the short distances within distribution systems. The primary distribution voltage is transformed by distribution transformers to lower secondary voltages (120–600 Vac) that are suitable for customer equipment. These transformers provide the final link in the chain of electrical power components from the generating sources to the ultimate power-consuming equipment.

Distribution transformers are very reliable devices with no moving parts and average lives of ~30 years. There are two basic types: liquid-immersed and dry-type. Liquid-immersed transformers typically use oil as a combination coolant and dielectric medium; they are normally used outdoors because of concerns about an oil spill or possible fire hazard. Electric utilities own about 90% of all liquid-immersed transformers. Dry-type transformers are air-cooled, fire-resistant, non-oil devices and thus do not need special oil-spill containment. Recent advances in liquid materials offset these traditional "advantages" for dry units. Many commercial and industrial (C&I) customers use secondary distribution dry-type transformers within buildings to transform the building or plant voltage (typically 480 Vac) to a lower secondary voltage (120–240 Vac). Large load center dry-type transformers are also used to transform the primary distribution voltage to the plant or building voltage. There are ~40 million liquid-immersed distribution transformers owned by electric utilities and an additional 4 million non-utility-owned liquid-immersed units in the United States (Barnes et al. 1995). Transformer manufacturers estimate that ~12 million dry-type distribution transformers are used by C&I customers in the United States. The definition for distribution transformers as considered in this study can be summarized as transformers that are continually energized; these fall within the voltage classes and capacities shown in Table 1.

Utility-owned distribution transformer efficiencies steadily improved from the 1950s to the 1970s with the introduction of improved materials and manufacturing methods. Following the energy price shocks of the 1970s, some utilities began to use purchasing formulae that factored the effect of transformer efficiency into the purchasing decision. Manufacturers responded by tailoring their products to the energy evaluation factors specified by customers, a practice that continues to this day. Thus, it is now possible to purchase a relatively high-cost, high-efficiency transformer or a unit with a lower first cost and lesser efficiency. Most of the nonutility distribution transformers are purchased on the lowest first-cost basis without evaluating the cost of the energy consumed by the units. These "nonevaluated" transformers may have ~50% more losses than utility transformers. The maximum efficiencies of liquid-immersed distribution

Table 1. Characteristics of distribution transformers typically used in the United States

Transformer type	Phase	Primary voltage (kV)	Secondary voltage (V)	Capacities (kVA)
Liquid-immersed	1	35 and below	600 and below	10–833
Liquid-immersed	3	35 and below	600 and below	15–2500
Dry-type	1	35 and below	600 and below	15–833
Dry-type	3	35 and below	600 and below	15–2500
Dry-type[a]	1 and 3	35 and below	600 and below	0.25–<15

[a]The smaller dry-type units are included for completeness, but they are a small contributor to the overall energy losses and are not likely to be included in an energy efficiency standard. The units below 9 kVA normally have primary voltages below 600 V.

transformers have improved over the past several decades, but nonevaluated dry-type units have decreased in efficiency because of the lack of economic incentives. Figure 1 shows efficiencies for 75–kVA, liquid and dry-type, three-phase transformers.

Distribution transformers used by utilities account for ~61 billion kWh of the annual energy lost in the delivery of electricity (Barnes et al. 1995). Nonutility liquid and dry-type transformers, although fewer in number, are less efficient and are estimated to consume an additional 80 billion kWh of electric energy on the customer side of the electric meter. New transformers purchased annually can be expected to consume ~4.6 billion kWh; thus, the potential for saving energy with more efficient transformers could be significant (i.e., ~0.9 billion kWh with a 20% reduction in losses).

This report demonstrates the potential for distribution transformers to achieve cost-effective national energy savings. A number of energy conservation options were analyzed, the results of

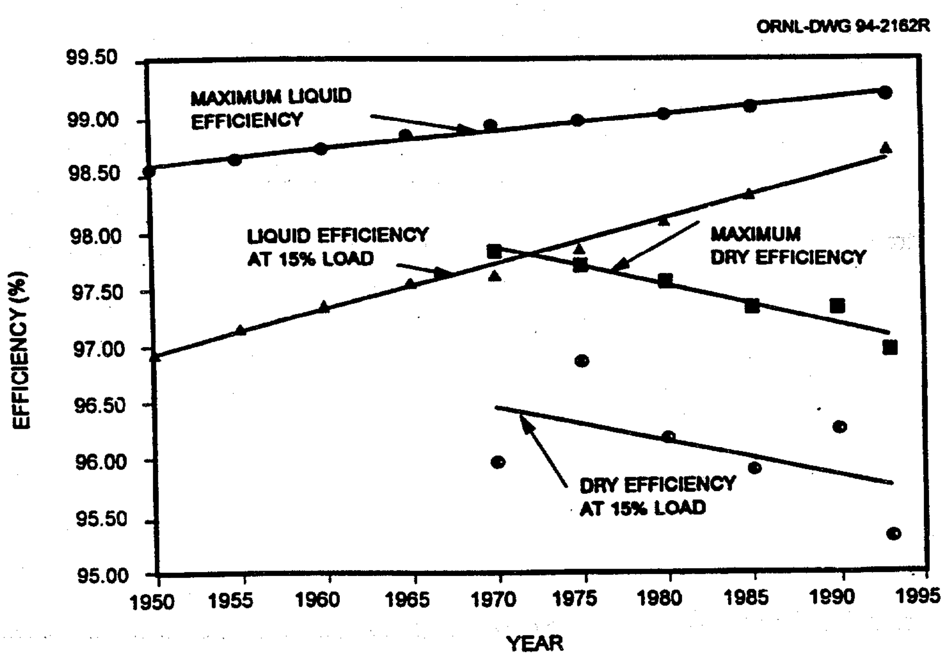

Fig. 1. Distribution transformer efficiencies over the years for 75-kVA, three-phase units. *Sources:* Barnes, P. R., et al. 1995. *The Feasibility of Replacing or Upgrading Utility Distribution During Routine Maintenance*, ORNL-6804/R1, Martin Marietta Energy Systems, Oak Ridge Natl. Lab. Also, transformer manufacturers' data.

which provide DOE with information for making a determination on proposing a national energy conservation policy for distribution transformers. Other countries are also considering energy conservation for distribution transformers. For example, Canada recently developed a national conservation policy based on maximum loss values for distribution, power, and dry-type transformers (Canadian Standards Association 1994).

TECHNICAL FEASIBILITY

Without regard to cost, it is technically feasible to design and to build distribution transformers of all types that provide significant energy savings compared with the typical units purchased in 1994. If energy-saving designs are restricted to those that are economically feasible using national average energy costs, there is a potential for moderate savings per transformer from liquid-immersed units and for more significant savings per transformer from redesigned dry-type units. Because utilities routinely evaluate transformers for minimum total owning cost (TOC), the technical ability to provide low-loss liquid-immersed transformers is well established. In contrast, dry-type transformers are routinely sold on a first-cost basis and have significant potential for improved savings.

The technology used to provide low-loss transformers is based upon changing the configuration and, hence, the relative amounts of materials and the use of lower-loss materials. For example, operating at a lower flux density by reducing volts per turn will reduce core losses but require more turns of the conductor and increase load losses. Similarly, lowering the conductor current density will reduce load losses but require more core material or a higher flux level, which produces higher no-load losses. Restrictions on weight and volume may reduce the selection further. A low-loss transformer requires the use of low-loss materials (i.e., high-silicon steel or amorphous metal for the core and increased amounts of copper or aluminum for the windings) configured in an optimal manner. The materials selected and the configuration define the cost of the transformer materials and the labor required to assemble the system (i.e., the transformer cost).

Dry-type transformer technology can provide transformers that offer lower losses at reasonable costs, but costs are higher for a given efficiency than for liquid-immersed transformers. Because air is the basic cooling and insulating system for dry-type transformers, all dry-type transformers will be larger than liquid-immersed units for the same voltage and capacity (kilovolt/kilovolt-ampere) rating. When operating at the same flux and current density, more material for core and coil implies higher losses and higher costs. These trade-offs are inherent in the design of dry-type units, but dry-type transformers have traditionally offered certain fire-resistant, environmental, and application advantages for industrial and commercial situations. Recent advances in liquid-filled units are reducing some of these advantages, but dry units will continue to be used in low-voltage, high-temperature-rise applications.

THE DISTRIBUTION TRANSFORMER MARKET

The total value of product shipments in the distribution transformer market was estimated to be ~$1.5 billion in 1992, coming from more than 230 companies having annual shipments of $100,000 or more. The outlook for the distribution transformer industry is not expected to be different from that of the past decade. The liquid-immersed utility transformer market is expected to grow at an overall growth rate of not more than 1% annually. The nonutility, predominantly dry-type transformer market growth is estimated to be a little higher (2.5%) than the utility-dominant liquid-immersed market. It is estimated that in terms of annual capacity sold, the liquid-immersed market (10 kVA–2.5 MVA) will increase from 64,631 MVA (1.14 million units) in 1993 to 99,195 MVA (1.41 million units) by the year 2030. For the same years the dry-type transformer market (0.25 kVA–2.5 MVA) is forecast to grow from 28,336 MVA (0.779 million units) to 70,650 MVA (1.615 million units). The market shares of open-wound and cast-resin, dry-type transformers compared with the total capacity sold in 2030 will be 28% (47,361 MVA) and 12% (20,298 MVA) respectively.

The structure of the distribution transformer market currently includes various market players and their interactions. Transformer purchasing decision makers play the most important role regarding energy efficiency. Electrical contractors or agents (who are not the users paying the future electric bills) are currently responsible for most C&I purchases of dry-type transformers. Utilities, on the other hand, establish their own loss evaluation criteria in buying their transformers. Several criteria such as first cost, TOC, band-of-equivalence, oversizing, and the choice of winding material are currently used when transformers are purchased. TOC is the only criteria producing minimum overall cost.

POTENTIAL ENERGY SAVINGS

Potential energy savings based on cost-effective energy conservation could be significant. Average loss reductions per kilovolt-ampere of capacity for cases developed in this study would be between 0.9 and 2.4 W/kVA of purchased transformer capacity. This translates into ~8–21 kWh of electricity saved annually or 240–630 kWh over 30 years (the average life of a transformer) per kilovolt-ampere of transformers purchased. It is estimated that in 1993 the total sales of distribution transformers were about 93,000 MVA. By 2000, sales are projected to be over 100,000 MVA. Savings from conservation would continue to grow with sales of new transformers. Table 2 indicates the initial rate of primary energy savings and the cumulative savings after 30 years. A national average power plant heat rate of 10,000 Btu/kWh has been assumed to estimate the primary energy savings shown in Table 2. Figure 2 projects the growth in cumulative savings for a cost-effective national energy conservation policy. Energy-efficient transformers would continue to provide savings over their useful lives. About 93% of these savings could be realized if distribution transformers below 10 kVA were excluded from an energy conservation policy. The details of the approach used are given in Appendix D.

IMPACTS ON MANUFACTURERS AND USERS

Energy-efficient transformers will increase the cost of production to transformer manufacturers because either more material or a better quality of material will be used. The effect on manufacturers' revenues will depend on how much of the cost increases caused by conservation can be passed through to consumers. If less than the actual higher production costs are passed through, profits will suffer; a pass-through above the increase in production costs will increase profits. A manufacturer's production costs will also be determined to some extent by the additional investments necessary for retooling to manufacture more-energy-efficient transformers. A cursory examination of the industry suggests that manufacturers of dry-type transformers will be more affected than manufacturers of liquid-immersed transformers because a greater number of dry-type transformers are not currently loss evaluated. Because the liquid-immersed transformer market is currently more than 90% loss evaluated, the impacts of energy conservation are expected to be small.

The energy efficiency of transformers also raises issues regarding the production capability of raw material suppliers. Most raw material suppliers are domestic and are estimated to be at 80% of full production capability; this available capacity may not be adequate in certain cases to meet any surge in demand for increased supply of raw materials. There will be a shift in demand

Table 2. Energy savings for a conservation case based on an average of the three lowest TOC designs
(quads of primary energy)[a]

Transformer	Annual savings rate in 2000	Cumulative savings 2000–2030
Liquid-immersed	0.0046	2.4
Dry-type	0.0108	6.5
Total	0.0154	8.9

[a]A quad of energy equals 1 quadrillion (10^{15}) Btu. TOC = total owning cost.

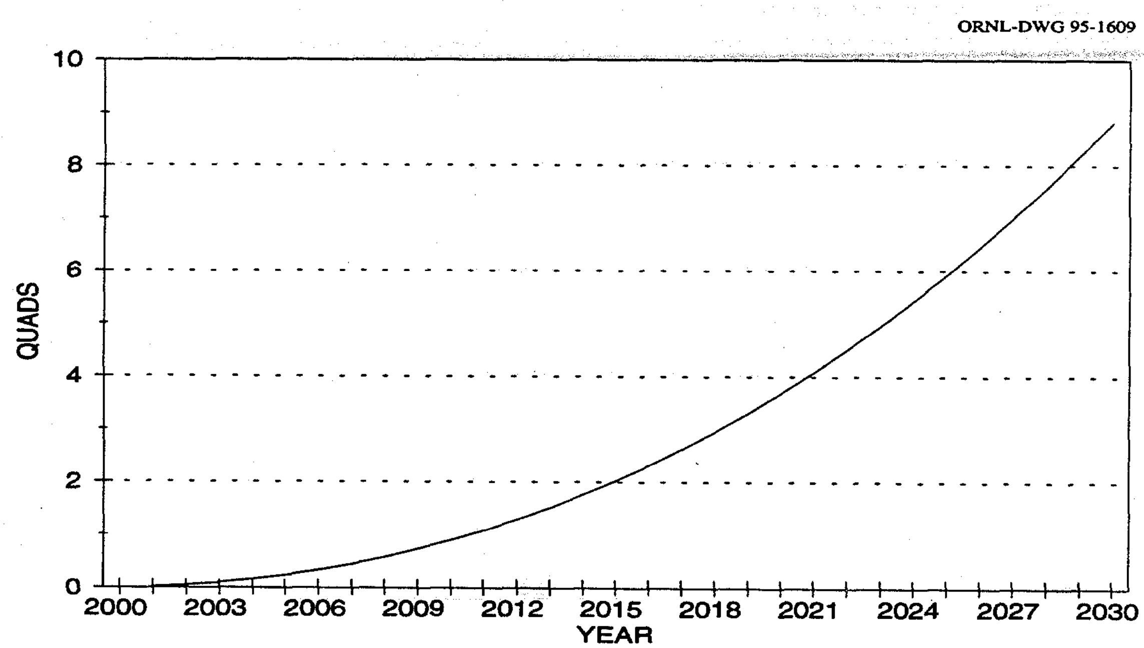

Fig. 2. Cumulative primary energy savings from 2000 to 2030 for a conservation case based on an average of the three lowest total-owning-cost designs. (See Subsect. 4.4.2.)

toward higher performance core materials. If amorphous-core technology is to be relied on to meet efficiency goals, the higher investments required and the patents associated with the technology are important issues of concern. It is estimated that the capacity utilization level of the magnet wire industry would increase from the current level of 80–84% if energy efficiency improvements for distribution transformers were accomplished by the use of copper alone.

CONCLUSIONS

A number of energy conservation options were analyzed. All of the conservation options considered for a national policy in this study are economically justified based on national average electricity costs. These options are also technically feasible, although some retooling may be required for the more energy-efficient, dry-type transformer designs. Based on a conservation approach similar to the options analyzed, a national energy policy for distribution transformers would have the potential for energy savings of 4.2–13.7 quads over the 30-year period from 2000 to 2030, assuming transformer sales grow at a rate of ~1–2% over the period. If the annual sales of transformer capacity does not grow at the assumed rate of 1–2% but remains constant at the 1993 level (i.e., a zero growth case), then the savings will be reduced to a range of 3.6 to 7.1 quads for the conservation options considered in this study. About 93% of these savings could be realized if distribution transformer sizes below 10 kVA were excluded from an energy conservation policy. Improved efficiency in dry transformers accounts for the majority of these savings.

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1. INTRODUCTION

1.1 BACKGROUND

Subtitle C, Sect. 124, of the Energy Policy Act of 1992, Pub. L. 102-486, Oct. 24, 1992, contains an amendment to Sect. 346 of the Energy Policy and Conservation Act (42 U.S.C Sect. 6317) requiring that the U.S. Department of Energy (DOE) assess the feasibility of energy conservation standards for distribution transformers. The objective of this study was to determine whether energy conservation standards for distribution transformers would have the potential for significant energy savings, be technically feasible, and be economically justified from a national perspective.

Distribution transformers are part of electric power distribution systems. Electrical energy is delivered to consumers by utility power transmission and distribution (T&D) systems. The transmission network delivers bulk power at high voltages (69–765 kV) from power plants to local distribution systems where the electrical energy is transformed to lower primary distribution voltages (ranging from 4 to 35 kV). High transmission voltages are used to transmit high levels of power over long distances. The high transmission voltages result in lower currents, which reduce line losses, the amount of conductor material needed, and costs. Once the electrical power has reached the distribution system, it is transformed to lower primary distribution voltages that are more economical for the short distances within distribution systems. The primary distribution voltage is transformed by distribution transformers to lower secondary voltages (120–600 Vac) that are suitable for customer equipment. These transformers provide the final link in the chain of electrical power components from the generating sources to the ultimate power-consuming equipment.

Distribution transformers are very reliable devices: they have no moving parts and have average lives of ~30 years. There are two basic types of distribution transformers: liquid-immersed and dry-type. Liquid-immersed transformers typically use oil as a coolant; these transformers are normally used outdoors because of concerns about a potential oil spill or possible fire hazard. Electric utilities own about 90% of all liquid-immersed transformers. Recent advances in liquid-filled units have greatly reduced these problems, and the units are now used indoors. Dry-type transformers are air-cooled, non-oil devices and thus do not need special oil-spill containment. Many commercial and industrial (C&I) customers use secondary distribution, dry-type transformers within buildings to transform the building or plant voltage (typically 480 Vac) to a lower secondary voltage (120–240 Vac). Large-load-center, dry-type transformers are also used to transform the primary distribution voltage to the plant or building voltage. In the United States, ~40 million liquid-immersed distribution transformers are owned by electric utilities, and an additional 4 million liquid-immersed units are nonutility owned (Barnes et al. 1995). Transformer manufacturers estimate that ~12 million dry-type distribution transformers are used by C&I customers in the United States.

Utility-owned distribution transformer efficiencies steadily improved from the 1950s to the 1970s with the introduction of improved materials and manufacturing methods. Figure 1.1 shows the efficiency improvement for a typical single-phase, 25-kVA, liquid-filled, pole-mounted transformer, a common distribution transformer used by electric utilities. Following the energy price shocks of the 1970s, some utilities began to use purchasing formulae that factored the effect of transformer efficiency into the purchasing decision. Manufacturers responded by tailoring their products to the energy evaluation factors specified by customers, a practice that continues to this day. Thus, it is now possible to purchase a relatively high-cost, high-efficiency transformer or a unit with a lower first cost and lesser efficiency. Most of the nonutility distribution transformers

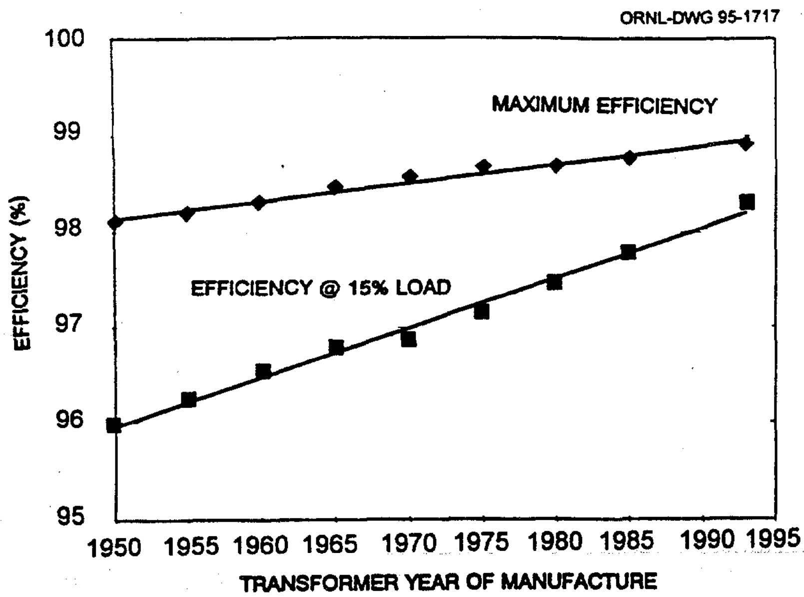

Fig. 1.1. Efficiency improved with time for a 25-kVA, liquid-filled distribution transformer.

are purchased on a lowest first-cost basis without evaluating the cost of the energy consumed by the units. These "nonevaluated" transformers may have 50% more losses than utility transformers. The maximum efficiencies of liquid-immersed distribution transformers have improved over the past several decades, but nonevaluated dry-type units have shown little or no improvements because of the lack of economic incentives. Figure 1.2 shows efficiencies for 75-kVA, liquid and dry-type, three-phase transformers. Cost savings through energy conservation should provide an incentive to increase the efficiency of dry-type units and some utility-purchased transformers that are currently not evaluated on a life-cycle-cost basis. However, many C&I transformers are purchased by contractors who do not benefit from the cost savings of energy conservation. For this reason, efficiency standards should be considered. Canada has recently developed maximum loss values for distribution, power, and dry-type transformers (Canadian Standards Association 1994).

Distribution transformers used by utilities account for ~61 billion kWh of the annual energy lost in the delivery of electricity (Barnes et al. 1995). Dry-type transformers, although fewer, are less efficient and are estimated to consume an additional 80 billion kWh of electric energy on the customer side of the electric meter. Small improvements in transformer efficiencies of 0.5–1.0% could result in an annual savings of tens of billions of kilovolt-hours. Thus, the potential for saving energy with more efficient transformers could be significant. In this study, a number of energy conservation options were analyzed, the results of which provide DOE with information for making a determination on proposing a national energy conservation policy for distribution transformers.

1.2 MARKET TRENDS

The total value of product shipments in the distribution transformer market was estimated to be ~$1.5 billion in 1992, coming from more than 230 companies having annual shipments of $100,000 or more (DOC 1994). The future outlook for the distribution transformer industry is not expected to be different from that of the past decade. The liquid-immersed utility transformer

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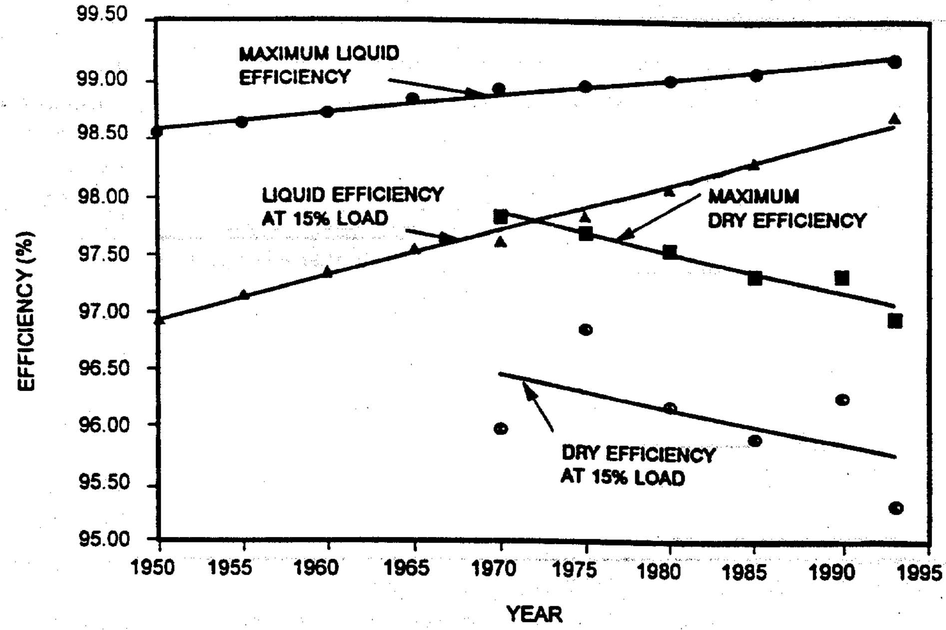

Fig. 1.2. Distribution transformer efficiencies over the years for 75-kVA, three-phase units. *Sources:* Barnes et al. 1995. *The Feasibility of Replacing or Upgrading Utility Distribution Transformers During Routine Maintenance*, ORNL-6804/R1, Martin Marietta Energy Systems, Oak Ridge Natl. Lab., and transformer manufacturers' data.

market is expected to grow at an overall annual growth rate of not more than 1% annually. Sales of liquid-immersed utility distribution transformers depend primarily on new housing starts, while gross private domestic investment provides a good indicator for the nonutility transformer market. The nonutility transformer market is expected to have an annual growth rate of ~2.5% (see Subsect. 3.1). Also, the average size of transformers is expected to increase annually by 0.5% for both liquid- and dry-type transformers.

It is estimated that ~0.38 million dry-type and 1.14 million liquid-immersed transformers were sold during 1993. The dry-type transformer market is expected to increase from 0.44 to 0.65 million units from 2000 to 2020. The liquid-immersed transformer market is expected to have a comparatively slower growth, increasing from 1.18 to 1.33 million units during the same period. In terms of capacity of transformers sold annually, the liquid-immersed transformer market is expected to continue to increase from 64,631 MVA in 1993 to 78,690 and 88,350 MVA by the years 2010 and 2020 respectively. The corresponding capacity volumes for dry-type units are 28,336, 43,116, and 55,192 MVA. By the year 2030, the number of liquid-immersed and dry-type transformers sold is projected to be 1.41 million units and 0.79 million units, respectively, with capacities of 99,195 MVA and 70,650 MVA.

1.3 STUDY APPROACH

The study methodology consisted of four major elements: development of a database, development of conservation options, assessments of the energy conservation options, and incorporation of feedback from "stakeholders." A database is required to accurately assess the potential energy savings for various energy conservation options. All of the options considered here are technically feasible. Each brief discussion of each element follows:

- *Database Development.* Collecting and processing data was a major part of the study. Data on transformer designs, losses, and sales were provided by the National Electrical Manufacturers Association (NEMA) and individual manufacturers. The Edison Electric Institute (EEI), the American Public Power Association (APPA), and selected utilities provided utility user information. The database includes the results of a survey circulated by EEI and APPA to their member utilities as described in a previous report (Barnes et al. 1994). User information on dry-type transformers was provided by the American Institute of Plant Engineers. In addition, the Federal Energy Regulatory Commission's Form 1, Energy Information Administration information, and trade journals were used. The basic information required included historical information on user purchases and costs and losses of new transformers for the various options considered in the study. Information on transformer loading factors was obtained from discussions with transformer manufacturers and utilities and limited surveys of commercial and industrial users.
- *Energy Conservation Options.* Technically feasible energy conservation (low-loss) options for distribution transformers were based on information provided by NEMA and individual transformer manufacturers. Cases with relatively low life-cycle costs were selected by the Oak Ridge National Laboratory (ORNL) for analysis.
- *Assessments.* The technical and economic analyses provided estimates of appropriate transformer loading factors, losses, and cost-effectiveness and energy savings for the energy conservation options.
- *Stakeholders' Input.* A distribution transformer review group consisting of manufacturers, users, material suppliers, and public interest groups was formed to provide data and to review this study (see Appendix A). Input from these stakeholders was incorporated in the final report.

1.4 SCOPE AND CONTENT

This report documents the assumptions, models, data, and conclusions of this study on the feasibility of achieving cost-effective energy conservation for distribution transformers. For purposes of this analysis, distribution transformers are defined as all transformers with a primary voltage of 480 V or more and a secondary voltage of 120–480 V with a rated capacity of 10–2500 kVA for both liquid-immersed and dry-type units. Smaller capacity dry-type units of 0.25–9 kVA that are used for the distribution of electric power are also considered for completeness. This study is limited to the consideration of transformers used in power distribution systems. Special-purpose, control, and signal transformers, as well as bulk power transformers, were excluded from consideration because they are not classified as distribution transformers.

Section 2 discusses the potential for higher-efficiency distribution transformers, and Sect. 3 describes the structure and elements of the transformer market. An analysis of selected technical options for energy conservation and potential cost-effective energy savings are described in Sect. 4. A preliminary assessment of the impacts of the energy conservation strategies on both manufacturers and users is presented in Sect. 5.

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2. CHARACTERIZATION OF DISTRIBUTION TRANSFORMERS AND THEIR LOSSES

2.1 OVERVIEW

This section discusses the key components of distribution transformers, the associated sources of energy losses, and the major differences between liquid and dry types.

Transmission and distribution of alternating current (ac) electric power requires the conversion of voltage and current levels to match the desired application. This conversion, accomplished by transformers, represents a significant portion of the investment in the T&D system. While the transformers used in the T&D system are acknowledged to be very efficient, the cumulative effect of the losses of a large number of distribution transformers can represent a substantial cost to the system. A major objective of transformer design is to achieve the lowest possible total owning cost (TOC) to owners/operators; this requires a trade-off between the capital cost of transformers and the cost of the transformer losses. The value of these losses may not be specified in all applications, and in this case the TOC reflects only the capital cost of the transformers.

This report addresses those transformers that perform the final transformation from utility distribution voltages (typically 4–35 kV) to final utilization voltages (600 V and below); hence, the designation "distribution transformer." These distribution transformers range in size from ~0.25-kVA single-phase to 2500-kVA three-phase transformers.

The definition for distribution transformers as considered in this study can be summarized as transformers that are continually energized; these fall within the voltage classes and capacities shown in Table 2.1.

Table 2.1. Characteristics of distribution transformers typically used in the United States

Transformer type	Phase	Primary voltage (kV)	Secondary voltage (V)	Capacities (kVA)
Liquid-immersed	1	35 and below	600 and below	10–833
Liquid-immersed	3	35 and below	600 and below	15–2500
Dry-type	1	35 and below	600 and below	15–833
Dry-type	3	35 and below	600 and below	15–2500
Dry-type[a]	1 and 3	35 and below	600 and below	0.25–<15

[a]The smaller dry-type units are included for completeness, but they are a small contributor to the overall energy losses and are not likely to be included in an energy efficiency standard. The units below 9 kVA normally have primary voltages below 600 V.

The vast majority of distribution transformers on the utility-owned distribution system are the liquid-immersed type, while those used in commercial, industrial, and institutional applications are predominately the dry type. The merits and limitations of each type are discussed in the following subsections.

In general, distribution transformers operate over a wide range of loads—some applications having substantial portions of the day and year near zero load. As is shown in Subsect. 2.2, light loading increases the importance of losses at low-load levels, since energizing current must always be present, even without load.

2.1.1 Principles of Transformer Operation

There are three basic elements in a transformer: the primary winding, the secondary winding, and the core. Figure 2.1 shows the key elements pictorially. The two windings are coils of wire wound around a core of high-magnetic-permeability material. By definition, the primary winding is the one connected to the electrical source, while the secondary winding is connected to the output or load. The core may be made of silicon steel or another magnetic material such as amorphous metal and provides a path for the magnetic flux that links all the windings. An alternating flux is set up in the core when the primary winding is connected to an ac voltage source. This alternating flux induces voltage in all windings that is proportional to the number of turns in the specific winding (Faraday's law).[1] In the ideal transformer there are no losses or leakage flux, and the ratio of the voltages induced is equal to the ratio of the number of turns in the respective windings. For example, a transformer with a 1000-Vac source applied to 100 turns in a primary winding will induce 100 V in a secondary winding with only 10 turns. By selecting the proper turns ratio, the designer can determine the ratio of input to output voltages. Simply put, the volts per turn is constant in each winding.

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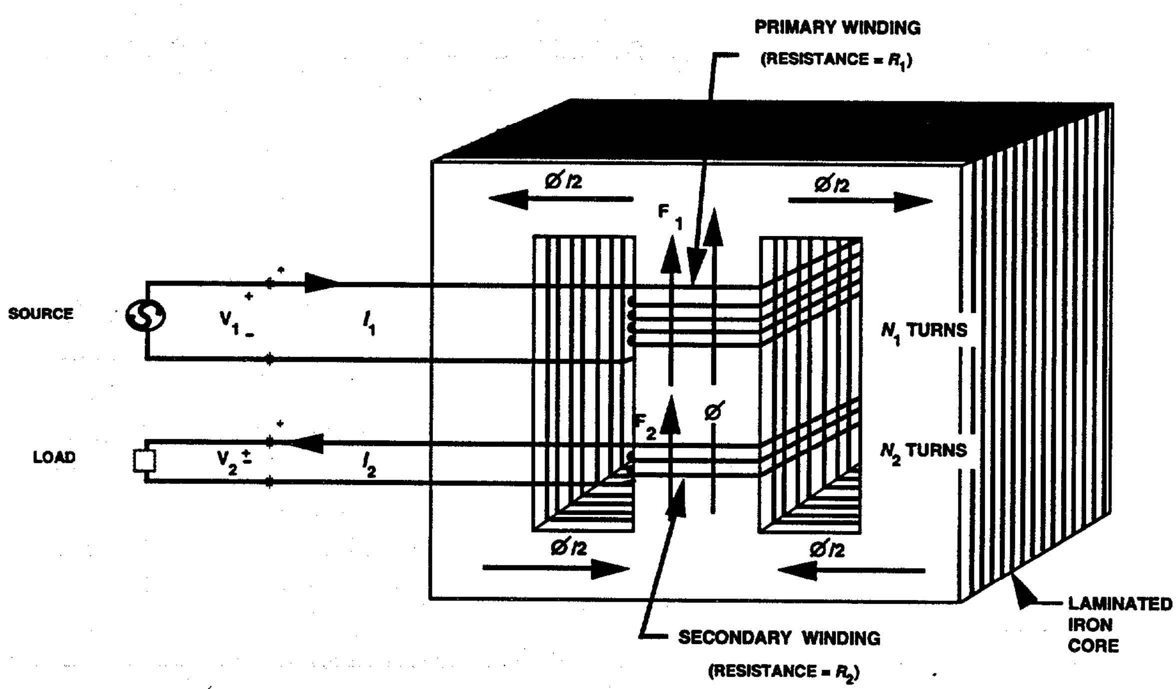

Fig. 2.1. Major internal elements of a transformer.

Because the ideal transformer neither stores nor loses energy, the power input to the primary winding must equal the power output to the secondary winding. As the power input is the product of the voltage and current on the primary side, the power output must be equal to the product of the voltage and current on the secondary side. This implies that the ratio of the primary and secondary current is inversely proportional to the turns ratio. Hence, the ideal transformer simply changes the voltage between the windings in proportion to the turns ratio and changes the current in inverse proportion. In the example given in the previous paragraph, the secondary current must be ten times the primary current. Assuming that the transformer's load is 5 kVA, then the primary current is 5 A, and the secondary current is ten times this, or 50 A or $I_1N_1 = I_2N_2$.

Obviously, transformers are not ideal, and while the modern transformer very closely approaches the ideal, there are losses. Specifically, there is a voltage drop through the transformer under load so that the voltage ratio is not exactly equal to the turns ratio, and an excitation current flows in the transformer even when no external load current is present. The excitation current reflects the presence of no-load losses, while the losses at load are in direct proportion to the product of the square of the current and the winding's effective electrical resistance, which is influenced by temperature. For these reasons, the turns ratio does not match the ideal relationship. Details of these loss mechanisms are discussed below.

In the transformer depicted in Fig. 2.1, the windings are separated to avoid confusion. In reality, the lower-voltage windings are placed next to the core and extend over the entire core leg; the high-voltage windings are placed outside and over the low-voltage windings. Because the core is at ground potential, this simplifies the problem of insulating the high voltage from the core material. Clearly, the windings must be insulated from ground and from low to high voltage. In addition, voltage drop in the windings requires an insulation from turn to turn and layer to layer of each winding (and between phases in three-phase units). The space required by the insulation effectively increases the size of both coil and core and hence the transformer's design volume. Multiple types of insulation systems are available, and the system selected determines whether the transformer is a dry or liquid-immersed type and its intended operating temperature. Furthermore, the amount of insulation required is dependent upon both steady-state and transient voltage levels and increases with the transformer's rated voltage.

There are two basic methods of winding transformers: (1) the core form, in which the two sets of windings surround a core, and (2) the shell form, in which a single set of windings is surrounded by core material, as is shown in Fig. 2.1. There is no inherent difference in cost or performance between the two designs, and the design chosen is somewhat dependent upon the setup of the manufacturing facility.

2.1.2 Major Transformer Loss Mechanisms: No-Load and Load Losses

As is noted in Subsect. 2.1.1, there are two major types of losses in transformers: no-load loss and load loss.

2.1.2.1 No-load losses

No-load losses are those losses required in the excitation of the transformer. No-load losses include dielectric loss, conductor loss due to excitation and circulating currents, and core loss. The dominant no-load loss is core loss, which is associated with the time-varying nature of the magnetizing force and results from hysteresis and eddy currents in the core materials. Core losses are dependent upon the excitation voltage and may increase sharply if the rated voltage of the transformer is exceeded. There is also some inverse dependence on core temperature.

Hysteresis losses in transformer core materials occur because the core materials resist realignment of the magnetic domains in the material. The power required to overcome this reluctance and change magnetic alignment is dependent upon the operating frequency, the amount and type of core material, and the magnitude of the magnetic flux density. Furthermore, the magnitude of hysteresis loss is dependent upon flux density, which is, in turn, dependent upon terminal voltage and the number of winding turns. This interdependence is generally referred to as the "machine equation" and is a consequence of Faraday's law of electromagnetic induction.

This relationship is expressed in the equation shown in note 1, which may be rearranged to express B_{max} in terms of induced voltage or volts per turn in terms of B_{max}.

The initial magnetization curve and a typical hysteresis curve for a ferromagnetic material are shown in Fig. 2.2. Clearly, the relationship between magnetic flux density and magnetic field intensity is nonlinear. For maximum operating performance at minimum capital cost, it is generally desirable to operate the transformer just below the knee, or bend, in the magnetization curve, reducing the quantity of core material and the associated cost. Care must be taken to ensure that the operating voltage levels do not push the transformer into the saturation region of the curve beyond the knee because this sharply increases losses and harmonics. Alternatively, reduction of the peak operating flux, while reducing hysteresis losses, results in the need for a larger cross section of core material and can thus increase transformer capital cost, weight, and volume. The use of different core materials also impacts size and capital cost.

The alternating flux induces in the core material small circulating currents much like eddies in a stream. These eddy-current losses in the core materials represent the other major component of core losses and are functions of the operating frequency, the flux density, the volume of core material, and the resistivity of the core material. To reduce eddy-current losses, the core materials are selected for high resistivity and are formed into thin sheets called laminations, which are separated by thin layers of insulating oxide coating and oriented to minimize the induced currents. These actions increase capital cost by increasing the core volume, the materials cost, and the assembly labor costs. Similarly, decreasing eddy currents by lowering the flux density increases the core material requirements and, potentially, the capital cost, weight, and volume.

The resistivity of the core material has traditionally been increased by alloying iron and silicon and cold-rolling the materials into thin laminated sheets of 7- to 12-mil thickness. These materials are then heat-treated to reduce hysteresis losses. While great strides have been made in reducing the losses in high-silicon-steel materials, a technique for producing materials in which the iron atoms are randomly oriented (amorphous metal) has been developed. In this process, a molten alloy of iron, silicon, and boron is allowed to spill in a ribbon onto a rapidly rotating drum where it is chilled at the rate of about a million degrees per second, forming a glasslike ribbon of material about 1 mil thick without crystalline structure. This material has good magnetic properties, low inherent hysteresis losses, and high resistivity. The very thin laminations greatly reduce eddy currents, but their extreme brittleness and the difficultly in handling them adds to the assembly cost. Because the saturation flux density of amorphous material is lower and because amorphous material cannot be packed as tightly as high-grade silicon steels, the effective operating flux levels in the core are reduced. As a result, cores made of amorphous material are generally larger—requiring more pounds of material, eroding the specific loss advantage of amorphous material, and increasing costs. The larger core cross section also requires more material for the coil (i.e., more turns and/or longer winding length); this generally increases core cost and load losses.

All amorphous-core transformers are liquid-immersed, wound core and were, until recently, limited to <2500 kVA. Transformer cores made of this amorphous-core material have <25% of the losses per pound of material demonstrated by the best transformer cores made of high-grade silicon steel. The drawbacks of the amorphous-core material include increased core costs, increased difficulty in fabrication, increased core volume and weight, and reduced saturation flux density. The present capital cost penalty relative to high-grade silicon steel appears to be ~25%. The amorphous-metal manufacturer and the Electric Power Research Institute (EPRI) are optimistic that in constant dollars this penalty can be reduced to less than 10% (Ng 1993).

Aside from the core material properties, other issues enter into the core performance such as the use of wound core or stacked core and the manner in which the core laminations are stacked in so-called buttlap, mitered, and steplapped cores to reduce joint fringing. Also, the degree of

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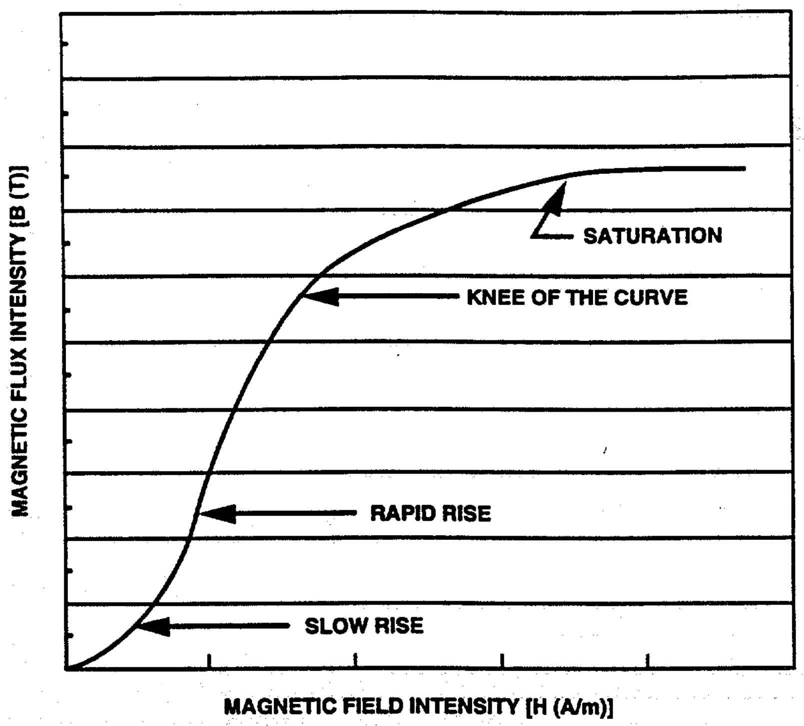

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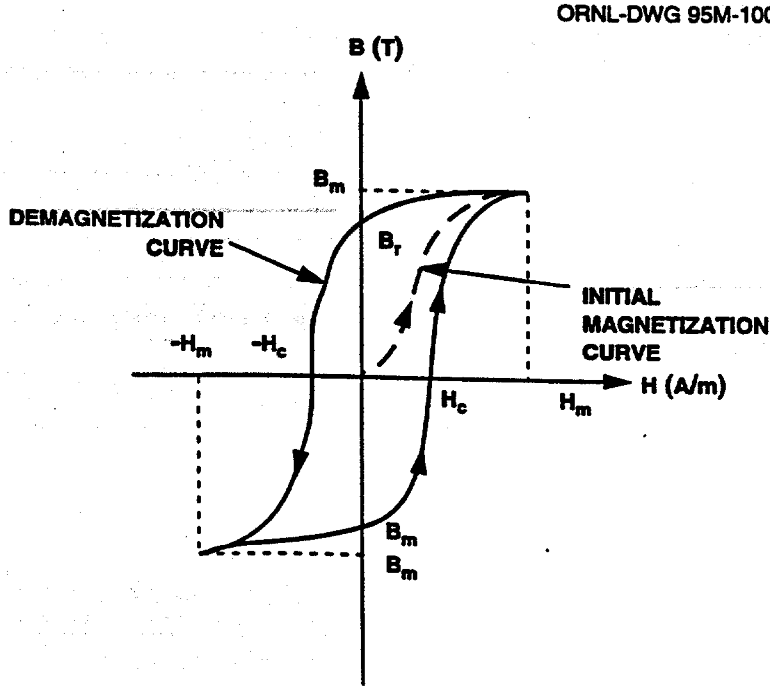

Fig. 2.2. Typical initial magnetization curve (top) and typical hystersis curve (bottom) for ferromagnetic material.

interleaving or booking in both wound and stacked cores ranges from single-sheet to four-sheet. These techniques are used to reduce core losses, but the more elaborate techniques are labor-intensive and increase core costs for a specified material. Generally, the better-performing, higher-cost materials are used in configurations that also require more labor.

2.1.2.2 Load losses

Those losses that are incident with the carrying of load are referred to as load losses. Unlike no-load losses, which are constant and always present, load losses vary with the square of the load current carried by the transformer and include (1) the resistive heating (I^2R) losses in the windings due to both load and eddy currents, (2) stray loss due to leakage fluxes in the windings, core clamps, and other parts, and (3) the loss due to circulating currents in parallel windings and parallel winding strands. For distribution transformers, the major source of load losses is the I^2R losses in the windings.

Load losses can be reduced by selecting lower-resistivity materials (such as copper) for the windings, by reducing the total length of the winding conductor, and by using a conductor with a larger cross-sectional area. Eddy currents are controlled by subdividing the conductor into strands and insulating the conductor strands and by conductor shape and orientation. Clearly, this involves a combination of material and geometric options that also depend upon the core dimensions.

Because dry-type insulation systems lack the additional cooling and insulating properties of the oil-paper systems, for the same rating the dry-type transformers tend to be more costly, larger, and have greater losses than a corresponding liquid-immersed unit. Moreover, for a given capital cost, volume, weight, and insulation system, transformers of the same voltage and kilovolt-ampere rating trade off no-load against load losses. This is illustrated conceptually by the cost vs losses surface in Fig. 2.3, which in reality is a set of discrete points established by available core dimensions.[2]

Because load losses vary with the square of the load current, transformer efficiency is load-dependent.[3] Furthermore, it can be shown mathematically that maximum efficiency occurs at the load point for which load losses and no-load losses are equal.

Most distribution transformers are generally lightly loaded for relatively long periods and are designed with lower no-load losses to operate with maximum efficiency at 25–50% load (Fig. 2.4). The curves shown in Fig. 2.4, which are typical of distribution transformers, illustrate two different applications: the first—called low no-load loss, high load loss—is for transformers that would be expected to be lightly loaded (i.e., low capacity factor); the second—labeled moderate no-load loss, low load loss—would be applied to a transformer with a higher capacity factor (i.e., capacity factor = average load/transformer capacity). The curves are easily plotted using equations of the type illustrated in note 3, values for the nameplate rating, load losses, and no-load losses. The effect on total losses is indicated by Fig. 2.5, which illustrates the general nature of this trade-off.

2.1.3 Characteristics of Liquid- and Dry-Type Transformers

Liquid-immersed transformers are the predominant type of transformer, representing the oldest technology and having an established performance record. They offer the best balance of design properties for dielectric, thermal, and cost performance and are the basis for all other design types. The liquid-immersed units have outstanding thermal and dielectric properties, the lowest purchase cost, the smallest dimensions, and the lowest losses per purchase dollar and are relatively unaffected by the operating environment. The key disadvantages are the possible

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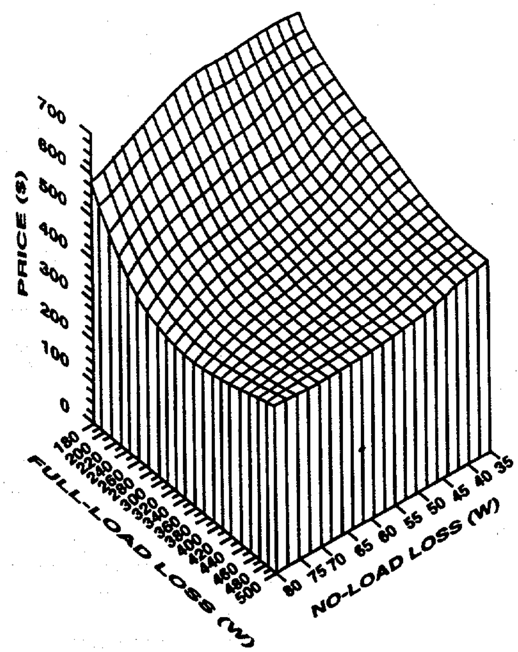

Fig. 2.3. Surface of cost vs losses for a typical 25-kVA distribution transformer. *Source:* Prepared using data supplied by the National Electric Manufacturers Association.

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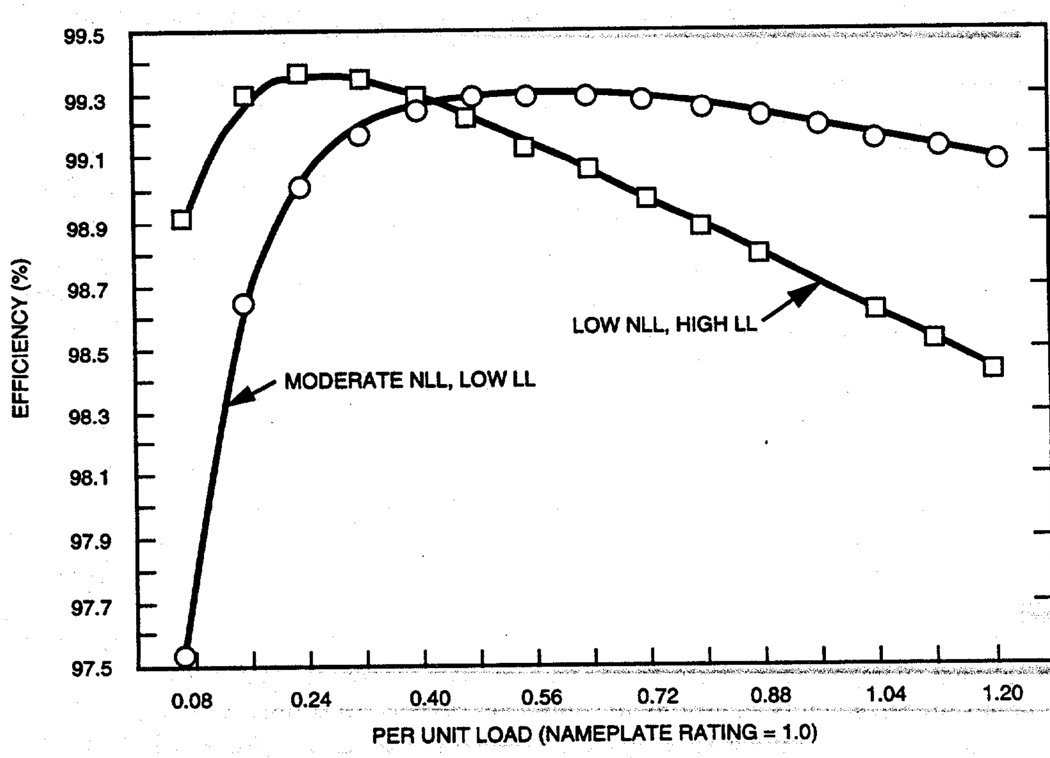

Fig. 2.4. Typical transformer efficiency vs per unit load relative to nameplate rating. NLL = no-load losses; LL = load losses.

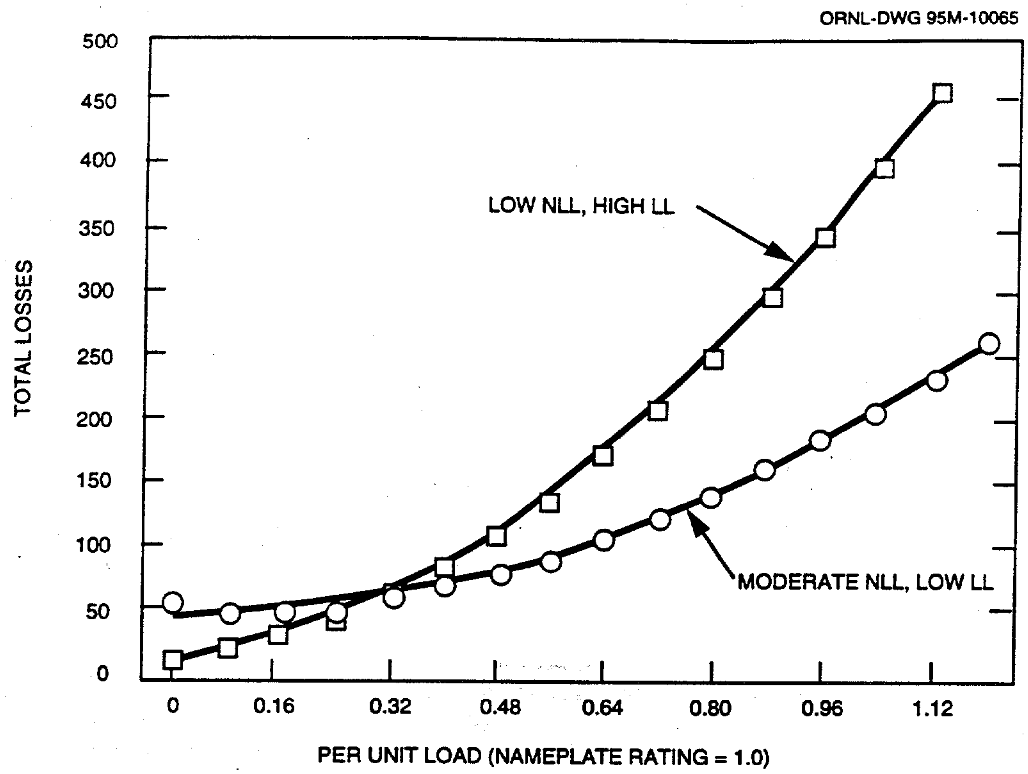

Fig. 2.5. Typical total losses as functions of load, indicating trade-off of relative load and no-load losses. NLL = no-load losses; LL = load losses.

susceptibility to fire, a lower temperature rise, and potential oil leaks. Fire-resistant liquids have been developed and, aside from the disadvantages of leakage and more restrictive thermal operating limits, compete favorably with dry-type transformers.

Dry-type transformers are available in several types but are generally open wound or encapsulated. The design temperature rise and hot spot temperature imply that several different insulating systems are available for dry-type transformers, but all dry-type transformers depend strongly on the insulating and cooling properties of air. The units are fire-resistant and present no leakage problem. They are generally more costly and heavier and have higher losses than liquid-immersed units. The insulation systems used in dry-type transformers permit operation at higher temperatures than those used in liquid-immersed units. Because little capital investment is required to begin manufacturing dry transformers, there are a large number of manufacturers, and turnover is high. Dry-type transformers are limited to operating voltages of less than 46 kV.

2.2 TRANSFORMER EVALUATION AND LOSS REDUCTION METHODS

This section discusses the general nature of loss evaluation and trade-offs in loss reductance. Without regard to cost, it is technically feasible to design and to build distribution transformers of all types that provide significant energy savings compared with the typical units purchased in 1994. However, if energy-saving designs are restricted to those that are economically feasible using national average energy costs, there is a potential for moderate savings per transformer from liquid-immersed units and for more significant savings per transformer from redesigned dry-type units. Because utilities routinely evaluate transformers for minimum TOC, the technical ability to provide low-loss liquid-immersed transformers is well established.

Typical values for losses in distribution transformers are given in Table 4.2 by size and insulating system. As a result of improved performance in core materials from both silicon steel and amorphous-core materials and increased demand for lower TOCs by utilities, transformer losses in oil-paper systems have decreased steadily since the 1950s. Generally, dry-type transformers have not experienced a corresponding reduction in losses. This reflects the fact that dry-type transformers are usually not evaluated for TOCs and are purchased on a lowest first-cost basis.

The TOC evaluation methodology, which has been used by utilities and some other large customers for a number of years, provides a balance between cost of purchase and cost of energy losses. The wide range of no-load-loss evaluation values (A factor) and load-loss evaluation values (B factor) for liquid-type transformers indicates the broad diversity of utility energy and capital expenses. Similar techniques could be used to develop A and B factors for dry-type transformer applications in industrial and commercial settings. However, while low-loss transformers are available for liquid-immersed applications, there has been limited incentive for manufacturers to supply low-loss, dry-type transformers. It appears that the limited customer demand for lower-loss, dry-type units has come from utility applications and special niche applications in industry.

The design specifications and maximum losses will define the continuous capacity (kilovolt-ampere), the overload capability and hence the thermal performance of the insulation system, the short circuit or fault current capability and transformer impedance, the phasing desired, the normal and unusual service conditions, the voltage regulation, and the basic impulse level. Specification of losses or efficiency is not common because this restricts the design. Instead, the utility practice is to specify loss evaluation values for no-load and load conditions and to allow the manufacturer to minimize the TOC.

The technology used to provide low-loss transformers is based upon changing the configuration and hence the amounts of coil and core materials and lower-loss materials. For example, operating at a lower flux density will reduce core losses but require more turns of conductor, increasing load losses. Similarly, lowering the conductor current density will reduce load losses but require more core material or a higher flux level, which will produce higher no-load losses. Restrictions on weight and volume may further limit the selection. To provide a low-loss transformer requires the use of low-loss materials (i.e., high-silicon steel or amorphous metal for the core and increased amounts of copper or aluminum for the windings) configured in an optimal manner. The increased core volume and weight associated with amorphous cores requires longer turns of conductor, increasing coil losses. The configuration and the materials selected define the cost of the transformer materials and the labor required to assemble the system (i.e., the transformer cost). Table 2.2 illustrates these trade-offs.

It is evident from Fig. 1.2 that maximum efficiencies for three-phase, 75-kVA, dry-type transformers have declined from about 97.8% in 1970 to 96.9% in 1995, while liquid-immersed units have slowly increased in efficiency over the same time period. In 1970 the liquid-immersed unit was about 0.7% more efficient (98.5 vs 97.8%), which can be attributed to the difference in the insulating value of oil vs air and the resulting smaller size of the liquid-immersed unit. In the intervening years the liquid-immersed units have slowly evolved to efficiencies of about 98.9%. However, nonloss evaluated transformers deteriorated in efficiency to under 98.0% from the 98.5% level of 1970. If during the same time period dry-type transformers had applied the same technology evolution, it is safe to project that dry-type transformers, if subject to a loss evaluation by the customer, would now approach 98.2% efficiency instead of the 96.9% efficiency currently produced. These comparisons depend on evolutionary development of the technologies, not major breakthroughs. For a detailed analysis of transformer design methods, see Feinberg (1979) and Stigant and Franklin (1973).

Table 2.2. Loss reduction alternatives

	No-load losses	Load losses	Cost
To decrease no-load losses			
• Use lower-loss core materials	Lower	No change[a]	Higher
• Decrease flux density by			
(1) increasing core CSA[b]	Lower	Higher	Higher
(2) decreasing volts/turn	Lower	Higher	Higher
• Decrease flux path length by decreasing conductor CSA	Lower	Higher	Lower
To decrease load losses			
• Use lower-loss conductor material	No change	Lower	Higher
• Decrease current density by increasing conductor CSA	Higher	Lower	Higher
• Decrease current path length by			
(1) Decreasing core CSA	Higher	Lower	Lower
(2) Increasing volts per turn	Higher	Lower	Higher

[a]Amorphous-core materials would result in higher load losses.
[b]CSA = cross-sectional area.

Can dry-transformer technology provide transformers with lower losses at reasonable costs? As is indicated in the previous paragraph, all types of dry transformers can be constructed with lower losses; however, costs will be higher for a given efficiency than for liquid-immersed transformers. Because air is the basic cooling and insulating system for dry-type transformers, all dry-type transformers will be larger than liquid-immersed units for the same kV/kVA rating; hence, it is not possible for a dry-type transformer to have a lower TOC than a liquid-immersed unit. When operating at the same flux and current density, more material for core and coil implies higher losses and higher costs. However, dry-type transformers have traditionally offered fire-resistant, environmental, and application advantages for industrial and commercial situations. Recent advances in liquid-filled units reduce these advantages. Therefore, the reduction in losses in dry-type transformers must be weighed against the increased capital costs of the units by using TOC or an equivalent evaluation method.

2.3 TRANSFORMER LOADING PRACTICES

Determination of both the size in kilovolt-amperes and the load factor of distribution transformers is an important task. Both continuous load and overload impacts on insulation system life must be considered. Methodologies have been developed to enable utilities to better size the transformer to the load characteristics (Schneider and Hoad 1992). Studies seem to indicate that distribution transformers are lightly loaded most of the time but have short periods of time in which loads may be 50–100% above the rated load. In other words, a 10-kVA transformer might be loaded at 15–20 kVA for periods of a few hours per year with slight loss in useful life (DOE 1980; Nickel and Braunstein 1981).

An important point to note is the relatively large spread in the peak load that implies a relatively large uncertainty in the transformer peak load or loading pattern. Nickel suggests a variable peak loading with an initial peak load of 0.6 to 1.0 and a final peak of 1.25 to 2.0 based upon a 1971 industry survey (DOE 1980; Nickel and Braunstein 1981). The transformer load is assumed to grow from the initial to the final peak at a specified rate, at which point the transformer is moved to a lower load location or retired.

The ratio of average losses to losses at peak load is called the loss factor and is used in deriving the load-loss evaluation (B) factor. The ratio of average load to peak load is referred to as the load factor and is equivalent to the transformer relative capacity (see note 3) only if the transformer's peak load is equal to the nameplate rating and coincident with the system peak load. This study refers to a transformer effective capacity factor when referencing transformer load and therefore assumes a coincidence of the transformer and system peaks and a relative peak load of 1.0. The capacity factor, load factor, and loss factor are strongly dependent on the transformer's loading pattern. The effective capacity factor used in this study is a root-mean-square annual average of the transformer's relative capacity. An empirically developed formula relating the loss factor to the load factor is $LSF = 0.15\ LF + 0.85\ LF^2$. The general relationship between loss factor and load factor has been published (Manning 1965). The above form of the equation is based on several representative utilities, and, as with other factors used in this analysis, for a given application there can be significant deviation from the assumed national average. Specific forms of the equation for commercial and industrial applications will require careful study.

A subject of major concern to utilities is projected equipment life. For distribution transformers a loading guide has been established (ANSI and IEEE 1981). This guide provides a method for determining the insulation's hottest spot temperature as a function of load and a relationship between temperature and time that is used to compute transformer life. Present distribution transformers are designed to operate 20 years at the design load and specified hot-spot temperature. Underloaded transformers are clearly less stressed thermally and may have lives extending well beyond 30 years, but transformers loaded to greater than nameplate rating for extended times may have significantly shortened lifetimes. The national average age data referenced below implies that distribution transformers may be significantly underloaded.

For this report, a national average for utility distribution transformer life of 31.95 years and a standard deviation of 6.4 years were used (Mougin 1992). Note that 30 years is the typical period used for evaluating TOCs.

While the present average age is well beyond the 20-year design life, there is evidence of attempts by utilities to more closely match load to transformer size. In making the decision to reduce transformer size, utilities must consider voltage regulation. Voltage drop in the transformer due to sudden load change can result in customer complaints. For example, an electric motor requires up to six times the operating current during startup, and if the motor is large relative to the transformer, voltage can be significantly reduced for up to 15 s until the motor reaches operating speed. A common solution to motor-caused voltage-drop problems is to oversize the transformer. The net result is an underloaded transformer with a relatively long life.

While the annual operating costs of transformers depend upon the per unit loading and are reflected in the TOC evaluation methodology through the loss evaluation values, another factor that will play an important role in dry-type transformer evaluation is the temperature rating of the unit. The increased importance results from the wider variation in the maximum operating temperature allowed in dry-type transformer insulation.

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NOTES

1. $E = 4.443 \times f \times N \times B_{max} \times A_{clw}$, where E = rated coil voltage (volts), f = operating frequency (hertz), N = number of turns in the winding, B_{max} = maximum flux density in the core (tesla), and A_{clw} = cross-sectional area of the core material in the coil window.

2. In addition to the voltage equation in note 1, a power equation expressing the volt-ampere rating in terms of the other input parameters is also used in transformer design. Specifically, the form of the equation is $kVA = 4443 \times f \times N \times B_{max} \times A_{clw} \times J \times A_{crw}$, where f, N, B_{max}, and A_{clw} are as defined in note 1, J is the current density (A/mm^2), and A_{crw} is the coil cross-sectional area (m^2) in the core window.

3. Efficiency (η) at a given load level is defined as output energy divided by the sum of output energy and losses. Assuming constant terminal voltage and no correction for temperature effects,

$$\eta = \frac{S \cos \Theta}{[S \cos \Theta + \text{core losses} + \text{load losses} \times (|S|/S_B)^2]} ,$$

where S = kVA load, S_B = nameplate rating, and $\cos \Theta$ = power factor. For this report, η is shown for $\cos \Theta = 1$. Because voltage fluctuation under operating conditions is limited, the voltage assumption is acceptable for well-designed distribution transformers. The ratio $|S|/S_B$ is called the relative capacity.

3. DISTRIBUTION TRANSFORMER MARKET

3.1 MARKET TRENDS AND FORECASTS

Liquid-immersed and dry-type are the two distinct types of distribution transformers, serving predominantly the utility and the nonutility sectors respectively. The total value of product shipments in the distribution transformer market was estimated to be ~$1.5 billion in 1992, coming from more than 230 companies having annual shipments of $100,000 or more (DOC 1994a). Amorphous-core transformers account for ~10% of new transformer sales (Howe 1993). The value of total U.S. transformer imports (which includes all categories of transformers except electronic—Standard Industrial Classification 3612) has been more than the value of its exports during the past several years, accounting for ~15 and 10%, respectively, of the total value of shipments in 1992 (DOC 1994b). Canada and Mexico have been the major trading partners for the United States, and it is expected that the North American Free Trade Agreement will provide a big boost for the U.S. transformer export market (DOC 1994b). Expected growth in the Mexican economy resulting from the passage of the North American Free Trade Agreement would stimulate the demand for electricity in Mexico and hence increase the demand for transformer products.

It is estimated that ~10% of the total liquid-immersed market serves the nonutility sector, and most liquid-immersed transformers in this market segment are three-phase, pad-mounted and station types. (The use of the pole type is declining, mainly owing to aesthetic concerns.) Conversely, more than 90% of the total dry-type market is in the nonutility (C&I) sector. Total current annual sales volumes of liquid-immersed and dry-type transformers in the 10 kVA–2.5 MVA range are estimated to be 1.1 million (64,631 MVA) and 0.38 million (28,336 MVA) units respectively. In addition, about 1.4 million single-phase, dry-type transformers in the 3- to 5-kVA range are sold annually, of which 25–30% are used for distribution transformer applications. Relative to the number of manufacturers, the dry-type market is comparatively more volatile than the liquid-immersed market because manufacturing of dry-type transformers is less capital-intensive and has particularly low startup costs. There are many dry-type manufacturers—total numbers in the 10 kVA–2.5 MVA range have been estimated anywhere from 200 to 400. However, only about 20 of these are major dry-type transformer manufacturers; most of the remaining manufacturers are only involved in either niche market segments (e.g., mining or railways) or in transformer rewinding. The number of smaller size (<10 kVA), dry-type transformer manufacturers is large (i.e., 5000–6000) in order to serve the numerous original equipment manufacturers (OEMs).

Dry-type transformers >10 kVA are predominantly three-phase compared with the single-phase dominance in the liquid-immersed transformer market. Open wound and cast resin are the two major categories of dry-type transformers, the latter being more expensive and used primarily in harsh environments such as cement and chemical plants and outdoor installations. Dry-type transformers gained a much wider acceptance in the marketplace during the 1980s following the U.S. Environmental Protection Agency (EPA) ban on the manufacture of polychlorinated biphenyls (PCBs) in 1979.[1]

The distribution transformer market generally consists of transformers of 10 kVA–2.5 MVA, although numerous dry-type transformers <10 kVA are classified as distribution transformers (see Subsect. 3.2.2). Currently, no published disaggregated information is available on annual sales and shipments of distribution transformers. The market data collected by the U.S. Department of Commerce (DOC 1994a) provide only the aggregate value of annual shipments; the data are disaggregated neither by the kind of transformers nor in terms of size and number of units. NEMA surveys the industry regularly to collect market information on distribution transformers, including both liquid-immersed and dry-type. Several size (kilovolt-amperage) and voltage classes are considered under each type, and the liquid-immersed type also disaggregates further into pole, pad-mounted, subsurface, power, and secondary unit substation classes. The NEMA data do not reflect the entire industry, particularly when only 5% of dry-type distribution transformer manufacturers are members (Patterson 1994). The NEMA data currently represent 66% and 72% of the total dry-type and liquid-immersed markets respectively (Hopkinson 1994). In the case of the liquid-immersed transformer market, the percentage of the total market represented by the NEMA data has continually decreased from 90% in 1980 to 72% in 1993 as some large non-NEMA manufacturers entered the market. Figures 3.1 and 3.2 show total annual shipments of distribution transformers in terms of size (megavolt-amperes) and number of units, respectively, for the period 1980–2030. The historical data in these figures are from NEMA and were updated to reflect the non-NEMA market share (as discussed previously); the exception is the cast resin dry-type market, for which historical data are based on Patterson (1994). Information on future years is based on ORNL projections.

The future outlook for the distribution transformer industry is not expected to be different from that of the past decade. Based on current customer practices, the industry predicts an overall annual growth rate of not more than 2% (Patterson 1994; Schrieber 1994). Sales of liquid-immersed utility distribution transformers depend primarily on new housing starts, while gross private domestic investment provides a good indicator for the nonutility transformer market. Projections made here for the utility (i.e., liquid-immersed) and the nonutility (i.e., open-wound dry-type, cast-resin dry-type, and liquid-immersed) markets are based on these parameters. The recent trend of low demand for utility transformers, due to stagnant new residential construction and reduced utility growth, is expected to continue in the future. In addition, affordability and demographic factors will cause new housing starts to grow more slowly than the overall economy (DOC 1994b; Christ 1994). The liquid-immersed utility transformer market is assumed in Figs. 3.1 and 3.2 to grow at an annual rate of 1%. The recovery

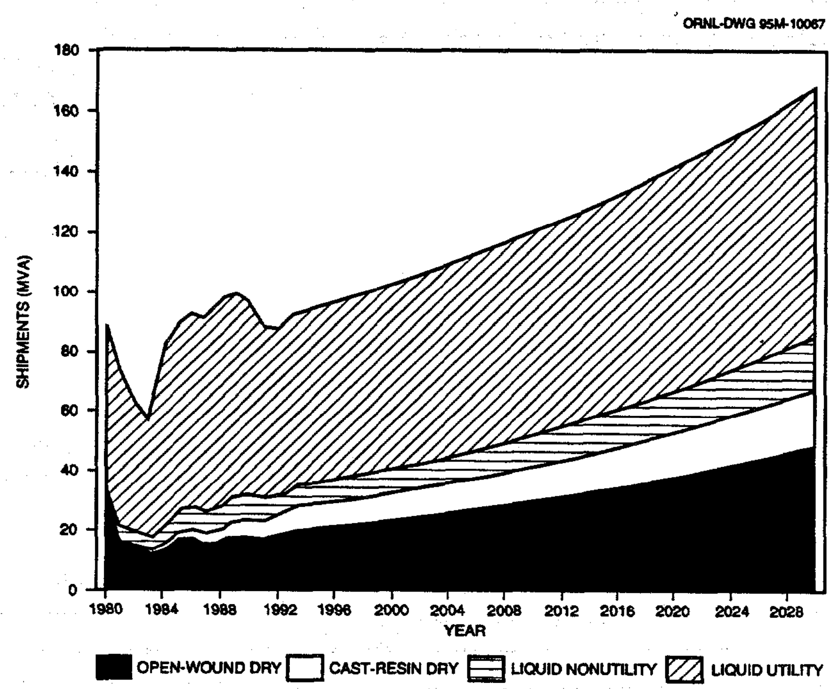

Fig. 3.1. Annual shipments of distribution transformers by megavolt-ampere (10 kVA–2.5 MVA), 1980–2030.

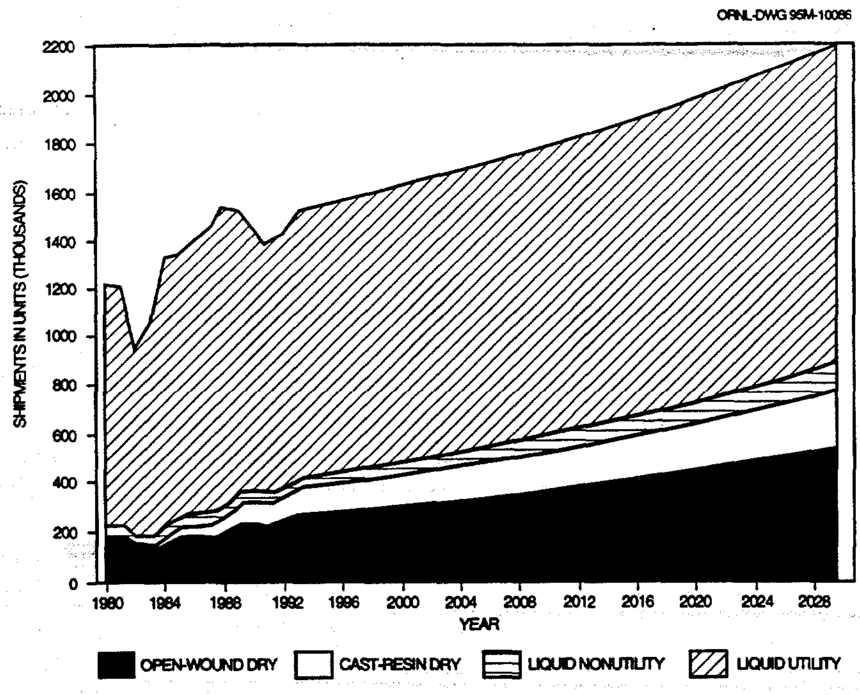

Fig. 3.2. Annual shipments of distribution transformers by number of units (10 kVA–2.5 MVA), 1980–2030.

of the U.S. manufacturing sector is expected to result in a moderate demand for the nonutility transformer market. The U.S. Office of Management and Budget predicts that low long-term interest rates (particularly important for fixed business investment) will be sustained over the rest of the 1990s and will result in a gross domestic product growth of 2.5–3%/year (OMB 1994). Based on the historical data used here, annual growth rates during 1983–1993 for liquid-immersed and dry-type distribution transformers are estimated to be 1.1 and 6%/year respectively. Thus, the assumed annual growth rates of 1 and 2.5% used here for the utility and nonutility transformer markets, respectively, are conservative compared with the historical growth rates. To forecast the number of units of liquid- and dry-type transformers, it is also assumed that the average size of transformers will increase in both cases annually by 0.5% (Fig. 3.2). The breakdown between the utility and nonutility liquid-immersed transformers is based on the assumption that the nonutility share includes (1) 4% of the total single-phase, liquid-immersed market and (2) 20% of the total three-phase, liquid-immersed market (Austin 1994).

3.2 CATEGORIZATION BY SIZE

In the distribution transformer 10-kVA to 2.5-MVA range, nearly all of the units are manufactured by the 20 or so major manufacturers. For <10 kVA (i.e., 0.25 kVA–9 kVA), the number of manufacturers increases to about 5000 in order to supply transformers to the numerous OEMs. These smaller size units are expected to be only ~4% of the market based on capacity of sales in 2030. An energy conservation policy that involved the 10-kVA to 2.5-MVA range would affect 95% of the distribution transformer market. A more detailed description of markets for the two size categories follows.

3.2.1 Distribution Transformers in the 10-kVA to 2.5-MVA Range

Table 3.1 shows the estimated annual shipments of liquid-immersed and dry-type distribution transformers for 1980–2030. As discussed earlier, forecast shipments (i.e., 1994–2030) of liquid-immersed and dry-type transformers shown in Figs. 3.1 and 3.2 are based on constant annual growth rates of 2.5 and 1.0%/year respectively. In the case of dry-type transformers, additional forecasts of shipments under an annual growth rate of 1.0% have also been made, as is shown in Table 3.1.

The annual sales volume of liquid-immersed transformers has remained steady at ~1 million units during the past two decades, as is shown in Fig. 3.2 and Table 3.1. It is estimated that about 1.14 million units (or 64,631 MVA) or liquid-type transformers were sold during 1993. The liquid-immersed transformer market will increase to 1.18 and 1.33 million units by the years 2000 and 2020 respectively. The corresponding annual capacities to be sold during those years are forecasted to be 70,087 and 88,350 MVA respectively. Almost 1.41 million units (or 99,195 MVA) of liquid-immersed transformers will be sold in the year 2030.

The market outlook for dry-type distribution transformers will grow substantially from its current level of 0.38 million units (or 28,336 MVA) to 0.44 and 0.65 million units by the years 2000 and 2020, respectively, under the assumed annual growth rate of 2.5%/year. About 32,255 and 52,854 MVA, respectively, are forecast to be the corresponding annual capacity to be sold during those years. By the year 2030 the annual sold capacity of dry-type transformers is projected to be 67,659 MVA (or 0.79 million units). The market share of open-wound and cast-resin dry-type transformers compared with the total capacity sold in 2030 will be 28 and 12% respectively. If the market growth rate of dry-type transformers is similar to that of liquid-immersed transformers (i.e., 1%/year), the total dry-type market is forecasted to be less than 60% of the market estimated under the growth rate of 2.5%/year in 2030. About 0.46 million units (or 39,213 MVA) of dry-type distribution transformers will be sold under the lower growth rate case in the year 2030.

Table 3.1. Annual shipments of distribution transformers (10 kVA–2.5 MVA), 1980–2030

	Liquid-immersed		Dry-type			
	1.0%/year		2.5%/year		1.0%/year	
Year	MVA	'000 units	MVA	Units (thousands)	MVA	Units (thousands)
1980	58,370	1,034	30,722	181	30,722	181
1985	70,613	1,131	17,920	213	17,920	213
1990	73,180	1,130	22,796	320	22,796	320
1995	66,145	1,148	28,509	394	27,681	382
2000	70,087	1,181	32,255	435	29,093	392
2005	74,264	1,215	36,494	480	30,577	402
2010	78,690	1,251	41,290	530	32,137	413
2015	83,380	1,289	46,716	584	33,776	423
2020	88,350	1,327	52,854	645	35,499	433
2025	93,616	1,367	59,800	711	37,310	444
2030	99,195	1,410	67,659	786	39,213	455

3.2.2 Distribution Transformers <10 kVA

Generally, transformers under 10 kVA are dry-type units although some liquid-immersed units in this size range are produced. It is estimated that about 1.4 million dry-type units <10-kVA (with an average of 1 kVA) were sold in 1993. These units are mostly single-phase units and are generally used by OEMs in machine tool applications. Distribution transformer applications in this size category usually average 3–5 kVA in capacity, and in 1993 they had a share of ~400,000 units (equivalent to 1200 MVA) of the total market of 1.4 million units. The growth of this smaller size, dry-type distribution transformer market is assumed to be similar to that of the larger size (i.e., >10 kVA) market. Assuming an annual capacity growth rate of 2.5%, it is estimated that the capacity of this market will increase from 1200 MVA in 1993 to 1426, 1826, and 2337 MVA by the years 2000, 2010, and 2020 respectively. In terms of number of units, the size of the lower kilovolt-ampere, dry-type distribution transformer market is almost equal to that of the larger kilovolt-ampere market. It is projected that this market will increase to 0.46. 0.56, and 0.68 million units by the years 2000, 2010, and 2020 respectively. Almost 0.83 million units (or 2992 MVA) of lower kilovolt-ampere, dry-type distribution transformers will be sold in the year 2030.

3.3 MARKET STRUCTURE

The structure of the distribution transformer market, shown in Fig. 3.3, includes various market players and their interactions. The market delivery channel varies with the end user, particularly between utility and C&I customers. Once a transformer leaves the manufacturer's production plant, manufacturers' representatives, OEMs, stocking distributors, agents, and electrical contractors play an important role in delivering transformers to end users. Factory-affiliated manufacturers' representatives—including agencies (usually used by small manufacturers) and salaried sales personnel from large manufacturers—are intermediaries that act as the marketing arm for transformer manufacturers. They usually do not stock transformers and are typically organized on a regional basis. These representatives act primarily as technical resources and brokers; all transformers are shipped directly from the manufacturer to the end user or distributor. Stocking distributors are generally independent electric equipment sellers that carry stock items, and their volume is such that they can obtain transformers directly from the factory or through manufacturers' representatives. The agents for end users mainly include either architect-engineers or engineering contractors who evaluate various transformer design options and make recommendations for purchases but rarely procure the transformers themselves (doing so only in the case of turnkey projects). The electrical contractor purchases transformers from the stocking distributors based on specifications developed by the agent or the contractor.

More than 90% of all utility transformer purchases are currently made directly from manufacturers; technical specifications are written by the utilities themselves. In some cases (e.g., some municipalities and rural electrification authorities) utilities buy transformers directly from distributors. Electrical contractors purchase transformers for C&I customers based on specifications written by agents or by the contractors themselves. Some heavy-industrial customers (e.g., General Motors Corporation) buy transformers directly from distributors based on specifications developed by their in-house experts. For large turnkey projects for C&I customers, agents may purchase transformers. Any large-volume or custom-order purchases (e.g., for the petrochemical or paper and pulp industry) are made directly from manufacturers. Small-volume or stock item purchases are not easily made directly from manufacturers these days. OEMs know exact transformer specifications and therefore usually buy from manufacturers

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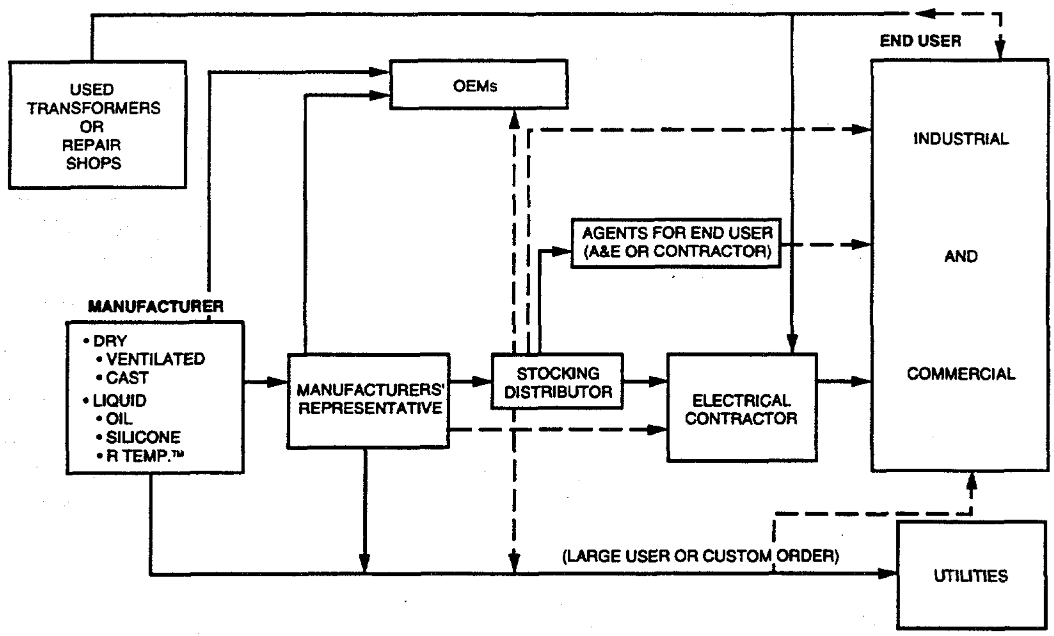

Fig. 3.3. Market delivery channels for distribution transformers. *Note:* The most common route is marked by solid lines. OEM = original equipment manufacturer; A&E = architect and entgineer.

directly. C&I customers buy OEM products either directly through OEMs or through agents or electrical contractors.

Rather than being repaired, transformers with major damage are usually replaced. When repair does take place, it usually occurs either in repair shops or at the original manufacturer's (typically when failure occurs within the warranty period). The only units that are normally repaired are medium-voltage units. Utilities will frequently repair their own distribution transformers because in many cases repair costs less than disposal and replacement. A recent ORNL study indicates that, on average, electric utilities are making reasonable decisions regarding the replacement or refurbishment of distribution transformers that are removed from service (Barnes et al. 1995). Most of the refurbishments occur on transformers that are <20 years old and have a significant amount of remaining life. The retirement age of transformers removed from service for a variety of reasons ranges from 14 to 35 years; the average is ~25 years. However, the average life of liquid-immersed transformers that remain in service is ~30 years or more. C&I customers sometimes purchase used transformers from an electrical contractor who has removed them because they are no longer adequate for the original C&I accounts.

Although all market participants play a role in expanding the market for energy-efficient transformers (i.e., those transformers purchased by utilities and nonutilities that consider energy cost in their purchasing decision), the most influential are individuals who are involved in writing technical specifications to purchase transformers. In cases where end users write their own technical specifications and buy transformers directly from manufacturers, lower loss transformers are usually purchased. More than 90% of utilities and some heavy industries (e.g., paper and pulp or petrochemicals) currently buy energy-efficient transformers. However, most C&I end users do not buy energy-efficient transformers. In these cases transformer requirements are specified either by an agent or by an electrical contractor who tries to minimize costs by buying cheaper transformers. These agents and contractors, not being the final users of the facilities and therefore not being those who pay electric bills, have little incentive toward energy efficiency. C&I building owners usually do not pay electric bills either, since that is the responsibility of the tenant.

Still others in the market (i.e., distributors, manufacturing representatives, and OEMs, who try to maximize profits by increasing sales volumes) do not promote more expensive, energy-efficient transformers. OEMs usually specify technical characteristics (e.g., voltage regulation or exciting current) and are more interested in Underwriters Laboratories certification. Communications between OEMs and their customers seldom involve discussions of energy efficiency. In addition, these various market players lack the training and incentives to promote energy-efficient transformers. Currently, the limited number of available evaluation tools are not widely used to facilitate cost justification and determine energy savings.

EPA recently launched the Energy Star Transformer Program in which electric utilities sign agreements to purchase cost-effective, high-efficiency transformers for their distribution systems (Thigpen 1995). In addition, leading manufacturers of distribution transformers have committed to producing Energy Star transformers and marketing them to electric utilities. EPA provides technical data and resources to utilities to help them perform complicated benefit-cost analyses of their transformer purchases.

End user demand is the most important issue in promoting an energy-efficient transformer market. Distribution transformer efficiency is often overlooked by end users and utility demand-side management (DSM) programs because even run-of-the-mill units appear to be very efficient when compared with energy conversion devices such as motors or lighting. For example, a good high-efficiency motor might have a full-load efficiency of 96% compared with a typical efficiency of 97% for a distribution transformer. Many end users are currently unaware of the economics of lower loss transformers, as is evidenced by their purchasing practices, which are discussed in detail in the following subsection. Thus, in the order of their importance to promoting distribution transformer energy efficiency—ranging from the most influential to the least—the market players are C&I end users, utilities, OEMs, distributors, and manufacturers.

3.4 PURCHASING PRACTICES

The discussion of the distribution transformer market structure in the previous subsection illustrates how different market players influence transformer purchase decision making. This subsection discusses five different types of purchasing practices used by these market players in the transformer market. These practices are first cost, TOC, band of equivalence (BOE), oversizing, and choice of winding material. The last two practices are the only ones not based on economics, but they play an important role in transformer purchase decision making for some end users.

3.4.1 First Cost

Purchases of transformers are often based on the first cost (without any consideration of long-term economics) when transformer evaluation and purchase decisions are not made by the end-user. This is particularly true where agents or electrical contractors make purchase decisions on the basis of temperature rise and low first cost for C&I end-users buying dry-type, pad-mounted transformers. These agents or contractors may have little incentive to take into consideration any economic factors other than the transformer's first cost. End-user concerns about higher first costs discourage OEMs and contractors from offering or recommending the more expensive, efficient options to customers who do not specifically request them. Transformer purchases are treated as capital expenditures for equipment with an expected life of 30–40 years;

however, lack of capital causes most small and midsized end-users to favor the short-term purchasing criteria (i.e., the first cost) with short payback periods (i.e., 1–3 years). In addition, these users are not always aware of, and in some cases are uncertain about, the costs and benefits of using energy-efficient transformers.

3.4.2 Total Life-Cycle Owning Cost

In recent years the increases in capital and operating costs for power plants, difficulties in siting new facilities, and concerns for the environment have forced utilities to evaluate energy efficiency. Both efficiency in generation and distribution and efficiency by utility customers (through DSM programs) have developed. Utilities invest in DSM programs to effect changes in their system load curve, typically improving load factor or reducing demand in order to avoid or to delay large investments in new generation facilities. Technical measures in some DSM programs include high-efficiency lighting, transformers, motors and cooling systems, or improved insulation and building envelopes. These concerns for energy efficiency have been translated by utilities into loss evaluations for their transformer and equipment purchases, expressed as dollars per kilowatt-hour saved. The higher the loss evaluation, the more the premium on minimizing energy losses. Recent developments such as deregulation of electric utilities will further boost the procurement of energy-efficient transformers. Deregulation will lead to vertical integration of the electric utility industry, and there will be more incentive than before to maintain system efficiency (particularly distribution and transmission) to be rate competitive. It tends to be a less attractive alternative for procurement of energy-efficient transformers for utilities when payback due to efficiency is a number of years in the future.

Since the early to mid-1980s, U.S. electric utilities have typically purchased distribution transformers using EEI's loss evaluation methodology to arrive at TOC[2] for comparing and selecting transformer bids from among suppliers (EEI 1981). TOC is a capitalized value, making the first cost of the transformer comparable to the lifetime energy costs. The "loss evaluation rates" (i.e., the rates that a utility is willing to pay per watt reduction in rated core and conductor losses) that are needed to calculate TOC are currently supplied by most electric utility purchasers after evaluating the specific application situation (e.g., duty cycle, cost of capital, and expected life). These loss values usually range from $2 to $4/W for core (no-load) losses and from $0.50 to $1.50/W for conductor (load) losses.

Most pole- and pad-mounted transformers are currently loss-evaluated, while almost no dry-type transformers are evaluated. In some cases, utilities also offer rebates to customers for undertaking loss evaluations and then monetary assistance to "buy down" a more expensive, more energy-efficient transformer where it meets utility savings criteria. For example, Bonneville Power Administration offers a one-time incentive of up to $0.15/kWh saved in the first year of operation to its utility and industrial customers (Howe 1993). Unfortunately, these programs rarely extend to the smaller distribution transformers that are common in C&I facilities. Thus, most commercial, institutional, and light-duty industrial end users, for whom a transformer purchase decision is more peripheral to their business than it is for a utility, do not use loss evaluations such as TOC, which require extensive analysis and the input of many variables.

Because of tightening in the availability of capital budgets these days, there is a growing trend even among utilities to use either some form of TOC (see Subsect. 3.4.3) or first-cost criteria for making liquid-filled transformer purchase decisions. The move away from the TOC purchasing criterion results in the selection of a less efficient transformer and hence reduces the energy conservation potential. A continuous improvement in the efficiency of liquid transformers (see Figs. 1.1 and 1.2) over the years could be attributed to a large extent to the use of the TOC purchasing criterion by utilities. Estimates of the potential energy that could be saved if distribution transformers were more efficient using the TOC approach are discussed in detail in Sect. 4.

3.4.3 Band of Equivalence

Many utilities using the TOC approach also apply a BOE in the selection process. This is used to compensate for uncertainties in loss evaluation factor assumptions, such as inflation, interest rates, and fuel costs, while making the final selection among transformer offerings from several suppliers. Since each capitalized present-value-dollar cost of losses is equal to a dollar of first cost in the TOC formula, BOE broadly considers all transformers within a band of TOC—typically 1 to 3% of the lowest TOC offering—as equal in TOC. The lowest price candidate is then selected as the winner from those within the band of "equivalent" TOC. The BOE practice is normally applied in one direction (i.e., to lower the efficiency), and hence it typically results in the selection of a less efficient transformer than would have been purchased if a rigid lowest TOC criterion were used. As results from each bid cycle provide a basis or reference for the next bid by each supplier, TOC and losses get compounded over time. The approach of selecting the lowest TOC transformer is known in the utility and transformer industries as a "hard evaluation" method of purchasing transformers. There is a need to develop a better method (other than BOE) to incorporate uncertainty into the TOC selection process. A minimum efficiency criterion may be one of the ways to promote purchases of more efficient transformers.

3.4.4 Oversizing

It is not yet a common practice in the industry (particularly in the C&I sector) to examine the estimated load and duty cycle of each transformer, the resulting I^2R conductor loss, and the impact of this loss on the cost of operation before purchasing transformers. Transformers are generally oversized in order to provide reliability under future anticipated loads, better motor performance, longer life, and lower load losses. A recent ORNL survey of local C&I establishments indicates their annual load factors to be in the 0.4–0.7 range (median around 0.59) for commercial users and 0.5–0.8 (median around 0.64) for industrial users.[3] Low-voltage transformers are comparatively underloaded at ~35%. A study by Williams, Duckett, and LaVallette (1990) also indicates that currently 33% of transformers are underloaded (having less than 60% of normal thermal capacity) because of low usage and that 85% of the underloaded transformers occur in C&I applications.

Annual operating costs of transformers depend on load losses and no-load losses, where load losses are a function of the percentage of time the transformers were operated at full load as well as at different loads during the year. Reducing the number of underloaded transformers would minimize a company's capital investment in transformers but not necessarily reduce losses due to improper loading. This can be accomplished by initially sizing the transformers correctly and by replacing grossly underloaded transformers with smaller units.

3.4.5 Choice of Winding Material (Aluminum vs Copper)

Some end users purchase transformers on the basis of type of winding material. Copper-wound transformers may be preferred over aluminum-wound ones because they are assumed to provide better efficiency and reliability. This may be due in part to (1) a perception relating to reliability problems in aluminum house wiring as well as (2) the observation that copper conductors have less resistance than aluminum conductors of the same cross section. In addition, most large utility power transformers have copper windings for mechanical reasons. While this issue was mentioned frequently in discussions with users during the informal ORNL survey, no data are available on its effect on actual transformer purchases.

As is discussed in Subsect. 2.2, the selection of conductor material for transformer windings is a part of all the other trade-offs that have to be balanced to achieve an acceptable transformer design. While it is true that copper has superior volumetric efficiency (per unit of cross section), aluminum, as a result of its lower density, is actually a superior conductor on a per pound basis. For instance, the manufacturer may take advantage of the volumetric efficiency of copper to use small copper conductors with more interwinding cooling area for air or oil flow. Such a copper transformer could have significantly poorer loss performance than a transformer of the same size using larger aluminum conductors sized not to require such large cooling ducts. It is thus not always true that a copper-wound transformer is more efficient than one with aluminum windings.

The Copper Development Association (CDA) has an ongoing electrical energy efficiency program to promote the use of copper in applications such as motors, transformers, cables, busbars, and ballasts (Black 1994). It supports the replacement of first-cost considerations with the total-cost concept among specifiers of electrical equipment and cable—based on the justification that larger-diameter wire (more copper per foot) in many applications can save enough energy via reduced heating (I^2R) losses to economically justify the extra initial cost. It is estimated that life-cycle-cost minimization will increase the existing nonutility transformer conductor weight by 300%, which could increase copper use by up to 30 million lb/year (Black 1994).

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NOTES

1. PCBs are nonflammable liquids once used as insulating fluids in transformers installed in buildings. No truly nonflammable liquid replacement for PCBs has been developed, and following the ban on the manufacture of PCBs, dry-type transformers were chosen increasingly for this market segment.

2. TOC is defined as the total of transformer first price plus cost of future transformer losses (i.e., core and conductor) discounted to present value.

3. Annual load factor = annual energy consumption (kWh)/[annual peak demand (kW) × 8760].

4. To determine the amount of load as a percentage of full load so that maximum efficiency can be obtained, the following equation is used:

$$(NLL/LL)^{1/2} = \%\ RL/100,$$

where NLL = no-load loss (watts), LL = load loss (watts), and RL = rated load (Morgan 1992).

4. ENERGY CONSERVATION ALTERNATIVES

4.1 OVERVIEW

Developed in this section are estimates of the potential energy that could be saved if distribution transformers were more efficient. First, the basis for designing a cost-effective transformer is discussed. Data from a survey of transformer manufacturers were used to define conservation cases based on maximum core and coil losses. Estimates of savings for each case are then given by comparing efficiencies for existing transformers with those that could be achieved using cost-effective designs.

4.2 MINIMUM TOTAL OWNING COST TRANSFORMER DESIGN CRITERION

Utilities typically evaluate new transformers through a loss formula. The loss formula indicates how a specific utility estimates the capitalized value of no-load and load losses for new transformers over the service life.[1] For instance, if values were \$3.00/W of rated no-load loss and \$1.00/W of rated load loss, then a transformer that had rated losses of 100 W (no-load) and 280 W (load), would have a capitalized value of losses for the entire study period of \$300 (no-load) and \$280 (load), or \$580 total. If it is assumed that the initial cost of a new transformer is \$500, then the TOC of the transformer over the 30-year study period would be \$1080 (i.e., \$580 + \$500). Therefore,

$$\mathrm{TOC} = \mathrm{NLL} \times \mathrm{A} + \mathrm{LL} \times \mathrm{B} + \mathrm{C} \ ,$$

where

TOC	=	total owning cost,
NLL	=	no-load loss in watts,
A	=	capitalized cost per rated watt of NLL (this is termed the A factor),
LL	=	load loss in watts at the transformer's rated load,
B	=	capitalized cost per rated watt of LL (this is termed the B factor),
C	=	the initial cost of the transformer including transportation, sales taxes, and other costs to prepare it for service.

The per watt of core loss value is typically called the A factor; the per watt of coil loss value, the B factor. While both A and B factors reflect the capitalized cost of losses, they differ in their rates for two main reasons. First, a watt of core loss represents a continuous loss that occurs whenever a transformer is energized, which is normally 100% of the time for most distribution transformers. This continuous loss of energy increases the cost per rated watt of core loss compared with a rated watt of coil loss, which occurs only while power is drawn through the transformer. The coil loss is roughly proportional to the square of the transformer load with the rated loss occurring at full load. Most transformers operate at less than full load for most of the time and may have extended operation, such as at night, at near zero load. The second reason for the difference in rates for the A and B factors is the cost of energy associated with the losses. Load losses are proportionally higher during peak periods when the per unit cost of producing electricity is relatively high.

In general, there are usually much higher cumulative energy losses per unit time associated with a rated watt of no-load loss, and this more than balances the usually higher rate of costs associated with load losses. As a rule of thumb, the capitalized value of no-load and load losses for utilities is often assumed to be \$3 and \$1/W respectively. The results of a recent survey of 90 large utilities indicated (1) an average no-load value of \$3.43 (A factor) with a standard deviation of \$1.84 and (2) an average load value (B factor) of \$1.09 (Powers 1994) with a standard deviation of \$0.90. Of the 90 utilities, 6 were publicly owned. The survey was for <100-kVA, single-phase, liquid-immersed transformers. Some utilities have different B factors for larger transformers; these B factors tend to be higher because they tend to serve customers that utilize transformers at higher capacity factors. In an ORNL study of transformer replacement policy, a national average A value of \$3.53 and a B value of \$1.44 were used (Barnes et al. 1995). For this study, two pairs of values were used to capture the effect of variations in transformer loads on the value of load losses. The value of losses for transformers <50 kVA was assumed to be \$3.50 for no-load and \$0.75 for load losses. The value of losses for 50 kVA and larger transformers was assumed to be \$3.50 per rated watt for no-load and \$2.25 per rated watt for load losses. (Appendix B presents the rationale for selecting these values.)

4.3 COST-EFFECTIVE TRANSFORMER DESIGNS

Much of the data on losses associated with cost-effective transformer designs used in this study are from a survey of transformer manufacturers, called the NEMA–ORNL survey, developed by ORNL and sent by NEMA to its members. Several non-NEMA manufacturers also submitted data. Utilities usually request that manufacturers submit bids for the lowest TOC transformer that they can design. Utilities specify the transformer features and their A and B factors. The NEMA–ORNL survey took this approach. It included what were believed to be the most common features that would be requested for each size and type of transformer. Transformer manufacturers were asked to submit the losses and price for the lowest TOC transformer they could design. The value of losses was determined by the A and B values presented above. Appendix C reproduces the questionnaire that was used in the survey. It requests that manufacturers reveal the transformer design that has the lowest TOC in terms of core losses, coil losses at rated load, and transformer price.

As is indicated in Appendix C, the survey requested losses and prices for three separate designs. The \$0/\$0 combination of A and B values is the design for a nonevaluated transformer. Most transformers that are purchased by nonutilities, including most dry-type transformers, are not evaluated. In the \$0/\$0 design, only the first cost is considered, and the price of the transformer is taken to be the TOC (i.e., the value of losses is not included in the purchase decision). Not considering the value of losses results in selecting transformer designs that have much higher life-cycle costs. This study considers conservation policies based on incorporating the value of losses into the transformer design and purchase decisions. A change in existing purchasing practices could result in saving both life-cycle costs and energy. Therefore, the \$0/\$0 design was requested in the survey to help establish a baseline efficiency.

The transformer types surveyed included six different liquid-immersed and six dry-type transformers. The liquid type included single-phase, 25- and 50-kVA pole-mounted transformers and a 50-kVA pad-mounted transformer. The other liquid-type, pad-mounted transformers were three-phase transformers of 150, 750, and 2000 kVA. The six dry-type transformers included 1- and 10-kVA single-phase sizes and 45-, 1500-, 2000-, and 2500-kVA three-phase sizes. Clearly, not all sizes and types of transformers are present in the survey. Appendix D discusses the method used to relate the limited number of sizes and types in the survey to the various types and sizes of transformers that are purchased.

The actual data for the survey results are proprietary and cannot be reported. There were 216 transformer designs submitted for 12 different types of transformers. Each type had at least three designs for each of the three A and B combinations. The liquid-immersed, 25-kVA pole, 50-kVA pole, and 50-kVA pad each had eight designs for each of the three A and B combinations.

4.4 FORMULATING ESTIMATES OF ENERGY SAVINGS

Six conservation cases have been developed (Table 4.1), and energy savings for these cases have been estimated. These cases are defined by transformers that meet maximum rated loss criteria. The energy losses (i.e., energy consumed by the transformers) for each conservation case were subtracted from energy losses for the base case to provide an estimate of savings. The base case defines energy use for existing transformer purchasing practices. The base case parameters are presented in Table 4.2.

4.4.1 Base Case

The limited number of transformers in the survey were selected to represent the range of typical types and sizes of transformers recently sold. Losses for the base case were estimated by the weighted average of losses for the evaluated and the nonevaluated designs from survey information. The percent of evaluated transformers was developed from information provided by transformer manufacturers. Appendix D provides the details on how this was done.

The base case nonevaluated transformers were assumed to have the average losses that were reported for the three lowest priced transformers for the \$0/\$0 evaluation in the NEMA–ORNL survey. It was assumed that the base case evaluated transformers have the same losses as transformers that have been recently purchased by utilities. These losses were calculated from the average no-load and load loss ratings reported in the EEI–ORNL survey. Appendix D details the approach used for making base case loss assumptions.

4.4.2 Conservation Cases

The conservation cases have been defined from the information reported in the NEMA–ORNL survey or additional information collected from transformer manufacturers. The NEMA–ORNL survey requested lowest TOC transformer designs for three pairs of A and B values. One pair of A and B values was \$0/\$0, indicating nonevaluated transformer designs. With

Table 4.1. Description of alternative cases

Case[a]	Basis of losses.
Base	Current purchasing practice
Low TOC	Losses from lowest TOC design
Median TOC	Losses from median TOC design
Average losses	Average losses of the three lowest TOC designs
High-efficiency	High-efficiency designs
2-year payback	Efficiency improvement that corresponds to approximately a 2-year payback of the increased capital investment

[a]All conservation cases are derived from transformer designs submitted to Oak Ridge National Laboratory by the National Electric Manufacturers Association or directly by manufacturers except the 2-year payback case that was provided by a transformer manufacturer. TOC—total owning cost.

Table 4.2. Base case transformer loss assumptions

Size (kVA)	Type	Rated NLL[a] (W)	Rated LL[a] (W)	Percent evaluated[b]	Effective capacity factor[c]
		Liquid			
25	Pole	62	333	85	0.2
50	Pole	106	549	85	0.5
50	Pad	104	569	85	0.5
150	Pad	320	1,702	85	0.5
750	Pad	1,061	6,267	85	0.5
2000	Pad	2,543	15,108	60	0.5
		Dry			
1	Small	24	83	1	0.2
10	Small	131	176	1	0.2
45	Lighting	375	1,792	1	0.2
1500	Epoxy cast	5,273	13,290	5	0.5
2000	Load center	6,383	22,362	15	0.5
2500	Epoxy cast	7,554	18,517	15	0.5

[a]NLL = no-load losses; LL = load losses.
[b]Assumed from discussions with industry sources.
[c]See Subsect. 2.3 for a definition of effective capacity factor.

the exception of the "2-year payback case," the conservation cases were defined from the survey responses for A/B values of $3.50/$2.25 and $3.50/$0.75. These two pair of A/B values were selected to represent national averages in valuing transformer losses (see Appendix B). This low TOC criterion ensures that the designs are cost-effective for the average end user.

The bases for the five conservation cases are listed in Table 4.1. These conservation cases define maximum load and no-load losses for all new transformers. To estimate total annual losses, the average transformer losses consistent with the maximum load and no-load loss values were multiplied by projected transformer sales. To estimate total savings, the energy losses associated with the conservation cases were subtracted from those for the base case.

The 2-year payback case was based on efficiency improvement that could be justified by recovering the additional capital cost of a more efficient transformer over approximately a 2-year time frame. This case was provided to ORNL by one transformer manufacturer; it should be recognized that similar cases developed by other manufacturers could result in different design efficiencies owing to differences in factors such as the base case assumptions and price. The rationale for this case is that it would appeal to end users that have a very short time horizon in which to recover any additional capital investment. This 2-year payback case does not recover all the energy savings that are economical. Rather, it skims off only the most profitable part of energy savings. For instance, this case would result in almost no savings for transformers that are purchased by utilities because most of the least efficient utility-purchased transformers have efficiencies that already meet this 2-year payback case. Table 4.3 compares the minimum efficiencies required by the 2-year payback case with the efficiencies reported in a survey of transformers that have been recently purchased by utilities. As Table 4.3 shows, these minimum efficiencies would affect very few utility purchasing practices. Also, they would have a minimal effect for those transformer purchases not meeting the minimum efficiency requirements for liquid-type transformers.

Table 4.3. Minimum efficiency for liquid-type transformers based on 2-year payback compared with efficiencies of recently purchased transformers

Transformer size (kVA), type, and number of phases	2-year payback efficiency[a] (%)	Average for observations with efficiencies below 2-year payback proposal[a] (%)	Observations in survey	Observations not meeting 2-year payback	Percent not meeting 2-year payback
10, pole, single-phase	98.40	98.33	38	4	11
15, pole, single-phase	98.50	98.43	33	3	9
25, pole, single-phase	98.70	98.67	54	3	6
37.5, pole, single-phase	98.80	NA	17	0	0
50, pole, single-phase	98.90	NA	52	0	0
50, pad, single-phase	98.90	98.66	51	2	4
75, pad, single-phase	99.00	98.83	36	2	6
167, pad, single-phase	99.20	99.15	39	6	15
225, pad, three-phase	99.00	98.84	28	1	4
500, pad, three-phase	99.20	99.07	50	7	14
1000, pad, three-phase	99.30	99.27	45	3	7

[a]All at 50% effective capacity factor.

The "low TOC case" is based on the design from the NEMA–ORNL survey with the lowest TOC for each type of transformer. The "median TOC case" is based on the design that represents the median TOC from submitted designs. Because the amorphous-core transformers had significantly different losses, they were excluded from selection for these two cases. The "average losses case" is based on averaging the losses for the designs with the three lowest TOCs, and if high-efficiency designs qualified as one of the three lowest TOCs, they were included in these averages. A final conservation case was defined as the "high-efficiency case." This case included the lowest TOC amorphous-core transformer for each transformer in the survey for which at least one high-efficiency design was submitted. No amorphous designs were submitted for the six dry-type transformers and for the 2000-kVA liquid-type transformer. For transformer categories where no amorphous-core designs were submitted, the most efficient of the nonamorphous designs was selected.

The present distribution transformer industry utilizes a number of competing technologies. Market forces play an important role in the determination of the technologies that are appropriate to achieve specific design goals. It is not the intent of this study to restrict transformer designs to a particular technology. The rationale for excluding the amorphous-core transformers in the low and median TOC options was to develop moderate high-efficiency cases that do not depend on a particular technology. For the A and B factors used to develop the low and median TOC cases, the amorphous-core designs submitted to ORNL tended to be TOC competitive. Therefore, if a national energy conservation policy was based on either the low or median TOC option, amorphous-core technology would not be excluded in the low TOC purchase decision process.

The average losses case may be more representative than the other cases for estimating energy savings for transformers purchased under a cost-effective criterion such as lowest TOC. This case represents in some measure the random nature of cost-effective transformer designs. In general, there can be significant divergence in losses and capital costs for equally cost-effective transformers. Because it incorporates several designs, the average losses case may be a better representation of the diversity in cost-effective designs than the other cases. It may be more representative of the real world than the cases that are based on selecting a single design. It should be reiterated that the transformer losses used to represent the average losses case do not represent the losses of a specific transformer design. Rather, they represent an average of the losses of the three lowest TOC transformers submitted for each category in the survey.

To understand the survey results in the context of cost-effectiveness, all the conservation cases based on the survey designs should be considered. The maximum loss values used to calculate energy consumption reflect specific designs for the low TOC case, the median TOC case, the 2-year payback case, and the high-efficiency case. In some instances the TOCs for the same type and size of transformer were not significantly different between cases. Therefore, energy loss differences among these cases define a range of conservation that is cost-effective. These cases present energy trade-offs that are similar to those that utilities face when they use the lowest TOC criterion to purchase transformers.

4.4.3 Calculating Savings

The approach used to estimate the potential annual energy savings in the first year of a conservation policy is described in this subsection. The focus is on calculating the energy consumed by transformers that would be sold in the first year of an energy conservation policy and comparing this with the energy consumed by the transformers that would be sold if an energy policy were not in effect (i.e., the base case). The energy savings is the difference in the energy consumed in these two cases. The average losses conservation case is considered here to demonstrate this approach. Tables 4.4 and 4.5 present analogous assumptions and calculations for the savings attributed to dry-type and liquid-immersed transformers respectively. Other cases were calculated in a similar manner, but their details are not presented because proprietary data would be revealed.

Column 1 in both Tables 4.4 and 4.5 indicates the type and size of transformers for which information was collected by the NEMA–ORNL survey. Although many more sizes and types of liquid- and dry-type transformers are sold annually, the data collected in the survey were limited to these twelve transformer sizes and types to reduce the burden on the transformer manufacturers participating in the survey.

The percentages used in col. 2 were arrived at by reviewing actual and estimated data from various information sources including a proprietary NEMA survey, individual manufacturers, and the EEI–ORNL survey of investor-owned utilities. One problem in making these distributions is that sales data for many of the specific transformer sizes is not available. For example, the proprietary sales data from the NEMA survey does not have sales separated out for many of the specific transformer sizes but rather reports sales data for ranges of transformer sizes. Therefore, the transformer sizes, and percentages, in Tables 4.4 and 4.5 actually represent ranges of transformers (see Appendix D). The projected annual transformer sales (in megavolt-amperes) presented in col. 3 were calculated by multiplying the percentages in col. 2 by the total projected sales of transformer capacity in 2000 (i.e., 33,682 MVA dry-type and 70,087 MVA liquid-immersed). This convention was used solely to facilitate calculation of energy losses and should not be interpreted as a projection of the sales for specific types and sizes of transformers. (*Note*: In Appendix D a subset of transformers was used in an exercise to compare the approach described here with using detailed sales and loss data; this approach resulted in a close approximation of the calculations using detailed data.)

In Table 4.4 the energy savings for dry-type transformers were adjusted to correct for temperature effects. The transformer load losses (col. 5) are transformer design losses at full load.

Table 4.4. Calculation of the first-year savings for dry-type transformers in 2000 for the average losses conservation case

Survey transformers by size[a] (kVA)	Annual sales allocated to survey transformers[b] (%)	Projected sales in 2000 (MVA)	Rated no-load losses[c] (W)	Rated load losses[c] (W)	Adjustment factor for full load temperature rise (fraction)	Rated load losses adj. for temp. rise[c,d] (W)	Effective capacity factor (fraction)	Calculated average energy loss per unit (kWh)	Average energy loss per kVA (kWh)	Estimate of energy consumed (billion kWh)	Estimate of energy savings (billion kWh)
					Base case dry-type transformer						
1	2.1	707	23.9	83.3	0.649	54.1	0.2	228.3	228.3	0.1615	*e*
10	2.1	707	133.2	175.9	0.649	114.2	0.2	1,206.6	120.7	0.0853	
45	49.5	16,668	374.8	1,791.9	0.649	1,163.0	0.2	3,690.9	82.0	1.3671	
1500	4.4	1,469	5,272.7	13,290.4	0.835	11,097.5	0.5	70,492.8	47.0	0.0690	
2000	37.6	12,661	6,382.6	22,362.5	0.835	18,672.7	0.5	96,804.6	48.4	0.6128	
2500	4.4	1,469	7,553.8	18,517.0	0.835	15,461.7	0.5	100,031.9	40.0	0.0588	
					Average losses conservation case dry-type						
1	2.1	707	14.3	45.7	0.649	29.7	0.2	136.0	136.0	0.0962	0.0653
10	2.1	707	51.0	136.3	0.649	88.5	0.2	477.8	47.8	0.0338	0.0516
45	49.5	16,668	191.7	1,323.7	0.649	859.1	0.2	1,980.0	44.0	0.7334	0.6337
1500	4.4	1,469	3,551.7	8,675.0	0.835	7,243.6	0.5	46,976.4	31.3	0.0460	0.0230
2000	37.6	12,661	3,375.0	12,050.0	0.835	10,061.8	0.5	51,600.2	25.8	0.3267	0.2862
2500	4.4	1,469	5,591.7	12,750.0	0.835	10,646.3	0.5	72,298.0	28.9	0.0425	0.0163
Total savings											1.0761

[a]Survey data are from the National Electric Manufacturers Association–Oak Ridge National Laboratory survey of transformer manufacturers.
[b]Transformer allocations are separate for liquid- and dry-type. The total projected sales of dry-type transformers in 2000 is 33,682 MVA.
[c]Results from transformer surveys.
[d]All dry-type transformer load losses are reduced by 0.649 for transformers below 50 kVA and 0.835 for transformers above 50 kVA to adjust for temperature rise at less than full capacity.
[e]Savings are calculated relative to the base case.

Table 4.5. Calculation of the first-year savings for liquid-type transformers in 2000 for the average losses conservation case

Transformer size (kVA)	Total sales (%)	Annual sales[a] (MVA)	NLL at full load[b] (W)	LL at full load[b] (W)	Adj. factor for full load temp. rise (fraction)	LL adjusted for temp. rise[b,c] (W)	Effective load (fraction)	Annual energy losses (kWh)	Annual loss per kVA (kWh)	Annual loss (billion kWh)	Unadjusted savings (billion kWh)	Adj. factor for existing efficiency[d] (fraction)	Adjusted savings (billion kWh)
25	23.5	16,469	61.8	333.3	0.806	268.6	0.2	635.6	25.4	0.4187			*e*
50	17.0	11,926	105.8	549.4	0.859	471.9	0.5	1,959.9	39.2	0.4675			
50	17.5	12,252	103.7	569.4	0.859	489.1	0.5	1,979.5	39.6	0.4851			
150	6.1	4,309	320.1	1,701.8	0.859	1,461.9	0.5	6,006.0	40.0	0.1725			
750	16.8	11,749	1,060.9	6,266.7	0.859	5,383.1	0.5	21,082.2	28.1	0.3303			
2000	19.1	13,381	2,543.1	15,108.5	0.859	12,978.2	0.5	50,699.9	25.3	0.3392			
25	23.5	16,469	40.3	312.0	0.806	251.5	0.2	441.1	17.6	0.2906	0.1281	1.09	0.1396
50	17.0	11,926	128.7	327.0	0.859	280.9	0.5	1,742.6	34.9	0.4156	0.0518	1.16	0.0601
50	17.5	12,252	113.7	331.7	0.859	284.9	0.5	1,620.0	32.4	0.3970	0.0881	1.16	0.1022
150	6.1	4,309	293.0	1,006.3	0.859	864.4	0.5	4,459.7	29.7	0.1281	0.0444	1.16	0.0515
750	16.8	11,749	1,082.0	4,810.0	0.859	4,131.8	0.5	18,526.9	24.7	0.2902	0.0400	1.16	0.0464
2000	19.1	13,381	2,577.0	11,108.3	0.859	9,542.0	0.5	43,471.6	21.7	0.2909	0.0484	1.16	0.0561
Total savings													0.4560

[a]Transformer allocations are separate for liquid- and dry-type. The total projected sales of liquid-type transformers in 2000 is 70,087 MVA.
[b]NLL = no-load loss; LL = load loss. Results from transformer surveys.
[c]All liquid-type transformer load losses are reduced by 0.806 for transformers below 50 kVA and 0.859 for transformers 50 kVA and above to adjust for temperature rise at less than full capacity.
[d]Savings for liquid-type transformers were adjusted by 1.09 for transformers below 50 kVA and 1.16 for transformers 50 kVA and above to account for existing transformers that have lower losses than this conservation case. (See Appendix D for an explanation of how this adjustment was assumed.)
[e]Savings are calculated relative to the base case.

Assuming effective capacity factors (col. 8) that reflect less than full load operation, load losses are adjusted downward (col. 7) by factors (col. 6) that account for reduced operating temperatures. The energy loss per unit in col. 9 was calculated as the no-load loss times 8760 (hours per years) divided by 1000 (watts per kilowatt) added to the load losses adjusted for temperature rise (col. 7) times the effective capacity factor squared times 8760 (hours per year) divided by 1000 (watts per kilowatt). The energy loss per kilovolt-ampere in col. 10 is the per unit losses in col. 9 divided by the kilovolt-ampere per unit in col. 1. The energy consumption allocated to each size and type of transformer (col. 11) is the energy losses per kilovolt-ampere (col. 10) times the projected megavolt-amperage in col. 3 times 1000 (kilovolt-amperes per megavolt ampere). The energy consumption allocated by survey transformer size for the average losses conservation case (col. 11) was subtracted from the corresponding consumption for the base case to arrive at the energy savings in col. 12. The total energy savings for dry-type transformers was estimated to be 1.076 billion kWh (0.01076 quad of primary energy) in 2000, assuming that 10,000 Btu of primary fuel is used to produce 1 kWh of electricity.

The same calculations were performed for liquid-type transformers in Table 4.5 with one additional adjustment. The energy consumed for each category of transformer in the average losses conservation case in col. 11 is subtracted from the corresponding energy consumed in the base case to arrive at the unadjusted energy savings (col. 12). The unadjusted energy savings were multiplied by an adjustment factor (col. 13) to account for transformers that already have lower losses than the maximum loss criteria that defines this conservation case (see Appendix D for an explanation of how the adjustment factor was derived). This adjustment was not necessary for dry-type transformers because they generally have losses higher than those assumed in the conservation cases. The total adjusted energy savings for liquid-immersed transformers is 0.456 billion kWh in 2000 (0.00456 quad of primary energy), assuming it requires 10,000 Btu of primary fuel to produce 1 kWh of electricity. Adding the savings for both liquid- and dry-type transformers gives a total savings of 1.5321 billion kWh (0.01532 quad). These savings are for 1 year for transformers purchased in the first year of a conservation policy. Savings would rapidly accumulate as these transformers were utilized in subsequent years and as additional transformers with the improved efficiencies associated with the conservation policy began to contribute to the savings in subsequent years.

4.5 ESTIMATED SAVINGS

Table 4.6 and Figs. 4.1 and 4.2 present estimates of the rate of potential energy savings per kilovolt-ampere of annual purchases and the contribution to the total rate of savings for each of the types of transformers surveyed. Savings rates per kilovolt-ampere differ significantly from one type of transformer to another and from one conservation case to another. The variation across types of transformers may be attributed to several factors. For instance, focusing on the average losses case, dry-type transformers generally have higher potential savings per kilovolt-ampere than liquid-type transformers. This reflects the fact that a significantly higher proportion of liquid-type transformers are evaluated and therefore have higher efficiencies. Therefore, liquid-type transformers have less potential for improvement in meeting the average losses case efficiencies. Also, the smaller dry-type transformers have much higher potential savings than larger units. This may indicate that purchasers and/or manufacturers are less sensitive to efficiency when transformers are used for small applications.

For some conservation cases the 25- and 150-kVA liquid-type transformer designs had lower conservation case efficiencies than for the base case. This may indicate that, for this particular size and type of transformer, the survey was not representative. One explanation is that, by

Table 4.6. Rate of annual energy savings for the surveyed transformers (kWh/kVA)

Transformer type and size (kVA)	Lowest TOC	Median TOC	Average losses	High-efficiency	2-year payback
Liquid					
25	4	0	8	15	1
50, pole	4	5	5	20	1
50, pad	9	5	8	21	2
150	4	0	12	20	2
750	7	2	4	13	2
2000	5	6	4	5	3
Dry					
1	113	106	92	113	NA
10	69	86	73	86	NA
45	52	26	38	52	33
1500	16	15	16	17	13
2000	27	17	23	27	17
2500	12	9	11	12	10

TOC = total owning cost; NA = not estimated.

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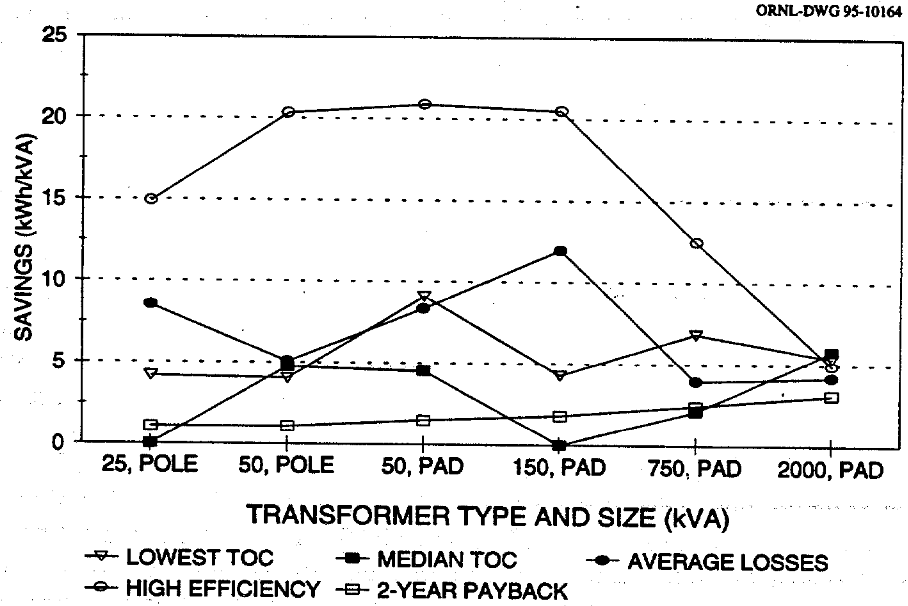

Fig. 4.1. Estimated normalized annual savings for liquid-type transformers by size and type for alternative conservation cases. TOC = total owning cost.

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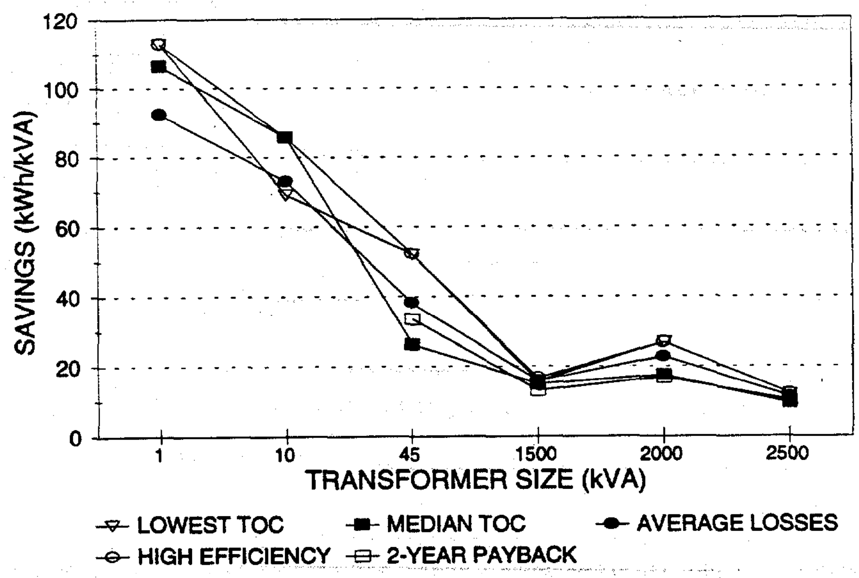

Fig. 4.2. Estimated normalized annual savings for dry-type transformers by size and type for alternative conservation cases. *Note:* The 2-year payback case has not been estimated for 1 and 10 kVA. TOC = total owning cost.

coincidence, the designs that were submitted were relatively low-price, low-efficiency transformers. For the conservation cases where efficiencies were below the base case, no savings have been attributed to the portion of annual sales represented by this size and type of transformer.

The variation in savings from case to case for the same type and size of transformer reflects the fact that the designs submitted in the survey varied significantly in terms of their losses. The lowest TOC transformers did not always correspond to the lowest loss transformers because the price of a transformer often exceeds 50% of the TOC; therefore, a lower transformer price can compensate for higher losses. One interpretation of these variations in losses is that they stem from differences in manufacturing processes, which may result in significantly different losses for transformers that are competitive in terms of their TOCs. This is particularly true for transformers that use energy-efficient but expensive core material. For instance, the amorphous-core transformers have significantly higher prices but can be competitive on the basis of TOC because they have significantly lower losses. A practical consideration is that, if possible, a conservation policy should have the flexibility to reflect levels of losses and combinations of no-load and load losses for which most manufacturers can achieve their most competitive TOC transformers.

An estimated fraction of the total megavolt-ampere of annual sales was assigned to each size and type of transformer in the NEMA–ORNL survey so that the total fraction of sales represented was 1.0 (see Appendix D). This results in a given type and size of transformer from the survey representing a range of similar sizes of actual transformer sales. Ideally, a more disaggregated approach in which one survey size and type would represent the sales of the same size and type should have been used. However, this would have imposed a much heavier burden on the survey respondents and would have resulted in limited responses from manufacturers. Also, annual sales data is aggregated into wide ranges, and this limits the possibility of disaggregated analysis.

Figure 4.3 gives a comparison of the relative contribution to savings by type and size of all transformers in the NEMA–ORNL survey, weighted by sales. The transformers under 10 kVA represent ~7% of the total savings. Therefore, if only transformers of 10 kVA and higher are

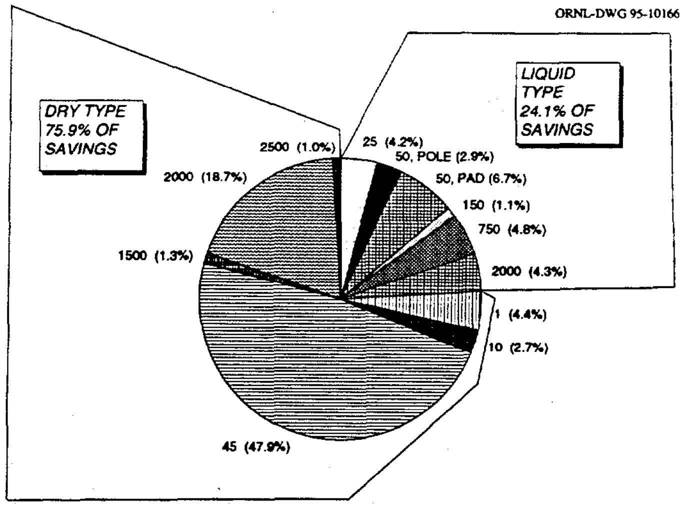

Fig. 4.3. Relative contribution to energy savings by type and size (in kilovolt-amperes) of transformer for the lowest total-owning-cost conservation case. *Note:* Numbers in parentheses are the percent of total savings.

considered, this would include ~93% of the total annual savings and cumulative savings that have been estimated in this study (see below).

The savings per kilovolt-ampere (Table 4.6) and the projections of estimated megavolt-amperage of transformer sales (Fig. 4.4) have been used to estimate the rate of savings in the first year of the policy and the cumulative savings over 30 years (Table 4.7). Figure 4.5 shows the growth in cumulative savings from 2000 to 2030. Utility transformer capacity is expected to grow at an annual rate of 1.0%. Nonutility transformer capacity is expected to grow 2.5% annually (see Table 3.1). It was assumed that 89% of liquid-type transformer capacity was owned by utilities. All dry-type transformers were assumed to be owned by nonutilities. The savings would tend to accumulate over the life of the transformers. Annual savings would tend to increase as the savings attributed to successive transformers that were purchased under the conservation policy accumulated. Thirty years was used to calculate the cumulative savings although savings would continue to increase as long as the conservation policy was effective in improving new transformer efficiency beyond what it would be without a national policy.

Several commenters on the draft of this report indicated that assumptions used to estimate the annual rate of energy savings and the cumulative energy savings were not appropriate. In particular they indicated that the assumed growth rate of dry-type transformers was too high and that the evaluation of load losses was too high. These assumptions have not been changed for the cases that have been presented in this study; however, because there is uncertainty in these assumptions, a sensitivity analysis was done to determine the effect of alternative assumptions.

Some transformer manufacturers believe that the sale of commercial and industrial transformers will grow at a much lower rate than the 2.5% compound annual rate that has been projected in this study. To determine the sensitivity of cumulative savings to a lower growth rate, it was assumed that these sales grew at an annual rate of only 1%, the same rate as that assumed for sales of utility transformers. This resulted in a reduction of cumulative savings for 30 years of from 18 to 30% depending on the case. Figure 4.6 portrays this for the average losses case and the 2-year payback case. If the annual growth rate is zero, the cumulative savings is reduced further by about 14%. For this case, the savings for all of the conservation options considered in this report range from 3.6 to 7.1 quads.

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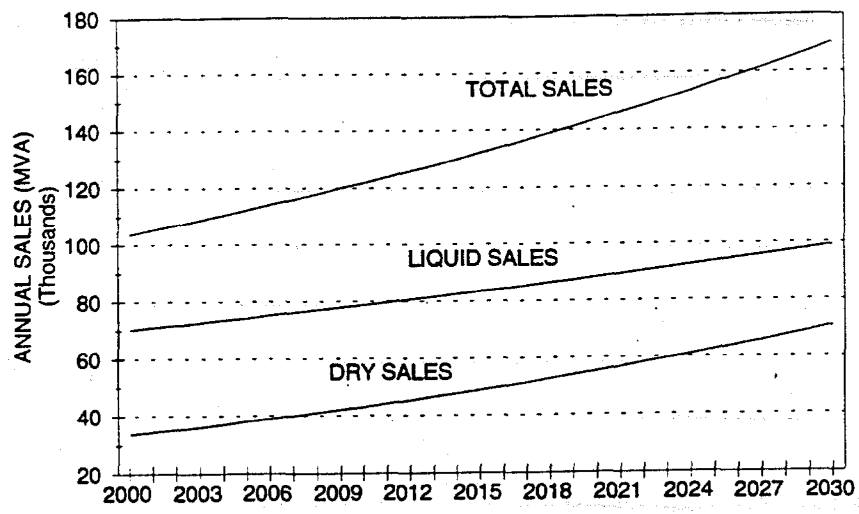

Fig. 4.4. Projected sales of distribution transformers.

Table 4.7. Estimated savings for alternative cases

Conservation cases (by transformer type)	Annual savings rate in 2000 (quads)	Cumulative savings 2000–2030 (quads)
Lowest TOC[a]		
Liquid	0.0040	2.1
Dry	0.0138	8.3
Total	0.0178	10.4
Median TOC		
Liquid	0.0021	1.1
Dry	0.0083	5.0
Total	0.0104	6.1
Average losses		
Liquid	0.0046	2.4
Dry	0.0108	6.5
Total	0.0154	8.9
High-efficiency		
Liquid	0.0104	5.4
Dry	0.0139	8.3
Total	0.0243	13.7
2-year payback		
Liquid	0.0006	0.4
Dry	0.0080	4.8
Total	0.0086	5.2

[a]TOC = total owning cost.

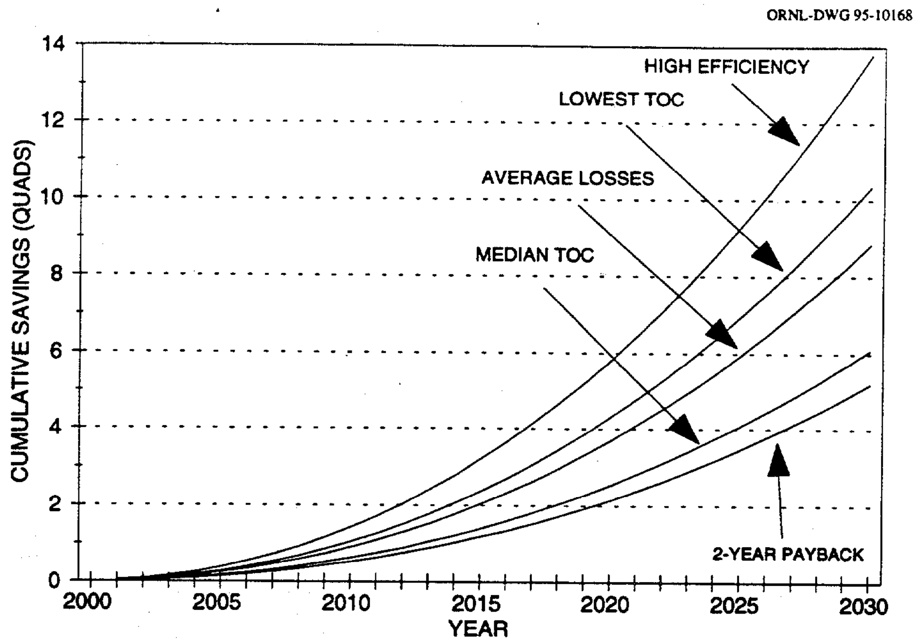

Fig. 4.5. Cumulative quads (10^{15} Btu) of primary energy savings from 2000 to 2030 for alternative conservation cases. TOC = total owning cost.

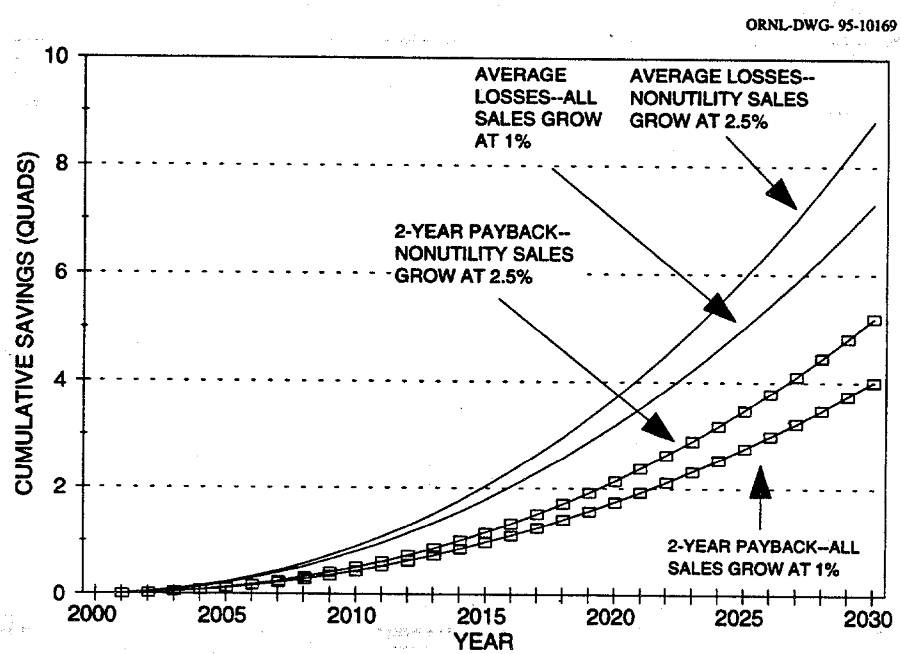

Fig. 4.6. Sensitivity of cumulative energy savings for reducing the annual growth rate of dry-type sales to 1.0% for the average losses case and the 2-year payback case.

Several comments indicated that the $2.25/W evaluation of load losses for transformers 50 kVA and over was too high. Also one comment held that an effective capacity factor of 0.5 (assumed for transformers 50 kVA and up) was too high. To test the sensitivity of conservation cases to these variables, all designs were selected based on evaluations from the survey at $0.75/W of load loss. Under this assumption, transformer designs had significantly higher load losses but somewhat lower no-load losses. At the same time, load losses for all transformers were calculated for a 0.2 effective capacity factor, which is more consistent with a $0.75 B factor. This resulted in the designs selected to represent the conservation cases having significantly higher rated load losses but somewhat lower no-load losses. The calculation of load losses for both the conservation cases and the base case was significantly reduced because of calculating load losses at 0.2 effective capacity factor for all transformer sizes. Figure 4.7 compares the energy savings with sensitivity cases for the lowest TOC case, average losses case, and high-efficiency case. As a result of the changes in assumptions, there was a 25% reduction in savings for the lowest TOC case, a 15% reduction for the average losses case, and a 16% reduction for the high-efficiency case.

The combination of lower growth for commercial and industrial transformers, a lower evaluation of load losses, and calculating losses using an effective capacity factor of 0.2 for all sizes would reduce the cumulative savings for the low TOC case by ~42%.

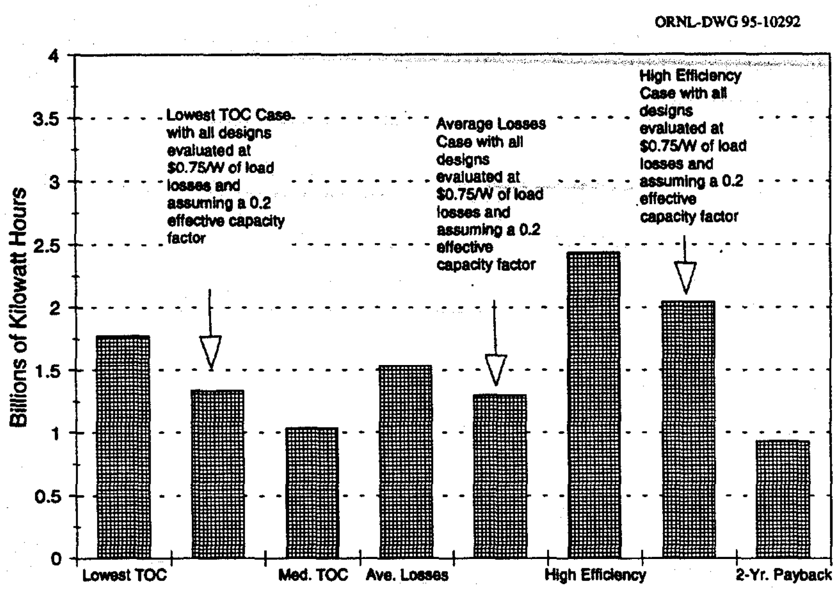

Fig. 4.7. Sensitivity of savings to the $0.75/W load loss evaluation and 0.2 effective capacity factor.

4.6 ENERGY SAVINGS AND ECONOMIC ATTRACTIVENESS

Table 4.7 indicates that energy savings vary significantly among the alternative conservation cases. To some extent this reflects variations in transformer designs. However, the lower savings attributed to the 2-year payback case result from a high rate of return on investment criterion that leads to reduced end user investment and, therefore, reduced energy savings.

A perspective on the significance of energy savings is presented in Fig. 4.8, which indicates the equivalent amount of baseload electric capacity that would have to be constructed annually to

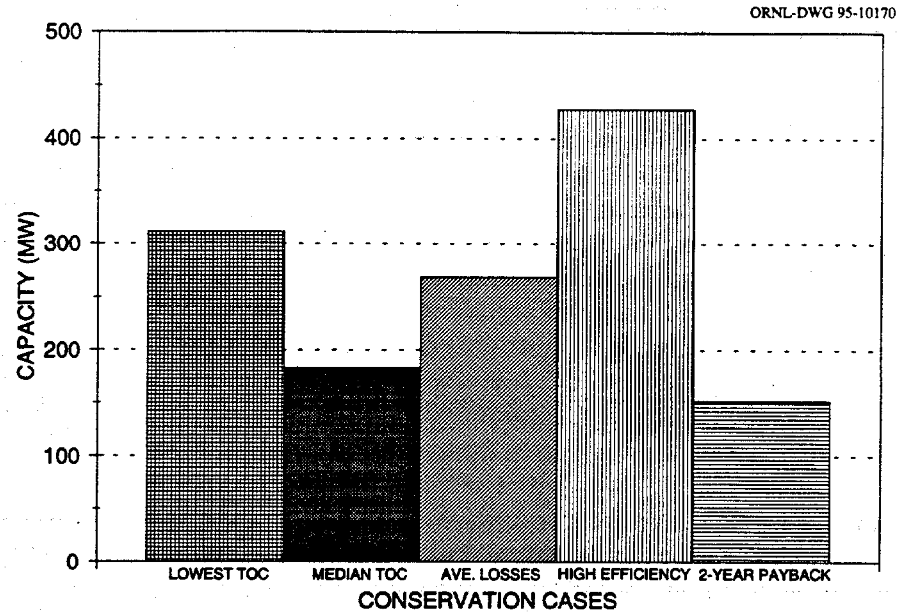

Fig. 4.8. Megawatts of generating capacity needed to produce the equivalent annual energy saved for the first year of the alternative conservation policies. (*Note:* This same amount of capacity, increasing at an annual compound rate of 1.6%, would have to be added every year to continue to provide the energy equivalent to the energy saved.) TOC = total owning cost.

supply the energy savings for the alternative conservation cases. The annual energy savings would reduce the increase in annual electric energy requirements projected by the North American Electric Reliability Council (NERC 1994) by from 1.5% to 4% depending on the case. For the low TOC case, the annual energy savings would be equivalent to constructing a large coal-fired power plant about every 2 years.

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NOTE

1. The TOC is a capitalized value making the first cost of the transformer comparable to the lifetime energy costs. The life-cycle costs reflect the discounted lifetime costs of the transformer, where capital costs reflect interest and depreciation plus other costs associated with the transformer's initial cost. The capitalized values can be converted to the equivalent discounted present values of the life-cycle costs by multiplying by the ratio of the fixed charge rate over the capital recovery factor.

5. IMPACTS ON MANUFACTURERS AND USERS

5.1 MANUFACTURERS

Energy-efficient transformers will typically have a higher initial cost because either more or higher-performance material is necessary for manufacturing them (discussed in detail previously). Manufacturers will be impacted because of (1) the higher variable material costs of core and conductor, (2) new product designs requiring additional investments for retooling and new capital equipment, (3) changes in labor content or assembly practices requiring retraining, and (4) the effects on revenue caused by higher product selling prices. Raw materials suppliers will also be affected. In general, impacts will be considerably more for the make-to-stock/shelf, high-volume, price-competitive transformer manufacturers than the make-to-order manufacturers of larger transformers.

5.1.1 The Silicon-Core Material Market

In addition to foreign electrical steel imports into the United States, there are only two domestic manufacturers of cold-rolled, grain-oriented silicon steel used as the core material in distribution transformers: Armco Inc. and Allegheny Ludlum Corporation, each of which has an almost equal share of the market. The five main grades of silicon steels used (in the increasing order of losses) are M2, M3, M4, M5, and M6. Differences among these steels are mainly due to final gauge (in the increasing order of thickness in the range of 7 to 14 mils respectively), although some differences in composition and processing may exist. Grades M5 and M6 are widely used by European transformer manufacturers, while the remaining three grades (i.e., M2, M3, and M4) are typically used in low-loss evaluated transformers by domestic transformer manufacturers. The M6 grade, particularly low-cost imported steel from the former Eastern Bloc countries, is used by domestic transformer manufacturers in non-loss-evaluated and very low “A” factor transformers. The use of such imported low-price M6 steel has been significantly increasing over the last year and a half.

Improving the efficiency of distribution transformers will shift the demand for the steel quality (i.e., from M6 to M2 and M3 grades), reducing the dependency on the imported M6 grade. Currently, the annual production level of grain-oriented silicon steel is estimated to be ~900 million lb at ~80% of full production capability (assuming that the capacity utilization rate of electrical steel is similar to that of the cold-finishing steel industry) (DOC 1994a). The increased amount of core material demanded by the improved efficiency of distribution transformers may be significant. For example, it is estimated that improving the efficiency of dry-type transformers from 96 to 97% will likely require an additional 15–25% of core materials (McConnell 1995). However, for a 1% increase in the energy efficiency improvements of all types of distribution transformers (which is less likely in the case of liquid-filled transformers whose megavolt-amperes account for ~2/3 of the total megavolt-amperes), the current industry capacity utilization rate would increase to 100% maximum. Additional significant grain-oriented silicon steel production capacity is thus unlikely to be necessary in addition to the production capacity available from (1) the shifting of production capacity from ordinary stainless steel to electrical core steel (and M4 and M6 grades to M2 and M3 grades of electrical steel) and (2) an increase of the current capacity utilization rate.

5.1.2 The Amorphous-Core Material Market

Today, almost 85% of the total annual market of 100,000 units of amorphous-core transformers is held by General Electric Company (GE). The other manufacturers, Howard Industries, ABB Power T&D Company, and Cooper Power Systems Division, have a significantly smaller market share. If a shift to amorphous-core transformers occurred, the impacts on existing transformer manufacturers would depend on (1) the ease of access to the technology, (2) the availability of amorphous-core material, (3) the level of necessary investments, and (4) the higher transformer selling price.

Although amorphous alloy strip may be less process intensive (i.e., manufacturing involves a smaller number of steps) than oriented silicon steel, the lack of access to the technology is feared to be a problem. EPRI, GE, and Allied Signal Amorphous Metals hold most of the U.S. patents for amorphous-metal and amorphous-core technology. The EPRI patents are available under licensing terms and conditions to U.S. manufacturers. By 1997 an important patent on amorphous ribbon manufacturing held solely by Allied Signal Amorphous Metals will expire. However, a critical patent on magnetic field annealing used during transformer core manufacturing is held by GE and will not expire until early in the next century. At present, GE has licensed Allied Signal Amorphous Metals to sublicense transformer manufacturers to use this patent.

Currently, Allied Signal Amorphous Metals is the largest and may be the only supplier of wound amorphous-core materials in the United States and possibly the world. It built a 20,000-T/year production plant in South Carolina several years ago. The plant is currently producing less than 15,000 T/year. Allied Signal Amorphous Metals has reported plans to expand the capacity to 60,000 T/year; this tonnage would represent ~50% of the current silicon electrical steel tonnage consumed each year for liquid-type distribution transformers in the United States. Availability of production capacity limited to a single producer and a higher cost of the ferro-boron ingredient used in raw materials raise the concern for amorphous-core raw material availability. Because the quantity as well as the cost of raw materials in this case is higher than that of the oriented silicon steel, the price of these transformers typically ranges from 20 to 40% higher than those made of silicon steel.

The cost of raw materials for amorphous-core transformers is twice that of the oriented silicon steel. The higher cost of these materials is due to the use of ferro-boron, the bulk of which is imported now. The cost of these materials has gone down during the past two decades (from $140/lb in 1978 to about $1.50/lb now) and may continue to do so as their applications increase, but the market will be finally determined by the user willingness to pay a price premium in order to have lower energy losses over the useful transformer lifetime. Most amorphous-core transformers are currently bought by municipalities and rural electrification authorities who need to buy private power and thus have a higher capitalized value of no-load losses of $4 or more per watt (Powers 1995). The continued evaluation of losses by utilities, together with the reduction in cost brought about by the availability of amorphous-core technology to other manufacturers in the next decade, would help in justifying a premium payment for the most efficient design offered by amorphous-core transformers.

5.1.3 The Copper and Aluminum Industries

It is estimated that currently ~57 and 25 million lb of copper is used annually for liquid-immersed and dry-type distribution transformers respectively (Black 1994). The corresponding numbers for aluminum are 41 and 28 million lb. CDA, under its Electrical Energy Efficiency Program, estimates an additional consumption of 34 million lb of copper (i.e., 19 million lb for liquid-immersed and 15 million lb for dry-type transformers) if energy efficiency improvements for distribution transformers were accomplished by the use of copper alone (Black 1994). Total copper shipments of insulated magnet wire in 1993 are estimated to be 568 million lb (an additional 64 million lb for uninsulated products) where major shipments for the transformer industry are limited to fewer than ten manufacturers (DOC 1994b). At present, the copper magnet wire industry is operating at about 80% of its full production capability (DOC 1994a). An additional demand of 34 million lb of copper due to energy-efficient transformers would increase the capacity utilization level of the magnet wire industry from the current level of 80 to 84%.

The use of aluminum alone for energy efficiency improvements for distribution transformers would be half that estimated for copper (i.e., 17 million lb) since aluminum is a two-fold better conductor than copper on an equal weight basis. Currently, there are 19 manufacturers of insulated aluminum magnet wire (of which 3—Phelps Dodge Magnet Wire Company, Essex Corporation, and Rea Magnet Wire Company—are major producers of copper magnet wire as well); annual shipments are ~47 million lb (DOC 1994b). Most shipments for transformers come from the uninsulated aluminum magnet wire industry for economic reasons; most transformer manufacturers insulate on their own, getting the raw material from metal production companies such as Alcoa and Reynolds Metals Company. The nonferrous rolling and drawing industry, currently operating at 80% of its full production capability, must reflect a significant increase in output (one that may not be readily seen when measured in percentage terms of the increased total industry's output) to satisfy the surge in a demand level of 17 million lb (or a 25% increase from the current level) even if energy efficiency improvements were achieved by the use of aluminum alone. The increased demand will most likely be felt by the uninsulated aluminum magnet wire industry. In addition, because the demand for both aluminum and copper magnet wires is currently met by the domestic industry, less vulnerability exists in the supply of magnet wires.

5.1.4 Distribution Transformer Manufacturers

Energy-efficient transformers will be more expensive (i.e., higher first cost) compared with conventional, less-efficient transformers because of higher material costs. The material cost of transformers is typically 50% of the selling price (also note that dry-type transformers are 30% more expensive than liquid-immersed for a given transformer rating). Of the total material cost, the core material cost contributes 50%; conductor and insulation material costs contribute the remaining 30% and 20% respectively (Patterson 1994). The difference in the costs among the various grades of steel used as the core material are substantial—$0.30–0.40/lb between M2 and M6 grades (the cost of M6 grade steel is $0.70/lb). The cost of efficient transformers will increase not only because of higher raw material costs but also, to a lesser extent, because of the lamination requirements of more efficient steels. (M2 grade steel requires more laminations because it is thinner than M6 grade steel—0.007 in. compared with 0.014 in.) For a 1000-kVA ventilated dry-type transformer with a core weighing around 3500 lb, the changeover from the M6 grade to the M2 grade core material will increase the cost of production by at least $1050–$1400 (the current selling price of such a transformer using the M6 grade steel is around $20,000).

The effect of higher product selling prices on manufacturers' revenues will depend on how much of the cost increases caused by design changes can be passed through to consumers. If less than the actual higher production costs are passed through, profits will suffer, while a pass-through above the increase in production costs will increase profits. A manufacturer's production costs will be determined to a large extent by the additional investments necessary and the costs of input materials. If a manufacturer's marginal cost of production is higher than the industry's, a reduction will occur in levels of demand and, hence, its revenues. It appears that the additional investment necessary for cost-effective conservation may not be large since it will not necessarily entail the use of a new, different technology. Moreover, an increase in the marginal cost of production and additional investments, if necessary, will affect all manufacturers in the industry similarly, minimizing the danger of customer switching. The transformer industry is dominated by a few major manufacturers (particularly true in the case of liquid-immersed transformers); thus, the industry is characterized by an oligopoly market structure where each firm faces a demand curve of finite elasticity. Consequently, a small increase in price will not result in a complete loss of sales due to induced entry of competitors, as it would under perfect competition.

More data and analysis are necessary to determine the actual impacts of conservation on manufacturers. A cursory examination of the industry suggests that manufacturers of liquid-immersed transformers will experience comparatively fewer impacts than manufacturers of dry-type transformers because more than 90% of the former market is currently loss-evaluated. Note also that the number of manufacturers in the latter case is a lot higher comparatively than the former case. Liquid-immersed manufacturers generally have a high-volume and price-competitive market requiring a high level of investments. Manufacturers of dry-type transformers are more volatile in nature because they are less capital intensive, serving numerous niche markets.

5.2 USERS

Energy conservation impacts on users will be mainly due to the higher cost of efficient transformers. The higher initial cost of efficient transformers means that more financial resources will be needed initially, but users will recover that additional investment through savings from reduced energy losses over the life of transformers. User impacts are not estimated for the conservation options considered here owing to lack of sufficient information. For illustrative purposes, the data from the 1994 NEMA survey of manufacturers have been used to show the likely user impacts of a 25-kVA, pole-type, liquid-filled transformer. The data include a range of designs where the ranges of A and B factors considered to determine the value of losses are $0.0–6.0 and $0.0–3.0 respectively. The $0/$0 combination of A and B values is used as the base case design for the analysis here. Note that the analysis presented here may not reflect the reality in certain cases: because of averaging, there is no one-to-one correspondence between the base case and the loss-evaluated case in the data provided.

Figure 5.1 shows the effect on the initial cost of a 25-kVA, pole-type, liquid-filled transformer (represented in terms of cost difference as a percentage of the base case cost) with the change in maximum efficiency. The base case design efficiency is calculated as 98.5%. There is a sharp increase in the efficiency initially when the cost premium to be paid is <32%. It is estimated that a 32% higher initial cost will be paid for the initial 0.57% efficiency improvement from the base case, while the next similar percentage cost difference would improve efficiency by only 0.12%. For liquid-filled transformers, which are currently loss-evaluated, to meet the minimum efficiency requirement of 98.7% for the 2-year payback case considered here of a 25-kVA, pole-type, liquid-filled transformer (discussed in Subsect. 4.4.2), additional initial cost to be paid by users is estimated to be <2%. Additional initial cost to be paid is estimated to be significantly higher (i.e., 6%) if they were not currently loss-evaluated (as is the case with dry-type transformers). The initial cost difference would also be a lot higher for higher kilovolt-ampere transformers, in which case additional total investments necessary for users could then be significant depending on the current fraction of the nonevaluated transformers.

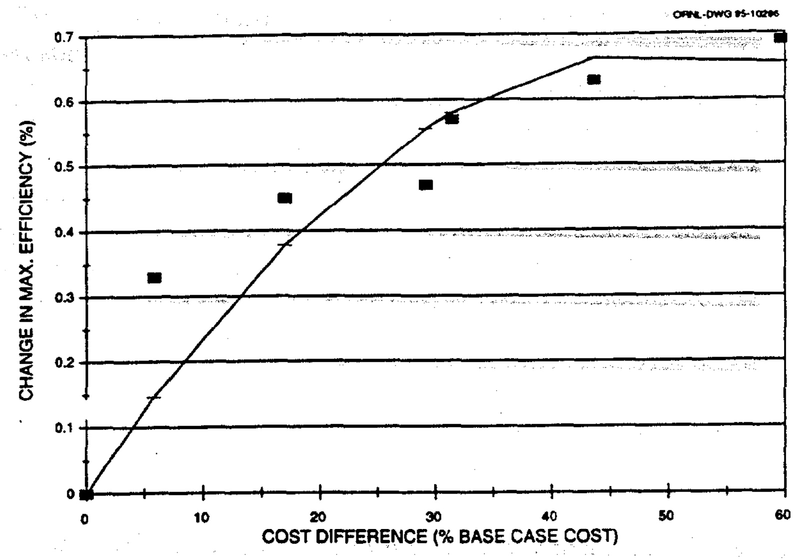

Fig. 5.1. Change in maximum efficiency as a function of initial cost difference for a 25-kVA, pole-type, liquid-filled transformer. *Source:* National Electrical Manufacturers Association.

The higher initial cost of transformers, however, will lower the annual energy cost through reduced energy losses over the life of transformers. Figure 5.2 shows the estimated simple payback period as a function of difference in the initial cost (expressed in terms of percentage of the base case cost) for a 25-kVA, pole-type, liquid-filled transformer. The payback calculation estimates the number of years required for energy-efficient-transformer users to recover the additional investment necessary through annual energy savings from lower losses. The base case

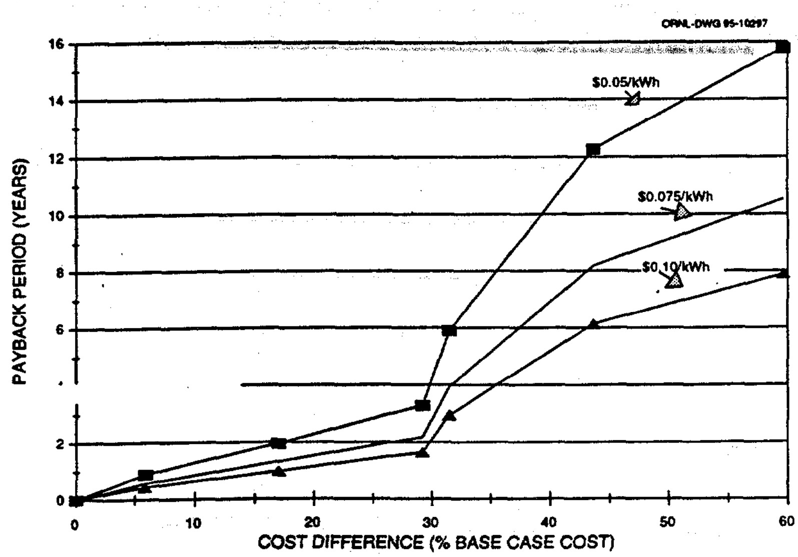

Fig. 5.2. Change in payback period as functions of initial cost difference and energy cost for a 25-kVA, pole-type, liquid-filled transformer. *Source:* National Electrical Manufacturers Association.

assumed for the payback calculation is the nonevaluated design (i.e., A/B = \$0/\$0). The sensitivity of payback period to the different energy costs is also shown in Fig. 5.2. For an energy cost of more than \$0.075/kWh, the payback period is estimated to be <5 years for the percentage difference in initial cost up to 35%. The payback period increases to 8.2 years maximum for an initial cost difference of 44% for the same range of energy cost.

The payback period is linearly sensitive to the energy cost. For example, for a 29% increase in initial cost, the payback period decreases from 3.2 to 1.6 years as the energy cost increases from \$0.05 to \$0.10/kWh. The payback period for dry-type and larger kilovolt-ampere liquid-filled transformers is considerably higher, more than 5 years in some cases. For example, payback periods for 80°C- and 115°C-rise dry-type transformers are estimated to be 9.7 and 8.1 years respectively (assuming a 115°C-rise transformer as the base case, an energy cost of \$0.06/kWh, and at 50% loading) (Howe 1995). Because the average transformer life is 25–30 years, a payback period of <10 years is likely to be attractive to users.

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6. CONCLUSIONS

6.1 ENERGY SAVINGS AND COST-EFFECTIVENESS

Most electric utilities use purchasing formulae that factor the effect of transformer efficiency into the purchasing decision. Most nonutility distribution transformers are purchased on the basis of lowest first cost without evaluating the cost of the energy consumed by the units. Most dry-type transformers are purchased by contractors or agents with no motivation to buy lower-loss, higher-cost units. These nonevaluated transformers may have 60–70% higher losses than utility-evaluated transformers. The maximum efficiencies of liquid-immersed distribution transformers have improved over the past several decades, but dry-type units have shown little or no improvement. An energy conservation policy would increase the efficiency of dry-type units and of some utility-purchased transformers that are currently not evaluated on a life-cycle-cost basis.

A national energy conservation policy for distribution transformers could save ~0.01–0.02 quad of primary energy in the first year. As more energy-efficient transformers were purchased, annual savings would continue to increase to 0.4–1.0 quad of primary energy after 30 years. Cumulative savings would be 3.6–13.7 quads of primary energy over a 30-year period.

There is a somewhat higher rate of savings per rated capacity (kilovolt-amperes) for dry-type transformers than for liquid-immersed transformers. This is explained by the fact that a much higher proportion of liquid-immersed transformers are purchased by utilities; they generally consider the value of losses in their purchase decisions, purchasing transformers that are relatively efficient compared with those purchased by nonutilities.

6.2 STAKEHOLDER IMPACTS

Energy-efficient transformers will increase production costs for transformer manufacturers as a result of the higher costs associated with the use of either more or higher performance materials. The effect on manufacturers' revenues will depend on how much of the cost increases can be passed through to consumers. If less than the actual higher production costs are passed through, profits will suffer; a pass-through above the increase in production costs will increase profits. A manufacturer's production costs will also be determined to some extent by the additional investments necessary. Manufacturers of dry-type transformers may be more affected by a national conservation policy than manufacturers of liquid-immersed transformers because most of the dry-type transformers are not currently loss evaluated. The energy efficiency of transformers also raises issues about the production capability of raw material suppliers. Most raw material suppliers are domestic and estimated to be at 80% of full production capability; this may not be adequate depending on the level of the surge in demand for an increased supply of raw materials. It is estimated that the capacity utilization level of the magnet wire industry would increase from the current level of 80 to 84% if energy-efficiency improvements for distribution transformers were accomplished by the use of copper alone.

Energy conservation would have less impact on users of liquid-immersed transformers than on users of the dry-type since the former market is currently more than 90% loss evaluated. A higher price will have to be paid for energy efficiency, particularly for purchases of dry-type transformers—requiring additional investments for short-term, return-oriented C&I end-users. However, the total cost, including both the cost of the transformer and the cost of energy, will decrease, particularly for dry-type transformers. The payback period for the additional investments necessary will be <10 years (i.e., one-third of the transformer life) under most conservation cases.

6.3 ECONOMIC JUSTIFICATION AND FEASIBILITY

A number of energy conservation options were analyzed. All of the conservation options considered in this study are economically justified using national average electricity costs. These options are also technically feasible, although some retooling may be required for the more energy-efficient, dry-type transformer designs. Based on a conservation approach similar to the options analyzed, a national conservation policy for distribution transformers would have the potential for energy savings of 3.6–13.7 quads over the 30-year period from 2000 to 2030. About 93% of these savings could be realized if sizes <10 kVA were excluded in an energy conservation policy.

Appendix A

DISTRIBUTION TRANSFORMER REVIEW GROUP

Appendix A
DISTRIBUTION TRANSFORMER REVIEW GROUP

Over 200 comments were received from the Distribution Transformer Review Group; as a result, many changes have been made. These include editing improvements, clarification of definitions and the approach, revised assumptions, deletion of some of the analysis, and presentation of additional analyses.

Significant revisions based on the comments include the following:

- Definitions of the terms used have been made more explicit. This includes a tighter definition of the distribution transformers that are considered in this study.
- A sensitivity analysis has been done for reduced growth rates for commercial and industrial transformers.
- A sensitivity analysis has been done using a significantly lower evaluation of load losses (the B factor) for 50 kVA and larger.
- A sensitivity analysis was done to indicate the effect on energy savings of assuming a 0.2 effective capacity factor for all transformer sizes instead of just transformer sizes <50 kVA.
- The availability of magnet wire and core steel for the production of higher efficiency transformers has been reassessed.
- Some of the advantages attributed to dry-type transformers have been revised.

It was not practical to address some comments. For instance, at least one comment suggested including data on additional transformer sizes to better represent dry-type transformer designs. Transformer sizes for which information was collected were limited to those sizes included in the Oak Ridge National Laboratory–National Electric Manufacturers Association (ORNL–NEMA) survey. Expanding and/or revising this survey was not practical within the time limits for this determination study. Other comments were associated with the feasibility and/or desirability of implementing standards; these were outside the scope of this document.

Finally, at least one comment objected to using the 2-year payback case on an equal footing with the other cases because the information for this case came from outside the survey. The point of the comment was that information for other cases was developed from survey information in which NEMA manufacturers had an equal chance to participate. The information for this case was taken from a single NEMA manufacturer. It would have been better to have all manufacturers submit their data for a 2-year payback case as was done for the other cases; however, because of time constraints, this was not practical. To address this concern, a qualification was added that indicates that data from other manufacturers could have modified these results. A list of the Distribution Transformer Review Group members follows.

Members/(Reviewers)	Perspective/Expertise
1. Allied Signal Amorphous Metals Patrick Curran, Manager 6 Eastmans Road Parsippany, NJ 07054	Amorphous metal

2. Aluminum Association Peter Pollak 900 19th Street, N.W., Suite 300 Washington, D.C. 20006	Aluminum conductor applications
3. American Council for an Energy Efficient Economy Howard Geller 1001 Connecticut Ave., N.W. Washington, D.C. 20036	National perspective, conservation issues
4. American Institute of Plant Engineers Mike Fening, Director 8180 Corporate Park Drive, Suite 305 Cincinnati, OH 45242	Commercial and industrial applications
5. American Physical Plant Association Diana Tringali, Director of Research 1446 Duke Street Alexandria, VA 22314	Commercial and industrial applications
6. American Public Power Association Kurt Conger, Director of Policy Analysis 201 M Street, N.W. Washington, D.C. 20037-1484	Municipal utilities
7. Black and Veatch Tom McCorkendale P.O. Box 8405 Kansas City, MO 64114	Commercial and industrial applications
8. Central Moloney, Inc. J. Edward Smith, Marketing Manager 2400 West Sixth Ave. Pine Bluff, AK 71601	Liquid transformer manufacturer (non-NEMA)
9. Copper Development Association Inc. William T. Black, Vice President 260 Madison Ave. New York, NY 10016	Copper availability and applications
10. Edison Electric Institute Matthew C. Mingoia, Standards Program Manager 701 Pennsylvania Ave., N.W. Washington, D.C. 20004-2696	Investor-owned utilities

11. Electric Power Research Institute Harry Ng, Power Delivery Group 3412 Hillview Avenue P.O. Box 10412 Palo Alto, CA 94303	Electric utility research
12. ERMCO Alan L. Wilks P.O. Box 1228 Dyersburg, TN 38025-1228	Liquid transformer manufacturer (non-NEMA)
13. Federal Pacific Transformer Company Carl Bush, Development Manager Old Airport Road P.O. Box 8200 Bristol, VA 24203-8200	Dry-type transformer manufacturers (non-NEMA)
14. Howard Industries, Inc. Gerald R. Hodge, Manager P.O. Box 1588 Lauret, MS 39441	Liquid transformer manufacturers (non-NEMA)
15. Lawrence Berkeley Laboratory Jim McMahon, Standards Group Leader One Cyclotron Road, 90-4000 Berkeley, CA 94720	National conservation standards
16. National Electrical Manufacturers Association Kyle Pitsor, Manager 2101 L Street, N.W., Suite 300 Washington, D.C. 20037	NEMA transformer manufacturers
17. National Rural Electric Cooperative Association Martin Gorden, Manager 1800 Massachusetts Ave., N.W. Washington, D.C. 20036	Rural electric cooperative utilities
18. Natural Resource Defense Council David Goldstein 71 Stevenson Street, Suite 1825 San Francisco, CA 94105	National perspective, energy conservation
19. Oak Ridge National Laboratory Paul R. Barnes, Review Group Chairperson P.O. Box 2008 Oak Ridge, TN 37831-6070	ORNL project leader utility applications

20. Stone and Webster Engineering Corp.
Ken R. Skinger
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P.O. Box 5200
Cherry Hill, NJ 08034

Commercial and industrial applications

21. Specialty Steel Industry of North America
James Will, President
Skip Hartquist
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Core steel availability and applications

22. National Institute of Standards and Technology
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Transformer efficiency measurements

Appendix B

ASSUMPTIONS FOR THE A AND B FACTORS

Appendix B
ASSUMPTIONS FOR THE A AND B FACTORS

This appendix explains the basis for "evaluating" or valuing transformer energy losses. This is important because it provides an economic criterion for the trade-off between a transformer's energy efficiency and its capital cost. The important assumptions in analyzing this trade-off are the rates at which energy is valued and at which a "typical" transformer loses energy as it serves an electrical load. These rates vary depending on factors associated with the individual end-user.

In this determination study a social cost perspective was taken in evaluating energy losses. In this perspective the cost to the end-user does not include taxes in calculating the optimal capital/energy trade-off. From the social perspective taxes are not included as a cost because while they are an expense to those that pay, they are a revenue to the government that collects. The practical implication for taking this perspective is that energy costs have been evaluated at a higher rate than they would be for commercial and industrial transformer end-users. Commercial and industrial end-users that do a total-owning-cost (TOC) evaluation for purchasing decisions would include the effect of taxes, which reduces the value of energy savings.

B.1 THE USE OF A AND B FACTORS FOR EVALUATING TRANSFORMERS

The A and B factors are used to measure the cost of transformer losses. They measure the capitalized cost per watt of a transformer's rated no-load and load losses. The A and B factors are multiplied by the no-load and load losses and then added to the initial transformer cost to determine its TOC. The TOCs of otherwise similar transformers can be compared to determine the one with the lowest lifetime owning cost. In this way differences in the efficiencies and prices of similar transformers can be compared to determine the one that is the most cost-effective on the basis of TOC.

B.1.1 The A Factor

The A factor reflects the cost per watt of energizing the transformer's core. The power to energize the core is constant whether or not the transformer is supplying a load. Therefore, the losses, called no-load losses, are also constant and are not related to the load the transformer is serving. Because core losses are constant over time, the power they require is part of a utility's base-load demand, and their cost (from the utility's perspective) is related to the capital, energy, and operation and maintenance (O&M) costs of base-load energy cost. These costs include generation, transmission, and distribution costs but exclude costs associated with the distribution transformer itself. An approximation of these costs would include the incremental capital, energy, and O&M costs of a utility's base-load power plants plus incremental transmission costs. These costs may vary significantly depending on the utility and its base-load power plants. However, an argument can be made that from a national perspective, the value assigned to the A factor should be more or less constant. The trend toward deregulation of generation and the resulting competition will tend to result in similar pricing across the United States.

Because of this trend, the analysis in this determination study has been done assuming a single value for the A factor of $3.50/W of no-load loss. At least two sources support a value in this range. First, a study of the incremental costs resulted in an A factor of $3.53/W in 1993 dollars (Barnes et al. 1995). This study estimated the incremental costs of a base-load, coal-fired power plant using Energy Information Administration assumptions of energy and capital costs. In addition, a review of A factors reported for 1994 by 90 major U.S. utilities indicated an average A value of \$3.43. This value increased to \$3.67 if utilities reporting A factors of \$0.00 were eliminated.

The \$3.50/W is a typical A value for utilities and can be supported with reasonable cost assumptions. However, A values significantly above or below \$3.50/W are common. For instance, the standard deviation of the A factors was \$1.84. Two-thirds of the reported values were either below \$3.00 or above \$4.00. This corresponds to the wide range of actual costs that utilities experience. The increased competition mentioned above will tend to reduce these disparities.

B.1.2 The B Factor

There is considerably more uncertainty in calculating the value of load losses for the B factor. In addition to the energy cost of losses, the B factor should reflect how the transformer is loaded. Losses in the transformer's coil (load losses) increase proportionally to the square of the load. Therefore, a transformer that has a continuous load at 80% of the rated load would have 64% (0.8^2) of the losses of a transformer continuously loaded at 100% (1.0^2) of the rated load. In reality most transformer loads fluctuate with the time of day, day of the week, and time of the year. Therefore, transformers that have identical rated load losses may have very different actual load losses because their loads are different. This turns out to be an extremely important issue in considering transformer efficiency. For instance, a typical utility value for transformer load losses is \$1/W. If this accurately represents the value of load losses for a transformer that has a constant load of 80%, then a transformer that has a constant load of 60% with the same per unit cost of lost energy would have a value of load losses of $0.6^2/0.8^2$ times \$1, or \$0.56. A similar discrepancy in the value of losses would result from comparing a transformer with a 40% constant load to a 30% constant load.

In addition to the variation in transformer loading that affects the value per rated watt of load loss, there is also the variation in energy costs. The load-losses cost is similar to the no-load-losses cost discussed above but with some important differences. First, the no-load-losses cost was discussed in terms of the supply of base-load generation. This was justified based on the constant nature of no-load losses. In contrast, load losses vary over time with the costs of generating electricity. During the peak period of a utility's load cycle, the costs of production are much higher because the units used during this period, such as gas turbines, tend to have higher fuel costs. Also, the generating capacity supplying energy during peak periods is operated for short durations; so capital costs are spread over fewer hours of production, resulting in higher costs per unit of production.

The appropriate value placed on a rated watt of load losses must include these varying tendencies. Experience indicates that for most transformers, the value of a rated watt of load losses tends to be significantly less than a rated watt of no-load losses because on average the transformer is operated at much less than its full rating where the load losses are measured. However, the higher a transformer's peak load (where it contributes to the system's peak) and the higher its effective load,[1] the higher the cost of the rated load losses. Therefore, accurate assessment of the value of reducing transformer load losses should account for the transformer loading. Higher or lower peak and/or effective loading should result in a higher or lower value of the B factor.

It follows from the above discussion that the rate at which load losses are valued, to a significant extent, depends on loading assumptions. Transformers that have relatively higher loads tend to have relatively high B factors. Transformers that have relatively low loads tend to have relatively low B factors. The value of the rated load losses varies with differences in transformer loading—even with identical production costs. To recognize these differences, a low B factor of $0.75 and a high B factor of $2.25 were selected.

The factors that contribute to this range include two different aspects of a transformer's load: the transformer's peak per unit load and the fluctuation of the transformer's load relative to its capacity. The transformer's peak per unit load is important because it is the basis for determining the transformer's contribution to peak system costs. The transformer's effective load is important because it is the basis for relating transformer actual load losses to the rated losses at full load. Both factors have a positive relation to the B factor.

The B factors of $0.75 and $2.25 provide a range that accounts for a significant variation in peak and average loads. They were chosen, in part, based on considering B factors reported in the survey of 90 utilities discussed previously. The participants in the survey were large investor-owned utilities. The B factors reported in the survey had an average value of $1.09 and a standard deviation of $0.90. About 41% of all B factors in the survey were between $0.50 and $1.00. If the B factors of $0.00 are eliminated from the survey, then the average B factor increases to $1.16. One standard deviation above these averages is about $2.00.

Some utilities develop alternate B factors that reflect typical loading patterns depending on the type of customer the transformer serves. For instance, a utility may assign a different B factor for industrial, commercial, and residential services. The survey of B factors was done by a transformer manufacturing division that focuses on the residential types of transformers. Therefore, the B factors that were reported in the survey are probably consistent with loads for residential and small commercial transformers. The $0.75 B factor is somewhat below the average in the survey. However, it is well within the normal range for utility-owned residential transformers.

Apart from the survey, incremental utility costs were modeled to determine the effect of loading parameters on the B factor. The $0.75/W lower range for the B factor approximates a transformer with a per unit peak load of ~1.0 and a loss factor of ~0.06.[2] Assuming a standard load profile, this would be consistent with a load factor of ~0.2. In this range the B factor is quite sensitive to changes in the effective load.

As is pointed out in the discussion of the survey, one standard deviation above the average B factor was about $2.00. It was assumed that larger transformers have a B factor of $2.25. This B factor that is somewhat above one standard deviation was chosen for several reasons. First, it was meant to reflect industrial and commercial transformers that tend to be loaded more highly than residential ones. Modeling the incremental utility costs and assuming a per unit peak load of 1.0 and an effective load of 0.5 resulted in a B factor of $2.25. Using a standard load profile, a 0.5 load factor is consistent with a loss factor of 0.3. Somewhat higher load factors would increase the loss factor. However, it can be argued that this may not increase the B factor significantly. As the load factor increases in this range, a higher proportion of power is provided from lower cost base-load sources. This lower cost of power partially compensates for the increase in losses.

Note that these assumptions can only attempt to account for general loading tendencies. Any individual transformer could be loaded in a way that would be contrary to the general trends. For instance, a lightly loaded transformer may have its peak and most of its energy losses at night during low-cost generation periods. This may be the result of a transformer serving a single residence where the occupant has a night job or a business such as a nightclub that operates on a night schedule. Such loads are not typical. Utilities, as a rule, do not purchase transformers for a specific load or case; rather, they are designed, built, and purchased for a range of loads. However, utilities do purchase for unusual cases when warranted.

B.2 COMMERCIAL AND INDUSTRIAL USERS

The above discussion treated transformers from the perspective of the utility. Because utilities purchase and operate ~60% of all transformer capacity, this is an important perspective. The remaining 40% of transformer capacity is owned by industrial and commercial establishments. There are at least two important differences between utility and nonutility transformer owners. First, utilities purchase and own transformers on a large scale. This provides them with the incentive to evaluate carefully the type of transformer that best meets their needs. They purchase most of their transformers directly from the manufacturer. This allows them to specify the detailed characteristics that they want. Also, utilities can afford to evaluate the loads that their transformers serve. In contrast to utilities, most commercial and industrial (C&I) firms purchase transformers on a very small scale. They do not become experts, and most of the time they cannot justify becoming transformer experts. They usually do not purchase directly from the manufacturer (see Sect. 3). Therefore, they demand much less input and exert much less control over their transformer purchases. They usually select a transformer that meets their needs on the basis of purchase price with little concern for energy efficiency.

The other important difference is that nonutilities may not pay the actual incremental costs of the power they consume because they pay for electricity based on a rate schedule. The cost to produce electricity reflects capital costs, fuel costs, and the O&M costs. The utility has a good understanding of the detail and complexity of how these costs are related to the load pattern, which varies over time. If the utility knows the typical load patterns for its transformers, it knows the cost of losses. On the other hand, the utility generates revenue by relating its costs to customer demand through a rate schedule. In general, the rate schedule attempts to relate electric demand to the costs incurred. It can do this only for broad patterns of customer demand, not for individual customers. Unlike the utility's ability to calculate its own incremental costs of production precisely, it charges customers based on a very simple rate schedule. C&I customers usually pay a monthly peak demand charge and an energy charge for their monthly consumption. The customer that owns a transformer must pay the cost of losses corresponding to the utility's simplified rate schedule. The important point is that to the extent that the customer's rate schedule does not accurately reflect the cost of supplying transformer losses, then the incentive for purchasing and operating a transformer will diverge from the utility perspective.

This study has used the TOC methodology to evaluate a range of A and B factors for C&I users. This was done by examining the electric rates of several utilities and substituting these rates for the incremental cost assumptions that were utilized in estimating A and B factors for utilities. An analysis from the C&I user perspective indicated that the evaluations of losses for C&I firms would tend to be somewhat lower than those assumed in this analysis. The C&I perspective differs from that of a regulated utility in that a net reduction in transformer costs would increase profits, resulting in higher taxes. Therefore, the incentive to reduce a transformer's life cycle cost through improving energy efficiency is reduced by the effect of taxes. In other words, the before-tax return must be higher to compensate for taxes. Utilities can ignore this effect because they pass increases or decreases in fuel costs on to their customers through fuel adjustment clauses. As is stated above, this analysis takes a social cost perspective in which tax costs are also government revenues and thus are assumed to have no net effect.

B.3 THE USE OF AVERAGES TO CALCULATE B FACTORS AND TO ESTIMATE ENERGY USE

One objective of this study is to determine if energy conservation for distribution transformers would be cost-effective. The NEMA–ORNL survey requested cost-effective designs for various A and B factors. Then the energy use resulting from these designs was compared with designs typical of existing transformer sales. In this way, potential energy savings have been estimated. The A and B factors have been assumed from weighted averages or typical values for incremental energy costs. This is fairly straightforward. However, assuming transformer loading based on averages or typical values is more complicated. As is explained above, load losses increase with the square of the load. The average of a sum of squares is not equal to the square of the average of the components used to calculate the squares. This difference between taking a simple average and averaging the squares is also important to recognize when estimating the energy savings.

The validity of using averages depends on whether they are a good representation of the sum of individual effects. The answer depends on the "dispersion" of transformer loading practices. If transformer loads are concentrated around the average value, an average evaluation will be a good approximation. The more widely dispersed the distribution of loads that make up the average, the less the average will approximate the sum of effects that would result from assessing individual loads.

An example has been calculated to show the effect of dispersion on load losses. Assuming a normal distribution with a mean transformer capacity factor of 0.5 and a standard deviation of 0.1 results in the average of the squares that is ~4% more than the square of the average. When a standard deviation of 0.2 is used, the average of the squares is ~15% larger. This indicates that unless the dispersion is very large, using average values should give a good approximation of the sum of individual values. Note that there is a paucity of data on distribution transformer loading patterns. Per unit loads that are assumed in this study have been based on a review of what little data is available.

REFERENCE

Barnes, P. R., et al. 1995. *The Feasibility of Replacing or Upgrading Utility Distribution Transformers During Routine Maintenance*, ORNL-6804/R1, Martin Marietta Energy Systems, Oak Ridge Natl. Lab.

NOTES

1. The effective load can be defined as the average over time of the per unit load squared.
2. The loss factor relates the average transformer power losses to the peak loss.

Appendix C

SURVEY FORMS

Appendix C
SURVEY FORMS

SURVEY OF MANUFACTURERS ESTIMATES OF PRICE AND LOSSES FOR LOWEST TOTAL OWNING COST TRANSFORMERS

OIL FILLED SINGLE PHASE TRANSFORMERS

25 kVA Pole Type Transformer

12470 GRDY/7200 No Taps 120/240 V Secondary
No Accessories or Transportation
Profit Margin Representative of Today's Competitive Market Conditions
Quote based on order of 500 transformers with 50 of this specific type.

			No-Load Loss at Rated Load	Load Loss at Rated Load	Selling Price
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$0.00 $0.00	________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$3.50 $2.25	________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$3.50 $0.75	________ Watts	________ Watts	$ ________

50 kVA Pole Type Transformer

12470 GRDY/7200 No Taps 120/240 V Secondary
No Accessories or Transportation
Profit Margin Representative of Today's Competitive Market Conditions
Quote based on order of 500 transformers with 50 of this specific type.

			No-Load Loss at Rated Load	Load Loss at Rated Load	Selling Price
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$0.00 $0.00	________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$3.50 $2.25	________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$3.50 $0.75	________ Watts	________ Watts	$ ________

50 kVA Pad Type Transformer

12470 GRDY/7200 No Taps 240/120 V Secondary. One HV load break bushing.
No additional accessories or transportation
Profit Margin Representative of Today's Competitive Market Conditions
Quote based on order of 500 transformers with 50 of this specific type.

			No-Load Loss at Rated Load	Load Loss at Rated Load	Selling Price
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$0.00 $0.00	________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$3.50 $2.25	________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$3.50 $0.75	________ Watts	________ Watts	$ ________

750 kVA Pad Type Transformer

12470 GRDY/7200 + or - 2.5% Taps 480Y/277 V Secondary--95 kV BIL HV, 30 kV BIL LV
No Other Accessories or Transportation
Profit Margin Representative of Today's Competitive Market Conditions
Quote based on order of 2 transformers of this specific type.

			No-Load Loss at Rated Load	Load Loss at Rated Load	Selling Price
Core Loss Evaluation Factor ($/watt)		$0.00			
Coil Loss Evaluation Factor ($/watt)		$0.00			
	ESTIMATES:		________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt)		$3.50			
Coil Loss Evaluation Factor ($/watt)		$2.25			
	ESTIMATES:		________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt)		$3.50			
Coil Loss Evaluation Factor ($/watt)		$0.75			
	ESTIMATES:		________ Watts	________ Watts	$ ________

2000 kVA Load Center Type Transformer

13200 Delta + or - 2.5% Taps 480Y/277 V Secondary--95 kV BIL HV, 30 kV BIL LV
No Other Accessories or Transportation
Profit Margin Representative of Today's Competitive Market Conditions
Quote based on order of 2 transformers of this specific type.

			No-Load Loss at Rated Load	Load Loss at Rated Load	Selling Price
Core Loss Evaluation Factor ($/watt)		$0.00			
Coil Loss Evaluation Factor ($/watt)		$0.00			
	ESTIMATES:		________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt)		$3.50			
Coil Loss Evaluation Factor ($/watt)		$2.25			
	ESTIMATES:		________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt)		$3.50			
Coil Loss Evaluation Factor ($/watt)		$0.75			
	ESTIMATES:		________ Watts	________ Watts	$ ________

DRY THREE PHASE TRANSFORMERS

45 kVA General Purpose Lighting Type Transformer

480 Delta 208Y/120 V, Universal Taps (+2--2.5%, -4--2.5%)--10 kV BIL HV 10 kV BIL LV
No Other Accessories or Transportation
Profit Margin Representative of Todays Competitive Market Conditions
Quote based on order of 20 transformers of this specific type.

			No-Load Loss at Rated Load	Load Loss at Rated Load	Selling Price
Core Loss Evaluation Factor ($/watt)		$0.00			
Coil Loss Evaluation Factor ($/watt)		$0.00			
	ESTIMATES:		________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt)		$3.50			
Coil Loss Evaluation Factor ($/watt)		$2.25			
	ESTIMATES:		________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt)		$3.50			
Coil Loss Evaluation Factor ($/watt)		$0.75			
	ESTIMATES:		________ Watts	________ Watts	$ ________

2000 kVA Load Center Type Transformer

13200 Delta + or - 2–2.5% Taps 480Y/277 V Secondary--95 kV BIL HV, 10 kV BIL LV
No Other Accessories or Transportation
Profit Margin Representative of Today's Competitive Market Conditions
Quote based on order of 2 transformers of this specific type.

			No-Load Loss at Rated Load	Load Loss at Rated Load	Selling Price
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$0.00 $0.00	________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$3.50 $2.25	________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$3.50 $0.75	________ Watts	________ Watts	$ ________

EPOXY CAST RESIN THREE PHASE TRANSFORMERS

1500 kVA Load Center Type Transformer

13200 Delta + or - 2.5% Taps 480Y/277 V Secondary--95 KV BIL HV, 10 kV BIL LV
No Other Accessories or Transportation
Profit Margin Representative of Today's Competitive Market Conditions
Quote based on order of 2 transformers of this specific type.

			No-Load Loss at Rated Load	Load Loss at Rated Load	Selling Price
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$0.00 $0.00	________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$3.50 $2.25	________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$3.50 $0.75	________ Watts	________ Watts	$ ________

2500 kVA Load Center Type Transformer

13200 Delta + or - 2.5% Taps 480Y/277 V Secondary--95 kV BIL HV, 10 kV BIL LV
No Other Accessories or Transportation
Profit Margin Representative of Today's Competitive Market Conditions
Quote based on order of 2 transformers of this specific type.

			No-Load Loss at Rated Load	Load Loss at Rated Load	Selling Price
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$0.00 $0.00	________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$3.50 $2.25	________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt) Coil Loss Evaluation Factor ($/watt)	ESTIMATES:	$3.50 $0.75	________ Watts	________ Watts	$ ________

DRY SINGLE PHASE TRANSFORMERS

1 kVA Transformer

240/480 No Taps 120/240 V Secondary ; 115 C Rise above ambient (40 C)
No Accessories or Transportation
Profit Margin Representative of Today's Competitive Market Conditions
Quote based on order of 100 transformers of this specific type.

			No-Load Loss at Rated Load	Load Loss at Rated Load	Selling Price
Core Loss Evaluation Factor ($/watt)		$0.00			
Coil Loss Evaluation Factor ($/watt)		$0.00			
	ESTIMATES:		________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt)		$3.50			
Coil Loss Evaluation Factor ($/watt)		$2.25			
	ESTIMATES:		________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt)		$3.50			
Coil Loss Evaluation Factor ($/watt)		$0.75			
	ESTIMATES:		________ Watts	________ Watts	$ ________

10 kVA Transformer

240/480 No Taps 120/240 V Secondary ; 115 C Rise above ambient (40 C)
No Accessories or Transportation
Profit Margin Representative of Today's Competitive Market Conditions
Quote based on order of 25 transformers of this specific type.

			No-Load Loss at Rated Load	Load Loss at Rated Load	Selling Price
Core Loss Evaluation Factor ($/watt)		$0.00			
Coil Loss Evaluation Factor ($/watt)		$0.00			
	ESTIMATES:		________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt)		$3.50			
Coil Loss Evaluation Factor ($/watt)		$2.25			
	ESTIMATES:		________ Watts	________ Watts	$ ________
Core Loss Evaluation Factor ($/watt)		$3.50			
Coil Loss Evaluation Factor ($/watt)		$0.75			
	ESTIMATES:		________ Watts	________ Watts	$ ________

Appendix D

APPROACH FOR ESTIMATING CONSERVATION CASE SAVINGS

Appendix D
APPROACH FOR ESTIMATING CONSERVATION CASE SAVINGS

This appendix provides supporting documentation for the calculation of energy savings in Sect. 4.

D.1 ESTIMATE OF BASE CASE LOSSES

Losses for the base case are the weighted average of the evaluated and the nonevaluated losses as defined in the following sections.

D.1.1 Nonevaluated Losses for Liquid and Dry-Type Transformers

The average losses for the three lowest total-owning-cost (TOC) transformers from the National Electrical Manufacturers Association–Oak Ridge National Laboratory (NEMA–ORNL) survey $0/$0 evaluation were used for nonevaluated losses.

D.1.2 Evaluated Losses for Liquid Transformers

Where available, the average losses from the Edison Electric Institute–Oak Ridge National Laboratory (EEI–ORNL) survey were assumed for the transformer sizes and types corresponding to those included in the NEMA–ORNL survey. For the 150-kVA, three-phase pad transformer that was not in the EEI–ORNL survey, the losses were conservatively assumed to be three times the losses for the single-phase, 50-kVA, pad-type transformer. For the 750- and 2000-kVA, pad-mounted, three-phase transformers, regression estimates were made of the relationship between transformer size and no-load losses and transformer size and load losses using average loss data from the EEI–ORNL survey for 250-, 500-, and 1000-kVA, three-phase, pad-mounted transformers. These estimated relationships were used to extrapolate the survey results to the no-load and load losses for the 750- and 2000-kVA transformers.

D.1.3 Evaluated Losses for Dry Transformers Below 50 kVA

The average losses for the three lowest TOC transformers from the evaluation of the $3.50-A-factor and $0.75-B-factor transformer designs submitted in the NEMA–ORNL survey were used for evaluated losses for dry-type transformers lower than 50-kVA capacity.

D.1.4 Evaluated Losses for Dry Transformers Above 50 kVA

The average losses for the three lowest TOC transformers from the evaluation of the $3.50-A-factor and $2.25-B-factor transformer designs submitted in the NEMA–ORNL survey were used for evaluated losses for dry-type transformers above 50-kVA capacity.

D.1.5 Weights

The fraction of evaluated and nonevaluated transformers was *assumed* based on estimates provided by the various surveys and manufacturers (see Table D.1).

Table D.1. Basis for assumed fraction of distribution transformers[a]

Transformer type and size (MVA)	Evaluated (%)	Nonevaluated (%)
Liquid-type, single-phase		
25, pole	85	15
50, pole	85	15
50, pad	85	15
Liquid-type, three-phase		
150	85	15
750	85	15
2000	60	40
Dry-type, single-phase		
1	1	99
10	1	99
Dry-type, three phase		
45, lighting type	1	99
1500, epoxy cast	5	95
2000, load center	15	85
2500, epoxy cast	15	85

[a]Estimates provided by surveys and manufacturers.

D.2 ADJUSTING FOR TEMPERATURE RISE OF TRANSFORMERS

The temperature rise adjustment factor compensates for reduced losses at lower loads as the transformer runs cooler, and therefore, load losses are less than proportional to the square of the equivalent capacity factor. The losses were adjusted by a factor of 0.835 for dry-type transformers that were evaluated at a $2.25 B factor. This adjustment is for an effective capacity factor of 50% of the transformer's nameplate capacity. The base case losses and the losses for the conservation cases were both adjusted downward by the same proportion. An analogous adjustment factor of 0.649 was used for dry-type transformers evaluated at a $0.75 B factor corresponding to a 0.2 effective capacity factor. For liquid-immersed transformers, adjustments were at 0.859 for transformers evaluated at a $2.25 B factor (corresponding to an effective load of 50%) and 0.806 for transformers evaluated at a $0.75 B factor (corresponding to an effective load of 20%).

D.3 HOW ENERGY ADJUSTMENT FACTORS ARE CALCULATED

In Subsect. 4.4.3, the energy savings attributed to new transformers meeting conservation case loss criteria is first calculated as the difference between energy consumed in a base case and the conservation case and then adjusted upward by an adjustment factor. An explanation of the rationale for this adjustment and an example of how the adjustment factors for liquid transformers were calculated follows.

The conservation cases are based on implementing alternative minimum energy efficiency criteria. Transformers with efficiencies lower than this criteria are assumed to improve to meet the criteria. However, transformer efficiencies higher than the conservation case criteria are assumed to remain above the criteria. For liquid-immersed transformers, used mainly by utilities, many transformer purchases have higher efficiencies than the conservation case criteria. In effect, the average transformer efficiency with implementation of a minimum criteria will consist of those transformers that have increased their efficiency to the criteria level plus those transformers that prior to the criteria had efficiencies equal to, or better than, the criteria. The resulting average energy efficiency due to implementing a minimum criteria will actually be higher than the criteria efficiency. Therefore, estimating the savings based on the difference between the average existing efficiency and the conservation case criteria efficiency will underestimate the savings. This is why energy savings have been adjusted upward for all liquid-immersed transformer cases except the higher efficiency case. Following is an example of how this was done.

The adjustment factors were calculated using 54 observations of the efficiencies of recently purchased 25-kVA, pole-type transformers. The energy consumed by these 54 transformers is considered to be the reference case energy consumption. The energy consumed by each transformer was calculated from its reported losses and effective capacity factors of 0.2 and 0.5. The energy consumed at each effective capacity factor was summed to give a reference case energy consumption total for each respective capacity factor.

Table D.2 provides an example of the adjustment calculation for a capacity factor of 0.2. For simplicity, the example uses only 5 observations of 25-kVA transformer efficiencies instead of the 54 observations that were used in the actual calculation. Column 2 gives the transformer efficiencies observed from the reported design losses at the assumed 0.2 capacity factor. The reference case efficiency is simply the average of the five observations. For illustration, the efficiency of the conservation case is assumed to be defined by a policy that sets a minimum value for the transformer efficiency at a given capacity factor. Column 3 gives the annual energy consumed by each of the observed transformers/cases. Column 4 gives the annual energy that would be consumed (532 kWh) by each of the observed transformers if they met only the conservation case efficiency as a minimum. In col. 5, the annual energy consumed is the minimum from either col. 3 or col. 4, which implies that transformers with efficiencies exceeding the minimum efficiency are unchanged by the policy.

Column 6 indicates the energy saved when transformers being purchased with efficiencies higher than the efficiency defined by the conservation case remain unchanged and transformers being purchased with lower efficiencies are improved to the conservation case efficiency. Column 7 is the energy saved if all transformers are exactly at the conservation case efficiency. The ratio of the 677 kWh saved in col. 6 to the 565 kWh saved in col. 7 results in an adjustment factor that can be applied to energy savings based on calculating the average savings between a base case efficiency and a conservation case efficiency. The ratio in the example is 1.20. The adjustment ratios that were calculated for the data set of 54 observations on losses for 25-kVA transformers were 1.21 for liquid-filled transformers <50 kVA (capacity factor of 0.2) and 1.18 for liquid filled transformers 50 kVA and higher (capacity factor of 0.5). These calculations were made using conservation case losses for the low TOC conservation case. The adjustments implied by the average losses case and the median TOC case were also calculated. The resulting adjustment factors were the same for the median TOC case. They were 1.09 for a 0.2 capacity factor and 1.16 for a 0.5 capacity factor for the average losses case. In the analysis the above adjustment factors were applied to all sizes of liquid-immersed transformers for the low TOC case, the median TOC case, and the average losses case. Adjustments were not made for the high-efficiency case because almost all existing purchases of transformers have lower efficiencies than those defined by the high-efficiency case losses; therefore, an adjustment was not required.

Table D.2. Example of how the energy savings adjustment factor was calculated for transformers that exceed conservation case efficiency[a]

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Observations/cases	Transformer efficiency (%)	Annual energy consumed for transformer as purchased	Annual energy consumed if all transformers conform to conservation case efficiency	Annual energy consumed if only transformers with efficiencies below conservation case conform to conservation case efficiency	Energy saved (col. 3 minus col. 5)[b]	Energy saved (col. 3 minus col. 4)
Reference case average	98.55	644				
Conservation case	98.80	532				
Transformer 1	98.20	803	532	532	271	271
Transformer 2	98.85	510	532	510	0	–22
Transformer 3	99.00	442	532	442	0	–90
Transformer 4	98.40	712	532	532	180	180
Transformer 5	98.30	757	532	532	225	225
Total		3225	2660	2548	677	565

[a]Unless otherwise indicated, all numbers are in killowatt-hours.
[b]Adjustment factor = col. 6: col. 7.

D.4 WEIGHING THE REDUCTION IN LOSSES CALCULATED FROM THE NEMA–ORNL SURVEY BY A PROPORTION OF ANNUAL SALES

Rates of energy savings per kilovolt-ampere of annual sales were calculated for each of the transformers included in the survey (see Tables 4.4 and 4.5 in Subsect. 4.4.3). These rates of savings were then multiplied by a proportion of annual sales, and the products were summed to get a weighted average savings per kilovolt-ampere. In this way the weighted savings can be multiplied by the total annual sales of transformer capacity to project potential savings. The survey of transformers included only a limited representation of all the types and sizes of transformers that are sold each year. Also, the annual sales figures collected by NEMA are aggregated into wide ranges of transformer sizes. For the determination study the weighted savings per kilovolt-ampere had to account for 100% of annual sales; so the rate of savings from each transformer included in the survey had to represent a range of transformer sizes. Therefore, the assumed distribution of total sales includes a higher proportion than the proportion of actual sales for specific transformer sizes.

Table D.3 indicates the distributions that have been assumed for allocating proportions of annual transformer sales to the categories included in the survey. The survey was intended to provide a sample of transformer designs that cover the range of liquid- and dry-type transformers. However, restrictions on the number of transformer sizes that could be surveyed and lack of information on the distribution of dry transformer sales (at the time inadequate) resulted in a gap for non-epoxy-case designs between 45 kVA and 2000 kVA. Therefore, out of necessity, the 45- and 2000-kVA designs are used to represent about 87% of all dry transformer sales. With more information on the distribution of transformer sales, it is clear that surveying two additional nonepoxy cast designs between 45 and 2000 kVA would have provided a more balanced allocation of sales to the surveyed transformers. Table D.3 gives the assumed allocations and provides the basis used in making these assumptions.

A check on the validity of representing losses for a range of transformer sizes with a limited number of representative sizes is done through an example below. This example uses NEMA sales and loss data for 11 sizes (10–500 kVA) of single-phase, liquid-type transformers. This data (not part of NEMA's annual data collection) is limited to liquid-type, single-phase transformers. The example is presented in Tables D.4, D.5, and D.6.

The example calculates the transformer energy savings per kilovolt-ampere as the difference in losses between minimum first cost designs ($0/$0) and designs that achieve minimum total owning costs for $3/W of no-load losses and $1/W of load losses ($3/$1). This data is used here only to demonstrate the approach that was used to weight the transformer savings; therefore, it does not reflect assumptions and results reported in other parts of this study.

The example compares the precise calculation of reduction in losses weighted by each of the 11 different transformer sizes with an approximation of the reduction in losses using only 2 of the 11 sizes. The average losses per kilovolt-ampere reported for the 25-kVA transformers were used to represent four transformer sizes less than 50 kVA. The average losses per kilovolt-ampere reported for the 50-kVA transformers were used to represent the seven transformer sizes from 50 to 500 kVA. Each category represented ~50% of the total kilovolt-amperes of sales for the 10- to 500-kVA, single-phase transformers. The average reduction in losses per kilovolt-ampere was calculated at an effective capacity factor of 50%. The weighted reduction in losses using the actual sales and losses for all 11 sizes was 2.75 W/kVA (see Table D.5). This differed from the approximation of weighted reduction in losses using only the 25- and 50-kVA transformers (see Table D.6) by less than 5% (2.88 W/kVA).

Table D.3. Proportion of annual sales used to weight the rate of energy savings for each type of surveyed transformer and basis for allocation assumptions

Size (kVA)	Sales (%)	Basis for allocation assumption
		Liquid
Single-phase		
25	23.5	Single-phase overhead 0–37.5 kVA
50	17.0	Single-phase overhead >37.5 kVA
50	17.5	All single-phase pad
Three-phase		
150	6.1	50% of three-phase pad <500 kVA
750	16.8	50% of three-phase pad <500 kVA plus 50% of >500 kVA
2000	19.1	All of secondary plus 50% of >500 kVA three-phase
Total	100.0	
		Dry
Single-phase		
1	2.1	50% of single-phase dry-type
10	2.1	50% of single-phase dry-type
Three-phase		
45	49.5	All low-voltage three-phase dry-type
1500	4.4	50% of three-phase epoxy cast
2000	37.6	All medium voltage three-phase, non-epoxy-cast dry-type
2500	4.4	50% of three-phase epoxy cast
Total	100.0	

Table D.4. Total losses for alternative designs calculated for 10- to 500-kVA, single-phase, liquid-type transformers

	Rated losses for $0/$0 at full load			Rated losses for $3/$1 at full load		
	No-load (W)	Load (W)	Total losses at 50% effective capacity (W)	No-load (W)	Load (W)	Total losses at 50% effective capacity (W)
10	44	237	103	31	124	62
15	53	323	134	39	184	85
25	79	486	201	55	261	120
37.5	108	615	262	76	345	162
50	153	736	337	101	438	211
75	217	944	453	139	617	293
100	271	1201	571	182	764	373
167	384	2059	899	263	1329	595
250	543	2950	1281	361	1888	833
333	746	3797	1695	429	2867	1146
500	1062	5060	2327	608	4050	1621

Table D.5. Calculation of the weighted rate of reduction in losses for single-phase, liquid-type transformers

Size (kVA)	Sales[a] (kVA)	Fraction of total sales[b] (%)	Reduction in losses per transformer[c] (W)	Reduction in losses per kVA[d] (W)	Weighted reduction in losses[e] (W/kVA)
10	1,184,530	5.3	41.25	4.13	0.22
15	2,620,890	11.8	48.75	3.25	0.38
25	5,940,025	26.8	80.25	3.21	0.86
37.5	1,628,025	7.3	99.5	2.65	0.19
50	5,432,700	24.5	126.5	2.53	0.62
75	1,856,250	8.4	159.75	2.13	0.18
100	1,636,300	7.4	198.25	1.98	0.15
167	990,644	4.5	303.5	1.82	0.08
250	260,250	1.2	447.5	1.79	0.02
333	167,499	0.8	549.5	1.65	0.01
500	463,000	2.1	706.5	1.41	0.03
Total	22,180,113	100.0			2.72

[a]These sales figures do not represent the entire distribution transformer industry.
[b]Calculated from col. 1. *Note*: because of rounding, total does not equal 100.
[c]Calculated from differences in total loses in Table D.4.
[d]Column 4 divided by col. 1.
[e]Column 5 times col. 3.

Table D.6. Approximation of the weighted rate of energy savings for single-phase, liquid-type transformers using 2 of 11 sizes

Allocation of transformer sales	Summation of fractions[a]	Reduction in losses per kVA[b] (W)	Weighted reduction in losses[c] (W/kVA)
10- through 37.5-kVA transformers[d]	51.3%	3.21	1.65
50- through 500-kVA transformers[e]	48.7%	2.53	1.23
Total	100%	5.74	2.88

[a]From Table D.5.
[b]From Table D.5.
[c]Column 2 times col. 3.
[d]Assume 10- to 37.5-kVA transformers have the same savings per kilovolt-ampere as 25-kVA transformers.
[e]Assume 50- to 500-kVA transformers have the same savings per kilovolt-ampere as 50-kVA transformers.

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