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OAK RIDGE NATIONAL LABORATORY

LOCKHEED MARTIN

Supplement to the "Determination Analysis" (ORNL-6847) and Analysis of the NEMA Efficiency Standard for Distribution Transformers

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POWER SYSTEMS TECHNOLOGY PROGRAM

MANAGED AND OPERATED BY
LOCKHEED MARTIN ENERGY RESEARCH CORPORATION
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SUPPLEMENT TO THE "DETERMINATION ANALYSIS" (ORNL-6847) AND ANALYSIS OF THE NEMA EFFICIENCY STANDARD FOR DISTRIBUTION TRANSFORMERS

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ABSTRACT

This report contains additional information for use by the U.S. Department of Energy in making a determination on proposing energy conservation standards for distribution transformers as required by the Energy Policy Act of 1992. An earlier determination study by the Oak Ridge National Laboratory determined that cost-effective, technically feasible energy savings could be achieved by distribution transformer standards and that these savings are significant relative to other product conservation standards. This study was documented in a final report, *Determination Analysis of Energy Conservation Standards for Distribution Transformers* (ORNL-6847, July 1996). The energy conservation options analyzed in this study were estimated to save 5.2 to 13.7 quads from 2000 to 2030. The energy savings for the determination study cases have been revised downward for a number of reasons. The transformer market, both present and future, was overestimated in the previous study, particularly for dry-type transformers, which have the greatest energy-saving potential. Moreover, a revision downwards of the effective annual loads for utility-owned transformers also results in lower energy savings. The present study assesses four of the five conservation cases from the earlier determination study as well as the National Electrical Manufacturers Association energy efficiency standard NEMA TP 1-1996 using the updated data and a more accurate disaggregated analysis model. According to these new estimates, the savings ranged from 2.5 to 10.7 quads of primary energy for the 30-year period 2004 to 2034. For the TP-1 case, data were available to calculate the payback period required to recover the extra cost from the value of the energy saved. The average payback period based on the average national cost of electricity is 2.76 years.

ACRONYMS AND ABBREVIATIONS

DOC	U.S. Department of Commerce
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
kWh	kilowatt-hour
MVA	megavolt-ampere
MWh	megawatt-hour
NEC	National Electrical Code
NEMA	National Electrical Manufacturers Association
ORNL	Oak Ridge National Laboratory
PU	per unit
RMS	root mean square
TOC	total owning cost

SYMBOL DICTIONARY

avg, av	subscript for average value
E_o	total annual energy supplied by all transformers
L	loss (may be subscripted)
LF	load factor (ratio of average load to peak load)
L_sF	loss factor (ratio of losses at average load to losses at peak load)
LL	load loss in watts at full-load rated temperature, consistent with IEEE C57.12.00 and C57.91-1981 (liquid) and C57.12.01 and C57.96-1989 (dry)
max	subscript for maximum quantity or a value related to a maximum quantity (i.e., S_{max} = load at maximum efficiency)
NL	no-load or core loss in watts at 20°C
η	efficiency (ratio of energy output to energy input)
PF	power factor
R	reduction of losses
r	constant market growth rate
RMS	subscript for root mean square average
S	per unit load relative to nameplate rating
S_B	nameplate rating in kVA
T	load loss temperature correction factor to correct to a specified temperature (i.e., 75°C for dry-type and 85°C for liquid-immersed transformers
U	number of transformer units of a specific type and size sold annually; often indexed with a subscript *i* indicating a specific year
ξ	case efficiency as defined in text

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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 and an earlier report, ORNL-6847, contain 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.

1. INTRODUCTION

1.1 BACKGROUND

Distribution transformers are used to transform the voltage of an electric utility power distribution line (4–35 kV) to a lower secondary voltage (120–480 V) suitable for customer equipment. Over one million new distribution transformers are purchased annually. Utility distribution transformers account for an estimated 61 billion kilowatt-hours (kWh) of the annual energy lost in the generation and delivery of electricity. Additional transformer losses in non-utility applications are estimated to be 79 billion kWh. Distribution transformers are very reliable and efficient devices, with no moving parts and average life spans of over 30 years. Because of the large number of units and the long periods of operation, even small changes in efficiencies can add up to large energy savings. Of the potential savings, about two-thirds could be realized through the use of more energy-efficient, cost-effective dry-type transformers by industrial and commercial customers; the remaining one-third could be achieved through the use of more energy-efficient distribution transformers by utilities.

Market forces do not necessarily encourage the use of energy-efficient transformers. Most dry-type transformers are installed inside buildings or plants and are purchased by contractors. Contractors are drawn to low-price (low-efficiency) transformers because they do not pay the energy costs associated with transformer losses. By contrast, utilities *are* concerned with operating costs, and about 85% are purchasing relatively efficient transformers. However, there are periods when some utilities with limited budgets will buy lower-cost, inefficient transformers. The extra cost of the fuel required by the higher losses from these inefficient transformers can often be passed on to ratepayers. Thus, the market structure and unique accounting procedures associated with distribution transformers result in a disincentive to use cost-effective, energy-efficient designs.

To determine if energy conservation standards for distribution transformers would save significant energy and be technically feasible and economically justified, the Energy Division of Oak Ridge National Laboratory (ORNL) conducted a determination study. This study — documented in the report *Determination Analysis of Energy Conservation Standards for Distribution Transformers* (Barnes et al. 1996) — found that cost-effective, technically feasible energy savings could be achieved by distribution transformer standards and that these savings are significant relative to other product conservation standards. The final report was reviewed by a special transformer review group consisting of manufacturers, utilities, commercial and industrial users, research laboratories, contractors, materials suppliers, and public interest groups. It was concluded that efficiency standards similar to those in the cases analyzed could save a significant amount of energy, on the order of 5 to 13 quads,[1] during the period from 2000 to 2030. While new information on the size of the transformer market and the anticipated market growth have reduced these estimated savings, the possible energy savings from more efficient transformers are still significant.

[1] A quad of energy equals 1 quadrillion (10^{15}) Btu.

1.2 UPDATED ANALYSIS

In 1996, the National Electrical Manufacturers Association (NEMA) developed and published an efficiency standard for distribution transformers, NEMA TP 1-1996, for its members (NEMA 1996). Since the NEMA standard was not available during the ORNL determination study, it was not analyzed. This standard is based on a short payback period to recover the additional cost of the more efficient transformers from the money saved by the reduced energy consumption.

The current report assesses NEMA TP-1 along with the options considered in the 1996 determination study with a more accurate analysis model and more accurate transformer market and loading data. The report presents a national energy savings analysis and a payback analysis. The payback analysis is limited to the NEMA standard, since much of the data in the determination study is not appropriate for a payback analysis. The assessments include a sensitivity study on the impacts of various levels of voluntary adherence to the NEMA TP-1 standard.

1.3 DEFINITION OF DISTRIBUTION TRANSFORMERS

Distribution transformers are defined by ANSI and IEEE standards (IEEE 1994). A distribution transformer is defined by paragraph 2.3.1.1 of ANSI/IEEE C57.12.80-1978 as a transformer for transferring electrical energy from a primary distribution circuit to a secondary distribution circuit or to a consumer's service circuit. A note at the bottom of this definition indicates that the rated capacity of distribution transformers ranges from about 5 to 500 kVA. However, ANSI C57.12.22-1989 provides a revised rating for pad-mounted distribution transformers. According to the C57.12.22 rating, pad-mounted distribution transformers are rated 2500 kVA and smaller, with high voltages of 34.5 kV and below and low voltages of 480 V and below. Low-voltage transformers with an insulation voltage class of 1.2 kV (120 to 480 V in the United States) are also listed as distribution transformers in IEEE Standard C57.12.00-1993. For dry-type transformers, IEEE C57.12.01-1989 defines preferred distribution transformers ratings, with single-phase transformers rated as low as 1 kVA.

For the purposes of this study, distribution transformers are taken to be any transformer in the distribution power circuit with a primary voltage of 480 to 34.5 kV and a secondary voltage of 120 to 480 V. The rated capacities include 10 to 833 kVA for single-phase liquid-immersed units, 15 to 833 kVA for single-phase dry-type units, and 15 to 2500 kVA for all three-phase units. These specifications are the same as those in NEMA standard TP-1. This range of transformers captures most of the distribution transformer market.

2. TYPICAL LOADING PRACTICE

2.1 INTRODUCTION

To determine the energy savings achievable by any standard, an estimate of the typical effective transformer loads is required. Utility transformer loads for new installations are often difficult if not impossible to predict because of the lack of detailed load information. Specifications for transformer sizes are frequently based on the size of service entrances, known possible loads, and square footage of the buildings to be served. There can be wide variations, however, in both residential and commercial loads. For residential loads, individual lifestyles can result in different loads for identical homes, and loads for similar commercial customers similarly vary because of differences in operational schedules, lighting levels, and so on. Thus, there is considerable variation in the average loads of utility transformers of the same size and type. For dry-type transformers, the requirements for safety and reliability are the drivers for typical loading of these units. Using the limited data available, this chapter summarizes typical loading practices.

2.2 UTILITY-OWNED LIQUID-IMMERSED TRANSFORMERS

2.2.1 Average Loads

The annual average per unit (PU) load for all of the distribution transformers in a utility's distribution system can be estimated by dividing the annual sales in megawatt-hours (MWh) by the megavolt-amperage (MVA) of installed capacity times 8760 hours and the average power factor:

$$\text{PU load} = \text{sales (MWh)}/(8760 \times \text{installed MVA} \times \text{power factor})\ . \qquad \textbf{(2.1)}$$

Except for the average power factor, this information is available in the Federal Energy Regulatory Commission (FERC) Form 1 database. The average power factor used for this calculation is the one measured at the distribution transformer, which is normally different from the power factors at substations or in the transmission system. For distribution transformer analysis, Nickel and Braunstein (1981) used 0.9 for the power factor, a figure that was based on an industry survey.

The analysis of the 1992 FERC Form 1 data is shown in Appendix A. If only residential and commercial sales are considered along with a power factor of 1.0, the FERC Form 1 data imply a per unit average load of 0.143. For an average power factor of 0.9, the per unit average load increases to 0.16, as shown in Table A.1.This calculation is misleading, however, because not all of the capacity in the inventory is installed and the industrial sales through utility distribution transformers are not included. The in-service capacity can be determined by subtracting the idle and in-stock capacity listed in the FERC Form 1 database. The in-service capacity is shown in Table A.2, along with the total sales to residential, commercial, and other customers. The "other" category includes sales associated with streetlights, railroads, interdepartmental uses, and government authorities. While most of the electricity sold is metered on the secondary side of utility distribution transformers, a large fraction of sales to industry and large government installations is metered at the primary distribution voltage level, and the distribution transformers associated with these sales are not included in the inventory of utility transformers. In an effort to include these sales, ORNL conducted a telephone survey of selected utilities. This survey indicated that 77 to 97% of total retail sales are metered at low voltages (below 600 V), with an average value near 85%. Assuming that 85% of total sales pass through distribution transformers, the estimate of per unit average load increases to 0.24, as shown in Table A.2. By contrast, if only 75% of total retail sales pass through utility-owned distribution transformers, then the per unit average load is estimated to be 0.21.

2.2.2 Effective Load

The per unit effective loads used in development of B factors (cost of load losses) in total owning cost (TOC) evaluations are not simple averages but are instead the discounted values of the square of the projected load growth adjusted for capital recovery. (See Appendix B for derivation of TOC.) Thus, this form of per unit effective load represents the economic contribution of load growth to the cost of load losses and is not the correct loading to use in evaluating the effects of efficiency standards. To evaluate the impact of an efficiency standard, the root mean square (RMS) per unit average of the load for each transformer size and type included in the standard is required.[1] Unfortunately, this quantity is not readily available and must generally be estimated using simple averages. Clearly, the long-term economic impacts and benefits of any efficiency standard must adjust the projected savings for present value and capital recovery, but for standards evaluations, this calculation is conducted later in the analysis.

As indicated above, the average per unit load from FERC Form 1 analysis can provide some indication of overall system average per unit load on transformers. However, FERC Form 1 analysis does not provide any information on the average per unit load for specific transformer sizes and types. If typical load profiles are available, the calculation of either the per unit average or the per unit RMS is a relatively easy task. Unfortunately, typical load profiles are not generally available at the transformer level, and an alternative approach must be used to arrive at the desired per unit average or RMS load. Examples of three normalized load profiles for commercial applications and of typical residential load and demand profiles for a 100-kVA single-phase transformer are shown in Figs. 2.1 and 2.2. The commercial load profiles are relative to the daily peak and provide minimal information for use in determining how a transformer serving the load might be loaded relative to its nameplate. The large residential unit (100 kVA) provides a great deal of information but is not very useful relative to annual data. Simple calculations can be performed to obtain for this particular day the 100-kVA transformer's load factor (0.47), capacity factor or average per unit load (0.69), per unit peak load (1.47), per unit RMS load (0.78), and loss factor (0.22). Because this particular day is well within the utility's peak load week, it is not representative of annual load behavior.

[1] The root mean square (RMS) load is the square root of the average of the load squared (load^2) for transformers by type and size. RMS load is a crucial assumption in determining base case losses. Transformer loads are known to vary widely, and typical use patterns vary based on specific utility practices and the type of load that the transformer serves. For instance, the load on a 25-kVA transformer used to serve a residential load would tend to differ from one that served an irrigation load. Also, because of differences in air conditioning and heating loads, a transformer serving a residential load in Vermont would tend to differ from one serving a residential load in Alabama.

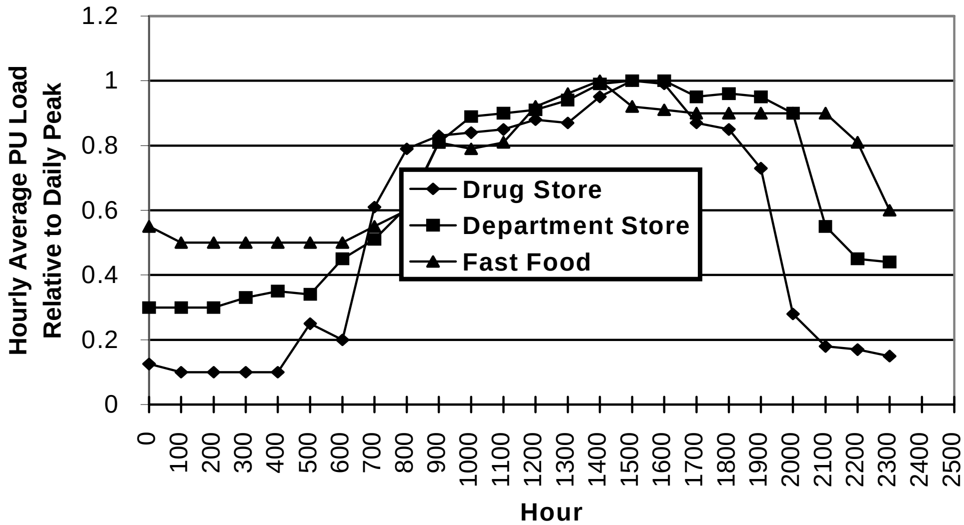

Fig. 2.1. Typical daily load profiles for a department store, a drugstore, and a fast food restaurant.

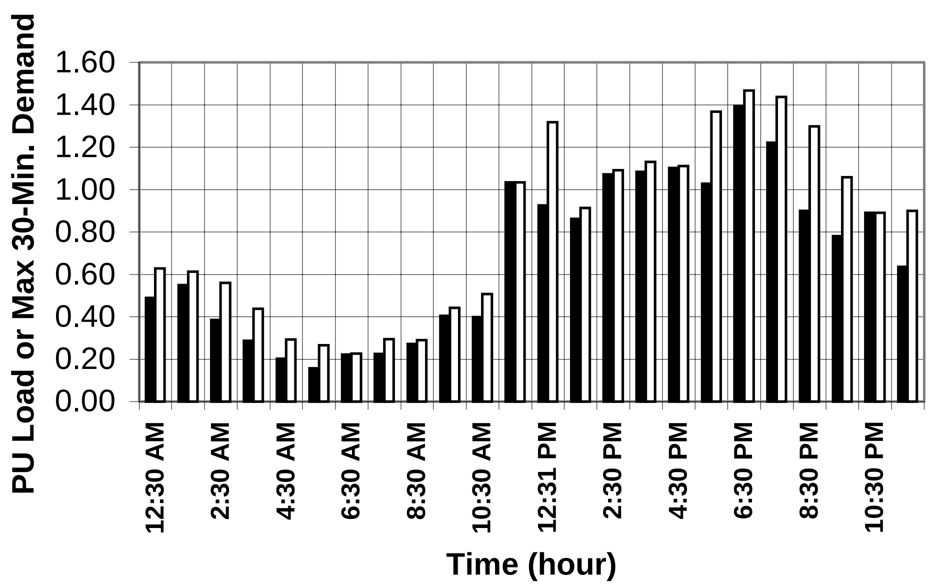

Fig. 2.2. Per unit hourly load and maximum 30-minute demand for June 18, 1994 (100-kVA) residential unit.

If annual average peak load (which could be obtained from demand metering or estimated from kilowatt-hour data) and annual loss factor (L_sF) data are available, then the per unit RMS load, ${S_{RMS}}^2$, is available through the calculation

$$ {S_{RMS}}^2 = L_sF \times \text{peak}^2 \ . \tag{2.2} $$

In general, loss factor data are not available, and various methods have been developed to relate loss factor to load factor. Two classic references in this area are Gangel and Propst (1965) and Westinghouse Electric (1959). Note that these data are more than 30 years old; hence, for residential load, the changing mix and characteristics of appliances and lifestyles warrants additional work in the determination of a and b. Despite the fact that load and loss factors are not directly related, arguments can be given to establish that the loss factor is less than the load factor but greater than the square of the load factor. Hence, the expression $L_sF = (a \times LF^2) + (b \times LF)$, where $a + b = 1$, has a legitimate mathematical but not physical basis. Generally accepted values of $a = 0.85$ and $b = 0.15$ are used for residential loads, but, if available, a and b values should be determined from specific utility data. While the methodology will enable estimation of L_sF from LF for commercial and industrial loads, no specific values for a and b for nonresidential loads are found in the literature. A general equation that is sometimes used for relating L_sF and LF is $L_sF = LF^{1.732}$, but the basis for this expression is unknown.

As the previous discussion makes clear, determining a representative per unit RMS or average load for each transformer size and type may not be easy. In earlier years utilities did considerable research on load characteristics and methods of predicting overall system and component loads. In most cases, given appropriate data, these methodologies are still valid. However, there are now several confounding issues such as changes in appliance characteristics and personal lifestyles. The expected load on a transformer is dependent upon the number and type of customers served, since the kW peak demand is related to the single customer kWh, the associated diversity or coincidence factors, and the peak responsibility factor (Nickel and Braunstein 1981). Utility personnel have indicated a strong trend toward simplifying the kWh/kW function, with many now using only a simple linear regression. Generally, diversity of load provides assurance that transformer peak loads will not exceed the sum of the individual loads. Diversity factors are very specific to the utility, the load, and the weather, but there are generic formulations that can be used with appropriate caution. The impact of weather (long, intense hot or cold periods) tends to reduce load diversity because most electric load is very dependent upon heating and/or cooling degree days. Since the allowed transformer peak loading is related to ambient temperature, regular long, hot periods may require adjustments to the transformer's loading pattern and size, as discussed in the IEEE loading guides (IEEE 1989, 1995).

There is no simple relationship between per unit RMS and simple averages. However, the ratio of average load to RMS load taken from typical load profiles suggests that at least a 1.10 multiplier would be prudent. Those transformers with low load factors and relatively high peaks will exhibit the greatest difference between RMS and average loads. Intuition and expected loading patterns would perhaps suggest that smaller units would experience the greatest peaks and lowest load factors and thus have the greatest difference between RMS and average. Unfortunately, the utility data obtained during our survey may not support this conclusion. These findings are presented following the discussion of utility data and peak demands.

2.2.3 Peak Demands

Many utilities have transformer management programs that monitor the peak demand on their transformers by demand meters or estimates from kilowatt-hour data. ORNL collected and analyzed data from selected utilities. Typical results are given in Figs. 2.3–2.5, which show relative loading, and in Table 2.1, which shows the analysis of single-phase, pole-mounted units. Of special note in Figs. 2.4 and 2.5 are the relative number of transformers with peak loads exceeding the nameplate rating. These data alone support a relative per unit load of 0.25 to 0.35. Fig. 2.5 provides some insight into the relative loading of small and large units. Clearly, the smaller unit has a greater proportion of the population, with peak load exceeding the nameplate rating, while the average load of the larger unit would appear to be greater. This trend is the expected classical loading pattern, but other transformer sizes do not support this conclusion, as is seen in Fig. 2.3. Figs. 2.4 and 2.5 present only the estimated peak load or demand. Average load, load factor, kilowatt-hours, loss factor, and power factor are not given. Nevertheless, the data imply a relatively low average load, since only a small fraction of transformers have peak loads above nameplate. Data provided from the same utility for 1988–94 consistently support this conclusion.

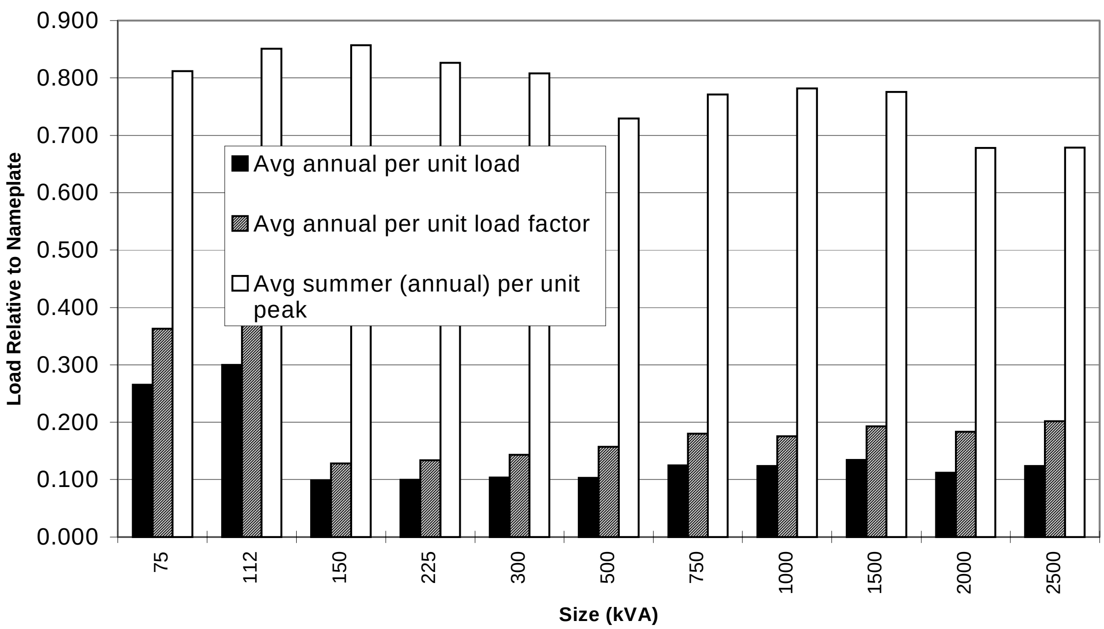

Fig. 2.3. Average loads, peak loads, and load factors for a utility's three-phase distribution transformers, 1995–1996.

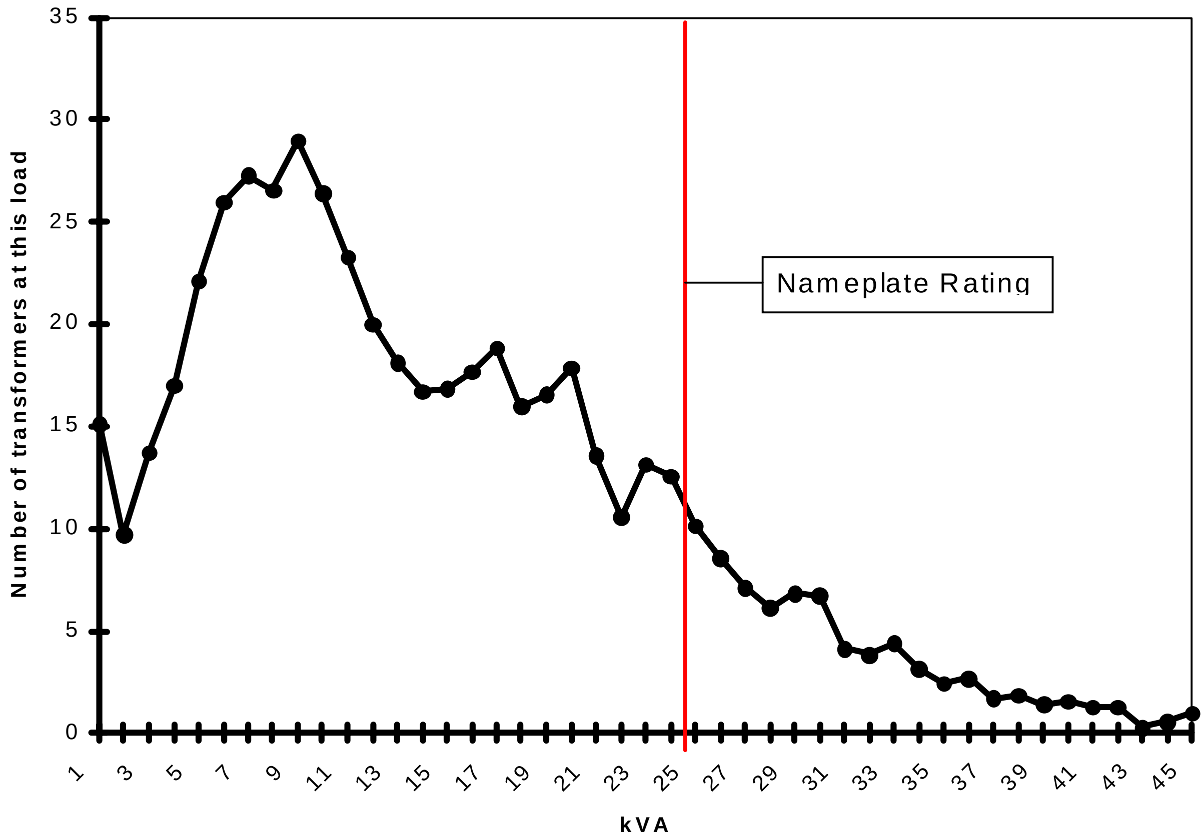

Fig. 2.4. Peak load distribution for 25-kVA transformers, summer 1994.

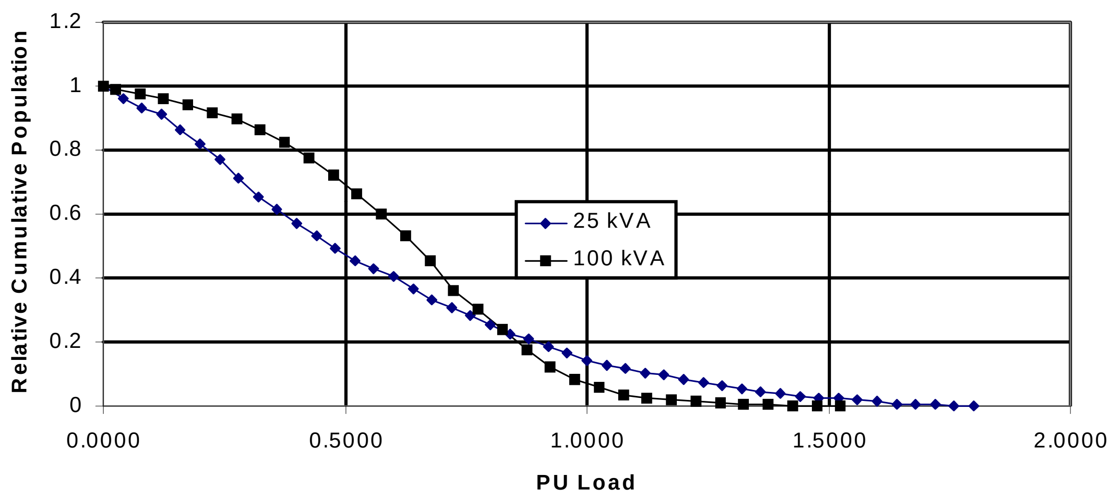

Fig. 2.5. Relative number of units with per unit load greater than or equal to *x*.

Table 2.1. Summary data for a utility's single-phase, pole-mounted distribution transformers

Size (kVA)	Summer (annual) peak (kW)	Summer (annual) PU peak (kW)	Total MWh	No. of installed transformers	kWh/ transformer	Annual PU avg load (kVA)	Annual PU load factor	Calculated loss factor	Annual PU RMS load
10	6.6	0.73	1,259,756	59,793	21,069	0.267	0.405	0.200	0.295
15	10.2	0.76	3,679,621	106,476	34,558	0.292	0.430	0.221	0.320
25	17.4	0.77	7,217,228	118,584	60,862	0.309	0.444	0.234	0.337
37	27.4	0.82	7,403,986	77,076	96,061	0.329	0.445	0.235	0.359
50	35.8	0.80	6,140,474	50,580	121,401	0.308	0.430	0.222	0.337
75	48.6	0.72	4,105,873	24,682	166,351	0.281	0.434	0.225	0.308
100	60.5	0.67	1,868,048	8,457	220,888	0.280	0.463	0.252	0.304
167	91.6	0.61	1,423,559	3,820	372,659	0.283	0.516	0.304	0.302
250	140.9	0.63	373,670	592	631,199	0.320	0.568	0.360	0.338
333	181.0	0.60	246,846	284	869,176	0.331	0.609	0.407	0.347
500	254.5	0.57	277,229	231	1,200,126	0.304	0.598	0.394	0.319
667	443.7	0.74	14,995	9	1,666,111	0.317	0.476	0.264	0.342
833	441.2	0.59	111,564	51	2,187,529	0.333	0.629	0.431	0.348

Note: PU = per unit.

2.2.4 Average Loading by Nameplate Capacity

Traditional wisdom would expect larger transformers, both liquid-immersed and dry-type, to be loaded more uniformly — i.e., to have a lower per unit peak loading and a higher average load (EPRI 1983; Nickel and Braunstein 1981). This logic is justified by the desire to increase reliability, which tends to reduce the peak load of large transformers. However, the utility survey data available to ORNL researchers indicate both a relatively low peak load and a low average load. This result may be representative of the utilities surveyed (most have high air conditioning loads) or of the application (high motor loads with frequent starts). In either case, the desire to prevent voltage sag and lighting flicker may prevent increased average load with increased size. Per unit RMS loading by nameplate capacity for liquid-filled utility transformers is shown in Fig. 2.6. Because there was insufficient data to support estimates of the loadings of larger units, a value of 0.5 was assumed until better data are available. Non-utility applications are loaded to 0.35 for low-voltage or 0.5 for medium-voltage per unit RMS.

2.3 DRY-TYPE LOW-VOLTAGE TRANSFORMERS

Dry-type low-voltage transformers are used in power distribution networks of large commercial and industrial buildings to transform the building voltage (typically 480 V) to a lower voltage of 120, 240, or 208 V (three-phase) for powering equipment and lights. The designs of building power networks are normally based on the National Electrical Code (NEC), which establishes the minimum standards for wiring design and installation practices to minimize fire and accident hazards. NEC rules are often enforced by being incorporated into local building codes. NEC requires that certain minimum loadings be assumed in designing branch circuits and feeders. In addition to the known or assumed minimum loading, engineering practice is to make provisions for future load growth by increasing feeder and panel capacities by 50% (Fink and Carroll 1969, ch. 17). Thus, the rated capacities of feeder distribution panels are very conservative, since not all circuits are fully loaded at the same time and since a 50% growth margin is included in the size specifications. In addition, because of the limited number of standard panel sizes (100 A, 200 A, 400 A, etc.), a much larger capacity than necessary would be selected, to accommodate a load that is closer to but larger than that of the next smaller panel size. This conservatism is also used in specifying the transformer that supplies the panel(s). Since additional loads can be added later, up to the panel rating, transformers are sized to adequately power the panel unless it can be established that additional loads will not be added over the life of the building. For example, a 200-A three-wire 120/240-V panel would require a 50-kVA transformer; and a 200-A three-phase four-wire 120/208-V panel would require a 75-kVA transformer.

Because of load diversity, the fact that many actual loads at outlets are well below the maximum circuit ratings, and the conservatism for future load growth, most low-voltage dry distribution transformers have a peak load of only about 50–60% of their rated capacity. An example of the load profile of a three-phase 75-kVA transformer in an office building is shown in Fig. 2.7. The peak load is about 44% of the rated capacity. The per unit average and RMS loads are 0.2 and 0.22, respectively. Several years ago, a conservation program in the form of more efficient lighting reduced the peak load on this unit by about 25% (the exact reduction is uncertain); thus, the transformer was initially loaded to about 58%. Prior to the conservation activities, the per unit average and RMS loads were about 0.26 and 0.29. A per unit RMS load of 0.35 is a reasonable assumption.

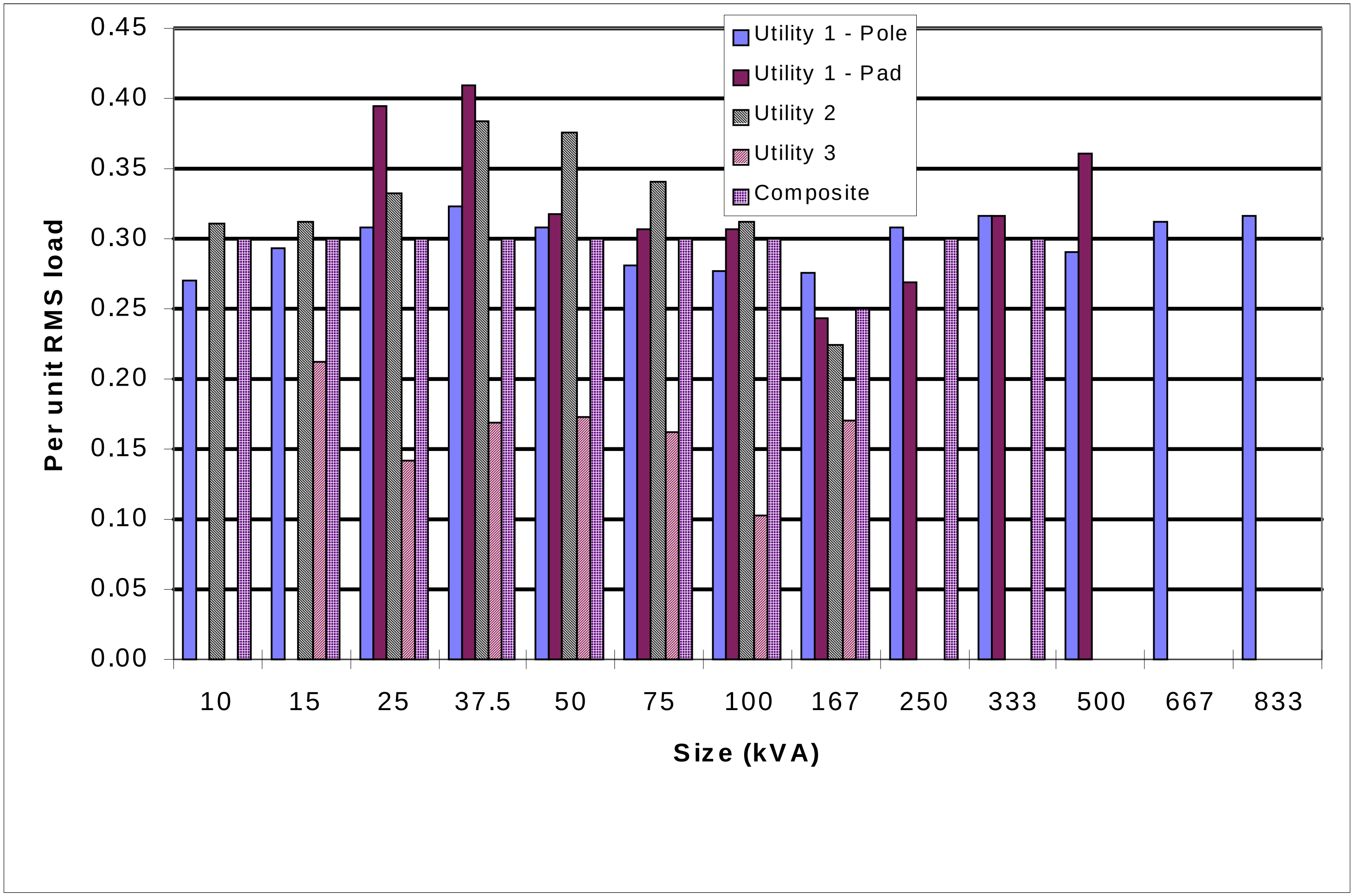

Fig. 2.6. Average RMS load for single-phase transformers by size for three utilities.

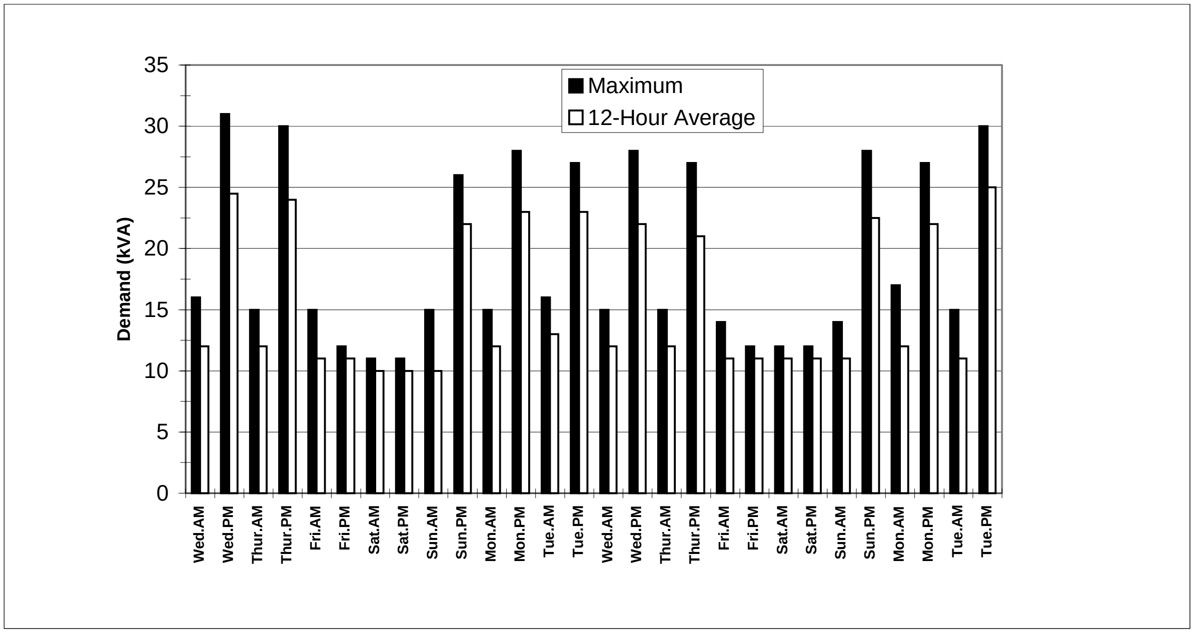

Fig. 2.7. Load profile for a dry-type three-phase 75-kVA transformer.

2.4 DRY-TYPE MEDIUM-VOLTAGE TRANSFORMERS

Relatively large three-phase dry-type medium-voltage transformers are typically used in unit substations to transform the utility primary distribution voltage to the building voltage for use in powering feeder circuits and large motors. Diversity in the loads among the various feeders results in a larger load factor and a higher average per unit load than the low-voltage transformers in the feeder circuits. The demand factor — the ratio of the maximum demand to the sum of the feeder peak demands — for various loads of "commercial power and general power" is typically 70% (Fink and Carroll 1969, ch. 16, p. 302). However, the average power is not affected by load diversity, and if the unit substation is sized on the basis of the demand factor, the per unit average and RMS power levels will increase by the inverse of the demand factor. Thus, if the low-voltage units in the branch circuits are loaded to 35%, then the unit substation could reasonably have an effective load of 50%.

Single-phase dry-type medium-voltage transformers are used in large industrial and commercial facilities where the building or plant voltage is in the medium-voltage class. They are also used to serve as unit substations in facilities where only single-phase power is required and in other special applications. The per unit effective load for unit substation applications will be similar to that of three-phase units. The smaller single- and three-phase units ($\leq$100 kV) that serve lighting panels, etc., can be expected to be lightly loaded in a way similar to low-voltage transformers. Fan motor loads used for continuous building ventilation and other applications result in these types of transformers' having relatively high effective loads. However, transformers associated with large motor loads are sized larger to reduce voltage sag and flicker caused by motor starting and inrush current, which can present major problems with cyclical loads. For medium-voltage applications in industrial or commercial applications, a load of 0.5 per unit is an acceptable value when voltage regulation issues are considered.

2.5 NON-UTILITY LIQUID-IMMERSED TRANSFORMERS

Non-utility liquid-immersed transformers are used in large commercial and industrial applications. These transformers may be located outdoors or in a transformer vault along with switchgear and control equipment. Because the load profiles for large industrial customers are typically flatter than those for residential and commercial customers (Fink and Carroll 1969, ch. 16), the per unit average and effective transformer loads can be higher. An ORNL survey of transformer loading by local industrial users found that per unit average loads ranged from 0.19 to 0.73, with the mean average being 0.47. The mean per unit average load for large commercial users was 0.38. RMS loads can be expected to be about 5% higher than the average loads, or about 40%. Thus, commercial and industrial non-utility liquid-immersed transformers have a per unit RMS load of 0.4 to 0.5.

2.6 FUTURE TRENDS

To cut inventory costs, some utilities are assessing their transformer requirements and are eliminating some of the sizes (*Electrical World* 1996). When a utility has fewer transformer sizes available, it must increase the range of loads for a given size, with the result that some units have higher loads. A survey of 37 utilities by Stone and Webster for Cooper Power Systems found that most utilities expect the average loads on distribution transformers to increase; none expected average loading to decrease (Austin 1994). A larger survey of 64 utilities by the Edison Electric Institute (EEI) found that nearly half of the respondents plan to load transformers initially at more than 100% (per unit peak) for new customers (Hall 1996).

2.7 SUMMARY

Under the NEMA standard TP 1-1996 (NEMA 1996), reference RMS load conditions for dry-type distribution transformers are 35% and 50% of nameplate loads for low-voltage and medium-voltage units, respectively. These reference loads are higher than the limited loading data examined in this study but appear to be consistent with engineering design practices. Smaller liquid-immersed distribution transformers that serve one or two residential customers or are used for outdoor lighting, pump houses, etc., have light annual per unit average loads ranging from a few percent to about 15%. On the other hand, large transformers equal to or greater than 100 kVA that serve commercial and industrial customers and large apartment buildings have higher average loads, typically ranging from 20 to 70% of nameplate loads, with mean values of about 35%. Based on the data from three utilities used in this study, the TP-1 standard reference load condition of 50% of nameplate loads for medium-voltage liquid-immersed transformers is too high for typical utility distribution transformers. However, if utilities start loading their transformers higher, as indicated by recent surveys, then the RMS load may increase for new installations.

3. ENERGY ANALYSIS MODEL

3.1 INTRODUCTION

A distribution transformer that is continuously energized and providing service to secondary load consumes energy 24 hours a day to magnetize the core and to overcome ohmic losses from eddy and conductor currents. Even when the transformer is not supplying power to a load, it is consuming energy because of losses in the core. The core losses are also called no-load losses. The transformer will normally experience varying load conditions with both diurnal and seasonal variability. As discussed in Sect. 2, when the load increases from a no-load condition to a finite load, the losses increase proportionally with the square of the load current due to ohmic losses in the coils. Thus, over a period of varying loads, the coil losses are a function of the effective or RMS load current; these losses are also a function of the RMS load if the load voltage is assumed to be constant.

3.2 ANNUAL ENERGY LOSSES

The annual energy losses for a transformer can be determined by its loss parameters ─ namely, the no-load losses (NL), the full-load losses (LL), and the temperature correction factor (T). The annual losses in kilowatt-hours are given by

$$L = 8.76 \times (NL + LL \times T \times \mathrm{S}^2) \quad , \tag{3.1}$$

where *NL* and *LL* are given in watts, *S* is the per unit RMS load computed for an annual period, and *T* is a temperature correction factor (see Appendix C). In general, *S* is slightly larger than the average per unit load given by

$$S_{\mathrm{av}} = E_{\mathrm{o}} \,/\, (S_B \times PF \times 8760) \quad , \tag{3.2}$$

where E_o is the annual energy supplied to the load by the transformer in units of kilowatt-hours, S_B is the nameplate rating of the transformer in kilovolt-amperes, and *PF* is the power factor. The power factor, defined as the ratio of the real power to the apparent power, varies as the utility system load changes. During moderate- to high-load conditions, the power factor ranges from 0.80 to 0.95, with an average value of 0.90 (Nickel and Braunstein 1981). For the analyses in this study, an effective value for *PF* is assumed to be 0.90.

Transformer efficiency varies with the load. The efficiency for the RMS load *S* with a unity power factor is

$$\eta = 1000 \times S \times S_B \times (S \times S_B + NL + T \times LL \times S^2)^{-1} \quad . \tag{3.3}$$

The annual energy consumption for each conservation case is calculated by adding the losses of the transformer capacity purchased during the year. A simplifying assumption is made that all transformers are placed into operation at the beginning of the year. For a conservation standards case where the transformer's losses are given in terms of an efficiency at a specified load, the losses are first determined by *assuming* that manufacturers will meet the standard with a design that minimizes both cost and materials. A design that maximizes the transformer efficiency at (or near) the load specified by the standard would permit the manufacturer to meet the standard at a minimum cost.[1] This assumption is necessary because there are many designs that a manufacturer could choose to meet the standard. However, it is likely in a competitive market that the choice will be close to a minimum cost design. For a conservation standard efficiency η_{std} , specified load S_{std} , and a maximum efficiency η_{max} at a per unit load S_{max} , the losses for a transformer designed to meet the standard are

$$NL_{std} = 1000 \times S_B \times S_{std} \times (1\text{-}\eta_{std}) \,/\, [1 + (S_{std} / S_{max})^2] \times \eta_{std} \tag{3.4}$$

and

$$LL_{std} = NL_{std} \,/\, [T \times (S_{max})^2] \ . \tag{3.5}$$

This approach is described in more detail in Appendix D. In the ORNL energy analysis model, S_{max} is set equal to S_{std} .

Transformer losses are determined for each transformer in the conservation case as a function of size, type, and operating voltage. Once the individual transformer annual losses at the operating load are determined, they are multiplied by the projected sales for each transformer. The total annual case losses, L_{case} , is determined by summing the losses for all transformers in the conservation case.

3.3 CONSERVATION CASE EFFICIENCY

The case efficiency is defined as the ratio of the annual energy supplied to customers by the new transformers E_o to the total annual energy supplied to the transformers. The case efficiency can also be expressed as a function of E_o and the conservation case losses; i.e.,

$$\xi = E_o \,/\, (E_o + L_{case}) \ . \tag{3.6}$$

The total annual energy (in kWh) supplied to customers by the new transformers, E_o , is determined by summing the energy supplied by all of the transformers in the conservation case and is equal to

$$E_o = \sum S_{Bi} \times PF \times S_{avi} \times 8760 \text{ hrs} \times U_i \ , \tag{3.7}$$

where i is the ith transformer in the case — for example, an evaluated 25-kVA medium-voltage liquid-filled transformer used for utility applications — and U is the number of units sold annually. The energy consumed by the transformers in kilowatt-hours can be expressed in terms of the case efficiency:

$$L_{case} = E_o \times (1 - \xi) \,/\, \xi \ . \tag{3.8}$$

[1] This is a simplifying assumption for the purposes of analysis. The minimum-cost design is affected by many factors, including core type and material costs, and actual designs will vary from manufacturer to manufacturer.

3.4 ENERGY SAVINGS

The annual energy savings associated with a standard or conservation program is simply the energy losses for the base case, $L_{\text{base case}}$, minus the energy losses for the conservation case, L_{std} . The annual energy saving is given by

$$E_{\text{savings}} = L_{\text{base case}} - L_{\text{std}} \quad . \tag{3.9}$$

Since transformers are generally efficient devices with efficiencies above 90%, the reduction of the losses may provide a better measure for the effectiveness of a conservation case. The reduction of losses for a conservation case in percentage is given by

$$R = 100 \times E_{\text{savings}} / L_{\text{base case}} \quad . \tag{3.10}$$

For nonevaluated transformers the energy savings is straightforward, since the losses of the base case exceed the losses for the conservation case. For evaluated transformers the calculation is more complicated because many of the transformers being purchased have higher efficiencies than the minimum efficiency specified by the conservation case. Only those transformers with efficiencies lower than the standard would be affected. Figure 3.1 shows the range of efficiencies for 25-kVA pole-mounted transformers taken from a survey of 54 utilities. To meet the NEMA standard, only about 6% of these utilities would have to purchase more efficient transformers. However, to meet

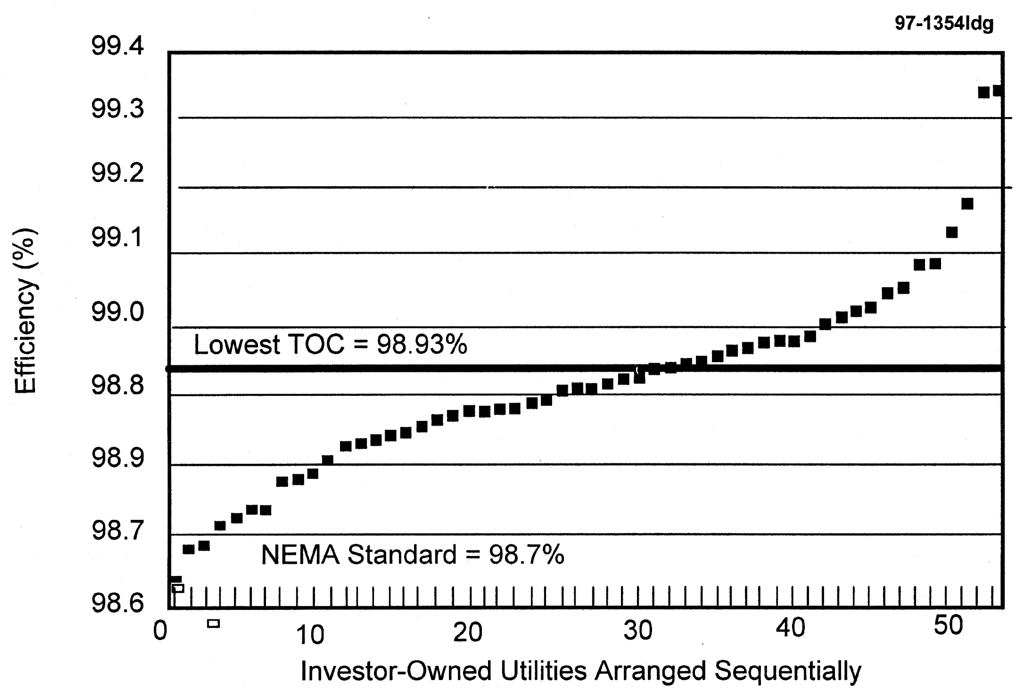

Fig. 3.1. Efficiencies of 25-kVA distribution transformers purchased by 54 utilities. Efficiencies are at 50% effective load. A total owning cost (TOC) efficiency of 98.93% is based on A = \$3.50 and B = \$0.75.

standards with higher minimum efficiencies, such as the TOC standard shown in Fig. 3.1, which is based on A = \$3.50/watt and B = \$0.75/watt, where A is the equivalent first cost of no-load losses and B is the equivalent first cost of full-load losses, many more utilities would be affected.

Calculations of the energy savings for evaluated transformers are based on a comparison of the losses defined by the efficiency standard to the average losses for transformers with efficiencies lower than the standard. The losses for transformers below the standard were determined from a survey of utilities for 11 types of liquid medium-voltage transformers, including 8 single-phase and 3 three-phase transformers. The average losses for these transformers were used to represent the losses of transformers of the same type and size. For transformers not included in the survey, the losses for a surveyed transformer of the same type that was closest in size were extrapolated according to the ratio of the unknown transformer to the known transformer's size to the 0.75 power. The fraction of transformers below the standard in the survey was used to estimate the total fraction of the evaluated capacity that would need to improve to meet the standard. The difference between the average for the losses of the transformers below the efficiency standard compared to the losses of transformers defined as just meeting the standard was used to determine the effect of the standard for this fraction of new transformer sales.

The energy savings over the conservation period of n years is the sum of savings that are achieved during the first year for n years plus the second year's savings for $n - 1$ years, etc. The energy savings over the n-year period with a constant market growth rate r are given by

$$E_{\mathrm{case}} = E_{\mathrm{savings}} \left[(1 + r)^{n+1} - (1 + r) - nr\right] / r^2 \quad . \qquad \textbf{(3.11)}$$

For the case where the rate of growth is zero, the case savings reduces to

$$E_{\mathrm{case}} = E_{\mathrm{savings}} \left[n(1 + n)/\, 2\right] \quad . \qquad \textbf{(3.12)}$$

3.5 LOAD SPECIFIED BY A STANDARD

The extent to which manufacturers would tend to design transformers for maximum efficiencies at the loads specified for meeting a standard (see Appendix D) could have an important impact on energy savings. In some cases losses could actually increase if actual operating loads are significantly below the specified load for meeting the standard's minimum efficiency. For instance, if the load specified for meeting the standard is 50% and the actual operating load for a transformer is 30%, the standard could be met by increasing the transformer's efficiency at 50% while reducing its efficiency at 30%. This would result from reducing full-load losses while increasing no-load losses. This condition of increased losses was observed for some sizes of evaluated liquid-immersed transformers during the analysis of the TP-1 standard conducted for Chapter 5.

This anomaly provides an important insight into setting standards. The TP-1 standard has been set for a 50% load for liquid-filled medium-voltage transformers. To the extent that transformers are designed to be at maximum efficiency at the load specified for meeting the standard, the ratio of the load to no-load losses will decrease if the load at which the efficiency is specified increases, and will increase if the load specified for the efficiency calculation decreases. If the actual loads at which transformers operate are less than the load specified for meeting the standard, the resulting transformer design will be less efficient under operating conditions than it would be if the specified load for meeting the standard was closer to the actual operating load. Therefore, for the same cost, a transformer designed to have its maximum efficiency at a 50% load will tend to have a lower efficiency operating at a 30% load than a transformer designed to have its maximum efficiency at a load between 30% and 50%.

A sensitivity evaluation of this effect is presented in Fig. 3.2. As this figure indicates, setting an efficiency standard as close as possible to the actual operating load of the transformer can have a significant effect in reducing energy losses. This graph suggests that, given uncertainty about existing loads and future load trends, setting an efficiency standard near 40% could be a good strategy. Fortunately, it appears from recent surveys that many new transformers have been designed with a maximum efficiency of between 40 and 45%.

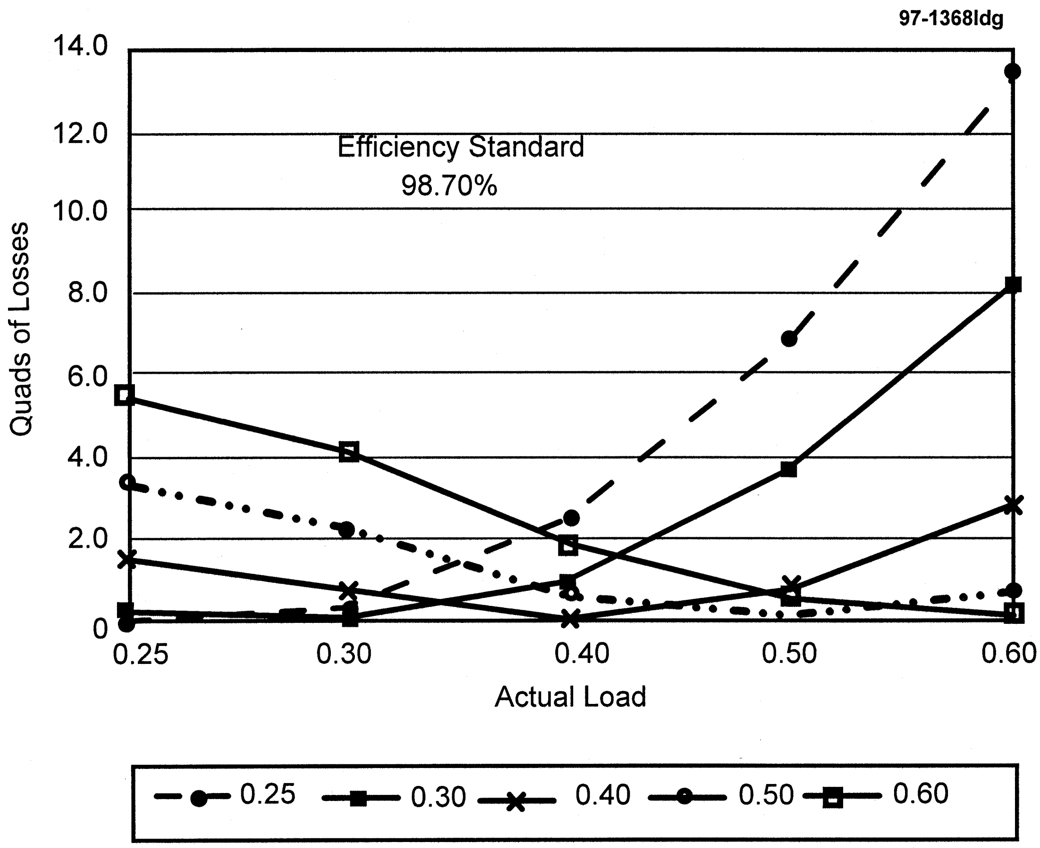

Fig. 3.2. Thirty-year cumulative differences in energy losses for designs that maximize transformer efficiency at five alternative loads, compared to energy losses if designs maximized efficiency at actual load.

4. THE BASE CASE

4.1 INTRODUCTION

The base case is the business-as-usual case with no mandatory conservation standards to influence the energy efficiencies of future transformer purchases. The time period for analysis is the period during which the first transformers purchased under the new standard are expected to operate; for distribution transformers, a period of 30 years is the normal life expectancy. Thus, not only must the base case define the present transformer market and the energy consumption associated with annual sales of distribution transformers, but it must also make a projection of the market and transformer efficiencies over the analysis period. The simplest projection is a constant sales growth rate along with no changes in transformer efficiencies. Due to the uncertainties associated with long-term projections, there is a high probability that any projection scenario will ultimately be shown to be incorrect.

For distribution transformers, there are no indications at this time that the commercial and industrial applications will change in the future. Anticipated changes for utilities, however, could influence their application of distribution transformers. Utility restructuring and competition may result in an emphasis on shorter payback periods, which implies the use of transformers with a lower capital cost and higher losses. On the other hand, the U.S. Environmental Protection Agency's (EPA's) Energy Star program and other conservation programs that promote energy efficiency will encourage utilities to purchase more efficient transformers. Thus, the future trend for utility distribution transformers is unclear, and until more information is available, the simple projection scenario of no changes in transformer efficiencies and a low constant rate of growth appears to be appropriate.

4.2 BASE CASE DEFINITION

The base case is defined as the energy consumption of new transformers with existing energy efficiency characteristics. For the purposes of this report, the estimate of annual energy consumption is based on 1995, the year of the most recent sales data. This annual estimate has been adjusted upward by an expected growth in sales to 2004, which is projected as the first year that energy conservation standards for transformers could be initiated. Cumulative energy consumption for the base case is defined for a 30-year period spanning 2004 through 2033. The rate of annual energy consumption has been assumed to be constant over this entire period except for changes resulting from projected increases in annual sales.

4.3 BASE CASE ASSUMPTIONS

Distribution transformer annual sales in nameplate capacity (MVA) and annual sales growth are parameters needed to conduct energy consumption or savings analysis for the base case and other conservation cases. Since transformer losses vary with size and type, the market characteristics associated with size and type are needed. These include the losses for evaluated and nonevaluated transformers, the number of evaluated transformers used for utility and commercial and industrial applications, and the total liquid-immersed transformer market associated with non-utility applications. The values and assumptions shown in Tables 4.1, 4.2, and 4.3 were developed from surveys of utilities and transformer manufacturers and follow-up discussions with the manufacturers.

Crucial base case assumptions utilized to calculate the energy losses include average transformer efficiencies by size and type of transformer and the annual sales of new transformers by size and type. Key assumptions discussed here include design losses, average transformer loading, and annual sales. These assumptions are made for each of 27 liquid-immersed transformers and 46 dry-type transformers.

4.3.1 Base Case Design Losses

Table 4.1 shows the typical energy losses for evaluated and nonevaluated liquid medium-voltage transformers. Essentially all utility-owned transformers are of this type. Commercial and industrial applications for liquid medium-voltage transformers are mostly for the larger sizes (see Table 4.2). Table 4.2 breaks out liquid medium voltage transformers by ownership (utility vs non-utility) and by whether the transformers are evaluated. Evaluated transformers typically have higher efficiencies than nonevaluated ones. In the absence of a definitive source for this breakout, it has been based on information from discussions with and informal information provided by transformer manufacturers. The loss characteristics describing utility transformers are probably more reliable than those for non-utilities because of the additional information from utility surveys (Barnes et al. 1996).

The TP-1 Survey was considered as one source for these assumptions. This survey of NEMA and non-NEMA manufacturers during 1996, conducted by NEMA and ORNL, respectively, and reproduced in this report as Appendix E, was undertaken to determine how transformer manufacturers would design transformers to meet the NEMA TP-1 transformer efficiency standard. The survey also requested information on nonevaluated transformers and the additional costs associated with the purchase of a TP-1 transformer instead of a nonevaluated one. However, there were relatively few responses to the survey, and there were significant variations in losses and efficiencies within many of the transformer categories. Therefore, typical losses and characteristic efficiencies for these types of transformers were taken from data supplied by NEMA and by various transformer manufacturers, as indicated in the source notes in Tables 4.1 and 4.3.

4.3.2 Base Case Loads

Table 4.2 breaks out the liquid medium voltage transformers by ownership and presents the characteristic annual RMS load. Data on the total transformer capacity in use and the total energy served is reported by major utilities on FERC Form 1. An initial assignment of RMS loads was based on a review of loads reported by several utilities (see Chapter 2). The loads for each type and size of transformer were then adjusted by a factor that made the aggregate of the individual loads weighted by sales consistent with the overall average load as calculated from the FERC 1 data (see Chapter 2).

In addition to the assumptions discussed above, the following assumptions, based on typical values from the literature, have been used:

- The average load is related to the RMS load approximately by $S_{av} = 0.9 \times S$.
- The weighted average per unit load for all utility-owned transformers is 0.24 (see Chapter 2).
- The power factor is assumed to be equal to 0.9 (Nickel and Braunstein 1981).

- The case time period is 30 years starting with year 2004.
- Primary energy is based on 10,455 Btu/kWh primary energy conversion to net generation of electricity (EIA 1996b) and transmission and distribution system losses to the transformers of 5.89% (Barnes et al. 1994), for a total of 11,070 Btu/kWh.

Crucial assumptions on future distribution transformer sales are discussed in Sect. 4.3.3.

Table 4.1. Base case design loss parameters: medium-voltage liquid-immersed distribution transformers

Single-phase						Three-phase					
Size (kVA)[a]	Evaluated		Nonevaluated		% eval.	Size (kVA)[a]	Evaluated		Nonevaluated		% eval.
	NL	LL	NL	LL			NL	LL	NL	LL	
10	31	193	44	237	85	15	63	204	94	356	85
15	40	212	53	323	85	30	104	366	156	623	85
25	58	312	90	460	85	45	141	489	224	868	85
37.5	81	412	108	615	85	75	227	759	319	1,353	85
50	101	540	153	670	85	112.5	268	1,117	443	1,853	85
75	133	718	217	944	85	150	312	1,650	450	2,100	85
100	166	873	271	1,201	85	225	396	1,998	647	3,172	85
167	256	1,350	384	2,059	85	300	587	2,577	822	4,126	85
250	361	1,888	543	2,950	85	500	721	4,021	1,178	5,738	85
333	429	2,867	746	3,797	66	750	1,053	5,973	1,900	8,000	85
500	608	4,050	1,062	5,060	62	1,000	1,337	6,486	1,946	11,306	68
667	739	4,391	1,273	6,063	60	1,500	1,747	8,841	2,721	14,470	60
833	876	5,239	1,528	7,231	60	2,000	2,197	14,464	3,369	18,961	60
						2,500	2,619	15,023	4,041	21,985	60

Sources: Barnes et al. 1994, 1996; NEMA letters to P. R. Barnes, September 15, 1995, and October 28, 1996; EEI utility survey (see Barnes 1994, Appendix A); and ORNL/NEMA surveys of manufacturers in 1996.

Note: NL = no-load losses in watts; LL = full-load losses in watts.

[a]Nameplate capacity of the transformer in kilovolt-amperes.

Table 4.2. Base case ownership and loading parameters for medium-voltage liquid-immersed distribution transformers

Single-phase						Three-phase					
	Utility			Non-utility			Utility			Non-utility	
Size (kVA)	Sales[a] (%)	Eval (%)	Load[b] RMS	Eval (%)	Load RMS	Size (kVA)	Sales[a] (%)	Eval (%)	Load[b] RMS	Eval (%)	Load RMS
10	100	85	0.25	—	—	15	100	85	0.25	—	—
15	100	85	0.25	—	—	30	100	85	0.25	—	—
25	100	85	0.25	—	—	45	100	85	0.25	—	—
37.5	100	85	0.25	—	—	75	97	87	0.25	10	0.35
50	100	85	0.25	—	—	112.5	94	90	0.25	10	0.35
75	100	85	0.25	—	—	150	94	90	0.25	10	0.35
100	100	90	0.25	—	—	225	94	90	0.25	10	0.5
167	94	90	0.2	10	0.5	300	94	90	0.25	10	0.5
250	94	90	0.25	10	0.5	500	94	90	0.25	10	0.5
333	70	90	0.25	10	0.5	750	93	90	0.35	15	0.5
500	65	90	0.3	10	0.5	1,000	70	90	0.4	15	0.5
667	50	90	0.3	30	0.5	1,500	50	90	0.4	30	0.5
833	50	90	0.3	30	0.5	2,000	50	90	0.4	30	0.5
						2,500	50	90	0.4	30	0.5

[a]Total utility sales are approximately 90% of the overall sales. For the percentage of sales, 100% is used to denote values greater than 99.9%.

[b]The overall average per unit load weighted by capacity of sales for utility transformers is 0.24.

Table 4.3. Base case design loss parameters: dry-type distribution transformers

Single-phase					Three-phase				
Size (kVA)[a]	Low-voltage		Medium-voltage		Size (kVA)[a]	Low-voltage		Medium-voltage	
	NL	LL	NL	LL		NL	LL	NL	LL
10	—	—	—	—	15	162	712	385	550
15	110	670	275	590	30	256	1,274	550	1,050
25	157	982	365	800	45	322	1,655	675	1,275
37.5	222	1,410	475	1,200	75	462	2,542	920	2,100
50	279	1,817	580	1,425	112.5	604	3,457	1,040	2,463
75	348	2,327	735	1,800	150	661	4,690	1,316	3,183
100	451	3,058	880	2,350	225	862	6,242	1,544	4,232
167	683	4,487	1,260	3,500	300	1,087	7,397	1,888	5,028
250	939	5,921	1,671	4,650	500	1,648	11,166	2,547	7,771
333	1,256	7,190	2,092	5,650	750	2,189	14,830	3,216	10,047
500	—	—	2,714	7,675	1,000	2,677	18,139	3,953	12,367
667	—	—	3,203	9,506	1,500	—	—	4,627	16,039
833	—	—	3,708	11,198	2,000	—	—	5,589	20,042
					2,500	—	—	6,574	24,318

Sources: Barnes et al. 1994, 1996; NEMA letters to P. R. Barnes, September 15, 1995, and October 28, 1996; Barnes 1994; and ORNL/NEMA surveys of manufacturers in 1996.

Note: NL = no-load losses in watts; LL = full-load losses in watts. All sizes are assumed to be nearly 100% nonevaluated.

Based on limited data, typical RMS loads range from 20 to 40% for low-voltage units and from 40 to 60% for medium-voltage units. The per unit loads of 35% and 50% for low-voltage and medium-voltage units, respectively, that are specified by NEMA TP 1-1996 (NEMA 1996) appear to be appropriate for the average RMS loads.

[a]Nameplate capacity of the transformer in kilovolt-amperes.

4.3.3 Market Trends and Forecasts

The market information on distribution transformers is based mainly on the annual industry surveys by NEMA. Since the NEMA data do not reflect the entire industry (representing only 80% and 72% of the total dry-type and liquid-immersed markets, respectively), ORNL attempted to collect the data from non-NEMA manufacturers. The estimate for the current distribution transformer market is based on the average values for 1993 to 1995 for both NEMA and non-NEMA manufacturers. Data for the liquid-filled transformer market of non-NEMA manufacturers, which included four major manufacturers, were collected through a survey designed by ORNL. The total market for liquid-immersed transformers, estimated by major size categories and by single- and three-phase units is shown in Fig. 4.1. The current market for liquid-immersed distribution transformers is estimated to be 68,150 MVA, or 1.5 million units. Single-phase transformers of less than 100 kVA hold the major market share, representing more than 50% of the total estimated liquid-immersed market, as shown in Fig 4.1. Single-phase transformers greater than 500 kVA are generally specialty and custom-ordered transformers and are assumed to be 0.3% (21 MVA) of the total market for single-phase transformers larger than 100 kVA (Smith 1996). The aggregate market data for the major size categories, further disaggregated into individual sizes based on the information obtained from several transformer manufacturers and a 1994 survey by NEMA, are shown in Table 4.4.

Compared to manufacturers of liquid-immersed transformers, non-NEMA manufacturers of dry-type transformers are numerous and smaller. However, only data from a large non-NEMA manufacturer were obtained from ORNL's survey. Therefore, the available market data on dry-type transformers (including data from NEMA manufacturers and a non-NEMA manufacturer) were increased by 20% to reflect the small and numerous non-NEMA manufacturers. The current total dry-type distribution transformer market is estimated to be 20,685 MVA, or 248,000 units; and it is disaggregated into seven major categories, as shown in Fig. 4.2. The three-phase low-voltage market is estimated to

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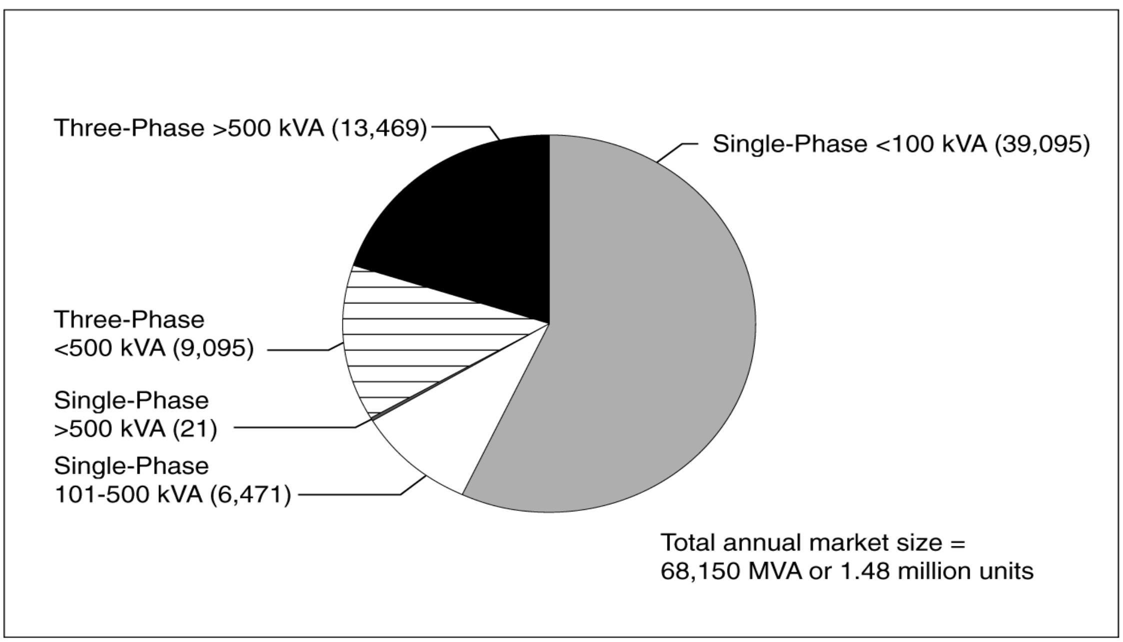

Fig. 4.1. Estimated 1995 market for liquid-immersed distribution transformers (MVA).

Table 4.4. Estimated 1995 annual medium-voltage liquid-filled distribution transformer market by capacity

Single-phase			Three-phase		
Size (kVA)	Sales in MVA	No. of units	Size (kVA)	Sales in MVA	No. of units
10	2,341	234,098	15	45	3,032
15	4,962	330,825	30	91	3,032
25	11,474	458,965	45	182	4,042
37.5	3,104	82,779	75	455	6,063
50	10,556	211,116	112.5	273	2,425
75	3,531	47,086	150	1,182	7,882
100	3,126	31,263	225	910	4,042
167	3,355	20,087	300	2,638	8,792
250	809	3,237	500	3,320	6,639
333	955	2,867	750	2,694	3,592
500	1,352	2,704	1,000	2,155	2,155
667	6	9	1,500	3,098	2,065
833	15	18	2,000	1,212	606
			2,500	4,310	1,724
All sizes	**45,587**	**1,425,053**		**22,564**	**56,093**

capture about 55% of the total market. The single-phase medium voltage market is assumed to be small, about 1% of the total dry-type market; and this market is disaggregated into further size categories (<100 kVA, 100–500 kVA, and >500 kVA) based on the 30%, 65%, and 5% distribution, respectively, among them (Nizinski 1996). The three-phase medium-voltage (>100 kVA) market is estimated to have the largest share (7820 MVA) of the total market among the different sizes considered here. It is assumed that 90% of this market, which is made up mainly of open-wound secondary unit substations and cast resin–type transformers, consists of sizes greater than 500 kVA, with an average size of 2000 kVA (Hurst 1996). No data were available explicitly for the three-phase medium-voltage (<100 kVA) market; it is assumed to be 5% of the total low-voltage market for the same size category reported by NEMA (Hopkinson 1996). The market shares of specific sizes within a major category are based on the NEMA survey of dry-type manufacturers and follow-up discussions with manufacturers, and are shown in Table 4.5.

Single-phase dry-type transformers of less than 15 kVA are not considered in the NEMA TP-1 standard (NEMA 1996). The market for single-phase 10-kVA dry-type transformers is small, not significantly different from that for 15-kVA transformers, shown in Table 4.5. However, about 1.4

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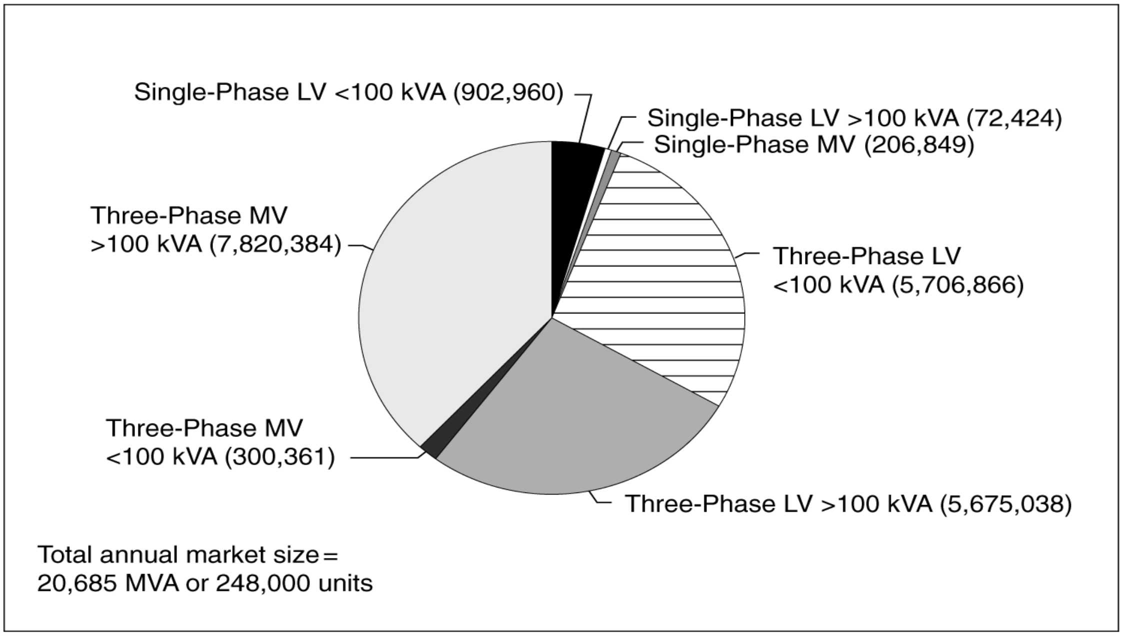

Fig. 4.2. Estimated 1995 market for dry-type distribution transformers (kVA).

million single-phase dry-type transformers of less than 10 kVA are currently sold in the market (with an average size of 1 kVA); these are used by original equipment manufacturers in machine tool applications. Distribution transformer applications in this size category usually average 3- to 5-kVA in capacity and currently have a share of ~400,000 units (equivalent to 1200 MVA) of the total market of 1.4 million units (Barnes et al. 1996). Therefore, the fact that single-phase dry-type transformers smaller than 15 kVA are not considered in the present study underestimates the total market for dry-type distribution transformers by 5.5% (in terms of megavolt-amperage).

The estimate of the liquid-immersed market in this report is about 3% higher, and for the dry-type market 27% lower, than the corresponding estimates made in the 1996 determination study (Barnes et al. 1996). The higher estimate shown in the determination study in the case of dry-type market is due to overestimation of the cast resin market (8000 vs 4000 MVA) and the use of a higher value for the non-NEMA market share (34% vs 20%). Limited information on estimates of the current size of the distribution market are available in the literature. The market data collected by the U.S. Department of Commerce (DOC 1994a) provide only the value of annual product shipments from manufacturers with shipments of $100,000 or more, and the data are limited to only a few major size categories for liquid-immersed and dry-type transformers, which makes it difficult to estimate the total market size. Most of the DOC data is limited to liquid-immersed transformers, and the 1992 estimates were found to be in the range of 65 to 80% higher (depending on the size category) than the values reported by NEMA (which do not include non-NEMA manufacturers). For example, the DOC estimate of the value of the overhead-type single-phase liquid-immersed 500-kVA and smaller transformers is $466 million, compared to a value of $356 million reported by NEMA. The Freedonia Group estimates the current size of liquid-immersed and dry-type markets as $1550 million and $445 million, respectively, an estimate that corresponds well to our estimates,

Table 4.5. Estimated 1995 annual dry-type distribution transformer market by capacity

Single-phase					Three-phase				
	Low-voltage		Medium-voltage			Low-voltage		Medium-voltage	
Size (kVA)[a]	Sales in MVA[b]	No. of units	Sales in MVA	No. of units	Size (kVA)	Sales in MVA	No. of units	Sales in MVA	No. of units
15	56	3,762	3	213	15	1,008	67,227	12	903
25	311	12,454	5	196	30	1,421	47,367	26	881
37.5	203	5,423	17	453	45	1,575	34,989	119	2,644
50	215	4,298	15	292	75	1,703	22,706	141	1,885
75	77	1,025	9	115	112.5	1,546	13,744	82	718
100	40	401	14	138	150	1,622	10,810	116	774
167	17	101	38	229	225	636	2,825	126	562
250	22	88	31	122	300	446	1,486	184	613
333	9	27	14	41	500	858	1,717	274	548
500	—	—	52	104	750	491	655	1,050	1,400
667	—	—	6	9	1,000	77	77	1,240	1,240
833	—	—	4	5	1,500	—	—	2,431	1,621
					2,000	—	—	969	485
					2,500	—	—	1,348	539
All sizes	**950**	**27,578**	**207**	**1,917**		**11,382**	**203,602**	**8,121**	**14,822**

[a]The 10-kVA size is not included in this table because it is not covered by NEMA TP-1. It is estimated that sales are about 55 MVA, or 5,500 units.

[b]The market for sizes less than 10 kVA used for power distribution applications is estimated at 1,200 MVA. The number of units in this size category is estimated at 400,000.

assuming that the dollar per kilovolt-ampere value in both cases is in the low 20s (Freedonia Group 1996).

The total distribution transformer line capacity of investor-owned electric utilities was estimated to be 1036 GVA in 1994, based on the latest FERC Form 1 data (RDI 1996). Total capacity increase and retirements during the same year were estimated to be 28 GVA and 16 GVA, respectively (RDI 1996). Annual sales of liquid-immersed distribution transformers to investor-owned electric utilities can be calculated by adding annual capacity increase and retirements. Total sales of liquid-immersed transformers in 1994 were estimated to be 64 GVA, assuming that 76% of total liquid-immersed transformers are investor-owned (EIA 1996c) and that 90% of the total liquid-immersed market is used for utility applications. Our estimate of the total liquid-immersed transformer market, based on 1995 NEMA sales data, is 68 GVA; this is 4% higher than the estimated 1994 consumption of 64 MVA. Note that this comparison of transformer sales is complicated by the fact that FERC Form 1 distribution transformer line capacity data found in the literature are not necessarily consistent from year to year — i.e., the total line capacity at the beginning of a given year does not always equal the total capacity at the end of the previous year. This is due to the variation in the number of utilities reported in the FERC Form 1 each year. Also, there is not a one-to-one correspondence between transformer sales and capacity additions, owing to the time lag between purchase of transformers and actual addition of transformer capacity. However, our estimate of the liquid-immersed transformer market, 68 MVA, compares reasonably well with that derived from FERC Form 1 consumption data.

The outlook for the distribution transformer industry is expected to be the same as that of the past decade. Demand for distribution transformers is based primarily on the rate of replacement for the installed base, new housing starts, and energy consumption demand growth. Since installed distribution transformers are relatively well-developed, efficient devices, the rate of replacement is generally low [estimated to be 20% of annual installations (Freedonia Group 1996)]. Replacements are mainly due to equipment failures and changes in voltage requirements. The annual growth of liquid-immersed transformers assumed here is 0.8% (the same as that assumed for dry-type transformers, as discussed later on). This growth rate is based primarily on the Energy Information Administration's (EIA's) forecast of growth in residential energy consumption, which takes into account new housing starts and several other factors (EIA 1996a). Affordability and demographic factors will cause new housing starts to grow more slowly than the overall economy (DOC 1994b), and the number of households is forecast to grow at 1.1% per year during the next 20 years (EIA 1996a). It is anticipated that growth in this sector will also be affected by increasingly energy-conscious consumers and more efficient electrical appliances, which will reduce the rate of energy consumption per household by 0.3% annually during the same period (EIA 1996a).

Dry-type transformers are used primarily in commercial and industrial applications; thus, estimates for the market growth of this type of transformer are based on the growth in industrial and commercial energy consumption. The dry-type transformer market is assumed to grow annually at 0.8%, the average of growth rates in commercial and industrial energy consumption forecast for the period 1994–2015 (EIA 1996a). Alternatively, the forecast of gross private domestic investment may also be used to forecast the dry-type transformer market, but it does not account for future energy efficiency and conservation potentials.

The growth rate of 0.8% for both liquid-immersed and dry-type transformers, assumed on the basis of the growth in total energy consumption, represents a pessimistic (or *low-growth*) scenario for the distribution transformer market. The rate of growth in electricity consumption (a better indicator for the transformer market than total energy consumption) is forecast to be twice the growth in total energy consumption due to a reduction in distillate fuel consumption. For example, in the residential sector, electricity consumption is forecast to grow at 1.6% per year, compared to 0.8% for total energy consumption during the 1995–2015 period (EIA 1996a). Similarly, for the commercial sector, the corresponding values are 0.7% and 1.5%, respectively.

Another scenario, an optimistic (or *high-growth*) scenario, has been considered here for the transformer market on the basis of growth in electricity consumption. The optimistic scenario assumes a growth rate of 1.6% per year for both liquid-immersed and dry-type transformers, twice the growth rate assumed under the low-growth scenario.

Although a substantial change in the product mix of transformers is forecast in the future, with pad-mounted transformers gaining at the expense of overhead types and three-phase transformers being substituted for single-phase designs, the growth rates are assumed not to vary with the size and phase of transformers considered here. Overhead vs pad-mounted types of transformers are not explicitly considered here, and the overall impact for a particular transformer size market may not be that significant. Since three-phase transformers often replace three or more single-phase units, this replacement demand will cause only moderate growth in three-phase distribution shipments.

Table 4.6 shows the estimated annual shipments of liquid-immersed and dry-type distribution transformers by different size categories for 1995–2033; for the estimated years, the low and high values of the range correspond to the low- and high-growth scenarios, respectively. Estimated total

Table 4.6. Annual shipments (in MVA) of distribution transformers in sizes of 10 kVA to 2.5 MVA, 1995–2033

Transformer type	1995	2000	2005	2010	2015	2020	2025	2033
Liquid-immersed								
Single-phase <100 kVA	39,095	40,684 – 42,324	42,338 – 45,820	44,058 – 49,605	45,849 – 53,703	47,713 – 58,139	49,652 – 62,941	52,920 – 71,463
Single-phase 101–500 kVA	6,471	6,734 – 7,006	7,008 – 7,584	7,293 – 8,211	7,589 – 8,889	7,897 – 9,623	8,218 – 10,418	8,759 – 11,829
Single-phase >500 kVA	21	22–23	23–25	24–27	25– 29	26 – 31	27 – 34	28 – 38
Three-phase <500 kVA	9,095	9,465 – 9,846	9,849 – 10,660	10,250-11,540	10,666-12,493	11,100 – 13,525	11,551 – 14,642	12,311 – 16,625
Three-phase >500 kVA	13,469	14,016 – 14,582	14,586 – 15,786	15,179 – 17,090	15,796 – 18,502	16,438 – 20,030	17,106 – 21,684	18,232 – 24,620
Dry-type								
Single-phase LV <100 kVA	903	940 – 978	978 – 1,058	1,018 – 1,146	1,059 – 1,240	1,102 – 1,343	1,147 – 1,454	1,222 – 1,651
Single-phase LV >100 kVA	72	75–78	78–85	82– 92	85 – 99	88 – 108	92 – 117	98 – 132
Three-phase LV <100 kVA	5,707	5,939 – 6,178	6,180 – 6,689	6,431 – 7,241	6,693 – 7,839	6,965 – 8,487	7,248 – 9,188	7,725 – 10,432
Three-phase LV >100 kVA	5,675	5,906 – 6,144	6,146 – 6,651	6,396 – 7,201	6,655 – 7,795	6,926 – 8,439	7,208 – 9,137	7,682 – 10,374
Single-phase MV	207	215–224	224–242	233 – 262	243 – 284	252 – 308	263 – 333	280 – 378
Three-phase MV <100 kVA	300	313–325	325 – 352	338 – 381	352 – 413	367 – 447	381 – 484	407 – 549
Three-phase MV >100 kVA	7,820	8,138 – 8,466	8,469 – 9,166	8,813 – 9,923	9,171 – 10,742	9,544 – 11,630	9,932 – 12,590	10,586 – 14,295

Note: LV = low-voltage; MV = medium-voltage.

annual shipments of liquid-immersed and dry-type transformers for the same period are shown in Figs. 4.3 and 4.4, respectively. As discussed earlier, annual growth rates are assumed to be constant and the same (i.e., 0.8% or 1.6%) for both types of transformers. Total annual shipments are estimated to increase to 92,251–124,576 MVA for liquid-immersed transformers and to 28,000–37,811 MVA for dry-type transformers, respectively, by the year 2033. It is estimated that the largest share of the liquid-immersed market (single-phase transformers <100 kVA) will grow from 39,095 MVA in 1995 to between 52,920 and 71,463 MVA in 2033. In the largest three-phase liquid-immersed market (transformers >500 kVA), annual shipments will grow to between 18,232 and 24,620 MVA by the year 2033. Similarly, the three-phase medium-voltage transformer (>100 KVA) will dominate the dry-type market, which is expected to grow from 7,820 MVA in 1995 to between 10,586 and 14,295 MVA in 2033. Annual shipments of 1,222 to 1,651 MVA are forecast for the single-phase low-voltage (<100 kVA) dry-type market by the year 2033.

The assumed growth rates of 0.8% and 1.6% (under the two scenarios) for both liquid-immersed and dry-type transformers are conservative compared with the historical growth rates and the projections available in the literature, as shown in Table 4.7.

4.4 BASE CASE ENERGY ANALYSIS

The energy analysis for the base case involves the determination of the energy delivered by new transformers and the losses attributed to the sales of these transformers at existing levels of energy efficiency. The energy analysis model described in Chapter 3 was used along with the assumptions

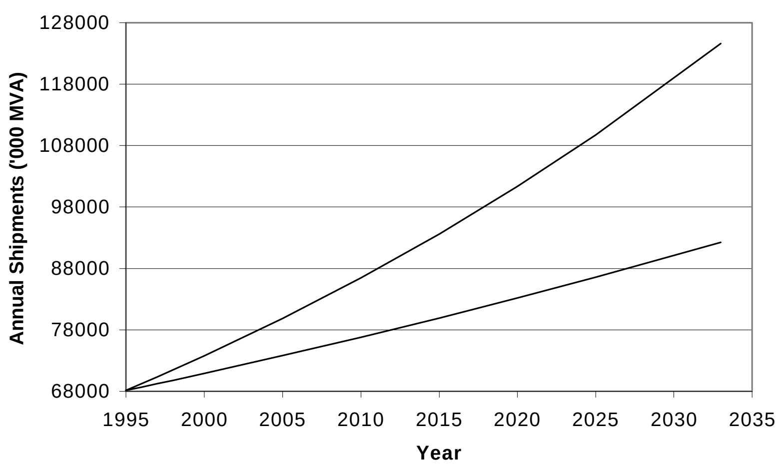

Fig. 4.3. Estimated annual shipments of liquid-immersed transformers, 1995–2033.

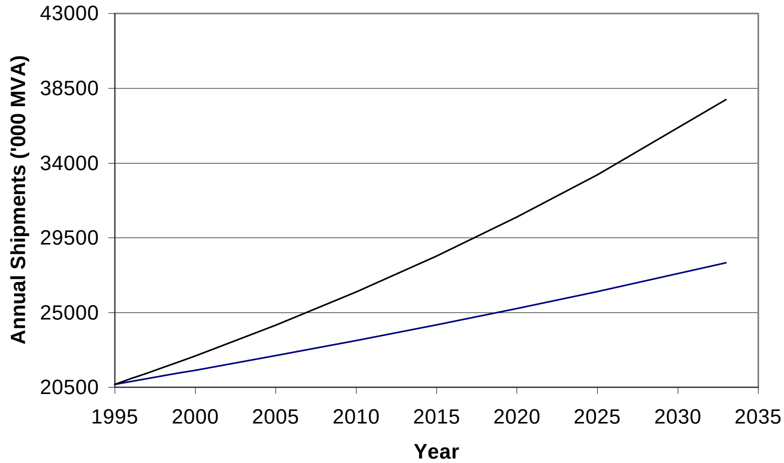

Fig. 4.4. Estimated annual shipments of dry-type transformers, 1995–2033.

Table 4.7. Historical and projected annual growth rates of distribution transformer shipments

Transformer type	Period	Basis for calculating/ projecting growth rate	Compound annual growth rate (%)	Source
All transformers, except electronic (SIC 3612)	1987–1994	Constant $ value	1.9	DOC 1996
Power and distribution (SIC 36122)	1987–1992	Constant $ value	2.3	DOC 1994a, 1990
Distribution[a]	1995–2000	Units	2.1–3.1	Business Trend Analysts 1995
Utility	1985–1995	Constant $ value	2.8	Freedonia Group 1996
Utility	1995–2005	Constant $ value	1.8	Freedonia Group 1996
Non-utility	1985–1995	Constant $ value	2.4	Freedonia Group 1996
Non-utility	1995–2005	Constant $ value	4.5	Freedonia Group 1996

[a]Including indoor and general-purpose commercial, institutional, and industrial transformers.

and parameters listed in Tables 4.1 through 4.5 to calculate the annual losses and energy delivered. The calculation of losses was done for sales in 1995, then escalated by a 1.2% annual growth rate to 2004, which is assumed to be the first year that efficiency standards would be in effect. Besides the annual volume of new sales, the base case can be characterized by the annual energy losses associated with the new sales and the average energy efficiency of new sales. The determination of the case losses is related to both the transformer efficiency characteristics and the characteristic load. The energy losses for each size of transformer defined in Tables 4.1 through 4.3 have been calculated and tabulated only by major category of transformer, as shown in Table 4.8.

The total losses for the base case are calculated to be 3619 million kWh of electrical energy and 0.0401 quads of primary energy in the year 2004. The total electric energy supplied by the transformers is 222,629 million kWh, and the base case efficiency is 98.4%. A breakdown of the annual losses by major transformer type and application is presented in Table 4.8. Figure 4.5 shows the cumulative base case losses over the 30-year period starting with year 2004 for two annual growth rates, 0.8% and 1.6%. The rate of sales growth makes relatively little difference in the cumulative energy losses.

Table 4.8. Estimated losses by type of transformer for annual sales starting in 2004 (millions of kWh)

	Non-utility		Utility		Totals by type
	Nonevaluated	**Evaluated**	**Nonevaluated**	**Evaluated**	
Transformer type					
Liquid-immersed, medium-voltage, single-phase	44	3	258	1040	1345
Liquid-immersed, medium-voltage, three-phase	177	38	61	326	601
Dry-type, low-voltage, single-phase	88	0	0	0	88
Dry-type, low-voltage, three-phase	1041	0	0	0	1041
Dry-type, medium-voltage, single-phase	25	0	0	0	25
Dry-type, medium-voltage, three-phase	519	0	0	0	519
Totals	1893	41	319	1366	3619
Primary energy					
First-year losses (quads)	0.0210	0.0005	0.0035	0.0151	0.0401
Cumulative losses, 30 years (quads)[a]	11.0	0.2	1.8	7.9	21.0

[a]Assuming a 1.2% growth rate for the transformer market.

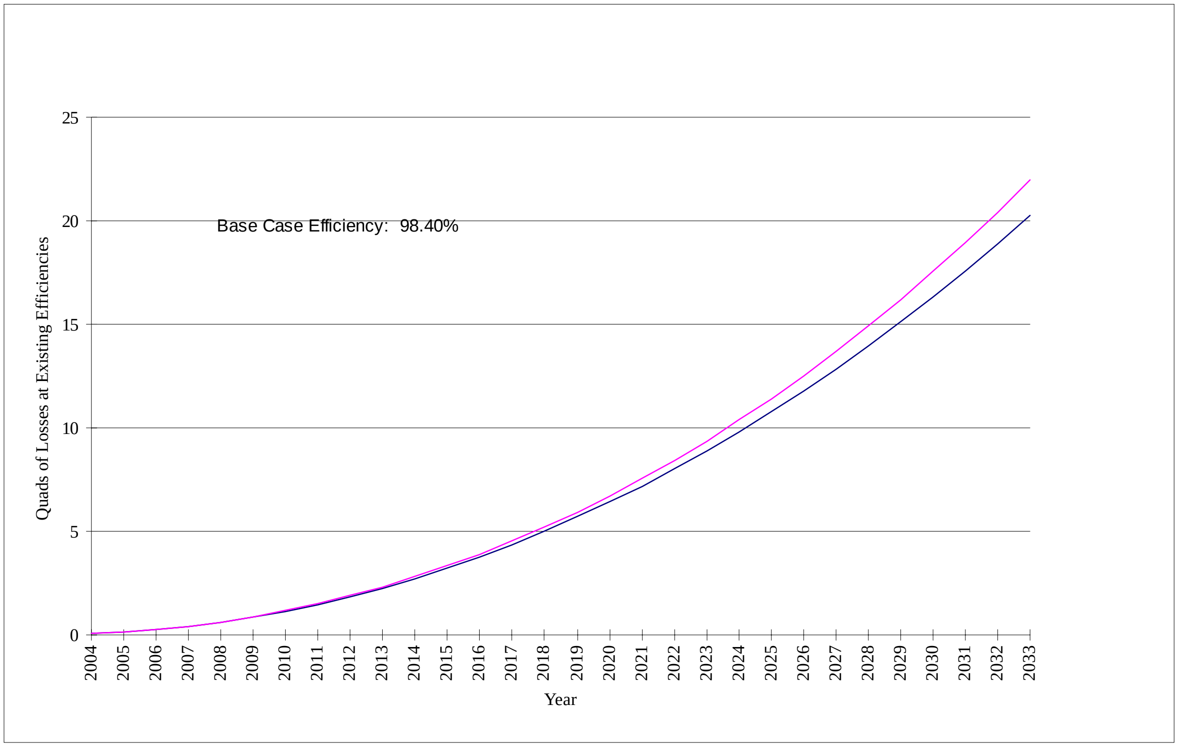

Fig. 4.5. Cumulative base case losses for new distribution transformer sales over 30 years, assuming 0.8 to 1.6% annual growth.

5. THE NEMA ENERGY CONSERVATION STANDARD

5.1 BACKGROUND

The 1996 NEMA standard, NEMA TP 1-1996 (NEMA 1996), is based on a short payback period to recover the additional cost of more efficient transformers from the money saved by the reduced energy consumption. This standard provides a description of the total owning cost (TOC) methodology for distribution transformers and tables of minimum transformer efficiencies for liquid-immersed and dry-type transformers for a range of transformer sizes. The minimum transformer efficiencies are shown in Tables 5.1–5.3. Medium-voltage liquid-immersed and dry-type transformers must meet or exceed the specified efficiencies at a per unit load of 0.5. Low-voltage dry-type transformers must meet or exceed the specified efficiencies at a per unit load of 0.35. The sensitivity of the NEMA load specifications to energy savings is presented in this section.

Table 5.1. TP-1 minimum efficiencies and transformer design losses assumed for liquid-immersed transformers

Single-phase				Three-phase			
Size (kVA)[a]	**Efficiency (%)**	**NL**	**LL**	**Size (kVA)[a]**	**Efficiency (%)**	**NL**	**LL**
10	98.30	43	173	15	98.00	77	306
15	98.50	57	228	30	98.30	130	519
25	98.70	82	329	45	98.50	171	685
37.5	98.80	114	455	75	98.70	247	988
50	98.90	139	556	112.5	98.80	342	1,366
75	99.00	189	758	150	98.90	417	1,668
100	99.00	253	1,010	225	99.00	568	2,273
167	99.10	379	1,517	300	99.00	758	3,030
250	99.20	504	2,016	500	99.10	1,135	4,541
333	99.20	671	2,685	750	99.20	1,512	6,048
500	99.30	881	3,525	1000	99.20	2,016	8,065
667	99.40	1,007	4,026	1500	99.30	2,644	10,574
833	99.40	1,257	5,028	2000	99.40	3,018	12,072
				2500	99.40	3,773	15,091

Note: The minimum efficiencies are for an effective per unit load of 0.5 for medium-voltage units. Medium-voltage units include 5-, 15-, 25-, and 35-kV classes. Average winding temperature is 85°C.

NL = no-load losses in watts; LL = full-load losses in watts. Values for NL and LL have been calculated using Eqs. (3.4) and (3.5), respectively.

[a]Nameplate capacity of the transformer in kilovolt-amperes.

Table 5.2. TP-1 minimum efficiencies and transformer design losses assumed for dry-type low-voltage transformers

Single-phase				Three-phase			
Size (kVA)[a]	Efficiency (%)	NL	LL	Size (kVA)[a]	Efficiency (%)	NL	LL
15	97.70	62	619	15	97.00	81	813
25	98.00	89	894	30	97.50	135	1,348
37.5	98.20	120	1,205	45	97.70	185	1,856
50	98.30	151	1,515	75	98.00	268	2,682
75	98.50	200	2,001	112.5	98.20	361	3,614
100	98.60	248	2,488	150	98.30	454	4,546
167	98.70	385	3,855	225	98.50	600	6,004
250	98.80	531	5,321	300	98.60	745	7,465
333	98.90	648	6,491	500	98.70	1,152	11,541
				750	98.80	1,594	15,963
				1000	98.90	1,946	19,491

Note: The minimum efficiencies are for an effective per unit load of 0.35 for low-voltage units and 0.5 for medium-voltage units. Medium-voltage units include 5-, 15-, 25-, and 35-kV classes. Average winding temperature is 85°C. For dry-type units, average winding temperature is 75°C.

NL = no-load losses in watts; LL = full-load losses in watts.

[a]Nameplate capacity of the transformer in kilovolt-amperes.

5.2 THE POTENTIAL ENERGY SAVINGS

Data on transformer designs that manufacturers would use to meet the TP-1 standard was obtained through a NEMA survey of NEMA transformer manufacturers and an ORNL survey of non-NEMA transformer manufacturers. The design information collected by the surveys included core losses and full-load losses for both nonevaluated and TP-1 transformers, as well as the added price for TP-1 units. One problem with the surveys was that relatively few firms participated. A review of the reported designs of existing transformers and the projected designs to meet the TP-1 efficiency standard suggested that averaging the design losses that were reported in the surveys would not yield a good representation of designs if a standard were imposed. On average, there were fewer than three responses per transformer category, and there were significant differences within many of the response categories. Even for the common 25-kVA liquid-immersed transformer category there were only six responses to the survey. Thus, if we were to utilize the six data points for the nonevaluated 25-kVA transformers, the true mean with a 95% confidence interval would be ±0.13% from the (sample) mean efficiency, which represents 15% of the losses. The uncertainty band for most other transformer categories would tend to be even wider because of fewer data points. For this analysis, losses for the TP-1 standard have been calculated as described in Chapter 3. The losses assumed for the base case are described in Chapter 4.

Table 5.3. TP-1 minimum efficiencies and transformer design losses assumed for dry-type medium-voltage transformers

Single-phase				Three- phase			
Size (kVA)[a]	Efficiency (%)	NL	LL	Size (kVA)[a]	Efficiency (%)	NL	LL
15	97.60	92	452	15	96.80	124	608
25	97.90	134	658	30	97.30	208	1,021
37.5	98.10	182	891	45	97.60	277	1,357
50	98.20	229	1,124	75	97.90	402	1,973
75	98.40	305	1,496	112.5	98.10	545	2,673
100	98.50	381	1,868	150	98.20	687	3,373
167	98.70	550	2,698	225	98.40	915	4,488
250	98.80	759	3,725	300	98.50	1,142	5,604
333	98.90	926	4,543	500	98.70	1,646	8,079
500	99.00	1,263	6,195	750	98.80	2,277	11,174
667	99.00	1,684	8,265	1000	98.90	2,781	13,644
833	99.10	1,891	9,280	1500	99.00	3,788	18,586
				2000	99.00	5,051	24,782
				2500	99.10	5,676	27,851

Note: The minimum efficiencies are for an effective per unit load of 0.35 for low-voltage units and 0.5 for medium-voltage units. Medium-voltage units include 5-, 15-, 25-, and 35-kV classes. Average winding temperature is 85°C. For dry-type units, average winding temperature is 75°C.

NL = no-load losses in watts; LL = full-load losses in watts.

[a]Nameplate capacity of the transformer in kilovolt-amperes.

Tables 5.1 through 5.3 present the minimum efficiency levels for the TP-1 standard and the core and full-load design losses assumed to meet the standard as determined by Eqs. (3.4) and (3.5). The potential energy savings can be calculated as the difference between the base case energy losses (see Chapter 4) and the losses resulting from transformers sold under the TP-1 standard. The model used for making these calculations is described in Chapter 3.

The estimated savings are presented in Table 5.4 in terms of the annual kilowatt-hours per kilovolt-ampere and the total savings in kilowatt-hours for 1995 and 2004. The 1995 savings are presented because this is the year upon which transformer sales data were based; 2004 is currently projected to be the first year of the transformer efficiency standards. Although the same TP-1 standard would apply to utilities and non-utilities, the losses per kilovolt-ampere are different because different loads have been assumed for utility versus non-utility applications. The total annual savings in 2004 would be 434 million kWh. The total annual savings is calculated as the annual savings per kilovolt-ampere times the annual sales for the given year. The annual savings in 2004 reflects the growth in sales, assumed to be at an annual rate of 1.2%.

Table 5.4. Estimated annual rate of savings of electric energy per kilovolt-ampere and annual savings by transformer type in 1995 and 2004

Size (kVA)[a]	Annual savings (kWh/kVA)	1995 sales (MVA)	Annual savings (GWh)	
			1995	2004
Liquid-immersed medium-voltage single-phase				
10	0.69	2,341	1.63	1.81
15[b]	(0.14)	4,962	(0.69)	(0.76)
25	0.54	11,474	6.24	6.95
37.5	0.14	3,104	0.45	0.50
50	0.30	10,556	3.19	3.55
75	0.55	3,531	1.94	2.16
100	0.03	3,126	0.11	0.12
167	0.41	3,355	1.37	1.53
250	0.75	809	0.61	0.68
333	2.69	955	2.57	2.86
500	3.43	1,352	4.64	5.17
667	3.86	6	0.02	0.03
833	3.25	15	0.05	0.05
Total		**45,586**	**22.1**	**24.6**
Liquid-immersed medium-voltage three-phase				
15	1.78	45	0.08	0.09
30	1.41	91	0.13	0.14
45	1.88	182	0.34	0.38
75	1.79	455	0.81	0.91
112.5	1.64	273	0.45	0.50
150	0.62	1,182	0.73	0.81
225	1.15	910	1.04	1.16
300	0.85	2,638	2.25	2.50
500	0.48	3,320	1.58	1.76
750	1.36	2,694	3.67	4.08

Table 5.4 (continued)

Size (kVA)[a]	Annual savings (kWh/kVA)	1995 sales (MVA)	Annual savings (GWh)	
			1995	2004
1000	1.93	2,155	4.16	4.63
1500	2.35	3,098	7.29	8.12
2000	3.50	1,212	4.24	4.72
2500	2.68	4,310	11.56	12.88
Total		**22,565**	**38.3**	**42.7**
Dry-type low-voltage single-phase				
15	31.14	56	1.74	1.94
25	26.80	311	8.34	9.28
37.5	28.55	203	5.80	6.45
50	27.65	215	5.94	6.62
75	21.10	77	1.62	1.81
100	22.64	40	0.91	1.01
167	18.95	17	0.32	0.36
250	16.38	22	0.36	0.40
333	17.83	9	0.16	0.18
Total[c]	**0.00**	**950**	**25.2**	**28.0**
Dry-type low-voltage three-phase				
15	41.31	1,008	41.64	46.36
30	33.29	1,421	47.30	52.66
45	22.68	1,575	35.72	39.76
75	21.04	1,703	35.83	39.89
112.5	17.71	1,546	27.38	30.49
150	12.93	1,622	20.97	23.35
225	11.14	636	7.08	7.89
300	9.78	446	4.36	4.85
500	8.03	858	6.89	7.67

Table 5.4 (continued)

Size (kVA)[a]	Annual savings (kWh/kVA)	1995 sales (MVA)	Annual savings (GWh)	
			1995	2004
750	5.63	491	2.76	3.08
1000	5.22	77	0.40	0.45
Total		**11,383**	**230.3**	**256.4**
Dry-type medium-voltage single-phase				
15	123.12	3	0.37	0.41
25	91.07	5	0.46	0.51
37.5	83.26	17	1.42	1.58
50	72.21	15	1.08	1.21
75	57.48	9	0.52	0.58
100	52.34	14	0.73	0.82
167	45.82	38	1.74	1.94
250	38.56	31	1.20	1.33
333	36.61	14	0.51	0.57
500	30.71	52	1.60	1.78
667	23.27	6	0.14	0.16
833	23.22	4	0.09	0.10
Total		**208**	**9.9**	**11.0**
Dry-type medium-voltage three-phase				
15	145.51	12	2.04	2.27
30	101.54	26	2.64	2.94
45	74.28	119	8.84	9.84
75	63.49	141	8.95	9.97
112.5	35.24	82	2.89	3.22
150	34.45	116	4.00	4.45
225	22.47	126	2.83	3.15
300	18.35	184	3.38	3.76

Table 5.4 (continued)

Size (kVA)[a]	Annual savings (kWh/kVA)	1995 sales (MVA)	Annual savings (GWh)	
			1995	2004
500	14.68	274	4.02	4.48
750	8.28	1,050	8.69	9.68
1000	7.99	1,240	9.91	11.03
1500	1.87	2,431	4.54	5.06
2000[d]	0.00	969	0.00	0.00
2500	0.62	1,348	0.84	0.94
Total		**8,118**	**63.6**	**70.0**

[a]Nameplate capacity of the transformer in kilovolt-amperes.

[b]For some transformers, meeting the TP-1 efficiency at the 50% load specified by the standard would tend to reduce their efficiency at the actual operating load of about 25%.

[c]The TP-1 Standard does not apply to dry-type low-voltage single phase transformers above 333 kVA although these transformers are included in Table 4.5.

[d]The TP-1 efficiency is below the base case efficiency for this size transformer.

The annual savings for 2004 and the cumulative savings for the first 30 years of the standard are presented in Table 5.5 by major transformer classifications. The annual savings are summed for the different major categories from the savings in Table 5.4. The cumulative savings are the annual savings in the first year of the standard, 2004, times a cumulative factor of 524, which accounts for the accumulation of energy from transformers that would be covered by the policy over a 30-year span. The factor 524 is for a 1.2% annual growth in sales. If annual sales grew at 1.6%, the cumulative factor would be about 546, or 4% higher; if sales grew at 0.8% annually, the factor would be 503, or 4% lower. The overall efficiency for the TP-1 case is 98.59%, compared to the base case efficiency of 98.40%. This is a reduction of 12.0% of base case losses.

There are no savings associated with the dry-type medium-voltage three-phase 2000-kVA transformers because the efficiency for the TP-1 standard is lower than that derived from the base case losses (see Tables 5.1 and 4.3).

Table 5.4 indicates that, in general, the smaller transformers have a higher rate of potential savings. As a group, dry-type, low-voltage, three-phase transformers, often called “lighting transformers,” have the most potential for energy savings if the TP-1 standard is implemented. The efficiency standards for this type of transformer combine potentially high energy savings per kilovolt-ampere with a significant part of the total annual sales volume.

Table 5.5. Transformer energy savings for NEMA Standard TP-1 for major types of transformers

Transformer type	Savings in 2004[a] (GWh)	Cumulative savings[b] (quads)
Liquid-immersed medium-voltage single-phase	25	0.14
Liquid-immersed medium voltage three-phase	43	0.25
Dry-type low-voltage single-phase	28	0.16
Dry-type low-voltage three-phase	256	1.49
Dry-type medium-voltage single-phase	11	0.06
Dry-type medium-voltage three-phase	71	0.41
All types	434	2.51

[a]Electricity savings for first year of TP-1 standard.
[b]Cumulative primary energy savings for the period 2004 through 2033.

5.3 LOAD SENSITIVITY ANALYSIS

The efficiency of a transformer is uniquely determined by its no-load and full-load losses and operating load. Setting a minimum efficiency standard includes specifying the load at which the transformer must meet the efficiency standard. Manufacturers will tend to design transformers that can meet the standard at the lowest cost. The costs related to the transformer's core (the determinant of no-load losses) and coils (the determinant of load losses) will be adjusted according to the specified load at which the standard must be met. The higher the specified load, the higher the design no-load losses and the lower the full-load losses. This tradeoff between the no-load and full-load losses could have a significant effect on the potential energy savings that result from a standard. If too high a load is specified, manufacturers will design transformers that overemphasize the importance of load losses relative to the actual load and underemphasize the importance of no-load losses.

This type of problem may well occur for medium-voltage liquid-immersed transformers under the TP-1 standard because it has specified a 50% load. As noted in Chapter 2, utilities, which purchase about 90% of liquid-type transformer capacity, typically use these transformers at loads much lower than 50%. The energy model described in Chapter 3 indicates that adjustment of the specified load to 36% would result in 74% more savings for liquid transformers than would occur at the 50% load specified in the TP-1 standard. This estimate was made by simultaneously adjusting both the specified load for the standard and the transformer's design losses for maximum efficiency to 36%. The total savings would be only about 11% higher because liquid transformers contribute only about 16% of total savings. This exercise demonstrates the importance of specifying the load for a standard as close as possible to the actual load. Given uncertainty about actual loads and the potentially large variation across different transformers, specifying the standard at a 40% load would be effective across a wide range of actual loads, as shown in Fig. 3.2.

5.4 PAYBACK ANALYSIS

Although the TP-1 survey data were not used to calculate energy savings, these data were used to calculate the payback periods. These data are appropriate for a payback analysis since information on each transformer included price information that was reported by the same manufacturer, and the data are therefore internally consistent. Although the survey responses were used for the payback analysis, little confidence should be placed in results for any given transformer category because of low survey response. However, the overall results should be more dependable because all survey results have been combined into a weighted average.

The payback analysis is based on the differences between the nonevaluated and TP-1 transformer designs presented in Tables 5.6 through 5.8. The losses shown are the average losses for the unevaluated transformers reported in the TP-1 survey and the manufacturers' submitted design losses to meet the TP-1 standard. The average annual energy saved was calculated for each category; this figure was multiplied by 6.92 cents/kWh (EIA 1997), the average price of electricity for all sectors in 1996, to give an average annual value of electricity saved. The annual energy saved used the assumed operating loads (see Table 4.2 and the note to Table 4.3). The average incremental cost for the TP-1 transformers was divided by the average annual value of electricity saved, to calculate the simple payback period for each size of transformer.

The individual paybacks for each category (size and voltage) of transformer were then weighted by the percentage that the category represented in total annual energy saved as a result of the TP-1 standard. Liquid-immersed transformers were broken out into two separate categories to account for differences in the assumed loading for utilities and non-utilities. The differences in loading result in different payback periods. The overall weighted payback for all transformers is 2.76 years.

Table 5.9 adjusts the overall weighted payback by the ratio of the national average price of electricity (6.76 cents) to the average price of electricity reported for each individual state (see Table 5.9). Fig. 5.1 graphically presents regional results of the payback analysis. The shortest payback times occur in areas where electricity prices are high; this includes California, Alaska, Hawaii, and most of the Northeast. The longest payback times are in regions where electricity prices are low, such as the Pacific Northwest and several midwestern and southeastern states. Regional paybacks are inversely related to the regional cost of electricity.

Table 5.6. Manufacturer survey data for liquid-immersed medium-voltage distribution transformers

Size (kVA)[a]	Noneval. transformers reported in survey		Submitted design losses to meet TP-1		Incremental cost[b]	Payback period (years)
	NL	LL	NL	LL		
Single-phase transformers						
10	45.5	258.5	36.0	195.5	$ 26	3.2
15	60.2	335.2	44.3	277.7	34	2.9
25	81.2	515.5	67.2	378.8	50	3.7
37.5	103.7	695.5	83.3	565.7	48	2.8
50	146.2	735.8	111.3	639.8	75	3.0
75	181.7	1,090.3	160.3	853.3	81	3.7
100	229.0	1,381.2	198.5	1,162.0	79	3.0
167	319.7	2,175.5	302.3	1,760.5	108	5.0
250	486.8	2,992.0	334.3	2,615.5	212	2.0
333	587.5	4,042.5	445.3	3,598.5	195	1.7
500	749.8	5,123.5	567.5	4,762.8	205	1.5
667	945.0	6,378.0	639.5	5,574.0	802	3.1
833	1,081.0	8,024.5	839.5	6,585.5	909	3.3
Three-phase transformers						
15	--------------------Nondisclosure[c]--------------------					2.7
30	--------------------Nondisclosure[c]--------------------					3.4
45	204.0	921.5	183.5	612.0	$154	6.4
75	325.0	1,431.0	211.0	1,072.3	295	3.6
112.5	412.0	1,875.7	329.0	1,373.3	327	4.7
150	555.0	2,455.5	419.8	1,626.8	495	4.3
225	721.8	3,597.8	563.8	2,356.5	706	4.8
300	939.3	4,438.3	742.8	2,770.3	907	4.8
500	1,323.3	6,439.3	970.5	4,623.8	1,030	3.6
750	1,602.5	9,489.8	1,363.5	6,300.3	1,338	3.4
1000	1,986.0	12,055.0	1,506.3	8,528.8	1,585	2.3
1500	2,711.0	16,600.5	2,389.8	11,335.3	2,261	2.7

Note: Data was provided for the 95-kVA basic insulation level (BIL) 15-kV voltage transformer class. NL = no-load losses in watts; LL = full-load losses in watts.

[a]Nameplate capacity of the transformer in kilovolt-amperes.

[b]The average price difference between the unit designed to meet TP-1 and a nonevaluated unit, with both A and B = $0.00.

[c]"Nondisclosure" indicates that the only response received was proprietary. Although the response cannot be disclosed here, it is included in the overall calculation of payback.

Table 5.7. Manufacturer survey data for dry-type low-voltage distribution transformers

Size (kVA)[a]	Noneval. transformers reported in survey		Submitted design losses to meet TP-1		Incremental cost[b]	Payback period (years)
	NL	LL	NL	LL		
Single-phase transformers						
15	153.3	599.0	83.0	400.0	$256	4.7
25	199.0	963.3	103.0	731.7	270	3.7
37.5	258.3	1,368.3	144.0	934.7	291	3.1
50	335.0	1,828.7	186.3	1,165.3	302	2.3
75	436.3	2,405.0	235.7	1,593.3	373	2.2
100	516.0	2,993.3	300.3	1,953.3	417	2.2
167	729.0	3,758.0	483.3	2,834.0	564	2.8
250	--------------------------------------Nondisclosure[c]--------------------------------------					3.2
333	--------------------------------------Nondisclosure[c]--------------------------------------					3.1
Three-phase transformers						
15	211.0	653.0	99.3	600.3	$314	4.4
30	277.3	1,347.0	150.7	1,158.7	296	3.4
45	363.8	1,699.8	202.0	1,432.8	313	2.7
75	485.0	2,512.5	296.5	2,097.8	476	3.4
112.5	667.5	3,531.3	397.0	2,873.0	629	3.1
150	783.0	5,091.3	475.5	3,853.0	789	3.0
225	1,032.5	6,565.8	614.5	5,275.8	879	2.7
300	1,190.0	7,998.8	754.3	6,662.0	909	2.6
500	1,900.0	9,612.5	1,308.0	8,629.5	1,274	3.0
750	2,625.0	12,550.0	1,844.0	11,453.3	1,587	2.9
1000	3,351.0	14,655.0	2,348.8	13,454.5	1,986	2.9

Note: Data was provided for the 95-kVA basic insulation level (BIL) 15-kV voltage transformer class. NL = no-load losses in watts; LL = full-load losses in watts.

[a]Nameplate capacity of the transformer in kilovolt-amperes.

[b]The average price difference between the unit designed to meet TP-1 and a nonevaluated unit, with both A and B = $0.00.

[c]"Nondisclosure" indicates that the only response received was proprietary. Although the response cannot be disclosed here, it is included in the overall calculation of payback.

Table 5.8. Manufacturer survey data for dry-type medium-voltage three-phase distribution transformers

Size (kVA)[a]	Noneval. transformers reported in survey		Submitted design losses to meet TP-1		Incremental cost[b]	Payback period (years)
	NL	LL	NL	LL		
150	------------------------------------Nondisclosure[c]------------------------------------					3.1
225	1,488.3	5,738.3	952.3	4,055.0	2,632	4.9
300	1,796.7	6,803.3	1,284.0	4,387.3	2,529	4.2
500	2,640.0	9,319.3	1,646.7	7,265.0	2,795	3.3
750	3,450.0	13,045.0	2,299.0	9,810.3	3,176	2.9
1,000	4,306.7	16,416.7	2,731.3	12,353.7	3,554	2.4
1,500	5,823.3	20,576.7	3,631.7	17,614.3	3,865	2.3
2,000	6,943.3	25,031.7	4,553.3	22,863.7	3,974	2.3
2,500	8,376.7	27,933.3	5,620.0	25,062.0	4,467	2.2

Note: No survey responses were received for single-phase transformers. Data was provided for the 95-kVA basic insulation level (BIL) 15-kV voltage class. NL = no-load losses in watts; LL = full-load losses in watts.

[a]Nameplate capacity of the transformer in kilovolt-amperes.

[b]The average price difference between the unit designed to meet TP-1 and a nonevaluated unit, with both A and B = $0.00.

[c]"Nondisclosure" indicates that only one response was received. Although the response cannot be disclosed here, it is included in the overall calculation of payback.

Table 5.9. Simple payback by state for TP-1 standard

State	Electricity for all sectors in 1996 (cents per kWh)	Simple payback (years)	State	Electricity for all sectors in 1996 (cents per kWh)	Simple payback (years)
Alabama	5.3	3.4	Montana	5.4	3.4
Alaska	10.1	1.8	Nebraska	4.7	3.9
Arizona	6.9	2.6	Nevada	5.7	3.2
Arkansas	5.9	3.1	New Hampshire	11.7	1.6
California	9.1	2.0	New Jersey	10.2	1.8
Colorado	6.1	3.0	New Mexico	6.6	2.8
Connecticut	10.7	1.7	New York	10.6	1.7
Delaware	6.7	2.7	North Carolina	6.5	2.8
District of Columbia	5.8	3.1	North Dakota	5.1	3.6
Florida	7.3	2.5	Ohio	6.0	3.0
Georgia	6.0	3.0	Oklahoma	4.6	4.0
Hawaii	11.5	1.6	Oregon	5.0	3.6
Idaho	4.1	4.5	Pennsylvania	7.7	2.4
Illinois	7.2	2.5	Rhode Island	10.0	1.8
Indiana	5.2	3.5	South Carolina	5.7	3.2
Iowa	5.4	3.4	South Dakota	6.0	3.0
Kansas	6.2	2.9	Tennessee	5.2	3.5
Kentucky	4.1	4.5	Texas	5.8	3.1
Louisiana	5.8	3.1	Utah	5.3	3.4
Maine	11.0	1.7	Vermont	11.2	1.6
Maryland	6.2	2.9	Virginia	6.0	3.0
Massachusetts	9.4	1.9	Washington	4.4	4.1
Michigan	7.2	2.5	West Virginia	5.2	3.5
Minnesota	5.4	3.4	Wisconsin	5.4	3.4
Mississippi	5.7	3.2	Wyoming	4.3	4.2
Missouri	5.3	3.4	**U.S. Average**	**6.6**	**2.8**

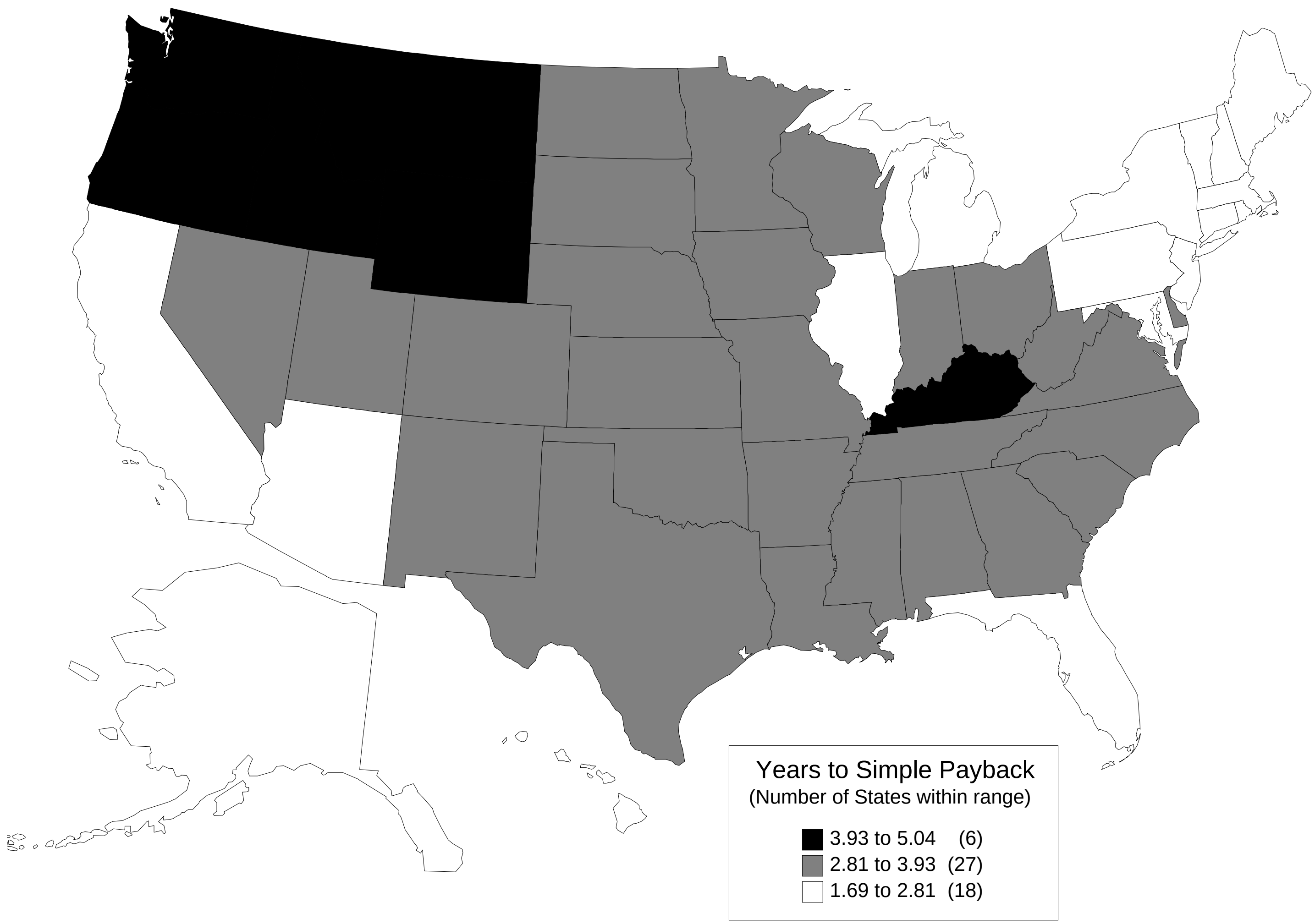

Fig. 5.1. Regional results of payback analysis.

6. THE DETERMINATION CASES

In the report *Determination Analysis of Energy Conservation Standards for Distribution Transformers,* ORNL-6847 (Barnes et al. 1996), five alternative conservation cases for distribution transformers were analyzed. Four of these cases are summarized in Table 6.1. One other case, the two-year payback case, was considered in ORNL-6847. However, it has been omitted in this analysis, since it was originally included in the previous study as a surrogate for the NEMA TP-1 standard.

The four cases in Table 6.1 have been reestimated with the disaggregated model to compute the savings. There is a difference from the earlier estimates of energy savings in the determination study because the assumptions in this report have been refined. The annual sales of dry-type transformers and the operating loads for liquid-immersed transformers have been revised and are significantly less than those utilized in the previous report (ORNL-6847). In addition to changes in these key parameters, the model used in this analysis is disaggregated into 73 different types of transformers, while the earlier report used only 12 types of transformers. The earlier report was based on a survey requesting proprietary information about manufacturer designs and prices for transformers that met *total owning cost* (TOC) criteria, which consisted of a lowest TOC for transformers of less than 50 kVA at a rate of $3.50 per watt of no-load loss and $0.75 per watt of load loss, and for transformers of 50 kVA and more at $3.50 per watt of no-load loss and $2.25 per watt of load loss.

The determination study developed conservation cases based on the survey responses. For instance, the lowest TOC case utilized the reported design losses for the transformer from each of the 12 categories that had the lowest TOC. The losses from each of these 12 lowest TOC transformers were subtracted from the typical losses for the base case, and the results were used to estimate a rate of savings per kilovolt-ampere for each of the 12 types of transformers. The 12 rates of savings were assigned to a fraction of total sales such that the fractions summed to 1.0 (100%). Then the sum of the savings per kilovolt-ampere times the corresponding assigned fraction of sales times the projected total annual sales across the 12 types of transformers gave an estimate of total savings for the case.

The no-load and full-load losses and price information that was used to define the cases is proprietary and cannot be disclosed. However, the transformer efficiency at a specified load for the cases can be

Table 6.1. Summary of conservation cases analyzed in ORNL-6847

Case	Transformers selected from survey as basis for losses	Cumulative savings (quads) for 30 years		
		Liquid	Dry	Total
Lowest TOC	Lowest total owning cost (TOC)	2.1	8.3	10.4
Median TOC	Median TOC	1.1	5.0	6.1
Average losses	Average losses of three lowest TOC transformers	2.4	6.5	8.9
High-efficiency	Highest-efficiency transformer of those submitted	5.4	8.3	13.7

disclosed, since proprietary data cannot be derived from this information. Table 6.2 shows the efficiencies for 12 transformer types in the determination study cases.

The losses for each of the 12 transformers that defined a case in ORNL-6847 were mapped either directly or through extrapolation to the 73 types of transformers in the disaggregated model utilized in Chapter 5 to estimate TP-1 savings. Where there was no corresponding transformer size from the ORNL-6847 survey, the transformer losses for the closest size of the same type defining the determination study cases were extrapolated using a rule of thumb. The extrapolation algorithm was the ratio of the extrapolated transformer size to the base transformer size taken to the 0.75 power times the design losses of the base transformer.

No dry-type medium-voltage single-phase transformers were included in the earlier survey described in ORNL-6847. For this category, dry-type medium-voltage three-phase transformers from the survey were extrapolated to single-phase transformers that were exactly one-third the rated kilovolt-amperage by taking one-third of their design no-load and load losses. The remaining transformers for this category were extrapolated using the 0.75 power rule of thumb described above.

The estimated savings for the determination study cases using the disaggregated model and the new market and load assumptions are presented in Table 6.3. These estimates are less than the estimates from the previous study (see Table 6.1). The cumulative liquid transformer sales assumed in the current study were about 10% less than in the ORNL-6847 report. However, the cumulative sales for dry-type transformers, which represent over 80% of estimated savings were only about one-half of those used in the previous study. This lower market level for dry-type transformers has resulted in lower energy savings.

Table 6.2. Transformer efficiencies corresponding to losses for determination study cases

Transformer size (kVA), type, and load	Efficiency (%) by case			
	Lowest TOC	Median TOC	Average losses	High-Efficiency
Liquid-immersed				
25, pole, 0.5	98.93	98.87	99.06	99.22
50, pole, 0.5	99.14	99.15	99.17	99.53
50, pad, 0.5	99.23	99.15	99.22	99.53
150, pad, 0.5	99.13	99.00	99.28	99.51
750, pad, 0.5	99.45	99.35	99.39	99.60
2000, pad, 0.5	99.49	99.50	99.47	99.50
Dry-type				
1, small, 0.35	95.47	95.50	94.88	95.50
10, small, 0.35	98.04	98.72	98.19	98.72
45, lighting, 0.35	98.70	97.58	97.99	98.70
1500, epoxy-cast, 0.5	99.29	99.28	99.30	99.32
2000, load center, 0.5	99.51	99.30	99.42	99.51
2500, epoxy-cast, 0.5	99.37	99.31	99.35	99.37

Table 6.3. Alternative conservation case savings: first year of policy and over a 30-year period beginning in 2004

Transformer type	Conservation case				
	TP-1	**Lowest TOC**	**Median TOC**	**Average losses**	**High-efficiency**
First-year savings (million kWh)					
Liq. med.-voltage single-phase	25	123	87	229	727
Liq. med.-voltage three-phase	43	94	76	89	225
Dry low-voltage single-phase	28	41	57	45	57
Dry low-voltage three-phase	256	599	209	350	599
Dry med.-voltage single-phase	11	15	15	15	15
Dry med.-voltage three-phase	70	213	193	208	221
Total	433	1086	650	936	1846
Savings over 30 years (quads)					
Liq. med.-voltage single-phase	0.14	0.71	0.50	1.33	4.22
Liq. med.-voltage three-phase	0.25	0.54	0.44	0.51	1.31
Dry low-voltage single-phase	0.16	0.24	0.33	0.26	0.33
Dry low-voltage three-phase	1.49	3.48	1.21	2.03	3.48
Dry med.-voltage single-phase	0.06	0.09	0.09	0.09	0.09
Dry med.-voltage three-phase	0.41	1.24	1.12	1.21	1.28
Total	2.51	6.30	3.70	5.42	10.70
Case efficiency	**98.59%**	**98.88%**	**98.68%**	**98.81%**	**99.21%**

7. SUMMARY AND CONCLUSIONS

7.1 EFFECTIVE LOADS

The NEMA standard TP-1 reference load for liquid-immersed distribution transformers — 50% of nameplate capacity (NEMA 1996) — appears to be higher than the typical loads for utility applications. Analysis of the FERC Form 1 data indicates that the per unit annual average load for utility-owned liquid-immersed distribution transformers is 0.24. The effective load (i.e., RMS load) appears to be about 10% higher, or 0.27. Limited data from several utilities surveyed by ORNL support a relatively low per unit effective load of 0.25 to 0.35. The lower-than-expected transformer loading may be due to high air conditioning loads or the application of high motor loads with frequent starts. The desire to prevent voltage sag and lighting flicker also contributes to the relatively low loading, even for the larger sizes. The data obtained from ORNL's survey of utilities indicate both a relatively low peak load and a low average load. Although the surveyed utilities are located primarily in the central and southern United States, the FERC Form 1 data indicate that the relatively low loading is being applied nationally. Limited data are available for nonutility applications; however, the reference loads in the NEMA TP-1 standard (0.35 for low voltage or 0.5 for medium voltage) appear to be only slightly high and not inconsistent with the available data.

7.2 DISTRIBUTION TRANSFORMER MARKET

There is no single source of information for the total distribution transformer market, and many of the data sources are not always consistent with other sources. We have considered various private and government sources along with checks on the reasonableness of the sales or transformer capacity (MVA) to arrive at the present and future market data presented in this report. The current distribution transformer market is shown in Table 7.1. Small dry-type single-phase transformers used for power distribution (less than 15 kVA) are listed separately. This market is significantly small, accounting for about 5.5% of the total dry-type distribution transformer market.

Table 7.1. Current distribution transformer market

Type of transformer	Av. size of unit (kVA)	No. of units	Total capacity (MVA)
Liquid-immersed	46	1,480,000	68,150
Dry-type[a]	83	248,000	20,660
Small dry-type (10 kVA)	10	~6,000	60
Small dry-type (<10 kVA)	3	~400,000	1,200

[a] Sizes that are described in NEMA TP-1 standard.

The future outlook of the distribution transformer industry is not expected to be significantly different from that of the past decade. The assumed growth rates ranged from 0.8 to 1.6% for both liquid-immersed and dry-type transformer markets. This range is consistent with low- to moderate-growth energy scenarios.

7.3 ENERGY SAVINGS

The energy savings from more efficient distribution transformers in the United States have been determined for the NEMA TP-1 minimum efficiency standard and the conservation cases considered earlier in the determination study (Barnes et al. 1996). The energy savings for the determination study cases have been revised downward because of a number of factors. The transformer market, both present and future, was overestimated in the previous study, particularly for dry-type transformers, which have the greatest energy-saving potential. In addition, a downward revision in the effective annual loads for utility-owned transformers has also resulted in less energy savings.

We have developed a more accurate disaggregated model to compute the base case losses and the energy savings due to an efficiency standard. This model was used to determine the savings resulting from the NEMA TP-1 standard as well as from the conservation cases. Data needed for the disaggregated model — i.e., data for all sizes and types of transformers — were not collected for the earlier conservation cases. Therefore, data for the complete range of transformers had to be developed from the limited earlier data by applying the 0.75 power rule, which relates the losses of similar types of transformers with different sizes. Unfortunately, this approach may not be as accurate as the analysis for TP-1, in which a complete set of data was available.

The energy savings for the cases considered in this report are summarized in Table 7.2. The savings ranged from 2.5 to 10.7 quads of primary energy for the period 2004 through 2033. For the TP-1 case, data were available to calculate the payback period required to recover the extra cost from the value of the energy saved. The average payback is 2.76 years.

7.4 CONCLUSIONS

The NEMA TP-1 minimum efficiency standard could save about 2.5 quads of primary energy cumulated during the 30-year period from 2004 through 2033 if there is 100% participation in compliance with the voluntary standard. TP-1 can be easily justified economically, since the simple payback period is, on average, less than 3 years. The conservation cases considered in the determination study could save more energy, from 3.7 to 10.7 quads. The payback periods for these cases could not be determined because of insufficient data from the earlier surveys. The potential for saving energy with an efficiency standard is increased if the load specified by the standard is near the effective operating load. For example, TP-1 saving could be increased to 2.73 quads if the liquid-immersed transformer loads were specified at 40% instead of at 50% in the standard.

Table 7.2 Results of the energy analysis

Conservation case	Losses[a] (quads)	Savings[a] (quads)	Loss reduction[b] (%)	Efficiency[a] (%)	Cumulative savings[c] (quads)
Base case	0.0401	NA[d]	NA[d]	98.40	NA[d]
NEMA standard TP-1	0.0353	0.0048	12.0	98.59	2.51
Median TOC	0.0330	0.0071	17.6	98.68	3.70
Average losses	0.0297	0.0104	25.8	98.81	5.42
Lowest TOC	0.0280	0.0120	30.0	98.88	6.30
High efficiency	0.0196	0.0204	51.0	99.21	10.70

[a]Primary energy for year 2004.
[b]Case loss reduction as defined by Eq. (3.10) for year 2004.
[c]Primary energy savings for 1.2% annual growth in sales over the period 2004 through 2033.
[d]NA = Not applicable.

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Appendix A: FERC Form 1 Summary

Table A.1. Analysis of 1992 FERC Form 1 Data

UTILITIES	Number of Transformers	Capacity MVA	Residential Sales (MWh)	Commercial Sales (MWh)	Residential Customers	Commerical Customers	Average Unit (kVA)	Average p.u. Load*
ALABAMA POWER CO.	542,541	17,466	12,069,268	8,629,869	1,004,343	150,526	32.19	0.150
APPALACHIAN POWER CO.	336,782	10,784	8,944,292	4,955,878	717,154	94,572	32.02	0.163
ARIZONA PUBLIC SERVICE CO.	189,600	11,722	6,066,830	6,904,072	549,778	68,650	61.82	0.140
ARKANSAS POWER & LIGHT CO.	284,945	10,089	5,102,300	3,840,370	503,741	63,068	35.41	0.112
ATLANTIC CITY ELECTRIC CO	127,706	4,781	3,289,492	3,100,133	402,950	51,996	37.44	0.170
BALTIMORE GAS & ELECTRIC CO.	180,505	11,590	9,677,272	2,500,060	949,258	94,862	64.21	0.133
BANGOR HYDRO-ELECTRIC CO.	37,321	861	515,381	143,800	85,613	12,421	23.07	0.097
BLACK HILLS CORP.	18,147	975	339,341	446,036	43,824	8,308	53.73	0.102
BLACKSTONE VALLEY ELECTRIC CO	12,591	745	363,917	396,066	74,764	8,575	59.17	0.129
BOSTON EDISON CO.	60,752	4,905	3,424,275	7,202,580	561,838	90,605	80.74	0.275
CAROLINA POWER & LIGHT CO.	378,169	14,933	10,490,030	8,060,282	846,232	145,858	39.49	0.158
CENTRAL HUDSON GAS & ELEC CORP.	83,636	2,340	1,527,459	1,156,954	221,077	31,423	27.98	0.146
CENTRAL ILLINOIS LIGHT CO.	61,856	2,815	1,507,911	1,310,638	167,447	20,026	45.51	0.127
CENTRAL LOUISIANA ELEC CO., INC.	112,357	3,289	2,353,449	1,061,478	178,981	23,648	29.27	0.132
CENTRAL MAINE POWER CO.	199,511	4,635	2,989,402	2,365,898	446,696	49,529	23.23	0.147
CENTRAL POWER & LIGHT CO.	207,474	8,055	5,407,570	4,181,265	485,713	72,649	38.82	0.151
CENTRAL VERMONT PUB SERV CORP.	65,690	1,212	813,279	775,031	118,239	16,205	18.45	0.166
CHEYENNE LIGHT FUEL & POWER CO	6,815	270	185,535	218,560	27,594	3,981	39.62	0.190
CINCINNATI GAS & ELECTRIC CO	153,192	9,565	5,552,285	4,456,160	520,026	58,384	62.44	0.133
CITIZENS ELECTRIC CO.	2,110	70	62,736	18,970	4,860	984	33.18	0.148
CITIZENS UTILITIES CO. (CT)	39,593	1,190	618,637	389,794	81,600	11,506	30.06	0.107
CLEVELAND ELECTRIC ILLUM CO	138,754	7,622	4,724,996	5,466,615	668,136	70,655	54.93	0.170
COLUMBUS SOUTHERN POWER CO	144,261	6,425	4,859,226	5,151,327	509,495	51,591	44.54	0.198
COMMONWEALTH EDISON CO.	529,363	35,028	19,269,209	22,661,665	2,965,652	280,451	66.17	0.152
COMMONWEALTH ELECTRIC CO.	58,575	2,254	1,584,219	1,021,038	266,513	34,348	38.48	0.147
CONCORD ELECTRIC CO	6,885	181	142,326	143,910	21,255	3,033	26.29	0.201
CONNECTICUT LIGHT & POWER CO.	221,433	10,007	8,253,207	7,820,932	980,146	88,333	45.19	0.204
CONNECTICUT VALLEY ELEC CO, INC.	3,643	61	56,809	62,022	8,871	1,354	16.74	0.247
CONOWINGO POWER CO.	9,911	392	371,709	145,627	31,402	3,172	39.55	0.167
CONSOLIDATED EDISON CO.-NY, INC.	78,702	23,305	9,845,397	23,527,194	2,544,846	403,475	296.12	0.182
DAYTON POWER & LIGHT CO	136,831	6,443	4,259,572	2,896,081	411,254	39,401	47.09	0.141
DELMARVA POWER & LIGHT CO.	103,387	4,564	3,232,067	3,140,515	333,485	41,905	44.14	0.177
DETROIT EDISON CO.	357,823	20,341	11,378,490	8,668,326	1,774,085	166,798	56.85	0.125
DUKE POWER CO.	590,409	33,394	17,827,792	15,812,145	1,431,403	225,245	56.56	0.128
DUQUESNE LIGHT CO.	99,243	5,089	3,069,087	5,358,492	520,077	52,695	51.28	0.210
EASTERN EDISON CO.	31,325	1,356	1,023,542	1,114,702	154,871	20,096	43.29	0.200
EDISON SAULT ELECTRIC CO.	7,994	252	144,203	173,141	16,919	2,964	31.52	0.160
EMPIRE DISTRICT ELECTRIC CO.	63,555	2,011	1,068,596	850,829	101,943	17,796	31.64	0.121
EXETER & HAMPTON ELECTRIC CO	6,885	258	215,442	109,596	28,946	4,724	37.47	0.160
FITCHBURG GAS & ELEC LIGHT CO.	5,692	162	127,371	98,860	22,766	2,768	28.46	0.177
FLORIDA POWER & LIGHT CO.	672,156	36,340	34,198,302	26,990,914	2,911,812	350,271	54.06	0.214
FLORIDA POWER CORP.	312,667	13,937	12,825,815	7,544,084	1,050,077	116,727	44.57	0.185
GEORGIA POWER CO.	538,137	25,493	14,939,172	17,260,614	1,408,953	181,996	47.37	0.160
GRANITE STATE ELECTRIC CO	8,172	332	233,379	320,104	29,360	4,854	40.63	0.211
GREEN MOUNTAIN POWER CORP.	29,294	893	563,608	584,053	67,201	11,245	30.48	0.163
GULF POWER CO.	113,008	4,054	3,596,515	2,369,236	265,374	36,009	35.87	0.187
GULF STATES UTILITIES CO.	283,632	12,651	6,824,670	5,474,432	510,003	64,000	44.60	0.123
HAWAIIAN ELECTRIC CO, INC.	29,764	2,689	1,730,537	1,698,076	224,417	30,320	90.34	0.162
HOUSTON LIGHTING & POWER CO.	393,266	27,073	16,375,400	12,541,636	1,250,888	164,051	68.84	0.135
IDAHO POWER CO.	161,267	7,220	3,474,325	4,147,843	250,750	51,784	44.77	0.134
ILLINOIS POWER CO.	191,323	7,947	4,137,858	3,055,345	495,948	56,800	41.54	0.115
INDIANA MICHIGAN POWER CO.	161,208	6,143	4,633,779	3,747,194	458,470	51,845	38.11	0.173
INDIANAPOLIS POWER & LIGHT CO.	81,228	5,471	3,675,431	2,158,752	349,539	38,066	67.35	0.135
INTERSTATE POWER CO.	47,734	1,775	931,849	776,521	126,935	30,808	37.19	0.122
IOWA ELECTRIC LIGHT & POWER CO	69,618	2,451	1,434,269	1,342,627	180,771	30,608	35.21	0.144
IOWA SOUTHERN UTILITIES	34,072	1,433	734,242	433,999	81,656	12,695	42.06	0.103
IOWA-ILLINOIS GAS & ELEC. CO.	57,612	2,783	1,142,078	1,268,117	175,591	20,257	48.31	0.110
JERSEY CENTRAL POWER & LIGHT CO	198,438	10,257	6,567,957	6,207,321	794,776	93,615	51.69	0.158
KANSAS CITY POWER & LIGHT CO.	97,901	5,602	3,172,611	4,984,285	365,069	48,522	57.22	0.185

Table A.1 (Continued)

UTILITIES	Number of Transformers	Capacity MVA	Residential Sales (MWh)	Commercial Sales (MWh)	Residential Customers	Commerical Customers	Average Unit (kVA)	Average p.u. Load
KANSAS GAS & ELECTRIC CO. (WR)	97,092	4,447	2,101,531	1,892,382	238,286	22,840	45.80	0.114
KENTUCKY POWER CO.	79,023	2,432	1,886,021	991,361	133,840	21,136	30.78	0.150
KENTUCKY UTILITIES CO.	176,731	6,111	4,278,098	3,080,045	356,287	59,685	34.58	0.153
KINGSPORT POWER CO.	12,652	558	591,502	302,692	35,413	3,986	44.10	0.203
LOCKHART POWER CO	2,827	82	53,138	14,395	4,594	741	29.01	0.104
LONG ISLAND LIGHTING CO.	179,888	9,835	6,787,601	3,473,585	902,885	98,396	54.67	0.132
LOUISIANA POWER & LIGHT CO.	182,366	9,127	6,996,327	4,307,235	522,641	60,145	50.05	0.157
LOUISVILLE GAS & ELECTRIC CO.	78,104	4,265	2,923,517	2,635,271	292,084	33,474	54.61	0.165
MAINE PUBLIC SERVICE CO.	11,568	222	176,814	155,267	28,102	5,261	19.19	0.190
MASSACHUSETTS ELECTRIC CO.	147,507	7,473	5,645,350	5,645,867	819,782	83,231	50.66	0.192
MAUI ELECTRIC CO LTD	9,124	465	295,148	286,284	42,238	6,933	50.96	0.159
METROPOLITAN EDISON CO.	148,504	5,904	3,567,292	2,637,650	390,339	46,615	39.76	0.133
MIDWEST POWER SYSTEMS, INC.	131,377	5,845	2,956,489	2,617,781	358,018	51,231	44.49	0.121
MINNESOTA POWER & LIGHT	37,897	1,247	816,240	821,376	100,784	15,358	32.90	0.167
MISSISSIPPI POWER & LIGHT CO	151,999	5,489	3,644,164	2,803,672	302,768	45,533	36.11	0.149
MISSISSIPPI POWER COMPANY	73,339	2,794	1,804,858	1,811,042	149,585	27,889	38.10	0.164
MONONGAHELA POWER CO.	172,499	2,963	2,527,247	1,742,469	292,646	33,749	17.18	0.183
MONTANA DAKOTA UTILITIES CO	32,835	1,144	695,717	771,692	92,717	16,378	34.84	0.163
MONTANA POWER CO.	107,387	3,518	1,738,899	2,018,319	210,483	38,077	32.76	0.135
MT CARMEL PUBLIC UTILITY CO.	2,449	65	43,980	12,474	4,557	957	26.54	0.110
NANTAHALA POWER & LIGHT CO	34,286	731	415,117	248,293	44,699	5,624	21.32	0.115
NARRAGANSETT ELECTRIC CO	53,352	2,207	1,783,754	1,877,738	284,711	31,417	41.37	0.210
NEVADA POWER CO.	57,527	5,323	4,372,948	1,963,539	328,387	45,245	92.53	0.151
NEW ORLEANS PUBLIC SERVICE, INC.	34,847	3,180	1,805,611	1,976,586	170,621	16,662	91.26	0.151
NEW YORK STATE ELEC & GAS CORP.	282,864	9,116	5,386,969	3,282,756	697,707	72,535	32.23	0.121
NEWPORT ELECTRIC CORP	5,256	276	192,552	199,363	27,243	4,230	52.51	0.180
NIAGARA MOHAWK POWER CORP.	410,343	16,462	10,298,064	11,555,795	1,378,467	141,129	40.12	0.168
NORTHERN INDIANA PUBLIC SERVICE C	107,418	4,554	2,343,303	2,608,614	344,861	40,034	42.40	0.138
NORTHERN STATES POWER CO (MN)	206,019	11,975	7,106,001	4,410,209	1,027,013	129,932	58.13	0.122
NORTHERN STATES POWER CO (WI)	67,111	2,347	1,574,622	811,965	172,802	26,405	34.97	0.129
NORTHWESTERN PUBLIC SERVICE CO.	17,928	921	352,801	198,204	44,241	8,607	51.37	0.076
NORTHWESTERN WISCONSIN ELEC CO	5,695	102	57,957	38,413	10,207	1,454	17.91	0.120
OHIO EDISON CO.	261,441	8,863	6,634,111	5,697,850	818,038	90,210	33.90	0.176
OHIO POWER CO.	230,000	7,468	5,728,601	4,176,841	565,020	72,860	32.47	0.168
OKLAHOMA GAS & ELECTRIC CO.	170,510	12,620	5,980,308	4,327,325	561,114	68,467	74.01	0.104
ORANGE & ROCKLAND UTILITIES, INC.	61,922	3,214	1,034,849	695,834	162,641	23,116	51.90	0.068
OTTER TAIL POWER CO.	40,192	1,698	941,844	522,527	95,870	23,625	42.25	0.109
PACIFIC GAS & ELECTRIC CO.	917,933	35,915	23,663,905	30,709,655	3,708,374	550,032	39.13	0.192
PECO ENERGY CO.	164,556	11,222	9,522,301	5,222,052	1,297,917	137,933	68.20	0.167
PENNSYLVANIA ELECTRIC CO.	175,727	6,946	3,590,161	3,488,165	485,599	66,631	39.53	0.129
PENNSYLVANIA POWER & LIGHT CO.	393,282	11,943	10,614,208	9,031,604	1,038,880	133,622	30.37	0.209
PENNSYLVANIA POWER CO.	53,004	1,407	1,050,601	781,830	121,147	15,287	26.55	0.165
PORTLAND GENERAL ELECTRIC CO	162,186	7,123	6,225,936	5,717,035	532,194	74,002	43.92	0.213
POTOMAC EDISON CO.	155,864	4,738	3,822,387	1,954,025	299,415	38,939	30.40	0.155
POTOMAC ELECTRIC POWER CO.	104,762	12,118	6,155,793	10,473,702	587,677	68,660	115.67	0.174
PSC OF COLORADO	168,942	9,355	5,561,513	10,131,595	859,561	115,753	55.37	0.213
PSC OF NEW HAMPSHIRE	124,387	4,332	2,342,789	1,224,080	344,409	52,056	34.83	0.104
PSC OF NEW MEXICO	66,757	2,688	1,671,563	2,375,799	267,546	32,045	40.27	0.191
PSC OF OKLAHOMA	143,015	6,377	4,139,572	4,091,944	402,010	51,937	44.59	0.164
PSI ENERGY, INC.	184,857	7,925	5,942,542	5,121,099	530,920	72,274	42.87	0.177
PUBLIC SERVICE ELECTRIC & GAS	302,064	19,704	9,816,046	17,454,352	1,623,396	213,344	65.23	0.176
PUGET SOUND POWER & LIGHT CO.	247,956	10,492	8,441,893	5,996,355	692,100	80,963	42.31	0.175
ROCHESTER GAS & ELECTRIC CORP.	73,733	2,888	2,084,934	1,949,750	299,327	29,256	39.17	0.177
ROCKLAND ELECTRIC CO	21,091	1,062	474,587	360,260	55,483	7,049	50.35	0.100
SAN DIEGO GAS & ELECTRIC CO.	161,567	9,829	5,611,070	6,066,556	998,432	116,982	60.84	0.151
SIERRA PACIFIC POWER CO	60,728	3,462	1,647,766	2,082,615	219,202	33,718	57.01	0.137
SIERRA PACIFIC POWER CO	59,669	3,427	1,571,350	2,077,857	214,530	33,159	57.43	0.135
SOUTH BELOIT WATER GAS & ELECTRI	2,062	103	43,198	27,279	5,482	711	49.95	0.087
SOUTH CAROLINA ELECTRIC & GAS	193,066	7,991	5,155,886	4,538,862	395,471	59,413	41.39	0.154

Table A.1 (Continued)

UTILITIES	Number of Transformers	Capacity MVA	Residential Sales (MWh)	Commercial Sales (MWh)	Residential Customers	Commerical Customers	Average Unit (kVA)	Average p.u. Load*
SOUTHERN INDIANA GAS & ELECTRIC C	46,436	1,870	1,119,517	1,044,824	101,547	14,316	40.27	0.147
SOUTHWESTERN ELECTRIC SERV CO.	24,685	611	364,906	244,298	33,344	5,743	24.75	0.126
ST JOSEPH LIGHT & POWER CO.	20,995	894	505,047	387,013	53,037	6,434	42.58	0.127
SUPERIOR WATER LIGHT & POWER CO	1,983	83	71,544	80,793	11,747	1,562	41.86	0.233
TAMPA ELECTRIC CO.	121,448	6,496	5,559,833	4,332,572	412,970	51,727	53.49	0.193
TEXAS UTILITIES ELECTRIC CO.	676,443	35,561	27,266,411	22,959,464	1,936,787	208,361	52.57	0.179
TEXAS-NEW MEXICO POWER CO.	97,787	3,131	1,947,593	1,964,097	176,998	30,644	32.02	0.158
TOLEDO EDISON CO.	73,263	3,631	1,940,661	1,619,478	254,268	26,006	49.56	0.124
TUCSON ELECTRIC POWER CO.	61,004	3,692	2,146,268	1,215,179	248,633	26,272	60.52	0.115
UNION ELECTRIC CO.	274,837	15,055	9,690,260	10,553,257	982,368	125,147	54.78	0.171
UNION LIGHT, HEAT & POWER CO.	26,713	1,441	1,028,082	730,486	96,723	10,110	53.94	0.155
UNITED ILLUMINATING CO.	56,574	3,493	1,799,455	2,303,216	273,936	28,848	61.74	0.149
UPPER PENINSULA POWER CO.	18,876	440	253,690	186,094	54,896	6,259	23.31	0.127
VIRGINIA ELECTRIC & POWER CO	523,135	27,552	19,984,489	17,692,997	1,617,743	175,653	52.67	0.173
WASHINGTON WATER POWER CO.	90,422	3,444	3,023,854	2,298,515	227,576	27,781	38.09	0.196
WEST PENN POWER CO.	294,400	6,449	5,396,533	3,374,355	561,659	63,368	21.91	0.173
WEST TEXAS UTILITIES CO.	80,471	2,469	1,343,774	1,057,568	141,681	25,438	30.68	0.123
WESTERN MASSACHUSETTS ELEC CO.	38,345	1,743	1,359,845	1,238,578	175,673	14,865	45.46	0.189
WHEELING POWER CO.	11,441	440	354,950	335,448	35,889	4,574	38.46	0.199
WISCONSIN ELECTRIC POWER CO	209,136	10,407	6,230,136	6,154,530	824,544	85,990	49.76	0.151
WISCONSIN POWER & LIGHT CO	137,494	4,534	2,571,242	1,524,543	302,395	40,901	32.98	0.115
WISCONSIN PUBLIC SERVICE CORP.	141,344	4,555	2,268,685	2,384,098	300,973	34,356	32.23	0.130
Totals	20,022,780	940,062	614,861,839	566,412,649	67,597,533	8,454,341	46.95	0.159

*A power factor of 0.9 has been used to compute the average load.

Table A.2. 1992 FERC Form 1 Data

UTILITIES	Transformers in Inventory	Capacity MVA	Transformers In-Service	In-Service Capacity	Number of Customers	Total Annual Sales (MWh)	Annual Sales Via Dist Xfmrs.	Average* p. u. Load
ALABAMA POWER CO.	542,541	17,466	529,315	16,550	1,160,981	39,136,209	33,265,778	0.255
APPALACHIAN POWER CO.	336,782	10,784	326,562	9,948	820,773	23,761,020	20,196,867	0.258
ARIZONA PUBLIC SERVICE CO.	189,600	11,721	174,416	10,557	623,100	16,034,731	13,629,521	0.164
ARKANSAS POWER & LIGHT CO.	284,945	10,089	274,263	9,253	588,191	14,699,692	12,494,738	0.171
ATLANTIC CITY ELECTRIC CO	127,706	4,781	123,520	4,606	456,460	7,668,300	6,518,055	0.179
BALTIMORE GAS & ELECTRIC CO.	180,505	11,591	175,656	11,015	1,052,088	25,307,432	21,511,317	0.248
BANGOR HYDRO-ELECTRIC CO.	37,321	861	37,321	861	115,434	1,574,528	1,338,349	0.197
BLACK HILLS CORP.	18,147	975	16,685	943	52,288	1,379,420	1,172,507	0.158
BLACKSTONE VALLEY ELECTRIC CO	12,591	745	11,236	570	83,904	1,226,938	1,042,897	0.232
BOSTON EDISON CO.	60,752	4,905	53,442	4,249	657,080	12,597,607	10,707,966	0.320
CAMBRIDGE ELECTRIC LIGHT CO.	2,334	165	1,881	131	44,714	1,298,313	1,103,566	1.069
CAROLINA POWER & LIGHT CO.	378,169	14,933	366,912	14,056	999,063	32,896,617	27,962,124	0.252
CENTRAL HUDSON GAS & ELEC CORP.	83,636	2,340	80,175	2,189	256,503	4,840,244	4,114,207	0.238
CENTRAL ILLINOIS LIGHT CO.	61,856	2,815	59,964	2,648	187,933	4,972,366	4,226,511	0.202
CENTRAL ILLINOIS PUB SERV CO.	106,801	4,234	100,929	3,739	308,752	7,327,890	6,228,707	0.211
CENTRAL LOUISIANA ELEC CO., INC.	112,357	3,289	112,222	3,024	208,335	5,863,212	4,983,730	0.209
CENTRAL MAINE POWER CO.	199,511	4,635	194,208	4,182	496,666	9,062,978	7,703,531	0.234
CENTRAL POWER & LIGHT CO.	207,474	8,055	199,582	7,467	568,265	15,803,038	13,432,582	0.228
CENTRAL VERMONT PUB SERV CORP.	65,690	1,211	63,898	1,148	134,661	1,978,337	1,681,586	0.186
CHEYENNE LIGHT FUEL & POWER CO	6,815	270	6,581	252	31,651	683,547	581,015	0.292
CINCINNATI GAS & ELECTRIC CO	153,192	9,565	135,240	7,923	584,691	16,436,040	13,970,634	0.224
CITIZENS ELECTRIC CO.	2,110	70	2,070	67	5,900	144,945	123,203	0.233
CITIZENS UTILITIES CO. (CT)	39,583	1,190	36,090	993	94,622	1,400,504	1,190,428	0.152
CLEVELAND ELECTRIC ILLUM CO	138,754	7,622	130,711	6,557	747,168	18,712,814	15,905,892	0.308
COLUMBUS SOUTHERN POWER CO	144,261	6,425	138,779	5,998	564,425	13,264,342	11,274,691	0.238
COMMONWEALTH EDISON CO.	529,363	35,028	517,457	33,703	3,259,577	71,065,816	60,405,944	0.227
COMMONWEALTH ELECTRIC CO.	58,575	2,254	52,340	1,911	304,380	3,206,036	2,725,131	0.181
CONCORD ELECTRIC CO	6,885	181	6,603	167	25,501	424,392	360,733	0.274
CONNECTICUT LIGHT & POWER CO.	221,433	10,007	215,359	9,734	1,075,409	20,365,822	17,310,949	0.226
CONNECTICUT VALLEY ELEC CO, INC.	3,643	61	3,600	61	10,246	156,817	133,294	0.277
CONSOLIDATED EDISON CO.-NY, INC.	78,702	23,305	74,518	22,020	2,950,612	35,119,289	29,851,396	0.172
CONSOLIDATED WATER POWER CO	505	8,686	365	5,435	1,012	1,140,252	969,214	0.023
DAYTON POWER & LIGHT CO	136,831	6,443	125,107	5,768	458,188	12,408,522	10,547,244	0.232
DELMARVA POWER & LIGHT CO.	103,387	4,564	98,274	4,251	376,704	9,533,418	8,103,405	0.242
DETROIT EDISON CO.	357,823	20,341	351,438	19,771	1,945,624	39,376,813	33,470,291	0.215
DUKE POWER CO.	590,409	33,394	575,601	32,029	1,672,970	60,935,188	51,794,910	0.205
DUQUESNE LIGHT CO.	99,243	5,089	97,621	5,014	576,616	11,557,196	9,823,617	0.249
EASTERN EDISON CO.	30,960	1,352	28,998	1,156	175,618	2,458,593	2,089,804	0.229
EDISON SAULT ELECTRIC CO.	7,994	252	7,269	214	19,928	557,375	473,769	0.281
EMPIRE DISTRICT ELECTRIC CO.	63,555	2,011	60,333	1,908	121,482	2,694,130	2,290,011	0.152
EXETER & HAMPTON ELECTRIC CO	6,885	259	6,412	235	35,119	457,116	388,549	0.210
FITCHBURG GAS & ELEC LIGHT CO.	5,692	162	5,198	142	25,573	379,304	322,408	0.288
FLORIDA POWER & LIGHT CO.	672,156	36,340	655,078	34,990	3,281,239	66,380,636	56,423,541	0.205
FLORIDA POWER CORP.	312,667	13,937	308,149	13,600	1,182,154	25,414,014	21,601,912	0.201
GEORGIA POWER CO.	538,137	25,493	512,961	22,997	1,604,811	55,614,242	47,272,106	0.261
GRANITE STATE ELECTRIC CO	8,172	332	6,815	302	34,500	644,590	547,902	0.230
GREEN MOUNTAIN POWER CORP.	29,294	894	27,973	825	78,526	1,692,179	1,438,352	0.221
GULF POWER CO.	113,008	4,054	108,676	3,830	301,713	8,161,835	6,937,560	0.230
GULF STATES UTILITIES CO.	283,632	12,651	281,121	12,309	583,766	27,436,818	23,321,295	0.240
HOLYOKE WATER POWER CO.	201	102	169	85	53	112,823	95,900	0.143
HOUSTON LIGHTING & POWER CO.	393,266	27,073	383,171	14,737	1,416,786	59,376,419	50,469,956	0.434
IDAHO POWER CO.	161,267	7,220	156,449	6,664	302,834	11,606,255	9,865,317	0.188
ILLINOIS POWER CO.	191,323	7,947	184,695	7,390	553,881	15,581,797	13,244,527	0.227
INDIANA MICHIGAN POWER CO.	161,208	6,143	158,348	5,863	517,391	14,259,949	12,120,957	0.262
INDIANAPOLIS POWER & LIGHT CO.	81,228	5,471	76,351	4,961	390,919	11,752,441	9,989,575	0.255
INTERSTATE POWER CO.	47,734	1,775	45,787	1,665	159,282	4,534,889	3,854,656	0.294
IOWA ELECTRIC LIGHT & POWER CO	69,618	2,451	66,757	2,268	212,070	4,274,932	3,633,692	0.203

Table A.2 (Continued)

UTILITIES	Transformers	Capacity	Transformers	In-Service	Number of	Total Annual	Annual Sales	Average*
IOWA SOUTHERN UTILITIES	34,072	1,432	32,701	1,329	94,863	2,361,162	2,006,988	0.192
IOWA-ILLINOIS GAS & ELEC. CO.	57,612	2,784	53,643	2,466	196,624	4,589,440	3,901,024	0.201
JERSEY CENTRAL POWER & LIGHT CO	198,438	10,257	190,511	9,535	893,125	16,574,401	14,088,241	0.187
KANSAS CITY POWER & LIGHT CO.	97,901	5,601	96,372	5,333	416,052	10,658,908	9,060,072	0.215
KANSAS GAS & ELECTRIC CO. (WR)	97,092	4,447	93,842	4,160	265,275	7,287,278	6,194,186	0.189
KENTUCKY POWER CO.	79,023	2,432	77,231	2,276	157,116	5,705,743	4,849,882	0.270
KENTUCKY UTILITIES CO.	176,731	6,111	170,500	5,389	425,377	12,551,782	10,669,015	0.251
KINGSPORT POWER CO.	12,652	558	12,180	520	39,715	1,804,267	1,533,627	0.374
LOCKHART POWER CO	2,827	81	2,679	76	5,352	191,359	162,655	0.271
LONG ISLAND LIGHTING CO.	179,888	9,834	154,191	7,742	1,009,313	15,443,788	13,127,220	0.215
LOUISIANA POWER & LIGHT CO.	182,366	9,127	172,586	8,195	593,297	26,701,341	22,696,140	0.351
LOUISVILLE GAS & ELECTRIC CO.	78,104	4,265	75,717	4,135	331,156	9,234,911	7,849,674	0.241
MADISON GAS & ELECTRIC CO.	18,870	1,173	17,497	1,053	114,216	2,310,018	1,963,515	0.237
MAINE PUBLIC SERVICE CO.	11,568	222	11,004	195	34,499	523,852	445,274	0.290
MASSACHUSETTS ELECTRIC CO.	147,507	7,473	137,517	6,556	908,606	15,304,099	13,008,484	0.252
METROPOLITAN EDISON CO.	148,504	5,904	145,241	5,509	440,295	9,934,412	8,444,250	0.194
MIDWEST POWER SYSTEMS, INC.	131,377	5,845	130,406	5,772	414,513	8,858,682	7,529,880	0.165
MINNESOTA POWER & LIGHT	37,897	1,247	35,284	1,075	117,168	8,039,939	6,833,948	0.806
MISSISSIPPI POWER & LIGHT CO	151,999	5,489	148,490	5,251	354,215	9,397,402	7,987,792	0.193
MONONGAHELA POWER CO.	172,499	2,963	169,383	2,837	334,543	9,167,541	7,792,410	0.348
MONTANA DAKOTA UTILITIES CO	32,835	1,144	29,396	1,008	109,834	1,829,933	1,555,443	0.196
MONTANA POWER CO.	107,387	3,518	100,911	3,066	255,233	6,973,801	5,927,731	0.245
NARRAGANSETT ELECTRIC CO	53,352	2,207	50,158	1,933	319,004	4,586,030	3,898,126	0.256
NEVADA POWER CO.	57,527	5,323	54,077	4,857	374,317	10,067,905	8,557,719	0.223
NEW ORLEANS PUBLIC SERVICE, INC.	34,847	3,180	32,251	2,509	189,682	5,129,622	4,360,179	0.220
NEW YORK STATE ELEC & GAS CORP.	282,864	9,116	273,090	8,233	782,772	13,209,253	11,227,865	0.173
NEWPORT ELECTRIC CORP	5,256	275	4,829	230	31,490	540,385	459,327	0.253
NIAGARA MOHAWK POWER CORP.	410,343	16,462	358,440	13,524	1,525,625	33,351,333	28,348,633	0.266
NORTHERN INDIANA PUBLIC SERVICE CO	107,418	4,554	103,403	4,111	388,223	13,271,106	11,280,440	0.348
NORTHERN STATES POWER CO (MN)	206,019	11,975	197,191	11,125	1,168,211	26,111,894	22,195,110	0.253
NORTHERN STATES POWER CO (WI)	67,111	2,346	64,128	2,150	201,347	4,529,793	3,850,324	0.227
NORTHWESTERN PUBLIC SERVICE CO.	17,928	921	16,461	772	53,615	894,077	759,965	0.125
NORTHWESTERN WISCONSIN ELEC CO	5,695	103	5,215	89	11,734	114,408	97,247	0.139
OHIO EDISON CO.	261,441	8,863	251,829	8,166	912,543	20,545,476	17,463,655	0.271
OHIO POWER CO.	230,000	7,468	224,364	7,052	648,358	28,948,620	24,606,327	0.443
OKLAHOMA GAS & ELECTRIC CO.	170,510	12,620	157,283	4,702	649,773	18,316,230	15,568,796	0.420
ORANGE & ROCKLAND UTILITIES, INC.	61,922	3,213	48,104	2,251	186,560	2,973,008	2,527,057	0.142
OTTER TAIL POWER CO.	40,192	1,698	38,434	1,560	121,947	2,926,878	2,487,846	0.202
PACIFIC GAS & ELECTRIC CO.	917,933	35,915	873,364	34,072	4,275,304	71,799,944	61,029,952	0.227
PECO ENERGY CO.	164,556	11,222	159,218	10,537	1,440,637	31,264,491	26,574,817	0.320
PENNSYLVANIA ELECTRIC CO.	175,727	6,946	163,291	5,959	556,541	11,710,902	9,954,267	0.212
PENNSYLVANIA POWER & LIGHT CO.	393,282	11,943	388,479	11,630	1,179,137	28,477,129	24,205,560	0.264
PENNSYLVANIA POWER CO.	53,004	1,407	51,064	1,297	136,760	3,513,321	2,986,323	0.292
PORTLAND GENERAL ELECTRIC CO	162,186	7,123	153,656	6,655	607,051	15,643,858	13,297,279	0.253
POTOMAC EDISON CO.	155,864	4,738	149,915	4,385	343,189	10,777,749	9,161,087	0.265
POTOMAC ELECTRIC POWER CO.	104,762	12,119	95,661	10,846	656,875	22,354,746	19,001,534	0.222
PSC OF COLORADO	168,942	9,355	162,011	8,659	976,095	19,003,387	16,152,879	0.237
PSC OF NEW HAMPSHIRE	124,387	4,332	120,870	4,031	398,153	6,206,786	5,275,768	0.166
PSC OF NEW MEXICO	66,757	2,688	65,841	2,602	300,492	5,358,246	4,554,509	0.222
PSI ENERGY, INC.	184,857	7,925	179,099	7,418	607,473	19,460,853	16,541,725	0.283
PUBLIC SERVICE ELECTRIC & GAS	302,064	19,704	297,668	19,154	1,853,398	36,786,395	31,268,436	0.207
PUGET SOUND POWER & LIGHT CO.	247,956	10,493	241,936	10,087	777,967	18,224,495	15,490,821	0.195
ROCHESTER GAS & ELECTRIC CORP.	73,733	2,888	65,183	2,175	332,565	6,455,986	5,487,588	0.320
ROCKLAND ELECTRIC CO	21,091	1,062	17,717	859	62,761	1,196,191	1,016,762	0.150
SAN DIEGO GAS & ELECTRIC CO.	161,567	9,829	157,453	9,409	1,117,352	15,093,221	12,829,238	0.173
SIERRA PACIFIC POWER CO	59,669	3,427	54,241	2,938	247,927	6,055,518	5,147,190	0.222
SOUTH BELOIT WATER GAS & ELECTRIC CO	2,062	103	2,062	103	6,234	165,606	140,765	0.173
SOUTH CAROLINA ELECTRIC & GAS	193,066	7,990	188,568	7,469	458,205	14,854,884	12,626,651	0.214

Table A. 2 (Continued)

UTILITIES	Transformers	Capacity	Transformers	In-Service	Number of	Total Annual	Annual Sales	Average*
SOUTHERN CALIFORNIA EDISON CO.	652,198	35,362	641,250	34,758	4,094,689	70,933,334	60,293,334	0.220
SOUTHERN INDIANA GAS & ELECTRIC CO.	46,436	1,870	44,414	1,732	116,065	3,953,177	3,360,200	0.246
SOUTHWESTERN ELECTRIC SERV CO.	24,685	611	23,361	553	39,794	877,530	745,901	0.171
ST JOSEPH LIGHT & POWER CO.	20,995	894	19,490	761	59,751	1,343,297	1,141,802	0.190
SUPERIOR WATER LIGHT & POWER CO	1,983	83	1,829	74	13,409	526,876	447,845	0.768
TAMPA ELECTRIC CO.	121,448	6,497	120,028	6,356	468,996	13,551,758	11,518,994	0.230
TEXAS UTILITIES ELECTRIC CO.	676,443	35,561	653,610	33,267	2,195,151	76,367,549	64,912,417	0.247
TEXAS-NEW MEXICO POWER CO.	97,787	3,132	91,000	2,777	207,885	6,063,137	5,153,666	0.235
TOLEDO EDISON CO.	73,263	3,631	70,776	3,429	284,700	7,601,055	6,460,897	0.239
TUCSON ELECTRIC POWER CO.	61,004	3,692	57,889	3,425	275,488	6,381,097	5,423,932	0.201
UNION ELECTRIC CO.	274,837	15,055	267,577	14,324	1,116,678	29,418,239	25,005,503	0.221
UNION LIGHT, HEAT & POWER CO.	26,713	1,441	25,240	1,327	108,127	2,807,171	2,386,095	0.228
UNITED ILLUMINATING CO.	56,574	3,493	53,356	3,052	305,159	5,152,824	4,379,900	0.182
UPPER PENINSULA POWER CO.	18,876	440	18,016	400	61,327	679,683	577,731	0.183
VIRGINIA ELECTRIC & POWER CO	523,135	27,552	510,307	26,293	1,819,054	54,664,734	46,465,024	0.224
WASHINGTON WATER POWER CO.	90,422	3,444	88,005	3,273	256,675	6,920,831	5,882,706	0.228
WEST PENN POWER CO.	294,400	6,449	285,809	6,141	636,629	15,882,702	13,500,297	0.279
WEST TEXAS UTILITIES CO.	80,471	2,469	78,095	2,292	179,573	4,067,352	3,457,249	0.191
WESTERN MASSACHUSETTS ELEC CO.	38,345	1,743	37,108	1,668	191,912	3,600,887	3,060,754	0.233
WHEELING POWER CO.	11,441	440	11,123	408	40,920	1,825,970	1,552,075	0.483
WISCONSIN ELECTRIC POWER CO	209,136	10,407	188,218	8,922	913,123	22,303,551	18,958,018	0.270
WISCONSIN POWER & LIGHT CO	137,494	4,534	134,656	4,260	345,124	7,433,018	6,318,065	0.188
WISCONSIN PUBLIC SERVICE CORP.	141,344	4,556	133,279	3,916	336,268	7,702,176	6,546,850	0.212
TOTALS	20,440,698	937,443	19,456,361	879,977	79,974,333	1,922,172,695	1,633,846,791	0.236

*Assumptions: Power factor is 0.9 and 85% of total electric sales pass through distribution transformers.

Appendix B: Derivation of Total Owning Cost

The usual expression for total owning cost (TOC) is of the form

TOC = bid price + cost of core losses + cost of load losses ,

where

cost of core losses = A($/W) × core loss (W) × loss multiplier

cost of load losses = B($/W) × load loss (W) × loss multiplier ,

and

A = equivalent first cost of no-load losses ($/W)

B = equivalent first cost of load losses ($/W) .

The A and B factors are given by the expressions

$$A = (SC + EC \times HPY)/(FCR \times 1000)$$

and

$$B = (SC \times RF + EC \times LsF \times HPY) \times PL^2 / (FCR \times 1000) ,$$

where SC = avoided cost of system capacity = GC + TD. The basic financial, cost, and load parameters are defined as follows:

SC = avoided cost of system capacity ($/kW) — The levelized avoided (incremental) cost of generation, transmission, and distribution capacity necessary to supply the next kilowatt of load to the transformer coincident with peak load.

GC = avoided cost of generating capacity ($/kW)

TD = avoided cost of transmission and distribution capacity ($/kW)

EC = avoided cost of energy ($/kW) — The levelized avoided (incremental) cost for the next kilowatt produced by the utility's generating system.

HPY = energized hours per year — Usually 8760, but lower in special cases (for example, seasonal loads).

FCR = fixed charge rate (%) — The cost of carrying a capital investment, made up of the weighted cost of capital, depreciation, taxes, and insurance. Expressed in decimal form.

RF = peak responsibility factor (unit-less) — A measure of the load diversity on the transformer. It is never greater than 1 and is expressed in decimal form.

L_sF = transformer loss factor (unit-less) — The ratio of average load losses to peak load losses. It is never greater than 1 and is expressed in decimal form.

PL = equivalent annual peak load (unit-less) — The transformer's levelized annual peak load. It is generally assumed that the load grows from an initial peak load with an estimated growth rate to some maximum level where the transformer is changed out to a lower load site. By its very nature, there is great uncertainty in this parameter. However, levelizing tends to reduce the impact of this uncertainty.

The loss multiplier (unit-less) is a measure of transmission and distribution system losses between the generating unit and the transformer being evaluated. It is generally about 50 to 75% of total system losses (5 to 7%).

The transformer cost and performance parameters are as follows:

P = bid price ($) — The price for which a manufacturer will supply the transformer delivered to a specified point.

NL = no-load or core losses (watts) — The excitation losses at rated voltage when the transformer is not supplying a load. These losses are continuous and are not load-dependent.

LL = load losses (watts) — Losses that are a result of I^2R losses and eddy current losses in the transformer windings. They are dependent on the square of the per unit load, and specifications should state the allowed temperature rise. Load at less than full load should be corrected to account for the effects of lower temperature.

Appendix C: Temperature Corrections

C.1 INTRODUCTION

The NEMA proposed standard TP-1 incorporates certain temperature adjustments in calculating the efficiency of both dry and liquid-immersed transformers. Basically, the load losses are measured or adjusted to full load rise plus 20°C — i.e., 85°C for liquid-immersed transformers and typically 150°C for dry transformers. The efficiency is then calculated from the equation

$$\eta = 100 \times (S \times \text{kVA} \times 1000)/(S \times S_B \times 1000 + NL + LL \times S^2 \times T) \ , \qquad \textbf{(C.1)}$$

where

- S = per unit load relative to nameplate rating = 0.35 for low voltage dry or 0.5 for medium voltage dry and liquid-filled transformers;
- S_B = nameplate rating in kVA;
- NL = no load or core losses in watts at 20°C;
- LL = load loss in watts at full-load rated temperature, consistent with IEEE C57.12.00 and C57.91-1995 (liquid) and C57.12.01 and C57.96-1989 (dry); and
- T = load loss temperature correction factor to correct to a specified temperature; i.e., 75°C for dry-type transformers and 85°C for liquid-immersed transformers.

C.2 LOAD LOSS CORRECTION FACTOR

Since efficiency is stated at 85°C for liquid-filled transformers, T = 1.0 as discussed below. For dry-type transformers, the standard assumes that 10% of the *LL* value is attributed to eddy and stray losses. The standard specifies six correction factors corresponding to 80°C, 115°C, and 150°C rise designs and either aluminum or copper windings. The choice of a value to use in the present analysis is discussed in the following paragraphs.

The nominal temperature correction point for liquid-immersed transformers is essentially full load temperature rise plus ambient; hence, no temperature correction is required. Liquid units could have been corrected to the same 75°C point as dry-type units, but the correction would have been minor (T = 0.97–0.98). Taking into account the change in oil viscosity essentially eliminates even this small correction; C57.91-1995 (par. 6.4.2, Load Loss, and par. 6.4.3, Viscosity of Oil) states that the reduction in viscosity of the insulating (cooling) liquid with increased temperature "tends to offset the increase in winding resistance." This implies that for this small temperature change, the average winding resistance is essentially constant and that no temperature correction is required in the standard specification. Temperature correction can be applied to liquid-immersed transformers loaded at less than full load; however, the effects are not as pronounced as those found in dry-type transformer evaluations.

On the other hand, the TP-1 efficiency standard for dry transformers does include a temperature correction. For dry transformers, the number of insulation classes (three), the number of conductor types (two), the wide range of loading conditions, the variation of design and ventilation types, the voltage levels (two), and the need to carefully consider the ambient temperature make this correction very difficult to include in a standard. Nevertheless, TP-1 includes in an appendix a set of temperature-correction coefficients. They are based upon the following assumptions:

- a 10% stray and eddy resistance component that varies inversely with temperature,
- both copper and aluminum conductor,
- three full-load temperature rises (insulation types),
- a 20°C ambient, and
- a conductor operating temperature of 75°C.

While this reduces the number of correction coefficients to six (three insulation systems times two conductor types), explicit evaluation of a standard would require a knowledge of the number of transformers produced in each size, voltage class, insulation system, and conductor type. Adding load variation further complicates the evaluation. Fortunately, the 75°C conductor temperature corresponds to a transformer with aluminum windings and 150°C full-load temperature rise operating at 35% load in a hot environment (40°C ambient) or at 50% load in a normal environment (20°C ambient), which essentially constitute the operating conditions for low- and medium-voltage dry transformers. Since most dry-type transformer designs incorporate a 150°C rise insulation system and an aluminum conductor and the correction factor presents a minimal load loss savings, in this analysis those cases requiring an the efficiency calculation from inputs *NL* and *LL* will use the correction factor T = 0.8152 for all dry transformer systems loaded as specified in TP-1. Evaluations of dry transformers loaded at other than the TP-1 levels require the calculation of a more realistic correction factor; unless otherwise indicated, this correction factor will be assumed to be an aluminum conductor with a 150°C full-load temperature rise above 20°C ambient. For those cases in this study for which only the efficiency is available and values of *NL* and *LL* are required, estimates of the losses are obtained by assuming an appropriate point of maximum efficiency (typically a 35% or 50% load), an appropriate load, and an appropriate temperature correction, and calculating the maximum *NL* and *LL* values just meeting the specified efficiency. Details and examples of these calculations are presented in Appendix D.

C.3 DRY-TYPE TRANSFORMERS

The correction factor for temperature for dry-type transformers is based upon material presented in IEEE C59.96-1989, *Guide for Loading Dry-Type Distribution and Power Transformers*.

To calculate the approximate change in the electrical resistance of the winding conductor relative to the full-load resistance, certain parameters must be specified — viz., the coefficient of resistance for the conductor material, the relative transformer load, the type of dry transformer, the ambient temperature, and the full-load temperature rise above ambient. Since eddy and stray losses vary inversely with temperature and dc resistive losses vary directly with temperature, the fraction of eddy and stray losses must be specified (5-15% is typical) to determine the final correction factor.

The coefficient is calculated as follows:

1. Determine conductor operating temperature at the operating load specified using the equation

$$T_{op} = S^{2m} \times T_{rise} \ , \qquad \textbf{(C.2)}$$

where

S = per unit load relative to nameplate;
m = 0.8 for a ventilated, self-cooled dry-type,
= 1.0 for a forced-cooled dry-type, or
= 0.7 for sealed self-cooled dry-type; use m = 0.8 if uncertain;
T_{rise} = 80°C, 115°C, or 150°C for 150°C, 180°C, or 220°C insulation system, respectively; use 150°C (220°C insulation system) if uncertain.

2. Calculate the resistance ratio from the equation

$$R_{op}/R_{ref} = (F + T_{op} + \text{ambient})/(F + T_{rise} + \text{ambient}) \quad , \tag{C.3}$$

where F = thermal coefficient of resistance = 225 for aluminum and 234.5 for copper, and the ambient temperature = 20°C unless otherwise specified. Note that TP-1 takes conductor temperature to be 75°C and thus does not explicitly specify either ambient or T_{op}.

3. Calculate the temperature correction factor using the equation

$$T = L_{dc} \times (R_{op}/R_{ref}) + L_{eddy} \times (R_{ref}/R_{op}) \quad , \tag{C.4}$$

where L_{eddy} = per unit load loss due to stray and eddy currents (0.1 unless specified) and L_{dc} = per unit load loss due to dc resistance ($1 - L_{eddy}$).

As an example, assume S = 0.5, m = 0.8, T_{rise} = 150°C, aluminum conductor, 10% eddy and stray loss fraction, and an ambient temperature of 20°C. Then,

$$T_{op} = 0.5^{1.6} \times 150 = 49.48°\text{C},$$

$$R_{op}/R_{ref} = (225 + 49.48 + 20)/(225 + 150 + 20) = 0.7455,$$

$$T = 0.9 \times 0.7455 + 0.1 / 0.7455 = 0.8051.$$

Note that, as would be expected, the average winding temperature (49.48 + 20 = 69.48°C) is less than the 75°C average specified by TP-1 and that the effective load losses are lower.

Appendix D: Calculation of No Load and Load Losses from a Specified Efficiency

Given the condition that a transformer design must exceed a specified efficiency level, the following inequality holds:

$$\%\eta \leq 100 \times S_B \times P \times 1000 \, / \, (S_B \times P \times 1000 + NL + LL \times P^2 \times T) \ , \qquad \textbf{(D.1)}$$

where

- P = per unit load relative to nameplate rating at which the efficiency is specified;
- S_B = nameplate rating in kVA;
- NL = no-load or core losses in watts at 20°C;
- LL = load loss in watts at full-load rated temperature, consistent with IEEE C57.12.00 and C57.91-1981 (liquid) and C57.12.01 and C57.96-1989 (dry); and
- T = load loss temperature correction factor to correct to a specified temperature; i.e., 75°C for dry type and 85°C for liquid-filled transformers.

Thus, for the efficiency to be greater than $\%\eta$, the inequality

$$\text{Total Losses} = (NL + LL \times P^2 \times T) \leq \text{kVA} \times P \times 1000 \times [(100 - \%\eta) \, / \, \%\eta] \qquad \textbf{(D.2)}$$

must hold for the specified load, P. The load point, $P_{\max\%\eta} = \sqrt{[NL/(LL \times T)]}$, is the point at which maximum efficiency occurs. Therefore, the maximum no-load loss just satisfying the above inequality is given by

$$NL = S_B \times P \times 1000 \times [(100 - \%\eta) \, / \, \%\eta] \, / \, [\, 1 + (P/P_{\max\%\eta})^2] \qquad \textbf{(D.3)}$$

and

$$LL = NL \, / \, [T \times (P_{\max\%\eta})^2] \ . \qquad \textbf{(D.4)}$$

For the TP-1 designs supplied by manufacturers, the value of $P_{\max}\%\eta$ ranges from 45 to 65%, with the majority near 50% for medium-voltage transformers. For low-voltage units, $P_{\max\%\eta}$ is near 35%. Hence, unless otherwise stated, the nominal load P, minimum $\%\eta$, and temperature correction factor used in this analysis assumes $P_{\max\%\eta} = P$ = 50% for medium voltage or 35% for low voltage, and T = 0.8152 for dry type or 1.0 for liquid-immersed.

As an example, consider the 150-kVA, low-voltage, aluminum, wound dry-type, three-phase transformer design. The specified minimum efficiency is 98.3% and

$$NL \leq 150 \times 0.35 \times 1000 \times (1.7/98.3) \, / \, 2 = 454 \text{ watts.}$$

Taking NL = 454 W, $LL = 454 / (0.8152 \times 0.35^2) = 4546$ W. Variation of $\%\eta$ with load for both nominal and temperature-corrected designs is shown in Fig. D.1. Temperature correction for an ambient of 40°C was calculated explicitly for the design; as discussed in the section on temperature correction, the NEMA standard's value (0.8152) is slightly larger than the calculated value of T = 0.8111 at P = 35% and T_{rise} = 115°C. Had the designer chosen to place the point of maximum efficiency at $P_{max\%\eta}$ = 50%, the minimal core and load loss values become NL = 609 W and LL = 2988 W. Similarly, if $P_{max\%\eta}$ = 60%, NL = 677 W, and LL = 2308 W, illustrating the extreme options open to the designer in meeting NEMA TP-1.

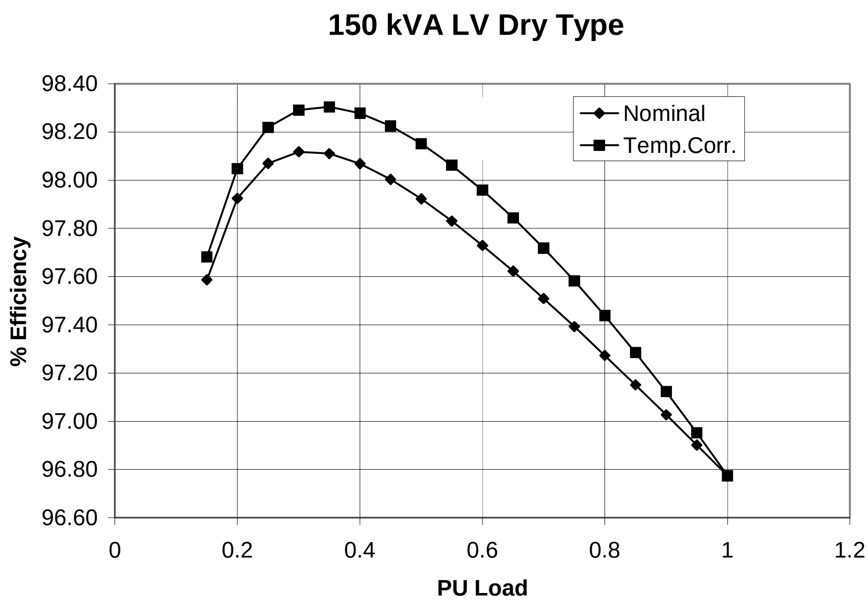

Fig. D.1

Appendix E: The TP-1 Survey of Transformer Manufacturers

This survey of NEMA and non-NEMA manufacturers was conducted by NEMA and ORNL during 1996 to determine how transformer manufacturers would design transformers to meet the NEMA TP-1 transformer efficiency standard. The survey also requested information on nonevaluated transformers and the additional costs associated with the purchase of a TP-1 transformer instead of a nonevaluated one.

July 15, 1996

DISTRIBUTION TRANSFORMER SURVEY DATA

Tables 1–4

Table 1. The NEMA minimum efficiency standard TP 1-1996 for distribution transformers

Single-Phase				Three-Phase			
Size (kVA)[a]	**Liquid MV**	**Dry-type LV**	**Dry-type MV**	**Size (kVA)[a]**	**Liquid MV**	**Dry-yype LV**	**Dry-type MV**
10	98.3	—	—	15	98.0	97.0	96.8
15	98.5	97.7	97.6	30	98.3	97.5	97.3
25	98.7	98.0	97.9	45	98.5	97.7	97.6
37.5	98.8	98.2	98.1	75	98.7	98.0	97.9
50	98.9	98.3	98.2	112.5	98.8	98.2	98.1
75	99.0	98.5	98.4	150	98.9	98.3	98.2
100	99.0	98.6	98.5	225	99.0	98.5	98.4
167	99.1	98.7	98.7	300	99.0	98.6	98.5
250	99.2	98.8	98.8	500	99.1	98.7	98.7
333	99.2	98.9	98.9	750	99.2	98.8	98.8
500	99.3	—	99.0	1000	99.2	98.9	98.9
667	99.4	—	99.0	1500	99.3	—	99.0
833	99.4	—	99.1	2000	99.4	—	99.0
				2500	99.4	—	99.1

Note: The minimum efficiencies are for an effective per unit load of 0.35 for low-voltage (LV) units and 0.5 for medium-voltage (MV) units. Medium voltage includes 5-, 15-, 25-, and 35-kV classes. Average winding temperature = 85°C for liquid-filled units, corresponding to a 65°C rise plus 20°C ambient. For dry-type units, average winding temperature = 75°C, corresponding to 55°C rise plus 20°C ambient.

[a]Nameplate capacity of the transformer in kilovolt-amperes.

DISTRIBUTION TRANSFORMER SURVEY DATA

Manufacturer Survey Code Number ________________

Table 2. Medium-voltage liquid-immersed distribution transformers

Single-Phase						**Three-Phase**					
Size (kVA)	**Noneval (0/0)**		**TP 1-1996**		**Δ price**	**Size (kVA)**	**Noneval (0/0)**		**TP 1-1996**		**Δ price**
	NL	**LL**	**NL**	**LL**			**NL**	**LL**	**NL**	**LL**	
10						15					
15						30					
25						45					
37.5						75					
50						112.5					
75						150					
100						225					
167						300					
250						500					
333						750					
500						1000					
667						1500					
833						2000					
						2500					

Note: Data should be provided for the 95-kVA BIL 15-kV voltage class. No-load (NL) and full-load (LL) losses should be provided in watts. The Δ price is the price difference between the unit designed to meet NEMA Standard TP 1-1996 and a nonevaluated unit with both A and B = $0.0.

DISTRIBUTION TRANSFORMER SURVEY DATA

Manufacturer Survey Code Number ________________

Table 3. Medium-voltage dry-type distribution transformers

Single-Phase						**Three-Phase**					
Size (kVA)	**Noneval (0/0)**		**TP 1-1996**		**Δ price**	**Size (kVA)**	**Noneval (0/0)**		**TP 1-1996**		**Δ price**
	NL	**LL**	**NL**	**LL**			**NL**	**LL**	**NL**	**LL**	
10						15					
15						30					
25						45					
37.5						75					
50						112.5					
75						150					
100						225					
167						300					
250						500					
333						750					
500						1000					
667						1500					
833						2000					
						2500					

Note: Data should be provided for the 95-kVA BIL 15-kV voltage class. No-load (NL) and full-load (LL) losses should be provided in watts. The Δ price is the price difference between the unit designed to meet NEMA Standard TP 1-1996 and a nonevaluated unit with both A and B = $0.0.

DISTRIBUTION TRANSFORMER SURVEY DATA

Manufacturer Survey Code Number ________________

Table 4. Low-voltage dry-type distribution transformers

Single-Phase						Three-Phase					
Size (kVA)	Noneval (0/0)		TP 1-1996		Δ price	Size (kVA)	Noneval (0/0)		TP 1-1996		Δ price
	NL	LL	NL	LL			NL	LL	NL	LL	
10						15					
15						30					
25						45					
37.5						75					
50						112.5					
75						150					
100						225					
167						300					
250						500					
333						750					
500						1000					
667						1500					
833						2000					
						2500					

Note: Data should be provided for the 600-V voltage class. No-load (NL) and full-load (LL) losses should be provided in watts. The Δ price is the price difference between the unit designed to meet NEMA Standard TP 1-1996 and a nonevaluated unit with both A and B = $0.0.