Loss Evaluation and Total Ownership Cost of Power Transformers—Part I: A Comprehensive Method

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***Abstract*—The key techniques employed in this paper reflect on a comprehensive method for calculating the cost of the electric power and energy needed to supply the life-cycle losses of power transformers. The method is applicable to transformer users who possess their own generation and transmission facilities. The proposed loss evaluation method is based on factors derived from relevant historical and forecasted data that are combined to determine the total ownership cost of power transformers. Finally, in a companion paper, the method is evaluated on a small-scale real system.**

***Index Terms*—Demand component of losses, energy component of losses, power transformers, system and cost parameters.**

I. Introduction

THE TOTAL losses in power transformers are, in principle, power losses (e.g., no load (NL), load (LL), and auxiliary (AUX) losses). In loss evaluations, each type of power loss is appraised on the basis of its demand (Euros/kW) and energy (Euros/kWh) component. The demand component is the cost of installing system capacity (generation and transmission) in Euros/kW to serve the power used by the losses. The energy component is the present value of the energy that will be used by one kilowatt of loss during the life cycle of the power plant under study in Euros/kWh [1]. Both demand and energy components are appropriately annuitized (i.e., levelized) to provide a total Euros-per-kilowatt (Euros/kW) figure which accounts for the sum of the present worth of each kilowatt of loss of power transformers throughout their life, or some other selected evaluation period. This figure represents the maximum amount that can be spent by a user on more efficient transformers to save a kilowatt of loss [1]. This subsequently determines the total ownership cost (TOC) of different transformer units. The TOC is used to compare the offerings of two or more manufacturers to facilitate the best purchase choice among competing transformers and, hence, support the purchase of more efficient transformers. This could be an incentive for transformer manufacturers to modify their transformer designs accordingly (i.e., increase their efficiency) and, at the same time, be confident that they can get a profitable share in the marketplace [2]. The net effect of such an incentive would be first to postpone any utility rate increases and second to accomplish significant energy conservation (and CO_2 emissions reduction).

This paper aims to provide a method for establishing the life-cycle ownership cost of power transformers by providing key advancements over any existing methods. The advancements include: 1) a method of incorporating the contribution of user's operating expenditures in costing the power to supply life-cycle losses of power transformers and 2) the calculation of the projected energy prices per the specific fuel used (or would be used) in the generation mix of the system (to supply the energy used by the losses), over the life cycle of the transformer under study. It is stressed that the method presented is applicable to transformer users who own their own generation and transmission facilities. Finally, in a companion paper [3], the application of the proposed method, on a real system, is presented.

II. State of the Art and Beyond

An extensive literature search has been performed to identify the characteristics of the existing loss evaluation techniques. Electric utilities have acknowledged the need to develop their own loss evaluation formulas for defining the ownership cost, including the cost of losses of power transformers, in the late 1960s [4]. Some of the earlier work for evaluating transformer losses has taken place in the early 1960s and was based on an annual cost approach [5], [6].

Furthermore, some studies that contributed significantly to the loss evaluation endeavours for distribution transformers were reported as early as 1963 [7], and further in 1981 [8], and in 1983 [9]. The most comprehensive material is found in a series of two papers published in 1981. Part I refers to the application of the total annual cost method, extended to properly account for energy cost inflation, load growth, and transformer change out [10] when accounting for the losses. Part II is a companion paper which describes, in detail, the system cost parameters and the load characteristics that are used in the cost of loss evaluations of distribution transformers [11]. On a similar note, a study published in 1988 [12] generically utilized the incremental loss approach for calculating the cost of losses by incorporating established and new concepts. The new concepts included a means to adjust for a loss decrease during the study period and generation additions occurring later in the study period.

In 1991, the IEEE C57.120 [1] has been formed to provide a universal method for establishing loss evaluation factors for power transformers and reactors, by reviewing what had already been reported. The quoted standard method is based on

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the present worth of annual requirements which is equivalent to the total levelized annual cost method established in previous approaches.

Some sporadic references regarding loss evaluation techniques still appear in the literature [13], the most comprehensive of which was reported in 2010 [14]. This study proposed the use of an environmental cost factor to account for the CO_2 emissions, in the loss evaluation methodology reported in IEEE C57.120 [1]. Moreover, a few leading organizations have capitalized on the available literature and have developed their own transformer cost-of-loss evaluation tools. A characteristic example is the calculation tool that has been developed by KEMA on behalf of the European Copper Institute, to perform a life-cycle costing of transformer losses and to calculate CO_2 emissions [15], [16]. Furthermore, ABB has developed the total ownership cost (TOC) calculator. The autocalculating tool converts the cost of no-load (A-Factor) and load losses (B-Factor) to net present value (U.S.$/watt). These factors are then multiplied by their respective transformer no-load (watt) and load losses (watt) and summed together to come up with the cost of losses (COL) in $U.S.. Then, COL is added to the purchase price to come up with the total ownership cost (TOC) [17].

On a final note, it appears [18] that when it comes to loss evaluations endeavours, transformer users that own their own generation and transmission systems need to follow a more rigorous approach rather than the approach incorporated by the industrial and commercial transformer manufacturers. The loss evaluation endeavours followed in the latter case are less complicated since they mainly require an understanding of the tariff rates payable to electric utilities. It should be noted that although the existing loss evaluation procedures are similar in nature, there are major changes when defining and evaluating the system cost and load parameters used in these processes. This is expected since the costing of losses is a process that each utility is developing according to its real facts and long-term objectives. However, these evaluations are usually used to compare the relative merit of alternative transformers, so different methods can be acceptable.

A. Advancements of the Proposed Method Beyond the State of the Art

The proposed method relates in firming the loss evaluation endeavour by providing the following advancements over the existing methods.

It is noted that the capital and operating expenditure of transformers users should be included in costing the life-cycle losses of transformers. One of the objectives of this work is to identify and weigh any associated operating costs to a corresponding demand and energy component of losses by defining "weighted multiplying factors."

Second, in life-cycle loss evaluations, it is imperative to rely on forecasts of escalated energy-related prices, over the expected life cycle of new power transformers. A proposed method is hereby introduced and numerically evaluated in the companion paper [3] by utilizing characteristics from a real system. The method uses statistical and economic models tailored for forecasting purposes. The suggested forecasting approach deviates from the IEEE C57.120-1991 method, where constant escalation rates are employed to determine the future energy values over the life cycle of the transformer under study. A widely used approach in economics (Markov-regime switching models) [19] is adopted, which allows escalation rates to switch between a mixture of constant rates, where the weight attributed to each constant term is purely determined by historical data. The application of the method pertains to the calculation of the projected energy prices per the specific fuel used (or would be used) in the generation mix of the system under study.

III. Theoretical Background of the Proposed Method

In the context of this work, a "system" includes all power-related facilities from generation down to the transmission level. If losses are seen as a load to the system, it is apparent that sufficient system capacity be required to accommodate the peak load and the associated losses. The installed capacity is determined by the system's peak demand including its peak load losses. There are two main system categories that can benefit from system capacity investments over the life cycle of new power transformers: generation and transmission. Since load losses occur primarily at peak load periods, determining the impact that a change in losses would have on the peak demand of each category the change affects over a future evaluation period is required. Hence, the costs of the additional capital and other fixed expenditures sized to supply the power used by the losses (coincident with the peak demand) over the life cycle of a power transformer constitute the demand component of losses (D).

However, the total cost of losses (TCL) evaluation [1] comprises a demand component and an energy component of losses (E). Energy charges are based on the average incremental cost of delivered power as obtained from generation units that are entitled to pick up the load. Hence, the energy component of the cost of losses comprises the variable costs of generating the additional energy consumed by the losses over the life cycle of a power transformer. Both demand and energy components should be calculated for all affected system categories (e.g., generation and transmission), over the life cycle of power transformers evaluated, as will be detailed in subsection A. Therefore, the two components are appropriately annuitized (i.e., levelized) to provide a total Euros-per-kilowatt figure per the generic illustration (1), that is, the TCL

$$\mathrm{TCL} = f_1(D,E)\cdot NL + f_2(D,E)\cdot LL + f_3(D,E)\cdot \mathrm{AUX}. \quad (1)$$

The calculated TCL accounts for the sum of the present worth of each kilowatt of loss $(\mathrm{NL}, \mathrm{LL}, \mathrm{AUX})$ as a function of the D and E components over some future evaluation period. The TOC of transformers is therefore defined by the purchase price $(P.P)$ of the transformer plus the TCL (1) as illustrated by

$$\mathrm{TOC} = P.P + \mathrm{TCL}. \quad (2)$$

A. Application of Method in Vertically Disintegrated Energy Systems

Although the principle described before concerns transformer users who own their own transmission and generation facilities, particular attention should be given where any vertically integrated utilities are "dis-integrated" into multiple businesses. These utilities may operate under the auspices of a regional transmission operator (RTO). One example could be the case for transmission companies as they receive orders from RTOs to install transmission capacity (which generally entails the purchase and installation of a set of power transformers) and no generation is necessarily added to the system in conjunction. In addition, there may be no transmission capacity added (outside of the RTO-ordered capacity). If it is, the transmission company does not issue funds for it. It is the responsibility of the generation company to provide funding for generation assets.

Thus, the loss evaluation method described in this paper should be appropriately modified to account for these disintegrated environments.

IV. Definition of Components

For the purpose of this study, the demand (D) and energy (E) components of the cost of losses are categorized and defined as follows.

a. Generation Category—Demand Component-$D_{g\_peak}(\mathrm{Euros/kW})$

The annual fixed cost (associated with the generation category's related expenses) required to serve a kilowatt of loss occurring at the time of the system's peak demand.

b. Transmission Category—Demand Component-$D_{t\_\mathrm{peak}}(\mathrm{Euros/kW})$

The annual fixed cost (associated with the transmission category's related expenses) required to serve a kilowatt of loss occurring at the time of the system's peak demand.

c. Generation Category-Energy Component-$E_{g\_\mathrm{peak}}(\mathrm{Euros/kWh})$

The annuitized variable cost (associated with the generation category's related expenses) required to serve the energy consumed by the losses occurring at the time of the system's peak demand, over the life cycle of a power transformer.

d. Transmission Category-Energy Component-$E_{t\_\mathrm{peak}}(\mathrm{Euros/kWh})$

The annuitized variable cost (associated with transmission category's related expenses) required to serve the energy consumed by the losses occurring at the time of the system's peak demand, over the life cycle of a power transformer.

V. Use of Capital and Operating Expenditure

Both capital and operating expenditures of a system represent the use of human and material resources. Therefore, they should be included in the total costing of supplying any losses (coincident with the system's peak demand) over the life-cycle evaluation of power transformers. The capital (fixed) expenditure should be associated with the demand component of the cost of losses whereas the operating expenditure may be associated with the demand and the energy component of the cost of losses as will be further discussed.

TABLE I
Capital and Operating Expenditure

Capital Costs	Operating Costs
New Peaking Generation Installation (G)*	Operation (G, T)*
Transmission System Fixed Costs (T)*	Repairs &Maintenance (G, T)*
	Green House Emissions Rights (G) *
	Fuels (G)*
	Other (G,T)*
* G: Generation Category, T: Transmission Category	

* G: Generation Category, T: Transmission Category

For example, capital expenditures may include investments on: 1) new peaking generation installations per kilowatt and 2) transmission system installations per kilowatt. Examples of substantial operating costs that could be of relevance to the TCL evaluations are tabulated in Table I.

For the case of power transformers, the method proposed in this paper suggests that any relevant operating costs should be apportioned in the main systems' categories involved (i.e., generation and transmission), as shown in Table I. Consequently, demand and energy components should be evaluated according to any relevant capital and operating costs classified under the expenses of generation and transmission categories, respectively. This provides the means to account for the cumulative effect that a change in losses would progressively have in these two categories. For example, a loss increase in the transmission level, at the time of the system's peak demand, would impact the cost per kilowatt of: 1) the planned additional peaking generation capacity and 2) any other associated capital and operating expenditure, from generation down to transmission category—where the loss change takes place.

A. Financial Factors

Since the loss evaluation should take into account, the present worth of the future variation of any associated costs, a further element that needs to be properly defined is the discount rate (d). It is thus the minimum acceptable rate of return from an investment and, as such, it should be above the interest rate which applies to the overall objectives of the business. It is proposed that an appropriate real discount rate should be based on the interest rate paid by the business (e.g., system's users) in the last five years. Moreover, the related literature [20], [21] recommends that the minimum required real discount rate, incorporated in loss evaluations, should be about 2% higher than the actual interest rate paid by the business. This is because the minimum return, necessary to justify spending optional capital, requires judgment that should take into account incentive, risk, opportunity cost, and accountancy procedures [22]. A real discount rate (d) should be utilized to determine the present worth factor (pw_j) and the capital recovery factor (crf_j). The present worth multiplier is the factor that determines the present worth of future costs. The capital recovery factor (crf_j) is the multiplier

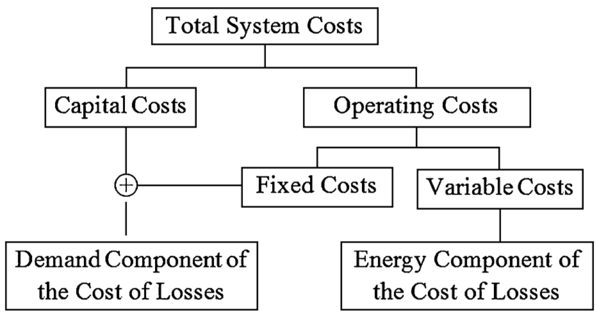

Fig. 1. Expenditure allocation to demand and energy components of the cost of losses.

that, when applied on the sum of j annual present worth costs, will yield the equivalent uniform equal amount for j years. In this way, a levelized cost is determined (i.e., an equivalent annual cost which takes future cost variations into account).

VI. Weighted Multiplying Factors

As discussed in Section V, the demand component of the cost of losses should comprise all capital-related expenditures sized to supply the power used by the losses at the time of the system's peak demand. It is further proposed that the demand component of the cost of losses should also embrace some portion (i.e., a percentage that is classified as a fixed cost) of any relevant operating expenditures (e.g., repairs and maintenance). This fixed cost portion (Fig. 1) should be added to the demand component of the cost of losses. The remainder portion (i.e., the variable costs of the operating expenditure considered) should be added on the energy component of the cost of losses. The energy component should embrace all variable costs (Fig. 1) that are a function of the energy units consumed.

It is suggested to use constant percentages as much as possible, derived from historical system's operation data, to allocate an operating expenditure to a corresponding demand and energy component of the cost of losses. These percentages should be kept under review, particularly when there is a substantial change in the plant's mix and/or capacity factor.

The latter can be realized by adopting the "screening curve" approach [23]. Screening curves (see Fig. 2) can be used to allocate a percent fixed (demand) component and a percent variable (energy) component to a particular operating cost item. This allocation can be a function of the system's capacity factor (CF)—or, alternatively, the load factor (LF).

A generic mathematical representation of the screening curve of Fig. 2 is given by (3) [23]. It represents the tabulated total costs of a particular operating cost item (e.g., operation or repairs and maintenance per year) as a function of the plant's capacity factor (CF) over the past years

$$\mathrm{TC} = \mathrm{DC} + \mathrm{CF} \times \mathrm{EC}. \tag{3}$$

TC represents the yearly total operating costs (e.g., operation total costs), DC represents the corresponding demand (fixed) related costs, EC represents the corresponding energy (variable) related costs, and CF represents the yearly capacity factor of the system under study.

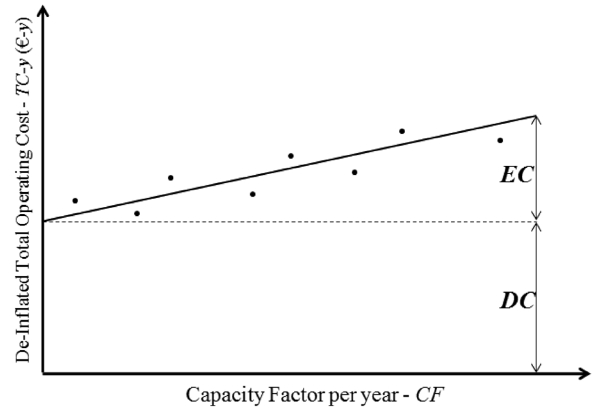

Fig. 2. Use of screening curves to estimate demand and energy components' weight factors [10].

As detailed in [23], the demand (fixed) cost DC is a constant flow of cost that when added to the energy (variable) cost EC will provide the total costs TC (e.g., the annual revenue requirements). Of course, this assumes a unity capacity factor CF. If CF is less than unity, EC will be reduced proportionally. However, DC remains unaffected because the capital cost to serve the demand must be paid irrespective if it is used or not. That explains why DC is called a fixed cost.

By moving further to divide each term of (3) by DC and inverting it, in order to obtain a percent weight factor for the DC as a function of the system's load factor LF, (4) is obtained

$$cc_{\cos t\_item} = \frac{\mathrm{DC}}{\mathrm{TC}} = \frac{1}{1 + \varepsilon \times \tau \times \mathrm{LF}} \tag{4}$$

where $(cc_{\mathrm{cost\_item}})$, is the percent weighted demand factor of the operating cost item under study, $\varepsilon = \mathrm{EC/DC}$, and $\tau = \mathrm{CF/LF}$. Conversely, the percent weight factor for the energy component is given by

$$ec_{\cos t\_\mathrm{item}} = 1 - cc_{\cos t\_\mathrm{item}}. \tag{5}$$

A. Allocation of Weighted Factors to Fuel Costs

There is one special case, namely, the cost of fuels, where further investigation is needed to allocate an appropriate set of weight factors. The cost of fuels should not be, in total, allocated to the energy component of the cost of losses, because part of the fuel is consumed in meeting the "zero load" losses. In the context of this study, the zero load losses are taken to depend on the type and size of the generating plant and, therefore, should be related to the demand component of the cost of losses. Therefore, a rigorous method is adopted (6) that characterizes the actual fuel consumption that takes place in a plant

$$\mathrm{Actual\_Fuel\_Consumption} = A \times \mathrm{INFR} + C \times \mathrm{ZRFL} \tag{6}$$

where A is the total "Sent Out" units (MWh) from the system's machines burning a particular fuel per year;INFR is the machines' corresponding incremental fuel rate (MT/MWh); C is the sum of machines running hours burning the same fuel per year (h); and ZRFL is the machines' corresponding zero load fuel rate (MT/h). ZRFL is the fuel consumption of the machine running at full speed but not synchronized to the system. It basically covers: 1) thermal losses—depending on the temperature and pressure which are substantially constant regardless of load; 2) steam consumption—to supply the friction and windage losses of the machines; 3) power consumption of auxiliaries (e.g., boiler fans, CW pumps, etc.); and d) power consumption of general auxiliaries (e.g.. air compressors, station lighting, etc.). It should be noted, however, that actual fuel consumption as given in (6) is an approximation. The fuel consumption is not necessarily a linear combination of the incremental cost (INFR) and the zero load fuel rate (ZRFL). Some combustion and steam units tend to have a very nonlinear cost versus load characteristic, especially steam units that have multiple control (steam admission) valves.

The demand $(\mathrm{DCF}_{\mathrm{fuel}})$ and energy $(\mathrm{ECF}_{\mathrm{fuel}})$ component percent weight factors of the total fuel cost for the plants machines can be calculated using (7) and (8), respectively

$$\mathrm{DCF}_{\mathrm{fuel}} = \frac{F \times \mathrm{ZRFL}}{E \times \mathrm{INFR} + F \times \mathrm{ZRFL}} \tag{7}$$

$$\mathrm{ECF}_{\mathrm{fuel}} = 1 - \mathrm{DCF}_{\mathrm{fuel}} \tag{8}$$

where $F = \sum_{j=1}^{n} C_j/n$ is the average of the sum of running hours of all machines in the period under study (n years) and ZRFL is the calculated zero load fuel rate. $E = \sum_{j=1}^{n} A_j/n$ is the average of the "sent-out" energy units in the period under study (n years) and INFR is the incremental fuel rate.

B. Allocation of Size Factors

Finally, it is necessary to determine the impact of a change in losses at the time that the system's peak demand would have on future system additions. The evaluation of the demand cost component of incremental losses is difficult because small changes in peak load have an uncertain effect on future generation or transmission capacity additions [11]. Therefore, this study has incorporated the suggestion of [7] which considers that a change in losses will not affect the scheduling of new facilities but may affect their size. The recommendation is that the demand component of losses should be evaluated at the incremental cost of increasing the size of planned facilities which is typically two-thirds of their average cost; for the transmission category, the size factor $SFcc_t = 2/3$ is generally assumed. For the generation category, (9) should be used

$$SFcc_g = \frac{2}{3} \times (1 + \mathrm{RM}) \tag{9}$$

where RM is the per-unit reserve margin of the generation capacity. The evaluation of the size factor basically suggests that the existing installed capacity is such that it can limit the calculated demand component of losses $(D - \mathrm{Euros/kW})$ for planned facilities by the determined size factor of each category.

VII. Escalated Energy-Related Prices

Energy costs are comprised of fuel costs and any other energy-related operating expenditure (e.g., operation, repairs, and maintenance). Life-cycle loss evaluations of power transformers inevitably depend on future energy-related price estimates. In this paper, the method to address this need primarily relies on: 1) forecasts of the system's energy requirements (MWh); 2) forecasts of the system's maximum demand requirements (MW); and 3) forecasts of the relevant fuel prices (Euros)—over the life cycle of the evaluated power transformers.

The forecasted energy requirements (UG) per year (j) result (10) in forecasted fuel consumptions (FuC) by incorporating appropriate net calorific values (NCV) and generating units' efficiencies (n_{ef}) per the fuel type (i) used. It should be noted that the efficiency of a generating unit may not be constant; but, in fact, associated with: 1) the amount of MW being generated and 2) the type of combustion cycle. As an approximation an annual average efficiency, the (n_{ef}) value is assumed in (10). N denotes the number of different fuels used in the electricity generation mix while LT denotes the life cycle of the transformer evaluated

$$FuC_{i,j}(\mathrm{MT}) = \sum_{\mathrm{i=1}}^{\mathrm{N}} \sum_{\mathrm{j=1}}^{\mathrm{LT}} \frac{\frac{\mathrm{UG_{i,j}(GJ)}}{\mathrm{NCV_i}\left(\frac{\mathrm{GJ}}{\mathrm{MT}}\right)}}{\mathrm{n_{ef_i}}}. \tag{10}$$

Hence, the forecasted fuel consumption (FuC_i) per year (j) is subsequently combined with the annual forecasted cost of each individual fuel (FFP) to obtain a total future fuel cost (FC)

$$\mathrm{FC}_{i,j}(\mathrm{Euros}) = \sum_{i=1}^{N} \sum_{j=1}^{\mathrm{LT}} FuC_{i,j}(\mathrm{MT}) \times \mathrm{FFP_{i,j}(Euros/MT)}. \tag{11}$$

A proposed method for estimating the annual forecasted cost of each individual fuel (FFP) is numerically evaluated in the companion paper [3] by utilizing a widely used approach in economics (Markov-regime switching models) [19].

VIII. Methodology—Demand Component Calculation

It is reiterated that the costs of the capital and other fixed expenditures appropriately sized to supply the power used by the losses (at the time of system's peak demand) over the life cycle of a power transformer constitute the demand component of losses.

A. Demand Component Attributed to Operating Costs (Euros/kW)

This subcomponent should be based on historical data describing all relevant operating costs of the system. Further data required for this evaluation are an inflation rate for those years that data are available. Once the relevant historical costs are obtained and classified per system's category, these are associated with the system's maximum demand (MW) of each year considered. The operating costs are then adjusted for inflation of each corresponding year. Each de-inflated cost item is plotted against the system's maximum demand (MW) of each corresponding year as illustrated in Fig. 3. By assuming that a linear relationship exists, a straight line is then fitted (12) on the plotted points by using the method of least squares

$$y(\mathrm{Euros}) = \alpha \times P(\mathrm{MW}) + \beta. \tag{12}$$

It is then possible to extract $\alpha - \mathrm{Euros/MW}$. This figure $\alpha - \mathrm{Euros/MW}$, is basically a constant increase of the rele-

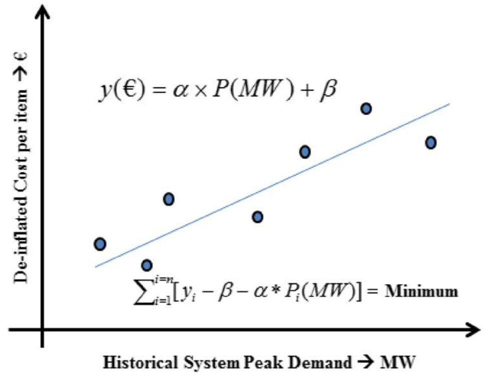

Fig. 3. Annual demand component for operating costs.

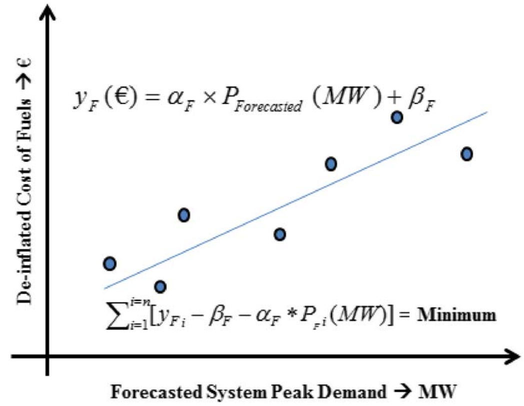

Fig. 4. Annual demand component for fuel costs.

vant operating cost per MW, as derived from the historical data available. By determining $\alpha(\text{Euros/MW})$, it can be therefore assumed that a similar future projection of the relationship that describes the operating cost item under study (Euros) and the system's demand (MW) exists, over the life cycle of the transformer under study.

This assumption is valid provided that no extraordinary conditions of system growth or recession will occur in the immediate future. Therefore, the demand component of losses attributed to the associated operating costs can be summarized on a per item (n) basis for generation (13) and transmission (14) categories-related costs, respectively

$$D_{g\mathrm{OP}_{\text{-item\_}n}} = \alpha_{g\text{\_item\_}n} \times cc_{\cos t\text{\_item\_}n} \times SFcc_g \tag{13}$$
$$D_{tOP_{\text{-item\_}n}} = \alpha_{t\text{\_item\_}n} \times cc_{\cos t\_item\_n} \times SFcc_t \tag{14}$$

where $D_{g\ op\text{\_item\_}n}$ and $D_{t\ op\text{\_item\_}n}$ are the annual demand components of the cost losses for each relevant operating expenditure for generation category and transmission category, respectively. Moreover, $\alpha_{g\text{\_item\_}n}$ and $\alpha_{t\text{\_item\_}n}$ are the incremental costs per MW, obtained as per the method illustrated by Fig. 3. The $cc_{\text{\_cost\_item\_}n}$ is the weighted multiplying factor for the demand component of each operating expenditure considered, as defined in Section VI. $SFcc_g$ and $SFcc_t$ are the size factors also defined in Section VI-B.

B. Demand Component Attributed to Fuel Costs (Euros/kW)

As already discussed, the cost of fuels should not be, in total, allocated to the energy component of the cost of losses, because part of the fuel is consumed in meeting the "zero load" generation losses, which is related to the demand component of the cost of losses. Fig. 4 illustrates the forecasted demand (MW) and the forecasted fuel prices FC, (euros) as per the system's needs over the life cycle of the transformer under study, following the analysis of Section VII. Therefore, the annual demand component that accounts for the fuel costs is given by

$$D_F = \alpha_F \times \mathrm{DCF_{fuel}} \tag{15}$$

where α_F is the incremental cost per MW of fuels, as obtained by the method of least squares, and $\mathrm{DCF_{fuel}}$ is the demand component percent weight factor for fuels as discussed in Section VI.

C. Aggregate Demand Component of Losses

The demand component of the cost of losses for each category is then obtained for generation (16) and transmission category

$$D_{g\text{\_peak}} = \mathrm{ACPG} + D_F + \sum_{n=1}^{j} D_{g_{OP\text{-item\_}n}} \tag{16}$$
$$D_{t\text{\_peak}} = \mathrm{ACTS} + \sum_{n=1}^{j} D_{t_{OP\text{-item\_}n}}. \tag{17}$$

ACPG (18) is the annuitized cost per kilowatt of planned peaking generation units and ACTS (19) is the annuitized cost per kilowatt of transmission system installations required to meet the system's increasing losses at the time of the system's peak demand

$$\mathrm{ACPG} = SFcc_g \times C_{\mathrm{PG}} \times crf_n \tag{18}$$
$$\mathrm{ACTS} = SFcc_t \times C_{\mathrm{TS}} \times crf_n \tag{19}$$

where C_{PG} and C_{TS} are the costs per MW of any planned peaking generation units and transmission system installations, respectively; crf_n is the capital recovery factor over the n years of evaluation; and $SFcc_g$ and $SFcc_t$ are the size factors that limit the calculated demand component of losses for the planned generation and transmission facilities, respectively.

Consequently, for evaluating the TCL of new power transformers installed at the transmission level, the aggregate annuitized demand component of losses is given by

$$D_{\mathrm{PEAK}} = D_{g\text{\_peak}} + D_{t\text{\_peak}}. \tag{20}$$

IX. Methodology Energy Component Calculation

The energy component of the cost of losses comprises the variable costs of generating the additional energy consumed by the losses over the evaluation period considered. These costs are evaluated according to: 1) the fuel usage and prices of the planned peaking generating units and 2) any variable operating

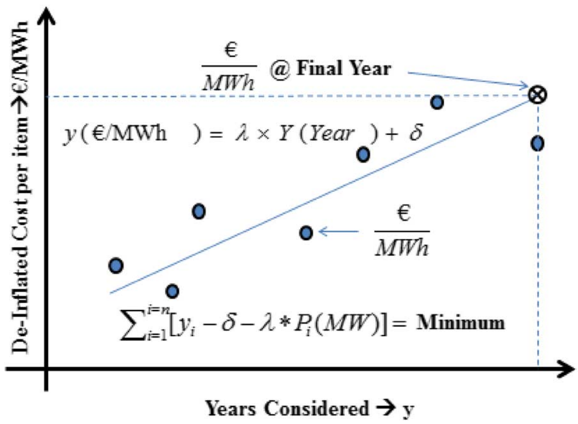

Fig. 5. Annual energy component for operating costs.

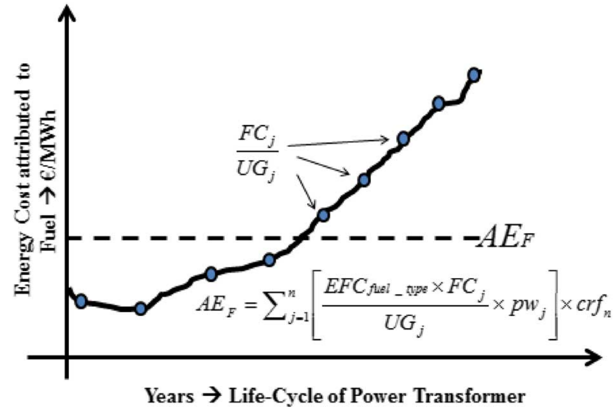

Fig. 6. Annuitized energy component of losses attributed to fuel costs.

costs (energy related) per kilowatt-hour over the life cycle of the power transformer under study.

A. Energy Component Attributed to Operating Costs (Euros/MWh)

Once the system's historical energy-related operating costs are obtained and classified per category, these are associated with the system's energy generation (MWh) of each corresponding year. The costs are then adjusted to consider the inflation of each year considered. Consequently, for each year, the ratio (Euros/MWh) of the de-inflated costs (Euros) to the total energy generated (MWh) per year is determined and subsequently associated with each corresponding year. That is, the ratio (Euros/MWh) of the de-inflated costs to the total energy generated per year is plotted against each corresponding year as illustrated by Fig. 5.

By assuming that a linear relationship holds, a straight line is then fitted (21) on the plotted points by using the method of least squares

$$y(\text{Euros/MWh}) = \lambda \times Y(\text{Year}) + \delta. \tag{21}$$

However, in order to associate the calculated energy component of the cost of losses toward the latest operating costs and, to a lesser extent, toward costs valid in previous years, y is calculated for the latest year for which data are available (i.e., $Y = latest\_year$ that data are available) and λ and δ in (18) are as determined by the least square method applied.

Therefore, the annual energy component of losses calculation is summarized per operating cost for generation (22) and transmission (23) categories related costs, respectively

$$E_{g_{op\_\text{item}\_n}} = (\lambda_{g\_\text{item}\_n} \times Y(\text{Latest\_Year}) + \delta_{g\_\text{item}\_n}) \times ec_{\text{item}\_n} \tag{22}$$

$$E_{t_{op\_\text{item}\_n}} = (\lambda_{t\_\text{item}\_n} \times Y(\text{Latest\_Year}) + \delta_{t\_\text{item}\_n}) \times ec_{\text{item}\_n} \tag{23}$$

where $E_{g\ op\_\text{item}\_n}$ is the annual energy component of the cost of losses of each relevant operating expenditure classified under generation category and $E_{t\ op\_\text{item}\_n}$ is the annual energy component of the cost of losses of each relevant operating expenditure classified under the transmission category. $\lambda_{g\_\text{item}\_n}$ and $\lambda_{t\_\text{item}\_n}$ are the incremental costs per megawatt-hour, obtained per the method illustrated by Fig. 5 for generation and transmission categories, respectively. ec_{item_n} is the percent weighted multiplying factor for the energy component assigned to each operating expenditure considered.

B. Energy Component Attributed to Fuel Costs (Euros/MWh)

In this case, it is again necessary to incorporate the forecasted system's energy requirements (UG) and the subsequent fuel consumption (FuC) as discussed in Section V. The annuitized energy component attributed to escalated fuel prices as per the forecasted fuel prices and usage $(\text{AE}_{F-}\text{Euros})$ is summarized

$$\text{AE}_F = \sum_{j=1}^{n}\left[\frac{\text{EFC}_{\text{fuel\_type}} \times \text{FC}_j}{\text{UG}_j} \times pw_j\right] \times crf_n \tag{24}$$

where FC_j (11) is the overall de-inflated fuel costs (Euros) allocated to energy per year, $\text{ECF}_{\text{fuel\_type}}$ is the percent energy component weight factor for fuels, UG_j is the system's forecasted MWh units generated per future year, pw_j is the present worth factor per year, crf_n is the capital recovery factor, and n is the evaluation period (years). Fig. 6 graphically illustrates the process of calculating the annuitized energy (AE_F) component attributed to varying fuel prices over the life cycle of the power transformer evaluated, per the fuel mix considered.

C. Aggregate Energy Component of Losses

The energy component of losses reflecting on all energy related costs is given for generation category (25) and transmission category

$$E_{g\_\text{peak}} = \text{AE}_F + \sum_{n=1}^{j} E_{g_{op\_\text{item}\_n}} \tag{25}$$

$$E_{t\_\text{peak}} = \sum_{n=1}^{j} E_{t_{op\_\text{item}\_n}}. \tag{26}$$

TABLE II
NOMENCLATURE

NLL (kW)	No Load Losses of Transformer
LL (kW)	Load Losses of Transformers
AUX (kW)	Auxiliary Losses of Transformers
PRFS (p.u)	Peak Responsibility Factor of Transformer [11]
PQD (p.u)	Levelized Annual Peak Load of Transformer as per its life-cycle, for Demand Component.
PQE (p.u)	Levelized Annual Peak Load of Transformer as per its life-cycle, for Energy Component.
LLF (p.u)	System's Loss Load Factor [11]
FOW (p.u)	Average hours per year the transformer cooling is operated
AF (p.u)	Availability Factor, the proportion of time that a transformer is predicted to be energized

For evaluating the TCL of new power transformers (i.e., installed at the transmission level), the aggregate annuitized energy component of losses is given by

$$E_{\text{PEAK}} = E_{g\_\text{peak}} + E_{t\_\text{peak}}. \tag{27}$$

X. TCL Evaluations of Power Transformers

It is proposed that the generic TCL formulation (1) per kilowatt per year for new power transformers installed at transmission level should be evaluated per (28). Table II tabulates the further particulars of the nomenclature used

$$\begin{aligned}\text{TCL}_{pt}&(\text{Euros/kW})\\ =&[D_{\text{BASE}} + 8760 \cdot AF \cdot E_{\text{BASE}}] \cdot \text{NLL}\\ &+ [D_{\text{PEAK}} \cdot \text{PRFS}^2 \cdot \text{PQD}^2] \cdot LL\\ &+ [8760 \cdot \text{LLF} \cdot E_{\text{PEAK}} \cdot \text{PQE}^2] \cdot LL\\ &+ [D_{\text{PEAK}} + 8760 \cdot FOW \cdot E_{\text{PEAK}})] \cdot \text{AUX}. \end{aligned}\tag{28}$$

Four terms are present in (28), namely, the no-load (NLL) cost of losses, the load loss (LL) demand cost, the load loss (LL) energy cost, and the load loss auxiliary cost. It is apparent that each type of loss is evaluated per its demand and energy component. However, these components should be evaluated separately for peaking generation and base generation units. The demand $(D_{\text{BASE},})$ and energy (E_{BASE}) cost components of the no-load losses (NLL) should be evaluated according to the related costs and energy for base load generation [10]. In contrast, the demand (D_{PEAK}) and energy (E_{PEAK}) cost component of the load losses (LL) should be evaluated according to the related costs and energy for peaking generation. Furthermore, the load loss term (LL) is separated into its demand and energy component by utilizing two separately calculated equivalent transformer annual peak loads $(\text{PQD}$ and $\text{PQE})$. PQD is the levelized annual peak load of the transformer that may concurrently account for the levelized annual transformer losses (PQD^2). The PQD results from the series of annual peak loads (in per unit) expected over the life cycle of the transformer under study per

$$\text{PQD}^2 = \left[\sum_{j=i}^{n} P_j^2 \times pw_j\right] \times crf_n \tag{29}$$

$$pw_j = \frac{1}{(1+d)^j} \tag{30}$$

$$P_j = P_{\text{initial}} \cdot (1 + CR_j)^{j-1}. \tag{31}$$

A real discount rate (d) is utilized to determine the present worth factor (pw_j) for each year j considered and the capital recovery factor (crf_n) for the n years of the evaluation period. P_{initial} is the initial transformer annual peak load (in p.u.) and CR_j is the transformer's annual compound peak load growth rate (in p.u.)

It should be noted that the energy-related cost items, such as fuels, repairs and maintenance, operation, etc., would be subject to inflation throughout the evaluation period (i.e. the life cycle of power transformers). Therefore, the effect of inflation is factored in the formula of the levelized annual transformer losses PQE^2 (32) as proposed by [10]

$$\text{PQE}^2] = \left[\sum_{j=i}^{n} P_j^2 \times pw_j \times (1 + IR(j)^{j-1}\right] \times crf_n \tag{32}$$

where IR reflects an annual constant or variable inflation rate for the years considered in the analysis.

XI. Conclusions

It is well established that the prevailing factors in the process of assessing the life-cycle losses of transformers are the demand $(D - \text{Euros/kW})$ and the energy component $(E - \text{Euros/kWh})$ of losses. These components should be updated when major conditions that justify system growth or recession take place—provided that they affect the overall financial objectives of the utilities. In particular, this paper defines a method to define power transformers' TOC. A method of incorporating the contribution of system's operating expenditures and the costs of the life-cycle losses of power transformers is provided. In a companion paper, the method is numerically evaluated on a small-scale real system.

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