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Optimum Design Return Period of EHV Lines Considering Reliability, Security and Availability

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SUMMARY

In overhead line design, reliability is provided by assigning a fixed return period to the extreme climatic loading events such as wind, ice and combined wind and ice. This implies some expected failure rate during the service life of a line. On the other hand, the security of a line is provided in two ways (1) designing structures for adequate longitudinal capacity and (2) inserting a number of containment structures (anti-cascading towers) at a fixed interval (e.g. normally every 20 to 25 structures). This study presents a basis for computing the optimum design return period of an overhead line considering initial line cost and the future failure cost. The optimization is done by balancing the initial line cost against the present value of the cost of losses due to line failures. The cost consists of two components; (1) expected cost of line replacement and (2) expected cost of energy not supplied considering unavailability of the line.

To develop the line cost model, spreadsheet models were developed in EXCEL for three different types of HV lines. These lines consist of Guyed-V tower, Tubular steel pole and H-Frame wood pole structures. For each line, a detailed design specification was developed to compute the line costs for various return period values. The design specification consists of prescribing meteorological loading parameters such as wind speed, ice thickness etc. for various return periods, wind and weight spans, conductor type and allowable tension values, insulator length and the standard vertical clearance allowed. Based on these parameters, the structures' weights (both suspension and strain types) are estimated and the initial cost for a section of radial line is computed for three specific return period values following IEC 60826. A regression model is used to compute the line cost for other return periods.

An energy cost model is developed based on the methodology outlined by Professor Billinton where the unsupplied energy is computed based on expected load, line failure rate and the repair duration and a parameter called IEAR (Interrupted Energy Assessment Rate). IEAR depends on the customer distribution and the cost under each distribution type and duration. The expected value of the line replacement cost is added to the unsupplied energy cost to obtain the present value of the damage cost. The present value depends on the discount rate and the service life of the asset.

A mathematical model is developed for a radial line configuration and it is shown that the optimum design return period is significantly influenced by the duration of the line repair once it has failed as

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well as the average Interrupted Energy Assessment Rate (IEAR). The line should be designed for a higher return period if the duration of repair is expected to be long to ensure that the line cost is balanced against the present value of the failure costs appropriately. The sensitivity analysis shows that the optimum design return period is strongly dependent on the repair rate and is less influenced by the discount rate and the line replacement cost considered.

KEYWORDS

Optimum design, Return period, Line cost, Failure cost, Reliability, Security

INTRODUCTION

In overhead line design, the reliability is provided by assigning a fixed return period to the extreme climatic loading events such as wind, ice and combined wind and ice. This implies some expected failure rate during the service life of a line. On the other hand, the security of a line is provided in two ways (1) designing structures for adequate longitudinal capacity and (2) inserting a number of containment structures (anti-cascading towers) at a fixed interval (e.g. normally every 20 to 25 structures). The containment structures are designed for the loss of phase conductors, shield wires etc.

Considering a High Voltage (50 kV to 230 kV) line being a part of the complex power network system, the most common security criteria (electrical) used in the bulk electric power system planning (BEPS) is N-1 criterion where there should be no outages if there is loss of a single BEPS component (such as a generating unit or a transmission line). Some utilities also use N-2 criterion or N-1-1 criterion where it is assumed that the system should be able to withstand the loss of two components at a time or the forced outage of a single component in conjunction with scheduled maintenance of another component. In the power network system, reliability includes system adequacy (sufficient generation to carry the load) and security (ability of the system to respond against any unexpected event such as transient faults etc.). For mechanical line design, these items (reliability and security) are treated separately. In the power network, the reliability includes system adequacy (sufficient generation to meet the load demand) and system security implying that the system is able to respond to transient disturbances (faults or unscheduled removal of components). This is contrary to the structural design of overhead lines where both reliability and security are treated separately.

SCOPE

The purpose of this study is to present a methodology to determine the optimum design return period of a HV line by balancing the initial line cost (LCOST) against the present value (PV) of the future failure costs (DCOST). The failure cost depends on the extent of the line damage (severity, duration of outage) and therefore, the security level provided in the line design. It is well known that the overestimation of the design wind and ice loads will significantly affect the initial of a line, while the underestimation of these loads would certainly impose "future" failure costs which, in some instances, could be quite significant. The future failure costs include the expected replacement cost of the failed section of the line and the cost of unsupplied energy due to the loss of a line under extreme weather events. This study attempts to more clearly define the terms of the relationship between the Transmission Line Design Engineer and the System Planning Engineer. The role of each engineer in determining the optimum design return period for a new transmission line is presented and clarified.

Figure 1 depicts the graphical representation of the two costs. The initial line cost will increase as the reliability increases while the future failure cost will decrease with increasing line reliability. It is expected that an optimum reliability can be found by balancing these two costs. Figure 1 also shows the point where the total cost is at minimum. An example problem is illustrated to show the application of the methodology in determining the optimum design return period of a line to extreme events.

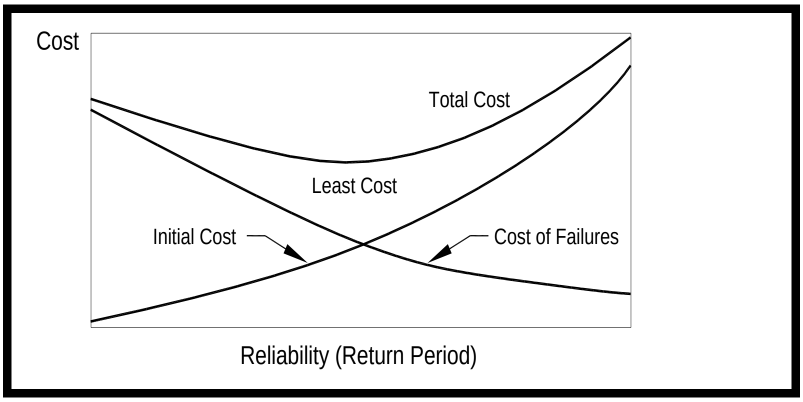

Figure 1. Typical Optimization Problem

HISTORICAL MAJOR LINE FAILURE (EXTREME EVENTS, CIGRE, 2008)

During the first week of January 1998, the transmission network in southern and western Quebec was subjected to a severe freezing rain storm event which covered 150000 square kilometers and affected 1.5 million customers from a few hours to 30 days in the provinces of Quebec and Ontario. Among installations rated 49 kV and above, over 2,000 wood pole structures and 617 steel lattice towers were destroyed or sustained significant damage. There were eight major cascade collapses among structures of the 735 kV transmission network. Figure 2 presents the 735kV line cascade caused by the 1998 ice storm in Quebec.

Following the 1998 ice storm in Canada, Hydro-Québec drew up a three-part intervention strategy:

- Emergency restoration of critical lines;
- Restoration of collapsed lines before the next winter peak;
- Reinforcement of the transmission system over the medium and long term.

COST MODEL (Haldar et al, 2012)

A cost model is developed based on a probabilistic system model and the mathematical expression is presented below.

$$C_T = C_I + \text{PV}\ (\ P_f C_R + \text{Outage Cost}) \qquad [1]$$

Where C_T = total line cost, C_I = initial line cost (LCOST), C_R =line replacement cost, P_f = annual probability of failure, PV = present value. The present value a function of service life and discount rate and outage cost is a function of expected energy not supplied multiplied by IEAR (described later).

LCOST

The **LCOST** includes only the cost of line materials and construction. The costs associated with engineering, survey, camp site development etc. are not included because they are invariant to the design return period. The failure rate λ is directly related to return period, **T**.

DCOST

The damage cost **(DCOST)** has two components (1) tangible cost and (2) intangible cost. The tangible portion of **DCOST** normally includes the expected replacement cost of the line after a failure **(FCOST)** and the cost of expected energy not supplied **(ECOST)**. FCOST primarily includes the replacement cost of the line section that failed during an extreme event. This cost can be estimated reasonably based on past data. FCOST is adjusted by the annual probability of failure (P_f) and the consequence. **ECOST** can vary widely depending on the consequence of the failure on the system, customer distributions and hence the composite customer damage function (CCDF) normally expressed in $/KWh (described in page 7, Table 1). **ECOST** will also be dependent on the system load (peak versus durational) as well as the system state during a failure event. The state probability in this study is computed based on a series system (no redundancy is assumed in the network, a radial line). Intangible costs could be the increase in the future insurance premium, societal cost etc.; which are difficult to quantify (Billinton and Allan, 1987). Intangible costs are not included in this analysis. The **PV** of the failure cost is determined based on the discount rate, service life of the asset and the annual cost ($/year) estimated. Figure 3 presents the flow diagram for developing various cost components.

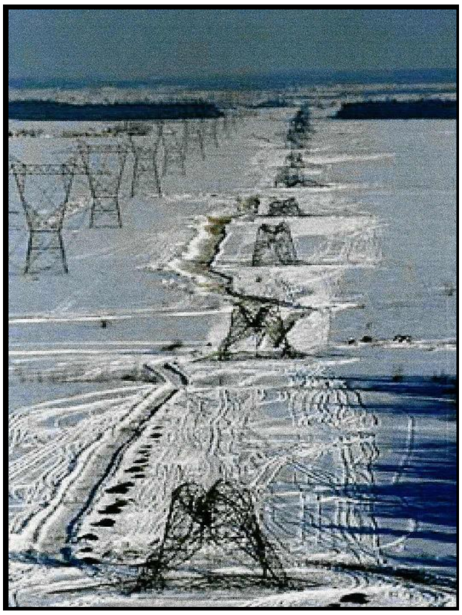

Figure 2 – A 735kV Line Cascade

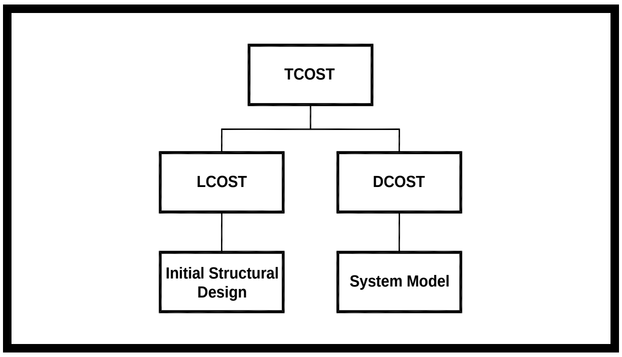

Figure 3 – Flow Diagram for Developing Cost Model

LINE COST MODEL (LCOST)

In developing the line cost model, the line is treated as a system where the major components such as the tower, foundation, conductor, insulator and hardware are interconnected as a "link". The structural design model considers this as a "series" system such that if one fails then the line fails and the bulk power supply is lost (radial line assumption).

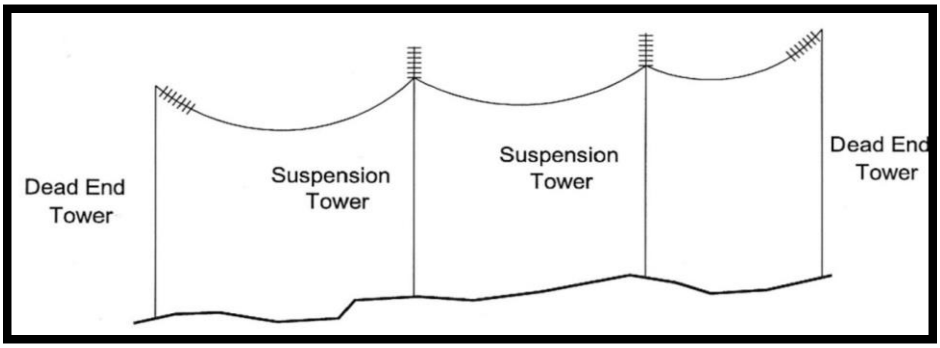

Figure 4 – Typical Line Layout

Figure 4 presents a line system which primarily consists of three subsystems. These are: (1) Suspension Structure Subsystem, (2) Dead End (strain) Structure Subsystem and (3) Conductor-Hardware Subsystem. The cost model is developed for a 230 kV line system which may use any one of the structure types (a) Guyed-V tower (b) Tubular pole structure and (c) H-Frame wood pole structure. Typical section of a line is modeled with a number of suspension structures supporting a fixed length of conductor and two fixed dead end structures. The end structures can be self-supported lattice tower or a guyed structure. To develop the line cost model, models were developed in EXCEL spreadsheets for three different types of overhead lines. For each line, a detailed design specification was developed to compute the line costs for various return period values. The design specification consists of prescribing meteorological parameters such as wind speed, ice thickness etc. for various return periods, wind and weight spans, conductor type and allowable tension values, insulator length and the standard vertical clearance allowed. Based on these parameters structural loads and the required structure heights are computed to support the conductor for acceptable clearance criterion. Once the structures' weights (both suspension and strain types) are estimated, the initial cost for a radial line is computed for three specific return period values (50 years, 150 years and 500 years). A regression model is used to compute the line cost for other specified return period values and is shown in equation [2].

$$LCOST = A + B \ Ln\,(T) \qquad [2]$$

Where A and B are regression constants. These constants were evaluated for the three different line configurations.

DAMAGE COST MODEL (DCOST)

An energy cost model is developed based on the methodology outlined by Professor Billiton where the unsupplied energy is computed based on line failure rate and the repair duration and a parameter called IEAR (Interrupted Energy Assessment Rate). IEAR depends on the customer distribution and the cost under each distribution type and the duration (Billinton, 2007, Table 1). The sector based interruption cost data (CDF, $/KW) can be grouped together at a particular load point to provide an aggregated cost data often called Composite Customer Damage Function (CCDF, $/KWh, also known as IEAR). The assumption is that all load curtailment will be distributed proportionally at a load point according to customer distribution shown in Figure 5 and in Table 1.

The expected value of the line replacement cost is also added to this unsupplied energy cost to obtain the present value of the damage cost. The present value depends on the discount rate and the service life of the asset. The expected customer interruption cost (ECOST) is related to expected energy not supplied (EENS) in equation [3] below.

$$ECOST = IEAR * EENS \qquad [3]$$

Where IEAR= Average Interrupted Energy Assessment Rate.

The expected cost ECOST can be determined explicitly as

$$ECOST = \lambda d \, L^{*} \, IEAR \tag{4}$$

Where L^{*}= load curtailment (MW), λ = line failure rate d = duration of load curtailment (hr.).

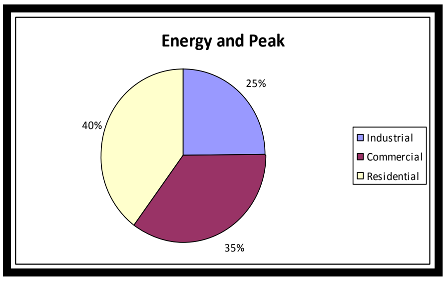

Figure 5 (a) Customer Distribution

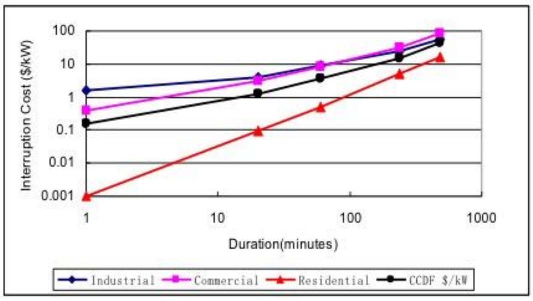

Figure 5 (b) Customer Interruption Cost

Once the annual unsupplied energy cost is determined, this can be added to the expected cost of failure, C_f which is determined based on the replacement cost of the failed line section, C_R in equation [5]

$$C_f = P_f * C_R \tag{5}$$

Where P_f is the probability of line failure and C_R is the cost of failure. The present value of the damage cost is calculated as:

$$PV \ of \ \ DCOST = \sum_{i=1}^{n} \frac{(ECOST + C_f)_i}{(1+r)^i} \tag{6}$$

where

n = service life or the planning horizon, and r = discount rate

Table 1 – CCDF (Billinton, 2007)

User Sector	**Interruption Duration**				
	1 min	**20 min**	**1 hr.**	**4 hr.**	**8 hr.**
Industrial	1.625	3.868	9.085	25.163	55.808
Commercial	0.381	2.969	8.552	31.317	83.008
Residential	0.001	0.093	0.482	4.914	15.690
	Composite Customer Damage Functions				
CCDF $/kW	0.153	1.243	3.710	15.475	42.617
CCDF $/kWh	9.180	3.729	3.710	3.868	5.327

This cost should be added to the direct line cost obtained for various return periods **(LCOST)** in equation [2] to obtain the total cost given in equation [1] and shown in Figure 1. Equation [6] can be approximated as PV * (ECOST+C_f) where PV is a fixed cost factor which depends on the service life of the asset and the discount rate.

LINE OPTIMIZATION MODEL

The total cost, C_T of the line is broken down in two parts. The first part covers the direct line cost which is a function of line configuration that includes structure type, span length, design wind and ice loads, insulator arrangement etc. and the second part consists of the present value of the damage cost. The total line cost can be presented as a function of line return period in Equation [7].

$$C_T = A + B\,Ln\,(T) + PV\;(\lambda d\,\alpha\,L^*\;IEAR + P_f\;C_R) \qquad [7]$$

where $\lambda = \frac{1}{T}$; $P_f = \frac{1}{2T}$; d = duration of outage; L^*= Peak load; and α = load factor

By differentiating equation [7] with respect to return period T and setting this to zero.

$$T_{optimum} = \left(\frac{[\alpha\; d\; P^*IEAR+0.5*C_R\;]PV}{B}\right) \qquad [8]$$

The following example data was used in the spreadsheets for lattice steel tower, tubular steel pole, and H-Frame wood structure lines as base case parameters, d = 8 hours, α = 0.8 P = 50MW, IEAR = $6163/MWh, PV = 15.78 (discount rate 6% and a service life of 50 Yeats, based on equation [6]); for steel Guyed-V tower, B=307717 and C_R =$200000. $T_{Optimum}$ is calculated as 106 years and is shown in Figure 6. A sensitivity analysis also shows that the optimum design return period is less influenced by discount rate and the cost of line replacement and more sensitive to the duration of outage and IEAR value used. Haldar (2011) has extended the concept to parallel line configuration as well to study the integration of a HVDC line in an existing 230kV power network system by minimizing the total cost and hence, determining the optimum return period.

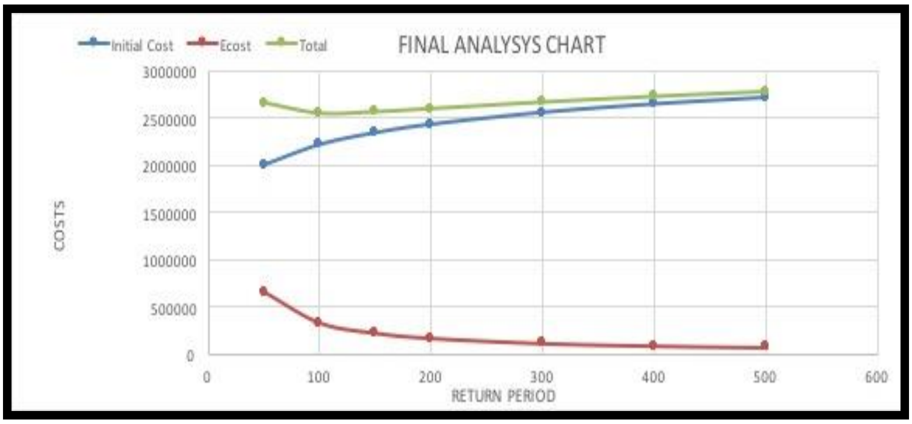

Figure 6– Optimum Return Period for a Lattice Steel Tower

SUMMARY AND CONCLUSIONS

The study presents a basis for computing the optimum design return period of an overhead line considering the initial line cost and the present value of the future failure cost. The optimization is performed considering the initial line cost and the cost of losses due to line failures. The failure cost consists of two components; (1) expected cost of line replacement and (2) expected cost of energy not supplied. A mathematical model is developed for a radial line configuration and it is shown clearly that the optimum design return period is significantly influenced by the duration of the line repair once it has failed and the cost of energy rate (IEAR parameter). The line should be designed for a higher return period if the duration of repair is expected to be long to ensure that the line cost is balanced against the present value of the failure costs. The sensitivity analysis also shows that the optimum design return period is less influenced by discount rate and the cost of line replacement and more sensitive to the duration of outage and IEAR value used.

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