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A Guide for Electrical Asset Replacement Strategy in Substations

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SUMMARY

Substation assets, including power transformers, stations switchgear and circuit breakers, along with associated transmission ingress and distribution egress connections represent critical infrastructure that must be proactively managed by the utility in such a manner such that reliability impacts and associated risks can be minimized. This paper describes a risk-based asset management ("AM") approach that can be used to proactively identify substation assets that must be proactively replaced based upon their lowest life-cycle costs. By replacing assets at this lowest life-cycle cost value, the utility is able to balance the risk of in-service failures of station infrastructure against the capital expenditures that are required to mitigate these risks.

This approach, which can be implemented by the utility as an "Asset Risk Framework", takes into consideration the substation assets' probability of failure and impact of asset failure in order to produce a quantified risk cost value. This risk cost is later annualized and subtotalled with the annualized capital cost of the asset in order to produce the total life-cycle cost of the evaluated asset – this also represents the total operating cost of the asset. The asset should optimally be replaced when it has reached its lowest life-cycle cost value. This is also referred to as the economic end-of-life criteria for the asset. This approach can be used to determine the individual replacement times for all substation assets within a given utility, which can be used to produce a data-driven long-term capital expenditure plan. Assets within the plan can be prioritized on the basis of their economic end-of-life criteria, and assets that are already past their economic life can be further prioritized through the determination of a benefit/cost ratio calculation. These assets can later be integrated into discrete capital investment projects as per short-term planning procedures.

A business case evaluation ("BCE") procedure can be applied to each short-term investment in order to measure the total cost of ownership ("TCO") and determine which investment scenario will yield the greatest net present value ("NPV") result.

KEYWORDS

Substation assets, Asset risks, Economic Analysis, Life-Cycle Costing.

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INTRODUCTION

Utilities continue to be challenged by internal and external stakeholders, including regulatory agencies, to provide a greater level of justification towards their capital investment programs and associated investment spending, and to ensure that the associated spending is meeting the needs of the utilities' customer base. At the same time, substation assets represent the highest risk components of a utilities' electrical system, as the potential impact of failure can be quite substantial depending on the number of connected customers as well as the criticality of those customers.

As a result, there is a need to both proactively manage substation assets in a manner that eliminates or minimizes potential risks to connected customers, while also establishing a detailed methodology and solution to justify the associated expenditures. A risk-based AM approach can be considered a best-in-class strategy[1], as this approach allows for a balance to be achieved between the risk of in-service failures of station infrastructure against the capital expenditures that are required to mitigate these risks.

Before any asset management approach can be implemented, it is necessary to collect and organize all available enterprise data on the utilities' asset base and system performance. This includes asset registry data and customer/load connectivity data from its AM/FM GIS platform, available inspection and investment spending data from its ERP platform, and real-time operational data from the utilities' OMS/DMS platform.

This raw data can be converted into meaningful metrics for deployment within an asset management approach. This includes the derivation of historical reliability data as well as the development of an asset condition assessment approach used to quantify the condition of a given asset. These two components can be used to develop an Asset Risk Framework, which is able to measure and quantify the risk of substation asset infrastructure.

This paper will discuss the key components of the Asset Risk Framework, including the determination of the probability and impact of failure respectively, the quantified risk and life-cycle cost calculation, and the resulting outputs that can be used for both long-term and short-term strategic replacement and prioritization of substation infrastructure.

PROBABILITY OF ASSET FAILURE

It is critical for the utility to develop an accurate approach to the prediction of substation asset failure. To this end, utilities must consider available historical reliability and performance data in order to derive a series of age-based hazard rate distribution functions for each evaluated substation asset class.

Figure 1 illustrates a typical example on how an age-based hazard rate function may be developed for the power transformer asset class through the use of historical reliability and performance data. In the first step, a sample of historical failure data is captured. Where historical failure data is limited, this dataset can be supplemented with assets that are still in-service. In the second step, various data optimization techniques, including censoring and truncation will be applied such that missing data can be fully populated and a complete dataset can be established. In the third step, a probability density function ("PDF") is produced using a maximum-likelihood estimation (MLE) method, such that the resulting function best aligns to the observed data. In the fourth and final step, the final hazard rate distribution function is produced and further validated by comparing the calculated or expected failures against the actual observed data.

A health index (HI) can also be measured for each asset as per an asset condition assessment (ACA) methodology. This health index represents a quantified condition score from 0 (very poor) to 100 (very good)[2], and is based upon specific degradation factors unique to each asset class which each contribute towards the overall failure probability of the asset. The health index results can later be converted into a condition-based failure probability calculation.

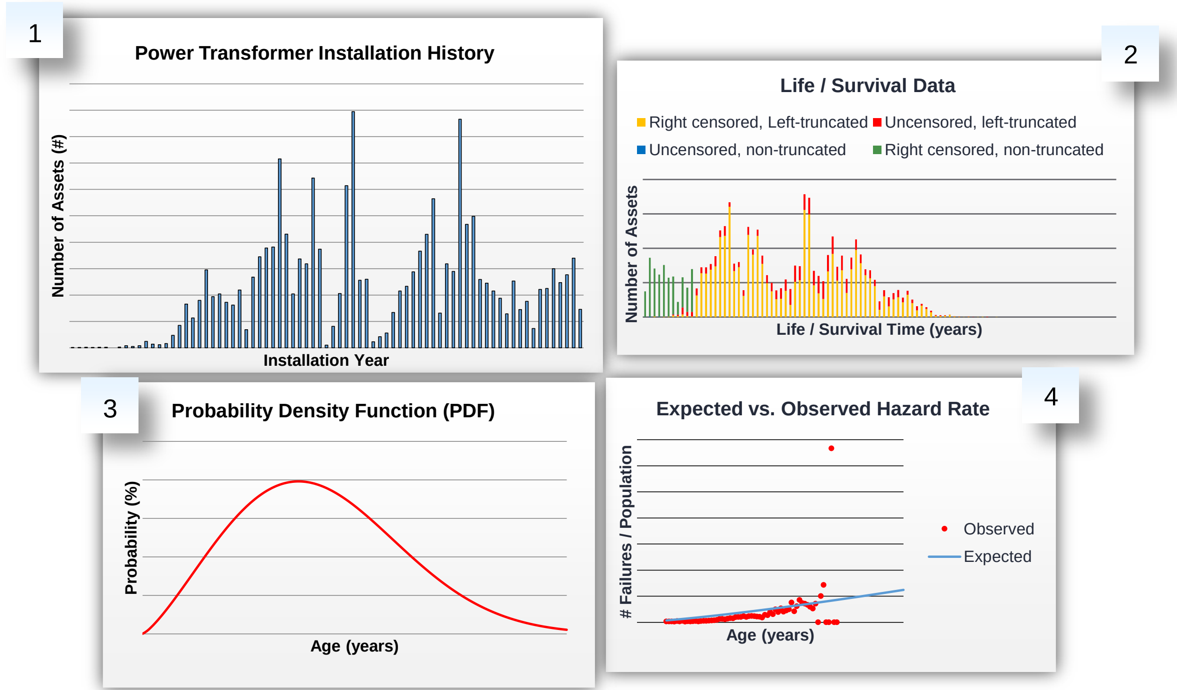

Figure 1 – Development of Age-Based Hazard Rate Function for Substation Assets

IMPACT OF ASSET FAILURE

The second component in determining the risk of failure for substation assets is to determine and quantify the impact of failure. This calculation considers the (1) financial impact to the utility for replacing the failed substation equipment under an reactive scenario, the (2) reliability impact to customers should an asset failure occur, the (3) environmental impacts and the (4) collateral damage impacts, including costs related to third-party claims and resulting safety hazards due to a catastrophic failure event.

Financial impacts typically include direct unit costs to replace the equipment, including materials, labour and incremental costs when replacing the asset under an emergency reactive scenario.

Customer/reliability impacts can be quantified through the use of customer interruption costs, which represent a measure of monetary losses for customers due to an interruption of electric service[3]. These costs are typically derived through the development of valuation studies, in which the customers' willingness to pay to avoid an outage is measured, along with direct losses incurred by the customer due to an electric interruption.

Environmental impacts for substation asset failures are typically quantified by considering the direct cleanup costs, fines and levies associated with major transformer oil spill events should a catastrophic power transformer failure take place.

Collateral damage impacts will consider internal and external safety impacts and related costs due to injury due to a major catastrophic station asset failure, along with potential third-party claims filed against the utility in cases where a catastrophic failure results in damages to customer property.

Figure 2 illustrates the total impact costs for a series of substation assets within a given system. As per these results, it can be seen that customer-related impacts clearly dominate the overall impact quantification result, and are therefore considered to be an integral driver in determining the overall risk of asset failure.

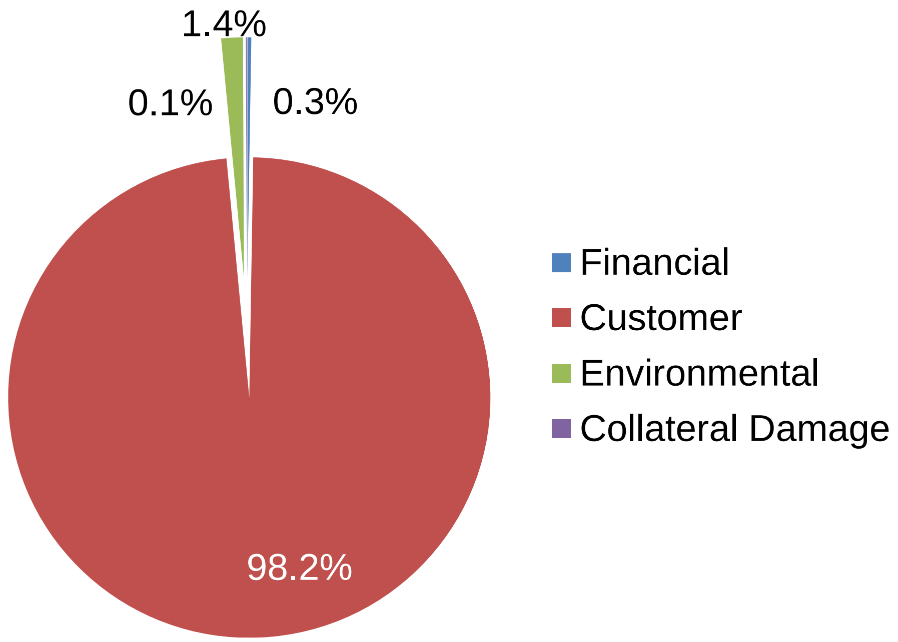

Figure 2 – Breakdown of Impact Quantification Parameters

RISK & LIFE-CYCLE COST CALCULATION

The risk of substation asset failure can be determined through the multiplication of the assets' probability of failure with the impact of failure. Because the impact of failure has been quantified into a dollar value, the overall risk of asset failure is also represented in dollars. This quantified risk can be determined for each substation asset, including power transformers, switchgear and circuit breakers, DC battery systems, transmission line ingress and distribution line egress connections.

Because the risk has been quantified into a dollar amount, it can now be compared to the capital investment spending necessary to mitigate the risk, as part of an economic life-cycle evaluation. The risk cost is balanced against the benefit of delaying capital spending by extending service life for as long as possible. Both risk and capital costs will be annualized across the life-cycle of the asset, and these components are subtotalled in order to produce the life-cycle cost or total operating cost of the evaluated substation asset.

The substation assets should be replaced when these life-cycle costs are at their minimum levels – this point in time as also referred to as the economic end-of-life criteria of the assets. This intervention timing that is determined for each substation asset represents one of the core outputs from the Asset Risk Framework, which can be used to derive a long-term investment plan and spending profile for each substation asset class, each substation and ultimately all substations within a utilities given' electrical system.

Figure 3 illustrates an example of a long-term spending profile for a series of substation assets. The results indicate that there exists a backlog of stations infrastructure that are already past their economic end-of-life criteria. By replacing this backlog immediately, the utility can achieve an "economic steady state" condition as total operating costs across all of the station asset classes will be immediately minimized. In practice, however, a utility will typically be unable to manage the backlog immediately, due to system, resource and operating constraints. When these factors are considered as part of a constrained capital program, the utility can assess when the backlog will be fully depleted, and determine a timeframe for when the economic steady-state condition can be achieved.

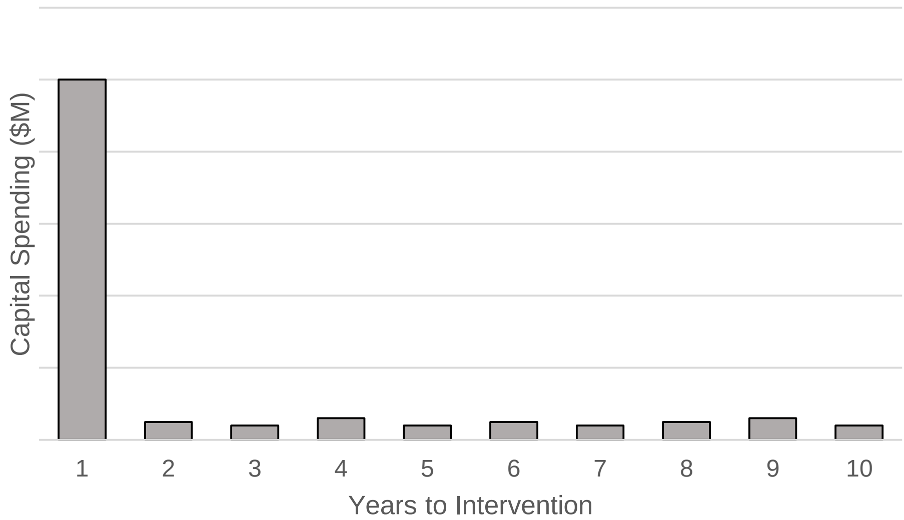

Figure 3 –Long-Term Capital Expenditure Plan derived from Economic End-of-Life Results

When all substation assets are replaced at their economic end-of-life criteria, the total costs of ownership (“TCO”) of those assets can be minimized. This is illustrated in an example in Figure 4, where TCO results are shown for an “existing” state of assets, as well as a “new” state of assets to be installed. There are other factors that can also result in further reduction of the TCO result.

For instance, consider an example where a given substation’s associated downstream feeders only possess manually-operable switches that are used for isolation, sectionalizing and load transfer procedures. Should a substation failure take place, it would take up to 4 hours on average to mobilize crews to the affected areas and to perform the manual switching, isolation and load transfer operations to get customers transferred to tie feeders supported from other substations. The TCO value would be very high under this configuration, due to the substantial impact of failure that would be produced from a possible substation-level failure.

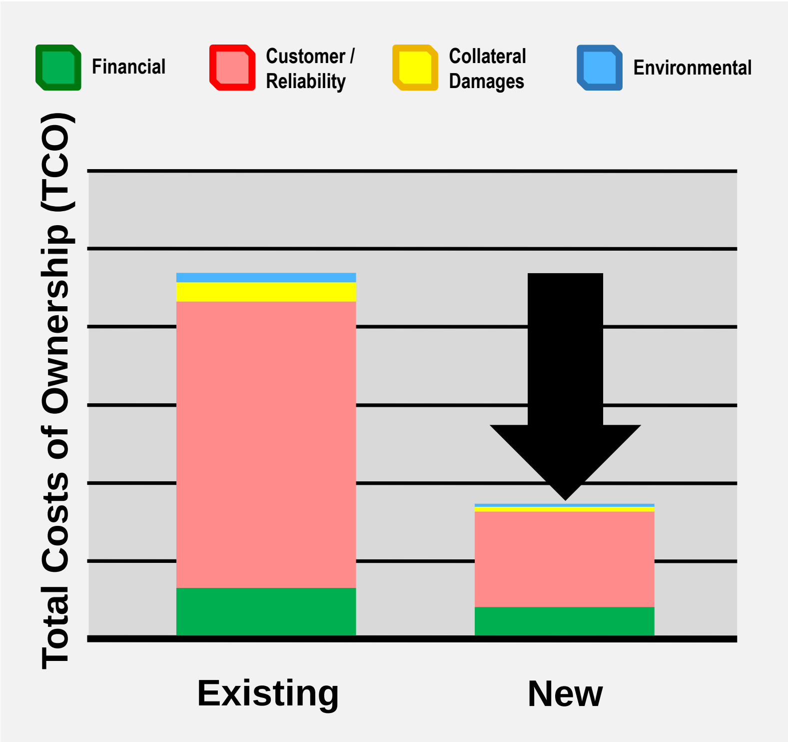

Figure 4 – Total Costs of Ownership (TCO) : Existing vs. New

Should all of the manual switches be replaced with SCADA-enabled switches, it would now take power system controllers up to 30 minutes on average to perform the same isolation, sectionalizing and restoration functions remotely from the control room. This net reduction in outage duration would also result in a net reduction of the TCO for this new configuration.

There would be a further decrease in TCO should a distribution automation ("DA") scheme be implemented. Under a DA scheme, all isolation, sectionalizing and restoration procedures could now be performed in under 1 minute, which substantially reduces the overall risk exposure to customers.

If we compare the TCO value between the existing configurations with manual switches with the TCO value from either the SCADA-enabled or DA-enabled configuration respectively, a net present value can be calculated for the overall investment as part of a BCE procedure. Equation 1 further details this NPV calculation.

- $NPV = (TCO_E) - (TCO_N)$ (Equation 1)

  Where:

  TCO_E = Total Cost of Ownership of Existing State of Assets

  TCO_N = Total Cost of Ownership of New State of Assets

Figure 5 illustrates the results for the example substation where three cases are considered: (1) continued like-for-like replacement of the manual switches and tie points for the stations' connected feeders at their respective economic end-of-life timing results, (2) installation of SCADA-enabled switches and (3) installation of a DA scheme.

As the greatest decrease in TCO will be achieved when implementing a DA scheme to an existing configuration with manual switches, this will also yield the greatest NPV result. This NPV result represents a key output of the BCE procedure that can be used to justify and defend short-term investments.

The NPV result represents a key output that can be used as part business case evaluation for investment programs and projects respectively.

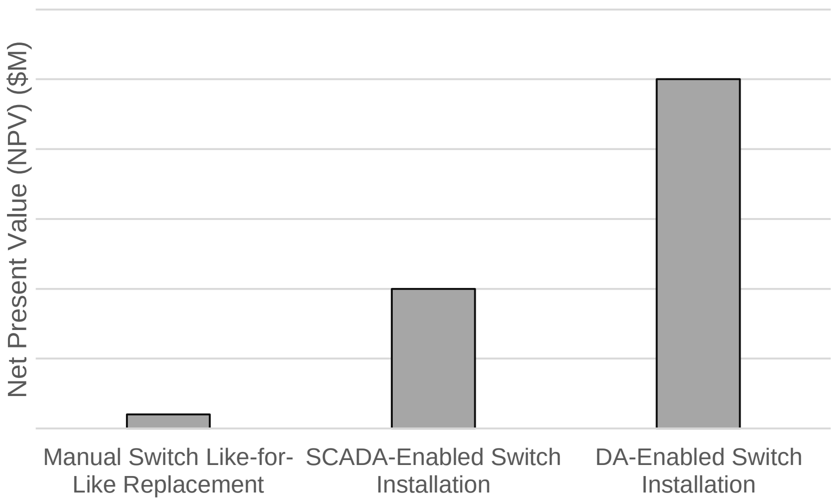

Figure 5 – NPV Results for Downstream Switch Investments

CONCLUSIONS

This paper has detailed has detailed a risk-based AM approach that allows for substation assets to be prioritized for intervention based upon their lowest life-cycle costing results, also referred to as the assets economic end-of-life criteria. This approach can be implemented by the utility as an Asset Risk Framework, in which the probability and impact of failure are determined in order to produce a quantified risk value.

This approach allows utilities to justify and defend their investments both from a long-term planning perspective through the creation of investment spending profiles, as well as from a short-term planning perspective through the evaluation of projects and programs using a BCE procedure. As customer interruption costs are considered as part of the impact of failure, this approach also allows utilities to consider the benefits to customers as part of their justification of major substation projects and program.

BIBLIOGRAPHY

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