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An empirical review of equipment replacement challenges in an electricity distribution network

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***Abstract*—A typical electrical utility comprises power generation plants interconnected to electricity transmission and distribution networks. Irrespective of the upstream challenges, the distribution network is directly customer facing, and this raises sensitivities to issues like safe and reliable electricity supply at affordable pricing, irrespective of increasing demand vagaries. In a developing country context, rapid urban sprawling exacerbates challenges for electricity distribution as the increasing need to expand networks often complicates how decisions are made regarding decommissioning, disposal, replacement, renewal, and upgrade of items of ageing equipment installed in distribution substations.**

Keywords—equipment replacement decisions; electricity distribution networks; engineering asset management

I. INTRODUCTION

A typical electricity distribution network comprises power lines infrastructure and a significant number of substations covering a wide geographical area. In areas that experience rapid urban sprawling, the network may be quite dense in some districts, and consist of residential, commercial and light industrial loads. The overriding concern for a utility operator is how to stay in business, and this motive inherently involves decisions on how to acquire, operate, maintain, and sustain networked infrastructure and distributed equipment against sophisticated customer demands for safe and reliable electricity supply at affordable pricing. The establishment of an electricity distribution network involves significant capital expenditure upfront to obtain real rights of servitude, to design, to acquire, and to install necessary infrastructure and substation equipment. Furthermore, there are onerous constraints to budgetary allocations for expansions in developing country environments due to urban sprawling. The constraints are exacerbated by the need to concurrently operate and maintain ageing substations to satisfy customer demands for stable supply.

In essence, electrical utility organisations have to make decisions with regard to :

i. optimizing capital and operating expenditures to sustain distribution network assets;
ii. balancing the operational performance of distribution network assets against business, functional and technical risks, as well as mitigating against vulnerabilities (e.g., *vis major* events like earthquakes, and/or *casus fortuitous* events like riots, thefts and vandalism);
iii. complying to changing legislative, regulatory, and sustainability imperatives.

Electricity distribution networks are permanent in nature and it is not uncommon for the infrastructure and substation equipment to be in operation well beyond the design life projections. Sustained heating of power lines, insulation deteriorations, weathering effects like corrosion, vagarious demand profiles, and wanton damage all result in degrading performance of distribution networks. In developing country situations, electricity distribution utilities remain under pressure to upkeep and extend the operating life of existing infrastructure and equipment, to develop new lines and substations to cater for expansions due to increasingly vagarious demand, whilst concurrently ensuring interconnectedness and interoperability of both old and new sections of an expanding network. Invariably, newer sections of a distribution network deploy latest technologies, and customer demands for high reliability of supply exacerbate trade-offs in terms of decisions to expand, refurbish, renew, renovate, replace, and upgrade infrastructure elements and substation equipment.

This paper uses empirical data from literature and a case study electricity distribution network to review how asset management decisions are made, specifically with regard to replacement of substation power transformers. Section 2 of the paper includes a brief review of literature on engineering asset management decision-making in electricity utilities. Empirical data from the case study utility is presented and briefly discussed in section 3, with some concluding remarks in section 4. The discussion emphasizes the importance of combining condition assessments from technical, functional, financial/economic and ecological dimensions to arrive at decisions to replace power transformers in electricity distribution substations.

II. Theoretical Review

A. Asset Management Decisions

An asset is a thing of value that provides a means to an end, thus, the management of an engineered asset like an electricity distribution network involves making informed decisions about how to maximize the value provided by the composite power line infrastructure and substation equipment. The perception of the value of the network by the electrical utility organization may be different from that of the customer, or the regulator, and the differences in the respective value propositions pose interesting challenges on how decisions are made to expand, refurbish, renew, renovate, replace, and upgrade infrastructure elements and substation equipment. In theory, the maximization of value should be with respect to the typically long life of an electricity distribution network. The implication is that throughout the life of the distribution network, decisions regarding value ought to balance the constraints imposed by business objectives, financial economics, operational ergonomics and safety, technical integrity and technological innovation, and sustainability imperatives (cf. [1] and [2]).

The article cited in [3] suggests that decisions should be geared towards comparisons between operational, maintenance and capital costs that result in the provision of required network reliability over time. This viewpoint reiterates the vague interpretation of value in terms of cost, performance, and risk as indicated in [4], and arises from the narrow and short term traditional emphasis on reducing maintenance costs. Although maintenance activities may be performed on transformer, switchgear, cable and support infrastructure, however, the asset management imperative means that both the substation and power lines must be in a condition to supply the kilowatt-hours demanded at affordable pricing and quality, as well as at the required level of technical integrity and safety, financial prudence, ecological/environmental compliance, and sentimental reputation.

A broader interpretation recognizes both qualitative and quantitative dimensions of the value of an asset, and the inevitability of rising capital and operational costs both in the short, and the long term. The overriding challenge is how to make decisions that satisfy short term imperatives but also maximize benefits provided by the assets over the long term. Benefits are subjective, and have a high qualitative content and bias, irrespective of the viewpoint. The broader mindset of value means that it is more beneficial to manage the rate at which the costs of operating and maintaining distribution assets rise over the longer term. This viewpoint emphasizes condition assessment [5] as the basis to quantify and qualify performance degradation and to indicate remaining life of an asset. Therefore, extrapolating from the asset hierarchy illustrated in Fig.1, an electrical utility needs to assess the condition of a distribution network to determine the extent of functional, economic, ecological, and technical degradation of the asset compared against current and anticipated demands for safety, reliability, price of electricity and financial probity. The ramification is that the condition of the distribution network needs to be described in at least four dimensions:

i. Functional – delivery of electricity at the required levels of safety, reliability and price;
ii. Technical – correct operation of control, protection and power transfer equipment, and power line infrastructure;
iii. Economic/Financial – acceptable quantification of distribution network benefit/cost ratio;
iv. Ecological – acceptable ecological footprint of distribution network.

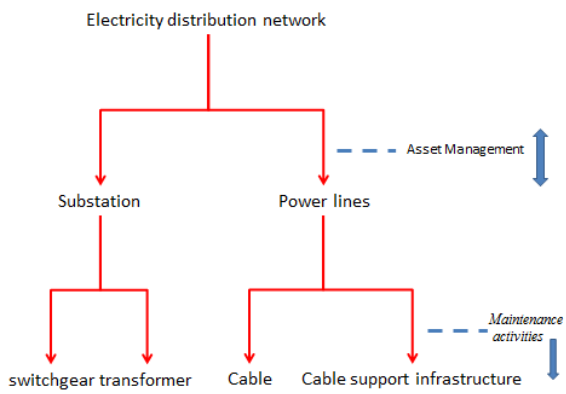
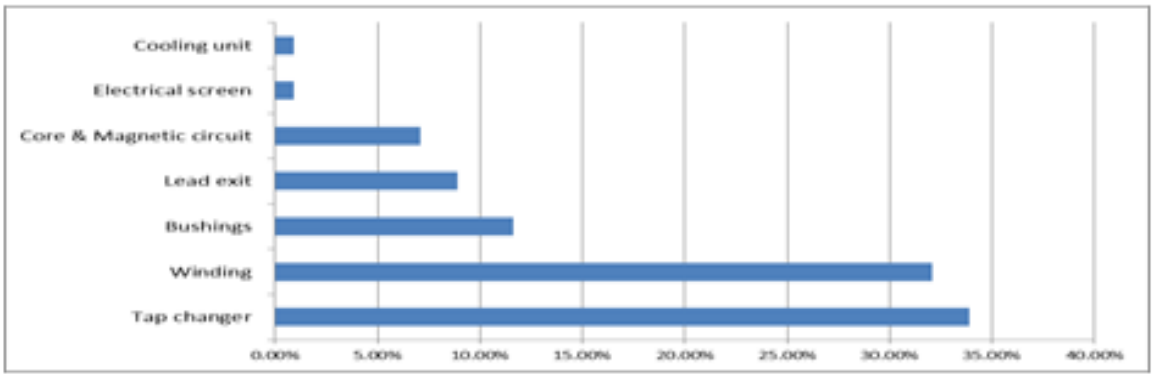


Fig.1. An asset hierarchy illustration of electricity distribution network

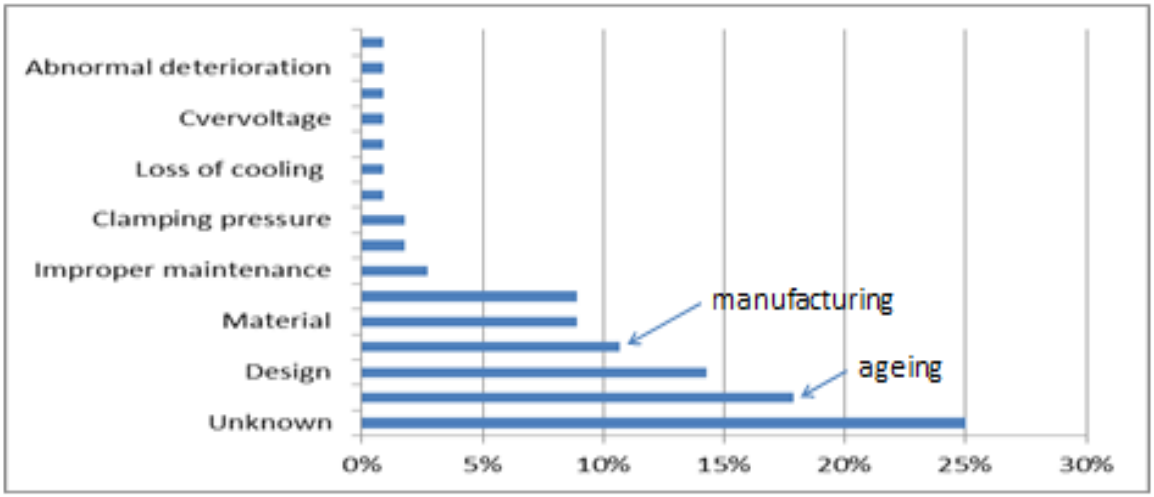
B. Asset Condition Assessment

A typical electricity distribution network spans a wide geographical area, and the power lines and associated support infrastructure are generally vulnerable to *vis major* and *casus fortuitous* events mentioned earlier. A number of technological approaches are discussed in literature with respect to monitoring with intent to identify and locate where failures have occurred, or may occur within a network (cf, [6], [7], [8], [9]). According to [10] cable failures mostly occur due to damage (poor workmanship). This is amplified by theft in some areas, with many of the failures located at cable joints. Substation infrastructure and equipment tend to be more vulnerable to lightning, rodents and reptiles, and vandalism. Inadvertently, the traditional roles and responsibilities in electrical utility organisations have unintentionally instituted a conventional emphasis on the technical condition of the power transformer, often with less emphasis on control, isolation and protection switchgear at substations. The articles referenced as [11], and [12], and report [13] describe methods for identifying the modes of failure and health indexing of a transformer. The assumption is often made (see, also [14], [15], [16]) that the transformer is the critical or most important equipment in an electricity distribution network, even though the failure of the smallest series connected switchgear component will result in electricity outage to the consumers fed from a substation.

Fig. 2 shows transformer failures and their causes as summarily reproduced from [17]. It is interesting to observe that over a period of 10 years, 66% of transformer failures were located, either in the tap changer (33.9%), or the winding (32.1%). The perplexing observation is that 25% of the causes of failure are classified as 'unknown', whereas, 'ageing', 'abnormal deterioration' and 'improper maintenance' contributed about 21.5% of the causes of failure. This begs to question whether the emphasis on transformer health index is overrated, since the location of the failures (in tap changers and windings) and the 'unknown' classification of failure causes may be related to switchgear. Ageing is a gradual process of deterioration, thus, it is worth questioning why maintenance activities could not mitigate against the 17.9% causes of failure classified as 'ageing'.



a) Failure location based on 112 transformer failures between 2000 and 2010



b) Failure cause based on 112 transformer failures between 2000 and 2010

Fig. 2. Example of transformer failure modes (source [17])

Perhaps, the inconsistencies observed may be that the practitioners tend to overlook the significance of switchgear by considering the transformer, instead of the substation, as the asset. The argument here is that any decision to replace a transformer should be based on a full assessment of the technical, functional, economic/financial, and ecological conditions of a substation, and not just on the technical health index of the associated transformer. After all, the electricity consumer is supplied from a substation, even if the transformer may be the largest item, the high percentage of 'unknown' failures that are mostly located in the tap changers and windings may be caused by switchgear operation. In the next sections of this paper, we present extracts of historical data from a case study distribution network and briefly discuss how decisions have been made based on such information.

III. Empirical Case Study

A. Case Study Environment

The nature of customers connected to both the transmission and distribution networks of the case study electricity organisation [18] is depicted in Fig.3. For the purposes of this paper, it is worth noting that electricity is supplied in bulk to municipalities, who in turn, distribute to the mix of consumers within the municipal demarcations. Also, the public sector owned electricity organisation and municipalities are both subject to more or less the same accrual accounting regulations.

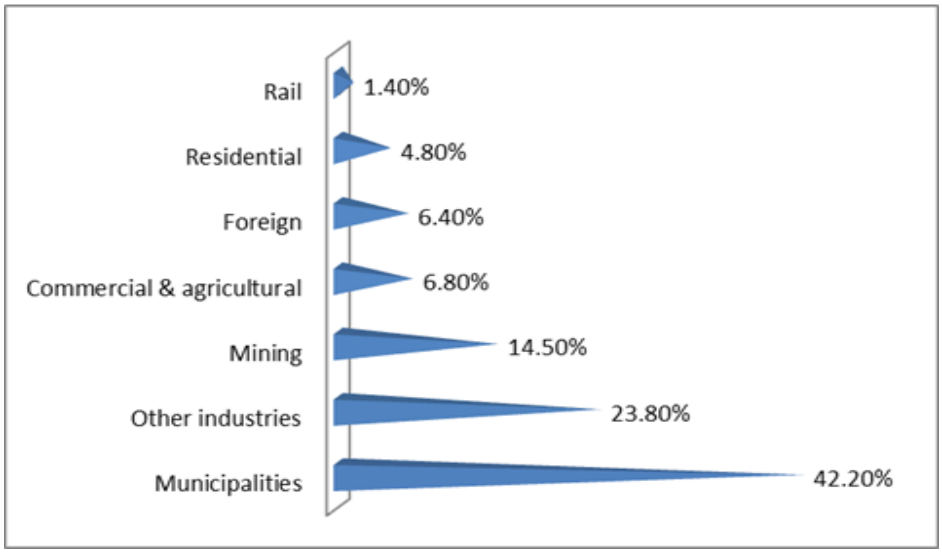


Fig. 3. Customers of case study electricity organisation (source [18])

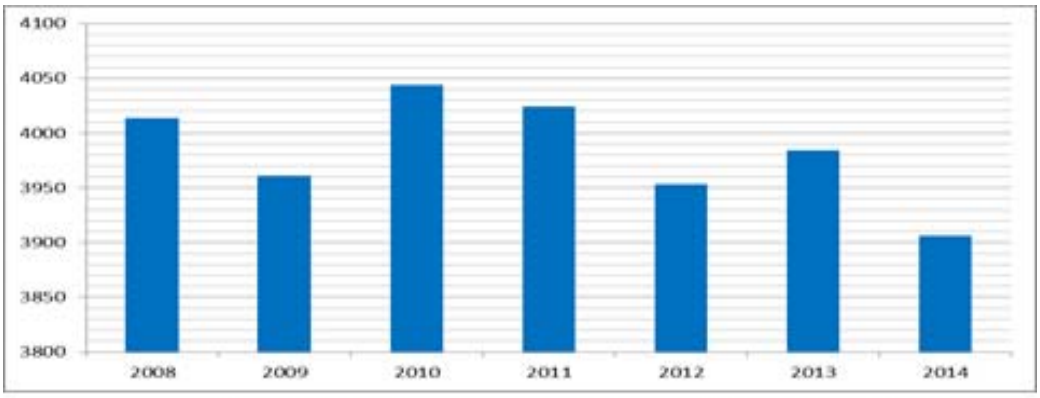
From the viewpoint of making asset management decisions, it is worth mentioning that the electricity enterprise is slowly transforming from a dominant fossil base to encompass a wide range of power generation platforms. The transmission and distribution networks also cover a range MVA/kV levels. Within the developing country context, and with the public sector as the monopolistic owner, custodian, steward and operator of the electricity enterprise, it is not surprising that the perception of value is even more subjective to governance structures, policy, legislative and regulatory regimes, as well as changes in economic, political and social development. Furthermore, global macro-economic and financial markets oftentimes exert conflicting and contradictory influences, and the effects on asset management decisions are magnified where both the polity and citizenry seek to redress past economic and socio-political exclusions. Some even argue that electricity is an essential public service, and should be subsidized as such. Thus, decisions to expand, refurbish, renew, renovate, replace, and upgrade electricity distribution infrastructure elements and substation equipment are complicated by the need to provide return on the economic investment as well as social dividend as defined by the wishes of the citizenry, albeit that, such wishes are more often bedevilled by contrasting value propositions. In this regard, the manager of an electricity distribution network must continuously consider and harmonise social equity demands compared against the utilisation of assets and the fiscal prudence demanded from a public sector enterprise. The distribution network manager has to concurrently contend with

i. fiscal prudence in budgetary execution
ii. economic efficiency in terms of resource allocation
iii. social equity in service delivery, and
v. ecological footprint as a prime sustainability imperative.

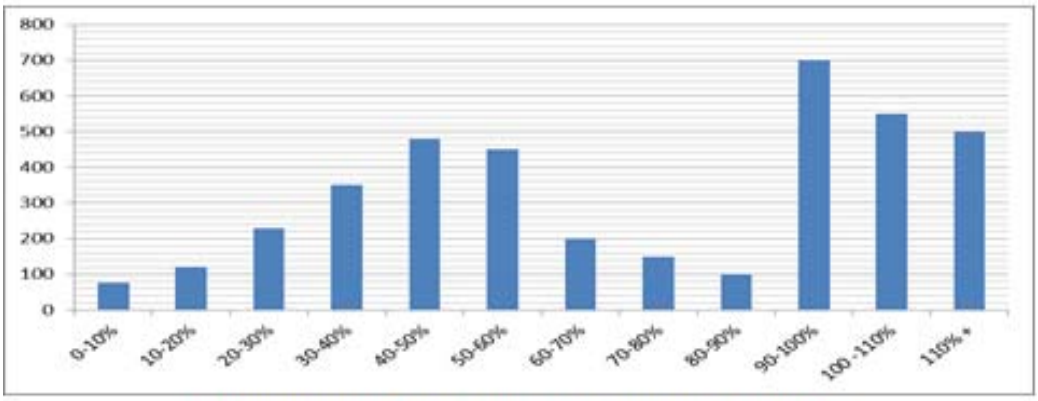
B. Analysis of Data on Distribution Network Transformers

For brevity, data discussed here arises from two main sources :

i. available records on distribution network transformers and failures between 2008 and 2014; followed by
ii. structured face-to-face interviews with nine operations and maintenance managers covering the respective zones of the distribution network.



a) Number of transformers installed on the entire distribution network



b) Typical loading of transformers against nameplate in 2014

Fig. 4. Number of transformers installed and average loading (source [18])

The picture in Fig.4a shows the number of transformers installed in the entire electricity (transmission and distribution) network each year in the ranges from 132/xxkV to 22/xxkV. The pattern evident in the top graph (Fig.4a) takes into consideration the effects of rezoning of the customers and the corresponding change in the sizing of the transformers between 2008 and 2014. For instance, 132/66kV substations are now primarily designed or deployed to provide bulk electricity to municipalities. Fig. 4b shows the averaged loading of the transformers compared against the nameplate in 2014. This graph suggests that there may be issues with the sizing or loading of transformers. The under-loading and overloading of some transformers may be interpreted in terms of utilisation of the substations, suggesting that there may be inconsistencies in how the electricity network is designed.

The number of transformers that failed during each year is shown in Fig.5a while the failure locations and likely causes are depicted in Fig.5b. The pattern in the number of failed transformers corresponds to the picture depicted in Fig.4a about the number of transformers installed. This mirrored pattern raises suspicion with regard to how substations are operated and maintained. Forty-five percent of transformer failures and their likely causes have been 'unclassified', but failures attributable to windings and insulation account for 26%. Interestingly, 6% of failures are attributable to protection switchgear. When this is added to the 'unclassified' causes of failures, then the resulting 51% of failures reported demonstrates that although the failure is assigned to the transformer, however, the view is at substation level of the asset hierarchy. Such focus on the transformer may confuse the decision making, and it is not surprising that the options have been to replace the transformer on the basis of age. As case in point, a particular 20MVA 88/22kV transformer that was manufactured in 1992 failed four times between 2010 and 2013. It is unclear what the failure rate was between 1992 and 2010. The degree of polymerization (DP) measured after

the transformer had failed in 2010 was 811.8ppm, well beyond the recommended 200ppm. The measurement of 811.8ppm is astonishing since DP is a time dependent ageing process that should show a trend rather than a sudden jump. Although this indicated that the transformer had reached end of life after 18 years, however, the question still remains as to why the operations and maintenance records did not reveal the deteriorating trend in the DP and other transformer health indices.

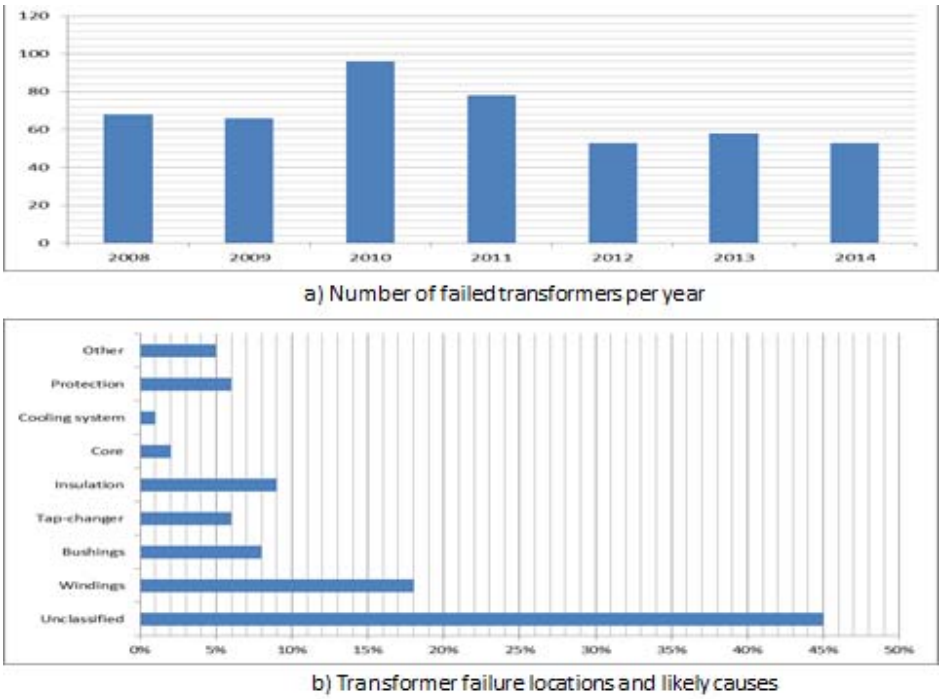


Fig. 5. Number of failed transformers and likely causes (source [18])

C. Analysis of Respondent Feedback

Seven interview questions on what informs decision making were posed to senior personnel of the case study electricity utility. The nine respondents cover the respective zones of the distribution network. With respect to the data, it was deduced from the responses that the power lines for the 22kV, 11kV, and 6.6kV networks consist mostly of overhead cables which are prone to phase to phase faults due to conductor clashing, and three phase faults due to vandalism. All the respondents commented that emphasis is placed on the technical condition of the transformer because it is quantitative and readily determinable. The respondent feedback indicated that when decisions are made to replace a transformer, the technical condition is weighted about 85%, the functional condition about 10%, and the economic condition less than 5%. The respondents were unsure about the frequency of transformer health index measurements but pointed out that the DP measurement was given high priority over oil analysis and temperature indices. The respondents offered five main reasons for replacement of transformers, such as :

i. technical condition – up to 65% of transformers were replaced when DP measurements exceeded 200ppm,
ii. capacity upgrade – about 25% of transformers were replaced due to the need to upgrade the capacity of a substation,
iii. safety and legal requirements – about 5% of transformers were replaced consequent to safety and legal requirements,
iv. financial condition – 3% of transformers were replaced when the financial position of the utility made it feasible,
v. technology change/obsolescence – about 2% of transformers were replaced due to technology obsolescence.

IV. Concluding Remarks

Although the respondents claim that the capacity of a substation to supply electricity as the load demands is usually considered, however, the respondent feedback, plus data on transformer failure locations and causes from both literature and case study environment do not provide convincing evidence. The uneven loading, and especially the overloading of some transformers raises questions as to substation utilization criteria or guidelines applied for network design, planning, operations and maintenance. A remarkable comment is the fact that both the literature and case study data showed that the most prevalent transformer failure type and cause is categorised as ‘unknown’ or ‘unclassified’. The implications of this category of transformer failure types and causes may result in inconsistent and confused decision making. Another comment is on the overrated emphasis on the substation transformer, whereas it would seem from the ‘unknown’ and ‘unclassified’ failures that

control and protection switchgear may be more significant contributors to decision making. Again, this viewpoint raises questions with regard to network operations and maintenance activities. These remarks have practical relevance when one considers that electricity distribution network assets are long-lived, such that short term decisions based on skewed information may result in negative long term impacts.

As illustrated in the flow diagram in Fig. 6, the study highlights that engineering asset management decisions for electricity distribution networks should be consistently made at a level which attempts to balance the respective stakeholders' value profiles. The qualitative aspects of the value of an asset may be inherently embedded in ecological/environmental, economic/financial, and functional value propositions of stakeholders other than the business organisation and electricity utility operator. The customer and consumer, regulator, and the public at large have respective perceptions of the value of an electricity distribution network, and hence influence the condition of the network. Therefore decisions regarding replacement of network elements should consistently apply recognizable weights to the respective value propositions of the various stakeholders.

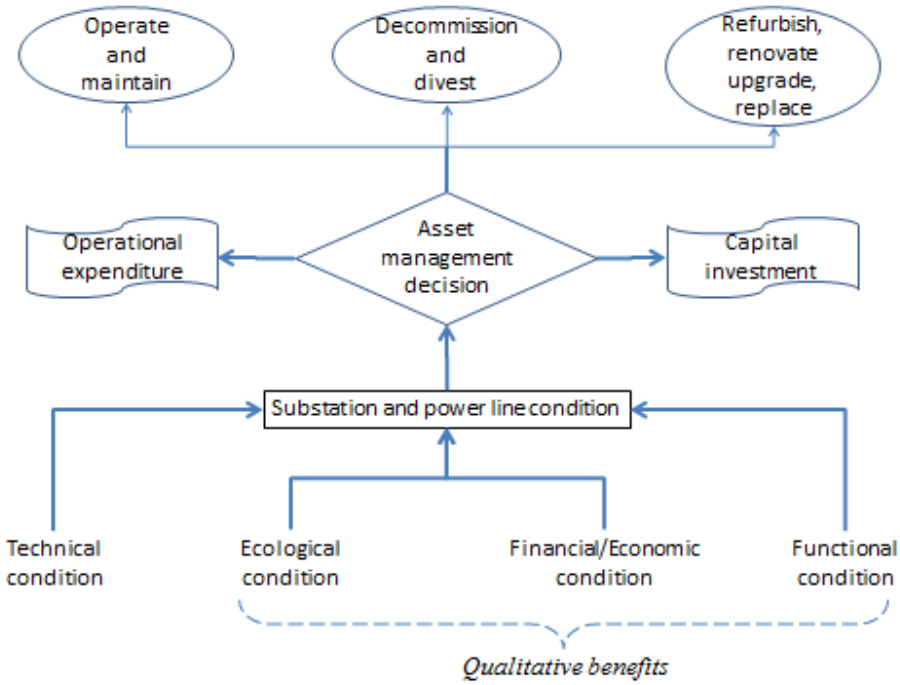


Fig. 6. An engineering asset management decision framework based on full scope condition assessment

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BIOGRAPHY

Include author bio(s) of 200 words or less.

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Ouma Bosaletsi is a registered professional engineer in South Africa. She holds a Bachelor of Science degree in Electrical Engineering from University of Cape Town, and conducted the study as a mini-dissertation in partial fulfilment of the requirements for a Masters in Engineering Management degree. Ouma started her working career in Eskom South Africa as an engineer-in-training, and now co-ordinates and manages preliminary and final designs of assets in Eskom distribution.