EVALUATION METHODS AND KEY PERFORMANCE INDICATORS FOR TRANSMISSION MAINTENANCE

By

Ferenc Bodrogi, Magyar Villmos Művek Rt, Hungary
Enrico Maria Carlini, GRTN, Italy
Leo Simoens, ELIA, Belgium
Joseph Maire, RTE, France
Richard Delpet, RTE, France
Hylco Hoekstra, Tennet, The Netherlands
Thomas Melkersson, Vattenfall, Sweden
Mike Allison, Black & Veatch, UK*

(On behalf of Study Committee C2 and JWG B3/C2-14, Task Force 02)

1. INTRODUCTION

Increasingly, the cost and performance of power transmission networks are important topics for all HV network users. For this reason, Transmission System Operators (TSOs), asset managers and service providers are looking for tools to assist them with the assessment of their performance and to permit them to keep as near as possible to their regulatory and customer requirements. In fact, their overall aim is to offer the lowest possible cost grid with acceptable technical performance. Accordingly, in the field of transmission maintenance, there is a demand for shared methods and common indicators that enable system operators and others to evaluate their performance. For TSOs, the aim is naturally to improve both their efficiency and effectiveness and to provide evidence to their customers and their regulators that they are actually doing so.

This paper reports the result of an investigation performed by means of a questionnaire issued by JWG B3/C2 – 14 early in 2003. Some 32 responses to the questionnaire were received from various countries.

2. MAINTENANCE POLICY AND PLANNING

Maintenance practice differs depending on the complexity of the asset and/or the technical characteristics of the components of a network. Also, utilities use different approaches to optimise maintenance. For the purpose of this paper, maintenance is classified as follows:

- Time Based Maintenance (TBM)
- Condition Based Maintenance (CBM) or Time Based Condition Assessment (TBCA)
- Reliability Centered Maintenance (RCM)
- Risk Based Maintenance (RBM)
- Corrective Maintenance.

The responses to the questionnaire show that most utilities use TBM and CBM/TBCA maintenance. Generally, TBM maintenance is used when diagnostic elements for condition monitoring are not installed (on the basis of technical or economic expediency) or when simple and repetitive maintenance actions are
involved. Figure 1 summarises the utility responses concerning maintenance strategies for the main transmission grid components:

<table>
<thead>
<tr>
<th>OHL</th>
<th>SWITCHGEAR</th>
</tr>
</thead>
<tbody>
<tr>
<td>TBM</td>
<td>23%</td>
</tr>
<tr>
<td>RCM</td>
<td>6%</td>
</tr>
<tr>
<td>RBM</td>
<td>6%</td>
</tr>
<tr>
<td>CBM/TBCA</td>
<td>9%</td>
</tr>
<tr>
<td>CORR MAINT</td>
<td>61%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>TRANSFORMER</th>
<th>PROTECTION AND CONTROL</th>
</tr>
</thead>
<tbody>
<tr>
<td>TBM</td>
<td>18%</td>
</tr>
<tr>
<td>RCM</td>
<td>15%</td>
</tr>
<tr>
<td>RBM</td>
<td>3%</td>
</tr>
<tr>
<td>CBM/TBCA</td>
<td>7%</td>
</tr>
<tr>
<td>CORR MAINT</td>
<td>57%</td>
</tr>
</tbody>
</table>

Figure 1: Distribution of maintenance strategies

**Outsourcing of Maintenance Work**

In most of utilities that responded (29 out of 32), outsourcing of maintenance has an important role. Generally, the reasons quoted for outsourcing are limited resources, the work is non-core business (i.e. personnel, training etc), and financial reasons.

In some utilities transmission maintenance is 100% outsourced and has been so for a number of years. In such cases, several maintenance service providers are often involved. Performance is measured principally by completeness of the work, timeliness and compliance with procedures. The work is monitored by contract managers and field auditors and is based on internal ‘service specifications’ which detail maintenance tasks/procedures and frequency (time-based inspections plus condition-based corrective maintenance for equipment deterioration and defects found during the inspections). The contractors are required to be certified for compliance with quality assurance standards (based on international standards).

Innovative approaches mentioned include ‘alliancing’ maintenance contracts, which give contractors more control over where and how the maintenance budget is spent and make them more accountable for equipment and system performance. In these cases, the maintenance performance KPIs proposed include asset availability, asset reliability, outage management, maintenance budget achieved, safety, statutory compliance, industry rule compliance, etc.
3. MAINTENANCE PERFORMANCE

In achieving the best value from delivered maintenance, companies use indicators to measure the performance of various aspects of maintenance. By far the most widely used measures concern characteristics of the work itself i.e. was the work completed on time, to the required standard and, were safety regulations met etc. Secondly, measures of cost effectiveness are used. Both measures offer the opportunity of an immediate impact. Thirdly, the measure considered most important, is the overall result i.e. reliability of the grid, determined by the number of equipment faults. Fourthly, the quality of preventive maintenance is evaluated by the ratio between preventive and corrective maintenance.

When maintenance is overdue, the principal reasons given, in priority order, are as follows: operational reasons (24); weather (14); staff resources (10); customer requests (7); financial resources (3); and, availability of spares (2).

Improvement of maintenance performance is actively pursued by almost all the utilities that responded. The general trend is that utilities are seeking improvement over rigid time based maintenance (TBM). A majority (23) of the utilities is working towards more adaptive strategies, mainly Condition Based Maintenance (CBM). That CBM is presently in an intermediate position is supported by the small number of companies (4) that claim to have introduced CBM widely and others (4) that use RCM as the predominant strategy. A larger number of companies (8) claim to use a combination of CBM/RCM. Because TBM is still widely used, the intervals are the subject of scrutiny in many companies. The following tactics are being tried to improve on intervals: use of CBM/RCM (6); ‘step and see’ (14); and, differentiation (3). The middle group ‘step and see’ was mentioned by one of the respondents and broadly represents what the other 13 companies actually do. Differentiation allows longer intervals for classes of equipment that require less maintenance or have lower duty.

In the questionnaire responses there were 3 remarks, in particular, that may be of interest to asset managers. The first emphasises the importance of organising feedback from the work performed. This must not just be left to the service provider and his crew, but must be part of the management philosophy throughout the organisation. Feedback is essential in the control of maintenance. But, feedback based on faults requires a sufficient number of faults, which of course, nobody wants. A solution, suggested by one utility, is to use a performance indicator that measures the rate of discovery of pre-fault phenomena. The authors believe this to be an excellent way of bringing out the quality of a maintenance organisation. Secondly, one of the smaller utilities suggested making use of the experience of others. This can be either bilateral between utilities or through one of the professional platforms where data and information are shared. Thirdly, equipment with less demanding maintenance requirements can be selected for some applications.

Many utilities use some form of benchmarking to compare their indicators or to set targets for indicators. The next most popular method of setting targets for indicators is the trend of the indicators themselves. Many utilities point to the influence of the regulator on the development of maintenance costs.

4. QUALITY OF MAINTENANCE

In answer to a question on the methods used to assure the quality of maintenance, many of the utilities answered that they use their own maintenance guidelines and internal supervision procedures. Around 44% of the utilities adopt ISO 9001 guidelines and about 19% have no documents relating to quality of maintenance. Of the utilities that follow the ISO guidelines, only 38% take environmental aspects into account by adopting ISO 14001.
It is interesting to note that most of Asia and Middle East countries (5/8) follow manufacturers’ recommendations concerning the periodicity of maintenance intervention. With regard to failures induced by maintenance, 44% of the utilities indicate that the most significant issue has been protection system failures (involving both relays and switchgear) and transformer failures due to tap changer maintenance. A few utilities (6%) mention failures caused by human error (e.g. forgotten earths) or accidental interference beyond the control of management.

5. SERVICE QUALITY INDICATORS

General

There is much confusion concerning the use of the terms ‘Availability’, ‘Reliability’ and ‘Quality of Supply’. Definitions given by system regulators differ from country to country and official definitions are confusingly similar. Mixed interpretation of the terms indicates the need for standardisation.

Availability Indicators

From the customer’s perspective, availability is a measure of the readiness of a system to deliver energy. Based on the responses to the questionnaire, utilities often measure availability of energy to the customer as follows:

- **Energy Not Supplied (ENS)**. This indicator is used by 19% of the utilities. It measures the summation of energy not supplied (interrupted power x duration) due to interruptions excluding network losses (MWh/yr).

- **Average Interruption Time (AIT)**. This indicator is recommended by Unipede for use with transmission grids. It is used by 16% of the utilities. AIT measures the total number of minutes that power supply is interrupted during the year. \( AIT = \frac{8760 \times 60 \times ENS}{AD} \text{ in min/year, where } AD = \text{annual demand (MWh/yr).} \)

Other performance indicators mentioned are: System Minutes Lost (SML); Average System Unavailability Index (ASUI); Average Customer Unavailable service Index (ACUI).

Reliability Indicators

Reliability is often used as a measure of the service level of the transmission network. From the customer perspective, it equates to the failure rate, i.e. the number of service outages experienced. The most significant reliability indicators are as follows:

- **System Average Interruption Frequency Index (SAIFI)**. This indicator, recommended by the IEEE, measures the average number of interruptions experienced by each customer. All planned and unplanned interruptions are used in calculating the index. This indicator is used by almost 30% of the utilities that responded to the questionnaire and many of the others use similar indices.

- **Customer Average Interruption Frequency Index (CAIFI)**. This indicator, also recommended by the IEEE, measures the yearly average number of interruptions per affected customer. An affected customer is one who experiences at least one interruption during the year. CAIFI is used far less than SAIFI.

From the Grid Operator perspective, reliability is related to possible service outages in the next ‘n-1’ situation. Consequently, the reliability of the grid can be extremely low although customers may not be aware of the situation. The most significant statistics used are as follows:
failure rate/yr \( (R = e^{\lambda}, \text{where} \lambda = \text{failure rate/yr}) \)
mean time to repair
outages/100 circuit km
number of successful restoration operations
number of malfunctions of protection
number of failures/yr classified by cause.

Some utilities use an index to indicate the overall state of the grid (for each voltage level). The Risk Situation Index (RSI) is an index based on the calculated consequences of all possible ‘n-1’ situations e.g. overloaded line or transformer, voltage out of limits or high level of Mvar flow, probability of each ‘n-1’ situation. This index of risk increases with planned outages of grid elements. Because this indicator gives a continuous evaluation of system risk, it is considered valuable for system operation.

Service Quality Indicators

Most utilities keep data about voltage dips and frequency variations which are more related to voltage quality. The service quality indicators most widely used, by 28% of the utilities, are as follows:

**System Average Interruption Duration Index (SAIDI).** This indicator, recommended by the IEEE, expresses the duration of outages customers experience during the year on average. All planned and unplanned interruptions are used to calculate the index. It is defined as the total hours of power interruptions normalized per customer served.

**Customer Average Interruption Duration Index (CAIDI).** This indicator, also recommended by the IEEE, measures the yearly average duration of interruptions normalized per affected customer. An affected customer is one who experiences at least one interruption during the year.

Almost all utilities keep records concerning the average duration of customer outages. Some of these are standard indicators, but others are not. Some interesting indicators mentioned are Customer Satisfaction Index (CSI), determined through inquiries; Average Incident Duration (AID); and, System Average Restoration Index (SARI).

As a result of the above review, to evaluate reliability, availability and service quality, it is recommended that the following internationally well defined key performance indicators (KPIs): AIT, SAIFI and, SAIDI, are also used for international maintenance benchmarking: UNIPEDE advises that only interruptions with a duration of longer than 3 minutes should be taken into account. In some systems (to meet regulatory targets, or where there are very low values of AIT etc), a Risk Situation Index may also be considered. Such an index can accommodate regulatory and commercial elements and can be customised to the specific requirements of the service concerned. This type of index, which is not yet standardised [1], could become of increasing value in the regulated market.

6. **FINANCIAL ASPECTS**

With regard to the structure of maintenance costs, it was found that the utilities that responded to the questionnaire have a reasonably common understanding of what should be included in maintenance costs i.e. basic enabling measures including safety permitting (77%); equipment modifications (68%); recurring maintenance including primary/secondary equipment (90%); tower painting (84%) and tree cutting (87%); corrective maintenance including planned maintenance (84%) and unplanned maintenance (87%); operational replacement costs (45%); and, refurbishment (48%). There was also agreement that capital
replacement costs (23%), and financial/operational impacts including imposed energy production (16%) and penalties (19%) are not generally considered as maintenance costs.

Financial performance indicators

The use of financial ratios to compare maintenance costs with utility operational expenditure or with total expenditure is shared. Generally, however, the cost of maintenance is used as basic data to make comparisons, for instance, per voltage level, per planning unit, per maintenance location etc. Also, it appears more common to use the trend of maintenance costs to follow performance rather than as a ratio to total expenditure.

Commercial/contractual performance indicators

The indicators used to follow maintenance performed by utilities’ own staff are mainly related to costs, observance of planning, completion of work, utilisation factor of staff and, failure statistics. They are for example: actual cost v budget; time to completion; observance of planned outages; maintenance cost/plant unit; staff/labour utilisation factor; completion of work; maintenance cost/number of work orders; achievement (%) against target baseline; work completed/work planned; and failure statistics.

The measure of contractors’ performance is based on the same indicators as for utilities’ own staff plus indicators related to flexibility and price. The contractor’s performance is also considered in relation to the award of future contracts.

Only a few (4) utilities use financial indicators to quantify their customer performance. These indicators are based predominantly on penalties. The use of bonuses or penalties payable to the regulator, grid-owner or customer as a result of meeting availability targets is relatively shared. Penalties payable to customers often depend on the number and duration of the interruptions. Sometimes the penalties are defined by the regulator taking account of the size of the customer and duration of the interruption. Sometimes the penalties take the form of a direct contract with the customer related to target availability; service quality or performance obligation. Whether or not a contract exists, customers regularly claim the cost of an outage. For producers, the penalties include, for example, the cost for ‘may not run’. Where utilities are not subject to penalties, many expect that they will become so in the near future.

Less than 30% of utilities use incentives to avoid re-planned work and encourage workers to complete work in the time initially planned. Among the criteria used in formulating incentives are: 100% achievement of planned work; focus on responsibilities, level of faults; and % of work complete. There are some other rather more repressive measures stated in outsourcing contracts.

7. CONCLUSIONS

It is concluded that the majority of utilities measure maintenance performance by means of cost evaluation and the final outcome i.e. grid availability and reliability. In order to improve on this outcome, most utilities (about 60%) already go further by making use of indicators to evaluate performance of the maintenance work itself. The responses to the questionnaire show that only about 40 % of utilities make use of ISO standards, which contain a system for improving quality of work, organisations and methods. Also, at the present time, there are no internationally recognised indicators for measuring the effectiveness and efficiency with which maintenance is performed. Although some international measures are available, they are not widely used in the context of measuring the efficiency and effectiveness of maintenance.

Improvement of maintenance performance is an issue that is being actively pursued by most utilities. Many companies are moving away from Time Based maintenance (TBM) towards more adaptive
strategies, mainly Condition Based Maintenance (CBM) and feedback is a vital part of this process. In addition, many utilities use outsourcing to varying degrees as part of their maintenance strategy. Furthermore, many companies use some form of benchmarking to compare their indicators or to set targets for their indicators. They also use the trend of their own indicators when setting targets. In many cases, the regulator is instrumental in setting targets for the cost and effectiveness of maintenance.

With regard to maintenance costs, utilities have a common view on what should be included and the costs are used in various different ways to measure maintenance performance. Due both to the downward pressure on costs exerted by regulators and the need to demonstrate improving performance, it is more common to use the trend of maintenance costs to measure performance rather than maintenance costs as a ratio of total expenditure.

8. RECOMMENDATIONS

It is recommended that:

Average Interruption Time (AIT), System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) are used as internationally recognised maintenance service quality indicators.

To ensure the quality of work, ISO standards of certification are adopted in order that maintenance work is performed correctly, to the required environmental standards, and safely.

A common definition of what main maintenance cost covers should include (and be limited to) the following items: basic enabling measures; recurring maintenance; corrective maintenance; operational replacement costs; environmental issues and obligations; and refurbishment. Capital replacement costs, financial and operational impact costs (like imposed energy production and penalties) should not be included.

For benchmarking, when comparing costs, for each voltage level the following indicators should be provided for maintenance costs associated with each of type of equipment:

- **Overhead Lines.**
  Cost of maintenance of OHL/route length (km)

- **Substations**. These costs should include all costs within the substation fence (i.e. HV, auxiliary, site, protection), subdivided as follows:
  - **Primary Equipment.** Cost of maintenance of substation HV equipment/
    (No. of CBs + p *No. of transformers), where it is suggested that p = 2.
  - **Protection.** Cost of maintenance of protection equipment/
    (No. of CB + No. of transformers).

9. BIBLIOGRAPHY


APPENDIX A – INDICATOR DEFINITIONS

*E-mail: allisonm@bv.com*
<table>
<thead>
<tr>
<th>Indicator</th>
<th>Formula System &amp; Service Quality</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>AIT</td>
<td>( \frac{8760 \times 60 \times ENS}{\text{yearly consumption (MWh)}} )</td>
<td>min./yr</td>
</tr>
<tr>
<td></td>
<td>( ENS = \text{energy not supplied due to outages during 1 year} )</td>
<td>MWh/yr</td>
</tr>
<tr>
<td></td>
<td>( ENS = \sum (\text{MW lost} \times \text{duration (h)}) )</td>
<td></td>
</tr>
<tr>
<td>SAIFI</td>
<td>( \frac{\text{number of interruptions/yr}}{\text{number of customers}} )</td>
<td>No./cust., yr</td>
</tr>
<tr>
<td>SAIDI</td>
<td>( \frac{\sum \text{duration of the interruption (min)}}{\text{number of customers}} )</td>
<td>min/cust., yr</td>
</tr>
</tbody>
</table>

Notes:  
(1) A ‘customer’ of a transmission grid is considered to be each company that has a connection contract to the grid.  
(2) Formulas to apply per voltage level.

**APPENDIX B - MAINTENANCE DEFINITIONS**

1. **Condition Based Maintenance (CBM)**. Maintenance scheduling is based on the results of visual inspections or monitoring of the condition of the equipment. Maintenance is performed only when the visual inspections or monitoring indicates that it is necessary. The monitoring may be on-line or off-line.

2. **Reliability Centered Maintenance (RCM)**. Reliability Centred Maintenance is a systematic way of establishing a Preventive Maintenance (PM) program or improving an existing PM program. RCM uses a structured methodology to establish the maintenance requirements for equipment based on the consequences of failure. The intent of RCM is to establish maintenance practices that focus more on the functional importance of a piece of equipment and its’ failure/repair history than on ‘time-directed’ overhaul tasks.

3. **Risk Based Maintenance (RBM)**. Risk Based Maintenance is basically RCM that takes into account the level of acceptance of the company’s (risk) strategies (e.g. environmental, sociological, exposure to penalties, community damage etc). This means that the importance of the asset in the system plays a key role. Examples of RBM might include regular insulator washing or vegetation clearance at certain times of the year.

4. **Time Based Maintenance (TBM)**. Time Based Maintenance is maintenance that is planned at fixed time intervals. Initially, scheduling of the regular maintenance intervals is likely to be based on the recommendations of the equipment manufacturer. But, the maintenance interval may change depending on the experience of the operator.

5. **Time Based Condition Assessment (TBCA)**. Time Based Condition Assessment (TBCA) is condition assessment performed at regular time intervals.

6. **Repair/Corrective Maintenance (i.e. Reactive Maintenance)**. Repairs initiated as a result of a component failure or externally caused condition of the system that requires an unscheduled maintenance event.