LEVERAGING OPERATIONAL DATA TO IMPROVE ASSET MANAGEMENT AND MAINTENANCE DECISIONS

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SUMMARY:

Utilities look for ways to improve system reliability while reducing cost. Corporate goals and business plans contain targets and trajectories of these two key objectives. However each utility has unique challenges given the diversity of systems and regulatory environments. The electric utility industry can look to the manufacturing sector for leadership in its quest. If we compare the industry to the auto industry we may conclude that it is more like the '70's U.S. manufacturers based upon industry metrics and process capability. There is a need to advance beyond counting "lemons" and rejects and move process sampling and measurement further up the assembly line to achieve these goals.

Arguably the electric utility business is a service industry and has challenges not found in the manufacturing environment. The airlines serve as a service industry model where successful strategies have been implemented. Many utilities have tried to model the success of the airlines with reliability centered maintenance (RCM) or derivatives of this approach. Early efforts are often successful in reducing obvious low-value work but many can't move beyond this. A critical element of success is the presence of a feedback loop from failure and operational data for analysis. Often this element is the weakest link and thus inhibits the process from delivering its full value.

This paper will discuss issues with reliability metrics, corporate goals, and other challenges facing utility asset managers in which the use of operational data could improve decision making. The discussion will focus on how operational data is often an overlooked process feedback resource for utility decision support.

ISSUES

Reliability Metrics and Measures

The electric utility industry has several widely used reliability measures and metrics. The usage depends upon several factors such as: state regulation, corporate ownership, and the vertical integration of services provided. Most of these metrics are long established and can be found consistently in corporate goals and incentive targets. These are often widely misinterpreted.

The most common convention with the majority of these metrics is the use of averages. While averages are intuitive, it is a misconception that they represent the central tendency of utility reliability. Unlike that of a normal distribution they represent only a minority due to the skewed underlying distribution of reliability data. The effects from exogenous sources such as weather and of the nature of failures in complex systems result in "long tails" and extreme outliers. The metrics are bounded by a lower limit of zero unlike normal distributions.

Most customers and many managers would implicitly equate median levels of reliability with SAIFI, when in fact the majority of the population (customers, circuits, etc.) receive service or deliver service better than the average service level. For customers it is hard to understand how they can receive service that it so far below the average. Conversely utility managers often fail to understand how hard it is to change the system average value even when they have successfully and dramatically improved reliability on a small population of assets.

The pursuit of first quartile performance is inherent in our culture. Skewed distributions suggest generic resource allocation implications such as:

(1) Uniform system remediation and maintenance approaches will not be as cost effective as those targeted on the poor performers (assuming that effective remediation exists).

(2) Cost-effective mitigation or maintenance may be possible on only a minority of the assets.

(3) Reliability goals are extremely non-linear with respect to resource allocation.

Despite generic implications, reliability goals are often approached linearly and independently from other utility goals. Despite consistent empirical operational data that suggests otherwise the majority of the utility assets are maintained in a uniform manner.

The following three sections will discuss utility metrics, or the lack thereof, and their usage in transmission, substation, and distribution reliability.

Distribution Metrics

System wide metrics summarize customer experience at aggregate levels. Average based metrics such as System Average Frequency Interruption, (the average customer frequency of interruption SAIFI) usually represent a level of reliability that is experienced by only the lowest third to quarter of a utility population. Customer experience may range from zero to fifteen outages per year for instance when the system average is one or less. In addition many widely used system level metrics have been adapted for use at discrete system unit levels such as the circuit level by utilities, reliability organizations, and regulators. In general most utility metrics are good overall point value indications of system reliability but have less value at the sub-system and circuit level.

The intent of this approach, to identify and correct under-performance, is fundamentally sound; however the application of these on sub-system and unit levels can impose arbitrary barriers that reduce their significance. Many indices are calculated annually, with the calendar year imposing an artificial reset to the calculation – invisible to the customer. For example distribution circuit frequency indices may mask the presence of frequently interrupted pockets of customers. Circuit experience may range from zero to six lockouts per year for instance when the average is approximately 1.5. Distribution circuit customer duration indices may indicate a "bad circuit" for the existence of one long storm interruption on a small fused lateral of another circuit.

Most distribution indices were intended to monitor general trends of a system on an annual basis, however from an asset management and maintenance perspective they lack enough temporal sensitivity. Often the timing of annual reliability results lags the budget cycle by three to six months, which can result investment based upon partial data or delayed remediation. Managers are pressed to make decisions within budget cycles and need rapid indication of results. Common manufacturing process metrics such as time between failures, time since last failure, or time since last maintenance would be of significantly more value to customers and managers than traditional annual utility reliability measures.

Transmission Metrics

Transmission systems have data that is also skewed despite the significant differences in configuration between transmission and distribution systems. Consequently these metrics suffer some of the same weaknesses as distribution metrics. Forced Outages per Hundred Mile Year, (the average frequency of interruptions per hundred miles of system exposure, FOHMY) are typical of transmission metrics. In most cases the worst ten percent of a population is responsible for sixty percent of the unreliability.

Transmission circuit experience may range from zero to five or more forced outages a year for an average of 0.5 per year. Depending on the system perhaps 55% of the transmission circuits have not had a forced outage in over three years, while the "average circuit" has approximately 0.5 interruptions per year. Many of the distribution metrics have in fact been applied directly to transmission. However the resulting customer indices often are very robust since networked systems seldom interrupt customers. Transmission availability is often cited as exceeding four nines, i.e. 99.99%; this lack of "headroom" limits the available trajectory of these metrics, and thus the value of these as strategic targets and benchmarks.

The changes in the transmission industry have increased diversity of transmission indices such as the use of connection point indices over customer based indices as more transmission-only companies emerge. The increased pressure of market mechanisms also has elevated the need to standardize underlying transmission data definitions which lag the distribution metrics standardization efforts despite a more diverse transmission environment.

The significance of this is evident when one examines the difference between the CIGRE working group definition for "forced outage"[1] versus the California Independent System Operator's (CISO) definition. Today's market driven systems, such as CISO, define any outage taken with less than the advance notice time limit as "Forced"[2]. Most non-market personnel may consider "Forced" to apply to automatic and "emergency" outages. Variations to the interpretation of outage restoration events are even more dramatic when comparing transmission reliability duration metrics.

This diversity and the lack of common definitions and data guidelines can impair benchmarking comparison, strategic goals & allocation processes, and ultimately performance based rates if left unchecked. To address this need Blue Arc Energy Solutions, Inc and SGS Statistical Services, LLC have voluntarily led an industry consortium of forty US transmission entities including utility, independent system operator, and reliability council representatives over the past eighteen months in an effort to update existing transmission reliability standards to produce the *Transmission Line Availability Data Guidelines and Definitions*, February, 2003[3]. The document is intended to provide a comprehensive guideline for definitions associated with the collection of data to assess the availability of electric transmission circuits and systems[4].

Substation Metrics

Unlike transmission and distribution there are almost no widely utilized metrics for substations or the equipment in the industry. Substation asset managers need a better line of sight to corporate reliability goals which traditionally use distribution metrics. Despite the fact that substation performance heavily influences transmission performance, has a greater potential for distribution customer impact than transmission line failures, and is where the majority of equipment maintenance resources are expended, substation asset managers have few metrics that directly relate substation performance and equipment maintenance to overall transmission and distribution reliability.

NOTE: The Electric Power Research Institute (EPRI) currently has a Transmission & Substation Asset Management Project for interested utilities that is targeted at developing transmission and substation grid equipment reliability metrics. The intent of the project is to develop metrics that improve reliability decisions for transmission and substation assets[2].

Substation reliability data is also a case of skewed data distribution. Indicators of skewness include: (1) in many systems 50% of the transmission breakers that have not seen a fault operation since the last maintenance interval, (2) 10% of circuit breakers that have not experienced a forced outage in over five or more years, (3) fault operations account for less than 20% of daily operations, (4) equipment failures account for less than 1% of daily operations.

In some utility regulatory environments prescriptive maintenance requirements stipulate uniform time based maintenance for utility assets. This seems logical for vegetation management and wood pole inspections where growth and decay respectively are more time dependent. However for the majority of substation assets equipment wear is not time dependent nor is service duty uniformly distributed.

The airline industry pioneered Reliability Centered Maintenance and has implemented strategies that perform engine maintenance not upon hours of operation but on the number of cycles, where one cycle consists of a take off and landing. The utility industry has begun RCM in many instances within substation equipment maintenance, but how many are have actually transitioned from time based? How many are leveraging operational data to accomplish this?

<u>Metrics Summary:</u> Averages afford simplicity but fail to expose the variability of utility system reliability. The effect of this can result in simple misconceptions that can easily be overcome through discussion. At its worst however it has the potential for poor public policy (in performance based rates) or corporate incentive goals.

Benchmarking and Corporate Goals

The following section discusses how these metrics are commonly embodied in industry benchmarking and corporate goal processes.

Utility benchmarking is an established tool for asset managers. Most benchmarks rely on averages and quartile assignments. Utilities commonly aspire to be "first quartile" in reliability measures. While the intention is noble, it may be unaffordable or unrealistic. Basic differences in definitions underlie the most heavily benchmarked reliability indices. In the most prevalent benchmarking format, an asset manager has little reassurance that peers have consistent definitions or data submittal practices. However "apples vs. oranges" arguments and/or cautions may erode an asset manager's credibility during high-level corporate goals discussions.

In a world dominated by financial targets, reliability metrics are imprecise and overly complicated. The perception starting point for reliability experts is close to a shaman or witch doctor. The accountant's results are immediate and definitive; spending stops and starts when the orders are given or at the end of a period. Budgets are forecasted and accounted for twelve times a year. Reliability results however lag remediation and expenditures. Reliability may even decline after remediation depending on other external forces. Reliability results are often only reported annually. The existing benchmarks and metrics do little to diffuse the cloud of mystery that surrounds reliability expertise.

Reliability benchmarks are often displayed as univariate comparisons as shown in Figure 1, below (the data is illustrative).

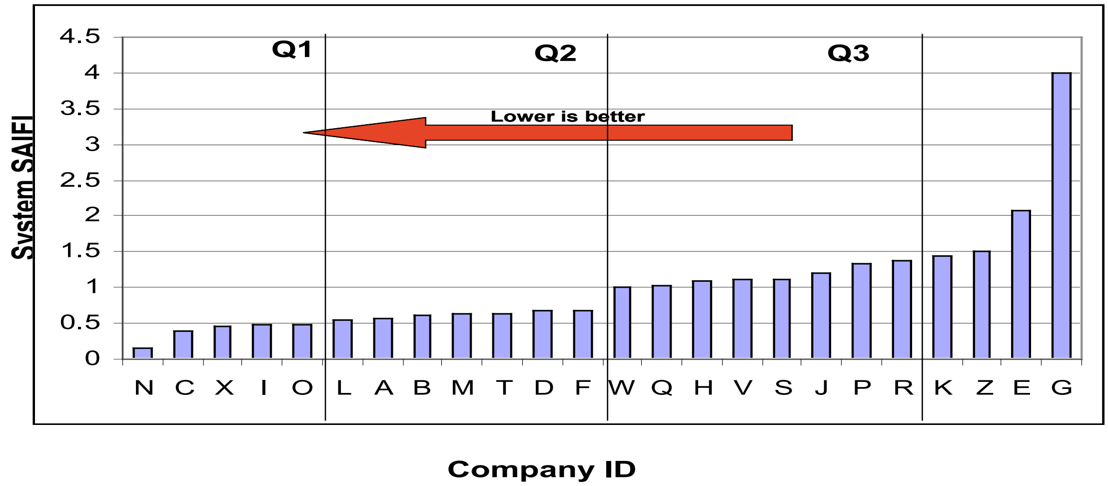

Figure 1 - Reliability Benchmarking, Univariate Format

Bivariate displays of reliability benchmarks are sometimes more insightful for goal setting and benchmarking processes. As evidence examine Figure 2.

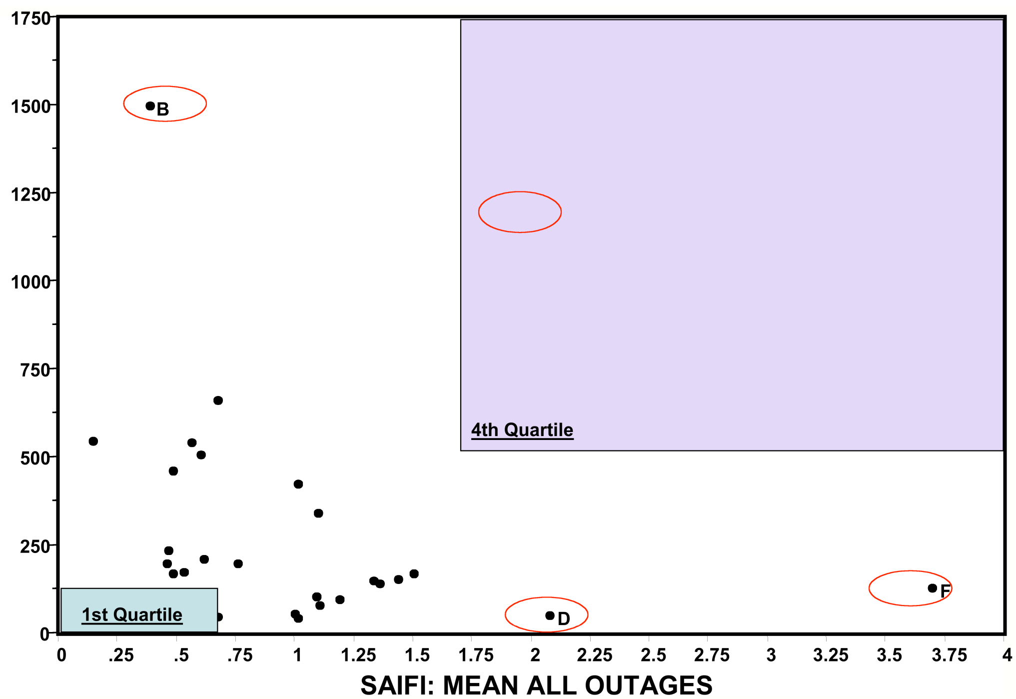

Figure 2 – Reliability Benchmarking, Bivariate Format

The first thing that stands out is how skewed the data is. Notice that the plot is not divided into four equal quarters. Notice how clustered the data is in the 2nd and 3rd quartiles. Also notice how far the outliers extend in either axis. Are the outliers in one dimension there due to a system attribute, i.e., square miles of service territory, or customer density per circuit. Conversely are duration outliers indicative of a system attribute such as radial sub-transmission or more related to practices such as resource policies during storm periods or pre-staging crews? How likely is it that an outlier utility can change the underlying driver in order to improve the metric?

The closed nature of most benchmarking results prevents further analysis. Since reliability is always about choices and tradeoffs, perhaps better goals would result if participant differences were examined in multi-dimensional displays rather than traditional univariate comparison.

Corporate goal setting is where the "rubber meets the road" for these choices and tradeoffs. The result is a mixture of key performance targets such as profitability, service reliability, customer satisfaction, and employee satisfaction. Key initiatives comprise each of these that will move key performance indicators in the proper direction to achieve the goals. Often key initiatives for one goal have overlooked interactions which negatively impact the other goal. Reliability and financial goals often interact negatively.

Reliability goals can also interact negatively with each other, i.e. customer and system reliability improves however one reliability metric actually worsens while the other improves. This is most often seen as a system frequency metric decline with a corresponding customer duration metric increase.

Consider the case of a company that focuses on eliminating human errors that occur in substations during maintenance. They eliminate outages that involve lots of customers but are of very short duration. If the program is successful it will likely reduce the frequency of interruptions, SAIFI. However the remaining average duration of outages, CAIDI, will increase. The fact that these outages have been eliminated is good for customers, but the duration metric indicates a decline in average duration which may be bad for asset managers or employee incentive plans. Distribution reliability initiatives such as distribution circuit fusing and sectionalizing can have the same effect since the effected customers is reduced (fewer lockouts) but the restoration period is generally due to the longer manual re-fusing now requiring dispatched switchmen.

Benchmarking and Corporate Goals Summary: Most reliability benchmarks and goals tend to oversimplify the complexity of utility system performance. Managers need better tools to set reliability goals and to predict outcomes and interactions to add value to corporate strategic processes.

Criticality Aversion

The next sections discuss several internal challenges related to reliability improvement for utility asset managers. The degree of difficulty of each issue varies from utility to utility.

It has been said that asset management and RCM revolve around two tenets:" Do the right things" and "Do things right". The airlines improved their maintenance program by eliminating low value tasks and by increasing the quality of the important tasks. As passengers we recognize the criticality of the consequences of engine failure, but as utility professionals we have an aversion to asset criticality concepts to avoid customer discrimination implications. Also a technical barrier arises. Experienced operators can usually recount the day that the least critical circuit on any other day became the most important circuit on a day with several contingencies.

Often asset and maintenance managers feel trapped between the unwillingness of utility personnel to assign criticality to assets and the need to prioritize maintenance resources. Treating all assets the same produces unbiased unreliability but it also ensures a uniform distribution of maintenance costs even when those costs are unjustifiable. Operational data can provide a method to break the deadlock. Asset loading, utilization, and number of operations can provide non-arbitrary and non-discriminatory rationales for maintenance prioritization of substation equipment maintenance.

Breaker maintenance based upon the accumulated fault current ($i^2 * t$) has been discussed for many years in condition monitoring circles. It is similar to the airline analogy that faults may be more indicative of breaker wear than time in service. Faults - where and how they occur - tell the maintenance manager and the operator something very important about breaker maintenance needs. The use of operational data for maintenance decisions is non discriminatory and technically defensible when properly applied.

Criticality Aversion Summary: Asset management is inherently a prioritization of resources. Successful implementation must overcome a reluctance to differentiate asset criticality. Operational data provides empirical evidence that provides the feedback necessary to discern criticality differences and needs.

Organizational Continuity and CMMS Challenges

Industry changes over the past few years have resulted in the separation of many vertically integrated utilities. In addition the industry experienced heavy merger and acquisition activity. Many companies have engaged in internal re-organization either to maintain competitiveness or to adapt to functional unbundling and/or mergers and acquisitions changes. How many organizations have swapped structures in the last two years? Whatever the reasons most utility asset and maintenance managers have switched positions and bosses several times in the last five years. The impact of this can be disruptive to maintenance managers and maintenance initiatives.

As an outcome of mergers activity many Computerized Maintenance Management Systems (CMMS) are changed in order to realize standardization and eliminate redundancies. These changes can be very disruptive to equipment maintenance initiatives. Historical retention of the previous system data can be cumbersome if not impossible. Since maintenance history is vital to the success of maintenance management, the lack of continuity can limit the effectiveness of RCM programs. Users may generalize this experience as “Data must go in but nothing comes out!”

Organizational Continuity and CMMS Challenges Summary: Utility managers must cope with the pace of unprecedented change within the industry. The pace of personnel and CMMS changes pose an added challenge of continuity in meeting corporate goals and stakeholder expectations.

Operations Data

This section discusses operational data sources, some of their limitations, and some of the benefits of leveraging this data to improve asset management decisions.

Operations data is often thought of as singular in purpose, since many organizations have separate maintenance and operations management groups. In the transmission environment FERC’s Standard Market Design seeks separation of the two functions and where Independent System Operators exist, the separation is complete. The operations data should be viewed as a maintenance tool despite the separation of function. It is generally an undervalued and underutilized resource however.

Operations data sources have some characteristics that limit their use. The rawer the data the more likely it is that increasingly more powerful computer tools will be needed to use it; thus the less likely it is that is utilized. Summary operations data such as daily reports or interruption reports or databases provide highly synthesized data with distinct advantages for overall analysis. Often these sources generate the high level metrics such as SAIFI or FOHMY, etc.

Lesser synthesized operations data such as SCADA archives, digital fault recorder data, and operations logging databases provide distinct advantages for equipment maintenance analysis. These sources indicate the duty and utilization of the equipment. As in the airline engine analogy these factors may be more predictive, like the number of engine cycles, of the equipment’s need for maintenance than the hours in service.

SCADA data is probably the rawest form of operational data. No other information is attached such as why the equipment operated. It is clean state information but lacks intelligence. These data sources are minimally synthesized sources. SCADA data is precise in its assignment of equipment, time, and operation but average maintenance personnel can't get enough data on a desktop to conduct extensive analysis.

Operations logging databases represent an operator's synthesis of a number of SCADA records. Several SCADA records, perhaps 10:1, will exist for a corresponding operations log database entry. Automatic lockouts for example are summarized as a single record in an operations log where SCADA logs include all intermediate sequence states and analog parameters. The operations log adds intelligence but loses detail. These data sources are moderately synthesized. Often these sources of data are for "operations only" so equipment identity data is missing or inconsistently entered (no validation). There is generally no incentive for operators to put information in their database in a maintenance manager's format.

Summary operations reports and subset databases such as the interruption databases are excellent sources for failure root cause analysis since they generally contain enough information to extract equipment failures, maintenance personnel failures, process failures, and external events beyond the control of the utility. (Interruptions may represent approximately $\leq$ 20% of the substation operating activity for distribution systems.) These data sources are highly synthesized. A problem with these sources is that they only deal with faults or failures of some kind and do not include load operations, planned outages, maintenance intervals, or successful equipment performance information. Maintenance analysis would be biased if decisions were made solely on the information found in these data sources.

While each operational data source has unique strengths and weaknesses in its ability to enhance maintenance, a combination of these sources it the most effective use of these resources for analysis and performance monitoring. Statisticians would classify this as reliability analysis of repairable systems and to be complete requires the addition of maintenance data such as in-service dates, maintenance dates, maintenance disposition, maintenance costs, and end of life data. The integration of operational and maintenance data sources provides the necessary data to utilize these tools for asset management and maintenance decisions.

<u>Operations Data Summary</u>: The use of operations data is often confined to the operations personnel. The advantage for use by maintenance and asset managers is the variability of explicit impacts from equipment unavailability and the in equipment service duty data. This advantage can be used to achieve the asset management objectives to "Do the right things" and to "Do things right".

CASE STUDIES

In order to illustrate the previously identified issues and concepts, two examples will examine operational data and its use. Circuit breaker maintenance implications will be examined in each.

CASE 1: Substation Bus Faults vs. Breaker Failures

Situation: A substation manager is concerned with the number of system substation bus faults (primary short circuit failures). The frequency of these events is his concern, despite the low impact on the corporate SAIFI goal; they do affect large blocks of customers when they occur. He suspects that it may be related to maintenance practices on circuit breakers.

Substation bus fault events can have significant customer impact. Distribution bus faults are generally higher in frequency than transmission bus faults due to the reduced physical clearance for external interference, i.e. wildlife contact, and for resulting arc zones. Bus interruptions are sometimes the result of bus faults and other times the result of dependent failures of breakers on the bus to operate (trip or close) for faults on protected zones external to the bus boundary. Regardless the resultant bus interruption is the often the desired outcome for either an independent event bus fault or an external event coupled with a dependent breaker failure. Despite the technical differences, all bus interruption events may be labeled "bus faults".

The substation manager must distinguish between the two in order to properly assess root cause and to prevent recurrence. Electric delivery systems are complex and blurring distinctions may provide misdirected remediation. Figure 3 illustrates the complexity of systems and the nature of external influences to a substation bus and breaker.

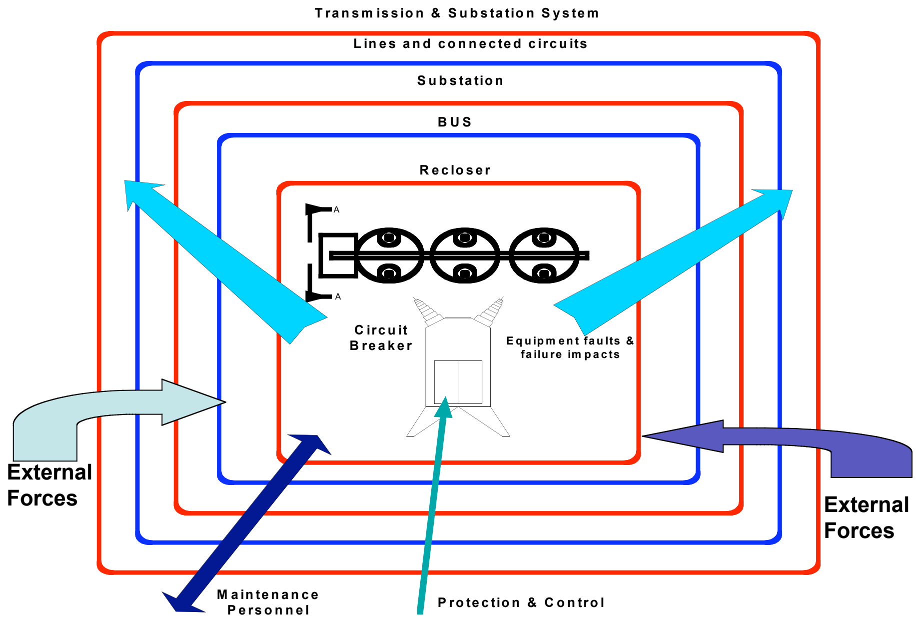

Figure 3 – Establishing Boundaries for Complex Systems Analysis

Monitoring bus faults may provide an organization with a performance indicator of substation asset's impact upon transmission and distribution reliability. In the automotive manufacturing analogy this is a "lemon" or reject car measure, since it focuses on the finished or delivered product; it is like the car that is completely assembled and tested at the end of production line, or perhaps closer to an auto manufacturer's recall statistic. In addition, the indicator is misleading if the maintenance manager is responsible for substation equipment maintenance only (system protection maintenance not under his responsibility). A more informative measure is the trend of breakers failing to operate, whether the failure results in a bus interruption or not. This is akin to auto manufacturing quality checks along the assembly line instead of a summary indication after the production is complete.

Operational data can provide the substation manager this "upstream" feedback concerning bus faults and substation maintenance's programmatic effectiveness. Where maintenance records at best indicate the summary number of operations from counters (if recorded by maintenance personnel), operational data provides the temporal domain to these operations, the type of operation, i.e. fault demand open, load demand close, load demand open, and by inference the equipment's criticality to the system by virtue of the system and customer impact of its failure to function.

A breaker can fail in several modes; it can fail dependently, i.e., preceded by external independent events, or it can fail independently fail, i.e., fault or fail to operate. The substation manager needs to know the breaker's susceptibility to external events as well as independent failure to properly assess maintenance effectiveness (as well as design modification requirements if warranted). Ideally this information is contained in maintenance records, but often only failure repair information or routine adjustment data is recorded.

The operational data provides the necessary information to assess the dependency of the circuit breaker failure. The data indicates several failure modes in this case. A fault tree diagram identifies several basic scenarios for failure. Each scenario suggests functional failures that have different maintenance implications. This limited selection illustrates the differences:

(1) A circuit breaker independently faults.

(2) Wildlife contact occurs at a breaker bushing, faulting the circuit breaker.

(3) A distribution circuit fault occurs; the circuit breaker faults upon demand open.

(4) A distribution circuit fault occurs; the circuit breaker fails to open upon demand.

Each scenario suggests something different. Some scenarios imply remediation which is beyond circuit breaker maintenance's realm such as remediation for substations in general, i.e. wildlife intrusion or suggest equipment design basis "hardening".

In some modes of failure the failure is related to maintenance, either what is done or what is not done. In scenario (1) the substation manager may ask:

(a) Whether maintenance was current or past due at the time of failure?
(b) Was the oil DGA performed recently?
(c) How recently were the contacts checked for cleanliness, pitting, contact penetration etc.?
(d) Is there a task missing that should be performed? i.e., hi-pot, thermo-vision, PDA, etc

While in scenario (2) the substation manager may ask:
(e) Did the bushings contain wildlife guards?
(f) Was the substation prone to wildlife contacts?
(g) Are additional substation wildlife protection measures required at this sub?

While in scenario (3) the substation manager may ask:
(h)Was the breaker travel tested recently?
(i) Was the oil DGA performed recently?
(j) Were internal live parts recently inspected?

While in scenario (4) the substation manager may ask:
(k) Was the mechanism lubricated recently?
(l) How long since the last known successful operation?

<u>Case 1 Summary</u>: The substation manager needs operational data that provides feedback about the effectiveness of maintenance tasks to ensure functional ability of circuit breakers. The analysis of the operational data will provide the necessary direction to improve the maintenance program. Without this loop, decisions are based upon gut feel, which may take the RCM program down some dead-end alleys or into overreaction. The approach should be to let the data steer the program with a rigorous root cause program to prevent recurrence.

CASE 2: Transmission Circuits, Analysis of Variance (ANOVA)

Situation: A transmission manager is assembling transmission budget expenditures and has more initiatives than dollars; she suspects that an annual expenditure for a specific insulator replacement project is no longer cost effective. She suspects an alternative allocation may prove more beneficial.

The project has been active for three years and was originated to address the high frequency of specific transmission line insulator failures resulting in forced outages. The manager assembles the forced outage history of transmission lines in the system for the past five years. The system lines are initially grouped into three major groups: the entire population, the completed insulator replacement lines, and the proposed lines for replacement. The forced outages for each group are examined for variance between groups. The manager confirms her suspicion that the proposed group has actually outperformed the group completed; see the third and fourth data sets in Figure 4.

The transmission manager's curiosity is piqued and decides to assess other functional groupings. She chooses some functional groupings such as tie lines, generation serving lines, and bulk customer load serving lines. The results indicate that the worst performer in the proposed or "Pending" (Figure 4) group actually performs significantly better than many lines in the Generation and Load serving category. The prioritization of this project now must be evaluated in light of this discovery since the criticality of some of the Generation and Load serving lines may demand higher reliability than the Pending lines. In addition while the Generation lines as a category have a mean that is below the industry average (assume = 60%) the Load serving lines have almost as many poor performers and even some that perform worse than the worst Generation lines.

If the industry average was significantly lower (assume =40%, Figure 4) the merit of the any funding decision might be lowered, however the differences between groups would not change. The variability and distribution of the operational data has more value for internal decision making than the average value of the system or category. These discoveries can help not only the transmission manager but also the substation manager. The analysis of operational data results are shown in Figure 4.

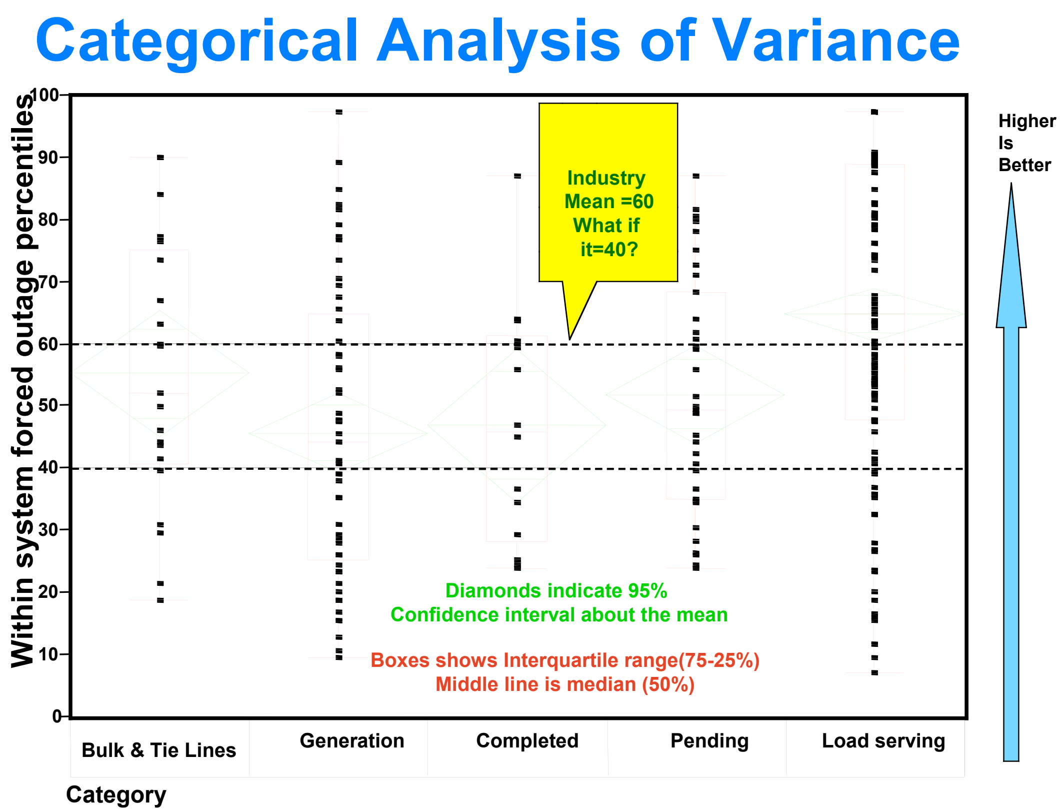

Figure 4 – Categorical Analysis of Variance (ANOVA)

The transmission manager may ask the following questions upon review:
(m) Should the insulator replacement project re-prioritized lower?
(n) Was the project as effective as desired?
(o) Are other assets in more need of allocation resources?
(p) Are other lesser performing lines serving a more critical function?
(q) Are specific lines skewing any of the group results?
(r) Why are some critical asset groups performing below the system average?

In addition the manager discusses the results with the substation manager who considers:
(s) What implications exist for transmission circuit breaker maintenance?
(t) Are uniform practices appropriate for variable duty and functional breaker duty?

(u) Are wear patterns different for the high frequency fault line breakers?

Case 2 Summary: The transmission manager needs operational data that provides feedback about the effectiveness of transmission projects intended to ensure the functional ability of transmission lines. The analysis of the operational data will provide the necessary direction to improve the transmission expenditures. In addition the sharing of this information may yield system reliability improvements in other areas beyond the transmission manager's control.

RECOMMENDATIONS

1. Understand your system and what is unique relative to peer comparisons.
2. Choose goals and metrics that are meaningful to your system and sensitive to time & results.
3. Leverage data sources and integrate data to assess root causes.
4. Establish feedback from maintenance and remediation actions.
5. Broadcast performance monitoring to inform and involve the organization.

CONCLUSIONS

The industry needs common definitions and improved metrics and benchmarks. The use of high level metrics has its place but asset and maintenance managers need more direct and timely feedback in order to improve system reliability while reducing cost. An over dependence upon summary averages can limit the ability of organizations to make good reliability and asset management decisions.

Rigorous processes are needed to balance reliability, cost, and customer satisfaction. RCM programs and other asset based strategies require dynamic and targeted feedback loops in order to be effective. Systems and processes must support the decision making ability of managers charged with optimizing system reliability and cost. Operational data and its analysis hold the key to the next quantum leap for utility asset management organizations.

BIOGRAPHY

Edward Kram, P.E. has a Bachelors Degree in Electrical Engineering from the University of Illinois at Champaign-Urbana. He worked in various engineering and management positions during his career at ComEd in Chicago, Illinois. Those assignments included substation protection field engineering, transmission maintenance analysis, and reliability planning.

In 2001 he left to start his own consulting company, Blue Arc Energy Solutions, Inc., specializing in reliability and maintenance analysis. During the past eighteen months he has co-authored the *Transmission Line Availability Data Guidelines and Definitions* document which involved the consensus of nearly forty transmission owner, independent system operator, and reliability council representatives in an effort to provide a comprehensive guideline for the assessment of availability of electric transmission circuits and systems.

He is currently active in the development of transmission and substation equipment metrics and is working with utilities on maintenance and asset management improvement initiatives. Edward is a member of the IEEE and of NSPE.

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[1] *Power system Reliability Analysis Application Guide*, CIGRE WG 03 of SC38 (Power system analysis and techniques)-1987, Appendix Section III,3-01-10, page 128

[2] *Classifying Forced Outages*, California Independent System Operator Maintenance Procedure No. 5, Version 1, Effective Date 9/7/00; CISO web page (3/5/03): http://www.caiso.com/docs/09003a6080/08/9c/09003a6080089cab.pdf

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[4] *Reliability Benchmark Analysis for Substation Systems and Equipment*, source: EPRI Website (02/28/03); http://www.epri.com/projstatlvl1.asp?program=249815&projnum=02S047585&value=02T038.0