Integration of Asset and Outage Management Tasks for Distribution Systems

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***Abstract*— Integration of asset management and outage management tasks for distribution system is proposed and discussed. The necessity of integration is presented, followed by a description of the concept of integration. The optimization of asset and outage management tasks based on the integrated processing and evaluation of the influence of optimization on the cost of system outage is elaborated. Potential benefit of integration in distribution system is analyzed in terms of system reliability and return of investment for utilities.**

***Index Terms*— outage management, asset management, distribution system, reliability, risk-based assessment**

I. Introduction

Faults in distribution system may cause interruption of power supply to customers. Since distribution systems in general encounter high frequency of faults caused by weather, component wear and other reasons, the need to reduce outage time caused by faults is required for several reasons.: a) better service to customers. Customers' requirement on the quality of service is constantly growing. As an example, sensitive loads in modern industry such as chip manufacture and ore smelter are very sensitive to interruptions in power supply. The consequence of failure is more severe nowadays than a decade before; b) return on investment for utility shareholders. The most direct impact of faults on the profit is the loss in customer billing, as well as maintenance expense.

Reliability indices defined in IEEE Standard 1366 are used to evaluate the impact of faults on power distribution performance [1]. The System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) are two most widely used indices. The lower the value of SAIDI and SAIFI, the better the performance in terms of reliability. According to a survey done by the IEEE Working group on distribution reliability , in the year 2007, the average SAIDI derived from SAIDIs provided by 61 utilities is 206.72 min/(customer*year), and the average SAIFI is 1.71 /(customer*year) [2].

Currently the improvement in distribution performance is hampered by four major defects: a) lack of data. Beside voltage and current measurement at substations, few monitoring devices for measurements are installed in a distribution system; b) aging of equipment. Most of the primary equipment installed in the USA distribution system is pretty old, in some instances over 30-40 years. c) ineffective processing of faults and maintenance scheduling caused by the lack of data. The fault location is currently based on trouble calls and manual switching [3] while maintenance is performed either with a run-to-failure strategy or with a fixed ahead-of-the-time planned schedule [4], which does not require operational data; d) independent planning and operation of asset and outage management. Those two functions are planned independently even though the equipment that may record and collect relevant data from the filed maybe common to both applications. .

Technologies have been proposed to reduce the frequency and duration of faults. For outage management, effort has been made to better process the trouble calls [5], supplement information from trouble calls with AMR system and other sources [6], and to investigate various methods to locate faults [7]-[9]. For asset management, condition-based maintenance has been proposed to prevent component failure and reduce cost by monitoring real-time electrical quantities and assessing condition of equipment [10, 11].

The new technologies in both asset management and outage management use non-operational data, which is recorded in the field intelligent electronic devices (IEDs), and reveals the current condition of the system. This paper considers the overlapping of IED database use by outage and condition-based asset management and proposes the concept of integration of asset management and outage management tasks. The expected benefits from integration include: savings in IED installation expenditures, efficient collection and use of non-operational data, reduced failure cost and better system reliability, and finally more return on investment.

The concept of integration is presented in section II, followed by benefits of integration in section III, which deals with optimization of asset and outage management tasks under the integrated database. Impact of integration on the benefits in asset and outage management is discussed in section IV and V respectively. Section VI contains conclusion, and is followed by acknowledgements and references.

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II. CONCEPT OF INTEGRATION

A traditional distribution utility business process approach is illustrated in Figure 1. In this approach, outage analysis is primarily based on inputs from outage detection, telling which customers are connected, and incident verification reporting (IVR), telling which customers have reported loss of power. Asset management is primarily based on off-line data without extensive use of operational and/or condition based non-operational data. With the development of new technology in fault location and maintenance prediction, system failures may be reduced in terms of frequency and duration.

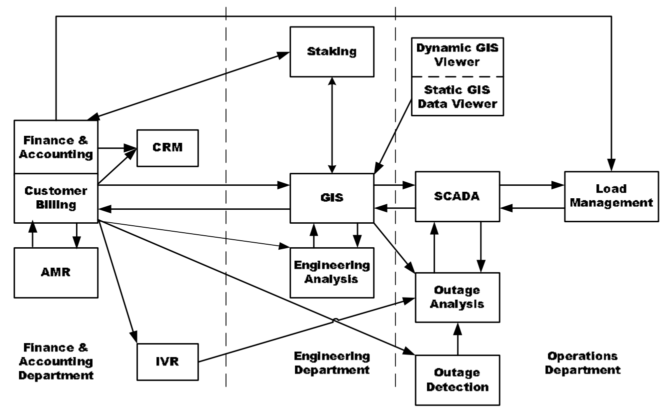

Fig.1: Traditional distribution utility business process

One of the constraints to implement those technologies is the availability of data. Condition-based maintenance, for instance, requires real-time field-recorded data to do the condition assessment, e.g. voltage, load current, etc. On the other hand, to implement a model-based fault location algorithm, an accurate system model is required, including system topology, on/off status of switching devices, parameters of components, etc. [9]

It can be seen from the discussion above that the flow of data required to improve the business process is no longer as shown in Fig.1. Outage management and asset management now share the need for certain data and models. It is more efficient to generate an integrated database. Integrating the outage and asset management tasks through the use of data and models of common interest should enhance the efficiency and effectiveness of the overall business process because it prevents either duplication or lack of investment in installing monitoring devices, and collecting and storing data. This strategy of using extensive field data provides two benefits:

a) due to improved maintenance, primary equipment will fail less frequently, reducing the number of forced outages;

b) due to more precise location of a faults and better prediction of the equipment “health”, outage restoration practices will be far more efficient and effective.

The benefit can be evaluated from two aspects:

a) System reliability. This is reflected by the impact on reliability indices.
b) Return on investment of utilities. This is measured by optimization in capital and operating expense.

The improved business process should explore the correlation of outage management with risk-based management of equipment assets leading to optimized equipment maintenance practices. This will reduce the risk of outages, as measured by reliability indices, energy not served, cost of failure, or other measures. The optimization may be implemented using an asset management concept that selects and schedules maintenance tasks to minimize outage risk.

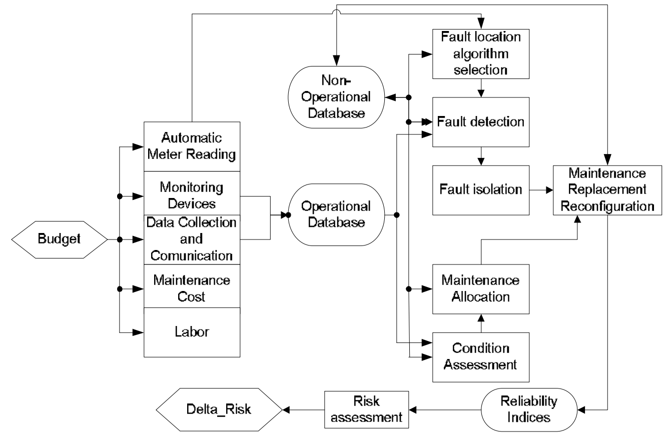

Fig.2: Integrated asset management and outage management tasks

The integrated asset management and outage management tasks are shown in Fig.2. Fault location and condition assessment retrieve field-recorded operational and non-operational data, as well as system models and configuration data from a common database. Based on this data, the reduction in failure cost is evaluated in an integrated risk-based assessment program. As very few data can be acquired from a distribution system, and the data is with poor quality, algorithms that is flexible in the number of inputs and is robust to inaccurate data is developed, which is introduced in the following sections.

III. OPTIMIZATION OF ASSET MANAGEMENT TASKS

One of major challenge faced by the utilities is the allocation of their resources for the expanding system while maintaining the system reliability. There are different methods followed in the industry to schedule the maintenance and replacement of the components. Most of the methods do not consider the maintenance schedule by optimizing the cost of maintenance and reliability indices.

Some state regulatory commissions require utilities to schedule maintenance cycles (time based maintenance) to insure system reliability. Some regulators have been instead setting minimum reliability standards, allowing the utilities to move from time based maintenance to condition based maintenance, and reliability centered maintenance practices. These are more cost-effective and also more focused at insuring reliability.

This work focuses on optimizing the cost of component maintenance schedule for utilities while ensuring the minimum reliability requirements. In the event a utility is not restricted with any reliability regulations, the utility could use this technique as a tool to optimize their maintenance task to reduce the energy not served (ENS) so that the revenue is maximized. The proposed technique could be illustrated using the following steps.

1. Identifying the Criteria for Equipment Condition Assessment and Allocating Reliability Distributions

In order to wisely allocate the predictive maintenance budget, it is important to identify the condition of the component. Most of the utilities perform routine component assessment and decide the condition of the component. This type of assessment cannot be generalized and every time it needs inspection before predicting the health level of the component.

Alternative to this would be to use the reliability models. When using reliability models the most common practice is to use the average failure rates. Even though constant failure rate models are faster, easily tractable and needs very few data for calculations, they will not accurately predict the condition [12]. Especially with age, components will have increasing failure rate and there is a high probability that the constant model will overstate the condition of the component. Use of constant failure rate models is very much common in power industry [13], and importance of developing techniques to model the failure of the components as a function of time in an efficient way must considered.

Updating the reliability models based on the periodic component inspection information will generalize the component condition assessment and this can be seen as a very powerful tool in predicting the health level of components [14].

Most of the components used in the power industry are made out of several parts. In terms of reliability each part in a component could be considered as a separate subsystem. Further the utility will have information about other factors that affect the life of a component, eg: age, loading, frequency of maintenance, fault history, environmental condition etc. We would like to adopt the approach given in [14], authors consider each condition that affect a component as a separate criterion and try to find the condition of a component based on reliability analysis and inspection data of each criterion and their importance to the components' healthy functioning.

It is very vital to identify appropriate criterions for each component. These criterions can't be generalized for similar components. Criterions may vary with topological location of the component, manufacturers, experience with particular type of component, etc. As a part of this project, [15] gives a detailed methodology to identify the criterions of power transformers and circuit breakers. These criterions are practical as they are based on their manufacturer equipment database, historical failure causes and maintenance activities. Similar approach could be taken to find the criterions of other components.

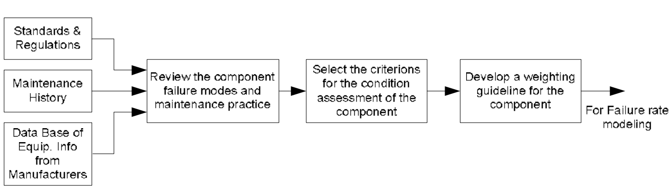

Fig.3: Criterion Selection Flowchart [15]

It should be noted that not all criterions have same importance when it comes to healthy functioning of a component. We use a similar approach taken by [14] to weight the importance of each criterion. Weighting of each criterion is based on the criterions' effect on the failure of the component and the number of maintenance / replacement needed for a criterion during the life of the component. Fig.3 describes the selection of criterions.

For each criterion of a component, we would like to assign a failure distribution. Failure rate distribution for a criterion will be assigned based on the standards and regulations, manufacturer data on each criterion, historical data and expected lifetime of the component [15].

Using a particular failure distribution for all the components and their criterions may result in obtaining inaccurate failure rates. The proposed technique allows us to use different failure rates for components and its criterions. Some of the common distributions that can be used are given in table 1.

TABLE I:
TYPICAL DISTRIBUTIONS

Type of Failure rate	Distribution
Constant with time	Exponential, Weibull
Increasing with time	Normal, Weibull
Decreasing with time	Gamma, Weibull
Increase and then decrease with time	Lognormal

When the age of a component is considered, older the component, the probability to fill increases, thus it will be a increasing failure rate. Probability of failure due to the topological location or geographical location will not change, thus we can use a constant failure rate model for these criterions. But the more the experience we have with a particular type of component, we will be able to predict the performance of the component much better, thus the failure rate of this criterion would be decreasing with time.

2. Compute failure rate model for each component

At the distribution level, condition data for many components are not available. If a utility is to move from time based to reliability based maintenance a database of condition data for all equipment must be developed and maintained. From this data, failure rates can be calculated based on the following discussion.

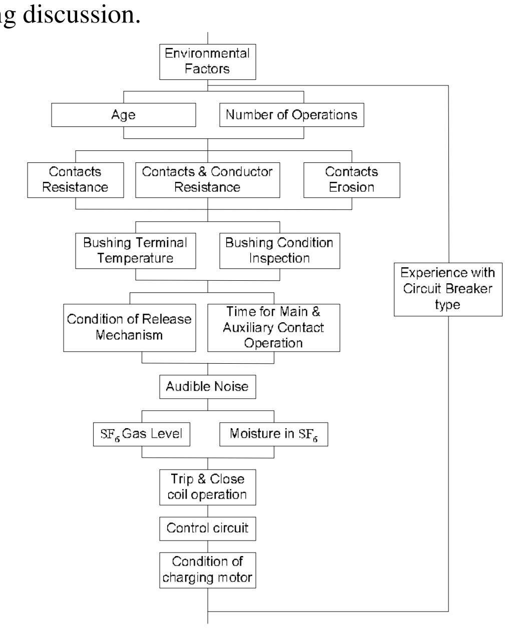

Fig. 4: Topology of SF6 Circuit Breaker

To calculate the failure rate of a component at any given time *t* many approaches are taken in the literature. In this analysis we would like to consider each criterion of the component as a subsystem and use a reliability topology (eg. series, parallel, series-parallel, parallel series, etc.) based on the relationship of each criterion with other criterions of the component based on effect of the component failure. Fig.4 illustrates the topology for a SF6 circuit breaker as an example

Each criterion will be assigned a weighted failure rate based on the discussion in step 1. Weighted failure rates for each criterion and topology of the criterions are used to determine the failure rate model of the component.

Once failure rate model of for component is determined, the next step is to find the condition of each component. Real time equipment monitoring data, failure rate model, component ratings supplied by the manufactures and the standards and regulations are used to determine the condition of each component. The condition of each component is considered in reliability point of view. Fig.5 illustrates the condition assessment and the output from the condition assessment can be a factor of, propositional to failure rate, remaining or qualitative assessment of health of the component.

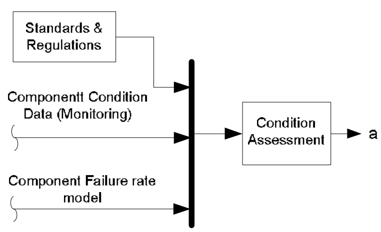

Fig.5: Condition Assessment Flowchart

3. Allocate the required level of maintenance for each component.

Distribution system performance can be degraded both by controllable events (e.g., lack of maintenance of components and irregular tree trimming) and uncontrollable events (e.g., lightning and accidents). When the performance of a utility is considered, it is not logical to measure the performance affected by the uncontrollable events. Thus in this analysis the reliability indices that are used would include only the events that can be controlled by the utilities. The subscript 'C' will be used to indicate that the reliability indices are calculated based only on the controllable events.

Once the condition of each component is computed, based on the performance / reliability requirements (required $SAIDI_C$, required $SAIFI_C$, required $CIME_C$, and maximum allowed ENS_C etc.) the utility should be able to schedule its maintenance. As a part of this work we have proposed an algorithm to achieve the required improvement of each component in such a way, that the total cost of improving the condition of components in the system is minimized [16].

For each component, an important index would be allocated. Important index would be a function of load type, location of the component, availability of redundant components in the system, time taken to maintain or replace the component upon failure, revenue loss upon failure of the component.

Based on the required maintenance and the important index of each component, components will be given a rank. Rank 1 would be given to the component which has high risk. Ranking of the components will give qualitative information for the future planning. Fig.6 illustrates the procedures involved in ranking the components.

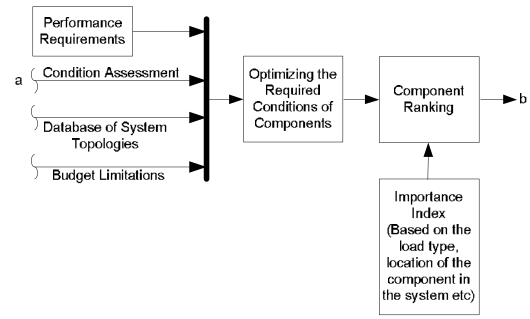

Fig 6: Optimal Component Ranking Flowchart

4. Ensure the required maintenance is cost effective than replacing the component.

Components ranked high are defective and needs immediate attention compared to the ones ranked low. Some of the higher rank components can be critically faulty and it may be economically competitive to replace the component than maintaining it.

Therefore at this stage budgetary calculation must be done to see whether it is cost effective to maintain the component. By maintaining a component we will improve but if the component is really bad, the replacement will improve the reliability by a huge margin. This will result in the utility achieving the required performance level, by not improving the components which have least rating. This budgetary calculation should include comparison between the remaining life of the component by maintenance and the maintenance cost versus the investment. Fig.7 shows this comparison.

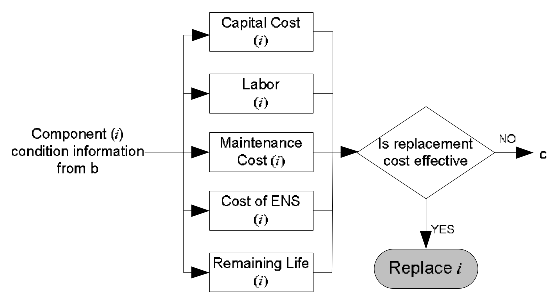

Fig.7: Maintenance Vs. Replacement

If replacing the component is cost effective, then utility should take necessary action to replace the component and check the next component in the queue (ranked next) cost effectiveness. If the analysis shows it is cost effective to maintain the component, go to the next step.

5. Guarantee that the maintenance/replacement of all the components will be under the allocated budget

This step is similar to the previous step. Here we want to ensure, that the required maintenance will not exceed the budget limitations. Out of the components which were not replaced, once again the high ranked components will get preference as they are the major contributors to the poor performance. Fig.8 explains the procedure.

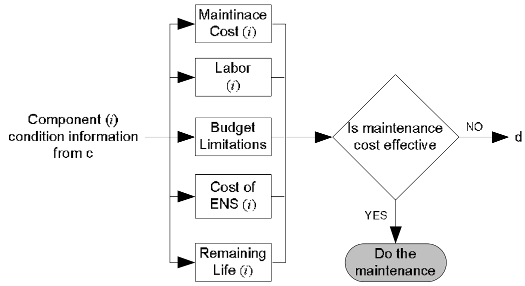

Fig.8: Is maintenance cost effective?

In this work we are considering an optimal scheduling scheme. All the parts in the component would be considered in similar way to that of deciding the criterions. In this analysis we minimize the cost of improving the parts while achieving the desired failure rate.

If the maintenance cost is within the allocated budget, the component will be scheduled for maintenance. The next component in the queue will be considered. The process will start from step 3. If the maintenance exceeds the allocated budget go to step 5.

6. Incase the component can't be maintained derate the component.

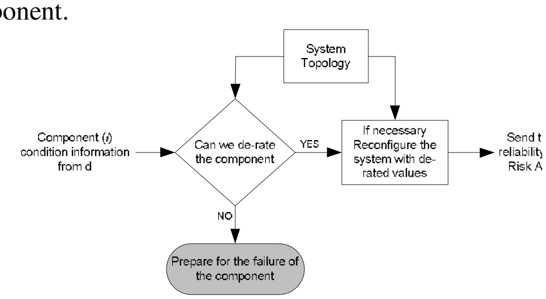

Fig.9: Component Derating and Reconfiguration

In the event the component maintenance exceeds the allocated budget, the proposed method allocates a new rating for the component (derate). The derating will be based on the system topology. We must ensure that the derating will not cause overloading the component, if the derating causes overloading to the component, then the system must be reconfigured and part of the load should be allocated to supporting feeders/ laterals in a way none of the components are overloaded. If we can't achieve a reconfigured system, without overloading any of the components, then the utility could leave the part of load that can't be supplied with reconfiguring the system, with the component and prepare for the failure. Process is explained in Fig.9.

IV. OPTIMIZATION OF OUTAGE MANAGEMENT TASKS

Accurate fault location in distribution systems still remains one of the main challenges in the utility industry. While many different fault location algorithms are proposed so far [5-10], finding exact fault location is quite often a major part of the overall repairing and restoring time. The question that still faces the developers of the algorithms is how to improve the accuracy of the algorithms through improvements in data recording and collection.

The work reported in this paper illustrates the issues associated with implementing accurate fault location in distribution systems. It has been recognized that fault location depends on data available for the implementation; hence the notion of performing a sensitivity study of the fault location algorithm due to the change in available data is conveyed. Implementation of an algorithm that takes advantage of spare measurements of voltage sags caused by the faults is introduced to illustrate how improvements in fault location may be achieved if an extensive field recorded data is used [17]. This fault location approach has been discussed in more details in other related references published earlier [18].

1. Fault location algorithm selection

Now that the asset and outage management share an integrated database, the accessible data for fault location is more elaborate than what was available when just a typical data base for outage management was considered. The expansion of data brings not only a larger quantity but also a variety, i.e. more types of data. This makes possible to implement several fault location algorithm that applicable for a given fault case. To improve the accuracy of fault location, the sensitivity of fault location algorithm to type, quantity and quality of data is studied, and the fault location algorithm selection is done based on the result.

The proposed study aims at revealing the sensitivity of fault location algorithms to several influencing factors:

a) Pre-fault load condition;
b) Distance of fault point from measurements;
c) Fault impedance;
d) Branch going out from the node between the fault point and measurement;
e) Imprecise field-recorded data.

The following steps in the sensitivity study are defined. First, fault scenarios associated with the influencing factors above are generated and simulated in ATP. Then, fault location algorithms are applied and the accuracy recorded. The minimum set of data and data accuracy requirement is then determined for each algorithm. After this study, one will be able to select a fault location algorithm from the list of algorithms and apply to a particular fault based on the faulted area and availability of data. The result from the selected algorithm will be the most accurate one, so field crew will be able to pinpoint the fault within the shortest time possible. Thus the overall time to carry out fault processing will be the shortest possible and the SAIDI will be reduced significantly.

2. New fault location algorithm development

Fault location algorithms for distribution systems should have the ability to cope with insufficient data, because of the general lack of widespread use of data recording devices in distribution systems. An algorithm proposed in [16] uses voltage sags recorded from the sparsely installed power quality meters (PQM) to detect the faulted node by comparing the measured and calculated values assuming fault occurred at different nodes. Differences in pre-fault and fault voltage magnitudes recorded by sparse voltage measurements in the system are utilized. The merits of applying this algorithm as a distribution system fault location method are as follows:

a) It deals with the reality of insufficient measurements (just from PQM) in distribution system, although the accuracy of the algorithm is affected by the number and placement of the measurements.

b) It minimizes the impact of fault impedance on the accuracy by considering fault as a special load connected to the faulted node.

c) It takes into account the characteristics of distribution system: non-transposed feeders, single-phased line sections and nodes, and radial topology.

d) It provides a list of likely fault locations so that field crew can start with the most likely fault location first and move down the list until the fault is found.

The flow chart of the algorithm is shown in Fig.10.

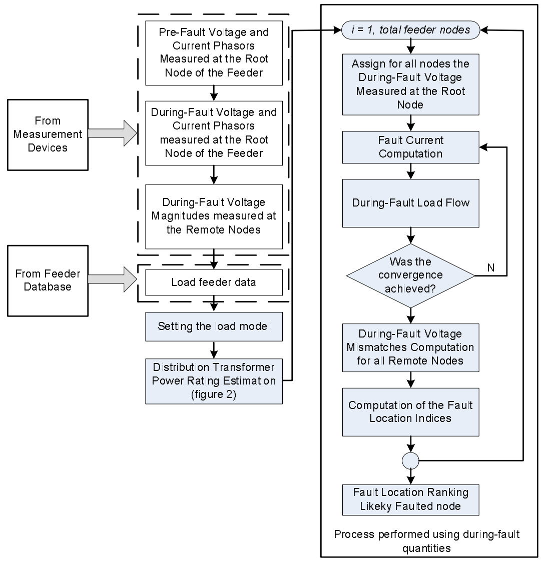

Fig.10 Flow chart of voltage-sag based algorithm [16]

Refinement of the voltage-sag based algorithm is studied. The erroneous system model and field-recorded data are taken into consideration and an evaluation of accuracy is done before running the main algorithm. Two indices, J and RI are introduced to quantify the influence of number of measurements and data quality respectively. If both J and RI are larger than a pre-set threshold, the algorithm is considered as not applicable to the case.

In the decision-making stage, the differences in accuracy of measurements are introduced by means of weighted least square function. This prevents error caused by single erroneous data. Fig.11 shows the flow chart of the refined algorithm.

3. Fault isolation strategy

To further reduce SAIDI, fault isolation strategy aims at restoring power to the largest number of customers by system reconfiguration during the period of maintaining and replacing of failed components. An optimization problem minimizing the loss of load, number of switches involved and phase imbalance is formed as follows:

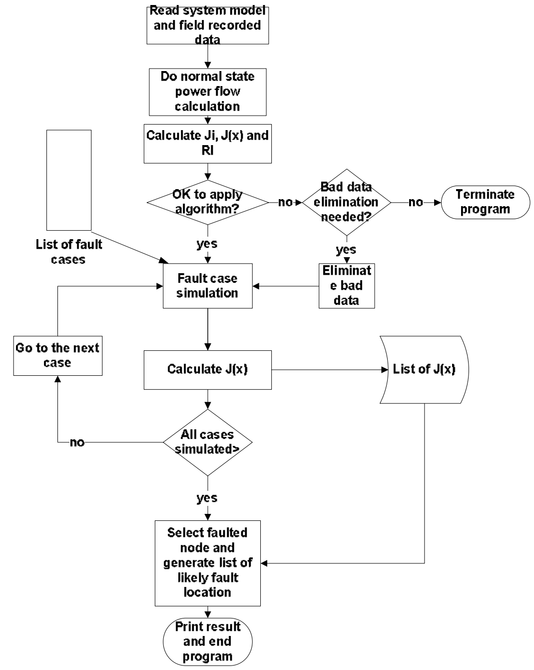

Fig.11 Flow chart of refined algorithm

Objective:

$$\min\{ \sum P_{Li} - \sum P_{Li}' = \Delta P_L \}$$

$$\min\{ N_{SW} \}$$

$$\min\{ \sqrt{(P_A'-P_B')^2 + (P_B'-P_C')^2 + (P_C'-P_A')^2} = \Delta P_\phi \} \quad (1)$$

$$\text{s.t.} \quad \begin{aligned} & V_i^{\min} \le V_i' \le V_i^{\max} \\ & P_{Tj}' \le P_{Tj}^{\max} \\ & \lambda_{SWm} \le \lambda_{SWm}^{\max} \end{aligned} \quad (2)$$

where:

variables with ’ are the values after reconfiguration;

P_{Li} is the load at node i;

ΔP_L is the total loss of load after reconfiguration;

P_A, P_B, P_C are three phase power at root nodes of the feeders;

ΔP_ϕ is the 3-phase load unbalance at root nodes of the feeders;

N_{SW} is the total number of switches involved in the reconfiguration;

V_i' is the voltage magnitude at node i after reconfiguration, with $V_i^{\min}$ and $V_i^{\max}$ as lower and upper limits of node voltage;

P_{Tj} is the output power transformer j, whose primary side is connected to the transmission system and the upper limit is $P_{Tj}^{\max}$;

λ_{SWm} is the failure rate of switch m, with $\lambda_{SWm}^{\max}$ as the maximum tolerable value.

V. OPTIMIZED OUTAGE COST THROUGH RISK-BASED ASSESSMENT

1. Optimized outage cost through risk-based assessment

Risk-based analysis is used to estimate outage cost in this paper. The risk is formed using selective reliability indices reflecting interests of both customers and utilities.

Reduction in risk is comprised of two parts: reduction from maintenance, $\Delta Risk_{AM}$ and reduction from refining fault location and hence other outage management tasks, $\Delta Risk_{OM}$.

The consequence of equipment failure can be expressed as the weighted sum of SAIFI, SAIDI, ENS (energy not served) and DevRisk (cost of maintenance) [19].

a) Effect on customer satisfaction:

$$SAIFI(k) = \lambda(k)\frac{n_k}{N} \tag{3}$$

$$SAIDI(k) = \lambda(k)\frac{\sum_{j=1}^{n_k} d_j}{N} \tag{4}$$

b) Revenue loss of utility:

$$ENS(k) = \lambda(k) P_j d_j \tag{5}$$

c) Cost of equipment failure:

$$DecRisk(k) = Cost(k)\left\{\lambda(k) + (1+r)^{-MTTF}\right\} \tag{6}$$

where:

$\lambda(k)$ is the failure rate of component k;

n_k is the number of interrupted customers for each sustained interruption;

N is the total number of customers served for the area;

P_j is the load connected at load point "j";

d_j is the duration of interruption experienced by the jth customer;

Cost(k) is the cost of repairing component k;

r is the rate of return acquired from deferring replacement of a component;

MTTF is the mean-time-to-failure of component k.

Since maintenance changes the factors of failure rate (λ) and mean-time-to-failure (MTTF), reduction in risk obtained from maintaining a component k can be expressed as follows:

$$\begin{aligned}\Delta Risk_{AM}(k) = {} & \alpha_1 \cdot \frac{\partial SAIFI(k)}{\partial \lambda(k)} \cdot \Delta\lambda(k) + \alpha_2 \cdot \frac{\partial SAIDI(k)}{\partial \lambda(k)} \cdot \Delta\lambda(k) \\ & + \alpha_3 \cdot \frac{\partial ENS(k)}{\partial \lambda(k)} \cdot \Delta\lambda(k) + \alpha_4 \cdot \left[\frac{\partial DevRisk(k)}{\partial \lambda(k)} \cdot \Delta\lambda(k)\right. \\ & \left. + \frac{\partial DevRisk(k)}{\partial MTTF(k)} \cdot \Delta MTTF(k)\right]\end{aligned} \tag{7}$$

where α_1~α_4 are the weighting factors.

Similar to expression of $\Delta Risk_{AM}$, the consequence of interruption from the outage management can be comprised of weighted sum of SAIDI, ASIDI (average service availability index), MAIFI (momentary average interruption event frequency index) and MED (major event day).

(1) Effect on customer satisfaction:

$$SAIDI(i) = \frac{r_i N_i}{N} \tag{8}$$

(2) Revenue loss of utility:

$$ASIDI(i) = \frac{r_i L_i}{N} \tag{9}$$

(3) Penalty for important customers sensitive to momentary interruptions:

$$MAIFI(i) = \frac{IM_i Nm_i}{N} \tag{10}$$

(4) Cost for reconfiguration:

$$MED(i) = \left\{SAIDI(i) \mid SAIDI(i) \geq T_{MED}\right\} \tag{11}$$

where

r_i is the restoration time for each interruption event;

N_i is the number of interrupted customers for each sustained interruption;

N is the total number of customers;

L_i is the connected kVA load interrupted for each interruption event;

IM_i is the number of momentary interruptions;

N_{mi} is the number of interrupted customers for each momentary interruption event;

T_{MED} is the major event day identification threshold value.

Since fault location practices change the duration of fault (r), number of interruptions (IM) and the range of affected area (N_m), risk reduction in one interruption event i is expressed as follows:

$$\begin{aligned}\Delta Risk_{OM}(i) = {} & \beta_1 \cdot \frac{\partial SAIDI(i)}{\partial r_i} \cdot \Delta r_i + \beta_2 \cdot \frac{\partial ASIDI(k)}{\partial r_i} \cdot \Delta r_i \\ & + \beta_3 \cdot \left[\frac{\partial MAIFI(i)}{\partial IM_i} \cdot \Delta IM_i + \frac{\partial MAIFI(i)}{\partial N_{mi}} \cdot \Delta N_{mi}\right] \\ & + \beta_4 \cdot \frac{\partial MED(i)}{\partial r_i} \cdot \Delta r_i\end{aligned} \tag{12}$$

where β_1~β_4 are the weighting factors.

The overall reduction of risk obtained in a reporting period is expressed as a linear combination of $\Delta Risk_{AM}$ and $\Delta Risk_{OM}$.

$$\Delta Risk = \sum \Delta Risk_{AM}(k) + \sum \Delta Risk_{OM}(i) \tag{13}$$

2. Optimization of capital investment

The optimization of investment is based on the risk-based assessment of outage cost. The investment is distributed among paying for installation of new monitoring devices, improving communication and database infrastructure, and budgeting the equipment repair/replacement cost so that the maximum reduction in outage cost can be achieved.

The topic of optimization of capital cost is not further explored in this paper and discussion of how optimized maintenance and outage management tasks may impact the strategy for capital investment will be reported in the future.

VI. INTEGRATION BENEFITS

As can be seen from the above discussions, both asset and outage management tasks can be enhanced from the integration. The impact of integration provides benefits in reducing number of scheduled (forced) outages and duration of random (fault) outages. Hence the improved performance of asset management and outage management has several positive impacts:

a) Customers impacts: The improvement in system reliability as measured by reliability indices indicates that the requirement of better service is met. This is reflected by the improvement in the values of the individual reliability indices as a result of better data recording and collection practices coming out of the integration concept if integrated outage and asset management.

b) Utility impacts: The investment in the equipment, information infrastructure and labor is more efficiently utilized if the optimization techniques for asset and outage management proposed in the paper are used. The return on investment is increased and may be assessed by the means of risk-based the reduction of outage and revenue increase due to reliability improvements.

V. Conclusions

The integration of asset and outage management tasks is proposed in this paper. The main contributions of this paper include:

- Current development in asset and outage management are analyzed, and possibility for an integration is pointed out;
- An integration of database for asset and outage management tasks is proposed;
- Optimization of asset and outage management tasks using integrated database is presented;
- A method to evaluate the impact on the reduction of failure cost brought by integration is outlined.

Implementation of the proposed integration and a quantified evaluation of the benefits of integration will be presented in future.

VII. Acknowledgment

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