

Energy Storage as a Tool for Enhanced Reliability: Framework Development and Lessons Learned

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SUMMARY

There is a growing interest in Energy Storage Systems (ESS) and other distributed energy resources (DER) as non-wires alternatives to resolve distribution issues and enhance the reliability of electricity supply to the end user (especially for feeders where reliability improvement techniques such as grid hardening cannot be used). Despite this interest, there is no clear operational framework or guidelines that utilities can follow to justify this additional investment or indeed, to quantify the benefits achieved from it. To bridge this gap in knowledge, the Electric Power Research Institute (EPRI), in conjunction with Hydro One developed a framework in which utility reliability targets can be used as a benchmark to size and locate DER and/or ESS, to operate parts of a utility feeder as a microgrid. This paper explains the development of this framework and more importantly, the lessons learned in the process of developing and applying it.

KEYWORDS

Distributed generation, Energy Storage Systems, Resilience, Reliability, Microgrids

Introduction

Improving the reliability of distribution systems has been an area of considerable interest, both from the academia and the industry, in the past decade [1]. This interest coupled with the advent of DERs and microgrids has led to a growth in interest in utilizing microgrids as a solution to enhance system reliability and customer resilience. According to the DOE definition, “A microgrid is a group of interconnected loads and distributed energy resources (DER) within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and that connects and disconnects from such grid to enable it to operate in both grid connected or island mode” [2],[3]. Historically, utilities have relied on grid hardening techniques (aerial/underground cable, vegetation management, etc.) and/or adding alternative feeder ties and distribution automation (DA) to improve the reliability of their distribution systems. Grid hardening techniques are effective and proven measures for improving distribution system reliability. However, sometimes these options are not viable due to customer preferences, cost, or for other reasons. In such scenarios, utilities must rely on utilizing distribution automation as the main solution for improving system reliability. Further, efforts towards grid modernization have led to a growing interest in utilizing energy storage systems (ESS) and other DER to provide backup during planned or unplanned outages, by leveraging the islanding capabilities of such systems in a local microgrid configuration. Such islanding capabilities can potentially help utilities to improve their SAIFI and SAIDI numbers, and to effectively increase supply reliability while potentially reducing O&M costs (such as vegetation management, as required by grid hardening measures). These measures also provide enhanced customer resilience during prolonged outages during natural disasters such as hurricanes, earthquakes, wildfires, etc.

Although techniques such as adding reclosers; fault location, identification and service restoration (FLISR) systems; and lately microgrids have been around for some time, from a utility perspective there is limited understanding as to how each of these techniques can be utilized in conjunction with each other to achieve a reliability target. Further, while DER and ESS based microgrids can provide a high degree of system reliability and customer resilience, there is limited understanding on how such systems can be sized and located on an existing distribution feeder. The high cost associated with DER and ESS further requires judicious use of these resources, which must be addressed through dedicated studies. This paper describes attempts made by EPRI and Hydro One to address these gaps. It describes a framework in which the benefits of each non-grid hardening reliability technique are analyzed sequentially, to achieve an ‘optimum solution’ based on a specified utility reliability target. The next section describes this framework, and the subsequent sections demonstrate its applicability through actual utility feeder application examples. A discussion of the lessons learned in the process are discussed thereafter. The paper finally closes with a discussion of anticipated future work and conclusions from this effort.

Reliability Framework

The analysis framework developed for reliability analysis is shown in Figure 1.



Figure 1 Analysis Framework for reliability analysis

The various parts of this framework can briefly be described in the following steps:

- **Step 1** – Data Gathering: Gather fault data from the past three years to calculate the feeder baseline SAIDI and SAIFI and component failure rates.
- **Step 2** – Optimal Switch Placement: Use a switch placement algorithm to optimally place distribution automation switches (with fault current interrupting capability) to minimize customer interruptions.
- **Step 3** – Load Transfer Schemes: Explore the option of load transfer using neighboring feeders.
- **Step 4** – Optimal ESS Placement: Identify section(s) of the feeder to be restored using storage-enabled microgrids based upon reliability objective.
- **Step 5** – Microgrid Analysis: Compute size of the energy storage system (ESS) based upon the load size of the feeder section to be restored.

The first step involves gathering all the necessary data for the feeder. The necessary data includes geographically coordinated fault data (total number of faults along with their geographical location on the feeder) for the last three years. This data is used to calculate the feeder SAIFI and SAIDI indices that form the baseline upon which the utility seeks to improve. The remaining parts of the framework assess the different reliability improvement techniques previously mentioned, to meet the utility's SAIFI and SAIDI targets. First, the placement of additional DA switches is evaluated. To achieve this objective, an OpenDSS [4] based optimal switch placement tool developed by Electric Power Research Institute (EPRI) is used [5],[6]. The algorithm used by this tool identifies the optimal location of a single DA switch to minimize customer interruptions, places a DA switch at the location and then calculates the reduction in customer interruptions (and hence reliability improvement) achieved by this step. If the utility reliability targets are not met, another switch is placed on the feeder (keeping the first switch in its location) and the calculation is repeated. This is repeated as many times as reasonable. At some point, the dollar value per incremental reliability improvement becomes too high (and customer interruptions cannot be further significantly reduced) to justify this approach. At this point, it may become more economic to restore sections of the feeder by alternate methods such as load transfer. In distribution planning this is achieved through engineering judgement. In the proposed approach, the instance where the load transfer option should be investigated is obtained from the analysis framework. This calculation often boils down to a simple calculation of 'unit reliability improvement achieved per dollar'. The switches placed in Step 2 create further feeder sections. Step 3 then allows the restoration of (a part of) the customer load through load transfer to neighboring feeders. Since the algorithm described in Step 2 does not automatically consider such a transfer, this step has to be done manually at present with input from the reliability engineer.

The upgrades required to existing distribution infrastructure to enable load restoration with other feeders (if any) dictate the costs per unit reliability improvement in this case. SAIFI and SAIDI numbers are recalculated and then compared against the targets at this stage. Finally, when Step 2 and Step 3 fail to achieve the set targets, restoration of customer load through DER placement is proposed. In this step, sections of the feeder, isolated due to a fault are re-energized through DER/ESS based microgrids that are operated in islanded mode. The reliability improvement required at this stage dictates the size of the microgrid and sometimes more than one microgrid may need to be created on the same feeder to achieve a given target. The size and mix of DERs required for each microgrid is part of a separate analysis where the main objective might be dictated by economics. The applicability of the framework was demonstrated on an actual distribution circuit in North America at the 23-kV voltage level. The radial feeder had historically poor reliability numbers and the utility utilized the developed

analysis framework to improve the supply reliability of this feeder to achieve their target. This is described next.

Application Example

The reliability improvement framework was applied to the analysis of a 23-kV class feeder containing two circuits, with historically poor reliability numbers. The feeder was radially fed with approximately 2,000 customers spread out over 60 km. The peak feeder load was approximately 2 MW and the feeder was located downstream of a 44-kV feeder, which itself is prone to a significant number of interruptions in a calendar year. A single line diagram of the feeder, indicating the boundaries of the two circuits (named ‘F1’ and ‘F2’ hereafter) is shown in Figure 2. Although each circuit was analyzed individually, for the sake of brevity only the analysis of circuit F2 is shown in this paper. The total number of customers fed from F2 was 602 (1322 for F1) while the total connected spot load on this circuit was 1.02 MVA (0.99 MVA for F1).

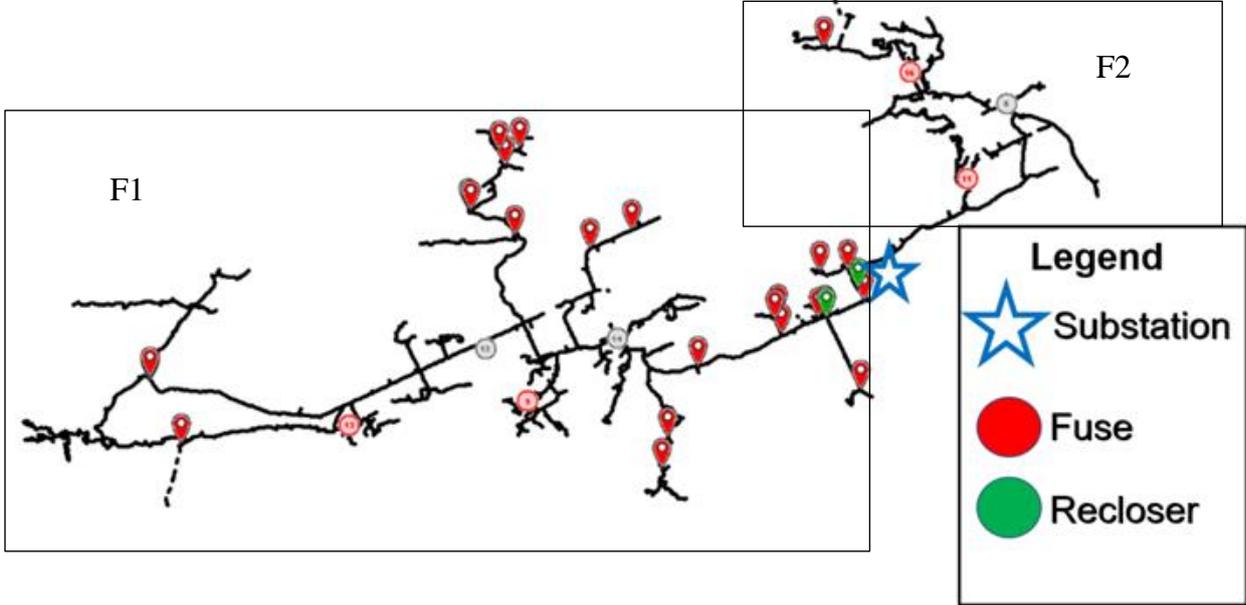


Figure 2 Simplified single line diagram of the feeder showing boundaries of the individual circuits.

Feeder Reliability History

In accordance with the first step of the reliability analysis framework, the baseline reliability indices were calculated for circuit F2, using failure data provided by the utility for the past 3 years. The period of evaluation was arrived at based upon two key factors: reliability indices are generally calculated as a running average over 3 years and infrastructure work/natural changes on distribution feeders generally tend to skew data sets longer than this period. Calculations indicated that the circuit F2 had a SAIFI of 1.36 interruptions/customer/year and SAIDI of 7.08 hrs/customer/year. The CAIDI value of 5.2 hrs/failure, was considered to be the ‘average time to repair’ in the analysis. In this case, the circuit SAIFI value was under the utility target of 2 interruptions/customer. However, the SAIDI value was in violation of the utility target of 5.5 hrs/customer. As a next step, the failure data was coordinated with available geographical information of fault location and failure rates (λ) were assigned to each conductor section of the circuit [8], [9]. The following formula was used in this calculation:

$$\lambda = \frac{\text{Total Faults on line section in a year}}{\text{Total length of line section}} * (\text{percent permanent faults})$$

In this equation, the term ‘percent permanent faults’ indicates the fraction of all faults on the feeder section that were permanent. The results of this calculation are shown in the simplified single line diagram of the system shown in Figure 3. Further to this calculation, fault data for the 44-kV circuit, located upstream of F2, was obtained from the utility. This data is summarized in Table 1.

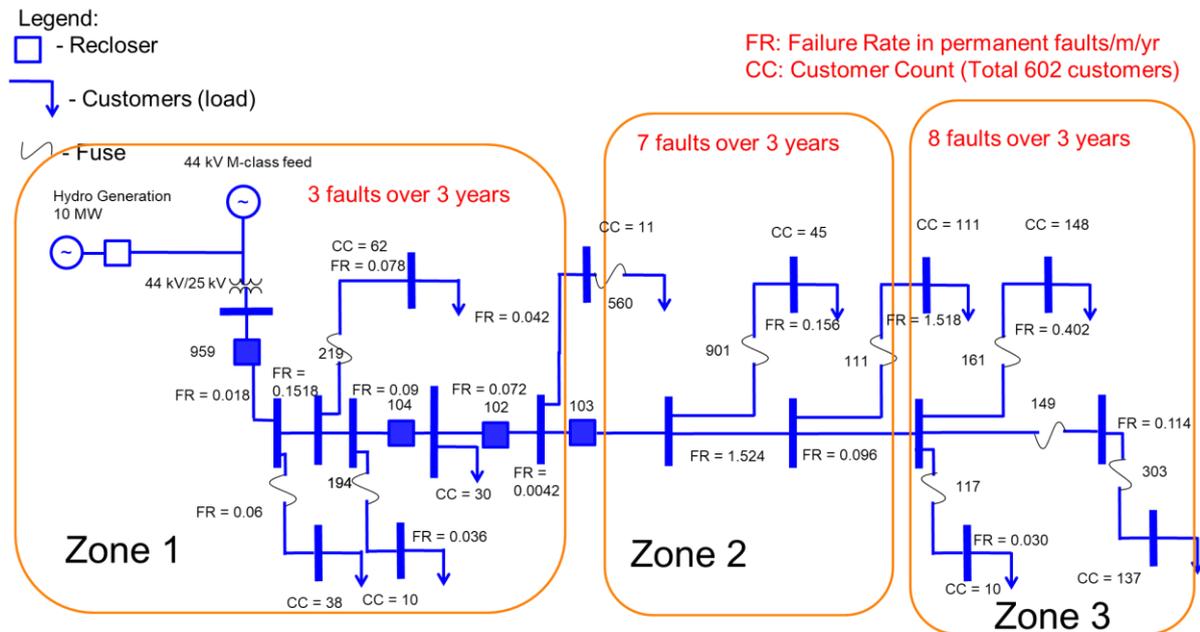


Figure 3 Simplified single-line diagram of circuit F2 with failure rates and customer count.

Table 1 Permanent faults on M-class feeder over three years

Year	2015	2016	2017
Number of Permanent Faults	6	5	0

Based upon the data shown in Table 1, the permanent faults per year on the M-class feeder were calculated as the average of the permanent faults over 3 years. This value of 3.66 faults/year was used in the rest of the reliability analysis, which is discussed next.

Optimal Switch Placement

After establishing the ‘feeder baseline’, the data shown in Figure 3, along with the utility simulation model in CYME, was used to create a simulation model of the circuit in the OpenDSS software platform. The switch placement algorithm previously described in [5], [6] was then applied to the simulation model. The results of this step are summarized in Table 2. These results showed that the additional of DA switches on the feeder produced minimum improvement, and even after the addition of two switches, the utility would not meet its SAIDI target. Considering the high installation and commissioning cost of such switches on the feeder (assumed to be \$100,000/switch as final installed cost) against the minimal benefits in terms of reliability improvement, the utility did not see any benefit in considering DA switch placement as a viable option. Further analysis into the reasons for the marginal improvements revealed:

- a. The high density of existing protective switches and a well-designed protective scheme minimized the benefits that could have been achieved from DA switch placement.
- b. Majority of the customers (greater than 60%) on the feeder were located in zone 3 (see Figure 3) while about 50% of the failures on the feeder happen upstream of this load zone. Since the feeder is radially fed, this implies that any fault on the feeder will affect the customers in zone 3. Thus, feeder topology and load distribution imply that unless an alternative source of supply is established, any permanent fault would result in disconnection of zone 3 (or most of the load). Thus, addition of DA switches, without an alternative energy source would not help.
- c. The fuse saving scheme employed on the circuit already, would have no further impact on the reliability even if additional switches were to be added.

Table 2 Summary of results from optimal switch placement on F2

Number of Switches Added	Customer Interruptions	Change in CI and SAIFI/SAIDI (%)	Projected Value of SAIFI	Projected Value of SAIDI
0	3319.97	0	1.36	7.08
1	3288.18	0.95	1.35	7.01
2	3267.82	1.57	1.34	6.97

Load Transfer

In step 2 of the reliability analysis, finding alternative sources of supply was established to be the optimum solution for circuit F2. However, F2 was a radial circuit with no ties to neighboring feeders. Further, constructing such a transfer scheme was considered prohibitively expensive by the utility. Hence, the possibility of transferring load from the feeder to neighboring feeders in a contingency condition was not a viable solution in this case. Instead, the next step in the framework of the optimal placement of an energy storage system (ESS) was considered.

Optimal Placement of ESS

Having gone through the first three steps of the reliability improvement (and having disregarded grid hardening solutions as being nonviable), without achieving the utility reliability objective, the optimal placement of an ESS and operating parts of the circuit(s) as an independent microgrid was ultimately considered as the solution of choice to meet the utility reliability targets. Since the process of ESS placement was not automated, this had to be done manually, based on the simplified single line diagram of Figure 3. The load zones shown in the figure were established based upon:

- a. Failure data provided by the utility.
- b. Location of the protective devices along the main feeder trunk.

The process of ESS placement, thus, consisted of restoring one or more of the load zones as ESS based microgrids while calculating the changes in reliability indices due to each. Based upon location, four scenarios for ESS placement were considered (these scenarios restored most of, or all of the feeder load). These scenarios are summarized in Table 3. The table considers the effect of using a single ESS versus a distributed ESS scheme, as well as the effect of location of the ESS, on the reliability indices. Further, based upon the load to be restored and the average time to repair (approximated to be the CAIDI of about 5 hrs), the size of ESS was also

calculated. In this case, it was assumed that the ESS power and energy requirements must support the load it is designed to handle, for a time equal to the average time it will take to restore power back after an unplanned outage.

Table 3 Summary of results from ESS placement on F2

Scenario	Description	Customer Interruptions	Projected Value of SAIFI	Projected Value of SAIDI	ESS Size (MWh)
Base	No ESS	3319.97	1.36	7.08	-
1	Restore zones 2 and 3 with a single ESS	1584.66	0.64	3.31	2.7
2	Restore zones 2 and 3 with an ESS in each zone	1106.64	0.45	2.31	2.7
3	Restore whole circuit with a centralized ESS	1183.4	0.48	2.47	3.5
4	Restore whole feeder with an ESS in each load zone	1032	0.41	2.15	3.5

Table 3 shows a few results that may be unexpected to the reader. While scenarios 1 and 2 consider only zones 2 and 3 to be restored, scenarios 3 and 4 analyze the effect of restoring the whole feeder. The results show that:

- Restoring the whole feeder does not necessarily yield the highest reliability improvement. For example, scenario 3, in which only the majority of the load is restored (albeit with a distributed ESS scheme) shows better reliability improvement than scenario 3, in which the whole feeder is restored. In general, this is because restoring a feeder using a centralized ESS scheme guarantees immunity against failures against faults that happen upstream of the feeder. However, it still leaves customers vulnerable to failures that occur on the feeder itself. In the present scenario, where ESS costs are fairly high (about \$450/kWh), such results are crucial since they imply higher supply reliability for a lower initial installed cost.
- In general, a decentralized ESS scheme was seen to work better. Operating parts of the feeder as independent microgrids not only guarantees immunity against failures that happen upstream of a feeder, it also guarantees that customers on the feeder are immune to failures that occur on the feeder itself. Customers will remain vulnerable to failures within the microgrid zone, but with appropriate design, such interruptions could likely be minimized.

Conclusions and Future Research

The case study of reliability improvement for circuits F1 and F2 offered some interesting insights into the utilization of microgrids as a reliability improvement technique. The key conclusions from the presented analysis are:

- The optimal placement of an ESS-based microgrid(s) is influenced by the distribution of faults and loads on a distribution circuit. For example, both circuits presented here have majority of their faults occurring in the latter half of the feeder. However, in one case maximum customers were in the front half of the feeder (F1) and in the other case they were located in the latter half of the feeder (F2). For feeder F1, maximum benefit

from ESS placement was derived by placing an ESS in the front half of the feeder, while for feeder F2, the maximum benefit was obtained by placing an ESS in the latter half.

- For the two circuits, using multiple distributed ESS provided more benefits as compared to using a single centralized ESS. However, this needs to be verified through more examples and implementations.
- The results of the reliability analysis were influenced more by faults on the upstream feeder rather than those on the circuits themselves. This is because faults upstream of the feeder interrupt all the customers on the feeder while most failures on a feeder with a well designed protection scheme result in interruption to only a part of the feeder load.
- The judgement of the reliability engineer cannot be ignored in this process. In fact, it became clear over the course of this analysis that reliability improvement is done on a case by case basis and is not a ‘one solution fits all’ exercise. Especially in cases where the placement of an ESS has to be decided, the judgement of the reliability engineer is invaluable. Often times, such a decision may come down to cost and prioritizing load. Automated tools can help in this process by providing an estimate of reliability improvement ‘per dollar of investment’ to the reliability engineer.

Based upon the analysis presented in this paper, the following areas of future research were identified:

- Presently, there is no way to mathematically determine the boundaries of a microgrid. The analysis shown in this paper has shown that the reliability improvement process is an optimization exercise that involves working through failure rates, customer distribution and size of the ESS unit. It is proposed in the future that this process be automated using algorithms that determine the best location for an ESS unit, given a certain size and reliability objective.
- The research should be extended to account for variability in fault data using techniques such as Montecarlo analysis.
- Future research should analyze the effect of variable repair times on different parts of the same feeder.
- Extend the proposed framework to include the microgrid analysis. Automate the process of selecting an optimal DER portfolio; including the DER types, sizes and controls.
- Implementation of a load prioritization scheme in the reliability framework, especially for cases where the Microgrid size becomes too large.

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