Application of A Predictive Reliability Assessment Methodology to PacifiCorp Distribution Feeders

Brad Williams, PacifiCorp
Sudhir Agarwal, General reliability

Abstract:
PacifiCorp has engaged in an aggressive program to modernize its Distribution Management System (DMS) by Year 2000. This is an important step to ensure that PacifiCorp meets its customer's reliability requirements in a satisfactory manner. Through Utah Power and Pacific Power, PacifiCorp provides electricity and energy-related services to 1.3 million retail customers in seven states in the western U.S. PacifiCorp's urban service area includes a portion of Portland, Ore., and Salt Lake City, Utah, plus more than 800 smaller towns, rural communities and surrounding areas. Using the historical outage data, PacifiCorp is monitoring its customer's supply reliability. The outage information is also used to predict the supply reliability at a customer location.

PacifiCorp initiated a pilot study of selected feeders to identify weak links and components that contribute to feeder unreliability. The study was done using the General Reliability's distribution system reliability program, DISREL. In this paper, a description of the program and its application to few selected feeders is described. It is expected that this analysis will help PacifiCorp to plan, design and operate the distribution facilities in a cost-effective manner while meeting its obligations to its customers and regulators.

Introduction:
The distribution system is an important part of the overall electrical network of a utility company as it links an end user to the utility's transmission and/or subtransmission network. Even in a deregulated environment, where a customer can choose an Electric Service Provider (ESP), state regulators will continue to hold utilities accountable for safety and reliability. For example, Pacific Power line crews will continue to plan and maintain the local electric distribution system. They will also continue to restore power in the event of an outage. From a customer's point of view, both reliability and the cost are two most important guiding factors in choosing a service provider. PacifiCorp has set a goal to reduce the customer outage minutes by 10% for all their feeders. Reliability as seen by a customer is dependent on many factors. Some of these factors are listed below:

1. Bulk Supply point reliability. This is dependent on the grid reliability and includes generation, transmission and subtransmission and sub-station reliability. Any improvement in bulk supply point reliability has a wider impact on all the customer's reliability who are connected to that point.
2. Distribution system reliability. This can be further divided into the following major categories:
   - Network design (planning) reliability based on the components that provide a final link between the bulk supply point and the customer's electric system. Major components include breakers, reclosers, circuits, transformers, isolators and fuses. Here circuit is used in a general sense and includes both primary and secondary feeders (overhead as well as underground).

- Network operational reliability based on O&M (operations and maintenance) practices followed by a utility. This also includes switching schemes employed by a utility to minimize the impact of an outage.
- Environmental factors. This includes major conditions that are beyond a utility control. For example outages caused by earthquakes, cyclones and tornadoes. A utility prepares itself to minimize the impact of these major events when they occur but it is very costly and rather impractical to design a system for these rarely occurring events.

3. Customer system reliability. This includes customer's network, appliances, and backup measures adopted under outage situations.

Both planning and operations reliability for a distribution system are important. If a utility does not have the facilities (both hardware and software) to supply power to its customers, no amount of O&M is going to improve the situation. Also having designed and built the most reliable system does not mean that it will not fail. Outages will occur but O&M practices followed by a company can help minimize both the frequency and duration of customer interruptions. It is highly desirable that in any decision making process, these two aspects are considered. But this is quite an involved job particularly when a utility tries to quantify the improvement in reliability based on any changes that it wants to make in its system and/or O&M practices. The major stumbling blocks are lack of component outage data and/or absence of mathematical models to represent a relationship among factors that can impact outage statistics. For example, it is rather obvious that preventive maintenance results in enhanced reliability as good maintenance provides an opportunity to replace components before they fail. It also detects hidden failures and components that are already in a failed state. But the determination of a component life cycle is a very complex process. There is no guarantee that a component once maintained will be as good as a new component? What is the relationship between the age of a component and its failure history? The other important issue mainly for overhead lines is the outages caused by vegetation. For utilities with overhead lines, vegetation growth is a major cause of outages. So the question is how often tree trimming should be done? Obviously it depends on vegetation growth and its impact on outages. This is an area that needs more data and research to develop good mathematical models.

Having outlined some of the difficulties in using a mathematical model, does this imply that the predictive analysis of a distribution feeder is a useless exercise. The other alternative is to use the historical performance indices to make decisions. Undoubtedly, this is better than using no information but the main objective here is to examine the customer reliability for future years. Can we trust the data collection, reporting and recording procedures? Do we have sufficient information recorded on the cause of outages? Even if a utility has taken all the care to collect this information, can we use this to predict reliability for a future time? Load is not constant, components age, network configuration changes and O&M practices continually change. We should not forget that customer's needs are changing. Their expectations are going up. What is more important to a customer - the duration of an outage or the number of times he is interrupted?

A predictive reliability assessment provides the best of both worlds. Application of the historical outage data (either collected from fields or obtained from a manufacturer) to study outages for the proposed network topology under changing load/customer demands provides the best solution in a consistent manner. The reliability indices computed by a predictive tool may not give the system performance in an absolute manner but they do provide information to compare various alternatives. What reliability improvements one can expect with the proposed changes. Which initiative gives an optimal benefit to cost ratio? Or what changes should be made to a distribution feeder to attain the set targets. For example if a utility want to decrease its CMI (Customer Minutes of Interruptions) by ten percent, what facilities should be planned to meet the target.

Pacificorp undertook a pilot study to assess the benefit of using predictive reliability assessment methods to decrease customer minutes by at least 10%. The objective was to come up with specific plans to meet the target. If there are more than one option available, which is usually the case, which option(s) should be implemented first? What is the payback period?

The main focus of this paper is to address both the distribution system planning and operations reliability. However no consideration either to component aging and vegetation growth is given in calculating reliability indices. Specific recommendations for improving the reliability of ten PacifiCorp's distribution feeders were made. These feeders were selected by PacifiCorp engineers to represent their typical feeder. The study was done using the General Reliability's DIStribution RELiability (DISREL) program.

DISTRIBUTION SYSTEMS RELIABILITY PROGRAM

The program, DISREL, is designed to aid electric utility and industrial/commercial distribution engineers with predictive reliability assessment of a distribution network. It computes a set of reliability indices including SAIFI, SAIDI, ASAI, load/ energy curtailed and the cost ($) of outages based on the component outage data and the cost of interruption to a customer. The program models time-sequenced switching actions taken by an operator/repair-person following an outage event. The program can model normally open transfer supply points (redundant supply, tie points) and the limitations on load transfer to other sources. The DISREL program also models distribution stations. The program automatically traces the fault interrupting devices (e.g. breakers and fuses) and the isolation points (normally open points). Typical outage data for major components and the cost of interruption data for different types of customer is supplied with the DISREL program.

The component data file contains data for each component (objects) included in the study. It is acceptable to define more components than are actually modeled in the study. The exact number of components that are included in the study is determined from the network topology file. Components that are not defined in the network topology file are simply ignored by the program.

The network data file contains the network topology information for the study system. All components specified in this file must already be defined in the component data file. The exact number of components that are included in the study is determined from the connectivity information given in this file.

The switching instructions data file contains time-sequenced switching instructions that an operator/repair person takes following an outage event. If a user specifies the switching instructions for a component, then these instructions override the switching logic implemented in the program. This optional file is read after the component and the network configuration files have been read.

The reliability data file contains component outage data. The outage data for a component can be specified in the component data file. Outage data specified in the component data file would be applicable to that component only. After reading the component data file, DISREL searches for the missing reliability data for a component in this file.

APPLICATIONS OF DISREL

The majority of outages seen by customers are caused by failures in the distribution system. The objective of reliability assessment is to ensure that customer service requirements are met in a cost-effective manner. By assessing reliability of a feeder using probabilistic methods, it is possible to objectively compare relative benefits of alternative distribution schemes in meeting customer service reliability. This analysis also helps in:

1. establishing the chronological changes in system performance and therefore helps to identify weak areas and the need for reinforcements,
2. establishing existing indices which serves as a guide for acceptable values in future reliability assessments,
3. enables previous predictions to be compared with actual operating experience,
4. satisfying performance-based ratemaking goals set by utilities or by regulators,
5. quantifying reliability benefits of distribution automation,

RELIABILITY INDICES

The program computes a set of reliability indices that have been recommended in various publications [1-3]. Some of the load point indices computed are as follows:

1. Frequency of load interruptions (occurrences per year)
2. Duration of load interruptions (hours per occurrence)
3. Duration of load interruptions (hours per year)
4. Frequency of customer interruptions (customer-interruptions per year)
5. Duration of customer interruptions (customer-hours per year)
6. Expected Unsupplied Energy (EUE in kWh per year)
7. Expected outage cost in dollars

DISREL also computes indices for the system under study. A list of system indices is as follows:

1. System Average Interruption Frequency Index (SAIFI)
2. System Average Interruption Duration Index (SAIDI)
3. Customer Average Interruption Frequency Index (CAIFI)
4. Average Service Availability Index (ASAI)
5. Average Service Unavailability Index (ASUI)
6. Expected Unsupplied Energy (EUE in kWh per year)
7. Expected outage cost in dollars ($)

DISREL STUDIES

The following ten distribution feeders were selected for DISREL studies.

1. **Brighton 12**
2. **Butlerville 13**
3. **Egin 11**
4. **Pinedale 21**
5. **Rattlesnake 22**
6. **Sandcreek 11**
7. **St. John 11**
8. **Town Feeder**
9. **Wamsutter**
10. **Woods Cross 12**

The main objective of the study is to evaluate the applied techniques and methodologies for the future reliability analysis of approximately 2000 of PacifiCorp's feeders under its distribution automation initiative.
For each feeder, the impact of removing an existing fuse and a switch was also studied.

DISREL RESULTS FOR BRIGHTON 12 FEEDER

In this paper, results are presented only for Brighton 12 feeder. DISREL component and network files were created from the data available in Feederall database. Default outage data supplied with the DISREL program was used and therefore reliability indices presented here should be used with utmost care to interpret the feeder performance in an absolute sense. However the data and the results can be used to rank and compare various options.

In order to examine various options, a brute force approach was used in both removing/adding switches and fuses. The following steps were taken:

1. Compute reliability indices for the existing feeder.
2. Remove one switch at a time and compute the reliability of the new configuration. The number of runs is equal to the number of switches present in the feeder.
3. Remove one fuse at a time and compute the reliability of the new configuration. The number of runs is equal to the number of fuses present in the feeder.
4. Add a switch (if not already present) at a junction where the main feeder divides into more than one branch. For each option, reliability indices were computed.
5. Add a fuse to the non-fused lateral branch. Again reliability indices were computed for each scenario.

This brute force approach of examining a large number of scenarios is quite possible due to the cheap computing power of a personal computer. It is not really necessary to use any optimization/selection techniques to reduce the computing time. The main advantage of using a computer program is to examine all credible outages for a number of scenarios. A sorted list of options was then created to rank options based on the customer minutes of interruptions.

The study provided an indication of the removed component's contribution to the feeder reliability indices such as SAIFI, SAIDI, EUE, and Outage Costs. Sometimes it is possible that one index may decrease while the other index may increase. Depending upon the type of customers served and the regulatory requirements that a utility needs to meet, one index or a combination of indices can be chosen to determine the relative importance of each of the existing fuse and switch. This index is called as the ‘design index’. If the inclusion of a component is contributing to the deterioration of the design index, then it becomes important to seriously evaluate the benefit of having the component in service.

After discussing with PacifiCorp engineers, SAIDI was chosen to be design index.

The following is a list of components which if individually removed from service results in a decrease in both SAIDI and the outage costs. The switching (isolation) time is assumed to be 90 minutes.

1. Switch 1371_1372
2. Switch 1400_1404
3. Switch 1373_1374

Normally one would expect that the feeder reliability should decrease if an existing fuse or a switch is removed. However, it should be remembered that the more components mat cause greater exposure to customer unreliability due to the component failures.

It should be noted that switch placement on a distribution feeder is not solely controlled by reliability considerations. Switches are placed for load balances and enabling ease of maintenance. Recommendations made here did no consider any factor other than reliability.
The second part of this study was to explore the benefits of including both manual and automated circuit sectionalizers and fuses to each feeder. The basis for adding new components should be as follows:

1. It should improve the feeder reliability. It means that the design index should decrease after adding the new component(s).
2. Savings in the outage costs and/or improvements in the feeder reliability justifies the cost of adding new component(s).

The following is a sorted list of only five components which if individually added to the feeder service results in a decrease of both SAIDI and the outage costs. The addition of the first component gives the largest improvement in SAIDI.

1. Switch 1394a_1385d
2. Fuse 1376a_1376
3. Fuse 1386_1387
4. Fuse 1378a_1377
5. Fuse REG_NOD_000_137

The following is a sorted list of only circuit sectionalizing devices (isolation time less than or equal to 5 minutes) which if individually added to the feeder service decreases both SAIDI (by at least 5%) and the outage costs. The addition of the first component gives the largest improvement in SAIDI.

1. Switch 1405_1406
2. Switch 1380_1382
3. Switch 1383_1385a

It should be pointed out that above ranking is based on reliability indices only. However the cost of installing a fuse is smaller than that of installing an automated switch.

Another index improvement cost ($) per improvement in customer minutes is computed to determine the ranking based on maximum return on investments. Using the improvement index a ranked list was prepared and is shown below:

Table: DISREL RESULTS FOR BRIGHTON 12 FEEDER

Option	**Improvement Costs ($/customer-minute)**
ADD _REG_NOD_000_137	**$1**
ADD _1385b_1386	**$10**
ADD _1386_1386a	**$13**
ADD _1394a_1385d	**$13**
REPLACE SWT_1404_1405	**$15**
REPLACE SWT_1400_1404	**$16**
REPLACE SWT_1406_1409	**$19**
ADD _1405_1406	**$21**
REPLACE SWT_1371_1372	**$24**
REPLACE SWT_1372_1373	**$27**
ADD _1370_1400	**$28**
REPLACE SWT_1373_1374	**$28**
REPLACE SWT_1410_1413	**$30**
REPLACE SWT_1410_1411	**$37**
REPLACE SWT_1414_1415	**$40**
ADD _1380_1382	**$47**
ADD _1383_1385a	**$47**
ADD _1376_1380	**$52**
ADD _1385a_1385b	**$63**
REPLACE SWT_1411_1412	**$69**
REPLACE SWT_1400_1401	**$77**
ADD _1385b_1385c	**$290**

(ADD = adding a new switch/fuse; REPLACE = replacing an existing switch by an automated switch)

Based on this list, adding a switch at REG_NOD_000_137 is the most beneficial. The ranked list of options is quite dependent on the design index and it can change if a different index is chosen as a design index. This is not a concern but brings out the fact that changes in a feeder react differently in meeting reliability guidelines. It is the type of customer who should be the deciding factor in selecting a particular option. There is also no reason to use a uniform index for all the feeders. The optimal level of reliability is decided by the regulatory requirements, competition, customer's willingness to pay and the cost incurred in providing facilities. The predictive analysis used in studies presented here provides a methodology to address above issues.

CONCLUSIONS

In this paper results are presented to identify fuses and switches which are not contributing to the feeder reliability. Or in other words, the removal of some of these components may not adversely impact the feeder reliability.

Methods implemented in the DISREL program can also be used to determine which fuses and automated switches should be installed to improve the feeder reliability.

It should be kept in mind that recommendations made in this paper are based on the study of an individual feeder. Based on the preliminary investigations for a feeder system (including whole or part of neighboring feeders to enable load transfer), it has been noticed that the recommendations can change. This requires more investigations and it is necessary to consider examining feeder systems that also include the distribution substations.

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