FEEDER OVERCURRENT PROTECTION DESIGN TOOLS FOR POWER QUALITY IMPROVEMENT

By

Thomas E. McDermott, Ph.D., P.E.
Consulting Engineer
EnerNex Corporation

Introduction

The utility uses overcurrent protection (OCP) devices (circuit breakers, reclosers, fuses, and sectionalizers) to detect and clear faults on the line, before the fault current damages conductors or equipment, or causes personal injury [1]. The devices should detect and clear the fault as soon as possible, but should not operate when there is no fault. Except for underground circuits, at least one automatic reclosing attempt would be made to restore service, since approximately 80% of faults will clear themselves when de-energized. But if the fault remains, the OCP devices should affect as few customers as possible while isolating the fault for repair. This sectionalizing feature affects reliability on the feeder, where reliability has been traditionally defined as the number and duration of long-term interruptions. A typical fault rate is 0.1 per mile per year on overhead primary distribution, and any method of reducing that fault rate (e.g., tree trimming, lightning protection) would also improve reliability. But the OCP devices have usually not been evaluated for impact on other aspects of power quality, such as voltage sags and momentary interruptions. This paper will present methods of doing that.

The standard reliability indices have recently incorporated the Momentary Average Interruption Frequency Index (MAIFI), as defined in equation (1), where momentary refers to an interruption of up to 5 minutes [2]. For interruptions greater than 5 minutes, the index is called System Average Interruption Frequency Index (SAIFI).

$$MAIFI = \frac{\sum N_{Momentary}}{N_{Served}} \tag{1}$$

MAIFI is the sum of the number of customers affected by each momentary interruption, divided by the total number of customers served. MAIFI could be defined for a feeder, substation, or utility system. A typical MAIFI value might be 6, in contrast to a typical SAIFI value of 0.5.

To assess voltage sags, the System Average RMS Variation Frequency Index has been developed [3], as defined in (2). The typical defined sag breakpoints for these indices are 90%, 80%, 70%, 50%, and 10%, the latter defining an interruption. In equation (2), the subscript 70 refers to voltage sags to 70% or less, but still greater than the next lowest index level at 50%. Like MAIFI, this is the average number of voltage sags per year that a customer would see at that level. Less commonly, the indices can be subdivided further by duration (see Table 1), or the number of phases involved, because single-phase or two-phase sags often have less impact than three-phase sags. A typical value for $SARFI_{70}$ is 20, and for $SARFI_{50}$ is 10.

$$SARFI_{70} = \frac{\sum N_{Sag-70\%}}{N_{Served}} \qquad (2)$$

Most distribution software packages have a reliability module that will output values for SAIFI and System Average Interruption Duration Index (SAIDI). More recently, some also output MAIFI. These packages can serve as design tools for evaluating OCP device placement for their impact on reliability. But for power quality purposes, it's necessary to consider voltage sags, and also interruptions even shorter than the 5-minute threshold of MAIFI. Table 1 shows the standard power quality duration scheme; note that a momentary interruption is 3 seconds or less, and a temporary interruption is 3 seconds to 1 minute. This extra granularity is important to many loads. A design tool should output the various SARFI indices to evaluate OCP device placement, and also their settings, for their impact on power quality.

Table 1 – IEEE Standard 1159-1995 Duration Categories For RMS Variations [5]

Category	Duration
Instantaneous Sag or Swell	0.5 cycles – 30 cycles
Momentary Sag or Swell	30 cycles – 3 seconds
Momentary Interruption	0.5 cycles – 3 seconds
Temporary Sag, Swell, or Interruptions	3 seconds – 1 minute
Long Duration	> 1 minute

Existing Methods

The typical OCP device setting tool will systematically apply faults at various critical locations, and make sure the devices operate properly for each fault. This doesn't predict how often the devices will operate. For that, faults would be systematically applied at many locations, and the response to each fault analyzed. The results are summed or weighted to produce a feeder-level or system-level performance index. This has been done at the customer level for a stochastic voltage sag analysis [6-7], where the sag level is estimated by the ratio of fault impedance to fault-plus-source impedance. The OCP device operation was idealized to an operating time, and for complicating factors like distributed generation, a more comprehensive circuit simulation would be required. However, transformer characteristics were addressed in detail.

At the feeder or substation level, a predictive reliability tool evaluated line recloser placement on MAIFI, but approximated fuse-saving with a percentage of success [8]. At the transmission substation level, a voltage sag critical radius method [9-10] will estimate the number of sags to a certain level appearing at the substation, due to faults on the transmission system. This method uses a "sliding fault" feature to place the fault anywhere along the line, to determine the exact distance at which the voltage sags to 70% (for example) at the substation. It can generate SARFI values due to transmission faults, without the complications raised by series device coordination and momentary outages on the feeder.

Power Quality Simulation Method

The main requirement of a PQ simulation method is that it produces figure-of-merit answers that can be used to compare different options. Sometimes these indices can be directly tied to customer damage costs for PQ-sensitive loads [11]. They can also be used to drive an automated optimization module. The most important set of PQ indices would be the SARFI family; the engineer could choose just a handful of indices, or several dozen indices that cover sag and swell levels, duration categories, and number of phases involved. This use of SARFI indices would be analogous to the reliability software tools, which are built around SAIFI, SAIDI, and other reliability indices as outputs to compare various options, and to drive optimization modules.

The baseline feeder SARFI indices come from events on the transmission system, coupled onto the distribution feeder bus through a step-down transformer. These baseline levels could come from either measurement or simulation [10], and they must account for the effect of transformer connections, summarized in Table 3 [9]. Assuming that most transmission faults are single-phase and most step-down transformers have a delta primary, the most predominant sag would fall into the 50% - 70% range phase-to-neutral, but is less than 50% phase-to-phase. The feeder OCP devices have no impact on these baseline SARFI levels coming from the transmission system.

Table 3 – Transformer Secondary Voltages with a Single-Line-to-Ground Fault on the Primary [9]

Transformer Connection	**Secondary Phase-Phase Voltages [pu]**			**Secondary Phase-Neutral Voltages [pu]**		
Wye Grnd / Wye Grnd Wye Grnd / Wye Ungrnd	0.58	1.00	0.58	0.00	1.00	1.00
Wye Ungrnd / Wye Grnd Wye Ungrnd / Wye Ungrnd Delta / Delta	0.58	1.00	0.58	0.33	0.88	0.88
Wye Grnd / Delta Wye Ungrnd / Delta	0.33	0.88	0.88	n/a	n/a	n/a
Delta / Wye Grnd Delta / Wye Ungrnd	0.88	0.88	0.33	0.58	1.00	0.58
Transformer Primary Voltages ➔	*0.58*	*1.00*	*0.58*	*0.00*	*1.00*	*1.00*

* - these values assume the transformer impedance is much greater than the source impedance

The feeder OCP devices will respond to currents caused by faults out on the feeder. Many are described with a time-current-curve (TCC), which plots the time to trip (or for the fuse to melt), as a function of the current. For a circuit breaker controlled by a relay, or for a recloser, this behavior can be approximated with equations (3)-(5), where M is the multiple of relay pickup setting or recloser trip coil rating. Equation (3) produces the time to reset when $M \leq 1$, or the device carries no fault current. Equation (4) produces the time to trip when $M > 1$, or the device carries fault current. Equation (5) expresses an idea that a device could accumulate time to trip in separate periods of fault current, before it resets. An automatic reclosing time is represented with a simple time delay, instead of an equation.

$$t_{reset}(I) = \frac{t_r}{\left|M^2 - 1\right|} \tag{3}$$

$$t_{trip}(I) = \frac{A}{M^P - 1} + B \tag{4}$$

$$\int_0^{T_0} \frac{1}{t(I)} dt = 1 \tag{5}$$

Table 4 shows a set of typical parameters to use with equations (3)-(5). The relay parameters in Table 4 provide a reasonable fit to both GE and Westinghouse electromechanical relays. Some devices, especially reclosers, will have several trip-and-reclose operations, possibly using different TCCs or parameter sets from Table 4.

Table 4 – Generic Time-Current Curve Constants [12, 13]

Device Characteristic	**A**	**B**	**P**	**T_R**
Moderately Inverse Relay	0.0515	0.1140	0.02	4.85
Very Inverse Relay	19.61	0.491	2.00	21.6
Extremely Inverse Relay	28.2	0.1217	2.00	29.1
Recloser – Fast Curve (A)	1.5	0.034	2.00	--
Recloser – Slow Curve (B)	10.00	0.095	1.85	--
Recloser – Extended Curve	27.0	0.13	2.05	--

An expulsion fuse could be represented in a very rough fashion with a straight line on log-log paper, but this is not a good model for PQ simulation or OCP device settings. Instead, a set of points from the manufacturer should be used, possibly with a spline fitted to the points. Of course the same approach could be used with actual relays and reclosers, rather than the generic model of equations (3)-(5) and Table 4. A current-limiting fuse should not be represented with a curve at all, but rather with I^2t values corresponding to minimum melt and total clearing times. Based on a calculated fault current, the simulator estimates the melting time from the I^2t.

A sectionalizer has no TCC behavior, but rather a counting behavior. It will count from one to three pulses of fault current, and then open during a subsequent period of zero current once the count has been reached. There is a count reset time, typically about one minute. The sectionalizer is often placed where no other device's TCC will coordinate with an upstream device's TCC. This may happen for laterals near the substation, because a fuse on that lateral will melt faster than the upstream breaker or recloser can open. That would mean a sustained interruption on that lateral, even if the fault was temporary. Use of a sectionalizer can prevent that.

The overall simulator for OCP device impacts on power quality starts with a stochastic fault simulation, as in [6, 7, and 10]. A large set of faults must be simulated, at many locations on the feeder, with different faulted-phase configurations and fault resistance levels. Each fault has a weighting factor to govern its contribution to the final result, which is a set of SARFI indices at the substation, feeder, or customer level. Figure 1 shows the simulation flow for each fault.

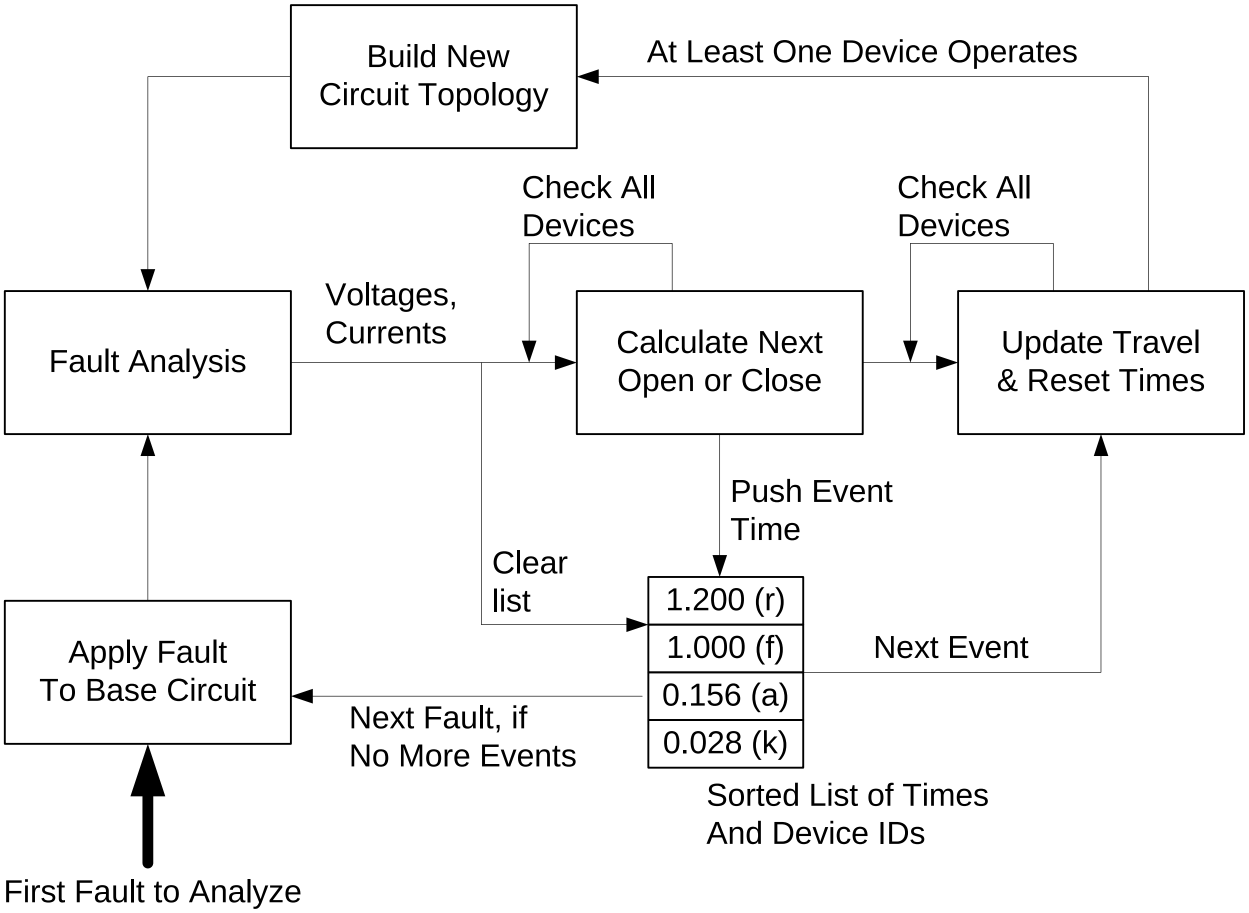


Figure 1 – Fault simulation method for power quality analysis [14]

The Fault Analysis function in Figure 1 computes at least the voltages at every load point, and the currents in every OCP device. From the currents, each OCP device calculates when its next state change (trip, melt, reset, reclose, lock out, etc.) would occur at that current level. These candidate operation times are kept in a sorted list of times and device IDs, and the soonest event will actually be executed. At this first event time that was actually selected, the other OCP devices moved only part way to their next operation, so their internal “travel time” is updated and stored. After that one device operation, the circuit configuration has changed, so the Fault Analysis function executes again. Each OCP device again calculates its next state change at the new current level, starting at the “travel time” saved from the previous iteration. This loop continues until no OCP device pushes a state change time onto the sorted list.

Under this method, the fault itself is an OCP device. A temporary fault will “open” if it has near-zero current for a certain period of time, and thus it may put an event time onto the sorted list. A permanent fault will never “open”, and never put an event time onto the sorted list. Either situation permits the loop in Figure 1 to finish. Then the next fault will be simulated on the base circuit with all OCP devices reset.

During all of these OCP device operations, the various load points will accumulate time in voltage sag, voltage swell, or interruption conditions. These are categorized by the standard PQ disturbance definitions, and then accumulated into the appropriate SARFI indices according to the weight factor for each fault. The process is conceptually simple, although it requires precise "book-keeping" to implement.

The simulation described is more complicated, in some respects, than existing tools for OCP device coordination or distribution reliability evaluation. In exchange, some important advantages are obtained:

- There is no assumption of a radial feeder, or a single source at the substation.
- Each OCP device responds independently to the voltage and current it sees, without special rules to govern interaction with other devices. A device can also reclose one or more times during simulation.

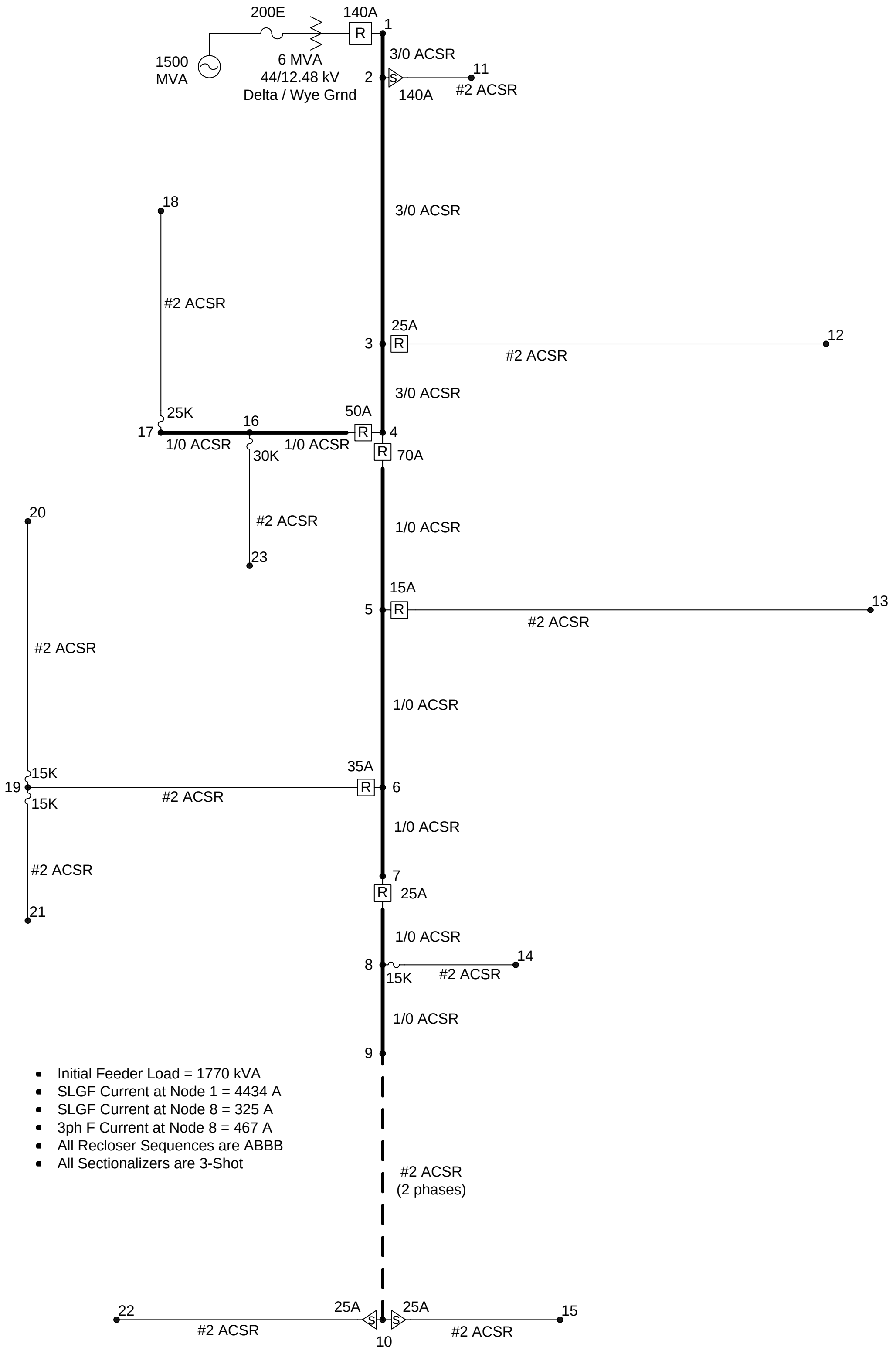
This flexibility can be especially important with distributed generation on the feeder [15].

Example

Figure 2 shows a sample IEEE tutorial feeder used to illustrate the method in a couple of cases [16]. This feeder is long and lightly loaded, with a three-phase main trunk out to Node 9, and only one three-phase lateral. All of the other laterals are single-phase. Beyond Node 9, the main trunk is actually two-phase, until the two laterals split at Node 10. The diagram is to scale in Figure 1, with 30 km from Node 1 to Node 10. Because the feeder is so long, several reclosers are applied in series to improve reliability. The reclosing sequence is ABBB to promote fuse saving for temporary faults on the laterals. The substation "breaker" is actually a recloser, because the fault current level is relatively low. One sectionalizer is used close to the substation, because the fault current is too high for a fuse to coordinate with the substation recloser. Two more sectionalizers are used far from the substation, because the fault current there is too low. Coordination with a fuse TCC there would force the recloser tripping times to accumulate as one moves back toward the substation, to a level that might permit conductor damage to occur.

This circuit has been solved in the EPRI PQ Planner software [17], using methods similar to those described in the paper, to produce a full set of SARFI indices at each node. Due to copyright restrictions, those results will not be presented here. PQ Planner is mentioned only to support feasibility of this method.

Figure 3 shows the device operations for a single-line-to-ground fault at Node 14, where the 15K fuse sees 267 amps and the 25A recloser sees 271 amps. The recloser trips at 0.0468 seconds, and then recloses 1.2 seconds later. Because the fault still exists, the 15K fuse clears 0.0280 seconds after that. At 267 amps, the simulated total clearing time for the fuse was 0.0748 seconds, accumulated during two separate periods of energization that were 1.2 seconds apart. If



- Initial Feeder Load = 1770 kVA
- SLGF Current at Node 1 = 4434 A
- SLGF Current at Node 8 = 325 A
- 3ph F Current at Node 8 = 467 A
- All Recloser Sequences are ABBB
- All Sectionalizers are 3-Shot

Figure 2 – Example distribution feeder [16]

the fault had been temporary, the fuse would not have blown after the reclose and may have recovered its full melting time. This is an example of successful fuse saving.

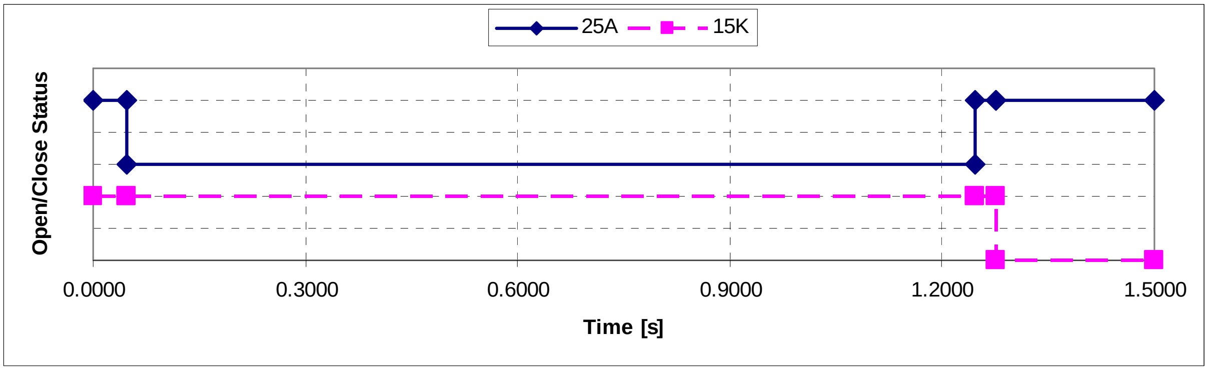


Figure 3 – Coordinating Recloser and Fuse Operations for Permanent SLGF at Node 14

Figure 4 shows the 70A and 25A recloser operations for a three-phase fault at Node 9, where the 25A recloser sees 394 amps and the 70A recloser sees 403 amps. The 25A device trips first on the A (fast) curve, after 0.0400 seconds, and then recloses 1.2 seconds later. Now 25A is on its B (slow) curve, but 70A is still on its A (fast) curve. The 70A device trips 0.0807 seconds after 25A reclosed, and then 70A recloses 1.2 seconds after that. Now both devices are on their B curves, and so 25A follows a sequence of 3 trips to lockout, with a slow tripping time of 0.1562 seconds and a reclose time of 1.2 seconds. The 70A device does not trip again, so beyond 3 seconds, the reclosers have coordinated properly. But all customers downstream of Node 4 have experienced a momentary interruption. This typically results in upstream feeder segments having a higher MAIFI or SARFI_{10} than downstream segments. A recloser feature called “sequence coordination” may prevent this from happening.

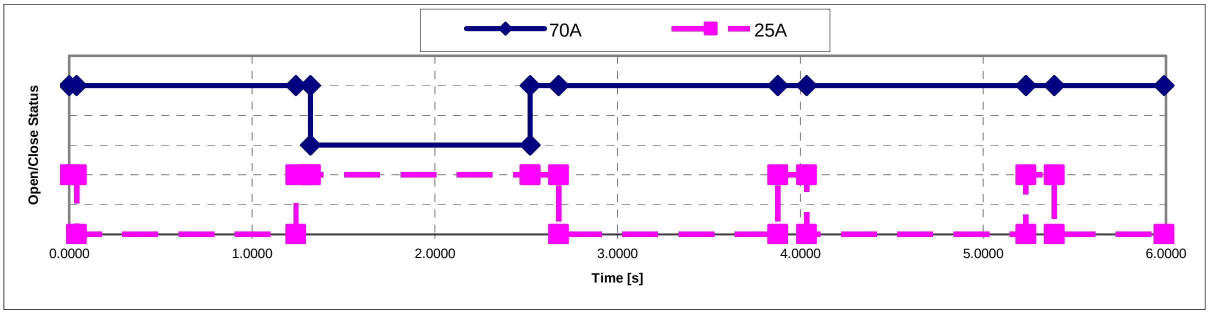


Figure 4 – Sympathetic Recloser Fast Trip for Permanent Three-phase Fault at Node 9

As discussed earlier, the simulator accumulates the times from Figures 3 and 4 into various SARFI indices, using the actual calculated voltages at each load point. It’s possible to simulate current-limiting fuses, changes to the recloser settings and sequencing, circuit routing, series reactors, and many other feeder design changes on the SARFI indices. Measures such as tree trimming or enhanced lightning protection can also be analyzed, since they are accounted for in the stochastic fault selection and weighting.

Commercial Software

Table 5 summarizes some features related to the proposed PQ simulation method, for seven commercial distribution software packages. In only a few cases was the software actually used; in other cases, public information on the Web sites was used. Therefore Table 5 may not be completely accurate, nor does it evaluate each feature in detail, nor does it cover all of the popular distribution software packages, but it's probably indicative of the general state of affairs. Note that all of these products compete on different criteria than their suitability for PQ simulation, and these criteria have been driven by customer demand and commercial success.

Table 5 – Commercial Software "Estimated" Feature Matrix [18-24]

Product	**Fault Voltages**	**Automated Protection**	**Reliability**	**MAIFI**	**Dynamics**	**Sag Analysis**	**Scripting**
CYMDIST	X	X	X	X			X
DIgSILENT	X	X	X	*	X		X
DistriView	X	X				**	**
EDSA	X	X	X		X		X
PSS/ADEPT	X	X	X				X
SynerGEE	X	X	X				X
WindMil	X	X	X				

* - has a similar capability for non-IEEE reliability indices
** - in a sibling product

The first two columns in Table 5 indicate that all seven packages will output the voltages at every node during the fault, and they all have some type of automated rule-checking, automated setting, and/or timing output for the OCP devices. Most also have reliability analysis, two of them (at least) considering momentaries. Those basic building blocks of PQ simulation are already in place. Two of the packages will simulate dynamics, but at least one of those does not include reclose behavior, or multiple trips, in the OCP devices. Most have a scripting capability, so it's at least conceivable to implement the book-keeping for SARFI accumulation. One product line has the voltage sag critical radius method implemented in its transmission product, but not in its distribution product. In order to implement PQ simulation as described in this paper, a product would need at least a quasi-static dynamics capability, with reclose and reset behavior in the OCP device models, and SARFI index outputs.

Conclusion

Distribution engineers should be using a PQ simulation tool that can produce SARFI outputs. This is the only rigorous way to evaluate different design options for their impact on power quality, especially for critical or sensitive loads, for power quality performance contract situations, or when distributed generation is on the feeder.

References

1. Roger C. Dugan, Mark F. McGranaghan, Surya Santoso, and H. Wayne Beatty, Electrical Power Systems Quality, 2nd Ed., McGraw-Hill, November 2002, pp. 81-110.

2. IEEE Guide for Electric Power Distribution Reliability Indices, IEEE Std 1366-2003 (Revision of IEEE Std 1366-1998), 2004.
3. D. L. Brooks, R. C. Dugan, M. Waclawiak, and A. Sundaram, “Indices for Assessing Utility Distribution System RMS Variation Performance” IEEE Transactions on Power Delivery, vol. 13, no. 1, Jan. 1998, pp. 254-259.
4. IEEE PES & IAS Task Force on Voltage Sag Indices - P1564, http://grouper.ieee.org/groups/sag/
5. IEEE Recommended Practice for Monitoring Power Quality, IEEE Std. 1159-1995, 2 November 1995.
6. Math H. J. Bollen, IEEE Tutorial on Voltage Sag Analysis, TP 139-0, October 1999.
7. Mohammed R. Qader, Math H. J. Bollen, and Ron N. Allan, “Stochastic Prediction of Voltage Sags in a Large Transmission System”, IEEE Transactions on Industry Applications, vol. 35, no. 1, January/February 1999, pp. 152-162.
8. M. T. Bishop, C. A. McCarthy, V. G. Rose, and E. K. Stanek, “Considering Momentary and Sustained Reliability Indices in the Design of Distribution Feeder Overcurrent Protection”, 1999 IEEE Transmission and Distribution Conference Proceedings, vol. 1, 11-16 April 1999, pp. 206-211.
9. M. F. McGranaghan, D. R. Mueller, and M. J. Samotyj, “Voltage Sags in Industrial Systems”, IEEE Transactions on Industry Applications, vol. 29, no. 2, March-April 1993, pp. 397-403.
10. Voltage Sag Predictor, http://www.pqsoft.com/vsp/index.htm
11. R. C. Dugan, D. L. Brooks, T. E. McDermott, A. Sundaram, "Using Voltage Sag and Interruption Indices in Distribution Planning", Proceedings IEEE Winter Power Meeting, pp. 1164-1169, February 1999, New York, NY.
12. Power System Relaying Committee of the IEEE/PES, IEEE Standard Inverse-Time Characteristic Equations for Overcurrent Relays, IEEE Std. C37.112-1996, New York, NY, 27 January 1997.
13. IEEE Standard Guide for the Application, Operation, and Maintenance of Automatic Circuit Reclosers, IEEE Std 321-1973, New York, NY, 1973.
14. Roger C. Dugan, Thomas E. McDermott, and Greg J. Ball, “A Methodology for Including Power Quality Concerns in Distribution Planning”, 5th International Conference on Electrical Power Quality and Utilisation (EPQU 99), September 15-19, 1999, Cracow, Poland.
15. T. E. McDermott and R. C. Dugan, “PQ, Reliability and DG”, IEEE Industry Applications Magazine, vol. 9, no. 5, Sept.-Oct. 2003, pp. 17-23.
16. Application and Coordination of Reclosers, Sectionalizers, and Fuses, IEEE Tutorial 80 EHO157-8-PWR, 1980, pp. 65-97.
17. PQ Planner Version 1.0: Power Quality for Distribution Planning, EPRI, Palo Alto, CA, December 1999. AP-110346, SW-110346-CD.
18. Aspen DistriView, http://www.aspeninc.com
19. Cyme CYMDIST, http://www.cyme.com
20. DIgSILENT Power Factory, http://www.digsilent.com
21. EDSA Technical 2004, www.edsa.com
22. Milsoft WindMil, http://www.milsoft.com
23. Siemens PTI PSS/ADEPT, http://www.pti-us.com
24. Stoner SynerGEE Electric, http://www.advantica.biz