WPRC – Western Protective Relay Conference 2020

Automated Fault Location Analysis – Utilizing a Short Circuit Model

R. Dixon
FirstEnergy Service Company
USA

R. Maxwell
FirstEnergy Service Company
USA

H. Falk
OTB Consulting Inc.
USA

P. T. Myrda
Electric Power Research Inst
USA

SUMMARY

One major east coast electric company on behalf of its transmission owning affiliates determined there was a need to improve the accuracy and speed of its fault location process especially for the 138 and 69 kV system. This system is heavily tapped with industrial customers and substations. The main objective of this project was to see if the need to call out staff, usually overnight, to run the fault-location program could be eliminated for the majority of faults that occur in a pilot/test area.

The overall objective of this effort is to reduce the time to determine where a fault has occurred with sufficient certainty to route field crews to the location of the fault quickly and improve restoration times. At some locations, there may be the ability to sectionalize the 69 kV or 138 kV transmission network so that operations staff can begin restoring customers in areas not directly affected by the faulted line section.

This paper will provide details regarding the implementation of the analytics methods and data handling and transformation required to fully automate the process. It will detail the automated determination of the appropriate fault current to use for the fault location, which appropriately removes the impact of the DC offset often present within the fault measurement made by the digital fault recorder. It will cover the process for automatically initiating the calculated location within the fault analysis program. As well as discuss the process for updating the fault analysis program with the network topology just prior to the fault, to increase accuracy.

KEYWORDS

Fault Location, Fault Analysis, Digital Fault Record, DC Offset, Event Record
.

Problem Statement

One major east coast electric company, on behalf of its transmission owning affiliates, determined there was a need to improve the speed of its fault location process especially for the 138 and 69 kV system. This system can be tapped with industrial customers and distribution substations. The main objective of this project was to see if the need to call out staff, usually overnight, to run the fault-location program could be eliminated for the majority of faults that occur in a pilot/test area.

When a fault occurs on a major transmission line, it is important that a protection engineer rapidly assess the situation and accurately determine the location of the fault. This information may then be used to minimize the outage duration. This task involves several steps.

First, the source of the trip and the associated line must be identified by operations. Then the appropriate sensor/instrumentation data associated with the tripped line needs to be evaluated. This data can be in the form of microprocessor relay records and/or DFR – Digital Fault Recorder files, which can sometimes be in a proprietary format. In addition to the different recording formats, the DFR records may only implement a few of the current or voltage measurements of the faulted line. Once the protection engineer has gathered all the appropriate data they must analyze the waveforms to determine the nature of the fault (phase -> ground, phase -> phase, three phase, or other), they find the correct branch in the short circuit model and the maximum fault current (usually in RMS). All of this is then manually entered into a fault analysis program software and a fault study is initiated to determine the approximate location of the fault. The goal of this project is to automate as many of these steps as possible to significantly reduce the amount of time required to determine the fault location and impact on the protection engineer. The desire was to do all of this using existing transmission equipment installed with only minimal field changes.

Objective

The overall objective of this effort is to reduce the time to determine where a fault has occurred with sufficient certainty to route field crews to the location of the fault quickly and improve restoration times. In addition, there may be the ability to sectionalize the transmission network so that operations staff can begin restoring customers in areas not directly affected by the faulted line section. The expectation is that by automating the analysis, the time previously spent in off-hour periods to contact a protection engineer, provide him or her with the needed information, and then perform the analysis would be greatly reduced. Streamlining this process should help improve restoration times and decrease the length of outages for customers.

Approach

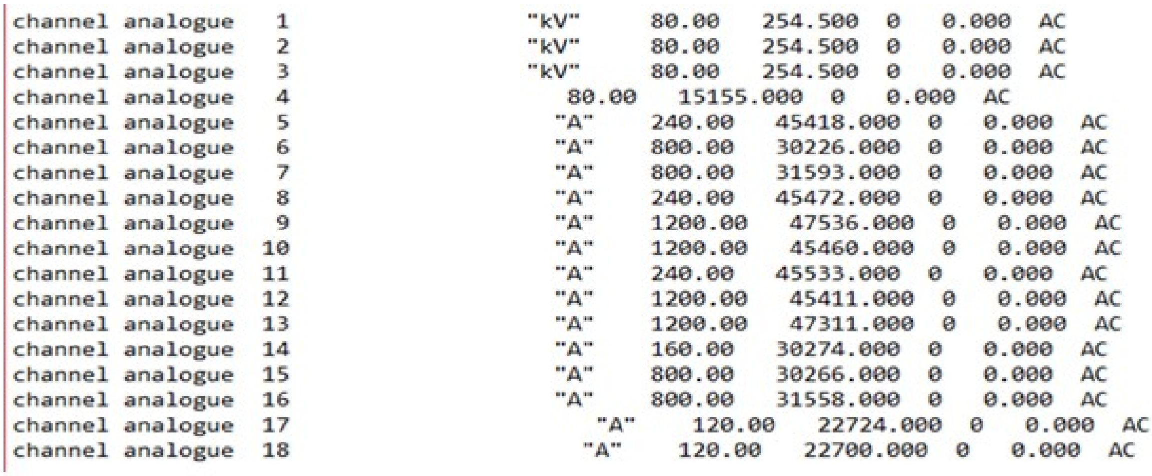
Using an interpreted, high-level, general-purpose programming language, three programs have been developed to help automate the manual process of calculating a fault location. The first of these programs, COG (COMTRADE Organizer), actively polls selected folders on a server for fault records and notifications that indicate a line has tripped. When found, this program moves these files to a different folder and prepares them for the second program, CTA (COMTRADE Analyzer) which performs the analysis. COG will also move historical records out of the folders when they should no longer be used for analysis. Once a fault record is moved to the appropriate folder, CTA will parse the fault information, start the fault analysis program, update it from the third program with the latest topology, calls upon a fault location macro within the fault analysis program, parse the fault analysis program results and e-mail the results to a specified e-mail group. The third program created, known as

EMSSync, polls historical EMS data, determines which equipment is out of service and provides this status to the fault analysis program. Finally, the CTA application moves the studied fault record to a historical folder so that each fault record is only studied once. While this process has been previously presented in references [1] [5], this paper will summarize the programs as they stand, since some programs have been modified.

Data Sources and Format

The two primary sources for fault information for the pilot area chosen are from microprocessor relay fault records and DFR records. The microprocessor relay files typically contain waveform data sampled at 16 samples/cycle for all the key electrical parameters (IA, IB, IC, IR, VA, VB, VC) as well as digital/trip states within the relay. The DFR format is a proprietary format of the vendor and requires special software to decode the output. Unlike the microprocessor relay fault files that are associated with a single relay/line, the DFRs can record waveform data for multiple lines (up to 32 possible analog channels per device). DFRs also record at a higher sampling rate of 96 samples per cycle. An additional challenge encountered was the limited number of analog channels monitored by the DFR at some older substations; as little as one phase current plus the residual current on a line. Also, since DFRs are necessarily not as common as microprocessor line protection relays, DFR records from a few buses away may need to be used for event analysis.

Figure 1 is an example of the data found in a typical DFR record.



```
channel analogue   1                    "kV"     80.00   254.500  0   0.000  AC
channel analogue   2                    "kV"     80.00   254.500  0   0.000  AC
channel analogue   3                    "kV"     80.00   254.500  0   0.000  AC
channel analogue   4                       80.00   15155.000  0   0.000  AC
channel analogue   5                      "A"    240.00   45418.000  0   0.000  AC
channel analogue   6                      "A"    800.00   30226.000  0   0.000  AC
channel analogue   7                      "A"    800.00   31593.000  0   0.000  AC
channel analogue   8                      "A"    240.00   45472.000  0   0.000  AC
channel analogue   9                      "A"    1200.00   47536.000  0   0.000  AC
channel analogue  10                      "A"    1200.00   45460.000  0   0.000  AC
channel analogue  11                      "A"    240.00   45533.000  0   0.000  AC
channel analogue  12                      "A"    1200.00   45411.000  0   0.000  AC
channel analogue  13                      "A"    1200.00   47311.000  0   0.000  AC
channel analogue  14                      "A"    160.00   30274.000  0   0.000  AC
channel analogue  15                      "A"    800.00   30266.000  0   0.000  AC
channel analogue  16                      "A"    800.00   31558.000  0   0.000  AC
channel analogue  17                         "A"    120.00   22724.000  0   0.000  AC
channel analogue  18                        "A"    120.00   22700.000  0   0.000  AC
```

Figure 1 Typical DFR record

To perform an automated fault location calculation, specific data will need to be parsed from both types of fault record. This information will in turn be used to prepare commands to be used to run a fault location macro within the fault analysis program.

COMTRADE Standard

Since the DFRs are proprietary format, it was decided to use the industry standard COMTRADE (Common Format for the Transient Data Exchange for Power Systems) format to analyze the DFR fault records. One would think that once a single COMTRADE file had been decoded, that COMTRADE files from any DFR or relay would be able to be analyzed by the program. However, while developing the waveform analysis application it became apparent that the COMTRADE formats from different equipment are not the same. Due to these differences, a revised CTA program was needed to handle the different types of relay and DFR files. At this time the program can only handle the COMTRADE exported from the one vendor's proprietary DFR records, but active testing is being completed to handle relay event COMTRADE files. Future work is also planned to integrate with a well-known COMTRADE event viewer software.

EDOA

EDOA (Energy Delivery Outage Analysis) is a program that the utility uses to track transmission operations. Transmission System Operators create event records in EDOA whenever a transmission trip occurs. An email is then sent from the EDOA system to a distribution list to inform personnel of the trip that occurred. When the e-mail is sent to the distribution group, a text file with the e-mail's contents is sent to the automated process. As discussed below, it was decided to use these notifications as the trigger to begin the automated event analysis process.

COG

COG (COMTRADE Organizer) is a program developed to move COMTRADE and EDOA records to appropriate active folders to make them available to be run by CTA. COG will also move out historical EDOA files that have stayed active for specific number of days, currently set for three days. The use of three days is to capture polling of different fault records that might happen manually due to communication failures or for faults that might happen around the midnight hour.

Data Cleansing

Active work at the utility to create a single source of truth for substation and transmission names is underway. In order to limit the number of cross reference tables needed, multiple individuals from different internal company groups have come together to sort out and agree on data governance. Since this team has not fully rolled out these names, an intermediate solution was needed for misaligned naming of transmission lines. For a variety of historical reasons, most naming conventions are not standardized between applications and devices. As a result, the name of the line in fault analysis program, the corresponding DFR COMTRADE file line/location names, and the EDOA names may be different. Differences may include names that are abbreviated differently, a dash that replaces a blank, or the suffix "LINE" may be appended to the name. Any automation program will need a cross-reference table, a form of "Rosetta Stone" to deal with the inconsistences between the various data sources. Figure 2 shows the process developed to automatically generating a master list of all EDOA line names and match them to the fault analysis program names using regular expression (REGEX) tools. The resulting table forms the basis for the EDOA cross-reference table data join that includes the EDOA line name, fault analysis program name and line length. Once created, this table will need to be updated as system changes occur, until the data governance group rolls out their standards.

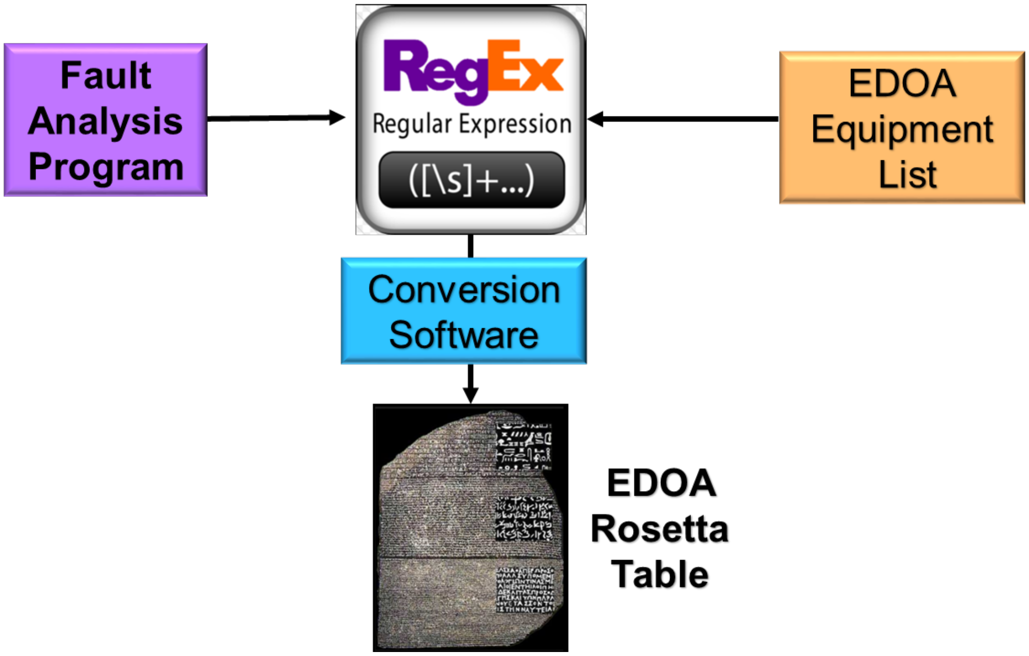


Figure 2
Build EDOA Rosetta Database – "Fuzzy" (regex) search

While in the plans, the company's data governance team is still a few years away from standardizing on IED naming. Therefore, the DFR cross-reference table of records is the most challenging since a single DFR installation at a single location (using multiple boxes) can monitor around 32 analog sensors. A special program using an array walking library was written to digest and walk all the configuration files and produce the DFR Cross-reference table. The columns include: Fault Analysis Program substation name, DFR Location, IA, IB, IC, IR, VA, VB, VC.

Also, experience has shown that DFRs can be triggered by events other than line faults (such as a capacitor bank switching). To avoid the processing of spurious event records, it was decided to initiate the automation process from an event generated by the utilities Transmission Operators in the EDOA system. [3]

Fault Analysis Program database and automation

The utilities primary fault analysis tool that was used is based on an extensive internal database of over 250 tables that describe in detail transmission lines and transformers, protective relays, breakers and their associated physical and electrical properties. It is constantly maintained and updated to accurately represent the current state of the electrical transmission grid.

The fault analysis program uses an open source database to hold all needed system information including line names, connectivity and electrical and physical (length) properties. Tables associated with the short circuit model were exported into a Microsoft Access database so specific tables and fields could be used in the automation process. Figure 3 is an example of using selected fault analysis program tables to build translation tables and provide electrical and physical data (line mileage) to CTA. [2]

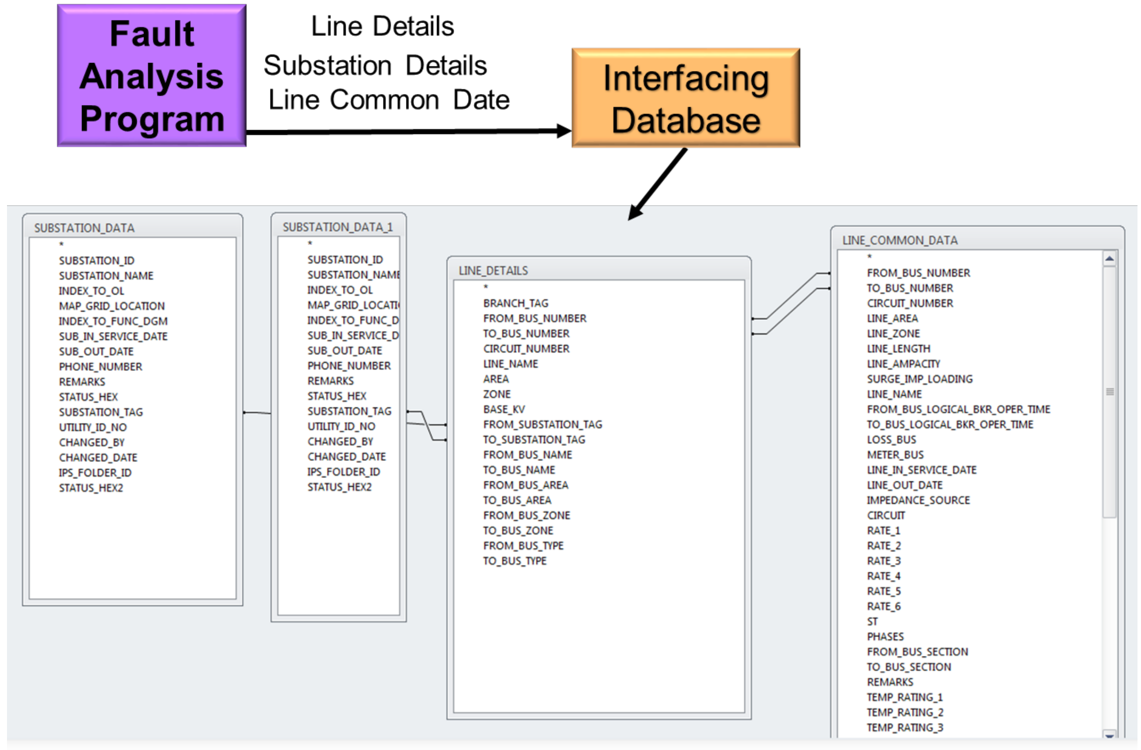


Figure 3
Build EDOA Rosetta Database – Fault Analysis Program data "join"

Cross Reference Tables

Using the process noted above, two independent cross-reference tables were created to deal with the inconsistences between the various data sources. After investigating the different formats of transmission line models in the short circuit database, it was found that this cross reference initially created was not robust enough to handle the complexity of the database. A new cross reference was needed.

Figure 4 is a representation of the real and fictitious buses along a sample transmission line model. Buses 9050 (Substation A) and 9509 (Substation B) are real busses that have protection modeled on them in the fault analysis program database. Tapped transformers are connected at buses 10602 and 402600 through fictitious busses 10601 and 239617 respectively. Due to recent efforts to update the short circuit database with the active protection on the lines, namely for PRC-027. The team used the fact that the real bus terminals of the line at Substations A and B have protection modeled at them, an SQL query was created and applied to the short circuit model database to provide the baseline for the revised cross reference table. That is, the query provided the fault analysis program information shown below only where a bus had relay data modeled at it. These locations are where fault record information can likely be retrieved from as well.

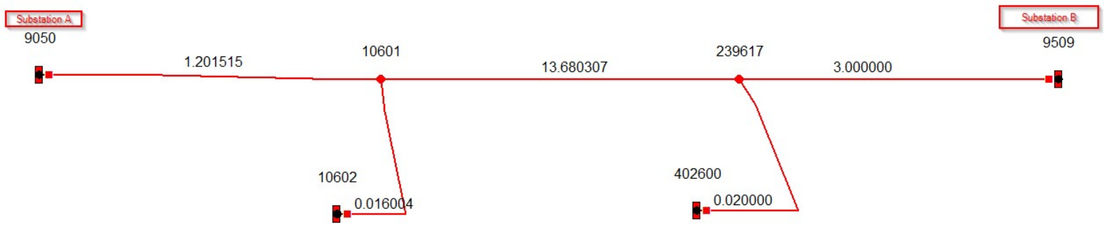
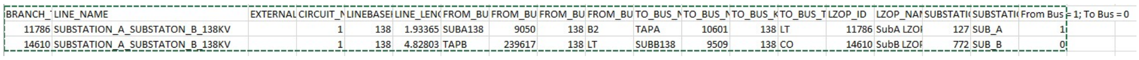


Figure 4
Short Circuit model (displaying line length in miles)

From this new query, a preferred cross reference table layout has been created.

- Station Location of IED (DFR or Relay)
- IED Name (For multiple recorders or PR vs BU relays)
- Line Exit (from the IED)
- IED (DFR or Relay) Channels
- Line Name
- External Branch ID (Reserved as future location where EDOA Line Name can be stored)
- Circuit Number
- Line kV
- Circuit Number Line Length
- From Bus Number
- From Bus Name
- To Bus Number
- To Bus Name
- From Sub Number
- From Sub
- To Sub Number
- To Sub
- LZOP ID
- LZOP Name
- LZOP Substation Tag/ID
- From Bus/To Bus Flip

To compute a calculated fault location, the required fault analysis program commands are based upon a fault analysis program 'from bus – to bus pair' that is shown in Figure 5. Since DFR and microprocessor records are based upon the IED location and the channel (terminal) name, care must be taken to supply these in the correct order for the fault analysis program analysis. The "From Bus / To Bus Flip" field is used to indicate where the fault analysis program from bus is not the same location as the DFR Station Location.



BRANCH_	LINE_NAME	EXTERNAL	CIRCUIT_N	LINEBASEI	LINE_LEN(	FROM_BU	FROM_BU	FROM_BU	FROM_BU	TO_BUS_N	TO_BUS_N	TO_BUS_K	TO_BUS_T	LZOP_ID	LZOP_NA	SUBSTATI(	SUBSTATI(	From Bus = 1; To Bus = 0
11786	SUBSTATION_A_SUBSTATON_B_138KV		1	138	1.93365	SUBA138	9050	138	B2	TAPA	10601	138	LT	11786	SubA LZOI	127	SUB_A	1
14610	SUBSTATION_A_SUBSTATON_B_138KV		1	138	4.82803	TAPB	239617	138	LT	SUBB138	9509	138	CO	14610	SubB LZOI	772	SUB_B	0

Figure 5
Fault analysis program Data Extract Example for sample line in Figure 4.

Due to this revelation, a revised application to regenerate a single cross-reference data table as noted above has been created. The revised program uses the previously mentioned process that merged the EDOA and fault analysis program data using REGEX tools. The application that analyzes the fault records and provides input parameters to fault analysis program (CTA) has been modified to handle this single cross reference.

Since the sources of the cross reference tables is subject to change, using the general-purpose programming language, a GUI (graphical user interface) has been created to refresh these cross references on the fly. The utility can go to the source databases, grab the latest data from each, and a new cross reference can be generated. A picture of this user interface is below in Figure 6.

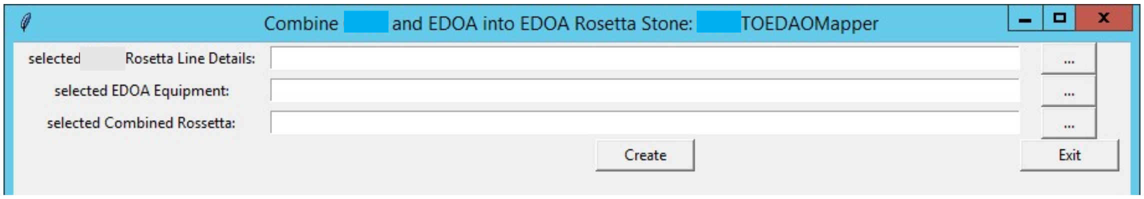


Figure 6: GUI for creation of fault analysis to EDOA cross reference

Running fault analysis program

When using manual methods to calculate fault locations, the engineer runs a macro in the fault analysis program using a standard GUI. This gives the protection engineer the ability to select the appropriate faulted lines and a fault's electrical parameters. Alternatively, a macro can be executed using the fault analysis program command line to automate the fault location process.

To achieve the automation desired as part of this project, it was desirable to run fault analysis program without the standard GUI. A command line interface to fault analysis program already existed, and the ability to create a batch file to launch fault analysis program via this interface was included in the CTA program.

The fault analysis program contains an "Equipment Category" feature which enables the user to include or exclude selected transmission facilities when using the program. Beyond a baseline model, a fault analysis program user can choose which power system elements to include in any particular fault analysis program session. At our request, the vendor added the capability to choose Equipment Categories for a fault analysis program session when launched via the command line interface to utilize this feature for this project.

Data Flow

Figure 7 shows the high-level data flow for the COMTRADE analysis (CTA) application. COMTRADE files from both microprocessor relays and DFR records are converted to COMTRADE format and placed into folders on the CTA server. As mentioned above, when a fault occurs, a file is sent from the outage management system and placed in the EDOA directory. The CTA program is periodically polling the EDOA directory for new fault files. Once CTA detects that a fault has occurred the following steps are taken:

1) The EDOA file is parsed and the name of the faulted line is extracted.
2) All CTA files in the CTA directory are inspected to determine if any are associated with the faulted line.

3) If an appropriate CTA file is found, all 3 of the COMTRADE files (.dat,.cfg,.hdr) are loaded and analyzed.
4) The oscillography/waveform data is analyzed to determine the maximum fault current and the type of fault.
5) Using the cross reference tables, a fault analysis program command string is created to run a fault location macro and provide the data needed to complete the analysis. (This is the same data that would be entered into the fault analysis program GUI if the calculation was being performed manually).
6) The fault analysis program is launched using the defined parameters. Once fault analysis program is finished with its analysis, it returns to the interactive GUI mode waiting for user input. To avoid launching multiple fault analysis program sessions on the server as additional fault notifications are received, it was decided to have CTA wait for a predefined period (currently 30 seconds) and then automatically kills/aborts the fault analysis program session (within Windows).
7) The output from the fault analysis program run is analyzed, sent to appropriate parties via e-mail, and the fault analysis program results file is timestamped and moved to the fault analysis program History directory.

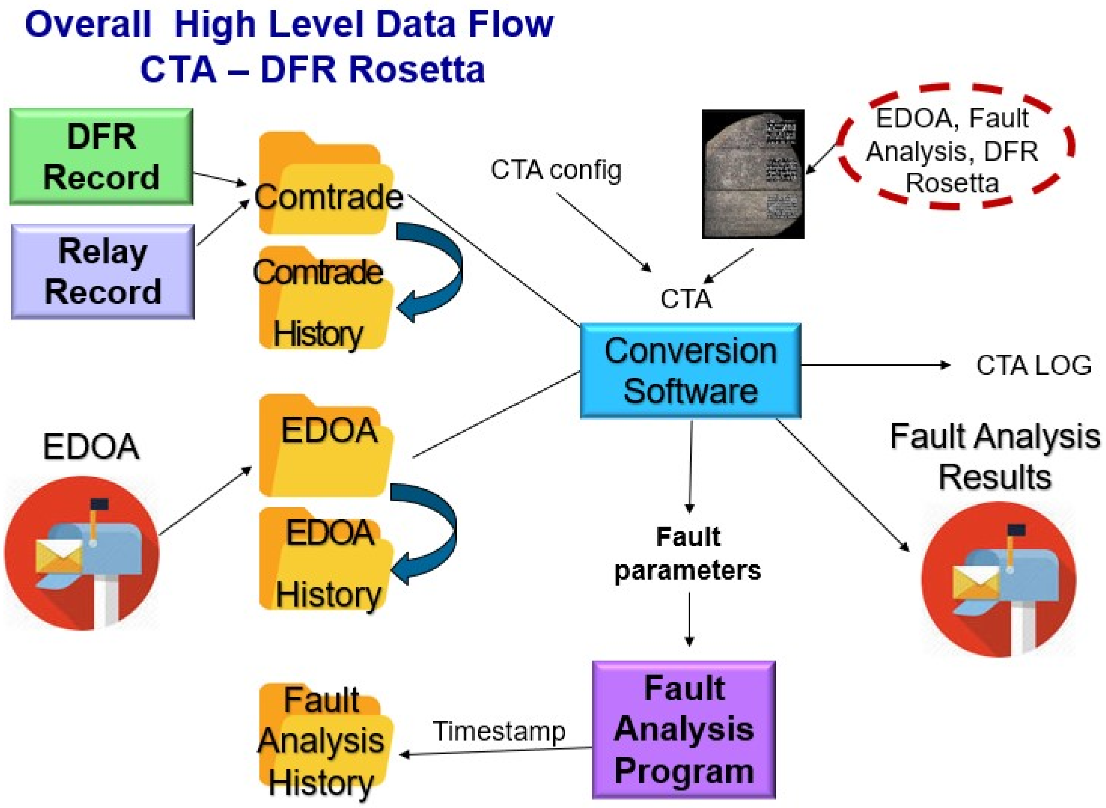


Figure 7
Overall High Level Data Flow CTA – COMTRADE analyzer automation

8) The EDOA file that started the entire process is moved to the EDOA history directory to avoid creating duplicate fault analysis program runs. It is possible that CTA files associated with a given fault will arrive after the EDOA notification. Therefore, an EDOA time window was implemented Figure 8 to keep the EDOA request "active" for a defined period after its arrival.
9) CTA returns to its polling mode waiting for another EDOA request to be generated

All the above steps and the results of the analysis are all logged to the CTA log file.

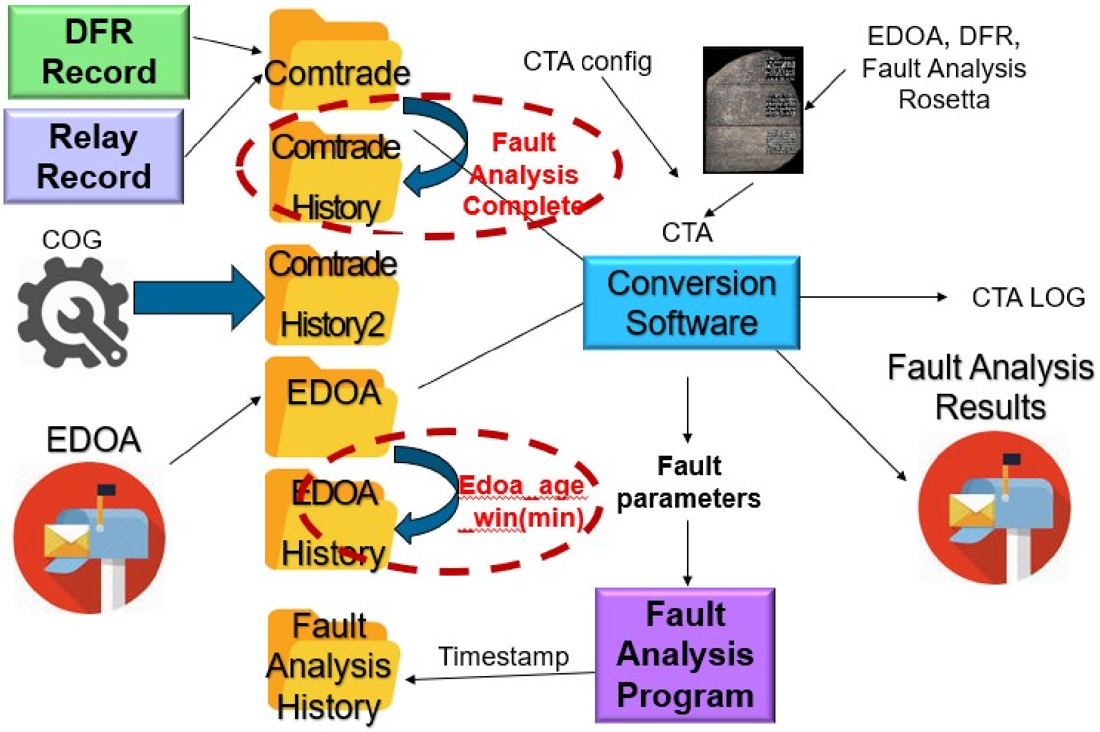


Figure 8
EDOA request AGE Window

Waveform Analysis - DC Offset Adjustment

In the manual process to determine the fault location, the protection engineer determines the fault magnitude. This involves interpreting the fault recorder waveforms and using engineering judgement to determine the approximate value of the fault current. In doing so, the engineer needs to take into account the DC offset and adjusts for the amount of offset. This occurs when a fault is suddenly applied to the system and the sine wave suddenly becomes asymmetrical (the positive and negative peaks are NOT equidistant from zero), and then returns to normal (symmetrical) after a few cycles. This asymmetrical response to the fault is called DC Offset and it is a naturally occurring phenomenon of the electrical system. Protection engineers need to adjust for DC offset when processing the data for fault location purposes. In Figure 9 below is an example of a fault with DC offset.

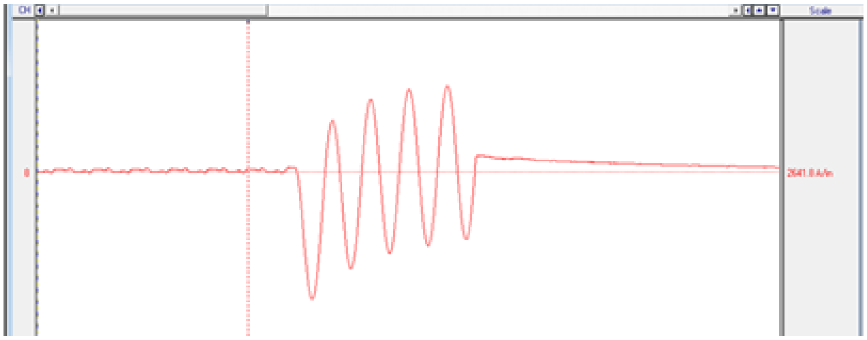
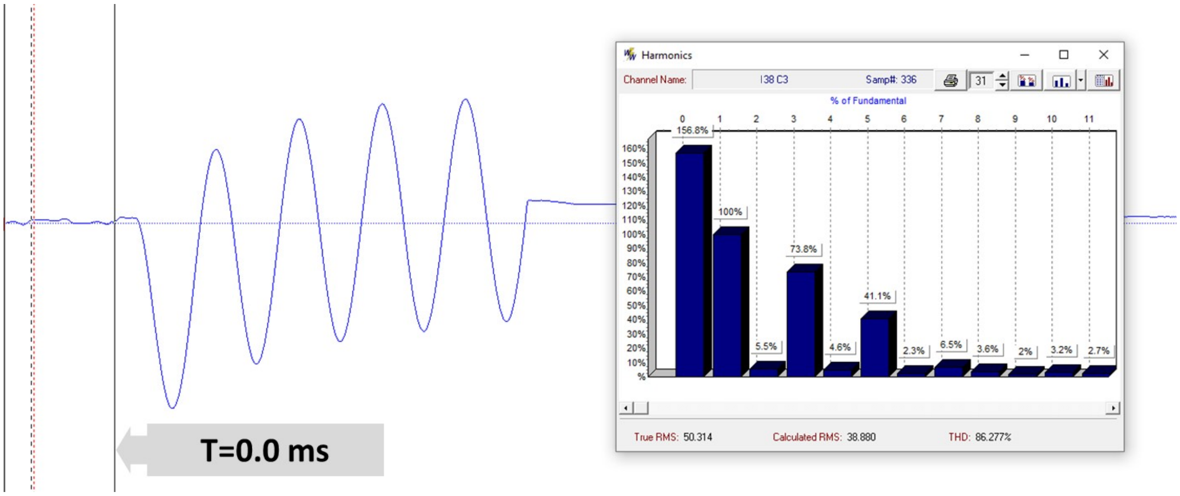


Figure 9: Fault with DC Offset

The authors have considered using harmonic analysis for faults to determine when the DC offset has diminished sufficiently to determine the fault magnitude. In Figure 10 below is a graphical representation of the harmonic analysis of a typical fault. In the example, the DC component is actually 156.8% of the fundamental 60 HZ value. Other prominent frequencies in the example are the 3rd and 5th harmonic which are at 73.8% and 41.1% respectively.

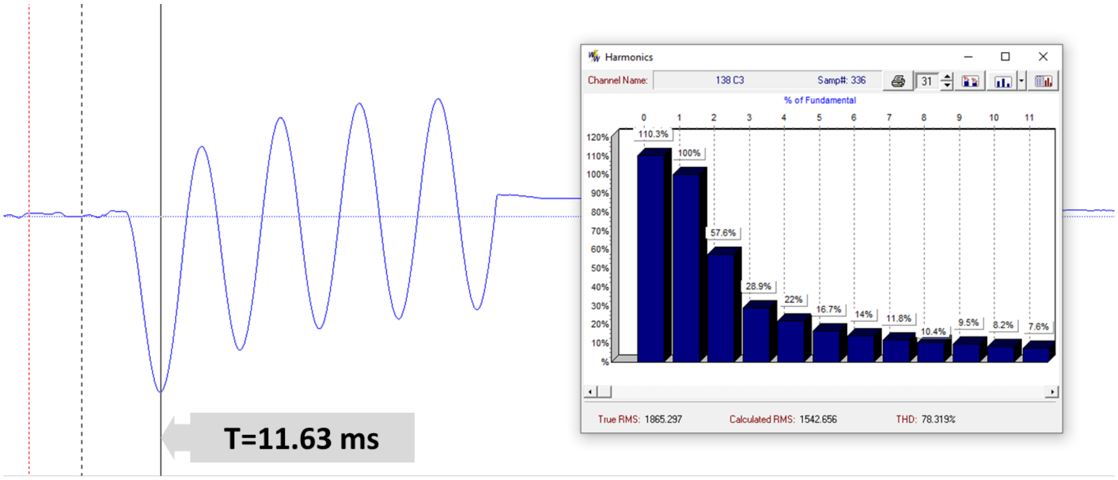

Harmonics

Channel Name: 138 C3 Samp#: 336

True RMS: 50.314 Calculated RMS: 38.880 THD: 86.277%

Figure 10: Initial Fault vs Initial Harmonic Content

As more time as shown in Figure 11 passes the DC offset begins to reduce. 67 samples or 11.63ms after the previous figure the DC offset has reduced to 110.3% of the fundamental. The sample rate is 5760 HZ or 1 sample every 0.1736 ms.

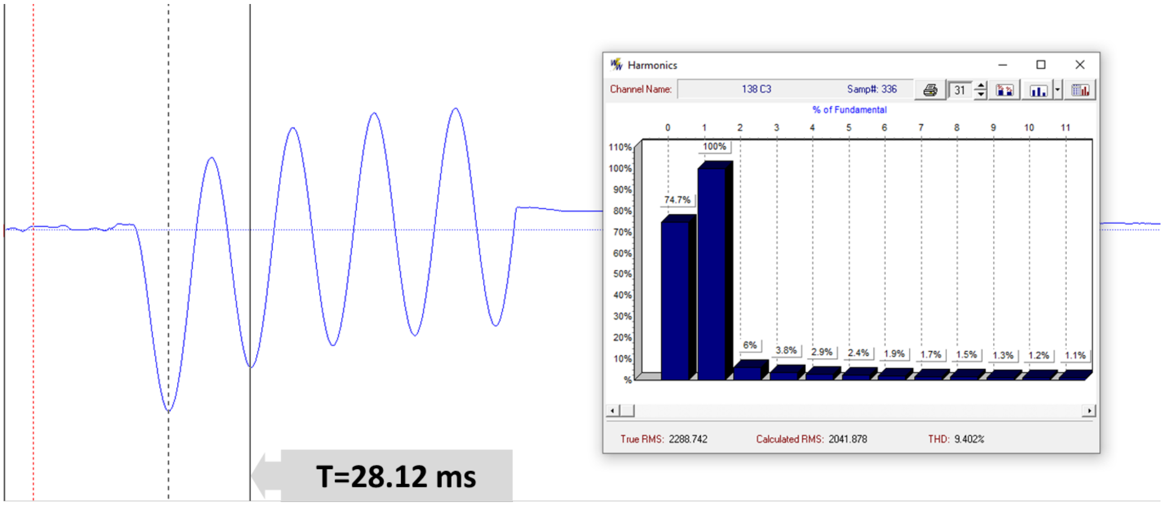


Channel Name: 138 C3 Samp#: 336 31

True RMS: 1865.297 Calculated RMS: 1542.656 THD: 78.319%

Figure 11: DC Offset and Harmonics at T=11.63 ms

After another 95 samples or 16.49 ms, the DC offset, as shown in Figure 12 below, has reduced to 74.7% of the fundamental.

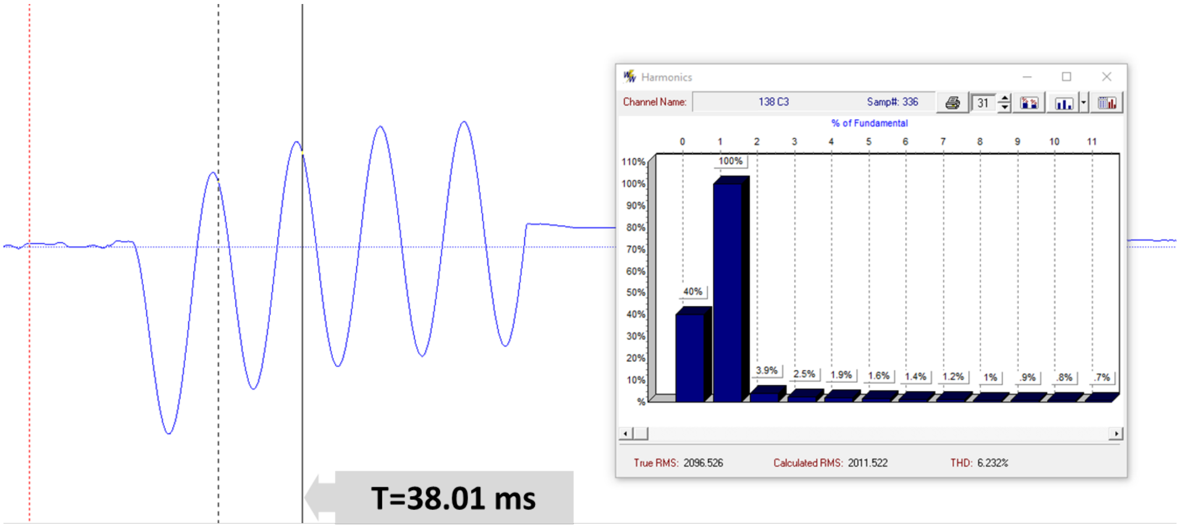


Channel Name: 138 C3 Samp#: 336 31

True RMS: 2288.742 Calculated RMS: 2041.878 THD: 9.402%

Figure 12: DC Offset and Harmonics at T=28.12 ms

In Figure 13, after 57 samples or 9.896 ms later the DC offset has reduced to 40% of the fundamental.

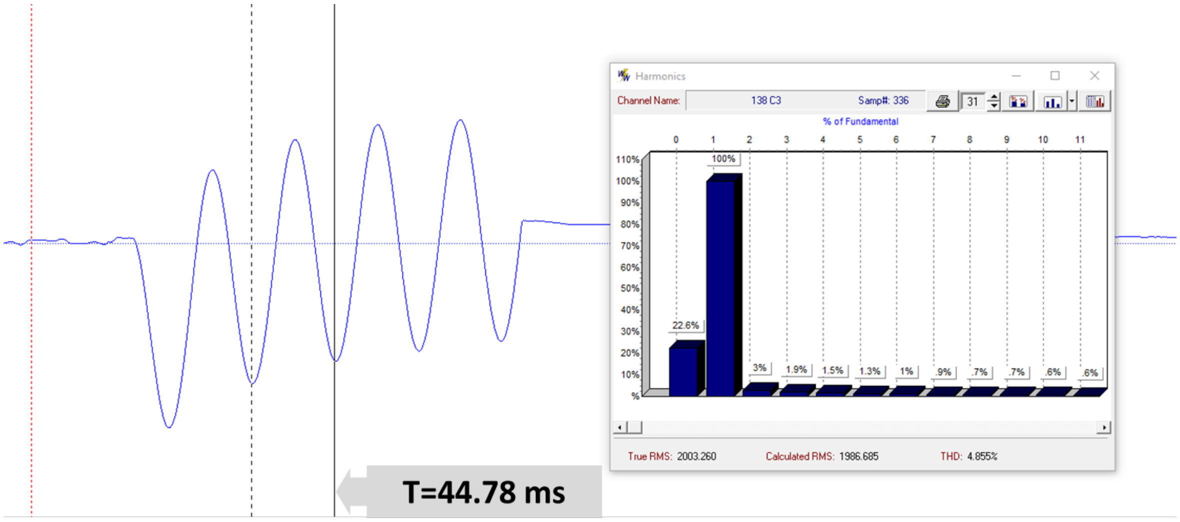


Channel Name: 138 C3 Samp#: 336

True RMS: 2096.526 Calculated RMS: 2011.522 THD: 6.232%

Figure 13: DC Offset and Harmonics at T=38.01 ms

Finally, in Figure 14 after 39 samples or 6.77 ms later the DC offset has settled down to only 20% of the fundamental. Also, the Calculated RMS has begun to settle out. The last three values were 2041, 2011, and 1986 amps. Based on these last three values the fault current to be used for the fault location calculation would be about 2000 amps. This value would be passed to the fault location macro along with other systems adjustments required by the current state conditions.



Channel Name: 138 C3 Samp#: 336

True RMS: 2003.260 Calculated RMS: 1986.685 THD: 4.855%

Figure 14: Stable DC Component at 44.78 ms

Based on the analysis just presented, the authors are proposing to use harmonic analysis to automatically process fault records and remove the effect of DC offset from the fault magnitude.

The question became how to convert the manual/visual algorithm into a repeatable and reliable algorithm. The theory of the manual to computational algorithm conversion is to create a filter that allows the DFT (Discrete Fourier Transform) DC-offset bin changes to be accentuated and to remove changes that are noise.

In order to create a computational filter, it was decided to normalize the DC-offset value against the average DC-offset value over the entire channel capture.

The implemented algorithm follows and is shown graphically in *Figure 15*:

1) Select COMTRADE Current Channels to Analyze
2) Determine the channel with the maximum current peak and the sample number of that peak.
3) Calculate an Array Discrete FFT values for the channel based upon the COMTRADE data, windowSize and sampling rate.
    a) Take the Bin zero (e.g. DC component) of the calculated DFT and add to the array at the beginning sample number slot of the window used to calculate the DFT.
    b) Index to the next current COMTRADE sample number
    c) Repeat until all samples of the current values have had DFTs calculated.
4) Calculate the delta of the DFT values for DC-Offset by sliding the window through all channels and store the results in a delta-change array.
5) Calculate the average DFT magnitude of change based on the absolute value of the values in the delta-change array. This average is used to normalize values to determine the delta-change array sample at which to declare the fault current. Create an array of these normalized values.
6) Because DFTs are calculated based on a window size, based on the sample number of maximum current value detected, find the equivalent sample number in the normalized DC-offset array.
7) Determine the value to be chosen as the fault value. The current code takes the average value from the delta array at the current peak *0.2 (for example, an 80% decrease).
8) Starting at the sample number of the peak current, index through the normalized array until the limit value, or less, is found. The limit of the search is currently four window sizes (for example, four cycles). If the limit is detected, record the sample number.
9) If the limit value is not located, set the detected sample number to that of the peak current.
10) Calculate the true RMS value of the current from the sample number forward based on the window size.
11) Return the true RMS value.

A summary of this process is shown in *Figure 17*.

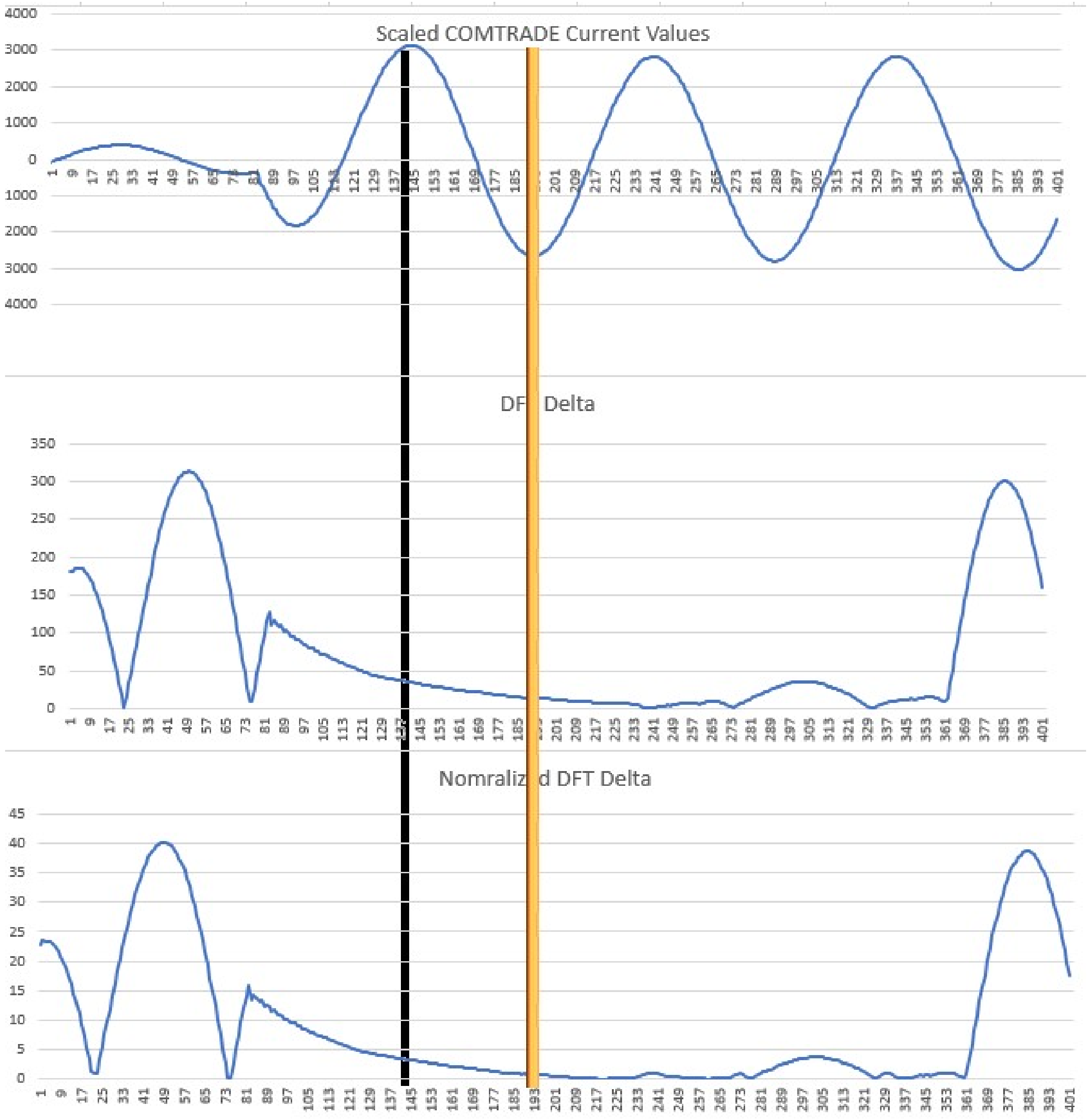
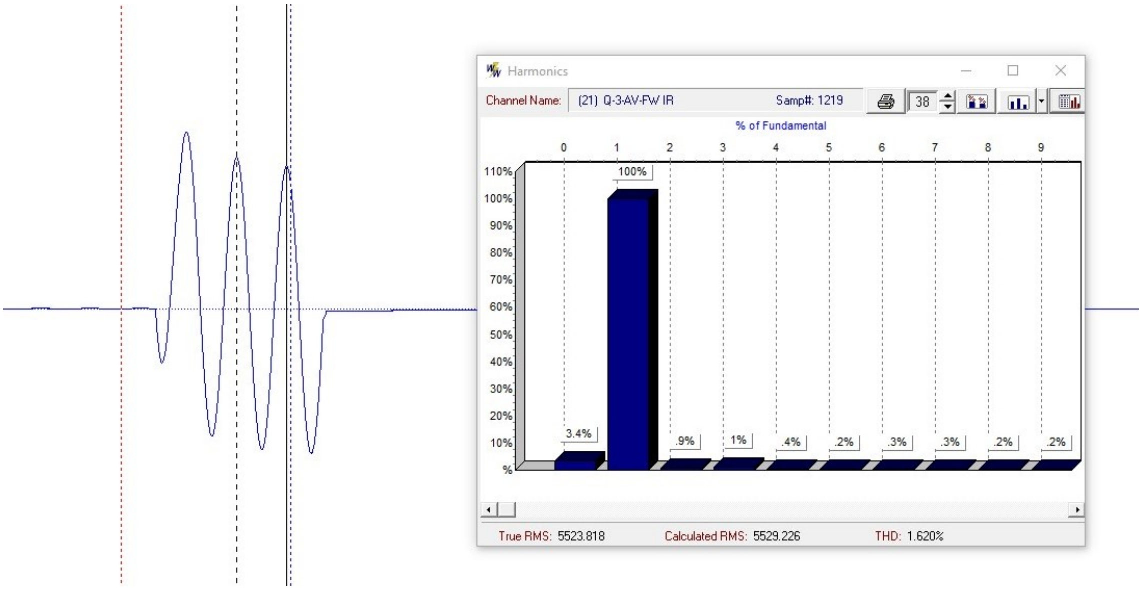


Figure 15: Algorithm Steps Graphically for the Example Fault

Additional Test of the DC Offset Adjustment

To further validate the proposed process, a recent line fault was manually processed through the algorithm. Fault currents were also visually determined by a protection engineer. As can be seen in Figure 16 the DC component is at 3.4% and the fault current is at approximately 5524 amps. The protection engineer interpreted the data as 5500 amps. The fault currents at the other potential DC percentages can be seen in the table at the right.

DC Percentage	Amps
40%	5900
20%	5400
10%	5550
3.4%	5524



Channel Name: (21) Q-3-AV-FW IR Samp#: 1219

True RMS: 5523.818 Calculated RMS: 5529.226 THD: 1.620%

Figure 16 – Recent Fault Processed Through Proposed Process

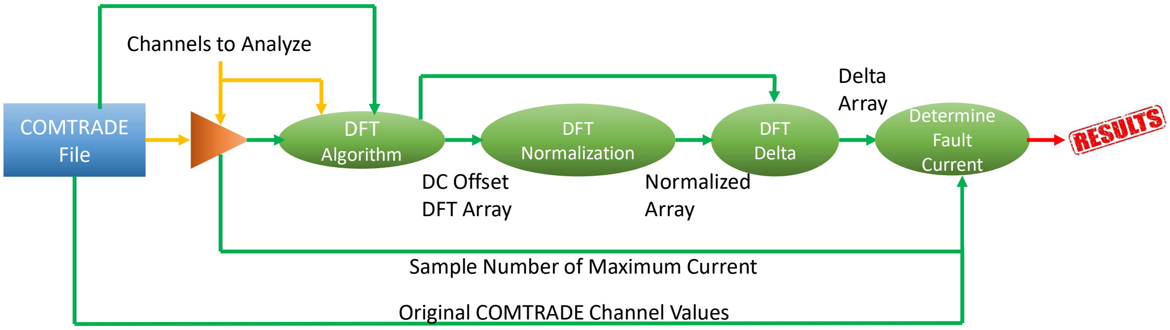
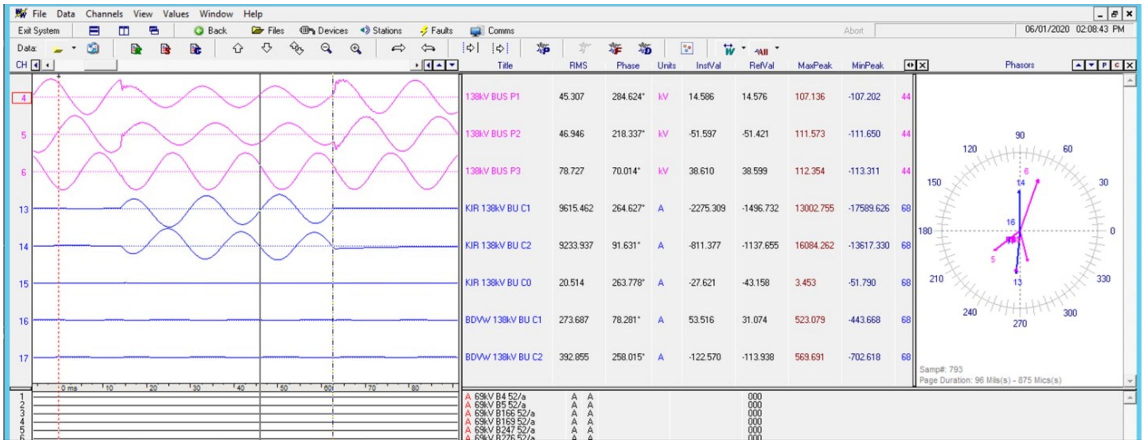


Figure 17: FFT Process

GUI for Fault Analysis

To analyze specific faults, a GUI (shown in Figure 20*Figure 18*) was set up to allow protection engineers to validate the automated analysis using the FFT process. Figure 18 shows a phase to phase fault that was run through the FFT processor. To have the fault analyzed, the user just has to select the .cfg file of the COMTRADE record and results will be displayed.

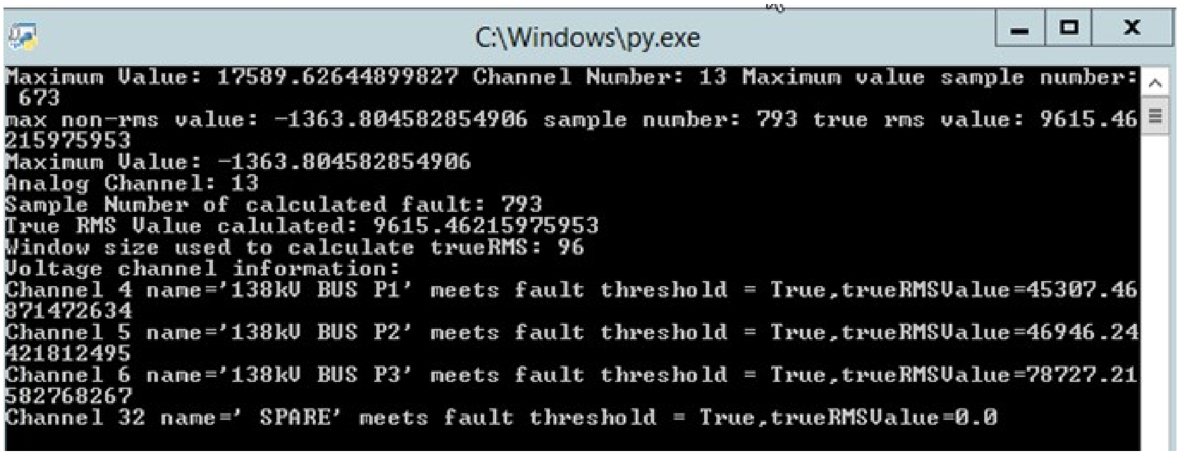


Title	RMS	Phase	Units	InstVal	RefVal	MaxPeak	MinPeak	
138kV BUS P1	45.307	284.624°	kV	14.586	14.576	107.136	-107.202	44
138kV BUS P2	46.946	218.337°	kV	-51.597	-51.421	111.573	-111.650	44
138kV BUS P3	78.727	70.014°	kV	38.610	38.599	112.354	-113.311	44
KIR 138kV BU C1	9615.462	264.627°	A	-2275.309	-1496.732	13002.755	-17589.626	68
KIR 138kV BU C2	9233.937	91.631°	A	-811.377	-1137.655	16084.262	-13617.330	68
KIR 138kV BU C0	20.514	263.778°	A	-27.621	-43.158	3.453	-51.790	68
BDVW 138kV BU C1	273.687	78.281°	A	53.516	31.074	523.079	-443.668	68
BDVW 138kV BU C2	392.855	258.015°	A	-122.570	-113.938	569.691	-702.618	68

```
A 69kV B4 52/a     A A   000
A 69kV B5 52/a     A A   000
A 69kV B166 52/a   A A   000
A 69kV B169 52/a   A A   000
A 69kV B247 52/a   A A   000
A 69kV B276 52/a   A A   000
```

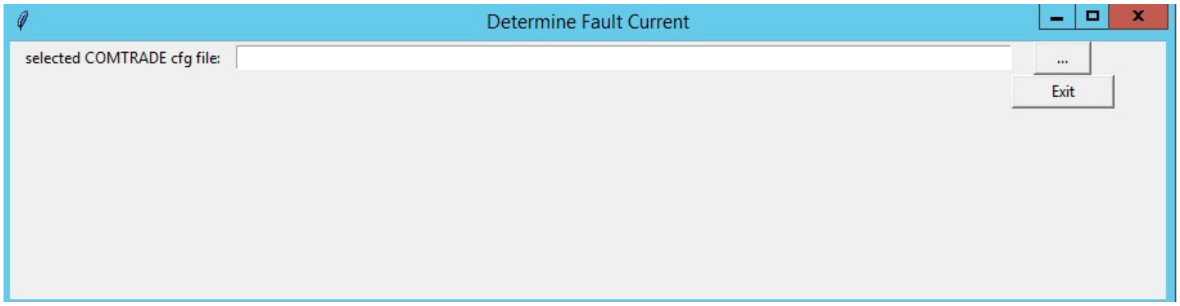
Figure 18: Display of fault information

Below in Figure 19 are the results of the FFT process. At this point only the current is used in any automated fault analysis, but for any voltage channels, the RMS voltages are reported at the time of maximum current so that an engineer, or an automation process someday, could verify the fault type and faulted phase(s).



```
Maximum Value: 17589.62644899827 Channel Number: 13 Maximum value sample number:
 673
max non-rms value: -1363.804582854906 sample number: 793 true rms value: 9615.46
215975953
Maximum Value: -1363.804582854906
Analog Channel: 13
Sample Number of calculated fault: 793
True RMS Value calulated: 9615.46215975953
Window size used to calculate trueRMS: 96
Voltage channel information:
Channel 4 name='138kV BUS P1' meets fault threshold = True,trueRMSValue=45307.46
871472634
Channel 5 name='138kV BUS P2' meets fault threshold = True,trueRMSValue=46946.24
421812495
Channel 6 name='138kV BUS P3' meets fault threshold = True,trueRMSValue=78727.21
582768267
Channel 32 name=' SPARE' meets fault threshold = True,trueRMSValue=0.0
```

Figure 19: FFT Results



selected COMTRADE cfg file:

Figure 20: User GUI for Manually Determining Fault Current

Fault Analysis – Topology Adjustment

In addition to fault analysis, various transmission system models are used for long term system planning, short term (maintenance) planning and real-time system operations. In general, long term system planning models do not make use of real-time system information, while maintenance planning and real-time system operations programs have the capabilities of using real-time (or near real-time) data. Short circuit models have a need for longer term models (breaker capability & substation ground grid calculations), mid-term models (relay settings), and near real-time models for fault location calculations.

System equivalent impedances, current flows and voltage distribution are affected by changes of system topology. At the utility, a fault analysis program has a base topological model (e.g. similar to an EMS) but historically has had no real-time outage information. As part of this phase of the project, a mechanism was provided that allowed the outage information known by the EMS to be provided to fault study program for use during a fault location analysis.

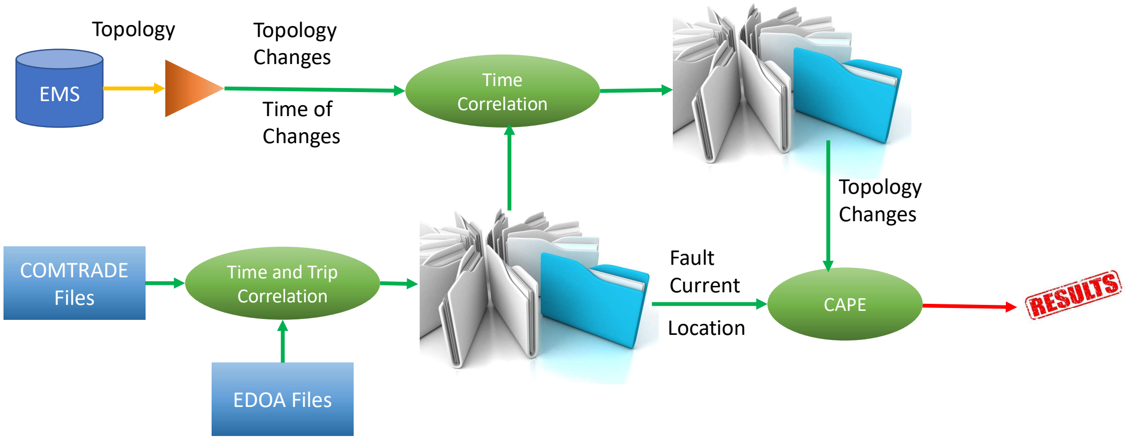


Figure 21: EMSSync Program Overview

Figure 21 shows the process that the EMSSync program uses to apply topological changes from the EMS system to the short circuit model. The process performs a query on the real-time EMS model approximately every 5 minutes (though EMSSync could handle up to 30 seconds) to extract present topological information. An EMS to short circuit model cross reference table is used to create a topology change file which contains the status of transmission elements. These files are then timestamped and placed into a directory of such files.

When performing an automated fault location, the CTA program searches the topology change file directory, comparing the fault time from EDOA and the selected COMTRADE file to the files in the topology change file directory. The file with the closest time stamp is chosen. The CTA program then creates a string of commands in the syntax of the fault analysis program to perform the required transmission network changes prior to running the fault location algorithm.

Experimentation has shown an improvement in calculated fault location accuracy when applying the transmission network changes taken from the EMS real-time model. As an example, a calculated fault location for an actual system fault that is shown in Figure 18, without applying topological changes, was 2.1 miles from the found fault location. The fault location, after applying topological changes, was within 0.4 miles of the actual fault. Figure 23 shows the manually calculated fault location without taking the topology change into account. Figure 24 shows the revised calculation due to the area outage.

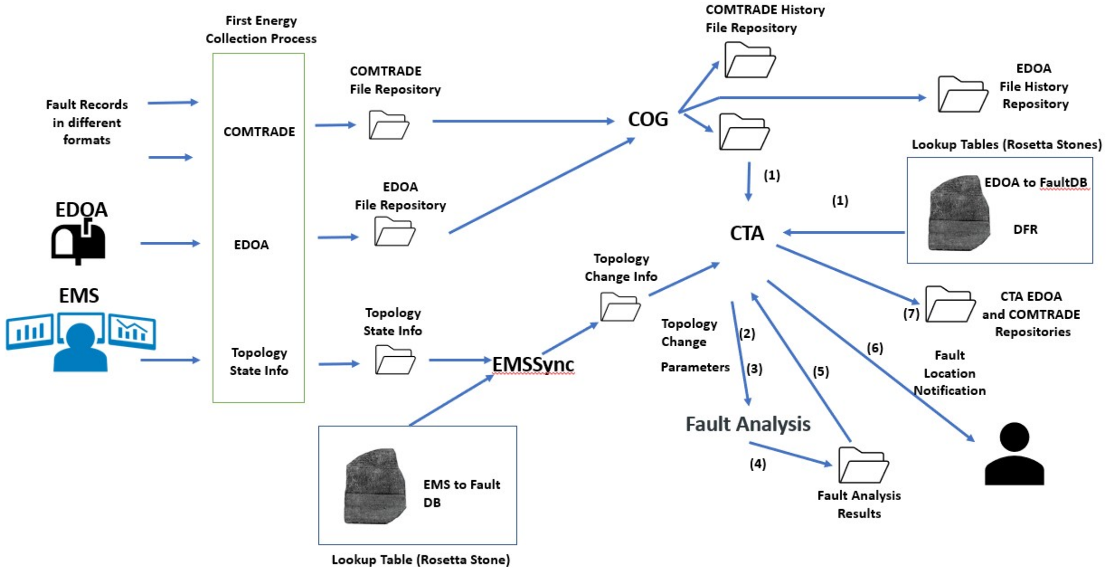


Figure 22: Updated Automatic Fault Location Process

Figure 23: Fault Location without area outage.

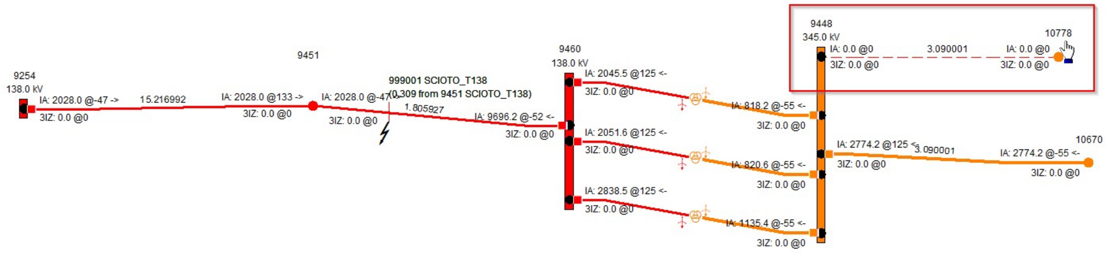


Figure 24: Fault Location with area outage.

Looking to the Future

- The output from the fault analysis program macro provides locations in percentages of real bus to real bus. The post processing of the calculated fault location will look to be improved to calculate a length from a specific terminal. This will require adding the full real bus to real bus line length to the fault analysis program database. Beyond this, a geographical view showing pole location could be accomplished by plotting the fault on the transmission GIS.
- For a permanent fault, one or both terminals may attempt an automatic reclose. This may result in a second fault record. At this time, both fault records might be analyzed assuming normal system conditions. Investigations are ongoing to determine how to improve this portion of the process.
- For faults where fault records from both terminals are available, a double ended fault location macro in the fault analysis program could be run. Efforts to get this macro calculation into the process are planned as well.
- Creation of a an EMSSync GUI for protection engineers to update the fault analysis program manually from the EMS data is to be developed. This will allow the engineers to update a short circuit study for operational investigations to determine fault clearing time as well as manually check results from the automated fault location process.
- The current COG, CTA, and EMSSync utilities run as processes instead of windows services. This means that if the server restarts, these utilities need to be manually restarted. These utilities need to be modified so that they can be used as windows services or restart automatically should the server restart.

Conclusion

This paper has presented how one can take the extracted data from fault records, adjust it to be able to “connect” across a single cross reference table (Rosetta Stone) using Fuzzy (regex) search tools and walking array tools. The resultant data can then establish a data source that can be automatically run using a fault analysis program fault location macro to locate the possible fault location. The results presented are a summary of the process flow and waveform analysis approach. Even though it is still being finalized, this paper shows that a very solid foundation has been built that can be used to fully automate the entire process. This paper has also presented how analyzing the 60Hz component of an unfiltered fault record can be determined and then used as an appropriate fault magnitude for applying the fault within fault analysis program. Adding in the appropriate topology changes to match the pre-fault system condition assists in providing an accurate location.

BIBLIOGRAPHY

[1] C. Black & G. Wilson Southern Company P. Myrda EPRI CIGRE GOTF October 2017, Cleveland, OH – “Automated Fault Location Analysis – Data Analysis Method”

[2] C. Black & G. Wilson Southern Company P. Myrda EPRI M. Gehrs Gehrs Consulting PAC World, June 2017 Wroclaw, Poland – “Benefits of Modern Database Tools Applied to Event Record Data Extraction”

[3] P. Myrda - (EPRI), C. Black, G. Wilson, Southern Company, M. Behe FirstEnergy CIGRE GOTF October 2016 Philadelphia, PA – “Automated Fault Location Analysis - Data Gathering Assessment”

[4] R. Maxwell & R. Dixon - FirstEnergy Service Corp, P. Myrda - EPRI, CIGRE GOTF October 2018 Reston, VA – “Automated Fault Location Analysis – Analytics Update”

[5] C. Black & G. Wilson Southern Company P. Myrda EPRI, PACworldUSA, June 2017 Wroclaw, Poland – “Automated Fault Location Analysis”