

Relay Record Interpretation and Conditional Fault Resistance Assessment in the Lamadji 90/15 kV Substation

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Abstract

This study examines an evolving disturbance on the T100B feeder at the Lamadji 90/15 kV substation using relay-display screenshots and previously tabulated NEPLAN short-circuit results. Visual inspection suggests an initial phase-A-to-ground fault, followed by an A-C-to-ground stage and a three-phase stage, with recurrence after an apparent reclosing operation. This chronology is provisional: raw COMTRADE samples, verified CT/VT ratios, and breaker-status records were not supplied. Reported peak currents of 1.5 and 5 kA give approximate RMS estimates of 1.06 and 3.54 kA only under a sinusoidal assumption. The closest three-phase current among six tested nodes is 3.83 kA at JDB15, with an 8.19% discrepancy using the rounded RMS estimate. At that assumed location, the tested A-G resistance of 7 Ω produces 1.072 kA, with a 1.13% discrepancy. These are amplitude agreements used for case selection, not independent validation. The proposed signal-processing and classification equations are retained as an unevaluated framework. The available scalar currents cannot uniquely separate fault resistance from distance, establish the feeder measurement equivalent of a busbar fault, or explain the reported general outage. The study therefore reports a conditional resistance candidate and specifies the data needed for quantitative validation.

Keywords

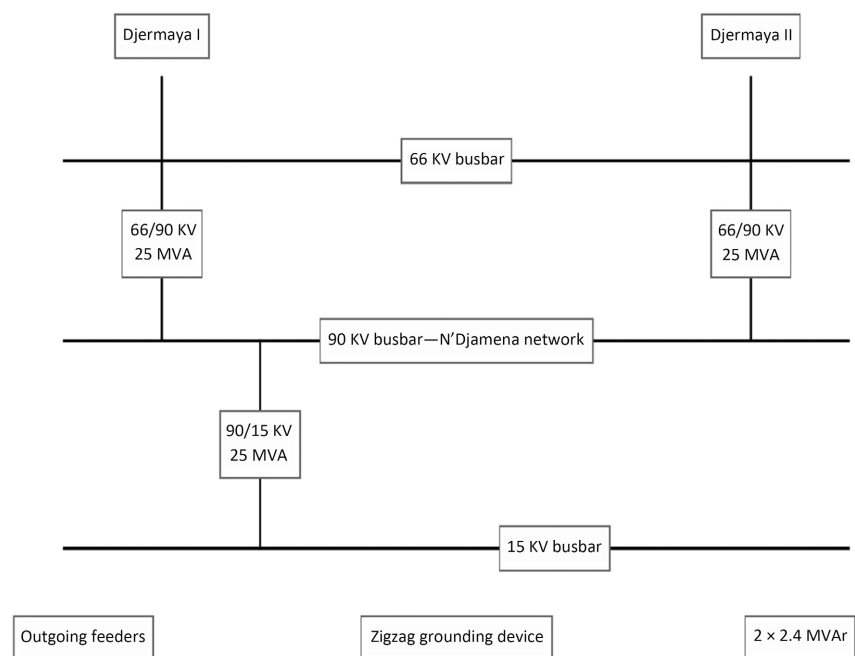
Digital Protection Relay, Fault Diagnosis, Fault Resistance, Grounding Reactor, NEPLAN, Power-System Protection, Substation

1. Introduction

Evolving earth faults can change the participating phases and the quantities seen by protection relays. Measurement-based fault sensing and location methods provide relevant approaches [1]-[5], but their application depends on measurement quality and verified network parameters. IEC 60909 supplies a framework for balanced and unbalanced short-circuit calculations [6] [7]; COMTRADE standardizes the exchange of transient records [8]. This paper examines the available evidence for a T100B feeder disturbance at Lamadji. Its contribution is a provisional reconstruction from relay screenshots and a transparent comparison with previously reported NEPLAN amplitudes. It also sets out a signal-processing framework for future evaluation. The framework is not presented as implemented or validated in this study. Resistance, feeder distance, instrument scaling, and the selected simulation measurement point are treated as sources of uncertainty. Sections 2 - 5 present the supplied system information, proposed framework, model assumptions, and amplitude comparisons; Section 6 gives the qualified conclusions.

2. Studied Substation and Recorded Fault

2.1. Electrical Architecture of the Lamadji Substation



Source: Redrawn from the supplied operational single-line diagram; this schematic is not an independently verified as-built drawing.

Figure 1. Schematic of the documented Lamadji voltage levels and main connections, redrawn with English labels. Device-level switching and vector groups are not inferred.

The Lamadji substation comprises 90, 66, and 15 kV voltage levels. The 66 kV section is connected to the Djermya thermal power plant, whereas the 90 kV section forms part of the N'Djamena transmission network. Voltage transformation and

distribution are provided by two 66/90 kV, 25 MVA transformers and a 90/15 kV, 25 MVA transformer. The 15 kV switchboard supplies several distribution feeders, including the T100B feeder considered in this study. Two 2.4 MVar capacitor banks provide reactive-power compensation. **Figure 1** summarizes these documented connections.

2.2. Power Transformer and Neutral Grounding System

The documented distribution transformer is rated 25 MVA, 90/15 kV, with a short-circuit voltage of 10.4%. The supplied description states that its 15 kV winding has no directly accessible neutral. A zigzag grounding transformer/reactor, designated BPN in the source documentation, provides an artificial neutral at the 15 kV busbar. The main transformer vector group is not established by this description. **Figure 2** reproduces the grounding connection.

The BPN provides a zero-sequence return path and limits earth-fault current. **Table 1** reproduces its documented ratings. Sequence-network equations are presented with reference to IEC 60909-0:2016 [9], without claiming that this edition was the actual software setting used for the supplied simulations.

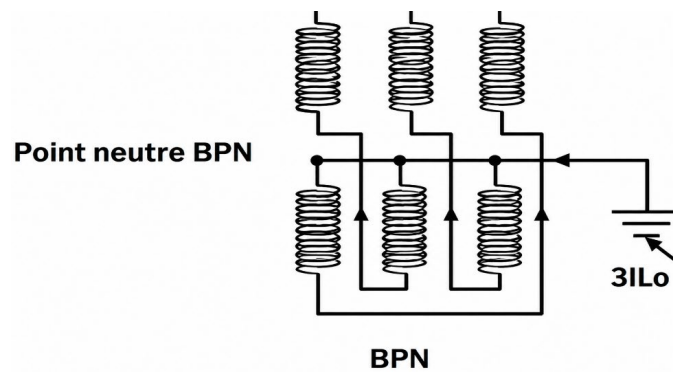


Figure 2. Documented zigzag grounding connection and residual-current path. BPN denotes the zigzag grounding device; the original French label “Point neutre BPN” means “BPN neutral point”.

Table 1. Documented transformer and grounding-device parameters.

Parameter	Value
Transformer rating	25 MVA
Transformation ratio	90/15 kV
Transformer short-circuit voltage	10.4%
BPN rated voltage	15.75 kV
BPN rated power	1600 kVA
BPN zero-sequence impedance	6.08 Ω
BPN short-time current	3500 A for 3 s
BPN connection	Zigzag
Cooling system	ONAN

The $6.08\ \Omega$ value represents the zero-sequence impedance of the grounding device. It must not be confused with the fault resistance R_f or the substation earth-grid resistance R_g , which describe different physical phenomena.

2.3. T100B Feeder and Protection System

The T100B feeder leaves the 15 kV busbar and supplies downstream distribution substations through aluminium conductors. The supplied documentation mentions Schneider Electric MiCOM P142 feeder relays. The manufacturer's manual [10] describes the relay family, but does not establish the installed T100B settings, CT/VT ratios, or firmware.

Feeder currents are measured by phase current transformers, while the residual current is obtained from a core-balance current transformer. Busbar phase voltages are supplied by a voltage transformer. These measurements are processed by the numerical relay for fault detection, tripping, event recording, and oscillographic analysis. However, the exact T100B relay configuration, current- and voltage-transformer ratios, protection thresholds, and operating delays must be confirmed from the original setting file.

2.4. Provisional Event Chronology and Date Discrepancy

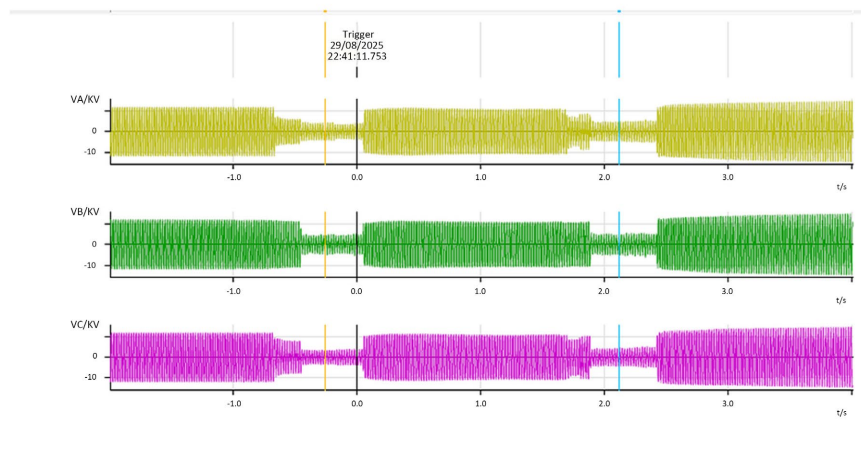
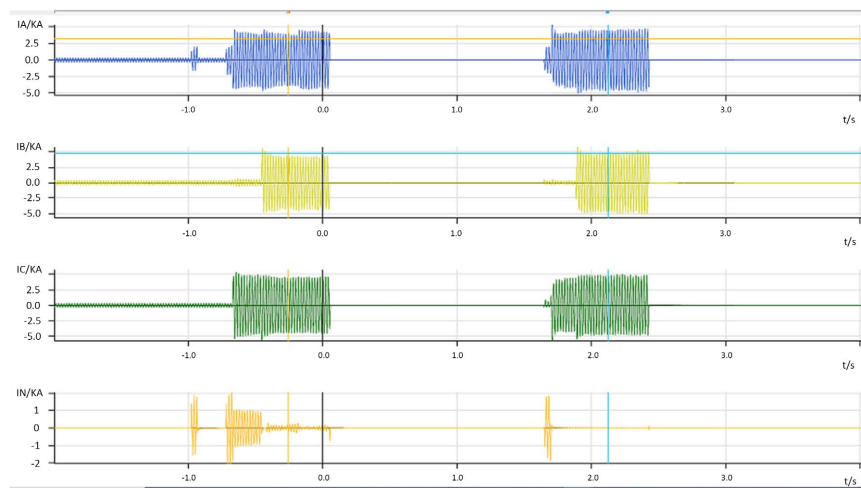
The supplied incident narrative dates the T100B disturbance to 29 August 2023 and reports a general substation outage. **Figure 3(a)**, however, displays the year 2025. The original event log was not supplied, so neither date can be confirmed here. Visual interpretation suggests an initial phase-A-to-ground interval of about 2.5 cycles, equivalent to 50 ms at 50 Hz; this is not a duration calculated from numerical samples.

The screenshots suggest a subsequent phase-A disturbance evolving to A-C-to-ground and then to a three-phase stage, followed by current interruption. A re-energization is interpreted as automatic reclosing approximately 2 s later, followed by recurrence and final interruption. The device identities and commanded opening/reclosing times are not verified by digital status channels.

This chronology suggests a progressive fault rather than an immediately established three-phase short circuit. Its physical origin and associated resistance cannot, however, be determined solely from the visual interpretation of the oscillograms.

2.5. Recorded Electrical Quantities

Figure 3 reproduces displayed phase voltages, phase currents, and a channel described as residual current. The residual channel must be distinguished from the zero-sequence current: $I_{res} = 3I_0$ for consistently scaled phase measurements. A separately measured core-balance CT channel must be checked against this definition and its own ratio. COMTRADE files [8] are needed to establish sample values and channel metadata.

(a) Phase-voltage records**(b) Phase-current and residual-current records**

Source: Relay-display records reproduced from the supplied incident report.

Figure 3. Relay-recorded quantities during the T100B feeder disturbance: (a) Phase voltages and (b) Phase currents and residual current.

The supplied evidence consists of screenshots, not raw oscillographic data. Sampling rate, scaling coefficients, primary/secondary units, CT/VT ratios, synchronization, and the exact meaning of the displayed peak values remain unverified. The chronology is therefore an interpretation; the two RMS values used below are estimates derived from reported peaks.

3. Proposed Signal Processing and Classification Framework

This section specifies a framework for future processing of discrete relay records. Equations (1) - (25) have not been evaluated on this incident: no sliding RMS trajectories, phase scores, sequence ratios, diagnostic-score trajectories, calibrated coefficients, or classification accuracy can be calculated from the supplied screenshots alone. Section 5 instead reports visual interpretation and two

scalar amplitude comparisons. The distinction applies to **Figure 4** and **Table 2** as well.

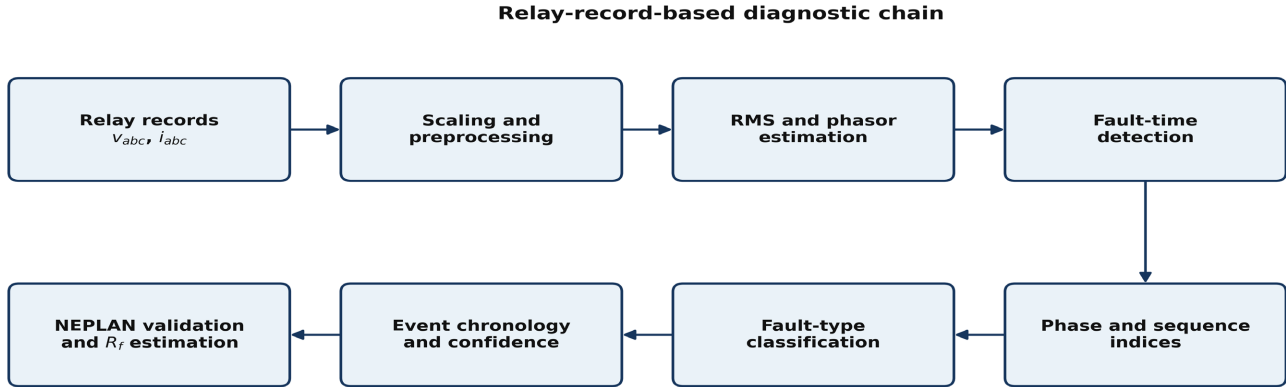


Figure 4. Proposed processing workflow. RMS/phasor extraction and classifier calibration were not executed on the supplied event; the final simulation block should be read as a future comparison step.

3.1. Signal Definition and Scaling

The recorded instantaneous phase voltages and currents are represented by

$$\mathbf{v}_{abc}(n) = \begin{bmatrix} v_A(n) \\ v_B(n) \\ v_C(n) \end{bmatrix}, \mathbf{i}_{abc}(n) = \begin{bmatrix} i_A(n) \\ i_B(n) \\ i_C(n) \end{bmatrix} \quad (1)$$

When the relay exports secondary quantities, the corresponding primary values are obtained from the current- and voltage-transformer ratios:

$$\mathbf{i}_{abc}^p(n) = K_{CT} \mathbf{i}_{abc}^s(n), \mathbf{v}_{abc}^p(n) = K_{VT} \mathbf{v}_{abc}^s(n) \quad (2)$$

The instantaneous residual current is

$$i_{res}(n) = i_A(n) + i_B(n) + i_C(n) = 3i_0(n) \quad (3)$$

A moving-mean subtraction can reduce a constant offset, but is not a validated removal of the decaying DC component of a fault waveform. It must be kept distinct from the total RMS calculation:

$$\tilde{x}(n) = x(n) - \frac{1}{N} \sum_{m=n-N+1}^n x(m) \quad (4)$$

For a trailing one-cycle window, an RMS-normalized DFT coefficient is defined below. Its phase reference is the oldest sample in that window, common to all phase channels:

$$\hat{X}[n] = \left(\sqrt{2/Nc} \right) \sum_{m=0}^{Nc-1} \tilde{x}[n - Nc + 1 + m] \exp(-j2\pi m/Nc) \quad (5)$$

Here, $Nc = f_s/f_0$ is assumed integer, f_s is the verified sample rate and $f_0 = 50$ Hz. Frequency deviation or noninteger windows require an explicitly documented estimator. The sliding total RMS is calculated on the original, correctly scaled samples:

$$X_{\text{rms}}(n) = \sqrt{\frac{1}{N_c} \sum_{m=0}^{N_c-1} x^2(n-m)} \quad (6)$$

Equations (2), (5), and (6) must be applied only after confirming the COMTRADE scaling coefficients, channel units, and CT/VT ratios.

3.2. Fault Inception and Clearing Time Detection

For each phase $k \in \{A, B, C\}$, the normalized current variation is defined by

$$\Delta I_k(n) = \frac{|I_{k,\text{rms}}(n) - I_{k,\text{pre}}|}{\max(I_{k,\text{pre}}, \mathcal{E}_I)} \quad (7)$$

The estimated fault-inception sample is the first instant for which the current, residual-current, or voltage criteria remain satisfied during N_p consecutive samples:

$$n_f = \min \left\{ n : \left[\max_k \Delta I_k(n) \geq \eta_I \vee I_{\text{res}}(n) \geq \eta_0 \vee \min_k V_{k,\text{rms}}(n) \leq \eta_V \right]_{N_p} \right\} \quad (8)$$

The fault-clearing sample is determined from the persistent return of the phase currents below a clearing threshold:

$$n_c = \min \left\{ n > n_f : \max_k I_{k,\text{rms}}(n) \leq \eta_c \text{ for } N_c^* \text{ samples} \right\} \quad (9)$$

The duration of a detected fault interval is

$$T_f = \frac{n_c - n_f}{f_s} \quad (10)$$

For the first reported disturbance interval, a duration of approximately 2.5 cycles corresponds to

$$T_f = \frac{2.5}{50} = 0.050 \text{ s} \quad (11)$$

The thresholds η_I , η_0 , η_V , and η_c must be derived from prefault variability and verified against the relay settings. They must not be selected solely from visual inspection of the oscillograms.

3.3. Phase Involvement Indicators

The voltage-sag depth of phase k is expressed as

$$D_{V,k}(n) = \max \left(0, \frac{V_{k,\text{pre}} - V_{k,\text{rms}}(n)}{V_{k,\text{pre}}} \right) \quad (12)$$

The relative phase-current increase is

$$D_{I,k}(n) = \max \left(0, \frac{I_{k,\text{rms}}(n) - I_{k,\text{pre}}}{\max(I_{k,\text{pre}}, \mathcal{E}_I)} \right) \quad (13)$$

Because phase-to-ground faults produce a zero-sequence current, the normalized residual-current energy over a diagnostic interval $\mathcal{W}$ is calculated as

$$E_0 = \frac{\sum_{n \in \mathcal{W}_{\text{res}}} i_{\text{res}}^2(n)}{\sum_{n \in \mathcal{W}} [i_A^2(n) + i_B^2(n) + i_C^2(n)] + \varepsilon_E} \quad (14)$$

A combined phase-involvement score is then defined as

$$S_k = w_I \bar{D}_{I,k} + w_V \bar{D}_{V,k}, w_I + w_V = 1 \quad (15)$$

where the overbar denotes the mean value over $\mathcal{W}$. The weights w_I and w_V must be established through simulation-based sensitivity analysis.

3.4. Symmetrical Component Analysis

The phase phasors are transformed into zero-, positive-, and negative-sequence components using

$$\begin{bmatrix} \underline{X}_0 \\ \underline{X}_1 \\ \underline{X}_2 \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \begin{bmatrix} \underline{X}_A \\ \underline{X}_B \\ \underline{X}_C \end{bmatrix}, a = e^{j2\pi/3} \quad (16)$$

For the phase currents, the zero-sequence component is therefore

$$\underline{I}_0 = \frac{\underline{I}_A + \underline{I}_B + \underline{I}_C}{3} = \frac{\underline{I}_{\text{res}}}{3} \quad (17)$$

The normalized ground-fault participation index is

$$\Gamma_0 = \frac{3|\underline{I}_0|}{|\underline{I}_A| + |\underline{I}_B| + |\underline{I}_C| + \varepsilon_I} \quad (18)$$

The current-unbalance index is defined from the negative- and positive-sequence currents:

$$\Gamma_2 = \frac{|\underline{I}_2|}{|\underline{I}_1| + \varepsilon_I} \quad (19)$$

A high Γ_0 may support an earth-return path and Γ_2 indicates asymmetry, subject to CT scaling, saturation, noise, and window choice. A balanced three-phase stage ideally has dominant positive sequence. These indicators were not calculated for the recorded disturbance.

Table 2. Diagnostic quantities and physical interpretation of proposed quantities; not evaluated on the recorded event.

Quantity	Equation	Diagnostic function	Validation or calibration requirement
I _{res}	(3)	Identifies the earth-current contribution	Confirm relay channel definition and CT scaling
$D_{I,k}$	(7)	Detects departure from the prefault current	Calibrate ε_I from prefault variability
$D_{V,k}$	(12)	Quantifies the phase-voltage depression	Confirm VT ratio and voltage-channel scaling
$D_{b,k}$	(13)	Quantifies phase-current involvement	Confirm CT ratio and current-channel scaling
E_0	(14)	Measures normalized residual-current energy	Define and report the analysis window $\mathcal{W}$
S_k	(15)	Ranks the involvement of each phase	Calibrate w_I and w_V by sensitivity analysis
Gamma 0	(18)	Measures ground-fault participation	Verify from zero-sequence current

Continued

Gamma 2	(19)	Measures fault asymmetry	Verify from negative-sequence current
J_q	(20) - (24)	Classifies the candidate fault type	Identify coefficients from validated NEPLAN cases
C	(25)	Measures decision separation	Set an acceptance threshold using validation cases

3.5. Fault Type Classification

The following scores combine phase involvement and sequence-component information. For the initial phase-A-to-ground hypothesis, the diagnostic score is

$$J_{AG} = \alpha S_A + \beta \Gamma_0 + \gamma \Gamma_2 - \delta (S_B + S_C) \quad (20)$$

For a phase-A-to-phase-C-to-ground fault, the score becomes

$$J_{ACG} = \alpha \frac{S_A + S_C}{2} + \beta \Gamma_0 + \gamma \Gamma_2 - \delta S_B \quad (21)$$

For a three-phase fault, the corresponding score is

$$J_{ABC} = \alpha \frac{S_A + S_B + S_C}{3} - \beta \Gamma_0 - \gamma \Gamma_2 - \delta \sigma_s \quad (22)$$

where

$$\sigma_s = \sqrt{\frac{(S_A - \bar{S})^2 + (S_B - \bar{S})^2 + (S_C - \bar{S})^2}{3}}, \bar{S} = \frac{S_A + S_B + S_C}{3} \quad (23)$$

The estimated fault class at a given time window is selected by

$$F[n] = \arg \max \{Jq[n] : q \in \{AG, ACG, ABC\}\}, \quad (24)$$

if the detection gate is active

The candidate fault classes in (24) are AG , ACG , and ABC . A normal state is handled separately by the persistence gate in (8), rather than by an undefined normal-state score. The coefficients α , β , γ , δ and weights wI , wV require calibration; no numerical coefficient values are available.

A future implementation must split verified simulation cases into training and held-out validation subsets before fitting normalization, coefficients, or thresholds. Split by simulated scenario, not overlapping windows from the same trace, to limit information leakage. Report the class counts, confusion matrix, overall accuracy, per-class sensitivity, and sensitivity to resistance, distance, loading, noise, and CT/VT uncertainty. Static short-circuit amplitudes alone cannot provide the time trajectories required for $Jq(n)$: transient records or an appropriate transient simulator are needed. No training or validation results are claimed here.

3.6. Chronological Reconstruction and Diagnostic Confidence

A bounded separation index can be defined for the two highest diagnostic scores, including when they are negative:

$$C[n] = (J(1)[n] - J(2)[n]) / (|J(1)[n]| + |J(2)[n]| + \varepsilon J), 0 \leq C[n] \leq 1 \quad (25)$$

where $J(1)$ and $J(2)$ are the highest and second-highest scores, and ε is positive. The absolute-value denominator avoids the invalid bound that would arise from dividing by a potentially negative largest score. C is a score-separation index, not a calibrated probability or an experimentally established confidence level.

Visual inspection alone suggests the provisional sequence AG, ACG, ABC , interruption, apparent reclosing, recurrence, and final interruption. It does not constitute application of Equations (7) - (25), nor establish the physical fault cause.

Quantitative reconstruction requires the original COMTRADE data and settings, channel definitions, calibration ratios, digital breaker states, and relay logic. Section 4 states an inverse-problem formulation; only a fixed-location scalar comparison is numerically available in Section 5.

4. NEPLAN Modeling and Fault Resistance Identification

The supplied NEPLAN description contains a 90 kV equivalent source, transformer, 15 kV busbar, zigzag grounding device, and feeder sections. The reproduced results concern node-wise three-phase and bolted A-G currents and a fixed-JDB15 A-G resistance sweep. No evaluated A-C-G case, transient model, or independent model validation is supplied, as shown in **Figure 5**.

4.1. Network Parameters

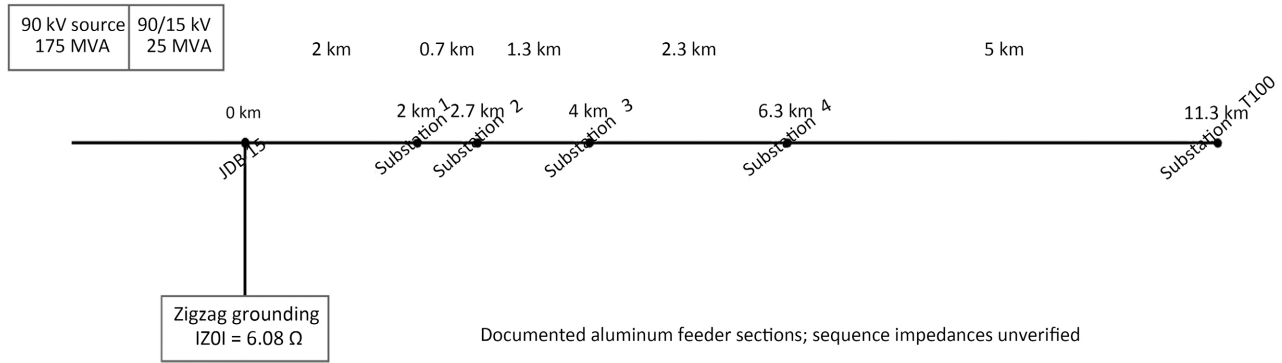


Figure 5. Documented feeder topology and section lengths, redrawn with English labels. JDB15 is the busbar node; no CT position is established by the supplied diagram.

For a short-circuit power of 175 MVA at the 90 kV bus, the source impedance is

$$|Z_s| = \frac{V_{LL}^2}{S_{sc}} = \frac{(90 \times 10^3)^2}{175 \times 10^6} = 46.29 \, \Omega \quad (26)$$

Using $\rho_s = X_s/R_s$,

$$R_s = \frac{|Z_s|}{\sqrt{1 + \rho_s^2}}, X_s = \rho_s R_s, Z_s = R_s + jX_s \quad (27)$$

The 175 MVA source short-circuit power is a reported model input. The value 46.29 Ω in (26) is its impedance magnitude under the stated voltage-base conver-

sion, not a verified complex impedance. The actual source X/R ratio used in NEPLAN is not documented; no substitute numerical value is assigned.

For the 25 MVA, 90/15 kV transformer with $u_k = 10.4\%$, the impedance referred to the 15 kV side is

$$Z_{T,\text{base}} = \frac{V_{T,\text{LL}}^2}{S_T}, |Z_T| = \frac{u_k}{100} Z_{T,\text{base}} = 0.936 \, \Omega \quad (28)$$

Equation (28) gives the impedance magnitude on the 15 kV base. Transformer resistance/reactance decomposition, vector group, zero-sequence connection, correction factors, and tap position used in the supplied calculation are undocumented. The absence of an accessible LV neutral does not determine the vector group.

The feeder sequence impedances are

$$Z_{1,L} = \sum_{m=1}^{N_L} (r_{1,m} + jx_{1,m}) \ell_m, Z_{0,L} = \sum_{m=1}^{N_L} (r_{0,m} + jx_{0,m}) \ell_m \quad (29)$$

The documented section lengths total 11.3 km. Positive-, negative-, and zero-sequence impedances, conductor temperature, and return-path assumptions actually entered in NEPLAN are not supplied. They cannot be recovered uniquely from the six tabulated current magnitudes.

The BPN is represented by

$$Z_{0,\text{BPN}} = R_{0,\text{BPN}} + jX_{0,\text{BPN}}, |Z_{0,\text{BPN}}| = 6.08 \, \Omega \quad (30)$$

The documented $6.08 \, \Omega$ is treated as the magnitude of the BPN zero-sequence impedance. Its resistive/reactive decomposition and the software grounding representation are not verified. It is neither the fault resistance nor the earth-grid resistance.

Table 3. Principal model parameters.

Parameter	Reported input or value	Verification and reproducibility status
Source	90 kV; short-circuit power 175 MVA	Reported; actual X/R and equivalent-source settings not supplied
Transformer	25 MVA; 90/15 kV; $u_k = 10.4\%$	Documented ratings; vector group, tap, R/X and correction factors unverified
BPN	Zero-sequence impedance magnitude $6.08 \, \Omega$	Documented value; R/X and software representation unverified
Feeder sections	2.0, 0.7, 1.3, 2.3, 5.0 km; total 11.3 km	Documented lengths; not independently surveyed
Line sequence data	No numerical impedances supplied	Actual Z1, Z2, Z0, conductor temperature and earth-return assumptions unavailable
CT/VT and residual channel	Ratios and scaling not supplied	Primary/secondary basis and Ires versus I0 mapping must be verified
Short-circuit calculation	Previously tabulated NEPLAN amplitudes	Version, standard edition, max/min mode, voltage factor and contributions not supplied

Continued

Measurement equivalent	JDB15 busbar node used in sweep	CT location, fault boundary and exported feeder-branch current unavailable
Prefault operating state	Not numerically supplied	Loads, motor contribution, voltage and switching state unverified

4.2. Prefault and Fault Models

The prefault network satisfies

$$\mathbf{Y}_{\text{bus}} \mathbf{V}^{\text{pre}} = \mathbf{I}^{\text{inj}} \quad (31)$$

Equation (31) is a network balance relation for the proposed model, not a demonstrated prefault validation. Prefault load-flow values, the voltage factor, load/motor contributions, and the short-circuit calculation options used to generate the supplied tables are unavailable.

For the phase-A-to-ground fault,

$$\underline{I}_{f,AG} = \frac{3\underline{V}_{1,\text{pre}}}{\underline{Z}_{1,\text{th}} + \underline{Z}_{2,\text{th}} + \underline{Z}_{0,\text{th}} + 3R_f} \quad (32)$$

For the phase-A-to-phase-C-to-ground fault with a common earth path,

$$\underline{V}_A = \underline{V}_C = R_{f,g} (\underline{I}_A + \underline{I}_C), \underline{I}_B = 0 \quad (33)$$

If NEPLAN uses separate earth paths, $R_{f,A}$ and $R_{f,C}$ must be entered independently.

For the balanced three-phase fault,

$$\underline{I}_{f,ABC} = \frac{\underline{V}_{1,\text{pre}}}{\underline{Z}_{1,\text{th}} + R_f} \quad (34)$$

Equations (32) - (34) express idealized fault boundary conditions. They do not establish that all three stages were simulated or that static IEC short-circuit outputs reproduce the observed transients. The choice between a prefault voltage and an IEC equivalent voltage source must be stated consistently in a reproducible calculation.

4.3. Resistance Identification

The investigated resistance set is

$$\mathcal{R}_f = \left\{ R_{f,\min} + p\Delta R_f \mid p = 0, \dots, N_R \right\}, \Delta R_f = \frac{R_{f,\max} - R_{f,\min}}{N_R} \quad (35)$$

For fault stage q , the recorded and simulated feature vectors are

$$\begin{aligned} \mathbf{y}_q^{\text{rec}} &= \begin{bmatrix} |I_A| & |I_B| & |I_C| & |I_{\text{res}}| & |V_A| & |V_B| & |V_C| \end{bmatrix}^T, \\ \mathbf{y}_q^{\text{sim}}(R_f, d) &= \begin{bmatrix} |\hat{I}_A| & |\hat{I}_B| & |\hat{I}_C| & |\hat{I}_{\text{res}}| & |\hat{V}_A| & |\hat{V}_B| & |\hat{V}_C| \end{bmatrix}^T. \end{aligned} \quad (36)$$

The fault resistance and location are estimated from

$$\begin{aligned}
(\hat{R}_f, \hat{d}) &= \underset{R_f \in \mathcal{R}_f, d \in \mathcal{D}}{\operatorname{argmin}} J(R_f, d), \\
J(R_f, d) &= \sum_{q=1}^{N_q} \sum_{h=1}^{N_y} w_{q,h} \left[\frac{y_{q,h}^{\text{sim}}(R_f, d) - y_{q,h}^{\text{rec}}}{\max(|y_{q,h}^{\text{rec}}|, \varepsilon_h)} \right]^2, \\
w_{q,h} &\geq 0, \sum_{q,h} w_{q,h} = 1.
\end{aligned} \tag{37}$$

Equation (37) is the proposed joint objective. Only features with verified scaling and a defined relay-equivalent simulation point should be included. Weights, feature uncertainty, and stage boundaries must be fixed before fitting. The complete feature vectors and joint search were not evaluated here; the available numerical exercise uses one A-G amplitude at a fixed node.

4.4. Identifiability and Reproducibility

Resistance and distance can both alter current magnitude, so the scalar fit is not a unique inverse solution. A future NEPLAN study must evaluate $J(R_f, d)$ on an explicitly reported two-dimensional grid using verified sequence parameters and relay-branch outputs. A measurement-consistent region can be defined as all pairs whose residuals lie within stated measurement and model tolerances. Without those tolerances and a joint grid, neither a numerical admissible-region boundary nor a resistance confidence interval can be reported. No synthetic surface is substituted for missing simulations.

Reproducibility requires the actual NEPLAN project/version, calculation standard and options, voltage factor, source X/R, transformer vector group and R/X, feeder sequence impedances, grounding data, prefault state, CT/VT ratios, and branch-output mapping. Manufacturer manuals establish possible device functions but cannot verify installation-specific values. **Table 3** distinguishes reported inputs from absent settings; the 7 Ω value below is a conditional grid candidate, not a fully identified field resistance.

5. Reported Simulation Amplitudes and Conditional Comparisons

5.1. Available Evidence and RMS Conversion Assumption

The source manuscript reports peak values of 1.5 kA for the initial residual-current stage and 5 kA for the three-phase stage. For a pure sinusoid without DC offset, $I_{\text{rms}} = I_{\text{peak}}/\sqrt{2}$, giving 1.06066 and 3.53553 kA, rounded to 1.06 and 3.54 kA in the supplied comparisons. These are derived RMS estimates, not sample-based RMS measurements. A transient DC component, harmonics, CT saturation, or peak-reading uncertainty can invalidate this conversion. The A-G comparison also assumes that the displayed residual channel corresponds to the simulated earth-fault current on the same primary base; this is unverified.

For synchronized samples, the waveform mismatch would be evaluated from

$$\text{NRMSE}_I = \sqrt{\frac{\sum_{n=1}^N \mathbf{i}_{\text{rec}}(n) - \mathbf{i}_{\text{sim}}(n)_2^2}{\sum_{n=1}^N \mathbf{i}_{\text{rec}}(n)_2^2}}. \quad (38)$$

Equation (38) is not evaluated because synchronized numerical waveforms are absent. Static NEPLAN short-circuit currents cannot by themselves supply a transient waveform comparison. The analysis below is confined to the supplied amplitude tables and rounded sinusoidal RMS estimates.

5.2. Spatial Variation of Simulated Fault Current

Figure 6 presents the NEPLAN currents at the six modeled nodes. The cumulative distances are 0, 2.0, 2.7, 4.0, 6.3, and 11.3 km from JDB15 to Poste T100. The three-phase short-circuit current decreases from 3.83 to 1.43 kA, corresponding to a 62.66% reduction. The bolted A-G current decreases from 2.46 to 1.15 kA, corresponding to a 53.25% reduction. Both trends are consistent with the increasing feeder impedance, as shown in **Figure 6**.

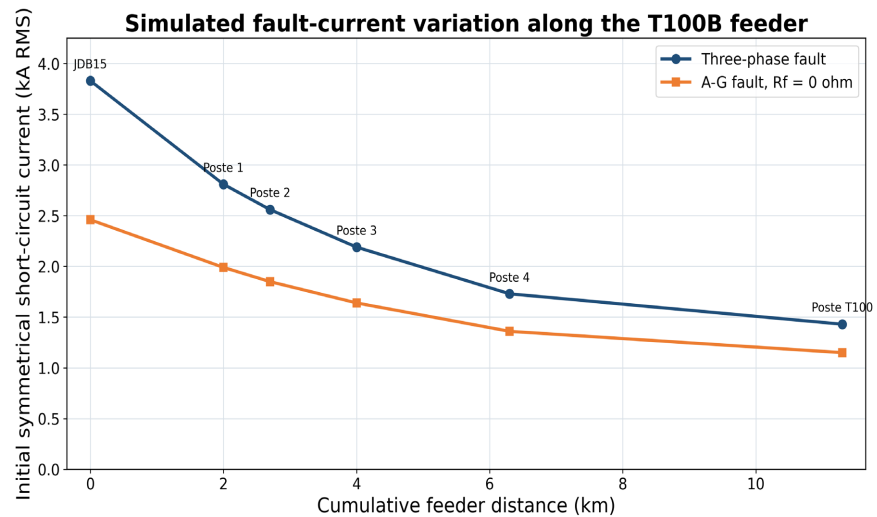


Figure 6. NEPLAN short-circuit currents versus cumulative distance along the T100B feeder. Data reproduced from the source-document simulation tables.

The derived 3.54 kA estimate is nearer to 3.83 kA at JDB15 than to 2.81 kA at the next tested node. This selects the closest amplitude among six discrete candidates; it does not locate the physical fault. JDB15 denotes a busbar node in the supplied topology, not a verified point immediately downstream of the T100B CTs. For a busbar fault, the total injected fault current need not equal the current in the feeder CT branch. A relay-equivalent comparison requires the fault boundary and the exported branch current to be identified; neither is established by the supplied tables.

5.3. Amplitude Agreement Used for Case Selection

For each available fault case, the relative amplitude error is

$$E_A = 100 \frac{|I^{\text{sim}} - I^{\text{rec}}|}{\max(|I^{\text{rec}}|, \varepsilon_I)}. \quad (39)$$

Using the rounded estimates retained in the supplied tables, the fixed-JDB15 A-G case gives 1.072 kA at 7 Ω versus 1.06 kA, a discrepancy of 1.13%. The selected three-phase node gives 3.83 kA versus 3.54 kA, or 8.19%. Their arithmetic mean is 4.66%. If the unrounded sinusoidal conversions are used instead, these values become approximately 1.07%, 8.33%, and 4.70%, respectively. This rounding sensitivity is smaller than the unquantified uncertainty in peak conversion and channel scaling, but prevents interpreting the quoted percentages as measurement accuracy. **Table 4** collects the two selection comparisons, as shown in **Figure 7**.

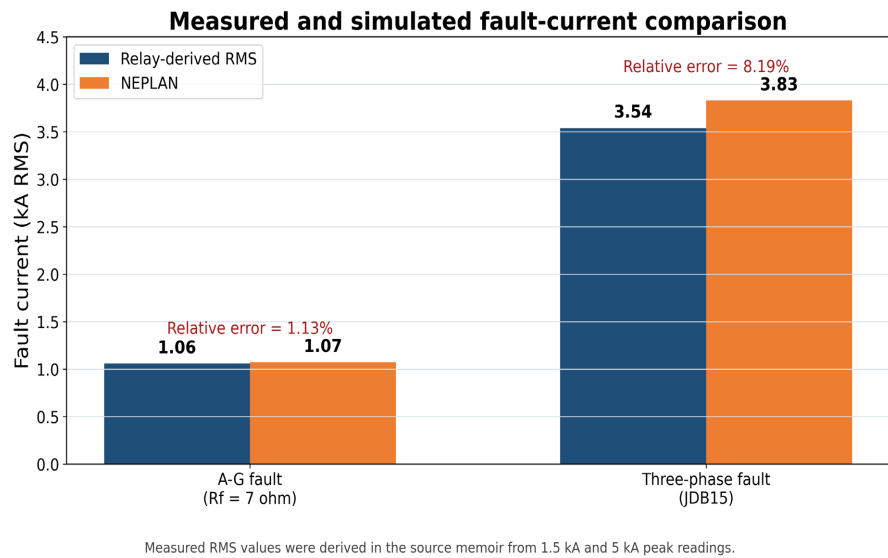


Figure 7. Derived sinusoidal RMS estimates and selected NEPLAN amplitudes. Values are rounded source estimates; the comparisons are used for selection, not independent validation.

Table 4. Measured and simulated fault-current comparison.

Fault case	Derived RMS estimate (kA)	NEPLAN (kA)	Selected model point	Discrepancy (%)	Result
A-G	1.06	1.072	JDB15; Rf = 7 ohm	1.13	Conditional grid candidate
Three-phase	3.54	3.83	JDB15	8.19	Selected amplitude candidate
Mean	-	-	Two comparisons	4.66	Mean selection residual

The A-G amplitude selects the resistance grid point and the three-phase amplitude selects the candidate node. Their discrepancies and their mean are in-sample selection residuals, not independent evidence of classification accuracy, location accuracy, or resistance identification. Unknown waveform distortion, channel scaling, model settings, and branch-current correspondence prevent a defensible acceptance threshold.

5.4. Conditional Resistance Candidate at JDB15

Figure 8 shows the complete resistance sweep reported for an A-G fault at JDB15. As R_f increases from 0 to 40 Ω , the simulated current decreases monotonically from 2.46 to 0.21 kA. The faulted-phase voltage rises from 0 to 8.50 kV, while the healthy-phase voltages remain between 7.75 and 11.16 kV.

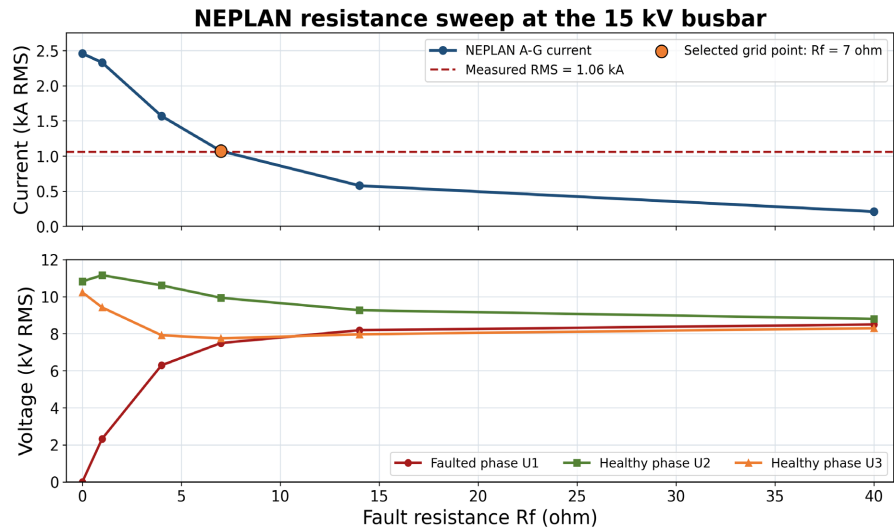


Figure 8. NEPLAN A-G current and phase voltages as functions of fault resistance at JDB15.

Within the supplied A-G sweep at the assumed JDB15 node, 1.072 kA at 7 Ω is closest to the rounded target of 1.06 kA. Thus, the fixed-location grid candidate is

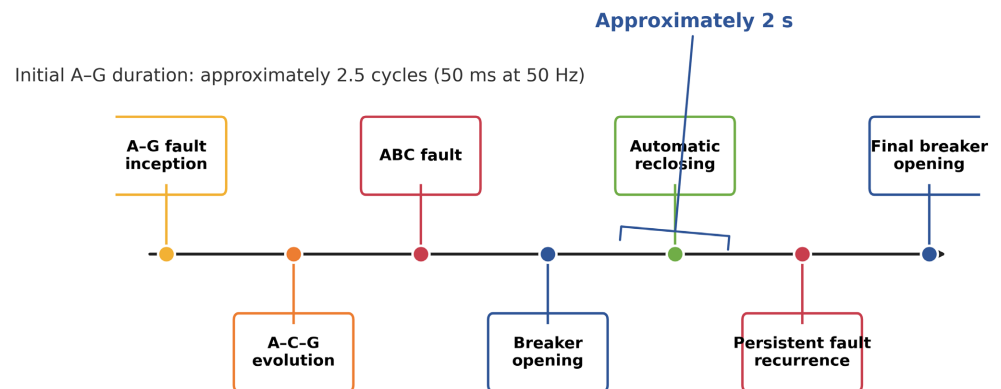
$$\hat{R}_f = \underset{R_f \in \{0,1,4,7,14,40\} \Omega}{\operatorname{argmin}} \left| I_f^{\text{sim}}(R_f) - 1.06 \right| = 7 \Omega. \quad (40)$$

Linear interpolation between the supplied 7 and 14 Ω current points gives approximately 7.16 Ω against the rounded 1.06 kA target. This is an interpolation of sparse outputs, not another NEPLAN run or an uncertainty bound; 7 Ω remains the directly simulated candidate. Ω is the SI symbol for ohm, and 7 Ω is a fault-resistance value rather than an abbreviation. The candidate depends on the assumed location, current-channel interpretation, and unverified model inputs. The available amplitudes do not prove that the actual fault resistance was 7 Ω , or that the event was a busbar fault.

5.5. Provisional Protection Sequence and Unresolved Outage Mechanism

Figure 9 summarizes the visual event interpretation: an initial AG interval of about 50 ms, an apparent ACG-to-ABC evolution, current interruption, apparent reclosing after about 2 s, recurrence, and final interruption. These are not verified breaker operation times. The incident narrative associates the sequence with T100B, but does not identify the breaker at each interruption through tagged status or trip records.

Recorded fault and protection-event chronology



Event order reconstructed from the available relay-record interpretation; intermediate times remain to be verified.

Figure 9. Provisional chronology inferred from relay screenshots. Breaker identities, trip commands, and intermediate timing require event and status records.

The supplied information cannot establish why a reported feeder disturbance led to a general substation outage. Upstream transformer protection, busbar protection, coupling actions, breaker failure, and operator switching cannot be confirmed or excluded. Establishing the mechanism requires time-correlated T100B, transformer, bus-coupler and upstream breaker states, protection pickup/trip logs, and the switching report. The date discrepancy (2023 in the narrative; 2025 in **Figure 3(a)**) likewise remains unresolved. These gaps prevent conclusions about selectivity, successful autoreclosing, or protection coordination.

6. Conclusion

The available screenshots suggest an evolving T100B disturbance and recurrence after apparent reclosing, but do not quantitatively validate the proposed diagnostic equations. Previously tabulated NEPLAN results provide conditional amplitude comparisons: JDB15 is the closest tested three-phase-current node, and $7\ \Omega$ is the closest A-G resistance grid point at that assumed location. The 1.13% and 8.19% discrepancies, and their 4.66% mean, use rounded sinusoidal RMS estimates and were used to select these cases. They are not independent validation. Current magnitude alone does not separate resistance and distance, and the supplied tables do not establish whether a JDB15 fault current represents the T100B CT measurement. Raw COMTRADE records, verified installation parameters, relay-equivalent branch outputs, a two-dimensional resistance-distance study, and separate classifier calibration/validation are required for stronger conclusions. The incident date and the mechanism of the general outage remain unresolved.

Author Contributions

Haroun Abba Labane: Conceptualization, Data curation, Formal analysis, Fund-

ing acquisition, Investigation, Methodology, Project administration, Resources, Supervision, Validation, Visualization, and Writing—original draft; Eyandzi Amos Omboua: Software, Supervision, Validation, Visualization, Writing—review & editing.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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