22nd International Conference on Renewable Energies and Power Quality (ICREPQ'24)
Bilbao (Spain), 26th to 28th June 2024
Renewable Energy and Power Quality Journal (RE&PQJ)
ISSN 2172-038 X, Volume No.22, September 2024

Distribution Expansion Planning of Electrical Networks Considering Electrical Losses and Financial Losses Due to Voltage Sags and Interruptions.

A. Gustavo Morales Espinoza[1], B. Juan Carlos Cebrian[1,2]

[1] Institute of Science and Technology
São Paulo State University.
Campus of Sorocaba – São Paulo, 18087-180 (Brazil)
Phone: +55 15 992494549

[2] Department of Electrical Energy and Automation
University of São Paulo

Abstract. Currently, distribution system planning is crucial to meet both the present and future electricity needs of customers with minimal investments. This paper introduces a novel methodology to solve the distribution expansion planning problem by employing a heuristic based on genetic algorithms (GA). The proposed GA aims to minimize investment costs, electrical losses, and financial losses due to voltage sags and power interruptions. This GA is applied in the 18-busbar network with three planning stages. The results show that the GA deals with efficiency with the multi-objective problem obtaining solutions with reduced iterations and with minimum investments considering electrical losses, and financial losses.

Key words. genetic algorithm, distribution expansion planning, distribution of electrical networks, and financial losses.

Nomenclature

s : Index of a simulated short-circuit event.
k : Index of the planning stage.
l : Index of line.
c : Index of customer.
$C_{inv(k)_{p.u}}$: Investment cost in k in p.u value.
$C_{Ele(k)_{p.u}}$: Electrical Losses Cost in k in p.u.
$C_{Fin(k)_{p.u}}$: Financial losses due to sag and interruptions in k in p.u.
$C_{inv(k)}$: Investment Cost in k.
$C_{inv_{max}}$: Maximum investment Cost.
$C_{Inst(l,k)}$: Installation cost of l in k.
$C_{Ren(l,k)}$: Removal cost of l in k.
$C_{sag(c)}$: Unitary cost of failures due to a sag.
$C_{SDI(c)}$: Unitary cost of failures due to a SDI.
$C_{LDI(c)}$: Unitary cost of failures due to a LDI.
d_{sag} : Duration of voltage sag.
$f_{Inst(l,k)}$: Installation factor of l in k.
$f_{Ren(l,k)}$: Removal factor of l in k.
$f_{Op(l,k)}$: Operation factor of l in k.
$I_{(l,k)}$: Allowable current of l in k.
$I_{max(l,k)}$: Maximum allowable current of l in k.
Iso : Isolation value.
$Iso_{(k)}$: Isolation in k.
I_R : Annual interest rate.
I_{max} : Maximum permissible current.
LDI : Long duration interruption.
N_s : Number of simulated short-circuits.
$N_{sag/yr}$: Annual voltage sags for the entire grid.
$N_{SDI/yr}$: Annual SDI for the entire grid.
$N_{LDI/yr}$: Annual LDI for the entire grid.
$N_{c(k)}$: Number of customers in k
$N^{sag}_{p/yr(c,k)}$: Annual failures due to sag of c in k.
$N^{SDI}_{p/yr(c,k)}$: Annual failures due to SDI of c in k.
$N^{LDI}_{p/yr(c,k)}$: Annual failures due to LDI of c in k.
N^{nod}_k : Number of nodes in loops in k.
N^{iso}_k : Number of isolated nodes in k.
$P_{trans}(s)$: Probability of transient for s.
$P_{sag}(s)$: Probability of sag para s.
$P_{SDI}(s)$: Probability of SDI para s.
$P_{LDI}(s)$: Probability of LDI para s.
$Pen_{(k)}$: Penalties in k.
$Pen_{(V)}$: Voltage penalty.
$Pen_{(I)}$: Current penalty.
Pen_{Dem} : Penalty for predicted demand.
Pen_{Rede} : Penalty for network topology
$Pen_{Rad(k)}$: Penalty for network radiality in k
$Pen_{Iso(k)}$: Penalty for network isolation in k
$R_{S/L}(s)$: Ratio between $P_{SDI}(s)$ and $P_{LDI}(s)$ for s.
$R_{(l,k)}$: Line impedance of l in k.
$Rad_{(k)}$: Radiality value in k.
sag : Voltage sag.
SDI : Short duration interruption.
w_{Inv} : Weight for investment Cost.
w_{Ele} : Weight for electrical losses cost.
w_{Fin} : Weight for financial losses due to sag and interruptions.
V_{min} : Minimum permissible voltage
V_{max} : Maximum permissible voltage
λ_{LDI} : Permanent failure rate.
δ^{inv}_k : Factor for annual interest rate for k.

1. Introduction

The continuous increment in energy consumption, driven by the modernization of society, creates challenges for the operation and planning of electrical networks [1], [2]. In this way, distribution expansion planning (DEP) aims to develop an efficient investment plan to meet user demands with the lowest cost while attending the power quality and reliability criteria defined by the regulatory bodies [1],[3],[4].

Solving the DEP problem requires modeling all involved binary, integer, and real variables, along with functions that represent real behaviors of the electrical grid. In literature, various proposed models, methods, and techniques achieve solutions based on defined objectives, such as minimizing investment and operational costs or enhancing network quality and reliability [3],[5]. Also, heuristics such as Genetic Algorithms, Particle Swarm Optimization (PSO), Ant Colony Optimization (ACO), Tabu Search, and hybrid algorithms have been applied to obtain sub-optimal solutions with acceptable processing time[1],[3],[6].

Traditional approaches have primarily focused on minimizing investment costs and electrical losses [4][10][11], often overlooking the significant impacts of financial losses due to voltage sags and power interruptions [7]. However, ignoring these factors can result in suboptimal solutions that compromise the overall performance and reliability of the distribution system. By doing so, utilities can make more informed decisions that prioritize not only upfront investment costs but also long-term operational efficiency and customer satisfaction.

This paper proposes a novel methodology that explicitly considers electrical losses and financial losses due to voltage sags and power interruptions to sensitive customers throughout the planning horizon. The main contributions are: i) the application of a probilistic model to estimate financial losses due to voltage sags and power interruptions, ii) an efficient matrix codification for GA; and iii) an matematic formulation to include electrical losses and financial losses due to voltage sags. The objectives aim to obtain an investment plan with lower operational costs, and to reduce costs associated with the poor quality of energy supplied to end customers.

2. Estimation of financial losses due to voltage sags and interruptions

Financial losses due to voltage sags and power interruptions (C_{Fin}) can be assessed using a stochastic approach based on the Monte Carlo method. In this regard, it is necessary to use the cumulative distribution function (CDF) of the Cumulative Probability of Voltage Sag Duration (P_{SgD}). A Fig. 1 shows a typical P_{SgD} curve adapted from [7]. This curve indicates that 30% of voltage sags have durations shorter than 0.04 s, 75% have durations shorter than 0.06 s, and 100% of voltage sags have durations shorter than 0.08 s, meaning all voltage sags have durations shorter than 80 ms.

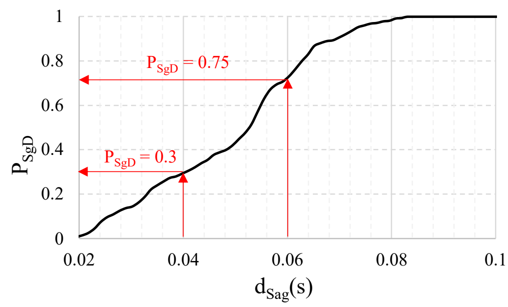
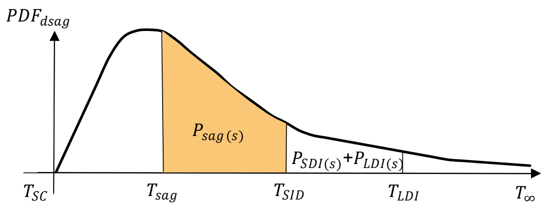


Fig. 1. Cumulative distribution function for voltage sag duration. Adapted from [7].

The process of assessing C_{Fin} involves obtaining short-circuit current values, determining fault clearing times, and utilizing P_{SgD}. In this approach, transients, sag, SDI and LDI can be considered electrical phenomena independently. Therefore, the probabilities of each phenomenon can be summed for each short circuit accordingly.

$$P_{trans}(s) + P_{sag}(s) + P_{SDI}(s) + P_{LDI}(s) = 1 \quad (1)$$



W

Fig. 2. Time interval for the probability of transients, sags, SDI, and LDI

From (1), $P_{trans}(s)$, $P_{sag}(s), P_{SDI}(s)$ e $P_{LDI}(s)$ can be obtained by considering the time interval of each sag, SDI and LDI event. Depending on historical data, each interval can be linked to a probability distribution function (PDF). For instance, as shown in Fig. 2 $T_{SC}(s)$, $T_{Sag}(s), T_{SDI}(s)$, $T_{LDI}(s)$ represent the begging of short-circuit, sag, SDI e LDI, respectively for s The probability for each phenomenon (P_f) is calculated as the integral of the PDF of d_{sag} or PDF_{dsag} between the time interval $[t_1, t_2]$,i.e., the difference between $P_{SgD}(T_2)$ and $P_{SgD}(T_1)$:

$$\int_{t_1}^{t_2} PDF_{dsag}(t) \cdot dt = P_{SgD}(t_2) - P_{SgD}(t_1) \quad (2)$$

It is important to mention that, after $T_{SDI}(s)$, momentary and permanent interruptions occur in the electrical grid. Thus, we can define $P_{trans}(s) + P_{sag}(s)$ as:

$$P_{trans}(s) + P_{sag}(s) = P_{SgD}(T_{SDI}(s)) \quad (3)$$

From (1). By inserting (3), we can obtain (4):

$$P_{SDI}(s) + P_{LDI}(s) = 1 - P_{SgD}(T_{SDI}(s)) \quad (4)$$

The relationship between $P_{SDI}(s)$ and $P_{LDI}(s)$ can be considered constant. Thus, for momentary faults, $P_{SDI}(s)$ and $P_{LDI}(s)$ can be evaluated by (6) and (7):

$$R_{S/L}(s) = P_{SDI}(s)/\,P_{LDI}(s) \quad (5)$$

$$P_{LDI}(s) = \frac{1 - P_{SgD}(T_{SDI}(s))}{1 + R_{S/L}(s)} \quad (6)$$

$$P_{SDI}(s) = R_{S/L}(s) \times \left(\frac{1 - P_{SgD}(T_{SDI}(s))}{1 + R_{S/L}(s)}\right) \quad (7)$$

The value of $R_{S/L}(s)$ can vary between 5 and 8, as defined in [7], or zero when there are no attempts to re-energize the electrical grid caused by reclosers. The probability of s affecting the electrical grid is evaluated as $1/N_S$, where N_S is the number of simulated short-circuits. Thus, the probability of an LDI event affecting the electrical grid $P_{LDI_{(s)}}^{N}$ due to s is:

$$P_{LDI_{(s)}}^{N} = \left(\frac{1 - P_{SgD}(T_{SDI}(s))}{1 + R_{S/L}(s)}\right) \times \frac{1}{N_s} \quad (8)$$

The total number of annual events between transients, sag , SDI e LDI that can affect the electrical grid ($N_{tot/yr}$) can be evaluated as:

$$N_{tot/yr} = \frac{\lambda_{SDI} \cdot L_{grid}}{\sum_{s=1}^{N_s} P_{LDI}^{N}(s)} = \lambda_{eve} \cdot L_{grid} \quad (9)$$

Where λ_{eve} represents the failure rate per km per year of the feeder, and L_{grid} represents the total length of the feeder in km (mainline and all branches). Thus, $sags$, SDI and LDI affecting the entire electrical grid can be estimated by (10)-(12) , respectively:

$$N_{sag/yr} = \left(\frac{\sum_{s=1}^{N_s} P_{sag(s)}}{N_s}\right) \cdot N_{tot/yr} \quad (10)$$

$$N_{SDI/yr} = \left(\frac{\sum_{s=1}^{N_s} P_{SDI(s)}}{N_s}\right) \cdot N_{tot/yr} \quad (11)$$

$$N_{LDI/yr} = \left(\frac{\sum_{s=1}^{N_s} P_{LDI(s)}}{N_s}\right) \cdot N_{tot/yr} \quad (12)$$

A. Financial losses due to voltage sags and interruptions

The calculation of C_{Fin} due to sag, SDI e LDI can be performed considering four relevant parameters:

- Uncertainty of the production process failure ($Un_{PT}(s,c)$) of c for each s;
- Probabilities of each phenomenon (among sag, SDI, LDI) affecting the common coupling point b (where c is a customer connected to b)
- Activity factors for c ($F_a(c)$);
- Unit costs related to sag, SDI and LDI for c, i.e., $C_{sag}(c)$, $C_{SDI}(c)$ and $C_{LDI}(c)$, respectively.

The values of $Un_{PT(s,c)}$ depend primarily on the type of equipment or production process and the magnitude and duration of the voltage sag. The total number of annual events between sags, SDI, and LDI that can affect the electrical grid for a particular customer can be calculated as follows:

$$N_{p/yr(c)}^{sag} = \frac{\sum_{s=1}^{N_s}\left[Un_{PT(s,c)} \cdot P_{sag(s,b)}\right]}{N_s} \cdot F_{a(c)} \cdot N_{tot/yr} \quad (13)$$

$$N_{p/yr(c)}^{SDI} = \frac{\sum_{s=1}^{N_s}\left[P_{SDI(s,b)}\right]}{N_s} \cdot F_{a(c)} \cdot N_{tot/yr} \quad (14)$$

$$N_{p/yr(c)}^{LDI} = \frac{\sum_{s=1}^{N_s}\left[P_{LDI(s,b)}\right]}{N_s} \cdot F_{a(c)} \cdot N_{tot/yr} \quad (15)$$

Thus, the financial losses C_{Fin} can be calculated as:

$$C_{Fin} = \sum_{c=1}^{N_c} \begin{pmatrix} N_{p/yr(c)}^{sag} \cdot C_{sag(c)} + \\ N_{p/yr(c)}^{SDI} \cdot C_{SDI(c)} + \\ N_{p/yr(c)}^{LDI} \cdot C_{LDI(c)} \end{pmatrix} \quad (16)$$

3. Problem Formulation.

The objective function aims to minimize the total cost of investment, electrical losses, and financial losses over the planning horizon. The constraints include radial topology, voltage limits, and maximum capacities of lines and substations.

$$\mathrm{F.O.} = \sum_{k=1}^{K} \begin{bmatrix} w_{Inv} \cdot C_{inv(k)_{p.u}} + \\ w_{Ele} \cdot C_{Ele(k)_{p.u}} + \\ w_{Fin} \cdot C_{Fin(k)_{p.u}} \end{bmatrix} \cdot \delta_{(k)}^{\mathrm{inv}} \quad (17)$$

$$w_{Inv} + w_{Ele} + w_{Fin} = 1;\ \delta_k^{inv} = \frac{1}{(I_R + 1)^{t_{k-1}}} \quad (18)$$

In (17), $C_{inv(k)_{p.u}}$, $C_{Ele(k)_{p.u}}$ and $C_{Fin(k)_{p.u}}$ represent per unit values, which can be obtained from (19)-(21). The factor δ_k^{inv} allows for the conversion of each cost value to present value. In (18), the values of w_{inv}, w_{Ele}, w_{Fin} can vary based on the energy utility's strategies. If reducing electrical losses is a priority, w_{Ele} can be increased, and similarly w_{Fin} can be prioritized if there are concerns about financial losses. Thus, the choice among investment costs, electrical losses, and financial losses is influenced by the values assigned to w_{inv}, w_{Ele} and w_{Fin}.

$$C_{inv(k)_{p.u}} = \frac{C_{inv(k)}}{C_{inv_{max}}} \quad (19)$$

$$C_{Ele(k)_{p.u}} = \frac{P_{Elec(k)}}{P_{Ele_{max}}} \quad (20)$$

$$C_{Fin(k)_{p.u}} = \frac{P_{Fin(k)}}{P_{Fin_{max}}} \quad (21)$$

The value of $C_{inv(k)}$ is calculated by (22), which considers the installation costs of new lines and substations and the costs of removal, in case of line and substation replacements.

$$C_{inv(k)} = \sum_{L=1}^{L} \begin{pmatrix} C_{Inst(l,k)} \cdot f_{Inst(l,k)} + \\ C_{Ren(l,k)} \cdot f_{Ren(l,k)} \end{pmatrix} \cdot f_{Op(l,k)} \quad (22)$$

$$C_{Ren(l,k)} = 0.3 \times C_{Inst(l,k)} \quad (23)$$

Where $f_{Inst(l,k)}$, $f_{Ren(l,k)}$ e $f_{Op(l,k)}$ are factors that enable the use of costs depending on the use of line l in k. $C_{inv_{max}}$, it is taken as a reference the cost of all installed lines considering the highest existing line cost.

$$C_{inv_{max}} = \sum_{l=1}^{L} C_{inv_{max}(l)} \quad (24)$$

$$C_{inv_{max}(l)} = Max(C_{l1}, C_{l2}, \dots, C_{ln}) \quad (25)$$

The cost of electrical losses is evaluated by (26). The maximum value $P_{Ele_{max}}$ is obtained from (27) considering the maximum allowable current of all lines.

$$P_{Elec(k)} = \sum_{L=1}^{L}\left(R_{(l,k)} \cdot I_{(l,k)}^{2} \cdot f_{Op(l,k)}\right) \tag{26}$$

$$P_{Ele_{max}} = \sum_{L=1}^{L}\left(R_{(l,k)} \cdot I_{max(l,k)}^{2}\right) \tag{27}$$

To eval $P_{Fin_{max}}$ by (28), it is considered that: $N_{p/yr(c)}^{sag} = N_{p/yr(c)}^{SDI} = N_{p/yr(c)}^{LDI}$.

$$P_{Fin_{max}} = N_{tot/yr} \cdot \sum_{c=1}^{N_c}\left(\begin{matrix} C_{sag(c)} + \\ C_{SDI(c)} + C_{LDI(c)} \end{matrix}\right) \tag{28}$$

$$N_{tot/yr} = \lambda_{grid} \cdot L_{grid} \tag{29}$$

The constraints considered in this paper are:

- Radiality and isolation: the network must remain radial and should not have isolated unconnected elements at each planning stage.
- Demand: the network must meet customer demand at each planning stage.
- Maximum load supplied by the substation: substations have a maximum load limit.
- Voltage and current limits: the voltage at the buses and the current in the lines must remain within the minimum and maximum limits at all stages.

4. Proposed Genetic Algorithm.

The problem presented in (17) can be considered a mixed-integer linear programming problem (MILP), for which one of the metaheuristic techniques known as Genetic Algorithms has been implemented. The essential input parameters for the algorithm include the scheduled demand per stage and the main line options to be considered. Additionally, the number of individuals in the population and the number of iterations required are considered as stopping criteria. The proposed Fitness Function (F.F) is as follows:

$$F.F. = F.O. + \sum_{k=1}^{K} Pen_{(k)} \tag{30}$$

$$\begin{aligned} Pen_{(k)} &= Pen_{Grid(k)} + Pen_{(V,k)} \\ &+ Pen_{(I,k)} + Pen_{Demand(k)} \end{aligned} \tag{31}$$

Subject to:

$$Pen_{(I,k)} = \begin{cases} 0\ , & |I| \leq I_{max} \\ 10^5, & |I| \geq I_{max} \end{cases} \tag{32}$$

$$Pen_{(V,k)} = \begin{cases} 0, & V_{min} \leq V \leq V_{max} \\ 10^5, & other\ cases \end{cases} \tag{33}$$

$$Pen_{Grid(k)} = Pen_{Rad(k)} + Pen_{Iso(k)} \tag{34}$$

$$Pen_{Rad(k)} = \sum_{k=1}^{n}\left(Pen_{Rad(1)} + .. + Pen_{Rad(k)}\right) \tag{35}$$

$$Pen_{Rad(k)} = \begin{cases} 10^5 \cdot N_k^{nod}, & Rad_{(k)} \geq 1 \\ 0, & Rad_{(k)} = 0 \end{cases} \tag{36}$$

$$Rad_{(k)} = \begin{cases} 0, & Radial\ Network\ in\ k \\ 1, & Non\ Radial\ Network\ in\ k \end{cases} \tag{37}$$

$$Pen_{Iso(k)} = \sum_{k=1}^{n}\left(Pen_{ISO(1)} + \cdots + Pen_{ISO(k)}\right) \tag{38}$$

$$Pen_{ISO(k)} = \begin{cases} 10^5 \cdot N_k^{iso}, & Iso_{(k)} \geq 1 \\ 0, & Iso_{(k)} = 0 \end{cases} \tag{39}$$

$$Iso_{(k)} = \begin{cases} 0, & Network\ without\ isolated\ blocks\ in\ k \\ 1, & Network\ with\ isolated\ blocks\ in\ k \end{cases} \tag{40}$$

For the development of the genetic algorithm, different steps are considered:

A. Encoding.

The proposed encoding is presented in Fig. 3. It represents the planning options for each line in the electrical network. Each gene in the chromosome corresponds to a line, storing information about the type of line to be installed at each planning stage.

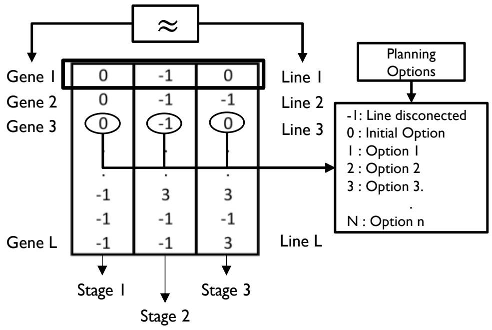


Fig. 3. Chromosome Encoding.

B. Initial Population

The creation of the initial population is generated with random values for each gene.

C. Selection, Recombination, and Mutation.

Selection is performed using the roulette method, favoring individuals with the best fitness function. Recombination (crossover) occurs with a crossover point and depends on a fixed recombination rate of the population. The mutation is applied randomly, with each gene of the chromosome considering a fixed mutation rate.

D. Topology Improvement.

After recombination and mutation, there is the possibility that the obtained individuals do not comply with the radiality and isolation constraints. Therefore, a topology improvement strategy is carried out in two steps. First, recovery for isolated networks, i.e., isolated blocks are identified, and a random bus within a block is chosen as a reference to try to connect the block to the network. If there is no possibility of a connection, another bus is randomly chosen. Second, recovery for non-radial networks, i.e., the lines forming a mesh within the network are identified, and a line is randomly disconnected in each mesh until all meshes are eliminated.

E. New Population.

For the next generation, 20% of the previous population is randomly chosen after recombination and mutation to promote chromosomal variety. The remaining 80% are used in the selection, recombination, mutation, and improvement steps.

5. Results.

The 18-bus network is used in this study, which consists of: 18 buses and two substations (nodes 17 and 18) operating at a nominal voltage of 13.8 kV, 16 load nodes, and 24 lines. Fig. *4* shows the initial topology. The values of the loads and lines can be found in [8].

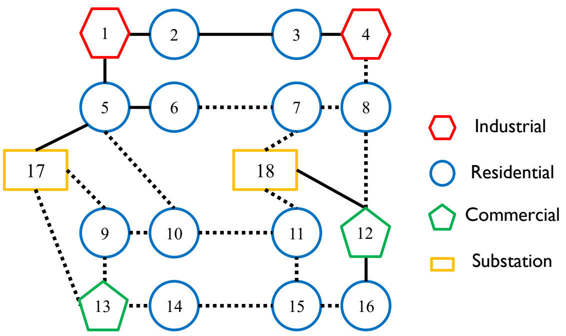


Fig. 4. Network of 18 Bus Adapted from [8]

The planning horizon is four years, divided into three stages: the first two are one year each, and the third is two years. The maximum current injections for both substations are 500 A for stage 1 and 1000 A for stages 2 and 3. The adopted interest rate is 10% per year, with conversion factors: $\delta_1^{inv} = 1$, $\delta_2^{inv} = 0{,}9091$, $\delta_3^{inv} = 0{,}8264$. Voltage limits are $V_{min} = 13110\,V$ and $V_{max} = 14490\,V$. Representing residential, commercial, and industrial customers, there are 143, 4, and 4 customers, respectively. Electrical losses are \$0.1/kWh, and financial losses can be estimated used the unitary values shown in Table I.

Table I. - Costs per simulated event in customers.

Customer Type	$C_{sag(c)}$ US\$	$C_{SDI(c)}$ US\$	$C_{LDI(c)}$ US\$	$F_a(c)$
Industrial	6124	6124	9903.9	0.23836
Residential	2.2	2.2	4.8	1
Commercial	250.1	250.1	532.9	0.35731

The GA is executed with an initial population of 50 individuals and 30 generations, using a recombination rate of 80% and a mutation rate of 10%. The tests are conducted on a computer with an AMD Ryzen 7 4800H processor, 16.0 GB of RAM, and an RTX 3050 graphics card. The implementation is in Python, with power flow evaluation using the OpenDSS software.

The specific weights for w_{inv}, w_{Ele} and w_{Fin}, were 0.7, 0.15, 0.15 respectively. Fig. 5 presents the fitness function values obtained for the best solution per iteration (blue), the best global solution (green), and the average fitness function value per iteration (red). The figure shows that in iteration 21, the individual with the best fitness function value of 0.12226 is found. Also, Table II shows the results of the values of C_{inv}, P_{Ele} and P_{Fin} and the F.F. of the best results found through the genetic algorithm, showing the inherent variability in the possible responses.

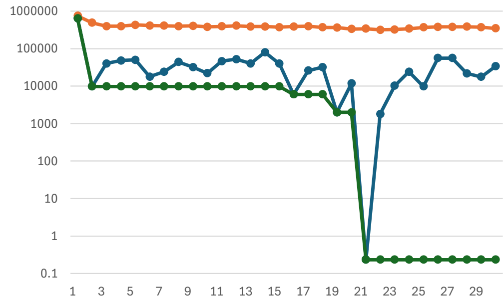


Fig. 5. Fitness Function Results Obtained by the Algorithm.

Table II. - Results obtained by the Genetic Algorithm.

Alternative	C_{inv} US\$	P_{Ele} US\$	P_{Fin} US\$	F.F.
1	3,7 k	1809,5k	222,9k	0.1148
2	3,9k	1660,4k	232,6k	0.1174
3	3,8k	2133,1k	931,4k	0.1222

The planning alternative that presented the lowest objective function has C_{inv} = 7,8k, P_{Ele} = 1809,5k, and P_{Fin} = 222,9k. We can observe that it has lower values of Cinv and P_{Ele}, but higher values of P_{Fin}. The respective chromosomal structure can be seen in Table III, and the network topology can be seen in Fig. 6.

A change in the topology over time is observed in Fig. *6*, highlighting that in Stage 1 all network buses were considered. This suggests that the algorithm prioritized significant investments in the first stage, allowing for reduction in subsequent stages. Despite the increase in electrical losses due to load growth, as shown in Table III, the algorithm's solution demonstrates a reduction in Financial Losses in Stage 3 compared to Stage 2, despite the increase in planned demand.

6. CONCLUSIONS.

This study presented an approach to solving the problem of distribution network expansion planning, focusing on three distinct objectives, i.e., Investment Costs, Electrical Losses, and Financial Losses due to sags and power interruptions. The proposed modeling is conducted through a multi-objective mathematical formulation. For that, the optimization technique based on the Genetic Algorithm is proposed to minimize the intended objectives. The effectiveness of the algorithm is evaluated on an 18-node network, and the results indicate that in terms of investment cost, the algorithm demonstrated superior solutions compared to previously proposed models. However, it is essential to highlight that there are models in the literature predominantly focused on investment cost. The proposed Genetic Algorithm stands out showing robustness and efficiency in dealing with different goals and offering superior performance in complex optimization scenarios. Despite the positive results, there are opportunities for improvement through some modifications GA process.

Acknowledgement

This work was financed in part by the Coordination for the Improvement of Higher Education Personnel – Brazil

(CAPES) – Financing Code 001 and by the Dean's Office for Research of the University of São Paulo (Pró-Reitoria de Pesquisa e Inovação, PRPI), process 22.1.09345.01.2.

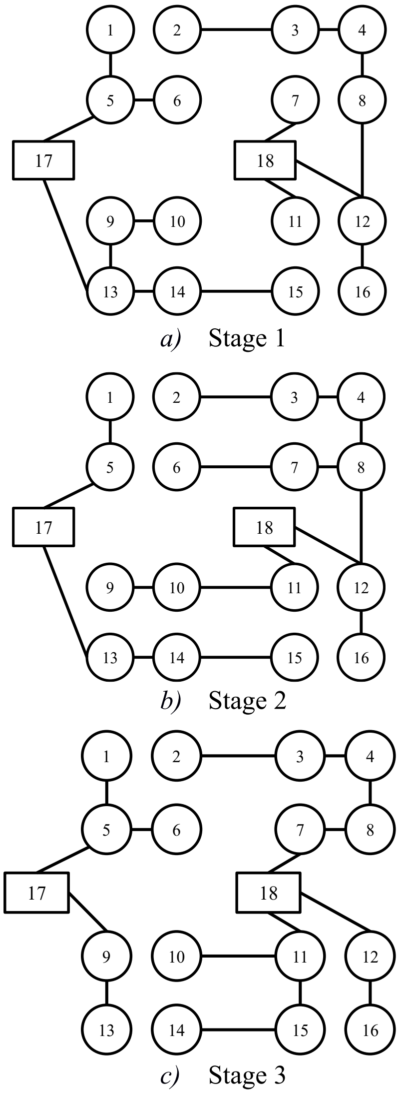


Fig. 6. Topology of the best result.

Table III. - Chromosome Matrix of the Best Solution.

Lines	Stage 1	Stage 2	Stage 3
1-2	-1	-1	-1
2-3	-1	0	0
3-4	-1	0	0
1-5	0	1	1
5-6	1	0	2
5-17	0	-1	-1
12-16	2	2	-1
12-18	2	1	0
4-8	1	2	2
5-10	-1	1	-1
6-7	-1	-1	2
7-8	2	-1	-1
7-18	1	3	1
8-12	-1	1	2
9-10	-1	1	2
9-13	2	-1	-1
9-17	3	-1	-1
10-11	3	3	2
11-15	1	-1	2
11-18	-1	3	3
13-14	1	2	1
13-17	-1	2	2
14-15	1	2	-1
15-16	-1	-1	3
C_{inv} US$	1.5k	1.5k	0.6k
P_{Ele} US$	207k	702k	900k
P_{Fin} US$	60k	96k	67k
Total Stage	269k	800k	968k
Global		2036k	

References

[1] A. Ehsan and Q. Yang, " State-of-the-art techniques for modeling of uncertainties in active distribution network planning: A review," *Applied Energy*, vol. 239. p. 1509-1523, 2019, doi 10.1016/j.apenergy.2019.01.211.

[2] G. L. Aschidamini *et al.*, "Expansion planning of power distribution systems considering reliability: A comprehensive review," *Energies*, vol. 15, no . 6, p. 2275, 2022.

[3] V. Vahidinasab *et al.*, " Overview of electric energy distribution networks expansion planning," *IEEE Access*, vol. 8, p. 34750-34769, 2020, doi: 10.1109/ACCESS.2020.2973455.

[4] H. Mubarak, H. Mokhlis, N. N. Mansor, M. Mohamad, A. S. Mohd Khairuddin, and S. Afzal, " Optimal distribution networks expansion planning with DG for power losses reduction," in *2021 Innovations in Power and Advanced Computing Technologies (i-PACT)*, Nov. 2021, pp. 1-5.

[5] P. Júnior and B. Rodrigues, "Planejamento de médio e longo prazo de sistemas de distribuição de energia elétrica com geradores distribuídos (GDs) considerando custos de confiabilidade, operação e expansão," 2014. [Online]. Available: http://hdl.handle.net/11449/100354

[6] M. Sedghi, A. Ahmadian, and M. Aliakbar-Golkar, "Assessment of optimization algorithms capability in distribution network planning: Review, comparison and modification techniques," *Renewable and Sustainable Energy Reviews*, vol. 66, p. 415-434, 2016, doi: 10.1016/j. rser.2016.08.027.

[7] J. C. Cebrian, J. Giacomini, C. A. Carneiro, G. B. Silva and H. K. Morales-Paredes, "A novel methodology to estimate probability density function of voltage sag duration and failure rates on power distribution systems," *IEEE Access*, vol. 11, pp. 16863-16874, 2023, doi: 10.1109/ACCESS.2023.3243552.

[8] J. C. Cebrian, J. V Milanovic, and N. Kagan, "Impact of the application of process immunity time on distribution expansion planning," 2014.

[9] S. Haffner, L. A. Pereira, L. F. Pereira, and L. Barreto, "Multi-stage model of optimization for the planning of the expansion of distribution systems," *Controle y Automacao*, vol. 17, no. 4, pp. 478-492, 2006.

[10] S. Kilyeni, C. Barbulescu, A. Simo, R. Teslovan and C. Oros, "Genetic algorithm based distribution network expansion planning," in *2014 49th International Universities Power Engineering Conference (UPEC)*, Sep. 2014, pp. 1-6, doi: 10.1109/UPEC.2014.6934812.

[11] R. S. Pinto, C. Unsihuay-Vila, and T. S. Fernandes, "Multi-objective and multi-period distribution expansion planning considering reliability, distributed generation and self-healing," *IET Generation, Transmission & Distribution*, vol. 13, no. 2, pp. 219-228, 2019, doi:10.1049/iet-gtd.2018. 5037.