An open-source tool for reliability analysis in radial distribution grids

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***Abstract*—We present an open-source software implementation of an approximate contingency enumeration approach for calculating reliability in distribution grids based on RELRAD. The tool is coded using the efficient programming language Julia, to ensure fast and scaleable calculations. The network topology is mapped as a graph. This allows us to efficiently determine load points affected by contingencies by using standard graph algorithms.**

The tool is demonstrated on a simple synthetic test system and an actual Norway distribution grid.

***Index Terms*—Power system reliability, open source, distribution grid**

I. INTRODUCTION

In several countries, there are incentives for distribution system operators (DSOs) to optimize the continuity of supply [1], [2]. The continuity of supply is measured by using reliability indicators such as the cost of energy not supplied (CENS). Consequently, DSOs need a tool for calculating the expected CENS in order to be able to plan their systems optimally.

Approaches for calculating reliability in radial operated distribution grids can be categorized into analytical approaches and Monte Carlo simulation (MCS) approaches [3]. For analytical approaches a minimal cut-set methodology or failure mode and effect analysis are typically used [3], [4]. However, contingency enumeration approaches have also been demonstrated [3], [5] as being suitable.

MCS approaches are generally slower than analytical approaches, as many iterations are needed for the simulation to converge [3], [6]. However, results from the MCS approaches and approximate analytical approaches can be expected to be quite similar [6]. It is also possible to further speed up analytical approaches by using network reduction techniques as demonstrated in [7].

A recent development of reliability assessment methods extends traditional approaches to calculating reliability to evaluate the benefits that distributed generation, energy storage, demand response, electrical vehicles, and microgrids may bring to distribution grid reliability [8]. Another recent study considers the impact of power system and ICT interdependencies on the reliability of the distribution system [9]. Recent works include reliability assessment within methodologies for the optimal placement of fault indicators in distribution grids [10]–[12].

Although, reliability assessment methodologies for distribution grids have existed for a while, there is a lack of open-source software available for this purpose. This paper fills this gap by presenting an open-source software implementation of a contingency enumeration approach for calculating reliability in distribution grids based on RELRAD, a method first presented in [3]. Originally, RELRAD was presented using high-level flow charts and equations. However, while the paper is easily human readable, it does not outline how to process the topology of the distribution grid. In order to implement RELRAD on a computer, a sound methodology for processing the topology is needed. We solve this shortcoming by rewriting the original approach in terms of graph theory. This allows us to use standard methods from graph theory to determine which parts of the network experiences an outage during contingencies. Moreover, graph libraries are available in most modern programming languages, which facilitates easy software implementation.

We have used the Julia programming language to implement the tool, which is a just-in-time (JIT) compiled language that was made for scientific calculations. It should therefore be suitable for performing calculations on large distribution grids. The code is available online at [13] under an open-source license.

In Section II, we present the algorithm that we have used to build the tool. Results from a small synthetic test network and an actual Norwegian network are presented in Section III, and conclusions are presented in Section IV. —

II. THE RELRAD ALGORITHM

RELRAD is an algorithm that calculates the CENS of loads in radially operated distribution grids [3]. It calculates how faults in each component contribute to the CENS for each load in the system. The algorithm relies on both statistical and topological assumptions. The topological assumptions are as follows:

1) The distribution grid in question is radially operated.
2) All faults are extinguished by a circuit breaker installed at the beginning of the supply feeders, and the circuit breakers work perfectly (i.e. the breakers always open when a fault occurs). We assume this circuit breaker to

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always be present at this position. However, the algorithm can easily be extended to consider other locations.

3) There are no transfer restrictions on reserve connections.
4) After a fault is located, the faulty line is isolated by the closest disconnectors and the loads are resupplied if possible, or otherwise wait for repair.
5) Automatic sectioning devices or remote control on certain disconnectors may be specified by reducing sectioning times for these disconnectors.

The statistical assumptions are as follows:

1) All faults are statistically independent.
2) Multiple faults are not represented.
3) All faults are repaired before the next fault occurs.
4) Switching equipment and transformers do not fail.

In this paper the distribution grid is described as a graph $\mathcal{G} = (V, E)$, where $V = \{v_1, v_2, \ldots, v_{n_n}\}$ is the set of vertices and $E = \{e_1, e_2, \ldots, e_{n_e}\}$ is the set of edges, n_n is the number of vertices (nodes) in the grid and n_e is the number of edges (lines, cables, switches, transformers, etc.) in the grid.

An edge e is represented as a tuple of vertices $e = (v, v^*)$ and associated with a set of properties: a permanent failure frequency $\lambda = \lambda(e)$, a temporary failure frequency $\lambda_t = \lambda_t(e)$, a temporary fault duration $t_t = t_t(e)$, and a repair time $r = r(e)$. In this paper we consider permanent failures as failures where the affected component must be repaired before it can be put back in service. Temporary failures are failures in which the component can be put back in service after a switching operation without first needing repair.

The set of edges E also include the set of switches $S = \{s_1, s_2, \ldots, s_{n_s}\} \subset E$, where n_s is the number of switches in the grid. In addition to the properties defined for edges, each switch s, is associated with a sectioning time $t_{sect} = t_{sect}(s)$, which is the time needed to operate the switch to isolate a fault. We define the Boolean function $c(s)$ for each switch, which returns true if the switch is closed and false otherwise. In the current implementation circuit breakers are not included in S, as it is assumed to be present at the beginning of the supply feeder.

By taking the state of the switches into account, we can define an acyclic directed graph $G \subset \mathcal{G}$, where the normally open switches are considered as open edges, and the direction is given by the graph traversal from the infeed to the graph leaf nodes. Therefore, G represents the radially operated distribution network, whereas $\mathcal{G}$ represents the full network topology, including possible reconfiguration options when faults occur.

The set of delivery points is defined as $L = \{l_1, l_2, \ldots, l_{n_l}\} \subset V$, where n_l is the number of delivery points. Each delivery point l has an associated average demand $P_i = P(l)$. The grid is fed by transformer stations $F = \{f_1, f_2, \ldots f_{n_f}\} \subset V$, where n_f is the number of infeed transformer stations. We assume the grid to be operated radially and be fed by a root node $v_{root} \in V$, which implies that all $f \neq v_{root}$ are considered as reserve connections.

The RELRAD algorithm can calculate different types of reliability indicators. The unavailability (U) for one load due to one contingency is calculated by multiplying the failure rate λ by the interruption duration t [3]:

$$U = \lambda \cdot t \tag{1}$$

In cases where the load is connected to the area that is disconnected during the line repair process, the interruption duration t is equal to the repair time r of the faulty component. In cases where the load can be fed safely during the repair process, the interruption duration t is equal to the maximum sectioning time t_{sect} of the switches involved in the faulty area isolation.

Algorithm 1 The RELRAD algorithm

```
procedure RELRAD($\mathcal{G}$)
    $G = open(\mathcal{G})$                          ▷ Acyclic graph
    $IC = 0_{n_l \times n_e}, IC \in \mathbb{R}^{n_l \times n_e}$
    $IC_t = 0_{n_l \times n_e}, IC \in \mathbb{R}^{n_l \times n_e}$
    $Q = (v_{root}, G[v_{root}])$
    while $Q != \emptyset$ do                  ▷ Iterate the queue of edges
        $e = Q.pop()$
        $(IC[:][e], IC_t[:][e])$ = COST($\mathcal{G}, e$)
        $Q \leftarrow [G[v^*][G[v^*]]]$           ▷ Add edges adjacent to $e$
    end while
end procedure
```

Algorithm 2 IC cost calculation algorithm

```
function COST($\mathcal{G}, e$)
    $R = []$
    $ic_e = 0_{n_l}$
    $ic_{e_t} = 0_{n_l}$
    if $e \notin S$ then
        $(IN, RN, t_{sect})$ =SECTION($\mathcal{G}, e$)
        for all $f \in F$ do
            $R = R \cup r(RN, f)$             ▷ Reachability matrix
        end for
    end if
    for all $l \in L$ do
        if $l \in R$ then
            $t = r(e)$
        else
            $t = t_{sect}$
        end if
        $ic_e[l] = ic(\lambda(e), t, P(l))$
        $ic_{e,t}[l] = ic(\lambda_t(e), t_t(e), P(l))$
    end for
    return $(ic, ic_t)$
end function
```

The energy not supplied (ENS) is calculated as [3]:

$$ENS = U \cdot P \tag{2}$$

where P is the reference (average) demand. Finally, CENS is calculated with the following equation [14], [15]:

$$CENS = ic(\lambda, t, P) = C_{ref}(t) \cdot ENS \cdot f_k \tag{3}$$

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where $C_{ref}(t)$ is the cost of energy not supplied if the interruption happens at the reference time, and f_k is a correction factor for the interruption not happening at the reference time. To keep the presentation simple, the algorithm steps described later will be specified for the calculation of CENS.

To descibe our implementation of RELRAD we use several procedures written in pseudocode. In pseudocode we use the notation $G[v]$ to represent the list of vertices adjacent to v and $G[v][v^*]$ to represent the edge from v to v^*. We will also define the mapping $d : v \to R$, where $R \in V$ is the set of vertices reachable from the vertex v, which will be written as $R = d(v)$. The procedure responsible for iterating over all elements that can fail is described in in Algorithm 1, the procedure responsible for calculating the CENS is described in Algorithm 2, and the procedure responsible for determining the sectioning is described in Algorithm 3.

Algorithm 3 Sectioning algorithm

```
function SECTION($\mathcal{G}, e$)
    $s = []$                                    ▷ Vertices seen
    $v = [\text{src}(e)]$                        ▷ Vertices to be visited
    $t = []$
    $IN = \emptyset$
    while $v \neq \emptyset$ do
        $nx = \text{pop}(v)$
        if $nx \notin s$ then
            $s \leftarrow nx$
            for all $n \in \mathcal{G}[nx]$ do
                if $\mathcal{G}[nx][n] \in S$ then
                    $s \leftarrow n$
                    $t \leftarrow t_{sect}(\mathcal{G}[nx][n])$
                else
                    $v \leftarrow n$
                end if
                $IN \leftarrow \mathcal{G}[nx][n]$
            end for
        end if
    end while
    $RN = \mathcal{G} - IN$
    $t_{sect,e} = \max(t)$
    return $(IN, RN, t_{sect,e})$
end function
```

First, the acyclic graph G is obtained from the graph $\mathcal{G}$ by opening the edges corresponding to the normally open switches. The Interruption Costs (IC) and Temporary Interruption Costs (ICt) are then initialized with a matrix of zeros of size (n_l, n_e), where the element (l, e) represents the cost for load l due to the failure of edge e. (We use IC instead of CENS in the algorithms for brevity.) Starting from the primary infeed v_{root}, the adjacent edges e are iteratively inspected through the function $COST(G, e)$, which calculates the contribution to the CENS due to failure of edge e and is described in Algorithm 2.

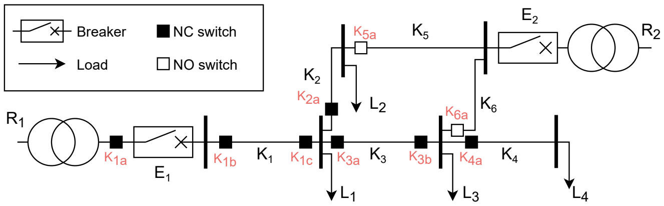

Fig. 1: Test network

In case of the failure of an edge, all loads downstream from the circuit breaker connecting the edge to the main feeder will experience an interruption. However, after appropriate sectioning, some loads may be supplied again through either the main feeder or a reserve connection. Other loads may have to wait for the failed component to be repaired or replaced. For Algorithm 2 to be able to calculate the CENS it needs to know which part of the network can be supplied after sectioning and which part must wait to be repaired or replaced. This is determined by the function SECTION$(\mathcal{G}, E)$ described in Algorithm 3, which identifies the portion of the network that will be isolated through sectioning. More specifically, three values are returned:

IN	is the portion of the network that is isolated by disconnecting the switches closest to the fault location, and thereby avoids energizing the fault.
RN	is the portion of the network that can ideally be energized after the isolation of the failed network section if a feeding bus is available.
t_{sect}	is the maximum sectioning time among the disconnectors that are operated in order to isolate the failed network section.

The function SECTION$(\mathcal{G}, e)$ essentially exploits a Depth First Search (DFS) approach in traversing the graph from the investigated edge until a switch is met.

The interruption time is equal to the sectioning time t_{sect}, for all loads in RN that can be reached from a feeder; the unreachable loads belong to the isolated section IN of the network, and therefore the repair time $r(e)$ is applied for these. Finally, the interruption costs are calculated for each load using (3).

The algorithm is coded in the Julia programming language (v1.4), and is available online at [13] under the open source-license GNU Library General Public License (LGPL). The library used for the graph-based modeling and processing is LightGraphs [16]. An extension of the LightGraphs library, called MetaGraphs, is used to store edge properties along each graph edge, such as the status of switches.

III. RESULTS AND DISCUSSIONS

In this section, we present results from a simple test network and a network from the Norwegian power system. The simple test system is provided to give the reader an impression on how the algorithm works, and the larger network is provided to show that the tool is applicable for real networks.

To assist in our explanation of the simple test system, we present the algorithm results for the system depicted in Fig. 1. The network consists of 6 lines (K_1 to K_6), 4 loads (L_1 to L_4, with an average power of respectively 5 MW, 4 MW,

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TABLE I: Input parameters for example case study

(a) Line parameters

	K_1	K_2	K_3	K_4
$\lambda[fail./year]$	0.1	0.05	0.15	0.1
$r[h]$	4	4	4	4

(b) Switch parameters

	$K_{1a}, K_{1b}, K_{3a}, K_{4a}, K_{6a}$	$K_{1c}, K_{2a}, K_{3b}, K_{5a}$
$t_{sect}[min]$	5	1

TABLE II: Contribution to expected CENS for each load and branch in NOK/year for example case

	L_1	L_2	L_3	L_4
K_1	0.0417	0.0333	0.0250	0.0167
K_2	0.0042	0.0800	0.0025	0.0017
K_3	0.0625	0.0500	0.0375	0.0250
K_4	0.0417	0.033	0.0250	0.8000
TOTAL	0.1500	0.9167	0.0900	0.8433

3 MW and 2 MW) and a set of disconnecting switches and breakers. The network is normally fed by the feeding bus R_1, and radially operated. A reserve supply point through R_2 is enabled by operating the normally open switches installed on lines K_5 and K_6.

Each line is characterized by a permanent failure rate λ, a temporary failure rate $\lambda_t = 0$, and a repair time r. The switches are characterized by a sectioning time t_{sect}. The input parameters considered in the example are reported in Table I.

For example, let us consider the contribution to the total CENS given by permanent failures on line K_1. In this example, for simplicity we assume a cost function $C_{ref}(t) = 1[NOK/MWh] \cdot t[h]$, where t is the interruption time in hours, and the correction factor $f_k = 1$ (with the assumptions that CENS is exactly equal to ENS). When K_1 fails, breaker E_1 opens, and switches K_{1b} and K_{1c} are opened to allow the line being safely repaired. After the failed line is disconnected (switching time $t_{sect} = 5min$ is used, as it represents the maximum sectioning time between the two switches, see Table I), the rest of the network can be supplied from R_2. The CENS for load L_1 is calculated using (3):

$$\begin{aligned} CENS_{L_1} &= C_{ref}(t) \cdot \lambda_{K_1} \cdot t_{sect} \cdot P_{L_1} \cdot f_k = \\ &= 1 \cdot 0.1 \cdot 5/60 \cdot 5 \cdot 1 = 0.0417 NOK/year \end{aligned}$$

The expected CENS in NOK/year on each network load for the remaining line failure cases are reported in Table II.

We will also present results from the network depicted in Fig. 4. The network was provided by a DSO in Norway, is radially operated by three reserve in-feeds and consists of 1137 nodes and 1139 branches. The voltage level is 22 kV, the total load is 2.68 MW, the size of the loads in the system are plotted in Fig. 2, and the failure rates of the lines are plotted in Fig. 3. The network model is very detailed and includes most of the components in the system including small joints, which we do not have reliability data for. To facilitate the visualization of the network we removed the branches without failure data when we post processed the results after running the algorithm. However, we ran the algorithm on the full network, which took 7.466 seconds on a DELL Latitude 5400 with Intel Core i7 1.90 GHz CPU and 32GB RAM memory. All the data needed to run the test case and the code for obtaining and generating the results will be available at [13]. The aggregated calculated reliability indicators for the network are reported in TABLE III.

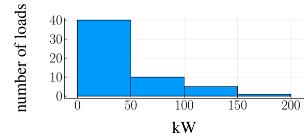

Fig. 2: Load demand in the realistic system

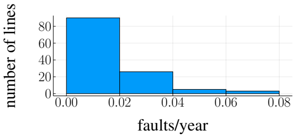

Fig. 3: Fault rates in the realistic system

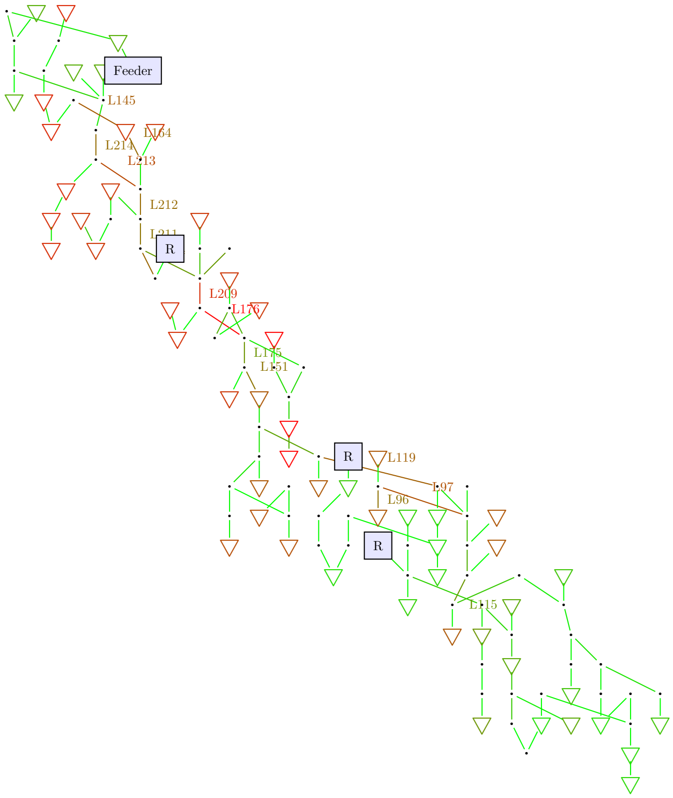

Fig. 4: Graph of test network. Reserve connections are indicated by R, and loads by $\triangledown$. The U of loads is indicated with a color gradient from red U to green. The lines' contribution to U is indicated by a gradient from red to green.

As the DSO considers the network to be sensitive data, we cannot use the geographical coordinates for the network. Therefore, nodes are positioned automatically by a package for plotting graphs. Consequently, line lengths and relative positions of nodes may not necessarily reflect the actual geographical lengths and positions. We used the Julia package TikzGraphs [17] to plot the network, which is well suited to drawing graphs for publication in papers. There are several packages for plotting graphs in Julia that may also be used

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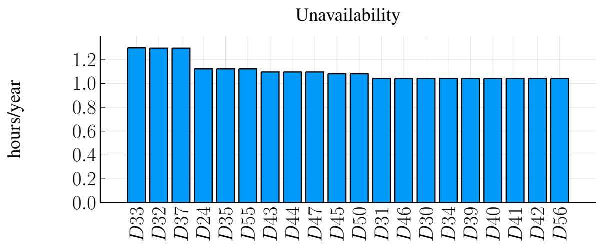

Fig. 5: The loads with the highest U

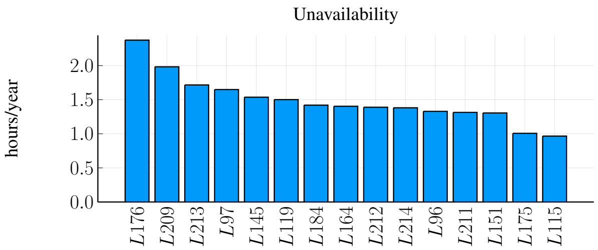

Fig. 6: Lines that contribute the most to U

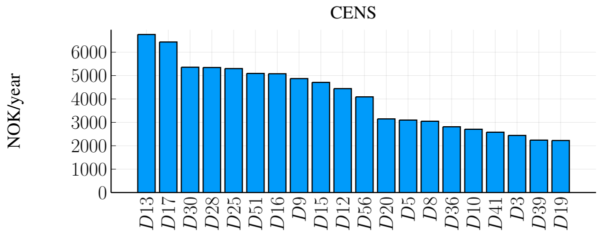

Fig. 7: The loads with the highest CENS

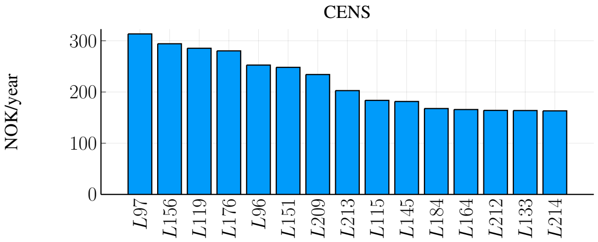

Fig. 8: The lines contributing the most to the load with the highest CENS (D13)

TABLE III: Aggregated results for the real case study

	CENS [kNOK]	ENS [MWh]	U [h]
yearly sum	116.70	1.34	39.67

for other purposes.

The U of loads may be of particular interest to DSOs. An overview of the loads with the highest U would be useful, as these are the loads most likely to complain about the quality of the reliability. Therefore, figures can be compiled that show the loads with the highest U as demonstrated in Fig. 5. To determine how to reduce U, we have plotted the lines in Fig. 6 that contribute the most to the U in the system. The name of these lines are also indicated in Fig. 4. Predictably, several of these lines are close to loads with high U. The visual representation in Fig. 4 provides DSOs with a good indication of the areas where reliability can be improved.

In Norway, the revenue cap for DSOs is negatively influenced by the CENS. Consequently, DSOs may be most interested in the CENS. Since the CENS is influenced by other factors than U, such as power demand and cost of interruption, the loads with the highest CENS may not coincide with the ones with the highest U. This is demonstrated in Fig. 7, which indicates the loads with the highest CENS. By comparing Fig. 5 and Fig. 7 it is apparent that the loads with the highest U do not also have the highest CENS.

Figures such as the one depicted in Fig. 8 can be useful in mitigating high CENS. It shows, the branches that contribute most to the CENS of one specific load (in this case, load D13 is the load with highest CENS). Similar figures can be made for each load in the system. The DSOs then have a means of identifying which lines are good candidates for reducing failure rates, sectioning times or repair times, if the goal is to reduce CENS for one specific consumer.

That the loads with high U and CENS are not necessarily the same is also apparent in Fig. 9, which indicates the CENS of loads in the plot of the network graph. From this figure, we can see that some of the loads with high CENS are situated in areas where most of the lines have quite high availability. The reliability calculation results will help the DSO to understand which lines contributes to CENS, either for the overall grid or for one specific consumer. In Fig. 9, the colour on the lines indicates each lines contribution to total CENS, but similar plot could have been made to show how each line contribute to the CENS of one specific consumer.

It should also be noted that the algorithm can be used to assess different operation strategies such as the consequence of changing the normal feed-in point to one of the reserve connections. The algorithm will then show how this change will affect both the total and the individual CENS (and U).

The current implementation of the algorithm does not take distributed generation into account. Smaller units that provide backup only for their own consumption can easily be considered by excluding them from unavailability calculation and adding a contribution to the calculated cost due to the lost access to the grid. It would be a more complex task to include larger units, that are capable and intended for powering an island of consumers. Finally, the modified load flow resulting from distributed generation will not affect the results of the current implementation, as one of the stated assumptions is that there are no transfer restrictions.

IV. CONCLUDING REMARKS

In this paper we have presented an open-source tool for calculating the reliability of radially operated distribution grids. It was coded in the modern programming language

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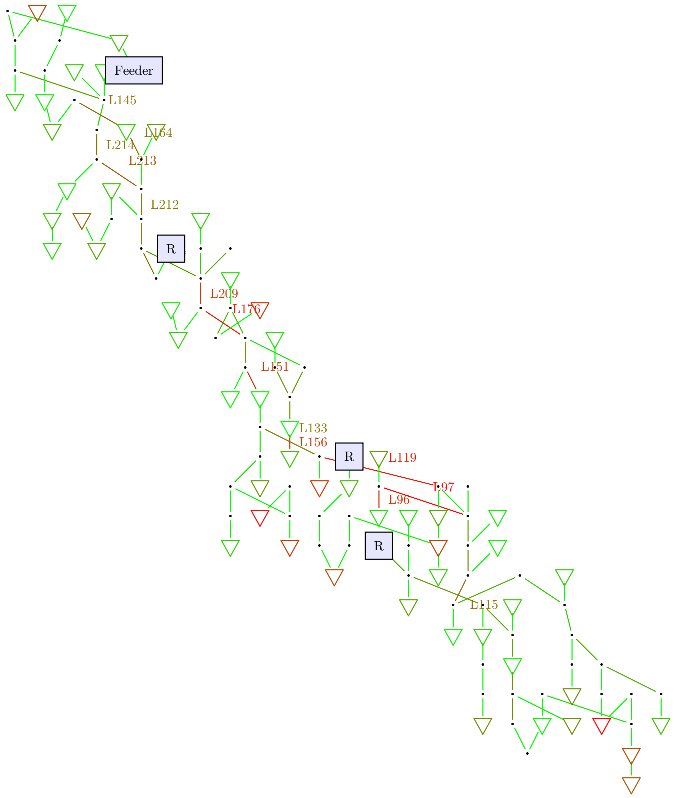

Fig. 9: Graph of test network, reserve connections are indicated by R, and loads by ▽. The CENS of loads are indicated by a color gradient from red to green. The lines' contribution to CENS is indicated by a gradient from red to green.

Julia to ensure fast computation. Results show that the code can compute the reliability of a Norwegian medium voltage distribution grid with more than a thousand buses in a few seconds.

The code was developed as part of an industry project with Norwegian DSOs involved. Software packages that can calculate reliability may be of a great help to them. For example, our tool can be used to achieve an overview of how the system is doing in terms of different reliability indicators, such as CENS and unavailability. This will provide them with useful insight into how the different indicators can be improved. Moreover, the code is freely available as an open source software package and can therefore be easily used in other tools, such as tools for suggesting network improvements or breaker positions.

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