# Development of Maintainability Metrics for Power Systems

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***Abstract*— This study focuses on developing methods to assess the optimality of maintenance campaign in terms of various criteria and the effect of maintenance on power system reliability. The assessment is based on a new set of metrics represented by power system maintainability indices. Adequacy metrics, in general, are ill-suited to deal with this problem: although the scope of power system adequacy assessment covers maintenance, the way it is done is either rudimentary or limited to a pre-specified list of maintenance requests. This study is centered on maintenance scheduling.**

**Several metrics of power system maintainability are conceptualized, detailed, and tested. The analysis of the metrics employs Monte Carlo simulations. The metrics are tested by simulations on a modified standard test system to demonstrate that they are suitable for use in maintainability assessment of power systems. They perform best, however, when evaluating the criticality of generators and power transmission lines within the context of maintenance campaign. The findings from this study underscore the potential for further enhancement of the described procedures. Priority must be given to formulating indices and accelerating their calculation.**

***Index Terms*— power system, maintainability, adequacy, maintenance scheduling, partial integer programming, Monte Carlo simulations.**

## I. INTRODUCTION

Russian power systems have a long-standing practice of scheduling the great bulk of maintenance for the summer. Summers enable inspections and diagnostics of remote facilities and power transmission lines that may be otherwise inaccessible. The summer shoulder season also creates spare generator capacity that can be disconnected for scheduled maintenance. Lower loads of transformers and power lines facilitate power grid equipment maintenance. As it stands now, maintenance scheduling is mostly done ad hoc based on past operational experience.

Recent years have seen higher average ambient temperatures and electricity consumption in the summer, which made maintenance campaigns more stressful and risky, eventually causing several major local accidents due to improperly chosen combination of equipment taken for maintenance. In this context, maintenance scheduling must meet a certain performance criterion, e.g. the minimum total probability of a capacity shortage. Smaller maintenance yards increase the risk of a failure to complete all work on time. A solution lies either in limiting the loads and damages, or in postponing maintenance to a different season, extending the duration of the maintenance campaign, and compromising reliability of the power system as a whole.

The above scenarios can be avoided if power system expansion planning incorporates the strategies that ensure, for example, minimum capacity shortages under arbitrary maintenance scheduling. This will lessen the reciprocal effect among individual equipment maintenance events, streamline their planning and completion of the maintenance campaign. Addressing this problem is proposed by developing a technique for maintainability analysis of power systems, which explores how much the risks of capacity shortages and expected energy not served (EENS) increase during maintenance campaigns. The approach has a lot in common with the research on vulnerability assessment of power systems [1, 2]. These

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studies seek to identify the components of the system whose disconnection results in the most damage, regardless of the probability of possible failures. The power system maintainability metrics advocated here are essentially vulnerability metrics as they identify the equipment critical for the reliability of the system under heavy-load conditions, i.e., the maintenance campaign.

The problem of power system maintainability is not a subject of much research either in Russia or in other countries. It is common to group maintenance-related problems into three categories:

1. Assessing adequacy in terms of maintenance. In this case, focus is made on simplified maintenance scheduling of generation units during the spring and summer [3, 4].
2. Selecting an optimal maintenance scheduling option with adequacy as a criterion and as a constraint. In this case it all depends on the statement and criterion for optimal maintenance scheduling problem. Scheduling can be based on any of the following criteria: the expected energy not served as such [5], minimum electricity costs in the power system in the market-driven context [6], minimum costs of emergency and scheduled maintenance informed by equipment life [7], the most compact use of maintenance yards [8].
3. Sizing the power system reserve capacity and identifying its components. Studies [4, 9, 10] treated maintenance scheduling of generation units as an auxiliary problem in distributing the maintenance component of the reserve capacity among subsystems.

The reasonably advanced maintenance scheduling methods could enable the application of existing solutions in a more elaborate and in-depth analysis of power system adequacy given maintenance data.

## II. MAINTAINABILITY INDICES AND CALCULATION ALGORITHM

This study understands power system maintainability as its capability to operate reliably during scheduled maintenance given possible failures and revisions of the maintenance schedule. Assessment of power system maintainability must rule out power system expansion options that increase the risk of capacity shortages during the maintenance campaign. Apart from the above, this area of research should also involve analyzing maintenance scheduling quality, aligning maintenance schedules of generation and network equipment, identifying the most damaging faults or their combinations during maintenance, formulating optimal measures to facilitate power system maintenance and its scheduling.

The first step in advancing assessment methods is to design indices and metrics that enable quantitative assessment of maintainability. This study considers six metrics:

1. Probability of capacity shortage during the maintenance campaign $p_{F_{maint}}$.

2. Expected energy not served (EENS) during the maintenance campaign, $EENS_{maint}$.

3. Index of the incremental probability $p_{F_{maint}}$ ($\alpha^i_{p_{F_{maint}}}$) / Expected energy not served $EENS_{maint}$ ($\alpha^i_{EENS_{maint}}$) for the *i*-th component of the power system during its maintenance:

$$\alpha^i_{p_{F_{maint}}} = 1 - \frac{p^{norm.i}_{F_{maint}}}{p^{maintenance.i}_{F_{maint}}}, \qquad \alpha^i_{EENS_{maint}} = 1 - \frac{EENS^{norm\ i}_{maint}}{EENS^{maintenance\ i}_{maint}}, \tag{1}$$

where $p^{maintenance.i}_{F_{maint}}$, $EENS^{maintenance\ i}_{maint}$ are the shortage probability and EENS during the maintenance campaign given the maintenance of the *i*-th component of the power system; $p^{norm.i}_{F_{maint}}$, $EENS^{norm\ i}_{maint}$ are the same, but the *i*-th component has no history of faults and maintenance.

4. Index of the incremental probability $p_{F_{maint}}$ / Expected energy not served $EENS_{maint}$ for the *i*-the component of the power system, in the case of the component's fault during the maintenance time:

$$\beta^i_{p_{F_{maint}}} = 1 - \frac{p^{norm.i}_{F_{maint}}}{p^{fault.i}_{F_{maint}}}, \qquad \beta^i_{EENS_{maint}} = 1 - \frac{EENS^{norm\ i}_{maint}}{EENS^{fault\ i}_{maint}}, \tag{2}$$

where $p^{fault.i}_{F_{maint}}$, $EENS^{fault\ i}_{maint}$ are the shortage probability and expected energy not served during the maintenance campaign, in the event of the *i*-th component's fault.

The metrics are calculated using Monte Carlo simulations. The model and computational procedure are derived from the models of power system adequacy assessment. The calculation algorithm for a single test is as follows:

1. Generate random maintenance requests for lines and generators of the power system at load centers. The requests specify the maintenance duration and limit its timing.
2. Schedule equipment maintenance.
3. Generate a new consumption profile at load centers

and random faults of equipment during maintenance time *T*. Use state duration modeling to find all random states of equipment during the maintenance period.

4. Find the optimal power shortage distribution for all time instances. Update maintainability metrics.

The proposed maintainability metrics are heuristic. They provide only an approximate estimate and depend on adequacy metrics of the power system as a whole. If the shortage probability and EENS are not large, indices (1) and (2) are only slightly sensitive to equipment maintenance and faults. An alternative and mathematically sound solution could be Sobol' sensitivity indices [11, 12]. They do not allow the assessment of probability metrics as such: estimating changes in the expected value and probability of a capacity shortage requires Monte Carlo simulations for each maintenance schedule, which is exorbitantly expensive in computational terms. Nonetheless, they are useful in estimating the sensitivity of EENS and the occurrence of a capacity shortage to equipment faults. This problem will be addressed in future research.

## III. Maintenance Schedule Optimization Based on the Optimal Power Flow

Optimization of maintenance scheduling and shortage distribution rests on the calculation of power flow of the grid, which is formalized by the optimal power flow model detailed in [13]. A similar solution addressing the Russian context is reported in [14], except that current loads are handled differently. The problem statement given below is developed to optimize power flows in radial networks. This notwithstanding, given the assumptions made at the end of the section, it can be used in simplified power flow optimization as part of reliability assessment.

The power flow of the grid at time *t* is formalized by the following equations:

1. The equation of the active power balance at bus *m* (the same holds true for the reactive power balance):

$$\begin{gathered}\sum_{km\in B}(P_{t,km}-I^{s}_{t,km}R_{km})-\sum_{mn\in B}P_{t,mn}=\\=\sum_{g=1}^{G}P_{t,g}+\sum_{l=1}^{L}\delta_{t,l}-\sum_{l=1}^{L}P^{load}_{t,l},\end{gathered}\tag{3}$$

where $P_{t,km}$ is the active power flow at time *t* in the incoming line *k* – *m*, MW; $I^{s}_{t,km}$ is the squared line current in the incoming line $k-m$ at time *t*, kA$^2$; $R_{km}$ is the resistance of incoming line *k* – *m*, Ohm; $P_{t,mn}$ is the active power flow in the outcoming line *m* – *n* at time *t*, MW; $G_m$ and $L_m$ are sets of all generators and all loads connected to bus *m*, while $G$ and $L$ are the number of generators and loads in sets $G_m$ and $L_m$, respectively; $P_{t,g}$ is the power of generator *g* at bus *m* at time *t*, MW; $\delta_{t,l}$ is the constraint on load power *l* at bus *m* at time *t*, MW; $P^{load}_{t,l}$ is the load power at bus *m* at time *t*, MW; $B$ is a set of incoming and outcoming lines connected to bus *m*.

2. The equation relating a voltage drop in the line *m* – *n* to its power flow [13] is:

$$\begin{gathered}V^{s}_{t,m}-V^{s}_{t,n}=2(P_{t,km}R_{mn}+Q_{t,km}X_{mn})-\\-I^{s}_{t,km}(R^{2}_{mn}+X^{2}_{mn}),\end{gathered}\tag{4}$$

where $V^{s}_{t,m}$ and $V^{s}_{t,n}$ are squared voltages at the beginning and at the end of line *m* – *n*, kV$^2$; $X_{km}$ is the reactance of incoming line *k* – *m*, Ohm; $Q_{t,km}$ is the reactive power flow at time *t* in the incoming line *k* – *m*, MVar.

3. The relation between the power flow and the current in line *m-n* is as follows:

$$V^{s}_{t,m}I^{s}_{t,mn}=P^{2}_{t,mn}+Q^{2}_{t,mn}\,.\tag{5}$$

Factoring in bus voltages as part of maintenance scheduling proves unwarranted at this stage of the research: it will complicate the optimization model, increase computational costs, and possibly render some scenarios impossible to optimize. The uncertainty related to reactive power distribution merits a dedicated analysis. Therefore, the statement of problem (3)–(5) is simplified as follows:

1. Voltage magnitude at all buses is the same and is equal to the reference voltage $V_b$.

2. The grid is homogeneous and the power factor of loads and power plants is the same.

3. The factor of power flows along the links is also the same $\cos\varphi_c$. It is not necessarily equal to the nodal power factor as it covers grid losses as well.

Then equality (3) remains unchanged, equality (4) is dropped, and equality (5) takes the form

$$I^{s}_{t,mn}=kP^{2}_{t,mn}\,,\tag{6}$$

where $k=\dfrac{1}{V_b^{2}\cos^{2}\varphi_c}$ is a fixed factor for all links.

Optimal power flow of the test system yielded the error in power flow estimates of less than 5%.

## IV. Problem Statement of Maintenance

### SCHEDULING AND POWER SHORTAGE DISTRIBUTION

The optimization criterion is the minimum costs of power generation given possible damage due to unserved energy.

The objective function combines the costs of electricity generation by power plants and the amount of the disconnected load power:

$$\sum_{t=1}^{T}\left(\sum_{g=1}^{G} c_g^G P_{t,g} + \sum_{l=1}^{L} c_l^L \delta_{t,l}\right) \to \min\,, \tag{7}$$

where $T$ is the number of hours in the maintenance scheduling period; $c_g^G$ is the cost of electricity produced by generator $g$, RUB/MW; $P_{t,g}$ is the power of generator $g$ under power flow $t$, MW; $c_l^L$ is the cost of limiting loads $l$, RUB/MW; $\delta_{t,l}$ is load limit $l$ under power flow $t$, MW.

Changing problem variables include:

1. Generator state $g$ under power flow $t$ (1 – generates power / 0 – is switched off) for $\forall t = 1, \dots, T$, $\forall g = 1, \dots, G$:

$$s_{t,g} \in \{0;\, 1\}\,. \tag{8}$$

2. The power output by power plant $g$ under power flow $t$:

$$s_{t,g} P_g^{\min} \le P_{t,g} \le s_{t,g} P_g^{\max}\,, \tag{9}$$

where $P_g^{\min}$ and $P_g^{\max}$ are the minimum and maximum active power of generator $g$, MW.

3. The time instance when generator $g$ is taken out of service for maintenance:

$$\begin{cases} \tau_g^G \ge 1, \\ \tau_g^G \le T - d_g^{gen.maint.}, \end{cases} \\ \tau_g^G \in Z_+ \ \forall g = 1, \dots, G, \tag{10}$$

where $d_g^{gen.maint.}$ is the maintenance duration for generator $g$, days; $Z_+$ is the set of positive integers.

4. The maintenance flag for generator $g$ (1 – under maintenance / 0 – not under maintenance):

$$r_{t,g}^G \in \{0;\, 1\} \ \forall g = 1, \dots, G\,. \tag{11}$$

5. The time instance when line $b$ is taken out of service for maintenance:

$$\begin{cases} \tau_b^{OHL} \ge 1, \\ \tau_b^{OHL} \le T - d_b^{line\,maint}, \end{cases} \\ \tau_b^{OHL} \in Z_+ \ \forall b = 1, \dots, B, \tag{12}$$

where $d_b^{line\,maint}$ is the maintenance duration for line $b$, days.

6. Line maintenance flag (1 – under maintenance / 0 – not under maintenance):

$$r_{t,b}^{OHL} \in \{0;\, 1\}\,. \tag{13}$$

7. Active power flow in line $b$:

$$\begin{cases} P_b \ge -(1 - r_{t,b}^{OHL}) P_b^{\max}, \\ P_b \le (1 - r_{t,b}^{OHL}) P_b^{\max}, \end{cases} \\ \forall b = 1, \dots, B, \tag{14}$$

where $P_b^{\max}$ is the maximum power flow in line $b$, MW.

8. Squared current in line $b$:

$$I_b^s \in R_+ \ \forall b = 1, \dots, B\,, \tag{15}$$

where $R_+$ is the set of positive real numbers.

9. Load limit $l$ under power flow $t$:

$$0 \le \delta_{t,l} \le P_{t,l}^{\max} \ \forall l = 1, \dots, L\,. \tag{16}$$

The constraints on bus balances are introduced using the equations of a simplified power flow model (3) and (6) detailed in the previous section. The model has no current constraints on lines because the accuracy of squared current estimates is lower than that of active power flow.

The timing for taking generators and lines out of service for maintenance is subject to additional constraints:

1. Maintenance of generator $g$ / line $b$ must be performed in full:

$$\begin{matrix} \sum_{t=1}^{T} r_{t,g}^G = d_g^{gen.maint.}, \\ \sum_{t=1}^{T} r_{t,b}^{OHL} = d_b^{line\ maint}. \end{matrix} \ . \tag{17}$$

2. Maintenance of generator $g$ / line $b$ is continuous and starts at $\tau_g^G / \tau_b^{OHL}$:

$$\begin{matrix} r_{t,g}^G \le 1 - \dfrac{\tau_g^G - t}{T}, \\ r_{t,g}^G \le 1 - \dfrac{t - (\tau_g^G + d_g^{gen.maint.} - 1)}{T}, \\ r_{t,\mathrm{b}}^{OHL} \le 1 - \dfrac{\tau_b^{OHL} - t}{T}, \\ r_{t,\mathrm{b}}^{OHL} \le 1 - \dfrac{t - (\tau_b^{OHL} + d_b^{line\,maint} - 1)}{T}. \end{matrix} \ . \tag{18}$$

3. Generator $g$ cannot generate power and be under maintenance at the same time:

$$\sum_{t=1}^{T} r_{t,g}^G + s_{t,g} \le 1\,. \tag{19}$$

All equipment under maintenance is assumed to be removed from service only once during period $T$. Optimal

TABLE 1. Adequacy Metrics of System Buses Under Optimal Maintenance Scheduling

| Bus | EENS, MWh | Probability of unserved energy, p.u. |
|---|---|---|
| 2 | 0.004 | 0.0006 |
| 3 | 8.33 | 0.23 |
| 4 | 2.32 | 0.11 |
| 5 | 9.66 | 0.33 |
| 6 | 31.57 | 0.62 |
| Total | 51.88 | 0.63 |

scheduling under this formulation is reduced to solving a partial integer programming problem subject to the quadratic constraint (6).

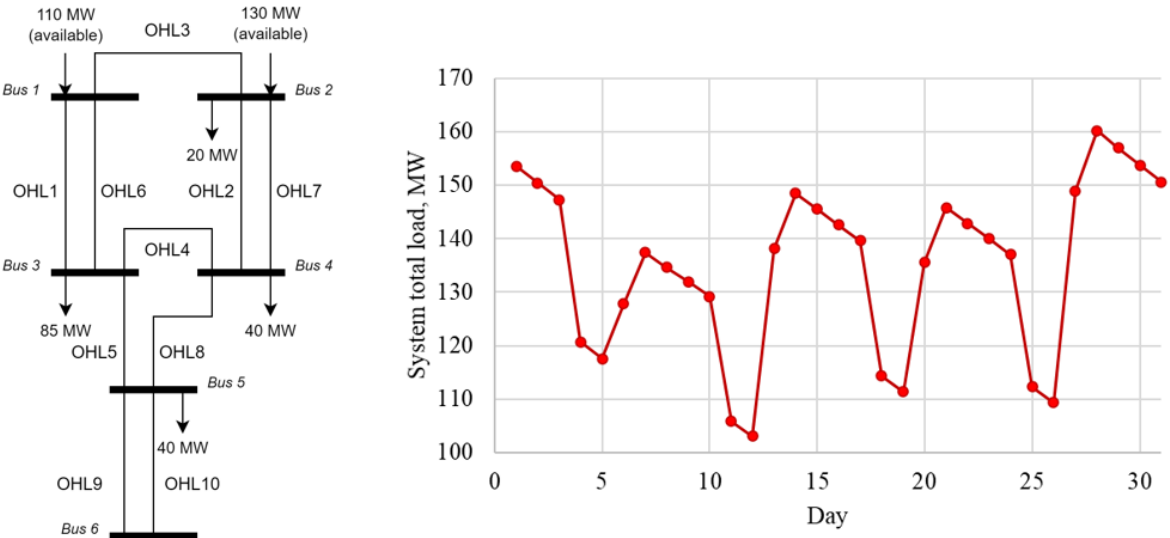
A similar formulation of the optimization problem is used for distributing power shortage among buses at the second step of maintainability indices calculation. In this case, the timing of taking generators and lines out of service for maintenance $\tau_g^G / \tau_b^{OHL}$ and flags of their states $r_{t,g}^G / r_{t,b}^{OHL}$ are fixed.

The proposed optimization model proves computationally expensive. A reasonable time of test calculations is achieved by decreasing the number of time intervals for which the optimization is performed. For the maintainability indices, it is essential to observe a relationship between the adequacy metrics, that serve as the basis for the indices. Therefore, in the Monte Carlo simulation, the optimization and calculation of metrics were performed exclusively for daily peak intervals, and not for all hours of the period covered by maintenance.

Apart from computational issues, this approach is motivated by the fact that hourly calculations require solving the unit commitment (UC) problem. The described statement treats it in simplistic terms: the set of generation units is optimal at the peak load hour regardless of the costs required to start-up or shut-down generators in power systems.

## V. THE TEST SYSTEM AND COMPUTATIONAL EXPERIMENT

Maintainability metrics were calculated for a modified Roy Billinton Test System (RBTS) [15]. The system additionally specifies fault/recovery rates for OHL switches and power plant equipment. A power transmission line connecting buses 5 and 6 was added to the model. The cost of limiting load is $c_l^L = 100$ thousand RUB per MW. Figure 1(a) shows the schematic of the



(a) (b)

*Fig. 1. The test system: (a) – schematic, (b) – load curve.*

TABLE 2. Example EENS / Probability of Unserved Energy in the System Under Different Power System Generator States

| Bus / Generator Type | In service | Fault | Under maintenance | Indices (1) | Indices (2) |
|---|---|---|---|---|---|
| Bus 1<br>Gen Type 1<br>40 MW | 23.79 / 0.50 | 40.33 / 0.64 | 102.17 / 0.80 | 0.77 / 0.37 | 0.41 / 0.22 |
| Bus 1<br>Gen Type 2<br>20 MW | 38.71 / 0.58 | 45.08 / 0.62 | 77.44 / 0.71 | 0.50 / 0.19 | 0.14 / 0.06 |
| Bus 1<br>Gen Type 3<br>10 MW | 47.13 / 0.61 | 50.21 / 0.62 | 61.00 / 0.67 | 0.23 / 0.08 | 0.06 / 0.02 |
| Bus 2<br>Gen Type 1<br>40 MW | 24.97 / 0.53 | 42.41 / 0.66 | 105.81 / 0.80 | 0.76 / 0.34 | 0.41 / 0.20 |
| Bus 2<br>Gen Type2<br>20 MW | 39.46 / 0.59 | 46.04 / 0.63 | 77.99 / 0.71 | 0.49 / 0.17 | 0.14 / 0.06 |
| Bus 2<br>Gen Type 3<br>5 MW | 48.38 / 0.62 | 48.72 / 0.62 | 59.67 / 0.65 | 0.19 / 0.04 | 0.01 / 0.01 |

power grid. The metrics were analyzed for a part of the maintenance campaign (the month of July). Figure 1(b) plots daily peaks for this month.

When generating random maintenance requests, the probability of generator and line maintenance was assumed to be 0.3. For generators, overhauls accounted for 40% of maintenance (28-day long overhauls, 14-day long moderate maintenance), for lines, this figure was 30% (14-day long overhauls, 7-day long moderate maintenance). The problem was solved by the branch-and-bound algorithm implemented in the PySCIPOpt library [16, 17]. Monte Carlo simulations were performed until the convergence was achieved in terms of the coefficient of variation (CV) of EENS and the power shortage probability. By the end of computations, the CV did not exceed 7% for all metrics, except for bus 2 indices. With excess generation capacity, a shortage at this bus is unlikely and can occur only in the rare event of simultaneous maintenance and faults. Tables 1 to 3 summarize the results of maintainability metrics calculations. Figure 2 plots the same results.

Analysis of the results leads to the following conclusions:

1. Simulations yielded a predictable result for generators. The higher the generator capacity, the more important the generator from the balancing standpoint. This holds both for the calculations with precise handling of maintenance data and for indices α and β. Grid limitations can disrupt this pattern, but that was not the case for the test system due to its small size and low loading factor.

2. The analysis of the transmission line revealed that the

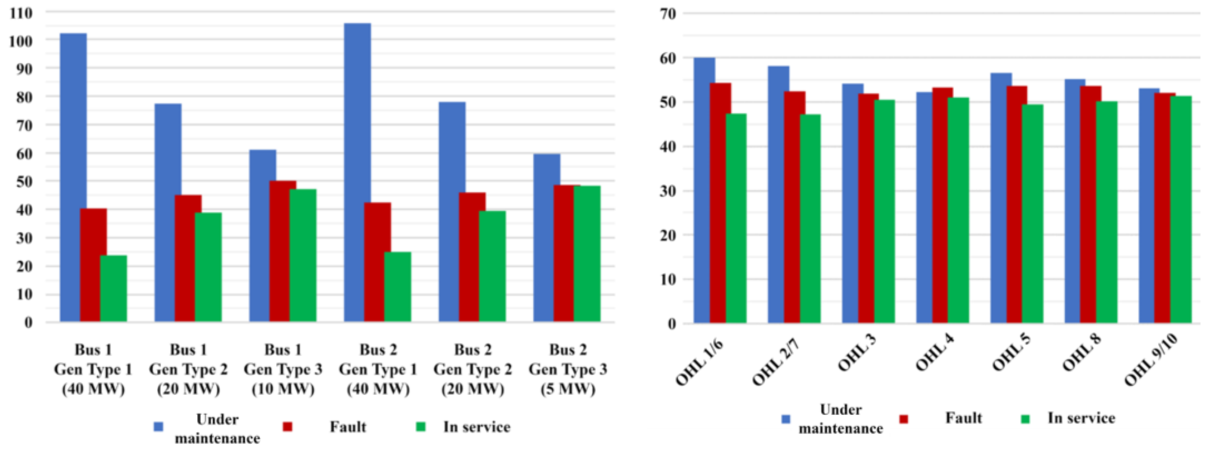


*Fig. 2. Example EENS by the system for various scenarios: (a) – for generators, (b) – for power transmission lines.*

TABLE 3. Example EENS / Probability of Unserved Energy in the System for Various Scenarios of Overhead Line States

| OHL | In service | Fault | Under maintenance | Indices (1) | Indices (2) |
|---|---|---|---|---|---|
| OHL 1/6 | 47.38 / 0.58 | 54.2 / 0.68 | 59.96 / 0.71 | 0.21 / 0.19 | 0.13 / 0.15 |
| OHL 2/7 | 47.23 / 0.58 | 52.37 / 0.66 | 58.01 / 0.68 | 0.19 / 0.15 | 0.10 / 0.12 |
| OHL 3 | 50.49 / 0.61 | 51.89 / 0.63 | 54.03 / 0.65 | 0.07 / 0.06 | 0.03 / 0.04 |
| OHL 4 | 50.91 / 0.62 | 53.21 / 0.64 | 52.20 / 0.65 | 0.02 / 0.04 | 0.04 / 0.03 |
| OHL 5 | 49.51 / 0.62 | 53.64 / 0.67 | 56.51 / 0.65 | 0.12 / 0.05 | 0.08 / 0.08 |
| OHL 8 | 50.12 / 0.62 | 53.54 / 0.66 | 55.05 / 0.65 | 0.09 / 0.05 | 0.06 / 0.07 |
| OHL 9/10 | 51.32 / 0.62 | 52.00 / 0.65 | 53.03 / 0.64 | 0.03 / 0.04 | 0.01 / 0.06 |

most critical lines are those connecting the power plants to the rest of the grid: OHL1/OHL6 and OHL2/OHL7. The test power grid is strongly connected. That is why index values for transmission lines were lower than those for generators. Furthermore, the average recovery time, just like the scheduled maintenance duration, was less for transmission lines. This affected the result.

3. The results are sensitive to the way random maintenance requests are modeled. This study adhered to the principle that any combination of maintenance events may occur simultaneously within a given period. It is clear that there is a need for additional analysis of statistical data on maintenance. This also applies to maintenance durations. An approximate estimation of the probability and duration of maintenance by simulations yielded abnormally high values of EENS and the probability of a power shortage.

4. Indices β for all components in all cases proved lower than indices α. This is due to the fact that scheduled outages of a power line or generator always last longer than those caused by faults.

5. Analysis of indices for components allows for the identification of the most critical equipment in the system but not the assessment of maintainability for the entire system. This can be done based on the data in Table 1, but other metrics need to be designed as well. Besides, indices α and β grow less distinct and informative as the power system expands.

6. The procedure considered is computationally expensive. Its application to real-world power systems would require optimizing the maintenance scheduling and shortage distribution algorithms, as well as developing new dedicated metrics.

Thus, while the proposed technique for assessing power system maintainability is feasible, it presents limitations to be addressed in future research.

## VI. CONCLUSION

This study formulates the problem of maintainability analysis for power systems as part of expansion and operation planning of the system. An array of maintainability indices and an algorithm to calculate them are proposed for solving.

The experimental case study demonstrates the feasibility of the calculation and analysis of the proposed metrics. The technique proposed enables the identification of the power system's equipment critical for maintenance scheduling and quantifying the effect of the maintenance campaign on the power system reliability. The results have proved extremely sensitive to estimates of the probability of equipment maintenance and its duration. To apply the proposed indices to a real-world power grid, it is essential to collect and analyze statistical data on maintenance.

This study has also highlighted the limitations of mixed-integer linear and nonlinear programming when used in equipment maintenance scheduling of power systems. In the case of the moderate-size test system, maintenance scheduling and solving the UC problem in its simplified form for a single month at a daily resolution took more than 10 minutes. Applying this approach to year-ahead planning in real-world power grids is impractical without further simplifications. Consequently, advancements in equipment maintenance scheduling techniques are crucial for realistically sized power grids.

Future research should focus on optimizing the computational procedure, specifically by addressing the unit commitment problem, designing new maintainability metrics based on Sobol' indices, and validating the index computation technique on a larger-scale power system.

## VII. FUNDING

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