Synthetic Test Case for Ukraine's Power Grid

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***Abstract*—Power systems research requires realistic test cases to demonstrate and benchmark algorithmic innovations. However, to keep power grid information secure, much of the data for actual systems cannot be publicly released. This motivates the creation of synthetic test cases designed to match the characteristics of actual power grids. By only using publicly available data, these synthetic test cases can be freely released for research and educational purposes. Motivated by the ongoing conflict in Ukraine, this paper presents a synthetic test case for the Ukrainian electric transmission system. With the ability to run power flow and other analyses, this test case is relevant to emerging research and educational activities related to power grid security. To develop the test case, we leveraged publicly available data on population centers, generators, and transmission topology and voltage levels along with synthetic test case creation methodologies from recent literature. After describing the process used to develop this test case, this paper presents validation results using several widely accepted criteria for assessing the test case's realism. As an illustrative application, we demonstrate one use case by solving a bilevel linearization of the $N-k$ interdiction problem to identify critical sets of line failures that cause the most load shedding.**

***Index Terms*—Synthetic grid, transmission line topology, resilient networks**

I. Introduction

Modern power grids face challenges including integration of renewable resources and electrified transportation, aging components, natural disasters, and cyber-attacks. To meet these challenges, power systems researchers are developing new algorithms for expansion planning, protection, control, and optimization of the power grid. Innovation and collaboration in power systems research require test cases that are both realistic and publicly available. Synthetic grid models are essential for power systems research, mirroring real-world power networks without sensitive data. They enable researchers to innovate, test methods, benchmark findings, and freely share their work.

In addition to the long-term challenges experienced by power grids worldwide, Ukraine suddenly faced major disruptions in February 2022 when Russia invaded. Days after the invasion, engineers performed extensive modeling and simulation to determine how to disconnect from Russia and synchronize with the Continental European Power System [1]. Missile attacks have damaged portions of Ukraine's energy infrastructure, impeding generation, transmission and distribution of power [2], [3]. Ukraine and its allies have been constantly working to analyze contingency scenarios, identify critical vulnerabilities, and prioritize repairs [4].

Disruptions to Ukraine's power grid may inspire the research community to develop new methods to protect energy infrastructure and assess the impact of attacks. Even before Russia's invasion in 2022, the 2015 cyber-attack on Ukraine's power system, which resulted in power outages affecting 225,000 customers for several hours, had generated extensive interest [5]–[8]. However, no publicly available synthetic model of Ukraine's power grid existed, so groups developing new protective algorithms benchmarked their performance against a set of standard test cases. In this paper, we fill this gap by creating the first synthetic model of Ukraine's power grid. Our test case will enable increased innovation and more realistic evaluations for new methods to defend against physical or cyber attacks on power grids.

To develop our test case, we use methods in the literature for creating "realistic but not real" network topologies from publicly available data. Foundational work in this area analyzed the statistical mechanics and graph properties of electrical power grids [9], [10]. The authors of [11] analyze the electrical and topological network characteristics of power systems. Other work in [12] develops an algorithm to randomly generate power grid topologies which should exhibit similar characteristics to real data. Their model is not based on real-world geographic data, but instead relies on graph generation models. Building on this approach, the authors of [13] use geographic information and data on generation and consumption to place generators, loads and substations on the map. Using this method and a statistical analysis of transmission line topology, a synthetic test case is created to study the effects of geomagnetic disturbances [14]. A full method for laying out substations, loads, generators, and transmission lines using publicly available data on energy consumption and generator locations, as well as graph theoretical methods to create realistic transmission line topologies is proposed in [15]. This paper is the basis for our approach in creating the Ukrainian test case.

After describing the test case development in Section II, we show results from validating the test case in Section III and provide an illustrative use case in Section IV. Regarding validation, the authors of [16] perform a thorough analysis of actual North American power networks to create metrics that can be used to evaluate the realism of synthetic test cases. We use their metrics to assess our model of Ukraine's power grid. We also evaluate several topological graph characteristics to detect any grid anomalies as described in [17]. As an illustrative use case, we next run the recently proposed algorithm in [8] to assess threats on system components for our Ukraine power grid model. This algorithm identifies which components, given some attack budget, an adversary would attack to cause maximum disruption to power delivery. We list the results and show how the amount of load shedding changes with the attack budget.

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II. Modeling Ukraine's Grid

This section describes our approach for creating the Ukrainian test case.[1] We place buses, generators, and loads and connect them with transmission lines and transformers.

A. Substations

As will be detailed below, we use publicly available information on Ukraine's generators and cities to identify locations for generators and loads along with their capacities and demands. We then assign these generators and loads to substations and define buses at different voltage levels within each substation. The resulting test case contains 1465 substations, 2284 buses, 1379 loads, and 64 generators.

We first collected power generation data for Ukraine from the World Resources Institute, which keeps a comprehensive database of power plants across the globe [18]. The dataset includes the generators' geographic locations, active power capacities, and fuel types. This dataset is directly used to site and size generators for our test case. To place loads, we used the coordinates and population data for Ukraine's 1,469 largest cities [19]. The peak winter power consumption in January 2022 was 22 GW [20], at which time the population was 43.79 million people, yielding a per capita active power consumption of 0.503 kW. Lacking data on reactive power consumption, we note that the authors of [15] use real data from U.S. cities to determine that a load power factor of 0.96 lagging is appropriate for designing test cases. We compute each city's reactive power consumption using this power factor. We then place loads at each city, with power consumption computed from these per capita values.

To site substations, we use the load and generator locations as well as a publicly available map of the European high-voltage transmission network from ENTSO-E [21]. For each load or generator, we group any loads and generators which are less than 2 km apart and place a substation at each location. Many of these substations can be found on the ENTSO-E map. Some substations on the map are in remote areas with minimal load or generation, not reflected in city or generator data. However, we incorporate these substations into our test case.

To assign voltage levels, we assume that the ENTSO-E map contains all transmission lines at 330 kV, 500 kV, and 750 kV. For substations found on the map, we assign buses at 330 kV and above only if a corresponding high-voltage line connected to the substation is shown. All the coal, gas and nuclear power plants in our test case can also be found on the map. For hydro or solar plants not on the map, we connect the generator to a 220 kV bus and also add a 110 kV bus to the substation. For cities not found on the map, we connect the load to a 110 kV bus and randomly add, with a probability of 30%, an additional bus at 220 kV. We add transformers to connect buses at different voltage levels within substations; we will describe choosing parameters for these transformers in Section II-C.

[1]The Github repository containing the test case data can be found at https://github.com/rjuly7/ukraine_test_case.

B. Transmission Lines

We add transmission lines to the test case to connect substations throughout the network. We use data from the ENTSO-E map to determine line locations at high voltages and use the methodology described in [15] to connect buses at lower voltage levels. This automated line placing method is designed to create a line topology that matches characteristics observed in real power networks. We then use data on typical conductors for each voltage level to compute the line electrical parameters.

1) Topology: We adapt the topology design described in [14], [15]. At each voltage level, we find the set of all buses at that voltage level, which we view as the nodes of a graph. We form a set of candidate transmission lines via the Delaunay triangulation of these nodes. Note that the minimum spanning tree (MST) is a subset of the Delaunay triangulation. We also add any 330–750 kV lines found on the ENTSO-E map which do not appear in the Delaunay triangulation. We rank the candidate lines by assigning a penalty of $\alpha\ell - 50c + 12f - \beta m$, where α is randomly selected from $[0.01, 0.2]$ with uniform distribution, ℓ is the line length in km, c is a binary variable representing whether the new line would increase graph connectivity, f is a binary variable indicating whether there is a parallel line at a different voltage level, β is randomly selected from $[2.5, 7.5]$ with uniform distribution, and m is a binary variable representing whether the line appears on the ENTSO-E map. We rank candidate lines iteratively, choosing the one with the lowest penalty. Factors favoring selection include shorter length, enhanced graph connectivity, absence of parallel lines at different voltage levels, and presence on the ENTSO-E map. The random perturbations ensure that we do not exactly match the real transmission lines on the ENTSO-E map in order to achieve our goal of a "realistic but not real" system while also allowing us to easily create multiple instances of the test case. We continue to rank and select lines until the number of lines is kN, where $k = 1.37$ for 110–220 kV lines, $k = 1.3$ for 330 kV lines, and $k = 1.22$ for 500–750 kV lines. Note that the authors of [15] designed a test case containing only $1.22N$ lines at each voltage level, but we found in our test case that additional lines were necessary for the AC power flow to converge. We will show in Section III that our test case falls within a reasonable range for the ratio of transmission lines to substations as described in [16]. Table I shows how many lines at each voltage level are found in the network.

TABLE I
TRANSMISSION LINE VOLTAGE LEVELS

Voltage (kV)	110	220	330	500	750
Line Count	1810	583	144	3	16

Note that [13] considers additional factors when selecting lines, including an estimate of future power flow and quotas in the minimum spanning tree, the Delaunay triangulation, and its neighbors. We may consider such factors in the future, but found that our method is sufficient to generate a test case that converges for AC optimal power flow.

2) Electrical Parameters: After defining the topology, we next determine the lines' resistances, inductances, and capacitances using the following expressions [22]:

$$R = \frac{r_d}{b}\ell \ [\Omega], \quad L = \frac{\mu_o}{2\pi}\ln\frac{D_m}{R_b}\ell \ [H], \quad C = \frac{2\pi\epsilon}{\ln\frac{D_m}{r_o}}\ell \ [F].$$

The values $\mu_o = 4\pi \times 10^{-7}\frac{H}{m}$ and $\epsilon = 8.85418782 \times 10^{-12}\frac{F}{m}$ are physical constants representing the permeability and permittivity of free space, respectively. For each voltage level, the appropriate conductor type and number of conductors in each bundle b is chosen from [22]. The per-distance conductor resistance r_d at 50°C, the geometric mean radius R_b, outer radius r_o, and the geometric mean distance D_m are found for each conductor in [22]. For bundled conductors, we do not use the individual conductor values for R_b and r_o, but rather compute the geometric mean radius and outer radius by considering bundle spacing to account for interactions between the conductors. In [22], this is notated by replacing R_b with D_{SL} and r_o with D_{SC}.

From these values, we obtain the line series resistance $r = R$, the line series reactance $x = 2\pi f L$, and the total line charging susceptance $b_c = 2\pi f C$. Note that the system frequency in Ukraine is $f = 50$ Hz.

For the line flow limits, we use the model in [23]:

$$(s_l^u)^2 = (v_i^u)^2|Y_l|^2\Big((v_i^u)^2 + (v_j^u)^2 - 2v_i^u v_j^u\cos(\theta_l^{\Delta m})\Big),$$

where s_l^u is the apparent power flow limit for line l from bus i to bus j, $|Y_l|$ is the magnitude of line l's admittance, v_i^u is the upper bound on voltage magnitude at bus i, and $\theta_l^{\Delta m}$ is the limit on the magnitude of the angle difference.

C. Transformers

We choose transformer parameters based on the distributions found in [16]. We assume that transformer reactance X, ratio between reactance and resistance X/R, and MVA rating follow a normal distribution with mean equal to the median from [16] and standard deviation selected so that 80% of our values are likely to fall within the 10% and 90% quantiles in [16]. After defining these normal distributions, we randomly select values for X, X/R, and the MVA rating for each transformer. However, we do not allow transformer MVA ratings to be limiting factors in the AC optimal power flow (OPF) problem. After randomly selecting MVA ratings as described above, we run an OPF problem without transformer MVA constraints. If any of the transformer power flows are above the limits, we adjust these limits to be 10% greater than the OPF solution's values. Therefore, we design our test case such that the transmission lines' thermal limits will constrain nominal power flows in the system rather than the transformers' ratings.

III. Validation

We first use the metrics set forth in [16] to evaluate the realism of our test case. The criteria from [16] are based on an analysis of representative North American power system data. See [16] for detailed explanations of each metric. For entries marked with "N/A" in Table III, note that no validation criteria were provided for 750 kV lines or transformers, and there are no transformers in our case with high-side voltage at 110 kV.

TABLE II
VALIDATION METRICS

#	Validation Metric	Criteria	Value
1	Buses per substation	Mean 1.7-3.5	1.4
2	Percent of substations with buses in kV range	<200 kV, 85-100% >200 kV, 7-25%	97% 32%
3	Substations with load	75-90%	93%
4	Load per bus	Mean 16-18 MW Exponential decay	11.3 MW Figure III
5	Generation capacity/load	1.2-1.6	3.40
6	Substations with generators	5-25%	4.1%
7	Generator capacities	25-200 MW, 40+% 200+ MW, 5-20%	23.4% 53.1%
8	Committed Generators	60-80%	62.5%
9	Generators dispatched >80%	50+%	59.4%
10	Generator MaxQ/MaxP	0.4-0.55, >70%	100%

To the best of our knowledge, there is no equivalent analysis for Eastern European power grids. We use the North American data to validate our test case, but recognize that the typical characteristics of North American power systems may not match those of Ukraine's grid. Future researchers may investigate such parameters for Eastern European systems. Although our test case generally matches the criteria in [16], there are repeated differences for metrics related to the numbers of buses, loads, and generators at substations. This is likely due to our modeling choice to site substations at cities and power plants and reflects the ratio between cities and power plants in Ukraine.

To help interpret the results, we first briefly explain the metrics in Table III. The criteria in (11)–(14) are based on statistics from the North American power systems listed in Tables 2 and 3 of [16]. For (11), we expect to see 80% of the transformer reactances within 0.05 p.u. and 0.2 p.u. For (12), we expect to see 40% below the median, 40% above the median, and 80% within the 10th and 90th percentiles of the statistics in [16]. In this table, transformer X/R ratios and MVA limit metrics are listed in order with a separating slash; e.g., 55% / 47% means 55% of the X/R ratios and 47% of the MVA limits are found in the specified percentile. Metric (13) prescribes that 70% of the line per-unit, per-distance reactances are within the 10th and 90th percentiles listed in [16], and metric (14) requires 70% of line X/R ratios and MVA limits to fall between the 10th and 90th percentiles. Again in (14), X/R ratio metrics are listed before MVA limit metrics with a separating slash. Metric (15) is the ratio of lines to substations at a given voltage level, (16) is the percentage of lines at a given voltage level which come from the minimum spanning tree (MST), (17) is the number of lines which come from the Delaunay triangulation or are second or third neighbors, and (18) is the total length of lines divided by the length of the MST.

We next summarize the results in Tables II and III and explain why some metrics do not meet the validation criteria.

TABLE III
VALIDATION METRICS BY VOLTAGE LEVEL

#	Validation Metric	Criteria	Test Case Value 110 kV	 220 kV	 330 kV	 500 kV	 750 kV
11	Transformer per-unit reactance, own base	80% within [0.05,0.2]	N/A	92%	95%	100%	N/A
12	Transformer X/R ratio and MVA limits, by kV level	40% below median 40% above median 80% within 10-90 range	N/A	55% / 47% 45% / 53% 93% / 97%	49% / 41% 51% / 59% 95% / 89%	33% / 0% 67% / 100% 100% / 100%	N/A
13	Lines p.u., per-dist. reactance, by kV level	70% within 10-90 range	100%	100%	100%	0%	N/A
14	Lines X/R ratio and MVA limits, by kV level	70% within 10-90 range	100% / 0.2%	100% / 3%	100% / 7%	100% / 0%	N/A
15	Lines/Substations	1.1-1.4	1.37	1.37	1.31	1.00	1.23
16	Lines on min. spanning tree	45-55%	73%	73%	76%	67%	75%
17	Distance of lines along Delauny triangulation	1, 65-80% 2, 15-25% 3+, 3-10%	100% 0% 0%	100% 0% 0%	83% 13% 4%	100% 0% 0%	100% 0% 0%
18	Total line length/MST	1.2-2.2	1.65	1.75	1.84	1.98	1.57

(1) *Number of Buses per Substation:* Our model averages 1.4 buses per substation, which is lower than the average of 2.3 from [16]. We designed the case such that there is only one bus per voltage level in each substation and connected loads and generators directly to the lowest- and highest-voltage buses, respectively, in the substation. Future work includes modeling generator step-up transformers within the substation, which would add additional buses.

(2) *Substation Voltage Levels:* We model substation and transmission line voltage levels at 110, 220, 330, 500, and 750 kV. The validation criteria from [16] suggests that 85-100% of substations contain buses at or below 200 kV, while 7-25% should contain a bus above 200 kV. We find that 96% of substations have a bus below 200 kV, which matches the validation criteria, while 32% of substations have at least one bus above 200 kV, which is outside the suggested range. However, only 8% of substations have a bus above 220 kV, so the overall distribution is still quite similar to those found in typical North American test cases.

(3) *Percent of Substations Containing Load:* Around 75-90% of the substations are expected to have a load, however around 93% of the substations in the Ukraine test case contain a load, making this slightly higher than expected.

(4) *Load per Bus:* Part of this validation criteria is that the distribution of load per bus is expected to exhibit exponential decay, with most buses containing small loads and very few buses containing large loads. Figure III demonstrates that our test case satisfies this criterion.

(5) *Ratio of Total Generation Capacity to Total Load:* This ratio is 3.40 for the Ukraine case, which is higher than expected. Future work will include accounting for electricity exports, which may reduce this ratio.

(6) *Percent of Substations Containing Generation:* Around 4% of the substations in the Ukraine case contain a generator, which is just under the expected range of 5-25%.

(7) *Generator Capacities:* The Ukraine case has a higher proportion of generators with large capacities than is typical for North American test cases in [16]. This is likely because Ukraine has more nuclear and large coal generators and fewer small solar installations than North American countries. We list the generator types in Table IV.

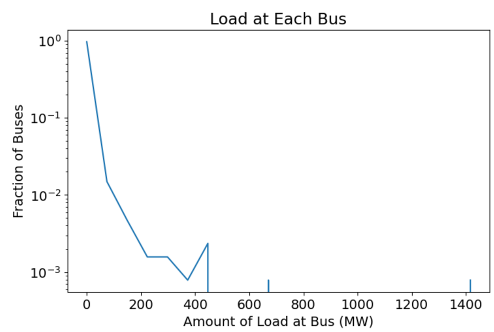

Fig. 1. Distribution of bus loads.

TABLE IV
GENERATOR TYPES

Type	Solar	Hydro	Coal	Gas	Nuclear
Count	27	9	21	3	4
Capacity (MW)	4–87	235–1540	120–3600	500–1200	2000–6000

(12) *Transformer X/R ratio and MVA limits:* As depicted in [21], there are only three 500 kV lines in the system. Therefore, it is not possible to have over 40% above or below the median, but the values are still reasonable, and all other lines fit the criteria.

(13) *Lines p.u., per-distance reactance:* The ranges in the criteria in [16] are quite narrow, and the 500 kV lines fall just under the specified range. Note that the frequency for Ukraine's grid is 50 Hz, so for identical conductor types the reactance will be smaller for lines in Ukraine compared to lines in North American 60-Hz power grids.

(14) *Line X/R ratio and MVA limits:* We use the approach in [23] which computes MVA limits based on specified phase angle difference and voltage magnitude limits. This approach tends to result in higher values than the typical limits found in [16].

(16) *Lines on minimum spanning tree (MST):* Our line placement method, based on that proposed in [14], produces a greater proportion of MST lines than typically found in North American power systems. However, it does

TABLE V
TOPOLOGICAL VALIDATION METRICS

#	Validation Metric	Criteria	Value
1	Mean node degree distribution	2–3	2.73
2	Maximum node degree distribution	9–16	9
3	Degree assortativity	-0.3–0.15	0.11
4	Size of largest maximal clique	3–4	4

reflect the proportion of MST lines found in the ENTSO-E data in [21] for 330–750 kV voltage levels, around 70%. Our future work may include refining this algorithm to match the typical quota for Ukraine's transmission network.

(17) *Distance of lines along Delaunay triangulation:* Our placement method only selects lines along the Delaunay triangulation, except at 330 kV where we incorporate additional lines from [21]. Again, we may adjust this algorithm in future work to better match typical quotas.

Next, we use the metrics proposed in [17] to identify any anomalies in our graph topology. These are classic metrics in graph theory which characterize graph connectivity; see [17] for further details. The results are summarized in Table V. Observe that our Ukraine synthetic grid meets each of the topological criteria for realistic power networks.

We also run an AC optimal power flow problem for the system and plot the results in Figure 2. This figure shows a color map for voltage magnitudes across the system and arrows along transmission lines for the the directions and magnitudes of power flows. For the lines, larger arrows correspond to higher amounts of active power flow.

IV. ILLUSTRATIVE USE CASE: $N-k$ CONTINGENCIES

Our model of Ukraine's transmission system can be used by power systems researchers to test new algorithms for assessing and defending against war-time threats. The worst-case grid attack problem was introduced in [24], in which an adversary seeks to find the set of the most critical component failures in the system. This problem is typically formulated as a bilevel optimization program called the $N-k$ interdiction problem. In the upper level, the attacker disconnects up to k out of N components in the system to maximize load shed. In the lower level, the defender (typically representing the grid operator) redispatches the system to minimize load shed given the failed components. In addition to physical attacks on system components, cyber attacks may infiltrate substation controls to compromise components [25]. For example, in the December 2015 cyber-attack on Ukraine's power system, attackers remotely accessed and opened breakers which directly cut power to consumers [7]. We consider the worst-case relay attack proposed in [25] and the solution method proposed in [8]. Here, attackers choose some number of relays to infiltrate to maximize load shed given an attack budget. Although the typical formulation of this problem is a nonconvex bilevel mixed-integer nonlinear program (MINLP) that is strongly NP-hard, the authors of [8] propose a linear relaxation of the lower-level problem which makes it tractable. We use their method to evaluate the worst-case line failures for our model of Ukraine.

We plot the load shed versus attack budget (i.e., the number of lines targeted) in Figure 3. For a given attack budget, we solve the relaxed problem formulated in [8] to find the combination of line failures which cause maximum load shedding. The plot demonstrates where the attacker gains significant load shed by adding another line to the attack: for example, a budget of three lines rather than two increases the worst-case load shed by 707 MW, or about 1.4 million additional customers.

V. CONCLUSION

Researchers developing algorithms to make power grids more flexible, resilient, and secure in the face of increasing extreme weather events and cyber threats require realistic models to test their methods. Synthetic grid models can be designed to match the properties of real-world networks without using private data. Ukraine's power system offers a compelling context for innovation in planning, control, and optimization due to conflicts in the region that have exposed vulnerabilities to cyber and physical attacks on its energy infrastructure and control interfaces. This paper presented the first synthetic model of Ukraine's power grid.

We gathered publicly available data on city locations, population, generators, and high-voltage transmission line locations to form the base of our synthetic model. We then used methods developed in previous literature to add additional, lower-voltage transmission lines and transformers and determine their electrical parameters.

To compare our model to other test cases, we computed several common validation metrics. Many validation metrics were consistent with expected values and both the generator dispatch from an AC optimal power flow problem and the transmission line topology generally match expected characteristics. However, some metrics (notably, the proportions of substations containing loads and generators and the number of buses per substation) were outside typical ranges. We discussed possible explanations for these discrepancies.

We then provided an illustrative use case for our model by solving a relaxed version of the $N-k$ interdiction problem to determine which combinations of line failures result in the worst-case load shed. The results demonstrate how our model provides useful information on grid vulnerabilities.

Our future work includes analyzing and improving certain aspects of our model which are not consistent with the expected validation metrics. In addition, augmenting the test case with information like contingency limits, component failure rates, and dynamic models would make it applicable for a broader range of studies.

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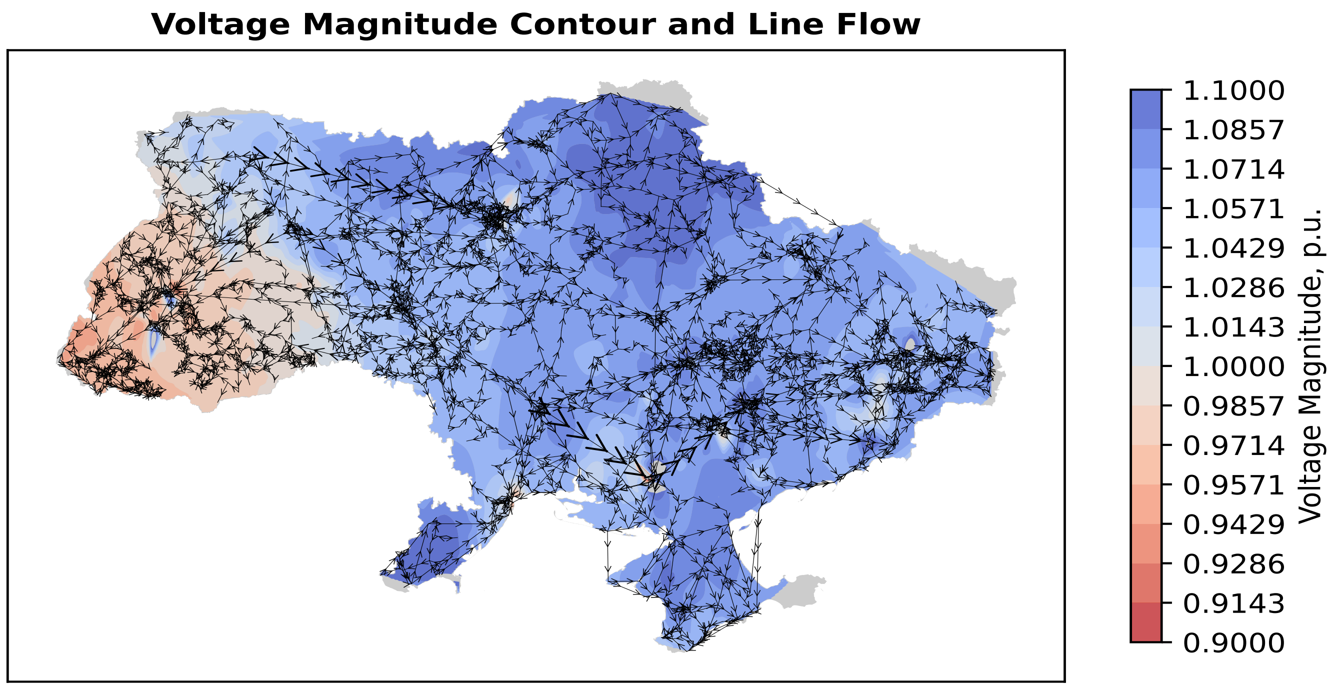

Fig. 2. Voltage magnitude contour plot and lines showing directions and magnitudes of power flows for the AC optimal power flow solution.

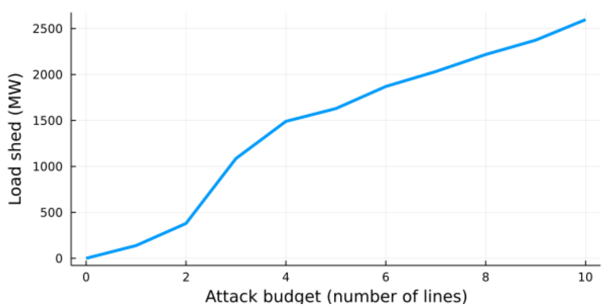

Fig. 3. Load shed vs. number of failed lines.

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