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A Methodology for Rating Electricity Transmission Lines to Assess the Most Important or Critical Lines

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Abstract: The proposed method, based on three combined criteria—Sn—design capacity of the power line, LF, (line flow)—power flow in an electric transmission line, MVA, and the ratio of LF/Sn—allows for ranking electric transmission lines when calculations are performed in normal/pre-emergency modes. A combined set of criteria used to study critical/post-emergency N-k modes is developed. The simulations were performed on the real Baltic 330 kV electricity transmission system. The results reveal that when the power system operates in different load modes, most of the critical power lines determined by our method fall into the actual set of important/"critical" power transmission lines. This allows us to significantly reduce the number of simulated combinations and shorten the calculation time required for it. During the study of the Baltic electricity system, it was found that the developed method was accurate and efficient and suitable for the assessment of the reliability of real electricity transmission networks when planning operational and perspective work modes. The simulations results revealed the high reliability of the Baltic electricity system. The 330 kV electricity transmission network of the Baltic countries fully meets the N-2 criterion (usually, electricity transmission networks are designed to meet the N-1 criterion).

Keywords: pre-contingency; combined set; ranking; Baltic system

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1. Introduction

Electrical power systems (EPSs) are among the largest and most complex systems that engineers deal with at the present time. EPSs contain many components of various types, scales, and complexity from low-power devices to power turbogenerators or high-voltage transmission lines. The management and operation of such complex systems is a truly complicated task.

The amount of renewable energy sources and their variable generation schedule require more complex solutions that help manage and balance rapidly changing electricity flows. The rapidly growing number of generating consumers is changing the settled/traditional stepped-down flow of electricity. Due to the large number of renewable energy sources (RES) in the distribution network, in some cases the power flows between transmission and distribution systems have become two-way/bidirectional, which raises additional management challenges for transmission system operators.

The primary and most important function of electrical system operators is system management (operational management). This concept is usually considered in the field of electric power systems as system management/control in real time; it includes system balancing, correction actions, disconnections/faults. For longer-term usage, the term planning is used, which describes actions that will be performed in the future (mid–term/long–term). The term planning is used to refer to the actions required to manage (operate) the system under certain conditions (scenarios) that may occur in the mid or long term. More about the planning of electrical systems can be found in references [1,2].

However, the fast EPS transformation is blurring the boundaries between real-time management and long-term planning. Today, renewable energy sources that are not easily predictable (for example, solar, wind, and tidal energy) [3,4] combined with highly unpredictable load patterns (electric car charging, climate change, etc.) [5] make both management and planning more demanding. Electric networks operate/work in their limit modes more and more often, whereby such variability/fluctuations shorten the resource of various elements of the electric system, and as a result, the reliability of the system suffers. It is becoming more and more important to predict possible power flows and their distributions in the power system and thus identify the most severe operating modes of the power system. Since our proposed ranking method is associated with severe/restricted operating modes, during which the safe limits of the thermal conductivity of the electrical network are exceeded, the safety assessment of the electrical system will be examined in more detail.

1.1. Reliability

Reliability describes the ability of a power system to supply electricity to all connected consumers in accordance with acceptable standards and quantities needed [6]. The reliability of an electrical system is characterized by two main aspects.

Adequacy is a measure of the ability of a bulk power system to supply the aggregate electric power and energy requirements of the customers within component ratings and voltage limits, taking into account scheduled and unscheduled outages of system components and the operating constraints imposed by operations [7].

Security is the measure of how an electric power system can withstand sudden disturbances such as electric short circuits or unanticipated loss of system components [7].

The power system security assessment is used to determine whether the network is adequately protected against potential contingencies. Generally, system security assessment can be divided into two main classes, i.e., static and dynamic security. In the former case, the response of the electric power system to unforeseeable events in the steady state is analyzed. A static safety study examines the significance of over voltages and/or under voltages in busbars (or nodes) and the overload extent of power transmission lines and transformers. If, in the event of unforeseen events, the voltage values of all buses do not exceed a predetermined standard value and no transmission line or transformer is overloaded, then the electrical network is considered to be statically safe. In addition, the security analysis of the power system can be performed in the working (on-line) and non-working (off-line) state. The first package is used in the operation phase of the power system, and its results determine preventive and corrective power system/network management policies, while the second package is used during the power system's planning phase, which also includes future operating modes. The aforementioned classification is shown in Figure 1. For more detailed information on system security assessment, refer to reference [8].

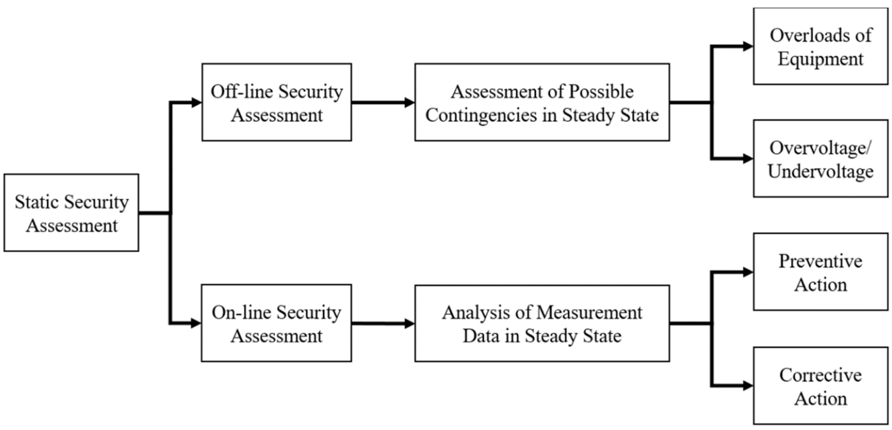

Figure 1. Classification of power system security assessment problems [2].

The purpose of off-line static safety assessment is to predict future flows in power transmission lines and voltages in busbars after unforeseen events/failures (contingencies).

Though this topic is extensively addressed in the scientific literature, it still remains an active research field, because the identification of severe operation modes enables the prevention of possible systemic accidents. A comprehensive review of static security is given in reference [9], which examines the methods and techniques used in this field in more detail.

The purpose of our proposed ranking is to move the evaluation of the static security from long-term planning to shorter time windows. However, the problem remains the same—long simulation/evaluation time. It would take a tremendous amount of time to study all the possible/real scenarios of operation modes and the question is whether it is necessary to explore everything. Varying conditions in electricity systems (volatility of generation, load variation) make long-term security simulations difficult or even pointless. It is probably more sensible to focus on the daily or hourly operating modes of the system.

1.2. Contingencies

In the scientific literature dealing with electrical power systems, the term "contingency" or "contingency analysis" is quite common. A contingency is a failure or loss of an element (e.g., generator transformer, transmission line, etc.) or a change in the state of a device (e.g., in a substation) in the power system. It is accepted that an electric power system is considered "safe" when it can withstand the failure of one or more elements and continue to operate without major disruptions/disconnections [10]. The first articles [11,12], which presented performance indices, were published more than 40 years ago, and this research area still remains active. Information technology has changed significantly in various aspects over the past few decades, but there is still no unified solution for contingency assessment.

Contingency analysis is a mathematical method to predict the failure of equipment or a specific line and take corrective action before the system enters an unstable state [13]. Contingency analysis can analyze the safety aspects of the power system during both planning and operation phases. Unforeseen circumstances can cause serious violations of the electrical network operational limits (safe operational limits of the electrical network). Therefore, contingency planning is an important aspect of safe operation, enabling smooth system operation through the protective aspects [14]. Contingency selection methods are shown in Figure 2.

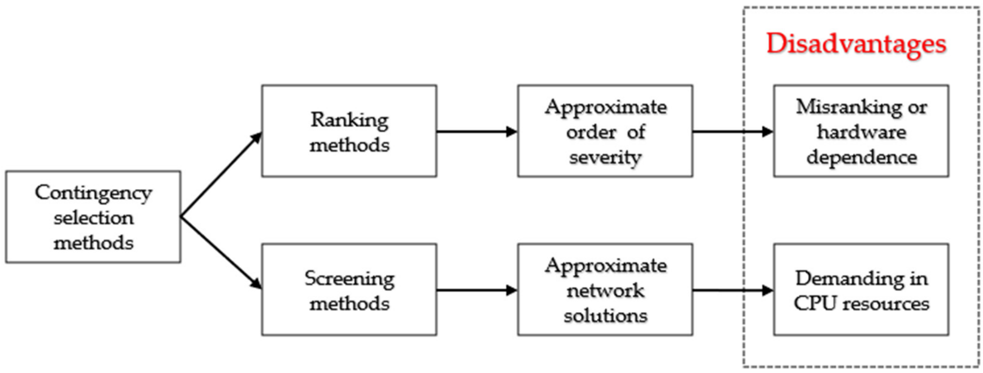

Figure 2. Contingency selection methods.

In real time, there are many possible events that can happen in electrical power systems. Impacts of various events on the power system varies, so contingency ranking and contingency screening help identify severe and less severe contingencies. The advantages and disadvantages of these methods are described below.

1.2.1. Screening

Power system contingency screening is a very important process in the field of power systems to ensure network reliability and stability. Contingency screening encompasses the identification and evaluation of potential contingencies or disturbances that may disrupt the normal operation of the power system. Contingencies include equipment failures, sudden changes in demand, or unexpected events such as extreme weather.

The most common selection method is to use the outcome of the first iteration of the fast decoupled power flow (FDPF) applied to each contingency. Tests and experience indicate that this is not a very reliable screening method. By using two iterations, a better result is usually obtained, although two iterations require double the computational resources and still do not provide useful/necessary information about the effect on reactive power sources. Another selection method (often used in the past) is the bounding method [15–17], which takes into consideration the localization of the fault. The effect of a line fault decreases rapidly with distance from the fault location. The electrical distance diminishes rapidly beyond a certain number of busbars/nodes surrounding the fault and transmission lines or nodes located beyond that certain number become of little significance from a contingency analysis point of view. For each contingency, the bounding method determines the bounding limit of nodes and computes the DC (or AC) power flow solution for the contingency in the bounded subnet/zone. However, this method is not widely used nowadays.

Up to this stage, the DC power flow solution for the bounded network has been fully computed and then it was used for checking line flow violations and selecting contingencies accordingly. The bounding method used nowadays does not require any preliminary calculations, it is performed for each new case, and it provides maximum flexibility in selecting contingencies. This method has been extended to AC network analysis and it has a wider range of applications than its earlier version.

1.2.2. Ranking

Contingency classification in power systems is the process of assessing and prioritizing potential contingencies or disruptions that may occur in the power grid. The goal is to identify and solve the most important problems to ensure the reliable operation of the electricity system.

Typically, power system engineers rely on their prior experience to assess system contingencies, which may not be appropriate for analyzing severe contingencies. Therefore, it is desirable to develop a contingency classification algorithm that classifies contingencies according to their relative severity. Contingencies can be classified according to their impact on transmission line load or bus voltages.

Ranking methods rank contingencies by their relative severity. The sequence of contingencies is determined according to the performance index (PI) or the system stress index [18]. PI is explicitly expressed in terms of network variables, such as active power flows or voltages, and they are directly evaluated. Several PI-based methods have been proposed and tested for power system security analysis; for example, some of them are considered a measure of the degree of line overload [19].

One of the disadvantages of ranking methods is the masking effect. There are cases where there are many heavy loads but no severe violations caused by them, but the PI value is similar to cases with one or more violations [20]. In addition, another important shortcoming is the incorrect ordering of contingencies, which appears mainly due to inaccuracies in the model used to calculate the PI and errors in the ordering of the relative severity of some contingencies.

The purpose of the Contingency Selection and Ranking function is to select a small number (specified by the operator) of the most important contingencies from a large list of possible contingencies and rank them according to their severity. This approach is suitable for systems where some misclassification of contingencies can be tolerated. In addition, the method is used for the determination of the stress level of the studied system in post-emergency assessment.

1.3. Overview of Other Methods

The other methods related to the identification of important/critical lines are listed in Table 1.

Table 1. Other methods.

Field of Application/Scope	Method/Index	Year	Reference
This approach provides a better balance between accuracy and efficiency in identifying vulnerable lines. The proposed generator-to-load power percentage is used as an indicator to assess the stability of the power grid.	Electrical betweenness	2022	[21]
The classification strategy identifies the most important transmission elements in a 500 kV transmission network. The power system network is analyzed using a node breaker model and steady-state analysis.	Ranking strategy	2019	[22]
The composite severity index allows an accurate assessment of the voltage on each line in terms of megawatts of overload and voltage instability. The line with the highest probability of severity for different faults shall be equipped with an interline power flow controller (IPFC).	Composite Severity Index (CSI); probability of severity	2016	[23]
The study provides the Composite Severity Index (CSI) and the Line Stability Index Lmn. By using them, it is expected to evaluate the line voltages that are related to overloads and voltage instabilities. Studies have been carried out in problem areas of the system to determine whether the IPFC technology improves efficiency in contingency management.	Real power efficiency index; line stability index (Lmn)	2016	[24]
Using high-speed rail load data and N-1 probabilistic power flow calculation, they create a correlation network taking into account the topological structure and the electrical connection between the branches. Based on the developed correlation network, an improved weighted K-shell decomposition method is applied to identify vulnerable lines.	K-shell decomposition method	2019	[25]
The method takes into consideration the risk of overloading and the risk of the operation of transmission lines in the event of cascading faults. At the topological structure level, this method pays attention to the influence of transmission lines on each other and the influence of each line on the entire power system, which can help more accurately determine important lines of the power system.	Topological potential field theory	2021	[26]
The method used in this article evaluates double circuit lines or two parallel lines from one node. The paper proposes contingency screening and risk assessment-based contingency classification to evaluate and classify N-2 contingencies using both transmission line overload consequences and occurrence probabilities that are integrated with operational conditions.	Classification method	2018	[27]

1.4. Practice of the Power System Utilization

From an operational point of view, N-1 contingency criterion (the occurrence of one contingency, i.e., one fault of any major unit) is usually used. An electrical power system can be described as N-1 safe when it can maintain normal operation after a single contingency, such as an unplanned loss of a transmission line, generator, or transformer. This standard is approved/used by system operators worldwide. It can be used to plan contingency operations, manage system operations, and perform immediate actions aimed at restoring a safe and stable operating state of systems within a reasonable time (usually within 15–30 min) after a single unforeseen event.

System operators monitor power systems in real time to ensure safe operating conditions and their ability to respond to emergency events in a timely and effective manner.

Operational control typically relies on real-time or near-real-time information provided by supervisory control and data acquisition (SCADA) systems. The results are used to assess actual operating conditions subject to key technical constraints and feed into network simulations that are used to update contingency assessments.

In the event of an emergency or N-1 contingency, system operators must be able to intervene in a timely and effective manner to stabilize the power system and return it to an N-1 safe state within the time set by the reliability standards. In the event of a power outage, system operators typically have recovery plans and procedures that are immediately activated to restore the power system to a stable and safe operating condition as quickly as possible [28]

2. Method

The proposed approach is partly similar to contingency ranking methods based on the performance index. Using the Power Flow Performance index, the system state is determined by the total load of all lines after a fault. The state with a higher index is likely to be more severe. Our method uses data from the normal (pre-emergency) mode, which is the main advantage of our proposed method over existing approaches, i.e., it is sufficient to perform one simulation and then the elements (in our case transmission lines) can be ranked according to the proposed criteria afterwards. The highest ranked lines (higher than a predetermined threshold (%)) of three lists created based on three criteria are included in the combined list. The size of the combined list can vary depending on the predetermined threshold (%) and the number of appearances of identical lines on at least two different lists. The construction of an efficient and accurate list allows us to reduce the number of contingency simulations. This is important for the N-2 scenario, as the total number of N-k contingencies increases exponentially. Generators and transformers are not included in this ranking.

The N-1 and/or N-2 contingency methods are usually used to check whether the electrical system (power or bulk system) can withstand unexpected/unplanned equipment disconnections/failures and maintain the electricity supply to consumers. We use N-1 or N-2 contingency criteria to check the pre-contingency list provided by the proposed method. Electric network operators themselves determine what load level is considered safe in the network or in individual power lines. In reference [29], the following load levels were considered acceptable: N-0 (50%) and N-1 (100%).

Power transmission lines will be ranked according to three criteria. These criteria are as follows: transmission line capacity Sn, line flow, MVA, and the ratio between line flow and line capacity.

Sn—design capacity of the power line, MVA. Though Sn partially determines whether the line is important for the electrical system, the design capacity of transmission lines and its importance do not always correlate/coincide. Some of the transmission lines may be spare or duplicate. There are also cases, such as those in Eastern Europe, where the capacity of the electricity network was designed with a large reserve and an expectation of significantly growing industry and consumption in the future.

LF (line flow)—power flow in an electric transmission line, MVA. The main indicator that determines the importance of a line for the power system. The more flow through the transmission line, the more electricity flow will be redistributed when it is lost.

The Ratio of LF/Sn. This ratio may seem to be a redundant criterion, but it also performs a function. The cumulative ratio level of power lines of the system determines the load level of the system. Also, by examining the electrical network, it was found that capacities of lines connected to the same busbar are usually the same; therefore, knowing the ratios of the lines, we can estimate future overloads on adjacent (neighboring) lines.

Checking all possible failure/contingency combinations is a tedious process, so such calculations are mostly used to check the system capacity in long-term planning. If the real or explored system is not large (<100 elements), then both N-1 and N-2 can be tested by performing a full check even in daily or hourly modes. However, larger systems typically use expert knowledge to verify at least some of the N-2 instances. Table 2 shows the variation of the number of possible combinations when a brute-force search (checking all possible combinations) is used (for the N-2 case) and when 10%, 20%, and 30% of the system elements are taken into consideration, respectively.

Table 2. Combination number in the cases of full check and 10, 20, 30% of lines.

Number of Lines in the System	Full Check	10%	20%	30%
100	4950	45	190	435
500	124,750	1225	4950	11,175
1000	499,500	4950	19,900	44,850
5000	12,497,500	124,750	499,500	1,124,250
20,000	199,990,000	1,999,000	7,998,000	179,970,000

When only 10% of the lines are taken into consideration for the N-2 case, the calculation time (combination number) is reduced by about 100 times, when 20%—about 25 times, and when 30%—about 11 times. The reduction in the number of combinations is especially important when the calculations are switched to daily or hourly modes.

2.1. Line Selection Algorithm

The proposed line selection algorithm is being used in pre-contingency mode. The SIEMENS PSSE 33.12 software version was used for simulations. The fixed slope Newton-Raphson method was used in power flow calculations. Allowable system total absolute mismatch—0,5 MVA, the maximum iteration number—20.

The following initial data are entered into the PSSE Baltic model: load, generation, voltage level in nodes, electrical parameters of lines, etc. The simulation with the data is performed. The second step is to check whether the model converges, if there are no unacceptable errors, or if the permissible number of iterations is not exceeded.

Next, it is checked whether the voltage level in the nodes corresponds to the permissible safe limits, and whether the design capacities of the power lines are not exceeded.

If the first steps were successful, then the ranking procedure initially uses the three lists based on previously described criteria—Sn, Ratio, LF. From each of the three lists, 20% of the lines are selected to form the initial list of ranked lines. Depending on the number of duplicate lines (same lines appearing in more than one list), the length of the initial list can contain from 20% to 60% of the number of all lines in the electrical network. The list should be shortened if the number of lines is >30% of all modeled lines. A block diagram of the algorithm is provided below in Figure 3.

A list-creation algorithm is needed to minimize the number of possible combinations. It should be understood that the single universal list may not exist and there will always be cases when a small part of the lines, which are significant for a certain mode, may not be included in the compiled list.

The disconnection of generators is not explored, and therefore the power lines connecting generators and distribution buses are also not disconnected. There are no isolated islands, so no load transfer (load throwover) function is used. Therefore, if a node (load) is connected to only one line, we do not include this line into any list of combinations. The generation and load nodes of the model are distributed in a way that ensures the redistribution of all power flow mostly at the 330 kV level. Only a negligible part of the power flow can be redistributed through lower voltage lines (110 kV). Thus, in the case of the N-2 simulation, only those combinations which ensure that no 330 kV node remains on an isolated island (in the case of their disconnection) were considered. Hence, if a node has two connected lines, only one can be disconnected.

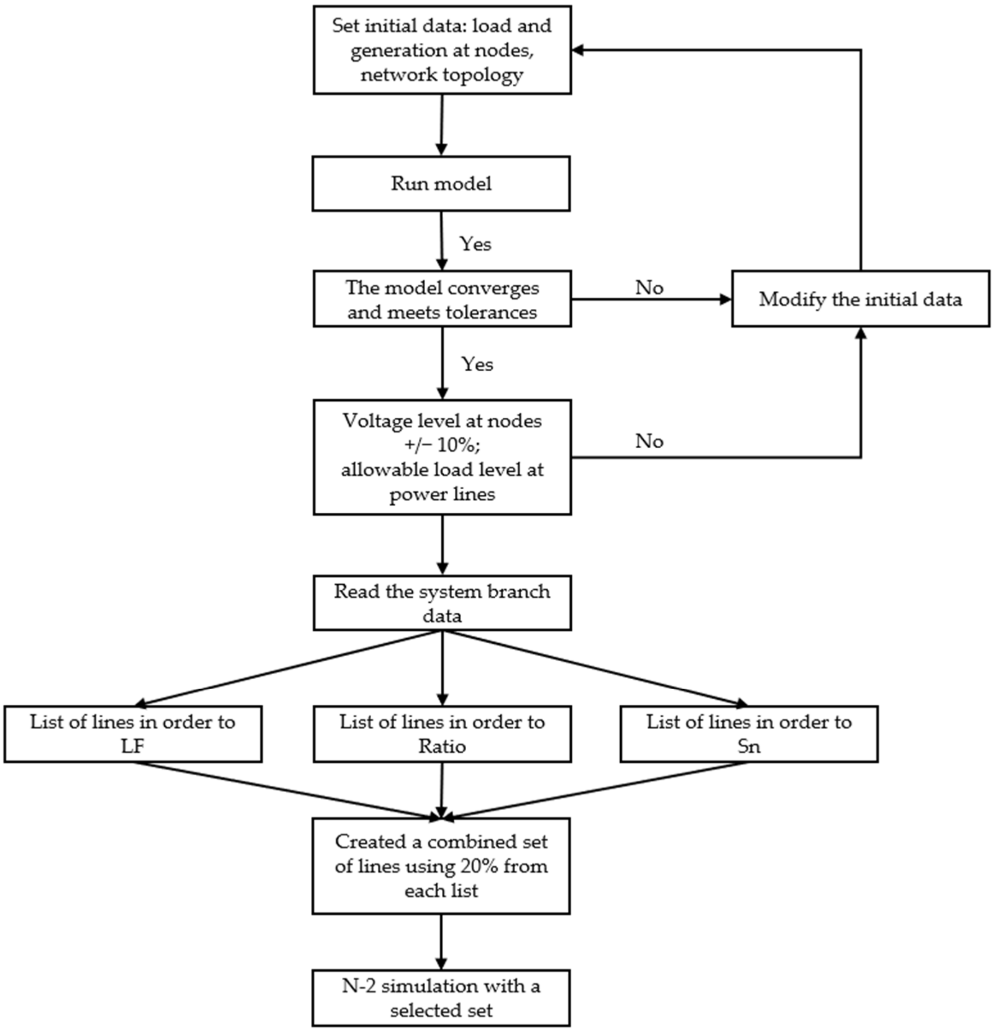

Figure 3. Algorithm for set creation.

2.2. Power Grid Description

The actual Baltic electricity network, which consists of the networks of three Baltic countries—Lithuania, Latvia, and Estonia—is used to test our method. The transmission network consists of 110 kV and 330 kV power lines. The network data for each country are presented in Table 3.

Table 3. The network data of the Baltic States.

State	Length of 330 kV Lines, km	Length of 110 kV Lines, km	Number of Lines to Model	Number of 330 kV Nodes
LTU	1896	4968	27	16
LV	1742	3812	24	19
EST	1634	3361	27	15

The official data of the Baltic countries are provided in sources [30–32]. The Baltic transmission network is specific in that it operates in the BRELL ring with the electricity networks of Russia and Belarus. Commercial traffic between the Baltic and Belarus/Russia is currently limited. Thus, Baltic countries operate on a kind of "isolated" island, as it does not have/use AC connections to other electrical systems. The Baltic region has four DC system connections with continental Europe and the networks of the Nordic countries. Three more connections are planned: Estonia—Finland, Estonia—Germany, Lithuania—

Poland. A map of the Baltic 330 kV power grid with the planned new 330 kV lines and future DC connections is presented in Figure 4. It should also be noted that the Baltic electricity system will be connected to continental European grids after 2025. In Figure 4, the red crosses indicate the point of disconnection with the BRELL system, the black circles indicate the 330 kV nodes/buses, and the solid green line indicates the existing DC links.

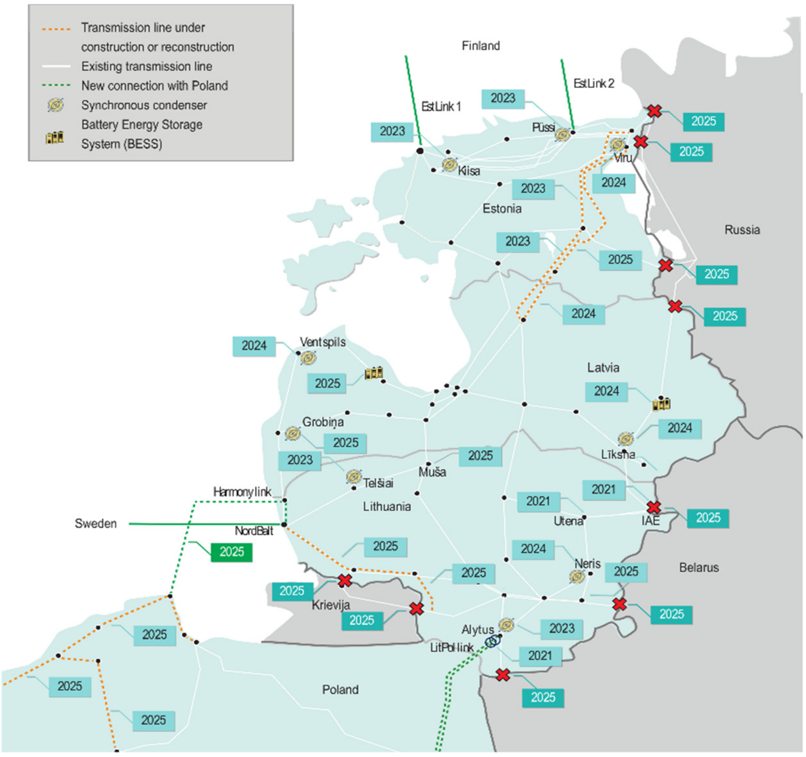

Figure 4. Development map of the Baltic network [33].

During this study, only the 330 kV power transmission network is simulated, and the number of simulated lines is 78. For the case of the N-2 and full check performed, the number of possible combinations is 3003. When only 10% of the lines are selected, the number of possible combinations shrinks to 28, when 20%—120, when 30%—276.

Generally, system operators, with historical data and expert experience, can reliably determine the periods of the heaviest load mode in the power system. We are considering the working mode of the normal scheme, before contingency, when capacities of power lines or transformers are practically reached, and these elements operate at their permissible static safety limits. By knowing the minimum and maximum modes, operators assess whether additional measures need to be taken, such as changing the scheme or limiting part of the load/power plants.

Four operating modes of different loads were simulated:

- Summer day (max).
- Summer night (min).
- Winter day (max).
- Winter night (min).

Different scenarios of the seasons and time of day allow us to reveal the distributions of different generation and load configurations in the electricity system. The system load was selected according to the data on the loads of the Baltic countries in recent years [34], and according to the maximum values of individual countries, which are usually experienced during the winter season in our region. The load data of the Baltic countries observed in 2022 are presented in Figure 5.

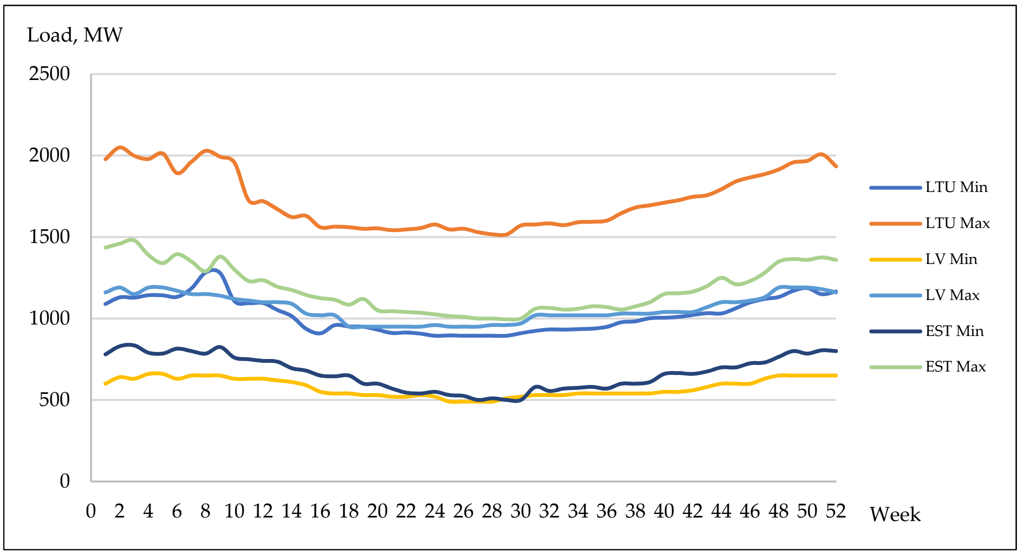

Figure 5. Weekly load data of the Baltic countries in 2022.

The highest total load in the Baltic system of 2022 was observed in the second week of the year, then it reached about 4720 MW, in Lithuania—2050, in Latvia—1190, in Estonia—1480. These values do not differ much from the maximum historical values, which are for Lithuania—2231 MVA, Latvia—1240 MVA and Estonia—1591 MVA. In winter max mode, we use approximated data—5000 MW.

Two load scenarios based on the actual (2022) and the planned (2030) electricity consumption were created. The historical and planned data of load values provided by the operator of the Lithuanian transmission system were used in this study (this data is provided in Table 4). Based on the given data of load growth, the future scenarios are created for all three Baltic countries.

Table 4. Lithuania's actual and planned electricity consumption.

Year	2016	2017	2018	2019	2020	2021
Actual consumption, MW	1979	1896	1999	2032	1939	2217
Year	2026	2027	2028	2029	2030	2031
Predicted consumption, MW	2184	2403	2364	2466	2655	2897

By using the given consumption data, we have modeled the following two load scenarios:

- Actual 2022.
- Planned for 2030 (Plan 2030).

The actual 2022 scenario basically corresponds to the current maximum load value in the winter max mode, and a 30% increase in the load is predicted by Plan 2030. The seasonal daily values of different load modes are presented in Tables 5 and 6.

Table 5. Actual 2022 mode load data.

Load State	Load, MVA			
	Summer Min	**Summer Max**	**Winter Min**	**Winter Max**
Lithuania	895	1520	1090	2200
Latvia	510	830	810	1200
Estonia	500	1120	610	1600

Table 6. Plan 2030 mode load data.

Load State	Load, MVA			
	Summer Min	Summer Max	Winter MIN	Winter Max
Lithuania	1160	1980	1420	2860
Latvia	650	1080	1050	1560
Estonia	660	1460	790	2080

For 2022, the minimum Baltic load was 1905 MW (the 28th week), and the maximum Baltic load was 5000 MW (the 7th week).

For Plan 2030, the minimum predicted Baltic load was 2610 MW, and the maximum predicted Baltic load was 6500 MW.

3. Results

3.1. Static Simulation Mode (Pre-Contingency)

The results of the static simulation before emergency mode allow us to assess the system load and how the load is distributed over the power lines. Figures 6 and 7 show the load scenarios of the Baltic system (in Winter max scenario) for different system loads (5 GW and 6.5 GW). Figure 6 shows the power/capacity distribution of the simulated lines.

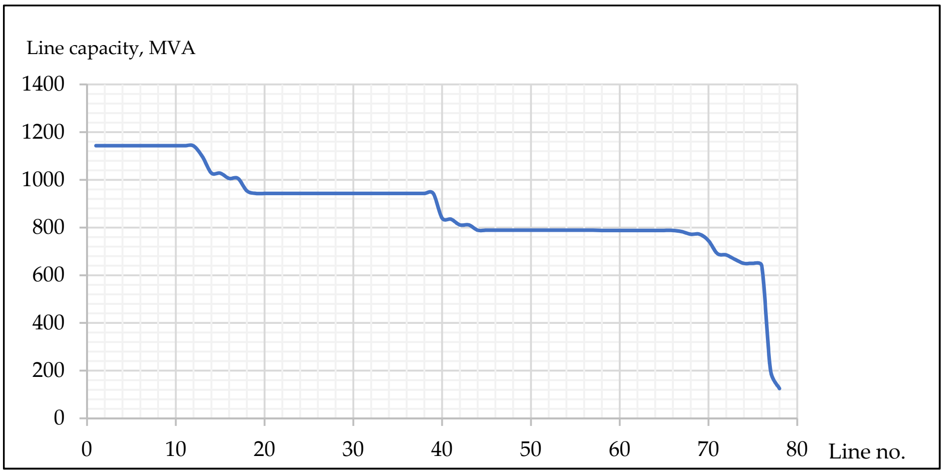

Figure 6. Capacity distribution of 330 kV lines.

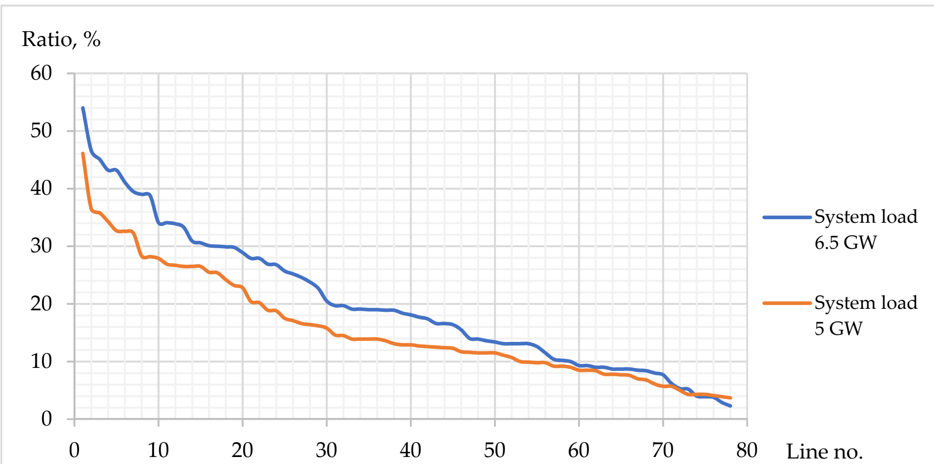

Figure 7. Graphs of Ratio vs. number of 330 kV lines with system load of 5 GW and 6.5 GW, respectively.

The cases with system load values of 5 GW and 6.5 GW (+30% from baseline) are presented in Figure 7. These loads correspond to the 2022 and 2030 (predicted) load scenarios of the Baltic States. In the case of the actual 2022 (5 GW) mode, the highest relative load level is 46.1%, and the average load is 15.7%. In the 2030 mode, the maximum load is 54%, and the average load is 20.1%. These changes in maximum and average loads do not appear to be large, but as the system is dominated by high-capacity (800–1000 MW) power lines, such changes are significant. The graphs using the same data as those given in Figure 6 but given in MVA unit are shown in Figure 8.

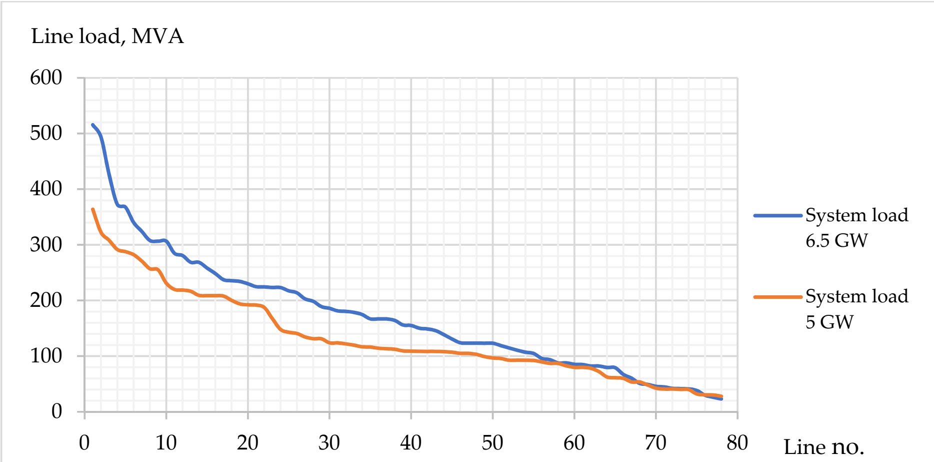

Figure 8. Plots of load scenario in LF unit vs. number of 330 kV lines with system load of 5 GW and 6.5 GW, respectively.

As shown in Figure 8, the maximum load on power lines in the base mode is 364 MVA, and the average load value is 133.8 MVA. In the 2030 mode, the maximum load is 515 MVA, and the average load is 171.9 MVA. The relative change between peak values is 41.5%. The relative change in average load is 28.5%, which is close to a 30% increase for the 2030 load mode.

In the Baltic system, the transmission capacity of the most powerful (highest capacity) power line is 1143 MVA, and the average transmission capacity of all lines is 877 MVA. The capacity of half (50%) of the simulated lines in the network exceeds 940 MVA.

After the evaluation of the load on the 330 kV transmission lines of the Baltic system, it can be noticed that the system has considerable reserve. In the normal (pre-contingency) operation mode, the most loaded line reaches only 50% of its capacity, which is not much compared to Western European networks. It was found that the transmission lines connected to large generation sources/nodes and interstate lines LTU-LV and LV-EST are the most heavily loaded.

As mentioned earlier, four different load modes were modeled under two scenarios, with eight variants in total. Winter max load modes are examined in more detail, assuming that other load modes are not so critical for the Baltic system. The results of other load modes are summarized in the conclusions.

3.2. Simulation N-2 Results

As mentioned earlier, four different load modes were modeled under two scenarios. Winter max load modes are examined in more detail, assuming that other load modes are not so critical for the Baltic system. The results of other load modes are summarized in the conclusions.

3.2.1. 2022 Winter Max Simulation Results

During the simulation, 805 different combinations (consisting of two power transmission lines) were considered whose disconnection caused an increase in power line load level to 50% or higher on at least one transmission line. The total number of possible combinations is 3003. In specific cases, one disconnection of two transmission lines can lead to an increase in the load/overload of more than one line. In total, 962 cases of exceeding the load level of 50% were identified during the simulation. This is normal because in pre-contingency mode the maximum load level was 46.1% and, after disconnecting two transmission lines, the other lines become more loaded/overloaded. Table 6 shows the results of ranked lines/elements by load ranges.

The highest load level observed after disconnecting two lines was 84.8%/710 MVA (789%), while for comparison much lower values of 46.1%/363.8 MVA, respectively, were determined in pre-contingency mode.

The load levels of the lines were divided into ranges in 10% increments to facilitate comparison of the results of different indicators. After static pre-contingency mode ranking, it was determined that the combined list identified the highest number of accurate combinations where both disconnected lines fall into the top 10% (i.e., above the 90th percentile) of any of the three lists. Thus, in this way the power line selection algorithm is being checked. The simulation results with the load results are presented in Tables 7–9.

Table 7. Combined (10%) set and individual criteria results based on a system load of 5 GW.

Range of relative load of operational lines, %	>50%	>60%	>70%	>80%
Number of combinations	962	258	17	2
Determined with the Sn	7	3	0	0
Determined with the LF	42	13	2	0
Determined with the Ratio	41	16	4	0
Determined with the combined (10%) set	113	36	5	0

Table 8. Combined (20%) set and individual criteria results based on a system load of 5 GW.

Range of relative load of operational lines, %	>50%	>60%	>70%	>80%
Number of combinations	962	258	17	2
Determined with the Sn	9	3	0	0
Determined with the LF	139	45	10	2
Determined with the Ratio	141	45	11	2
Determined with the combined (20%) set	289	75	14	2

Table 9. Combined (30%) set and individual criteria results based on a system load of 5 GW.

Range of relative load of operational lines, %	>50%	>60%	>70%	>80%
Number of combinations	962	258	17	2
Determined with the Sn	75	46	1	0
Determined with the LF	257	90	12	2
Determined with the Ratio	251	77	13	2
Determined with the combined (30%) set	510	149	15	2

The combined (10%) set shows the most accurate results in all ranges. The list of ranked lines provided by the combined set consists of 16 transmission lines, which corresponds to 120 possible combinations. Sn, LF, Ratio lists each have 8 transmission lines, and the number of possible combinations is 28.

With the combined (10%) set, which is 4.3 (120/28) times larger (than Sn, LF, Ratio), 5 out of 17 heaviest modes with a load level higher than 70% were determined, which is not very accurate. The Ratio list results are similar to those provided by the combined set, so it is not beneficial to use the combined list in this case.

Table 8 shows the results obtained with 20% (i.e., lines above 80th percentile) highest ranked lines selected according to Sn, LF, Ratio factors and the combined (20%) set.

The results of the combined (20%) set are most accurate when the load level on operating lines is higher than 70%. The list of ranked lines provided by the combined set consists of 30 transmission lines, which corresponds to 435 possible combinations. LF results are also very similar to the Ratio list when evaluating all loaded (>50%) lines, but not as accurate as the combined (20%) set. All the lists provided by using Sn, LF, Ratio indicators consist of 16 transmission lines, and the number of possible combinations is 120.

The combined (20%) set was 3.6 times (435/120) larger than the LF, Sn, and Ratio lists. In total, 14 out of the 17 heaviest modes, when the load level is set higher than 70%, have been found. Sn list results are poor because the most powerful line in the network is not connected to any generator/load nodes. Sn list results are poor because the most powerful line in the network is not connected to any generator/load nodes.

The following results were obtained by using lists containing 30% of the highest ranked lines according to Sn, LF, Ratio criteria and the combined (30%) set.

The results provided by the combined (30%) SET are most accurate when the load level on operational lines is higher than 70%. The list of ranked lines provided by the combined set consists of 43 transmission lines, which corresponds to 903 possible combinations. Ratio results are similar (13 vs. 15) to those obtained by using the combined (30%) set when considering only the most loaded (>70%) lines. The lists of Sn, LF, Ratio consist of 24 transmission lines each, and the number of possible combinations is 276.

The combined (30%) set is 3.3 times (903/276) larger than the Sn, LF, Ratio lists. In total, 15 out of the 17 heaviest modes, when the load level is higher than 70%, have been found. The results of the Ratio list are similar to those obtained by using the combined list. In total, 13 out of 17 cases have been found by using the Ratio list, so it is sufficient to use the Ratio list.

Summary of the 5000 MW Case

In the winter min mode, the generation structure (location and amount of energy) practically did not change, as only the generation and load level in the nodes changed according to the mode data. The maximum possible load level in power lines with the loss of two elements is 71.2%. There were 678 cases where the load level exceeded 50%.

In the summer min and max modes, the load level of the Baltic system was 1905 MVA and 3470 MVA, respectively. The results of maximally overloaded lines were similarly distributed. Maximum possible load level in summer max mode is 78.4% and 712 cases of exceeding the load level of 50% were detected. The maximum load level in summer min mode is 64.1% and 564 cases of exceeding the load level of 50% were detected. The most accurate combinations were found with the all-combined sets.

3.2.2. 2030 Winter Max Mode Simulation Results

The 2030 winter max is another mode explored when the system load level is 6500 MW. Simulation results with load results are presented in Tables 10–12.

The maximum possible load level obtained by a disconnection of two lines was 114.8%/880.3 MVA (745 Sn). For comparison, the values of 54%/426.2 (789) MVA were determined in pre-contingency mode, respectively.

The results obtained by using the combined (10%) set are most accurate when the load level on operational lines is higher than 90%. The list of ranked lines obtained with the combined list consists of 14 transmission lines, which corresponds to 91 possible combinations. All the lists produced with Sn, LF, Ratio lists each have 8 power lines, and in those cases the number of possible combinations is 28.

Table 10. Combined (10%) set and individual criteria results based on a system load of 6.5 GW.

Range of relative load of operational lines, %	>60%	>70%	>80%	>90%	>100%
Number of combinations	1035	410	48	10	5
Determined with the Sn	29	13	9	6	3
Determined with the LF	43	17	7	3	3
Determined with the Ratio	43	17	7	3	3
Determined with the combined (10%) set	109	45	13	8	3

Table 11. Combined (20%) set and individual criteria results based on a system load of 6.5 GW.

Range of relative load of operational lines, %	>60%	>70%	>80%	>90%	>100%
Number of combinations	1035	410	48	10	5
Determined with the Sn	59	25	12	6	3
Determined with the LF	282	60	14	6	3
Determined with the Ratio	138	57	15	7	4
Determined with the combined (20%) set	333	138	25	9	5

Table 12. Combined (30%) set and individual criteria results based on a system load of 6.5 GW.

Range of relative load of operational lines, %	>60%	>70%	>80%	>90%	>100%
Number of combinations	1035	410	48	10	5
Determined with the Sn	130	73	20	7	3
Determined with the LF	372	107	28	8	5
Determined with the Ratio	243	98	24	8	5
Determined with the combined (30%) set	551	243	39	10	5

The combined list in this case is 3.25 times (91/28) larger than the LF, Sn, and Ratio lists. In total, 8 out of the 10 heaviest modes have been found when the load level is higher than 90%.

The results obtained with the combined (20%) are most accurate in all load ranges. All five of the most loaded lines are determined by using the combination (20%) set. In the case of the combined set used, the list of ranked lines consists of 30 transmission lines, which corresponds to 435 possible combinations.

Ratio results are also quite accurate. However, 7 of the 10 most loaded are identified when the relative load of operational lines is higher than 90%. Sn and LF perform worse in determining the most loaded six lines.

The results obtained with the combined list are most accurate in all relative load ranges. In the case of the combined list used, the list of ranked lines consists of 44 transmission lines, which corresponds to 946 possible combinations.

The ratio and MVA lists are also quite accurate, as 8 out of 10 combinations have been found when the relative load of operational lines is higher than 90%.

4. Discussion

The simulation results confirmed the acceptable accuracy of the proposed algorithm. Eight working modes of current and forecasted/estimated load of the Baltic power system were explored in detail. The most accurate combinations of critical lines were determined by using our approach based on the combined list. Since the load level in all eight variants was highly variable, the N-2 simulation results varied accordingly. The maximum load level after the loss of two lines was varying from summer min mode—64.1% (system load 5 GW) to winter max mode—114.8% (system load 6.5 GW).

In this study, it was found that the most accurate results were obtained when using the combined (30%) set, but the number of combinations in the case of this list is largest, with on average 905 combinations depending on the duplication of lines. Using this set, 87.5% out of 10 and 75% out of 20 most loaded operational lines were identified correctly. The shorter set—combined (20%) is slightly less accurate—81.5% out of 10 and 68.3% out of 20 most loaded operational lines, but the number of combinations is significantly lower, on average—428. The shortest set—combined (10%) is the most inaccurate, because 40% out of 10 and 27.5% out of 20 most loaded operational lines were identified correctly.

When examining individual combinations in more detail, it was found that some power lines appear more than one time on different lists, i.e., disconnection of the mentioned lines has the greatest influence on the overloading of operational lines, which depends on the network topology, generators, and load distribution in the electricity transmission network.

Based on the results of our study, the most rational solution (offering the best accuracy to computational demand ratio) is to use a threshold of 20%. The 30% combined lists provide slightly better results, but the number of combinations is two times higher (in comparison to the case of the 20% combined lists), which results in the double calculation time of the contingency combinations. This is especially important for identifying critical power transmission lines when planning daily or hourly work modes.

During the investigation, it was found that the most efficient way to rank lines was to use the Ratio of LF/Sn indicator, while the lowest efficiency was achieved using the parameter Sn of power transmission line. Further research will be focused on the use of weighted factors on each of the three lists. Such an approach may lead to a more efficient construction of the combined list.

It is necessary to note that our simulations were performed on the Baltic electricity system. Each power system differs in the topology of its power lines, the number of nodes, and the distribution of load and generation in the system. Therefore, the application of our ranking method to another system requires N-2 simulations to determine the rational size of the list of ranked lines based on the three indicators mentioned above.

5. Conclusions

A new method for ranking lines of the electricity transmission network has been developed. The method allows for the determination of the most critical pre-emergency modes by using normal/pre-emergency mode calculations, which sometimes allows us to reduce the computational and other resources required, including simulation time. The time aspect is especially important when working with large power systems, which also include electricity transmission networks. Based on our investigation, it is recommended to use a combined set 20% (of every criterion), i.e., percentage value from the total number of power transmission lines, because the accuracy is slightly lower than that obtained with a set of 30%, but the number of combinations is more than two times lower, or the simulation time is two times faster. This is especially important for identifying critical power transmission lines when planning daily, hourly, or 15 min. operation modes.

The three most effective parameters determined during this study are used in the developed methodology for ranking electric transmission lines: Sn—design capacity of the power line, MVA; LF (line flow)—power flow in an electric transmission line, MVA, and the ratio of LF/Sn.

High reliability of the Baltic electricity system has been confirmed: maximum load level (the most loaded power transmission line) with the loss of two lines varied in the range from 64.1% (during the summer minimum mode, power system load—5 GW) to 114.8% (the winter maximum mode, power system load—6.5 GW).

The proposed method addresses only one step in the reliability assessment of a power system. The use of our approach reduces the simulation time and selects the most important/critical lines of the system, but still an N-k contingency analysis is required. Our future work will be focused on post-contingency mode evaluation.

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