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Transmission expansion planning considering Probabilistic Risk Assessment

Implemented at Swedish National Grid

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Abstract

Svenska kraftnät (Swedish National Grid) is the transmission system operator in Sweden and is responsible for maintaining and developing the Swedish transmission grid. One of the tasks included in this responsibility is transmission expansion planning, which means analyzing and planning the capacity in the future transmission grid for the requested load and generation. Historically, the N-1-criterion has been used to evaluate the reliability in transmission grid expansion planning. This criterion is deterministic, which means that all failures in the grid are considered equally, regardless of the differences in probability. In a system with an increased share of intermittent energy sources and load, it is increasingly demanding to plan and build a system that is N-1-secure in all situations. Probabilistic Risk Assessment (PRA) is a complementing method that takes the probability and consequence of different faults into consideration. The possible benefits of using PRA are higher utilization of the power grid, greater system operating flexibility, better support for system planning, and an overall optimization of socio-economic benefits.

In this master thesis project, a method for PRA in transmission expansion planning at Svenska kraftnät is proposed. The method consists of three steps: generation of operating states, contingency analysis, and reliability assessment. Historical frequency and duration of faults in the transmission grid are used to estimate the probability of different contingencies. The method results in three reliability measures for the system: expected energy not supplied (MWh/year), expected duration of outages (h/year), and expected duration of overloads (h/year). The three reliability measures are combined into a composite comparison index, which can be used to compare different alternatives in transmission expansion planning. The proposed method is tested on a PSS/E model of the Swedish transmission grid and 14 different operating states. Four different investment alternatives are analyzed, including changes in load and generation, and grid reinforcements. The conclusion is that the proposed method is a useful tool for power system analysis at Svenska kraftnät and that the process for generating the operating states must be further developed.

Keywords

Probabilistic risk assessment, PSS/E, Transmission expansion planning, National grid

Sammanfattning

Historiskt har det deterministiska N-1-kriteriet använts för att bedöma transmissionsnätets tillförlitlighet vid långsiktig nätplanering. Detta innebär att systemet ska dimensioneras för att klara ett bortfall av någon systemkomponent under värsta tänkbara driftfall, exempelvis topplasttimmen. I ett elsystem med alltmer intermittent förbrukning och produktion kan det dels vara svårt att veta vad som är det värsta tänkbara fallet, och dels kan det bli mycket kostsamt att dimensionera ett system som är N-1-säkert i alla lägen. Därför är det intressant att införa kompletterande probabilistiska verktyg.

I detta examensjobb föreslås en metod för att beräkna och använda probabilistiska mått för att bedöma transmissionsnätets tillförlitlighet. Metoden använder flera tänkbara driftfall med varierande sannolikhet och värden på hur sannolika olika typer av fel i systemet är. Tänkbara fel analyseras och resulterar i mått på systemets förväntade överlaster och avbrott, uttryckt i timmar per år och energi per år. Dessa nyckeltal kombineras till ett sammanvägt mått, som kan användas för att jämföra olika nätanslutningar och investeringsalternativ.

Nyckelord

Probabilistisk riskbedömning, PSS/E, Transmissionsnätsutveckling, Stamnät

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List of acronyms and abbreviations

ACER	The European Union Agency for the Cooperation of Energy Regulators
API	Application Programming Interface
CSAM	Coordinating Operational Security Analysis
EDLC	Expected Duration of Load Curtailments
EDOL	Expected Duration of Overloads
EENS	Expected Energy Not Supplied
GARPUR	Generally Accepted Reliability Principle with Uncertainty modelling and through probabilistic Risk assessment
KMA	Swedish National Grid's short term market analysis
NDB	The Network Database, *Nätdatabanken*
PLC	Probability of Load Curtailments
PRA	Probabilistic Risk Assessment
Svk	Swedish National Grid, *Svenska kraftnät*
TEP	Transmission Expansion Planning

Chapter 1

Introduction

This chapter describes the specific problem that this thesis addresses, the context of the problem, the goals of this thesis project, and outlines the structure of the thesis.

1.1 Background

Swedish National Grid (Svenska kraftnät, Svk) is the transmission system operator in Sweden and is responsible for maintaining and developing the Swedish transmission grid in a sustainable, safe, and cost-effective way. One of the tasks that are included in this responsibility is transmission expansion planning, which involves investigating and proposing grid investments necessary to maintain a robust transmission grid that has the capacity for future demand and generation. Efficient and accurate methods for transmission expansion planning are crucial for the ability to handle the big amount of applications of connecting to the transmission grid and avoid over- or under-dimensioning the system.

Historically, the N-1 criterion has been used to evaluate the reliability in transmission grid expansion planning. The N-1 criterion means that the system should always be able to handle a failure in any system component in the worst-case scenario, without violating the security limits [1]. The criterion is deterministic, which means that all failures in the grid are considered equally, regardless of the differences in probability. Probabilistic Risk Assessment (PRA) is a complementing method that takes the probability and consequence of different faults into consideration [2].

With the increased share of intermittent energy sources, a complement to the N-1 criterion is necessary to keep a good balance between reliability and costs in the power grid. It is also increasingly demanding to present the worst-case scenario in the operation of the grid, as it may not necessarily occur at peak load. The possible benefits of using PRA are higher utilization of the power grid, greater system operating flexibility, better support for system planning, better understanding and monitoring of the power system, and overall optimization of socio-economic benefits [2].

The current development and implementation of a PRA methodology in Europe is regulated in Coordinating Operational Security Analysis (CSAM), which is decided by The European Union Agency for the Cooperation of Energy Regulators (ACER) [2]. According to the regulation, the PRA methodology should be fully developed by the end of 2027, for use in operation and operational planning. Since 2019, all TSOs within ENTSO-E have researched and prepared for a transition to PRA as a complement to the N-1 criterion.

1.2 Problem

As a part of the coordination of operational security analysis within the European Union, Svk needs to evaluate the current internal processes for reliability assessment and examine the needs and expectations of the new probabilistic tools. The regulation applies to system operation and operational planning, up to one year ahead. When the short-term planning moves to a probabilistic approach, Svk also needs to evaluate and adjust the methods and processes used for long-term transmission expansion planning.

The responsibility for transmission expansion planning at Swedish National Grid is located at the department *Power system* and the unit *Network development*. The network development unit handles connection requests and identifies the need for network reinforcements. The unit investigates changes that affect the physical network, for example, lines, substations, compensation devices, and transformers. One central part of the current investigation process is the static load flow analysis, which means analyzing the system with respect to voltages and currents in steady-state. The system is analyzed both in the normal operating state and after N-1-contingencies, where for example a line, busbar, or transformer is disconnected. If a requested connection to the grid is expected to cause over/under-voltages or thermal overloads in any network element, actions are suggested.

The current process for static load flow analysis is deterministic, which in short means that the system is dimensioned for handling the worst contingency in the worst operating state, regardless of the probability for the different contingencies and operating states, and regardless of the expected consequences. In order to comply with the coming EU regulations for operational planning, probabilistic tools for static load flow analysis are required.

This master thesis project will answer the following research questions:

- Which method is suitable for the implementation of probabilistic risk assessment in the Swedish transmission system expansion planning process?
- Which reliability and power system data are needed for the implementation?

1.3 Purpose

The purpose of this master thesis project is to propose a probabilistic risk assessment method suitable for long-term system transmission expansion planning at the Svk.

1.4 Goals

The goals of this master thesis project are to:

- Identify a PRA method for transmission expansion planning that is compatible with ENTSO-E's and ACER's requirements
- Identify the data required for performing an analysis using the previously identified PRA method
- Identify changes that have to be done in the current internal processes for power system analysis at Svk, in order to implement the PRA method
- Test the PRA method on a Svk grid model

1.5 Research Methodology

The research methodology in this project will be divided into two phases. In the first phase, a literature review will be performed to obtain an overview of available methods and previous experience of PRA in transmission expansion planning processes. In the second phase, the identified method or methods will be evaluated and implemented at Svenska kraftnät. The implementation will include data analysis of existing power system simulation data, and power flow calculations in existing software at Svk.

1.6 Delimitations

- The project does not include any construction of grid models or scenarios. Svk already has a couple of scenarios that can be used for this project.
- The collection of reliability data is not in the scope of this project. This project will only state what data that is required and try to use existing reliability data at Svk
- The focus will be PRA for long-term planning and not for operational use

1.7 Structure of the thesis

Chapter 2 presents a literature review of theory and previous implementation of PRA for Transmission Expansion Planning (TEP). Chapter 3 presents the PRA-method that this master thesis project has identified as suitable. Chapter 4 presents results from a case study where the method presented in chapter 3 is tested with existing power system models at Svk. In chapter 5, the method and the results are discussed, regarding performance, relevance, and validity. Finally, chapter 6 presents the conclusions and what is left as future work.

Chapter 2

Background

This chapter presents a literature review of the theory and previous work that is relevant to this master thesis project. The literature review has focused on previous research and implementation of PRA for system development within the European Union.

2.1 GARPUR

Generally Accepted Reliability Principle with Uncertainty modelling and through probabilistic Risk assessment (GARPUR) was an EU-funded project that started in 2013. It was a collaboration between 7 TSOs from Belgium, Bulgaria, the Czech Republic, Denmark, France, Iceland, and Norway, and 12 R&D providers [3]. The aim of the project was to design and develop new probabilistic reliability criteria and PRA methods for the European power system [4]. The project resulted in a PRA framework feasible for timescales from real-time operation to long-term, in the context of operational planning, asset management, and system development. Figure 2.1 presents an overview of GARPUR's different time scales and contexts of reliability management. The work in GARPUR-project was performed in 11 different work packages.

2.1.1 Reliability management

According to GARPUR's definition, reliability management is divided into three functional blocks [5]: Modelling task, Assessment task, and Control task. In the modeling task, the transmission system is modeled considering the environment and possible threats. In the assessment task, different candidate decisions are assessed by calculating performance measures and checking

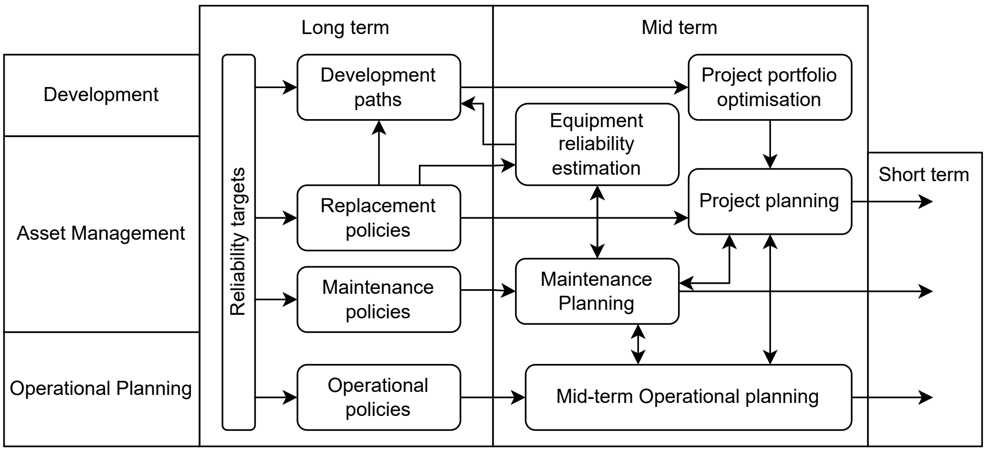

Figure 2.1: An overview of different workflows in reliability management contexts for long and mid-term planning. Source: Adapted from [5]

reliability criteria. The control task aims to select optimal combinations of the candidate decisions with respect to reliability criterion and socio-economic maximization.

2.1.2 System development method

Work package 4 in the GARPUR projects handled different aspects and problems with PRA in the context of system development. The work package resulted in two reports. The first report [6] presented an analysis of the present system development process at European TSOs, and the second report [7] presented a method for PRA for usage in long-term system development. The method focused on handling the uncertainty of future operating states of the power system. In short, the method presented in GARPUR starts with the construction of macro scenarios for the future system on a zonal level. In the next step, monte-carlo simulations are used to construct possible demand and production levels in different bidding zones. The result from the monte-carlo simulations is still on an aggregated level for each bidding area. To be able to do power flow calculations in a model of the physical grid, the results from the monte-carlo-simulations are transferred to a nodal model, considering buses and branches in the network. The bus-branch operating states can then be used for contingency analysis and risk assessment. In the zonal to nodal conversion, clustering techniques are used to reduce the size of the data set, together with sampling to get different distributions of demand within a bidding zone.

An example where the method was tested on a 10-bus network was presented in the last report of work package 4 [7]. The clustering was done with the K-medoids algorithm and the Chebychev similarity measure. In the example, the reliability analysis was performed with a deterministic N-1 contingency analysis. The report refers to parallel work packages developing methods for probabilistic contingency analysis.

2.2 Implementation examples

Within the GARPUR project, the method for system development was tested by two TSOs in real-life network models [8]. In the first study, the Belgian TSO Elia tested the method on a part of the 50–150 kV transmission system in the south-west part of Belgium [9]. In that study, four different investment options were compared with respect to the expected system operating cost. The cost included expenses for balancing the system before and after contingencies and the cost of curtailment of load and production. The scenarios used in the analysis were created from simulations based on historic grid data, such as demand and generation availability.

In the other study, the GARPUR framework was tested by the Norwegian TSO Statnett [8]. A Bayesian updating scheme was used to estimate the failure rates of different contingencies. Then, two different investment options were compared with respect to expected interruption costs and investment costs. Another paper from Statnett shows more details about a similar implementation [10]. The method is described in [11] and uses methods from [12] and [13] for the construction of weather-dependent failure rates for overhead lines.

In [14], the practice of using probabilistic methods in the Polish transmission system development is presented. A probabilistic analysis is compared to a deterministic analysis on a 39 bus 110–220 kV network. Eleven different development options were compared. Two different probabilistic analysis methods were compared, one using a two-point estimation algorithm for load flow, and one using a Latin hypercube sampling (LHS) method to determine random states of the system.

Another paper from Poland [15] compared a deterministic N-1 contingency list with a probabilistic contingency list. The probabilistic analysis was based on a randomized process with individual failure rates assigned to each branch. The analysis was done on a test network model developed by the Polish TSO, with a fixed demand and generation.

Idaho Power Company have tested probabilistic reliability assessment for comparing three different strategies for their 75-year transmission system planning [16]. In the study, the software TRELSS was used to perform the reliability analyses. The input parameters to the simulations were a fixed outage rate for lines and transformers respectively, and a case with peak load level. The different build-out strategies were compared with respect to Expected Unserved Energy (EUE), Expected Unserved Demand (EUD), System Average Interruption Frequency Index (SAIFI), and System Average Interruption Duration Index (SAIDI).

In a previous master thesis project [17], a method for PRA in system development in the Netherlands was tested. The method included Bayesian data analysis of historical failure data, contingency selection based on an acceptable probability level, and finally an assessment of the consequences of each selected contingency. The value of lost load (VOLL), was used to put a value on the consequences. The method was tested both without re-dispatch actions, assuming that all overloaded lines are disconnected, and with re-dispatch actions, where the generation is changed to avoid overload after each contingency. The method was implemented in PowerFactory and Python. A replica of the Netherlands' transmission grid was used for the simulations.

The development of operating scenarios for the future power grid typically involves huge data sets. In order to make the amount of data manageable, it is common to use some kind of clustering method to group similar cases. [18] used a probabilistic power flow method with Monte Carlo simulations and K-means clustering.

2.3 EU regulations

In 2017, the European Commission established a new guideline on electricity transmission system operation [19]. In article 75 it is stated that all TSOs should develop a methodology for CSAM. In accordance with that article, ACER released a CSAM in 2019 [20]. This methodology aims to coordinate system operation and operational planning, up to one year ahead. The methodology should be in use by all TSOs in 2027. For long-term system development, the CSAM does not specify specific requirements.

2.4 Current probabilistic practice at Svk

For Svk's short- and long-term market analysis (KMA and LMA), probabilistic methods are used to create forecasts of the future power grid, for example regarding the power deficit expressed in LOLE and EENS. The KMA report is based on known investments and decisions in the grid, while the LMA presents some macro-assumptions about installed capacities in the future system. With the support of historic weather data, possible outcomes of the future grid at a zonal level are created. These outcomes include for example the demand and generation in each market area in the Nordic power system and the power flow between the areas. These scenarios are mainly used for analysis at an overview system level, and not planning the grid at a topological level.

For the current transmission expansion planning process at Svk, the software PSS/E is used for power flow calculations and contingency analysis. The analyses are based on plans for the future grid topology, and high- and low-load scenarios. The high load scenario is the expected load during the peak load hour for a normal winter, while the low load scenario represents an hour in the summer with low load. From the scenarios, some typical operating states are constructed, considering for example different distributions of wind-power production and power flow directions between areas. The N-1-criterion forms the foundation of the static power system analysis, where line overloads, under-voltages, and over-voltages after contingencies decide the need for further grid investments. A contingency can for example be a loss of a single line, transformer, or busbar. The probability of the contingencies is not considered.

2.5 Reliability of the Swedish national grid

The reliability of different components in the Swedish transmission grid was analyzed in a previous master thesis work from 2004 [21]. In that report, historic outage data for the years 1997-2002 was used to calculate the average frequency and duration for faults in Svk's 220–400 kV grid. A summary of the results from the report is presented in table 2.1.

Each year, ENTSO-E publishes a report called DISTAC (Disturbance Statistics and Classification), that presents disturbance statistics in the Nordic and Baltic countries. The report presents failure rates for different components, the cause of the faults, and the energy not supplied (ENS) caused by disturbances. The duration of the faults is not included in the report. The DISTAC report includes statistics on all grids on the voltage levels 110–400 kV, which means that the regional networks are included in the statistics, and not only the national grid. A summary of the DISTAC report from 2021 [22] is presented in table 2.2 and 2.3.

Object	**Failure rate [per year]**		**Failure duration [h]**	
Voltage level	220 kV	400 kV	220 kV	400 kV
Line [per km]	0.0122	0.00501	1:41:53	5:03:03
Shunt reactor	0.181	0.354	26:05:30	39:34:15
Busbar	0.0173	0.0269	1:28:06	3:25:17
Shunt capacitor	0.0833	-	16:48:00	-
Series capacitor	-	4.92	-	16:54:42
Voltage transformer	0.00134	0.00128	3:40:30	15:50:00
Current transformer	0.000797	0.00179	38:30:00	41:36:15
SVC unit	4.25	2.33	101:49:16	5:31:40
Transformer	-	0.0222	-	0:06:30
Surge arrester	0.00216	0.000712	0:06:00	4:53:30

Table 2.1: The average failure rate per object and average duration per fault in the Swedish transmission grid 1997-2002. Source: [21]

Object	**Failure rate [per year]**			
Voltage level	220 kV		400 kV	
Year	2021	average	2021	average
Overhead line [per 100 km]	0.87	0.73	0.51	0.34
Power transformer [per 100 devices]	0	3.04	0	2.09

Table 2.2: Failure statistics from the 2021 DISTAC report. The average values are calculated from the statistics during the years 2012-2021. Source: [22]

ENS [MWh per year]			
220 kV		400 kV	
2021	average	2021	average
26.9	88.5	10.5	53.0

Table 2.3: Energy not supplied (ENS) from the 2021 DISTAC report. The average values are calculated from the statistics during the years 2012-2021. Source: [22]

2.6 Summary

The literature review shows that PRA for system development has been tested by multiple TSOs. A summary of the differences between the previous implementations is presented in table 2.4. From the literature review, and the current processes and available tools at Svk, a feasible PRA method is proposed, see the last row in table 2.4. The proposed method includes

Reference	Historic outage data	Variable failure rate	Probabilistic scenarios	Clustering	Corrective actions	Deterministic contingency assessment	Probabilistic contingency assessment	Dynamic line rating	Optimal power flow	Software
[9]	-	-	-	✓	✓	✓	-	Seasonal	✓	Power-Factory
[10]	✓	Weather	✓	-	✓	-	✓	Seasonal	-	PSS/E
[14]	-	-	-	-	-	✓	-	-	✓	PLEXOS
[15]	-	-	-	-	-	✓	✓	-	✓	Plans, PLEXOS
[16]	-	-	-	-	-	-	✓	-	-	GE PSLF, TRELSS
[17]	✓	Ageing	✓	✓	✓	-	✓	-	-	Power-Factory, Python
Proposed	✓	-	✓	✓	✓	-	✓	-	-	PSS/E, Python

Table 2.4: Summary of previous system development PRA implementations and the proposed method for this project

historic outage data to decide the probability and expected duration of line outages. Data from the existing short- and long-term market analysis at Svk can be used to develop different operating states with the support of clustering methods, where the cluster sizes can be used to decide the probability of different states. Each operating state can then be analyzed with PSS/E, where contingency analysis can be performed, eventually including corrective actions. Corrective actions can for example be adjustment of transformer taps, generation adjustments, or load curtailment. Finally, the probabilistic assessment tool in PSS/E can be used to calculate the expected loss of load and energy not served (LOLE and EENS) for the case. The PSS/E Python

API can be used to create software that automates the method and creates a summary of the different cases and contingencies.

Chapter 3

Method

This chapter explains the method used in this master thesis project. The method is based on the method presented in GARPUR but is adapted to fit the scope of this master thesis project. The method is divided into three parts. The first part is to generate scenarios, grid models, and operating states to analyze. The second part is to perform contingency analysis at the different operating states. Finally, the reliability of the system is assessed. Figure 3.1 presents an overview of the three steps in the method. In 3.5, a small example is presented.

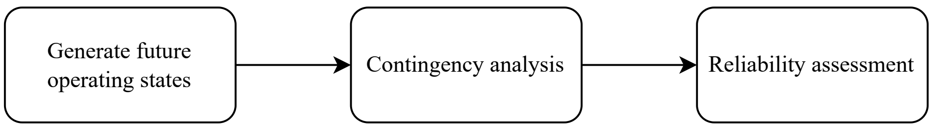

Figure 3.1: An overview of the three parts of the method

3.1 Operating state generation

The operating state development process is about constructing operating states for network studies in the form of bus-branch models. The generation of possible operating states is out of scope for this master thesis project and therefore, existing data at Svk will be used to a large extent. This section will in short describe the methods used at Svk to generate scenaros and operating states. It will also describe the methods used in this project to analyze already existing operating states.

The method used for operating state development roughly follows the scenario development process presented in GARPUR. In GARPUR [7] the process is divided into the following steps:

- Generate macro scenario
- Generate monte-carlo years for demand and renewable energy on a zonal level, so-called micro scenarios
- Market analysis, calculate cross border power flows and thermal dispatch
- Translation of demand and generation to nodal level, including clustering

The macro scenario construction is about making assumptions about the future power grid on a macro scale, for example, how much wind power will be installed and how much the consumption will grow. In this report, a single macro scenario for 2025 will be used. The macro scenario is developed by Svk and is presented in Swedish National Grid's short term market analysis (KMA) published in 2022 [23]. The macro scenario mainly includes already-known decisions and plans for 2025. For the same report, Svk have done monte carlo simulations and market analysis for the 2025 macro scenario. The method for generating this simulation data is described briefly in section 3.1.2.

The conversion of the zonal simulations results to the nodal grid model is also a task that is out of scope for this report. Therefore some existing grid operating states will be used and these will be compared to the results from the monte carlo simulations in Svk's short-term market analysis. This is further described in section 3.1.4

3.1.1 Grid modelling

The grid model is a bus-branch model of the Nordic transmission grid constructed by Svk. The data of the Swedish grid is retrieved from Svk's Grid Database (Nätdatabanken, NDB), which contains information on the grid in Svk's observability area, as defined by [24], which include parts of the regional transmission grids. The model is available for future years, where the model for each year contains the planned commissioning of grid investments for the year in question.

3.1.2 Market simulations

For KMA [23], market simulations are performed to study the expected operation of the Nordic power system in the future five years. The models for the future years are based on known plans and decisions. The simulations are performed in the software EMPS [25]. The model uses historical weather data to simulate outcomes of the future system. The weather data contains 35 historical weather years. The results from the simulations are for example the production and demand in each bidding area in the Nordic power system and the active power flow between the areas.

3.1.3 Clustering of simulation data

The market simulations mentioned in 3.1.2 is performed using weather data with hourly resolution from 35 historical years, which gives around 300 000 simulated hours for each year of study. This is a large amount of data for further analysis with power flow calculations and contingency analysis. To reduce the number of operating states to analyze, the simulation data can be clustered, as mentioned in [7]. The clustering aims to group similar outcomes to a group and use one operating state to represent all operating states in that group. The number of members of the group tells how probable the operating state is.

A method for clustering proposed in [7] is K-medoids-clustering using a Chebychev distance measure. The algorithm used in K-medoids-clustering is described in [26]. In short, the algorithm works as follows:

1. Choose k medoids of the N data points greedily, minimizing the cost function
2. Assign each data point to its closest medoid
3. Calculate if any swap between a medoid and a non-medoid data point can reduce the cost function
4. Perform the swap with the highest reduction of the cost function
5. Repeat step 3 and 4 until there is no swap that can decrease the cost function

A distance measure is used to decide which medoid is the closest one. The Chebychev distance measure between two data points x and y is calculated as

$$d_{xy} = \max_{j} |x_j - y_j| \tag{3.1}$$

where x_j and y_j is the coordinates of the data points x and y. The cost function is the sum of the distance from each data point to its assigned medoid.

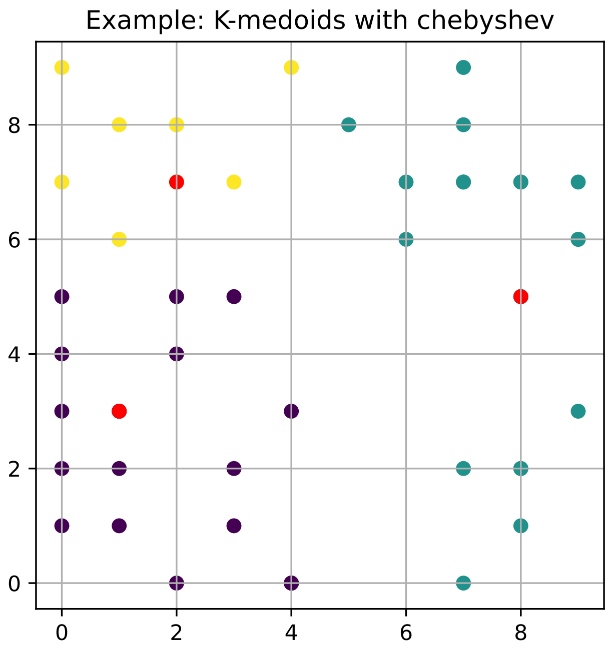

Figure 3.2: An example of K-medoids with Chebyshev distance measure and three clusters ($k = 3$). The three red dots are the medoids and the other colors show the division into three clusters

An example of K-medoids with a two-dimensional feature set and Chebyshev distance measure is shown in figure 3.2.

As mentioned in [7], it can be relevant to group the simulation data before clustering to capture correlations better. Grouping is also useful to include variations in other parameters in the risk assessment, like summer/winter ratings for lines or different failure frequencies for winter or summer. The proposed grouping is

- Day of week (Workday/weekend)
- Time of day (morning/noon/afternoon/evening/night)
- Season (Winter, Spring, Summer, Autumn)

which give in total $2 \times 5 \times 4 = 40$ groups.

The K-medoids algorithm requires the number of clusters k as a parameter. As described in [7], the monte carlo simulations of a power system with different weather years create data points that are more or less homogeneously spread, and not divided into clear clusters. This is a so-called segmentation problem rather than a clustering problem. As discussed in [27], there is no objective method for determining the right number of clusters in a segmentation problem. [27] suggests that the number of clusters can be selected to 10 % of the number of data points. This reduces the 90 % of the data while keeping the error in the range 5 - 10 % when computing for example Expected Energy Not Supplied (EENS).

In the clustering, the active power flows between the bidding areas in Sweden and from Swedish areas to adjacent areas, are used as the feature set for the clustering. There are 14 such flows, listed in table 3.1. A map showing the different bidding zones is shown in figure 3.3. The notation *from* and *to* defines positive direction power flow. Power flowing in the opposite direction is represented with a negative number.

From	To
SE1	SE2
	FI
	NO4
SE2	SE3
	NO3
	NO4
SE3	SE4
	DK1
	FI
	NO1
SE4	DE
	DK2
	LT
	PL

Table 3.1: Inter area active power flows used as feature set in the clustering. The areas are defined in figure 3.3

3.1.4 Translation from zonal to nodal model

In order to perform contingency analyzes of the different operating states, the market simulations must be translated to the bus-branch model. This is a challenging task with large uncertainty since the aggregated market simulator result lacks information about the location of production and demand within an area. The current practice at Svk is to construct the bus-branch models

Figure 3.3: Bidding areas in Sweden and adjacent areas. Source: [28]

manually and by practice make the distribution of load and production as realistic as possible. There is an ongoing research project at Svk that aims to develop a systematic method for translating market power system market simulations to the bus branch model. The software SAMNETT [29] will be used, which integrates EMPS with a transmission grid power flow model.

Because the method for zonal to nodal translation is not fully developed, some pre-defined, bus-branch operating states for 2025 are used instead of creating them from the market simulation data. These operating states were created internally at Svk by engineering assessments of challenging power flows in the Swedish transmission grid. There are 14 such operating states, described in table 3.2. The directions of the flows refer to the general flow of active power between the bidding areas in Sweden. For example, north flow means power flowing from the south of Sweden to the north of Sweden. The inter-area flows of the 14 operating states are visualized in figure 3.4.

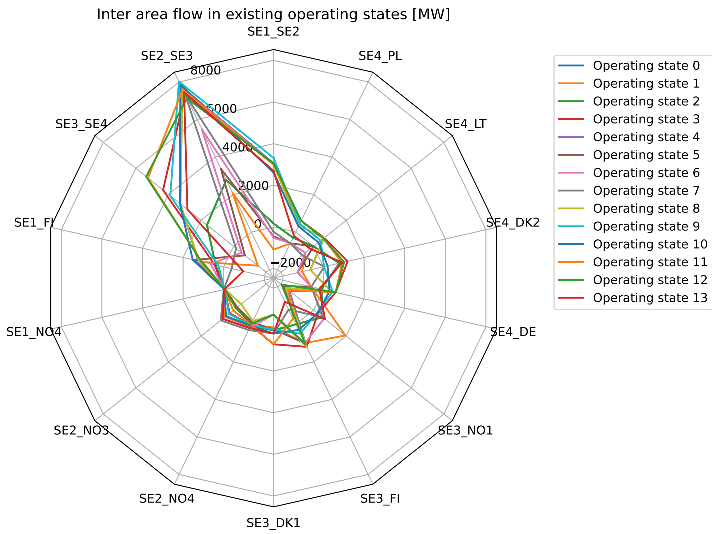

Figure 3.4: The inter-area power flows in pre-defined operating states

3.1.5 Assessing probability of pre defined operating states

For the risk assessment and comparison between different operating states, it is interesting to give a measure of how probable the different operating states are. The primary idea was to cluster data from the KMA to construct representative operating states from the medoids and decide the probability from the cluster size. But because some pre-defined operating states are used instead of constructing them from the monte carlo simulation data, that idea is not usable. However, it is interesting to assess how probable the pre-defined operating states are. For this, an alternative method inspired by K-medoids is used. The 14 operating states are assumed to represent all possible

Operating state	Description
Operating state 0	Low load - general scenario
Operating state 1	Low load with north flow and high wind
Operating state 2	Low load with south flow
Operating state 3	Low load and high hydropower production
Operating state 4	High load - general scenario
Operating state 5	High load with north-east-flow
Operating state 6	High load with north flow
Operating state 7	High load with north-west flow
Operating state 8	High load with south-east flow
Operating state 9	High load with south flow
Operating state 10	High load with south flow and much wind power
Operating state 11	High load with south flow and export to Denmark
Operating state 12	High load with south flow and import from Denmark
Operating state 13	High load with south-west flow

Table 3.2: Qualitative descriptions of the 14 pre-defined operating states

operating states for the system during one year. The probability is calculated by interpreting the operating states as medoids and then calculating how many KMA data points have the specific operating state as its closest medoid. In the same way as described in section 3.1.3, the inter-area power flows are used as the feature set to measure the distance between data points and medoids.

3.2 Contingency analysis

A contingency is a non-planned disconnection of one or more components in the system due to a fault. All contingencies to analyze are listed in a contingency list $\mathcal{C}$. In this report, three types of contingencies in the Swedish transmission grid are considered:

- Line faults
- Busbar faults
- Transformer faults

The frequency of a contingency is the expected number of occurrences per year and is calculated from the historical failure frequency of the corresponding component. The following chapters describe the calculation of failure frequency for different components. The duration numbers given in table 2.1 are in the format HH:MM:SS, and are converted to hours as

$$D = HH + MM/60 + SS/3600 \tag{3.2}$$

3.2.1 Lines

The historical failure frequency for lines in Svk's 220 kV and 400 kV grid is given in table 2.1. This is given in occurrences/km/year. The failure frequency for a line with length L is calculated as

$$F_l = f_l L \tag{3.3}$$

where f_l is the failure frequency per kilometer for the related voltage level. For 220 kV, $f_l = 0.0122\,\mathrm{km^{-1}y^{-1}}$ and for 400 kV, $f_l = 0.005\,01\,\mathrm{km^{-1}y^{-1}}$. The length L of a line is given in the NDB grid model as the length between two nodes in the grid. The duration of the faults is

$$D_{l400} = 5.0508\,\mathrm{h} \tag{3.4}$$

for 400 kV and

$$D_{l220} = 1.6981\,\mathrm{h} \tag{3.5}$$

for 220 kV.

It is assumed that most branches in the bus-branch model are lines that can be isolated by breakers, and forms independent contingencies. See the assumed configuration in figure 3.5. However, in some parts of the Swedish transmission grid, the lines are connected in a so-called T-connection. This means that one line is connected to another, without a breaker in between. This is illustrated in figure 3.6. A fault on a such line leads to the opening of all connected breakers and a disconnection from all connected substations. The T-connected parts of the grid form separate contingencies, with a failure frequency calculated from the total line length

$$L = L_1 + L_2 + L_3. \tag{3.6}$$

The T-connected parts of the grid can be identified by a specific flag in the grid model.

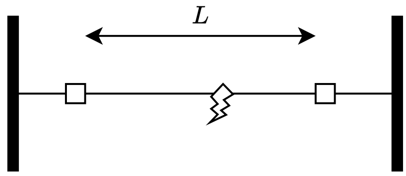

Figure 3.5: Normal line. Failure causes disconnection from both substations

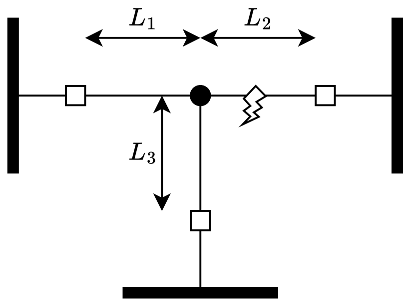

Figure 3.6: An example of a T-connected line. Failure causes disconnection from all three substations

3.2.2 Transformers

Failures in 400/220 kV transformers are considered in the contingency analysis. It is assumed that the transformer can be isolated by breakers on both the high voltage and low voltage side, see figure 3.7. The failure frequency of such faults is given in table 2.1 as

$$F_t = 0.0222\,\mathrm{y}^{-1} \tag{3.7}$$

and the duration

$$D_t = 0.1083\,\mathrm{h} \tag{3.8}$$

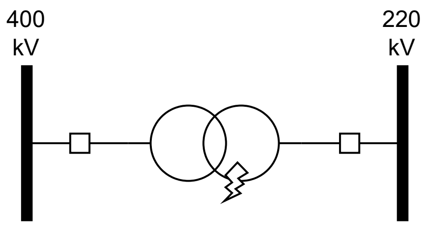

Figure 3.7: 400/220 kV transformers are included in the contingency analysis. Failure causes disconnection from both busbars

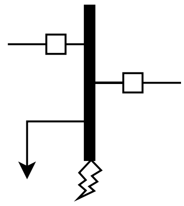

Figure 3.8: Busbar failure in single breaker substations. Causes disconnection of all connected devices

3.2.3 Busbars

Most substations in the transmission grid have a double breaker configuration. It means that a fault in one busbar under normal operating conditions doesn't cause disconnection of any lines or load. A busbar fault in a single breaker configuration, however, leads to the disconnection of all connected equipment, see figure 3.8. Only busbar faults in single breaker substations are considered in this report. The failure frequency and fault duration for busbars in $220\,\mathrm{kV}$ and $400\,\mathrm{kV}$ substations is given in table 2.1 as

$$F_{b220} = 0.0173\,\mathrm{y}^{-1} \tag{3.9}$$

$$D_{b220} = 1.4683\,\mathrm{h} \tag{3.10}$$

for $220\,\mathrm{kV}$ substations and

$$F_{b400} = 0.0269\,\mathrm{y}^{-1} \tag{3.11}$$

$$D_{b400} = 3.4214\,\mathrm{h} \tag{3.12}$$

for $400\,\mathrm{kV}$ substations.

3.3 Reliability assessment

3.3.1 Loss of load

The definitions for PLC, EDLC, and EENS in this section are based on [1]. The constant T represents the number of hours in one year and is used to convert values between probability and hours per year. The value is

$$T = 8760\,\mathrm{h} \tag{3.13}$$

Let S_{LC} denote all system states with load curtailments, i.e. all contingencies that lead to loss of load. The Probability of Load Curtailments (PLC) is defined as

$$PLC = \sum_{i \in S_{LC}} p_i \tag{3.14}$$

where p_i is the probability of state i.

The probability of the system state i is calculated as

$$p_i = p_{os} p_c \tag{3.15}$$

where p_{os} is the probability of the pre-contingency operating state and p_c is the probability of the contingency associated with the system state i. The probability of a contingency c is calculated as

$$p_c = \frac{F_c D_c}{T} \tag{3.16}$$

where F_c is the failure frequency expressed in hours per year and D_c is the average duration per fault.

The Expected Duration of Load Curtailments (EDLC) expressed in hours per year is calculated as

$$EDLC = PLC \cdot T \tag{3.17}$$

The EENS expressed in MWh per year is calculated as

$$EENS = \sum_{i \in S_{LC}} p_i P_i T \tag{3.18}$$

where P_i is the power of the lost load.

The reliability values can also be expressed for a specific system state i, for example,

$$EENS_i = p_i P_i T \tag{3.19}$$

and

$$EDLC_i = p_i \cdot T \tag{3.20}$$

3.3.2 Line overload

In the NDB grid model, the thermal rating of lines, including limiting components, is given. Four different rates are given, calculated for summer and winter conditions, and for normal and disturbed operations. The rate for the disturbed operation is normally higher than the value for normal operation and is allowed for 15 minutes. For this report, rate B is used, which means disturbed operation during winter conditions.

If a contingency causes a current higher than rate B in any line in the transmission grid, a line overload is registered. The set of system states with overloads is denoted S_{OL}. The Expected Duration of Overloads (EDOL) is defined as

$$EDOL = T \sum_{i \in S_{OL}} p_i \tag{3.21}$$

where p_i is the probability of the state i. The probability is calculated in the same way as for loss of load, see equation 3.15.

3.3.3 Islanding

It is assumed that islanding of the power grid is not allowed. If a contingency creates an island that is not connected to a slack bus, all devices in that island are disconnected. This means that all eventual load in the island is lost. With the introduction of microgrids, island operation of power grids may be more common and a disconnection from the transmission grid may not cause disconnection of customer load. But from a transmission grid perspective, this can still be interpreted as a disconnection.

3.4 Health index

The connection of new production and consumption to the system, or investments like new power lines, affects the reliability of the system. To be able to compare different alternatives, it is relevant to have an aggregated measure of the system's reliability. A method inspired by [30] is used. In that report, energy security in different countries is expressed in 20 different metrics. The metrics are converted into a 0-100 scale for each year in the study, and then a mean along the 20 metrics is calculated. Finally, the score of five years was summarized, generating an overall score between 0 and 500 for each country.

In this report, the three reliability measures are scored on a scale of 0-1 and summarized, generating a comparison index between 0 and 3. The index is relative and can be used to compare different alternatives in a study, regarding system reliability. The method for calculation is:

1. Determine which scenario and investment results in the highest and lowest EDLC, EENS, and EDOL

2. Subtract EDLC, EENS, and EDOL with the lowest of each value, and divide with the maximum value, generating scores in the interval 0-1
3. Invert the scale, such that 0 corresponds to the worst case (highest EDLC, EENS, and EDOL) and 1 the best (lowest EDLC, EENS, and EDOL)
4. Summarize the three scores for each scenario and investment to get the health index
5. Calculate the composite health index for each investment, by calculating the weighted sum of the health index for all operating states and that specific investment

3.5 Reliability assessment example

Figure 3.9 shows an example of a network with six buses, three loads, one transformer, three regular lines, and one T-connected line. Bus E and F are single breaker substations and therefore include busbar faults. The input parameters and frequency and duration of all considered contingencies are shown in table 3.3. The lost load caused by the contingencies is shown in table 3.4.

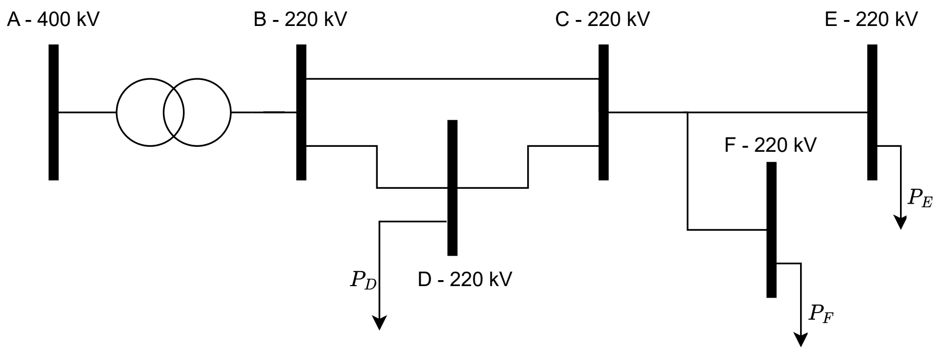

Figure 3.9: An example network for contingency analysis

A single operating state with probability $p_{os} = 1$ and $P_D = 100MW$, $P_E = 50MW$, $P_F = 20MW$, gives the EENS-values presented in table 3.5.

Id	Type	Buses	V [kV]	L [km]	F [per y]	D [h]
1	Line	B-C	220	25	0.3050	1.6981
2	Line	B-D	220	10	0.1220	1.6981
3	Line	D-C	220	20	0.2440	1.6981
4	T-Line	C-E-F	220	40	0.4880	1.6981
5	Busbar	E	220	-	0.0222	1.4683
6	Busbar	F	220	-	0.0222	1.4683
7	Transformer	A-B	400	-	0.0173	0.1083

Table 3.3: Example contingency list

Id	Lost load P	$EDLC_i$ [h/year]
1	-	0
2	-	0
3	-	0
4	$P_F + P_E$	0.8287
5	P_E	0.0326
6	P_F	0.0326
7	$P_D + P_E + P_F$	0.0019

Table 3.4: Loss of load for contingencies in 3.3

Id	Lost load P	$EENS_i$ [MWh/year]
4	70 MW	58.0056
5	50 MW	1.6299
6	20 MW	0.6519
7	170 MW	0.3186

Table 3.5: Expected energy not supplied for contingencies in 3.3

3.6 Software implementation

The clustering of operating scenarios using the Python library *kmedoids* [31] and all plots are produced with *matplotlib.pyplot* [32].

An overview of the software algorithm for contingency analysis and reliability assessment is shown in figure 3.10. The software is implemented in Python and uses PSS/E and its Python Application Programming Interface (API) for contingency analysis. The probability for each contingency is loaded into PSS/E, and the reliability assessment module is used to calculate the probability of line overloads and loss of load. The contingency and reliability result for each case is saved in a Python pandas data frame and exported to

Excel for further inspection and analysis.

All software is executed on an HP laptop with a 12th Gen Intel Core i5-1235U CPU and 16 GB RAM.

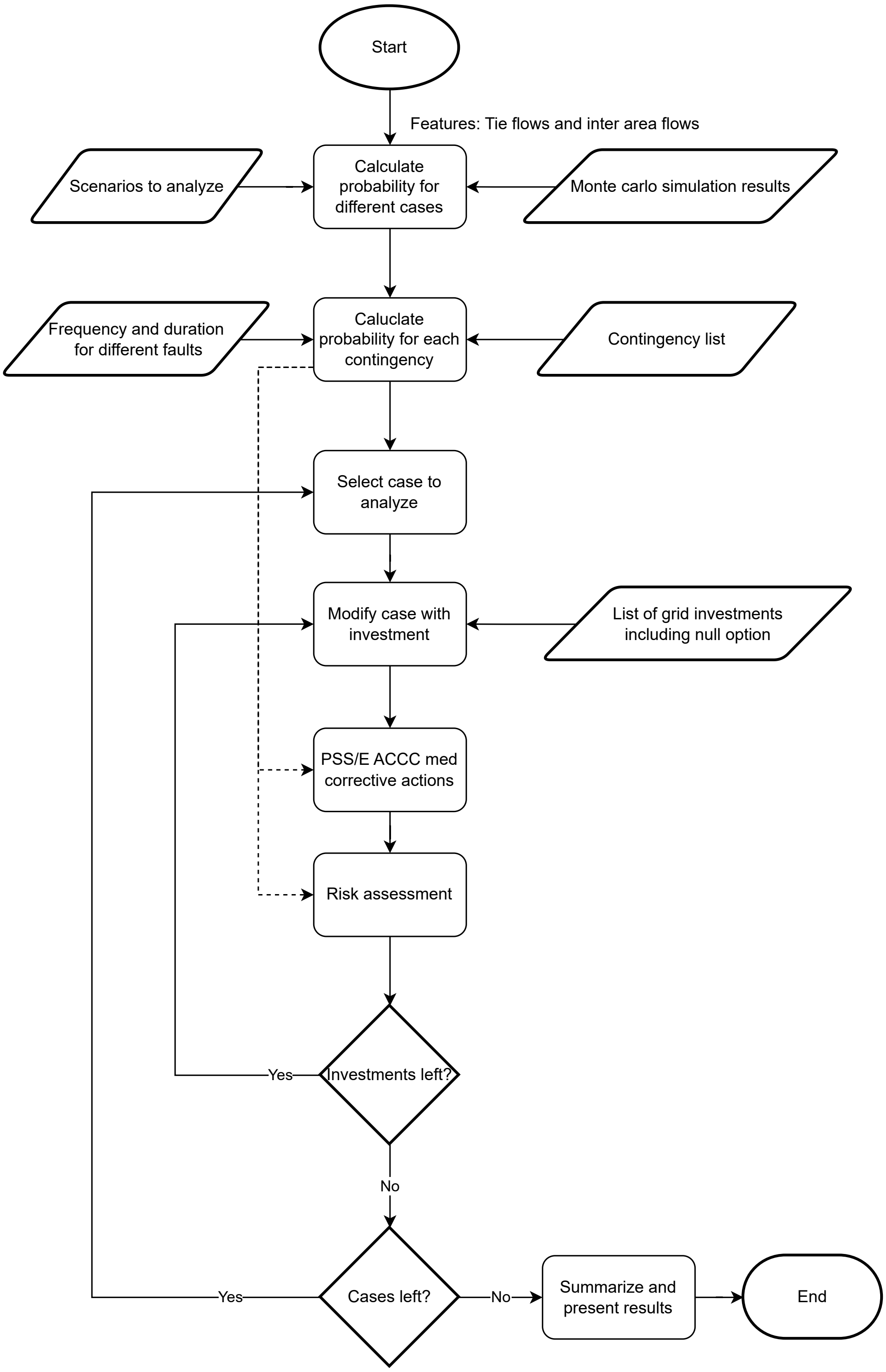

Figure 3.10: Software algorithm for contingency analysis and reliability assessment

Chapter 4

Results and analysis

4.1 Clustering of market simulation data

The data from the market simulations mentioned in section 3.1.2. was grouped into 40 groups and clustered three different numbers of clusters, $k = 0.01N$, $k = 0.05N$, and $k = 0.1N$ where N is the number of data points in the group before clustering. The number of data points in each cluster for the group winter-workday-morning with $k = 0.01N$ is plotted in figure 4.1. The runtime of the clustering algorithm was 88 s for $k = 0.1N$ and 57 s for $k = 0.01N$. The cost function and the maximum Chebyshev distance for the winter-workday-morning group for different k-values are shown in table 4.1

k	Maximum distance	Cost function
$0.1N$	1222.81	3 540 558.47
$0.05N$	1925.19	5 270 261.42
$0.01N$	2607.69	5 947 986.92

Table 4.1: Maximum chebyshev distance and K-medoid cost function for KMA data. Group: winter-workday-morning

To assess how well medoids represent the data points in the group, a duration curve for the inter-area flow between two areas were plotted, see figure 4.2. As seen, the cluster medoids cannot represent situations with power flow from SE2 to SE3 below 3500 MW. These situations are rare in the KMA simulation data and happen less than 1 % of the time. This may be acceptable given that the data size is reduced by 99 % ($k = 0.01N$). If the number of clusters is $k = 0.1N$, the snapshots between 1000 and 7000 MW are well represented in the cluster medoids, see figure 4.3.

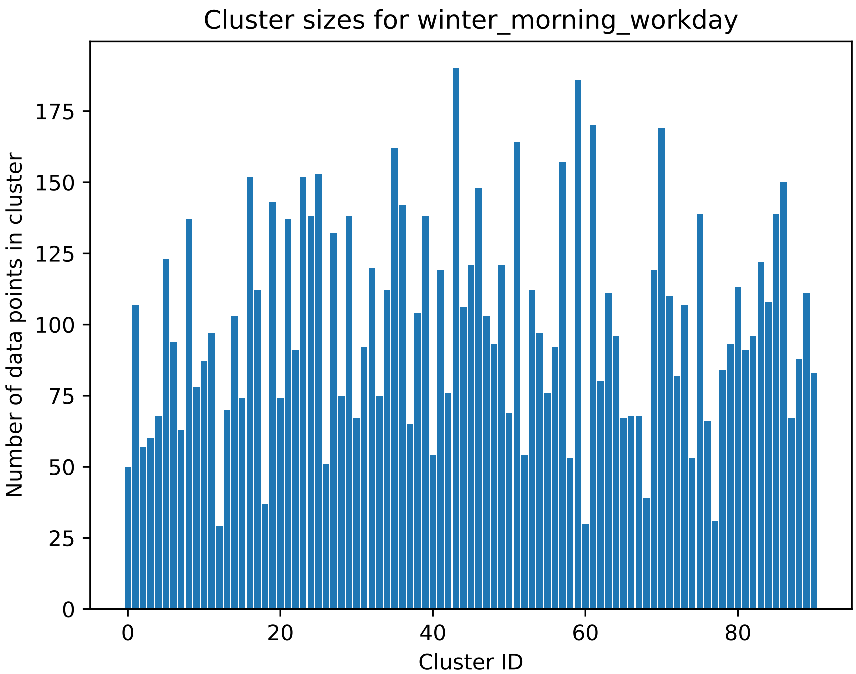

Figure 4.1: Cluster sizes for group winter morning workday. $k = 0.01N$

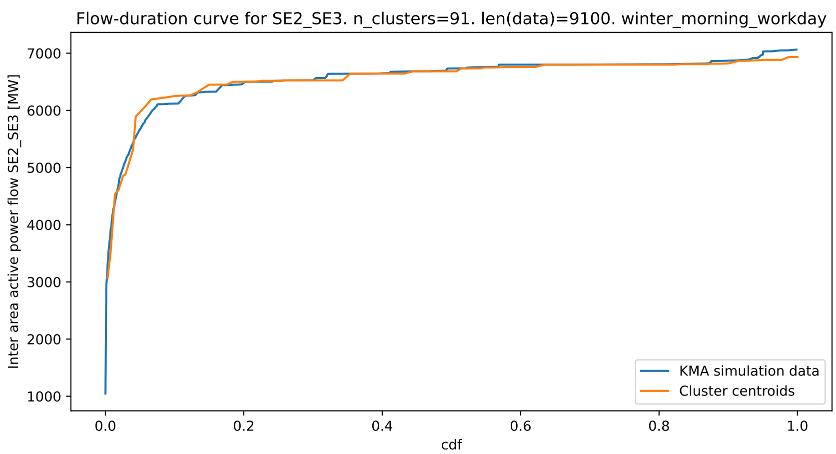

Figure 4.2: Load duration curve for 91 cluster centroids and KMA simulation data. Group: winter morning workday.

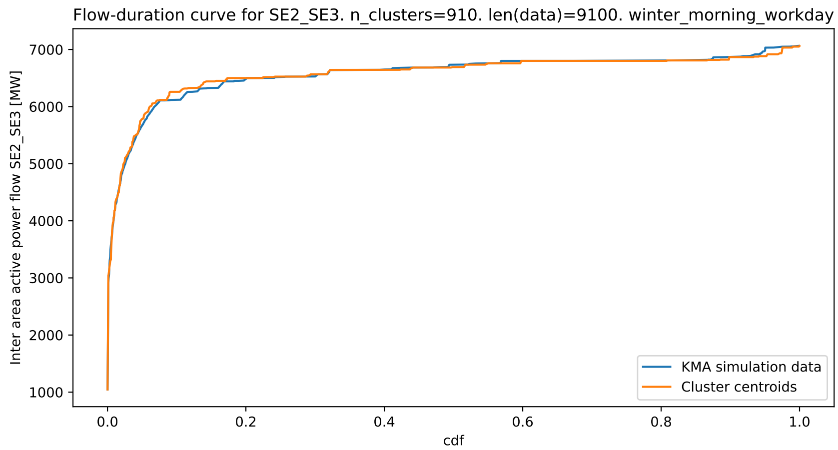

Figure 4.3: Load duration curve for 910 cluster centroids and the KMA simulation data. Group: winter morning workday

4.2 Probability of existing scenarios

The probability of the 14 scenarios was calculated using the method described in 3.1.5. The results are presented in table 4.2. The operating state with the highest probability has 25.64 % and the lowest has 0.45 %.

Operating state	Probability
Operating state 10	0.2564
Operating state 3	0.1670
Operating state 0	0.1446
Operating state 2	0.1400
Operating state 13	0.0935
Operating state 12	0.0486
Operating state 8	0.0357
Operating state 9	0.0259
Operating state 7	0.0233
Operating state 11	0.0222
Operating state 1	0.0176
Operating state 6	0.0142
Operating state 4	0.0066
Operating state 5	0.0045

Table 4.2: Calculated probability of existing 2025 scenarios, according to the method in section 3.1.5

4.3 Reliability assessment of existing operating states

The software algorithm presented in 3.6 was executed on the 14 scenarios with no additional grid investments. The resulting EENS, EDLC, and EDOL values for the system are presented in table 4.3. The results for each operating state are plotted in figure 4.4, 4.5, and 4.6.

The grid topology and contingency list are the same in all operating states, and the same failure probabilities and duration are used for the operating states. Therefore, the probability of outage at all individual buses, and hence EDLC, should be the same in all operating states. However, as seen in figure 4.5, EDLC in the low load operating states (operating state 0-3) is lower than in the high load operating states (operating state 4-12). The reason is that PSS/E seems to discard curtailments of small loads in the reliability assessment module. In the high load operating states, all detected buses with loss of load have a load higher than 1 MW. At the low load operating states, some of these buses have a load less than 1 MW, and they are not registered as loss of load. So the probable explanation is that PSS/E discards load curtailments below 1 MW.

Measure	Base case	Unit
EENS	297.28	MWh/year
EDLC	24.82	h/year
EDOL	7.98	h/year

Table 4.3: Resulting weighted measures for the system with 14 operating states, without any investments (base case)

4.4 Testing grid investments

The algorithm was tested with 5 different applications or investment alternatives:

1. Add a 100 MW firm load at a bus in the radial grid in SE2
2. Add a 220 kV line between the bus in investment 1 and an adjacent bus
3. Investment 1 in combination with investment 2
4. Add 500 MW or 1000 MW firm generation in the meshed grid in SE2

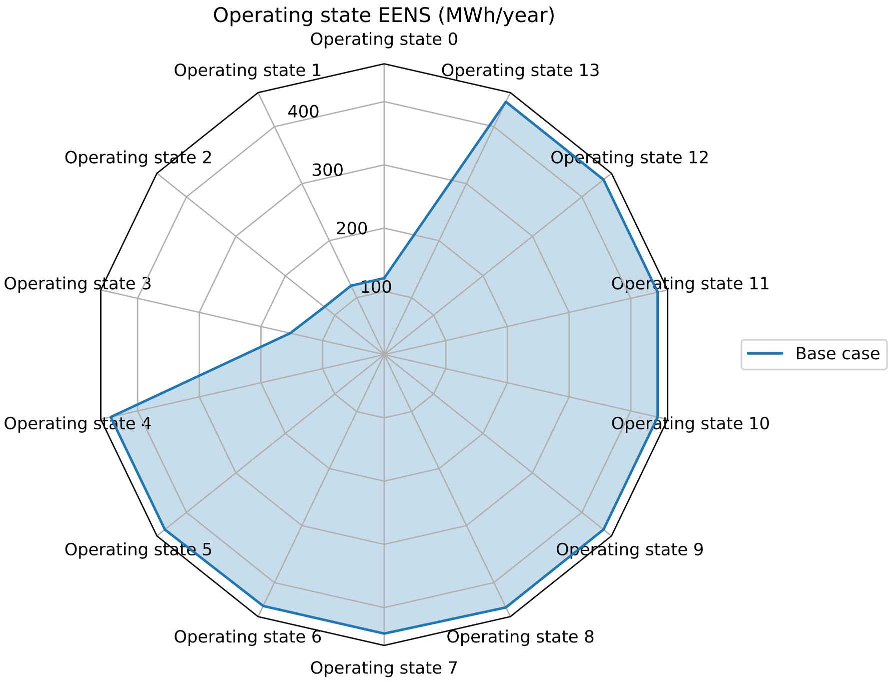

Figure 4.4: Calculated EENS for the different operating states

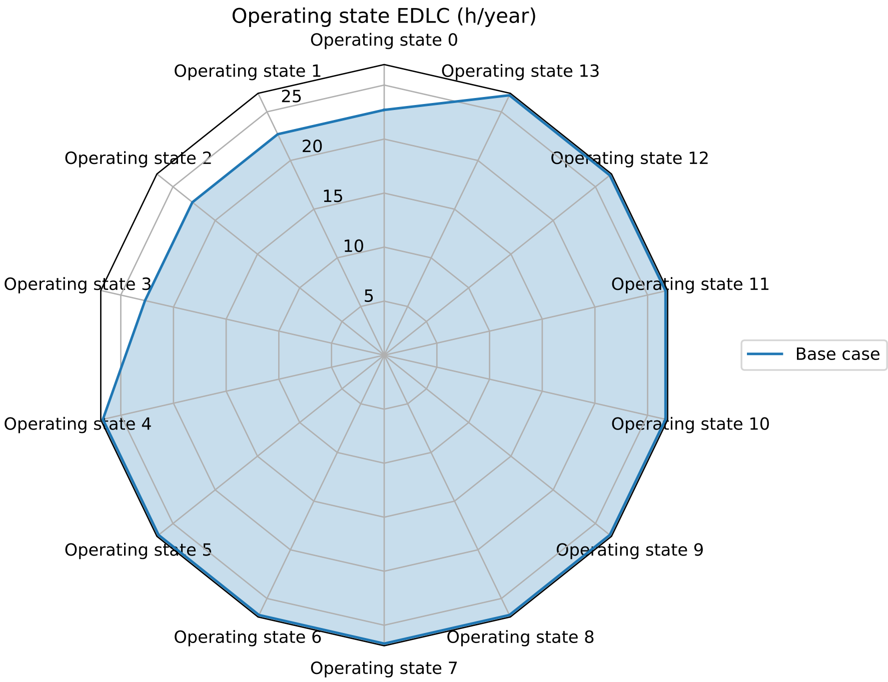

Figure 4.5: Calculated EDLC for the different operating states

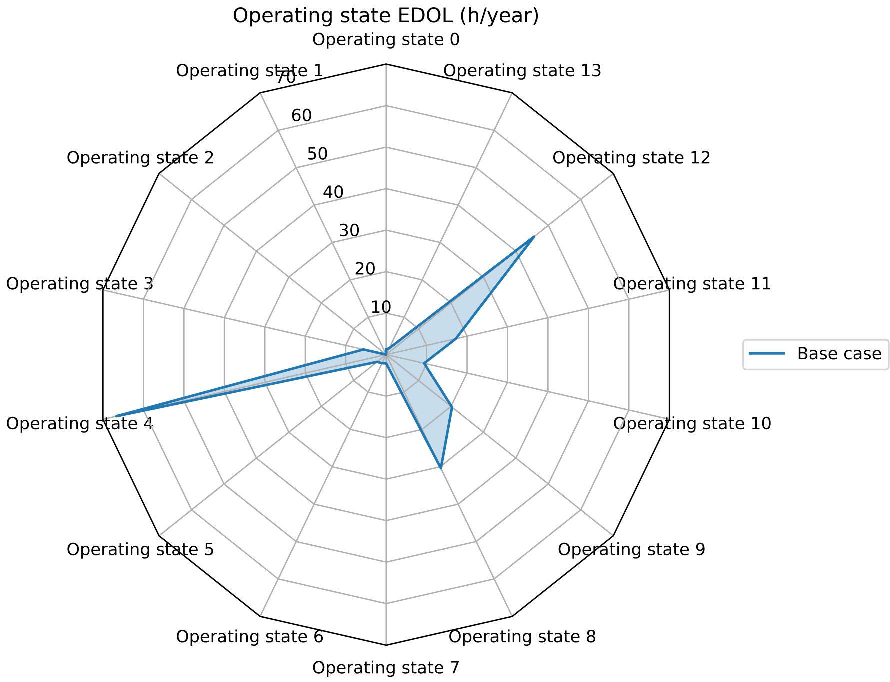

Figure 4.6: Calculated EDOL for the different operating states

The first alternative represents an application from an industry that wants to connect to an existing connection point in the 220 kV transmission grid. The is located in a radial part of the transmission grid with the highest EDLC (6.4060 h/year). The load is modeled as a firm load, meaning the power is constant 100 MW in all operating states. Alternative 2 aims to lower the EDLC value of the bus in investment 1, by building a new line to a neighboring bus. This makes the grid redundant. The third alternative is a combination of investments 1 and 2 and aims to represent a situation where a new connection to the grid is combined with grid reinforcements.

Alternative 4 is independent of the other three and represents an application to connect 1000 MW generation to a bus in the meshed 400 kV grid. This generation is modeled as a firm generation, which means that the power is constant in all operating states. The 500 MW alternative is used as a reference to see if it has a higher or lower impact on the transmission grid.

The alternatives with added load or generation in the system are balanced by scaling the power in all generators in the bidding area (SE2), such that the net import/export is unchanged.

The runtime for the algorithm with the 4 investments, 14 operating states, and 900 contingencies was 13 minutes. The results for the different investments are presented in the following subsections.

4.4.1 Investment 1

The result for investment 1 is presented in table 4.4. The investment mainly affects EENS, since the added load is located in a bus with a high outage probability, which means that the non-served energy to the newly added load is high. Since the added load is 100 MW in all operating states, EENS is increased in all of them, as seen in figure 4.7. EDLC is not affected, which is expected since the topology of the grid is not changed. The overload is slightly increased, due to changes in the power flowing in the network.

Measure	**Base case**	**Investment 1**	**Unit**
EENS	´297.28	937.90	MWh/year
EDLC	24.82	24.82	h/year
EDOL	7.98	8.56	h/year

Table 4.4: Resulting weighted measures for the system with 14 scenarios, with investment one

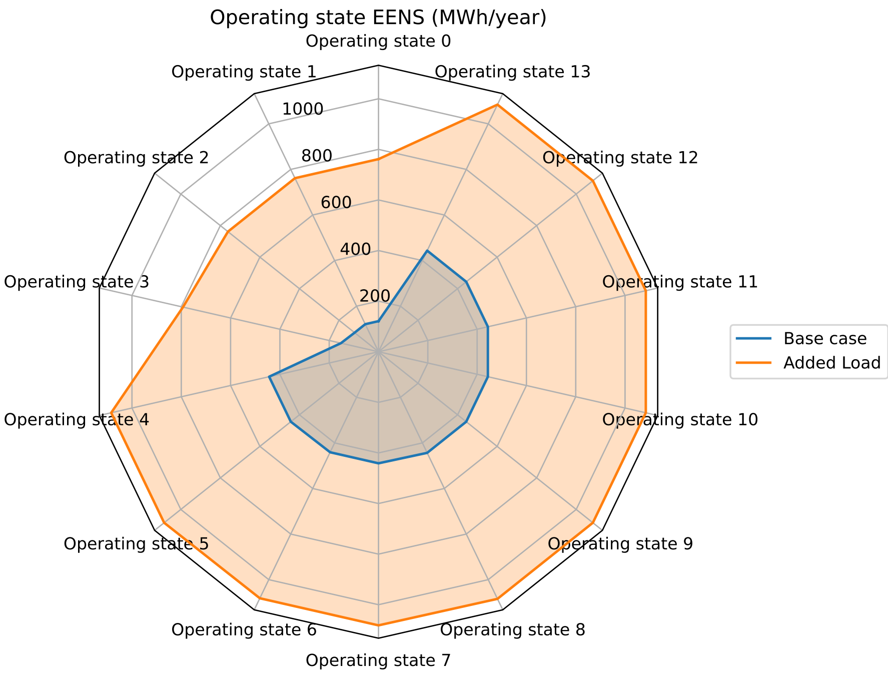

Figure 4.7: EENS for the different operating states, with investment 1 and without investments

4.4.2 Investment 2

The result for investment 2 is presented in table 4.5. EENS is decreased, due to the decrease in EDLC, see figure 4.8. EDLC is decreased since the investment creates redundancy for the involved buses.

Measure	Base case	Investment 2	Unit
EENS	297.28	174.30	MWh/year
EDLC	24.82	18.42	h/year
EDOL	7.98	7.86	h/year

Table 4.5: Resulting weighted measures for the system with 14 scenarios, with investment two

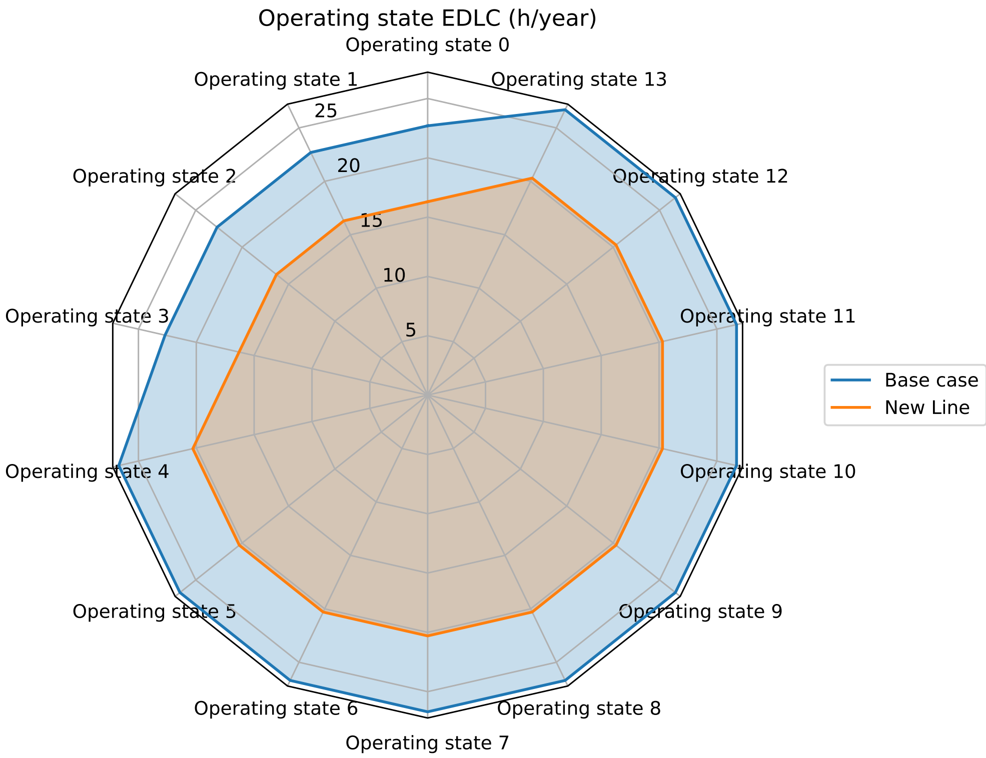

Figure 4.8: EDLC for the base case and with investment 2

4.4.3 Investment 3

This investment is a combination of investments 1 and 2. The results are shown in table 4.6. EENS and EDLC is the same as for investment 2, but the EDOL is increased

Measure	Base case	Investment 3	Unit
EENS	297.28	174.30	MWh/year
EDLC	24.82	18.42	h/year
EDOL	7.98	8.63	h/year

Table 4.6: Resulting weighted measures for the system with 14 scenarios, with investment three

4.4.4 Investment 4

Investment 4 shows an example of an application from a firm generation, that connects to a substation in the meshed 400 kV transmission grid. 500 and 1000 MW feed in is analysed. The results are shown in table 4.7 and in figure 4.9. EENS and EDOL are not affected, which is expected since the grid topology and load levels are unchanged. The overload changes due to the changed flow in the grid. Figure 4.9 shows that operating state 13 results in more overloads with the increased feed-in power. Operating state 11 shows the opposite, fewer hours with overloads with increased generation power. The weighted results in table 4.7 show that 500 MW firm power reduces the expected overloads and that 1000 MW increases the expected overloads.

Measure	Base case	500 MW	1000 MW	Unit
EENS	297.28	297.32	297.38	MWh/year
EDLC	24.82	24.82	24.82	h/year
EDOL	7.98	6.99	9.84	h/year

Table 4.7: Resulting measures for the system with 14 operating states, with investment four (500 or 1000 MW feed-in)

4.5 Health index

The maximum and minimum values of the reliability measures among all operating states and investments are shown in table 4.8. The health index for each operating state and investment was calculated according to the method described in section 3.4.

The resulting health indices are shown in figure 4.10. The results indicate for example that investment 1 (Added load) makes the system health worse for

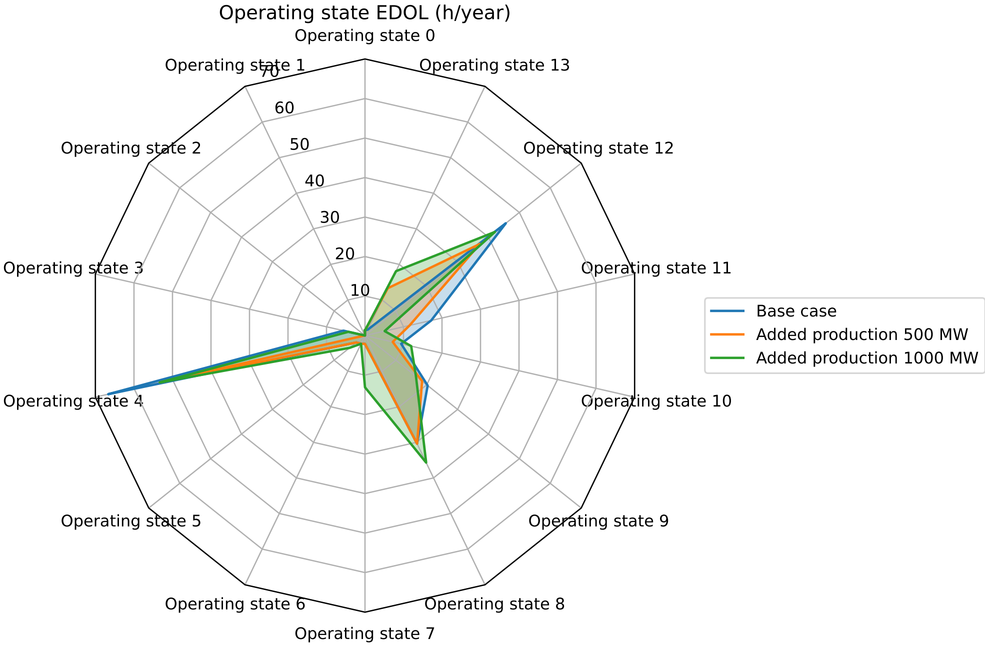

Figure 4.9: EDOL for the base case and with investment 4 (500 or 1000 MW feed-in)

Measure	Max	Min	Unit
EENS	1084.24	70.6	MWh/year
EDLC	26.7	16.3	h/year
EDOL	66.80	0	h/year

Table 4.8: Maximum and minimum values among the operating states and investments

all analyzed operating states. It also indicates that the most critical operating state among all investments is operating state 4. Another indication is that investment 4 leads to similar health or health improvements in all operating states except operating state 13, where it shows to be worse than the base case.

The aggregated health index for each investment, weighted by the operating state probabilities is shown in table 4.9. This indicates that the new line (investments 2 and 3) gives a big positive impact on the system's health, over the base case. The results also indicate the load increase in investment 3 gives a relatively small impact on the overall health compared to investment 1. Finally, the health indices indicate that a firm load of 500 MW (investment 4) gives a slight improvement in the system health while 1000 MW makes the health index slightly lower.

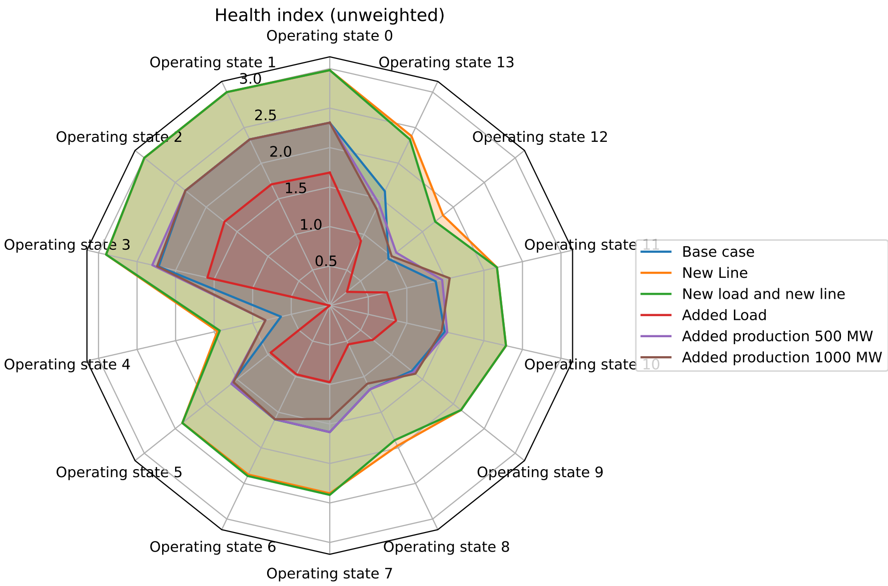

Figure 4.10: Health index for all operating states and investments

Investment	Health index
Investment 2	2.58
Investment 3	2.56
Investment 4 (500 MW)	1.85
Base case	1.84
Investment 4 (1000 MW)	1.81
Investment 1	1.20

Table 4.9: The health index of the different investment alternatives

Chapter 5

Discussion

In this chapter, the method and the results are discussed, regarding performance, relevance, and validity.

5.1 Operating states

The method for generating operating states was not fully tested in this master thesis project, since a fully developed tool for translation from market simulations to full-scale bus-branch models was missing. For example, the benefits of grouping the market simulation data before clustering could not be evaluated. However, the clustering algorithm itself was successfully tested and shows an example of how the operating states can be selected when the tool for zonal-to-nodal conversion is fully developed.

The selection of k (the number of clusters) is a parameter that can be varied depending on the needs. The tests showed that a higher k gives clusters with smaller internal deviation, but on the other hand, gives more operating states to analyze in the next steps in the method. More testing and evaluation must be performed in order to decide what is a reasonable number of clusters.

The next steps in the method were tested with 14 pre-defined operating states, which were limited in terms of load level variation. Four of the operating states had low load (operating state 0-3) and the other ten operating states had high load (operating state 4-13). The high-load operating states are originally constructed from a scenario with the expected maximal load during a normal winter. The probability calculation in section 4.2, which uses inter-area flows was used to assess the probability, shows that the high load operating states (4-13) have a joint probability of $54\,\%$. It is important to note that these probability values try to represent the probability of a flow pattern in the grid and not the load level. So therefore, when the probabilities are used to calculate EENS values, which are strongly connected to load levels, the results are somewhat misleading. This can be solved by using more operating states and ensuring that they cover different load levels. With the proposed grouping of operating states, mentioned in section 3.1.3, this problem is reduced, since at least the seasonal and time-of-day variation of loads are reflected in the operating states.

The load equivalents in The Network Database (Nätdatabanken, NDB) is not always actual loads, but equivalents of the underlying grids at lower voltages. Such grids can contain both load and generation, which means that the actual loss of load due to the disconnection of a bus modeled with a load, may not fully correspond to the actual end-user disconnection. So the EENS should not be interpreted as load curtailment of end customers, but the curtailment of the transmission grid's expected delivery to the underlying grid.

5.2 Contingency analysis

In the contingency analysis, only single faults in busbars, lines, and transformers are considered. This means that not all possible faults in the system are considered. According to the DISTAC report [22] for the years 2012–2021, only 63 % of the faults in Sweden are line or cable faults, 1 % of the faults are busbar faults and 5 % of the faults are transformer faults, summing up to 69 %. 12 % of the faults in DISTAC are reported as control equipment faults and 5 % as failures in Compensation devices etc. Such problems are not considered in this master thesis project. Another limitation in the contingency analysis is that HVDC links are assumed to have no downtime. The limitations in the contingency analysis mean that the reliability assessment may underestimate the risk of outages and overloads.

Another limitation in the contingency analysis is that cables and overhead lines are not separated, and the same failure frequency is used for both. According to the DISTAC report [22], the frequency of faults in cables was $0.0275\,\mathrm{km}^{-1}$ and over head line faults $0.0034\,\mathrm{km}^{-1}$ during the period 2012-2021. It is still quite a few cables in the Swedish transmission grid, but with increased cabling, it may be important to take into account the difference in failure probability between cables and overhead lines.

The contingency analysis method is somewhat limited, as the loss of generation or load is primarily compensated at the slack bus, which may not be fully realistic. In reality, units in the Frequency Containment Reserve (FCR-N or FCR-D) is used as primary control, which means that the change in load or generation is initially compensated by many units distributed in the system. Also, overloads in the system are typically not allowed, meaning that the control room has to take actions to resolve the problem, often called corrective actions. This can involve curtailment of load and production, affecting EENS.

5.3 Reliability assessment

In the reliability assessment, loss of load and line overloads is considered. In reality, there are more reliability measures that are relevant for power system analysis. For example, the operating of a power system isn't just about currents, but also voltages. For power producers, indexes of production curtailment can also be a relevant measure.

The method in this report shows a way to measure reliability but can't tell which system risk that is acceptable or not. For this, some kind of socio-economical analysis must be performed that results in target values of the system reliability. As a reference, such targets do already exist for resource adequacy, i.e. the ability to meet the demand with generation and import. The Swedish Energy Markets Inspectorate (Energimarknadsinpektionen) has calculated that the theoretical socio-economically optimal level of security of resource adequacy is 0.99 hours per year [33]. This value is used to decide the need for a strategic reserve or other capacity mechanisms. A similar value for system reliability would be necessary if the deterministic N-1 criterion should be replaced by a probabilistic one.

5.4 Software implementation

The software algorithm was implemented in Python and uses PSS/E and its API for power flow and contingency analysis. The probabilistic indexes were partly calculated using PSS/E, by using the module *Reliability Assessment*, where frequencies and duration of the contingencies and the results from the contingency analysis were used as input parameters. It is worth noting that the *Reliability Assessment* module was quite unstable, and often caused PSS/E to crash without any error messages.

5.5 Health index

The implementation of the health index showed an example of how a composite index for reliability assessment could be defined. The way the health index is defined in this report may have limited usage, as it is a relative measure dependent on which alternatives that are included. The value is not useful for comparisons over time or between different studies. With a decided reliability criterion, as discussed in section 5.3, it would be possible to change the health index definition, to measure the reliability relative to the reliability target. For example, a positive index if a variable is better than the target, and a negative if it is worse. That would make the index more useful for individual studies and make the measure comparable among studies and over time.

5.6 Test of grid investments

In the results chapter, some investments were tested to evaluate the performance of the method. In the first investment, 100 MW firm load was added to a bus with expected load curtailment of 6.4060 h/year, which means that the EENS for the system would increase with about 640 MWh/year. This is confirmed by the measured EENS, which increases from 297 MWh/year to 937 MWh/year.

Investment 2 was about adding a line between to radial parts of the transmission grid, which is expected to reduce the EDLC from 6.4060 h/year to 0 h/year. The resulting system EENS is reduced from 297 MWh/year to 174 MWh/year, which means 123 MWh/year in decreased EENS. The load at the bus with the redundancy is 28 MW in the high-load operating states, and between 8 and 10 MW in the low-load operating states, which means that the decrease in EENS is as expected.

Chapter 6

Conclusions and Future work

6.1 Conclusions

This master thesis project has presented a method for transmission expansion planning that includes probabilistic measures for the risk of load curtailment and overloads. Historical failure frequency and average fault duration for lines, busbars, and transformers have been used for the calculation. The method has been successfully tested on a PSS/E model of the Swedish transmission grid for the year 2025, and 14 different operating states. The method has been tested with added firm load and firm production, to show how the method can be used to study applications of connecting to the transmission grid. The conclusion is that the second and fourth goals in section 1.4 are fulfilled.

The current internal processes at the network development unit Svk has been used as a foundation when designing the method in this master thesis project. This means that the presented method is highly compatible with current internal processes. However, there are some changes required, primarily regarding mapping outage statistics to the contingency analyses and the change of reliability criterion from the deterministic N-1 criterion. As discussed in 5.3, a reliability criterion that can replace the N-1 criterion is not available. So the conclusion regarding the third goal in section 1.4, is that further development of PRA must be done before changing the processes, but that the method presented in this master thesis can be used as a complementary tool supporting the transmission expansion planning.

Regarding the first goal in section 1.4, it is hard to say if the method is fully compatible with ENTSO-E's and ACER's requirements, as the requirements referred to (CSAM) mainly apply to shorter-term analysis, up to one year ahead, see section 2.3. The scope of this project is transmission expansion planning, or system development, which has a longer time horizon than the method developed in CSAM. In addition to that, the method in CSAM is under development, so it is at the time of writing hard to make conclusions about similarities and differences between the method in this master thesis project and CSAM.

6.2 Future work

6.2.1 Test the method with more operating states

The method in this report was tested with just 14 operating states, that had limited variation in for example load level. As a first step in future work, the method should be tested and verified with more operating states.

6.2.2 Economical analysis

The PRA method in this master thesis project can be used to compare different investment alternatives in the grid, in terms of power system reliability. One limitation is that the cost of investments and economic benefits of connecting more load or generation is not included. In order to use PRA for socio-economic optimization, an economic analysis must be included.

6.2.3 Weather data in the PRA-algorithm

The market simulations mentioned in 3.1.2 use weather data to construct possible operating states for the system. This weather data could be stored together with the operating states, which enables the possibility to use weather data for more purposes in the PRA-algorithm. For example, the weather data can be used for utilizing weather-dependent failure rate of lines, where for example high winds may increase the probability of short circuits in overhead lines. Weather data could also be used for dynamic line rating, where the capacity of lines is changed according to wind speed and temperature.

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