Master's Thesis

Net Position Forecast of Week-Ahead and Day-Ahead Common Grid Models

Towards improving the coordinated capacity calculation and outage planning coordination process of transmission system operators in Europe by means of machine learning forecast modeling and load flow calculation – A case study of the coupled German, Danish, and Luxembourg bidding zone

In partial fulfillment of the requirements for the degree
Master of Science in Power Engineering
at the Department of Electrical and Computer Engineering
School of Engineering, Technical University of Munich.

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Abstract

Since 1996, due to a series of European Union regulations, the European electricity market has evolved from being controlled by national monopolies to becoming more liberalized and interconnected. These changes allow for an increased cross-border flow of electricity across Europe and increased market liquidity. The benefits include a more flexible market, making it easier for end-users to plan and secure electricity capacities well in advance, from day-ahead to real-time delivery. Due to the increased interconnectivity of the European grid, the need for both regional and Pan-European cooperation among Transmission System Operators (TSOs) led to the creation of entities like the European Network of Transmission System Operators for Electricity (ENTSO-E) and the Regional Coordination Centres (RCCs). This thesis focused on investigating the current forecasting approach used to perform Net Position Forecast (NPF) within the Day-Ahead and Week-Ahead common grid models (CGMs) used by RCCs to deliver the Day-Ahead Capacity Calculation and the Week-Ahead Outage planning Coordination services to the TSOs. The results show the associated errors from all the existing NPF methods and implemented a new methodology that was used to perform NPF for both the Day-Ahead and the Week-Ahead use cases.

Zusammenfassung

Seit 1996 hat sich der europäische Strommarkt aufgrund einer Reihe von EU-Verordnungen von der Kontrolle durch nationale Monopole hin zu einer stärkeren Liberalisierung und Vernetzung entwickelt. Diese Veränderungen ermöglichen einen verstärkten grenzüberschreitenden Stromfluss in ganz Europa und eine höhere Marktliquidität. Zu den Vorteilen gehört ein flexiblerer Markt, der es den Endverbrauchern erleichtert, Stromkapazitäten weit im Voraus zu planen und zu sichern, von der Day-Ahead- bis zur Echtzeitlieferung. Aufgrund der zunehmenden Vernetzung des europäischen Netzes führte die Notwendigkeit einer regionalen und europaweiten Zusammenarbeit zwischen den Übertragungsnetzbetreibern (ÜNB) zur Schaffung von Einrichtungen wie dem Europäischen Netz der Übertragungsnetzbetreiber (ENTSO-E) und den regionalen Koordinierungszentren (RCC). Diese Arbeit konzentrierte sich auf die Untersuchung des aktuellen Prognoseansatzes, der zur Durchführung der Nettopositionsprognose (NPF) innerhalb der gemeinsamen Day-Ahead- und Week-Ahead-Netzmodelle (CGMs) verwendet wird, die von den RCCs genutzt werden, um die Day-Ahead-Kapazitätsberechnung und die Week-Ahead-Koordinationsdienste für die Ausfallplanung an die ÜNB zu liefern. Die Ergebnisse zeigen die mit allen bestehenden NPF-Methoden verbundenen Fehler und implementierten eine neue Methodik, die zur Durchführung von NPF sowohl für die Day-Ahead- als auch für die Week-Ahead-Anwendungsfälle verwendet wurde.

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List of Abbreviations

ACER Agency for the Cooperation of Energy Regulators

CACM Capacity Allocation and Congestion Management guideline

CCRs Capacity Calculation Regions

CGM Common Grid Model

CCC Coordinated Capacity Calculation

cNTC Coordinated Net Transmission Capacity

CNECs Critical Network Elements and Contingencies

NEMOS Nominated Electricity Market Operators

ENTSO-E European Network of Transmission System Operators for Electricity

EU European Union

IGM Individual Grid Model

NRAs National Regulation Agencies

OPC Outage Planning Coordination

LFC Load Flow Calculation

PTDFs Power Transfer Distribution Factors

RCCs Regional Coordination Centres

RAM Remaining Available Margin

RAs Remedial Actions

STA Short-term Adequacy Forecasts

SOGL System Operation Guideline

TSO Transmission System Operator

UCTE Union for the Coordination of the Transmission of Electricity

Chapter 1

Introduction

1.1 Background, Motivation, and Problem Statement

Across the span of nearly three decades, starting with the entering into force of the inaugural energy package policy by the European Union (EU) in 1996, the trajectory of EU energy policies has led to the steady evolution of the European electricity network. This progression resulted in the emergence of an integrated European energy market, characterized by a liberalized power sector - encompassing transmission, distribution, generation, and retail commercial entities [1] [2]. The liberalization of the power sector also led to the establishment of National Regulatory Authorities (NRAs) to oversee and regulate the Transmission System Operators (TSOs) within member countries. Figure 1.1 below shows the timeline of the major steps that have shaped the evolution of the European electricity market [3].

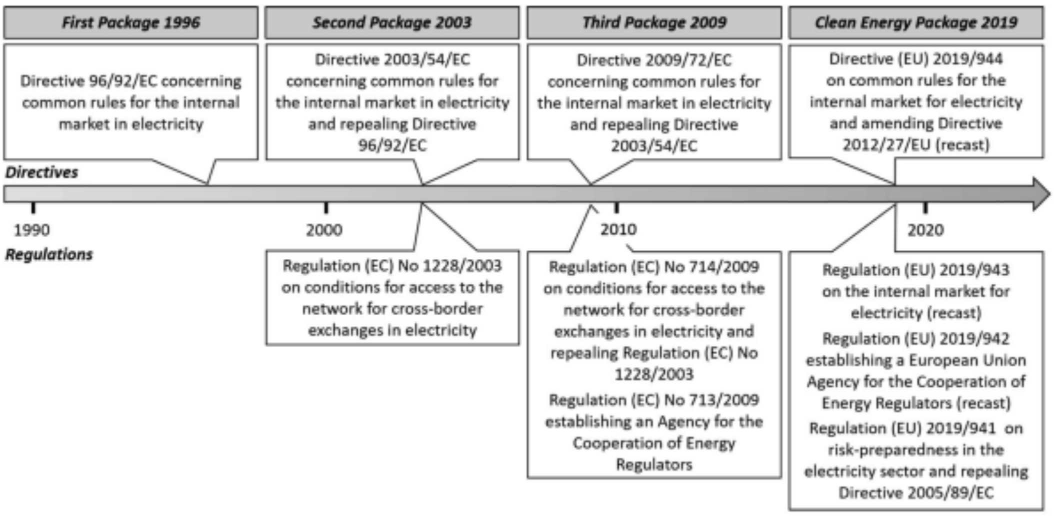


Figure 1.1 Timeline of major EU regulations that shaped the market [3]

The successful integration of the European electricity networks gave rise to what could be defined as an *"interconnected Super Grid"* with the objective of ensuring energy security among EU countries through coordinated efforts: promoting coordinated energy efficiency measures, increased use of renewable resources, and coordinated infrastructure development and maintenance planning to facilitate cross-board electricity transmission across the EU [4]. The expert group on electricity interconnection set up by the European Commission in 2016 concluded in the report *"Towards a sustainable and integrated Europe (2017)"* - that the socio-economic value of electricity interconnection in the EU comes from their ability to increase the efficiency of the electricity systems, reducing the costs of meeting electricity demand while improving the security of supply and facilitating the cost-effective integration of the growing share of renewable energy sources in the system [5]. In line with fast-tracking the European energy transition goals and in recognition of the vital role that deepening electricity transmission interconnectivity in Europe towards achieving energy transition goals; the EU Commission following the regulation on the Governance of the Energy Union (2018/1999)[1]; has further increased the interconnection target to at least 15% by 2030 from the previous 10% target set by 2020, to encourage EU countries to interconnect their installed electricity production capacity - the goal is that each country should have by 2030 electricity cables that allow at least 15% of the electricity produced on its territory to be transported across its borders to neighboring countries (EU Commission, 2019) [4] [5].

Expectedly, as the degree of transmission interconnectivity of the European grid increased, more cross-border electricity exchange between various countries *(in some instances, same as a "Bidding Zones" (BZs))* and across multiple capacity calculation regions (CCRs) - these are regions created within the framework of the interconnectivity of the European grid for the coordination of capacity calculation on a regional level for different electricity market timeframes (intraday, day-ahead, and year-ahead markets), to ensure that a secure and optimal capacity is available within each of the region's electricity market [3]. As a result, alterations made to a country's power grid, such as planning for outages, investing in new grid infrastructure, and capacity allocations, have impacts that extend beyond its own borders [6] [7]. A more specific definition of a bidding zone as defined within the ENTSO-E Network Code on Capacity Allocation and Congestion Management [8] is the following:

> *"A bidding zone is the largest geographical area within which market participants are able to exchange energy without capacity allocation.*

To ensure the security and stability of the power flows across multiple Transmission System Operators (TSO) borders in Europe, the EU established the regulatory framework that led to the creation of the European Network of Transmission System Operators (ENTSO-E) in July 2009 and subsequently, the Regional Coordination Centers (RCCs) in July 2022 through the clean energy package (CEP) regulation (EU) 2019/943[2]. Figure 1.2 was extracted from [3]: it shows the developments of the various roles and tasks performed by the TSOs, ENTSO-E and the creation of the RCCs roles and obligations with the entering into force of the CEP in 2022. [9] covered more details on the roles and services provided by RCCs like *TSCNET Service GmbH* for the TSOs within its regional focus and on a Pan-European level.

[1] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018R1999
[2] CEP: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943

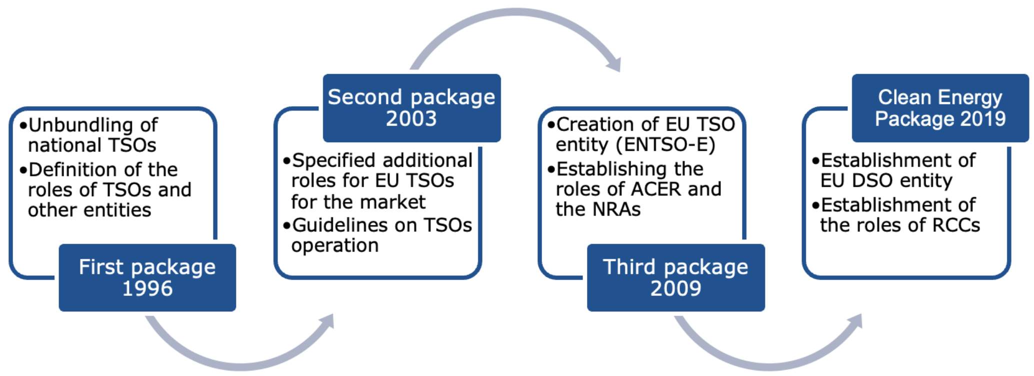


Figure 1.2 TSOs, ENTSO-E and RCCs roles development trajectory [3]

Some of the services provided by the RCCs include performing coordinated capacity calculation, creation of common grid models (CGMs) by merging the individual grid models (IGMs) delivered by the TSOs, and coordination of outage planning processes [9]—within each TSO's IGM data is contained information such as the Net Position Forecast (NPF) for a given market time unit (MTU) and a representation of its grid topology based on the "UCT DEF standard" defined by ENTSO-E [17]. Figure 1.3 shows a representation of an IGM with a circle: the tie-lines is the connection of the IGM to its neighbouring TSOs.

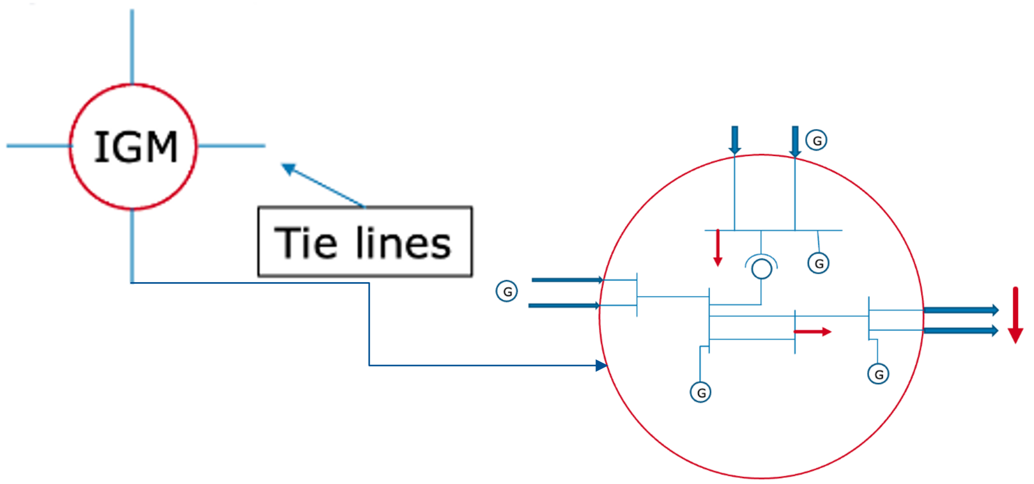


Figure 1.3 A representation of an IGM with Tie Lines

All of these services require grid model data on varying timeframes (intraday, day-ahead, week-ahead, and year-ahead), to ensure grid transmission security and resource adequacy. Hence, having high accuracy of forecast grid data within the forecast CGM files is vital for the integrity of the regional coordination services provided by the RCCs. One such key data for grid models is the Net Position Forecast (NPF) of the participating TSOs within the individual grid model (IGMs) provided by each of the TSOs. The Net Position (NP) of a TSO within a particular CCR relative to another TSO in a given period of time can be mathematically defined as:

$$NP_i = G_i - L_i \pm \Sigma_{i \leftrightarrow j} Exchange_{i \leftrightarrow j} \tag{1.1}$$

where G_i and L_i is the generation capacity and load demand within TSO for same Market Time Period "i" and the *Exchange* is the cross-board capacity transmitted between the two TSOs "$i \leftrightarrow j$" for same Market Time Period. From Equation 1.1, we see that forecasted *Net Position* per TSO is a function of its forecasted active power and active generation, and the flow exchange interactions with its neigbouring borders for a given Market Time Unit.

From [9] we learned that the component of the flows within a zone *(which corresponds to a TSO)* will depend on where the source and sink are located, as well as the grid configuration and the broader region defined by its bordering zones. For example: Figure 1.4 shows the various components of a 100MW flow within a simplified grid with three zones, A, B, and C. Using the parameters of Equation 1.1 it is mathematically feasible to calculate the Net Potion of each of the three zones relative to each other as a summation of each of the zones internal flows plus or minus the exchange between neighboring zones.

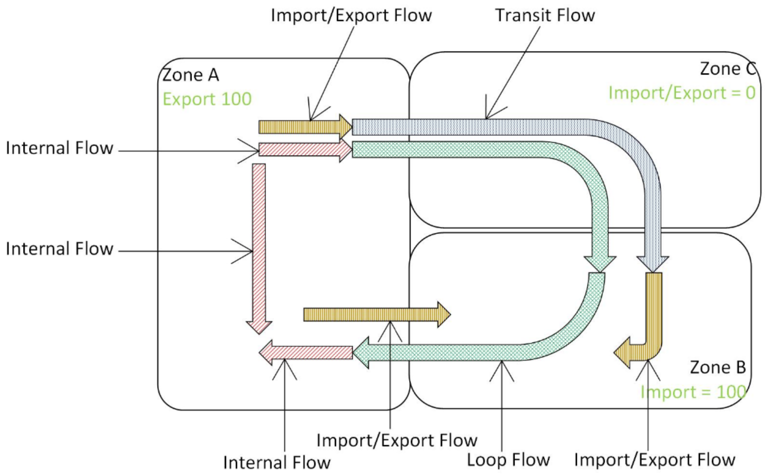


Figure 1.4 Components of power flow decomposition as defined by ENTSO-E

A more specific definition of net position within the context of the European electricity market is contained within the ENTSO-E Network Code on Capacity Allocation and Congestion Management [8]. It states the following:

> *"Net Position is the netted sum of electricity exports and imports for each Market Time Period for a given geographical area. In the context of the Network Code, geographical area is a Bidding Zone"* [8]

The CGM is a merged collection of IGMs of all the relevant TSOs grid models. The goal is to have an accurate CGM as an input model for load flow analysis and other relevant grid-related computations, such as outage planning inconsistency computation and day-ahead coordinated capacity calculation. The accuracy of Net Position Forecast (NPF) within the CGM used for either Coordinated Capacity Calculation (CCC) or the Pan European Outage Planning Inconsistency Computations plays a critical role in ensuring that social welfare within the European electricity market is maximized and that the power flows induced by the computed allocated capacities for each border within a given CCR does not results to multiple overloaded critical network elements (CNEs) or leads to a scenario where the impacted TSO has to implement re-dispatch and counter trading fallback to ensure that sufficient capacity is allocated for trading during real-time operation [9, 10, 14]—the criticality of NPF on end-users electricity cost forms the motivation for this research. More details about the CGM creation and its relevant component's definitions will be covered in the second chapter of the report. In summary, an accurate net position forecast ensures:

– A more secured Pan-European electricity grid

– Cheaper electricity cost for end-users - maximum social welfare

– Less counter-trading and re-dispatch of capacities between TSOs during real-time operation

1.1.1 Research Objectives and Goals

For this research, we investigated the accuracy of the Day-Ahead NPF of relevant TSOs from the day-ahead congestion forecast (DACF) IGMs provided by the TSOs to the RCCs for the coordinated computation of the day-ahead capacity calculation (DACC) process - this process results in the Day-Ahead Net Position Forecast values published within the *"Day-Ahead LFC Block Program of UCTE Control Blocks"* of Vulcanus Platform[3]. We compared the DACC NPF with the Realised market flow Net Position values for the same MTUs. The DACF NPF was also compared to the Measured Physical flow Net Position values for the corresponding Week-Ahead MTUs for the Week-Ahead Outage Planning Coordination use case. Both the Realized and Physical flow results are published on the Vulcanus Platform. Within the framework of the European electricity market, the Realised Flows and Measured Physical Flows results are the reference true representation of the situation of the grid networks vis a vis the electricity market for each bidding zone borders per MTU for their corresponding use cases:

– The Realized Flows Net Position results for each MTU is the Net Position of the market after electricity trading is closed - which makes it more relevant for the single day-ahead market coupling trading.

– The Physical flow represents the real-time status of flows across the border lines for a given bidding zone for each MTU. It shows if there are existing overloads in the networks after the close of the market - this is particularly relevant for the Week-Ahead *"Outage Planning Inconsistency (OPI)* computation as the goal of the OPI process is to ensure that there are no resulting outage planning inconsistencies for the week-ahead Outage Planning Coordination process while ensuring the security of the Pan European grid.

The second objective of the research is to implement a NPF Proof of Concept (PoC) that predicts future MTU Net Position of a given country (Bidding Zone) by means of

[3] https://verification.swissgrid.ch/

active load demand and actual generation forecast using Machine Learning time-series forecast algorithm; scaling the forecast load and generation proportionally within the reference DACF CGM and finally calculating the forecast Net Position using the scaled (adjusted) CGM as input model in a load flow engine like PowerFactory to perform the load flow calculation. A case study of Germany and its surrounding borders was used to demonstrate the PoC within the framework of the thesis research. The implemented NPF results from the PoC are then compared to the corresponding NPF results from the *"Day-Ahead LFC Block Program of UCTE Control Blocks"*. The following flow chart (Figure 1.5) illustrates the basic steps and methodology followed towards achieving the set goals and objectives of the thesis.

> *"Ultimately, the two central goals of this research thesis are to successfully quantify the resulting mean absolute error and the corresponding mean percentage errors of the two Net Position Forecast approaches for the Day-Ahead & Week-Ahead use cases and to demonstrate that the proposed NPF toolchain can be successfully implemented."*

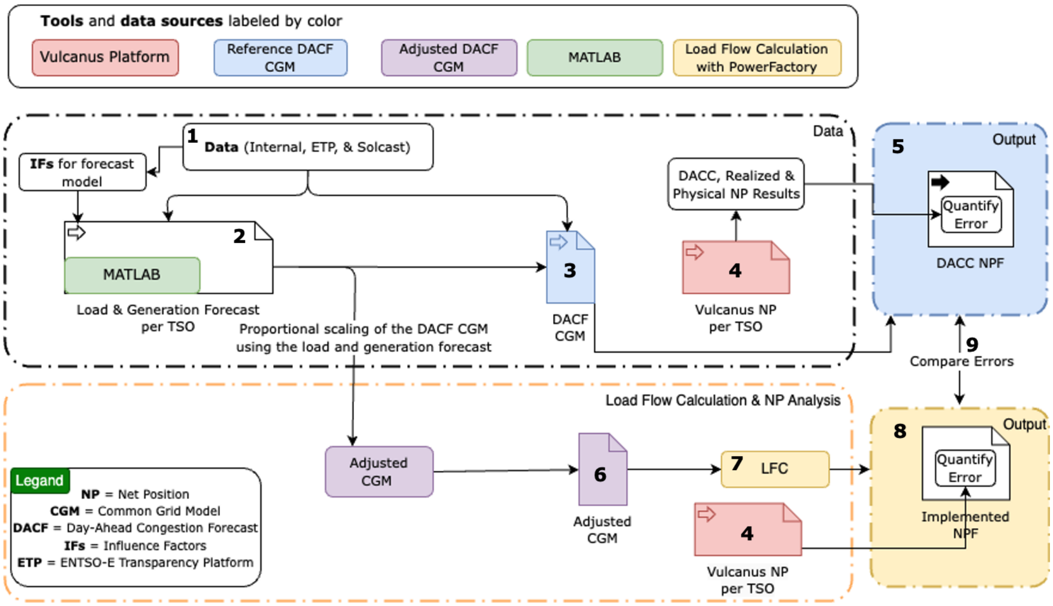


Figure 1.5 Conceptual flow chart of the thesis research implementation steps

Chapter 2

European Grid Operations & Implementation Methodology

This chapter explains the fundamental realities of the current European electricity network grid operations as a consequence of the integrated transmission network architecture of the European grid. The first part of the chapter will focus on the grid operations of TSOs in Europe as obligated by the guidelines from the European Commission Regulation (EU) 2017/1485[1]. The second section will further explore how the EU regulation facilitated a sequence of electricity markets and how TSO co-operation through the European Single Market Coupling and Pan-European Outage Planning Coordination is ensuring maximum social welfare gains to the end-users. The third part will explain how the grid model data from the TSOs are defined within the IGMs and then transformed into CGMs by the RCCs. The fourth section covers the fundamentals of forecast models, their features, and how they apply to NPF and its significance to the electricity market. Finally, the fifth section will explain the concept of load flow calculation and how it was applied to this thesis research.

2.1 Grid Operations of TSOs in Europe

Grid operations in Europe by the TSOs have evolved over the years in line with the evolution of the European electricity market as captured in Figure 1.1 and 1.2. These evolutions not only resulted in a liberalized interconnect electricity market but also opened up the market into multiple Capacity Calculation Regions (CCRs) characterized by a sequence of electricity markets that starts years before the actual delivery of capacity to the end-user and continues up to real-time operations [3]. Despite the increased complexity and challenges involved in the operation of the highly interconnected European grid, ACER published in the 2020 *"Monitoring the Internal Electricity and Natural Gas Markets"* that over 150 million euros of yearly welfare gains to end-users have been achieved as a result of the interconnected electricity system in Europe [11]. Figure 2.1 taken from ENTSO-E map[2] and overlayed by a regional visualization of the market; shows the sequence of the electricity markets in Europe based on the evolved electricity market regulations. Due to the high level of cross-border grid interconnection, each TSO has to take into

[1] (EU) 2017/1485: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R1485
[2] ENTSO-E map: https://www.entsoe.eu/data/map/downloads/

account the impact of changes on its grid as a result of changes from other TSOs in the same region or even in a different region of Europe —such changes could have significant welfare impact on multiple TSOs across multiple regions [6, 7, 16]. Hence, the coordination and cooperation between TSOs as well as the exchange of information on the state of the whole grid between multiple regions is essential to securely operate the grid in Europe.

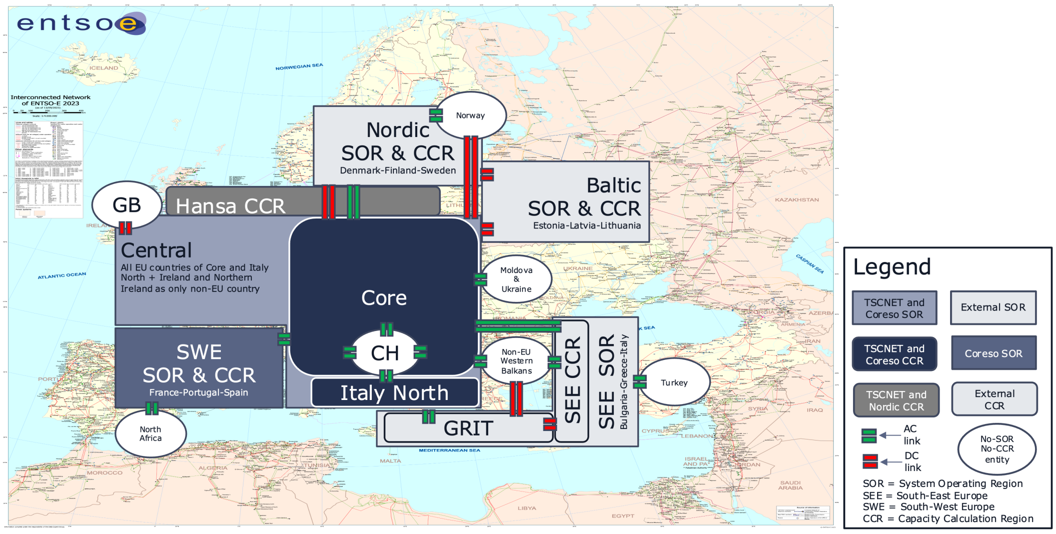


Figure 2.1 Regional Visualization of the Electricity Markets in Europe [8]

EU regulation (EU) 2017/1485 with the aim of safeguarding operational security and the efficient use of the interconnected system and resources across the EU, laid down detailed guidelines and obligations for the grid operations of TSOs. The regulation mandated TSOs to ensure the operational security of their operation, coordination of outages, and the availability of secured and sufficient cross-border capacity for the market within their control areas. The creation of entities such as ENTSO-E and the RCCs have played a significant role in the coordination of regional and Pan-European TSO coordination across Europe and the centralization of the System Operating guidelines for TSO operations across the EU [6, 8, 9].

2.1.1 Market Coupling and Coordinated Capacity Calculation

The liberalized electricity market also resulted in a significant increase in market liquidity for multiple CCRs [12]. The increased liquidity was largely driven by increased competition between many new *Market Participants* who now have the opportunity to participate as a result of lowered barriers to entry. Increased competition also created new challenges such as cases of multiple electricity price differentials and increased the likelihood of market manipulation if proper mechanisms to ensure the integrity and transparency of Market Participants' activities were not mandated [13]. These new challenges raised the need for the EU Regulation No 1227/2011[3] on wholesale energy market integrity and transparency (REMIT) and also propelled the creation of the Single Day-Ahead and Intraday Market

[3]REMIT: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32011R1227

Coupling Operation between the TSOs and the Nominated Electricity Market Operators (NEMOs) in Europe to ensure both the integrity of the market and to maximize welfare gains [10, 16, 27].

The process aggregates the allocated capacities calculated from the Coordinated Capacity calculation—performed by the RCC of various CCRs—into a single central platform and with the *Euphemia algorithm* it factors in the situations on all the relevant TSOs grids and finds the optimal electricity price for the entire region while maximizing welfare gains [14]. It is important to note that maximum social warfare gains for the market do not necessarily correspond to securing lower electricity prices for end-users but are aimed at achieving market results that optimize the allocation of resources with economic efficiency, coupled with a fair and competitive interplay between supply and demand. ACER's 2018 monitoring report estimated that as of 2018 when the market coupling operation consists of 22 EU countries, the benefit to end-users in the form of welfare gains is approximately one billion euros [15].

2.1.2 Outage Planning Coordination

One of the obligations that is within the responsibilities of a TSO from the EU regulation (EU) 2017/1485 is the guidelines to all TSOs on outage coordination within their control responsibility area. In other to fulfill the requirements of outage coordination on a Pan-European level, the Outage Planning Coordination (OPC) project was established at the ENTSO-E level with significant support from the RCCs from regional levels—its goals focused on harmonizing the procedures of outage planning coordination for all European TSOs. The success of the OPC project led to the launch of the Pan-European IT tools[4] for Outage Planning Coordination. One of the outputs of the OPC process is the *OPC Unavailabilty Plan* for the Week-Ahead—which gives the status of the Pan-European coordinated outages for the following week.

On a regional level, TSCNET initiated the Outage Planning incompatibility Process (OPI) with the aim of determining whether the Week-Ahead OPC process is secure for grid operation using the continental reference CGMs provided by ENTSO-E. If the OPI computation determines that the grid is not secure, it is designed to iteratively perform an optimization, suggesting possible *Remedial Actions*, while performing security assessment on the grid until it finds a secured grid scenario. OPI process steps for Week-Ahead computation consist of a combination of the availability status of one or more relevant grid elements mapped within the reference continental CGM [18]. The reference CGM is then transformed into an *"Improved Model"* through a process that scales the DACC NPF from the referenced DACF CGM with the Net Position values from the Vulcanus *"Day-Ahead LFC Block Program of UCTE Control Blocks"* for the Week-Ahead forecast of the electricity grid situation using a method called the *"Last comparable Reference Day"* approach. The "Improved Model" is also referred to as the *"Week-Ahead CGM"*.

[4] OPC Platform launch: https://www.entsoe.eu/news/2020/06/19/launch-of-the-pan-european-it-tools-for-outage-planning-coordination-and-short-term-adequacy-assessment/

Figure 2.2 illustrates how the Last comparable Reference Day NPF is created for the week-ahead improved model generation process assuming a scenario of no missing relevant Vulcanus files and no bank holidays within the previous week. One of the objectives of this research is to compare the NPF results from our PoC and the NPF values from the Reference Day approach and quantify the corresponding mean absolute error (MAE) and percentage error.

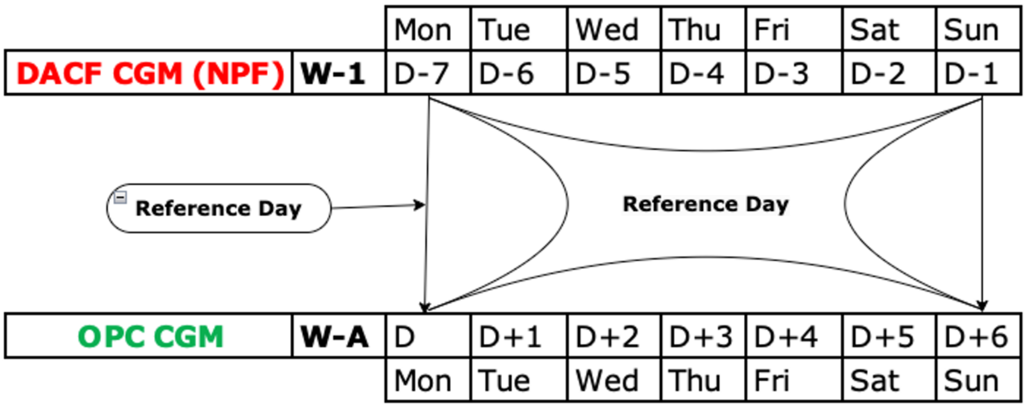


Figure 2.2 Illustration of the *"Reference Day"* NPF approach

W-A in Figure 2.2 represent the Week-Ahead analyzed with the OPI tool, **W-1 and D-X {X = 1, 2, 3, 4, 5, 6, 7}** represent the previous week from which the reference day DACF NPF will be sourced.

2.2 Common Grid Model (CGM) – UCTE definition

The creation of the Common Grid Model (CGM) to facilitate grid information exchange between TSOs was mandated by the Articles 67(1) and 70(1) of Commission Regulation (EU) 2017/1485. To fulfill the EU 2017/1485 obligation on data exchange, ENTSO-E TSOs adopted the common grid model methodology [8] within the System Operations Guidelines (SOGL)[5] (Art. 64-71), Capacity Allocation and Congestion Management Guidelines (CACM GL) (Art. 16-19)[6] and Forward Capacity Allocation (FCA GL)[7] (Art. 17-20) - the three GLs provides a set of rules and network codes for the establishment of a common grid model to enable the performance of coordinated tasks by the RCCs [8]. The information exchanged within the CGM by the TSOs is contained in their "individual grid models" (IGMs) that are then merged by the RCCs—IGMs are created by each TSO based on scenarios, which represent the forecasted status of the power system for a given time-frames, ranging from one Year-Ahead (Y-1) to the Intraday (ID) process [8, 17, 18]. Figure 2.3 shows an electrical diagram representation of 3 TSOs IGMs and its CGM equivalent. A CGM according to the (CACM GL, Art. 2(2)) is described as:

[5]SOGL: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R1485
[6]https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:02015R1222-20210315
[7]FCA GL: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R1719

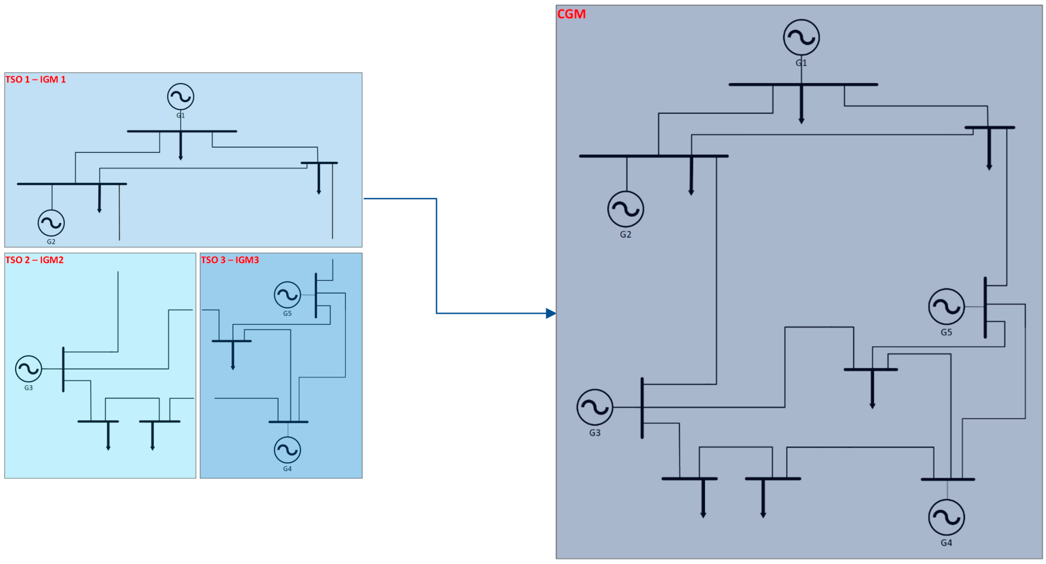


Figure 2.3 Illustrations of a CGM of three TSO's merged IGMs

> *"A union-wide data set agreed between various TSOs that describe the main characteristic of the power system (generation, loads, and grid topology) and rules for changing these characteristics during the capacity calculation process".*

As mentioned in Chapter One of the report, the set of validation rules for changing the characteristics of the grid within the CGM are defined within the ENTSO-E's UCTE definition documentation on the quality of datasets and calculations for system operations [17]. The technical report on "The EU Electricity Network codes" by [18] gives a more detailed overview of the CGM processing pursuant to CACM GL, FCA GL, and SOGL. The basic business process RCCs employ to create the common grid model is shown in Figure 2.4. The main process steps such as the ENTSO-E Validation, Tie-Line Inconsistence checks, and Base Case Model improvement & scaling are explained below:

- *ENTSO-E Validation*—this step of the CGM merging process validates the individual grid models provided by the TSOs, using the rules established by ENTSO-E UCTE definition [17]. If the validation fails, the TSO might be notified, or the model replacement process is applied as a fallback.

- *Tie-Line Inconsistencies*—this step is performed on the connection points between two TSO's "X-nodes". The simulation of the nodes for such a connection is defined according to the UCTE format using the ID number starting with "X" - called the "X-nodes". The line between two X-nodes is known as a "Tie-Line". A tie-line inconsistency occurs when the two X-nodes that forms a line have different power exchange status.

- *Base case improvement & Scaling*—refers to the process step where the difference between actual active power exchange between different bidding zones and the scheduled market power exchange (Vulcanus Platform) is determined. Based on a defined difference threshold between the base case model Net Position values and the Net Positon on Vulcanus and also depending on the service use case (for example for CSA, CCC or OPC), if the defined requirements is reached, scaling (or adjustment) will be applied to determine the NPF per MTU.

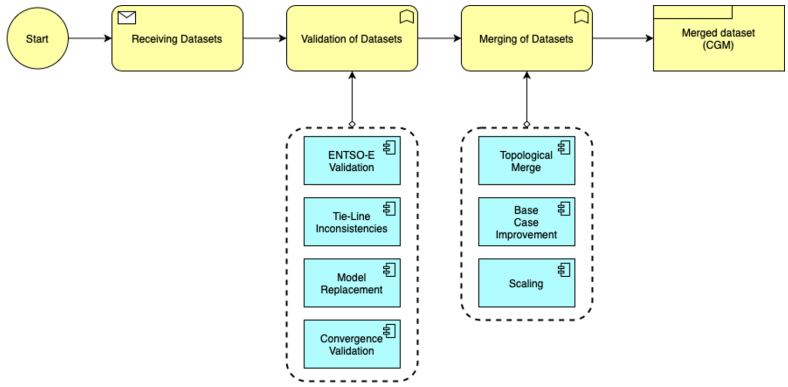


Figure 2.4 Basic process steps followed by RCCs to create a CGM

2.2.1 CGM Load and Generation Scaling Methodology

There are five types of load and generation scaling (or shift key) methodology that can be derived from the ENTSO-E Generation and load shift key implementation guide [20]. A high-level explanation of the aim of load and generation scaling is such that any change in the balance of one TSO is transformed into a change of injections in the nodes of that TSO or control area —the reference for the scaled transformation is on forecast information about the generating units and loads of the relevant TSOs or control areas [18, 20]. We will list the types and briefly define each of them:

– *Proportionally to base case generation or load*—all defined generation and load nodes in an area, are proportionally scaled to the base case generation and load.

– *Proportional to the participation factors*—all the list of generation nodes or load nodes in a defined area, are defined with individual participation factors.

– *Proportional to the remaining available capacity*—the scaling of the generation is computed proportionally to the remaining available generation, depending upon the shift (up for positive shift or down for negative shift margin).

– *Depending upon a merit order list*—all chosen generation nodes shifts up or down according to the merit order list defined in the group by the relevant TSOs.

– *Interconnection shift key*—the scaling is performed through a change of pattern on the interconnection flows from external defined areas ('b', 'c', ...) to the benefit of the area 'a'. The areas represent the grid model of interest.

We used the *"Proportional to base case generation or load"* scaling method in this research with the assumption that all the nodes within our study area are relevant for the adjustment—this scaling step is fundamental in our algorithm for generating the *"Adjusted CGM"* per MTU:

$$K_l(n,a) = L(a)\frac{P_l(n,a)}{\Sigma_i P_l(i,a)} \quad \{i = 1,2,3,...n\} \tag{2.1}$$

$$K_g(n,a) = G(a)\frac{P_g(n,a)}{\Sigma_i P_g(i,a)} \quad \{i = 1,2,3,...n\} \tag{2.2}$$

Equation 2.1 and 2.2 represent the participation of node *"n"* in the shift (or adjustment), among selected load and generation nodes (in the case of this research: among all nodes in our study area) respectively. $P_l(n,a)$ and $P_g(n,a)$ represent the active load and generation in node *"n"*, belonging to area *"a"*.

2.2.2 Critical Network Elements and Contingencies - CNECs

Critical Network Elements (CNEs) are lines modeled in either an IGMs or the CGM that are critical for the transmission of electricity in a transmission network [9, 10]. It could be an internal line of a particular TSO or a Tie-Line connecting two TSOs. Usually in the simulation of N-1 or N-2 outage contingency analysis on the grid, the impact of the simulated outage(s) on the CNE is the focus [10]. Simulated contingency analysis is performed in other to determine the impact of the simulated failure or outage of an element on the transmission capacity of the CNE [10, 24]. CNEC is a combination of a CNE and a contingency. Figure 2.5 is a sample representation of a CNEC in a CGM composed of 3 IGMs in yellow and one simulated outage contingency in red.

2.3 Load & Generation Forecasting with ML Modeling

Earlier in Chapter One, we demonstrated that the *Net Position* of a bidding zone (or a chosen market area) is a function of the load demand and available generation within the bidding zone and its flow exchange with surrounding borders using Equation 1.1—this equation could also be described as a set of variables representative of the situation of the bidding zone's electricity market in the electrical grid of the zone. Therefore, it is feasible to forecast the Net Position per MTU of a zone by forecasting the corresponding load demand and available generation of the zone for that MTU, scaling the zone's IGM using the forecasted load & generation, and calculating the border exchange using a load flow engine. Previous research on load demand and power generation studies confirmed that both load and generation vary from one location to the other subject to some factors we defined as *"Influencing Factors - IFs"* [21, 22]. A list of the IFs that characterize the load and generation of any given location is shown in Table 2.1[8].

[8] "x" and "-" indicate if a factor was considered for the forecast or not respectively

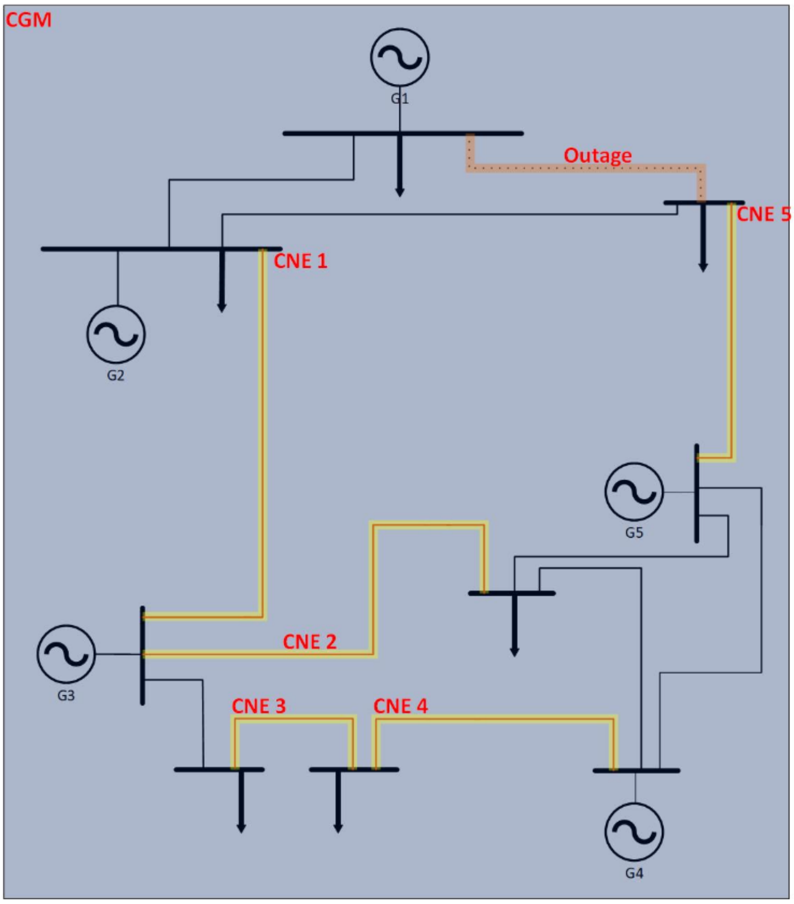


Figure 2.5 An example of CNEC within a CGM

Table 2.1 Influencing Factors (IFs) on Load & Generation Forecasting

IFs	Load Forecast	Generation Forecast
Historical weather profile	x	x
Historical generation outages	-	x
Historical load demand	x	-
Historical generation availability	-	x
Holidays and special days profile	x	-
Forecast weather profile	x	x
Forecast generation outages	-	x
Forecast load demand	-	x

For our research, we trained machine-learning models in MATLAB using historical time-series influencing factors based on established characteristics of load and generation usage patterns of our study areas (countries). Our study area for forecast modeling is the Bidding Zone Germany (DE+)[9] and its surrounding borders[10]. Figure 2.6 shows a map representation of the EU Bidding Zones, including Norway and Switzerlands [19]

[9]DE+ represents the coupled Denmark, Luxembourg, and Germany grid model.
[10]The "holidays and special days" of Austria was assumed for other BDzs

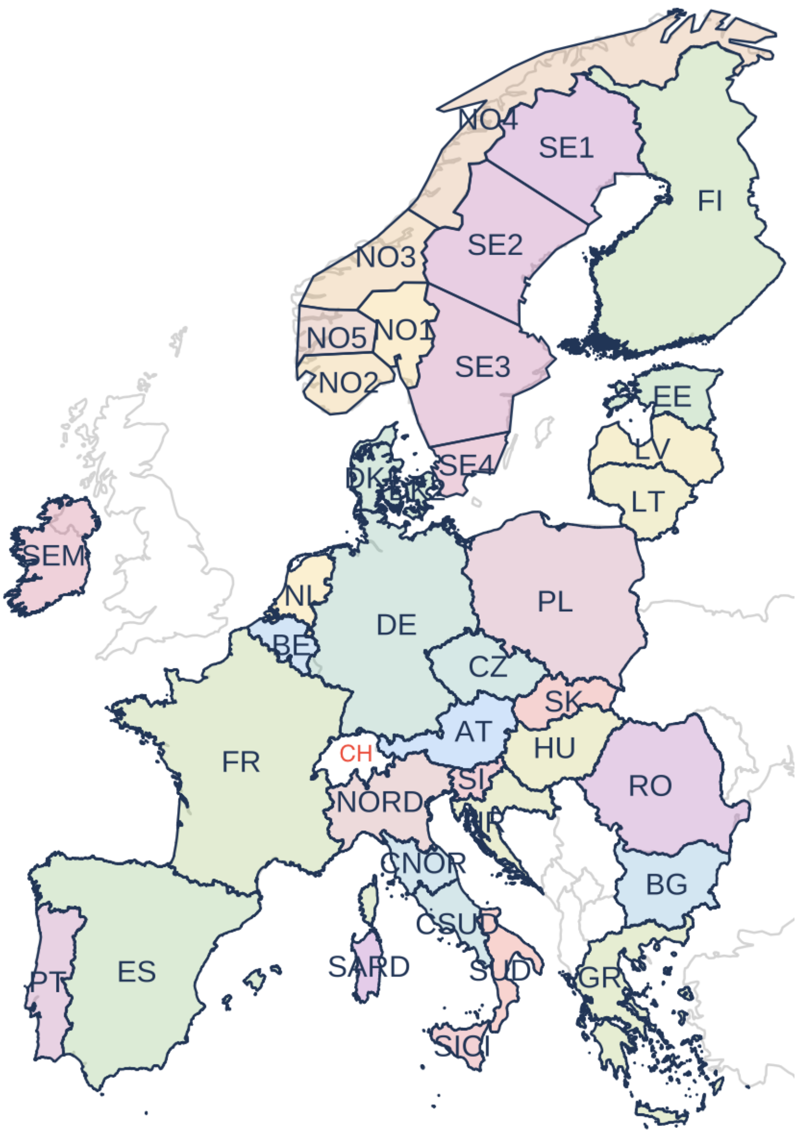


Figure 2.6 EU bidding zones (incl. Norway & Switzerland) [19]

Table 2.2 shows the Bidding zones within our research study area—the table contains information on the load and generation forecast methods used in our research. expGPR ML and SQexpGPR ML are Exponential and Squared Exponential Gaussian Process Regression (GPR) supervised machine learning models respectively. We chose the two GPR machine learning model functions for the load and generation forecast because they both were the best-performing trained models from the MATLAB regression learner application module for our load and generation forecasting respectively. The theoretical basis of the Gaussian Process ML Regression can be found in [26]. The model training data set consists of an hourly resolution of historical *IFs* as defined in Table 2.1. The model prediction step is performed by the model by prediction of future timesteps using the Forecast Influence Factors. After predicting the first step, subsequent steps consider the previous forecasted timestamp of load and generation to ensure a supervised machine learning model [25]. Algorithm 2.1 describes the high-level forecasting procedure used for the load and generation forecast for our research.

Table 2.2 Models Study Area - Focusing on Germany & Relevant Bidding Zones

Bidding Zones	Load Demand [MW]	Generation [MW]	Exchange & NP [MW]
DE+ - Germany	expGPR ML model	SQexpGPR ML model	LFC & Σ of Tie-Line Flows
AT - Austria	expGPR ML model	SQexpGPR ML model	LFC & Σ of Tie-Line Flows
BE - Belgium	expGPR ML model	SQexpGPR ML model	LFC & Σ of Tie-Line Flows
CH - Swiss	expGPR ML model	SQexpGPR ML model	LFC & Σ of Tie-Line Flows
CZ - Czech	expGPR ML model	SQexpGPR ML model	LFC & Σ of Tie-Line Flows
FR - France	expGPR ML model	SQexpGPR ML model	LFC & Σ of Tie-Line Flows
NL - Netherlands	expGPR ML model	SQexpGPR ML model	LFC & Σ of Tie-Line Flows
PL - Poland	expGPR ML model	SQexpGPR ML model	LFC & Σ of Tie-Line Flows

Algorithm 2.1 Algorithm for Load & Generation Forecast using Machine Learning

Data: Historical Hourly *load IFs* per Bidding Zone
Result: Load & Generation forecast per MTU

```
1  Define a for-loop per MTU to ensure a recursive ML model;
   while Input IFs meet requirements do
2      train expGPR ML model on input data per zone;
       if Model is trained then
3          Perform load & generation forecast using validation data within defined
           for-loop;

4          Calculate the RMSE of forecast vs actual per bidding zone;
5      else
6          Check input data set for error;
           Repeat step 2
```

2.3.1 Current state of NPF modeling

Net Position forecasting is performed with the aim of providing accurate predictions of market results in the future [8]. The process is performed with the primary goal of ensuring that the balance of the grid model for the future market timeframe optimizes for not only the security of the grid but also maximum welfare gains for either the day-Ahead, intraday capacity calculation process and for the outage planning coordination process across Europe [8, 16, 27]. The common established process for NPF for European TSOs is described in the ENTSO-E Common Grid Model Alignment Methodology [8][11] (CGMAM)—part of the CGM methodology approved by all ENTSO-E's NRAs in 2017. Some of the NPF modeling methods proposed within the CGMAM documentation was from three RCCs—CORESO, Nordic RCC and Baltic RCC within the CGAM Annex II documentation. They proposed a correlation between Net Position and a set of exogenous forecasted input variables

[11] CGMAM: https://docstore.entsoe.eu/Documents/Network%20codes%20documents/Implementation/cacm/cgmm/Common_Grid_Model_Alignment_Methodology.pdf

(wind, solar, load, generation, temperature) representative of the situation of the electrical market and the electrical grid in the chosen market area as well as neighboring bidding zones. The CGMAM provided the foundation principles of NPF by proposing three basic approaches for NPF modeling:

1. Reference day exchanges or substitution approach
2. Using exogenous forecast data as influence factors
3. Using outage data for lines or power plants

While some of the TSOs have followed the forecasting guidelines established within the CGMAM to develop their NPF models for the creation of future time-frame IGMs, for some services the *Reference Day* approach is still the default approach. CORESO on the other hand has over the years developed their originally proposed NPF forecasting approach into an internal NPF tool for forecasting Net Positions for the CORE region's day-ahead capacity calculation process.

2.3.2 Research Questions on Net Position Forecast

In order to effectively identify relevant research questions on Net Position Forecast, it is important to first identify how the parameter *"NP"* influences the calculation of different parameters in load flow calculation, market coupling optimization, and outage planning coordination inconsistencies computations. Equation 1.1 gives a simplified representation for calculating the Net position for an MTU between two TSOs sharing a border and exchanging capacities. Within the context of market coupling in Europe, NPF also plays a significant role in the social welfare impact of the calculated capacities within the coupled single day-ahead or the single intraday electricity market [10, 14, 15, 31]. For instances with the capacity calculation process; the value of the NPF within each of the TSO's forecast IGMs coupled with the characteristics of the Critical Network Element and Contingency (CNECs) within the grid model limits the maximum power that can be transferred, from one TSO to the other in a given bidding zone or CCR [14]. Each CNEC models an individual constraint to represent the transit on the Critical Branch in the presence of a specific Critical Outage (CO) such that the *N-k* security criterion is taken into account in the calculation of the secured total transmissible capacity within the CCR in a given market timeframe [10]. Equation 2.3 - 2.6: define all the relevant parameters that are used within the context of capacity calculation for both the Flow-based and the Coordinated Net Transfer Capacity (cNTC) approach [10]:

$$RAM^{\pm}_{\mathit{CNEC}} = F_{\mathit{max,CNEC}} - FRM_{\mathit{CNEC}} - (F_{\mathit{ref}} - \Sigma_{i \to j} PTDF_{i \to j} \times Exchange_{i \to j}) \quad (2.3)$$

$RAM^{\pm}_{\mathit{CNEC}}$ is the the value of positive or negative available capacity on the CNEC taking into account the quantity of capacity already assigned or reserved within the flow-based domain, the $F_{\mathit{max,CNEC}}$ is the thermal rating of the critical network element, FRM_{CNEC} is the Flow Reliability Margin, F_{ref} is the reference Flow of the CNEC for a given bidding-zone border exchange. F_{ref} also represent the active power flow forecast on each of the monitored CNEC for a given forecasted grid situation for example the day-ahead congestion forecast model, $PTDF_{i \to j}$ and

Exchange$_{i \rightarrow j}$ are respectively the Power Transfer Distribution Factor of the bidding-zone border i→j on the CNEC and forecasted bidding-zone border i→j Exchange. The PTDF$_{i \rightarrow j}$ represents the impact of the exchange of capacities between $i \leftrightarrow j$ on the monitored CNECs. It is calculated with the following equation:

$$PTDF_{i \rightarrow j} = \frac{\Delta F_{\textit{ref}}}{\Delta Exchange_{i \rightarrow j}} \tag{2.4}$$

An admissible flow-based domain within a flow-based grid model for the computation of capacity of a bidding zone is determined by the characteristics of the CNECs defined within the grid model of the bidding zone. The boundary equation is shown below [14, 27]:

$$RAM^{-}_{\textit{CNECj}} \leq F_{\textit{CNECj}} \leq RAM^{+}_{\textit{CNECj}} \tag{2.5}$$

F$_{\textit{CNECj}}$ is the transit capacity from the *"CNECj"* within the bidding zone *"j"* that is calculated with the following equation [10]:

$$F_{\textit{CNECj}} = \Sigma_{i=1}^{N} PTDF_{i,CNECj} \times NetPosition_i \tag{2.6}$$

where N is the total number of Bidding Zones included in the flow-based model, $PTDF_{i,CNECj}$ is the Power Transfer Distribution Factor of the Bidding Zone *"i"* on the *"CNECj"*, $NetPosition_i$ is the difference between the matched supply and the matched demand quantities belonging to Bidding Zone *"i"*.

From Equation 2.3 - 2.6, we see the critical influence of Net Position and related parameters like capacity exchange and load forecast within the governing equations that determine the accuracy of load flow computation. It is also embedded within the underlying equations for calculating regional cross-border capacities for either the Flow-based or the cNTC approach. Keeping all the defined parameters from the equations in mind, we can now come up with possible research questions on Net Position Forecast that we will attempt to answer in the course of this research. Some of the questions that come to mind are below:

1. How do we quantify the accuracy of an NPF?

2. What are all the relevant influence factors to accurately forecast NP?

3. Could the impact of inaccurate NPF on social welfare be quantified across all relevant use cases?

4. How do we calculate and allocate the associated market cost from inaccurate NPF without significantly impacting social welfare negatively?

With this research, we answered some of the above questions. Our hope is that our contributions from this research will serve as a good starting point for any interested researcher in the future to also contribute towards answering the above questions, and perhaps even suggesting new unanswered questions in the field.

2.4 Load Flow Calculation

Load flow (or power flow) calculation (LFC) forms the basis for the steady-state analysis of power systems and can be used to analyze both small and large-scale electrical grids for a wide range of applications from systems expansion and maintenance planning to real-time security analysis on grid operations [28–30]. This section explains the fundamentals of load flow calculation and how it was used within the context of this research thesis. There are two distinct types of LFC methods: *"AC and DC LFC"*—depending on whether a non-linear or linear equation is used to define each of the bus (or node) and the branch element of the electrical system in a Jacobian matrix [29].

The main objective of load flow studies is to solve four steady-state electrical quantities (at each node and branch element in the grid). Each node *i* —represents the connection of grid components—and is defined with a potential V_i, voltage angle θ_i, active and reactive power components P_i and Q_i. We can also categorize the nodes of any electrical system into three types using a combination of two known and two unknown characteristics of the system to formulate a non-linear equation of the system for an AC load flow calculation or a linear equation of the system for a DC load flow calculation—with the reactive power component of the system neglected [28]. The three types of electrical nodes (or buses) are:

– *PQ Nodes*—these type of nodes has a known active power P_i and reactive power Q_i, while their potentials V_i and voltage angles θ_i are unknown. They represent mostly the connection point of the grid and the loads or static generators that consume or feed in a fixed amount of active and reactive power respectively in the system

– *PV Nodes*—these type of nodes a designed to consume or feed-in defined quantity of power P_i, while simultaneously keeping the nodes' potentials V_i on a certain defined level; with the voltage angles θ_i and the reactive powers Q_i unknown.

– *Slack (or reference) Nodes*—are the nodes that compensate for all the grid-wide surplus or deficit of load or generation in order to maintain the system's balance of power. They serve as an infinite power or load supply for the system, with the V_i and θ_i fixed.

By applying Kirchhoff's law to each node [28], we get Equation 2.7:

$$\mathbf{I} = \mathbf{YV};\ I_i = \frac{P_i - jQ_i}{|V_i|}\ \ \{i = 1, 2, 3, ...n\} \tag{2.7}$$

Where **I**, **V** and **Y** represent the vector of current, voltages, and admittance at the nodes of the system respectively. I_i represents the net sum of injected current at the node *i*. $V_i = |V_i|e^{j\theta_i}$ is the *i* voltage of the vector **V**. The matrix representation of the admittance vector **Y** is symmetrical and consists of diagonal elements "Y_{ii}" that represent the *self-admittance* of the node and equals the sum of all the admittance of connected branches to node *i*. The off-diagonal elements "Y_{ij}" represent the *mutual-admittance* between node *i* and node *j*, and are equal to the negative sum of the admittances between the two nodes. Mathematically: $Y_{ij} = G_{ij} + jB_{ij}$. Where G and B represent the *conductance* and *susceptance* of the respective nodes.

Based on a specified generating state and transmission network structure, we can represent an electrical system of *N* number of nodes, with two power flow equations (using the basic quantities defined above) for a load flow engine to solve the steady operation state of the system [28, 29].

$$P_i = \Sigma_{j=1}^{N} |V_i||V_j|[G_{ij} cos(\theta_i - \theta_j) + B_{ij} sin(\theta_i - \theta_j)] \;\; \{i = 1, 2, 3, ...n\} \tag{2.8}$$

$$Q_i = \Sigma_{j=1}^{N} |V_i||V_j|[G_{ij} sin(\theta_i - \theta_j) + B_{ij} cos(\theta_i - \theta_j)] \;\; \{i = 1, 2, 3, ...n\} \tag{2.9}$$

With a defined load flow configuration of either DC or AC; a load flow engine such as the *DIgSILENT PowerFactory* or the *Schneider Electric TNA* will calculate—iteratively in AC mode or linearly in DC mode—other electrical quantities of interest (listed below) from the electrical grid using either the Newton-Raphson or the Fast-Decoupled root-finding algorithm to solve Equation 2.8 and 2.9.

- Current flowing through each branch element
- Total system load
- Total amount of generation dispatched
- Loading of branch elements (e.g. transformers)
- Apparent power through each branch element
- Voltage drop between buses
- Network losses

These calculated quantities are of interest to electrical network operators like the TSOs in order to ensure that the power system operates efficiently and within secured limits. Once the LFC is successful, the NPF from the PoC can be calculated by summing the Tie Line flows for each zone. Algorithm 2.2 shows the high-level algorithm for the implemented LFC and NPF in this research.

Algorithm 2.2 Algorithm for Load Flow Calculation & NP Forecasting

Data: Adjusted CGM files per MTU
Result: LFC & NPF of Adjusted CGM per MTU
Define the DC PowerFactory Configuration settings;
while *Adjusted CGM file per MTU passes post-processing validation rules* **do**
  Perform DC LFC;
  if *LFC successful - convergence* **then**
    Automatically write out the corresponding LF results for active power flow into a defined CSV file;
    Calculate the NPF on the LF results and write to a separate CSV file;
  else
    Report Adjusted CGM validation error;
    Skip to the next MTU Adjusted CGM file & repeat step 2

For our research, the load flow engine was configured in DC mode in other to guarantee convergency for the LFC. The reason we chose DC configuration even though it sacrifices result accuracy compared to the AC LFC is because due to the proportional adjustment of our grid's (CGM) active power component P_i, the reactive component Q_i was not uniformly compensated to account sufficiently for the adjustment on the active components. This mismatch between active and reactive power within the grid resulted in cases of singularity[12] of the Jacobian matrix representation of the grid [29]. Since the Newton-Raphson method requires an inverse of the Jacobian as part of its solution algorithm, the load flow solution diverges in AC mode because the reactive component is not neglected. In DC mode, we could calculate the flows across all the borders, which is sufficient for the implementation of this research PoC.

It is important to note that we only focused our CGM proportional scaling adjustment on the nodes' active and reactive power components within the grid focus study area. Despite the localization of the adjustments, its impact on the power flows across the entire grid was beyond the study area as seen from our load flow calculation results. There are two main reasons for such load flow calculation outcomes:

1. The high level of interconnectivity between the various TSO individual grids that were merged by the RCCs into a common grid model - CGM.
2. There are many flow paths between demand and supply in a transmission network, and the flow will automatically distribute itself over all possible paths and will prioritize the paths that offer the least resistance and technical limitations.

[12] Singularity of the Jacobian matrix means division by zero

Chapter 3

Data Collection, Processing and Results Analysis

In the first part of this chapter, we provide details on the sources of the data used for our studies and the processing challenges in ensuring high-quality input data used as influence factors for the training and prediction of load and generation forecasts. The second part covers the result analysis from the studies: the load and generation forecast, the adjusted CGM generation, the load flow calculation, and finally the results of the net position forecast.

3.1 Data Collection and Processing

For data collection, we used four primary sources—two of which are open sources and could be accessed publicly and the rest are closed source:

– TSCNET Internal CGM generation tool

– ENTSO-E Transparency Platform (ETP)

– Solcast Weather Data Platform

– ENTSO-E Scheduling Verification Platform - Vulcanus

3.1.1 Reference Day-Ahead CGM Data per MTU

In Chapter 2, we explained in detail the Pan-European processes involved in the creation of CGMs for various use cases, following the same approved guidelines depending on the market application or the timeframe in the future in which the CGM is forecasting the market situation of the grid. Our research focus is on the day-ahead capacity calculation process and the week-ahead outage planning coordination process. The relevant CGM used for both use cases are different but the scaled week-ahead net position values within the seasonal referenced Year-Ahead CGM [18] used for the OPI computation are taken from the outcome of the day-ahead capacity calculation process of the previous week's CGM—the day-ahead capacity calculation process for each MTU is performed using the DACF CGMs. The *Reference Day* scaling of the previous week's Net Position values on the referenced seasonal Year-Ahead CGM as a substitute for the NPF of the Week-Ahead;

transforms the Year-Ahead CGM into the so-called *"Week-Ahead"* CGM for the week ahead OPI computation. Figure 3.1 shows a sample reference DACF CGM file for one MTU and the corresponding Adjusted CGM contained in one file after the reference file is scaled using the proportional load and generation scaling algorithm—the sample is shown for Austria's (AT) Node block. The box in green indicates the new node data after the Python adjustment script has successfully performed the adjustment for the 00:30 MTU DACF CGM.

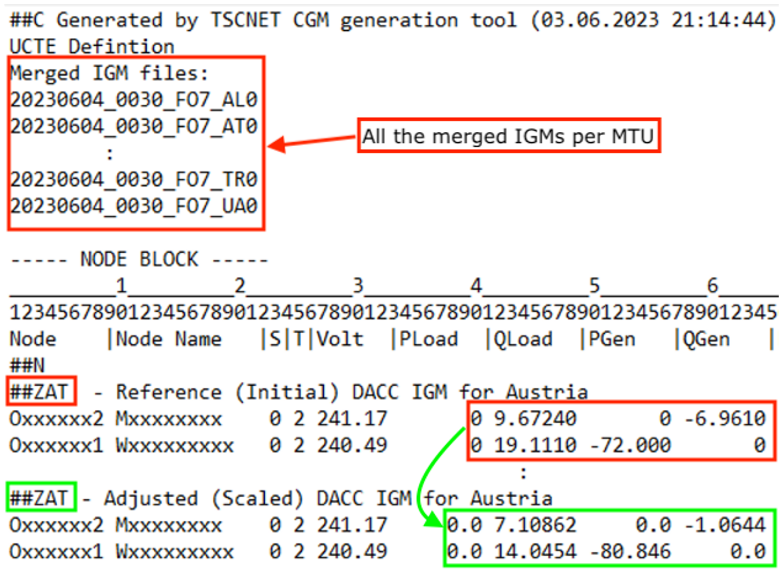


Figure 3.1 UCT format CGM file with both initial and adjusted grid data

We considered One Week of Day-Ahead CGM files (total of 336 MTUs) for our study as the reference DACF CGM files per MTU. All the files were internally generated using the "TSCNET CGM generation tool". The reference CGM creation process is an output from the coordinated security analysis process (CSA). The algorithm for the adjusted CGM generation is shown in Algorithm 3.1:

Algorithm 3.1 Proportional Scaling Algorithm for *Adjusted CGM* Creation

Data: Referenced CGM and forecast load and generation files per MTU
Result: Ajusted CGM per MTU
Define a variable = total sum of the Reference CGM active load and gen;
Define a variable = the proportional scaled active load and gen;
Define a variable = the proportional scaled reactive load and gen;
while *Reference CGM and corresponding forecasted l and g files per MTU exist* **do**
    if *Forecast load and gen exist for a given zone* **then**
        Scale bidding zone with corresponding forecast load and gen;
    else
        No scaling required: copy initial grid data into the new Adjusted CGM file;
    Create a new CGM file with the scaled values for the relevant zones;

3.1.2 Historical Load and Generation Data

From the open-sourced ETP[1], we could gather all the historical load demand and available generation data per MTU from all the 10 relevant countries that constitute the seven relevant bidding zones for this research. For some countries (e.g: Germany), the MTU resolution for its data from ETP were in 15-minute intervals, others were in hourly interval. We processed all input data that were in 15mins intervals into hourly intervals with a Python script that generates the average of 4 successive elements for any given column of a data set. The total period of historical load and generation data collection from the ETP spanned from 2015 till the 30th of June, 2023—a total of seven and half years of historical data.

The ETP also contains generation outage data per generation type corresponding to a given TSO—the challenge with collecting the outage data is that it requires significant data processing in other to accurately map a particular outage to the correct generation type of a particular TSO. Internally, from TSCNET and in collaboration with CORESO, we obtained up to two years of processed generation outage unavailability data from the vendor *Logarithmo*.[2] The following steps for data processing was implemented by Logarithmo:

– Gathering the planned generation unavailability data from ETP per power plant block

– Computing the unavailable power as *"installed capacity"* minus *"available capacity"*

– Processing the outage data such that the correct hourly mean unavailable power values per TSO and generation type are calculated (i.e., handle mixed index frequencies per block and finally aggregate over all blocks per TSO)

Each TSO had varying types of generation outages. To harmonize the consideration of generation outage data as one of the IFs for the forecasting of generation for each of the 10 countries, all the gathered generation outages per type for each country were summed up into a single column called *"Total_Outage"* to be considered within the ML model training and prediction algorithm. Due to the limited number of historical outage data sets we could gather, the training data set for generation forecast was limited to a historical data set of *"One Year and four Months"* and a validation data set of *Two Months - May and June of 2023*. The training data set for the load forecasting was *Seven Years* of historical data and a validation data set of *Six Months - January to June of 2023*.

3.1.3 Historical Weather Data

We got all relevant historical weather data for our studies from the Solcast[3] Weather Data platform. The platform is accessible to the public but requires that all users create an account to access the data. For students and researchers, a certain

[1] ETP: https://transparency.entsoe.eu/
[2] https://www.logarithmo.de/en/
[3] https://solcast.com/

quantity of historical data is accessible for free while other users have to pay to access the data on the platform. We gathered seven and half years period of historical weather data from 2015 till 30th June 2023. Some of the data we collected from the platform includes; hourly historical temperature profile, solar irradation, weed speed, and relative humidity.

3.2 Results Analysis

In this section, we analyzed the results of the load and generation forecast per country, the load flow calculation results, and the corresponding net position forecast results.

3.2.1 Load & Generation Forecast Analysis

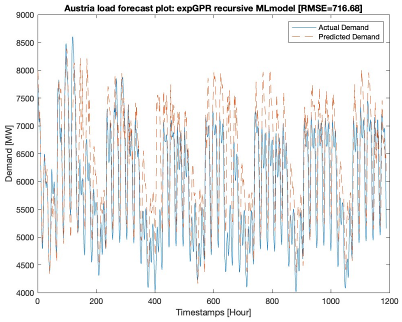
The accuracy load and generation forecast results per country are indicative of the quality of the influence factors data used to train the ML model and the quantity of historical training data set for both load and generation forecast. From our results, we see that the load forecast for all the zones modeled performed much better in terms of the accuracy of the forecast compared to the generation forecast. A good measure of forecast accuracy is the statistical Root Mean Square Error (RMSE) of the predicted values compared to the actual expected values. The load forecast results had much lower RMSE numbers compared to the generation RMSE—this is most likely due to the smaller training data size used for the generation forecast. Figure 3.2 to 3.5 shows a plot of the predicted load and generation vs the actual for the countries within our study area.

3.2.2 Load Flow Calculation Analysis

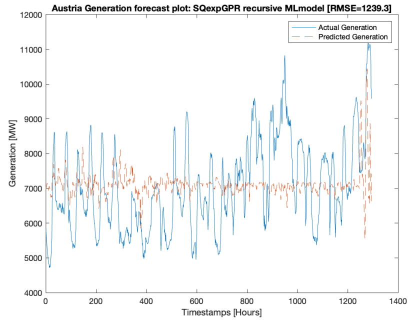
We successfully performed DC LFC on 86 adjusted CGM files—this corresponds to 86 hours of MTUs. From the results of the LFC we could analyze the flow decomposition within the German+ coupled bidding zone. Figure 3.6 shows the LFC from all adjusted 24 CGM on the 4th of June, 2023. We see from the LFC that for the shown business day, most of the day-ahead procured capacities were from 09:00 AM till 16:00 PM, the most exchanged capacities are between the German D2-D7 and D2-D8 borders. We also see from the result that while Germany is importing capacities from Denmark, it is exporting to Luxembourg—this is due to the high share of renewable power generation in Denmark largely from Wind resources.

3.2.3 Net Position Forecast Analysis

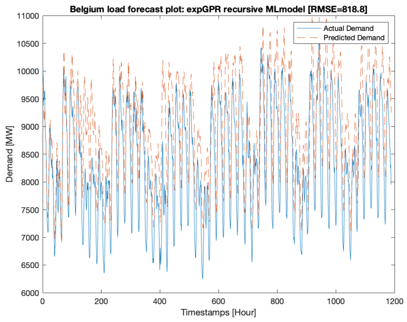
The results of the NPF are analyzed for the day-ahead and week-ahead use cases respectively. For both cases, the NPF from the referenced CGM published on the Vulcanus platform is compared with the results of the NPF from the adjusted CGM LFC. Figure 3.7 to 3.10 shows the mean absolute error (MAE) and the percentage error of NPF from the reference CGM and the Adjusted CGM compared to the Realized Flow and Measured-Physical Flow Net Position values published on the Vulcanus platform. Equation 3.1 - 3.3 were used to calculated the MAE and the %Errors. Focusing on the German DE+ results, we see that the associated NPF



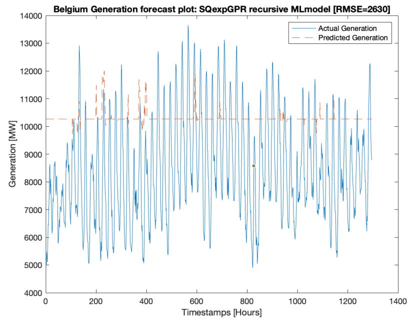
(a) Austria Load Forecast



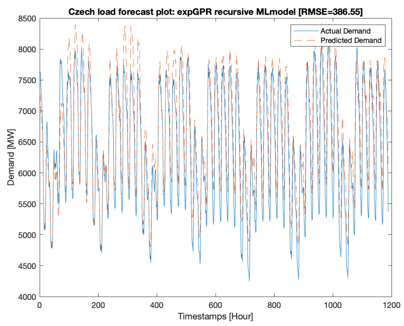
(b) Austria Generation Forecast



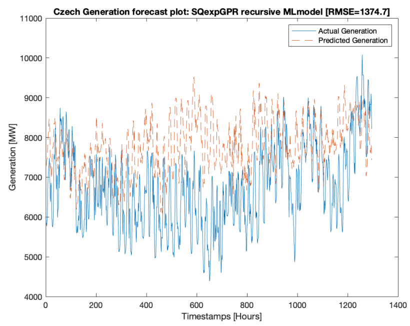
(c) Belgium Load Forecast



(d) Belgium Generation Forecast



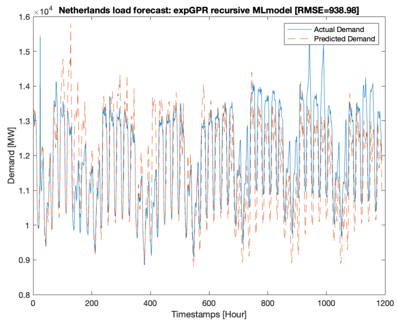
(e) Czech Load Forecast



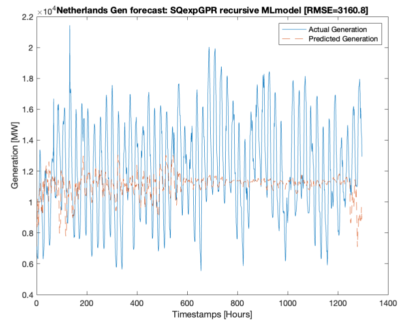
(f) Czech Generation Forecast

Figure 3.2 Load and Generation Forecast - AT, BE, & CZ

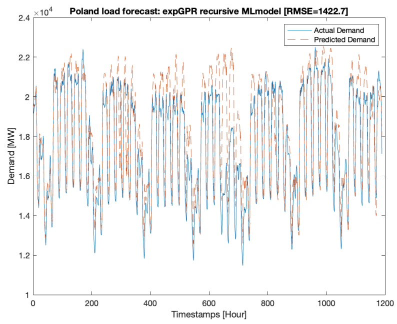
error for the Day-Ahead use case compared to the Realized Flow Net Position is equal to an MAE of 1623MW over a period of three business days 72 (hours)—this corresponds to a percentage error of 35%. For the Week-Ahead use case, the associated error compared to the Measured-Physical Flow Net Position published on Vulcanus is equal to 5804MW in three business days—corresponding to a percentage error of 620%. The implication of the associated error from the referenced NPF approach for the week-ahead and the NPF coming from the DACF that generated the reference DACC CGM is that for both the Day-Ahead and the Week-Ahead use cases, the forecasted Net position results would require significant remedial action measures such as re-dispatching of reserve capacities, counter-trading of capacities, etc, by the TSOs during real-time operation. Such measures do impact social



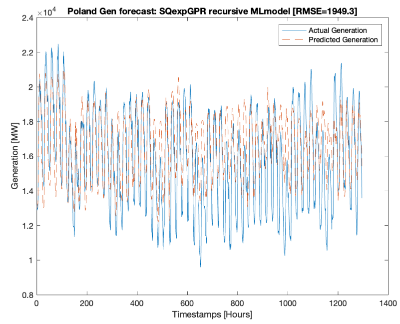
(a) Netherlands Load Forecast



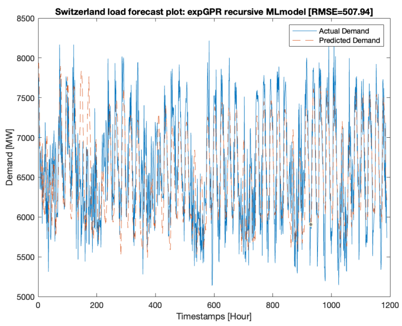
(b) Netherlands Generation Forecast



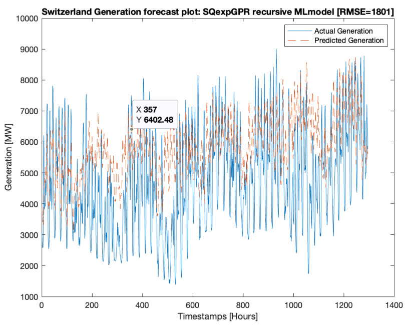
(c) Poland Load Forecast



(d) Poland Generation Forecast



(e) Switzerland Load Forecast



(f) Switzerland Generation Forecast

Figure 3.3 Load and Generation Forecast - NL, PL, & CH

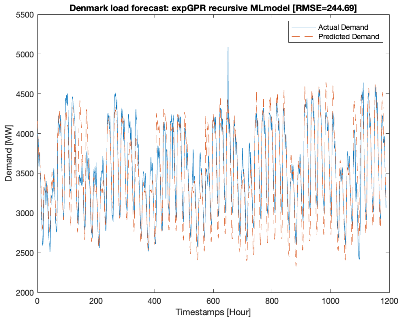
welfare in a way that results in higher energy prices for end-users.

$$MAE_{day-ahead} = \frac{1}{n}|NP_{predicted} - NP_{realized}| \tag{3.1}$$

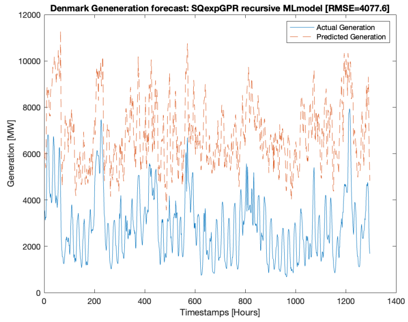
$$MAE_{week-ahead} = \frac{1}{n}|NP_{predicted} - NP_{Mphysical}| \tag{3.2}$$

$$\%Error = |\frac{1}{NP_{actual}}[NP_{predicted} - NP_{actual}]| \tag{3.3}$$

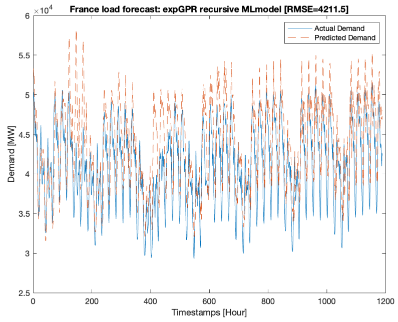
For our NPF PoC implementation, we hoped that our NPF would result in a more accurate NPF for both the Day-Ahead and the Week-Ahead use cases when com-



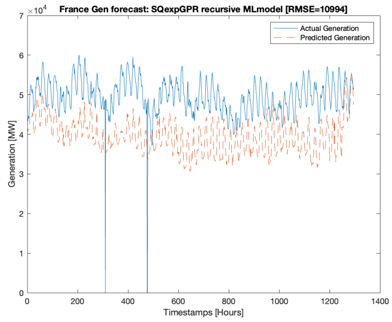
(a) Denmark Load Forecast



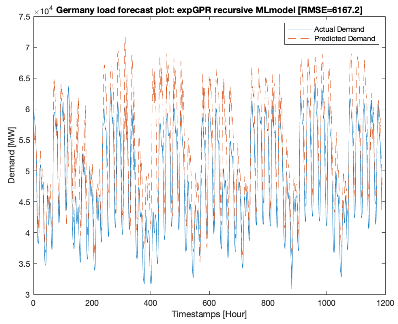
(b) Denmark Generation Forecast



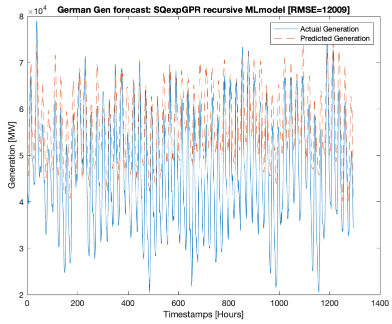
(c) France Load Forecast



(d) France Generation Forecast



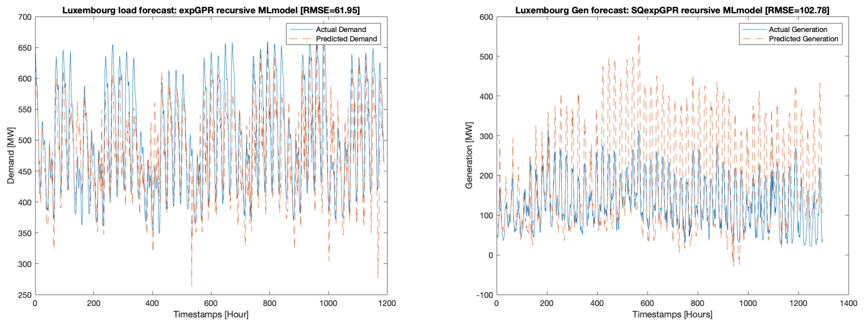
(e) Germany Load Forecast



(f) Germany Generation Forecast

Figure 3.4 Load and Generation Forecast - DK, FR, & DE

pared to the Reference Day approach and the outcome of the DACF process. On the contrary, the accuracy of the results from our NPF PoC was not better. From Figure 3.7 to 3.10, focusing on the DE+ zone, we see that the associated error for the Day-Ahead use case compared to the Realized Flow Net Position is equal to an MAE of 48870MW over a period of three business days—this corresponds to a percentage error of 830%. For the Week-Ahead use case, the associated error compared to the Measured-Physical Flow Net Position published on Vulcanus is equal to 41502MW in three business days—corresponding to a percentage error of 4262%. The large percentage error difference our results show is largely due to the influence of the generation forecast results that were used for the scaling of the Adjusted CGMs. The accuracy of the generation forecast was largely impacted by



(a) Luxembourg Load Forecast **(b)** Luxembourg Generation Forecast

Figure 3.5 Load and Generation Forecast - LU

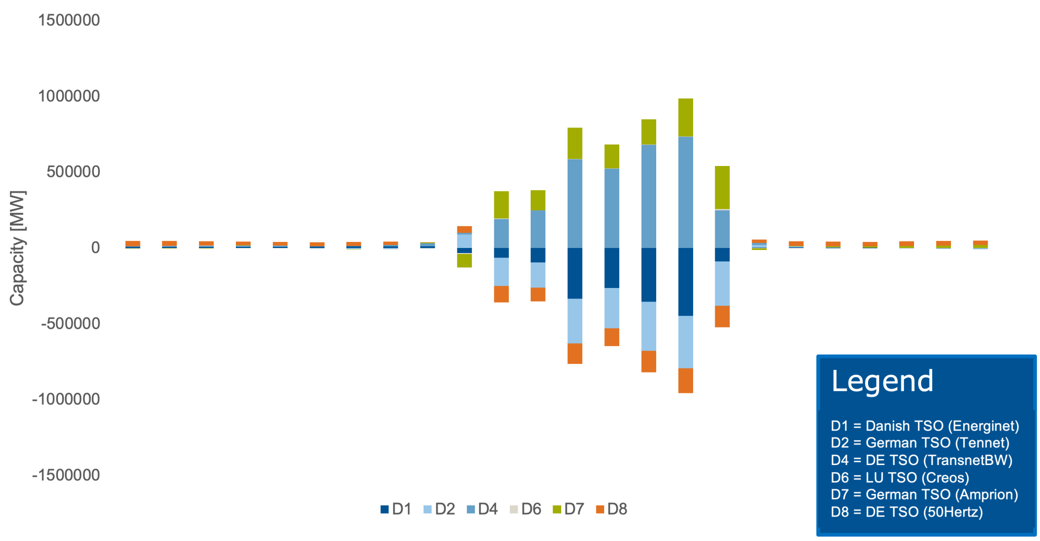
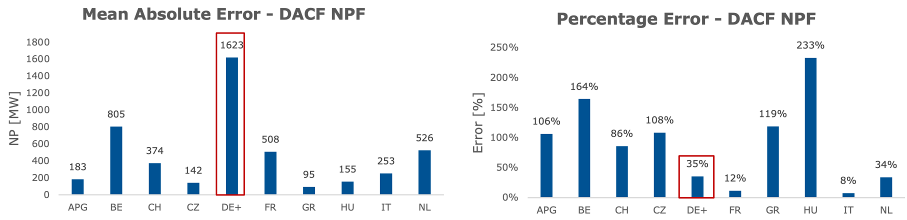


Figure 3.6 Load Flow Decomposition within DE+ for Adjusted CGM

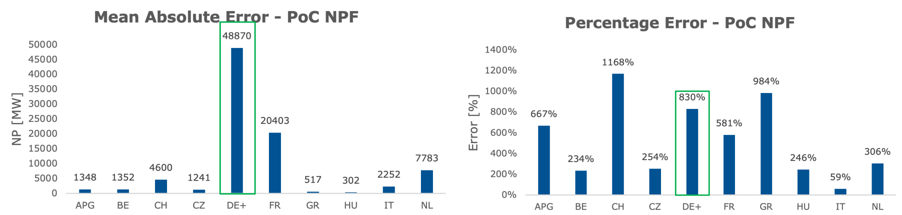
the quality of the outage data and also the fact that we did not have significant historical data from the forecast compared to the load forecast. Also, when the actual historical load and available generation from the ETP data are compared with the summation of the active load and generation component of the referenced CGM over a time period, the data on the ETP per country is significantly higher than the data contained within the CGM.

However, with the results we have from the NPF PoC, we have successfully demonstrated that it is feasible to forecast NPF with the proposed approach in this thesis. We have also identified potential approaches that can be implemented in future research to improve the NPF PoC results outcome.



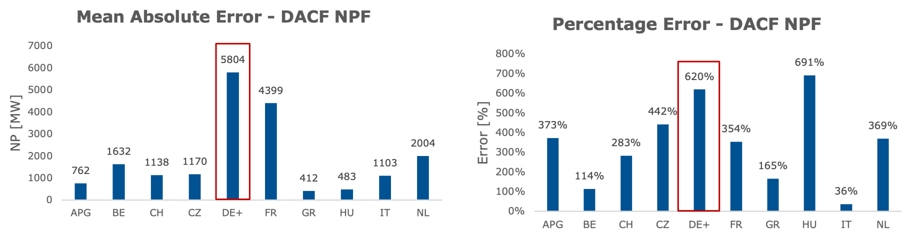
(a) MAE - Day-Ahead Use Case **(b)** %Error - Day-Ahead Use Case

Figure 3.7 DACC NPF compared to the Realized Flow Net Position



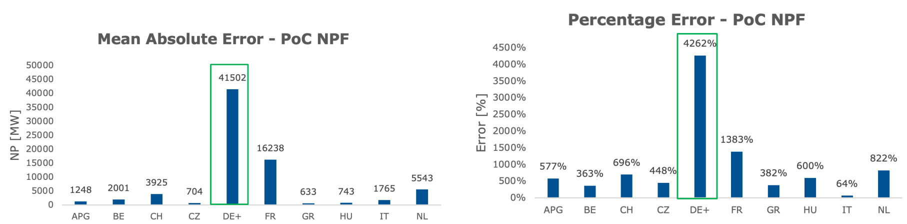
(a) MAE - Day-Ahead Use Case **(b)** %Error - Day-Ahead Use Case

Figure 3.8 Adjusted NPF compared to the Realized Flow Net Position



(a) MAE - Week-Ahead Use Case **(b)** %Error - Week-Ahead Use Case

Figure 3.9 DACC NPF compared to the Measured-Physical Flow Net Position



(a) MAE - Week-Ahead Use Case **(b)** %Error - Week-Ahead Use Case

Figure 3.10 Adjusted NPF compared to the Measured-Physical Flow Net Position

Chapter 4

Conclusion

4.1 Summary

In the scope of the thesis, we had three main objectives: first is to quantify the corresponding error of the Day-Ahead NPF from the day-ahead congestion forecast (DACF) IGMs provided by the TSOs to the RCCs for the coordinated computation of the day-ahead capacity calculation (DACC) process compared to the actual Realised market flows Net Position values for the same MTUs. The second objective is to quantify the corresponding error associated to the referenced day DACC NPF approach used for the OPI process to the actual Measured Physical flow Net Position values for the corresponding Week-Ahead MTUs. The third objective of the thesis is to implement an NPF Proof of Concept (PoC) that predicts the future MTUs Net Position of a given country (Bidding Zone) by means of active load demand and actual generation forecast with a Machine Learning time-series forecast algorithm, scaling the forecast load and generation proportionally within the reference DACF CGM and finally calculating the forecast Net Position using the scaled (adjusted) CGM by performing load flow calculation with a load flow engine. We successfully achieved all the objectives of the thesis and below are the conclusions from our research:

– Successfully performed DC LFC in PowerFactory for 86 Adjusted CGMs and implemented the proposed NPF PoC within the research thesis.

– The results from the NPF PoC were less accurate compared to the DACF NPF: both for the Day-Ahead and the Week-Ahead use cases. Mostly due to the accuracy of the generation forecast.

– The NPF PoC results from our implementation, confirm that the accuracy of NPF per zone is influenced by the accuracy of load and generation forecast of the zone and the exchange of capacity with neighbouring zones.

All forecast models of this study were implemented and realized in MATLAB and the CGM scaling, the LFC and NPF calculation were all implemented using Python.

4.2 Outlook

Despite the lower accuracy of the implemented NPF PoC compared to the existing DACF NPF approach, we have identified potential steps and areas of research focus that could lead to improved results for the proposed NPF PoC. From the experience with our load and generation forecast, we see that improving the initial load and generation forecast is crucial to ensure an accurate NPF.

- A possible approach is to constraint the historical training data set with real-time NP results for each zone in the CGM
- It is also important to ensure quality processing of input data from multiple external sources (ETP, Solcast. . .)

Future research could focus on the following:

- Improving the load and generation forecast models
- Investigating the potential electricity tariff cost in Euros to end-users due to NPF errors in the Day-Ahead Market
- Researching the impact of different load and generation scaling methods on the accuracy of NPF

Appendix A

Net Position results published on Vulcanus Platform & Calculated

Date 01.06.2023 - 07.06.2023

Day Ahead LFC Block Programs of UCTE Control Blocks in MW

		Amprion	Amprion	Amprion	Amprion	Amprion	Swissgrid	Swissgrid	Swissgrid	Swissgrid	Swissgrid	Swissgrid	Amprion	Amprion	Swissgrid	Amprion	Amprion	Amprion	Swissgrid	Swissgrid	Swissgrid	Amprion	Vulcanus
Date	Time CET	BE	DE	NL	APG	PL	CH	FR	IT	SHB	GR	SMM	RO	BG	AK	CZ	HU	SK	TR	ES+	PT	UA	TOTAL
		Linkebeek	Brauweiler	Arnhem	Wien	Warszawa	Aarau	St. Denis	Roma	Ljubljana	Athens	Belgrade	Bucharest	Sofia	Tirana	Praha	Budapest	Zilina	Ankara	Madrid	Lisboa	Lviv	
01.06.2023	00-01	-317	-5032	2068	1104	-832	2606	9931	-6754	1227	-769	-78	176	-463	215	-487	-1796	1048	3	-416	-1435	1	0
	01-02	-302	-4580	1233	850	-430	285	12245	-6835	1285	-829	-80	341	-419	302	-688	-1617	1078	9	-287	-1563	2	0
	02-03	-284	-4988	1273	742	76	-86	11953	-6850	1299	-783	-42	417	-437	357	-565	-1370	1123	14	-635	-1215	1	0
	03-04	-1073	-5657	1556	508	195	68	13138	-6736	1149	-729	-20	450	-408	393	-527	-1338	1131	-251	-767	-1083	1	0
	04-05	-338	-6340	1876	434	155	195	13188	-6626	1174	-846	-31	446	-316	378	-515	-1315	1104	-225	-1034	-1366	0	-2
	05-06	-574	-7307	2515	404	-958	1954	12917	-6526	1361	-919	-36	432	-458	388	-624	-1353	1050	141	-1091	-1309	-6	1
	06-07	-699	-9765	2897	1986	-1364	3867	10761	-5907	1596	-325	54	364	-334	620	-892	-1666	959	150	-1563	-737	-4	-2
	07-08	-51	-9009	2037	2171	-923	4668	7930	-6032	1446	-107	-14	244	-140	533	-971	-1340	954	118	-1632	115	1	-2
	08-09	-120	-6989	1092	2172	-145	3786	5079	-6188	1443	-143	-26	242	115	440	-806	-542	849	123	-239	-146	2	-1
	09-10	-96	-1091	1493	1090	867	2655	2713	-6547	508	-566	-47	373	313	121	-902	204	798	6	-262	-1829	200	1
	10-11	469	2306	1157	206	1424	-347	2787	-6547	211	-441	-31	393	384	95	-1033	610	735	-276	10	-2310	199	1
	11-12	683	5035	2133	-376	342	-1223	1893	-6522	-187	-294	-155	406	443	110	-1014	989	143	-288	84	-2384	181	-1
	12-13	1546	6441	2125	-852	53	-772	152	-5451	-236	-196	-273	408	376	156	-1712	878	-37	-487	29	-2329	180	-1
	13-14	1704	7667	1975	-832	4	-1023	287	-5451	-381	-349	-201	-173	198	155	-1710	774	-38	-487	-185	-2115	180	-1
	14-15	1711	7282	2070	-881	204	-1134	728	-5451	-306	-491	-186	58	146	146	-1690	612	-13	-487	-208	-2092	-18	0
	15-16	1637	6808	2509	-1043	442	-1045	1464	-6163	-7	-646	-231	195	147	157	-1753	329	38	-477	178	-2428	-110	1
	16-17	657	4590	3447	-1096	399	-892	3538	-6163	-9	-868	9	105	-103	132	-1283	-255	399	-241	282	-2532	-116	0
	17-18	1479	-68	2381	-190	81	262	5580	-6113	488	-647	21	0	-455	108	-1402	-1021	418	70	1102	-2066	-28	0
	18-19	122	-3127	3025	474	-635	2663	6410	-6543	1213	-628	39	-235	-817	484	-1392	-1710	706	48	1403	-1492	-9	-1
	19-20	414	-5957	2374	1904	-1420	3749	5490	-6294	1320	-402	29	-432	-672	482	-1222	-1943	1030	102	2022	-562	-10	2
	20-21	306	-7141	1910	2444	-1177	5173	6276	-6141	1192	-412	-44	-598	-670	455	-909	-2056	1119	150	385	-255	-6	1
	21-22	323	-6847	1922	2607	-1344	4938	8411	-6288	1239	-391	2	-380	-731	467	-952	-2111	1144	145	-1928	-222	-3	1
	22-23	116	-5828	1002	2624	-798	5097	7544	-5971	1204	-1082	20	41	-653	343	-572	-2055	969	150	-1504	-646	-1	0
	23-00	-48	-3975	962	1288	-308	3563	8276	-6406	973	-855	-29	239	-536	108	-292	-2002	1071	115	-207	-1943	6	0

Figure A.1 Day-Ahead LFC Block Program of UCTE Control Blocks NPF

Date 01.06.2023 - 07.06.2023

Realized Control Programs of UCTE Control Blocks in MW

		Amprion	Amprion	Amprion	Amprion	Amprion	Swissgrid	Swissgrid	Swissgrid	Swissgrid	Swissgrid	Swissgrid	Amprion	Amprion	Swissgrid	Amprion	Amprion	Amprion	Swissgrid	Swissgrid	Swissgrid	Vulcanus
Date	Time CET	BE	DE+	NL	APG	PL & UA	CH	FR	IT	SHB	GR	SMM	RO	BG	AL	CZ	HU	SK	TR	ES+	PT	TOTAL
		Linkebeek	Brauweiler	Arnhem	Wien	Warszawa	Laufenburg	St. Denis	Roma	Ljubljana	Athens	Belgrade	Bucharest	Sofia	Tirana	Praha	Budapest	Zilina	Ankara	Madrid	Lisboa	
01.06.2023	00-01	462	-4699	1436	1154	-812	2599	9164	-6703	1262	-613	-93	154	-410	215	-484	-1876	1019	3	-215	-1466	97
	01-02	626	-4295	783	966	-393	647	10400	-6534	1301	-739	-95	323	-346	315	-651	-1652	1053	9	-176	-1464	78
	02-03	590	-4936	689	821	76	409	8907	-5879	1314	-726	-52	422	-366	370	-515	-1367	1104	14	329	-1157	47
	03-04	-173	-6617	853	720	195	478	10991	-5791	1128	-711	-35	472	-413	393	-446	-1343	1094	-251	657	-1157	44
	04-05	578	-6567	1151	701	188	696	11694	-6225	1174	-826	-46	462	-287	378	-454	-1437	1074	-225	-693	-1307	29
	05-06	415	-6793	1655	728	-879	2346	10793	-6223	1358	-931	-44	410	-442	394	-571	-1502	1027	141	-917	-979	-14
	06-07	263	-9668	2124	1960	-1323	3956	8888	-5275	1569	-296	39	328	-321	620	-780	-1788	935	150	-722	-645	14
	07-08	238	-8654	1057	2090	-758	4921	5353	-5565	1425	6	-14	223	-186	533	-879	-1556	921	118	-453	1179	-1
	08-09	-454	-5163	-273	1925	125	3961	3152	-5549	1353	25	-25	232	124	440	-819	-773	840	123	133	708	85
	09-10	-879	-1043	392	1067	1279	3393	2329	-5453	443	-419	-46	376	344	121	-1166	41	799	6	-211	-1483	-110
	10-11	-276	2168	320	185	1859	1308	1324	-5777	93	-294	-29	367	399	95	-1025	659	694	-276	-180	-1761	-147
	11-12	369	4094	1352	-376	966	258	1425	-5898	-228	-219	-154	388	447	110	-1112	781	159	-288	-296	-1958	-180
	12-13	818	4373	1739	102	716	24	106	-5216	-171	-16	-273	358	410	156	-1473	811	12	-487	164	-2322	-169
	13-14	1173	5141	1772	-78	913	-122	496	-5398	-286	-101	-276	-201	327	155	-1711	882	6	-487	-442	-1858	-95
	14-15	1293	4462	2029	144	759	-165	613	-5353	-252	-408	-271	69	264	146	-1647	455	8	-487	446	-2100	5
	15-16	1401	2868	2491	339	1165	339	574	-5999	-76	-475	-266	172	167	157	-1772	-179	22	-477	1843	-2243	51
	16-17	749	2802	2202	412	176	628	2743	-6011	-14	-518	-66	126	-55	132	-1181	-766	405	-241	720	-2175	68
	17-18	1213	-1374	490	594	721	2608	4504	-5712	505	-451	-71	-13	-389	108	-1309	-1404	412	70	1608	-2035	75
	18-19	974	-3375	1110	1021	-694	3215	4357	-5784	1352	-480	-69	-226	-751	484	-1019	-2046	738	48	1711	-514	52
	19-20	1369	-6513	956	2249	-1673	3795	4848	-5224	1363	-130	-85	-501	-641	542	-724	-2433	1024	102	1297	484	105
	20-21	1172	-7432	1079	2653	-1543	4728	5055	-4885	1220	3	-117	-657	-617	515	-648	-2576	1089	150	382	536	107
	21-22	1342	-5453	1200	2832	-1547	4366	5674	-4737	1347	9	-106	-421	-703	467	-713	-2604	1098	145	-2104	-29	63
	22-23	934	-4969	1295	2616	-1159	4447	4903	-4960	1324	-637	-83	34	-553	343	-528	-2425	975	150	-1732	101	76
	23-00	839	-6425	783	1263	-50	3480	7595	-4943	1091	-595	-53	214	-502	121	-303	-2235	1023	115	-625	-730	63

Figure A.2 Realized Control Program of UCTE Control Blocks NPF

Date	08.06.2023 - 14.06.2023																					
		Measured Load Flows of UCTE Control Blocks in MW																				
		Amprion	Amprion	Amprion	Amprion	Amprion	Swissgrid	Swissgrid	Swissgrid	Swissgrid	Swissgrid	Swissgrid	Amprion	Amprion	Swissgrid	Amprion	Amprion	Amprion	Swissgrid	Swissgrid	Swissgrid	Vulcanus
Date	Time CET	BE	DE+	NL	APG	PL & UA	CH	FR	IT	SHB	GR	SMM	RO	BG	AL	CZ	HU	SK	TR	ES+	PT	TOTAL
		Linkebeek	Brauweiler	Arnhem	Wien	Warszawa	Laufenburg	St. Denis	Roma	Ljubljana	Athens	Belgrade	Bucharest	Sofia	Tirana	Praha	Budapest	Zilina	Ankara	Madrid	Lisboa	
08.06.2023	00-01	287	-10638	2070	1207	-2279	3154	8284	-3855	1589	-465	416	257	737	-29	439	-1838	946	142	-376	-46	2
	01-02	289	-10593	2205	1162	-1914	2298	9636	-4344	1793	-659	443	284	839	56	243	-1595	1051	142	-266	-1069	1
	02-03	171	-10001	2008	1211	-1435	1064	9780	-4361	1731	-935	369	272	882	110	471	-1468	1041	125	-51	-983	1
	03-04	378	-10331	1734	1255	-1651	966	10972	-4394	1669	-1000	356	238	884	134	524	-1460	993	152	-47	-1373	-1
	04-05	326	-10744	1866	1167	-1194	1259	10338	-4097	1686	-969	288	230	879	112	544	-1432	995	170	-229	-1194	1
	05-06	166	-11046	2152	1491	-896	2058	9503	-3898	1836	-612	616	62	619	134	251	-1519	935	170	-875	-1145	2
	06-07	-154	-10605	2303	1894	-890	3018	8134	-3934	1755	-238	626	-338	789	163	-268	-1866	792	171	-1385	32	-1
	07-08	-628	-9958	2148	2108	4	3395	5637	-4469	1630	51	435	-495	1086	64	-578	-1749	664	121	-707	1241	0
	08-09	-1362	-6376	2469	2111	586	3008	3136	-4603	1429	326	291	-467	1402	-28	-828	-1369	581	65	-1851	1482	2
	09-10	-1276	-1727	2206	1843	1667	1390	2037	-4556	1074	198	65	-445	1581	-101	-1504	-1032	525	24	-2994	1027	2
	10-11	-441	-308	2290	1818	2263	397	401	-4847	840	-339	-19	-314	1603	-163	-1554	-800	457	-204	-1852	773	1
	11-12	-160	-408	3616	1553	1705	-211	-19	-4821	553	-338	-40	-185	1697	-153	-1834	-473	143	-44	-1238	655	-2
	12-13	66	1611	4445	1611	1598	-788	-434	-4899	504	-235	55	-47	1658	-113	-2481	-386	-2	-290	-1713	-160	0
	13-14	522	-1899	4647	1050	1323	-747	-474	-5003	464	-346	172	125	1497	-117	-2199	-500	45	-452	-1430	-477	-1
	14-15	807	2102	5058	1391	1126	-527	-1604	-5328	593	-409	139	12	1531	-114	-2046	-808	78	-446	-1362	-192	1
	15-16	1138	640	5435	1166	630	-527	-1103	-5781	610	-625	156	-147	1354	-125	-1445	-1086	86	-283	9	-100	2
	16-17	1476	-802	4696	1227	-207	-270	762	-6007	712	-730	204	-203	1115	-157	-1189	-1408	387	-368	1032	-272	-2
	17-18	521	-2944	4523	1215	-127	72	1605	-5712	1279	-666	240	-170	747	-153	-903	-1602	465	46	1857	-292	1
	18-19	436	-4975	4110	1444	-1231	2941	919	-5186	1520	-869	345	-474	454	-29	-308	-1991	625	150	2417	-299	-1
	19-20	1256	-7934	2888	2439	-1281	5033	632	-5411	1530	-980	631	-621	690	56	278	-2303	898	147	1540	515	3
	20-21	1923	-7899	2384	2879	-553	4559	857	-5397	1375	-1078	403	-974	589	96	296	-2492	1032	193	-185	1990	-2
	21-22	1926	-8282	1867	2920	-1199	5085	2143	-4779	1343	-662	463	-701	307	93	624	-2451	1067	140	-2480	2577	1
	22-23	908	-7643	1274	1811	-1185	4310	2427	-3359	1286	-883	523	-378	390	-18	742	-2277	1002	179	-1501	2392	0
	23-00	427	-6271	1456	1712	-1603	2714	4236	-3428	1391	-952	213	-105	563	-78	412	-2082	1047	88	-1045	1308	3

Figure A.3 Measured Load Flow of UCTE Control Blocks NPF

ENTSO-E RG CE Verification Platform / Repository

Home | Frequencies | Programs | **Load flows** | Primary reserves | Legacy tables | Message board ▾ | Administration ▾ | Info ▾ | Logout TSCNET

‹ | 08.06.2023 | › | Physical Flow (1) ▾ | Hourly | Quarterly | Download ...

Measured Load Flows of UCTE Control Blocks in MW

Updated at 20.06.2023 14:22:28	Amprion BE Linkebeek	Amprion DE+ Brauweiler	Amprion NL Arnhem	Amprion APG Wien	Amprion PL & UA Warszawa	Swissgrid CH Laufenburg	Swissgrid FR St. Denis	Swissgrid IT Roma	Swissgrid SHB Ljubljana	Swissgrid GR Athens	Swissgrid SMM Belgrade	Amprion RO Bucharest	Amprion BG Sofia	Swissgrid AL Tirana	Amprion CZ Praha	Amp H Buda
00 - 01	287	-10638	2070	1207	-2279	3154	8284	-3855	1589	-465	416	257	737	-29	439	-1838
01 - 02	289	-10593	2205	1162	-1914	2298	9636	-4344	1793	-659	443	284	839	56	243	-1595
02 - 03	171	-10001	2008	1211	-1435	1064	9780	-4361	1731	-935	369	272	882	110	471	-1468
03 - 04	378	-10331	1734	1255	-1651	966	10972	-4394	1669	-1000	356	238	884	134	524	-1460
04 - 05	326	-10744	1866	1167	-1194	1259	10338	-4097	1686	-969	288	230	879	112	544	-1432
05 - 06	166	-11046	2152	1491	-896	2058	9503	-3898	1836	-612	616	62	619	134	251	-1519
06 - 07	-154	-10605	2303	1894	-890	3018	8134	-3934	1755	-238	626	-338	789	163	-268	-1866
07 - 08	-628	-9958	2148	2108	4	3395	5637	-4469	1630	51	435	-495	1086	64	-578	-1749
08 - 09	-1362	-6376	2469	2111	586	3008	3136	-4603	1429	326	291	-467	1402	-28	-828	-1369
09 - 10	-1276	-1727	2206	1843	1667	1390	2037	-4556	1074	198	65	-445	1581	-101	-1504	-1032
10 - 11	-441	-308	2290	1818	2263	397	401	-4847	840	-339	-19	-314	1603	-163	-1554	-800
11 - 12	-160	-408	3616	1553	1705	-211	-19	-4821	553	-338	-40	-185	1697	-153	-1834	-473
12 - 13	66	1611	4445	1611	1598	-788	-434	-4899	504	-235	55	-47	1658	-113	-2481	-386
13 - 14	522	1899	4647	1050	1323	-747	-474	-5003	464	-346	172	125	1497	-117	-2199	-500
14 - 15	807	2102	5058	1391	1126	-527	-1604	-5328	593	-409	139	12	1531	-114	-2046	-808
15 - 16	1138	640	5435	1166	630	-527	-1103	-5781	610	-625	156	-147	1354	-125	-1445	-1086
16 - 17	1476	-802	4696	1227	-207	-270	762	-6007	712	-730	204	-203	1115	-157	-1189	-1408
17 - 18	521	-2944	4523	1215	-127	72	1605	-5712	1279	-666	240	-170	747	-153	-903	-1602
18 - 19	436	-4975	4110	1444	-1231	2941	919	-5186	1520	-869	345	-474	454	-29	-308	-1991
19 - 20	1256	-7934	2888	2439	-1281	5033	632	-5411	1530	-980	631	-621	690	56	278	-2303
20 - 21	1923	-7899	2384	2879	-553	4559	857	-5397	1375	-1078	403	-974	589	96	296	-2492
21 - 22	1926	-8282	1867	2920	-1199	5085	2143	-4779	1343	-662	463	-701	307	93	624	-2451
22 - 23	908	-7643	1274	1811	-1185	4310	2427	-3359	1286	-883	523	-378	390	-18	742	-2277
23 - 00	427	-6271	1456	1712	-1603	2714	4236	-3428	1391	-952	213	-105	563	-78	412	-2082
TOTAL	9002	-133233	69850	39685	-6743	43651	87805	-112469	30192	-13415	7390	-4584	23893	-360	-12313	-35987

Figure A.4 Screenshot of the Vulcanus Platform's user interface

04.06.23	Data Time	AT	BE	CH	CZ	DE+	FR	GR	HU	IT	NL	PL	SK	UA	PL & UA	
Sunday	2023-06-04 00:00:00	1530	-41	-2159	1376	44553	-22758	-2032	-1885	-4884	-1399	-2440	833	-1329	-3768,73	
Sunday	2023-06-04 01:00:00	1655,165	643,8315	-2840,06	1393,959	44222,85	-21543,2	-2098,5	-1831,12	-5341,76	-1453,9	-2674,76	943,6396	-1405,05	-4079,81	
Sunday	2023-06-04 02:00:00	1722,862	248,8075	-3379	1321,011	43057,96	-17797,6	-2161,65	-1687,49	-5525,69	-1680,24	-2870,46	916,5331	-1673,26	-4543,72	
Sunday	2023-06-04 03:00:00	1912,137	242,5658	-3518,86	1367,917	41263,98	-16139,9	-2213,46	-1669,25	-5598,89	-1017,45	-2473,11	833,7323	-1795,33	-4268,44	
Sunday	2023-06-04 04:00:00	1950,146	280,5667	-3691,35	1276,331	39690,7	-14433,3	-2255,45	-1621,1	-5878,3	-919,784	-2019,44	878,3656	-1857,16	-3876,6	
Sunday	2023-06-04 05:00:00	1926,661	636,0271	-3027,63	1416,669	35717,51	-13456,7	-2184,5	-1390,14	-5736,14	-876,252	-1530,6	933,547	-1773,14	-3303,74	
Sunday	2023-06-04 06:00:00	1757,88	821,081	-2334,01	1692,277	32544,26	-11801,3	-2045,44	-1170,84	-5148,07	-567,387	-1952,78	843,5571	-2013,97	-5206,75	
Sunday	2023-06-04 07:00:00	1144,217	630,8991	-1898,1	1736,24	34019,55	-11520,5	-2016,67	-1002,02	-5560,2	-1449,12	-1625,16	655,0284	-2200,91	-3826,07	
Sunday	2023-06-04 08:00:00	671,2641	49,52705	-1876,05	1966,396	32289,68	-9809,75	-1649,86	-308,796	-5494,74	-3081,64	-150,58	394,8547	-2319,01	-2469,39	
Sunday	2023-06-04 09:00:00	1168,194	768,9783	-225,493	2512,179	17305,85	-2904,22	-1368,79	529,6686	-4824,74	-11995,7	2590,64	391,9995	-772,217	1818,424	
Sunday	2023-06-04 10:00:00	757,4018	230,5305	-1498,64	2013,796	17486,97	-2285,52	-1444,86	744,7789	-4932,31	-4422,92	1626,062	193,9448	-1075,34	550,7259	
Sunday	2023-06-04 11:00:00	460,5356	-156,656	-3219,14	1593,898	29643,2	-5177,63	-1678,12	732,2076	-4943,92	-4377,52	164,0935	-90,1851	-1425,16	-1261,07	
Sunday	2023-06-04 12:00:00	597,7097	-132,169	-3813,46	1635,117	31413,75	-6905,65	-1665,01	912,9836	-4492,48	-4117,31	-585,326	-449,218	-1343,63	-1928,96	
Sunday	2023-06-04 13:00:00	759,1987	127,6246	-6615,95	1848,762	34677,17	-10617,1	-1459,72	990,3338	-3245,42	-3709,26	-791,383	-428,457	-1247	-2038,38	
Sunday	2023-06-04 14:00:00	1015,56	226,882	-4179,27	1901,829	30563,53	-10287,8	-1353,64	938,6896	-2790,48	-3571,52	-551,907	-463,147	-1156,61	-1708,51	
Sunday	2023-06-04 15:00:00	1138,968	240,6301	-3755,09	1886,822	31116,58	-9899,09	-1539,72	472,9068	-3511,25	-4273,46	-562,64	-220,462	-1187,03	-1750,26	
Sunday	2023-06-04 16:00:00	1509,781	725,0109	-1480,22	2212,439	18577,4	-7745,01	-1460,7	-48,9631	-4487,69	-2869,13	994,3445	355,4486	-707,929	286,4151	
Sunday	2023-06-04 17:00:00	1069,593	-77,9295	-2269,51	1614,605	44270,28	-12122,2	-1720,15	-922,236	-5428,24	-16331,2	595,1811	361,7888	-1293,69	-698,511	
Sunday	2023-06-04 18:00:00	591,6737	-425,619	-2511,19	853,9974	42318,44	-15393,9	-1803,13	-1719,01	-7101,17	-4832,17	-760,787	453,3773	-1647,27	-2408,06	
Sunday	2023-06-04 19:00:00	521,9591	98,00433	-2810,27	682,9057	40253,79	-15231,9	-1577	-2095,23	-6983,7	-2810,4	-526,031	602,5921	-1366,31	-1892,34	
Sunday	2023-06-04 20:00:00	610,7751	-349,161	-1087,72	632,5679	37479,53	-15939,1	-1320,8	-2223,81	-6773,77	-1798,62	-278,352	753,0669	-992,076	-1270,43	
Sunday	2023-06-04 21:00:00	535,4875	-422,701	-1329,28	379,5529	41609,67	-16634,9	-1251,04	-2531,99	-7142,57	-1095,29	-1852,37	781,9548	-1170,42	-3022,79	
Sunday	2023-06-04 22:00:00	571,5881	-255,415	-1642,68	313,3009	42579,3	-17092,7	-1659,48	-2273,61	-6903,77	-523,322	-2843,64	740,9001	-1181,69	-4025,33	
Sunday	2023-06-04 23:00:00	786,807	-96,8781	-2793,2	468,8492	42546,85	-17639,2	-1987,85	-1970,89	-5286,01	-132,674	-2787,29	754,2452	-1223,74	-4011,03	
Monday	2023-06-05 00:00:00	819,0103	356,4674	-3726,59	338,6542	54005,7	-21480,5	-2029,12	-1852,73	-8325,49	-789,965	-2465,62	679,8019	-1523,64	-3989,25	
Monday	2023-06-05 01:00:00	1019,61	627,3785	-4531,4	117,1137	55903,2	-18646,5	-2197,65	-1840,01	-9175,83	-1102	-3068,23	715,7718	-1823,64	-4891,87	
Monday	2023-06-05 02:00:00	1365,962	538,4324	-4955,58	125,7311	56206,51	-18143,5	-2218,88	-1751,15	-9105,34	-1011,82	-3148,61	700,2489	-1931,59	-5080,19	
Monday	2023-06-05 03:00:00	1620,786	393,4318	-4756,94	301,9869	53581,26	-16477,7	-2268	-1701,76	-9001,36	-1131,12	-3114,29	710,3034	-1863,49	-4977,79	
Monday	2023-06-05 04:00:00	1489,783	642,7358	-4468,4	181,5359	49537,14	-14243,5	-2230,17	-1736,45	-8544,56	-1272,57	-2702,74	681,5049	-2074,03	-4776,77	
Monday	2023-06-05 05:00:00	1061,098	765,3207	-3629,19	-22,1925	43123,86	-13775,2	-1893,2	-1780	-7385,37	-808,775	-1862,74	665,0566	-1783,18	-3645,92	
Monday	2023-06-05 06:00:00	159,2002	475,792	-2097,55	-241,876	40025,38	-10244,9	-1115,08	-2243,98	-7051,87	-962,851	-1371,58	525,9279	-1620,93	-2992,51	
Monday	2023-06-05 07:00:00	-1223,8	-169,638	-1779,2	-597,649	40008	-3892,82	-641,254	-2104,35	-8560,65	-2157,71	-5818,08	572,9417	-1665,18	-7483,27	
Monday	2023-06-05 08:00:00	-1024,63	-949,972	-1464,75	-285,455	38626,31	-4789,73	-532,578	-1209,04	-9732,57	-4400,46	-4821,31	345,009	-1484,5	-6305,8	
Monday	2023-06-05 09:00:00	-409,193	-1593,01	-1692	-409,084	43221,96	-10728	-611,894	-613,818	-7814,39	-5986,32	-4944,91	29,50806	-900,266	-5845,18	
Monday	2023-06-05 10:00:00	-263,777	-1835,27	-2106,1	-256,236	42558,05	-9026,84	-399,48	-247,128	-7352,57	-9776,44	-4556,68	-61,0944	-733,647	-5290,33	
Monday	2023-06-05 11:00:00	219,5671	-1594,62	-2270,49	-15,3396	46999,46	-10275,7	-253,17	54,92631	-6252,59	-20875,9	-3530,52	54,34901	-198,912	-3729,44	
Monday	2023-06-05 12:00:00	-271,234	-1618,3	-2681,12	-226,827	41534,88	-13982,8	-197,398	46,61043	-7394,92	-7465,03	-4280,21	-223,988	-273,064	-4553,28	
Monday	2023-06-05 13:00:00	-423,766	-1418,9	-2748,02	-257,121	46705,59	-15743,5	-138,696	-132,102	-7632	-7698,9	-4807,36	-322,437	-382,793	-5190,15	
Monday	2023-06-05 14:00:00	-1041,26	-1452,02	-2732,15	-65,51	44770,93	-13473,1	-175,565	-450,442	-7634,57	-7537,56	-4583,67	-180,977	-620,495	-5204,17	
Monday	2023-06-05 15:00:00	-1537,4	-1387,79	-3043,68	-369,538	54027,27	-13731,5	-669,442	-1071,53	-8415,42	-10747,8	-5282,41	-12,6332	-962,338	-6244,75	
Monday	2023-06-05 16:00:00	-963,257	-496,543	-1500,55	-25,1696	60844,92	-12027,9	-918,315	-1433,46	-6712,99	-31776,6	-4141,03	167,0312	-383,361	-4524,39	
Monday	2023-06-05 17:00:00	-1179,34	-557,59	-2199,52	-426,608	49329,18	-16684,9	-1100,33	-2061,81	-7441,1	-6707,33	-5789,31	457,1164	-934,762	-6724,07	
Monday	2023-06-05 18:00:00	-854,103	-403,151	-2126,38	-467,868	46360,24	-19622,6	-801,957	-2463,26	-6012,74	-4756,48	-5832,37	541,989	-734,073	-6566,44	
Monday	2023-06-05 19:00:00	-388,983	-440,238	-1473,2	-443,349	42866,35	-20209,6	-672,181	-2517,43	-6200	-3153,97	-4865,72	832,1634	-707,163	-5572,88	
Monday	2023-06-05 20:00:00	-66,267	-63,1922	-614,728	-178,651	38884,01	-19989	-403,225	-2670,49	-5746,91	-1875,93	-5286,76	948,2766	-574,979	-5861,74	
Monday	2023-06-05 21:00:00	174,8565	539,9595	-630,771	-40,092	38919,1	-19185,9	-593,234	-2624,77	-5530,53	-984,959	-5870,78	1005,291	-534,434	-6405,21	

Data Time	D1	D2	D4	D6	D7	D8	DE
2023-06-04 00:00:00	8203,48	3154,641	-1174,46	-963,031	-619,937	35951,91	44552,6
2023-06-04 01:00:00	8883,659	4139,501	765,1679	-885,399	-797,193	32117,12	44222,85
2023-06-04 02:00:00	9525,715	5283,917	2013,382	-855,081	-1150,35	28240,38	43057,96
2023-06-04 03:00:00	9626,87	4909,404	2283,338	-812,847	370,5326	24886,69	41263,98
2023-06-04 04:00:00	9270,355	4731,51	1632,478	-762,182	385,3798	24433,16	39690,7
2023-06-04 05:00:00	10100,48	-912,269	1756,3	-832,249	27,759	25577,48	35717,51
2023-06-04 06:00:00	10996,9	-5190,48	2691,618	-903,888	-1409,41	26359,52	32544,26
2023-06-04 07:00:00	11760,57	-6836,68	7932,536	-1113,18	1114,922	21161,39	34019,55
2023-06-04 08:00:00	11784,35	-2362,77	19182,41	-1667,74	3862,707	1490,732	32289,68
2023-06-04 09:00:00	-31769,4	89784,06	10193,95	-6956,41	-88340,9	44394,49	17305,85
2023-06-04 10:00:00	-63733	-186030	190622,7	3691,035	181496,4	-108560	17486,97
2023-06-04 11:00:00	-95716	-164595	247413,2	1873,077	131758,8	-91090,6	29643,2
2023-06-04 12:00:00	-333741	-295314	585965,9	1708,014	206825,5	-134031	31413,75
2023-06-04 13:00:00	-263105	-265310	523582,6	1832,259	156274	-118597	34677,17
2023-06-04 14:00:00	-354425	-324159	680338,4	2030,641	166715,8	-139937	30563,53
2023-06-04 15:00:00	-446441	-346849	734650,2	2168,069	250230,3	-162641	31116,58
2023-06-04 16:00:00	-87932,1	-292934	249482,1	8961,3	282281,1	-141281	18577,4
2023-06-04 17:00:00	1663,885	18983,96	13226,36	-2221,04	-10251,1	22868,21	44270,28
2023-06-04 18:00:00	4611,746	6412,898	-346,535	-1255,75	2697,812	30198,26	42318,44
2023-06-04 19:00:00	2446,051	1316,16	-1033,5	-941,21	8208,228	30258,06	40253,79
2023-06-04 20:00:00	1632,416	-537,049	-620,703	-860,276	10747,9	27117,24	37479,53
2023-06-04 21:00:00	1241,346	-1128,4	-1638,04	-878,415	13446,69	30566,49	41609,67
2023-06-04 22:00:00	976,9773	-2221,53	-986,043	-855,084	13930,07	31734,91	42579,3
2023-06-04 23:00:00	1174,286	-3615,15	-1826,45	-834,985	18815,18	28833,97	42546,85
2023-06-05 00:00:00	2591,798	-2093,72	633,1439	-863,972	25176,04	28562,4	54005,7
2023-06-05 01:00:00	2441,165	-5292,97	-243,788	-744,114	35171,82	24571,09	55903,2
2023-06-05 02:00:00	3124,524	-5916,46	402,6718	-719,343	36515,27	22799,85	56206,51
2023-06-05 03:00:00	2975,74	-7130,38	-1107,56	-724,106	32470,06	27097,51	53581,26
2023-06-05 04:00:00	2680,609	-5639,23	-3179,69	-739,98	28240,73	28174,71	49537,14
2023-06-05 05:00:00	2489,649	-5351,41	-4824,57	-774,625	27328,66	24256,15	43123,86
2023-06-05 06:00:00	2295,845	-684,769	-4541,85	-828,335	19165,21	24619,28	40025,38
2023-06-05 07:00:00	2670,683	-5529,28	-3812,69	-983,315	20904,53	26758,08	40008
2023-06-05 08:00:00	2165,409	-8232,53	-5972,1	-1339,91	17114,3	34891,14	38626,31
2023-06-05 09:00:00	10151,27	-5801,72	-7722,09	-1954,1	11199,87	37348,74	43221,96
2023-06-05 10:00:00	16131,59	-1136,6	-2963,07	-2654,63	-10336,2	43516,96	42558,05
2023-06-05 11:00:00	23245,29	-3637,98	-1419,15	-3318,25	-23801,8	55931,34	46999,46
2023-06-05 12:00:00	31692,43	-7028,39	-3067,75	-4303,19	-38380,6	62622,43	41534,88
2023-06-05 13:00:00	32588,02	-6388,23	2234,202	-3914,84	-29232	51418,44	46705,59
2023-06-05 14:00:00	34798,16	-4000,01	-1942,45	-3754,98	-22248	41918,17	44770,93
2023-06-05 15:00:00	27948,94	-2484,52	3193,444	-2442,93	-4948,67	32761	54027,27
2023-06-05 16:00:00	21953,33	1318,179	1349,497	-2076,7	9022,398	29278,22	60844,92
2023-06-05 17:00:00	12301,03	-7083,77	-6239,04	-1689,77	24379,6	27661,13	49329,18
2023-06-05 18:00:00	9200,593	-4606,34	-4878,06	-1437,98	22085,07	25996,96	46360,24
2023-06-05 19:00:00	5299,716	92,05959	-3782,95	-1215,11	20975,24	21497,39	42866,35
2023-06-05 20:00:00	4064,415	-300,459	-4501,2	-1094,28	21777,95	18937,58	38884,01
2023-06-05 21:00:00	4256,84	616,5079	-5941,9	-1066,37	22236,07	18817,95	38919,1

Figure A.5 Screenshot of Implement NPF PoC results

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