Tariff Transitions

Assessing the Grid Impact of Adjusted Injection Charges for Large-Scale Producers in the Netherlands

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By

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Executive summary

The Dutch electricity grid is increasingly facing challenges due to grid congestion. If left unaddressed, this may ultimately lead to electricity supply disruptions, substantial economic losses, and a decline in living standards. Tackling this issue is essential to ensure a reliable electricity infrastructure and to safeguard economic and social stability.

In 2024, the Netherlands Authority for Consumers and Markets (ACM) published an overview of all measures it has taken or plans to take to reduce grid congestion in the Netherlands. These measures include, among other things, the introduction of different tariff structures in order to incentivize a more efficient use of existing electrical grid infrastructure. One such tariff structure focuses on the adjustment of injection charges for large-scale electricity producers, whereby they would pay a transport-dependent tariff for injecting electricity into the grid.

While different studies suggest that injection charges could help to mitigate grid congestion, a comprehensive grid analysis to fully quantify and evaluate the impact of these charges on grid load and the subsequent need for network reinforcement was not yet conducted. This study aimed to fill that knowledge gap.

Therefore, this research focused on assessing the effects of adjusted injection charges for large-scale electricity producers on the electricity grid in the Netherlands. To address the main research question, three sub-questions were formulated and answered. These sub-questions provided insights into the effects of different injection charge designs on grid load and the need for network reinforcement, and also formed the basis for recommendations to the Netherlands Authority for Consumers and Markets (ACM), the relevant regulatory authority in this context.

The results of this study were obtained by constructing a network model based on the electricity network topology of the municipality of Reimerswaal in the Netherlands, incorporating data and insights from relevant sources. The model included electricity generation technologies such as onshore wind and solar PV production and applied a priority dispatch policy, giving preference to local renewable electricity generation over imports from elsewhere.

In total, four different injection charge variants were assessed. These include, a uniform tariff based on the kWcontract and kWmax charge components, a time-dependent tariff based on the kWcontract and kWmax components, a uniform tariff based on the kWh component, and a combination of the time-dependent tariff based on the kWcontract and kWmax components together with a uniform tariff based on the kWh component.

The results demonstrate that by using an adjusted injection charge, the peak grid load can be reduced by up to 35.55%. This reduction can be achieved with the injection charge variants which are based on the transport-dependent charge components of kWcontract and kWmax. The peak load occurred more frequently under the general and uniform variant, whereas the time-based variant led to an equal or lower number of peak load months. Additionally, the variant that only included a uniform kWh tariff did not change any of the injection-related peak loads in comparison to the base scenario. However, this variant did

reduce the import-related peak loads from elsewhere, but this was only a marginal reduction of up to 0.99%. The variant which included a combination of the time-based kWcontract and kWmax charge components and uniform kWh tariff, also had the same reduction of maximum grid load from injection, as well as the declined imports, as achieved by the respective individual variants.

Furthermore, as electricity networks must be designed and reinforced to handle the peak loads, the need for network reinforcement can be minimized when the maximum loads are lower. Therefore, it can be concluded that injection charges can be beneficial in reducing the grid load and thus also in reducing the need for network reinforcements. This reduction in grid load was seen in the variants which included an injection charge on the kWcontract and kWmax charge components. Consequently, these variants are also reducing the need for network reinforcements. However, while the maximum loads were the same for all of these variants, the occurrence of these peaks was the lowest in the variants which also included a time-based charge component. Therefore, these variants are better in limiting the frequency of stress on the grid. Additionally, the variant which included a uniform kWh tariff limits the need for imports from elsewhere, which can also help in mitigating the grid loads, and thus potentially the needs for network reinforcements. However, this only applies to substations where the maximum grid load from imports is higher than from injection. Otherwise, the injection peaks remain dominant, which implies that the network still needs to be reinforced to facilitate these peak loads.

For the ACM, it can be concluded that the adjustment of injection charges for large-scale electricity producers could be beneficial in reducing grid load and subsequently in minimizing the need for network reinforcement. However, the effectiveness of the injection charges is dependent on its design. From this study, the variant which included time-dependent charges on the transport-dependent charge components of kWcontract and kWmax scored the best in terms of reducing peak load and its occurrence, and subsequently also in reducing the need for network reinforcements. The variant which besides these components also included a uniform kWh tariff did impact import-related peak loads, but this effect was only marginal at a reduction by up to 0.99%. Therefore, this variant does not have preference above the variant without uniform kWh tariff, as it does not add substantial added value for implementation. But, besides the impacts on grid load and need for network reinforcements, also other aspects should be considered by the ACM. This includes aspects such as legitimacy, feasibility, and stakeholder support, as well as externalities such as the impact on existing and to-be-developed renewable electricity projects, renewable electricity production, progress toward climate and policy goals, electricity prices, and the competitiveness of the Netherlands in international markets.

In conclusion, applying well-designed injection charges for large-scale producers in the Netherlands could incentivize market participants to reduce injection during periods of surplus and/or limit electricity demand. This could reduce peak loads and could reduce the need for network reinforcements. While the findings suggest that such charges may contribute to more efficient grid use, the design and implementation of such measures require careful consideration as factors beyond the direct impact on the electricity grid are also important. In addition to technical effectiveness, factors such as legitimacy, feasibility, and stakeholder acceptance, as well as potential economic and environmental implications, must also be taken into account.

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1. Introduction

This chapter begins by introducing the societal issue that forms the foundation for the research conducted in this master's thesis. Thereafter, the research knowledge gap will be identified through a literature review. The steps involved in the literature review process are outlined, including core concepts, search strategy and selection criteria used. Furthermore, a table overview summarizing twelve relevant articles is provided along with a synthesis that highlights the current knowledge gaps. Additionally, the main research question of this thesis will be highlighted, as well as the research approach and the corresponding sub-questions. These will be introduced together with their data needs, research methods and tools. Lastly, the outline of this thesis will be provided.

1.1 Societal issue

The Netherlands aims to achieve a 55% reduction in greenhouse gas emissions by 2030 compared to 1990 levels, and wants to become climate neutral, with net-zero greenhouse gas emissions, by 2050 (Ministry of Climate Policy and Green Growth, n.d.). To achieve this, the government aims, among other things, to generate 70% of all electricity in a sustainable manner by 2030, and in 2050 almost all energy supplies must be sustainable and CO_2-neutral (Netherlands Enterprise Agency, n.d.-b). In 2023, 48% of the total produced electricity in the Netherlands was generated from renewables (Statistics Netherlands, 2024-b). These renewable electricity sources include electricity production from natural sources such as biomass, sun, wind and water.

This all sounds very promising, but renewable sources also have drawbacks. Electricity generated from solar and wind present challenges to the electricity grid because of their intermittent nature. This intermittency means that these technologies cannot consistently produce electricity at all times of the day (EnergyX, n.d.). As a result, peaks in electricity production or demand can lead to increased use of the grid, potentially resulting in grid congestion. Grid congestion occurs when the transmission capacity of the electrical grid is insufficient to meet its usage demand (Müller, 2024).

As the electricity grid approaches its limits in many areas, grid congestion is becoming an increasingly significant issue in the Netherlands (ACM, 2024-a). Estimations by Venema et al. (2024) suggest that grid congestion could result in an economic loss of approximately €10 billion to €35 billion annually. However, besides economic damage, living standards could also dramatically decrease. It is estimated that in 2030 almost 1.5 million households would face issues due to grid congestion (Elshof, 2024). These issues include flickering lights, disruptions to household appliances, and the automatic shutdown of solar inverters. Furthermore, congestion can result in longer lead times for new grid connections and existing connection upgrades for, among other things, residential, commercial, and industrial projects, thereby delaying electrification possibilities and the expansion of renewable electricity sources (Wassenberg & Weulen Kranenberg, 2024). Additionally, in extreme cases, grid congestion may even lead to power outages for parts of the electricity network, making it unable to use electricity from the grid (Müller, 2024).

1.2 Core concepts

In 2024, the Netherlands Authority for Consumers and Markets (ACM) published an overview of all measures it has taken or plans to take to reduce grid congestion in the

Netherlands (ACM, 2024-e). These measures include, among other things, the introduction of different tariff structures in order to incentivize a more efficient use of existing electrical grid infrastructure. One such tariff structure is the so-called feed-in tariff (ACM, 2024-e).

This feed-in tariff consists of a charge that large-scale electricity producers must pay to deliver electricity into the grid. Currently, a transport-dependent tariff is paid by electricity consumers, but not by electricity producers (Van Cappellen et al., 2022; Van Cappellen et al., 2024; Vrolijk et al., 2018). As a result, large-scale electricity producers do not pay any transport-dependent tariffs and are also not incentivized to make more efficient use of the existing grid infrastructure.

A feed-in tariff may consist of an annually payable transport-dependent grid tariff and/or a one-time connection fee for the public grid, which would then be charged in addition to the existing tariffs (Van Cappellen et al., 2024). The adjustment of such tariffs is intended to reflect the costs that large electricity producers impose on the grid and ensures a fairer distribution of costs between consumers and those delivering electricity (ACM, 2024-e). In theory, these cost-reflective tariffs would create price signals that incentivize more efficient use of the grid and thereby decrease grid congestion (Passey et al., 2017).

It is important to note that this proposed feed-in tariff structure differs from the traditional feed-in tariffs in energy policy. In literature, feed-in tariffs are a policy mechanism that obligates regional or national grid utilities to buy renewable electricity at a fixed price over a fixed time period (Jäger-Waldau, 2012).

The proposed feed-in tariff of the ACM does not adhere to this definition. Therefore, to avoid confusion, this study uses the term ‘injection charge’ as defined by the European Union Agency for the Cooperation of Energy Regulators (ACER). An injection charge applies when a network user connected to the distribution grid pays distribution tariffs for injecting electricity or the possibility to inject (ACER, 2021). This definition includes instances where only parts of distribution costs are charged or only some network users injecting are affected.

Thus, following this definition, please note that the ACM's proposed feed-in tariff refers to an adjustment of the existing injection charge, one which currently does not include a transport-dependent charge component.

1.3 Search strategy

In order to determine the research knowledge gap, a thorough search for published literature has been carried out. As this subject is not yet widely covered in literature, the search within the Scopus electronic database yielded insufficient results. Therefore, the majority of the research was conducted using the Google Search engine.

Search terms included terms related to injection charges, including, in Dutch, “Producententarief” (English: producer tariff) and “Invoedingstarief” (English: feed-in tariff), and, in English, “Feed-in grid charges” and “Injection charge ACER”. The search was conducted in February 2025.

1.4 Selection criteria

After conducting the initial search, various selection criteria were applied to narrow down the total number of articles and to only include those relevant to the subject. Articles that only reference other published literature were excluded, as were those that only mention terms related to injection charges without offering any substantive information.

1.5 Identified articles

In total, twelve articles have been used for this literature gap review. Table 1 provides a summary of these articles together with the aim of that particular study.

Table 1: Summary of the selected articles and corresponding study objectives.

Number	Reference	Aim of the study
1	Van Cappellen et al. (2022)	This study, commissioned by Netbeheer Nederland, identifies policy measures that can help to make more efficient use of the existing electrical grid infrastructure. In total, eight different policies have been proposed and elaborated upon.
2	Koutstaal et al. (2012)	This study, commissioned by the Ministry of Economic Affairs, Agriculture and Innovation, examines the effects of injection charges, with a focus on electricity prices, the competitive position of Dutch electricity producers, and investments.
3	Blom et al. (2022)	This study, commissioned by the Netherlands Court of Audit, examines the current tariff system for electricity, gas, and heat transport in the Netherlands, as well as its relation to potential future bottlenecks in the energy transition.
4	Den Ouden et al. (2016)	This report examines the relationship between network tariffs and flexibility, focusing on the potential of dynamic tariffs to unlock flexibility in industry and greenhouse horticulture.
5	Aalbers et al. (2012)	This article analyzes the regulation of electricity distribution networks in the context of increasing distributed generation. It examines how different tariff structures can incentivize network operators to make optimal investment decisions.
6	Hakvoort et al. (2013)	This study examines the tariff structure for electricity transmission by focusing on the impact of large consumers and local generation on network costs, and whether these factors justify adjustments in cost distribution through network tariffs.
7	Vrolijk et al. (2018)	This study, commissioned by the Overlegtafel Energievoorziening, investigates whether current network tariffs hinder an efficient, reliable, and sustainable energy supply and looks into possible adjustments within the tariff structure to remove these obstacles.

8	Van Cappellen et al. (2024)	This study, commissioned by the ACM, analyzes the impact of six variants of an injection tariff in the Netherlands on those delivering electricity, international energy markets, the electricity grid, and electricity bills for end consumers.
9	NVDE (2017)	This position paper explores three dimensions of flexibility: congestion, balancing, and portfolio management, and is thereby focusing on current areas for improvement and future challenges.
10	Netbeheer Nederland (2024-b)	This position paper describes the view of the Dutch system operators on the topic of injection charges and is thereby focussing on the cause, considerations, recommendations, and attention points for future research.
11	Geschke et al. (2024)	This policy assessment, commissioned by Energie-Nederland, covers the potential impact of injection charges for the Netherlands on renewable projects, electricity prices and security of supply.
12	ACER (2023)	This report provides an overview of electricity transmission and distribution tariff methodologies across Europe, analyzing cost allocation models, charging mechanisms, and their implications for different network users. It also offers recommendations for improving current and future tariff structures.

1.6 Literature review

The reviewed literature on injection charges for electricity producers provides a diverse range of perspectives. The identified studies explore various aspects, from the adherence to the principle of cost-reflectivity and the impact on electricity prices to the effects on grid congestion, system operators and the equal level playing field in an international context. In this section, all of these identified perspectives will be covered.

1.6.1 Cost-reflectivity

Different studies have acknowledged that the adjustment of injection charges could lead to a better cost-reflectivity of the network costs. To begin with, Van Cappellen et al. (2022) recognize that injection charges are more cost-reflective and they also use a calculation example to showcase that the injection charge tariff leads to more costs for producers with a lot of production. Den Ouden et al. (2016) acknowledge that the adjustment of injection charges would lead to a better distribution of costs between producers and consumers. In addition, Aalbers et al. (2012) highlight that current regulation, which sets injection charges at zero, may not sufficiently account for the impact of distributed generation on network costs. The position paper of Netbeheer Nederland (2024-b) also states that introducing injection charges could lead to a more cost-reflective tariff structure. Additionally, the study by Van Cappellen et al. (2024) recognizes that the adjustment of injection charges as a policy measure could potentially improve cost-reflectivity.

1.6.2 Effects on electricity prices

The effects of injection charges in relation to electricity prices have been studied in different pieces of literature. As for example by Koutstaal et al. (2012), Geschke et al. (2024) and Van Cappellen et al. (2024). The study by Koutstaal et al. (2012) identifies the effects of injection charges with a focus on electricity prices, the competitive position of Dutch electricity producers, and investments. The studies of Geschke et al. (2024) and Van Cappellen et al. (2024) both identify that the adjustment of injection charges in the Netherlands could lead to fewer new renewable energy projects. Thereby, Geschke et al. (2024) suggest that injection charges could lead to higher electricity prices for end consumers. Van Cappellen et al. (2024) quantifies this even further and argues that the electricity price could increase by around 10%. However, they also argue that this price increase would then boost the revenues for existing electricity producers, which could result in market recovery and ultimately lead to a new equilibrium where electricity prices rise by only an estimated 1% (Van Cappellen et al., 2024). Additionally, the study indicates that while electricity prices are expected to rise, the reduction in net tariffs could offset this increase, resulting in total electricity costs for consumers remaining roughly the same as before the adjustment of injection charges.

1.6.3 Effectiveness of injection charges

Van Cappellen et al. (2022), Blom et al. (2022), Hakvoort et al., (2013), Aalbers et al. (2012), Vrolijk et al. (2018), NVDE (2017), Netbeheer Nederland (2024-b) and Van Cappellen et al. (2024) all have addressed the effectiveness of electricity charges in relation to grid congestion in their studies. Van Cappellen et al. (2022) argue that uniform tariffs fail to provide sufficient incentives to modify behavior regarding the use of electricity grid capacity at specific locations or times of day. Blom et al. (2022) and Hakvoort et al. (2013) acknowledge that the absence of an injection charge is suboptimal for the electricity system, particularly in terms of long-term efficiency and system cost minimization. Furthermore, Aalbers et al. (2012) acknowledge that in areas with high levels of distributed generation, injection charges could be used to limit its adoption and prevent network disruptions. Vrolijk et al. (2018) highlights that the current tariff structure, which only charges consumers, may hinder efficient grid use. Therefore, they argue that it would be more logical to impose a cost-based, transport-dependent tariff on producers to encourage efficient grid behavior. The position paper from the Nederlandse Vereniging Duurzame Energie (NVDE) highlights that in the current tariff structure, electricity producers may have an incentive to continue producing, even though it might be more beneficial for the system operator to reduce grid injection (NVDE, 2017). They note that this might be due to the missing injection charges for electricity producers. Additionally, the position paper of Netbeheer Nederland (2024-b) emphasizes that introducing injection charges could encourage a more efficient use of the electricity grid. The study by Van Cappellen et al. (2024) also highlights that injection charges can reduce the impact on grid load and thus reduce grid congestion. They note that this effect is most significant in areas where new electricity production, especially solar parks and onshore wind, is expected to be established in the coming years. The study estimates that grid load could decrease by 5% to 15% at these substations. Thereby, the study suggests that the changes in grid load could also reduce the need for network reinforcement.

However, while these studies provide that injection charges could increase efficient net use and battle grid congestion, the study by Van Cappellen et al. (2024) also notes that no grid analysis has been conducted in their study to fully determine the impact on the electricity grid. Therefore, the authors suggest that, among other things, future research should focus on a more detailed grid analysis to determine the impact of an injection charge on the grid. The position paper by Netbeheer Nederland (2024-b) also supports this by acknowledging that further research is needed to qualitatively assess the impact on the electricity grid.

1.6.4 Impact on system operators

The impact on system operators has also been addressed in the literature. The study by Hakvoort et al. (2013) highlights a few economic arguments for and against the extra injection charges. Hereby, they also provide an estimate of the income for transmission and regional distribution system operators under the assumption of an injection charge of €1.00 per MWh for central electricity production. Netbeheer Nederland (2024-b) emphasizes the importance of a simple and transparent tariff system, ideally with a single time-dependent structure for all system operators, though adjustments may be necessary for local network conditions. The study by Van Cappellen et al. (2024) provides a forecast for the earnings of system operators in 2030 and allocates these earnings across various grid tariff components. Additionally, they briefly address that although changing the current tariff structure may be complex for system operators, this complexity should not impede its development.

1.6.5 International context

Few studies, as for example the ones from ACER (2023) and Netbeheer Nederland (2024-b), have addressed the international landscape of injection charges. ACER (2023) identified that multiple European Union (EU) countries already have implemented an injection charge, however, the Netherlands only has a small lump sum fee, which only partly covers the system operator’s costs. Most countries motivate the use of injection charges based on cost-reflectivity. Countries that did not impose such tariffs argued for example that it could otherwise distort competition within the EU, network costs had already been recovered through other methods, or that they want to support more renewable energy generation and storage. Furthermore, in some countries, the national law prohibited or restricted the use of injection charges. Furthermore, it is noted that none of the National Regulatory Authorities of EU countries identified any unusual competitive disadvantage for generators as a result of injection charges. Still, Netbeheer Nederland (2024-b) advocates for a minimum injection charge across the EU to ensure fair competition. However, ACER (2023) acknowledges that only in a few countries the impacts of injection charges have really been studied.

1.7 Identified knowledge gaps

While the existing literature reaches a consensus on several aspects, such as the potential of injection charges to improve cost-reflectivity and their impact on increasing electricity prices, and provides information about the international context and effects on system operators, significant research gaps remain regarding the impact of these charges on the electricity grid.

Although multiple studies suggest that injection charges could help to mitigate grid congestion, a comprehensive grid analysis has yet to be conducted to fully quantify and evaluate the impact of these charges on grid load and the subsequent need for network reinforcement. Understanding the effects of various injection charge designs on grid congestion and infrastructure requirements is crucial for determining its role in optimizing grid efficiency and ensuring the stability of electricity networks.

1.8 Main research question

The research gaps that have been identified earlier demonstrate a significant opportunity to explore in further research. In particular, there is a need to assess how adjusted injection charges for large-scale electricity producers might impact the electricity grid load and the subsequent need for network reinforcement.

Therefore, the main research question of this research is:
What would be the impact of adjusted injection charges for large-scale electricity producers on the electricity grid in the Netherlands?

1.9 Research approach

In this research, an effort will be made to estimate and assess the impact of adjusted injection charges for large-scale electricity producers in the Netherlands. To address this research objective, it is essential to select a suitable research approach. A research approach serves as a comprehensive plan that guides the research process and includes going from broad theoretical foundations to specific techniques for data collection and analysis (Creswell, 2009). The primary consideration in determining the appropriate approach is selecting the research design that best aligns with the research goals.

Therefore, in this study, a modeling approach will be used. Within the modeling approach, models are constructed with the help of specific representational means and can be used in different ways (Boon & Knuuttila, 2009). The added value of using models does not lie in them being accurate representations of some real target systems, but rather in their independent systemic construction. In this study, the modeling approach is used to fill the knowledge gap of not knowing the impacts of adjusted injection charges for large scale-electricity producers in the Netherlands on multiple aspects. Therefore, the policy intervention will be worked out in the model and assessed via different scenarios to determine its impact.

The modeling approach thus seems like a good fit to answer the main research question and achieve the research objective of this study. This is also further acknowledged due to the advantages of using the modeling approach, such as that it can be safer and cheaper to model and simulate certain situations rather than applying it in the real world (BBC Bitesize, n.d.). However, there are also some drawbacks to using this approach. For example, the costs of creating and running a simulation model can still be very high (BBC Bitesize, n.d.) and time-consuming (FutureLearn, 2022). Additionally, the quality of the analysis and corresponding results depend on the quality of the input data for the model and the model itself.

While it is important to acknowledge the limitations of the modeling approach, its advantages still outweigh the drawbacks for this particular study. Adjusting the injection charges for large-scale electricity producers and observing its effects in real-time would be too expensive and time-consuming, making the modeling approach a more cost-effective solution for assessing the potential impact beforehand.

The modeling approach offers a variety of methods that can be used. One such method is the network modeling approach. Network modeling offers a practical approach to understand and optimize network performance under diverse operating conditions through simulation (Provenzano, 2024). In network modeling, networks consist of nodes and edges (Saive, 2022). In the context of the electricity grid, nodes typically represent substations, while edges correspond to transmission lines connecting these substations or linking substations to end consumers. Results derived from these simulations can be analyzed to evaluate network performance and pinpoint potential issues (Provenzano, 2024).

Therefore, this study will employ the network modeling approach to assess the impacts of adjusted injection charges for large-scale electricity producers on the electricity grid in the Netherlands. This approach is particularly suitable as electricity producers, each utilizing varying electricity generation technologies, are likely to respond to changes in the network tariff structure in diverse ways, thereby influencing the overall grid performance and the need for network reinforcements.

1.10 Sub-questions

In this subsection, the sub-questions are introduced together with their required data, research methods and analytical tools.

1.10.1 First sub-question

To begin with, the first sub-question of this research aims to determine the extent to which adjusted injection charges for large-scale electricity producers influence grid load. This is a crucial aspect, as it directly assesses the impacts of different tariff variants on grid usage and the potential occurrence of congestion. Therefore, the first sub-question is:

To what extent do adjusted injection charges for large-scale electricity producers influence grid load?

To answer this sub-question, a network model can be used to simulate the electricity supply and demand over time and location and over the existing grid infrastructure, which will then form the base scenario. Thereafter, the model will incorporate different types of injection charges and their corresponding effects on electricity producers, allowing for the assessment of changes in grid load at various points in the network over time.

Data for this analysis will be gathered through desk research. Information on the electricity grid layout can be obtained from datasets provided by the regional distribution system operator (DSO), like Stedin, as well as the Dutch transmission system operator (TSO), TenneT. Data on electricity supply and demand can be found in various online articles, reports, and databases. However, these sources will likely need to be combined and refined in order to produce an accurate and comprehensive dataset for further analysis. Furthermore, the impact of different variants of injection charges on producers will be investigated through desk research, drawing on relevant studies, reports and covenants. Additionally, where necessary, reasonable assumptions will be made.

As the network needs to be modeled, this will require an analytical tool. Therefore, the model will be developed using Python, as this software is free, open-source and supports a wide range of useful packages (Python, n.d.). Information on the grid layout can be viewed in a Geographic Information System viewer (GIS-viewer). Additionally, the results from the desk research on electricity supply and demand can be viewed using Microsoft Excel.

1.10.2 Second sub-question

After the establishment of the change in grid load, the larger impact on the electricity grid can be assessed, as well as the future requirements for the need for network expansion. This is an important aspect that also contributes to the societal relevance of this study as the current grid congestion in the Netherlands leads to longer lead times for new grid connections and existing connection upgrades for, among other things, residential, commercial, and industrial projects, thereby delaying electrification possibilities and the expansion of renewable electricity sources (Wassenberg & Weulen Kranenberg, 2024). Therefore, the second sub-question is:

To what extent do adjusted injection charges for large-scale electricity producers impact the need for network reinforcement in the Netherlands?

To answer this sub-question, the results from the previous sub-question, derived from the network model can be used. If certain variants of the injection charge result in a lower peak load, the network will require less capacity, and additional expansion may not be necessary. Consequently, peak load data from scenarios with and without injection charge variants is particularly relevant, as it reflects the potential necessity for network infrastructure reinforcements. This data is thus essential to identify where congestion may occur and where network reinforcements might be required.

The data that is required for this assessment has already been gathered for the first sub-question, and no additional tools will be needed.

1.10.3 Third sub-question

Finally, the last sub-question of this study needs to provide a formulation of relevant outcomes based on the research findings. Recommendations to the Netherlands Authority for Consumers and Markets (ACM) are highly relevant, as it is the regulatory authority that sets and supervises the network tariff structure for producers and consumers in the Netherlands. In addition, in this specific case, the ACM aims to publish a draft decision on an adjusted injection charge in 2025 (ACM, 2024-c). Thus, the ACM is the appropriate body to which these recommendations are addressed. Therefore, the last sub-question is:

Which considerations should the Netherlands Authority for Consumers and Markets take into account when proposing an adjustment of the network tariff structure for large-scale electricity producers in the Netherlands?

In order to provide an answer to this sub-question, the findings from the previous sub-questions, along with relevant studies consulted throughout this thesis, will be taken into account. All of this information has been gathered over the thesis duration and no additional sources or tools have to be used.

1.11 Thesis outline

After the establishment of the societal problem, current knowledge gaps, research questions and approaches, the following chapter provides additional information on network tariffs. This chapter will include their definition, purpose, method for tariff setting, guiding principles, and the various components that apply to different types of network users. Additionally, the next chapter also touches on the current and future network costs. Thereafter, Chapter 3 offers more information on the injection charge. This chapter will first present the strategic objective of the ACM, followed by the proposed injection charge variants and the accompanying stakeholder feedback. Furthermore, this chapter will present the variants used in this study, including their design, potential behavioral effects and design scores. Chapter 4 explains the method used in this study by introducing the model and the approach used to develop it. The following chapter presents the model results, while Chapter 6 discusses them further to address the first and second sub-questions. Based on the results and insights gained throughout this study, recommendations to the ACM are given in Chapter 7. Chapter 8 contains the conclusions of this study, followed by Chapter 9 which will discuss the limitations of this study and provide recommendations for future research. Chapter 10 offers a personal reflection on the societal relevance of this study, as well as an academic reflection and the link between this study and the master’s program. Thereafter, the references can be found.

2. Background information

This chapter will provide additional information about network tariffs, including their definition, purpose, the method for tariff setting, guiding principles, and the various components that apply to different types of network users. Additionally, the current and future network costs of the Netherlands are being explored.

2.1 Defining network tariffs

The most commonly used definition of network tariffs is that these tariffs are price components which are paid by electricity consumers to finance the past and future costs of building and operating the electricity grid (European Commission, 2015; Glowacki, 2023).

2.2 Purpose of network tariffs

The primary purpose of network tariffs is to recuperate operating expenses and investments for the network operator (Hennig et al., 2022). However, there is some variation in academic and regulatory literature regarding the full range of objectives these tariffs should serve. For instance, according to ACER (2021), electricity tariff design aims at recovering the costs incurred by a monopolistic system operator, while also stimulating efficiency. So, they acknowledge that the primary goal of the tariff is cost recovery, but they also point out that efficiency relates to cost-reflectivity and can send economic signals to network users for optimal network usage. Hereby, ACER (2021) notes that since network charges can be of considerable cost to network users, the way how tariffs are set can provide additional incentives to adapt user behavior. The effectiveness of such signals depends on various factors, such as the type of network user and the share of the network costs in the final electricity bill.

2.3 Setting network tariffs

In Europe, National Regulatory Authorities (NRAs) are responsible for determining or approving the fees that users pay for the transmission and distribution of electricity (ACER, n.d.). This includes either directly setting the rates or approving the methods system operators use to calculate them. Tariff methodologies for transmission system operators (TSOs) and distribution system operators (DSOs) should cover their costs, while also providing incentives to enhance their operational efficiency (ACER, n.d.).

In the Netherlands, each system operator is responsible for a specific geographic area. As a result, users cannot choose any alternative system operator, but are bound to the grid that is managed by the system operator in their area. This creates a natural monopoly for the system operator in that region, and therefore, as end-users have no option but to rely on the grid of the designated system operator, network tariffs are being regulated (Blom et al., 2022).

A natural monopoly occurs when it is most efficient for a single organization to manage all production or services in a market rather than having two or more competing providers, mainly due to the high initial costs of investments (Gans, 2016; Joskow, 2007). The electricity network is a prime example, as constructing separate networks would require significant infrastructure investment, making it economically unattractive for multiple providers to operate in the same area. Since the system operator is the only provider of this service in that particular area, they might be tempted to set exorbitantly high network fees, causing end-users to pay more than necessary. This could result in inefficiencies in the functioning of the electricity network (Blom et al., 2022). To prevent this, regulations are put in place. For the electricity network, this includes regulations on network tariffs, which ensure the network remains affordable and accessible for connected users.

In the Netherlands, the corresponding NRA is the Netherlands Authority for Consumers and Markets. The ACM uses the following general outline in which they set the network tariffs (ACM, 2021-a; ACM, 2024-d):

- Firstly, the ACM publishes a method decision (Dutch: methodebesluit) in which the regulations for the regional system operators of electricity are set, in accordance with Article 41, first paragraph of the Elektriciteitswet 1998. This decision outlines the methodology for determining the discount on allowed system operator revenues, aimed at promoting efficient business operations, establishing quality factors, and calculating the volume for each tariff component for which a rate is set. The method decision is set for a period of 3 to 5 years.
- Thereafter, the ACM applies the method decision to determine the starting revenues for each network operator. These starting revenues are based on the previous year's income.
- Then, this starting revenue will be adjusted according to the ACM decision regarding the x-factor and the Netherlands consumer price index. The x-factor is an annual adjustment applied to the allowed revenues per system operator, which can result in either a reduction or an increase, depending on the value set by the ACM. The new adjusted allowed revenue then determines the maximum income for the first year of the new regulation period. The length of this regulation period is determined by law and is currently set at 3 to 5 years. Within this legal range, the ACM decides on the exact duration for each regulatory period in its method decision. The method decision also determines the q-factor and calculation volumes per tariff carrier for each network operator. The q-factor quantifies the system operator's performance compared to others (Blom et al., 2022). A positive factor means better performance and higher allowed revenues, while a negative factor means worse performance and lower allowed revenues. The calculation volumes for each network operator consists of the prognosed contracted capacity of users on their network. These factors will also be considered by the ACM in the setting of maximum allowed revenues per system operator per year.
- Additionally, the total income for each network segment is translated into end-user rates through tariff components (Blom et al., 2022). These charge components typically include a measurement unit, which can either be fixed, volumetric, or capacity-based (Picciariello et al., 2014). The costs per component varies per network segment.
- Eventually, it is the responsibility of the system operators to submit their annual tariff proposals to the ACM. The ACM then assesses whether these proposals meet the required criteria and ensures that the tariffs do not result in revenues exceeding the allowed income. The ACM has the authority to accept or reject the proposals based on this evaluation. Once the ACM approves the tariff proposals, the system operators are required to apply these tariffs for their end-users. The ACM publishes the yearly tariffs that system operators can ask for their service in the tariff decision (Dutch:

tarievenbesluit), in accordance with Article 41c, first or third paragraph of the Elektriciteitswet 1998.

2.4 Network tariff principles

Network operators must set charges for network access and use in a way that is cost-reflective, transparent, non-discriminatory, and takes into account the need for network security and flexibility (ACER, n.d.; Regulation (EU) 2019/943, art. 18(1)). In addition, these charges should reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator and must not include unrelated costs supporting unrelated policy objectives (Regulation (EU) 2019/943, art. 18(1)).

Cost-reflective tariffs should account for the system costs imposed by each network user and allocate these costs proportionally in the tariff structure (Banet, 2020). Heider et al. (2024) found that relevant stakeholders, including representatives from politics, a DSO, and the NRA, consider the principle of cost-reflectivity to be the most important. The principle of transparent tariffs considers that the methodology for determining network tariffs should be transparent and accessible to all relevant stakeholders (CEER, 2017). Non-discriminatory network tariffs should aim to ensure that all end-users are treated equally and all network users should contribute to the recovery of the system costs (Banet, 2020). Tariffs should also consider the need for network security and flexibility. Network security involves safeguarding the electricity system against disruptions, failures, and external threats. Tariffs should account for the costs and efforts required to maintain the system's working. Network flexibility refers to the ability of the network to adapt to changing conditions, such as the integration of renewable energy sources or fluctuations in electricity demand. Tariffs should factor in the need for the system to be able to handle such changes efficiently.

2.4.1 Additional principles

The European Distribution System Operators (E.DSO) also include fairness, incentives for efficient network use, understandability, implementability and limited complexity as guiding principles for tariff structures (E.DSO, 2021). Furthermore, the Council of European Energy Regulators (CEER) also acknowledges that tariffs should be non-distortive, predictable and simple (CEER, 2017).

2.4.2 Trade-offs

It is good to note that designing network tariffs always involves trade-offs between different objectives and principles (Hennig et al., 2022). Moreover, it is not possible to create a tariff that perfectly satisfies all of these criteria simultaneously. For example, a fully cost-reflective tariff might be highly complex and difficult to communicate, potentially undermining transparency and non-discrimination. This highlights that there is no one-size-fits-all solution in tariff design, but rather that the tariff performance depends on the relative weight given to each objective and principle (Hennig et al., 2022). The optimal balance between these objectives and principles for tariff design depends on local circumstances and should be assessed and determined in close consultation with relevant stakeholders.

2.5 Types of network users

Before getting into the charge components of network tariffs, it is good to distinguish the two main types of network users in the Netherlands. There is a clear distinction between small and large-scale electricity consumers, which is primarily based on the size of connection capacity they have. Small consumers have a maximum connection capacity size of 3 x 80 Amperes [A], and large-scale electricity consumers have a connection capacity size that is greater than this (Stedin, n.d.-f). Furthermore, there is a distinction in billing procedure as small consumers get their billing from their system operator via their energy supplier, while large-scale consumers get their billing direct from the system operator. Additionally, the network tariffs for each user category are different.

2.6 Network tariff components

In the Netherlands, the distinction between small and large-scale consumers is also reflected in the network tariffs. Small electricity consumers pay a capacity tariff, which is not determined by their actual power usage, but by an average value as defined in the tariff code (Dutch: Tarievencode elektriciteit) (Blom et al., 2022). The tariff depends solely on the capacity of their connection and not on their annual consumption or the load on the connection. For large-scale electricity consumers however, the transport-dependent tariff is based on their consumption, and they also need to pay a network tariff that is based on their contracted capacity, as well as their peak load capacity (Blom et al., 2022; Van den Beld, 2022).

As this research focuses on a change in the tariff structure for large-scale connections, an overview of the existing tariff structure for this category of users has been outlined below.

2.6.1 Network tariffs for consumers

To begin with, if one wishes to establish a new connection to the electrical grid, a one-time connection fee is required (Stedin, n.d.-c). Additionally, if the new connection cable exceeds 25 meters in length, an extra fee is charged for each additional meter of cable (Van Cappellen et al., 2024).

Furthermore, the periodic network tariffs that large-scale electricity users need to pay to the system operator consist of the following components (Stedin, n.d.-d):

- Periodic connection fee [€/year]: A fixed amount per year to maintain the network connection (Stedin, n.d.-a).
- Transport-independent tariff (fixed tariff) [€/year]: A fixed amount per year that covers costs that are independent of the capacity of the network connection and does not vary with the total amount of energy consumed or supplied (Borenstein, 2016). An example of such costs are administration fees (ACM-ConsuWijzer, n.d.).
- Transport-dependent tariff: The transport-dependent fees reflect the costs of electricity transport across different network segments, including annual depreciation and capital costs on invested assets (Van Cappellen et al., 2024; Vrolijk et al., 2018). The transport-dependent fee is the largest component of the total network costs and is dependent on multiple components. The basic ones are, the contracted capacity per year [kWcontract/year], monthly peak load [kWmax/month] and annual consumption [kWh/year] (Stedin, n.d.-d). Additionally, charges for reactive power apply when the power factor falls outside the specified limits, as outlined in Article 2.27 of the electricity grid code (Dutch: Netcode elektriciteit) (Stedin, n.d.-c).

Note here that the annual consumption fee only applies to consumers based on the low and medium voltage grid (Stedin, n.d.-d; Van Cappellen et al., 2024). Consumers on the grid with a connection above 20 kV are not subject to this consumption fee (Van Cappelen et al., 2024).

There are also additional costs that a network user must pay, but not directly to the system operator, such as the costs for the electricity meter (Stedin, n.d.-c). Unlike small consumers, large-scale consumers do not have a legally set maximum for their metering tariff and do not have an electricity meter from their system operator. Instead, they must contract a commercial metering company to install and maintain the necessary equipment and report their power data to the system operator (Van Cappellen et al., 2024).

2.6.2 Network tariffs for producers

It is important to note that there is a main difference between large-scale consumers and large-scale producers of electricity in the Netherlands. That is, that in contrast to the consumers, producers do not have to pay any transport-dependent tariffs for electricity injection (Van Cappellen et al., 2022; Van Cappellen et al., 2024; Vrolijk et al., 2018). Currently, this has been fixed in Article 29, second paragraph of the Elektriciteitswet 1998, and in the same paragraph, it is mentioned that an injection charge for electricity producers can be applied through an executive decree (Dutch: Algemene Maatregel van Bestuur).

However, following a ruling by the Court of Justice of the European Union on 2 September 2021, such tariff-setting must be the responsibility of the independent NRA rather than the legislator or via an executive decree (ACM, 2021-b). As a result, future legislation must ensure that this authority is transferred to the ACM rather than to policymakers.

2.7 Current and future network costs

Research from the Netherlands Authority for Consumers and Markets highlights that the current electricity grid management costs are around €7 billion (ACM, 2024-b). However, through the need for grid expansion and network reinforcements, network costs could increase to between €18 billion and €25 billion by 2050. The network tariffs for residential consumers could increase from €250 in 2025 to between €600 and €800 per year in 2050, and for large-scale consumers, the costs could rise to two to three times their current levels (ACM, 2024-b). This projected rise in costs, as calculated by the ACM, is consistent with research conducted by the Dutch TSO TenneT and other research organizations.

As noted by Van Cappellen et al. (2024), the interaction between the energy transition and non-transport-dependent tariffs is limited. However, the transport-dependent tariff will be significantly impacted by the transition in the coming years. As a result, it is increasingly important to ensure a fair distribution of costs among all network users (ACM, 2024-b). Therefore, the next chapter will provide a detailed explanation of the solutions proposed by the ACM to reform current network tariffs, aiming to achieve a fairer and more cost-reflective allocation of costs among all grid users.

3. Injection charge

In the previous chapter, it was established that there is a mismatch between the current and future optimal distribution of network costs. At present, consumers are subject to a transport-dependent tariff, while producers are not. In response, the ACM published a comprehensive overview in 2024 outlining the measures already implemented or planned to reduce grid congestion in the Netherlands, which includes the adjustment of the injection charge (ACM, 2024-e).

Before introducing the different designs of the injection charge, the strategic objective of the ACM will be further explained to explain what the ACM wants to accomplish with this adjusted tariff. Thereafter, this chapter will delve into various designs of the injection charge and explore the potential effects of each. These insights will then be used in the next chapter to construct a model aimed at quantifying the impact of the proposed injection charge designs.

3.1 Strategic objective of the ACM

The strategic objective of the ACM is to accelerate the energy transition (ACM, 2024-a). Through adjustments to the tariff structure, the ACM aims to contribute to this goal. The role of the tariff structure is to encourage network users to use the grid more efficiently. Historically, the tariff structure was relatively simple, with little differentiation, which limited incentives for efficient and flexible grid usage. By varying the network tariffs for users, so-called tariff incentives can be introduced, encouraging users to make more flexible and more efficient use of the grid. For example, shifting electricity use to quieter periods on the grid. When the grid is used more efficiently, more parties can have access to it, which reduces the need for future grid expansions, and thus can save a lot of investment capital (ACM, 2024-a).

Incentives to use the grid more efficiently can thus play a significant role in solving grid congestion. Moreover, for the long term, it is crucial to stimulate flexible grid use and ultimately make it the norm (ACM, 2024-a). By promoting flexible use, the costs of grid expansions can be kept as low as possible. New users, through an adapted tariff structure, can also be encouraged to make efficient use of the grid. This reduces the need for grid expansions, helping to keep the future electricity grid affordable for everyone (ACM, 2024-a).

In addition, the tariff structure determines what portion each connected user contributes to the revenue of the network operators. Therefore, a distribution that is more fair and cost-reflective has gained more interest and is especially relevant for the future, as network costs could continue to rise (ACM, 2024-b).

3.2 Proposed injection charge variants

In order to achieve these goals, the ACM has proposed the solution of adjusted injection charges (ACM, 2024-e). However, the ACM has not worked out any detailed solution yet. Instead, they have commissioned the research firm CE Delft to investigate the potential options and their corresponding effects (Van Cappellen et al., 2024).

The six variants that have been studied are (Van Cappellen et al., 2024):

1. Uniform injection charge, with kWcontract and kWmax as charge components

2. Injection charge differentiated by time, with kWcontract and kWmax as charge components
3. Injection charge differentiated by location, with kWcontract and kWmax as charge components
4. Injection charge differentiated by time and location, with kWcontract and kWmax as charge components
5. Injection charge differentiated by time and location, with kWh as charge component
6. Connection fee with in addition limited deep or deep connection costs

They state that more variants are possible and that this is not an exhaustive list, but that calculations using these variants provide valuable insights into the potential effects of an adjusted injection charge and can help to determine which options may be more effective. Additionally, they suggest that, in general, a larger effect can be expected with greater differentiation, such as by time and location (Van Cappellen et al., 2024). However, they question whether using all tariff components is the optimal solution for cost-reflective tariffs.

3.3 Critique on proposed variants

However, there is also critique from market parties on these proposed variants.

3.3.1 Reducing new energy projects

To begin with, Energie-Nederland opposes an injection charge in general, as it would have significant negative effects on the deployment of sustainable generation, supply security, affordability, and could increase dependence on imports (Energie-Nederland, 2024). They note that already commissioned projects did not account for these costs in their business models, and that an increase in costs could reduce the number of renewable energy projects in the medium term, potentially putting the Dutch government's climate ambitions at risk. Holland Solar, NedZero & Energy Storage NL (2025) also state that they are opposed to the injection charges and requested the ACM to suspend the development thereof. All of these trade associations argue thereby that the uncertainty surrounding network tariffs is harmful to investors, as they tend to plan for the worst-case scenario, which may lead to delays or cancellations of financial investment decisions, ultimately hindering the realization of renewable energy projects (Energie-Nederland, 2024; Holland Solar & NedZero, 2024; Holland Solar et al., 2025).

3.3.2 Rise in costs

With less domestic renewable electricity production, there may be a greater reliance on non-sustainable electricity generators or increased imports, both of which could lead to higher electricity prices (Energie-Nederland, 2024). Even after accounting for secondary effects, such as rising electricity prices, the returns on both existing and new renewable investments could still be negatively impacted. Furthermore, Energie-Nederland (2024) states that although network costs for consumers may decrease if producers also pay an injection charge, the increase in electricity prices would outweigh these savings, resulting in an overall rise in costs.

3.3.3 Unfair for already commissioned generators

Holland Solar and NedZero (2024) argue that already commissioned electricity generators should be exempt from an injection charge, or otherwise fully compensated, as this cost could not have been anticipated in their investment decisions. Therefore, they are in favor of the sixth variant, as it is the only variant that is separating old and new generators. However, Netbeheer Nederland is opposed to this option, as a connection fee with in addition limited deep or deep connection costs would require determining the marginal costs per connection, which is only feasible to a limited extent (Netbeheer Nederland, 2024-a). They argue that since most costs are systemic and cannot be attributed to individual connections, a deep connection fee cannot be established in a cost-reflective manner.

3.3.4 Locations are not always free to choose

Furthermore, Energie-Nederland, Holland Solar, and NedZero express concerns about a tariff based on location, as spatial planning in the Netherlands is largely determined by local governments, through mechanisms like zoning plans and permits, rather than the choices of the producers themselves (Energie-Nederland, 2024; Holland Solar & NedZero, 2024). Additionally, multiple producers may seek to operate in the same low-cost area, which could eventually drive up the tariff in that area. Netbeheer Nederland also opposes using network tariffs to influence the locational choices of electricity producers (Netbeheer Nederland, 2024-a; Netbeheer Nederland, 2024-b).

3.3.5 Uncertainty for producers

Additionally, Holland Solar, NedZero and Energy Storage NL also state that time-based tariffs bring uncertainty to producers as it is not clear how things will change over time (Holland Solar & NedZero, 2024; Holland Solar et al., 2025). Energie-Nederland (2024) also acknowledges that these uncertainties introduce additional risks and states that investors will factor this into their investment decisions. They state that shifting this risk to market participants, rather than a regulated system operator, may therefore result in higher electricity prices and potentially lead to an overall increase in costs for end-users.

However, Netbeheer Nederland is in favor of a time-based tariff, as they state that it is cost-reflective and can provide incentives for efficient grid usage (Netbeheer Nederland, 2024-a; Netbeheer Nederland, 2024-b). While they prefer a uniform time-based tariff for all system operators, they acknowledge that time-dependent peak loads can differ by location due to local circumstances. Therefore, differentiation by location is not an objective in itself, but could be considered if research demonstrates that it is necessary in order to achieve a cost-reflective tariff.

3.4 Proposed injection charge variants of this study

Considering the arguments presented by market parties, this study will not focus on tariffs based on location. This decision is also in line with the arguments provided above and has specifically been made due to the fact that an electricity producer is not solely entitled to choose their locational site, but also did not choose their neighbors. A producer cannot choose their neighbors, but if these neighbors use the grid more heavily, the producer may need to bear part of the costs, which is not truly cost-reflective. Furthermore, the uncertainty surrounding location-based tariffs could lead to higher electricity prices due to increased risk premiums, ultimately impacting consumers. Also note that an additional one-time fee for new connections will not be considered, as it would provide only a short-term incentive and is subject to the same concerns as previously outlined.

Consequently, this study will focus on the following tariff variants:

1. Uniform injection charge, with kWcontract and kWmax as charge components
2. Injection charge differentiated by time, with kWcontract and kWmax as charge components
3. Uniform injection charge, with kWh as charge component
4. Injection charge with kWcontract and kWmax differentiated by time, and kWh as a uniform charge component

3.5 General assumptions and applicable laws and regulations

Before going more in-depth into the proposed variants, it is important to highlight some general assumptions and applicable laws and regulations.

3.5.1 Network segments

To begin with, it is good to note that besides the different tariff components, the electricity grid itself is also divided into multiple segments and corresponding user types. Following Article 3.2.3. of the tariff code for electricity (Dutch: Tarievencode elektriciteit), a differentiation between different network segments can be made (ACM, 2016). For the transport-dependent costs, the following classification of voltage levels is being used:

a. Extra High Voltage (EHV) ≥ 220 kV (including EHV/HS transformer)
b. High Voltage (HV) ≥ 110 kV and < 220 kV
c. High Medium Voltage (HMV) ≥ 25 kV and < 110 kV (including HV/HMV transformer)
d. Transformer HV+HMV / MV
e. Medium Voltage (MV) > 1 kV and < 25 kV
f. Transformer MV/LV
g. Low Voltage (LV) ≤ 1 kV

Please note that large-scale electricity producers are certainly not connected to LV-grids as the low voltage grid does not have enough capacity to deliver the required amounts of energy. Also, while it is good to note that these different categories exist, the focus of this research does not consider a full (legal) analysis on all of the possible tariff structures. Therefore, in order to keep it simple, it is assumed that every large-scale electricity producer needs to pay the same amount for injection, regardless of the segment they are connected to. This assumption is also in line with Regulation (EU) 2019/943, art. 18(1) as network charges should be applied in a way which does not discriminate between production connected at the distribution level and production connected at the transmission level. So, this assumption is also in line with the principle of non-discrimination, and ensures an equal level-playing field (Vrolijk et al., 2018).

3.5.2 Maximum tariffs

Furthermore, it must be noted that injection tariffs in the European Union are also bound to a maximum. Specifically, Regulation 838/2010 states that the average transport tariff for injection for the Netherlands should not exceed €0.50 per MWh over the course of a year (Netbeheer Nederland, 2024-b; Van Cappellen et al., 2024). In calculating this maximum, the costs for connection, system services, resolving transport constraints, reactive power compensation, and grid losses are excluded. Additionally, this is an average rate, and the rate may be higher during certain time blocks or for individual injectors. In line with this reasoning, the base tariff can thus be higher than €0.50 per MWh. For example, the tariff used by Van Cappellen et al. (2024) is equal to €2.50 per MWh.

3.5.3 Tariff rates

Due to the inherent uncertainties and trade-offs in tariff setting, it is not possible to develop a fully substantiated method for exact cost allocation, especially for long-term network costs (Hennig et al., 2022; Van Cappellen et al., 2024). Ultimately, the choice of tariff structure is determined by the ACM within the boundaries set by laws and regulations. Therefore, it should be noted that this study does not focus on the exact tariff rates, but rather on the estimated effect of a changed tariff structure on the electricity grid.

3.5.4 Focus on wind and solar

It is good to note that the designs of the variants in this study mainly concern measures to battle grid congestion coming from wind and solar electricity production facilities. This abstraction has been made as these technologies are dependent on weather influences and are therefore dependent on external influences which cannot be steered. Furthermore, as weather patterns can spread over a large area at the same time, this makes that the production of electricity coming from solar and wind can both have enormous simultaneous peaks, but also simultaneous lows. Given these characteristics, the rationale behind implementing injection charges is to reduce these simultaneous peaks from occurring, thereby helping to prevent grid congestion. By encouraging a more even distribution of grid usage throughout the day, the grid can be utilized more efficiently (ACM, 2024-a). Typically, the electricity grid operates at or near full capacity during peak periods, while sufficient transport capacity is generally available outside these times.

3.6 Analysis of proposed injection charge variants

The proposed tariff variants that will be used during this study will now be analyzed more in-depth, including their design, potential behavioral effects and design scores.

3.6.1 First variant

The first variant, a uniform injection charge, contains a fee on the kWcontract and kWmax charge components. Currently, such a fee does not exist for large-scale electricity producers. The design of this option can be uniform for all large-scale electricity producers, which means that the design is always applicable and for every source of electricity generation.

The kWcontract and kWmax components have been chosen as they represent the contracted capacity per year and the peak load per month, both very important parts of grid congestion.

As stated earlier, the kWcontract represents the annual contracted capacity, in kW/year. The contracted transport capacity is the maximum required capacity that a connected user expects to need at any given time during the year (Stedin, n.d.-c).

The kWmax charge component represents the highest actual load on the grid, measured at a connection point by a connected user. It is determined based on the maximum value, recorded during any 15-minute measurement period. The kWmax value then represents the peak load over a given time period, such as per month [kWmax/month] (Van Cappellen et al., 2024).

As exceeding the contracted capacity is prohibited, the kWmax may not surpass the value of kWcontract (Stedin, n.d.-e). Therefore, connected users want to keep their peaks below the contracted capacity, which means that they must set their contracted capacity at the level that is most economically advantageous in order to keep their costs as low as possible.

This variant of the injection charge therefore aims to accomplish two main goals, increasing cost-reflectivity by also requiring producers to pay for grid usage, and stimulating efficient grid usage by keeping maximum injection peaks low.

Design and potential behavioral effect
In this particular case, the design is very simple and straightforward, as it is general and uniformly applicable. Therefore, all large-scale electricity producers are subject to the same tariff rates per component, meaning they all pay the same rate per kW for the kWcontract component, and the same rate per kW for the kWmax component.

Following the logic outlined above, large-scale electricity producers are likely to set their kWcontract at a level that is most economically advantageous for them. They will weigh the additional costs of a higher contracted capacity against the extra revenue they can earn by selling electricity above this threshold. This means producers will optimize their contracted capacity to balance grid fees with potential market revenues, ensuring they do not pay for more grid capacity than necessary. Consequently, as the observed kWmax may not exceed the kWcontract value, the kWmax value thus needs to remain below or equal to the value of the kWcontract (Stedin, n.d.-e).

Since wind and solar are fundamentally different technologies, a distinction between these two categories will be made.

Wind
As the current tariff system does not account for any kWcontract or kWmax fees, most wind farms ask for connections at their rated capacity. However, the rated power of the turbines is reached only 1% to 10% of the time (European Wind Energy Association, 2005). Most of the time wind turbines operate at partial loads, depending on the wind speed. From the power system point of view, wind turbines can be regarded as production assets with an average power, which is 25% to 30% of the rated capacity, and sometimes has 3 to 5 times higher production peaks (European Wind Energy Association, 2005). Therefore, if they will be charged for the size of the connection, the contracted capacity will probably be lower in order to have less costs and increase profits.

Regarding this information, it is plausible to assume that with an injection charge, the connected capacity will be around 75% of the rated wind turbine or farm capacity. This allows large-scale electricity producers to keep connection costs low and maintain sufficient grid access to accommodate most of their production, without risking contractual violations or extreme curtailment. The kWcontract will then thus be at 75% of the rated capacity of the turbines. Given that kWmax may not exceed kWcontract, kWmax must remain less than or equal to kWcontract (Stedin, n.d.-e).

Solar
Because electricity production from solar in the Netherlands exceeds 70% of the total installed capacity for only 3% of the year, Holland Solar and Netbeheer Nederland agreed in 2020 to use a connection value set at 70% of the installed capacity (Netbeheer Nederland, 2020). However, later on, in 2022, the Netherlands Environmental Assessment Agency reported that a grid connection sized at 45% to 50% of the peak capacity appears to offer an optimal balance between costs and sustainable energy production (Beurskens et al., 2022). Therefore, it is assumed that the kWcontract for solar will be at 50% of the installed peak capacity. This means that solar production above this value will need to be either curtailed, or used or stored behind the connection. Here, it also applies that electricity producers must keep their kWmax peaks at or below the contracted value of kWcontract.

Design score
Such a design is scoring high on simplicity and transparency, as it is the same tariff for everyone, at every moment in time. Furthermore, the design is also more cost-reflective than the current tariff system as it includes a tariff charge on the transport-dependent charge component for electricity producers. The design is thereby aligning with the principles as outlined earlier of being, among other things, cost-reflective, transparent, non-discriminatory and accounting for the need for network security and flexibility (ACER, n.d.; Regulation (EU) 2019/943, art. 18(1)).

However, the simplicity in this design also has a downside. It might not give enough stimulation to the market parties to limit their peak electricity injection at certain times, potentially making the proposed effect less effective. This downside has also been acknowledged by Van Cappellen et al. (2022), as they state that uniform tariffs fail to provide sufficient incentives to modify behavior regarding the use of electricity grid capacity at specific locations or times of day.

3.6.2 Second variant
The second variant, rather than being generally applicable and uniform across all time frames, introduces a time-dependent weighting factor to the kWmax charge component for different electricity generation technologies. The incorporation of a time-dependent factor is an important aspect, as some forms of electricity production are more time-dependent than others. For example, electricity from windmills can only be generated when there is wind, and electricity from solar panels can only be generated when there is enough solar irradiance. Hereby, there are two main factors that affect the general behavior of the electricity production of wind and solar power, specifically, seasonal changes and the day and night cycle (Mulder, 2014).

For example, there is more wind in winter than in summer, while there is more solar irradiance in summer than in winter. These differences can be quite large, as for example in the Netherlands, there is a factor six difference between the solar insolation in midsummer and midwinter (Mulder, 2014). Also, wind power is almost two times stronger in winter than during the summer. Next to this seasonal difference, there is also a diurnal day and night rhythm, with more sun and wind during the day than during the night. In general, wind tends to reach its maximum speed about four hours after the solar peak, something which typically occurs around noon (Mulder, 2014). The wind speed follows this pattern because it is influenced by the surface temperature. Here, solar radiation heats the surface, which in turn warms the atmosphere above it, driving the observed wind speeds.

These patterns imply that, for example, when there is high solar irradiance over a large area, all solar parks are likely to generate a significant amount of renewable electricity. While this is beneficial in terms of renewable energy production, it also increases the likelihood of grid congestion. And as of right now, there is no incentive for producers that make use of intermittent energy sources to reduce their electricity output, as electricity producers are not required to pay any transport-dependent tariffs.

Other electricity sources, such as coal plants or gas turbines, are more flexible as they rely on storable fuels like coal and gas, which are less dependent on seasonal and daily patterns.

Therefore, this variant of the injection charge is specifically designed to reduce the occurrence of simultaneous injection peaks, which are mostly driven by intermittent renewable sources such as wind and solar power. By introducing time-dependent weighting factors, it aims to spread out electricity production more evenly, thereby potentially reducing the injection peaks and the need for costly network reinforcements.

Design and potential behavioral effect

Building on the information above, a monthly and hourly time schedule can be developed to enhance the likelihood of achieving the aforementioned goals. By carefully structuring the time-dependent charges according to both seasonal and daily variations in energy production, it might be possible to incentivize producers to better spread out the injection of electricity.

Therefore, for this variant, an additional weighting factor will be applied to better reflect the seasonal and time-dependent aspects of the injection. However, this will only be applied on the kWmax value as this value is measured during any 15-minute measurement period and the highest value per month is being evaluated. So the different seasonal and hourly production patterns play a role here. In contrast, the kWcontract component is the same during the whole year and does not change within this time period.

As the electricity generation patterns of wind and solar technologies are fundamentally different, a distinction between these two categories will be made.

Wind

To begin with, the presented design here is coming from the pattern of onshore wind electricity production, as this represents the biggest production category of wind energy in the Netherlands (Statistics Netherlands, 2024-a). The table design has been adopted from the study by Van Cappellen et al. (2024) and is shown in Table 2. This table was constructed based on a data analysis of various substations operated by regional and national system operators.

Table 2: Design of time-dependent injection charges for electricity generated by wind.

Onshore wind	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	Red	Red	Yellow	Yellow	Yellow	Yellow	Yellow	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Yellow
2	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Red	Yellow	Yellow	Yellow	Red	Red	Red	Red	Red	Red	Red	Red	Red	Yellow	Yellow
3	Yellow	Yellow	Yellow	Dark green	Dark green	Dark green	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Dark green	Yellow	Yellow	Dark green	Yellow
4	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Red	Red	Red	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow
5	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow
6	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Red	Red	Red	Red	Yellow	Yellow	Yellow	Yellow	Yellow
7	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Dark green	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow
8	Yellow	Yellow	Yellow	Dark green	Dark green	Dark green	Dark green	Dark green	Dark green	Dark green	Dark green	Dark green	Dark green	Dark green	Dark green	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow
9	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Red	Yellow	Red	Yellow	Red	Red	Red	Yellow	Yellow	Red	Red	Yellow	Yellow	Yellow	Yellow
10	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Red	Yellow	Yellow	Yellow	Red	Yellow	Red	Red	Red	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow
11	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Red	Red	Red	Red	Red	Red	Yellow	Red	Red	Red	Red	Red	Red	Red	Yellow	Yellow
12	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red
Weekend	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red

Table 2 presents the hourly weighting factors for onshore wind electricity injection for each month, with separate hourly profiles for weekends during the year. The colors in Table 2 represent different weighting factors for the kWmax component. In this context, the red color indicates periods with a high level of electricity injection into the grid, which may put additional stress on network components and therefore corresponds to a higher weighting factor (Van Cappellen et al., 2024). All of the weighting factors are listed in Table 3. While the kWcontract still remains constant during all time steps, the kWmax is now multiplied by these weighting factors according to the color indicated in Table 2. However, the kWmax may still not exceed the value of kWcontract, which means that a producer cannot inject more than their maximum contracted capacity into the grid at any given time, even after applying the weighting factor. Thus, only the weighting factor larger than 1.00, represented here by the color red, will actually reduce the maximum allowable injection into the grid for a specific time step.

Table 3: Colors and weighting factors for time-dependent injection charge design.

Color	Weighting factor
Red	1.25
Orange	1.00
Yellow	0.75
Dark green	0.50
Light green	0.25

Note that the light green, dark green, yellow, and orange colors indicate that the contracted value can still be used in full. The red color represents a multiplication factor greater than 1.00. This means that during these hours, producers may not inject more than the contracted capacity divided by the multiplication factor.

Solar

For the solar PV design, the table has also been adapted from the study by Van Cappellen et al. (2024) and is presented in Table 4.

Table 4: Design of time-dependent injection charges for electricity generated by solar PV.

Solar PV	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1																								
2																								
3																								
4																								
5																								
6																								
7																								
8																								
9																								
10																								
11																								
12																								
Weekend																								

As can be observed from this table, the profile of the weighting factors for solar PV production is distinctly different from that of onshore wind. The weighting factors specified in Table 3 are used for this table as well.

Design score

Since this design also considers the seasonal and daily patterns of renewable electricity production technologies, which depend on natural sources like wind and solar, the variant more accurately reflects the injection patterns throughout the year. Therefore, this design is likely to have a greater impact compared to the first variant, as the latter does not account for the timing of injection.

This design may also contribute higher in cost-reflectivity than the first variant, as it also takes the timing of injection into account. However, it is more complex than the first variant, which could make it more challenging to understand and execute.

3.6.3 Third variant

The third variant contains a uniform charge component, however, it is based on the kWh component instead of kWcontract and kWmax. Therefore, every kWh that is being produced and fed into the grid is being charged with an additional fixed fee.

However, there is still a difference in behavioral effects coming out of this tariff fee. As this injection charge is applied to every kWh, it is not giving any incentives for the producers to limit their contracted capacity or monthly peak load, as this is not being charged. Instead, the marginal price of one additional unit of electricity becomes higher, as it now also needs to incorporate the injection charge fee, making the bidding price in the electricity market higher (Van Cappellen et al., 2024).

As this price becomes higher, the probability that they can sell the electricity declines. Therefore, the producer can sell less electricity and thus demand declines. As this happens on a larger scale, the chances of grid congestion occurring may decline, and so may the need for network reinforcements.

Design and potential behavioral effect

Since this design includes a kWh tariff, it is evident that the system operator will charge for every kWh of electricity produced and injected into the grid.

This means that the extra injection tariff increases the marginal bidding price for electricity producers in each hour. As this bidding price becomes higher, it is reasonable to say that the demand for electricity will become lower, as not everyone is able and willing to pay more for their electricity. The height of this effect is dependent on the ability and willingness to pay, and is dependent on various aspects, including consumer type and purpose. For example, businesses which use electricity for their chemical processes for pharmaceutical products might have a higher willingness to pay for electricity than residentials using electricity for their dishwashers.

However, as small end-users are supplied by retailers, often on bilateral contracts with standardized terms and a fixed price per unit, they do not observe real-time prices and will therefore not respond to them (Lijesen, 2007). Also, if consumers expect that prices will rise in the future, they will take on a fixed contract for a longer period. In 2023, only around 3% of residential consumers had a contract for dynamically changing prices (Zwaan, 2025). Therefore, it is assumed that the proposed effect of this variant will not imply a big behavioral change in demand for residential consumers in the short term.

But, this is not only the case for residential consumers, it is also the case for companies. Companies can also choose a fixed contract with fixed prices during a fixed term. Thereby, they are also not directly impacted when market prices rise.

Thus, short term impacts on demand will probably be very low as consumers with fixed prices will not directly feel the urge to change behavior based on price signals from the market. However, in the long run, an effect on the demand could be the case. If prices keep rising, people will try to minimize their electricity usage by energy savings, invest in energy alternatives, or invest in their own electricity storage or production. Therefore, an impact in the demand could be measured.

As it is very hard to determine the exact future price trends and also isolate this from other real world variables, assumptions for this variant have to be made. Therefore, the concept of demand elasticity will be used. Demand is elastic when a change in price leads to a large change in the quantity demanded (Hofstrand, 2020). Demand is inelastic when a change in price leads to only a small change in the quantity demanded.

To begin with, it must be noted that the empirical literature suggests that demand elasticities for electricity are generally low (Lijesen, 2007). Csereklyei (2019) found that in the European Union, the short-term electricity demand in all sectors is highly price and income inelastic, meaning that there is no significant effect of changing prices. However, in the long run, price does have a significant impact on electricity demand. For residential consumption, it is estimated that a 1% increase in electricity price leads to an average of about 0.55% decrease in electricity consumption (Csereklyei, 2019). For industrial users, the same 1% price increase leads to about 0.88% electricity consumption decrease. For Pakistan, Jamil & Ahmad (2011) found that agriculture is inelastic to electricity price, implying that an increase in price does not change its usage in this sector.

Design score

As this design also considers that the producers pay their respective fee for using the electricity grid, it is clear that cost-reflectivity is more present than in the current model where they do not pay any. However, as this kWh charge will most likely be directly transferred into the bidding price of the producers, the end consumer will face the chance of an increased electricity bill. But, as the network costs for end consumers will become less, due to producers also paying partly for it, it might also be the case that there will only be a limited increase in total end-consumer costs (Van Cappellen et al., 2024).

Even though there might be an increase in direct end-consumer costs, the total saved social costs of this proposed variant might be higher. As the raise in electricity price may lead to less consumption of electricity, it might be that the grid congestion becomes less, leading to a lower chance of network disruptions and also less need for network reinforcements. When this would be the case, the overall increase in (temporarily) higher prices might be lower than the potential higher societal costs of grid congestion and its corresponding effects.

3.6.4 Fourth variant

This fourth variant combines the second and third variants to include and combine multiple incentives for producers in order to reduce grid congestion and increase cost-reflectiveness. These incentives can be found in the corresponding variants, and this variant aims to combine these in order to achieve the best result. Therefore, this variant makes use of time-dependent tariffs to take into account the varying electricity injection patterns, but also the uniform variant which leads to a change in demand.

Design and potential behavioral effect

As already outlined above, this variant will thus introduce fees on three different charge components, kWcontract, kWmax and kWh. Hereby, the time-dependent kWcontract and kWmax components lead to a change in producer injection patterns, whereas the uniform kWh tariff leads to less requests for electricity demand.

Design score

As this design incorporates multiple variants and their corresponding effects, this design will most likely have the largest effect in a positive way on the grid load and need for network reinforcements. This variant thus does not only improve cost-reflectiveness, but can also incentivize producers to make better use of the grid in multiple ways. However, because this variant is a combination of multiple tariff-components, it is less simple than the other variants. This complexity may hinder the implementation and execution of the variant.

4. Method

Now that the background information on network tariffs has been provided, variants of injection charges have been explained, and their behavioral effects have been explored, it is time to determine the actual impact of such charges on the electricity grid and the resulting need for network reinforcement. Therefore, this study employs a network model to simulate and analyze these impacts. In this chapter, the model will be introduced and the approach for developing it will be further elaborated upon.

4.1 Model background

To begin with, this study makes use of a network model which represents the electrical grid infrastructure within a defined geographical scope. Within this model, electricity production sources and electricity demand will be allocated, and a priority dispatch will take place in which renewable electricity generation sources are given preferential access to meet demand before conventional generation or backup resources are used (Oggioni et al., 2013). This approach reflects the policy logic that was widely implemented in European electricity systems to reduce curtailment and support renewable integration. While current EU regulations now limit priority dispatch to small, innovative, or existing installations, applying this approach in the model allows for analysis of potential impacts of changes in renewable production on system operation (Glowacki, 2024).

In this study, this model will be created within Python, as this software is free, open-source and supports a wide range of useful packages (Python, n.d.). The main package that will be used is NetworkX, as this is a package for the creation, manipulation, and study of the structure, dynamics, and functions of complex networks (Hagberg, n.d.).

In order to work with Python, JupyterLab will be used through Anaconda Navigator. Hereby, Anaconda Navigator will be used as a graphical user interface to simplify the management of Python environments and packages (Anaconda, n.d.). Anaconda Navigator is a desktop application that allows users to easily launch various applications such as JupyterLab, without the need to work directly with command-line interface commands.

JupyterLab is an advanced, extensible environment for creating shareable computational notebooks that combine code, data, visualizations, and text (JupyterLab, n.d.). It offers a customizable, interactive workspace that is ideal for prototyping and explaining code, exploring and visualizing data, and sharing ideas with others, making it a powerful tool for this research.

4.2 Model setup

Before diving deeper into the creation of the model, a general outline of the model will be given. This framework showcases the general steps that will be taken to develop and set up the model and generate results that are relevant for this study. This outline can be found in Figure 1.

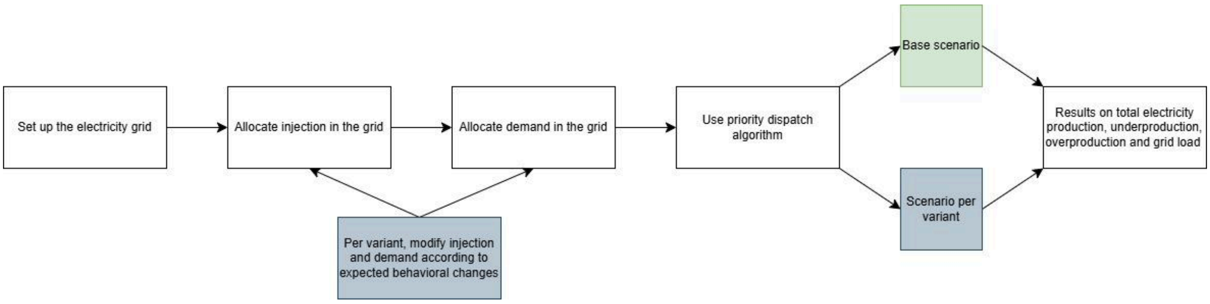


Figure 1: Conceptual outline of the model setup.

As illustrated in Figure 1, the model setup proceeds as follows. First, the electricity grid layout will be set up and modelled within Python. Next, the electricity injection will be allocated in this modeled electricity grid and the demand will be added as well. The priority dispatch algorithm will then be used to determine the results for the base scenario. Thereafter, the proposed effects of the four variants will be used to modify the electricity injection and demand according to the expected behavioral changes. The model will then again be executed with the priority dispatch algorithm and the results for each of the variants will be gathered. These results can then be compared and the corresponding effects of each variant in relation to each other and to the base scenario can be determined.

4.3 Setup of the electricity grid

To begin with, the electricity grid layout needs to be set up. This layout provides the foundation upon which additional elements can be added to model the electricity system of interest for this study. More specifically, the electricity system of the municipality of Reimerswaal, which lies in the province of Zeeland in the Netherlands. This geographical region has been chosen as there is a lot of injection-related grid congestion at the distribution system level and data about this area is available. In Figure 2, on the left, the injection-related grid congestion of the Netherlands is shown, and on the right, a more zoomed-in view of the province of Zeeland is provided and the municipality of Reimerswaal has been outlined. Here, the white areas indicate regions with no congestion, yellow highlights areas where limited transport capacity is available without a waiting list, orange marks areas currently under investigation, and red signifies insufficient transport capacity, resulting in a waiting list.

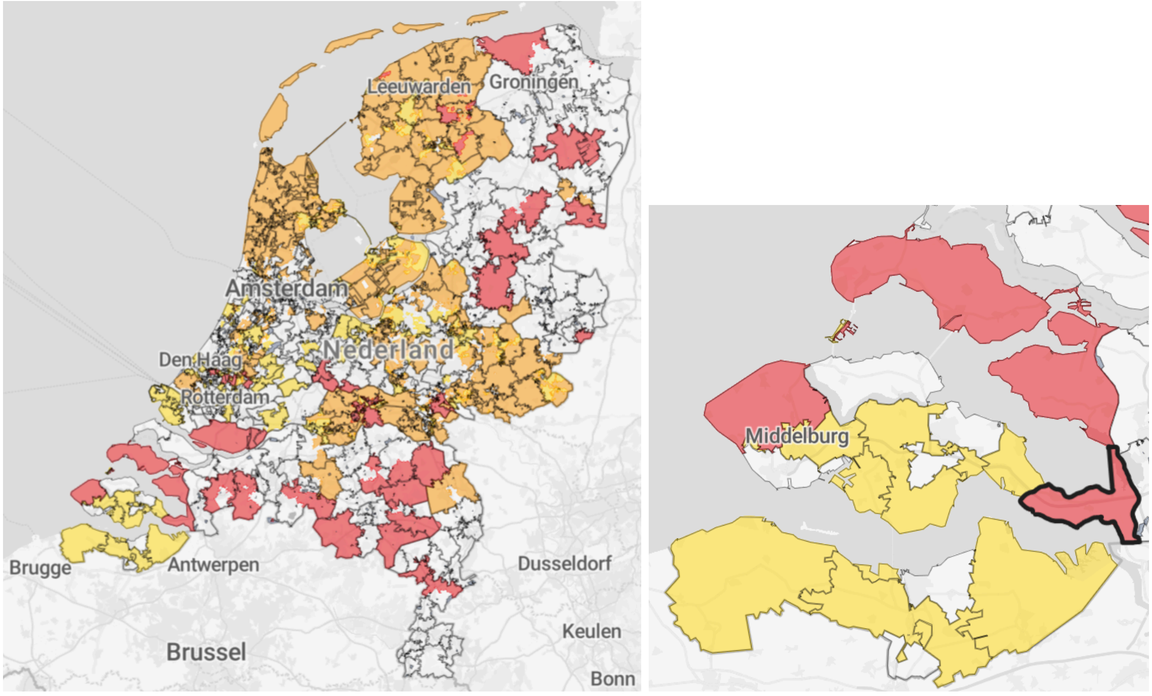


Figure 2: Injection-related grid congestion in the Netherlands as of April 2, 2025.

To highlight the issue of injection-related grid congestion in the province of Zeeland, it can be noted that, for instance, in the Noordring area, covering the municipalities of Schouwen-Duiveland and Tholen, there are 71 unique requests, with a total queued capacity of 33.6 MW (Netbeheer Nederland, n.d.). Additionally, in the municipality of Reimerswaal, there are 3 unique requests in the queue for a connection, totaling a capacity of 43.2 MW. Comparing these areas, it can be noted that the municipality of Reimerswaal is thus faced with a significant demand for injection-related capacity from only a few electricity production facilities.

It is good to note that, in both of these areas, the national system operator, TenneT, has enough capacity, but the DSO, Stedin, does not (Netbeheer Nederland, n.d.). And it will take multiple years to expand the local network capacity to facilitate all of these new connections. Therefore, this would be an area in which the adjusted injection charges could potentially alleviate the issue of injection-related net congestion.

It must be noted that this area of the municipality of Reimerswaal is, of course, characterized by its own characteristics. For instance, the municipality serves as a crucial (international) transport hub, facilitated by the Schelde-Rijnkanaal, a key railway line, the A58 motorway, and an extensive network of cables and pipelines (Gemeente Reimerswaal, 2022). Furthermore, the municipality is home to large-scale solar and wind farms, which produce renewable electricity. Additionally, there are numerous agricultural enterprises in the area, many of which use greenhouses. These businesses are transitioning to more sustainable practices, with a portion of them also acting as owners or operators of renewable energy installations themselves. In addition to agriculture, the municipality also contains several industrial areas (Gemeente Reimerswaal, 2022).

Locational data on the electricity grid of the province of Zeeland can be found through the open data page from Stedin. Here, Stedin provides the locational information about their low-, medium-, and high-voltage networks, including substations and distribution boxes (Stedin, n.d.-b).

This data is in the form of a Shapefile, which can be visualized through a Geographical Information System (GIS) viewer, such as the one provided by mapshaper, which is online accessible via mapshaper.org. In Figure 3, on the left, the data for the whole province of Zeeland is visualized using mapshaper, and on the right, the data of the municipality of Reimerswaal has been shown.

Figure 3: Electricity grid layout of Zeeland and the municipality of Reimerswaal.

For this study, the electricity grid layout of the municipality of Reimerswaal has been modeled in Python. Due to the complexity of the open data, which includes long, unidentifiable names for components, and non-connected components, it has been chosen to add all of the transformers and cable connections manually. Hereby, the low-voltage cables and cabinets were excluded from this model due to the large number of data points and the limited time available.

In Figure 4, on the left, the original data points (excluding the low-voltage cables and cabinets) are mapped onto satellite data, and on the right the modeled layout is shown. In the modeled model, the red points are the high-voltage substations, the blue points are medium-voltage substations and the green points are medium-voltage to low-voltage transformer stations.

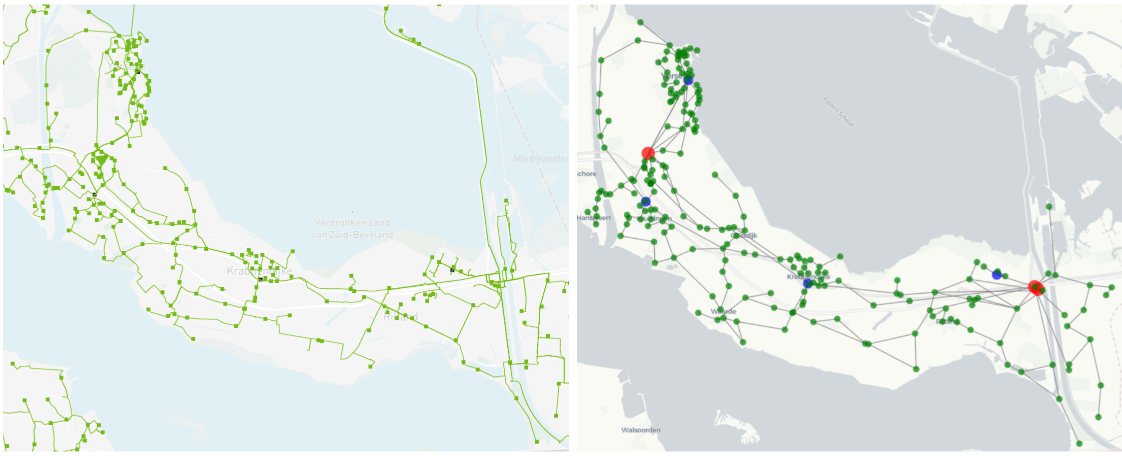


Figure 4: Comparison between original and modeled electricity grid layout.

It is good to note that the substations in the open data of Stedin are not following the same grid segments as the tariff code for electricity (Dutch: Tarievencode elektriciteit) as outlined earlier. Instead they follow the following classification (Stedin, n.d.-b):

a. High Voltage (HV) ≥ 50 kV
b. Medium Voltage (MV) for > 400 Volt and < 50 kV
c. Transformer MV/LV
d. Low Voltage (LV) ≤ 400 Volt

4.4 Adding injection

With the grid layout modeled in Python, the model can be extended to include the injection from large-scale electricity producers as well as the backup possibilities provided by electricity imports. The specifics of the electricity production sites in the municipality of Reimerswaal, coming from onshore wind and solar farms, are addressed in the following sections.

4.4.1 Onshore wind parks

In 2023, the municipality of Reimerswaal had a total of 51 onshore wind turbines, with a combined installed capacity of 98.22 MW (WindStats, n.d.). These turbines are distributed over 3 different windparks. This distribution can also be seen in Figure 5.

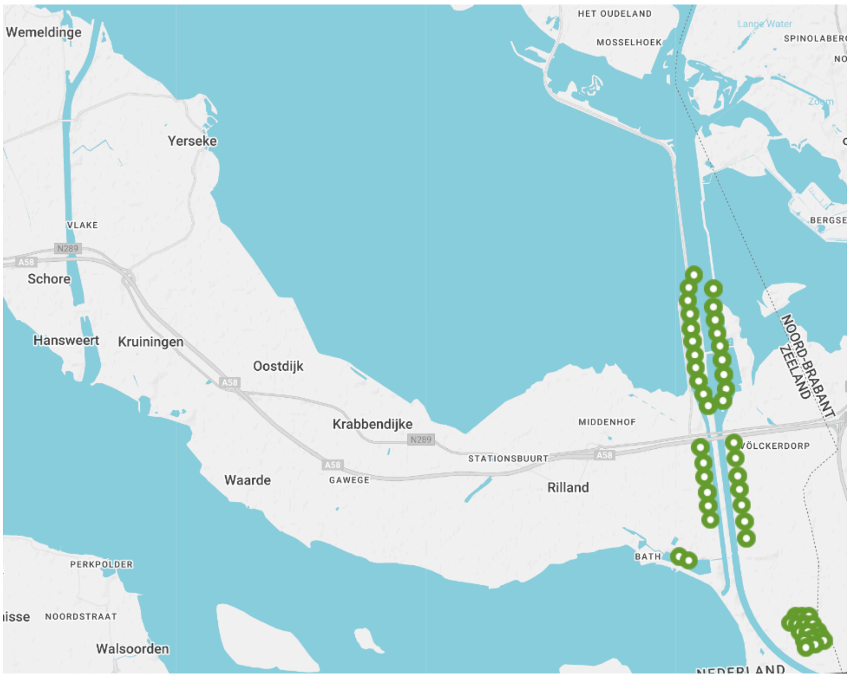


Figure 5: Visualization of the onshore wind turbines in the municipality of Reimerswaal.

Windpark Kreekraksluis

The wind farm around the Schelde-Rijnkanaal is called Windpark Kreekraksluis and comprises 33 Nordex N100/2500 wind turbines, each with a capacity of 2.5 MW (Winvast, n.d.).

Based on information from the online grid map of the high-voltage network, it can be seen this windpark has been split into north and south, each with their own 20 kV substation (HoogspanningsNet, n.d.). These substations are connected with 20 kV cables to the HV station, which can transform the voltage to 10 or 150 kV.

Windpark Bath

Windpark Bath, located near Bath, consists of 2 Vestas V47/660 turbines with each having a capacity of 0.66 MW (The Wind Power, n.d.-b).

This windpark is assumed to be connected to the nearest MS substation available, based on the information from Article 2.3.3 of the tariff code electricity (Dutch: Tarievencode elektriciteit) and Article 2.25 of the electricity grid code (Dutch: Netcode elektriciteit) (Stedin, 2023).

Windpark Anna-Mariapolder

Additionally, in the southeastern part of the area lies the Windpark Anna-Mariapolder, which includes 16 EWT Directwind 900/52 turbines, rated at 0.9 MW each (The Wind Power, n.d.-a).

This windpark is connected via a 10 kV substation and 10 kV cables to the HV transformer station where the voltage can be increased to 20 or 150 kV (HoogspanningsNet, n.d.).

4.4.2 Onshore wind production

In order to go from installed wind capacity to actual wind production, more data on the wind turbines and wind speeds are needed. The production can then be calculated manually, but luckily there is a website that can do this automated, renewables.ninja. This website has been the research output of Stefan Pfenninger and Iain Staffell, and the underlying methods are detailed in Pfenninger & Staffell (2016) and Staffell & Pfenninger (2016).

Within the website, the location and wind turbine type can be selected and the capacity [kW] and hub height [m] variables need to be filled in. Then, the results showcase a figure which visualizes the daily mean production over the whole year, as well as the monthly capacity factors. The hourly data on the electricity production output can then be downloaded as a CSV-file, and this data will be used in the model as standard injection.

It is good to note that this research utilizes 2019 weather data from the MERRA-2 dataset, as it is the only dataset provided by the website.

Furthermore, as the windmills in Windpark Bath and Windpark Anna-Mariapolder are very clustered, it has been chosen to only model the production data on the center location of the turbines here, as the differences in production are limited. For Windpark Kreekraksluis, four different sections can be identified, and the center of every section is being used as location data for representative production circumstances within such a section.

4.4.3 Solar parks

In 2023, the electricity production from solar irradiance was mainly coming from large-scale solar parks. In total, there were 64 MWp of registered solar panels in the municipality of Reimerswaal, of which 45 MWp consists of solar panels on fields (Netherlands Enterprise Agency, n.d.-a).

The locations of the solar parks can be found in Figure 6 below (Netherlands Enterprise Agency, 2025).

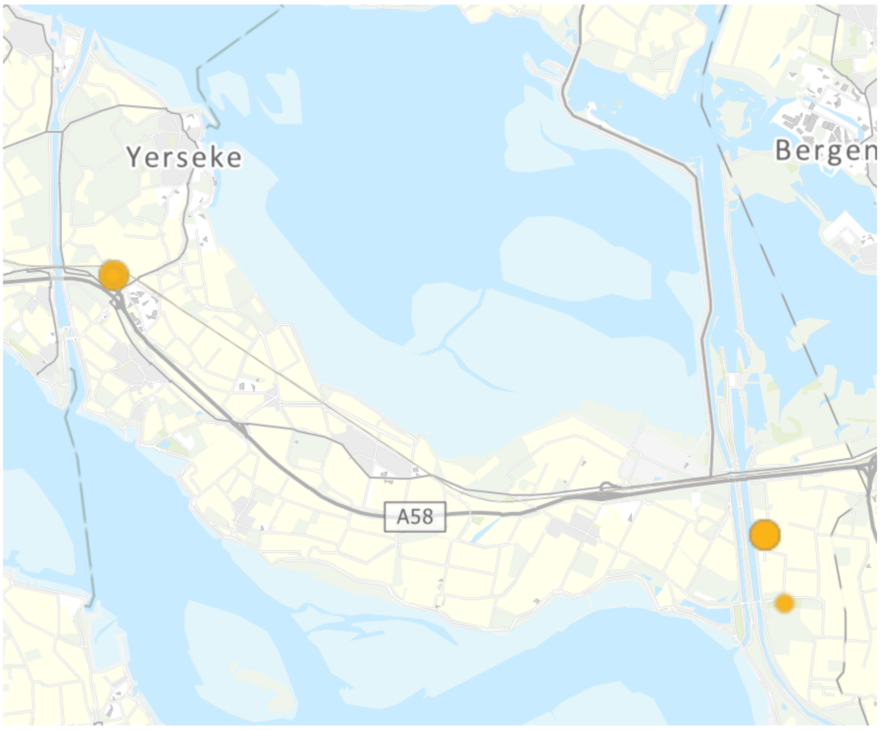


Figure 6: Solar parks in the municipality of Reimerswaal.

Solar park Rilland
The solar park Rilland (Dutch: Zonnepark Rilland) lies within the area of the Windpark Kreekraksluis, consists of an installation of 11.75 MWp and was the largest bifacial solar park of Europe in 2019 (Stultiens, 2019).

This solar park is connected to a 10 kV substation and via 10 kV cables to the HV transformation station where it can be transformed to 20 or 150 kV (HoogspanningsNet, n.d.).

Solar park Reimerswaal
The solar park Reimerswaal (Dutch: Zonnepark Reimerswaal) by ScheldeZon is a solar park with 9.5 MWp, realized on the terrain of the sewage treatment plant of the Water Authority Brabantse Delta in Rilland (De Jonge Baas, 2019). This location is shown in the bottom right corner within the figure above.

This solar park is connected with the public grid via the substation of the sewage treatment plant. This station has a voltage of 20 kV and is connected to the HV transformation station via 20 kV cables. At the HV station, it can be transformed to 10 or 150 kV (HoogspanningsNet, n.d.).

Solar park Kamperweg
Furthermore, the solar park Kamperweg (Dutch: Zonnepark Kamperweg) is a 24 MWp solar installation in Kruiningen (left point in the figure) by the Dutch onion company Wiskerke Onions (Janssen, 2022). The wholesaler uses the electricity to fully transition to sustainable practices and the remaining electricity is supplied to businesses in the surrounding area.

This solar park is connected to a 10 kV substation and via 10 kV cables to the HV transformation station where it can be transformed to 50 or 150 kV (HoogspanningsNet, n.d.).

4.4.4 Additional solar installations

It should be noted that there is also 17 MWp of rooftop solar capacity connected to large consumption connections in the municipality of Reimerswaal (Netherlands Enterprise Agency, n.d.-a). However, these installations are not considered in this study, as most projects are smaller than 0.5 MWp, which is relatively insignificant compared to the larger onshore wind and solar parks (Netherlands Enterprise Agency, 2025). As a result, the impact of these rooftop solar panels on the overall grid is relatively limited. Additionally, these projects are mostly owned by companies that are likely to use most of the generated electricity for themselves during their operations. Consequently, the amount of surplus electricity available for export to the grid remains relatively low, especially when compared to dedicated onshore wind and solar parks that are primarily designed for electricity sales.

4.4.5 Solar park production

As also with the electricity production from wind, the site of renewables.ninja has been used to determine the hourly solar electricity production over the whole year. Here, also the MERRA-2 dataset from 2019 has been used, and the capacity [kW], system loss [fraction], tilt [°] and azimuth [°] need to be filled in manually per solar park.

A tilt of 35° has been assumed and the azimuth has been determined through viewing the position of the solar panels within the solar parks via Google Earth. Furthermore, per solar park, a total system loss of 10% has been assumed, which is the standard given value within renewables.ninja.

4.4.6 Imports

In addition to the existing production facilities, three additional nodes with an unlimited import capacity have been added. These nodes are connected to the HV substations based on the network topology of the municipality of Reimerswaal, allowing for an unlimited electricity supply to meet demand at all times. Conversely, in periods of overproduction, these nodes enable the export of electricity from the municipality to other areas.

4.4.7 Assigning injection to the model

Now that the hourly injection and backup possibilities from imports have been established, they can be assigned to specific locations within the modeled grid.

In the figure below, it can be seen that there are 3 HV substations and 4 MV substations in the municipality of Reimerswaal.

Figure 7: Plot of the modeled HV and MV substations in the municipality of Reimerswaal.

Most of the large-scale production sites are connected at substation HV_2. These include, windpark Kreekraksluis, windpark Anna-Mariapolder, solar park Rilland and solar park Reimerswaal. This station can transform between 10, 20 and 150 kV (HoogspanningsNet, n.d.). Windpark Bath is connected at substation MV_1 following the tariff code as explained above. The solar park Kamperweg is connected at substation HV_3, which can transform between 10, 50 and 150 kV(HoogspanningsNet, n.d.).

It must also be noted that substations HV_1 and HV_2 are connected through a 150 kV cable of the TSO, TenneT (HoogspanningsNet, n.d.). Additionally, the names and locations of the extra nodes follow the same structure as those of the HV substations.

4.5 Adding demand

After the injection has been added to the model, the demand in the grid, per node, has been determined.

4.5.1 Standard usage profiles

At first, the standard usage profiles for various Dutch user types in 2023 were downloaded from MFFBAS (2025). These standard profiles provide the quarterly share of total annual electricity consumption for each user type. Since the production data is available on an hourly basis, the data from each quarter within an hour was summed to obtain the hourly share of total annual consumption. Within the dataset, the following profile categories are distinguished:

- E1A: ≤ 3 x 25 A, non-remote readable meter;
- E1B: ≤ 3 x 25 A, remotely readable meter, night tariff regime;
- E1C: ≤ 3 x 25 A, remotely readable meter, evening tariff regime;
- E2A: > 3 x 25 A ≤ 3x 80 A, non-remote readable meter;
- E2B: > 3 x 25 A ≤ 3x 80 A, remotely readable meter;
- E3A: > 3 x 80 A, < 100 kW, operation time ≤ 2000 hours;
- E3B: > 3 x 80 A, < 100 kW, operation time > 2000 hours, ≤ 3000 hours;
- E3C: > 3 x 80 A, < 100 kW, operation time > 3000 hours, < 5000 hours;
- E3D: > 3 x 80 A, < 100 kW, operation time ≥ 5000 hours;
- E4A: All measured connections switched on by the control signal of public lighting with a connected power of less than 100 kW.

4.5.2 Demand for small consumers

As small consumers have a connection below 3 x 80 Amperes, E1B and E2B have been chosen as representative standard usage profiles. E1B has been chosen because the night tariff regime is a common tariff type for small consumers. E2B has been chosen to represent small consumers who need to have more capacity than a regular 3 x 25 Ampere connection. Lately, more and more consumers are upgrading their connections due to, for example, electrification of home appliances and electric vehicle charging at home (ANWB, n.d.). The distribution between the Dutch household profiles of E1B and E2B is approximately two-thirds to one-third.

To determine the amount of usage per household, it has been chosen to take the average electricity consumption of households in 2023 in the municipality of Reimerswaal, which is equal to 2680 kWh (AlleCijfers, 2025).

The number of households allocated to each node was determined using a combination of neighborhood data from the interactive map on AlleCijfers (n.d.) and observations from Google Maps. Subsequently, the number of households connected to each corresponding substation was established using the open dataset from Stedin via mapshaper.org, along with additional analysis using Google Maps.

Determining the hourly electricity consumption values

To then calculate the total hourly residential electricity consumption, the following steps were taken. First, for each node, the number of households was multiplied by the average annual electricity consumption per household. This annual value was then distributed across the hours of the year by applying a weighted combination of two standard load profiles, using two-thirds of the profile of E1B and one-third of the profile of E2B.

4.5.3 Demand for large-scale consumers

As large-scale consumers have a connection greater than 3 x 80 Amperes, the profiles of E3B, E3C and E3D have been chosen to represent their electricity usage patterns. E3B has been chosen for the profile of offices, small industrial businesses and retail stores (without cooling), as they mostly have operating days and hours which represent between 2000 and 3000 operating hours per year of electricity usage. E3C has been chosen to represent restaurants as they mostly have extended operating hours in comparison to offices and retail stores. E3D has been chosen to represent retail stores (with cooling), agriculture, horticulture and large-scale industry.

It is important to note that there are other categories, such as cafés and hotels. However, due to their limited presence within the municipality of Reimerswaal, they have been excluded from the scope of this study.

To determine the hourly usage per category, it is necessary to use averages for electricity usage per usage type.

Profile of E3B
The average electricity usage for offices has been determined by multiplying the average office size, 770 square meters, with the average annual electricity consumption per square meter for this category, which is 54.9 kWh/m² (Statistics Netherlands, 2019; Troostwijk Research, 2021). This results in a total of 42.3 MWh per year for an average office.

It is very hard to determine an exact amount of electricity usage for small industrial businesses, as they are all different. However, there are about 3800 industrial clusters in the Netherlands, of which small and middle big companies use around 50 PJ electricity in total (Kamphuis et al., 2023). This means that every industrial cluster uses around 3.7 GWh/yr.

For retail stores (without cooling), the average floor space of a wine shop has been chosen. This kind of store has an average of 85 square meters and uses 105.2 kWh/square meter, which means a total of 8.9 MWh/year (Custers, 2017; Statistics Netherlands, 2019).

Profile of E3C
Restaurants have an average floor area of 141 square meters and an average annual electricity consumption of 227.8 kWh per square meter, resulting in a total electricity usage of around 32.1 MWh per year (Slob, 2020; Statistics Netherlands, 2019).

Profile of E3D
Retail stores (with cooling) have been represented by supermarkets, with an average of 941 m², and electricity usage of 243.6 kWh per square meter, meaning that there is a total electricity consumption of 229.2 MWh/year (Custers, 2017; Statistics Netherlands, 2019).

The average electricity usage of an agricultural business is 3.6 GJ/hectare, which is equal to 0.1 kWh/m² (Van der Meulen, 2022). Since the agricultural area differs for each farm, the amount in square meters will be determined by using measuring tools of Google Maps. Thereafter this amount will be multiplied with the average electricity usage to get the total amount of electricity consumption in kWh/year.

The average electricity usage of a horticultural business is 19 kWh/m² (Smit, 2023). As the horticultural areas are not the same for every business, the corresponding area will be determined by using measuring tools of Google Maps. Thereafter, this amount will be multiplied with the average electricity usage to get the total amount of electricity consumption in kWh/year.

There are also some large-scale and electricity intensive industries in the municipality of Reimerswaal. Note that as most companies are private, there is only limited publicly known information. For this study, some notable ones, for which information is available, are selected. For example, the sewage treatment plant of Water Authority Brabantse Delta. The total amount of electricity usage from Water Authority Brabantse Delta for purifying sewage water in 2019 was approximately 15000 MWh, divided over 17 treatment plants (Water Authority Brabantse Delta, 2020). This means that per treatment plant there is about 882.4 MWh/year of electricity usage. Additionally, Wiskerke Onions B.V. needs around 15% of their own solar park of 24 MWp, which comes down to approximately 3600 MWh/year (Heijboer, 2022). Furthermore, Lamb Weston EMEA Kruiningen is a large consumer of electricity. Based on the report from Lamb Weston Holdings, Inc. (2024), the total energy consumption in 2023 from 19 facilities combined was 14990933 GJ. This means per facility there was around 219.2 GWh of energy usage per year. Of this, 22.1% was used on electricity, resulting in an average annual electricity consumption of 48.4 GWh per facility (Lamb Weston Holdings, Inc., 2024).

Determining the hourly electricity consumption values
After establishing the average yearly consumption for each category and determining the number of units per category at each node, the total annual consumption per node is calculated by multiplying these values. For each profile, the consumption across relevant categories is then summed to obtain the total yearly usage. This total is then multiplied by the corresponding standard hourly distribution profile, which represents the share of consumption during each hour, to accurately convert the annual figures into hourly electricity consumption values in kWh.

4.6 Dispatch

Since the production and demand are now added into the model, the dispatch can take place. Power system dispatch determines the optimal operation pattern of the power grid to meet the power demand (Yang et al., 2023). In this study, as only renewable electricity generation technologies (solar and wind) are available within the municipality of Reimerswaal, the choice has been made to use a priority dispatch. In this approach, renewable generation sources are given preferential access to meet demand before conventional generation or backup resources are used (Oggioni et al., 2013). As there are no conventional generation sources in the municipality, only backup resources can be used. It is assumed that these are always available and will only be used if the local renewable production in Reimerswaal cannot fulfill the total demand at a certain time step. This dispatch logic has been implemented in the Python code.

4.7 Variants

The different injection charge variants as outlined in Chapter 5 have been implemented in the model as described. However, it is good to note that for the third and fourth variant, extra additional assumptions were made.

Following the analysis by Van Cappellen et al. (2024), it is assumed that through market recovery, the electricity price will only be a fraction of 1% higher with injection charges than without. Netbeheer Nederland (2024-a) also considers this price scenario to be the most realistic and therefore recommends using this scenario as the basis for further research.

Furthermore, since not all categories described in section 4.5.3 are covered within the section of the third variant, certain assumptions are necessary. It is assumed that horticulture exhibits the same price inelasticity as agriculture, given the close relationship between these sectors. Additionally, retail stores (with cooling) are considered comparable to industrial consumers, as they cannot simply suspend their processes. Offices, retail stores (without cooling), and restaurants are assumed to behave more like residential consumers and are therefore grouped accordingly.

5. Results

This chapter presents the results of the model. Additional results are included for completeness and may be of interest to readers seeking further detail.

5.1 Production

To begin with, the total renewable production within the base scenario and the injection charge variants will be shown. Note here that the base scenario and the third variant have the same values for production, as nothing has changed here in the size of the connection. In addition, the values for the second and fourth variants are identical because both have the same change in connection capacity.

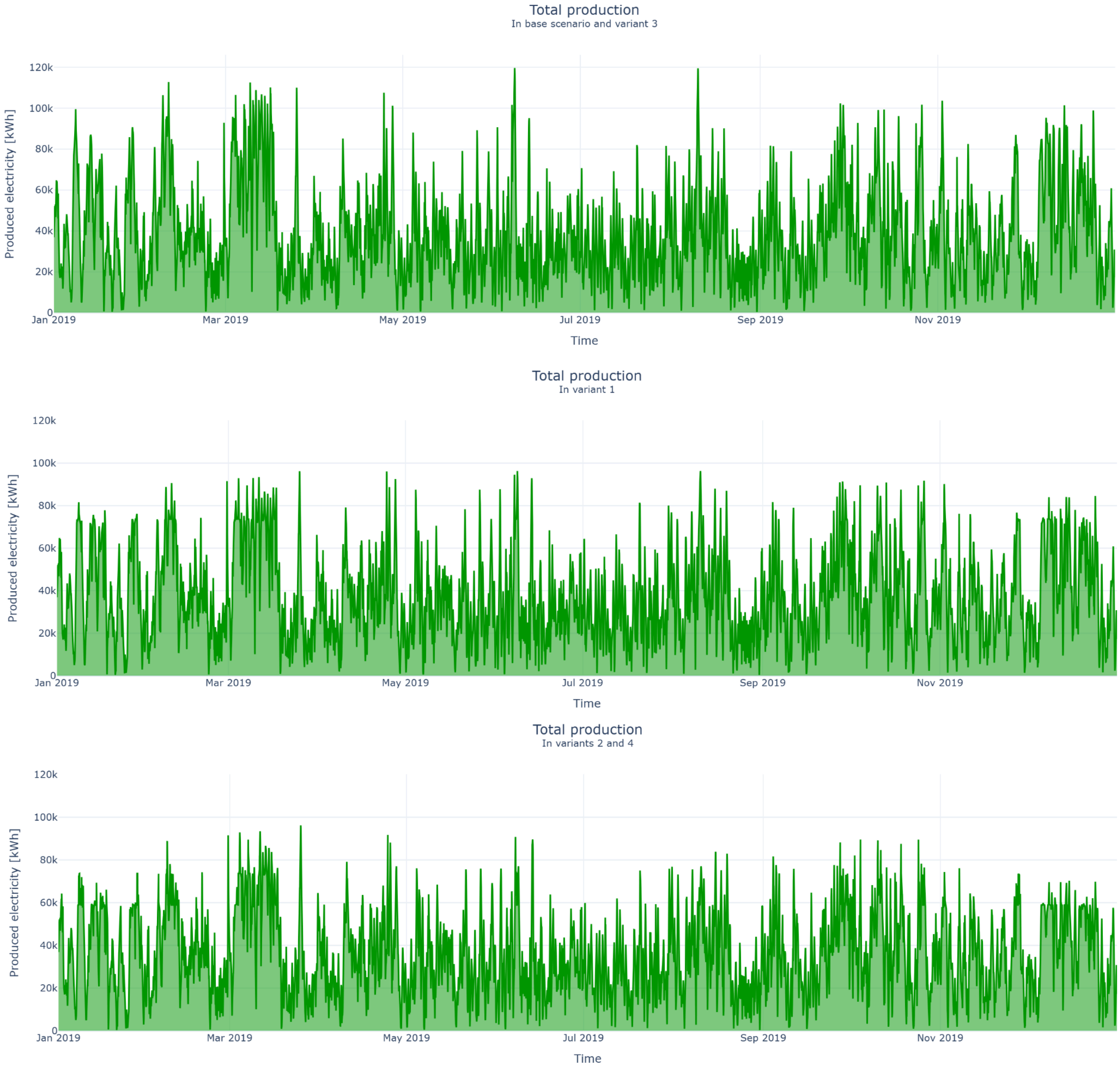


Figure 8: Total production across the base scenario and injection charge variants.

Looking at these graphs, it is clear that in the base scenario and in the third variant there is a significantly higher electricity production than in the other variants. Whereas in the other variants the production does not even reach 100 MWh, the production in the base scenario and third variant almost reaches 120 MWh. While the same pattern can be recognized, the peaks have thus tremendously been reduced in the first, second and fourth variants.

Furthermore, it can be observed that production in the first variant exhibits some higher peaks compared to the second and fourth variants. However, this difference is relatively small when compared to the much larger gap between the first variant and the production in the base scenario and third variant.

To go more in-depth in the production differences, the production of substations MV_1 (wind dominated) and HV_3 (solar PV dominated) have been plotted below. Note that the same base scenario and variant combinations as mentioned above also apply here.

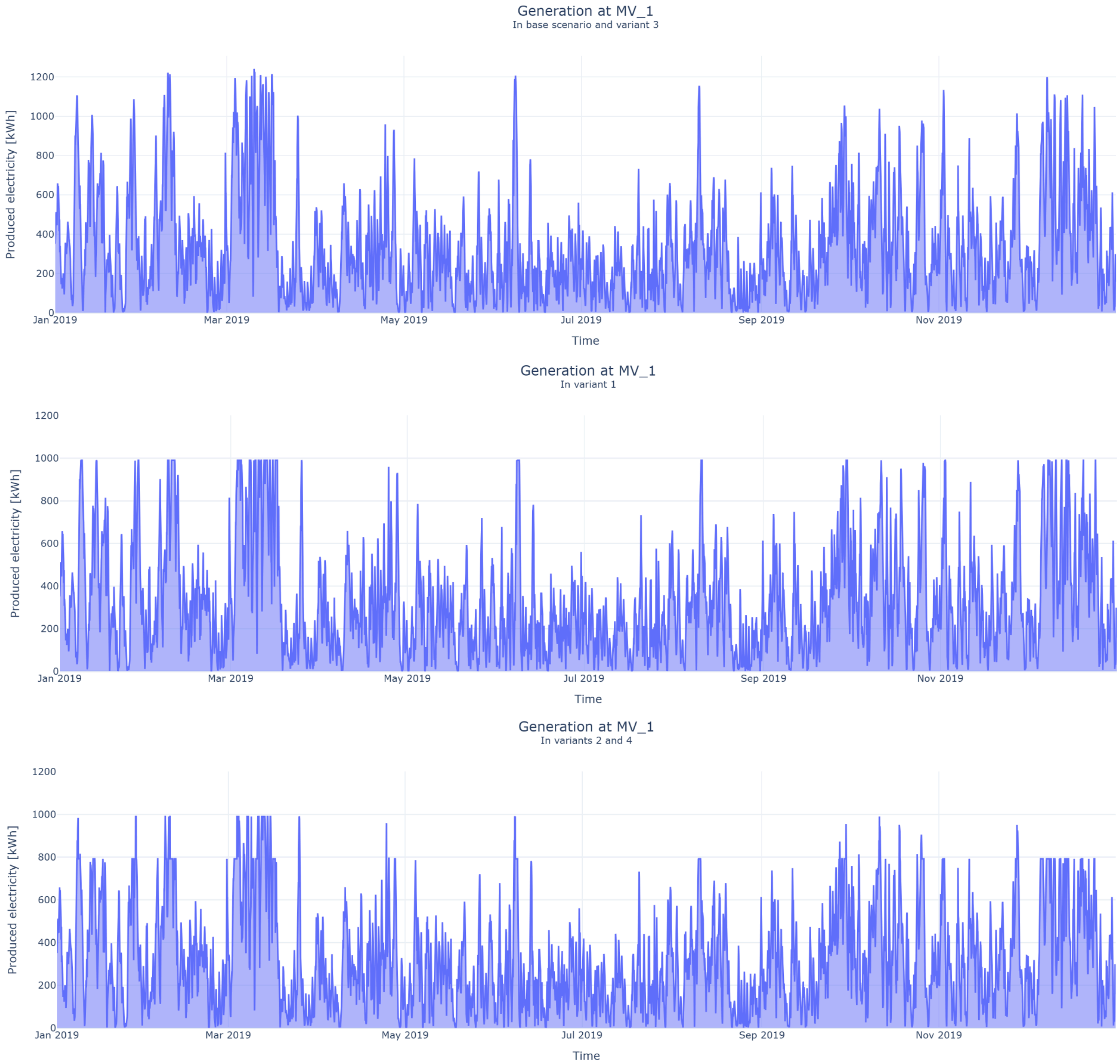


Figure 9: Generation at MV_1 across the base scenario and injection charge variants.

Figure 10: Generation at HV_3 across the base scenario and injection charge variants.

From the graphs, it is clear that the base scenario and third variant exhibit substantially higher production peaks compared to the other variants. While the second and fourth variants show a reduction in peak production relative to the first variant, this difference is minor compared to the much larger gap between this variant and the base scenario or the third variant. This also reflects the same pattern as observed earlier in the total production graphs.

Additionally, a comparison of electricity generation technologies reveals that while wind production peaks have diminished, the decrease is even more pronounced for electricity generated from solar PV. This results in a noticeably smoother production profile for solar PV.

5.2 Demand

After examining the production patterns, it is also important to consider the demand patterns within the municipality of Reimerswaal. Note that there are again combinations of variants that share the same demand scenarios. Here, the base scenario and first and second variants all have the same demand profiles. Additionally, the third and fourth variants also have the same demand profiles.

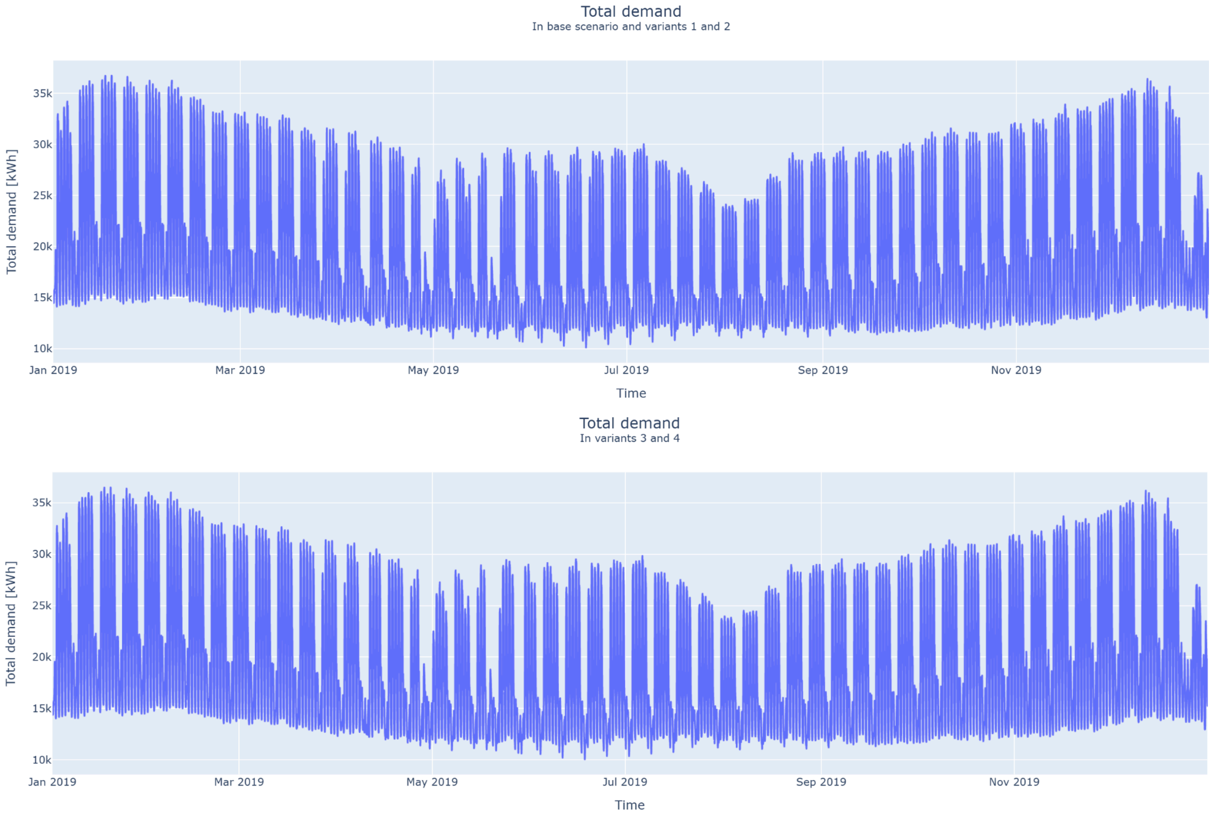


Figure 11: Total demand across the base scenario and injection charge variants.

Comparing these two graphs, it is hardly noticeable that there is any difference at all. The demand follows exactly the same pattern, and the amplitude of the fluctuations is also almost identical. Only when looking really closely can one identify that there is a marginal difference between these plots.

5.3 Dispatch

After the dispatch has taken place, with extra backup nodes if necessary, it can be noticed that there are times of shortcomings, but also of overproduction.

5.3.1 Underproduction

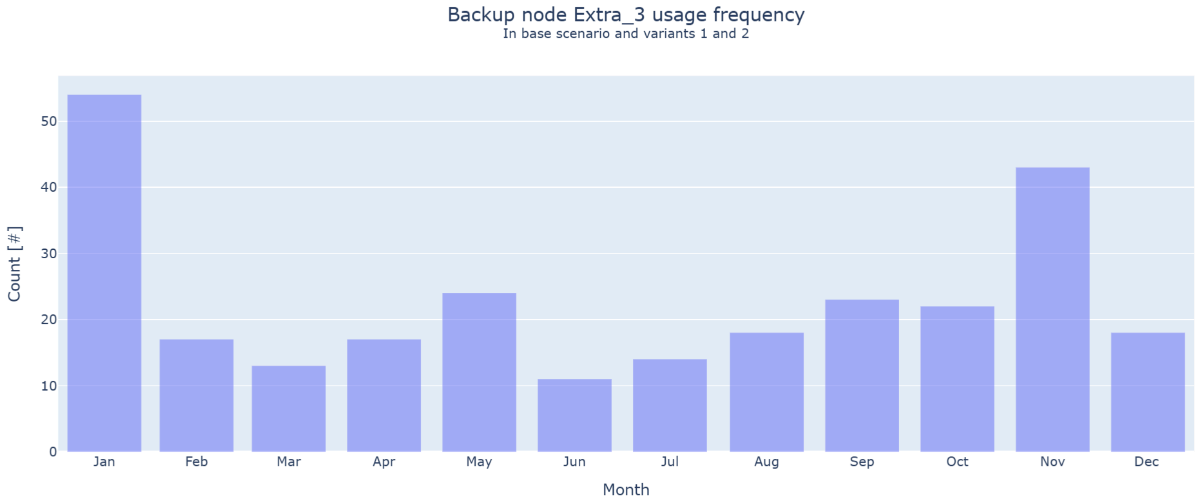
To begin with, the times of shortcomings are discussed. Table 5 highlights how often the backup node Extra_3 was used, and how much electricity was supplied from this node. Please note that backup nodes Extra_1 and Extra_2 were not used during the dispatch, regardless of the scenario or variant, so that is why they are not included in the table.

Table 5: Backup usage and supply across the base scenario and injection charge variants.

Underproduction	**Base scenario**	**Variant 1**	**Variant 2**	**Variant 3**	**Variant 4**
Timesteps backup node used [#]	274	274	274	268	268
Total supplied [MWh]	647.15	647.15	647.15	641.71	641.71

When scanning the table, a clear pattern emerges. The values are identical for the base scenario and the first and second variants, while the third and fourth variants also match each other. In these variants, the backup node has been used 2.19% less than in the other ones. The supplied amounts of electricity from the backup node in the third and fourth variants are approximately 0.84% lower than in the base scenario and first and second variants. Using the numbers as presented in the table, it can be calculated that for the base scenario, as well as for the first and second variants, about 3.13% of the total hours in the year require backup from Extra_3 to meet the demand. For the third and fourth variants, this is about 3.06%.

Following this, it is also good to have more insights into the distribution of usage of the used backup node, Extra_3, over the year. Therefore, the following plots can be beneficial.



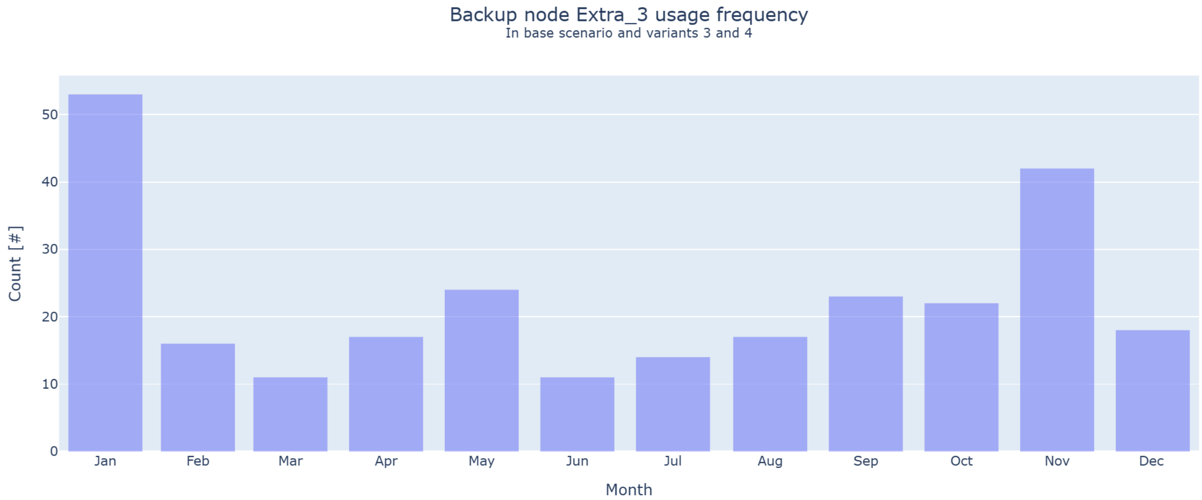


Figure 12: Monthly backup count across the base scenario and injection charge variants.

These plots highlight that the backup node Extra_3 needs to be used during every month throughout the year. However, it is evident that the backup node is required most during the months of January, May, and November. The backup node is needed least during the summer months. Another thing that can be observed in the figure is that there is no big difference between the variants. The usage of the backup node in the base scenario and first two variants has the same pattern as in the third and fourth variants. The only difference is that in some months, the need for the backup node is a bit less in the last mentioned variants, but this is not significant.

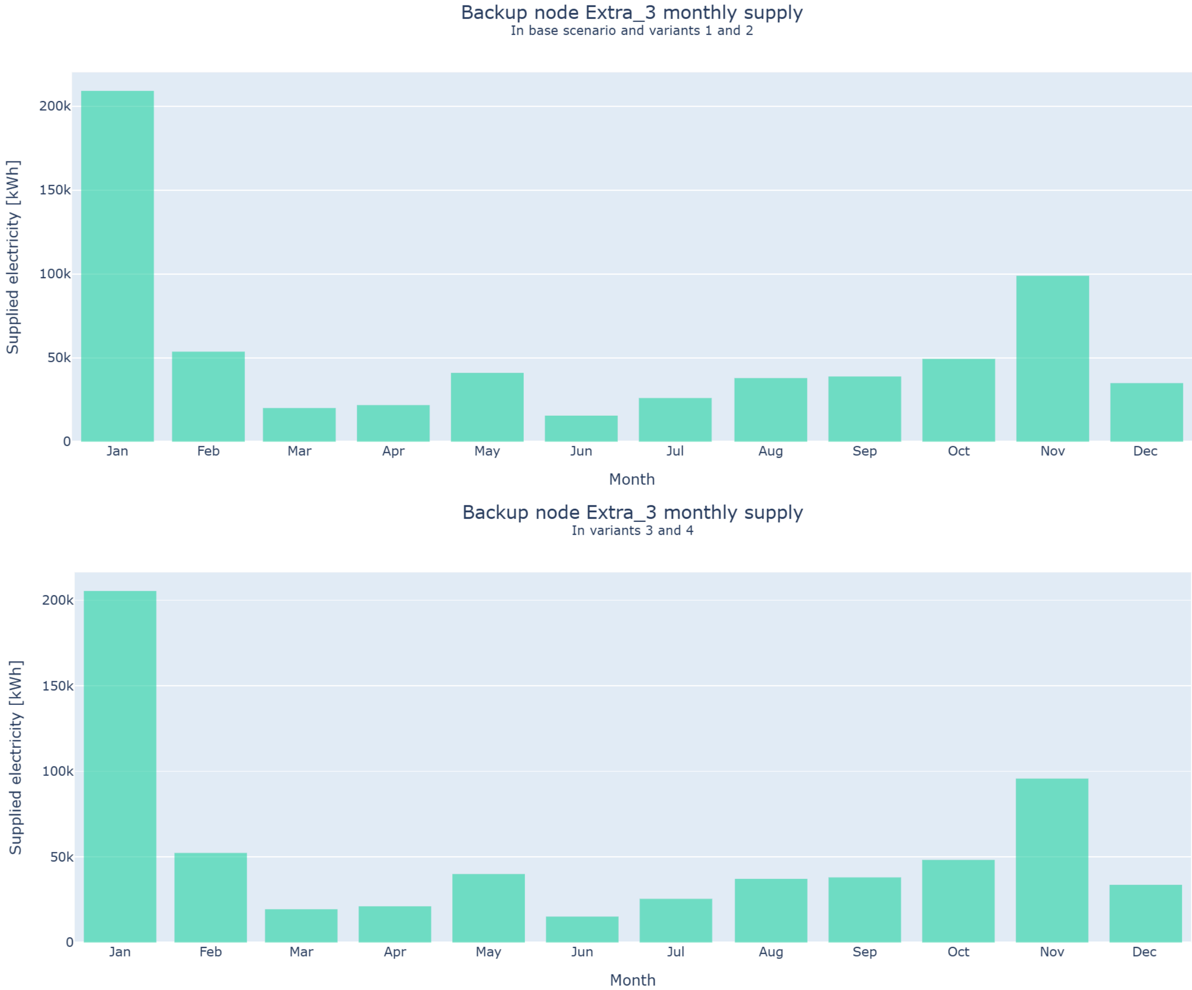


Figure 13: Monthly backup supply across the base scenario and injection charge variants.

When looking at the supplied electricity of each month, it is clear that January needs the most and June needs the least amount of electricity from the backup source. Furthermore, it is remarkable to see that while some months have a higher amount of usage frequency compared to others, they do not need more electricity in total. For example, the month September has a higher frequency of usage than October, but in total, October needs more electricity from the backup node. Additionally, comparing the values from the base scenario and first and second variant to the third and fourth variants, it can be noticed that there is only a small difference. Overall, the pattern is the same and only the heights of the peaks are marginally different.

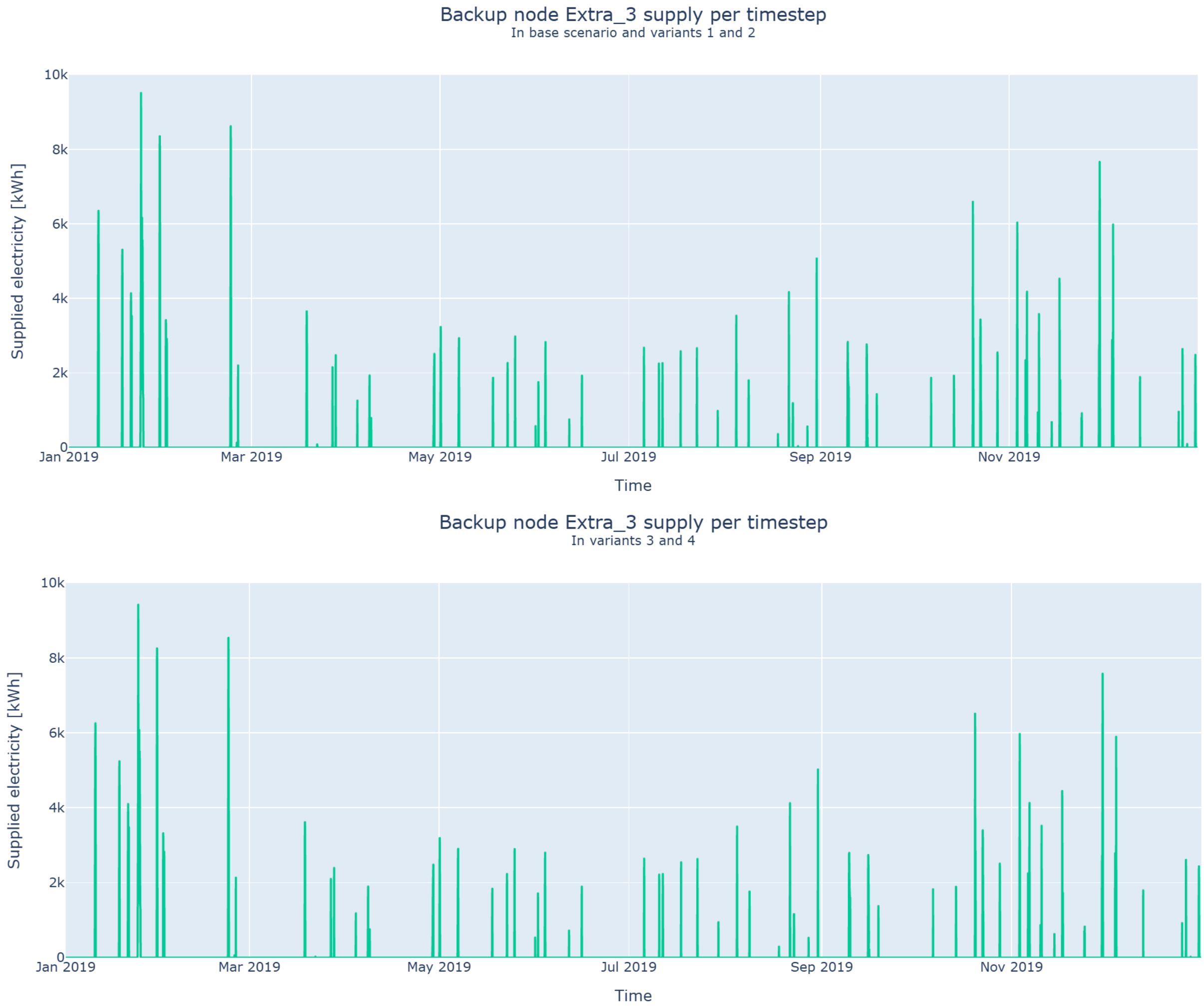


Figure 14: Backup supply across the base scenario and injection charge variants.

Upon examining these plots, it can be seen that the distribution is spread out over the year, but there are a few huge peaks spiking out, especially in January, March and November. Furthermore, it is again evident that the differences between the two situations are minimal. Both the overall pattern and the amplitude of the peaks are nearly identical.

5.3.2 Overproduction

Now the usage of the backup nodes have been presented, it must be noted that there are also times of overproduction. In these times, the electricity production in the municipality of Reimerswaal is greater than the demand. This will now be highlighted.

At first, a table overview will be used to report the amount of times during the year that there has been a surplus from the nodes, as well as how large this surplus is over the course of a year. Note here that the amount is expressed in GWh, as the total amounts are very large.

Table 6: Overproduction across the base scenario and injection charge variants.

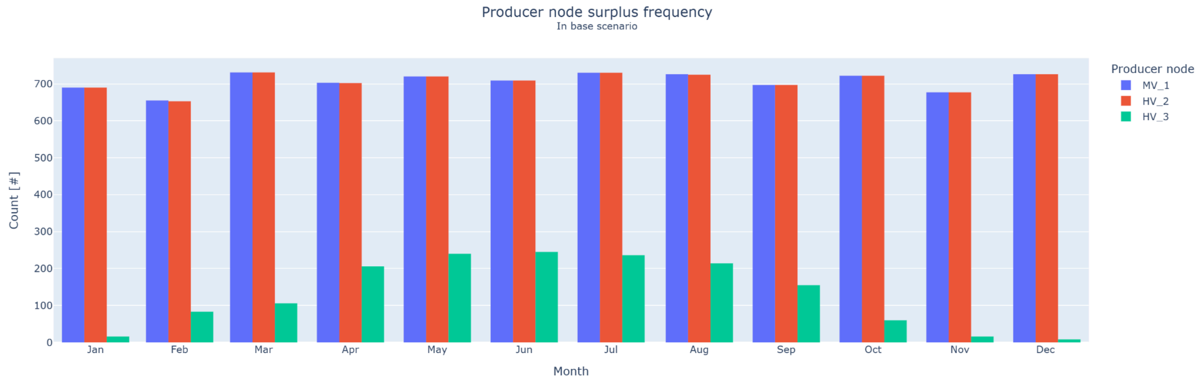
		MV_1	HV_2	HV_3
Frequency [#]	Base scenario	8486	8482	1585
	Variant 1	8486	8482	1585
	Variant 2	8486	8482	1362
	Variant 3	8492	8489	1601
	Variant 4	8492	8489	1411
Surplus amount [GWh]	Base scenario	2.91	274.43	7.58
	Variant 1	2.88	265.56	5.37
	Variant 2	2.82	254.79	4.03
	Variant 3	2.91	274.78	7.68
	Variant 4	2.82	255.16	4.12

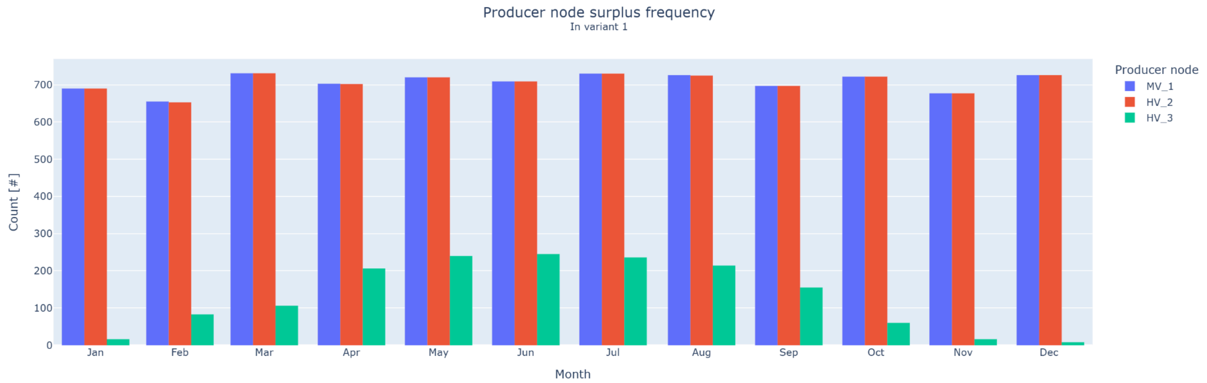
Table 6 shows that the frequency of overproduction at MV_1 and HV_2 is relatively high compared to the total number of hourly time steps in a year. In the base scenario, as well as in the first and second variants, oversupply occurs at MV_1 for approximately 96.87% of the time. For the third and fourth variants, this percentage increases slightly to around 96.94%. Furthermore, HV_2 also follows the same pattern as before, with equal values for the base scenario and the first and second variants, and equal values for the third and fourth variants. Here, the frequency of electricity surplus during the year is also very high. HV_3 shows a different pattern, with much greater variation in frequency. Here, the node has the highest frequency of oversupply in the third variant, being about 18.28% of the year. Then, the base scenario and first variant have the same value, translating to 18.09% of the year of times of overproduction. The fourth variant follows with 16.11% of the time, and the second variant has the lowest oversupply frequency, occurring approximately 15.55% of the time.

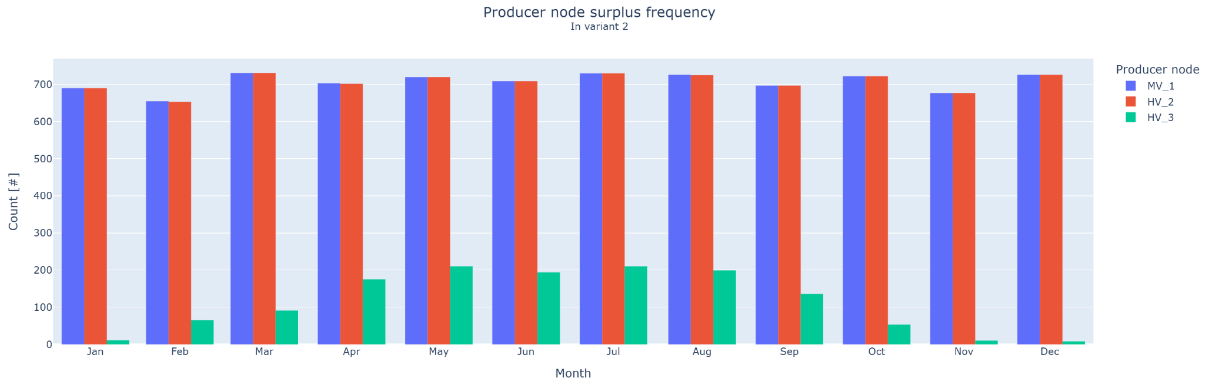
In addition, Table 6 showcases that the overproduction is the highest at HV_2 under all circumstances. Also, the production surplus at HV_3 is higher than at MV_1 in all instances. This is remarkable, as the frequency is way lower at HV_3 than at MV_1. At MV_1, the production surplus in the base scenario matches that of the third variant. Additionally, both scenarios yield the highest production surplus among all the variants. Thereafter, the first variant follows closely, with only a slight reduction in surplus in comparison to the base scenario and third variant. The lowest production surplus can be observed in the second and fourth variants, with both having identical values. At HV_2 there is a large variation in surplus values. The highest value is in the third variant, followed by a slightly lower surplus in the base scenario. Thereafter, the first variant has the most overproduction, with a difference of -3.36% compared to the third variant. Then, a leap is made to the fourth variant, which has an even lower value. However in the second variant the oversupply is the lowest, with values of roughly 7.27% less than in the third variant. HV_3 also shows a diverse variation. In the third variant there is the most surplus, followed by the base scenario. The first variant has less overproduction, accounting for about 30.08% less in comparison to the third variant. This is already a huge difference, however, the fourth variant shows an even lower surplus. Notably, the second variant has the lowest value overall, resulting in a reduction in overproduction of approximately 47.53% compared to the third variant.

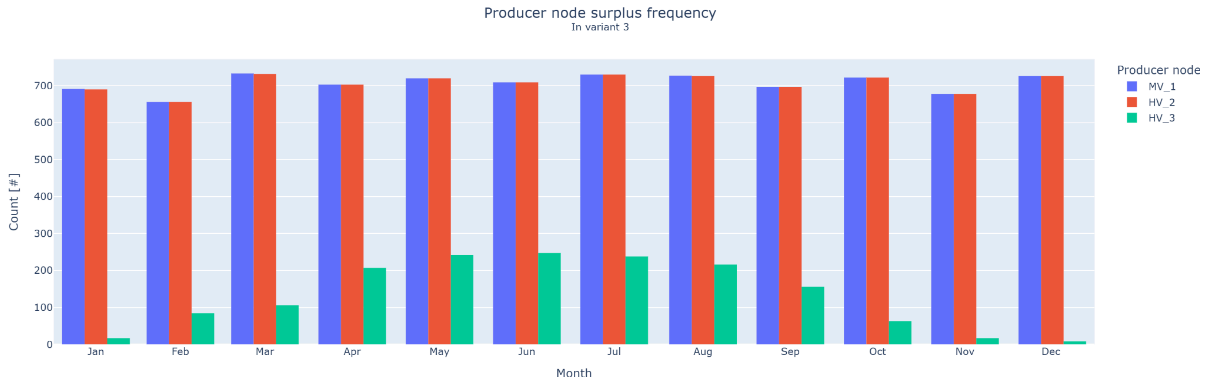
As is already clear from the descriptive analyses, and also can be seen very easily from the table, most production surplus is happening in the third variant, followed by the base scenario. Thereafter, respectively, from the first, fourth and second variants. It is remarkable that while the surplus frequency is the same for the base scenario and first variant, the overproduction of the first variant is lower in all production nodes. Moreover, even though the frequency is the same for the base scenario and first and second variants at both MV_1 and HV_2, the surplus amounts differ on each. This also holds true for the third and fourth variants.

As a follow-up, it could be beneficial to examine the monthly distribution of overproduction throughout the year. Therefore, these will now be presented.









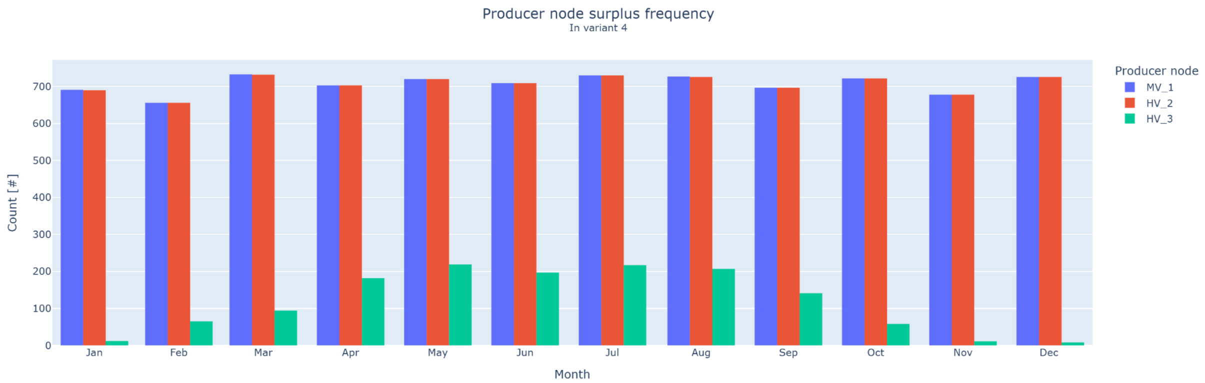


Figure 15: Monthly surplus counts across the base scenario and injection charge variants.

As can be seen in these plots, the producer surplus frequency at nodes MV_1 and HV_2 is pretty consistent over the course of the year, regardless of the variant. This in contrast with node HV_3, whereby the producer surplus is low in January, grows until the summer months and then declines again. This pattern is especially visible in the base scenario, as well as in the first and third variants. In the second and fourth variants, the surplus frequency in the month June is less than in May and July. It can be observed that, at HV_3, the surplus frequency in the second and fourth variants is lower at every time step compared to the base scenario and the other variants.

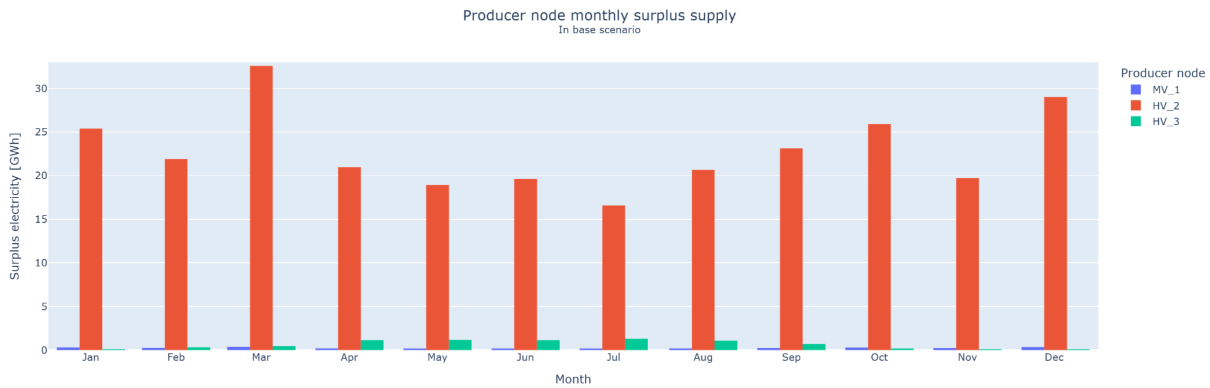
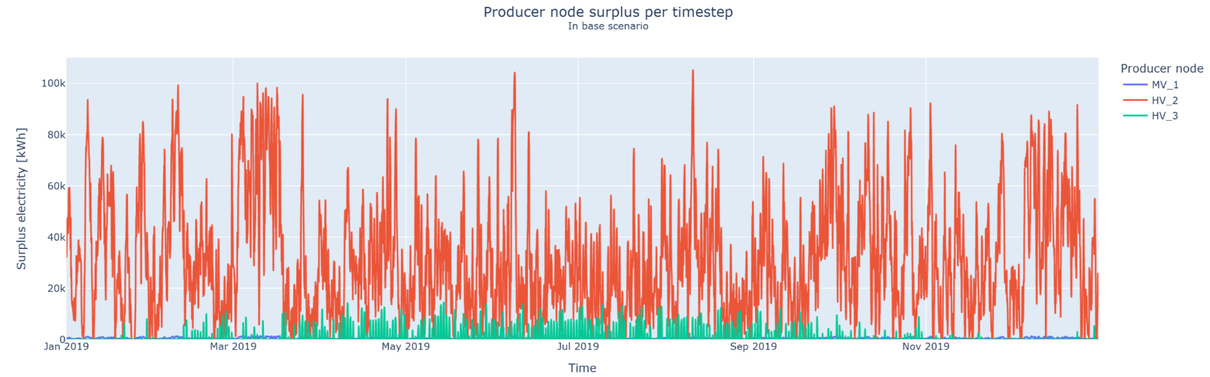
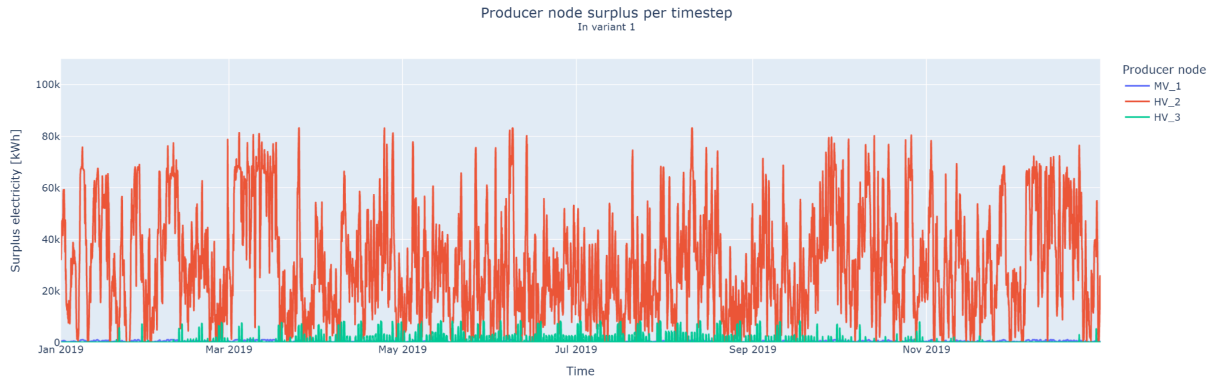
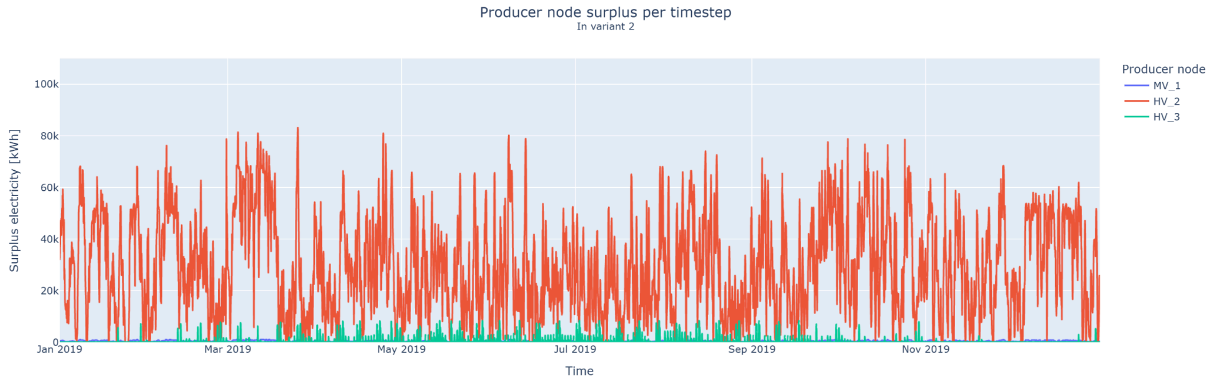


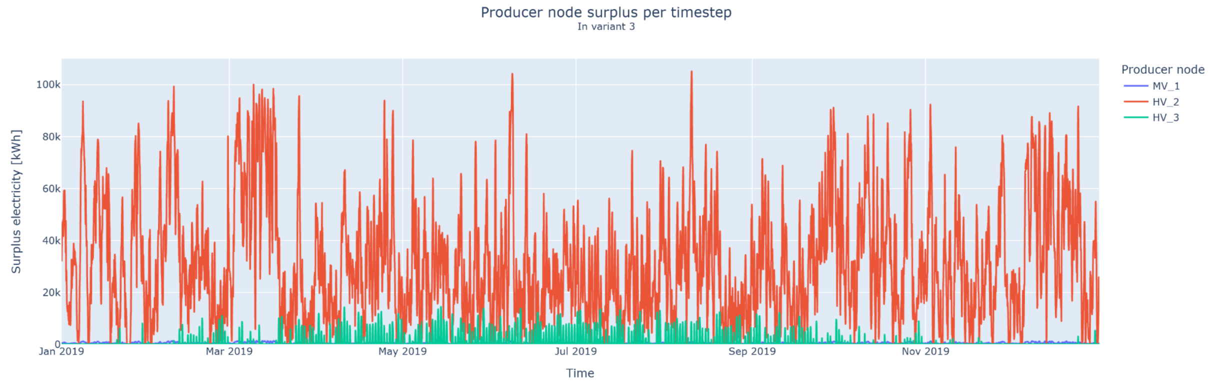
Figure 16: Monthly surplus across the base scenario and injection charge variants.

From these plots, it is clear that the surplus production is the highest at HV_2, especially in March. During this month, in the base scenario and third variant, this peak is the highest in comparison to the other variants. The base scenario and third variant have in March at HV_2 approximately 15.64% more surplus than the second variant. From these plots it is clear that HV_2 has a very dominant surplus in comparison to the other nodes. What is remarkable to see is that while some months have a higher frequency of surplus occurrence, the total electricity surplus is lower in comparison. For example, May has a higher frequency of surplus occurring than April, but the surplus in April is greater than in May in the base scenario, as well as in all other variants. Furthermore, it can be noticed that variants the second and fourth variants have less surplus in all nodes compared to the base scenario and other variants.









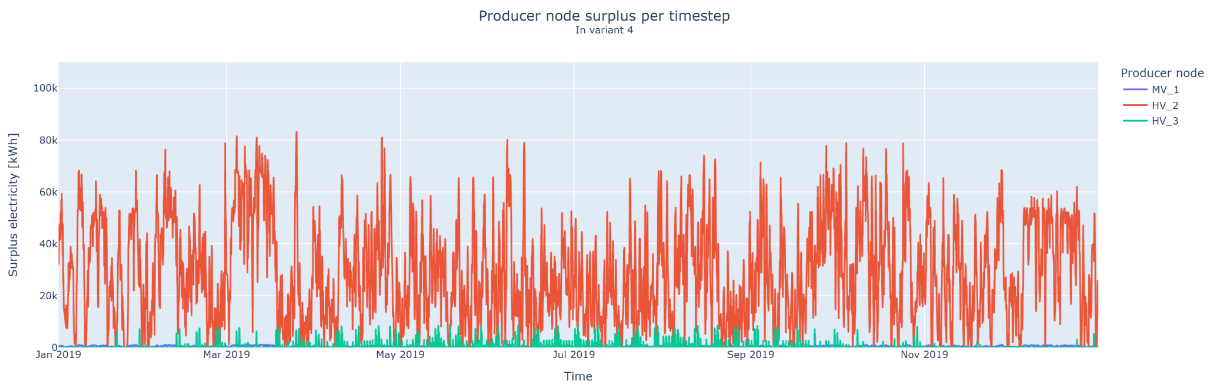


Figure 17: Surplus across the base scenario and injection charge variants.

From the plots shown above, it is clear that the amplitude of HV_2 is very large. The amplitude fluctuates between roughly 0 MWh and 105 MWh. In the third variant, this amplitude is the highest, followed by the base scenario. Comparing the first two variants with the third variant, there is about a 20.89% decline in peak power at HV_2 for the first and second variant. Furthermore, in the base scenario and in the third variant, the peaks, as well as the total production of HV_3 during the summer months, is higher than in the other variants. In the plot, the difference between the production nodes becomes more clear, the surplus at MV_1 compared to others, is almost negligible.

5.3.3 Substation loads

It is also important to discuss the monthly peak loads on each substation, including the extra backup node Extra_3, to gain a better understanding of the grid loads during the year. These will be discussed per substation.

Table 7: Monthly loads at MV_1 across the base scenario and injection charge variants.

MV_1	Base scenario	Variant 1	Variant 2	Variant 3	Variant 4
1	1102.73	990.00	990.00	1102.73	990.00
2	1221.48	990.00	990.00	1221.48	990.00
3	1241.25	990.00	990.00	1241.25	990.00
4	959.46	959.46	959.46	959.46	959.46
5	785.82	785.82	785.82	785.82	785.82
6	1206.60	990.00	990.00	1206.60	990.00
7	732.54	732.54	732.54	732.54	732.54
8	1151.53	990.00	792.00	1151.53	792.00
9	1054.72	990.00	954.81	1054.72	954.81
10	1038.33	990.00	990.00	1038.33	990.00
11	1133.94	990.00	950.50	1133.94	950.50
12	1199.53	990.00	792.00	1199.53	792.00

At substation MV_1, both the base scenario and third variant have identical values, which are also the highest among all variants. In these two scenarios, the peak load is 25.38% higher compared to the other variants. Conversely, the maximum load in the other variants is 20.24% lower than in the base scenario and third variant. Furthermore, the first variant has reached its maximum load in nine of the twelve months, whereas the second and fourth variants have done so in only five. The base scenario and third variant only experience this maximum in one month of the year, namely in March.

Table 8: Monthly loads at HV_2 across the base scenario and injection charge variants.

HV_2	Base scenario	Variant 1	Variant 2	Variant 3	Variant 4
1	93726.56	75937.33	72675.00	93726.56	72675.00
2	99487.83	78966.00	78966.00	99487.83	78966.00
3	101018.80	83300.00	83300.00	101018.80	83300.00
4	94081.24	83300.00	81175.00	94081.24	81175.00
5	79222.14	78464.73	67871.42	79222.14	67871.42
6	104424.68	83300.00	80318.20	104424.68	80318.20
7	77132.12	77132.12	68714.46	77132.12	68714.46
8	105305.29	83300.00	74183.55	105305.29	74183.55
9	93533.44	80399.57	77902.20	93533.44	77902.20
10	92192.41	80667.49	79012.09	92192.41	79012.09
11	97152.68	79482.63	72996.40	97152.68	72996.40
12	94114.77	77326.56	63006.12	94114.77	63006.12

At HV_2, it is also clear that in the base scenario and third variant there are the highest peaks, which occur here in August. This peak is 26.42% higher than in the other variants. Here, the maximum load in the other variants is 20.90% lower than in the base scenario and third variant. The peaks in the base scenario, as well as in the second, third and fourth variants only occur once per year. However, the maximum load from the first variant occurs four times during the year. Additionally, it is good to note that the height of the peaks in the first, second and fourth variants are the same.

Table 9: Monthly loads at HV_3 across the base scenario and injection charge variants.

HV_3	Base scenario	Variant 1	Variant 2	Variant 3	Variant 4
1	13010.39	12000.00	12000.00	13010.39	12000.00
2	15848.80	12000.00	12000.00	15848.80	12000.00
3	16908.45	12000.00	12000.00	16908.45	12000.00
4	18465.70	12000.00	12000.00	18465.70	12000.00
5	18618.98	12000.00	12000.00	18618.98	12000.00
6	17775.27	12000.00	12000.00	17775.27	12000.00
7	17807.01	12000.00	12000.00	17807.01	12000.00
8	16979.20	12000.00	12000.00	16979.20	12000.00
9	16697.14	12000.00	12000.00	16697.14	12000.00
10	13819.31	12000.00	12000.00	13819.31	12000.00
11	11661.94	11661.94	11604.95	11661.94	11604.95
12	10606.92	10606.92	10606.92	10606.92	10606.92

At HV_3, the same pattern occurs as in the previous substations. The load is the highest in the base scenario and third variant, and this maximum is only reached during one month. Here, this peak is reached in May. The peak here is 55.16% higher than in the other variants, which is really significant. The peak load in the other variants is 35.55% lower in the other variants than in the base scenario and third variant. What is remarkable from this table is that the maximum value of 12000 kWh occurs an equal amount of times in the first, second and fourth variants, namely ten out of the total of twelve months.

Table 10: Monthly loads at Extra_3 across the base scenario and injection charge variants.

Extra_3	**Base scenario**	**Variant 1**	**Variant 2**	**Variant 3**	**Variant 4**
1	9516.99	9516.99	9516.99	9422.93	9422.93
2	8621.89	8621.89	8621.89	8535.90	8535.90
3	3657.07	3657.07	3657.07	3616.74	3616.74
4	2516.45	2516.45	2516.45	2485.29	2485.29
5	3238.25	3238.25	3238.25	3193.09	3193.09
6	2834.30	2834.30	2834.30	2802.92	2802.92
7	2680.07	2680.07	2680.07	2645.75	2645.75
8	5073.17	5073.17	5073.17	5025.32	5025.32
9	2837.87	2837.87	2837.87	2799.66	2799.66
10	6598.52	6598.52	6598.52	6513.67	6513.67
11	7665.47	7665.47	7665.47	7578.58	7578.58
12	5984.33	5984.33	5984.33	5897.24	5897.24

For the extra backup supply from Extra_3, another pattern occurs. All of the peaks of this connection are used in January, regardless of the scenario or variant. What can be seen however, is that the node is supplying the most in the base scenario and the first and second variants. However, this is only 1.00% more than in the third and fourth variants. The import-related peak in these variants is thereby only 0.99% lower than in the other variants. Furthermore, it is good to note that all of the peak load values only occur during one month of the year.

Overall, it can be seen that certain patterns occur. The substation load values are the highest in the base scenario for all the supplying nodes. Also, the values of the substations are the same for the base scenario and third variant, except for the import supply needed from Extra_3. However, it is important to note that since Extra_3 is connected via HV_3, and the maximum values at HV_3 are higher throughout all months, the grid load values shown in the table for HV_3 represent the monthly peak load values at that substation.

Furthermore, it can be noted that the fourth variant has the least maximum values and occurrence of them in every node. Thereafter, the second variant follows, with only having a marginal higher maximum value for import via the Extra_3 node. But, as already mentioned earlier, Extra_3 is connected to HV_3, and HV_3 exhibits higher maximum values in all months, so the contribution of Extra_3 can be considered negligible in this context. So, actually, the second and fourth variants share the same spot of having the lowest overall substation values and their frequency of occurrence. The first variant also has the same lowest values, although these occur more often at substations MV_1 and HV_2. The base scenario and third variant have the highest values at MV_1, HV_2 and HV_3.

6. Discussion of the results

In this chapter, the findings presented in the previous chapter are analyzed to address the first and second sub-questions of this research. First, the impact of adjusted injection charges on grid load is examined, followed by an exploration of the implications for network reinforcements.

6.1 Influence on grid load

This subsection will be used to provide an answer to the first sub-question:
To what extent do adjusted injection charges for large-scale electricity producers influence grid load?

The results presented in Tables 7 to 10 provide valuable insights into the relationship between the different variants of injection charges and the corresponding substation loads. As observed, the implementation of adjusted injection charges has led to notable changes in the peak loads at the substations.

For substation MV_1, a substation which has a production capacity consisting of two windmills, both the base scenario and third variant have a 25.38% higher peak load than the other variants. This means that the first, second and fourth variants are thus more effective in creating a lower peak load at the substation. The peak injection in these variants has been reduced by 20.24% compared to the base scenario and third variant. Notably, the second and fourth variants reach their peak in only five out of the twelve months, whereas the first variant reaches it in nine. Therefore, the second and fourth variants are the most effective in minimizing both the magnitude and frequency of peak load at MV_1.

HV_2, a substation which is connected to two windparks and two solar parks, also shows the same behavior. The peak load is the highest in the base scenario and third variant, with an increase of 26.42% in comparison to the other variants. The peak injection in the first, second and fourth variants is 20.90% lower than in the base scenario and third variant. The second and fourth variants only reach their peak during one month, whereas the first variant reaches this during four. Here, the second and fourth variants thus also present themselves as being the most effective in obtaining a reduced substation load.

At HV_3 however, a substation which represents a solar farm, there are no differences between the first, second and fourth variants. They all have the same values and reach their peak during ten of the twelve months. However, it is noted that the peak load is significantly lower in the first, second and fourth variants. Specifically, in the base scenario and third variant, the peak is 55.16% higher compared to these variants. The first, second and fourth variants thereby have a peak load that is 35.55% lower compared to the base scenario and third variant. This clearly demonstrates a substantial improvement achieved with the first, second and fourth variants in reducing the load at this substation.

In addition to the local production, the electricity from backup source Extra_3 was also required during certain time steps. In contrast, backup sources Extra_1 and Extra_2 were not used during any of the time steps throughout the year. Since the import source Extra_3 is connected to substation HV_3, and electricity generation at HV_3 exceeded the peak loads from imports from Extra_3 throughout the year, the substation load was primarily driven by local generation. However, it does indicate that the production from other areas outside of the municipality of Reimerswaal was also needed to fulfill demand during each time step. This is also evident from the table and plots presented in Section 5.3.1 of the Results chapter. Differences between the values for the base scenario and the first two variants in comparison to the third and fourth variants are observable. However, these differences are only marginal, as the peak load from imports in the third and fourth variants is up to 0.99% lower than in the other variants. Additionally, it is good to note that all of the peaks only occur during one month, January, regardless of the scenario or variant.

It can thus be concluded that the adjustment of an injection charge could be beneficial in reducing the substation load, and thereby the overall grid load. However, not all of the injection charge variants support this statement. The maximum load values of the third variant are still the same as in the base scenario, except for a difference in import-related peak loads via Extra_3 by up to 0.99%. Therefore, this variant is only having a limited impact. Tariffs based solely on the kWh charge component did thus not sufficiently encourage efficient grid usage, as overall peak loads remained unchanged. In contrast, the first, second and fourth variants, which are based on the kWcontract and kWmax charge components, demonstrate a large reduction in overall grid load. While the maximum values are the same at MV_1, HV_2, and HV_3, this maximum occurs more frequently in the first variant. This makes the second and fourth variants being more effective in limiting the frequency of peak load. Between these variants, the only difference lies in the peak load from imports via Extra_3, which is slightly higher in the second variant. However, the peak reduction was limited to a maximum of 0.99%, and since this import-related peak load remained below the peak load from injection at HV_3, it did not affect the overall grid load at this substation.

Comparing these results with the study by Van Cappellen et al. (2024), it can be noticed that in the study conducted here, the results are relatively on the higher side. In this study, the differences in the highest monthly peak load for the substations MV_1, HV_2 and HV_3 are respectively -20.24%, -20.90% and -35.55% compared to the base scenario. In the study by Van Cappellen et al. (2024) the range for onshore wind and solar PV dominated substations lies between -1% and -19%. The differences in results can be explained by the distinct assumptions, scenarios, methodology, and scope of the research. For example, Van Cappellen et al. (2024) use a 2030 forecast that assumes that the injection charge will lead to less growth in the amount of new electricity production assets and an increased relocation of assets compared to the intended asset growth for 2030. Based on this adjusted project development, they calculate the expected electricity supply profile and the corresponding load on the grid. This method is thus certainly different from the method used in this study, as this study uses the existing generating facilities to behave differently throughout the year, which in response provides a new injection profile and subsequent grid load.

However, a similar pattern is observed in this study as in the research of Van Cappellen et al. (2024). Substations that are dominantly connected to solar PV technologies have a higher peak load reduction than substations that are dominantly connected to onshore wind electricity generation technologies. Additionally, the reduction of up to 0.99% in the import-related peak load found in this study is consistent with the 1% reduction reported by Van Cappellen et al. (2024).

6.2 Need for network reinforcements

This subsection will be used to provide an answer to the second sub-question:
To what extent do adjusted injection charges for large-scale electricity producers impact the need for network reinforcement in the Netherlands?

To begin with, it is good to know that network reinforcement is defined as the installation of assets to increase the capacity of the existing network (Stevenson, 2022). This process typically involves upgrading existing transformers to accommodate higher loads and reinforcing existing underground cables to improve reliability and performance. Furthermore, it is important to note that electricity networks must be designed and reinforced to handle the highest peak loads, not just average loads (Heinen et al., 2011; Netbeheer Nederland, 2024-b). This also implies that the network is thus underutilized during non-peak times.

So, this means that if the peak grid load can be reduced, network reinforcements can also be minimized. Following the analysis from above regarding the load at the substations, it can be concluded that the appropriate injection charge can be beneficial in reducing the grid load. Therefore, the right injection charge design can thus also be beneficial in limiting the need for network reinforcements. This has also been acknowledged by Van Cappellen et al. (2024), and is beneficial for multiple reasons. To begin with, by limiting the need for network reinforcements, costs for expansion can be mitigated. This is beneficial as the societal costs therefore do not rise in the near future and the affordability of the grid can thereby be prolonged. Additionally, when the grid load from the current connected users decreases, it could free up capacity for others. This would be very valuable for the Netherlands as the current congestion often results in extended lead times for new grid connections and existing connection upgrades (Wassenberg & Weulen Kranenberg, 2024). As a result, these delays hinder electrification possibilities and the expansion of renewable electricity sources.

When it comes to injection charge options that can efficiently limit the need for network reinforcement, the first, second and fourth variants, all of which include the kWcontract and kWmax charge components, have demonstrated significant effectiveness. However, the design of the first variant, a uniform tariff across all large-scale electricity producers, led more often to the occurrence of the peak load than the second and fourth variants, which included a time-dependent tariff. So, the second and fourth variants are better in limiting the frequency of stress on the grid. Moreover, the fourth variant, which introduces a uniform applicable kWh tariff, also limits the import-related peak loads from elsewhere, and thereby potentially reduces the need for network reinforcements. However, this is only the case in certain situations. If the demand in an area is higher than the production is capable of delivering, the imports need to fulfill this missing need to maintain network balance. So, in areas where the production is not enough to fulfill demand, the imports may determine the eventual need for network reinforcements. On the other hand, when the demand in an area is lower than its production, limiting the demand even further leads to less imports, but does not lead to less need for network reinforcements. In such a case, the production is dominant, so limiting the production peaks through an injection charge can then be beneficial in limiting the need for network reinforcements as the peak loads are being limited. Following this analysis, it can thus be that the third variant, which introduces a fixed kWh tariff which affects demand, can thus also lead to less need for network reinforcements. However, the results of this study indicate that this was not the case for the municipality of Reimerswaal, as the import-related peak load was consistently lower at all time steps than the corresponding values at the connected substation HV_3. As a result, peak loads from the production source became more dominant.

7. Recommendations to the ACM

This chapter provides a concise analysis of the implications of the injection charge, along with recommendations to the Netherlands Authority for Consumers and Markets (ACM), the relevant regulatory authority in this context. The ACM is the regulatory authority that sets and supervises the network tariff structure for producers and consumers in the Netherlands. In addition, in this specific case, the ACM aims to publish a draft decision on an adjusted injection charge in 2025 (ACM, 2024-c). Therefore, the ACM is the appropriate body to which these recommendations are addressed.

This chapter will thereby provide an answer to the third sub-question:
Which considerations should the Netherlands Authority for Consumers and Markets take into account when proposing an adjustment of the network tariff structure for large-scale electricity producers in the Netherlands?

7.1 Results of this study

To begin with, based on the analysis of this study, it can be noted that the adjustment of injection charges for large-scale electricity producers could be beneficial in reducing grid load and subsequently minimizing the need for network reinforcement. This is also in line with earlier studies, such as the study by Van Cappellen et al. (2024). Results of this study show that, in the base scenario, the peak load is up to 55.16% higher than in scenarios that include variants with an injection charge component. This indicates that the appropriate injection charge variant can reduce peak grid load by up to 35.55%. This is a larger difference than the results of Van Cappellen et al. (2024), which estimates that the grid load could decrease by 1% to 19% for onshore wind and solar PV dominated substations. However, this difference can be explained by the use of different assumptions and scenarios, as well as a distinct methodology and scope. It should also be noted that in this study, the peak load did not change for the injection charge variant that only included a uniform kWh tariff. Therefore, it must be said that the effectiveness of injection charges is dependent on their design.

In this study, an analysis has been made of four different variants of an injection charge. Here, the variants that included a charge on the kWcontract and kWmax components scored the best in terms of being able to mitigate peak grid load and limit the need for network reinforcements. The designs which also included a time-dependent scheme with different weighting factors and variations for wind and solar PV technology did not provide any additional reduction in peak load in the observed substations. However, at the substations where wind or a combination of wind and solar dominated the production, the time-dependent schemes did result in a less frequent occurrence of injection peaks. Furthermore, the designs which included a uniform kWh charge component showcased a reducement in import-related peak load from elsewhere. However, this effect was only marginal, with a maximum reduction of up to 0.99%. This marginal effect has also been acknowledged by Van Cappellen et al. (2024). Moreover, the impact of imports on the eventual peak grid load at a substation is highly dependent on local conditions. In an area where local demand is higher than its production, the effect of the uniform kWh component can contribute to an overall reduced peak grid load. Whereas in areas where the production is higher than the demand, the effect of a reduced import will probably not lead to an overall lower peak load at a substation. So, when this is the case, an injection charge based on the kWcontract and kWmax charge components will be more effective in reducing the overall peak loads.

7.2 Considering other studies

Considering other studies, as described earlier in this research, Blom et al. (2022) and Hakvoort et al. (2013) acknowledge that the absence of an injection charge is suboptimal for the electricity system, particularly in terms of long-term efficiency and system cost minimization. Vrolijk et al. (2018) also highlight that the current tariff structure, which only charges consumers, may hinder efficient grid use. Therefore, they argue that it would be more logical to impose a cost-based, transport-dependent tariff on producers to encourage efficient grid behavior. In line with this, Netbeheer Nederland (2024-b) and Van Cappellen et al. (2024) recognize that introducing injection charges can be beneficial in encouraging a more efficient use of the electricity grid. The position paper from the Nederlandse Vereniging Duurzame Energie highlights that in the current tariff structure, electricity producers may have an incentive to continue producing, even though it might be more beneficial for the system operator to reduce grid injection (NVDE, 2017). Moreover, Aalbers et al. (2012) state that in areas with high levels of distributed generation, injection charges could be used to prevent network disruptions. Van Cappellen et al. (2024) acknowledge that injection charges can reduce the impact on grid load and network reinforcement, a finding that is confirmed by this study when the appropriate tariff variant is applied. Furthermore, introducing injection charges for producers will lead to a more balanced and fair cost distribution between consumers and producers (Aalbers et al., 2012; Den Ouden et al., 2016; Netbeheer Nederland, 2024-b; Van Cappellen et al., 2022; Van Cappellen et al., 2024). Additionally, ACER (2023) notes that none of the National Regulatory Authorities of EU countries identified any unusual competitive disadvantage for producers as a result of injection charges.

However, the adjustment of injection charges also entails certain drawbacks and negative externalities. To begin with, looking at Figures 8 to 10 and Table 6 in Chapter 5, it can be noticed that the renewable electricity production, as well as electricity surplus becomes a lot less in certain variants. This has also been acknowledged by Energie-Nederland (2024) and Koutstaal et al. (2014). While limiting the production peaks is ideal to mitigate peak loads and reduces the need for network reinforcements, it thus also results in lower renewable electricity generation, which might undermine climate targets and plans of the Dutch government. Moreover, when there is less renewable electricity available, electricity prices could also rise (Energie-Nederland, 2024; Geschke et al., 2014; Koutstaal et al., 2014; Van Cappellen et al., 2024). However, the study by Van Cappellen et al. (2024) indicates that, while electricity prices are expected to rise, the reduction in net tariffs could offset this increase, resulting in total electricity costs for consumers remaining roughly the same as before the adjustment of injection charges. However, Energie-Nederland (2024) thinks differently about this subject matter, they state that although network costs for consumers may decrease when producers pay an injection charge, the increase in electricity prices would outweigh these savings, resulting in an overall rise in costs. In addition, an increase in network costs for producers or an increase in electricity costs for consumers might also affect the competitiveness of the Netherlands in international markets (ACER, 2023). Eventually, this might also lead to less renewable projects in the Netherlands, as well as a departure of electricity intensive industries to other countries (Energie-Nederland, 2024;

Geschke et al., 2024; Holland Solar & NedZero, 2024; Van Cappellen et al., 2024). Moreover, it can lead to more imports, as the electricity prices might be cheaper in other countries or if there is not enough local electricity production, which can be triggered if the business climate for renewable projects in the Netherlands is not lucrative enough (Energie-Nederland, 2024; Koutstaal et al., 2014).

7.3 Design choice

While these are only a selection of things to consider, many more aspects are important and may be decisive for the final design. Some important aspects here include legitimacy, feasibility and stakeholder support. Additionally, regarding the design choice, it is good to note that designing network tariffs always involves trade-offs between different objectives and principles (Hennig et al., 2022). Moreover, it is not possible to create a tariff that perfectly satisfies all criteria simultaneously. This highlights that there is no one-size-fits-all solution in tariff design, but rather that the tariff performance depends on the relative weight given to each objective and principle (Hennig et al., 2022). The optimal balance between these objectives and principles for tariff design depends on local circumstances and should be assessed and determined in close consultation with relevant stakeholders. Ultimately, the choice of tariff structure is determined by the ACM within the boundaries set by laws and regulations. This makes it even harder for the ACM to design an injection charge that is able to fulfill the proposed objectives, while also getting support from stakeholders.

Getting support from stakeholders for the adjustment of injection charges in the Netherlands will not be easy. In general, Energie-Nederland (2024) opposes an injection charge. But they are not alone, Holland Solar, NedZero & Energy Storage NL (2025) also state that they are opposed to the injection charges and requested the ACM to suspend the development thereof.

Additionally, stakeholders hold varying perspectives regarding the different injection charge variants. For example, Holland Solar & NedZero (2024) argue that, regardless of the chosen variant, already commissioned electricity generators should generally be exempt from such a tariff or otherwise fully compensated, since they could not have anticipated this in their investment decisions. Furthermore, Energie-Nederland, Holland Solar, and NedZero express concerns about a tariff based on location, as spatial planning in the Netherlands is largely determined by local governments, through mechanisms like zoning plans and permits, rather than the choices of the producers themselves (Energie-Nederland, 2024; Holland Solar & NedZero, 2024). Additionally, multiple producers may seek to operate in the same low-cost area, which could eventually drive up the tariff in that area. Netbeheer Nederland also opposes using network tariffs to influence the locational choices of electricity producers (Netbeheer Nederland, 2024-a; Netbeheer Nederland, 2024-b). In addition, Holland Solar, NedZero and Energy Storage NL also state that time-based tariffs bring uncertainty to producers as it is not clear how things will change over time (Holland Solar & NedZero, 2024; Holland Solar et al., 2025). Energie-Nederland (2024) also acknowledges that these uncertainties introduce additional risks and states that investors will factor this into their investment decisions. Shifting this risk to market participants, rather than a regulated system operator, may therefore result in higher electricity prices and potentially lead to an overall increase in costs for end-users. However, Netbeheer Nederland is in favor of a time-based tariff, as they state that it is cost-reflective and provides incentives for efficient grid usage

(Netbeheer Nederland, 2024-a; Netbeheer Nederland, 2024-b). Hereby, they are not opposed to a differentiation by location, as the peak loads may vary over time and location and are dependent on local circumstances. However, if possible, a uniform tariff for all system operators is preferred.

Considering these aspects, it becomes clear that all of the stakeholders have different interests. As stated by Hennig et al. (2022), the complexity of network tariff design lies in the fact that it always involves balancing multiple, often conflicting objectives and considerations. As a result, there is no single perfect solution, and each design choice inevitably requires trade-offs and compromises. Therefore, the recommendation to the ACM is that they should keep the design as simple and transparent as possible, while still obtaining their proposed objectives. As such, the results of this study highlight the potential of a time-dependent tariff design based on the kWcontract and kWmax charge components. This corresponds to the second variant analyzed in this study. This variant has potential, as from the results of this study, it is effective in reducing the peak loads, as well as their frequency of occurrence. Therefore, it is an effective measure to reduce stress on the grid. Furthermore, the variant holds a simple and transparent design. In addition, the variant aligns with the core principles of network tariffs, as this design is cost-reflective, transparent, non-discriminatory, and takes into account the need for network security and flexibility (ACER, n.d.; Regulation (EU) 2019/943, art. 18(1)). This has also been recognized by Van Cappellen et al. (2024), which state that this variant scores good on being objectively, transparent and non-discriminatory. Netbeheer Nederland is also in favor of a time-based tariff, as they state that it is cost-reflective and provides incentives for efficient grid usage (Netbeheer Nederland, 2024-a; Netbeheer Nederland, 2024-b). However, it must be noted that Holland Solar & NedZero (2024), as well as Energie-Nederland (2024) are not in favor of using time-dependent tariffs. These trade associations reason that it brings extra uncertainty to investors, which they will factor into their investment decisions, which may lead to higher electricity prices and potentially hinder the realization of new renewable energy projects and increase costs for end-users (Energie-Nederland, 2024; Holland Solar & NedZero, 2024; Holland Solar et al., 2025). But, as already mentioned, Energie-Nederland, Energy Storage NL, Holland Solar and NedZero are opposed to the injection charges in general (Energie-Nederland, 2024; Holland Solar et al., 2025). Therefore, the alternative options would also likely not receive their support.

Concerning the other variants, while it is true that the first variant of this study is simpler, as it uses a uniform design based on the kWcontract and kWmax charge components, this simplicity comes at a cost. With this variant, peak grid load occurs more frequently, leading to repeated stress on the grid, which is undesirable and should be avoided. In addition, the uniform tariff fails to consider the timing of injection, which is an important factor, as simultaneous injection peaks are what must be avoided to lower the risk of grid congestion. Therefore, the uniform variant is not the recommended variant to the ACM. The third variant, which concerns a uniform kWh tariff, is also not recommended to the ACM as it did not lead to any reduction of the peak load, but only led to a marginal reduction in import-related peak loads. Furthermore, since the monthly peak load values from imports were lower than the peaks from injection at that specific substation, there was no reduction in the overall peak load at the substation, and thus also no reduction in the need for network reinforcement. As a result, this variant did not lead to any significant change compared to the current situation and therefore does not offer substantial added value for implementation. The fourth variant, which integrates elements of both the second and third variants by combining time-dependent charges on the kWcontract and kWmax components with a fixed kWh tariff, achieves a similar reduction in peak load from injection as the second variant, while also slightly decreasing the peak load from imports as seen in the third variant. However, the reduction in import-related peak loads is only marginal, and this approach introduces additional complexity without providing substantial added value. Therefore, the fourth variant is not preferred over the second variant.

8. Conclusion

In this chapter, the conclusions drawn from the previous chapters are presented. This chapter summarizes the main findings of the study and provides a comprehensive answer to the main research question.

This research focused on assessing the effects of adjusted injection charges for large-scale electricity producers on the electricity grid in the Netherlands. To address the main research question, three sub-questions were formulated and answered. These sub-questions provided insights into the effects of different injection charge designs on grid load and the need for network reinforcement, and also formed the basis for recommendations to the Netherlands Authority for Consumers and Markets (ACM), the relevant regulatory authority in this context.

To begin with, the results demonstrate that by using an injection charge, the peak grid load can be reduced by up to 35.55%. This reduction can be achieved with the injection charge variants which are based on the transport-dependent charge components of kWcontract and kWmax. The peak grid load occurred more frequently under the general and uniform variant, whereas the time-based variant led to an equal or lower number of peak load months. Additionally, the variant that only included a uniform kWh tariff had no effect on peak grid loads compared to the base scenario. However, this variant did reduce the import-related peak loads from elsewhere, but this was only marginal at a maximum reduction of up to 0.99%. Moreover, since the peak from grid import remained below the peak from injection at the connected substation, the reduced import peak did not affect the overall peak load at this substation. The variant that combined the time-dependent charges on the kWcontract and kWmax components with a fixed kWh tariff, achieved a similar reduction in peak load from injection, while also slightly decreasing the peak load from imports, as was achieved by the respective individual variants. Furthermore, the observation was made that substations predominantly connected to solar PV technologies experienced greater peak load reductions than those mainly connected to onshore wind generators.

Secondly, as electricity networks must be designed and reinforced to handle the highest peak loads, the need for network reinforcement can be minimized when the maximum loads are lower. Following the results from above, it can be concluded that injection charges can be beneficial in reducing the peak grid load and thus also in reducing the need for network reinforcements. This reduction in grid load was observed in the variants that included an injection charge on the kWcontract and kWmax charge components. Consequently, these variants also reduce the need for network reinforcements. However, while the peak values were the same across all of these variants, the frequency of peak load occurrences was the lowest in the variants that also included a time-based charge component. Therefore, these variants are better in limiting the frequency of stress on the grid. Additionally, the variant which included a uniform kWh tariff limited the need for imports from elsewhere, which can also help in mitigating the grid loads, and thus potentially the needs for network reinforcements. However, this only applies to substations where the import-related peak load is higher than from injection. Otherwise, the injection peaks remain dominant, which implies that the network still needs to be reinforced to facilitate these peak loads.

Furthermore, regarding the recommendations to the ACM, it can be noted that the adjustment of injection charges for large-scale electricity producers could be beneficial in reducing grid load and subsequently in minimizing the need for network reinforcement. However, the effectiveness of the injection charges is dependent on its design. From this study, the variant which included time-dependent charges on the transport-dependent charge components of kWcontract and kWmax scored the best in terms of reducing peak grid load and its occurrence, and subsequently also for reducing the need for network reinforcements. The variant that included a uniform kWh tariff alongside these charge components also impacted import-related peak load. However, the effect was only marginal, with a reduction of up to 0.99%. Additionally, as the injection peak at that substation was more dominant than the peak load from imports, this did not change the overall peak load at the substation, and thus also did not impact the need for network reinforcements. Therefore, this variant does not have any preference above the variant without a uniform kWh tariff, as it introduces additional complexity, without providing substantial added value. But, besides the impacts on peak grid load and need for network reinforcements, also other aspects should be considered by the ACM. This includes aspects such as legitimacy, feasibility, and stakeholder support, as well as externalities such as the impact on existing and to-be-developed renewable electricity projects, renewable electricity production, progress toward climate and policy goals, electricity prices, and the competitiveness of the Netherlands in international markets.

In conclusion, applying well-designed injection charges for large-scale producers in the Netherlands could incentivize market participants to reduce injection during periods of surplus and/or limit electricity demand. This could reduce peak loads and could reduce the need for network reinforcements. While the findings suggest that such charges may contribute to more efficient grid use, the design and implementation of such measures require careful consideration as factors beyond the direct impact on the electricity grid are also important. In addition to technical effectiveness, factors such as legitimacy, feasibility, and stakeholder acceptance, as well as potential economic and environmental implications, must also be taken into account.

9. Limitations and future research

This chapter outlines the limitations of the study and provides recommendations for future research.

9.1 Limitations

During this study, several assumptions were made to assess the impact of different variants of injection charges for large-scale electricity producers on the electricity grid. Firstly, it was assumed that these charges are primarily targeted at wind and solar PV farms. As a result, only onshore wind and solar PV farms were included in the variant designs and in the model. Additionally, a limitation of the study is that only four different variants have been studied, while more variants would be possible. Furthermore, assumptions have been made on the behavioral effect of the different variants of the injection charges, and consequently these behavioral effects were only made on the onshore wind and solar PV farms.

In addition, the model was only constructed on the net topology of the municipality of Reimerswaal, including only the substations and generators that were available in 2023, potentially impacting the generalizability of the results. Additionally, the weather conditions for the generators were derived from a dataset from 2019, which is of course also an assumption, as it might not be an accurate representation of the weather in coming years. Also, the assumption was made that if the resource is available, electricity can and will be generated. Thus, no account has been made for downtime for maintenance or malfunctions.

Furthermore, the distribution of demand during the year was derived from a 2023 dataset with standardized profiles, which was also assumed to correspond to a certain user type. Additionally, the demand per user type and for specific large-scale electricity users has also been estimated and assumed.

In this study, a priority dispatch has been used, which is assumed to prioritize local renewable electricity generation over electricity imports. However, in real-world conditions this might not always be the case, as from an economic point of view it might be cheaper to use imports, so then the local production might be curtailed or scaled down. The extent to which this occurs depends on market conditions and contractual arrangements. Furthermore, technical factors such as grid losses and transmission capacity constraints were not included in the model, making it more abstract than real-world grid conditions.

These assumptions were necessary to make the study feasible, however, they may affect the accuracy and generalizability of the findings. These limitations should be taken into account when interpreting the results.

9.2 Future research

Future research could aim to address these limitations. To begin with, future research could focus on expanding the scope of this study by including other generation types beyond onshore wind and solar PV farms, as well as by considering additional variants of the injection charge. Furthermore, future research could focus on obtaining more detailed data on the behavioral effects of producers in response to adjusted injection charges, and incorporate this information into the design of the variants in order to enhance the variant designs. Subsequently, this can then also be incorporated in the analysis of the effects on the electricity network to improve the results. Additionally, considering a broader geographical region could enhance the generalizability of the results. In addition, the accuracy of the results could be improved by using more recent, multi-year, or prospective weather data, and by accounting for generator downtime. Similarly, incorporating up-to-date, multi-year, or projected demand distribution profiles and demand data could further refine the analysis. Future studies could also improve the results by making use of alternative modeling techniques and the inclusion of data on electricity imports. Lastly, accounting for technical factors such as grid losses and transmission capacity constraints would make the model and the results more reflective of real-world grid conditions.

10. Personal reflection

This chapter presents a personal reflection on the societal relevance of the study, an academic evaluation of its contributions, and an analysis of its connection to the objectives of the master's program.

10.1 Reflection on societal relevance

Regarding the societal relevance of this study, its timing and practical value are particularly strong, as the ACM is aiming to publish a draft decision on an adjusted injection charge in 2025 (ACM, 2024-c). The results from this study may therefore be of added value to them in relation to choosing the right tariff structure and motivating this choice to stakeholders. Furthermore, the results of such a study on the grid implications of various injection charge designs are also highly relevant in today's society, as currently the Dutch electricity grid is congested in most areas, which means that there is no or little room for new grid connections or connection upgrades of existing connections (Wassenberg & Weulen Kranenberg, 2024). As a result, there are currently long lead times for new projects such as the construction of residential neighborhoods, the electrification of industry, and the expansion of renewable electricity sources. If the injection charges can help to overcome this problem to even a little extent, this will mean that the Netherlands can move faster towards the policy and climate goals of 2030 and beyond.

Additionally, the prediction from the ACM (2024-b) is that the network tariffs for residential consumers could increase from €250 per year in 2025 to between €600 and €800 per year in 2050, and for large-scale consumers, the costs could rise to two to three times their current levels. As currently the large-scale producers do not pay any transport-dependent tariffs for their injection, while Dutch consumers do, it is important that the costs are shared fairly. As the injection charge can also contribute to a more equal cost division between grid users, it is highly relevant for Dutch society, especially as network costs are likely to become significantly more expensive in the future.

10.2 Academic reflection

This master's thesis has built upon existing literature, using the work of Van Cappellen et al. (2024) in particular as both a starting point and a catalyst for this research. The analysis presented in this study provides a new perspective to the existing literature by offering a comprehensive grid analysis that quantifies and evaluates the impact of various injection charge designs on grid load and the subsequent need for network reinforcement. While this research has certain limitations, it does provide valuable insights. As such, this study advances the current literature on the subject and can serve as a foundation for future research.

10.3 Link to master's program

The subject of overcoming electricity grid congestion and research topic of assessing the impact of adjusted injection charges aligns with the program of the CoSEM master, particularly within the energy track. The issue of grid congestion in the Dutch electricity grid exemplifies a technical challenge within a complex socio-technical system. In such a system, technological components like electricity grid infrastructure and wind farms are closely connected to societal structures, such as laws and public policies (Bauer & Herder, 2009).

Solving this issue requires an interdisciplinary approach, which is central to the CoSEM program. This research applied various methodologies, theories and tools that have been learned throughout the study. For example, this study made use of a Python based network model to evaluate the impact on grid load after certain policy changes. Furthermore, this research aligns with the CoSEM program as it not only focuses on technical aspects or solutions, but also keeps in mind and considers broader public, private, institutional and societal contexts.

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