Master’s Thesis – Master Energy Science

Techno – economic evaluation of market-based congestion management mechanisms: a case study

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Abstract

This thesis examines the techno-economic evaluation of market-based congestion management mechanisms in the Goor Business Park. With grid congestion emerging as a major challenge due to increasing electricity demand and the limited capacity of existing infrastructure, this research investigates alternatives to grid expansion. The primary focus is identifying an optimal market-based congestion management mechanism to alleviate grid congestion in a business park environment, which is critical to advancing the energy transition. Using the Python for Power System Analysis (PyPSA) software, three congestion management scenarios were modeled: a scenario with storage units for each company, a scenario with a group transport agreement, and a scenario with a capacity market. The performance of each scenario was evaluated based on several critical indicators, including grid dispatch, storage and photovoltaic (PV) capacity, solar curtailment, load shifting, load shedding, and associated financial costs. The comparative analysis revealed that Scenario 3, which introduced a capacity market and limited storage units, emerged as the optimal solution. This scenario balanced operational efficiency and congestion reduction and minimized the need for costly infrastructure upgrades by dynamically allocating grid resources and integrating targeted storage and load-shifting mechanisms. In contrast, Scenario 1, while minimizing annual costs, required high initial investments due to the extensive use of storage units. Scenario 2, which relied on load shedding and shifting, had the highest operating costs due to frequent load shedding, making it the least feasible. The results suggest that market-based mechanisms, particularly capacity markets, offer a sustainable and cost-effective approach to managing grid congestion, especially in business parks where electrification is increasing. The study highlights the potential for these mechanisms to serve as an alternative to grid expansion, in line with EU directives to increase grid flexibility. This research contributes valuable insights into the practical application of market-based congestion management and provides a framework for its implementation in similar settings.

Acknowledgments

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Table of Contents

1. Introduction

In 2015, the European Union and the Netherlands signed the Paris Climate Agreement to limit global warming to below 2 degrees Celsius, or even 1.5 degrees Celsius, to mitigate the impact of climate change (UNFCC, 2015). To achieve this goal, EU member states have committed to becoming climate neutral by 2050, which requires a net elimination of greenhouse gas (GHG) emissions. An interim target has been set to reduce GHG emissions by 55% from 1990 to 2030 (VVD et al., 2021). The European Commission has proposed an even more ambitious goal of reducing emissions by 90% by 2040 to help achieve the 2050 target (European Commission, 2024). The Netherlands is transitioning from fossil fuels to sustainably generated energy, also known as the energy transition, to reduce GHG emissions. For instance, by 2030, 70% of the total electricity production must be generated from renewable energy sources, and 42.5% of the total final energy consumption must come from renewable energy sources, as stated in the Renewable Energy Directive (RED) III of the European Commission (2023). The Netherlands has a significant way to go to achieve these percentages. Therefore, various modifications will be necessary in the way different sectors of the economy consume and produce energy.

For example, electricity generation is undergoing structural changes. In the past, it was mainly produced in gas- and coal-fired power plants. However, more and more electricity is generated from sustainable energy sources such as solar and wind power. This is evident in the increasing number of applications for wind turbines and utility-scale solar farms in the Netherlands (PBL, 2022). However, there is a mismatch between the supply and demand of renewable electricity. Solar energy is mainly produced during midday hours when electricity demand is low. Conversely, during periods of high energy demand, mainly in the evening when people return home, the supply of solar energy is limited (Calero et al., 2022; Steen et al., 2014). Due to this mismatch, excess electricity may be generated during peak generation hours when demand is low. This surplus of generated electricity may not all be fed into the grid because it could exceed its capacity. This issue is rooted in the historical development of the electricity grid. In the past, the grid was designed to handle a constant electricity supply from fossil fuel power plants, which determined its capacity. However, the increasing injection of renewable intermittent energy sources can exceed the grid's capacity, leading to substantial problems for the energy transition (Steen et al., 2014).

The electrification of various sectors is crucial to the energy transition to use sustainably generated electricity. Deploying electric units and systems can reduce energy consumption and lower greenhouse gas emissions by decreasing the use of fossil fuels. However, there has been a surge in electricity demand due to the increasing use of electrification in the industrial, residential, and mobility sectors to become more sustainable (IEA, 2024). The increase in electrification necessitates a larger capacity of the electricity grid than is available because the grid was not designed to handle this growth in electricity demand (PBL et al., 2023; Steen et al., 2014).

These capacity issues, or congestion, are situations where a power line or transformer has exceeded the physical limit of safe operation (van Blijswijk & de Vries, 2012). In other words, the distribution lines do not have sufficient capacity to distribute the electricity, which will also be the focus of this research. Many areas in the Netherlands are facing grid congestion for feed-in and offtake. This could have significant negative impacts on achieving future energy transition goals. For example, an overloaded grid can prevent solar and wind farms from connecting to it, resulting in less renewable investments (van der Korput, 2024). Additionally, it may lead to the curtailment of solar and wind power, losing valuable renewable electricity (Goop et al., 2017). Furthermore, grid congestion also has significant implications on the offtake side, as it prevents new businesses and new housing districts from connecting to the grid (NOS, 2022, 2023).

One of the leading solutions to reduce or avoid grid congestion is reinforcing the grid by building new transmission and distribution lines, substations, and transformers (Fotouhi Ghazvini et al., 2019). However, this task requires significant capital investments. For instance, starting in 2025, €8 billion will need to be invested annually (Chakravarthi et al., 2023; Ministry of General Affairs, 2023). Despite these significant investments, the grid expansion is not keeping pace with the increase in electrification and renewable power being fed into the grid (Jetten, 2023). Even if the grid is expanded, it is doubtful that a connection can be realized due to the extensive waiting list. Because there are 9,400 companies on the waiting list for off-take and 10,000 for feed-in of electricity, according to Netbeheer Nederland (2024b), other measures are needed to prevent grid congestion from delaying the energy transition. For instance, congestion management offers a solution to utilize the available capacity efficiently without surpassing the constraints of the power grid (Pillay et al., 2015).

A case study will, therefore, be conducted at a business park in Goor that experiences grid congestion, where congestion management will be applied. More about this will be explained in the coming sections. No new connections for off-take can be requested in this business park, and no solar or wind-generated electricity can be fed back into the grid. As a result, new businesses cannot be established, and existing businesses cannot expand. In addition, businesses cannot make their processes more sustainable because solar panels are not allowed to feed back electricity, and heat pumps cannot be installed because no more significant connection is possible. Making business parks in the Netherlands more sustainable is a crucial part of the energy transition, as there are about 3800 business parks in the Netherlands, which are responsible for about a third of the total electricity consumption and half of the gas consumption in the Netherlands every year (TNO, 2023). In this specific business area, market-based congestion management mechanisms are modeled to investigate whether they can prevent or reduce congestion and are more cost-effective than grid expansion at the specific location. This leads to the following research question:

What is the optimal market-based congestion management mechanism for reducing grid congestion at the medium voltage level for the business park in Goor?

To answer this question, it is necessary to break it down into several sub-questions. First, to properly understand and apply market-based congestion management mechanisms to a business park, it is necessary to understand the market mechanism of the Dutch energy market. The working of the Dutch energy market is a complex process, reflected in the different market areas, each of which has its own way of working. Therefore, it is essential to analyze the energy market regarding grid congestion. It is also essential to investigate different market-based congestion management mechanisms and how they would work. In particular, how market-based congestion is managed in the Netherlands. The next step is to explore how market-based congestion management mechanisms can be applied to the case study. This will involve modeling the specific business park using data obtained from Arcadis. Different congestion management methods can be evaluated through the model by examining technological and economic indicators. This leads to the first sub-question:

What is the technical-economic performance of the market-based congestion management mechanisms applied to the business park in Goor?

Finally, the different market-based congestion management mechanisms will be compared and ranked. An optimal market-based mechanism will be chosen so that the grid congestion in the business park can be reduced as efficiently as possible. Acknowledging that this research focuses on the companies' perspective within the business park is crucial. These companies must utilize the congestion management mechanism in a manner that is appealing to them. This provides the final sub-question:

How can the implemented mechanisms be compared and ranked?

The proposal has the following structure: First, the state of the art and the theoretical framework will be explained. Then, the methods for answering the research questions will be described. Finally, the agreements and the planning of the thesis will be discussed.

2. Theory

2.1. State of the art and knowledge gap

Congestion management is defined as managing the transmission and distribution of power between customers based on priority and is considered one of the most important processes for maintaining network security and reliability (Sourabh & Kaur, 2018; Yusoff et al., 2017). Grid operators can reduce or prevent congestion through congestion management mechanisms. This approach optimizes grid capacity and can decrease the need for significant investments in grid expansion (Chen et al., 2021).

Numerous congestion management mechanisms have been proposed in scientific literature. These mechanisms can be categorized as direct and indirect control methods. Indirect methods, known as market-based methods, utilize price incentives and contracts to influence customer demand flexibility (Huang et al., 2014). These methods include static and dynamic access tariffs, grid capacity markets, intraday shadow prices, and local flexibility markets (Hennig et al., 2023; Huang et al., 2014). Due to market failures or forecast errors, only part of the congestion can sometimes be resolved so that the DSO can use direct control methods as a backup (Tomar, 2023). With this approach, DSOs have direct control over high-capacity end-use assets that can be reduced during periods of congestion. These mechanisms include reconfiguration, reactive power control, and active power control (Huang et al., 2014).

Of all these mechanisms, market-based solutions are the most efficient in addressing the problems caused by increasing grid congestion, as they can prevent it economically (Fotouhi Ghazvini et al., 2019; Hennig et al., 2023). The European Commission (2019) is urging these market-based congestion management methods. Therefore, this research will further focus on these types of mechanisms. Market-based congestion management mechanisms are well described in the literature but are rarely applied in real-world situations, partly due to their lack of maturity. (Sayfutdinov et al., 2022; Tomar, 2023). To achieve future widespread adoption and implementation, it is necessary to pay more attention to the techno-economic factors of market-based congestion management techniques. Furthermore, no one-size-fits-all solution exists, so each situation must be adequately evaluated to solve the grid congestion problem.

This research includes three key components: analysis of the energy market and congestion management, techno-economic evaluation of congestion management methods using a case study approach, and ranking of the applied mechanisms. Based on established literature, the analysis of the energy market structure examines different market areas related to grid congestion, including day-ahead, intraday, and imbalance markets, concerning quantitative methods used by Mulder (2021), Mulder & Willems (2019) and Tanrisever et al. (2015). This part of the research will be primarily descriptive and explanatory, as it will mainly analyze the energy market by describing the main market areas related to grid congestion and how they operate. In summarizing the existing literature, it highlights the lack of reviews tailored explicitly to the Netherlands, as van Blijswijk and de Vries (2012) noted. It underscores the importance of techno-economic analysis in examining the feasibility and effectiveness of congestion management practices, as illustrated by the research of Tomar (2023).

Additionally, techno-economic analysis is an essential tool for assessing the feasibility of energy systems and examining their technical and economic aspects (Cuisinier et al., 2021; Lemaitre & Peri, 2019; Timmerman et al., 2017). This approach evaluates energy systems' optimal configuration and operation while describing critical technical and economic characteristics. Although techno-economic analysis has been used in studies such as those by Asija et al. (2018) and Keyvani & Flynn (2022) to evaluate congestion management methods, its application remains relatively limited. In order to comprehensively analyze market-based congestion management mechanisms within the energy systems of business parks, a techno-economic approach is essential. This requires the development of a robust model for the business park that allows the calculation of various economic and technical indicators to support decision-making (Sayfutdinov et al., 2022). Finally, based on the results of the techno-economic analysis, the applied mechanisms are compared with each other to rank them and select the optimal mechanism. By integrating these components, this research aims to contribute to the scientific understanding of market-based congestion management methods in the Dutch electricity context and to provide actionable insights for improving grid efficiency and reliability in business park settings.

2.2. Electricity market in the Netherlands

Following the introduction of the Electricity Act in 1998, the Dutch energy market has been liberalized since July 2004 (Ministry of Internal Affairs, 2024a). This aimed to promote competition between suppliers and give industrial consumers and households the freedom to choose their suppliers (ACM, 2007). Furthermore, the energy market is no longer regulated by the government but is now driven by supply and demand. When the energy market functions appropriately, competition can improve the quality and security of energy supply for consumers and businesses, resulting in lower energy bills. This section explains the roles of the various parties, market domains, and price formation to explore how this market mechanism works and why it may or may not be effective.

2.2.1. Market Roles

After implementing the Electricity Act of 1998, the electricity market structure was reorganized and now consists of seven different components, as shown in Figure 1. These components are all regulated through the market, meaning that multiple commercial parties can participate in these electricity market segments. However, transmission and distribution are distinct from supply and generation in the Dutch electricity sector. Additionally, a natural state-regulated monopoly exists to manage the national and regional electricity grids (Tanrisever et al., 2015). This regulated monopoly was established to ensure the reliability and efficiency of the electric grid. Competition in this area can lead to decreased reliability as parties may prioritize profit over quality. Furthermore, Figure 1 illustrates that a monopoly supports some of the metering. However, large consumers can choose their own metering company approved by the TSO, while the regional grid operator regulates metering services for small consumers (vmned, n.d.). Consumers cannot choose metering companies, making this aspect a regulated monopoly. Conversely, wholesale consumers can choose their metering company, making this aspect regulated by the market. Metering companies are responsible for installing energy meters, collecting consumption data, and transmitting it to grid operators (Tennet, n.d.-b). The roles of the different parties in the electricity sector can be in the physical or administrative domain. The physical domain includes everything related to production, transportation, and consumption, while the administrative domain includes all parties that maintain the relationship between customers and the market or grid operators.

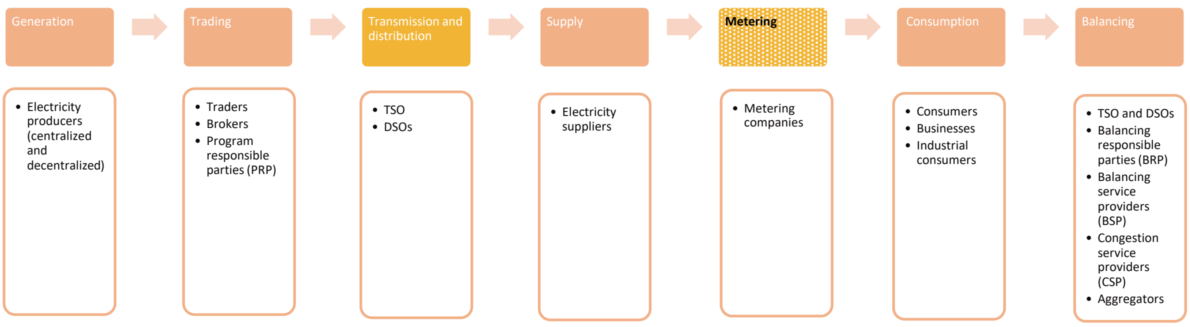

Figure 1: Structure of the Dutch electricity market. Orange indicates that the market regulates the component, and yellow indicates that it is a (partially) regulated monopoly.

Physical domain

First, various electricity producers operate in the electricity market, ranging from centralized multi-megawatt power plants to households with solar panels. Large producers must apply to the TSO to physically connect to the high-voltage grid, while small producers have their connection established by the regional DSO (Tennet, n.d.-a). Once this connection is established, companies can offer their production capacity on various markets by employing a balance responsible party (BRP) or a congestion service provider (CSP). These two parties will be discussed in more detail below. The TSO and DSOs are responsible for transporting and distributing the generated electricity from producers to consumers.

Tennet is the only TSO responsible for the high-voltage grid in the Netherlands. There are six regional DSOs, and they manage the electricity network between the consumers and the high-voltage grid. The tasks of the TSO and DSOs are defined by law and consist of establishing connections for producers and consumers and carrying out the transportation of electricity. They must ensure a reliable and safe electricity supply by building, maintaining, and operating the electricity network (Tennet, 2024b). In addition, the TSO is responsible for facilitating an efficient electricity market and maintaining the balance between supply and demand to ensure the grid frequency remains at 50 Hz. The responsibility for balance enforcement lies with Tennet, while the TSO and DSOs are responsible for preventing grid congestion (Tennet, 2024b).

Administrative domain

Besides Tennet's responsibility for balancing the grid, BRPs are responsible for balancing the offtake and feed-in of one or more allocations in their portfolio (Netherlands enterprise agency, n.d.). A BRP may have multiple large consumers or producers in its portfolio, or it may be a large consumer or producer. Every day, a BRP must send its forecast of the next day's electricity consumption and production to the TSO (Tennet, n.d.-a). This is also known as an e-program and is done every quarter of an hour, called an imbalance settlement period (ISP). Tennet ultimately compares the actual feed-in and offtake to the e-program. If the BSP deviates from the e-program, Tennet rewards or penalizes them with an imbalance in volume and price. A detailed explanation of how this imbalance settlement works is provided below.

Electricity suppliers can also act as a BRP and be financially responsible for balancing all affected customers' total consumption and production (Tennet, n.d.-a). They may generate energy by owning a gas plant or purchasing electricity on wholesale markets (forwards futures, day-ahead, and intraday, as explained in the next section). The primary functions of an electricity supplier are to offer contracts in which an agreed-upon electricity price is established, to supply electricity, and to bill for electricity (Ebskamp et al., 2021). In addition to the BRPs, Balance Service Providers (BSPs) offer their electricity or capacity to Tennet to balance the grid in case of unexpected imbalances. Tennet qualifies the BSPs, enabling them to address any grid imbalances quickly. The BSPs can provide various balancing products to the TSO and receive a fee for their services.

Like the BSPs, congestion service providers (CSPs) offer congestion management services to the TSO or DSOs (Tennet, n.d.-a). However, there is a distinct difference between these two parties. Both offer electricity or capacity to the TSO and DSO to maintain balance, but congestion management services are location-based, unlike balancing services. Thus, the primary responsibility of a CSP is to manage local electricity surpluses and shortages in situations where the grid operator anticipates congestion (Gopacs, n.d.-a). These bids to reduce congestion are entered into the so-called congestion market GOPACS. Its operation is explained in more detail below. Finally, in the energy market, there are also aggregators that bundle flexibility from multiple small producers and consumers into a portfolio (ACM, 2019; Q. Wang et al., 2015). They offer the capacity of this portfolio to the wholesale or balancing market. Aggregators can provide this flexibility to BRPs or BSPs or act in this role themselves. These aggregators make it easier for small parties to provide flexibility, even if they have little impact on electricity markets. When bundled in a portfolio, their impact can be increased.

2.2.2. Market domains and their mechanism

The electricity market comprises various domains, each with distinct goals and stakeholders. These include wholesale markets, balancing markets, and imbalance and congestion markets. The following sections discuss the functioning of each market.

Wholesale markets

There are three types of wholesale markets: futures/forward, day-ahead, and intraday markets. A distinct set of market mechanisms determines the electricity pricing in each market domain. The first domain is distinguished by a long-term pricing structure, with prices being formed through the interaction of two financial products: futures, which are traded anonymously on an open auction with transparent prices for all participants, and forwards with over-the-counter trading, which involves financial agreements made between two parties. Trading of these two financial products occurs on the exchange platforms of ICE (2024), ENDEX (European Energy Derivatives Exchange), and EEX (2024)(European Energy Exchange). Futures are traded for a fixed duration of up to four years, with contracts available for specific months, quarters, and years in the future (Tanrisever et al., 2015). The price for these long-term contracts is determined by considering the average expected spot market prices at the moment of trade between two parties (Redl et al., 2009). However, most electricity volumes are not traded via the exchange but rather through over-the-counter contracts, also known as forwards (KIVI, 2021). These contracts involve agreeing on a specific price to supply electricity for an extended period at a fixed rate. The futures/forward market is primarily intended for large consumers, producers, and BRPs who wish to hedge against the highly volatile prices of the spot markets (Biggar & Hesamzadeh, 2022). Prices on ENDEX and EEX are often slightly higher than those on the spot markets, but this provides the parties involved with financial security for several years.

The day-ahead and intra-day spot markets are utilized to trade electricity in the short term. In Europe, two power exchanges facilitate spot markets to which the Netherlands is linked: The two power exchanges in question are EPEX Spot and NordPool Spot. On these exchanges, the price is determined by the bidding zone in which each country is represented. Also, electricity is traded before physical delivery in the day-ahead market, but there is a double-sided blind auction every day for every hour of the next day (Lopes, 2021). The market closes at noon on the day prior to the electricity supply, and no further orders can be placed in the order book (NordPool, 2022). The market is cleared at this point, meaning the price has reached a level where supply and demand are equal (Tanrisever et al., 2015). The day-ahead market uses the law of supply and demand and the marginal price method to determine the price of electricity (Schweppe et al., 2013). Marginal costs are defined as the variable costs incurred by a producer to generate an additional amount of electricity expressed in MWh (Y. Wang et al., 2023). Nevertheless, it is assumed that a linear function expresses the total costs.

All producers submit bids to the market operator to sell electricity at the short-run marginal cost they incur every hour of the next day. This assumption is only valid in the context of perfect competition. Subsequently, the bids are arranged in ascending order of price, thereby delineating a supply curve, referred to as the merit order curve (Cludius et al., 2014). Renewable energy sources have lower short-run marginal costs than gas and oil-fired power plants, which are more expensive and further up the supply curve (Kyritsis et al., 2016). A demand curve is also established in contrast to the supply curve. It starts with the buy orders with the highest price and descends to those with the lowest price. The supply and demand curves are shown in Figure 2. The price of electricity is determined by the intersection of the supply and demand curves, also known as the market clearing price (MCP) (Fan, 2022). The last activated sell order determines the MCP; every seller is paid this price while every buyer pays this same price.

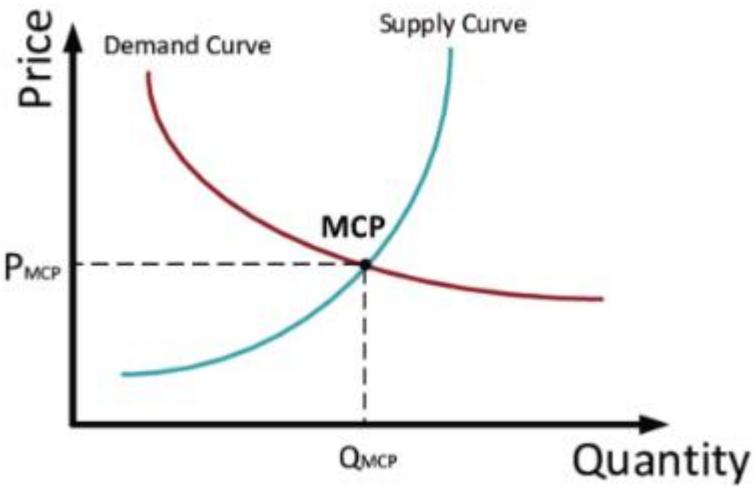

Figure 2: The supply and demand curves of the day ahead market. Where MCP stands for market clearing price. Figure retrieved from Fan (2022).

When the day ahead market closes at noon, also known as clearing, the intraday market opens, as shown in Figure 3. Participants can adjust their market position by buying or selling electricity until about half an hour before the market closes to balance their portfolio near real-time (Lopes, 2021). This balancing process involves continuous buying or selling of electricity in blocks of hours, half-hours, or quarters, with transactions completed up to 5 minutes before delivery (Koch, 2022). In the intraday market, exchange with a marginal pricing method is not used, but the pay-as-bid principle is applied. A trade is executed when a sell order and a buy order match, allowing electricity to be sold continuously throughout the day, particularly before the market closes (Rosenlund Soysal et al., 2017). Furthermore, auctions are conducted in the intraday market, employing a methodology analogous to that employed in the day-ahead market (Epex Spot, 2024). Consequently, upon the price being cleared, all parties pay the same electricity price. However, the electricity is sold in blocks of fifteen minutes. The market is cleared on the day of delivery at 3 p.m.

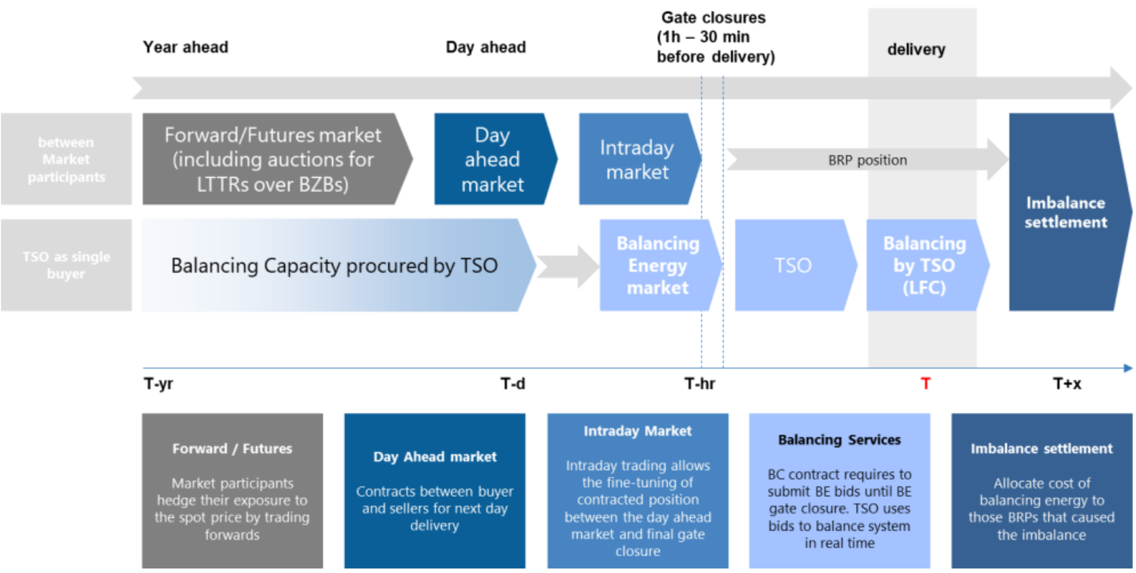

Figure 3: Timeline of the different domains in the electricity market. Figure retrieved from Acer (2023).

Balancing markets

Electricity supply and demand bids are matched on various electricity markets. However, there may be a mismatch between supply and demand after the market closes. Tennet is responsible for maintaining the grid's balance because the grid's frequency must be 50 Hz at all times (Poplavskaya & de Vries, 2019). Since Tennet is not allowed to be an active party in the electricity market, the BSPs, with their crucial role in resolving imbalances, have an essential role to play. Tennet has many balancing products available, and the BSPs can make their capacity available for any of these balancing products. The European Commission (2017) specifies three standard balancing products in the Electricity Balancing Guideline: the Frequency Containment Reserve (FCR), the Automatic Frequency Restoration Reserve (aFRR), and the Manual Frequency Restoration Reserve (mFRR), each of which differs in activation speed and duration.

FCR is the primary reserve capacity asset and is the grid operator's first resort to maintain the balance in the grid. Figure 4 shows that it is activated first and must continuously and automatically release full power within 30 seconds for 15 minutes (Tennet, 2024c). According to EU regulations, the amount of FCR to be purchased is determined. This is achieved by creating a daily merit order consisting of 4-hour blocks, from which Tennet selects and automatically activates the chosen BSPs based on the order (Tennet, 2024c). An agreed price is paid (pay-as-bid), and marginal pricing is not utilized. The bids are symmetric, meaning the BSPs must procure the same amount of positive and negative primary reserves (Tennet, 2024c). It is worth noting that Tennet activates products only when an imbalance occurs, not in response to a predicted imbalance.

If the imbalance is prolonged or the volume is too large, the aFRR, also known as the regulating capacity or secondary reserve, is automatically activated. There are two principal methods of providing aFRR. One is through up-regulation, whereby additional power is fed into the grid, or less power is withdrawn from the grid. The other is down-regulation, whereby power is withdrawn from the grid, or less power is fed into the grid (Tennet, 2023b). When Tennet activates the aFRR, it will gradually replace the FCR after 30 seconds, and within 5 minutes, full power should be available (Tennet, 2023b). In order to guarantee the availability of sufficient aFRR, BSPs are required to submit bids for the supply of aFRR power to Tennet. Noncontracted BSPs can also submit a free bid (Tennet, 2023b). The contracted and free bids are combined into two distinct merit orders, one for down- and one for upregulating. For each 15-minute interval, these merit orders are established, also called an imbalance settlement period (ISP). Ultimately, the highest bid price for an ISP on the upward regulation side determines the upward regulation price. In contrast, the lowest bid price for downward regulation determines the downward regulation price (Tennet, 2022).

When the imbalance is still unresolved after activation of the aFRR, the mFRR, or tertiary reserve, is manually deployed, which supports or gradually replaces the aFRR (Tennet, 2023a). This should be fully available after 12.5 minutes and last at least 5 minutes; it could even be hours supporting the grid frequency to regain balance. Unlike FCR and aFRR, where free bids are used to create a merit order where the price is determined, mFRR is used through pre-contacted capacity that can be up- or down-regulated and must be available at all times (Tennet, 2023a). Through a daily tender, BSPs can be contracted to be deployed immediately when mFRR is called (Tennet, 2023a).

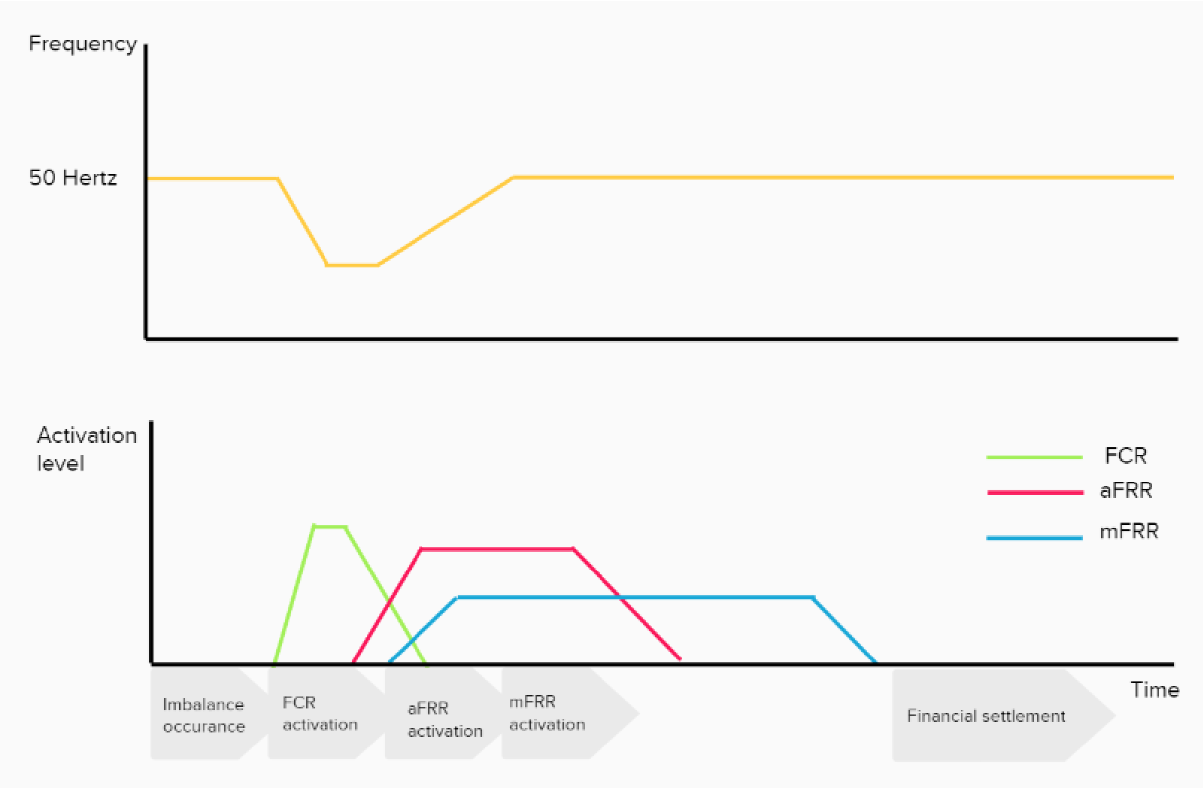

Figure 4: The balancing process in the Netherlands. Figure retrieved from Tennet (2024a).

2.2.3. Imbalance settlement

In addition to balancing services offered by BSPs to Tennet, some BRPs play a role in balance enforcement. This is because they balance supply and demand within their portfolio. Before the scheduled delivery of electricity, BRPs must submit a commercial trading schedule to Tennet by 14:30 (Ministry of Internal Affairs, 2024b). This is a forecast of the total production and consumption per quarter of an hour of the entire portfolio of a BRP for the subsequent day, along with the transactions required to achieve this (Tennet, 2022). In practice, on the day of delivery, the actual production and consumption will differ from the predictions made in the commercial trade schedule. This discrepancy can be attributed to various factors, including a reduction in solar energy generation due to the presence of clouds or an increase in consumption due to the reduction, as mentioned above, in production. This discrepancy between the predicted and actual values is an imbalance (Tennet, 2022). Figure 3 illustrates that the imbalance is not settled until the day the electricity is delivered.

The same merit orders used for the aFRR bids determine the price for the occurred imbalance, as shown in Figure 5. As illustrated in the merit order, the highest upward bid establishes the upward regulation price per ISP, while the lowest downward bid determines the downward regulation price per ISP. Additionally, a mid-price can be observed and calculated by averaging the upward and downward regulation prices. The imbalance price per ISP is determined based on the regulatory state. By this regulatory state, Tennet indicates the activation state of balancing energy (Tennet, 2022). The different regulation states are listed in Table 1.

Table 1: Regulation state for balancing services. Retrieved from (Tennet, 2022).

Regulation state	**Explanation**
0	Tennet does not regulate upward or downward during an ISP. The mid-price is used for imbalance settlement.

-1	Tennet only regulates downward during an ISP. The downward regulation price is used for imbalance settlement. The upward price is the same as the downward price.
+1	Tennet only regulates upward during an ISP. The upward regulation price is used for imbalance settlement. The downward price is the same as the upward price.
2	Tennet regulates upwards and downwards during an ISP. The upward and downward regulation prices differ, but they are used for imbalance settlement.

The BRPs may be in surplus, meaning they feed in more electricity or withdraw less from the grid than the commercial trade schedule predicted. Alternatively, they may be in shortage, meaning they feed in less electricity or withdraw more from the grid than predicted. The determination of the imbalance price and the subsequent financial flows are contingent upon the regulatory state utilized by Tennet and the status of the BRPs, whether in surplus or shortage (Tennet, 2022). The complete overview is provided in section 8.1 of the Appendix.

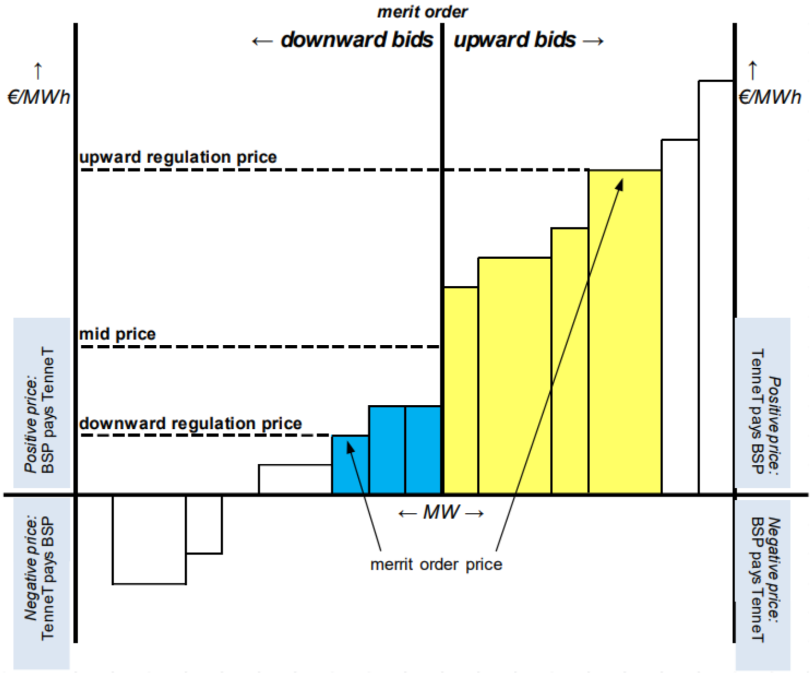

Figure 5: The merit order for determining the price for aFRR and the imbalance price. Where it says BSP, it could also say BRP. Figure retrieved from (Tennet, 2022).

2.3. Literature review on congestion management

This section commences with a review of the scientific literature to identify the state of the art of market-based congestion management. It then focuses on the Netherlands to examine how grid operators and the methods used regulate congestion management.

2.3.1. Congestion management from scientific literature

The scientific literature delineates various other mechanisms in addition to Dutch grid operators employing diverse market-based congestion management techniques. The following sections summarize the potential applicability of various mechanisms identified in the literature to the business park. In this context, it can be assumed that the business park is connected to the distribution electricity network.

Grid operators can apply congestion management through grid tariffs, charges levied on customers for using the electricity grid (Hennig et al., 2022). To illustrate, the tariffs for a wholesale consumer comprise a periodic connection charge, a connection fixed charge, a capacity charge, and a metering charge (Stedin, 2024). The elements above are aggregated into a single, fixed tariff, which the user must pay over a specified billing period. Grid tariffs can encourage users to utilize the grid efficiently to reduce congestion at specific times (Hennig et al., 2023). One such approach is implementing a fee for delivered electricity per kWh, an energy-volume grid tariff. Alternatively, a fee for measured peak consumption in kW can be imposed, which can also be regarded as a capacity grid tariff. Furthermore, a limit to the tariff for capacity in kW can be established. When the user's capacity is below this limit, they will pay a low price. Conversely, when the capacity exceeds this threshold, penalties can be applied. (Hennig et al., 2022, 2023).

Besides static grid tariffs, grid operators may also utilize dynamic tariffs that are subject to change based on the varying conditions present on the grid. One illustrative example is critical peak pricing, whereby the grid operator raises tariffs on specific days or times when peaks occur in the grid (Fridgen et al., 2018). This is essentially the same as the charge mentioned earlier for peak consumption, except that it is dynamic. For instance, when high electricity demand is anticipated, the grid operator may increase the tariffs for grid use. This could be implemented through volumetric tariffs (€/kWh), encouraging users to reduce their electricity consumption during these periods (Freier & von Loessl, 2022).

Another dynamic tariff that employs an economically driven congestion management mechanism is distribution locational marginal pricing (DLMP). DLMP enables the application of different tariffs to different nodes within the distribution grid (Huang et al., 2014). It extends the locational marginal pricing (LMP) methodology applied to wholesale power markets (Hennig et al., 2023). The DLMP is defined as the cost required to deliver a specific quantity of energy to a given node, taking into account the constraints of the electric power grid and, in this case, the capacity of the distribution grid (Liyanapathirane et al., 2021). In certain instances, DLMP is employed to signify solely the costs associated with the network (Abdelmotteleb et al., 2018). However, it is also utilized to represent the aggregate network costs and electricity market price (Li et al., 2014). In a dynamic tariff, only the costs associated with the network are utilized to determine the DLMP. (Hennig et al., 2023). As congestion on the grid occurs locally, a solution must be developed at that same level. The ability to set prices at specific locations enables the grid operator to influence consumer behavior, encouraging or discouraging electricity use or feed-in at congested points (Babagheibi et al., 2022). This is one of the critical benefits of the DLMP, which can be used effectively to manage congestion on the grid (Bai et al., 2018).

As previously stated, grid congestion is defined as a shortage of transport capacity at specific times. In order to prevent the grid from reaching its maximum capacity, a local market can be created in which capacity is limited, which will ultimately reduce grid congestion (Fuller et al., 2011). The DSO provides a scarcity product in this capacity market, namely grid capacity. Customers may submit capacity bids one day in advance, indicating the capacity they anticipate requiring for the following day (Morell-Dameto et al., 2024). Customers requiring a more significant capacity are charged a higher price in this market structure. In essence, the total capacity that can be utilized is contingent upon the supply available in the market, which can potentially prevent congestion. The capacity market need not be operated daily. Instead, it can be deployed when congestion is anticipated, and capacity can be auctioned for each hour of the following day (Morell-Dameto et al., 2024).

An alternative to the local capacity market is the local flexibility market, which can also be employed for congestion management. However, these two types of markets exhibit distinct characteristics. In the capacity market, customers act as buyers of the market product, namely network capacity, offered by the DSO (Morell-Dameto et al., 2024). Conversely, in the flexibility market, the DSO assumes the buyer role of the market product, namely flexibility, offered by customers (Valarezo et al., 2021). Flexibility can be defined as the adjustment of production and consumption patterns based on a price incentive or activation signal to contribute to certain services (Jin et al., 2018). Grid users provide a flexible service to the DSO by adjusting their consumption in exchange for a fee. One example is the congestion platform GOPACS, which the Dutch grid operator deployed. This is explained in more detail in the subsequent section. The DSO purchases this flexibility to alleviate grid congestion (Schittekatte & Meeus, 2020). Various frameworks for local flexibility markets have been proposed in the literature as potential solutions to congestion problems, including those of Esmat et al. (2018) and Olivella-Rosell et al. (2018). However, each flexible market operation comprises three distinct processes: contracting and bidding, activation, and settlement (Jin et al., 2018). In the initial phase, market participants discuss the price and quantity of flexibility (Jin et al., 2018). The pay-as-bid principle is employed in most local flexibility markets to determine the price of flexibility. In most cases, the exact matching principle is also utilized (Radecke et al., 2019). For instance, the matching principle employed by GOPACS is frequently utilized, wherein all flexibility requests and offer orders are aggregated in an order book for a specific market area. Once matched, the orders are accepted. The procured flexibility is activated in the second process, and an activation message is sent (Jin et al., 2018). Finally, the finalization of flexibility transactions occurs through settlements and payments.

2.3.2. Congestion management in the Netherlands

In order to facilitate system balancing, market participants must submit a commercial trading schedule to Tennet, which indicates the expected production and consumption of electricity. This is also referred to as an e-program. Nevertheless, grid congestion is not a consequence of electricity consumption but rather of transportation. Consequently, BRPs must submit a transmission forecast for each quarter hour of the subsequent day for all connections within their portfolio. On the day preceding the actual transportation of electricity, BRPs are required to transmit transmission forecasts to the grid operator by 14:30 (Enexis Netbeheer, n.d.-a). A so-called T-program enables network operators to ascertain the locations and temporal patterns of congestion. All connections exceeding 1 MW must submit a T-program to the relevant grid operator (Ministry of Internal Affairs, 2024b). Transmission forecasts permit TSOs and DSOs to ascertain anticipated transmission capacity shortages' locations and temporal extents. This analysis is conducted daily for delivery, affording sufficient time to resolve congestion. The specific resources employed for this purpose will be elucidated below. These mechanisms can be divided into market-based and non-market-based congestion management methods; this section describes both methods deployed in the Netherlands.

Market-based

Market-based congestion management methods employed in the Netherlands are integrated into the grid operator platform for congestion solutions (GOPACS). This platform is also referred to as the congestion market, although in reality, it operates based on existing electricity markets and is not itself a market. It facilitates congestion management for all grid operators (GOPACS Foundation, 2023). Various products are offered on this platform.

Firstly, on the day preceding the congestion period (day -1), the grid operator forecasts the anticipated transport capacity on the day of actual transport (day 0). Suppose it becomes evident that there will be a shortage of transport capacity in a given area, resulting in congestion. In that case, the grid operator may request the assistance of the entities that have entered into a capacity reduction contract. In this contract, it is agreed that at certain times and under certain conditions, the grid operator may impose a temporary transport restriction on the affected party in the congestion area (GOPACS foundation, 2023). These contracts are brokered through CSPs, or the parties themselves become CSPs. The day before congestion is expected at 8:00 (day -1), the grid operator publicly discloses the specific parties with capacity reduction contracts to be affected, as well as the precise times at which transport capacity will be reduced the amount of capacity to be reduced which is contractually agreed upon. These contracts are only available to parties with flexible generating or consuming units, as a reduction in transport capacity is required and can only be achieved if these units can shift their expected generation or consumption over time (ACM, 2022). There are two forms of capacity reduction contracts, i.e., the network operator can provide this transportation reduction with or without a call. With a call, the grid operator always asks one day in advance (day -1) whether the transport capacity can be reduced. Without a call, the network operator can always invoke the agreed reduction of transport capacity if necessary (GOPACS Foundation, 2023). For each call, the parties receive a fee proportional to the lost production or reduced consumption and a fixed fee for the provision of transport capacity.

Capacity-limiting contracts are called for day-ahead (day -1). However, insufficient transport capacity may remain available after the day-ahead market closes. If such circumstances prevail, the grid operator can disseminate a call for a dispatch bid on the GOPACS platform at 15:30 before the day of congestion (day-1) (Enexis Netbeheer, n.d.-a). Redispatch is a change in dispatch, in most cases from power plants, whereas the dispatch is reduced at the congestion point and increased outside the congestion point (Hemm et al., 2022). Congestion can be avoided by shifting this feed-in and take-out from the grid. On the GOPACS platform, a market message is disseminated by the grid operator, indicating the location of congestion, the time blocks in which it is expected to occur, and the extent to which demand for transport should be reduced. CSPs could submit a redispatch intraday market bid in response to this market message, as several intraday markets are linked to the platform (GOPACS foundation, 2023). The bids mentioned above are contingent upon a specific location, as grid congestion must be addressed locally. To illustrate, if the grid operator anticipates excess electricity to be produced or consumed, market participants in the congestion area may submit a buy order. This must then be matched by a sell order outside the congestion area to prevent disruption to the balance on the national grid. GOPACS is employed to ascertain whether this order does not result in congestion elsewhere. When this is not the case, the orders are matched, and the difference in price between them is referred to as the spread, which is remunerated by the grid operator (GOPACS Foundation, 2023). Finally, on the day of congestion (day 0) until 8:15, CSPs can still submit bids; from then on, the grid operator can call the redispatch bids (Enexis Netbeheer, n.d.-a). The operational principle of this process is illustrated schematically in Figure 6.

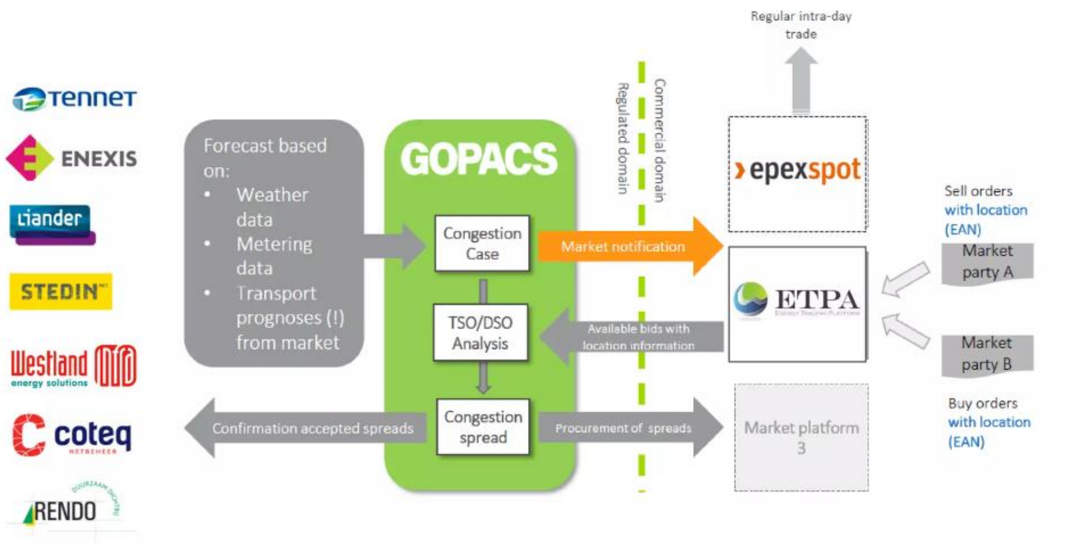

Figure 6: The operation of GOPACS involves the grid operator on the left and the CSPs placing buy or sell orders in the intraday markets, respectively. Eventually, specific orders are selected to resolve congestion issues, and the grid operator pays for the spread between the matched orders. Figure retrieved from (Muiskens & te Hoorte, 2022).

A numerical example can be worked out to clarify the operation of GOPACS. Suppose too much electricity is being produced in a particular area, for example, because there are many solar panels. The grid operator wants to increase the consumption in this area for a certain period. The grid operator then posts a market message on GOPACS asking for more electricity to be used temporarily. This is also called a buy order because the parties buy more electricity than will have already been done. Figure 7 shows a market message requesting a buy order for 2 MW from 11:00 until 12:00. In order not to disturb the balance of the national grid, this has to be compensated by a sell order outside the congested area. For example, a generator could take advantage of this by producing 2 MW of electricity from 11:00 to 12:00. The party with the buy order wants a price for his electricity that is lower than the market price; otherwise, it would not be more advantageous to consume more electricity, so he wants to pay, say, 90 euros for it. The seller wants a slightly higher price than the market price and asks, for example, 110 euros. The difference in price between the buy and the sell order is called the spread; in this example, it is 20 euros. The network operator will pay for this spread so that the congestion can eventually be resolved.

Request for **buy** orders in **ARCHEM (LEMELE), ARRIEN, OMMEN, STEGEREN, WITHAREN**
Request for **sell** orders in **Buiten ARCHEM (LEMELE), ARRIEN, OMMEN, STEGEREN, WITHAREN**

Hide problem volume

Datum	**27-05-2024**																			
Uren	**11**				**12**				**13**				**14**				**15**			
Kwartieren	**00**	**15**	**30**	**45**	**00**	**15**	**30**	**45**	**00**	**15**	**30**	**45**	**00**	**15**	**30**	**45**	**00**	**15**	**30**	**45**
Vereist in MW	2	2	2	2	2	2	2	2	4	4	4	4	4	4	4	4	2	2	2	2

Figure 7: Example of a market report in GOPACS. In the problem volume, the first column lists, one below the other, the date, hours, quarters, and demand in MW. Figure retrieved from (Gopacs, n.d.-b)

In addition to the free bids CSPs can place on GOPACS, there may also be an agreement with the relevant grid operator that requires CSPs to place bids. This product, called a Bid Obligation Contract, provides more certainty in congestion management for the grid operator and the CSPs (GOPACS foundation, 2023). It has been agreed that contract CSPs are required to submit a bid to GOPACS. This does not mean the bid will be accepted with certainty, as the grid operator selects the most cost-effective bids (GOPACS Foundation, 2023). However, it gives the grid operator more options because, for example, bids in a congested area will still be called where they would not be if market participants were not required to submit bids. The grid operator was thus dependent on free bids. CSPs receive a fixed monthly fee for this congestion management product and compensation when the bid is accepted (Enexis Netbeheer, n.d.-a).

Non-market based

If excessive prices are charged for participation in congestion management, healthy market forces are no longer created (Netbeheer Nederland, 2024a). In this case, network operators can invoke a statutory fee to apply congestion management. This is also known as non-market-based congestion management. However, according to European Commission (2019) regulations, it should only be used when there is no market-based alternative, when all available market-based resources have been exhausted, when there are not enough participants, or when market-based bids worsen congestion. Specific fees are allocated depending on whether the parties need to reduce or increase their electricity demand or production (Partners in Energie, 2024).

Alternative transport rights

In addition to the two contracts mentioned above, other contracts can help with congestion management. Parties enter into a connection and transport agreement (ATO in Dutch) with the grid operator, which, among other things, specifies the transport of electricity for offtake and feed-in. This is a contract with a firm transport capacity, which the party can use at any time (Ministry of Internal Affairs, 2024b). In addition, non-firm ATOs will soon be available, allowing the transport capacity in a contract to be variable. This is also called an alternative transport contract in the Netherlands because it is an alternative to the fixed transport contract (ATO). These are briefly explained in Table 2, along with other alternative transport rights. Ultimately, these transport rights will help grid operators with congestion management.

Table 2: Overview of the various alternative transport rights available. Information retrieved from Netbeheer Nederland (2023, 2024b).

Type:	Description:	Available from:
Collective capacity limiting contract	The capacity-limiting contract is the same as the Capacity-Limiting contract but organized into a group. Ultimately, the group ensures that less power is used during peak periods.	Now, only in pilot form
Group transport agreement (TO)	A group transport agreement is essentially an ATO but an agreement between the system operator and a group rather than an individual. As a result, the individual companies no longer have a separate agreement with the system operator; they agree together. The group must stay within an agreed transmission capacity, less than the sum of the transmission capacity, if each company had a separate ATO. As a result, more capacity is released into the grid.	Q2 2024 (now only available in pilot form)
Non-firm ATO:		
-Time block bound transport right	The customer shall contract the transport capacity in time blocks in advance. The time blocks are always outside the peak hours; during these peak hours, the parties are not entitled to transport capacity.	Q1 2025
-Time duration bound transport right	The customer contracts transport capacity for a certain number of hours per year. The system operator may limit the transport capacity outside of these hours.	Q1 2026
-Energy volume transport right	An ATO contracts for transmission capacity in kW or MW. However, this transportation right is contracted for a specific daily energy consumption in kWh or MWh.	Not available for now
-Fully variable transport right	Under this agreement, the customer contracts for fully variable transport capacity. As a result, the desired capacity is not guaranteed to be available when needed.	Q1 2025

3. Methods

Two sub-questions, each with its own research method, have been formulated to answer the main research question. The results of these sub-questions will ultimately lead to an answer to the main research question. The different research steps required to answer the research question are shown in Figure 8 and will be explained in more detail below.

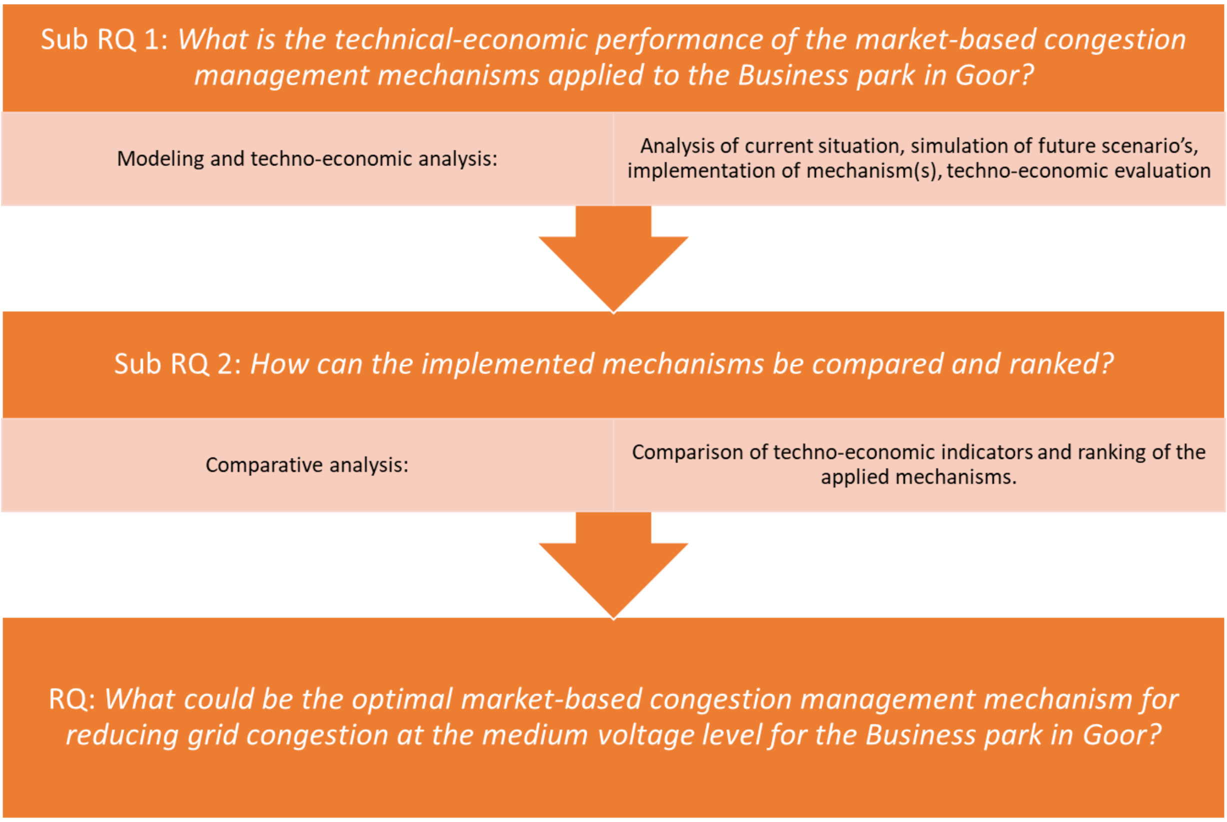

Figure 8: Overview of research steps.

3.1. Method sub-question 1

This section outlines the methodology employed to conduct a techno-economic evaluation of the business park in Goor. The evaluation was conducted in a series of steps. First, the model utilized for the techno-economic analysis was presented. Subsequently, an analysis of the current situation was conducted. This entailed an examination of the network situation in the business park and the challenges it faced. Subsequently, the data utilized in the evaluation were delineated, accompanied by an explication of their respective sources. In instances where data were unavailable, assumptions were formulated, and data were generated. To gain insight into the current situation, a comprehensive analysis was conducted employing a multifaceted approach encompassing businesses' usage profiles and connections' physical and contracted capacity. Furthermore, the influence of companies with solar panels on the existing circumstances was investigated by examining the generated generation profiles. Furthermore, the model utilized in this study was elucidated. Ultimately, prospective scenarios were analyzed. These scenarios entailed augmented electricity consumption due to the elevated load profiles of businesses and the necessity for electric vehicle charging. Additionally, it was conceivable that an increasing number of companies would install solar panels. Congestion management mechanisms were implemented in these prospective situations to circumvent congestion on the grid.

3.1.1. Python model

Python model

This research employed the Python for Power System Analysis (PyPSA) software, which utilizes the Python language, to identify an optimal, market-based congestion management mechanism for the business park in Goor (Brown et al., 2024). It is an open-source toolbox developed in Python to simulate and optimize contemporary power and energy systems. The software was developed at the Frankfurt Institute for Advanced Studies to reduce the gap between power system analysis software and general energy system modeling tools (Brown et al., 2018). Additionally, it is principally designed to simulate the operation and optimal investment of energy systems over various periods.

PyPSA is a partial equilibrium model that employs linear power flow equations to optimize both short-term operational costs and long-term investment costs through a linear problem (Brown et al., 2018). The model's objective function is to minimize the total system cost comprised of variable and fixed costs. This encompasses the costs associated with generation, transmission, and storage while accounting for technical and physical constraints (Brown et al., 2018). This optimization guarantees the most cost-effective operation and investment in the energy system. The objective function can be expressed as follows:

$$Min\left[\sum_{b,x} c_{b,x} * G_{b,x} + \sum_{b,x,t} o_{b,x} * g_{b,x,t} + \sum_{b,s} c_{b,s} * P_{b,s} + \sum_{b,s} \varsigma_{b,s} * E_{b,s} + \sum_{b,x,t} o_{b,s} * j_{b,s,t}\right] \tag{1}$$

The objective function of aggregate generator capacity ($G_{b,x}$) on each bus (b) for technology (x) and their annual fixed cost per capacity ($c_{b,x}$). The representation of a generator unit dispatch at time step t ($g_{b,x,t}$) incorporates variable costs ($o_{b,x}$). $P_{b,s}$ and $E_{b,s}$ correspond to the power and energy capacity of storage technology s, with the associated fixed costs of $c_{b,s}$ and $\varsigma_{b,s}$, respectively. In conclusion, $j_{b,s,t}$ represents the dispatch of a storage unit (s) with the associated variable cost of $o_{b,s}$.

It is essential to highlight that the objective function and constraints include variables about storage. It should be noted, however, that the storage components will only be utilized in future scenarios. They are only referenced in this context. In order to guarantee the optimal functioning of the network and the safety of its users, a series of constraints are applied to the model. These constraints include, but are not limited to, power balance, generator capacity, link capacity, battery dispatch, and energy storage capacity constraints (Brown et al., 2018). Each constraint plays a distinct role in maintaining the integrity and functionality of the network.

Power Balance Constraint (bus nodal balance constraint): The power balance constraint guarantees that the total power supply is consistent with the total power demand at each time step, thereby maintaining grid stability and reliability. This is expressed mathematically as follows:

$$\sum_{x} g_{b,x,t} + \sum_{s} j_{b,s,t} = d_{b,t} \qquad \forall b,t \tag{2}$$

Where $g_{b,x,t}$ is the dispatch of the generators and $j_{b,s,t}$ is the dispatch of the storage units. $d_{b,t}$ is defined as the demand at bus b at timestep t. This constraint guarantees that for each bus, the power generated plus the power flowing in from the grid or discharging the battery minus the power flowing out to feed back to the grid or charge the battery is equal to the power demanded. This balance is critical in maintaining grid stability and ensuring that the grid operates appropriately.

To illustrate, the central node linked to the primary grid guarantees that the grid supply is duly accounted for. If the aggregate demand at a given company node is 100 kW at a specific time, the sum of the power supplied by the grid and that generated by solar sources must be equal to 100 kW. Each company node guarantees that the local photovoltaic generation is incorporated into the power balance. To illustrate, if Company 1 generates 20 kW from photovoltaics (PV) and requires 80 kW, the grid must provide the remaining 60 kW.

Generator Capacity Constraint: Each generator must operate within the maximum power output capacity designed to prevent any generator from exceeding its safe operational limits. This constraint is defined as follows:

$$0 \leq g_{b,x,t} \leq G_{b,x} \quad \forall b,x,t \tag{3}$$

Where $g_{b,x,t}$ is the dispatch of a generator with capacity $G_{b,x}$. To illustrate, each company's PV generator must operate within its maximum capacity. If Company 1 has a PV capacity of 50 kW, it is not permitted to generate more than this amount, even in the event of high solar irradiance. Similarly, the grid generator (which represents the assumption of each company's grid load) must also operate within its capacity to ensure that the grid does not supply more than it can handle. In the model, the electricity drawn from the grid is represented by a generator whose marginal cost is the price of electricity.

Link Capacity Constraint: The maximum capacity of each link (off-take or feed-in) serves to prevent overloading of the connections between different parts of the grid. This constraint guarantees that the power flow through each link does not exceed its designed capacity:

$$0 \leq l_{l,t} \leq L_l \qquad \forall l,t \tag{4}$$

Where L_l is the capacity of link l, with $l_{l,t}$ representing the power flow through that link. For example, the links connecting the central grid to each company node must not exceed their maximum capacity. If a link has a capacity of 100 kW, it cannot transmit more than 100 kW. Similarly, links allowing companies to feed excess solar power back to the grid must also adhere to their capacity limits. For example, if Company 1 can feed back a maximum of 50 kW, it cannot exceed this limit even if it has surplus generation.

Battery dispatch constraint: The dispatch of storage units, represented by the symbol $b_{b,s,t}$, is subject to constraints analogous to those that apply to generators. However, storage units can both discharge power into the grid and absorb power from the grid, resulting in negative dispatch values when charging. The constraint for storage dispatch is given by:

$$j_{b,s,t}^{min} * P_{b,s} \leq j_{b,s,t} \leq j_{b,s,t}^{max} * P_{b,s} \qquad \forall b,s,t \tag{5}$$

The time-dependent availability of the storage unit ($j_{b,s,t}^{min}$,minimum dispatch limit) is given per unit of the total capacity. It should be noted that the value of $j_{b,s,t}^{min}$ may be negative in certain instances. This is because the dispatch of storage units ($j_{b,s,t}$) can result in a positive discharge into the grid, and a negative absorption of power from the grid. Furthermore, the variable $P_{b,s}$ represents the power capacity of the battery unit, while $j_{b,s,t}^{max}$ denotes the maximum dispatch limit.

Energy storage capacity constraint: It is of the essence that the energy levels of all storage units, as represented by $e_{b,s,t}$, remain consistent from one time step to the next. This ensures the precise monitoring of energy stored and released by storage units over time. Moreover, the energy levels are constrained by the storage energy capacity ($E_{b,s}$), which is represented by the following equation:

$$e_{b,s,t} = e_{b,s,t-1} + \eta_{n,s,+} * j_{b,s,t}^{+} - \eta_{n,s,-} * j_{b,s,t}^{-} \tag{6}$$

Where $e_{b,s,t-1}$ is the energy level at timestep $t-1$, $\eta_{n,s,+}$ and $\eta_{n,s,-}$ are the charging and discharging efficiency respectively, $j_{b,s,t}^{+}$ is the charge and $j_{b,s,t}^{-}$ the discharge power.

$$E_{b,s}^{min} \leq e_{b,s,t} \leq E_{b,s}^{max} \quad \forall b,s,t \tag{7}$$

To illustrate, we may consider a battery storage unit at Company 2 with an energy capacity of 500 kWh. If the battery is initially charged to 300 kWh and then discharges 50 kWh (considering 90% efficiency), the energy level for the subsequent time step can be calculated as 300−50/0.9. If the battery also charges 30 kWh (with 95% efficiency), the new energy level would be 244.4 kWh plus 30 kWh multiplied by 0.95, resulting in a total of 272.9 kWh. This ensures accurate tracking of energy levels.

By adhering to the abovementioned constraints, the PyPSA model ensures efficient, reliable, and safe energy system operation, optimizing the overall cost while respecting the physical and technical limitations of the grid and its components. To illustrate the configuration of the business park, Figure 13 is provided. It demonstrates that the businesses are interconnected via diverse medium-voltage ring networks. When this is to be modeled, the resulting complexity is considerable. It was, therefore, assumed that all companies are connected to a single medium-voltage ring. Figure 9 illustrates that all the companies are linked to a single circuit, which can be considered a ring. The ring mentioned above is then connected to a medium-voltage substation. The buses represented by the equations mentioned earlier are illustrated as a company in Figure 9. Subsequently, a PV generator or storage unit is attached to the bus, as mentioned above. As previously stated, the grid offtake is a generator coupled to its bus, as illustrated by the black line in Figure 9. Moreover, the interconnection between the entities mentioned above and the grid offtake is also referred to as a link. Each link is assigned a capacity to ensure that no company exceeds its contracted capacity. This prevents any company from withdrawing more power from the grid than its contract permits. This approach allows for the straightforward modeling and analysis of various congestion management mechanisms.

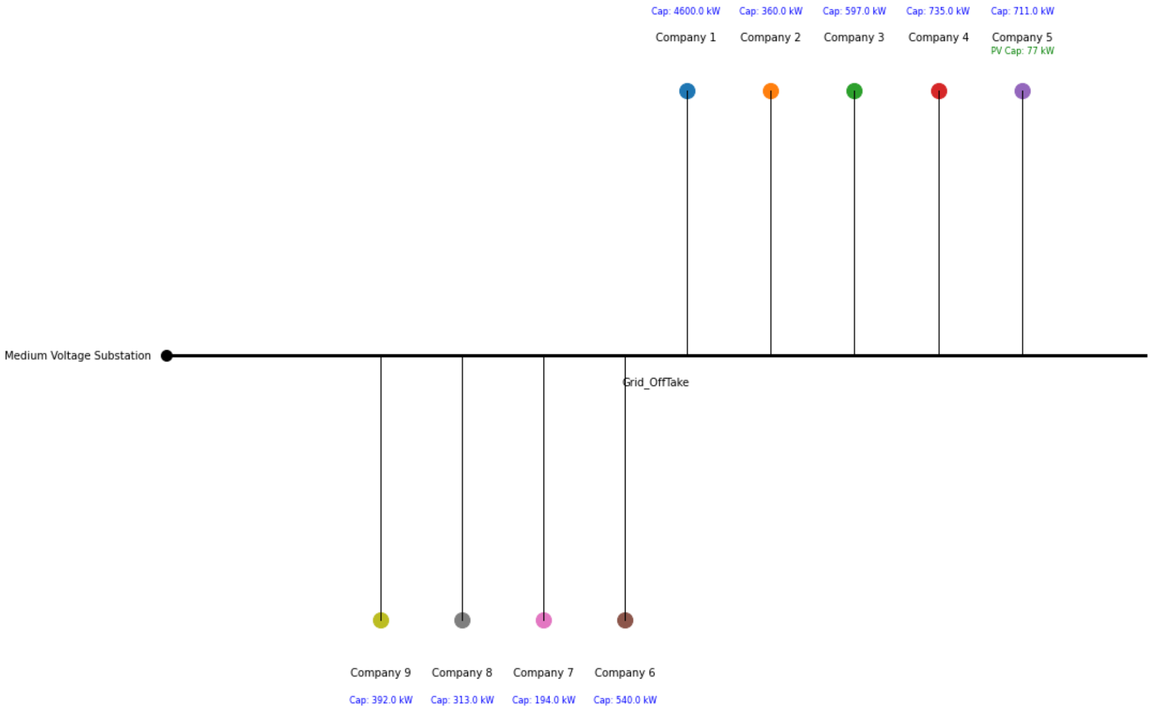

Figure 9: The configuration of the business park's electrical infrastructure. The contracted capacities of the connection and PV panels are indicated for each company.

3.1.2. Analysis of current situation

The techno-economic analysis was based on empirical data from actual business park areas in the town of Goor in the province of Overijssel. As illustrated in Figure 10, Goor is currently situated within an orange congestion zone. This indicates a deficit in transportation capacity, prompting the network operator to ascertain the remaining availability of capacity following the implementation of congestion management strategies (Netbeheer Nederland, 2024c). Moreover, Figure 10 illustrates that the current and requisite capacity for off-take is nearly equal. This indicates that, at present, the electricity needs of these companies can be met. However, a problem is likely to arise as their electricity consumption increases. A considerable amount of capacity is currently available. The available capacity is insufficient to meet demand on the feed-in side, indicating an apparent deficit. Additionally, there is a considerable amount of power in the queue. These queues may impede the ability of new companies to secure connections and current companies to obtain larger connections. Such circumstances may impede the capacity of companies to pursue greater sustainability.

The congestion and queues observed can be alleviated by increasing the grid's capacity by installing additional cables. However, Tennet has indicated that a reduction in scarcity in the electricity grid may be expected in the province of Overijssel, of which Goor is a part, until 2031 (Tennet, 2023c). This signifies that congestion will persist until 2031, which will significantly impact the business park in Goor, among other factors. In order to continue to meet the growing electricity demand, congestion management mechanisms will be deployed, allowing companies to install charging stations, solar panels, and heat pumps in a manner that is sustainable despite the congestion.

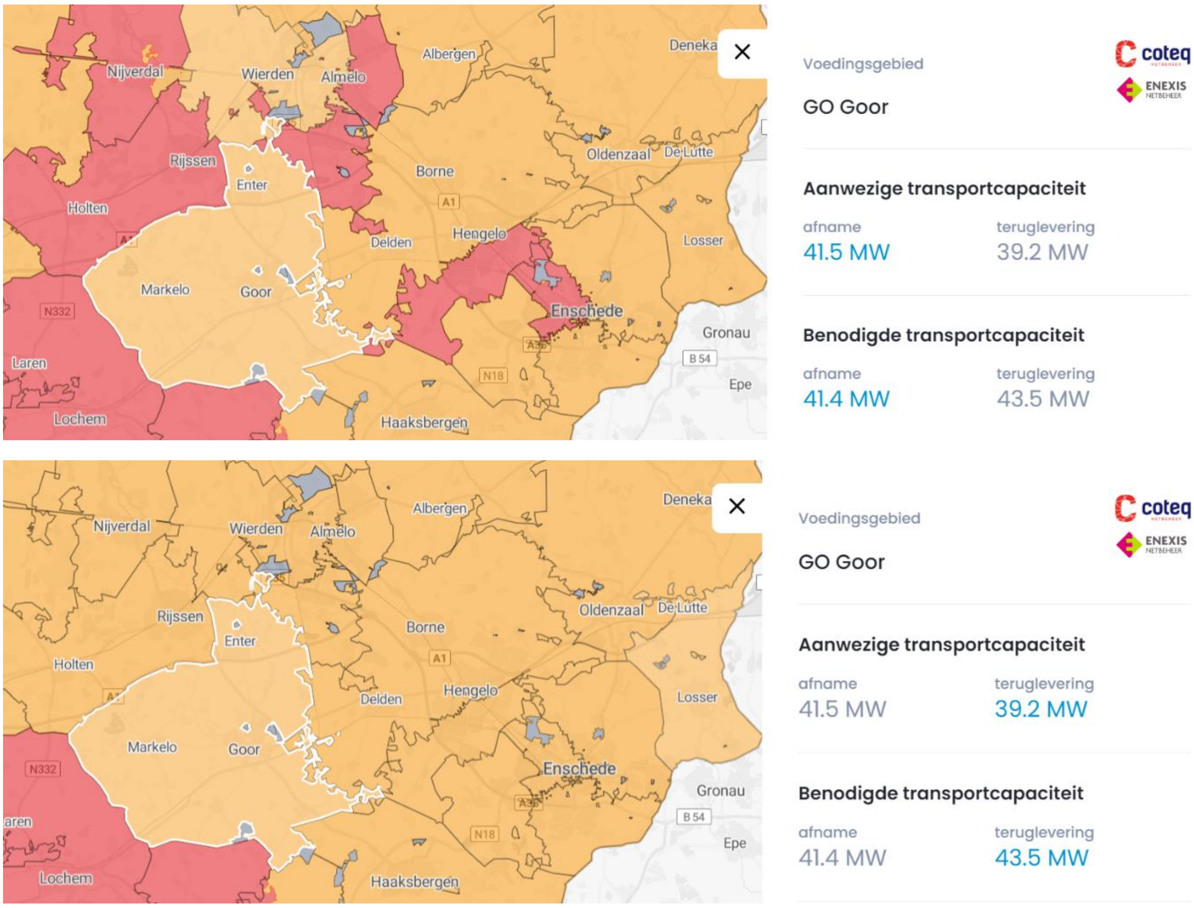

Figure 10: The following map illustrates the capacity of the village of Goor. The top map depicts congestion in the offtake, while the bottom map illustrates congestion in the feed-in. The orange indicates structural congestion and points to the research on congestion management. It is uncertain whether capacity can still be made available. The figures illustrate the right side's existing (aanwezige) and required (benodigde) transport capacities. It can be observed that there is a shortage on both the offtake and feed-in sides. Figure retrieved from (Netbeheer Nederland, 2024c).

The area under investigation encompasses four small business parks, as illustrated in Figure 11. It should be noted that not all business parks were subjected to a separate analysis. Instead, this study assumed that the entire area could be considered a single, large business park. This is because, otherwise, the analysis would become unmanageably complex. Arcadis is currently engaged in a project titled "Goor vol energie," which involves entrepreneurs working collaboratively to optimize the utilization of the electricity grid (NOS, 2024). The companies involved in this project account for 70% of the electricity consumption. However, they cannot obtain a more significant connection due to grid congestion, and the newly installed solar panels cannot feed electricity back into the grid. In order to ascertain which market-based congestion management methods can be applied in this large business park, consumption data must be analyzed. The data set comprised consumption data in kWh per quarter hour for nine large consumers in the year 2023. The data will be utilized in the course of this research. However, grid congestion is not a consequence of peaks in electricity consumption but rather of peaks in power, which is indicated in kilowatts (Hennig et al., 2023). Consequently, the data was transformed from kWh per quarter-hour to kW per quarter-hour using formula 8.

$$Power\ (kW) = \frac{Electricty\ consumption\ (kWh)}{time\ (hours)} \quad (8)$$

Large consumers, also known as wholesale consumers, play a significant role in the electricity grid. These consumers, with a connection of more than 55 kW and linked to the medium-voltage grid (ACM, 2024), are crucial due to their substantial power usage for their appliances (Mateo et al., 2021).

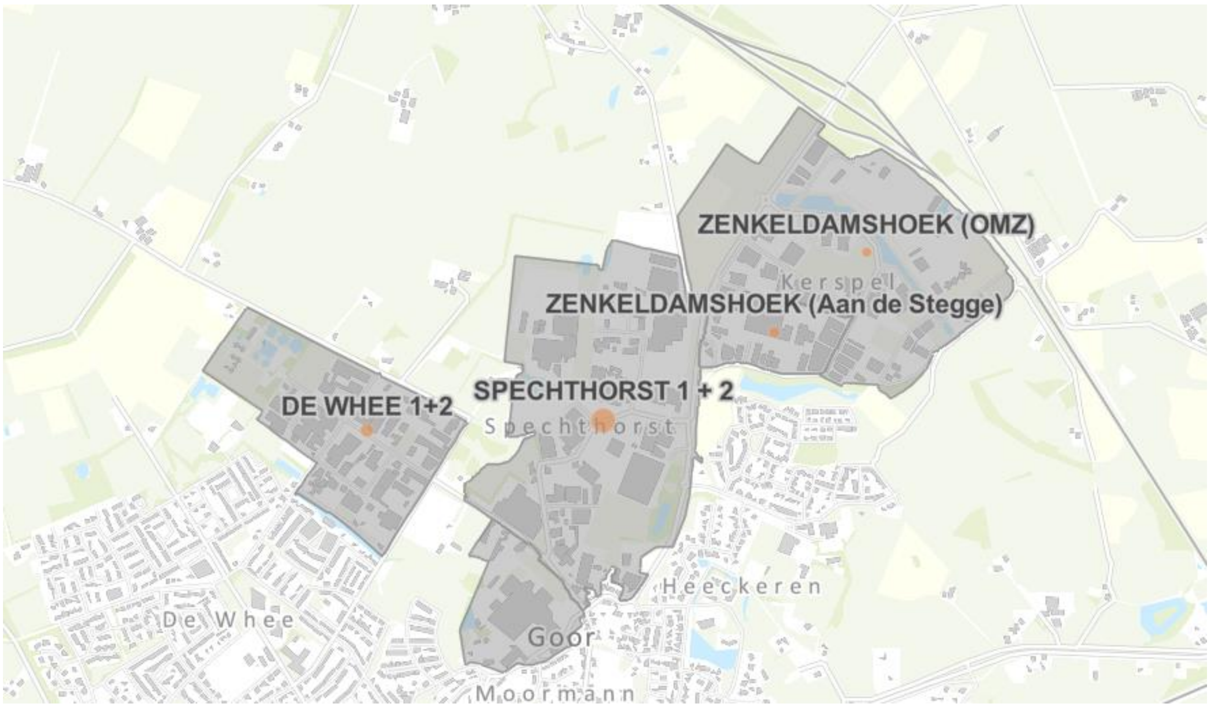

Figure 11: Overview of the business park in Goor. Figure retrieved from E-laad (2022).

The municipality of Goor presents a unique scenario with the coexistence of two distinct grid operators on the business park-Coteq and Enexis. This departs from the typical setting where a single grid operator is responsible for a specific area. The intertwining of these different grids is visually depicted in Figure 12.

Figure 12: Overview of medium voltage cables of the grid operators Coteq and Enexis. The purple lines are those from Coteq. Moreover, the red lines are from Enexis. Figure retrieved from the project of Arcadis.

This study, focusing on companies connected to the medium-voltage grid, underscores the importance of understanding their energy consumption. The participants engaged in the project are connected to either Coteq's or Enexis' network. All participants with a connection exceeding 55 kW are considered large consumers. Nevertheless, the size of the connection can determine the company's position within the network. Once the connection exceeds 173 kW, it is classified as medium-voltage (Enexis Netbeheer, n.d.-b). Any connection between 55 kW and 173 kW is connected to the low-voltage grid, with voltages between 230 and 400 V, depending on the connection size. This study will not address the issue of large consumers despite their significant energy consumption. Instead, the focus will be on companies connected to the medium-voltage grid. Table 3 presents the physical and contracted capacity of the companies where consumption data is available and used in this study. Physical capacity represents the limit of the connection's capacity, whereas contracted capacity denotes the power the company must pay for (NAL, 2023). The contracted capacity can be exceeded without the physical capacity being exceeded. However, this is subject to significant penalties. Moreover, in the event of grid congestion, a company is even prohibited from exceeding the contracted capacity. In addition, only one company has a contracted capacity to deliver solar energy back, which indicates how much power can be delivered back. This is also listed in Table 3.

Table 3: The physical capacity of the connection and the contracted capacity of the companies under study. This data originates from Arcadis' project. Due to privacy considerations, the names of the companies have been omitted.

Company	Physical connection capacity (kW)	Contracted capacity off-take (kW)	Contracted capacity feed-in (kW)
Company 1	6000	4600	0
Company 2	630	360	0
Company 3	1260	597	0
Company 4	1303	735	0
Company 5	217	111	0
Company 6	630	517	500
Company 7	630	164	0
Company 8	630	373	0
Company 9	1260	322	0

Figure 13 provides a schematic representation of the network topology within the Goor business park. The high-voltage grid of Tennet facilitates the transportation of electricity from the central station to the network of Enexis, where it is converted to medium voltage. Subsequently, the medium voltage is distributed to the different medium voltage rings via the medium voltage substations. The various wholesale consumers are connected to these medium voltage rings. A district station is also connected to the medium voltage ring, where the voltage is transformed to low voltage. Furthermore, the distribution/transformer station is a connection point for the smaller wholesale consumers and households. The Coteq network is connected to the Enexis network, yet their topologies remain identical.

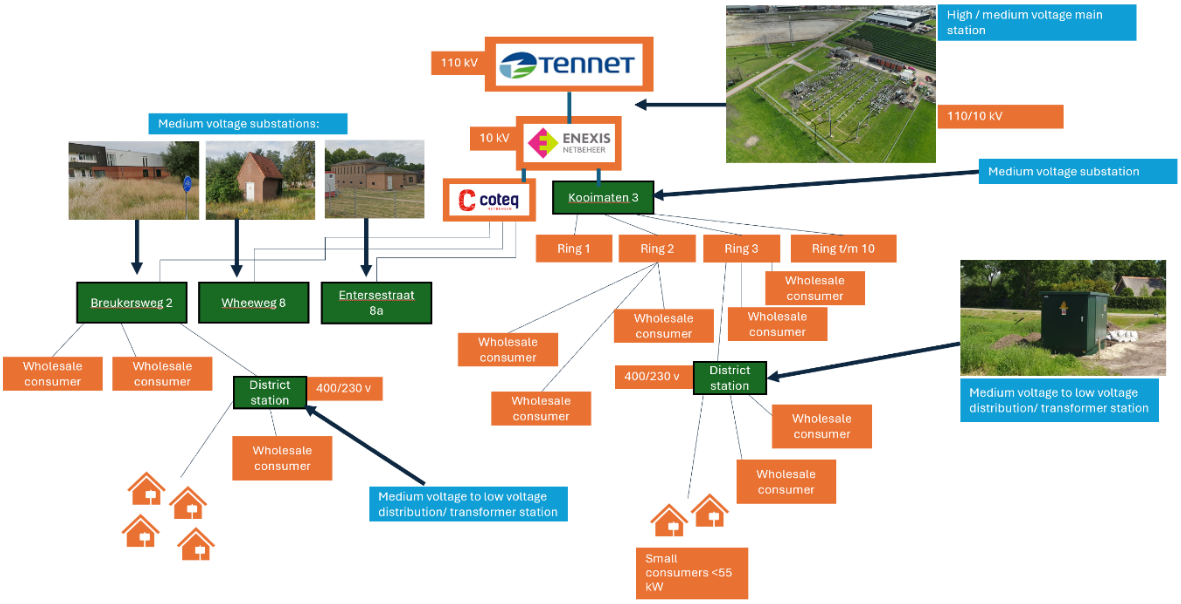

Figure 13: Overview of the grid topology of Coteq and Enexis. The voltage level at which large consumers are connected to the district substation is designated as low. Conversely, medium voltage is the designation for consumers connected to medium voltage substations. This study will concentrate on the latter. The data were sourced from Arcadis' project.

No data about solar energy generation was available from the companies that might have solar panels on their roofs. Consequently, this data was generated. A dataset was available from the project above, developed by the Netherlands Enterprise Agency (RVO), the Netherlands' Cadastre, the Land Registry and Mapping Agency (Kadaster), and the National Program Regional Energy Strategy (NP RES). This dataset lists the potential for solar energy and the solar panels installed per municipality building (RVO et al., n.d.). It should be noted, however, that this dataset is not publicly available. It was obtained through Arcadis. The dataset illustrates the current and potential future solar panel installations on each building's roof. It provides the number of square meters of solar panels installed and the estimated number of square meters that could be installed.

For the generation profile of the solar panels, an east-west orientation was chosen instead of the south orientation, which was customarily used. The orientation of the solar panels in an east-west configuration results in a reduction in electricity generation at noon, with a corresponding increase in generation at this time compared to a south orientation, as illustrated in Figure 14. A south orientation's peak power is higher than an east-west orientation's (Khatib & Deria, 2022). However, this lower power causes less electricity to be injected into the grid at noon. The peak consumption occurs in the morning and late afternoon, respectively. Consequently, the east-west orientation generates more electricity precisely when there is a peak in consumption (Laveyne et al., 2020). This ultimately ensures that there is less surplus electricity and, as a result, less electricity is injected into the grid, which can mitigate congestion. However, an east-west orientation is associated with a yield that is, on average, 15% lower than that of a south orientation (Khatib & Deria, 2022).

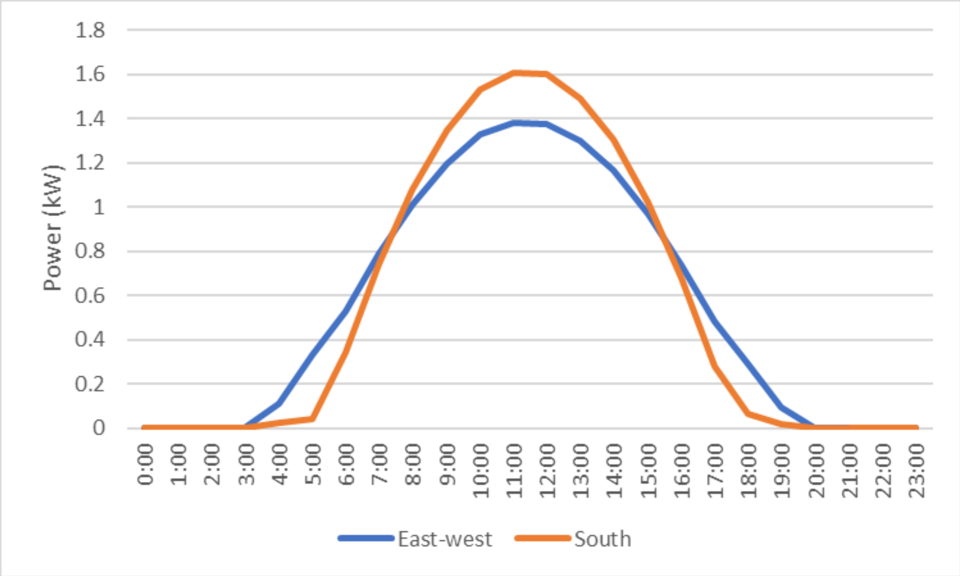

Figure 14: Generation profile of east-west versus south orientation. Both are two kWp systems and are located in the municipality of Goor. The data is from July 2, 2018, and is from the European Commission (2022).

The generation profiles are from a European Commission (2022) PVGIS database. A location, orientation, and tilt can be chosen in this database. Based on these input variables, a generation profile is generated for the chosen years. To illustrate the contrast between a favorable and unfavorable solar year in terms of irradiance, two distinct years were utilized for the generation data. Figure 15 illustrates the irradiance data from different years. For analysis, 2018 and 2016 represented a good and bad solar year, respectively. In this study, only the favorable solar year was initially included, as this is the period during which solar panels generate the most electricity. This results in the most significant stress on the power grid when surplus electricity is fed into the grid.

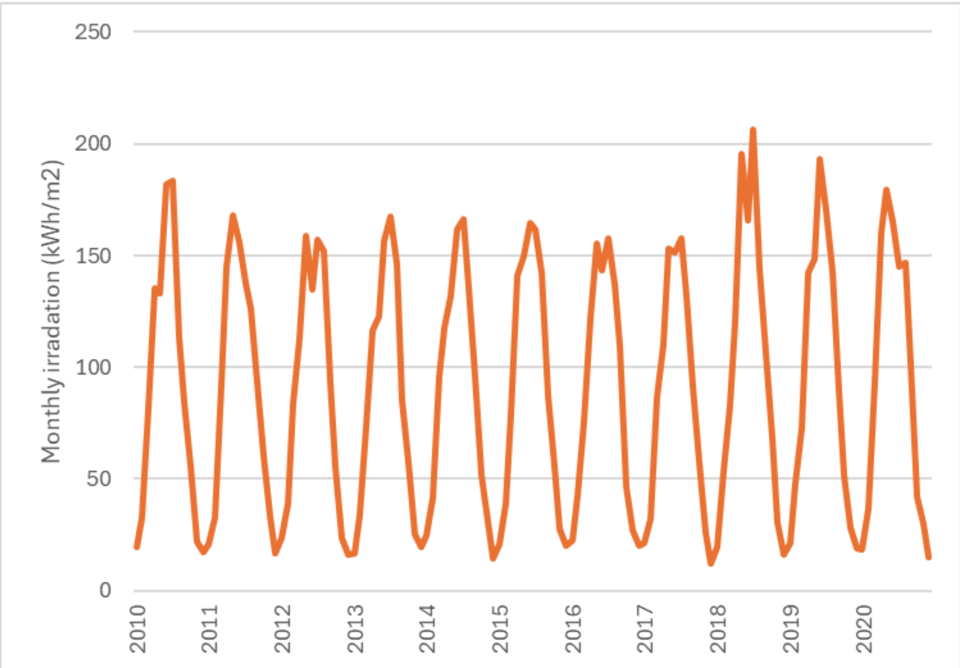

Figure 15: Graph for the irradiance data from different years. The data is from the European Commission (2022).

A generation profile was derived from the European Commission's database (European Commission, 2022). To utilize this profile, a normalized profile was first prepared using Formula 9. The power at time step t, denoted by P, is the amount of power generated at that specific point in time. The total amount of generated power for the entire period, denoted by Ptotal, is the sum of all the power generated throughout the period.

$$Normalized\ profile\ (t) = \frac{P\ (t)}{P\ total} \tag{9}$$

Subsequently, the potential for solar panels on the roof in terms of square meters and the dimensions of a solar panel were used to determine the number of solar panels and, subsequently, the peak power for each company, using Formula 10, where # panels are the number of solar panels.

$$Peak\ power\ (kWp) = peak\ power\ 1\ panel\ (kWp) * \#panels = kWp\ per\ panel * \frac{Roof\ area\ (m^2)}{Dimensions\ 1\ panel\ (m^2)} \tag{10}$$

Formula 11 illustrates how the total peak power and the normalized generation profile were utilized to calculate each company's generation profile. The input data used for these formulas is presented in Appendix section 8.2.

$$Generation\ profile\ (t) = peak\ power\ (kWp) * full\ load\ hours\ (h) * normalized\ profile\ (t) \tag{11}$$

This study assumed that the electricity price dataset consists of day-ahead market electricity prices for each company under examination. This implied that the price could fluctuate on an hourly basis. Furthermore, these electricity prices were utilized to calculate the companies' electricity costs. The data were obtained from Entsoe (2023) and represented the 2023 electricity prices. Additionally, the dataset included instances of negative electricity prices. In the context of off-take, this signified the potential for revenue generation. Conversely, in the case of feed-in, it denoted the existence of associated costs. This was incorporated into the model as well.

3.1.3. Analysis of future situation

This study considered the present situation and the relevance of grid congestion to future scenarios. Due to the limited time available to grid operators, grid expansion often requires years. The results of a congestion study conducted by Tennet (2023c) have revealed that the electricity grid in Goor is still anticipated to encounter structural congestion until 2031. Furthermore, congestion may still occur beyond the projected timeframe. To analyze the future situation, a scenario in which no electricity grid expansions have been realized is considered, thus maintaining the current capacity. It is, however, anticipated that there will be an increase in electricity consumption. In this study, 2040 is assumed to be the future year under analysis. The companies have sufficient time until the present year to enhance the sustainability of their business processes and invest in electric vehicles, which will increase their electricity consumption. Moreover, the current lack of capacity precludes the possibility of future expansion or sustainability for companies. In order to analyze the future situation at the business park, it is necessary to make certain assumptions regarding electricity consumption. A report by TNO has revealed that the electrification of heat demand can result in a 47% increase in electricity consumption by business parks (Kamphuis et al., 2024). This figure already accounts for any potential electricity savings achieved through insulation measures, for instance. Furthermore, this study assumes that companies will electrify their heat demand, which leads to the conclusion that future electricity consumption will increase by 47%.

Furthermore, it is assumed that the companies in question will utilize solar panels, which may be installed in the future. The installation of solar panels enables businesses to become more sustainable and potentially reduce their energy expenditure, provided that the correct amount is installed. Due to grid congestion, feeding anything back into the grid is impossible. If they do so, the grid operator may impose a fine. The RVO et al. (n.d.) dataset provided data on the number of solar panels already installed by companies and the amount of roof area that could be utilized for solar panel installation. At the outset, a single company had already installed solar panels. However, in the projected future scenario, it was assumed that all companies would fully utilize the surface area designated for solar panels.

In addition to considering the electricity consumption of various commercial enterprises, it is also essential to factor in the charging of electric vehicles. When a significant number of electric vehicles are charging simultaneously, it can lead to the grid's capacity being exceeded, resulting in grid congestion (Brinkel et al., 2022). It is impossible to obtain real-time data on the number of electric vehicles owned by businesses in the business park, nor is there real-time data on the charging profiles of these vehicles, which may be present on the premises. Consequently, assumptions were made to include electric vehicle data in this study despite the lack of available data.

As illustrated in Figure 11, the participating companies are situated within one of four distinct small business parks. A dashboard developed by E-laad (2022) can be utilized to ascertain the projected number of electric vehicles for future years. This enumerates the projected number of electric trucks and vans to operate by 2040. By employing this forecasting methodology, it is possible to establish a charging profile for the anticipated number of electric vehicles across the entire business park. Furthermore, a standardized profile has been employed for the e-truck, which is derived from a report of Noordijk et al. (2020b), and a standardized profile has also been utilized from another report by Noordijk et al. (2020a) for the e-vans. The normalized profiles are illustrated in Figure 16. The figure demonstrates that the e-van and e-truck are primarily charged during the afternoon when solar irradiance is at its maximum. By employing the number of e-trucks and e-vans and the normalized profiles, among other variables, a charging profile can be established. This can be achieved through the application of formula 12.

$$Charging\ profile\ (t) = \#evs * energy\ usage\ 1\ year\ (kWh) * 4 * normalized\ profile\ (t) \qquad (12)$$

The charging profile uses the standard unit of power, the kilowatt (kW), as its measurement. In contrast, the energy consumption of an electric truck or van is expressed in kilowatt-hours (kWh). The charging profile, expressed in kW per quarter hour, allows us to calculate the energy consumption by multiplying the figure by four, as shown in Formula 12. The symbol "#evs" represents the number of electric vehicles. The energy usage per year of the electric truck and the van is derived from the report of Noordijk et al. (2020b). To understand the effect of electric vehicle charging on the net congestion of the business area, we chose a scenario of charging mainly during the day, when the business load is at its peak. This creates 'worst case' scenarios that need to be addressed with congestion management mechanisms. Additionally, solar energy is generated simultaneously as charging, which can be used directly for the charging hub but is insufficient for the entire load.

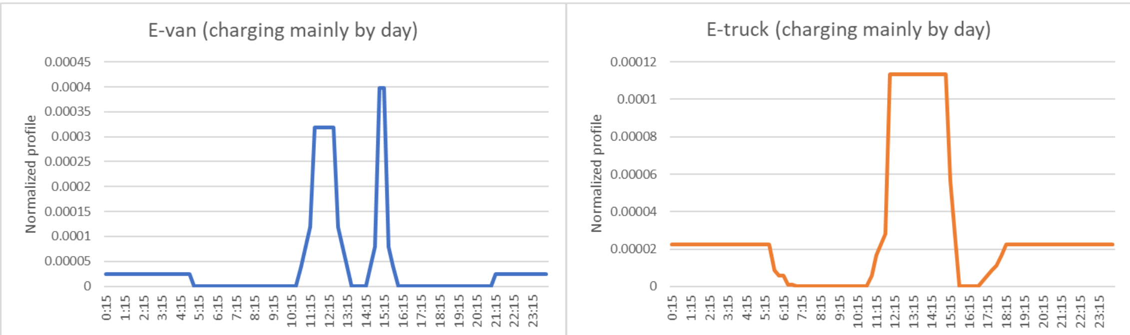

Figure 16: Normalized electric van and truck profiles from Noordijk et al. (2020a, 2020b). The charging profiles represent a full day, and the numbers indicate the proportion of a total year.

3.1.4. Congestion Management Scenario 1

In this scenario, the identical input data were utilized as in the prospective scenario; however, specific congestion management mechanisms were employed to obtain a viable solution. Furthermore, the subsequent scenarios encompass the financial commitments necessitated by implementing congestion management. The assumptions in this scenario are listed in Table 4 and explained in further detail below.

Table 4: Assumptions made in the first Scenario.

Assumptions:
The charging hub has no offtake connection.
Additional links between each company are added to share the solar energy generated.
Links from each company to the charging hub have been added to provide electricity from the PV panels or the company's power connection.
Each company and the charging hub have a storage unit.
Load shedding can be used if necessary.

This scenario ensured that as much of the power generated by the solar panels as possible could be used and that the companies could share solar power. Additional links between the companies, from one company to the other, have been added to the model to make this possible. In addition, the charging hub will also need to obtain power, as it does not have a connection to draw power from the grid. Therefore, links from each company to the charging hub have also been added to the model. These links can bring excess power from the PV panels to the charging hub. Nevertheless, there may also be times when there is not enough solar power, so the links can also be used to use power from the companies that still have capacity. In this way, the capacity the companies are not using can meet the load demands of other companies or the charging hub. It is assumed that this is done administratively, so there are no physical cables between the companies and the charging hub. This could also be done administratively using an energy hub, but physical cables can also be laid, although the latter involves additional costs.

Battery energy storage is a crucial player in the system, especially during winter or when no capacity is available for off-take. These storage units ensure a continuous power supply, even during low solar power generation periods, providing a sense of reassurance about the system's reliability. They allow energy to be drawn from the PV panels or the grid when capacity is available and store it for later use when capacity is no longer available. While the size of the storage units could be optimized, this study focused on the system's design and operation, ensuring a seamless power supply. The calculation used for the storage units is shown in Equation 13.

$$P_{b,s,p} = peak\_load_c - average\_load_c \tag{13}$$

Where $P_{b,s,p}$ is the potential power capacity for each company and the charging hub, and $peak\_load_c$ and $average\_load_c$ are the peak and average load of each company and the charging hub.

Load shedding is applied when the company's loads, particularly the charging hub, cannot be served due to a lack of off-take capacity. This approach involves switching off non-critical loads to reduce power consumption during peak periods. While load shedding is a vital congestion management method, it is not preferred due to its high cost. Therefore, the model first searches for an alternative solution, and load shedding is applied only if it cannot find one. It is assumed that the load to be reduced is non-critical, as there is no data on whether this load is critical.

It should be noted that the model does not include investments, even though Formula 1 indicates that they could be included. When investments are incorporated into the model, an accurate, objective value cannot be determined. Consequently, the decision was made to calculate the investments separately. Table 5 presents the values utilized in the calculations and other crucial values pertinent to this scenario. In order to calculate the investments and O&M costs of the storage and PV panels, it is necessary to multiply the capacity by the relevant costs, as seen in Formula 1. Furthermore, the model incorporates the capacity and efficiency of the storage units. The efficiency of the storage system is a one-way efficiency, applicable only to the charging or discharging processes. The C-rate is the rate at which the battery charges or discharges concerning its maximum capacity (Bobanac et al., 2021). Thus, a C-rate of 0.5 signifies that a battery can charge or discharge its maximum capacity within two hours.

Table 5: Input values that are used in the model.

What	Value	Unit	Source
Investment PV	700	€/kWp	Own experience Arcadis
O&M PV	5	€/kWp	(Lensink & Schoots, 2023)
Investment Storage	500	€/kWh	(Cole & Karmakar, 2023)
O&M Storage	12.5	€/kWh	(Jongsma et al., 2021)
Storage efficiency (one-way)	93	%	(Bobanac et al., 2021)
Storage c-rate	0.5	-	(Bobanac et al., 2021)
Load shedding costs	10	€/kWh	(Ghaemi et al., 2022)

3.1.5. Congestion Management Scenario 2

In the second scenario, the various companies initially established a group transport agreement, a cost-effective measure that enhances the system's financial sustainability. This and other assumptions are listed in Table 6 and further explained below. In this instance, the companies are no longer entering into individual contracts; instead, they are entering into a contract collectively. The advantage of this form of transportation agreement is that the overall capacity of the contract is less than if all contracts were entered into individually. This will result in the liberation of capacity that other companies can utilize. In this instance, the released capacity is allocated to the charging hub, thus facilitating its connection to the electricity grid. The peak capacity of each company was calculated using Formula 14, and based on this, the new capacity was determined.

Table 6: Assumptions made in the second Scenario.

Assumptions
All the companies enter into a group transport agreement, allowing capacity to be shared and used for the charging hub.
The charging hub will now have a capacity for a connection.
The charging hub gets a small solar field.
Only the charging hub has a storage unit.
Load shedding can still be used if necessary.
Companies and the charging hub can now shift their load, which is attractive because it allows them to shift their load to times with a reduced electricity price.

$$New\ offtake\ capacity_c = Max\ (load\ profile_c) \tag{14}$$

The "c" represents the company. Formula 15 determines the remaining capacity utilized by the charging hub.

$$Offtake\ capacity\ charging\ hub = \sum_1^c Old\ offtake\ capacity - \sum_1^c New\ offtake\ capacity \tag{15}$$

The aggregate of these capacities constitutes the capacity entered into the group transmission agreement, which thus represents the capacity of the business park. The new capacity of each company is listed in Table 7. It should be noted that these new capacities were only utilized to calculate the group capacity, given that the model assumes a shared capacity. Ultimately, the total capacity of the business park remains unaltered.

Table 7: Old and new capacity based on the group transportation agreement.

Company	Old contracted capacity off-take (kW)	New contracted capacity off-take (kW)
Company 1	4,600	3,017
Company 2	360	211
Company 3	597	671
Company 4	735	198
Company 5	111	105
Company 6	517	636
Company 7	164	234
Company 8	373	392
Company 9	322	317
Charging hub	0	1,998
Total	7,779	7,779

Due to the group's capacity limitations, the aggregate loads may still exceed the available capacity. In order to prevent these loads from exceeding the capacity, a method of load shifting has been introduced. Companies can transfer their load from periods of high demand to low demand. This approach ensures that the capacity is not exceeded and that the load of the companies and the charging hub remains within the desired parameters. In order to encourage the practice of load shifting, a reduction in the price of electricity has been implemented. One effective method for encouraging load shifting is to implement a price incentive structure that consumers perceive as advantageous. The paper of Kazhamiaka et al. (2017) employs a time-of-use pricing structure for electricity, wherein a differential is observed between the daytime and nighttime rates. In this study, a time-of-use schedule is not employed; instead, an electricity price reduction is utilized. The underlying assumption is that the price reduction is based on the average electricity price for the specified year. This equates to €0.10/kWh. It should be noted that not all companies' loads are flexible, and thus, they cannot shift their entire load to other times. It is, therefore, assumed that the companies can shift 30% of their total offtake capacity and that the charging hub can shift 46% of its offtake capacity. The figures mentioned above have been derived from the research conducted by Hassanniakheibari et al. (2020) and Gerritsma et al. (2019).

There are two methods through which companies can reduce their expenditure related to electricity costs: the first is through load shifting, and the second is by taking advantage of other opportunities for cost reduction. First, when they reduce their load, they incur a reduction in expenditure due to the decreased electricity consumption. This is also demonstrated in Formula 16. Furthermore, they can use electricity at a reduced price when upshifting, as illustrated by Formula 17. These formulas are not directly included in the model but are calculated separately. However, the amount of load shifted upwards and downward is calculated. Although these are costs, they will be more advantageous than using electricity at regular electricity prices. This would render it advantageous for companies to shift their load.

$$Downward\ shifting\ savings\ _t(€) = Downshifted\ load_t\ (kW) * actually\ electricity\ price\ _t \left(\frac{€}{kW}\right) \quad (16)$$

$$Upward\ shifting\ costs\ _t(€) = Upshifted\ load_t\ (kW) * reduced\ electricity\ price\ _t \left(\frac{€}{kW}\right) \quad (17)$$

Furthermore, it was assumed that load shedding remains a viable option. This process is analogous to that described in the preceding scenario. Moreover, two additional elements have been incorporated into this scenario to guarantee the effective reduction of the charging hub's load. Given the considerable discrepancy between the capacity of the charging hub connection and the peak load, it is imperative to implement measures to address this imbalance. Accordingly, a solar field with a capacity of 2000 kWp will be installed in front of the charging hub, and a battery with a capacity of 1000 kWh will be added. Both have the exact investment costs of the previous scenario. Two additional assumptions have been made that contribute to servicing the load of the charging hub. In conclusion, the input values utilized in the model and enumerated in Table 5 are identical to those employed in this scenario. However, supplementary input values are employed in this scenario, as detailed in Table 8.

Table 8: Input values used in the second congestion management scenario.

What	Value	Unit	Source
Electricity price (DAM) reduction for load shifting	0.10	€/kWh	(Kazhamiaka et al., 2017) and based on the average DAM price of 2023
Percentage of offtake capacity companies that can be used for load shifting	30	%	(Hassanniakheibari et al., 2020)
Percentage of offtake capacity charging hub that can be used for load shifting	46	%	(Gerritsma et al., 2019)
Charging hub PV capacity	2000	kWp	Assumption
Charging hub storage capacity	1000	kWh	Assumption

3.1.6. Congestion Management Scenario 3

The last scenario introduces a capacity market as a market-based congestion management mechanism. This assumption has been made, and the other assumptions used in this scenario are listed in Table 9. In this market, companies can submit hourly bids for their needed capacity. Since capacity is a scarce commodity in this market, companies that need more capacity will naturally pay a higher price. Due to time constraints, building a capacity market with hourly bids into the model was complicated, so a simplified version was implemented. This assumes that the bidding process has already taken place, so capacity is allocated to each company hourly. Therefore, the cost of bidding is not included in this scenario; it is only the effect of the allocated capacity on, for example, grid offtake and its cost. The goal of this capacity market with allocation is to assess the discrepancy between hourly and fixed capacity for each company. Furthermore, this capacity market enables the charging hub to obtain capacity allocation. The capacity allocation is as follows: each hour, a priority list is created based on the companies in question, with the company experiencing the highest load for that hour given the highest priority. In the prioritization process, the charging hub is always the final consideration, as service provision to the companies is deemed greater. The company with the highest demand at a given hour is allocated the requisite capacity, and the remaining capacity is then distributed to the next company in line, which also receives the necessary capacity. If any capacity remains at the end of the process, it is allocated to the charging hub. This results in a designated capacity for each company for each hour.

Table 9: Assumptions made in the third Scenario.

Assumptions:
A capacity market is introduced, with capacity allocated to companies hourly.
Based on this capacity market, the charging hub will have a capacity for connection.
The charging hub has the same solar field as the previous scenario.
Only company one and the charging hub will have a storage unit.
Load shedding can still be used if necessary.
Only the charging hub, Company One, and Company Four can shift their load.

Moreover, the potential for load shifting and load shedding remains. Without these mechanisms in place, developing a feasible solution is impossible. It should be noted, however, that this scenario does not assume that every company can shift its load. Only the two companies with the most significant original offtake capacity, as indicated in Table 7, can resort to load shifting. The maximum amount that can be shifted in this scenario is calculated based on the original capacity of the respective entities, thereby allowing for the most significant possible degree of load shifting. Company 1 and Company 4 are the entities that can utilize 30% of their capacity for load shifting. For the charging hub, this figure remains at 46%. The input values about load shifting and load shedding, as outlined in Table 5 and Table 8, also apply in this scenario. Additionally, Table 10 lists the remaining input values specific to this scenario.

Table 10: Input values used in the third congestion management scenario.

What	Value	Unit	Source
Charging hub PV capacity	2000	kWp	Assumption
Charging hub storage capacity	4000	kWh	Assumption
Company 1 storage capacity	500	kWh	Assumption

The PV capacity of the charging hub remains consistent with the previous scenario. However, there is a notable enhancement in the storage capacity. This is because the charging hub is the final entity to be considered for each hour in the grid off-take capacity allocation. Consequently, the remaining available capacity is allocated after considering all other companies. A substantial storage unit may allow the charging hub to retain its load. Furthermore, a modest storage unit is incorporated into Company 1's configuration. This is because Company 1 has the highest load among all the companies in question. Therefore, the storage unit can be utilized effectively to store surplus solar energy for later utilization. Consequently, this company requires a reduced grid capacity, increasing capacity for the other companies and the charging hub.

3.2.Method sub-question 2

Ultimately, the various market-based congestion mechanisms were compared based on the techno-economic indicators that emerge in the abovementioned analysis. Based on this comparison, the mechanisms can be ranked to determine the optimal congestion management method for the companies in the business park from various perspectives. To illustrate, the analysis considers the quantity of electricity drawn from the grid, the extent of load shifting, and the degree of load shifting. Furthermore, it compares solar generation and curtailment. Furthermore, the total investment requirements for each scenario are compared. In addition, the financial implications of load shedding, load shifting, and O&M costs are considered by comparing the electricity costs for each company across all scenarios.

4. Results

This section presents the findings of the techno-economic evaluation of the business park in Goor. Firstly, the present and future circumstances of the business park are examined. Subsequently, the results of the various market-based congestion management scenarios are presented and analyzed. Subsequently, a comparative analysis is conducted to evaluate the performance of the various scenarios.

4.1. Current situation

The nine companies within the business park are linked to the medium-voltage network, exhibiting disparate electricity consumption patterns. Table 11 delineates the companies' annual electricity consumption, contracted offtake, and feed-in capacities. Notably, three companies have significantly higher electricity consumption, resulting in more significant power peak and contract capacities.

Table 11: This overview presents the respective electricity consumption and peak power figures for the companies in question. For privacy reasons, the companies are annotated. All data is retrieved from the project within Arcadis.

Company	Annual electricity consumption (kWh)	Peak power demand (kW)
Company 1	10,266,700	2052
Company 2	185,960	143
Company 3	2,327,170	456
Company 4	321,424	134
Company 5	322,098	71
Company 6	1,420,650	432
Company 7	171,969	158
Company 8	498,104	266
Company 9	512,704	215

Figure 17 illustrates the power demand profiles for Companies 1, 3, 6, and 9, presented in total, weekly, and daily units. The load profiles of Companies 1 and 6 demonstrate minimal variation throughout the year, indicating that seasonal changes do not significantly influence their operations. This indicates that these facilities operate year-round, presumably as processing plants. In contrast, Companies 3 and 9 demonstrate pronounced seasonal variations, exhibiting reduced load during the summer months, particularly for Company 9. This is likely attributable to its reliance on electricity for heating during the winter. The weekly profiles for all companies demonstrate reduced activity during the weekends. Companies 6 and 9 exhibit a typical workday pattern, with elevated power demand in the morning and a decline in the late afternoon. Company 1's daily profile indicates a longer workday, with a notable increase in power consumption after midnight, sustained until the evening. Company 3's daily profile is anomalous because its data were provided as total daily consumption, failing to capture hourly peaks accurately.

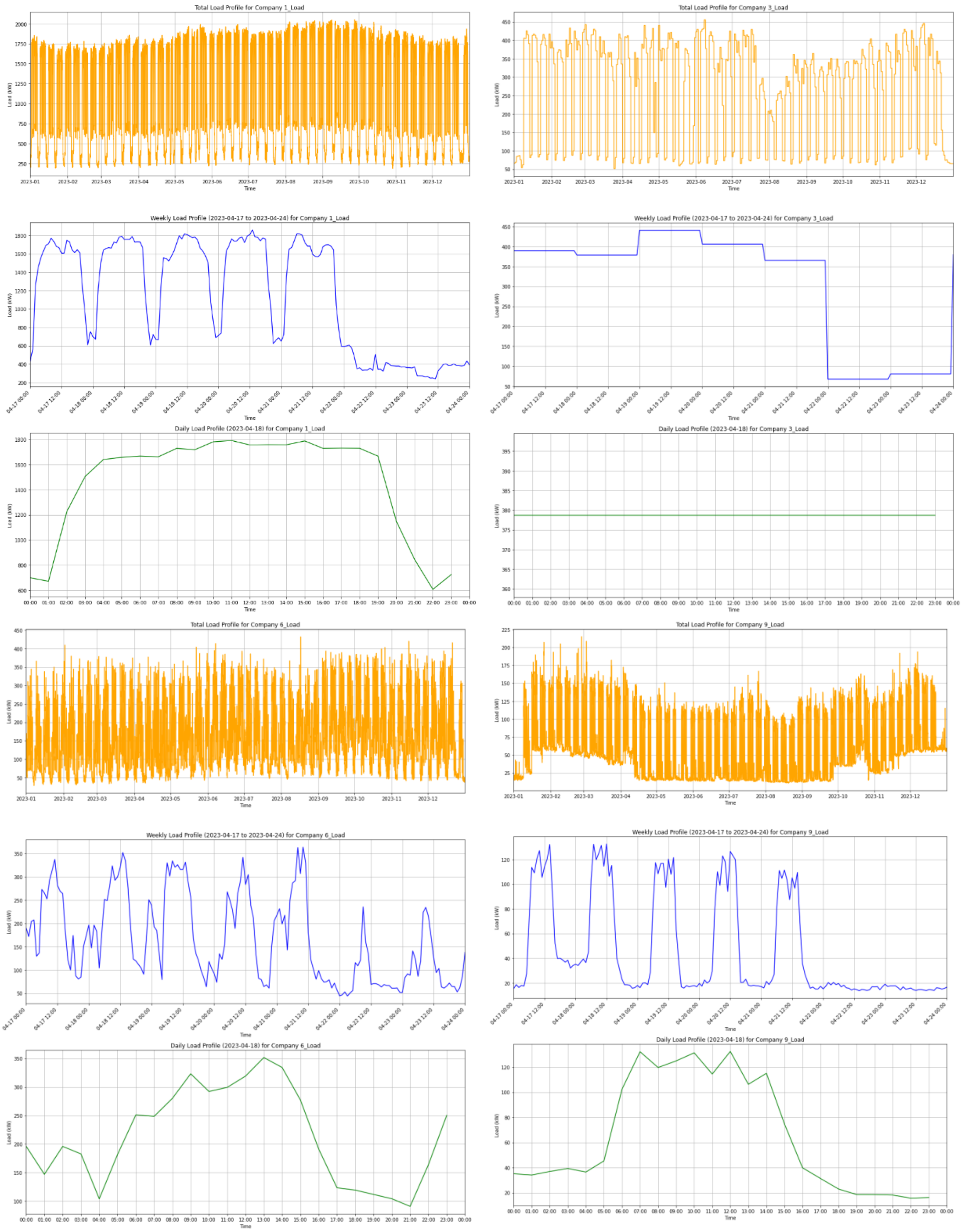

Figure 17: Total, weekly, and daily load profile of the four companies with the most significant electricity consumption.

Furthermore, Table 3 and Table 11 elucidate discrepancies between the companies' contracted and peak power requirements. This is sometimes deliberate, as companies anticipate an uptick in future electricity demand. However, many companies are unaware of the contracted capacities they have been provided and may have more capacity than is required. To address this issue, the ACM plans to implement the "Use-It-Or-Lose-It" principle (ACM, 2023), which will require companies to justify any contracted capacity that exceeds their actual needs. Any excess capacity that is not adequately justified will be revoked. Figure 18 illustrates the cumulative load profiles of all companies, demonstrating a notable disparity between the highest peak capacity and the maximum contracted peak. This indicates that the business park's power grid can accommodate future load increases. The excess capacity is concentrated primarily among companies with the highest contracted capacities, as illustrated in Figure 19.

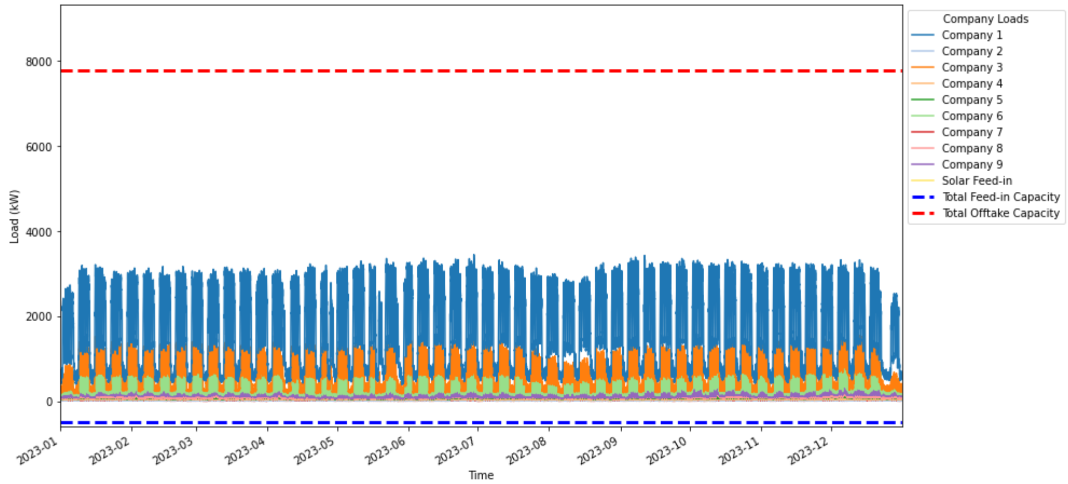

Figure 18: The aggregate load of all companies with the total capacity for take-up and feed-in.

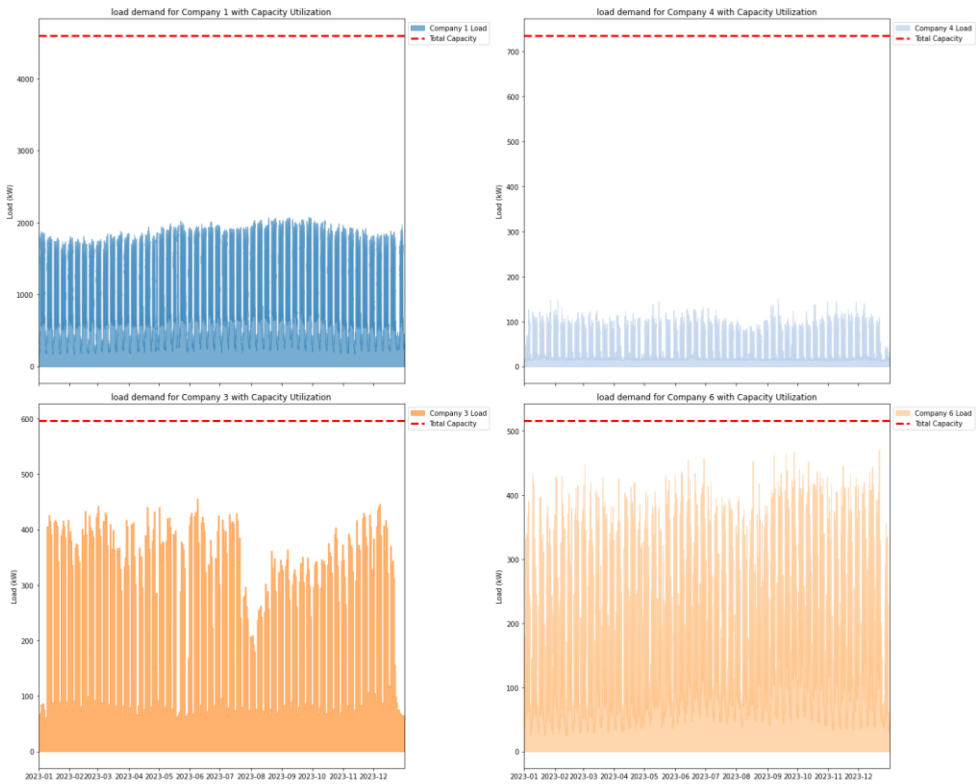

Figure 19: Load profiles with the off-take capacities of the four largest electricity consumers.

Company 6 is the only business with solar panels installed, with a peak output of 77 kW. It also has a feed-in capacity contract to return excess electricity to the grid. However, Company 6 must pay to feed electricity into the grid if electricity prices turn negative. During times of overproduction, solar power is curtailed. The solar panels generate 41,750 kWh annually, of which 6,700 kWh is curtailed. Figure 20 shows the annual pattern of solar production and curtailment, with most curtailment occurring during summer when electricity prices are negative. The model determines whether to draw power from the grid or use solar energy based on marginal costs. As the marginal cost of solar power is nearly zero, the model prioritizes grid electricity when its price equals zero, leading to the curtailment of solar energy (Mayer et al., 2015).

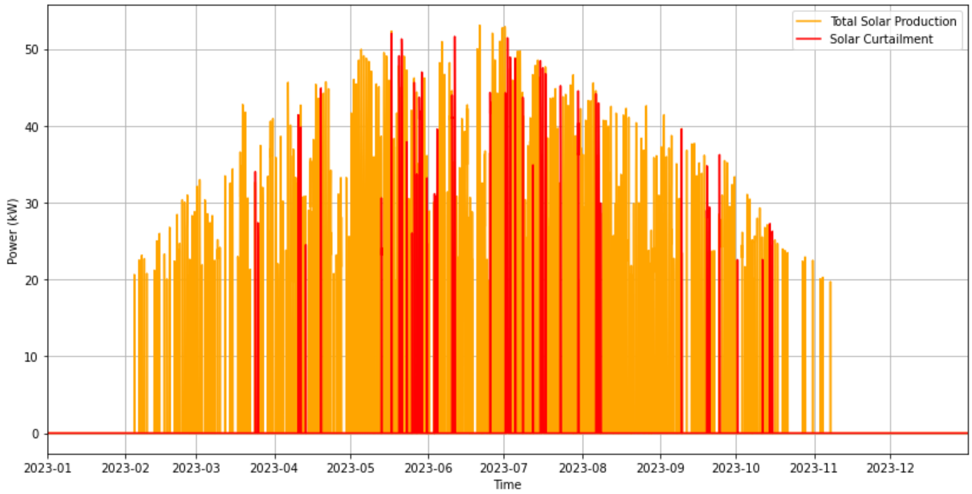

Figure 20: PV power production and curtailment of company 6.

After optimization, the net load demand and solar energy utilization were calculated using the objective function. Figure 21 illustrates a slight reduction in total load, indicating minimal solar energy utilization. This is attributed to the limited capacity of Company 6's PV panels. Solar energy's impact on the overall load is minimal, as the installed capacity in kilowatts is insufficient to create a tangible difference. The net grid load, including associated costs, is calculated by the model and presented in Table 12.

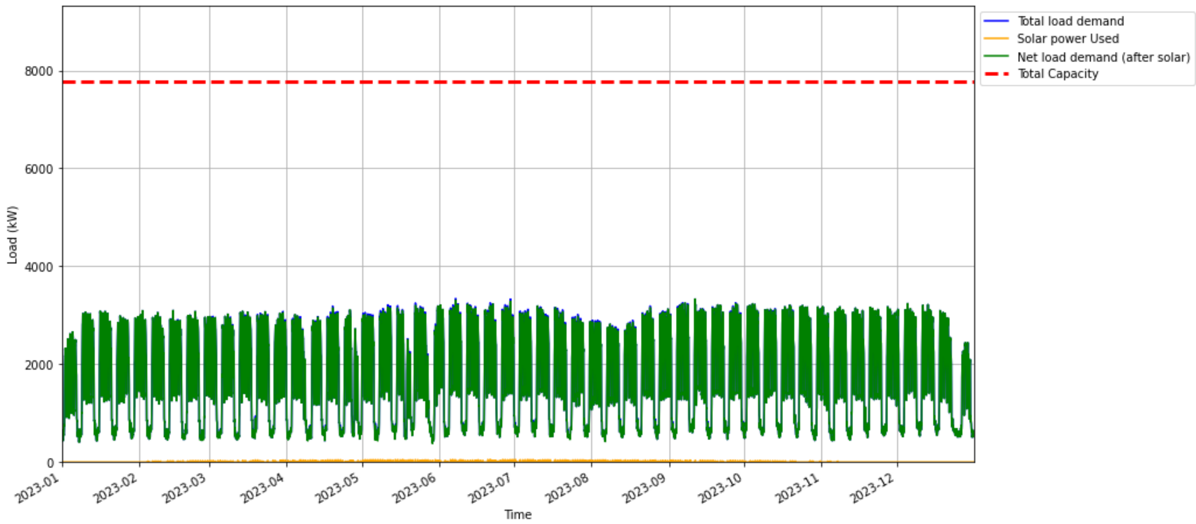

Figure 21: Result of the optimization in which the companies' net load and solar energy are calculated.

Table 12: Grid-offtake and associated electricity costs. These electricity costs are calculated using the prices for the day ahead.

Company	Grid-offtake (kWh)	Annual electricity costs (Day ahead prices)
Company 1	10,266,700	€ 1,040,396
Company 2	185,960	€ 18,162

Company 3	2,327,170	€ 240,682
Company 4	321,424	€ 32,453
Company 5	322,098	€ 30,834
Company 6	1,378,890	€ 135,156
Company 7	171,969	€ 17,872
Company 8	498,104	€ 52,922
Company 9	512,704	€ 52,832

4.2. Future situation

Aggregating the load from all companies and the charging hub reveals that Company 1 and the charging hub contribute the most to exceeding the offtake capacity, particularly during peak demand. This is primarily because the peak capacities of the companies often coincide, resulting in an exceedance of the contracted offtake capacity. This scenario represents an extreme case where all-electric vehicles are charged simultaneously, which is unlikely to occur regularly. Nevertheless, grid congestion represents a significant concern, as it could impede the hub's capacity to charge vehicles. In the absence of a grid connection, the hub would be incapable of charging vehicles, which could have a significant impact on transportation. It is, therefore, imperative that effective congestion management strategies are implemented in order to avoid such disruptions. Furthermore, Figure 22 illustrates that the quantity of solar energy generated but not directly utilized exceeds the feed-in capacity, even when all companies are permitted to utilize it. As a consequence of grid congestion, the surplus energy cannot be fed back into the grid and is therefore subject to curtailment.

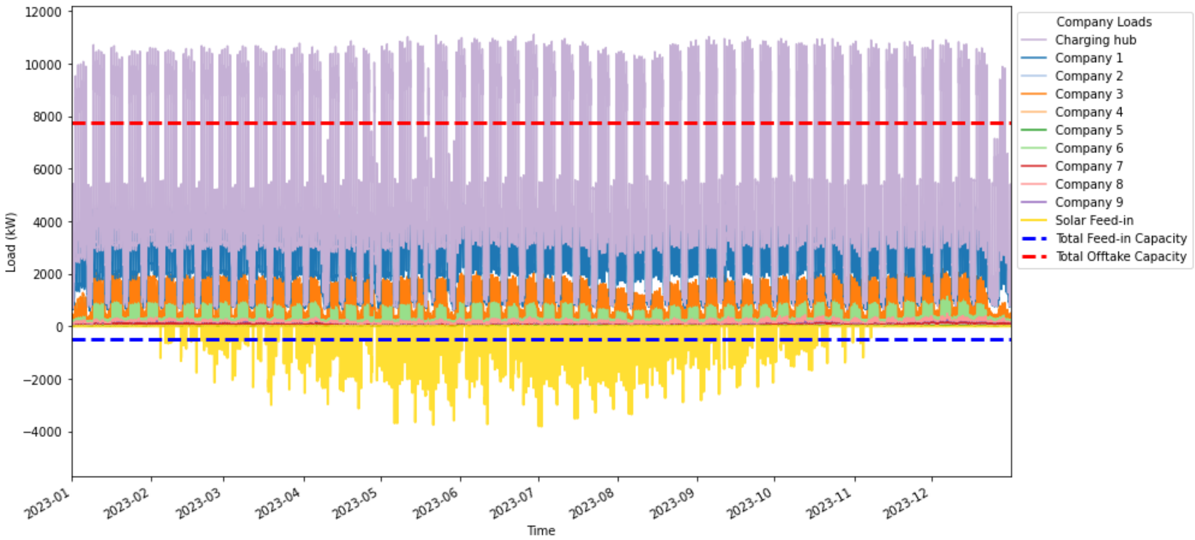

Figure 22: The companies' Total load and solar feed-in in the future scenario.

As illustrated in Figure 23, despite the implementation of solar energy, numerous instances exist where the aggregate grid load from the business park surpasses the offtake capacity. While solar energy contributes to a reduction in the overall company load, it is not a sufficient means of maintaining the park within its contracted capacity. This issue is particularly challenging during the winter months when the limited solar energy generation makes it difficult for companies to reduce their loads. Notably, the model does not optimize this scenario, as the combined load of businesses and the charging hub exceeds the capacity of the business park, and no load-reduction measures have been implemented. In this instance, the model cannot provide a viable solution, resulting in the absence of calculated values. The objective of this scenario was to illustrate the influence of augmented load, the incorporation of PV technology, and the introduction of a charging hub on the overall load. Further details regarding these values can be found in Section 8.3 of the Appendix.

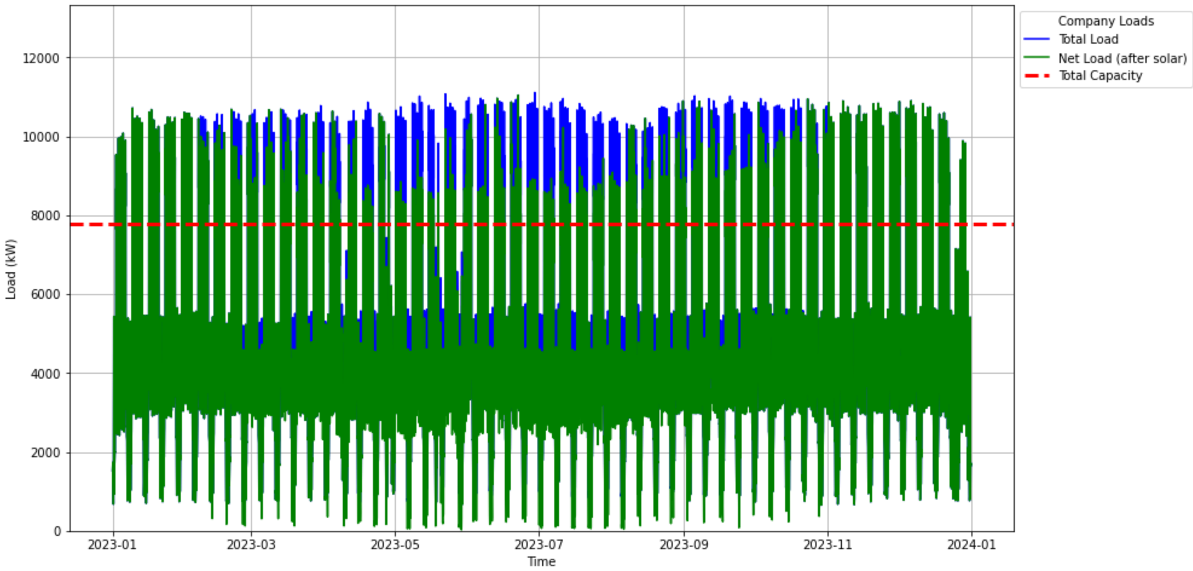

Figure 23: The net load of all companies after using solar energy in the future scenario.

4.3. Congestion Management Scenario 1

In this scenario, several assumptions have been made. First, the charging hub is assumed not to have an off-take connection. Second, additional links between companies are assumed to allow for solar energy sharing. Third, each company is assumed to be connected to the charging hub to supply electricity from either PV panels or the company's power connection. Moreover, each company and the charging hub are furnished with storage units, and load shedding can be utilized if necessary.

Following the integration of storage units for the charging hub and participating companies, it becomes evident that businesses can share electricity generated from PV systems and their offtake capacities. In exceptional circumstances, load shedding may also be employed to alleviate the impact of peak loads. Figure 24 demonstrates that the aggregate capacity of the business park is no longer exceeded following the implementation of congestion management mechanisms. This demonstrates that the model has effectively identified a solution that maintains grid capacity within acceptable limits. Figure 25 proves that individual companies remain within connection limits, confirming effective congestion management.

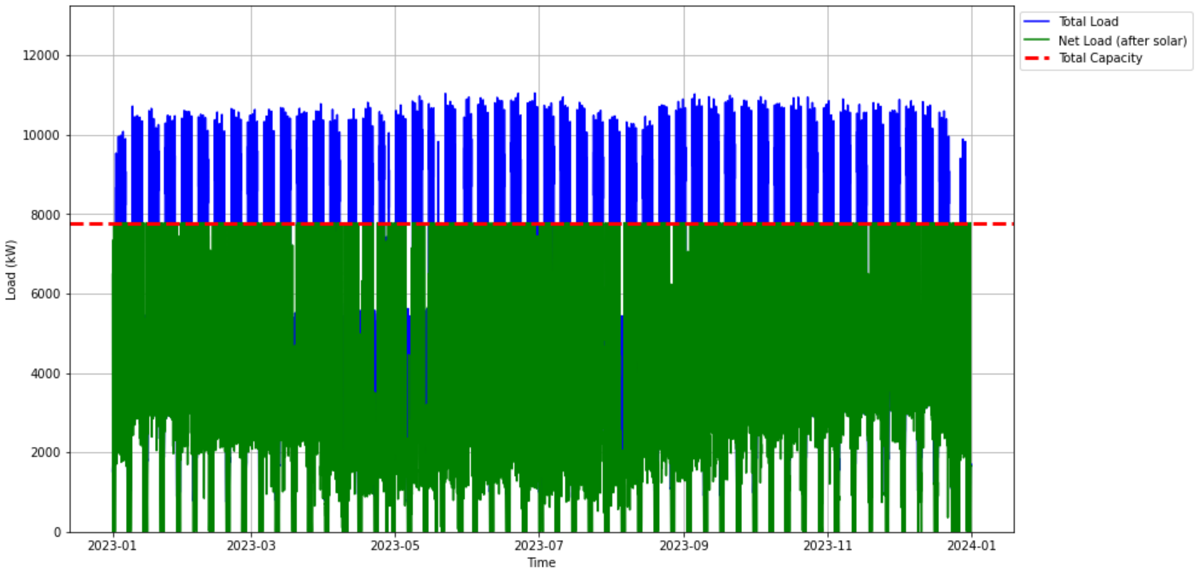

Figure 24: The net load of all companies after using solar energy, storage units, and load shedding in congestion management scenario 1.

Figure 25: The load of the four companies with the largest offtake capacity in the first congestion management scenario.

Table 13 presents the grid offtake for all companies in the congestion management scenario. It demonstrates that the charging hub does not draw electricity from the grid due to its lack of a direct connection. Instead of a direct grid connection, the charging hub relies on electricity provided by other companies through their respective capacities, resulting in a markedly elevated grid offtake for those companies compared to the projected future scenario. The role of storage units in this configuration is paramount, as they ensure that when companies have surplus capacity, the electricity is stored and delivered to the charging hub. Furthermore, storage mitigates the necessity for load shedding, as evidenced by the negligible amount of shed load compared to grid offtake, as illustrated in Table 13. Nevertheless, this advantage is contingent upon a considerable investment in storage units.

In the projected future scenario, a considerable proportion of solar energy would be curtailed, with companies utilizing only a modest amount. In this scenario, the presence of storage units enables companies to share solar energy and supply it directly to the charging hub, thereby reducing the curtailment of solar energy to a significant extent. As Figure 37 from the Appendix in Section 8.4 and Table 13 illustrates, the proportion of curtailed solar energy is markedly lower than that projected for the future scenario. Nevertheless, a considerable degree of curtailment persists at Companies 3 and 4, partially attributable to negative electricity prices. These prices suggest an excess supply in the market, rendering it uneconomical to utilize the entirety of the generated solar energy.

Table 13: The companies' grid offtake, solar production, curtailment, electricity, and load-shedding costs in the first congestion management scenario.

Company	Grid-offtake (kWh)	Annual electricity costs (Day ahead prices)	Total used solar production (kWh)	Solar curtailment (kWh)	Load shedding (kWh)	Load shedding costs
Company 1	19,874,600	€ 1,814,600	769,402	96,272	467	€ 4,670
Company 2	1,175,000	€ 94,843	27,496	3,697	0	€ 0
Company 3	3,396,230	€ 327,042	1,468,320	250,135	0	€ 0
Company 4	2,240,390	€ 181,115	940,147	158,831	419	€ 4,190
Company 5	570,541	€ 50,225	0	0	71	€ 710
Company 6	2,456,080	€ 216,123	160,349	18,560	226	€ 2,260
Company 7	586,962	€ 48,398	11,799	1,606	0	€ 0
Company 8	1,304,580	€ 110,574	315,898	56,873	0	€ 0
Company 9	1,211,030	€ 103,266	46,078	6,254	76	€ 760
Charging Hub	0	€ 0	0	0	235	€ 2,350

Figure 26 and Figure 38 illustrate the State of Charge (SOC) graphs and storage dispatch for one week in February and one week in July, respectively, as representative examples. Please refer to section 8.4 of the Appendix for a detailed illustration of the summer week. Table 5 assumes a C-rate of 0.5 for the storage units, as this rate offers optimal performance according to the findings of Bobanac et al. (2021). This is corroborated by the figures, which demonstrate that the storage dispatch for the charging hub is at most half of the total capacity, as confirmed by Figure 26. In these figures, a negative dispatch indicates the initiation of a charging process, while a positive dispatch indicates the commencement of a discharging process.

As illustrated in Figure 26 and Table 14, the largest storage units belong to Company 1 and the charging hub due to their substantial loads. The available capacity is frequently employed to recharge these storage units. For Company 1, most charging occurs at night with sufficient capacity. Solar energy can also be used during daylight hours to charge the storage unit; however, this is less common during winter due to limited solar generation. The efficiency of these storage units demonstrates their reliability in managing solar energy. The charging hub's state of charge (SOC) indicates that energy is retained until the early afternoon when its load peaks and requires energy from storage. Additionally, Company

1's SOC fluctuates throughout the day, likely due to its contribution to its load and that of other companies.

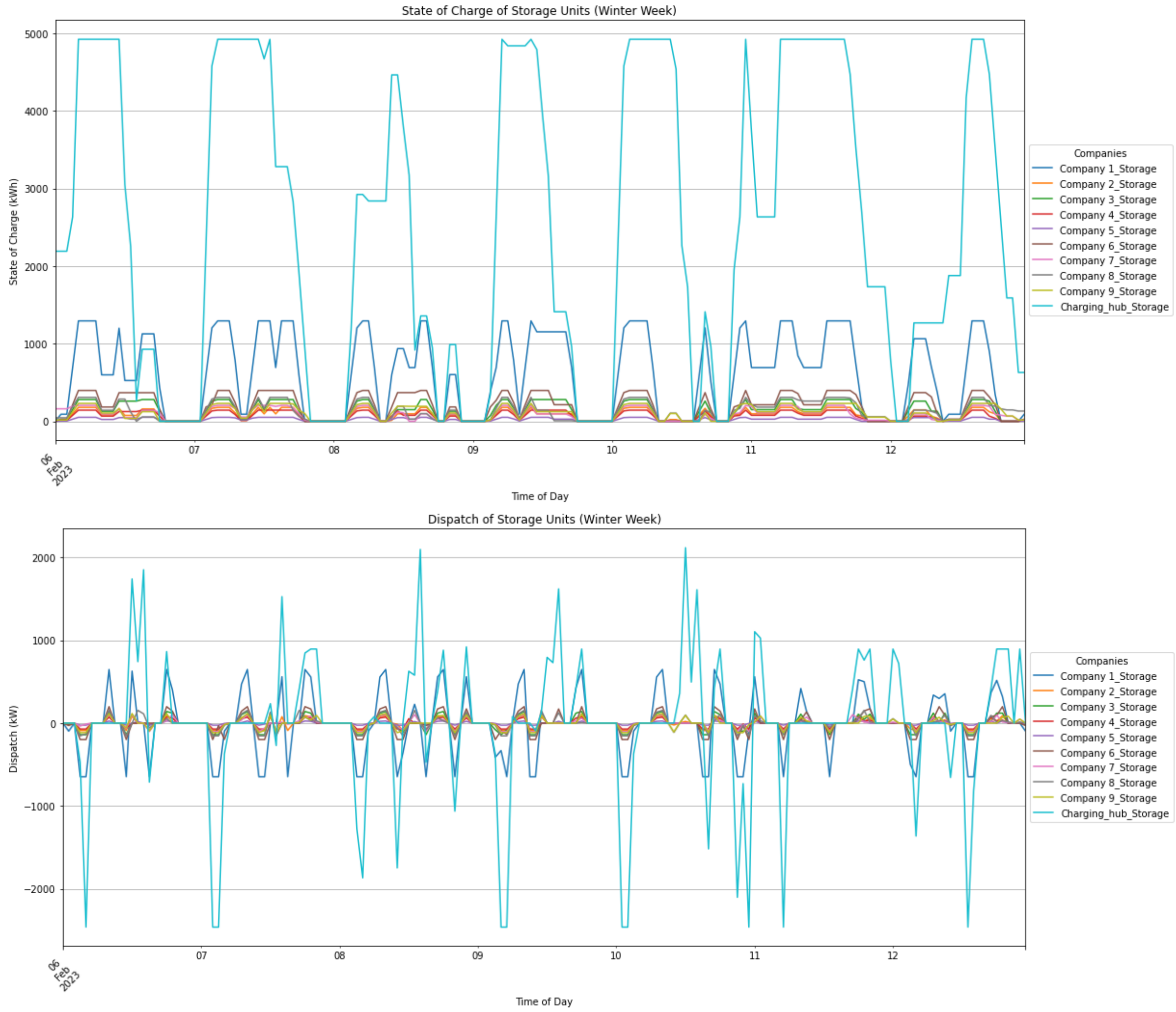

Figure 26: The upper graph illustrates the state of charge (SOC) of all companies' storage units and the charging hub over the seven days from February 6th to February 12th. The bottom graph illustrates the storage dispatch for the week above. The charts mention 2023, but it should be 2040. This could not be changed; otherwise, the code would not work.

Figure 27 illustrates how the charging hub load is supplied. In both the winter and summer weeks, the primary power sources are Company 1 and the system's storage unit. As illustrated in Figure 25, Company 1 possesses considerable residual capacity, enabling it to function as a power source. Notably, there is a distinction between the two seasons. During the summer months, other companies primarily supplement peak demand, whereas, in winter, the system's storage unit provides this support. This discrepancy can be attributed to the solar panels supplying power to the charging hub during summer. Furthermore, the data indicate that during the winter, the charging hub draws power from companies in the evenings, while during the summer, it draws power from its storage unit. This is due to the availability of solar energy. It is crucial to acknowledge that the power provided by the companies was not distinguished between the capacity derived from solar panels and that from storage units.

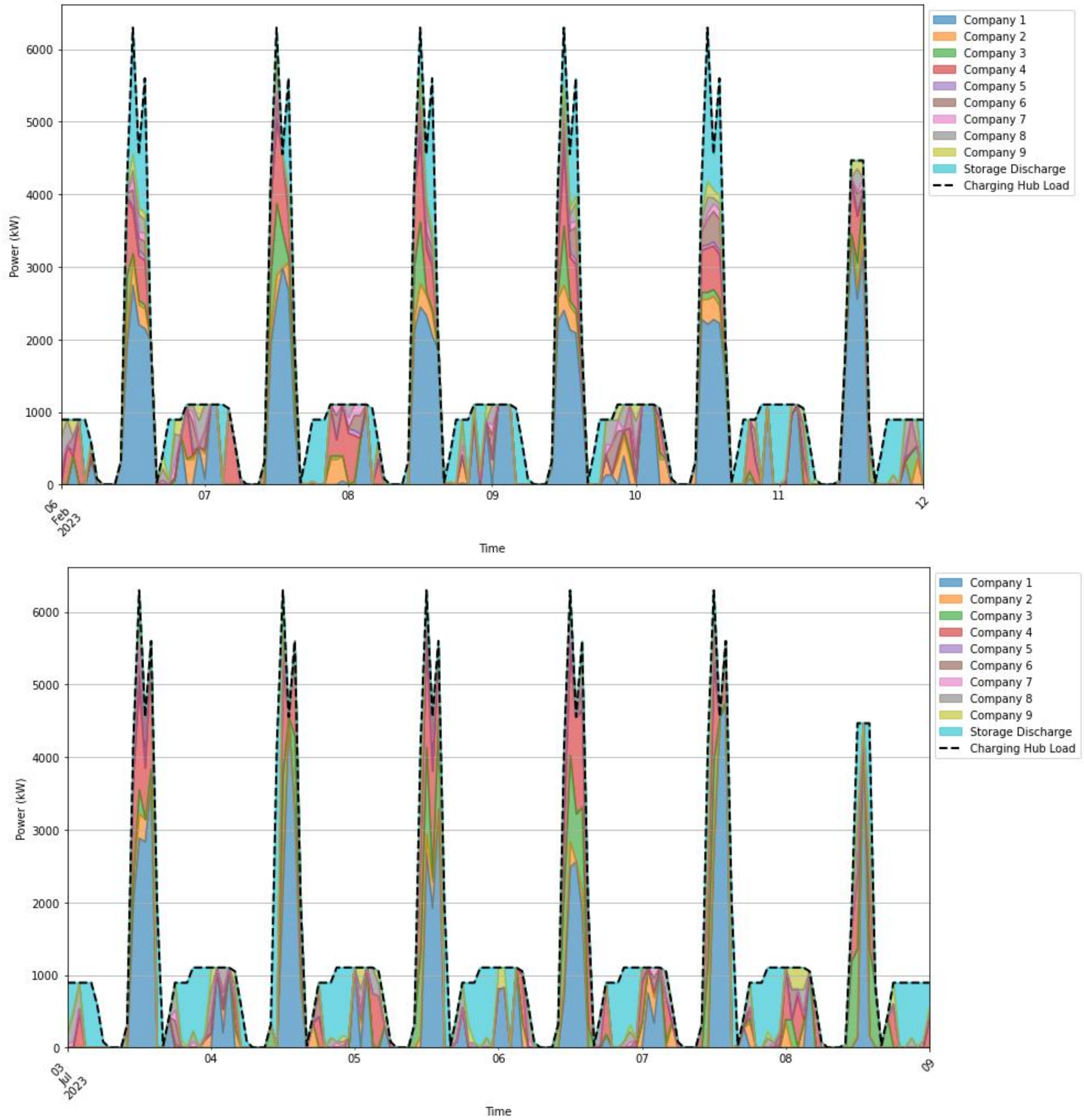

Figure 27: The upper graph showcases the crucial energy sources utilized by the charging hub during the winter week of February 6 to 12. The lower graph depicts the same for the summer week of July 3 to 9. The charts mention 2023, but it should be 2040. This could not be changed. Otherwise, the code would not work.

Table 14 presents the financial data about the investments and O&M costs associated with the storage and PV units. Meeting the business park's demands necessitates considerable storage capacity, which also requires a substantial financial investment. A substantial financial commitment to solar panel installations is also required, although this cost remains constant across all scenarios. It is, however, essential to note that these investments in solar panels are not merely financial; they are vital for ensuring the long-term sustainability of the business park.

Table 14: Storage and PV investments and O&M in the first congestion management scenario.

Company	Storage capacity (kWh)	Storage investment	Annual Storage O&M	PV capacity (kWp)	PV investment	Annual PV O&M

Company 1	1293	€ 646,739	€ 16,169	1,377	€ 963,900	€ 6,855
Company 2	179	€ 89,466	€ 2,237	50	€ 35,000	€ 250
Company 3	280	€ 13,874	€ 3,497	2,733	€ 1,913,100	€ 13,665
Company 4	143	€ 71,705	€ 1,793	1,748	€ 1,223,600	€ 8,740
Company 5	51	€ 25,387	€ 635	0	0	0
Company 6	397	€ 198,425	€ 4,960	258	€ 180,600	€ 1,290
Company 7	205	€ 102,252	€ 2,556	21	€ 14,700	€ 105
Company 8	308	€ 153,876	€ 3,847	593	€ 415,100	€ 2,965
Company 9	230	€ 115,051	€ 2,876	83	€ 58,100	€ 415
Charging Hub	4922	€ 2,461,000	€ 61,525	0	0	0

4.4. Congestion Management Scenario 2

In this second scenario, several assumptions are made. Firstly, it is assumed that all companies enter into a group transport agreement, which allows them to share offtake capacity. Secondly, this capacity can also be used for the charging hub. The charging hub now has a grid connection, a small solar field, and an independent storage unit. Load shedding remains a potential strategy if it is deemed necessary. Furthermore, both the companies and the charging hub can shift their load, which is advantageous because it allows them to move consumption to times when electricity prices are lower.

Implementing the group transport agreement effectively eliminates the necessity for individual capacity contracts. Instead, the overall capacity is determined by the combined peak load of all companies and their previous individual capacities. This shift considerably impacts the total capacity, as illustrated in Figure 28. A modest discrepancy is maintained between the total load peak and the group transport capacity, enabling companies to exceed their capacity in unforeseen circumstances without incurring immediate penalties. The capacity difference created by this group contract, shown in Figure 28 as the gap between the blue and red capacity lines, can be allocated to the charging hub's grid connection.

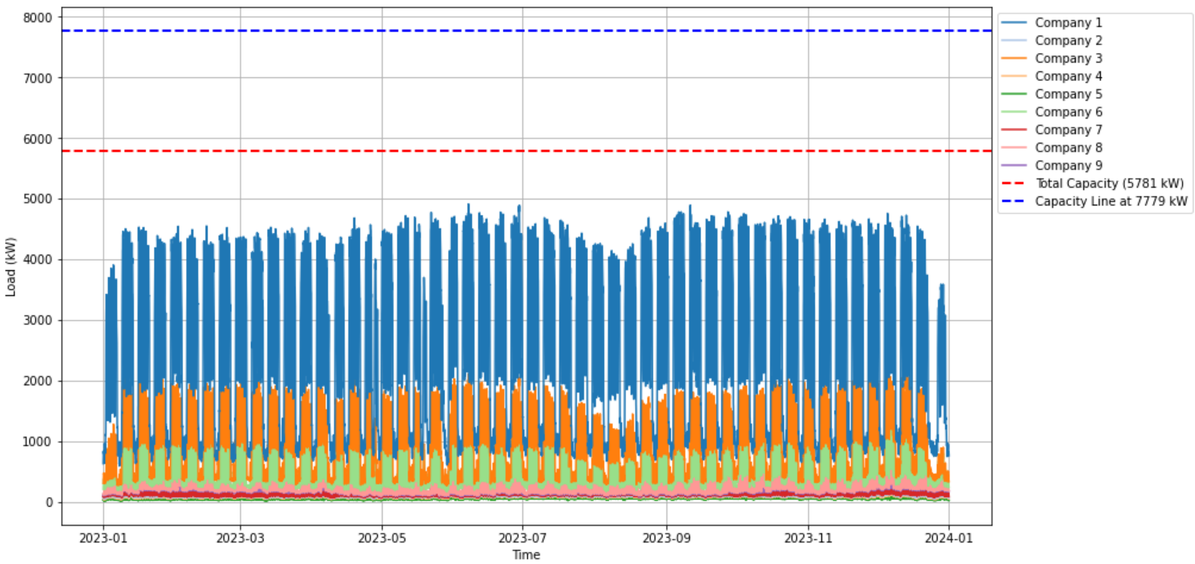

Figure 28: Effect of the group transport agreement. The significant difference between the red and blue capacity lines is used to measure the capacity of the charging hub connection.

As detailed in Section 3.2.4, load shifting provides cost savings in two main ways. First, downward load shifting negates the need to consume electricity during peak price periods by eliminating the need to purchase electricity at those specific times. Second, upward load shifting occurs during periods of low demand and reduced electricity prices, ensuring optimal cost efficiency. In addition, companies are motivated by the prospect of an electricity rebate, as shown in Table 15, which illustrates the cost savings of load shifting across all companies. The above savings were calculated using formulas 16 and 17.

In this scenario, the reduced storage capacity, limited to the charging hub unit, eliminates the possibility of storing excess electricity. In addition, the charging hub has a small solar field to generate additional power, but this restricts a significant amount of solar energy. As shown in Table 15 and Figure 39 in the Appendix, Section 8.5, a significant portion of the solar energy produced is curtailed, primarily due to unfavorable electricity prices, making it more cost-effective to purchase conventional electricity. In addition, companies cannot sell excess power back to the grid, which further contributes to the high level of curtailment.

Table 15: Grid-offtake, solar production, curtailment, and electricity costs with and without load shifting of the companies in the second congestion management scenario.

Company	Grid-offtake (kWh)	Annual electricity costs (Day ahead prices)	Annual electricity costs without shifting (Day ahead prices)	Difference in costs	Total used solar production (kWh)	Solar curtailment (kWh)
Company 1	15,264,000	€ 1,509,547	€ 1,531,197	€ 21,650	748,863	116,811
Company 2	404,207	€ 35,614	€ 37,137	€ 1,523	27,100	4,093
Company 3	3,161,000	€ 316,250	€ 322,898	€ 6,648	1,347,610	370,848
Company 4	448,676	€ 41,617	€ 43,584	€ 1,967	865,723	233,255
Company 5	460,739	€ 43,222	€ 44,205	€ 5,983	0	0
Company 6	2,064,640	€ 190,250	€ 196,285	€ 6,034	156,422	22,488
Company 7	383,889	€ 33,140	€ 35,327	€ 2,186	11,520	1,886
Company 8	715,953	€ 67,345	€ 71,295	€ 3,950	291,907	80,864
Company 9	800,059	€ 75,093	€ 78,121	€ 3,028	44,702	7,630
Charging Hub	7,555,980	€ 620,164	€ 651,890	€ 31,726	982,222	275,111

To determine which congestion measures are most effective in keeping the load below capacity, Figure 29 was constructed. During the summer, solar generation is sufficient to meet demand, reducing reliance on the grid. However, during the winter months, when solar output is low, load shedding, load shifting, and storage discharges are necessary to keep the grid load below capacity. These measures are also observed during the summer but to a much lesser extent. It is essential to recognize that load shifting is only viable for a portion of the total load and that the remaining portion must be significantly reduced to achieve the desired net load.

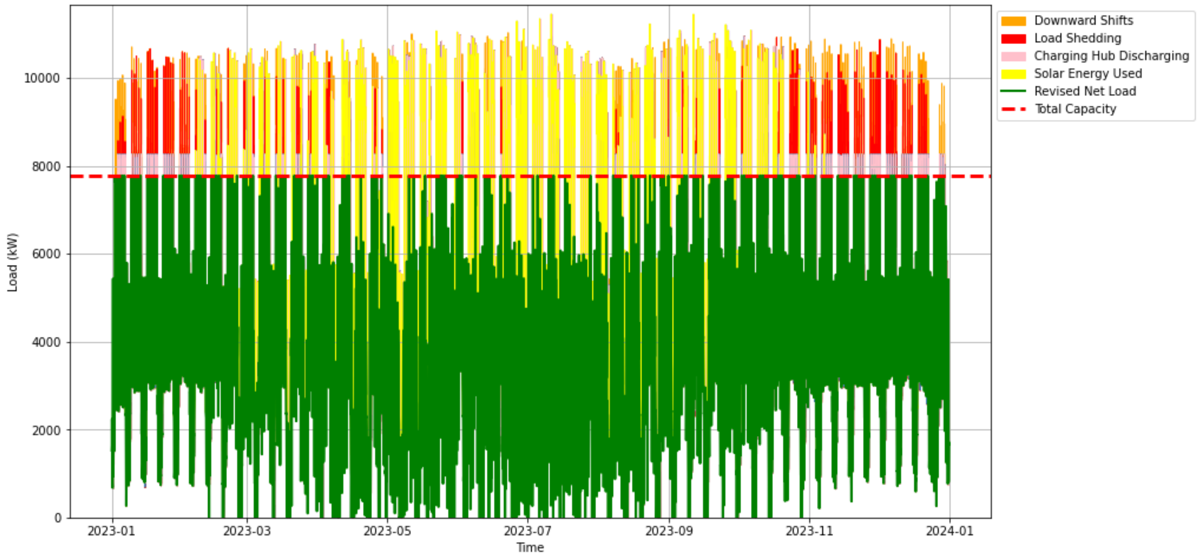

Figure 29: The business park's net load and the congestion management mechanisms and energy flows ensure the net load remains below capacity.

As noted above, a cost is associated with the upward shift during reduced electricity prices. The price reduction is so significant for many hours that it results in a negative electricity price. This ultimately results in a shift from costs to revenues, as shown in Table 16. However, this revenue is relatively modest compared to the total electricity expenditure. In addition, downshifting can generate savings, although this is not a significant result for all companies. Table 16 shows that the financial impact of load shedding is significant, with cases where these costs exceed those of electricity consumption.

Table 16: Total load shedding and shifting with the associated costs for each company in the second congestion management scenario.

Company	Load shedding (kWh)	Load shedding costs	Downward/upward shifting (kWh)	Upward shifting costs	Downward shifting savings
Company 1	24,887	€ 248,870	185,380	-€ 3,168	€ 18,482
Company 2	30,680	€ 306,800	13,362	-€ 197	€ 1,335
Company 3	24,294	€ 242,940	59,296	-€ 692	€ 5,956
Company 4	27,584	€ 275,840	17,441	-€ 194	€ 1,773
Company 5	3,351	€ 33,510	8,731	-€ 90	€ 893
Company 6	17,112	€ 171,120	54,227	-€ 652	€ 5,383
Company 7	39,420	€ 394,200	19,334	-€ 211	€ 1,975
Company 8	30,108	€ 301,080	35,227	-€ 390	€ 3,560
Company 9	22,074	€ 220,740	27,004	-€ 277	€ 2.751
Charging Hub	57,299	€ 572,990	303,252	-€ 1,022	€ 30,703

Figure 30 illustrates the times when companies shift their load up or down. The data shows downward shifting occurs during peak hours for Companies 1, 6, 8, and the Charging Hub, primarily in the afternoon and afternoons. These are when load levels are highest, but solar energy is unavailable, as the figure represents a typical winter week. Upward shifting occurs during periods of high-capacity availability, particularly at night when most businesses have lower loads, allowing unused capacity to be used. Figure 30 also shows that load shifting is unnecessary on weekends, as company and charging hub loads are lower than on weekdays.

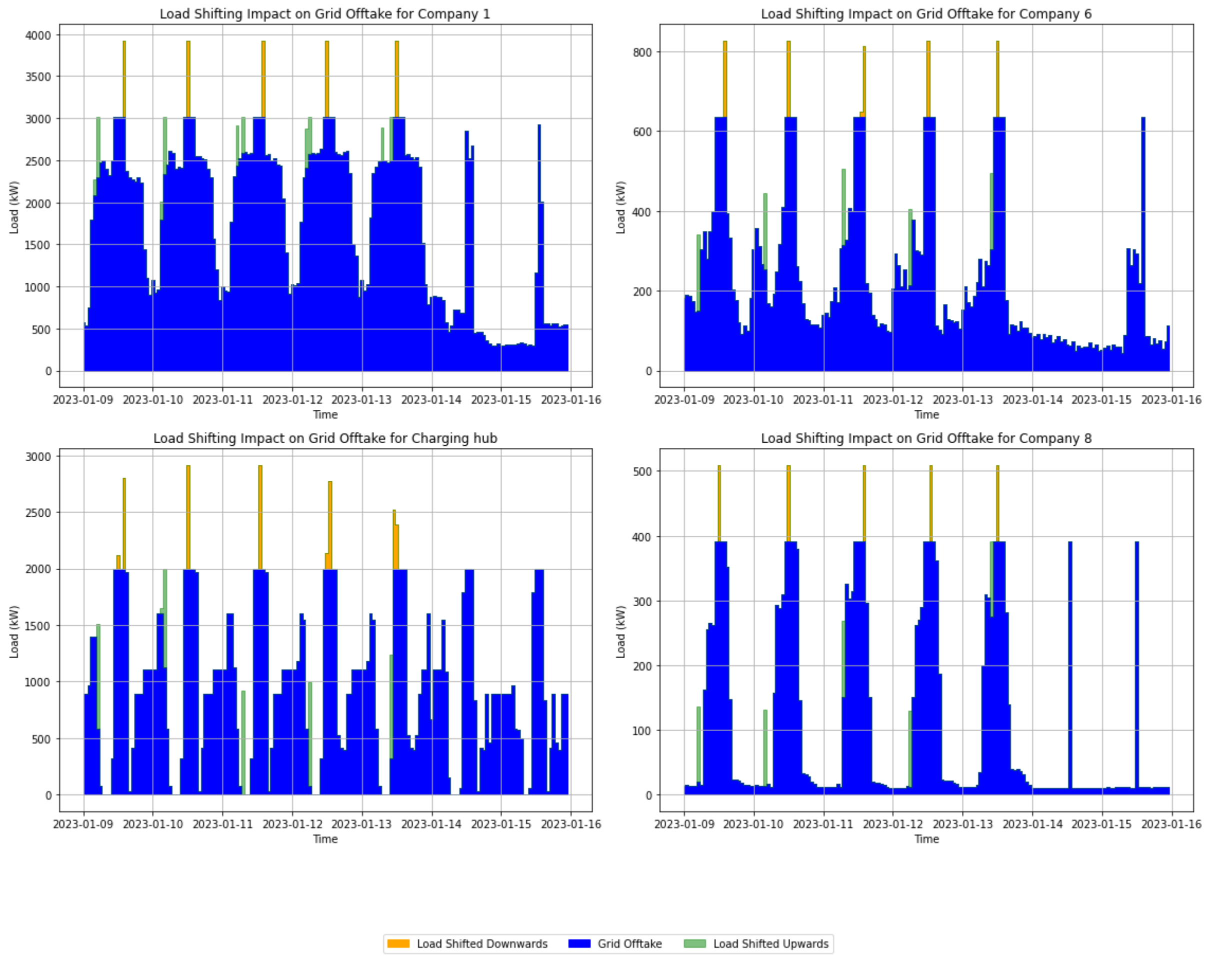

Figure 30: This graph shows the impact of upward and downward load shifting on the grid offtake. It shows data during the week of January 9 through 16. The charts mention 2023, but it should be 2040. This could not be changed; otherwise, the code would not work.

Due to the use of load shifting and load shedding strategies, the storage unit is utilized minimally, as shown in Table 17. It is important to note that the only storage unit is located at the charging hub, which now also has solar panels, a significant capital investment. This is a notable change from previous scenarios where no solar panels were installed for the charging hub.

Table 17: Storage and PV investments and O&M in the second congestion management scenario.

Company	Storage capacity (kWh)	Storage investment	Annual Storage O&M	PV capacity (kWp)	PV investment	Annual PV O&M
Company 1	0	€ 0	€ 0	1,377	€ 963,900	€ 6,855
Company 2	0	€ 0	€ 0	50	€ 35,000	€ 250
Company 3	0	€ 0	€ 0	2,733	€ 1,913,100	€ 13,665

Company 4	0	€ 0	€ 0	1,748	€ 1,223,600	€ 8,740
Company 5	0	€ 0	€ 0	0	0	0
Company 6	0	€ 0	€ 0	258	€ 180,600	€ 1,290
Company 7	0	€ 0	€ 0	21	€ 14,700	€ 105
Company 8	0	€ 0	€ 0	593	€ 415,100	€ 2,965
Company 9	0	€ 0	€ 0	83	€ 58,100	€ 415
Charging Hub	1000	€ 500,000	€ 12,500	2000	€ 1,400,000	€ 10,000

4.5. Congestion management Scenario 3

This scenario introduces a capacity market where capacity is allocated to companies hourly. The charging hub now has a grid connection, using the same solar field as in the previous scenario. Only Company 1 and the Charging Hub have storage units, and load shedding remains an option if necessary. In addition, only Company 1, the Charging Hub, and Company 4 can shift their load.

The capacity market optimizes the available capacity in the industrial park by allocating capacity based on the highest hourly load. This ensures that the company with the highest load at any given time receives the most capacity, as shown in Figure 31, resulting in a more equitable capacity distribution among companies. Previously, underutilized excess capacity is now used more efficiently, freeing up more capacity for the business park. Figure 31 compares Company 1 and Company 4, showing a significant difference between their allocated and initial capacity. Without the capacity market, much of this capacity would remain unused.

The charging hub, initially allocated limited capacity, receives additional capacity through the market, as shown in Table 18 and Figure 31. At night, when the total load is low, the charging hub receives significant capacity, even though its load is minimal during these hours, emphasizing the need for its storage unit. In addition, the average allocated capacity for the companies is much lower than their initial withdrawal capacity, indicating improved capacity utilization throughout the park. Figure 31 shows that for Companies 3, 6, 7, and 8, the allocated capacity is often equal to their initial capacity, suggesting that their initial allocations were well suited to their peak demand needs.

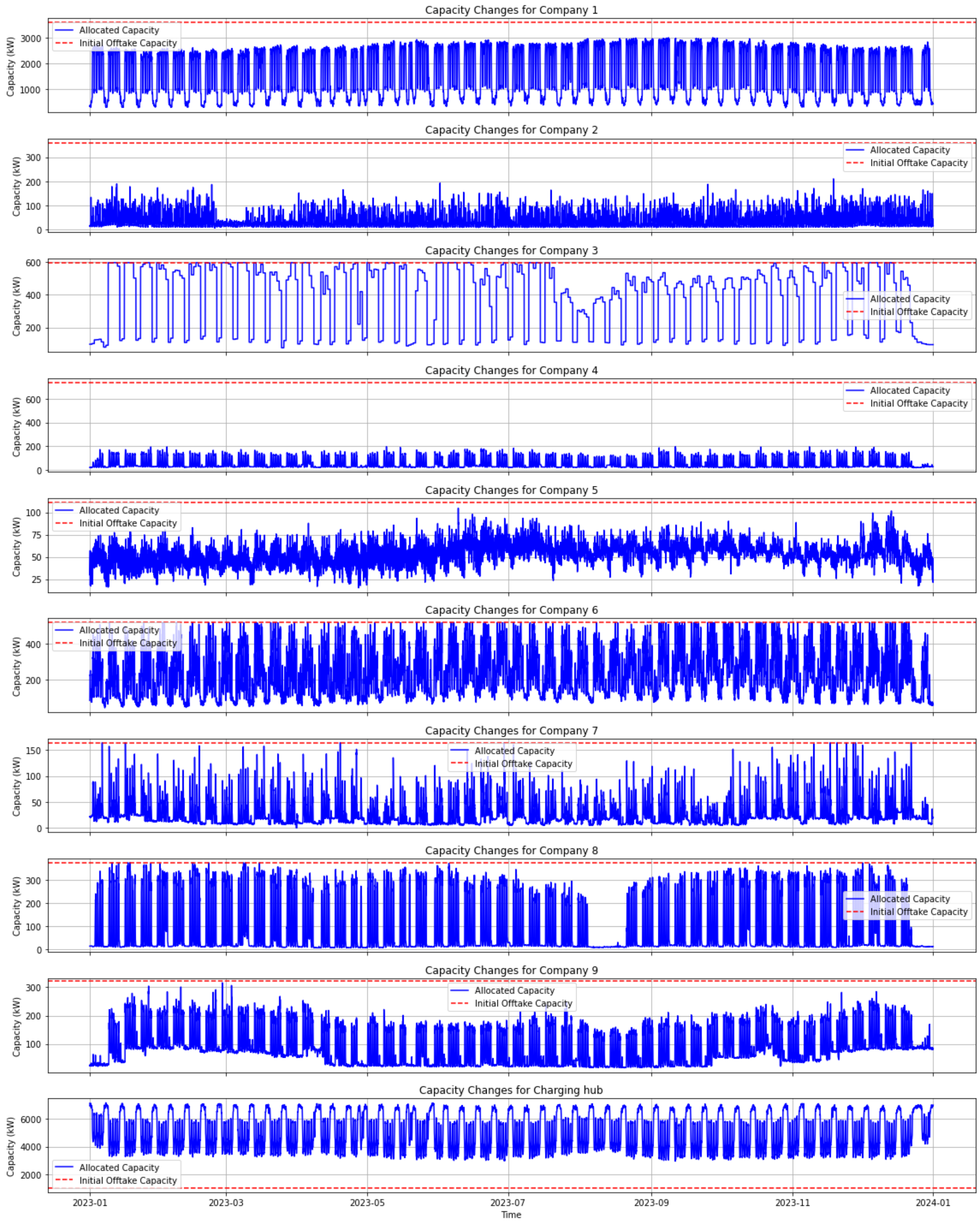

Figure 31: The graphs compare the allocated capacity obtained through the capacity market and the initiative offtake capacities of all companies.

Table 18: Initial and average capacities of the companies and the charging hub in congestion management scenario 3.

Company	Initial capacity off-take (kW)	Average allocated capacity (kW)

Company 1	3,600	1,722
Company 2	360	31
Company 3	597	387
Company 4	735	54
Company 5	111	54
Company 6	517	238
Company 7	164	29
Company 8	373	84
Company 9	322	86
Charging hub	1000	5094
Total	7,779	7,779

The ability of Company 1, Company 4, and the charging hub to shift their loads offers potential for electricity cost savings, although the savings are minimal. Table 19 shows a notable correlation between grid electricity consumption and costs for Company 1 and the charging hub, with Company 1 incurring higher average costs. The charging hub consumes electricity primarily during periods of high solar output when prices are low. In addition, the hub's storage unit is charged primarily at night, when capacity is plentiful and electricity prices are lowest, as shown in Figure 32, during the winter months.

During the summer, the storage is charged primarily during the middle of the day due to excess solar energy. When the storage is discharged at high prices, greater savings are achieved. However, despite the significant solar energy used to charge the hub's storage, much of the solar energy is still curtailed, especially during the summer, as shown in Table 19 and Figure 42 in section 8.6 of the Appendix. For some companies, this curtailment represents a large portion of their solar production. As in the previous scenarios, this is driven by negative summer electricity prices, making using grid power more cost-effective than solar power.

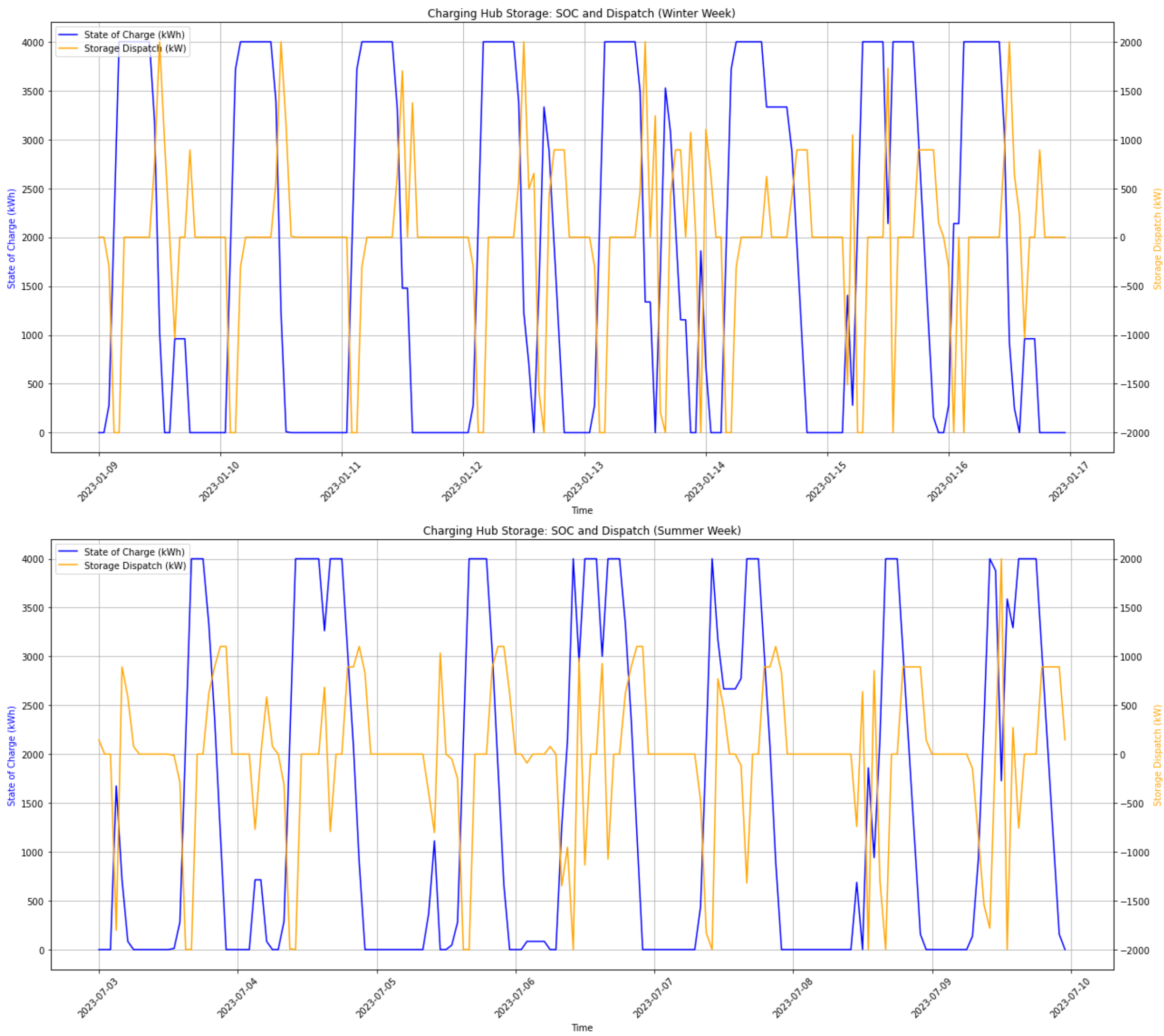

Figure 32: The upper graph depicts the SOC and dispatch of the charging hub's storage unit over seven days, from January 9th to February 16th. The bottom graph provides a similar illustration for the week of July 3 to 9. It should be noted that the charts in question refer to the year 2023, although the correct reference point is 2040. Such alterations would not be feasible otherwise, as the code would no longer function as intended.

Table 19: Grid-offtake, solar production, curtailment, and electricity costs with and without load shifting of the companies in the third congestion management scenario.

Company	Grid-offtake (kWh)	Annual electricity costs (Day ahead prices)	Annual electricity costs without shifting (Day ahead prices)	Difference in costs	Total used solar production (kWh)	Solar curtailment (kWh)
Company 1	14,457,000	€ 1,460,610	€ 1,473,160	€ 12,550	777,245	88,429
Company 2	248,117	€ 24,613	€ 24,613	€ 0	27,148	4,045
Company 3	2,940,610	€ 309,031	€ 309,031	€ 0	1,335,020	383,436
Company 4	357,812	€ 31,751	€ 37,159	€ 5,408	855,854	357,812
Company 5	413,603	€ 40,096	€ 40,096	€ 0	0	0
Company 6	1,753,150	€ 172,762	€ 172,762	€ 0	155,628	23,281

Company 7	205,234	€ 21,607	€ 21,607	€ 0	11,595	1,810
Company 8	540,930	€ 59,382	€ 59,382	€ 0	293,599	79,172
Company 9	631,243	€ 65,975	€ 65,975	€ 0	45,030	7,302
Charging Hub	9,718,490	€ 711,066	€ 726,768	€ 15,702	1,024,890	232,447

To evaluate which congestion measures are effective in keeping the load below capacity, Figure 33 was created. The figure shows that significant solar energy helps keep the load below capacity. Storage is also used effectively, especially in the winter and summer, to store excess electricity. Load shedding is used in the winter when solar generation is low, and electricity consumption is high. Load shifting occurs throughout the year, especially in winter, for the same reasons as load shedding. However, it represents a smaller portion of the total load because only a limited amount can be shifted, and only two companies and the charging hub can do so.

Figure 33: The business park's net load and the congestion management mechanisms and energy flows ensure the net load remains below capacity.

Figure 33 shows a significant reduction in load, especially in winter when solar generation is insufficient to meet demand. While effective, load shedding comes at a significant cost, as shown in Table 20. However, these costs are not borne by the companies and are included only to illustrate the impact. Load shifting also saves costs, although its impact on total electricity costs is limited.

Table 20: Total load shedding and shifting with the associated costs for each company in the third congestion management scenario.

Company	Load shedding (kWh)	Load shedding costs	Downward/upward shifting (kWh)	Upward shifting costs	Downward shifting savings
Company 1	42,277	€ 422,770	112,562	-€ 2,399	€ 10,151
Company 2	13,695	€ 136,950	0	€ 0	€ 0
Company 3	19,134	€ 191,340	0	€ 0	€ 0
Company 4	20,651	€ 206,510	51,884	-€ 215	€ 5,193
Company 5	1,782	€ 17,820	0	€ 0	€ 0

Company 6	14,071	€ 140,710	0	€ 0	€ 0
Company 7	4,354	€ 43,540	0	€ 0	€ 0
Company 8	9,254	€ 92,540	0	€ 0	€ 0
Company 9	7,731	€ 77,310	0	€ 0	€ 0
Charging Hub	49,998	€ 499,980	158,505	€ 89	€ 15,792

Table 20 and Figure 34 show that the load shift is relatively small compared to the total offtake. Company 1 experiences minimal load shifting, with an insignificant impact on its offtake. In contrast, Company 4 shifts a significant load due to its large initial offtake capacity, as the percentage that can be shifted is calculated on this basis. The use of solar energy also contributes to fluctuations in Company 4's dispatch, sometimes resulting in net-zero dispatch. Similarly, the charging hub's grid withdrawal varies daily due to the influence of storage, as storage dispatch fluctuates. Company 4 shows a significant upward load shift when sufficient spare capacity is available.

Figure 34: This graph shows the impact of upward and downward load shifting on the grid offtake. It shows data during the week of February 11 through 17. The charts mention 2023, but it should be 2040. This could not be changed; otherwise, the code would not work.

The investment and O&M costs for the storage and PV systems have remained unchanged compared to the previous scenario. A storage unit was incorporated into the system, and the capacity of the charging hub's storage unit was augmented, as illustrated in Table 21. This consequently entails a greater investment in storage and O&M than in the preceding scenario.

Table 21: Storage and PV investments and O&M in the third congestion management scenario.

Company	Storage capacity (kWh)	Storage investment	Annual Storage O&M	PV capacity (kWp)	PV investment	Annual PV O&M
Company 1	500	€ 250,000	€ 6,250	1,377	€ 963,900	€ 6,855
Company 2	0	€ 0	€ 0	50	€ 35,000	€ 250
Company 3	0	€ 0	€ 0	2,733	€ 1,913,100	€ 13,665
Company 4	0	€ 0	€ 0	1,748	€ 1,223,600	€ 8,740
Company 5	0	€ 0	€ 0	0	€ 0	€ 0
Company 6	0	€ 0	€ 0	258	€ 180,600	€ 1,290
Company 7	0	€ 0	€ 0	21	€ 14,700	€ 105
Company 8	0	€ 0	€ 0	593	€ 415,100	€ 2,965
Company 9	0	€ 0	€ 0	83	€ 58,100	€ 415
Charging Hub	4000	€ 2,000,000	€ 56,250	2000	€ 1,400,000	€ 10,000

4.6. Comparative analysis

This section compares and ranks the three market-based congestion management mechanisms, focusing on key metrics such as grid offtake, storage and PV capacity, load shifting, load shedding, and investment and operating costs, as shown in Tables 22 to 26.

Grid offtake and electricity costs

As shown in Table 22, Scenario 1 has the highest grid usage and cost. This is because the charging hub is not connected to the grid and relies on the company's storage units to meet its electricity needs. The additional grid-supplied electricity is required to account for storage losses. Scenario 2 has lower grid usage but higher electricity costs, primarily because load shifting occurs during high-cost periods. In contrast, Scenario 3 achieves a more balanced outcome by reducing grid dependency through capacity sharing, enabling companies to manage their electricity demand more efficiently, thereby reducing overall grid usage and electricity costs.

Table 22: The three congestion management scenarios' grid offtake and electricity costs.

	Scenario 1		Scenario 2		Scenario 3	
	Grid-offtake (kWh)	Annual electricity costs (Day ahead prices)	Grid-offtake (kWh)	Annual electricity costs (Day ahead prices)	Grid-offtake (kWh)	Annual electricity costs (Day ahead prices)
Total	**32,815,413**	**€ 2,946,186**	**31,259,143**	**€ 2,932,242**	**31,266,189**	**€ 2,896,893**

Storage and PV capacity

Table 23 shows that Scenario 1 leads in storage capacity because each company and the Charging Hub have storage units. However, it lags in PV capacity because the charging hub has no solar generation. Scenario 2 adds PV capacity to the charging hub but has less storage capacity and relies more on load shifting and load shedding. Scenario 3 optimally combines storage and PV capacity with the Charging Hub and Company 1 equipped with storage units benefiting from solar panels, making it highly efficient at managing solar energy and reducing curtailment.

Table 23: Storage and PV capacity of the three congestion management scenarios.

	Scenario 1		Scenario 2		Scenario 3	
	Storage capacity (kWh)	PV capacity (kWp)	Storage capacity (kWh)	PV capacity (kWp)	Storage capacity (kWh)	PV capacity (kWp)
Total	**8,008**	**6,863**	**1,000**	**8,863**	**4,500**	**8,863**

PV generation and curtailment

According to Table 24, Scenario 1 has the lowest solar curtailment due to its high storage capacity, which allows more solar energy to be stored and used. However, the total solar energy utilization remains limited due to the lower PV capacity. In Scenarios 2 and 3, the solar energy utilization is nearly identical. However, Scenario 2 more effectively minimizes curtailment through upward load shifting during solar generation peaks, maximizing the use of available solar energy.

Table 24: PV generation and curtailment of the three congestion management scenarios.

	Scenario 1		Scenario 2		Scenario 3	
	Total used solar production (kWh)	Solar curtailment (kWh)	Total used solar production (kWh)	Solar curtailment (kWh)	Total used solar production (kWh)	Solar curtailment (kWh)
Total	**3,739,489**	**592,228**	**4,476,069**	**1,112,986**	**4,526,009**	**1,177,734**

Load shifting and load shedding.

As shown in Table 25, Scenario 1 relies primarily on storage, eliminating the need for load shedding or shifting. In contrast, Scenario 2 relies heavily on load shifting and shedding due to limited storage, resulting in higher operating costs. Scenario 3 takes a more balanced approach, combining load shifting with storage, reducing reliance on load shedding, and keeping operating costs lower than Scenario 2.

Table 25: Load shifting and shedding with their associated costs of the three congestion management scenarios.

	Scenario 1		Scenario 2		Scenario 3	
	Load shedding (kWh)	Downward/ upward shifting (kWh)	Load shedding (kWh)	Downward/ upward shifting (kWh)	Load shedding (kWh)	Downward/ upward shifting (kWh)
Total	**0**	**0**	**276,809**	**723,254**	**182,947**	**322,951**
	Load shedding costs	**Load shifting savings (including upward**	**Load shedding costs**	**Load shifting savings (including**	**Load shedding costs**	**Load shifting savings (including**

		shift costs)		upward shift costs)		upward shift costs)
Total	**€ 0**	**€ 0**	**€ 2,768,090**	**€ 84,695**	**€ 1,829,470**	**€ 33,660**

Investments and annual costs

In Table 26, Scenario 1 has the highest initial investment costs due to the extensive use of storage units. However, its operating costs are the lowest because storage minimizes the need for load shedding. Scenario 2 has the lowest initial investment but the highest annual costs because frequent load shedding increases operating costs. Scenario 3 strikes the best balance between initial investment and operating costs by using a capacity market to efficiently allocate resources, reduce load shedding, and lower ongoing costs.

Table 26: The investment and annual costs of congestion management scenarios. The annual costs include the electricity and O&M costs and the load-shedding costs.

	Scenario 1		Scenario 2		Scenario 3	
	Total investments (storage +PV)	Total annual costs (electricity, O&M, load shedding)	Total investments (storage +PV)	Total annual costs (electricity, O&M, load shedding)	Total investments (storage +PV)	Total annual costs (electricity, O&M, load shedding)
Total	**€ 8,681,875**	**€ 3,080,566**	**€ 6,704,100**	**€ 5,757,117**	**€ 8,454,100**	**€ 4,833,148**
Total	€ 11,762,441		€ 12,461,217		€ 13,287,248	

Ranking

Scenario 3 emerges as the most effective solution for managing grid congestion, offering a balanced approach combining moderate investment and lower operating costs. It optimizes the use of storage, PV generation, and load shifting while introducing a capacity market to ensure the efficient allocation of resources. This makes Scenario 3 the most sustainable and viable long-term strategy for the Goor Business Park. While Scenario 1 minimizes annual costs, its high initial investment in storage and reliance on grid power limits its practicality. Scenario 2, with the lowest upfront investment, is the least viable in the long term due to its reliance on frequent load shedding, which drives up operating costs. Therefore, Scenario 3 is the most appropriate congestion management mechanism, providing a scalable, flexible solution to reduce grid congestion while supporting the park's energy needs.

5. Discussion

This section not only presents the research study's limitations and discusses further theoretical and practical implications but also highlights the potential for future research to make significant contributions to the field.

5.1. Limitations

The model's outcomes are contingent upon the nature of the input data. Although the load profiles of the companies are authentic and enable realistic results, assumptions had to be made regarding future load profiles, particularly about the increased electricity demand resulting from heat demand. A more precise assumption could have been formulated by employing authentic profiles, such as those about heat pumps, to more accurately capture the timing and magnitude of the projected increase in demand. The assumption that all companies will install heat pumps demonstrates the potential impact on grid congestion; however, incorporating more specific data would improve the model's accuracy.

Furthermore, utilizing a normalized profile for solar panel generation impacts the results, as it does not fully reflect actual conditions. Due to the unavailability of empirical data, the reliance on constructed profiles for electric truck and van charging also affects the validity of the findings. The use of non-real-time data, while necessary, compromises the external validity of the model, as it may not fully represent future energy consumption patterns.

A further limitation is that only one year of data was utilized for analysis due to the inherent difficulty of forecasting future consumption, generation, and electricity prices over several years. As the model applied 2023 prices to a prospective 2040 scenario using generation data in 2018, any discrepancies between these datasets can significantly affect the results. Including data from multiple years in the analysis would provide a more robust reflection of reality and facilitate a more comprehensive understanding of long-term impacts.

The model used in this research is a simplified representation of real-world conditions. It assumes that all businesses in the business park are connected to a single medium-voltage ring, whereas there may be multiple rings. A more complex network would allow for greater accuracy and a more complex model. The decision to simulate a single ring was based on the unavailability of comprehensive data and the inherent complexity of modeling multiple rings. In addition, the model assumes that all companies have access to day-ahead electricity prices, which is not always the case, as companies may have different pricing agreements or time-of-use tariffs. Another simplification is that the model does not consider the total capacity of the medium-voltage substation, which is often a key location where congestion occurs due to insufficient capacity. This assumption limits the model's ability to capture potential congestion at the station level in real-world scenarios. Despite these simplifications, the study provides valuable insights into the effectiveness of congestion management mechanisms within the constraints of a medium-voltage ring.

It should be noted that this research is a case study, which inherently limits its generalizability. Nevertheless, the model can be adapted to different datasets, enabling its application to other business parks or areas. Including a greater variety of company profiles could enhance the study's generalizability. Notwithstanding these constraints, the study effectively illustrates the influence of market-based congestion management strategies and their associated techno-economic consequences.

5.2. Theoretical and practical implications

This research makes a notable contribution to the existing literature on market-based congestion management mechanisms by applying theoretical concepts to a practical case study in the Goor Business Park. While existing studies, such as those by Asija et al. (2018) and Keyvani & Flynn (2022), concentrate on larger systems or more theoretical applications, this research demonstrates how market-based solutions can be implemented on a local level to address the often-overlooked issue of congestion in business parks.

The Python Model for Power System Analysis (PyPSA) simulates and optimizes modern power systems, and this study used it for medium-voltage networks. In contrast to other research using this model, which has concentrated on macro-grid solutions, this study focuses on micro-grid environments, providing empirical evidence on the practical application of these mechanisms in situations where grid expansion is delayed and investment costs are high. Furthermore, this study illustrates that market-based mechanisms can serve as a viable alternative to costly infrastructure upgrades in alignment with EU directives that aim to enhance grid flexibility. By providing a comprehensive techno-economic assessment, this thesis addresses a significant gap in the existing literature on the practical implementation of congestion management strategies in industrial parks. These parks are critical to the energy transition, given their high demand and potential for renewable energy integration.

From a practical standpoint, grid operators may adopt market-based congestion mechanisms, such as local flexibility markets, as a cost-effective alternative to grid expansion. These mechanisms facilitate the optimization of load management and the more efficient utilization of existing capacity. Furthermore, business park managers could benefit from shared energy resources, particularly solar energy and storage systems, to effectively balance supply and demand, thereby reducing overall costs. It is recommended that policymakers promote market-based solutions by providing incentives and establishing appropriate regulatory frameworks. This approach will help facilitate the energy transition while avoiding the delays and high costs typically associated with large-scale grid expansions. This research highlights the significance of these solutions in addressing congestion issues, which, if unresolved, could impede economic growth and environmental objectives.

5.3. Future research

Although this research demonstrates the effectiveness of market-based congestion management mechanisms, future research should explore alternative mechanisms, such as locational marginal pricing (LMP) and the GOPACS platform. LMP prices electricity based on location, accounting for grid limitations and congestion costs, offering a more targeted congestion management approach where grid capacity varies across nodes (Huang et al., 2014). Similarly, further investigation into the potential of GOPACS, which is currently employed in the Netherlands to address local congestion, may be warranted, given its capacity to facilitate flexible transactions between grid users (GOPACS foundation, 2023). Future research should compare these mechanisms' techno-economic performance with the market-based solutions explored here to determine their relative strengths and weaknesses.

Furthermore, expanding the geographic scope of the analysis is particularly important for assessing the performance of mechanisms such as LMP designed to work more effectively in extensive and complex networks. LMP could prove beneficial in regions where electricity consumption patterns are diverse, and congestion is more spatially distributed, areas that may be beyond the capabilities of local flexibility markets. A larger geographic study area would allow for a more accurate evaluation of LMP, as it relies on location-based pricing and grid constraints that are more apparent in larger, more complex networks (Hennig et al., 2023). This could provide deeper insights into optimizing congestion management strategies that take advantage of regional demand shifts and generation flexibility.

In addition, conducting more case studies in different economic zones or regions could further validate these mechanisms. Exploring different grid infrastructures, consumption patterns, and energy policies would help assess the adaptability of market-based mechanisms in different real-world contexts. This combined approach of a broader geographic scope for LMP and additional case studies would increase the robustness of the results and provide broader applicability.

Future studies would be beneficial in investigating hybrid congestion management solutions that combine market-based mechanisms with selective grid reinforcements. Such approaches could achieve a balance between cost minimization and congestion reduction. Additionally, research into the behavioral responses of firms to market incentives like dynamic pricing and capacity contracts could provide valuable insights into how to improve participation and commitment to congestion management schemes. Understanding these behavioral dynamics is essential for optimizing the effectiveness of market-based mechanisms and ensuring their adoption across various sectors.

6. Conclusion

This research developed a comprehensive model using the Python for Power System Analysis (PyPSA) platform to assess the cost-effectiveness and operational viability of diverse market-based congestion management strategies within the Goor Business Park, including capacity markets and dedicated capacity contracts. By focusing on a localized environment, the study provided insights into the practical application of these mechanisms, particularly in areas experiencing delayed grid expansions and high investment costs for these expansions.

The analysis compared three distinct congestion management scenarios, each offering a different strategy for reducing grid congestion. Following an evaluation of key metrics, including grid offtake, storage capacity, PV generation, load shifting, load shedding, and associated investment and operational costs, Scenario 3 was identified as the optimal solution for managing grid congestion at the business park.

Scenario 3 introduces a capacity market whereby grid capacity is allocated to companies hourly. This ensures that grid limits are respected and congestion is minimal. The charging hub is allocated a specific capacity from the market, thus ensuring that the grid is not overloaded. As in scenario 2, solar energy is generated at the charging hub, while only one company and the charging hub are equipped with storage units. The storage systems permit the accumulation of surplus solar energy during periods of high generation, which can then be utilized during peak demand. This reduces the necessity for reliance on the grid. Furthermore, load shifting is permitted for the charging hub, and two other companies, enabling them to adjust their energy consumption during periods of high demand, thus further alleviating grid congestion. Load shedding remains a potential strategy, but its implementation is mitigated by utilizing storage and load shifting.

Scenario 3 is distinguished from the others by its compelling combination of dynamic capacity allocation, storage, and load shifting, which results in reduced operational costs compared to the other scenarios. Although Scenario 1 has the lowest annual costs due to the extensive utilization of storage units, its considerable initial investment costs and heightened reliance on grid offtake render it less feasible. In contrast, Scenario 2 necessitates a reduced initial investment but entails considerably elevated operational costs due to the frequent implementation of load shedding. Scenario 3 represents a compromise between the other scenarios, with moderate initial investment costs and reduced operational expenses. It optimizes the use of storage and solar energy.

This scenario presents a viable and sustainable methodology for reducing grid congestion, particularly in a medium-voltage network like Goor Business Park. By leveraging capacity markets to allocate grid resources dynamically and integrating targeted storage and load-shifting mechanisms, Scenario 3 minimizes the necessity for costly infrastructure upgrades. These findings have significant implications for grid operators, business park managers, and policymakers. For grid operators, utilizing capacity markets provides a flexible and cost-effective means of managing grid congestion. Furthermore, business park managers benefit from shared energy resources, such as solar panels and storage systems, which optimize energy use. It would be prudent for policymakers to consider promoting capacity markets and promoting storage solutions to support the energy transition and manage the growing demand for electricity without the necessity for extensive grid expansion.

In conclusion, Scenario 3 represents the optimal market-based congestion management mechanism for the Goor Business Park. This approach balances investment costs, operational efficiency, and congestion reduction, offering a scalable solution that supports the energy transition's economic and environmental goals. This study offers a framework for implementing market-based mechanisms in analogous business park contexts, facilitating a more flexible and sustainable future for energy systems at the medium-voltage level.

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8. Appendix

8.1. Imbalance price and direction of payment

During ISP with	Imbalance position BRP	Imbalance price	Direction of payment
Regulation state 0	BRP shortage	P_{mid} (+)	BRP → TSO
		P_{mid} (-)	TSO → BRP
	BRP surplus	P_{mid} (+)	TSO → BRP
		P_{mid} (-)	BRP → TSO

During ISP with	Imbalance position BRP	Imbalance price	Direction of payment
Regulation state +1	BRP shortage	P_{up} (+)	BRP → TSO
		P_{up} (-)	TSO → BRP
	BRP surplus	P_{up} (+)	TSO → BRP
		P_{up} (-)	BRP → TSO

During ISP with	Imbalance position BRP	Imbalance price	Direction of payment
Regulation state -1	BRP shortage	P_{down} (+)	BRP → TSO
		P_{down} (-)	TSO → BRP
	BRP surplus	P_{down} (+)	TSO → BRP
		P_{down} (-)	BRP → TSO

During ISP with	Imbalance position BRP	Imbalance price		Direction of payment
Regulation state 2	BRP shortage	$P_{up} \geq P_{mid}$	P_{up} (+)	BRP → TSO
			P_{up} (-)	TSO → BRP
		$P_{up} < P_{mid}$	P_{mid} (+)	BRP → TSO
			P_{mid} (-)	TSO → BRP
	BRP surplus	$P_{down} \leq P_{mid}$	P_{down} (+)	TSO → BRP
			P_{down} (-)	BRP → TSO
		$P_{down} > P_{mid}$	P_{mid} (+)	TSO → BRP
			P_{mid} (-)	BRP → TSO

A complete overview of the imbalance price and the direction of payment depending on the regulation state and the imbalance position of the BRP. Information retrieved from (Tennet, 2022).

8.2. Solar energy input data

Table 27 lists the input data used to create the generation profiles of the solar panels. The dimensions and power of the solar panels are taken from a Hyundai solar panel (Hyundai Energy Solutions, 2022). The full-load hours are the number of hours in a year that the renewable resources, in this case, the solar panels, produce electricity at their maximum capacity (ECN & TNO, 2019). There is a difference in full-load hours for south-facing and east-west-facing solar panels.

Formula 18 was also used to create the generation profile. Namely, the inverter's startup and default power were considered. The moment the solar panels produce less power than the inverter's startup power, the inverter is not turned on, and the solar energy is not converted. The moment the solar panels produce enough power, the solar energy is converted based on the inverter's standard power.

Table 27: Input data used for the generation profiles of the solar panels.

What	Value	Unit	Source
Size of solar panel	1.98	M^2	(Hyundai Energy Solutions, 2022)
Power solar panel	410	Wp	(Hyundai Energy Solutions, 2022)
Full-load hours (east-west orientation)	890	hours	(ECN & TNO, 2019)
Inverter power (as a percentage of power solar panels)	85	%	Own experience Arcadis
Inverter startup power (as a percentage of inverter power)	7.5	%	Own experience Arcadis

$$IF\left((normalized\ profile\ (t) * P * Fh) > IP_s, MIN(IP, normalized\ profile\ (t) * P * Fh), 0\right) \quad (18)$$

Where P is the total output of the solar panels, Fh stands for full-load hours, and IP_s and IP are the inverter's startup and standard power.

8.3.Future scenario

This research assumes that the business park will be analyzed in 2040, with the power grid's capacity remaining unchanged until then. Consequently, contractual obligations about off-take and feed-in remain fixed, precluding the possibility of an expansion in electricity consumption. Nevertheless, prospective sustainability stipulations will necessitate a reduction in CO_2 emissions on the part of companies. It is thus postulated that businesses in the park will install solar panels, electrify their heat demand by utilizing technologies such as heat pumps, and adopt electric vehicles, which will be charged at a shared hub.

As previously stated in the methodology, it is assumed that there will be a 47% increase in electricity consumption due to the electrification of heat demand (TNO, 2023). This assumption was necessary due to the substantial alterations to the electricity profile inherent to heat pump usage. However, since no empirical data is available to predict these profile changes, we assume that the overall increase in consumption will occur without alteration to the daily profile. Table 28 summarizes the impact of these sustainability measures, indicating that both electricity consumption and peak power demand are expected to increase. However, the capacity contracts for offtake remain unchanged, resulting in several companies exceeding their contracted peak demand, as illustrated in Figure 35. Furthermore, introducing a charging hub with considerable electricity consumption intensifies the issue. Due to grid congestion, the charging hub cannot secure a grid connection, resulting in a lack of contracted capacity. Consequently, alternative solutions are necessary to power the charging hub, or electric vehicles cannot charge. Table 28 further illustrates the elevated peak demand of the charging hub, particularly when multiple vehicles are charging simultaneously. However, this represents an extreme scenario that is unlikely to occur frequently.

Figure 35: The load of the four companies with the largest offtake capacity in the future scenario.

Table 28: Overview of electricity consumption of the companies in the future scenario.

Company	Contracted capacity off-take (kW)	Annual electricity consumption (kWh)	Peak power demand (kW)
Company 1	4600	15,091,862	3016
Company 2	360	273,360	210
Company 3	597	3,420,985	670
Company 4	735	472,494	197
Company 5	111	473,483	105
Company 6	517	2,088,352	635
Company 7	164	252,793	233
Company 8	373	732,212	391
Company 9	322	753,675	316
Charging Hub	0	12,051,717	6298

It is presumed that companies will install solar panels as part of their sustainability initiatives. The entire roof area, as calculated by RVO et al. (n.d.), will be dedicated to this objective. Nevertheless, only one company has a feed-in capacity contract, which precludes the remaining companies from feeding excess energy into the grid. Consequently, any surplus solar energy must be curtailed. Table 29 illustrates the capacity and production of the installed solar panels, highlighting notable discrepancies between energy generation and the amount curtailed, particularly for Companies 3, 4, and 8. Figure 36 further proves that a significant proportion of the business park's total solar energy production is curtailed. This phenomenon occurs because solar generation often peaks when company demand is at its lowest, and solar output can exceed the peak electricity demand. Without a feed-in contract, these companies cannot return surplus energy to the grid. One potential solution is to size the solar panel installations following the electricity demand of each company. However, this may not fully leverage the available roof space for solar generation. Therefore, it is imperative to identify solutions that will optimize solar energy utilization while reducing curtailment.

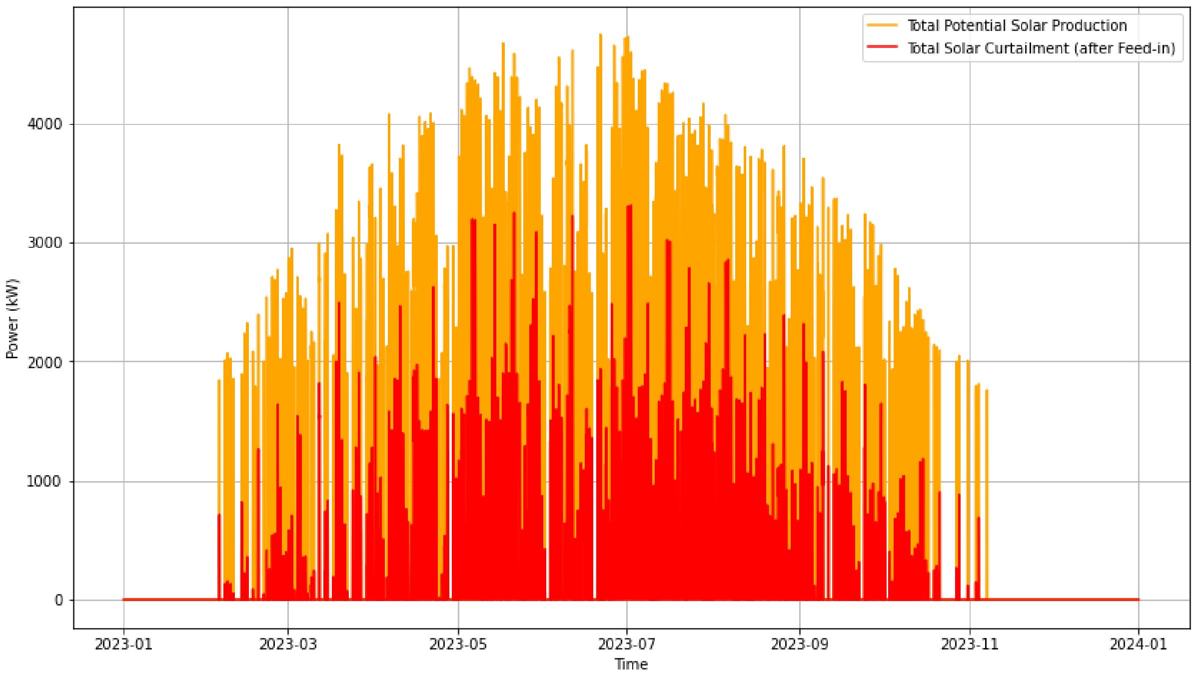


Figure 36: All companies' total solar production and curtailment in the future scenario.

Table 29: Solar energy data in the future scenario.

Company	Contracted capacity feed-in (kW)	PV capacity (kWp)	Total potential solar production (kWh)	Solar curtailment (kWh)	Solar energy used (kWh)
Company 1	0	1,377	865,674	48,922	816,752
Company 2	0	50	31,193	1,201	29,992
Company 3	0	2,733	1,718,460	1,134,160	584,300
Company 4	0	1,748	1,098,980	959,363	139,617
Company 5	0	0	0	0	0
Company 6	500	258	178,909	6,566	172,343

Company 7	0	21	13,405	716	12,689
Company 8	0	593	372,771	157,956	214,815
Company 9	0	83	52,332	3,921	48,411
Charging Hub	0	0	0	0	

8.4. Congestion Management Scenario 1

Figure 37 displays the total used solar production and curtailment of all the companies.

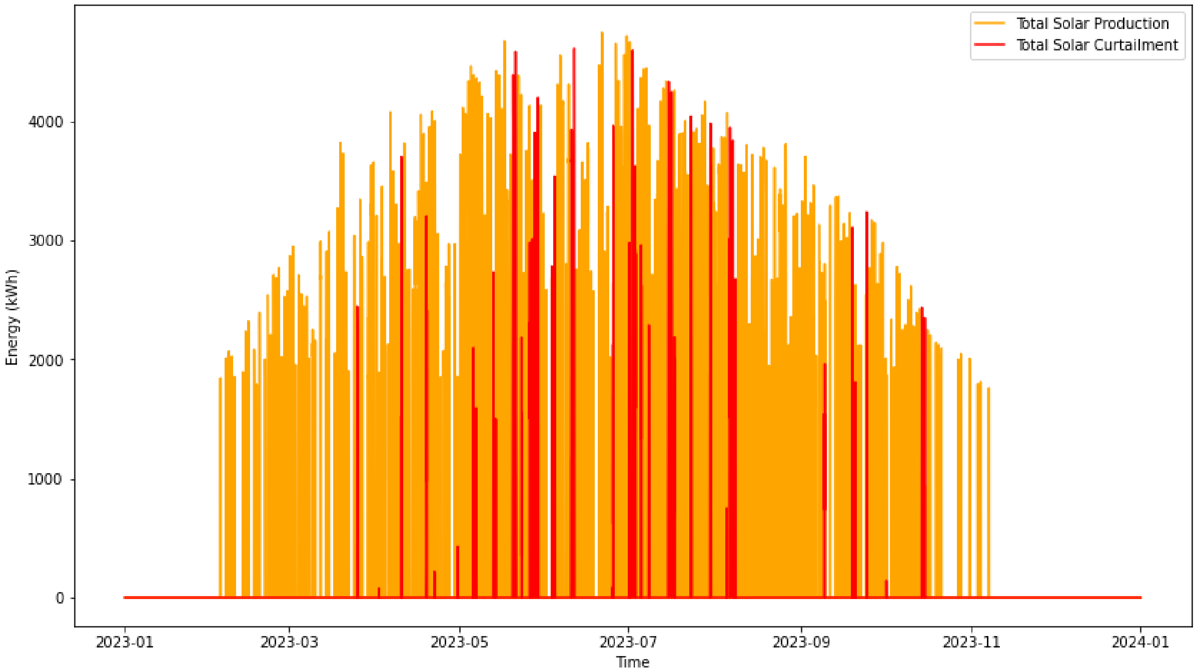
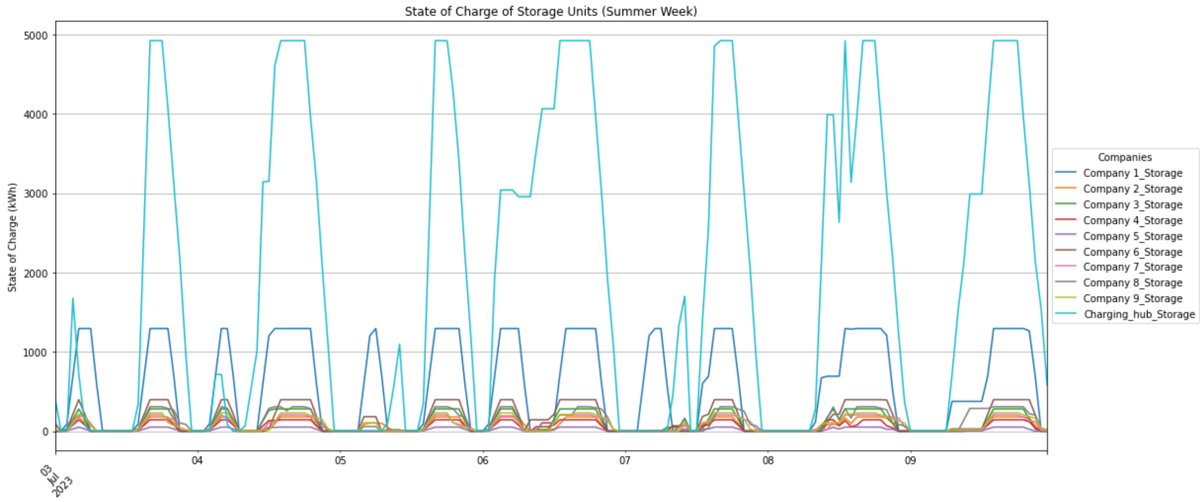


Figure 37: All companies' total solar production and curtailment in the first congestion management scenario.

There are discernible discrepancies between the graphs in Figure 26 and Figure 38, which can be attributed primarily to the higher solar energy production observed during the summer. During the summer, most of the day's energy is derived from solar sources, which charge the storage units to capacity. Conversely, in the winter, most of the day's energy is derived from other sources, with solar energy only contributing at night when capacity is available. The primary distinction can be observed in the storage units' state of charge (SOC). In the winter week, the state of charge (SOC) is maintained until the early afternoon, whereas in the summer, it lasts until the evening. This can be attributed to the fact that, during the summer months, companies and the charging hub receive sufficient electricity from the solar panels, thereby reducing their grid offtake. Subsequently, the stored energy is discharged in the evening, obviating the grid electricity requirement during that period.



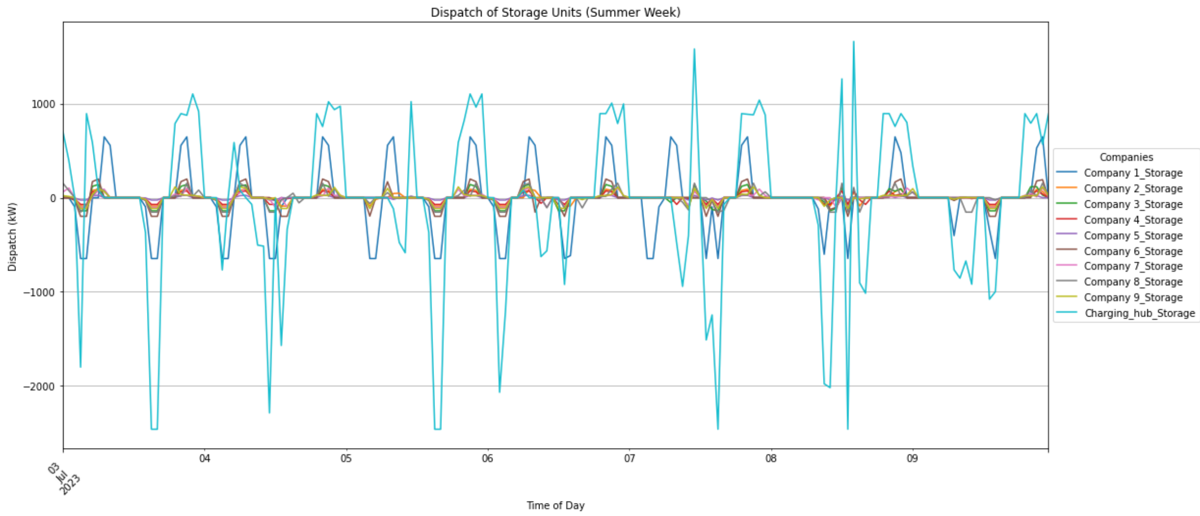


Figure 38: The upper graph illustrates the state of charge (SOC) of all companies' storage units and the charging hub over the seven days from July 3rd to July 9th. The bottom graph illustrates the storage dispatch for the aforementioned week.

8.5. Congestion Management Scenario 2

Figure 39 displays the companies' total used solar production and curtailment.

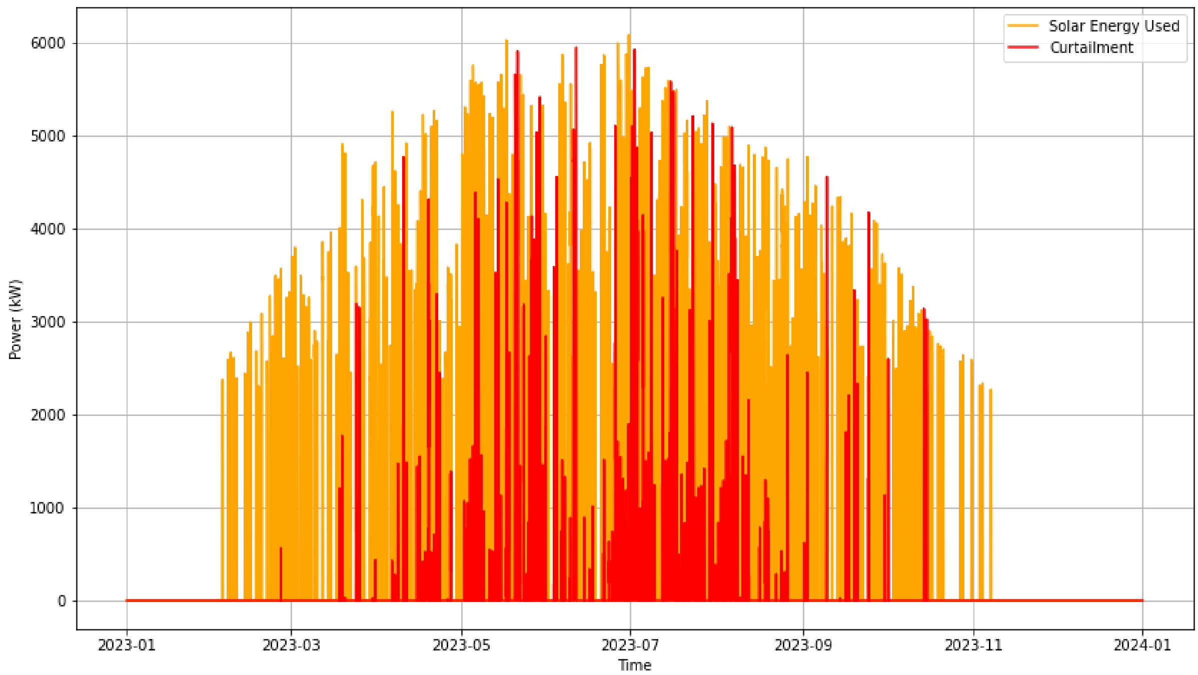


Figure 39: All companies' total solar production and curtailment in the second congestion management scenario.

As illustrated in Figure 40, the aggregate load of all companies and the charging hub remains below the capacity of the business park due to the effectiveness of the congestion management mechanisms and the assumptions made for the charging hub.

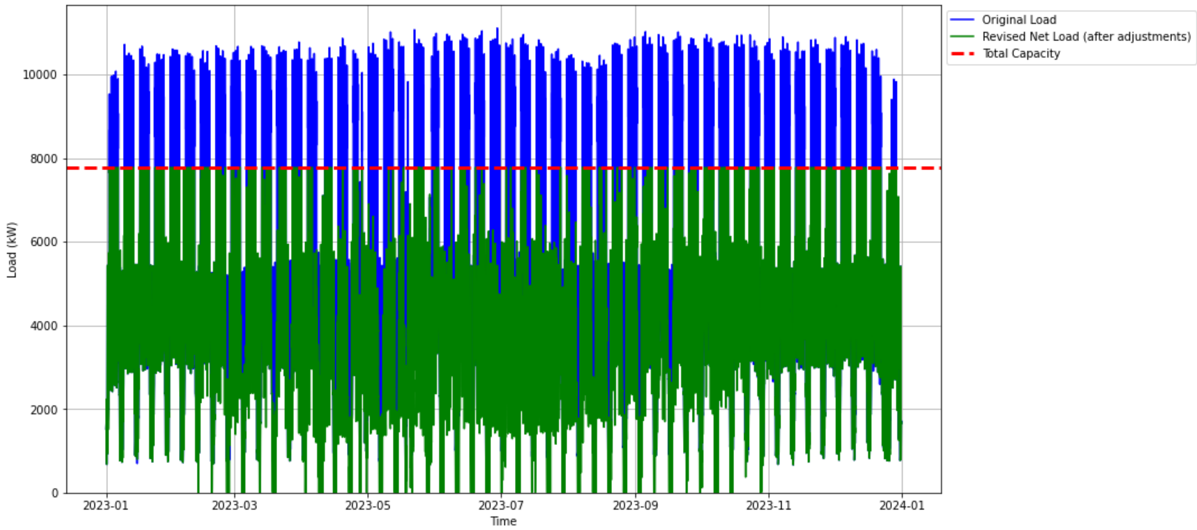


Figure 40: The net load of all companies after using solar energy, storage units, load shifting, and load shedding in congestion management scenario 2.

8.6. Congestion Management Scenario 3

Employing the capacity market, load shifting of companies 1 and 4 and the charging hub, and, when necessary, load shedding, the total load of all companies and the charging hub remains below the total capacity of the business park. This is demonstrated in Figure 41. It should be noted that the use of solar energy and the storage units of Company 1 and the charging hub also contribute to maintaining the load below capacity.

Figure 41: The net load of all companies after using solar energy, storage units, load shifting, and load shedding in congestion management scenario 3.

Figure 42 displays the companies' total used solar production and curtailment.

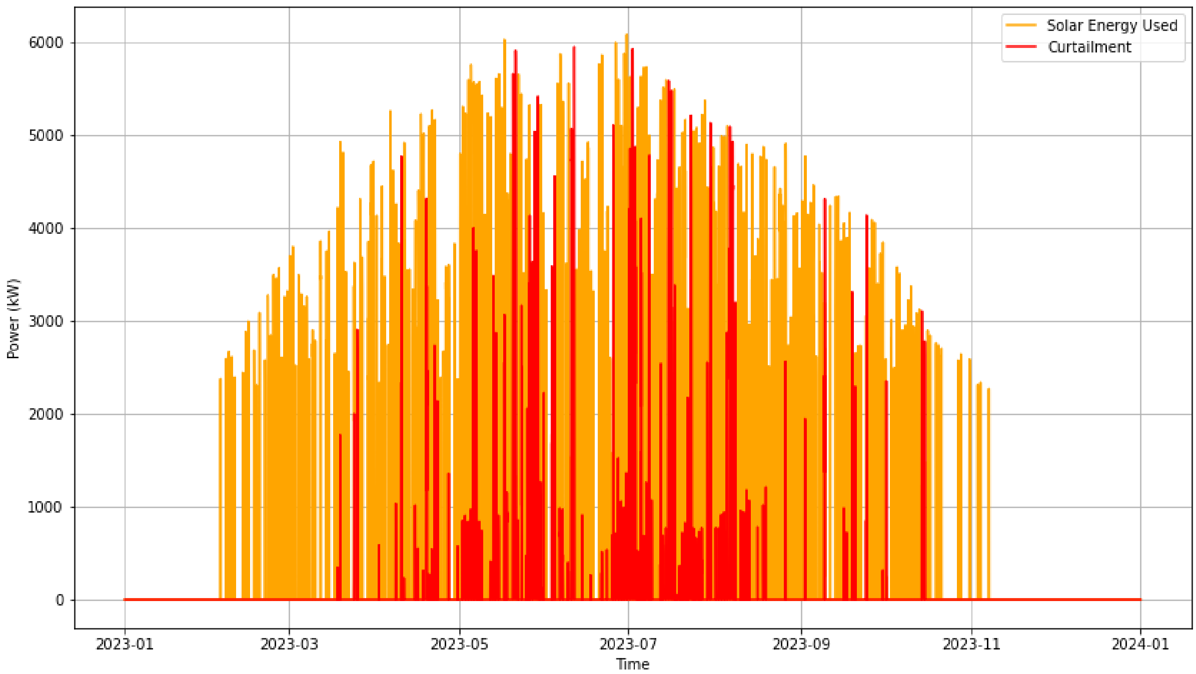


Figure 42: All companies' total solar production and curtailment in the third congestion management scenario.