Towards New Grid Tariffs: Recommendations for Restructuring Grid Tariffs

A Master's Thesis on the Evaluation of Time-of-Use contracted power tariff for large-scale electricity consumers in the Dutch distribution system

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Towards New Grid Tariffs: Recommendations for Restructuring Grid Tariffs

A Master's Thesis on the Evaluation of Time-of-Use contracted power tariff for large-scale electricity consumers in the Dutch distribution system

By

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Executive summary

Addressing grid congestion in the Dutch distribution grid requires price-based solutions, such as restructuring grid tariffs. One such proposal is the introduction of a Time-of-Use (ToU) contracted power tariff for large-scale electricity users. With this structure, power can be contracted each hour in a day, with varying contract prices, aiming to incentivize lower grid usage during peak moments. It is yet unclear whether this tariff structure provides a meaningful contribution to reduce grid congestion. This study is therefore guided by the following question: "*How can Time-of-Use contracted power tariffs contribute to reducing grid congestion and improving efficient grid usage in the Dutch distribution grid, given modelled large-scale electricity user behavior?*". A demand response estimation model has been created to answer this question.

First it was explored how large-scale electricity users react to price signals, by reviewing earlier literature on the matter. It was found that there was not yet a model that was both sufficiently scalable and detailed to analyze the effects of grid tariffs on a physical grid. Thus, a new demand response estimation model was created based on components from models from literature, and an interview with a large-scale electricity consumer.

The created model assumes large-scale electricity consumers show cost-minimizing behavior. The cost-minimization is subject to consumer-specific constraints based on historical consumption data. A redistribution of daily energy usage is optimized based on commodity costs, grid tariffs and a penalty for deviations from a reference profile. The penalty for deviating from the reference profile was based on price elasticities of electricity demand, which were implemented by means of a scenario analysis. This approach was chosen because regression analyses showed that changes in energy demand could not be explained by changes in electricity prices. Network capacity, electricity prices and total demand levels are assumed to be exogenous, as no demand growth or structural system changes are included in the analysis.

The introduction of a ToU contracted power tariff is evaluated using system efficiency as the guiding principle from grid tariff design. System efficiency is in this study operationalized as both peak reduction and an adjusted load factor as performance indicators. The adjusted load factor concerns the ratio of average load over peaks in the system, thus representing the efficiency of grid usage. A modelled medium-voltage network segment in the Maasvlakte is analyzed to assess the effects of the ToU contracted power tariff on these performance indicators.

With the model built, it could be explored how the ToU contracted power tariff influences the performance indicators. The ToU contracted power tariff, as an addition to the ToU volumetric tariff and ToU peak tariff, leads to a marginal additional peak reduction. The highest measured additional peak reduction is 0,008 MW and only occurs in scenarios with moderate assumed flexibility of consumers, and in the week with the system peak. The original system peak in the modelled grid is thus reduced to from 12,660 MW to 12,652 MW as a result of a ToU contracted power tariff. The tariff also does not reliably improve the adjusted load factor of the system, thus unreliably incentivizing efficient grid usage.

The limited effectiveness of the ToU contracted power tariff is explained in its pricing structure. The tariff primarily incentivizes load shifting, rather than peak reduction, because if consumption is already below the contracted capacity, any additional load does not increase the costs and only the timing of the contracted capacity determines the cost level. The tariff thus incentivizes load to shift to other hours, rather than to reduce peaks in energy usage. The adjusted load factor is generally reduced because the load shifting drives the average load and peak loads further apart.

Based on the results in this study, the ToU contracted power tariff is not considered a reliable instrument for reducing grid congestion or improving system efficiency. Its complementary value on top of the ToU volumetric and peak tariff is limited, and its complexity may complicate proper implementation. Implementing the ToU contracted power tariff would thus increase the complexity of grid tariffs significantly, while only having a very limited influence on peak reduction. It must also not be forgotten that the ToU tariffs apply to an entire year, though peaks in the system are found to be a rare phenomenon.

In future congestion management considerations, tariff structures must be considered that directly address the locational, temporal and peak-driven dimensions of grid congestion. Future research into consumer-specific estimations of price elasticities would further improve the realism and relevance of future analyses.

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Nomenclature

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Table 1: Abbreviations

Abbreviation	Meaning
ACM	Autoriteit Consument en Markt
CEER	Council of European Energy Regulators
DSO	Distribution System Operator
LDC	Load Duration Curve
ToU	Time-of-Use
TSO	Transmission System Operator

Variables main analysis

Table 2: Components of cost-minimization with unit and description

Symbol	Unit	Description
Sets and indices		
$T = \{1,\ldots,8670\}$		All hours in the modelled year
$H = \{1,\ldots,24\}$		All hours in a day
$D = \{1,\ldots,365\}$		All days in the modelled year
$M = \{1,\ldots,12\}$		All months in the modelled year
$For\ every\ t \in T$:		
$h(t) \in H$		
$d(t) \in D$		
$m(t) \in M$		
Parameters		
e_t^{ref}	kWh	Energy from reference year at time t
E^{tot}	kWh	Total amount of energy to be redistributed
ℓ_t	kW	Baseload at time t
$\underline{P}_t$	kW	Upper limit for load at time t
R	kW	Ramping limit
$p_t^{commodity}$	€/kWh	Price per kilowatt hour
p^{kWh}	€/kWh	Base tariff per transported kilowatt hour
p_t^{kWh}	€/kWh	Variable tariff per transported kilowatt hour at time t
p^{kWmax}	€/kW	Base tariff per kilowatt for monthly peak
p^{kWc}	€/kW	Base tariff per contracted kilowatt
p_t^{kWc}	€/kW	Variable contracted power tariff at time
$C_{h(t),d-1}^{variable}$	kW	Variable contracted power level in hour h(t) from previous day
L_t	kW	Weighted load for peak tariff calculation at time t
$s(t)$	0/1	Weekend indicator at time t. 1 if weekend, 0 if weekday
$w_{m(t),h(t)}^{kWhWD}$	Dimensionless	Weighing factor volumetric tariff weekdays in month m(t) and hour h(t)
$w_{m(t),h(t)}^{kWhWE}$	Dimensionless	Weighing factor volumetric tariff weekends in month m(t) and hour h(t)
w_t^{kWh}	Dimensionless	Weighing factor volumetric tariff at time t
$w_{m(t),h(t)}^{kWmaxWD}$	Dimensionless	Weighing factor peak tariff weekdays in month m(t) and hour h(t)
$w_{m(t),h(t)}^{kWmaxWE}$	Dimensionless	Weighing factor peak tariff weekends in month m(t) and hour h(t)
w_t^{kWmax}	Dimensionless	Weighing factor peak tariff at time t
$w_{m(t),h(t)}^{kWcWD}$	Dimensionless	Weighing factor contracted power tariff weekdays in month m(t) and hour

		h(t)
$w^{kWcWE}_{m(t),h(t)}$	Dimensionless	Weighing factor contracted power tariff weekends in month m(t) and hour h(t)
C^{flex}_t	€/kWh	Flexibility costs at time t in euro’s
T_{scope}	#	Number of hours in chosen scope
D^{scope}	#	Number of days in chosen scope
D^{month}_m	#	Number of days in chosen month
ε_t	Dimensionless	Elasticity of electricity demand at time t
Δq^{ε}_t	kWh	Difference in energy per timestep for elasticity calculation
Δq_t	kWh	Difference in energy per timestep
q^{2024}_t	kWh	Energy during time t in 2024
q^{2022}_t	kWh	Energy during time t in 2022
q^{ε}_t	kWh	Energy during time t for elasticity calculation
Δp^{ε}_t	€/kWh	Difference in commodity price at time t for elasticity calculation
Δp_t	€/kWh	Difference in commodity price at time t
p^{2024}_t	€/kWh	Commodity price at time t in 2024
p^{2022}_t	€/kWh	Commodity price at time t in 2022
p^{ε}_t	€/kWh	Commodity price at time t for elasticity calculation
$P^{abs,red}$	%	Percentage of absolute peak reduction
P^{ref}	kW	Peak from reference profile
$P^{s,abs}$	kW	Peak from optimized profile for absolute peak reduction
$P^{rel,red}$	%	Percentage of relative peak reduction
$P^{s,rel}$	kW	Peak from optimized profile for relative peak reduction
t^*	h	Hour of highest peak in reference profile
e_{t^*}	kW	Energy at highest peak in reference profile
η^s_{95}	%	System efficiency based on peaks from the 95th percentile
A^s	kW	Average load from optimized profile
P^s_{95}	kW	Peak from 95th percentile from optimized profile
$Q_{95}(x)$	Dimensionless	95th percentile from x
dMC	€	Marginal costs of flexibility
dTC	€	Total costs of flexibility

Decision variables

e_t	kW	Optimized power level in hour t
e_{t-1}	kW	Optimized power level in previous hour t
C^{fixed}	kW	Fixed contracted power for entire year
$C^{variable}_{h(t),d}$	kW	Variable contracted power in hour h(t) at day d
$\underline{C}^{variable}_{h(t),d}$	kW	Potential variable contracted power level in hour(t) at day d
L^{max}_{scope}	kW	Peak load in scope

Objective components

$C_{commodity}$	€/scope	Total commodity costs
C_{kWh}	€/scope	Total volumetric tariff costs
C_{kWmax}	€/scope	Total peak tariff costs
$C_{kWcontracted}$	€/scope	Total contracted power tariff costs
C_{flex}	€/scope	Total flexibility costs
Z	€/scope	Total costs

Variables in-depth analysis

Table 3: Components of cost redistribution calculation

Symbol	**Unit**	**Description**
Parameters		
R_c^{total}	€	Total revenue from grid category
R_c^{kWh}	€	Revenue from volumetric tariff from grid category
R_c^{kWmax}	€	Revenue from peak tariff from grid category
R_c^{kWc}	€	Revenue from contracted power tariff from grid category
V_c^{kWh}	kWh	Volume of transported kilowatt hours in grid category
V_c^{kWmax}	kW	Volume of peak capacity in grid category
V_c^{kWc}	kW	Volume of contracted capacity in grid category
T_c^{kWh}	€/kWh	Tariff level of volumetric tariff in grid category
T_c^{kWmax}	€/kW	Tariff level of peak tariff in grid category
T_c^{kWc}	€/kW	Tariff level of contracted power tariff in grid category
D_c^{kWh}	%	Percentage of allowed revenue recovery from volumetric tariff
D_c^{kWmax}	%	Percentage of allowed revenue recovery from peak tariff
D_c^{kWc}	%	Percentage of allowed revenue recovery from contracted power tariff
T_{new}^{kWh}	€/kWh	Newly calculated tariff level of volumetric tariff in grid category
T_{new}^{kWmax}	€/kW	Newly calculated tariff level of peak tariff in grid category
T_{new}^{kWc}	€/kW	Newly calculated tariff level of contracted power tariff in grid category

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Ruben Frans

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Chapter 1: Introduction

1.1 Context

The Dutch electricity grid is congested. In other words, there is a scarcity of transport capacity in the electricity grid (RVO, 2024). As the grid cannot be expanded quickly enough, various companies and projects are unable to obtain a connection to the grid (Netbeheer Nederland, 2024), delaying the energy transition, housing development and causing severe economic damages (Rabobank, n.d.).

Currently 9 million megawatt hours of electricity cannot be used, leading to a loss of added value of between €10 to €35 billion each year (Venema et al., 2024). Also, if companies decide to leave the Netherlands, due to being unable to be more sustainable (Rabobank, n.d.) and due to having to pay higher tariffs as compared to other countries (VNO NCW, n.d.), it is expected to cause an additional €5 to €15 billion in economic damage each year (Venema et al., 2024). Currently, an estimated 14.000 companies are on a waiting list for a connection to the grid (Energievergelijker, 2025). For comparison, the total investments in the grid were €8,4 billion in 2024 and are expected to rise to €15,1 billion in 2040 (Netbeheer Nederland, 2025a).

The cause of grid congestion can be attributed to both changes on the demand and supply side of electricity. On the supply side, electricity used to be produced by power plants which are dispatchable and central., meaning level of electricity production can be adjusted according to the demand for electricity, and that electricity travels relatively short distances. Now there has been a significant increase in renewable energy sources (Centraal Bureau voor de Statistiek, 2025), which are both intermittent and decentralized. Due to the intermittency of the sun and the wind, it is uncertain when which amount of electricity is produced by renewable sources. While this may not be a problem by itself, the decentral nature of these sources does prove problematic (Schermeyer et al., 2017). If there is a sudden increase of electricity production, and local demand is not high enough to use this electricity locally, the remaining electricity will flow to other places in the grid resulting in so-called feed-in congestion.

On the demand side, there has not been a significant increase in electricity consumption since 2008 (CLO, 2025). However, the simultaneity of electricity demand has increased (De Boer, 2023). Electrification of for example heating and transport mean an increase of electricity usage at very specific times. This causes peaks in grid usage, leading to so-called offtake congestion.

1.2 Solutions for grid congestion

Generally, two types of solutions are considered for solving grid congestion. These are grid expansion and efficient grid usage. If the grid is expanded, there is no longer the problem of grid congestion, but there is a risk of overdimensioning. Regardless, grid operators in the Netherlands face serious challenges such as shortages of technically skilled personnel, materials and space (Stedin, 2023) and long legal procedures. Various solutions are proposed to address these challenges, such as standardization of construction, closer collaboration with contractors and shortening legal procedures (Stedin, 2023). However, the grid cannot be expanded as quickly as the demand for electricity, at specific moments, is rising. This calls for other solutions.

Efficient grid usage concerns actively preventing or reducing grid congestion, in which congestion management plays a big role (Netbeheer Nederland, n.d.). Reducing peaks of electricity demand is an important component of congestion management and is thus closely related to grid efficiency. Efficiency is a broad term, so for the sake of this study it is understood as explained by the ACM (2021): allowing for as much transport of energy as possible, with a given network capacity. A wide variety of theoretical solutions fall under increasing the efficiency of grid usage, which can be categorized in three types: technical solutions (RVO, 2025b), explicit demand response and implicit demand response (Ranaboldo et al., 2024).

Technical solutions refer to physical changes to the grid that are not grid expansions. An example is storage of electricity or electricity conversion, in such a way that electricity is stored at times of low grid usage and discharged at times of feed-in congestion (Enexis Netbeheer, n.d.-a). This ensures local usage of electricity, alleviating the rest of the grid. Alternatively, multiple generation devices can be connected to a single cable (cable pooling), which makes it easier to limit extreme generation capacities (Stedin, n.d.-a). If energy is shared between local companies, under a shared contract with the grid operator, an energy hub is created. This ensures local electricity generation and usage, also alleviating the grid (RVO, 2025a). While various other solutions exist, these will not be analyzed further.

Demand response involves providing financial incentives to increase grid efficiency (IEA, n.d.), and can be categorized in explicit demand response and implicit demand response. Explicit demand response refers to incentives based on contracts with the grid operators. For example, under specific contracts grid operators can remotely control consumer appliances, curtail load programmes of medium and large consumers, or create bidding platforms, such as GOPACS (GOPACS BV, n.d.), on which bids are made to lower or increase grid usage to reduce congestion (Ranaboldo et al., 2024).

Implicit demand response concerns financial incentives by means of price signals (Ranaboldo et al., 2024). These typically come from grid operators by means of grid tariffs and can be organized in such a way that they promote efficient grid usage (European Commission, 2025). The grid tariffs in the Netherlands do not yet provide a clear incentive for more efficient grid usage, save for one specific tariff component recently introduced in the transmission grid (ACM, 2024b). This tariff concerns a peak tariff, where a monthly charge is paid per kilowatt for the highest measured peak in each month.

Under the new structure, weighing factors for each hour in a month are introduced that represent the level of grid usage, and are multiplied with the load on each hour before determining the measured peak. For example, for moments higher or lower grid usage, these weighing factors would be 1 and 0,6, respectively, meaning a measured peak during low grid usage is cheaper. These types of tariffs are often referred to as time-of-use (ToU) tariffs. Similar initiatives are proposed for large-scale electricity users in the distribution grid, where for both a peak charge and a volumetric charge a ToU principle is proposed (CE Delft, 2025). The third transport related grid tariff in the Netherlands, a contracted power tariff, may also adopt a ToU structure in the future. However, Stedin is yet unsure about the effects this structural change will have.

1.3 Economic reasoning

The need for a new grid tariff structure can also be explained with economic theory, which will here be explained to substantiate the possible effectiveness of ToU tariffs. Following the taxonomy of goods from Ostrom (2005), economic goods can be categorized based on whether they are excludable and rivalrous. In literature, transport in the electricity grid is regarded as having both public good and club good characteristics (Künneke, 1999). Public goods are non-excludable and non-rivalrous, meaning one's consumption of the good does not limit the others', and that consumers cannot be prevented from consuming the good. Club goods are non-rivalrous but excludable, meaning consumers can be prevented from consumption. Thus, transport capacity in the electricity grid can largely be regarded as non-rivalrous. That is, however, until congestion occurs (Godby et al., 2013).

With the emergence of grid congestion, the non-rival nature of transport capacity changes. Instead, the good shows characteristics of a congestible club good (Glachant et al., 2017), a good that becomes rivalrous with a high level of consumption (McNutt, 1999), which is exactly what happens with grid congestion. In simpler terms, due to the finite grid capacity and increasing use of the grid, transport capacity becomes scarce. This changes the perspective on how transport capacity should be priced, thus requiring a new perspective on grid tariffs.

From a governance perspective, if transactions are frequent and assets are slightly specific, such as capacity in the grid tied to location and time, pure market governance is not deemed most efficient. Instead, hybrid mechanisms combining both regulation and market-like pricing are appropriate (Baumol & Williamson, 1986). Similarly, applying the First Welfare Theorem is problematic, because the allocation of capacity is non-convex (for example due to fixed costs and various constraints) and potential markets for capacity are incomplete. Thus, second-best solutions for pricing transport capacity are necessary.

One such second-best solution can be scarcity-reflective pricing. ToU tariffs can reflect the scarcity of transport capacity. For example, usage of capacity in the grid can be made more expensive during periods of peak grid usage, where capacity is scarce. Appropriate ToU tariffs could thus not only mitigate congestion but also move towards outcomes closer to Pareto efficiency. These tariffs do so by incentivizing to shift grid usage to moments of low grid usage, thus improving the utilization of existing infrastructure.

1.4 Literature review

As a new perspective on grid tariffs is needed, a literature review has been conducted to better understand current perspectives on grid tariffs and understand where the perspective needs renewing. Found knowledge gaps in this review will guide this study.

Grid congestion is driven by increasing peak demand (Henning et al., 2023). Smart network tariffs can help in resolving grid congestion (Henning et al., 2023), however current network tariffs are outdated (Henning et al., 2022). Heider et al. (2024) have created a new framework to test grid tariffs on various performance indicators and show how volumetric tariffs score poorly on increasing system efficiency, but also that no single network tariff outperforms the other. It thus remains a question what grid tariff structure is best suited for the Dutch electricity grid.

While there are some base principles and criteria grid tariffs should adhere to (Vaughan et al., 2023) and on which grid tariffs can be tested (Hennig et al., 2022), there lacks a common understanding of the relative importance of such principles and criteria (Heider et al., 2024). In Vaughan et al. (2023), a list of criteria and their relative importance is created, but without accounting for the increased flexibility potential that tariffs may impose. Flexibility may not be a goal in itself, but an incentive for flexibility is found an important (secondary) function of grid tariffs (Hennig et al., 2023; Nilsson & Bartusch, 2025). Thus, new grid tariffs are needed, but it is not only unclear what type of grid tariff is most suited for the Dutch context, it is also unsure how grid tariffs must be assessed. This thus calls for a new assessment of proposed grid tariff structures.

Grid tariffs can lead to efficient grid usage and possibly reduce grid congestion (Henning et al., 2022), but other principles must also be accounted for. Ribo-Perez et al. (2025) mention that it remains a question how tariffs must be designed to be cost-reflective and to solve grid problems stemming from rapid electrification. Stakeholder acceptance is key for rapid integration of new grid tariffs (Ribo-Perez et al., 2025), but it is often hard to obtain the perspectives of consumers, as not all people are similarly educated on the topic (Trong & Yang, 2023). Nilsson & Bartusch (2025) reinforce this point, saying the broader population lacks the knowledge to interact with new grid tariff designs.

Grid tariffs are often analyzed with simulations or models to understand their performance. The found literature names various shortcomings in previous attempts to model grid tariffs. The most prevalent shortcoming is related to consumer behavior. Behavior is rarely accounted for in analyses (Gunkel et al., 2023; Hennig et al., 2022), and/or various consumer segments are not accounted for (Bjarghov et al., 2022; Gohary et al., 2023), even though these segments can have different responses. If responses are modelled, they are often assumed to be instantaneous, though there could be a delay in a consumer's reaction (Govaerts et al., 2023). It is also mentioned that locational and temporal differences, such as in demand or supply of electricity, can be accounted for to greater extent in future studies (Morell-Dameto et al., 2023). This is especially important in the context of grid congestion, as congestion is typically a locational and temporal problem.

Concludingly, current grid tariffs are outdated, and it must be understood what criteria are relevant for grid tariffs, how grid tariffs must be designed, and how grid tariffs must be analyzed. This calls for an analysis of existing theories and approaches to grid tariff design, a new method of grid tariff analysis, and the analysis of new grid tariff structures. The analysis of grid tariffs can be improved twofold. First by including consumers of electricity in more detail, second by accounting for temporal and locational differences in electricity demand and supply. These knowledge gaps will guide this study.

1.5 Proposed grid tariff structures

As new grid tariffs must be analyzed and redesigned, an overview of (proposed) grid tariffs in the Netherlands is presented. The current grid tariff structure for large-scale electricity users provides very little incentive for peak reduction however, as the only minor incentive to reduce one's peak comes from a monthly peak charge (Berenschot, 2024). In other European countries, ToU tariffs have already been implemented (ACM, 2021), and seem to have potential for peak reduction (CE Delft, 2025).

In the Netherlands, there are three tariff components that are variable and depend on the amount of transported energy. There is a monthly peak charge, where the height of the tariff depends on the height of the measured peak. A volumetric charge, where a tariff is paid per transported kilowatt hour. And lastly a contracted power tariff for the contracted capacity on a connection (Stedin, n.d.-b). There are serious plans to implement a ToU structure for both the peak charge and volumetric charge for large-scale users in the distribution grid according to experts within Stedin. The ToU principle is introduced here by means of weighing factors that are specific for hours in a month. These weighing factors take on values between for example 0,2 and 1. The amount of kilowatt hours transported, or the height of the peak, is then multiplied with the weighing factor on the moment of transportation or when the peak is measured. In this example, it means that during times of low grid usage, 5 times the peak capacity or usage can be used for the same price as compared to peak moments (ACM, 2024b). The ToU tariff structures are as of now only proposed for large-scale electricity users connected to the medium voltage grid.

The third grid tariff studied by CE Delft (2025) is the ToU contracted power tariff. When implemented as a ToU tariff, a capacity can be contracted for each hour, with each hour having a dedicated weighing factor determining the price for that hour. The chosen daily structure is adopted for an entire year. The ToU contracted power tariff can potentially lead to an increase in efficient grid usage but also leads to higher complexities CE Delft (2025). While for Stedin the ToU volumetric and peak tariffs are logical steps ahead, they are yet unsure about the potential of a ToU contracted power tariff. Regarding the need for new tariffs and the analysis thereof, this tariff change is a logical focus for this study.

1.6 Research questions

This study aims to analyze the proposed change to a time-of-use (ToU) contracted power tariff. To analyze this tariff structure, the study will combine simulation modelling with literature reviews so that representative consumer behavior and contextual factors are incorporated. The research question guiding this study is therefore formulated as follows:

"How can Time-of-Use contracted power tariffs contribute to reducing grid congestion and improving efficient grid usage in the Dutch distribution grid, given modelled large-scale electricity user behavior?"

As explored during the literature review, there is limited consensus on how the demand response of electricity users should be modelled. Since consumer behavior is an important component of this analysis, a large part of the study will be dedicated to understanding the behavior of large-scale electricity users. This leads to the first sub-question:

1) *How do large-scale electricity users respond to price signals from grid tariffs?*

Once established how consumers react to price signals, this behavior must be translated into a model to analyze the effects of the ToU tariff. This requires building a model and implementing the identified consumer behavior. Therefore, the second sub-question is formulated as follows:

2) *"How can the demand response of large-scale electricity users to price signals from grid tariffs be represented in a simulation model?"*

Finally, once the behavioral model is created, the simulated electricity consumers can be exposed to the ToU tariff. The results of this analysis can be used in a network model to assess the impact of the grid tariff on a model of an electricity grid. Thus, the final sub-question is formulated.

3) *"What is the impact of a time-of-use contracted power tariff on grid congestion and efficient grid usage in the simulated Dutch distribution grid?"*

In conclusion, it is first analyzed how large-scale electricity users respond to price signals from grid tariffs. Then, a behavioral model is created representing this behavior, so that the effects of grid tariffs can be assessed in a network model. Thus, an answer to the main research question is expected to be found.

1.7 Complex Systems Engineering and Management affiliation

The Complex Systems Engineering and Management (CoSEM) Master program at Delft University of Technology revolves around designing within complex systems, considering multiple domains such as economics, technology and institutions. Within the CoSEM Master's degree, a specialization can be chosen in either energy, information and communication and transport and logistics. The chosen specialization is energy. Complex systems, such as the electricity system, are typically characterized by the presence of a multitude of actors, technologies and institutions, and their respective complex interactions. Analyzing new grid tariffs as a solution for grid congestion covers precisely these topics.

The components of the electricity system, the behavior of its users and existing institutions have led to an unfavorable situation with the emergence of grid congestion. Formulating an analysis on possible solutions to this situation thus requires a thorough understanding of each of these aspects and their interactions. First the way in which electricity consumers react to tariff changes must be understood, which requires a stakeholder analysis. Then, the effects from tariff changes on the physical grid must be understood, which requires modelling the to be analyzed part of the grid. Lastly, recommendations must be made for further improvements of grid tariffs and potentially other solutions for grid congestion, necessitating an understanding of the institutional environment.

The inclusion of multiple types of analyses, methods and knowledge fields is typical for a thesis in the CoSEM Master's degree. The focus on the electricity grid and grid congestion makes for typical subjects related to the energy specialization.

1.8 Scientific contribution

The scientific contribution of this thesis is twofold. First, a new method to estimate the response of electricity consumers is designed. Second, a new grid tariff structure is analyzed, that has not yet been analyzed thoroughly.

Current methods that estimate the response of large-scale electricity are categorized in bottom-up and top-down approaches. Bottom-up approaches estimate demand response a priori, by modelling the physical components of a process or company, to then perform a profit-maximization or cost-minimization. The physical limits of the assets determine the constraints within these optimizations. This approach is typically used for large-scale electricity users. Top-down approaches estimate demand response a posteriori, based on historical data or pilots. These approaches are typically used for households.

In the case of large-scale electricity users, bottom-up approaches are too time intensive for the scale that is relevant here. Alternatively, top-down approaches are too reliant on data that is not available. Therefore, a hybrid method is proposed, where historic data is used in combination with a cost-minimization function to determine the demand response of multiple large-scale electricity users simultaneously.

This method will be employed to determine the effectiveness of a time-of-use contracted power tariff. To the author's knowledge this tariff structure has not been analyzed in this manner, thus providing new academic insights for solutions for grid congestion in this study.

Both the introduction of a new method to determine demand response, and the analysis of a new type of grid tariff, may thus serve as a contribution to existing literature on grid congestion and tariff structures.

1.9 Societal contribution

Grid congestion poses major societal challenges in the Netherlands, delaying housing development, industrial electrification and the integration of renewable energy. This thesis contributes to a solution to this challenge by furthering the discussion surrounding the analysis and design of grid tariffs as solutions for grid congestion.

First, distribution system operators such as Stedin can use the newly created analysis approach to identify locations or periods where congestion may arise, to see if investments in the grid are still needed after the introduction of new grid tariff structures. Also, using the model for other tariff analyses may increase efficiency in decision-making.

Second, this thesis provides an analysis of a time-of-use contracted power tariff, which has not yet been implemented in the Netherlands, but might find its introduction in the near future. By assessing its potential impact on grid congestion and efficient grid usage, this thesis contributes to understanding whether or not such tariffs can effectively incentivize peak reduction, without imposing unintended effects. These insights are relevant for ongoing discussions surrounding grid tariff design and allow for more informed decision making by regulators, operators and large-scale electricity users.

Linking consumer behavior, tariff design and physical grid constraints, this thesis helps to bridge the gap between economic policy instruments and the physical grid. It thus contributes to the broader societal goal of enabling the energy transition while minimizing the disruption caused by grid congestion.

1.10 Structure

The structure of this study is as follows. In Section 2, the theoretical framework for this study is presented, exploring the origin, necessity and design principles of grid tariffs, and presenting earlier methods of modelling demand response. Section 3 explores the method of this analysis, where a newly created method for estimating demand response is explained. In Section 4 the method is applied to analyze the effectiveness of the ToU contracted power tariff, and the acquired results are presented. Section 5 presents the conclusion and a discussion in the form of presenting a conclusion, policy recommendations, the limitations of the study and recommendations for future research. Lastly, a reflection is presented in Section 6.

Chapter 2: Theoretical Framework

Building on the found gaps in literature from the introduction, this chapter explains the theoretical foundation for the analysis of grid tariffs. Because electricity grids are regulated natural monopolies, tariffs are not market prices, but regulatory instruments. This chapter therefore starts with a short explanation of the economics of natural monopolies and regulation, before turning to the criteria for grid tariff design and the modelling of consumer behavior.

2.1 Natural monopolies and regulation

Electricity grids are natural monopolies that are regulated. In this section it is explained what natural monopolies are, and why regulation is necessary.

2.1.1 A brief history

On April 19th, 1886, the first public power plant opened in Rotterdam, serving a handful of lamps and streetlights (Centraal Bureau voor de Statistiek, 2024). Electricity sales rose, leading to a connection to another municipality, with more municipalities adopting electricity. From 1910 on, local energy companies merged into regional and provincial energy companies with interconnected grids. Eventually, energy companies merged into a national cooperation of energy providers, managing both the transportation and generation of electricity. The national grid was finalized in 1953 (Centraal Bureau voor de Statistiek, 2024).

Within this electricity system structure, there were very little incentives for energy companies to improve their efficiency (Emergy Consultancy B.V., 2024). Generation, transmission and distribution were all managed by single energy companies, with no competition within any of these domains. At the European level, what is called the liberalization of electricity markets started in 1996, when Directive 96/92/EC was adopted (Tanrisever et al., 2015). Its objective was to establish an energy market across the European Union that was efficient, competitive and sustainable. The directive required member states to either legally or functionally unbundle Distribution System Operators (DSO’s), responsible for the low to medium voltage grids, from electricity generation or supply activities. Under legal unbundling, a system operator is legally separate entity from its other activities, while still being able to influence strategic decisions indirectly. Functional unbundling refers to a system operator that must operate independently in terms of decision-making but can still own companies with other activities (Carbon Collective, 2022).

With the introduction of the Electricity Act in 1998, what is the liberalization of the Dutch electricity system started (Tanrisever et al., 2015). This act laid the foundation for market competition and the establishment of Tennet as the national Transmission System Operator (TSO). The TSO is responsible for managing the high-voltage grid. While Tennet operated this grid at the time, the ownership of the grid remained with the regional energy companies. The ownership of the high voltage grid was gradually transferred to Tennet, until Tennet had full ownership in 2008.

In 2006, the Netherlands went further than legal and functional unbundling, introducing ownership unbundling with the ‘Wet Onafhankelijk Netbeheer' (Independent Network Management Act) (Energiewijzer.nl, 2016). Now generating companies were no longer allowed to operate the distribution or transmission grids. The unbundling allowed for more focus on core tasks, easier regulation, low incentives for favouritism within distribution grids to guarantee third party access and higher security of supply (De Nooij & Baarsma, 2009; Baarsma et al., 2006).

2.1.2 A natural monopoly

The transmission and distribution grids are regarded as natural monopolies (Gómez, 2013) and are lawfully treated as such. Normally, economic efficiency is thought to be highest in cases with high competition. However, a natural monopoly emerges in contexts where economic efficiency is highest with a single supplier. There are two main reasons the electricity grid operators are natural monopolies.

Fixed costs and economies of scale

A natural monopoly arises in industries where high fixed costs prevent other firms from competing. Fixed costs are expenditures that do not change with a change in the number of goods or services produced (Hayes, 2025b). These expenditures are often sunk, meaning that once invested, they cannot be easily recovered or sold (Hussain, 2025). The fixed costs are spread over more units as production increases, so the average fixed costs per unit declines with increased outputs (Greer, 2021). This phenomenon is associated with economies of scale. The larger an electricity grid is, and the more electricity is transported, the lower the average total costs per unit of transported electricity is. These economies of scale arise from the high fixed costs of infrastructure, combined with the low marginal costs of transporting additional electricity once the grid is built. It is thus beneficial to have a large electricity grid. Also, due to the size and intrusiveness of electricity grids, it makes little sense to have multiple grids operating alongside each other (Gómez, 2013).

High sunk fixed costs and economies of scale lead to a situation where it is typically more efficient to have a single supplier (Greer, 2021). That is why electricity grids are usually dominated by natural monopolies, such as the transmission system operator (TSO) and distribution system operators (DSO's).

Network externalities

If the value of a good or service increases with the number of users, network externalities are present (Künneke, 1999). A common example of a network externality occurs on social platforms. A social platform increases in value if it has more users that can interact with each other. There is a distinction between direct and indirect network externalities. The example of a social platform entails a direct network externality, because its value increases directly as the number of users increases. However, in the case of electricity grids there are only indirect network externalities. Users of an electricity grid usually do not care about the size of the grid, as long as it delivers electricity, but the stability of the grid and the security of supply can be positively influenced by a grid expansion (Künneke, 1999).

The occurrence of network externalities reinforces the idea that a single, interconnected grid is more efficient. It is less efficient if there are separate grids in the same area operated by different companies.

2.1.3 A regulated monopoly

Natural monopolies are typically subject to economic regulation, which plays a significant role in the structuring of grid tariffs. The basics of regulation will be explained in this section, with first a microeconomic proof for the need of regulation, and then an overview of general types of regulation and regulation in the Netherlands.

Microeconomics

In economic terms, there is always the goal of maximizing social welfare. Normally, to do so a company sets its price at its marginal costs, which ensures allocative efficiency. This means that all resources are used where they are most valued, and thus social welfare is maximized. However, this theory assumes low fixed costs, free entry and exit to the market and no economies of scale (Hayes, 2025c). With natural monopolies this works differently. Due to the high average cost of, in this case the electricity grid, and the low marginal costs of electricity transportation, setting the price on the marginal costs would mean the grid operator goes bankrupt (Haworth, n.d.). This is shown in microeconomic terms in Figure 1.

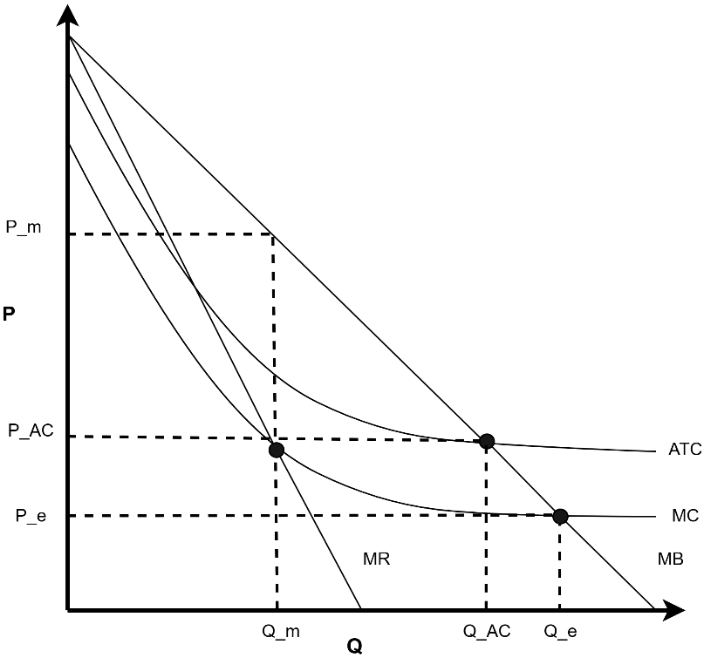


Figure 1: Cost and benefit curve of a natural monopoly

In a perfect market, the most efficient outcome in this case is when the price (P) is set at the intersection of the marginal benefit (MB) curve and the marginal cost (MC) curve. This leads to a quantity of Q_e and a price of P_e. However, at this point the price is below the average total costs (ATC), which means that per transported unit of electricity the grid operator makes a loss (Henning et al., 2022).

Alternatively, if the grid operator can set a price by itself, it would be set higher, at P_m. This is because there the marginal cost equals the marginal revenue (MR), and thus the largest profit can be made. However, this leads to a lower level of output (Q_m) than the most efficient output (Q_e). Especially in the case of electricity this is unwanted, as electricity is both seen as a necessity of life, and as a necessity for a healthy economy (Netbeheer Nederland, 2014). Thus, consumers must be protected from the market power of grid operators (Pérez-Arriaga, 2013).

An alternative is for a government to set the price at where average total costs curve intersects with the marginal benefit curve, which is called average cost pricing (Hayes, 2025a). Now the quantity shifts to Q_AC, with P_AC as the corresponding price. This still does not lead to the most efficient outcome, but it does prevent negative profits and ensures more grid usage (Q_m). This principle is often the basis for regulation. However, in reality it is a lot harder to determine the exact cost curves, and the price consists of various components, so the actual regulatory structure is not as simple as average cost pricing.

Regulation

The operators of transmission and distribution grids are natural monopolies and must be regulated for a more economically efficient outcome (Trong & Yang, 2023). Regulation means government involvement in markets, and the enforcement of its rules (CFA Institute, 2024). In choosing a way to regulate a monopoly, generally a balance must be found between ensuring financial sustainability for the monopoly, and acceptable prices for those connected to the grid (Gómez, 2013), as already shown in Figure 1. A grid operator must make enough money to finance necessary investments to maintain a certain quality, while at the same time this should not be to the detriment of those connecting or connected to the grid.

There are typically two methods of regulation: cost-of-service (also known as rate-of-return) regulation and incentive-based regulation (Gómez, 2013). In short, cost-of-service regulation allows network operators to recover their main operating costs and earn a specified rate of return (Cambini, n.d.). This type of regulation lowers financial risk for the regulated companies, but there is very limited incentive for efficiency improvements. In incentive-based regulation, a level of revenue is predetermined based on historic data, which creates an incentive to lower costs or increase efficiency, and thereby increase profits (Gómez, 2013).

In the Netherlands, the method of regulation is determined in a so-called method decision of the Dutch regulator Autoriteit Consument en Markt (ACM). A method decision prescribes how the allowed revenues of the system operators are determined (ACM, 2023). The structure of grid tariffs is determined in the Tarieven Code Elektriciteit (Overheid.nl, 2025).

Distribution grid operators in the Netherlands are currently regulated through a variant of incentive-based regulation known as yardstick regulation. The revenue cap is determined by sector-wide efficient historical cost levels, adjusted for quality and efficiency. The cap is thus driven by the average efficient costs rather than the individual DSO's costs (both operational costs and capital costs). DSO's that invest significantly ahead of others may therefore face a risk of temporary or partial under compensation. This weakens investment incentives, which may have contributed to lacking grid expansion. The lacking grid investments are regarded as part of the cause for grid congestion (Equans, 2024; ACM, 2025b).

For the period of 2027-2031, the regulation method is expected to change (ACM, 2025b). With this change, allowed revenues are initially based on ex-ante estimates of efficient costs, but are later corrected through ex-post reconciliation based on the realised efficient costs. There will therefore be fewer financial risks associated with making necessary investments.

Investments will be ex-ante tested for necessity based on investment plans, and efficiency tests are applied ex post through monitoring and process-based reviews. Moreover, societal costs of underinvestment are considered significantly more severe by the ACM, which justifies this risk (ACM, 2025b). Also, given the challenges grid operators face, such as a shortage of technically skilled personnel, materials and space (Westerveld, 2024), overinvestment is considered unrealistic anyway (ACM, 2025b).

2.1.4 The purpose of grid tariffs

As explored, due to the natural monopoly characteristic of the transmission and distribution grid, regular pricing does not lead to social welfare maximization. Due to the importance of electricity, the market power of these monopolies must be controlled, resulting in a need for regulation.

The grid operators in the Netherlands are regulated in such a way that the allowed revenue is predetermined for each year but will change to a system where all efficient costs are recovered by the regulating authority. These revenues are collected by means of grid tariffs. From an economics perspective, tariffs must be just high enough to ensure financial sustainability for grid operators and allow for grid operators to finance investments necessary for their grids. On the other hand, market power of natural monopolists must be limited, to prevent economic inefficiencies. In pure economic terms, the purpose of a grid tariff is thus to recover efficient costs for grid operators, secure capital for necessary investments, and safeguard access for consumers, thereby approximating second-best social welfare maximization.

With the economic foundation of grid tariffs established, the next step is a detailed analysis of grid tariff design considerations and structures. These considerations are in a broader context than just the economic purpose of grid tariffs.

2.2 Criteria for grid tariffs

With the economic purpose of grid tariffs established, other principles for grid tariff design can be analyzed. Current principles for the design of grid tariffs can be found in both law and literature. To find the principles in law the regulations from the European Parliament have been analyzed. To find interpretations on these principles from regulators, the guidelines from the Council of European Energy Regulators (CEER) and the ACM have been studied. In this section first the principles from law and regulation and literature are presented, after which they are explained based on a synthesis of interpretations from law, regulation and literature.

2.2.1 Principles from law and regulation

Found principles from European law and the interpretations thereof are cost reflectivity, transparency, efficiency, non-distortion, non-discrimination and must take into account the need for security (of supply) and flexibility (European Union, 2019, art. 18). These principles are defined in Article 18(1) and Article 18(2) of Regulation (EU) 2019/943 on the internal market for electricity, and read as follows:

> *“1. Charges applied by network operators for access to networks, including charges for connection to the networks, charges for use of networks, and, where applicable, charges for related network reinforcements, shall be cost-reflective, transparent, take into account the need for network security and flexibility and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator and are applied in a non-discriminatory manner. Those charges shall not include unrelated costs supporting unrelated policy objectives.*
>
> *Without prejudice to Article 15(1) and (6) of Directive 2012/27/EU and the criteria in Annex XI to that Directive the method used to determine the network charges shall neutrally support overall system efficiency over the long run through price signals to customers and producers and in particular be applied in a way which does not discriminate positively or negatively between production connected at the distribution level and production connected at the transmission level. The network charges shall not discriminate either positively or negatively against energy storage or aggregation and shall not create disincentives for self-generation, self-consumption or for participation in demand response. Without prejudice to paragraph 3 of this Article, those charges shall not be distance-related.*

> *2. Tariff methodologies shall reflect the fixed costs of transmission system operators and distribution system operators and shall provide appropriate incentives to transmission system operators and distribution system operators over both the short and long run, in order to increase efficiencies, including energy efficiency, to foster market integration and security of supply, to support efficient investments, to support related research activities, and to facilitate innovation in interest of consumers in areas such as digitalisation, flexibility services and interconnection."* (European Union, 2019, art. 18)

Then there are the interpretations of European law from regulators. The principles mentioned by the CEER are cost reflectivity, non-distortion, cost recovery, non-discrimination, transparency, predictability and simplicity. The basis for grid tariffs presented by the ACM consists of cost reflectivity, improving system efficiency, transparency and non-discrimination (ACM, 2021). However, the European framework is leading according to the ACM. Each principle will be explained in the following sections based on the explanations from both law and the interpretation of regulators.

2.2.1 Principles from literature

To find principles in literature, a short literature review had been conducted. The found principles from the literature review are presented in Table 4. Transparency and security have respectively been translated to simplicity and efficiency to align with the findings from the literature review.

Table 4: Found prinicples in literature and their sources

Principle	Sources
Cost reflectivity	Vaughan et al. (2023); Heider et al. (2024); Trong & Yang (2023); Hennig et al. (2022); Regalini & Lo Schiavo (2025); Morell-Dameto et al. (2023); Ribo-Perez et al. (2025); Nilsson & Bartusch (2025); Van der Holst et al. (2025)
Simplicity	Vaughan et al. (2023); Trong & Yang (2023); Hennig et al. (2022); Nilsson & Bartusch (2025); Van der Holst et al. (2025); Ribo-Perez et al. (2025); Heider et al. (2024); Bjarghov et al. (2022)
Efficiency	Vaughan et al. (2023); Hennig et al. (2022); Trong & Yang (2023); Bjarghov et al. (2022); Ribo-Perez et al. (2025); Nilsson & Bartusch (2025); Van der Holst et al. (2025)
Cost recovery	Trong & Yang (2023); Hennig et al. (2022); Bjarghov et al. (2022); Morell-Dameto et al. (2023); Van der Holst et al. (2025)
Equity	Vaughan et al. (2023); Heider et al. (2024); Bjarghov et al. (2022); Morell-Dameto et al. (2023); Inderberg et al. (2024)
Non-discrimination	Vaughan et al. (2023); Trong & Yang (2023); Hennig et al. (2022); Van der Holst et al. (2025)
Policy alignment	Heider et al. (2024); Regalini & Lo Schiavo (2025); Velkovski et al. (2024)

While this study does not aim to evaluate all criteria quantitatively, the resulting framework serves to position the tariff's effects on grid congestion within a broader set of criteria.

2.2.2 Cost reflectivity

Presented as European law, grid tariffs must be cost reflective. The CEER argues that tariffs paid by network users must reflect the cost they impose on the system, and incentives must be presented to avoid future costs. Tariffs should only reflect costs, and not create artificial behavior incentives, which is also called non-distortion (CEER, 2017). To reach a tariff structure that imposes costs on those who incur costs, it must consist of multiple components which capture the need for investment or operation (Vaughan et al., 2023; CEER, 2017). The CEER lists location, time of use and power quality as the primary cost drivers.

In literature, typically three types of cost contributions in the context of an electricity grid are mentioned. First there are two types of cost contribution associated with the use of the grid, generally called short-run marginal costs (SRMC) and long-run marginal costs (LRMC) (Della Valle, 1988). SRMC is the cost of transporting an additional unit of energy, with fixed capital equipment. The LRMC represents costs when one extra unit of electricity needs to be transported, where this may require a network expansion in the future. The LRMC thus reflects all costs that arise over time, assuming the grid can be expanded efficiently. Third, residual costs are the costs remaining after costs of grid usage have already been applied (Batlle et al., 2020). These costs are thus typically not recovered with transport-based grid tariffs.

As mentioned by Henning et al. (2022), it is difficult to determine how a usage profile impacts the total network costs. Economic theory suggests that grid usage should be priced as close as possible to actual costs imposed on the system, particularly under conditions of scarcity. Without congestion, the consumption of energy only contributes to the SRMC, whereas usage of the grid during congestion would contribute to the LRMC. Lastly, connections to the grid and other fixed costs contribute to the residual costs. As a result, the time and location of grid usage largely determine whether costs arise in the short or long run. Fully cost-reflective grid tariffs should therefore approximate scarcity pricing by differentiating charges across time (ToU) and location and by combining usage-based and fixed tariff components. This is in line with the principles of scarcity pricing mentioned in Section 1.2.

2.2.3 System efficiency

In literature, system efficiency is used with various meanings. The ACM (2021) defines it as an efficient design of the grid and the usage thereof. The design and usage are efficient if as much energy as possible can be transported with a given capacity of the grid, by spreading the load over time, and by limiting the distance between generation and consumption of electricity (ACM, 2021). In the case of this study, it is especially efficient use of the grid that is of interest, as tariffs can influence consumption behavior.

Under system efficiency, a notion of economic efficiency can be understood. Economic efficiency is obtained when an allocation of resources maximizes welfare in the system, which can be approximated by grid tariffs that provide the correct price signals.

If tariffs are to increase system efficiency (thus focussing on efficient usage of the grid, and not efficient design of the grid), they must incentivize peak load reductions and increase the utilization of the grid outside of peak periods. Grid tariffs must thus through price signals reduce system peaks, meaning grid tariffs must have a sort of demand response mechanism. Some articles specifically describe peak reduction as a separate criterion (Trong & Yang, 2023; Nilsson & Bartusch, 2025), which for the sake of this study is summarized as system efficiency. In addition to temporal incentives, grid tariffs can incentivize grid usage in specific locations to increase system efficiency. This consideration is also mentioned by the directives for grid tariffs from the ACM (2021) but falls outside of the scope of this study.

2.2.4 Other principles

With the increasing prominence of grid congestion and its consequences, the system efficiency is regarded as the most pressing principle. It is thought that a more efficient electricity grid would yield the largest increase in social welfare and largest reduction in grid congestion. Therefore, the system efficiency, or grid efficiency, will be the focus of this study in the analysis of the proposed contracted power tariff. However, to still provide a complete overview, all other relevant principles in grid tariff design are also mentioned. These principles are the following.

Cost recovery

Cost recovery constitutes the fundamental requirement of grid tariff design, as mentioned in Section 2.1.4. Grid operators must be able to recover their costs to be financially sustainable (Hennig et al., 2022), and to be able to invest in their grids (CEER, 2017). As mentioned under cost reflectivity, residual network costs are typically not covered in usage-based grid tariffs. A perfectly cost reflective grid tariff may therefore not always recover total system costs. It is thus important that grid tariffs not only reflect the costs users incur but also account for the residual costs in the system. This principle is referred to as cost recovery.

In the Dutch revenue regulation, any discrepancies between the recovered costs and realized efficient costs are systematically corrected by the ACM. From 2027 onwards, the revenue regulation will change, but does not change the underlying principle that deviations are corrected by the ACM (ACM, 2024a).

There are instances where network costs are partially recovered through public funds, rather than only through grid tariffs. An example is the Dutch offshore transmission system “Net op Zee” (Algemene Rekenkamer, 2018). This grid is financed through government subsidies, reducing the share of costs that must be recovered through tariffs. Arrangements like these illustrate that cost recovery can be complemented by public funding mechanisms.

Non-discrimination

According to the European Parliament, grid tariffs must be implemented in a non-discriminatory manner (European Union, 2019, art. 18), and the CEER (2017) states that there must be no undue discrimination between network users. What constitutes non-discrimination in practice is open to interpretation, however. Vaughan et. al (2023) define non-discrimination as the indifference to electricity usage and consumer demographics. Henning et. al (2022) distinguish three dimensions on which discrimination can occur: time, location and flexibility of loads, arguing that discrimination based on time and flexibility can be considered due, as it reflects differences in the extent to which users contribute to system efficiency. While locational differentiation is more controversial, it is increasingly recognized by regulators as a potential tool for improving system efficiency (ACM, 2021; ACM, 2025a).

Simplicity

Simplicity, or non-complexity, encompasses several related principles, including transparency, predictability and understandability. According to the European Union (2019, art. 18) and ACM (2021) grid tariffs must be transparent, while literature emphasizes on intelligibility and understandability for all consumers (Vaughan et al., 2023), ease of implementation (Heider et al., 2024) and acceptance (Ribo-Perez et al., 2025). Transparency is distinct from simplicity in that complex tariffs can be communicated transparently. However, it is closely related to simplicity, thus being treated as part of the broader simplicity principle. In essence, simplicity requires grid tariffs to be understandable so that consumers can respond to them appropriately.

Excessive complex tariffs are prone to misinterpretation, which may lead to consumers acting against the intended effect of the tariff. When tariffs require technical expertise to understand, it may lead to inequitable outcomes by disproportionately benefitting customers with such expertise (Nilsson & Bartusch, 2025). For grid operators, simpler tariff structures also allow for more accurate revenue forecasting, as they reduce uncertain consumer behavior (Henning et al., 2022). Cost-reflective grid tariffs tend to be complex, as network costs vary over time, location and usage. Trade-offs between cost reflectivity and simplicity are therefore inevitable in tariff design.

Equity

Equity is a broadly defined concept in literature and is interpreted as extending beyond non-discrimination in this study. Equity is often associated with fairness (Bjarghov et al., 2022), non-discrimination (European Union, 2019, art. 18), but also the protection of vulnerable consumers, which allows for deliberate differentiation between user groups (Morell-Dameto et al., 2023). Equity may thus require forms of differential treatment, setting it apart from non-discrimination. An example of a tariff structure where this is the case is ‘low-income pricing’, where low-income consumers are exempted from certain payments (Battle et al., 2020).

Equity is also related to energy justice, which is about the morality in the design and operation of energy systems (Jenkins et al., 2020). Energy justice is generally understood along three dimensions: recognition justice, procedural justice and distributive justice (Inderberg et al., 2024). These dimensions emphasize the importance of inclusive decision-making and fair distribution of costs and benefits. Energy justice considerations are often underrepresented in literature (Inderberg et al., 2024), stressing the importance of energy justice considerations in tariff design.

Policy alignment

In literature, it is argued that it is important that grid tariffs do not contradict political objectives. For example, if sustainability is a political priority, grid tariffs should not hinder the adoption of renewable energy sources (Heider et al., 2024). For example, according to Regalini and Lo Schiavo (2025) the Italian regulator introduced tariff exceptions from the standard Italian tariff for electric vehicle charging infrastructure. This was done to encourage investment in charging infrastructure and increase electric vehicle adoption. In Velkovski et al. (2024), it is argued tariffs must be designed specifically for energy sharing in renewable energy communities. However, in the directive from the European Parliament, it is said that grid tariffs must not include unrelated costs for supporting unrelated policy objectives (European Union, 2019, art. 18), and according to a decree from the Court of Justice of the European Union (2025), regulators are always independent in approving grid tariffs.

2.2.5 System efficiency as a focus of this study

While all principles are relevant for the evaluation of grid tariff design, it is not analytically desirable to give them equal weight within a single study. Given the current prominence of grid congestion in the Netherlands, and its adverse effects, this study prioritizes system efficiency, or grid efficiency, as the primary evaluation criterion. This focus is further justified by the nature of the proposed ToU contracted power tariff. It is namely mostly intended to affect system peaks, rather than to improve on any other principle. System or grid efficiency is understood here as the extent to which tariffs contribute to the reduction of peak loads and the improvement of the utilization of existing network capacity. This principle is further operationalized in Section 3.3.4.

In conclusion, to analyze the effects of the introduction of a Time-of-Use contracted power tariff, it will be tested on its influence on the system efficiency and its peak reduction. Now remains the question of how these tariffs should be implemented in what type of model. This will be explored in the following section.

2.3 Modelling approaches

The analysis of the effects of the proposed grid tariffs on the system efficiency necessitates a quantitative analysis. The response of large-scale electricity users to price signals must be estimated to determine how these signals change their load profiles (Furió & Moreno-Del-Castillo, 2024). A literature review was conducted to learn from earlier studies on grid tariffs and demand response. Two main approaches to estimate demand response have been identified, which will each be explained separately, after which a new method of determining demand response will be explained.

2.3.1 Bottom-Up a priori

There have been various studies approximating demand response with an approach I would consider as bottom-up a priori. This approach bases itself on limitations of assets and processes (bottom), to estimate (a priori) a response of the asset or relevant company (up).

The seemingly most prominent method used is a cost-minimization method, whereby an optimal scheduling of electricity usage is calculated by minimizing the costs associated with the to be scheduled processes. The costs of a certain process containing multiple cost components is minimized, with regards to constraints in this minimization which are often derived from physical limitations of assets. These approaches are thus largely used for very specific processes, and yield results of high precision, but tend to get very complex due to the necessary knowledge on the specific assets. For example, in Fisco-Compte et al. (2025) and Söderholm et al. (2025) the optimal production scheduling is determined for a single specific asset, and for refrigeration and heat pump systems, respectively. Deguenon et al. (2025) mention 36 studies which use a revenue optimization model to determine the behavior of energy storage. 6 of these studies employed stochastic components to represent uncertainty. Other studies analyze manufacturing processes or entire companies based on cost-minimization (Jagana et al., 2024; Lu et al., 2025; Adetunji et al., 2025; Liu et al., 2025; Zhang et al., 2025; Ren et al., 2025).

Lastly, some studies analyze demand response from a system perspective, where multiple processes across different sectors interact (Bergaentzle & Gunkel, 2022; Yao et al., 2025; Chong et al., 2025). All the mentioned studies take an a priori bottom-up approach, meaning they start at the asset level, and model a process or industry with combinations of these assets.

Bottom-up approaches are specific for assets or processes, and suffer from scalability issues (Massidda & Marrocu, 2025). If the effects of grid tariffs are to be analyzed for an entire part of a grid, with multiple connected companies, it would be too time intensive to take a bottom-up, a priori approach. Though Massidda and Marrocu (2025) argue based on the study from Ponocko and Milanovic (2018) that detailed analyses like these can provide estimates for whole populations, this is only true for household analyses. A bottom-up a priori approach is thus not sufficient to model demand response for this study.

2.3.2 Top-down a posteriori

There are some studies adopting a top-down a posteriori approach, whereby the demand response is determined based on empirical insights (a posteriori), through pilots or historical data on electricity usage (top-down) (Hofmann et al., 2025). When historical data is used, the demand response is generally determined by using price elasticities (Furió & Moreno-Del-Castillo, 2024), which describe the relationship between the change in demand for a product after a price change. Hennig et al. (2022) advice using price elasticities to improve analysis models. Though this approach may yield less theoretically precise results, the results are more practical for policy analysis (Massidda & Marrocu, 2025). With pilots, demand response is determined through exposing households to different tariff structures (Hofmann & Lindberg, 2021; Hofmann & Lindberg, 2023; Sæle et al., 2015; Faruqui et al., 2017). Though not immediately relevant for this study, as there is a focus on large-scale electricity users in the medium voltage grid instead, the idea of using a posteriori insights is valuable.

Top-down approaches suffer less from scalability issues, as they do not rely on very specific information, such as physical limits of specific assets. Rather, top-down approaches are based on historical data and often directly applicable to aggregations of users (Massidda & Marrocu, 2025). Though more scalable, these approaches are less precise, and historical data must be available. Also, no studies have been found adopting a top-down a posteriori approach for large-scale electricity users, except for some elasticity calculations. Grid wide analyses of grid tariffs for large-scale electricity users would be useful, however (Bergaentzle & Gunkel, 2022).

2.3.3 A new method: bottom-up a posteriori

Existing studies on large-scale electricity users seem to focus only on asset-level optimization, and do not scale well to multiple users simultaneously. On the other hand, top-down approaches only concern households, and do not seem to be applied to large-scale electricity users.

Due to the inapplicability of both the top-down and bottom-up modelling approaches, a new demand response estimation method must be created. For this study, this new method will be a hybrid between bottom-up a priori and top-down a posteriori approaches. This hybrid approach will be based on historical usage data and combining this data with a cost-minimizing behavior. This allows for a scalable behavioral model that is grounded in historical data but also represents cost-minimizing behavior from large-scale electricity users. The cost-minimization will be based on at least the grid tariffs, to understand their effects on energy usage, where energy usage per hour will be the decision variable.

2.4 Other types of grid tariffs

Finally, to understand the context of the ToU contracted power tariff relative to other tariff designs, a brief literature review was conducted to identify other existing grid tariff structures. The list of grid tariff structures identified in literature has been included in Appendix A.2. Each tariff includes a concise description of its design, and in some cases includes information on its implementation in other countries.

The main findings of this analysis indicate that, in Europe, there have already been cases of locational grid tariffs, and there is a range of other tariffs that may be relevant for addressing grid congestion. Also, the analysis reveals that the academic literature often provides limited or incomplete explanations of different grid tariff types. Therefore, the inclusion of a comprehensive overview of grid tariff structures each with a concise description, was considered valuable, regardless of its limited relevance to the core analysis.

Chapter 3: Method

In this section, the method with which the proposed grid tariff structure will be analyzed is presented. This section starts by presenting the research design, then the conceptual model, model formalization, implementation and lastly presenting model verification and validation. Both the new method for demand response estimation, and the network simulation model are explained in this section.

3.1 Research design

To both understand the impact of a time-of-use contracted power tariff, this study adopts a two-stage research design. As was found in the literature review, the analysis of grid tariffs for large-scale electricity users first requires the development of a new demand response estimation method. After this new method has been explained, it will be applied to assess the introduction of a time-of-use (ToU) contracted power tariff. The research designs for the new method and the tariff evaluation are explained separately.

3.1.1 New demand response estimation method

As explained in Section 2.3, new method to estimate demand response is necessary to evaluate grid tariffs on a larger scale. This new method estimates how electricity demand of large-scale electricity users responds to alternative grid tariff structures, while addressing limitations of prior methods.

Due to the availability of historic data within Stedin, opportunities were found to base the method on historical consumption data and make it applicable to large populations of large-scale electricity users, while maintaining a bottom-up representation at the individual consumer level. Within Stedin, large-scale consumers are defined by their connections to the grid, with some consumers owning multiple connections. The basis of the model will therefore be a cost-minimization for each connection of a large-scale electricity user. This choice is grounded in reality, as it defines grid congestion and tariffs at the connection level, rather than at the level of consumers.

It must then be determined what is optimized, and what cost components drive the costs of large-scale electricity users. First, the optimization concerns a redistribution of energy, where a new daily load profile is created based on a total amount of energy in the reference day. Second, for this method it has been determined that these costs consist of the relevant transport-based grid tariffs (relevant because not all consumers are subject to the same tariff structure), the commodity costs of electricity and a cost associated with flexibility. The selection of cost components for large-scale electricity users was based on a semi-structured interview with a representative of Zero Emission Services conducted in March 2024, and on expert knowledge within Stedin. Lastly, the optimization must be constrained to improve realism. These aspects of the model will be explained in more detail in Section 3.3.1.

3.1.2 Time-of-Use contracted power tariff evaluation

The introduction of the time-of-use (ToU) contracted power tariff must be evaluated. This evaluation will be conducted from a modelled physical grid perspective, focusing on system efficiency and peak reduction rather than economic welfare. System efficiency is defined in line with Section 2.2 as the ability of the grid to transport electricity given existing capacity constraints. In other words, the tariff should cause peak reductions to relieve the Dutch grids of grid congestion.

This evaluation thus follows a quantitative modelling approach, based on various scenarios. First the status of the grid before tariff implementation is analyzed with a network analysis tool to understand where the current peaks in the system are, and what the current system efficiency is. Then the ToU tariff is introduced, and the behavior is estimated with the created model mentioned in 3.1.1. This leads to the creation of new load profiles, which are implemented in the network tool to analyze the peak reduction and the new system efficiency.

This two-step approach allows for a direct translation of behavioral changes as a result of new tariffs into physical network effects. This analysis especially focuses on changes in peak demand and load distribution, rather than trying to accurately forecast loads. Resulting outcomes must therefore be interpreted as general effects instead of precise predictions. Based on these outcomes, policy implications are discussed, focusing on the potential effectiveness of contracted power tariffs and broader lessons for grid tariff design.

3.1.3 Empirical application with Vision

A real network segment will be analyzed as an empirical case study where the newly created load profiles from the behavioral model are implemented. This quantitative, exploratory case study sheds light on the relative effects of ToU grid tariffs on physical grid performance. Especially the influences on peak reduction and system efficiency are analyzed, as these criteria are most important in the context of grid congestion.

The selected grid area is a real network segment of Stedin's distribution grid. To analyze representative operating conditions, two weeks per half year are selected from the reference year to analyze. For each half year, one week is chosen for its relatively high peak loads, and one week is chosen for its average loads. This selection ensures a broad understanding of the effects of grid tariffs for various grid conditions. Multiple scenarios are analyzed in the selected weeks, where key parameters of the behavioral model are varied. It is thus systematically explored how demand shifts translate into changes in peak reduction and system efficiency.

Vision has been chosen as the network analysis tool to perform the network analysis for various reasons. First, this tool is already in use within Stedin. This means that network areas and reference load profiles have already been created within the tool, which saves time. Also, the tool is already assumed to behave as intended and is therefore not subjected to verification and validation within the scope of this thesis. The tool is very well suited for load flow calculations and provides all outputs necessary for this analysis without unnecessary complexity. For example, PowerFactory was also an option, but is a lot more complex and takes more time to get used to, without providing more useful information for this analysis.

There are two limitations to using Vision as a network analysis tool. First, in the way Stedin has structured the data surrounding the tool, it does not allow for the injection of electricity from large-scale electricity users. Energy can only be injected by dedicated generation nodes. Only reflecting demand-side flexibility may underestimate broader system effects. Second, within Stedin only the 10-kilovolt medium voltage grid is available for analysis. This means that some types of large-scale consumers are exempted from the analysis. To minimize the consequences of these limitations, a 10-kilovolt grid will be chosen that has a wide variety of large-scale electricity users. This way the analysis is still useful to make meaningful calculations on the chosen performance criteria.

3.2 Conceptual model

The conceptual model for the approach is this study is shown in Figure 2. It describes how grid tariffs influence electricity consumption of large-scale electricity users, and how this behavior translates into impacts in the physical electricity grid. There are five components to this model, which are the exogenous inputs, the behavioral mechanism, the output of the behavioral model and the grid loading and the output of the network analysis.

The system boundary is defined around large-scale electricity users connected to the to be analyzed network segment. Small-scale electricity consumption and electricity generation profiles are treated as exogenous and remain fixed throughout the analysis. The size of the grid is also fixed, as no network investments will be modelled. The conceptual model thus lays focus exclusively on the short- to medium-term demand-side behavioral responses of large-scale consumers, and the implications of their behavior on the physical grid. This represents the short- to medium-term nature of implicit demand response strategies, with the expansion of grids being regarded as a long-term solution.

The exogenous inputs include connection-specific consumption patterns from the reference year. This includes both the actual consumption of each consumer, and the medoids of average and peak consumption for each consumer. The medoids will be elaborated on later but represent the feasible range of demand adjustment. Then, three types of cost components determine behavioral incentives, grid tariffs, energy prices and costs associated with flexibility. Behavioral decisions are based on short-term foresight and cost-minimization.

The behavioral mechanism redistributes electricity demand over time, to minimize the total costs, within predetermined constraints. An adjusted load profile for each large-scale electricity consumer serves as the output of the behavioral mechanism. These adjusted load profiles reflect the redistribution of a fixed daily energy demand from the reference year, rather than a change in total consumption. It is thus assumed that large-scale electricity consumers do not lower consumption as a result of grid tariffs.

The adjusted load profiles are then implemented in a network analysis tool, to assess their impact on the physical state of the electricity grid, serving as the final output. The resulting impacts are presented in terms of consumption peaks and system efficiency, which will be compared to the reference situation.

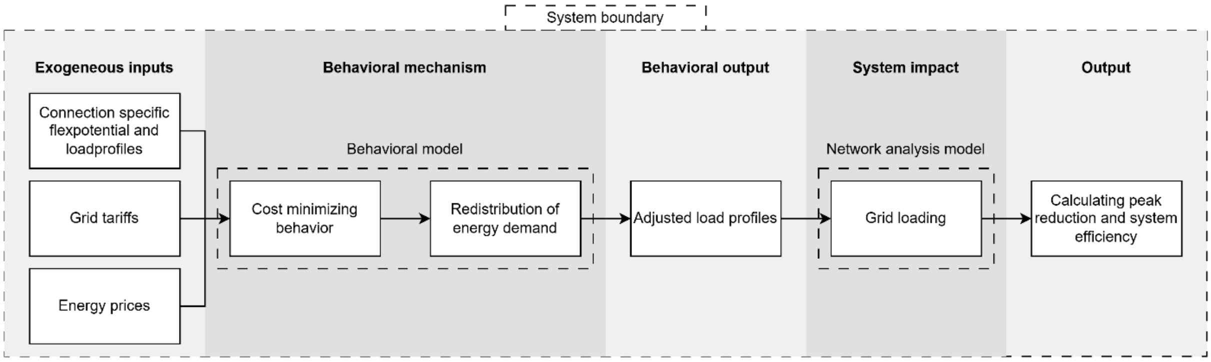


Figure 2: Conceptual model

3.3 Model formalization

In this section the explanation and mathematical formalization of the created model and the key performance indicators are explained. First a general explanation of the model is given, then the formalization is presented.

3.3.1 Model explanation

The proposed demand response estimation method follows a short-term, quantitative and model-based approach. As the model assumes the consumers are electricity price takers, the model concerns a cost-minimization over transport-based tariffs, commodity costs and flexibility associated costs. Unless mentioned otherwise, 2024 is used as the reference year. The reasoning for the made assumptions is explained in more detail in Section 3.3.5 and Section 3.4.3.

The solution space of this minimization is a determining factor in the realism of this model. Generally, this solution space is determined by means of modelling specific assets or processes, and their physical limits. However, as this approach was deemed too time intensive and not scalable, the feasible range of demand adjustment is instead constrained using empirically consumption patterns. Stedin keeps track of the load profiles from large-scale electricity users, and has calculated the average- and peak electricity usage per hour per consumer. The average- and peak usage are assumed to serve as the lower- and upper limit of electricity consumption for each hour in the model, thus determining the solution space. This approach has been chosen so that the model cannot generate peaks that have never occurred before, and are thus unlikely to happen. On the other hand, having the average usage as a lower limit ensures that at least a realistic load profile will occur. This approach is based on the assumption that it would be too costly for large-scale electricity users to adopt never seen before load profiles as a result of tariff changes, and will only spread their electricity usage to avoid peaks.

Large-scale electricity users are generally active on balancing and congestion markets (personal communication, 2025), serving as revenue components in the minimization. These revenues have not been included in the analysis for two reasons. First, the price formation of these revenues depends on complex market interactions, which introduces high uncertainty and limited explanatory power within the scope of this model. Second, though the model would closer represent reality, they were excluded as the focus on this study is on tariff-induced behavior. Incorporating these markets would increase model complexity and reduce the interpretability of the tariff effects.

This new modelling approach is primarily suited for two types of analyses. First the interaction effects of different grid tariffs can be assessed. It allows for multiple tariff structures to be introduced simultaneously and be assessed for their impact. Second, the model can provide indicative estimates of electricity demand patterns for large-scale consumers. However, results from a small sample are likely to be unreliable. The strength of this approach rather lies in the analysis of a large pool of consumers, as is necessary for assessing the impact of grid tariffs on the physical grid. With a large pool of modelled consumers, the individual estimation errors are expected to average out. The model can thus yield valuable insights into how tariffs influence the physical grid, as long as there are sufficiently large datasets.

This approach combines the bottom-up approach by means of a cost-minimization with a top-down approach by means of basing the solution space, flexibility costs and energy redistribution on historical data. As established in Chapter 2, this type of approach has not been employed before, but is deemed necessary in the analysis of new grid tariffs. Understanding the effects of grid tariffs on the physical grid namely requires understanding the behavior of all consumers connected to the analyzed part of the grid.

This model will be used to understand the effects of the introduction of a time-of-use contracted power tariff. The load profiles that are produced by this method will be implemented in a network analysis tool to understand the impact of this new tariff structure on the grid.

3.3.2 Mathematical formalization of response estimation model

It is assumed that large-scale electricity users operate on a cost-minimization basis. To approximate this behavior, a cost-minimization function is used for each connection of a large-scale electricity user. This minimization function searches an optimal redistribution of a total amount of energy for a day, based on a day in the reference period. All functions and components of the demand response estimation model are explained in this section.

Optimization function and constraints

Objective function

The costs of the large-scale electricity users that have been modelled consist of both the commodity price of electricity ($C_{commodity}$), the three transport-based tariff components (C_{kWh}, C_{kWmax} and C_{kWc}) and a cost for flexibility (C_{flex}). The commodity costs, volumetric tariff and costs for flexibility are in euros per kilowatt hour, the peak tariff and contracted power tariff are in euros per kilowatt. According to Zero Emission Services (personal communication, 2025), the main cost drivers are the transport related grid tariffs, commodity costs and revenues from balancing or congestion markets. As mentioned, balancing and congestion market revenues have not been implemented in the model. Periodical charges have not been included in this optimization function as they are assumed to not influence electricity demand.

A cost component not mentioned by Zero Emission Services (personal communication, 2025) or Stedin are the costs of flexibility. This component penalizes deviations from reference profiles and will be explained in more detail later in this section.

The complete cost-minimization function is expressed in equation 1. The implementation of each component in this objective function will be explained separately.

$$\min Z = C_{commodity} + C_{kWh} + C_{kWmax} + C_{kWc} + C_{flex} \qquad (1)$$

Redistribution

The energy balance is presented in equation 2, where the total amount of energy in the new daily profile (sum of e_t) in kilowatt hours must be equal to or larger than the total amount of energy used by a large-scale electricity user in the reference day ($E^{tot\,ref}$). Though not technically a redistribution, as it can distribute more energy than was available from the reference profile, in this study it is referred to as a redistribution.

Electricity demand is constrained to be non-negative. The decision variable representing the load and the total energy from the reference load are therefore defined with a lower bound of zero (equation 2.1 and 2.2). The model thus only optimizes electricity consumption and does not electricity injection. Within Stedin this is also the standard approach in Vision, where all redelivery of electricity from large-scale electricity users is set to zero. Injection thus does not influence the final analysis and therefore falls outside of the scope of this study.

This redistribution approach implies that demand response consists only of load shifting. Feed-in, or behind the meter generation is not represented specifically, but is reflected in historical net demand profiles as its input. Export tariffs, market revenues or bidirectional power flows thus fall outside of the scope of this study. This demand-only scope is due, because the focus for this model is on offtake congestion, or peak reduction, only.

$$\sum_{t \epsilon T} e_t \geq E^{tot\,ref} \tag{2}$$

$$e_t \geq 0 \tag{2.1}$$

$$E^{tot\,ref} \geq 0 \tag{2.2}$$

Solution space

It must be determined in what space a solution can be found. Without further constraints, the model will assign all energy usage during the cheapest moments, which is likely to be at night during the weekends. Thus, the new load profile of a company must be approximated in such a way that it is physically possible for a consumer to adopt this profile. Therefore, baseload and upper-limit constraints, based on historical data, have been introduced that vary each hour. The data on which these constraints are based are explained in Section 3.4.1.

The baseload (ℓ_t) and upper limit ($\underline{P_t}$) constraints are respectively shown in equation 3 and equation 4, and are expressed in kilowatts. A constraint for the connection capacity has not been included as a consumer cannot consume more electricity than what was historically measured, which by definition conforms to the connection capacity. The lower limit is also based on historical consumption data. The implementation of these constraints is explained in more detail in Section 3.4.1.

$$e_t \geq \ell_t \tag{3}$$

$$e_t \leq \underline{P_t} \tag{4}$$

Contracted capacity

A company cannot demand more electricity each hour than its contracted capacity. In this study, the contracted capacity is determined by the optimization and analyzed as both a fixed (C^{fixed}) and variable ($C_{h(t)}^{variable}$) variant to analyze the influence of a ToU contracted capacity. The contracted capacity applies to all hours in the modelled year (T). If the contracted power is fixed, equation 5 is used as a constraint, and when the contracted power is variable, equation 6 is used as a constraint. The contracted capacity is expressed in kilowatts.

$$e_t \leq C^{fixed} \quad \forall t \in T \tag{5}$$

$$e_t \leq C_{h(t)}^{variable} \; \forall t \in T \tag{6}$$

Ramping

Lastly, ramping limits (R) are added as constraints to the optimization function. A company cannot change its energy usage between hours more than the ramping constraints allow. The upper and lower ramping constraints are formally expressed in equation 7 and 8 respectively. Both ramp limits are determined by looking at the maximal ramping, thus the largest difference in energy usage between hours, either upwards or downwards that has occurred during a reference year.

$$e_t - e_{t-1} \leq R \tag{7}$$

$$e_{t-1} - e_t \leq R \tag{8}$$

Commodity price

The first component of the optimization function is the commodity price of electricity. It is assumed that all large-scale electricity users have dynamic electricity contracts so that they are subject to variable electricity prices ($p_t^{commodity}$), and that the electricity price is fully known to them within 24 hours. Prices are expressed in euros per kilowatt hour. Taxes are not included, because as every cost component increases by 21%, it does not change the optimal solution. Also, no less energy will be used due to the nature of the redistribution. The total costs for the commodity price are calculated through equation 9.

$$C_{commodity} = \sum_{t \in T} p_t^{commodity} \, e_t \tag{9}$$

Volumetric tariff

The volumetric tariff, or kWh tariff, can be included in the model both via a fixed rate and a variable rate. If a fixed rate is used, the medium-voltage (MV) values from 2024 from Stedin (n.d.-b) are used and the power level is multiplied with this rate (p^{kWh}). If a variable rate is used, the price per transported kilowatt hour is multiplied with a weighing factor (w_t^{kWh}) which depends on the moment it was transported. These weighing factors are dimensionless and are dependent on the month, weekday and hour in which a kilowatt hour is transported, and are different between weekdays ($w_{m(t),h(t)}^{kWhWD}$) and weekends ($w_{m(t),h(t)}^{kWhWE}$). They are elaborated upon under the model implementation section.

The actual price per kilowatt hour in the minimization function is determined by multiplying the base price with the relevant weighting factor at time t, which is determined in equation 10.2. Here $s(t)$ equals 1 during weekends and 0 during weekdays, ensuring the correct weighing factors are used. Then the base price is multiplied with this weighing factor as shown in equation 10.1. The total annual cost equation of the volumetric tariff in the optimization is shown in equation 10.

$$C_{kWh} = \sum_{t \in T} p_t^{kWh} * e_t \tag{10}$$

$$p_t^{kWh} = w_t^{kWh} * p^{kWh} \tag{10.1}$$

$$w_t^{kWh} = (1 - s(t)) w_{m(t),h(t)}^{kWhWD} + s(t) w_{m(t),h(t)}^{kWhWE} \tag{10.2}$$

Peak tariff

The peak tariff is determined by measuring the highest peak in a month, and then assigning a tariff per kilowatt of capacity used on that peak moment. With a fixed peak max tariff, a fixed price is paid per kilowatt (p^{kWmax}). With a variable peak tariff, the load with which the costs are calculated (L_{scope}^{max}) is determined only after multiplying the measured loads with the relevant weighing factor (w_t^{kWmax}). Like with the volumetric tariff, the height of the weighing factor depends on the month, day and hour it is measured. The determination of the weighing factor at time t is expressed in equation 11.3, and the weighted load per hour (L_t), which is used to determine the costs, is determined as in equation 11.2. The monthly peak is found with equation 11.1.

Because this is a monthly tariff, it must be adjusted to the scope of the model. For example, if the scope is a week, the tariff has too much weight if it is assumed as a monthly tariff. Therefore, the total costs are multiplied with the ratio of days in the scope versus the days in the month of the scope leading to the cost term in equation 11.

$$C_{kWmax} = \frac{D^{scope}}{D_m^{month}} \sum_m p^{kWmax} \; L_{scope}^{max} \tag{11}$$

$$L_{scope}^{max} = \max_{t \in T_{scope}} L_t \tag{11.1}$$

$$L_t = w_t^{kWmax} \; e_t \tag{11.2}$$

$$w_t^{kWmax} = (1 - s(t)) w_{m(t),h(t)}^{kWmaxWD} + s(t) w_{m(t),h(t)}^{kWmaxWE} \tag{11.3}$$

Contracted power tariff

The tariff for the contracted power can be implemented in the model in both a fixed and variable manner. When fixed, the level of contracted power (C^{fixed}) is determined by the highest peak in the scope, as expressed in equation 12.1. The costs for the year are calculated by multiplying this level with the base tariff for contracted power per kilowatt (p^{kWc}). Here a correction is applied as shown in equation 12. As the contracted power tariff also concerns a monthly tariff, but the model can also run for days or weeks, the tariff must be weighed accordingly. This is done by multiplying the total costs with the ratio of days in the scope (D^{scope}) versus days in the relevant month (D_m^{month}).

$$C_{kWc} = \frac{D^{scope}}{D_m^{month}} p^{kWc} \; C^{fixed} \tag{12}$$

$$C^{fixed} = \max_{t \in T} e_t \tag{12.1}$$

If the contracted power tariff is variable, a different power level can be contracted for each hour in a day ($C_{h(t),d}^{variable}$). However, whatever pattern of contracted power is chosen for a day, will take effect for the entirety of the year. In other words, the hourly levels of contracted power are the same for every day. In a model with a rolling horizon this can be problematic, as the contracted power tariff thus introduces an intertemporal decision problem. The optimal contracted power levels depend both on the consumption patterns over the entire model scope, while at the same time these levels constrain and influence daily consumption decisions. To solve this, the contracted power levels are updated iteratively in the model. For each 24 hours, the model optimizes the hourly schedule based on all cost components. After solving one day, the contracted power profile is updated using equation 13.1, whereby the highest value is chosen between the previous level ($C_{h(t),d-1}^{variable}$) and the potential level ($\underline{C}_{h(t),d}^{variable}$).

This approach assumes that contracted power can be increased with the occurrence of higher peaks but cannot be reduced later. Therefore, contracted power profiles become a non-decreasing structure over time, ensuring feasibility for all subsequent days while still allowing active price signals for each day.

To determine the costs, the base tariff per kilowatt of contracted power (p^{kWc}) is multiplied with the relevant weighing factor (w_t^{kWc}). This calculation is made for each hour (equations 13.2 and 13.3). Then, the sum of these costs is divided by 24 to get an average cost per hour, which constitutes the monthly costs. The total costs per scope are calculated following equation 13. Since the contracted power tariff is a monthly tariff, the same weighing correction is introduced as in the peak tariff.

$$C_{kWc} = \frac{D^{scope}}{D_m^{month}} * \frac{1}{24}\sum_{t\in T} p_t^{kWc}\ C_{h(t),d}^{variable} \tag{13}$$

$$C_{h(t),d}^{variable} = max(C_{h(t),d-1}^{variable}, \underline{C}_{h(t),d}^{variable}) \tag{13.1}$$

$$p_t^{kWc} = w_t^{kWc} * p^{kWc} \tag{13.2}$$

$$w_t^{kWc} = (1 - s(t))w_{m(t),h(t)}^{kWcWD} + s(t)w_{m(t),h(t)}^{kWcWE} \tag{13.3}$$

Costs of flexibility

Shifting electricity consumption to other moments in a year or day, means planning operational processes of companies differently. This can be costly, as not all machinery is flexible, and for example because it demands longer working hours. To represent the costs that arise when shifting load, the cost of flexibility is added in the minimization function for each consumer. The total cost of flexibility equals the sum of the flexibility costs per hour (C_t^{flex}) in euros per kilowatt hour over the modelled period, as per equation 14.

$$C_{flex} = \sum_t C_t^{flex} \tag{14}$$

These costs are expected to be different for all types of consumers. Therefore, it would be beneficial to introduce an empirical component that can be determined for each consumer separately. However, as will be explained later, this empirical approach was not statistically reliable. Nevertheless, the logic behind this approach remains the same, and in future studies empirical analyses may be more viable. Therefore, the approach is explained as if the empirical approach is still feasible.

First the general equation for determining the price elasticity of demand is given in equation 14.1. The elasticity is calculated by comparing the load profiles in kilowatts, for example from 2022 and 2024 (q_t^{2022} and q_t^{2024}), for each consumer, and by introducing the electricity prices in euros per kilowatt hours of 2022 and 2024 (p_t^{2022} and p_t^{2024}) for each timestep. Here p_t^{ε} and q_t^{ε} represent the hourly prices and quantities from the year for which the elasticity is to be calculated. This yields a price elasticity per customer for each timestep. If elasticity is determined empirically, equations 14.2 and 14.3 are used. Equation 14.1 is only viable if all timestep are of one hour.

$$\varepsilon_t = \frac{\Delta q_t^{\varepsilon} / q_t^{\varepsilon}}{\Delta p_t^{\varepsilon} / p_t^{\varepsilon}} \tag{14.1}$$

$$\Delta p_t^{\varepsilon} = p_t^{2024} - p_t^{2022} \tag{14.2}$$

$$\Delta q_t^{\varepsilon} = q_t^{2024} - q_t^{2022} \tag{14.3}$$

Rewriting to Δp_t yields equation 14.4, in which the marginal costs of flexibility are expressed. These can be calculated with the calculated price elasticity from equation 14.1. If the elasticities are obtained empirically, for example by using data from 2022 and 2024, the reference year must be 2022, both for the quantity (q_t^{2022}) and the price (p_t^{2022}). Δq_t is here then the deviation in the new profile from the 2022 profile (equations 14.5), and Δp_t is here the difference in price from the modelled year and the reference yar. If elasticities are not calculated empirically, but sourced from literature, equation 14.8 can be used directly, with the analyzed year being the same as the reference year. For clarity and continuity, a calculation for 2022 is given as an example.

$$\Delta p_t = dMC = \frac{p_t^{2022}}{|\varepsilon_t|} \frac{\Delta q_t}{q_t^{2022}} \tag{14.4}$$

$$\Delta q_t = e_t - q_t^{2022} \tag{14.5}$$

$$\Delta p_t = p_t^{commodity} - p_t^{2022} \tag{14.6}$$

As the marginal costs are equal to the difference in total costs over the difference in quantity, the total costs can be determined by multiplying with Δq_t (equation 14.7). This yields the total costs of flexibility per timestep, as shown in equation 14.8, if the elasticities would be calculated empirically. If elasticities are included by means of scenarios, the reference year changes. Equation 14.9 shows the example for a scenario-based elasticity analysis for 2024. The reference commodity price is denoted as an absolute value, because negative commodity prices would otherwise lead to negative costs of flexibility.

$$dTC = dMC * \Delta q_t = C_t^{flex} \tag{14.7}$$

$$C_t^{flex} = \frac{|p_t^{2022}|}{|\varepsilon_t|} \frac{(\Delta q_t)^2}{q_t^{2022}} \tag{14.8}$$

$$C_t^{flex} = \frac{|p_t^{2024}|}{|\varepsilon_t|} \frac{(\Delta q_t)^2}{q_t^{2024}} \tag{14.9}$$

3.3.3 Network analysis in Vision

Vision is an exogenous network model. This means that the grid in the model does not change over time, for example due to network reinforcement. The tool is also deterministic, as there are no stochastics or uncertainties introduced in the model. Introducing stochastics falls outside of the scope of this thesis, as it does not improve on the realism or the interpretability of the results. Any such changes would only lead to false securities. Only alternating current flows are considered.

Vision works on hourly, static timesteps. For every component in the model, be it a line, transformer or consumer, has a dedicated load for each hour in the scope that is analyzed. The inputs of the model are thus the optimized load profiles from large-scale electricity users, and other profiles that have not been optimized such as low voltage demand or generation of electricity. The output of the model are the loads on these elements as a result of a load flow calculation. There are no constraints in the network analysis model that constraint optimized load profiles any further than the constraints in the behavior model.

One specific output is chosen for further analysis. This is a 25 kilovolt to 10 kilovolt transformer that feeds the entire area. This transformer aggregates the total load of the entire network area and therefore provides a representative account of the total system loading. It is therefore unlikely that the analysis of additional elements would yield different insights into the effects of the ToU contracted power tariff. The load per hour on this transformer is used to derive the key performance indicators which are defined in the next section.

3.3.4 Key performance indicators

To understand the influence of the ToU contracted power tariff on the system efficiency, system efficiency as a principle must be operationalized. It was established that system efficiency covers both peak reduction and efficient grid usage. Because of this definition, the chosen performance indicators are absolute peak reduction, relative peak reduction and adjusted load factor. Each indicator will be explained separately.

Absolute peak reduction

The first key performance indicator on which the analysis will be based is the absolute peak reduction. The absolute peak reduction is characterized as the difference between the highest peak in the reference scenario and the highest peak in the optimized scenario. The timing of this peak is therefore irrelevant for this indicator. This indicator captures if peaks are shifted to other moments, and is important because from a grid congestion perspective, the highest peak in the system determines the network constraint. Grid congestion is thus determined by means of load levels, rather than constraint violations.

The mathematical expression of absolute peak reduction is shown in equation 15. The peak from the reference scenario (P^{ref}) is based on the highest load from that scenario, as per 15.1. Then the highest peak from the optimized load ($P^{s,abs}$) is determined as per 15.2. Then the percentage of peak reduction is determined in equation 15. The peak loads are in kilowatts.

$$P^{abs,red} = 100 - \left(\frac{P^{s,abs}}{P^{ref}} * 100\right) \tag{15}$$

$$P^{ref} = \max_{t} e_t^{ref} \tag{15.1}$$

$$P^{s,abs} = \max_{t} e_t \tag{15.2}$$

Relative peak reduction

The second key performance indicator on which the analysis will be based is the relative peak reduction. With relative peak reduction, the peak reduction within the same hour is meant. For example, if there is a peak in the reference scenario at 18:00, then that peak is compared to the new load at that same hour in the optimized scenario. This performance indicator therefore shows how well the tariff forces electricity to no-peak moments, rather than creating new peaks.

The mathematical expression of this performance indicator is expressed in equation 16. The highest peak in the reference scenario (P^{ref}) is determined, as per expression 16.1. Then it is determined at what hour this peak has occurred, with expression 16.2. Lastly, the peak for comparison ($P^{s,rel}$) is determined by finding the load associated with the time found in 16.2 (e_{t^*}), as shown in 16.3. Then the percentage of relative peak reduction is determined in equation 16.

$$P^{rel,red} = 100 - (\frac{P^{s,rel}}{P^{ref}} * 100) \tag{16}$$

$$P^{ref} = \max_t e_t^{ref} \tag{16.1}$$

$$t^* = arg \max_t e_t^{ref} \tag{16.2}$$

$$P^{s,rel} = e_{t^*} \tag{16.3}$$

Adjusted load factor

Lastly, the adjusted load factor is defined as in Section 2.1.2. If tariffs are to increase system efficiency, they must incentivize peak load reductions and increase the utilization of the grid outside of peak periods. While peak reductions have already been addressed as performance indicators, the utilization of the grid outside of these peaks has not. The changes in utilization of the grid outside of peak hours will be captured by using an adjusted load factor as a key performance indicator. The load factor, generally the ratio of average load over peak load, is adjusted in the sense that the 95th percentile of peaks make up the peak load. This approach is chosen to prevent occasional extreme peaks and outliers to distort the adjusted load factor calculation. The efficiency represents a dimensionless ratio, and a higher efficiency is considered better.

The mathematical expression of this key performance indicator (η_{95}^s) is presented in equation 17. First the 95th percentile peak from the scenario (P_{95}^s) is determined, as in equation 17.1. Then the average load (A^s) is determined by taking the sum of all loads in the analyzed period and dividi ng the sum by the hours in that period (T^{scope}), as shown in equation 17.2. The sum consists of the absolute values of all loads, because without absolute values, opposing flows would cancel out in the average load, leading to an underestimation of grid utilization.

$$\eta_{95}^s = \frac{A^s}{P_{95}^s} * 100 \tag{17}$$

$$P_{95}^s = Q_{95}(\{e_t\}_{t=1}^T) \tag{17.1}$$

$$A^s = \frac{1}{T^{scope}} \sum_{t=1}^{T^{scope}} |e_t| \tag{17.2}$$

3.3.5 Formalization assumptions

In how the model is formulated, various assumptions have been made that will be explained in more detail in this section. These assumptions are subdivided into three categories: actors and contracts, behavior and technical assumptions.

Actors and contracts

There are three important fundamental assumptions about the consumers that will be analyzed. First, consumers are assumed to act rationally, thus rationally reacting to price signals and aiming to lower costs. They have full knowledge of the energy prices and what costs are associated with their load profile for a horizon of 24 hours. Longer horizons would only be beneficial to the analysis if they are longer than a month. Horizons longer than a month are problematic however, as this severely impacts the computational time, and would take away from the realism because the commodity price is known 24 hours in advance. Future research could explore models with longer horizons, but then for example with fixed commodity costs, if faster computers or solvers are available or if there is more time.

Lastly, large-scale consumers are assumed to have dynamic commodity contracts and are price takers, meaning they are exposed to hourly electricity prices. It would be more realistic to model the actual contracts consumers have, but data on contract structures was not available. Also, assuming consumers are price takers with dynamic electricity prices is a commonly used approach in other cost-minimization studies (Deguenon et al., 2025).

Behavior

The behavior of the modelled consumers is only based on the costs of their load profiles, within the constraints that are based on historical consumption data, and do not show strategic behavior. This may overestimate the effects of the contracted power tariff, as it is likely that consumers reserve more capacity for the sake of company growth in the future. In future analyses, projected growth can be implemented in the model, allowing for an approximation of strategic behavior. For this analysis this was not possible due to the lack of data and time.

Consumers can also only shift their load, instead of lowering their total energy use. This may underestimate the effects of the ToU contracted power tariff, as increased costs may lead to lower electricity usage, thus lowering peaks. However, as most consumers are industrial users and the analysis considers 2024 as if the ToU tariffs were already applied, total energy consumption is assumed to remain unchanged with no change in energy efficiency. The flexibility is thus represented as a redistribution of energy use. Also, demand response is often understood as load shifting, rather than load reduction (Binyet et al., 2022).

Lastly, behavior is not influenced by balancing or congestion markets. Including these effects would increase model complexity and reduce clarity of the results. For future studies aiming to capture more realistic consumer behavior, these factors could be incorporated.

Technical assumptions

Lastly there are some technical assumptions. The flexibility of consumers, both in ramping and in the solution space is represented by historical load. Therefore, peaks cannot be higher than historical loads. There is also no redelivery of energy, and flexibility costs are assumed to be symmetrical, meaning the same costs are associated with more or less usage than the reference profile. The model is also deterministic, meaning there are no uncertainties introduced. These assumptions have a limited impact on the analysis, as incorporating additional realism in this context would increase complexity and make interpretations of results more difficult.

3.4 Model implementation

In this section it will be explained how the formalized model will be translated to a model that can be used for the analysis. First the implementation of the demand response model is explained, then the implementation of the network model is elaborated on.

3.4.1 Demand response estimation model

In this section it is described how the mathematical formulation presented in Section 3.3 is implemented computationally. The focus lies on the computational environment, data handling and the implementation of different cost components and constraints. Each of these subjects are explained separately.

Computational environment and model settings

The model has been created in a Python environment, within the Databricks environment of Stedin. Creating the model in this Databricks environment allows for direct references to consumer data Stedin has collected. Given the non-linear nature of the optimisation problem, the Gurobi (13.0.0) solver is chosen to solve the minimisation problem. Regardless of the non-linearity of the problem, it remains convex, ensuring the existence of a unique global optimum. In this study the default settings of Gurobi are used.

Prior to model execution, various model settings can be adjusted by the user. First, each simulation is performed for a specific connection of a large-scale electricity user, which is inserted in the model by means of a unique EAN code. It can also be specified what cost components in the optimization are disabled, fixed or variable. Then the user can determine the temporal scope of the model. The model can be executed for a single day, week, month or year. Lastly the user can make changes to the flexibility of a consumer by either increasing or decreasing the height of the upper and lower bound, and by assigning an elasticity value for the cost of flexibility.

Regardless of the selected temporal scope, the optimization is performed with a rolling horizon with a window of 24 hours. This period has been chosen because generally large-scale electricity consumers know electricity prices 24 hours in advance, and it allows for calculations that are not too computationally heavy. Also, it prevents unrealistic load redistributions, as otherwise the model would assign most loads to weekends due to their lower weighing factors. As an output, the model provides the incurred costs, and the optimal redistribution of the load profile.

Data handling and inputs

Within the model all constraints and input parameters are consumer-specific, except for inputs concerning the tariffs. A dedicated script generates an input file for each selected EAN code, which contains all the relevant constraints and parameters for that connection. The inputs for this file are derived from historical consumption data collected by Stedin and stored within the Databricks environment. Per EAN, the load profiles and the constraints data from 2024 constitute the input that the model needs. If elasticities are calculated empirically based on 2022, 2022 must also be the reference year.

Objective function and constraints

Objective function

The objective function and the constraints of this minimization problem are implemented as defined in Section 3.3. The model thus minimizes total electricity-related costs, subject to consumer-specific constraints. Total daily energy consumption must thus always be at least equal to the daily energy consumption in the reference profile. This ensures that demand response takes the form of a temporal redistribution, rather than a reduction in energy use as a result of new tariffs.

Upper and lower bounds

The upper and lower are based on the so-called 'flexpotential' that is measured for each large-scale electricity user by Stedin. The flexpotential is determined by the difference between the measured average electricity usage of a consumer, and a measured peak usage of a consumer. Figure 3 shows this principle. In this fictitious example, the blue area is the flexpotential, or in the context of the optimization, the solution space.

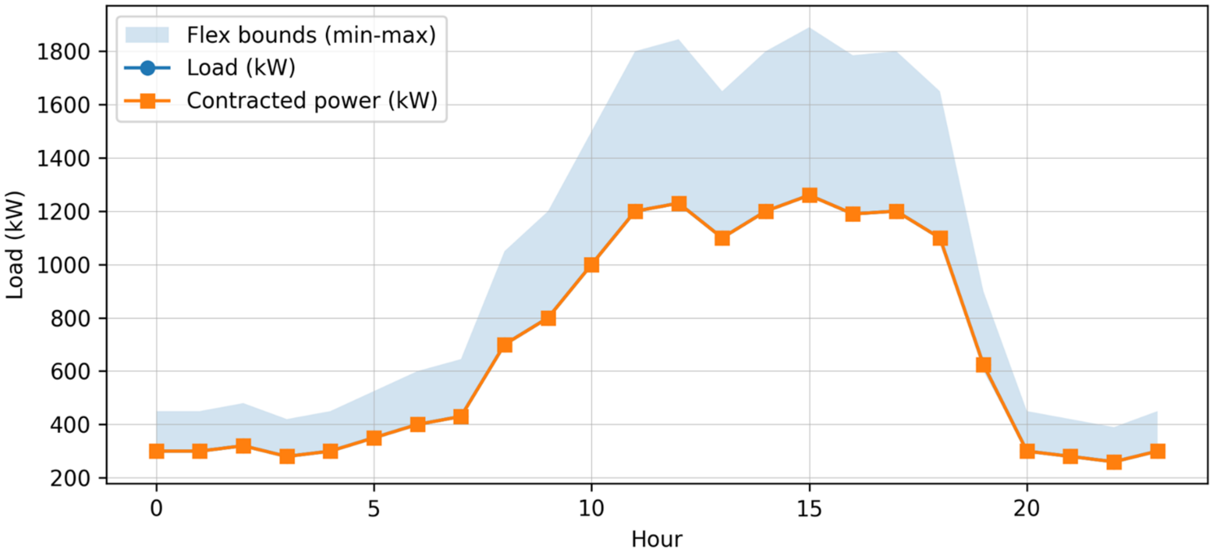


Figure 3: 'Flexpotential' and solution space fictitious example

To determine the values for peak and average consumption, Stedin applies the medoid method. Here a distinction is made in days during the autumn and winter, and days in the spring or summer, resulting in a total of 14 days which each have unique upper and lower bound data. Unlike a mean, the medoid selects an actual load profile that best represents the other load profiles of the same day in the same half year, minimizing the average distance to all other load profiles in that same period. This approach makes sure that the profiles reflect a realistic consumption level instead of a theoretical average. The medoid of the off-peak loads is not collected by Stedin for a lot of consumers. Thus, while this would have been an interesting alternative, it would limit the scalability of the model. Therefore, the upper- and lower bounds will be updated by means of a scenario analysis to understand their effects on the total peak reduction.

The data on the flexpotential is only available for 2024, but can be scaled to other years. To translate the flexpotential to another year, the upper- and lower bounds from 2024 are multiplied with a scale factor. This scale factor is based on the median of daily energy usage for each season and day type. This factor is multiplied with all hours within the day type, to preserve the intraday shape of the upper and lower bounds. The median is used rather than the mean to suppress outliers and missing data. These calculations have been verified by recalculating the new bounds by hand.

To ensure that the model is always feasible, the reference profile also influences the upper and lower bounds. If the consumption of the reference profile is higher than the upper bounds from the flexpotential, the upper bounds are updated to the reference level. In the same way, the lower bounds are updated to the reference level if the reference load is lower than the lower bounds. This method ensures feasibility for these constraints, while still maintaining historical validity.

Constraint file

The constraint file that is created per EAN consists of the upper and lower bounds for hourly electricity consumption, ramping constraints derived from the maximum hourly ramp in the reference load profile, and elasticity parameters which are used for the cost of flexibility calculation, if they are implemented empirically. Load profiles from the reference year are used as the baseline against which demand redistribution is evaluated. These reference profiles contain hourly consumption data in kilowatts for an entire year.

Implementation of cost components

Here follows the explanation of how each cost component is implemented in the model. It should be noted that for each tariff, the height of the tariff is increased by dividing it with the average weighing factor over the entire year, which is 0,561. This is because grid operators would make less revenue if the tariff heights were unchanged, while introducing weighing factors. This is a similar approach for tariff height estimation as used by CE Delft (2025). For each of the tariff components, the medium-voltage (MV) tariffs from 2024 are used (Stedin, n.d.-b), as only consumers on the MV grid category are analyzed, and because 2024 is also the reference year for this study.

Commodity price

The commodity price used in the model corresponds to the hourly electricity price for 2024, excluding any taxes. It is exogenous, meaning modelled consumers cannot influence the commodity price. Each hour in the year contains a dedicated energy price per kilowatt hour and may take on a negative value in some cases. These negative prices are retained in the optimization to represent realistic market signals. Depending on the selected temporal scope, the relevant set of prices is applied. Hourly prices are imported from an external Excel file, which is adapted from Jeroen.nl (n.d.), with a graph shown in Figure 4.

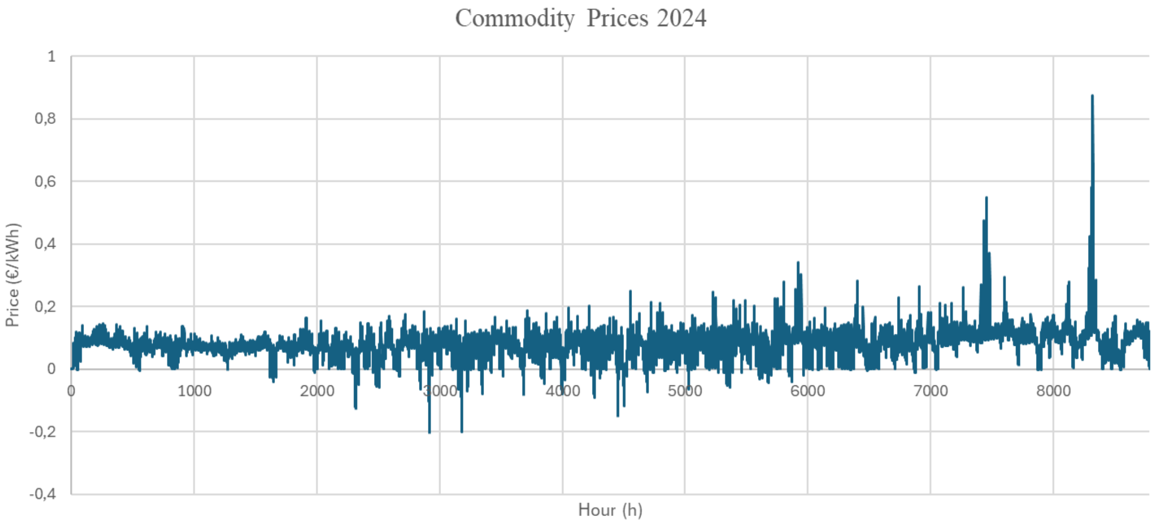
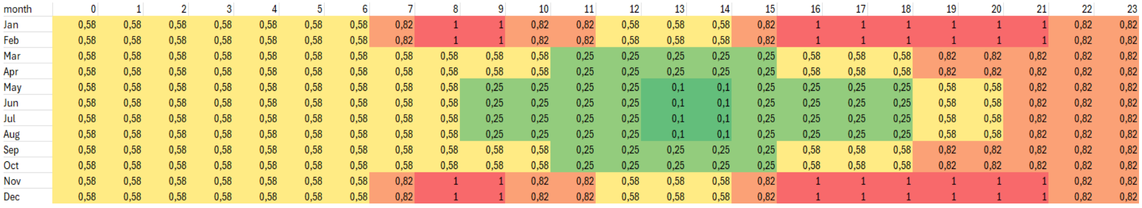


Figure 4: Graph commodity price 2024 adapted from Jeroen.nl (n.d.)

It is assumed that all consumers are exposed to hourly electricity prices, allowing them to respond dynamically to them. This assumption overestimates realized flexibility of consumers, if consumers do not have dynamic energy contracts. However, the assumption is justified given the limited data on contract structures, and the increasing prevalence of dynamic pricing in the Netherlands. For consumers who do not face hourly prices in reality, the prices can be interpreted as stochastic prices signals, reflecting market uncertainty. Regardless, the approach represents a high-flexibility scenario and provides insights into how commodity prices interact with grid tariffs.

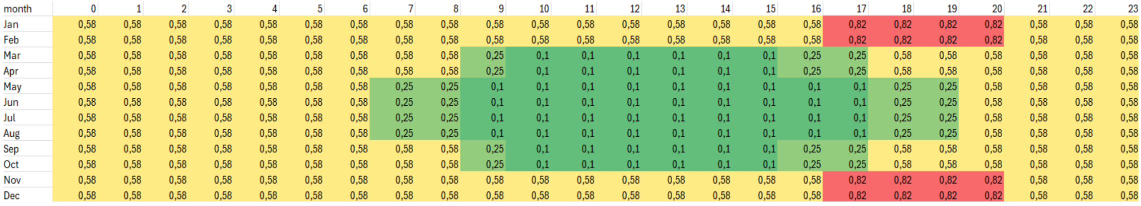
Weighing factors

The weighing factors for the ToU tariffs are adapted from proposed weighing factors from Stedin. The value of a weighing factor depends on the month, day and hour for which the factor is relevant. A distinction is made in weekdays and weekend days. As explained in the model formalization section, the tariff levels are multiplied with the relevant weighing factors. The weighing factors implemented in the model are shown in Figure 5 and Figure 6, showing the weekday and weekend weighing factors, respectively.



month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,82	1	1	0,82	0,82	0,58	0,58	0,58	0,82	1	1	1	1	1	1	0,82	0,82
Feb	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,82	1	1	0,82	0,82	0,58	0,58	0,58	0,82	1	1	1	1	1	1	0,82	0,82
Mar	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,25	0,25	0,25	0,25	0,58	0,58	0,58	0,82	0,82	0,82	0,82	0,82
Apr	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,25	0,25	0,25	0,25	0,58	0,58	0,58	0,82	0,82	0,82	0,82	0,82
May	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,25	0,25	0,25	0,1	0,1	0,25	0,25	0,25	0,25	0,58	0,58	0,82	0,82	0,82
Jun	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,25	0,25	0,25	0,1	0,1	0,25	0,25	0,25	0,25	0,58	0,58	0,82	0,82	0,82
Jul	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,25	0,25	0,25	0,1	0,1	0,25	0,25	0,25	0,25	0,58	0,58	0,82	0,82	0,82
Aug	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,25	0,25	0,25	0,1	0,1	0,25	0,25	0,25	0,25	0,58	0,58	0,82	0,82	0,82
Sep	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,25	0,25	0,25	0,25	0,58	0,58	0,58	0,82	0,82	0,82	0,82	0,82
Oct	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,25	0,25	0,25	0,25	0,58	0,58	0,58	0,82	0,82	0,82	0,82	0,82
Nov	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,82	1	1	0,82	0,82	0,58	0,58	0,58	0,82	1	1	1	1	1	1	0,82	0,82
Dec	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,82	1	1	0,82	0,82	0,58	0,58	0,58	0,82	1	1	1	1	1	1	0,82	0,82

Figure 5: Weekday weights



month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,82	0,82	0,82	0,82	0,58	0,58	0,58
Feb	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,82	0,82	0,82	0,82	0,58	0,58	0,58
Mar	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,1	0,1	0,1	0,1	0,1	0,1	0,25	0,25	0,58	0,58	0,58	0,58	0,58	0,58
Apr	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,1	0,1	0,1	0,1	0,1	0,1	0,25	0,25	0,58	0,58	0,58	0,58	0,58	0,58
May	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,25	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,25	0,25	0,58	0,58	0,58	0,58
Jun	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,25	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,25	0,25	0,58	0,58	0,58	0,58
Jul	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,25	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,25	0,25	0,58	0,58	0,58	0,58
Aug	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,25	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,25	0,25	0,58	0,58	0,58	0,58
Sep	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,1	0,1	0,1	0,1	0,1	0,1	0,25	0,25	0,58	0,58	0,58	0,58	0,58	0,58
Oct	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,25	0,1	0,1	0,1	0,1	0,1	0,1	0,25	0,25	0,58	0,58	0,58	0,58	0,58	0,58
Nov	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,82	0,82	0,82	0,82	0,58	0,58	0,58
Dec	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,82	0,82	0,82	0,82	0,58	0,58	0,58

Figure 6: Weekend weights

Volumetric tariff

The volumetric grid tariff is implemented similarly to the commodity price, as it is strictly also a price per kilowatt hour. However, the volumetric tariff can be specified as either fixed or variable. In the fixed case a constant price of €0,0176 per kilowatt hour is applied. In the variable case, time-dependent prices are read from an external Excel file in which the hourly weighing factors have already been applied. In this case, the base price per kilowatt hour is €0,0314.

Peak tariff

The peak tariff is also implemented in both a fixed and variable way. When fixed, a price of €2,8524 per kilowatt is assumed. When set to variable, the prices from an external Excel file are assumed, which contains the prices already multiplied with the relevant weighing factors. In the variable case, a price of €5,0845 per kilowatt is assumed.

Contracted power tariff

The contracted capacity tariff is implemented in a similar manner to the peak tariff, with fixed or variable prices imported from an external Excel file. The prices for the fixed and variable structure are €1,9167 per kilowatt and €3,4166 per kilowatt, respectively.

Though the contracted capacity tariff is a monthly tariff, its structure applies to an entire year. This poses a challenge when combined with a rolling-horizon optimization, as the structure of the contracted capacity depends on the consumption levels, yet the consumption levels are influenced by the tariff itself. As mentioned, a single contracted capacity structure cannot be determined in advance. To address this two-way relationship, the structure of the contracted capacity is updated iteratively. After each daily optimization, the contracted capacity is increased if the newly calculated day contains higher contracted levels than the previous day. The structure cannot be updated to a lower level. This approach combines the annual contracted capacity with the rolling-horizon feature of the model and preserves the interaction between consumption and contracted capacity costs.

Flexibility costs

The underlying principle of the flexibility cost formulation is that it is a penalty term that discourages deviations from the reference profile. The elasticity values used in the cost of flexibility term can either be calculated empirically or be introduced as external parameters in the form of a scenario analysis. For the analysis in this study scenarios will be introduced to represent varying degrees of demand flexibility. This allows for an exploration of how consumers react to various tariffs depending on their assumed flexibility, without having to rely on unreliable empirical estimates. Should more robust and representative elasticity estimates become available, they can immediately be implemented to improve the realism for these scenarios.

Prior to this approach, various regression analyses were conducted to determine whether changes in consumption could be explained by changes in electricity price. In Figure 7 and Figure 8 four regression analyses are shown which were conducted to explore this correlation. In these analyses $\frac{dq}{q}$ was plotted on the y-axis and $\frac{dp}{p}$ on the x-axis. In Figure 7, this analysis was performed for days, meaning all relative price changes and relative demand changes were compared for all hours in all similar days within the same half year, leading to 624 datapoints. In Figure 8 the same analysis is performed but then for all similar hours in similar days within the same half year, leading to 26 data points. This analysis was performed for a connection known to have a dynamic pricing contract for electricity in both 2022 and 2024.

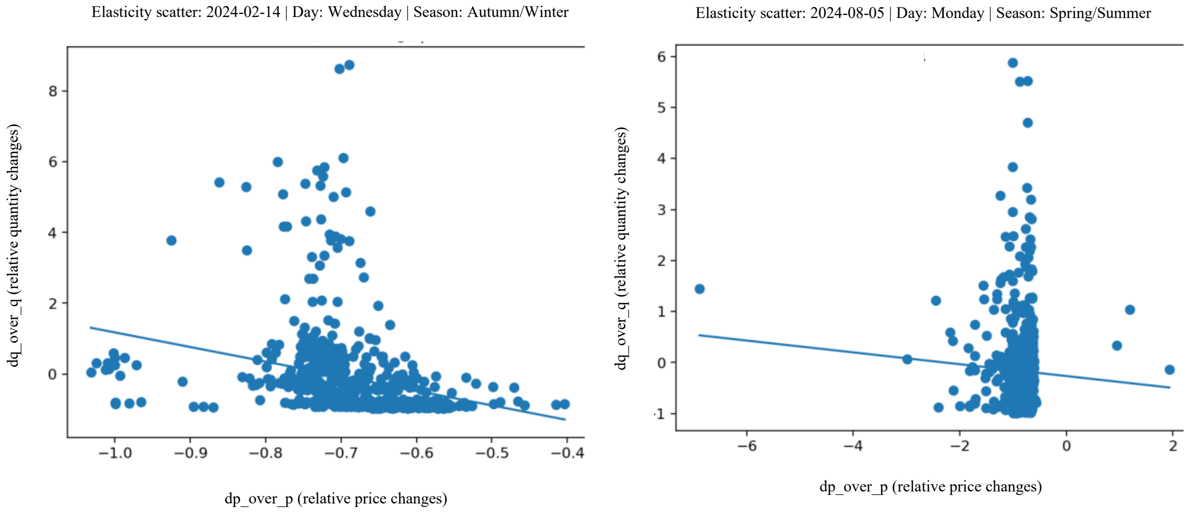


Figure 7: Scatterplots Wednesday Autumn/Winter and Monday Spring/Summer

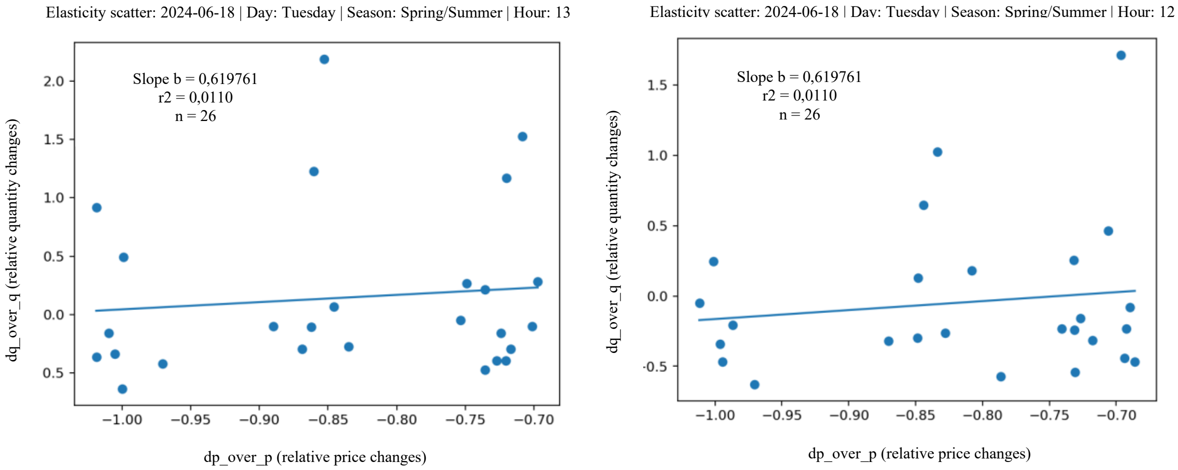


Figure 8: Scatterplots Tuesday Spring/Summer hours 12 and 13

The hypothesis was that a negative relation emerges, as logically higher electricity prices would lead to lower electricity consumption. Though this can be seen in Figure 7, the found R-squared values were consistently below 0,1, meaning commodity price changes do not explain changes in demand. It can thus be concluded that electricity prices are not a good predictor for demand changes. Rather, changes in demand are more likely to be explained by for example production processes and technical limits. In Figure 8, a positive relation is found, also with R-squared values sub 0,1. This contrasts with the hypothesis but reinforces the conclusion that changes in the commodity price do not explain changes in electricity demand.

This analysis was performed for a sample of days and hours, all leading to similar results. These scatterplots are not shown in this thesis because those shown here are regarded as representative for the population, and do not change the formulated conclusion. Also, though more connections could have been analyzed, the connection from this analysis was the most fitting and was expected to show the most significant correlation. It is expected that analyzing other connections in the same manner would only have reinforced the conclusion that the available data is not sufficient to support empirically estimated elasticities.

This conclusion does not mean that no further research must be conducted to the estimation of connection specific elasticities. For this analysis, only specific datasets were used, both due to restrictions in access to other types of data and due to time constraints. There is more data available within Stedin which can be used to control for other influences determining the demand of large-scale electricity users, leading to more accurate elasticity estimates. Including such estimates in the created model would significantly increase the consumer heterogeneity and make for an interesting analysis. For the analysis in this thesis, the elasticities will be introduced by means of a scenario analysis to reflect heterogeneity in flexibility costs.

3.4.2 Network segment in Vision

The network segment chosen for this analysis is the Massvlakte medium voltage network. This network is chosen for its large variation in connected large-scale electricity users, which are characterized by pronounced peaks in electricity demand. The objective of this study is to analyze peak reduction and demand shifting as a result of new grid tariffs, so this network provides a relevant empirical setting.

The network model includes all components downstream of a 25-kilovolt to 10-kilovolt transformer. Network areas connected to higher-voltage transformers could not be analyzed due to constraints on the data availability within Vision. A total of 65 large-scale consumers is connected to the chosen network segment. However, for five of these consumers there was no data from 2024, meaning they are only included as unaltered loads in the analysis. One additional user could not be imported in Vision, a problem that also occurred when using the original Vision files provided by Stedin. This appears to be an internal software issue, so no further solution was pursued. This connection was therefore excluded from the analysis. This means that the final dataset consists of 59 large-scale electricity connections. Other than large-scale connections, the network area also included low voltage loads and generation units. These profiles are not subjected to the behavioral model and are thus treated as unaltered exogenous loads.

Within Stedin's data structure, power injection by large-scale electricity users is implemented as zero net demand. This does not pose a problem for the analysis, as the behavioral model already only changes electricity consumption. Power injection by generation units is represented in Vision, and therefore still included in the load flow calculations.

The network model used in this study is routinely applied within Stedin. Within the scope of this thesis, as mentioned in Section 3.1.3, validation and verification are therefore not performed. The correctness of the load flow calculations is assumed verified and valid based on prior internal validation and use.

3.4.3 Implementation assumptions

This section discusses the assumptions related to model implementation. These are subdivided into three categories: technical and data assumptions, behavioral assumptions, and solver assumptions.

Technical and data assumptions

The solution space is determined by historical average and peak consumption. The use of average consumption is due to missing data on minimum consumption and is therefore adjusted in scenario analyses. This is explained in more detail later, but the use of average consumption as a lower bound is justified because the lower bound is adjusted during a scenario analysis later in the study.

The tariff levels are all based on the levels from 2024, and the ToU tariff levels are determined based on the assumption that they recover the same costs as the non-ToU tariffs. This approach was also used by CE Delft (2025) and allows for an effective translation from non-ToU tariff levels to ToU tariff levels.

The loads in the network analysis tool that are not subject to the cost-minimization, such as generation or consumers with missing data, are assumed to remain unchanged. Excluding certain consumers may underestimate the aggregated effects of the ToU tariffs. However, the total number of modelled loads is reported, thus allowing to assess the extent of missing connections.

The contracted capacity is re-contracted without taking historical contracted capacities into account. As historical data is already used as an upper limit, it limits the consumption to realistic levels, which may be above the actual contracted capacity if the capacity was historically exceeded. Also, contracted capacities may end up higher than before the ToU contracted power tariff. This modelling choice is thus more realistic than to model the upper limit as the contracted capacity.

Behavioral assumptions
The implemented elasticities are assumed to be uniform over time, and are assumed to be representative for the modelled consumers. They have been derived from literature on large-scale electricity users, and are varied by means of a scenario analysis, making this the most feasible assumption on elasticities in the absence of empirical estimations.

Solver and model assumptions
It is assumed that the default settings of Gurobi are sufficient for this analysis, as is indicated b the results of the model verification and validation. The verification and validation are discussed in the next section.

The Vision network model is assumed to be valid based on prior internal validation within Stedin. This model will thus not be validated further.

3.5 Model verification

The created demand response model must be tested to explore if the model works as intended. This process is referred to as model verification. First the cost-minimization model will be verified, by exploring the effects of the implemented cost units and constraints. The Vision network analysis model will not be verified, nor validated. It is assumed that the network analysis model works properly, as it is already widely in use within Stedin, and because network data, such as network topology, has been provided by Stedin directly.

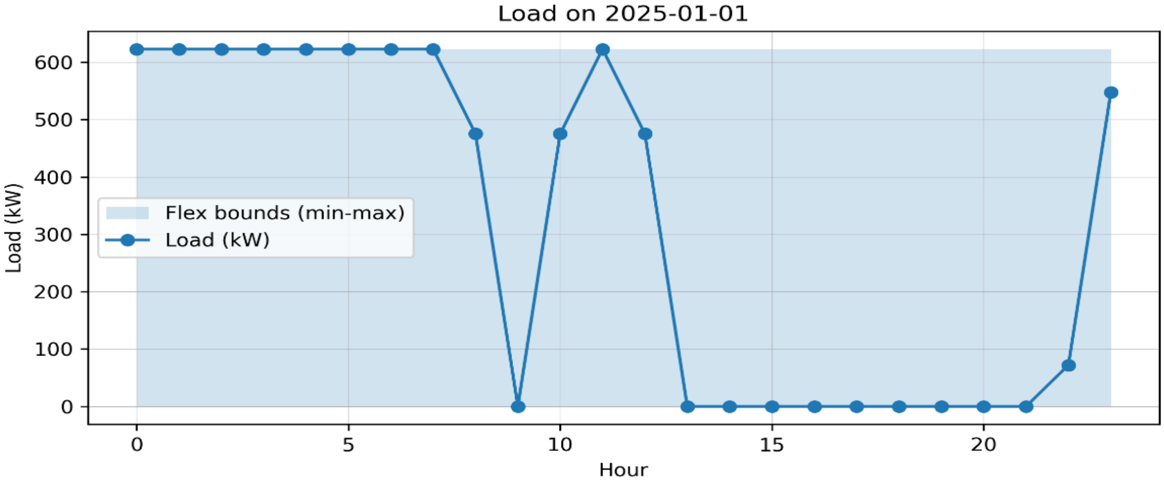
To determine if the time-of-use tariffs are implemented properly, they will be analyzed by exploring their effects in a model with very wide constraints. The active constraints in these verification scenarios are a ramping of 475,2 kilowatts, an upper limit of 623 kilowatts and a lower limit of 0 kilowatts, unless mentioned otherwise, and a total of 7651,2 kilowatts to be redistributed. 2024 tariffs were used in this verification process.

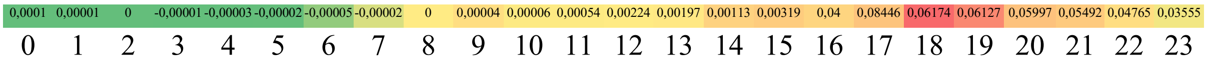
For each verification of a tariff, only the relevant tariff is variable and has time dependency. Other tariffs are turned off and thus have no effect on the optimization. This ensures that the effects of each tariff are isolated and can be analyzed separately. Later, all fixed tariffs will be verified simultaneously.

3.5.1 Separate cost components

Commodity price

Setting the commodity price as the only cost component in the model results in the load profile shown in Figure 9. Here a daily profile is shown. For clarity the hourly commodity prices have also been added in Figure 9. A weekly or monthly load profile is not shown because it would not serve as a clarification due to how unclear the graph is. Do note, in the figure it says 2025, this is because initial tests were run in a 2025 scenario with 2024 prices.





0,0001	0,00001	0	-0,00001	-0,00003	-0,00002	-0,00005	-0,00002	0	0,00004	0,00006	0,00054	0,00224	0,00197	0,00113	0,00319	0,04	0,08446	0,06174	0,06127	0,05997	0,05492	0,04765	0,03555
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23

Figure 9: Variable commodity price, 01-01-2025 as scope

The behavior shown in both figures is as expected. The model uses the most energy during times where the energy price is lowest and uses less energy when these costs rise. The model yields a total daily cost of €495,42, which corresponds to the calculation made by hand.

Volumetric tariff

The variable volumetric tariff is calculated by multiplying the transported energy at time t with the weighing factor at time t. With weighing factors being higher during times of high grid usage (typically between 7:00 am and 10:00 am, and 18:00 pm and 21:00 pm), it is expected that energy usage is low at these moments. By only including the volumetric tariff as a variable tariff in the cost-minimization, and by giving a maximum ramping, line capacity and redistributable energy, the effects of the volumetric tariff can be isolated and analyzed.

Figure 10 and Figure 11 show the daily and weekly load respectively. Only the volumetric tariff has time dependency. The plots show expected behavior. Electricity is mostly used during cheap moments, and especially during the weekend. The behavior on the last day is caused by the fact that it does not matter when electricity is consumed during this behavior. In such cases, the model assigns load randomly.

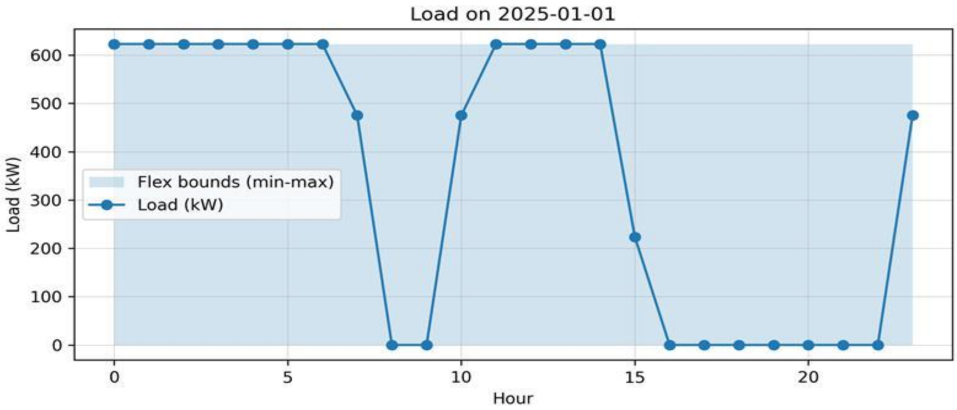


Figure 10: Variable volumetric tariff, 01-01-2025 as scope

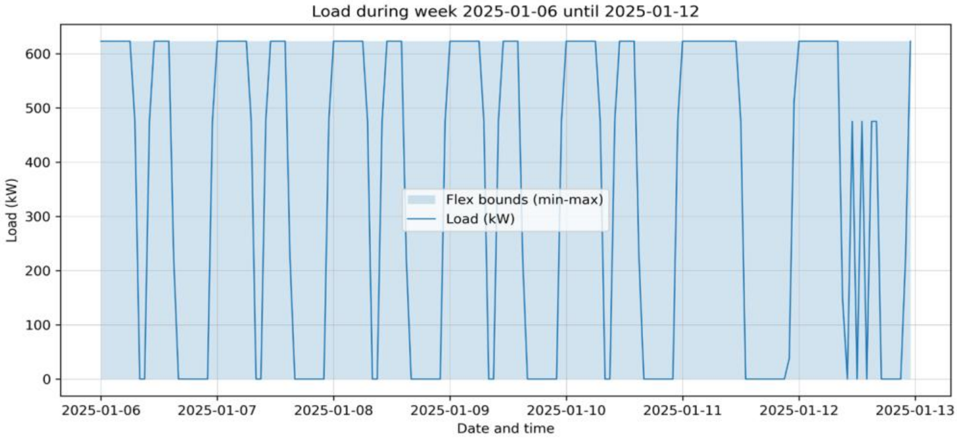


Figure 11: Variable volumetric tariff, 01-2025 as scope

When looking at the daily profile, the load profile follows the weighing factors very accurately, with any deviations explainable with the ramping constraints. Looking at these load profiles, it can be concluded that the model shows expected behavior with the introduction of a time-of-use volumetric tariff.

Under these conditions the model calculates a total cost for the volumetric tariff of €150,07 for a day. Calculation by hand for this load profile yields the same results, proving the cost calculation function works properly. This also means the minimization itself is expected to work as intended.

Peak tariff

The peak tariff is a monthly tariff determined by measuring peak usage and charging for every kilowatt in that peak. When this tariff is variable, the highest peak is multiplied with the weighing factor relevant for when the peak was measured. This tariff should thus reduce usage peaks during moments of high grid usage, since then these weighing factors are highest.

In Figure 12 and Figure 13, the daily and weekly profiles are shown respectively. The behavior shown is as expected. The daily profile follows the exact structure of the weights for that month, where peaks are reduced with high weighing factors and increased with lower weighing factors. For example, at 8:00, there is a weighing factor of 1. At 6:00 a weighing factor of 0,58 is initiated. Logically this would mean that the peak at 6:00 should be approximately 1,7 times higher than the peak at 8:00. This is what the model shows, as the peak at 6:00 is 450 kilowatts, and the peak at 8:00 is 261 kilowatts. In the weekly plot it can be seen that the model implements the weekly weighing factors correctly.

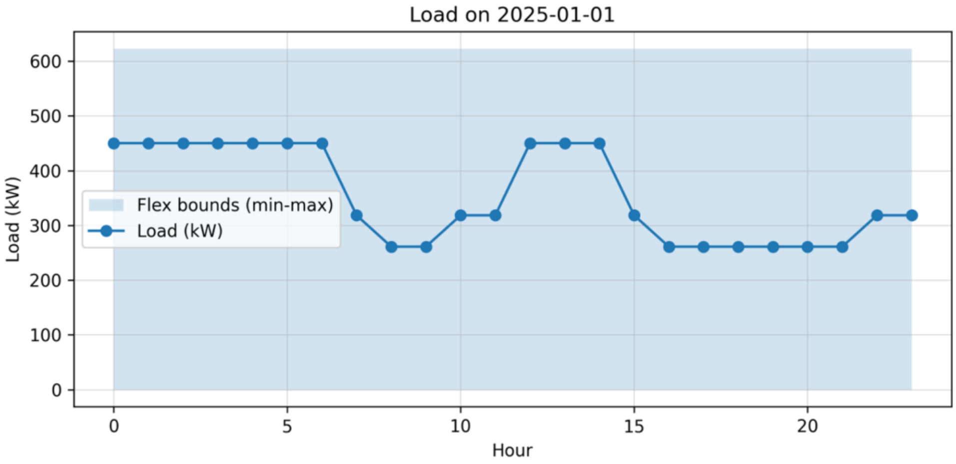


Figure 12: Variable peak tariff, 01-01-2025 as scope

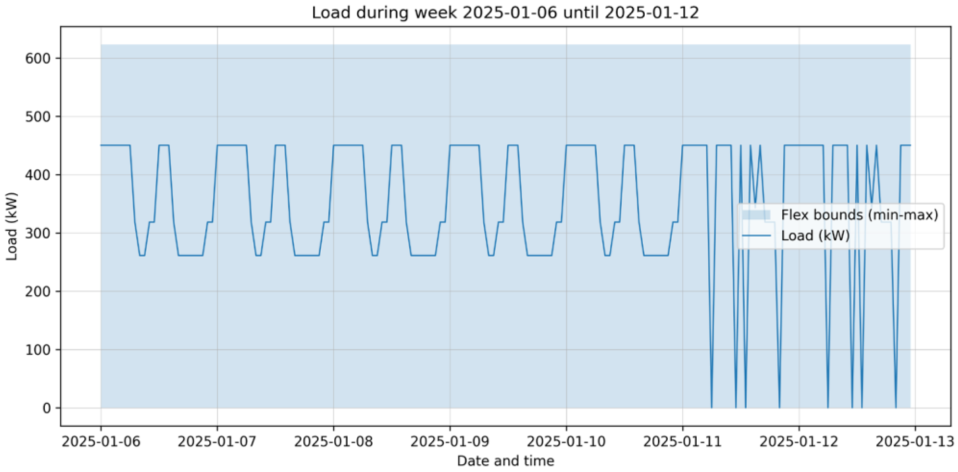


Figure 13: Variable peak tariff, 01-2025 as scope

To verify that the cost component is implemented correctly, a calculation by hand has been done. Both the calculation from the model and the calculation by hand reveal a total cost of €38,55 for 01-01, with €5,0845 per kilowatt. This verifies that the model calculates the peak tariff correctly.

Contracted power tariff

To verify the correct implementation of the variable contracted power tariff, a similar scenario to the previous scenarios was run. For this scenario the variable contracted power tariff was the only included tariff. Figure 14 and Figure 15 show the load pattern for a day and a week respectively as a result of running this scenario.

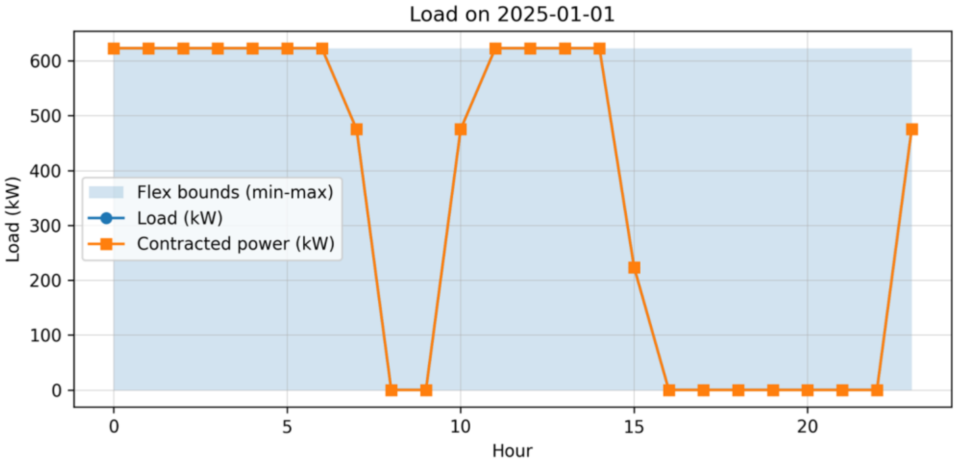


Figure 14: Variable contracted power tariff, 01-01-2025 as scope

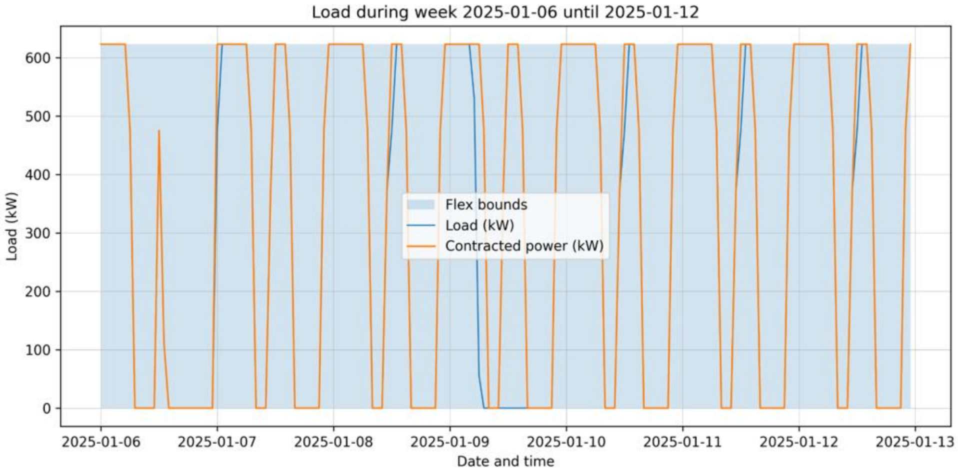


Figure 15: Variable contracted power tariff, 01-2025 as scope

The daily behavior follows the structure from the volumetric tariff, which is expected because essentially the contracted power tariff comes down to a volumetric tariff with timesteps of one hour and a scope of a day. The difference between the contracted power tariff and volumetric tariff lies in how the monthly costs are calculated and how the contracted capacity levels change iteratively.

For the sake of verifying the iterative behavior of this tariff, the first and fourth day have less power to be redistributed. On the first day a different contracted power structure is adopted than on the second day, because more power must be redistributed on this second day, increasing the contracted power level. Then, on the fourth day, the load profile no longer follows this structure because then again, less energy is to be redistributed. This can also be seen by looking at the slight deviation from the contracted power structure at the start of each day. Due to the ramping, the load cannot follow the sudden increase in the contracted power structure on every day after the first day. This sudden increase is caused by the fact that the first day starts by already having a contracted power level.

The total costs per month are calculated using the contracted power structure from the last day in a month. Here the contracted levels are multiplied with the relevant costs, and then the average over all costs of the last day is taken to get the monthly tariff. In a daily scenario, the model yields a total cost of €21,95, which corresponds to the costs derived from a calculation by hand, and corresponds to monthly price if multiplied with the months in the day.

Costs of flexibility
To verify the correct implementation of the costs of flexibility, some calculations are made with a new scenario, now in the year 2022. New to this scenario are the elasticity, electricity price and load of the corresponding hour in the year 2022. The elasticity (at hour 12 of January first) was calculated empirically as -1,2222, with q_t^{2022} = 481 kilowatts, p_t^{2022} = €0,166, q_t^{2024} = 534,4 kilowatts and p_t^{2024} = €0,151.

The model was first run without any deviations from the reference profile (2022), resulting in near-zero (-€3,41*10^-13) flexibility costs. Then, one extra kilowatt of power was forced into the load pattern at hour 12 of January first. This led to a flexibility cost of €0,000283. This is the expected flexibility cost, as shown in equation 15. For a second run a deviation of 100 kilowatts was forced, leading to a flexibility cost of €2,83, proving the quadratic function works as per equation 16. These calculations prove the flexibility costs have been implemented in the model correctly and yield expected results.

$$(15) \quad \frac{0{,}166455}{|-1{,}2222|}\frac{(1)^2}{480{,}96} = 0{,}000283$$

$$(16) \quad \frac{0{,}166455}{|-1{,}2222|}\frac{(100)^2}{480{,}96} = 2{,}83$$

These calculations also show that the flexibility costs work for elasticities implemented by means of scenarios, as the elasticity is then a given and that q_t^{2022} and p_t^{2022} take on values for another year.

3.5.2 Fixed tariffs

The tariffs and commodity price can be set to a fixed level. To verify that this approach works as intended, the base scenario has been calculated with only fixed cost components. All cost components except for the flexibility costs are activated at the same time, as the model should construct a straight line for a load profile, regardless of what tariffs are active. In this case, a total of 4.800 kilowatts of energy is redistributed, all other constraints are the same as in the previous scenarios.

The load profile for all fixed tariffs is presented separately in **Error! Reference source not found.Error! Reference source not found.**. The load profiles behave as expected. For the commodity-cost and fixed kilowatt hour tariff cases it does not matter when electricity is used or how much electricity is used during an hour, so the optimizer may produce a seemingly random schedule. This also explains the peak at the end of the day, as the model strictly speaking has no reason not to have this peak at the end of the day.

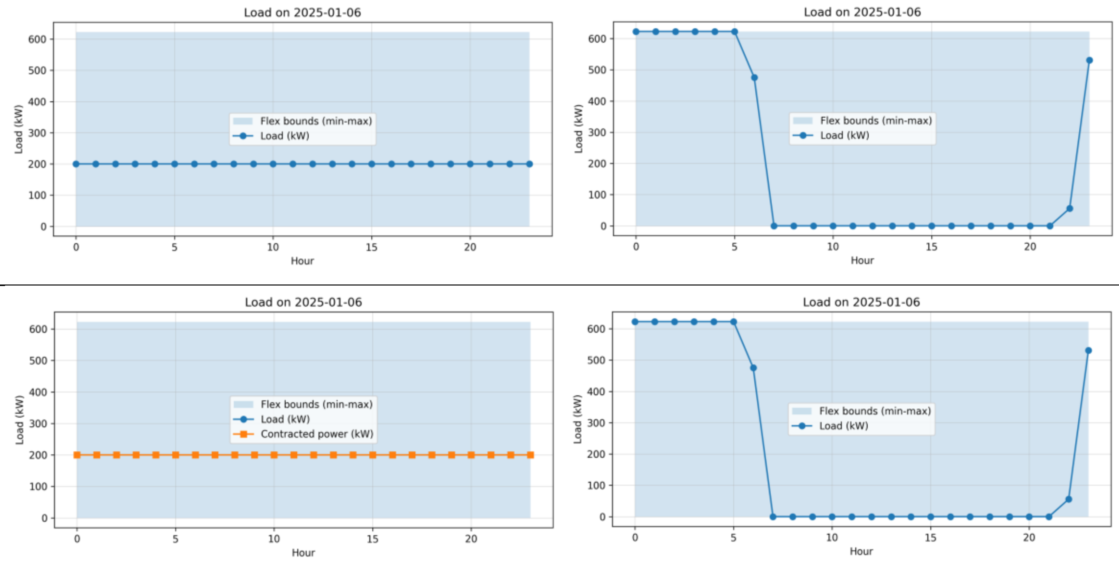


Figure 16: Load profiles with fixed tariffs

In contrast, the fixed peak and contracted power tariffs do make the optimization dependent on the height of the load. In these cases, increasing the load at any moment can raise the monthly charge, because the tariffs are determined by the highest load in the selected scope. Therefore, the optimizer should spread load evenly, which can be seen in **Error! Reference source not found.**.

The total costs for each daily scenario were the following. The total commodity costs were €76,52, assuming a price of €0,01 per kilowatt hour. The costs for the volumetric tariff were €134,68, assuming €0,0176 per kilowatt hour. The costs for the peak tariff were €29,34, assuming €2,8524 per kilowatt. Lastly the costs for the contracted power tariff were €19,71, assuming €1,9167 per kilowatt. The peak and contracted power tariff costs were divided by 31, because the selected month was January. All these costs match the costs calculated by hand, verifying the correct implementation of fixed tariffs in the model.

3.5 Model validation

Now that it has been shown the model works as intended, the model can be validated. This will be done in four steps. First the model is validated conceptually, to prove the conceptual validity of the model and evaluate assumptions conceptually. Then the model is validated internally, to show the model does what it should do and contains defensible assumptions. Then it is tested whether the behavior of the model is plausible and lastly a sensitivity analysis is performed to validate the internal interactions of the model.

3.5.1 Conceptual validation

This section describes the conceptual validity of the created model. It explores why the model is suitable to analyze grid tariffs on a system level.

The created model is representative for a situation in which large-scale electricity consumers are exposed to various tariff configurations, electricity prices and a penalty for deviation from their reference profile. In this way, instead of predicting exact consumer behavior, the model aims to analyze the influence on different tariff structures on electricity consumption to explore how tariffs may affect peak reductions and the adjusted load factor.

The behavior of the modelled consumers is represented by a cost-minimization framework based on the tariffs, electricity price and flexibility costs. A cost-minimization is found valid here, as the modelled consumers are assumed to be price takers in their relevant markets. Similar approaches are commonly used in literature to analyze demand response, as shown in Section 2.3. This approach allows for the model to capture the interaction effects of tariffs and consumption decisions, without requiring process-level data.

To maintain the scalability of the model, so that a physical grid area can be analyzed, the model does not represent specific industrial processes but includes historical consumption data to determine the ramping and solution space in the optimization. Unrealistic shifts in energy consumption are prevented through the costs of flexibility. In this way, the model can represent different levels of flexibility for consumers, while remaining grounded in observed behavior.

The model represents a trade-off between behavioral realism and scalability. It remains grounded in historical data, but does so in a way that simplifies consumer decision-making and optimization constraints. The model is therefore conceptually valid for analyzing how grid tariffs influence the chosen performance indicators on a system level.

3.5.2 Internal validation

This section presents the internal validation of the optimization model. The objective is to verify that the model behaves as expected, and that the interaction of all components in the model is internally consistent. For the internal validation, real customers in the distribution grid operated by Stedin are analyzed.

Fixed and variable tariffs

To present the internal validation of all cost components and constraints, four scenarios are created. There are two fixed tariff scenarios, one with and one without flexibility costs, and there are two variable tariff scenarios, also with varying flexibility costs.

Fixed tariffs scenario

To verify correct model behavior under fixed tariffs and historical ramping and flexpotential data, the load profiles in Figure 17 and Figure 18 are shown. The plots show the flexpotential, load profile from 2024, the new load profile, and the contracted capacity. The load from a logistics company is optimized. It should be noted that because the reference year already had fixed network tariffs, it does not mean the model should always follow the reference profile, such as in cases without costs for flexibility.

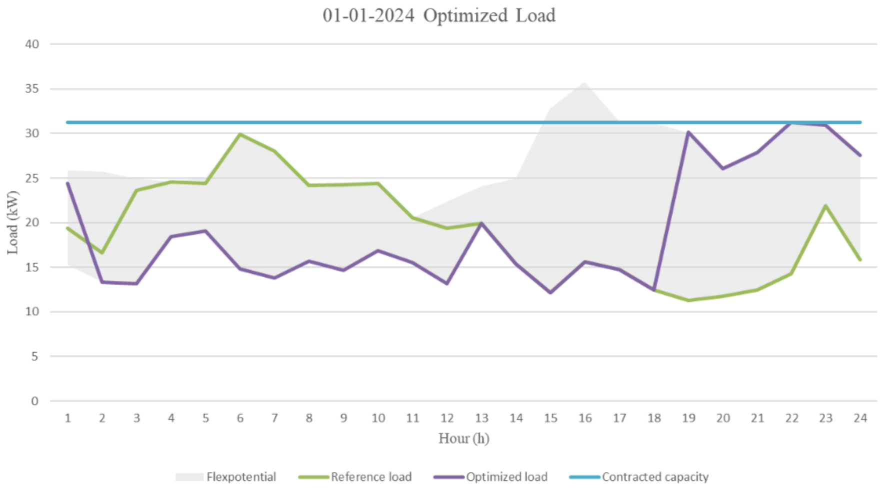


Figure 17: Redistribution with all cost components fixed, no flex costs

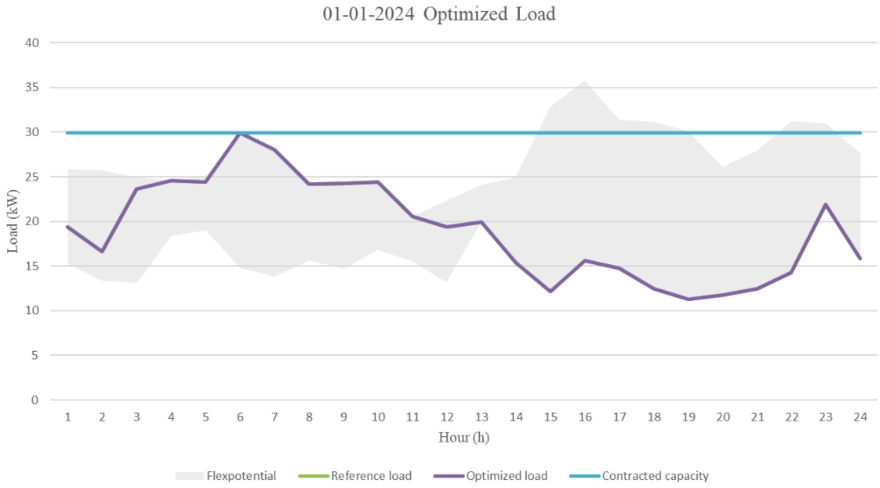


Figure 18: Redistribution with all cost components fixed with flex costs (elasticity = -0,2)

When looking at Figure 17, intuitively one might expect that the load is as straight as possible. However, though the contracted capacity line is completely straight, as intended, the rest of the load seems random. This is expected behavior, because only the peak and contracted power tariffs incentivize peak reduction. Once a peak is reached, the rest of the load can be distributed randomly. The chosen distribution is thus one of many optimal distributions. The figure thus also shows how the flexpotential works as the solution space, as it limits the new load profile from being lower than the solution space from hour 19. It can also be seen that the energy balance constraint works, because at least the energy from the reference load is redistributed as compared to the reference profile.

Figure 18 also contains all tariffs in a fixed manner, but now also has the costs for flexibility enabled. For this scenario an elasticity of -0,2 is chosen. This value has no further meaning for the realism of the results, as it is used only to show the model behavior, but is chosen based on elasticities from literature (Chang et al., 2019; Cialani & Mortazavi, 2018). The figure shows how in this scenario the new load profile closely follows the reference profile, because it would incur costs if any deviations were made. The load profile deviates slightly, because it appears to be less expensive to have a lower contracted capacity and peak, than to fully follow the reference profile. It thus shows how the peak tariff, contracted power tariff and flexibility costs interact.

Variable tariff scenario

To validate the model under fully variable tariffs, all tariff components are set to time-varying values. In these scenarios the same consumer has been analyzed as with the fixed tariff scenario. Figure 19 and Figure 20 show the same information as in the fixed scenario, but now two days are calculated in sequence to show the workings of the rolling horizon.

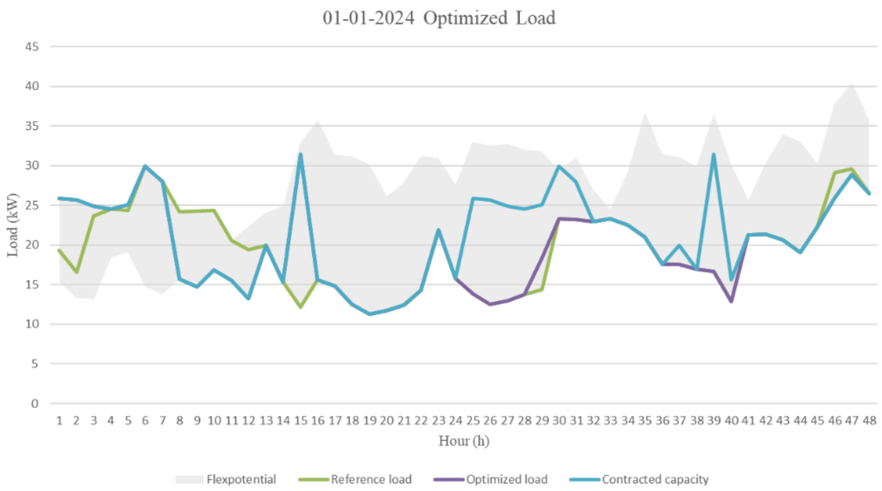


Figure 19: Redistribution with all cost components variable, no flex costs

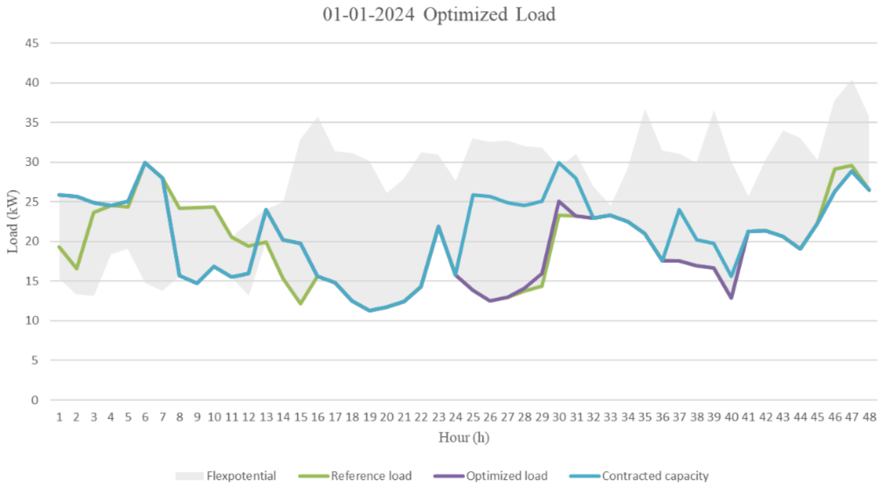


Figure 20: Redistribution with all cost components variable with flex costs (elasticity = -0,2)

Several observations can be made based on Figure 19. First it can be seen that the optimized load reacts to the variable tariffs. There is more consumption between hours 1 and 3, and less consumption during the expensive hours, such as between hours 7 and 11. The second day, from hour 25 on, the profile shows how the contracted capacity remains in the same pattern as the previous day, until it is updated at hour 31. This update is necessary due to the height of the base load constraint. During this second day, less total energy is to be redistributed so the new load profile no longer follows the contracted capacity structure.

In Figure 20 the costs of flexibility are introduced, again with an assumed elasticity of -0,2. It shows how the flex costs cause the variable tariffs to have less of an effect on the load, for example at hour 15. The figure also illustrates how higher loads lead to updates in the contracted capacity, such as at hour 41, confirming that contract levels are iteratively determined by the optimization.

Across all scenarios, all optimized solutions satisfy all model constraints. The energy balance is met, and no violations of power bounds, ramping or contracted capacity were present. This confirms that the model behavior shown in the figures is internally consistent and fully compliant with all model constraints. It also shows how the base load constraint is very restrictive, often limiting the ability for shifting loads. As mentioned in Section 3.4.1, the solution space will therefore be varied in a scenario analysis to understand its effects on peak reduction.

Validity of cost calculations

Individual cost components have already been verified separately in Section 3.5.1. However, an additional consistency check is performed to validate the combined cost formulation in the full optimization model. To do so, the total costs are recalculated after using the model based on the optimized load profiles, and then compared to the values presented by the model.

The same four scenarios are used as the validity test for fixed and variable tariffs. The profiles for these scenarios can be seen in Figure 17, Figure 18, Figure 19 and Figure 20. For each of these scenarios, and the reference load of 2024, the total costs are calculated and presented in Table 2. In this case a scope of a week is chosen which starts 2. The scenarios B.1 and B.2 represent recalculations of the reference load from 2024, where B.1 contains fixed tariffs and B.2 contains variable tariffs. The scenarios O.1 to O.4 represent scenarios with fixed tariffs and no flexibility costs, fixed tariffs with flexibility costs, variable tariffs and no flexibility costs and lastly variable tariffs with flexibility costs, respectively.

It must be noted that the costs for the fixed base scenario are an underestimation, because the contracted capacity is assumed to be equal to the peak load in that scope, whereas in reality it is often contracted significantly higher. The table therefore only serves to show the optimization works, instead of providing realistic cost calculations.

Table 5 shows how the costs for the fixed scenarios are always similar. This is as expected, because there is no incentive to deviate from the reference profile, except to have a lower peak usage because of the peak and contracted power tariffs. As it was seemingly necessary to maintain this peak load, there was no further incentive to deviate from the reference load.

Table 5: Cost comparison various scenarios for internal validation

Cost component	B.1	O.1.	O.2.	B.2	O.3.	O.4.
Commodity	34,88	34,88	34,88	242,64	238,80	242,10
Volumetric tariff	61,39	61,39	61,39	80,73	79,62	80,24
Peak tariff	25,30	25,29	25,30	45,09	43,48	44,39
Contracted power tariff	17,00	17,00	17,00	16,43	12,94	13,03
Flex costs	-	-	0,00	-	-	0,41
Total	138,56	138,56	138,56	384,89	374,83	380,17

For the variable scenario it shows how the optimized costs for the are always lower than the estimated costs from the reference profile. The differences in costs are limited, but this is as expected. As mentioned before, the limited flexpotential of this consumer limits the room for improvement, thus making it harder to save costs significantly. It also shows how with flexibility enabled, the costs are significantly closer to the reference profile, which is also as expected. It can thus be concluded that the cost-minimization acts as intended.

Extreme values

As a final internal validity test, some scenarios are created with extreme values for certain variables. The model should still be able to perform under these conditions and show logical behavior. Six extreme scenarios are tested, where first each cost component is set to extreme heights, then the flexpotential is increased significantly and lastly the elasticity is set to an extreme number. In all scenarios all tariffs are set to variable and a single day is modelled. Not all variables are changed for all scenarios, because this would be too time intensive. Therefore, a sample is taken of various significant changes and their effects. An elasticity value of -0,2 is assumed unless stated otherwise.

Commodity price

First it is analyzed if the model responds correctly to an extreme value for the commodity price. The commodity price is set at €1.000 per kilowatt hour at hour 11. The resulting load profile is shown in Figure 21. The figure does not show a significant load reduction in hour 11. Though counter intuitive, this is intended behavior. This is because the flexibility costs are increased to the same extent as the commodity price, balancing out the costs. The resulting behavior is thus as expected.

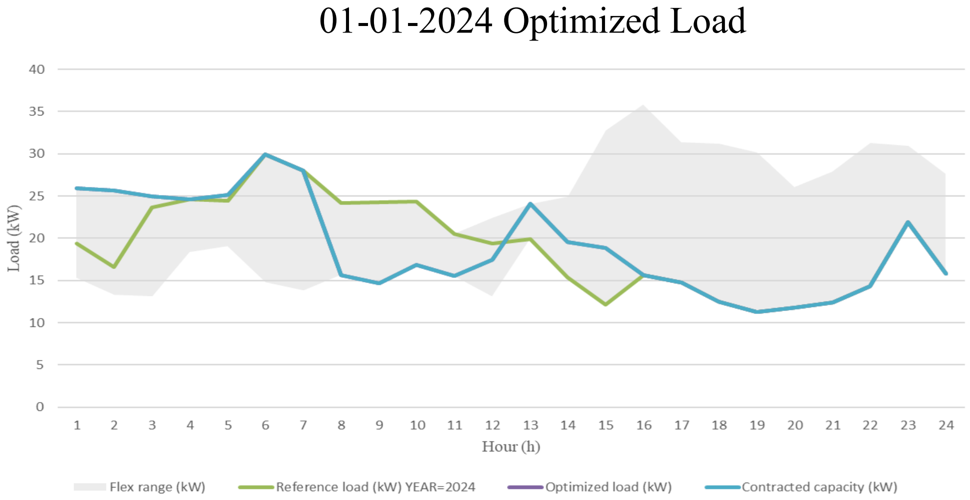


Figure 21: Redistribution with commodity price = 1.000 at hour 11 (12 in plot)

Volumetric tariff

Now the volumetric tariff is set to €-1.000 per kilowatt hour at hour 15. It is expected that the model tries to ramp up its consumption for this hour. The expected behavior is shown in Figure 22, where at hour 15 (hour 16 in the plot) the model fully utilizes the solution space to draw power. It does so while still cohering to the set constraints.

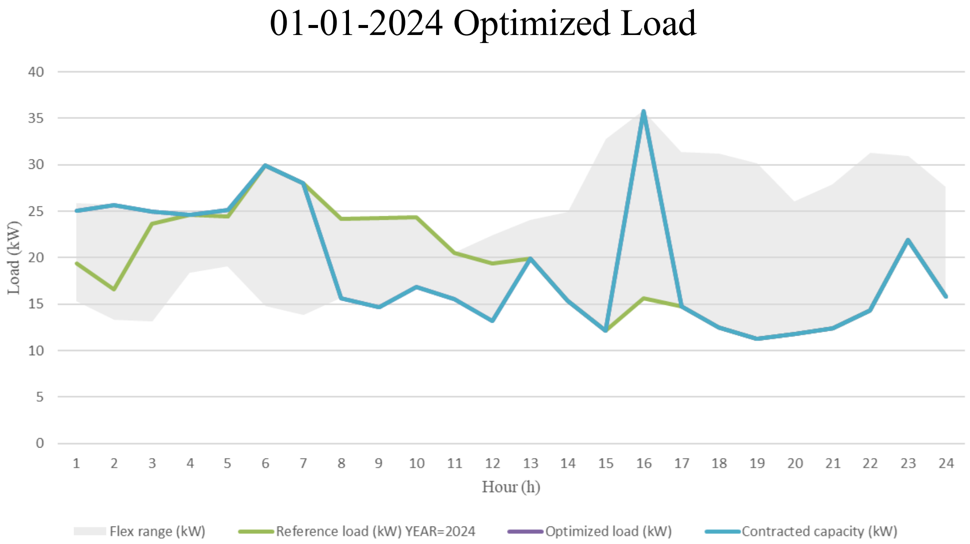


Figure 22: Redistribution with volumetric tariff = -1.000 at hour 15 (16 in plot)

<u>Peak tariff</u>

For the peak tariff a weighing factor is set to an extreme value. At hour 11 (12 in Figure 23) the weighing factor is set to 1000. The same behavior is expected as with the commodity price, so that the load is minimized at that hour. Figure 23 shows the expected behavior. The load indeed decreases at hour 11, indicating the model tries to minimize the total costs. The peak tariff does not influence the flexibility costs, so this time the price signal is not cancelled out.

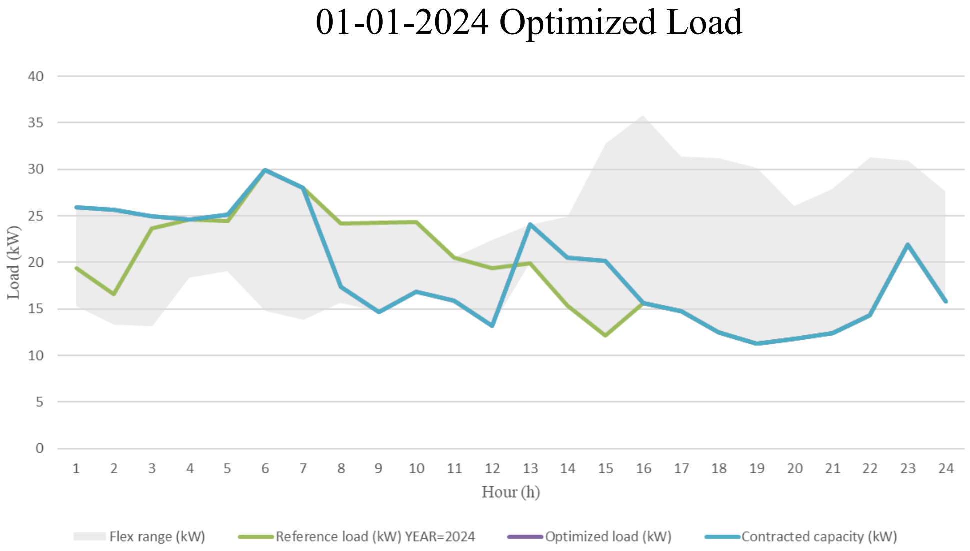


Figure 23: Redistribution with peak tariff weighing factor = 1.000 at hour 11 (12 in plot)

<u>Contracted power tariff</u>

The contracted power tariff was set to €-1.000. When the contracted power tariff becomes negative, the model exhibits unbounded infeasibility behavior. This is because the model tries to contract an infinite amount of power at 17. Though ramping constraints limit the rate at which contracted capacity can change, they do not impose an upper bound on its absolute level. This allows the optimization to increase the contracted power to an infinite level. The contracted capacity is also not bounded by the flexpotential, because the contracted capacity level is chosen for an entire scope. This behavior is thus expected mathematically, but a modelling limitation that clarifies the economic domain in which the model is valid. Addressing it would require additional contractual constraints and modelling complexity. Since grid tariffs are unlikely to ever reach negative prices, this improvement falls outside of the scope of this study.

Flexpotential

For this situation the solution space is increased. The upper bounds are increased with 1000%, and the lower bounds are decreased with 1000%. For the sake of the analysis the costs of flexibility are turned off. Figure 24 shows how the model still behaves as expected. The load is highest during cheap hours, and lowest during expensive hours. Then, since the energy from the reference day has already been distributed in the cheaper hours, the load reaches zero to lower the total costs. It is visible that the ramping constraints prevent the model from drastically changing the load. The model thus behaves as intended under these conditions.

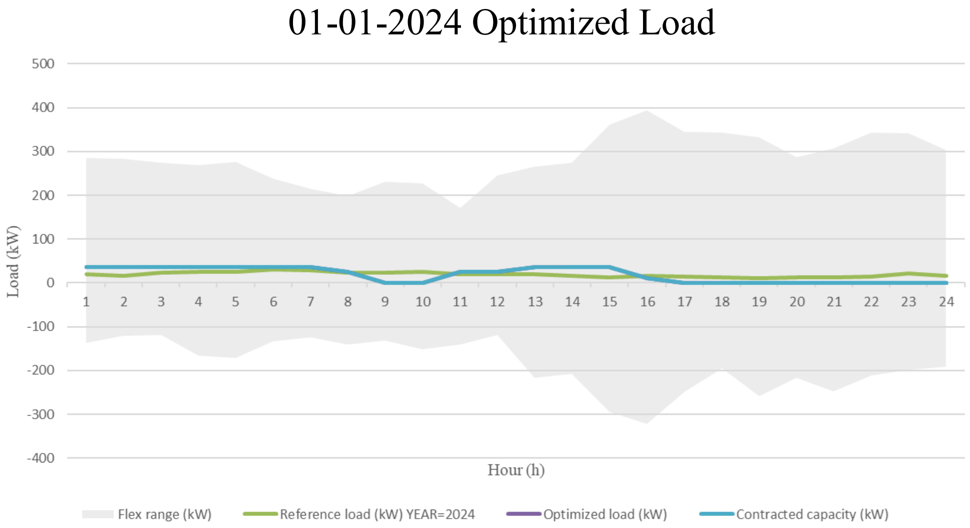


Figure 24: Redistribution with increased solution space

Costs of flexibility

Logically higher elasticities would lead to lower flexibility costs and thus lead to profiles deviating from the reference profile. Alternatively, low elasticities lead to load profiles closely following the reference load. To test this assumed behavior, the elasticity has been set to -1000 for the first scenario, and to -0,0001 for the second scenario. Figure 25 and Figure 26 show the scenario with a high elasticity value and a low elasticity value, respectively. Figure 25 shows the expected behavior, as little effort is made to stick to the reference profile. Figure 26 also shows expected behavior, as the load is now significantly more similar to the reference load.

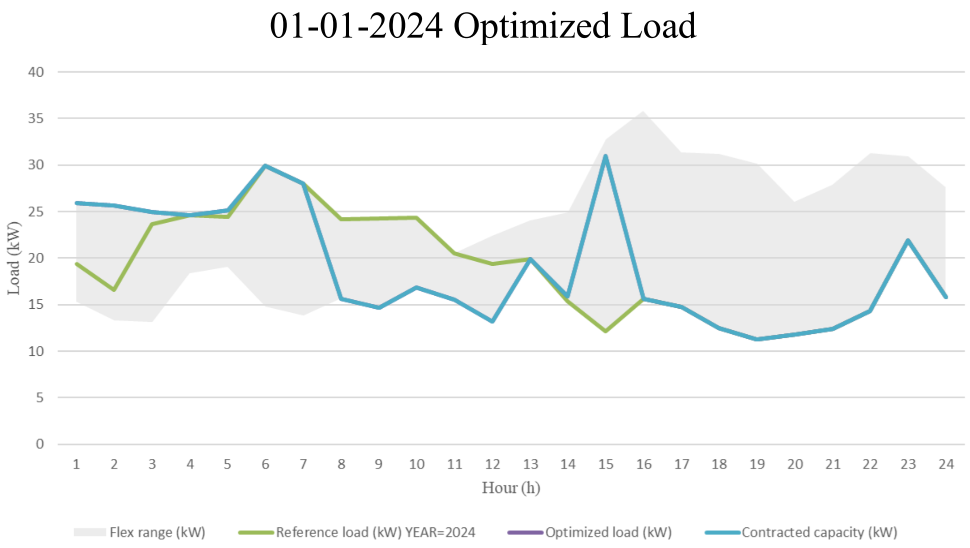


Figure 25: Redistribution with high elasticity value (-1000)

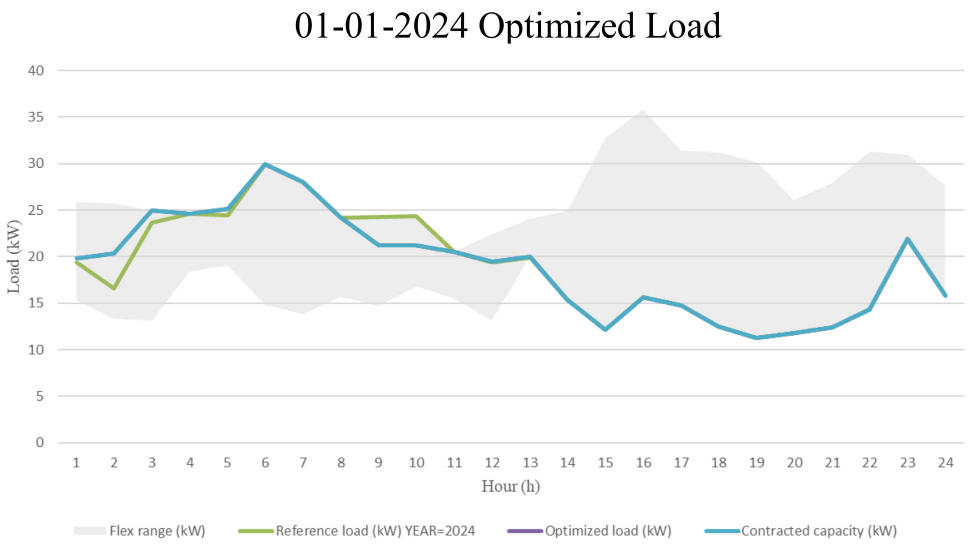


Figure 26: Redistribution with low elasticity value (-0,0001)

With the interaction effects, cost calculations and behavior as a result of extreme values analyzed, it can be concluded that the model behaves as expected. The components of the model and their interactions work as intended. These analyses allow for the conclusion to be made that the model is internally valid.

3.5.3 Behavioral plausibility

It is inherently difficult to determine whether the behavior is truly plausible, as a new model is made that has never been used before. As already argued, the model cannot show behavior that is outside of the realm of possibility for consumers as it is grounded in historical data. However, it is still important to make sure the model can handle different types of consumers and does not produce implausible behavior regardless of the constraints. The results show that the model is indeed capable of optimizing consumer-specific loads rather than applying the same optimization pattern across all consumers. Three different parties are researched, named party X, Y and Z respectively for anonymization. An elasticity of -0,2 is assumed with no mutations to the flexpotential.

To assess the behavioral plausibility, load duration curves (LDCs) are examined for three different consumers. For each consumer a LDC is made for the autumn/winter period and for the spring/summer period to show seasonal heterogeneity. All LDC's are created for January and June. Figure 27 and Figure 28 show the LDCs of party X, Figure 29 and Figure 30 show the LDCs of party Y for the same months and lastly Figure 31 and Figure 32 show the LDCs for party Z which can feed power back into the grid.

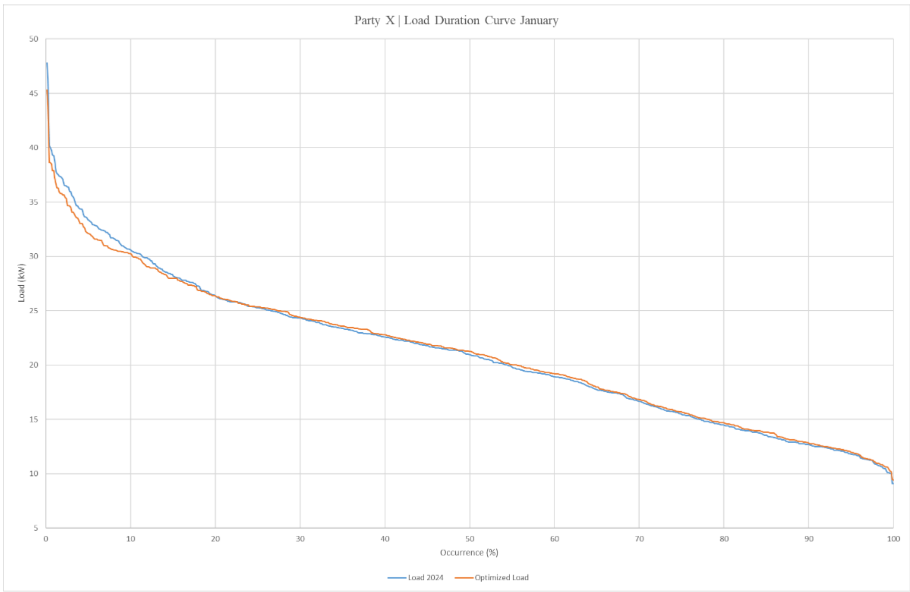


Figure 27: Load Duration Curve January, party X

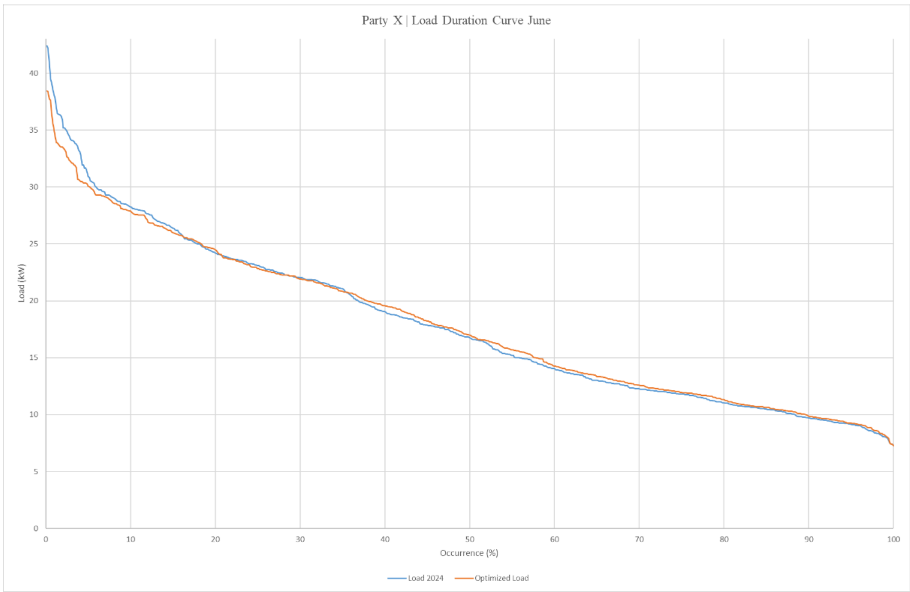


Figure 28: Load Duration Curve June, party X

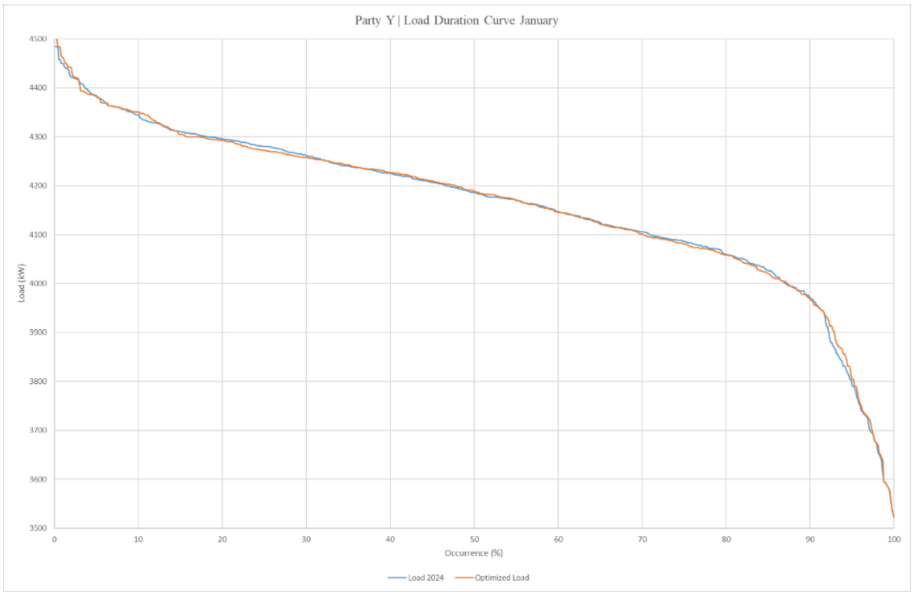


Figure 29: Load Duration Curve January, party Y

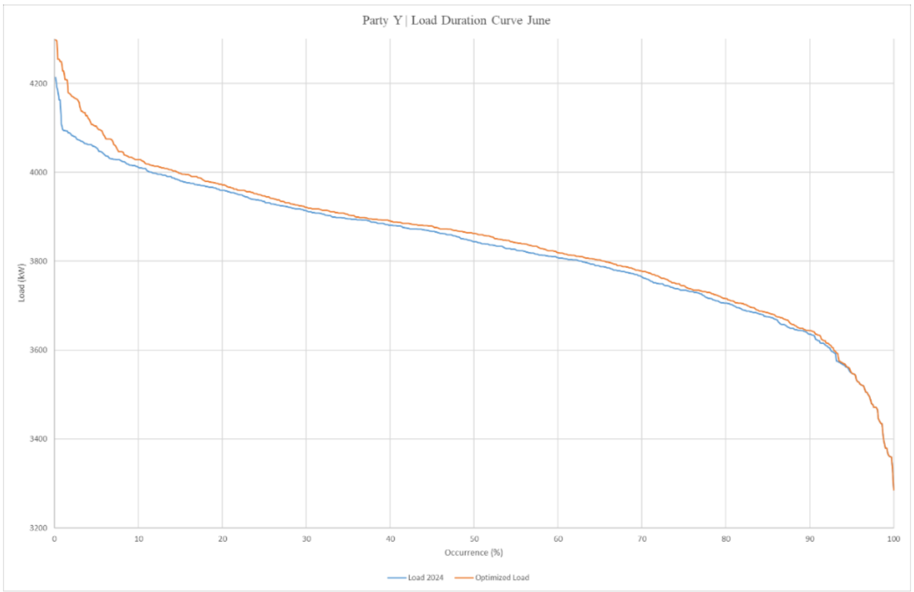


Figure 30: Load Duration Curve June, party Y

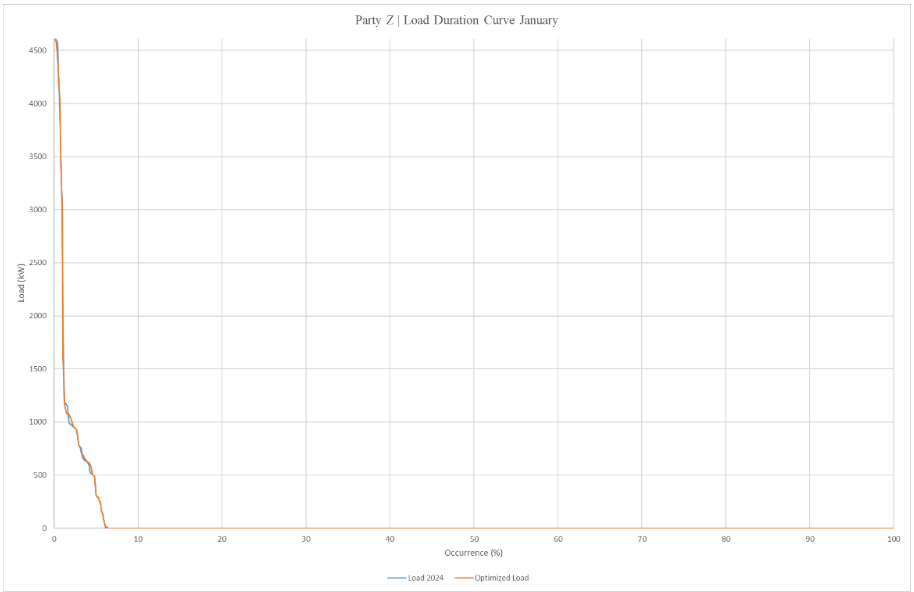


Figure 31: Load Duration Curve January, party Z

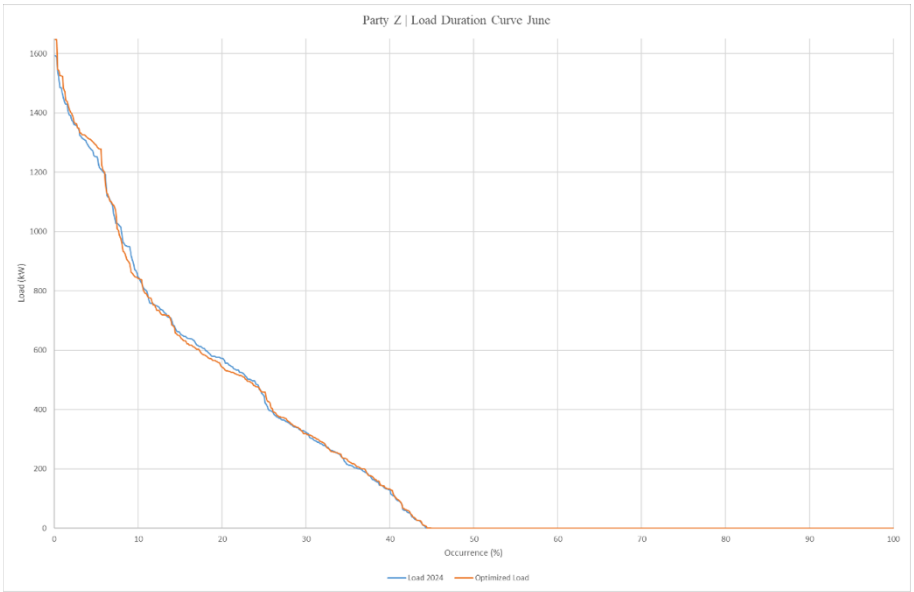


Figure 32: Load Duration Curve June, party Z

In general, the optimized LDCs show a smooth and gradually declining shape, except for the LDCs from party Z. The smoothly declining shapes indicate that load shifting is distributed over many hours instead of being concentrated in extreme peaks. This aligns with realistic consumer behavior, where flexibility is generally spread across various appliances and activities. The model thus primarily reallocates average loads, rather than altering essential base loads or inducing unrealistically high peaks. The steeper shapes represent significant peaks in consumption, and redelivery of energy. Since these shapes closely follow the reference patterns, the resulting variations are still considered plausible.

The LDC of Party Y shows interesting behavior, as more load is used as compared to the reference profile. This is due to a combination of negative commodity prices, very low weighing factors (0,1) and ample of room in the flexpotential. It shows that party Y minimizes costs by increasing revenues, which is deemed plausible and expected.

The LDC for party Z is rather steep and has a lot of moments where there is zero load. This consumer is an example of a consumer that can redeliver power to the grid. As explained, redelivery of power is not possible in the model, thus leading to a load of 0. This is also the case for Vision.

Seasonal differences between autumn/winter and spring/summer profiles are also preserved in the optimized LDCs. Higher base loads and steeper curves in the winter period can reflect heating-related demand, while flatter curves in summer indicate lower deviations in consumption. This indicates that the optimization does not alter fundamental optimization patterns for each consumer. The model also allows for heterogeneity across connections, as resulting LDCs remain distinct between connections. The model thus does not force a single optimal load shape for all connections.

In conclusion, the LDCs show that the optimized load profiles remain structurally similar to the reference profiles, while also exhibiting plausible shifts in response to price signals. The absence of extreme peaks and the preservation of seasonal characteristics and heterogeneity across consumers support the conclusion that the model produces behavior that is plausible within the assumed constraints and cost components.

3.5.4 Sensitivity analysis

The variables used in the model are inherently uncertain. To assess the robustness of the results presented in the previous sections, a sensitivity analysis is conducted. The sensitivity analysis examines whether the main qualitative conclusions, such as peak reduction and load shifting behavior remain consistent under reasonable variations in key parameters. The results of this analysis must therefore be interpreted in a qualitative manner. If similar patterns emerge across various parameter values, it can support the conclusion that the model outcomes are in fact robust and are not dependent on only a single parameter choice. Robustness in this sensitivity analysis implies that qualitative mechanisms, such as lower peak reduction with less flexibility, remain consistent.

For the sensitivity analysis, the same connection is analyzed as in Section 3.5.2. Though it does not matter which connection is calculated, this connection is chosen for continuity. The day chosen for this analysis is 05-01-2024, because this day contains the highest peak from the week used in Section 3.5.2. Such a high peak is useful for the clarity of the analysis.

For both sensitivity analyses, the peak reduction, load shifting and emergence of new peaks are presented. The peak reduction is based on the hour containing the highest peak in the reference profile. In this analysis, this peak occurs at 21:00, 05-01-2024 (39,27 kilowatts). This hour is tied to a weighing factor of 1 and thus represents an hour that is relatively expensive. The total load shift is determined by taking the sum of the absolute values from the difference between the new profile and reference profile for each hour, which is then divided by two. New peaks and when they occur are presented in a separate table. The inclusion of this information gives insight into whether new peaks occur in the system, and thus whether tariffs cause general peak reduction, or only reduce specific peaks, leading to new peaks in the system.

Flexibility

In the first analysis of the sensitivity analysis, both the elasticity value for the costs of flexibility and flexpotential values are varied. The flexpotential is varied by increasing the upper limit with the mentioned percentages and decreasing the lower limit with the mentioned percentages. These scenarios provide an insight into the interaction of elasticities and flexpotential and show the main drivers for peak reduction and load shifting. Elasticity is treated here as a behavioral parameter instead of any empirically fixed value. The sensitivity analysis thus explores a plausible range of elasticities to understand how behavioral responsiveness affects peak reduction and load shifting. The results from this scenario are presented in Table 6. Table 7 presents the height of the new peak and when this peak occurs.

From Table 6 multiple conclusions can be made. First it becomes apparent that peak reduction in this scenario requires the base load constraint to provide ample room. Only when the base load limit is decreased can the peaks be decreased further. A baseload decrease of 10% results in an increased peak reduction of approximately 16% with the lowest elasticity, and an increased peak reduction of 271% with the highest elasticity (where elasticity increases with 1000%). Decreasing the base load with 20% only leads to a further decrease of the peaks when the elasticity is high enough. The load shift always increases as a result of an increased flexpotential and higher elasticity values. Peak migration only occurs when the flexpotential is increased. The new peak is at 22:00, which is coupled to a weighing factor of 0,82. This shift is thus as expected.

It can be concluded that elasticity primarily affects load shifting, while peak reduction only occurs when there is also enough flexibility available. The interaction between flexibility and elasticity shows that the model produces reliable outcomes with varying parameters, assuming the flexpotential allows a response to price signals. Without enough flexpotential, there is limited peak reduction, reflecting system constraints rather than system instabilities.

Table 6: Sensitivity analysis elasticity and flexpotential for peak reduction and load shift, all variable

Flexpotential | Elasticity	Elasticity = -0,05		Elasticity = -0,2		Elasticity = -0,5	
	Δ Peak (kW)	Σ Shift (kW)	Δ Peak (kW)	Σ Shift (kW)	Δ Peak (kW)	Σ Shift (kW)
No mutation	1,40	1,45	1,40	2,52	1,40	4,99
Flexpotential -2 * 10%	0,00	0,34	0,00	1,34	0,00	3,15
Flexpotential +2 * 10%	1,63	1,84	4,73	7,17	5,19	10,20
Flexpotential +2 * 20%	1,63	1,89	4,71	7,38	8,79	17,39

Table 7: New peaks from peak reduction and load shifting, elasticity and flexpotential scenario

Flexpotential | Elasticity	Elasticity = -0,05		Elasticity = -0,2		Elasticity = -0,5	
	Peak	Hour	Peak	Hour	Peak	Hour
No mutation	37,89	21:00	37,87	21:00	37,87	21:00
Flexpotential -2 * 10%	39,27	21:00	39,27	21:00	39,27	21:00
Flexpotential +2 * 10%	37,72	22:00	37,92	22:00	37,62	22:00
Flexpotential +2 * 20%	37,72	22:00	37,94	22:00	37,18	22:00

Contracted power tariff

In the second analysis, the influence of the contracted power tariff is examined by increasing its weight in the minimization. In one scenario only the contracted power tariff is variable with costs for flexibility enabled. In the second scenario all tariffs are set to variable with costs of flexibility enabled. An elasticity of -0,2 is assumed for all cases and was chosen based on elasticities from literature (Chang et al., 2019; Cialani & Mortazavi, 2018). To ensure peak reduction is feasible, the base load constraint is reduced by 50%. The contracted power tariff is varied by scaling its weight in the objective function. The results of this analysis are shown in Table 8 and Table 9.

The results show that the contracted capacity tariff only explains a limited share of the found peak reduction. Doubling or quadrupling the weight of the tariff only leads to increases in peak reduction of 2,1% and 4,2%, respectively. When all cost components are variable, peak reduction is reduced. This is because the commodity price counteracts peak reduction, as it provides different price signals. The results also show that the contracted capacity tariff not only reduces peaks, but also constraints peak to similar levels across multiple hours if all other tariffs are fixed. The contracted capacity is determined by the maximum hourly demand, so it leads to periods of constant load levels rather than high peaks.

It can be concluded that the contracted capacity tariff only marginally contributes to peak reduction, especially if for example the commodity price counteracts its price signals. In scenarios with otherwise fixed tariffs, the contracted capacity leads to a more uniform load profile during peak periods. These effects are in line with expectations and show that the contracted power tariff influences load shifting instead of peak minimization.

Table 8: Sensitivity analysis contracted power mutation for peak reduction, load shift (baseload -50%)

Tariff mutation	Only kW contracted and flex costs variable		All variable	
	Δ Peak (kW)	Σ Shift (kW)	Δ Peak (kW)	Σ Shift (kW)
No mutation	9,05	25,22	4,70	7,38
x0,5	8,95	24,83	4,69	7,30
x2	9,24	26,00	4,75	7,55
x4	9,43	26,73	4,82	7,88

Table 9: New peaks as a result of peak reduction and load shifting, contracted power mutation analysis

Tariff mutation	Only kW contracted variable		All variable	
	Peak (kW)	Hour	Peak (kW)	Hour
No mutation	30,22	20:00 - 23:00	37,94	22:00
x0,5	30,32	20:00 - 23:00	37,95	22:00
x2	30,02	20:00 - 23:00	37,93	22:00
x4	29,85	5:00 & 20:00 - 23:00	37,92	22:00

In conclusion, the sensitivity analyses show that the model produces consistent and plausible responses for various parameter settings, if there is sufficient flexibility available. The effects of flexibility, elasticity and all cost components explain the found effects in a coherent manner. The model is therefore considered suitable to apply it in a real network segment and start the main analysis. This will be addressed in the following chapter.

Chapter 4: Results case study Maasvlakte

The main research question of this thesis is about how time-of-use (ToU) contracted power tariffs contribute to improving system efficiency. It first had to be understood how large-scale electricity users react to price signals from grid tariffs and how this can be implemented in a model. With the newly created model, these sub questions have been answered. This means that the analysis can now move on to understand how the implementation of a ToU contracted power tariff influences the system efficiency. This will be analyzed by means of a case study, where the created method is applied for a real network segment.

4.1 Case study setup

The case study is conducted for the medium-voltage (MV) network area of the Maasvlakte. In total 59 connections (EAN codes) are modelled for four representative weeks of 2024. This analysis is performed for a single MV transformer feeding the MV network area. The aggregated load on this transformer is used to compute the key performance indicators, namely the absolute peak reduction, relative peak reduction and the improvement in the adjusted load factor. Results must be interpreted as illustrative for similar industrial MV segments. However, the diversity of consumers in the area suggests that a broad range of load characteristics relevant for other networks is captured. For each performance indicator a summary of results will be presented.

In the main analysis of the case study, it is assumed that the volumetric tariff and peak tariff are already implemented as ToU tariffs. According to Stedin, the Dutch DSO's are planning to propose these tariffs to be ToU and are thus especially interested in the added benefit of a ToU contracted power tariff. Also, the ToU contracted power tariff is primarily intended as an addition to the two to be implemented ToU tariffs, and a stand-alone introduction of the contracted power is highly unlikely according to Stedin. The analysis will therefore focus on the added value of the ToU contracted power tariff on top of the already ToU volumetric and peak tariff. At the time of writing, no public documents detailing the proposal are available, so this assumption is based on expert input from Stedin.

4.2 Scenario setup

To assess the impact of the ToU contracted power tariff, a set of scenarios is constructed. These scenarios provide a range of the expected effects on the key performance indicators. In all scenarios the commodity costs are variable, and costs of flexibility are always active. If a tariff is not appointed as ToU, it is set to fixed. The following combinations of cost components are analyzed in the scenario analysis: (1) all tariffs fixed, (2) only ToU contracted power tariff, (3) only ToU volumetric and peak tariff, (4) all ToU tariffs. This distinction in scenarios allows for isolation of influence, and thus an overview of what influences are explained by which tariff. The core analysis remains the comparison of the tariff configurations 3 and 4.

Four weeks are selected for a detailed analysis. These weeks are chosen based on the load profile at the transformer from the reference year, which is also shown in Figure 33, where the red bars represent the chosen weeks. For both the autumn/winter period and spring/summer period, following the flexpotential structure, two weeks are selected. Within each period, one week with an average load profile and one week with a peak load profile is selected. This allows for the analysis of the tariff under both regular and extreme operating conditions, and with different flexpotentials. The selected weeks in 2024 are week 8 (average autumn/winter week), week 25 (peak spring/summer week), week 30 (average spring/summer week) and week 50 (peak autumn/winter week). These weeks capture both seasonal variation and variation between average and extreme operating conditions, thus covering the main dimensions of load variability.

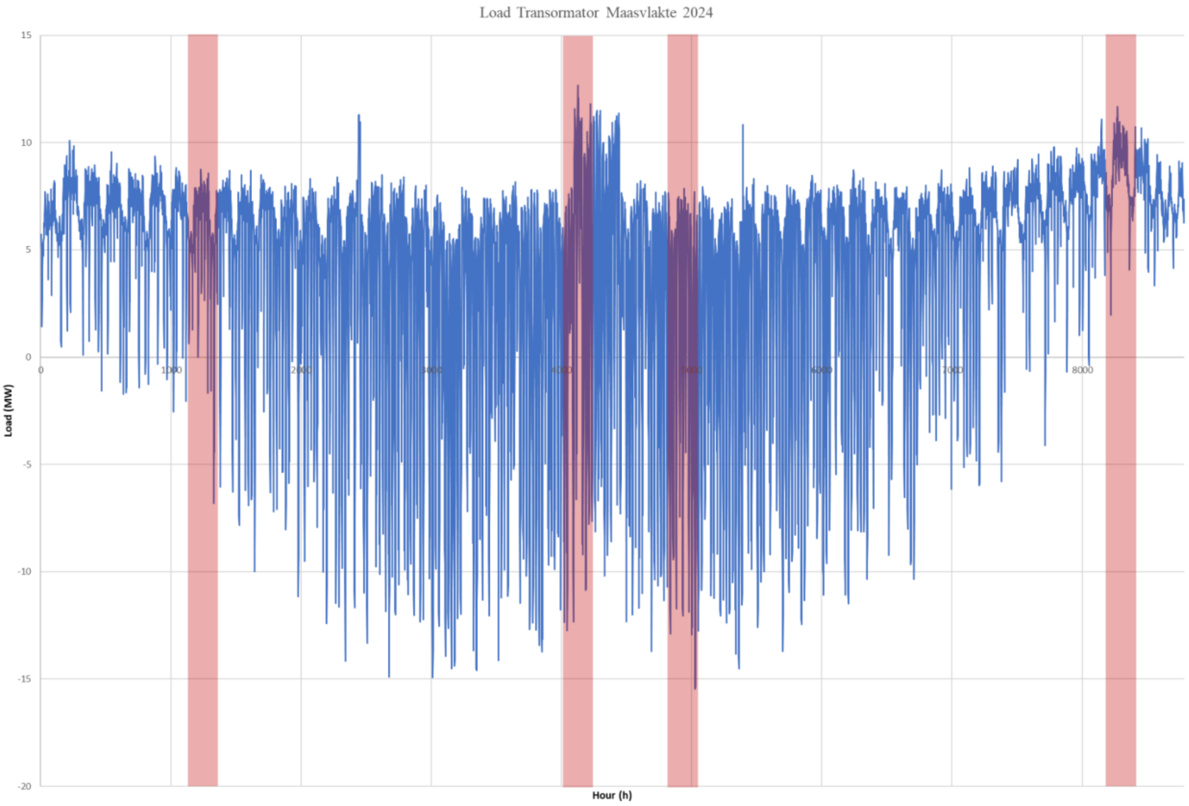


Figure 33: Reference load on a transformer from the Maasvlakte for week selection

Within each selected week, several input parameters are varied to obtain a comprehensive set of scenarios. The elasticity and baseload constraints are varied. For conservative flexibility scenarios an elasticity of -0,23 is assumed. For optimistic flexibility scenarios an elasticity of -0,43 is assumed. These elasticity values are mentioned by Cialani & Mortazavi (2018) in an overview of elasticities found in various studies. These specific values were found by Bojnec & Papler (2016) (Cialani & Mortazavi (2018) reference the wrong article). Long-run elasticities are considered to be the most appropriate, as large-scale electricity users have knowledge of tariff structures in advance, and can adjust their behavior accordingly. These elasticity values are consistent with elasticity ranges found by Chang et al. (2019) and are therefore found a fitting range for the sake of this analysis.

It must be noted that it is not the purpose of the analysis to provide precise estimations based on true elasticity values. Instead, its purpose is to explore a plausible range of behavioral responses to assess the range of impacts from the ToU contracted power tariff.

For the baseload constraint three configurations are considered, with first an unchanged baseload, representing limited room for consumers to alter behavior. Then a conservative flexibility scenario where the baseload constraint is reduced with 10%, representing consumers having the room to alter their demand to levels below their average demand. Lastly an optimistic scenario with a baseload constraint reduction of 20%. The baseload has been chosen to alter because of its importance in load shifting, and because it is expected that large-scale electricity users can adopt load profiles below their average usage.

Peak load constraints are not altered, because it is unlikely that large-scale electricity users would increase their consumption beyond historical peak levels. Also, there was ample room in the flexpotential to facilitate peak shifting. A sample of scenarios was examined to verify whether the solution space was large enough to facilitate peak shifting. If the baseload constraint itself determines the system peak, it cannot be reduced. In most cases, sufficient flexibility is available even without any alterations to the baseload constraint.

This scenario analysis design results in a total of 96 scenarios. Now the results will be presented.

4.3 Scenario results

The ToU contracted power tariff was evaluated on its impact on peak reduction and the adjusted load factor. For each performance indicator, the minimum, maximum and average effects are reported. To see the effects of the ToU contracted power tariff, the fixed and variable rows of the same week type must be compared. Finally, several load duration curves from the analyzed transformer are presented to show where and how peaks shift.

In this results section, all found results are presented in full. The inclusion of tariff configurations 1 and 2 allows for understanding what improvement on performance indicators can be attributed to which cost component. The load shifting results are shown in Table 25, Table 26, Table 27 and Table 28, Appendix B.

To understand the results provided in this section, one must compare the results for the 'kWc fixed' scenario with the 'all variable' scenario. This difference denotes the effectiveness of the ToU contracted power tariff. These scenarios are highlighted in grey. In the tables for peak reduction and the adjusted load factor, the original peak or load factor is mentioned in the name of the table. In the tables with aggregated results, only the scenarios with and without a ToU contracted power tariff are included.

4.3.1 Absolute peak reduction

The results for the absolute peak reduction are presented in Table 10, Table 11, Table 12 and Table 13. In these tables, the columns highlighted in grey must be compared to see the effect of the introduced ToU contracted power tariff.

From Table 14 it follows that, in general, the introduction of a variable contracted power tariff only leads to slightly larger absolute peak reductions. Here the rows denoted with a fixed contracted power tariff must be compared to rows containing the variable contracted power tariff. In particular the minimum peak reductions remain unchanged, as they originate from the most conservative flexibility scenario. Still, the results seem to strongly depend on the assumed baseload reduction. However, even under optimistic flexibility assumptions, the increase in peak reduction as a result of the ToU contracted power tariff remains small. The largest additional absolute peak reduction as a result of the ToU contracted power tariff is 0,008 MW, which occurs in a peak week with an assumed elasticity of -0,43 and a baseload reduction of 0% and 10%.

There are cases where the absolute peak reduction becomes smaller as a result of the ToU contracted power tariff, such as in Table 11. This occurs in both peak weeks and average weeks, with the largest baseload adjustments and assumed elasticities of -0,43. This phenomenon can likely be attributed to the fact that the contracted power tariff in some situations induces peak-shifting behavior, rather than peak-reducing behavior. The contracted power tariff then causes extreme synchronization in peaks, creating new system peaks. This is supported by the fact that there is more load shifting in these moments, and by the fact that the relative peak reduction is highest in these moments.

Table 10: Absolute peak reduction average week 19-02 - 25-02, in MW, peak: 8,753 MW

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
No mutation	0,075	0,076	0,081	0,081	0,131	0,132	0,139	0,140
-10%	0,154	0,157	0,168	0,171	0,278	0,282	0,298	0,294
-20%	0,168	0,173	0,180	0,184	0,308	0,318	0,293	0,281

Table 11: Absolute peak reduction peak week 17-06 - 23-06, in MW, peak: 12,660 MW

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
No mutation	0,195	0,201	0,238	0,244	0,339	0,350	0,410	0,418
-10%	0,275	0,282	0,336	0,342	0,482	0,493	0,582	0,590
-20%	0,304	0,310	0,381	0,386	0,525	0,537	0,591	0,590

Table 12: Absolute peak reduction average week 22-07 - 28-07, in kW. peak: 7,853MW

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
No mutation	0,125	0,127	0,135	0,135	0,162	0,163	0,175	0,176
-10%	0,350	0,352	0,382	0,384	0,432	0,439	0,476	0,481
-20%	0,404	0,411	0,429	0,435	0,412	0,418	0,451	0,457

Table 13: Absolute peak reduction peak week 09-12 - 15-12, in kW. peak: 11,665 MW

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
No mutation	0,141	0,145	0,158	0,161	0,231	0,236	0,258	0,263
-10%	0,176	0,181	0,199	0,205	0,298	0,305	0,335	0,340
-20%	0,186	0,191	0,211	0,216	0,270	0,275	0,280	0,285

Table 14: Aggregated results tariff comparison absolute peak reduction, in MW

Weektype	Contracted power tariff	Minimum	Maximum	Average
Average	Fixed	0,081	0,476	0,267
	Variable	0,081	0,481	0,268
Peak	Fixed	0,158	0,591	0,332
	Variable	0,161	0,590	0,337

4.3.2 Relative peak reduction

The effects of the ToU contracted power tariff on the relative peak reduction are shown in Table 19. This measure thus compares the load in the optimized week with the reference load at the hour on which the original peak occurred. If relative and absolute peak reductions are similar, it means the system peak occurs at the same hour. If relative peak reductions exceed the absolute peak reductions, it indicates that a new system peak has emerged at a different hour. Reductions are expressed in megawatt hours. Table 15, Table 16, Table 17 and Table 18 show all results for each scenario. In these tables, the columns highlighted in grey must be compared to see the effect of the introduced ToU contracted power tariff.

From Table 15, Table 16, Table 17 and Table 18 it follows that the baseload mutation and elasticity are key drivers of peak reduction. Sufficient flexibility is required to shift peaks, and relative peak reductions arise precisely as a result of such peak shifting. There were no scenarios where the relative peak reduction decreases as a result of the ToU contracted power tariff, which is as expected.

It can be concluded from
Table 19 that the introduction of the ToU contracted power tariff generally leads to more relative peak reduction. As with absolute peak reduction, the magnitude of the effect remains limited. The largest additional peak reduction as a result of the ToU contracted power tariff is 0,009 MW, occurring in a peak week under the most flexible conditions (Table 16).

Table 15: Relative peak reduction average week 19-02 - 25-02, in MW, peak: 8,753 MW

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
No mutation	0,075	0,076	0,081	0,081	0,131	0,132	0,139	0,140
-10%	0,154	0,157	0,168	0,171	0,278	0,282	0,298	0,301
-20%	0,168	0,173	0,180	0,184	0,308	0,318	0,327	0,335

Table 16: Relative peak reduction peak week 17-06 - 23-06, in MW. Peak: 12,660 MW

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
No mutation	0,201	0,201	0,238	0,244	0,339	0,350	0,410	0,418
-10%	0,282	0,282	0,336	0,342	0,482	0,493	0,582	0,590
-20%	0,304	0,310	0,381	0,386	0,557	0,567	0,690	0,699

Table 17: Relative peak reduction average week 22-07 - 28-07, in MW. Peak: 7,853MW

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
No mutation	0,125	0,127	0,135	0,135	0,162	0,163	0,175	0,176
-10%	0,350	0,352	0,382	0,384	0,466	0,470	0,502	0,506
-20%	0,440	0,442	0,493	0,495	0,643	0,648	0,725	0,729

Table 18: Relative peak reduction peak week 09-12 - 15-12, in MW. Peak: 11,665 MW

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
No mutation	0,141	0,145	0,158	0,161	0,231	0,236	0,258	0,263
-10%	0,176	0,181	0,199	0,205	0,298	0,305	0,335	0,341
-20%	0,186	0,191	0,211	0,216	0,327	0,334	0,373	0,379

Table 19: Aggregated results tariff comparison relative peak reduction, in MW

Weektype	Contracted power tariff	Minimum	Maximum	Average
Average	Fixed	0,081	0,725	0,300
	Variable	0,081	0,729	0,303
Peak	Fixed	0,158	0,690	0,348
	Variable	0,161	0,699	0,354

4.3.3 Adjusted load factor

Table 24 shows the aggregated effects on the adjusted load factor. Results are expressed as deviations from the reference efficiency from the reference week. The adjusted load factor is defined as the ratio between the average load and the 95th percentile of load within the same scope. The full results for all scenarios are reported in Table 20, Table 21, Table 22 and Table 23. In these tables, the columns highlighted in grey must be compared to see the effect of the introduced ToU contracted power tariff.

Table 24 shows that the adjusted load factor generally decreases because of the ToU contracted power tariff. The only exception concerns the minimum improvement, where the decrease of efficiency becomes less severe after the ToU contracted power tariff. The largest efficiency increase as a result of the new ToU tariff is by 0,09%, occurring in an average week with an assumed elasticity of -0,43 and a 20% baseload reduction. The largest efficiency decrease as a result of the new ToU tariff is by 0,999%, occurring in an average week with an elasticity of -0,43 and a baseload reduction of 20%.

Table 20: Adjusted load factor average week 19-02 - 25-02, in %, base efficiency: 75,305%

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
No mutation	75,928	75,975	76,032	76,013	75,715	75,862	75,705	75,725
-10%	75,679	75,756	75,919	75,896	75,765	75,638	75,561	75,533
-20%	75,638	75,648	75,651	75,634	75,712	75,683	75,131	75,221

Table 21: Adjusted load factor peak week 17-06 - 23-06, in %, base efficiency: 65,630%

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
No mutation	65,717	65,713	65,742	65,741	65,108	65,111	65,129	65,114
-10%	65,197	65,189	65,190	65,171	64,813	64,821	64,923	64,930
-20%	65,008	65,001	64,943	64,929	64,580	64,579	64,670	64,688

Table 22: Adjusted load factor average week 22-07 - 28-07, in %, base efficiency: 85,550%

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
No mutation	85,604	85,614	85,589	85,596	85,552	85,555	85,411	85,424
-10%	85,624	85,618	85,626	85,638	85,641	85,726	85,838	85,857
-20%	85,324	85,344	85,400	85,423	85,025	85,117	85,079	84,080

Table 23: Adjusted load factor peak week 09-12 - 15-12, in %, base efficiency: 82,900%

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
No mutation	83,786	83,789	83,767	83,772	83,910	83,927	83,947	83,529
-10%	83,813	83,810	83,789	83,795	83,998	83,961	83,802	83,812
-20%	83,860	83,859	83,839	83,836	84,094	84,047	83,764	83,751

Table 24: Aggregated results tariff comparison improvement Adjusted load factor, in percentage

Weektype	Contracted power tariff	Minimum	Maximum	Average
Average	Fixed	75,131	85,838	80,579
	Variable	75,221	85,857	80,503
Peak	Fixed	64,670	83,947	74,459
	Variable	64,688	83,836	74,422

4.3.4 Load duration curves

Whereas the previous sections quantify peak effects and efficiency effects, the load duration curves can provide insights into the redistribution of load over the entire profile. To illustrate where load shifts occur, and to verify that these shifts do not cause new system peaks, a selection of load duration curves is presented. Out of the 48 available curves from tariff configurations 3 and 4, four curves are chosen as representatives. For both peak weeks and average weeks, the scenarios with the smallest and largest absolute peak reductions under the ToU contracted power tariff are shown. These curves are shown in Figure 34, Figure 35, Figure 36 and Figure 37.

Although it would be informative to present load duration curves that compare the effects of the fixed and ToU contracted power tariff directly, even in the case with the largest differences in peak reduction only very subtle differences are present. This is consistent with the findings from Sections 4.3.1 to 4.3.3, where these small differences have already been reported. As an illustrative example, Figure 38 shows the load duration curves where the fixed and variable scenarios are compared, and represents the scenario where the difference in absolute peak reduction is largest between the fixed and ToU contracted power scenarios. The primary purpose of the load duration curves is thus to illustrate how peaks are reshaped, and where the reduced peaks are compensated, rather than to show the added effects of the ToU contracted power tariff.

The load duration curves show that the highest peaks are indeed reduced, but that the severity of the effect remains limited. It can also be seen how in some weeks, not only the highest peak is reduced, but also that the load is reduced as far as to the 40th percentile. At the same time, the load in the mid-range of the distribution increases relative to the reference profile, indicating the redistribution of load.

The load duration curves confirm that the introduction of the ToU contracted power tariff does not lead to new system peaks and show that the additional peak reduction resulting from the ToU contracted power tariff is very limited. This is in line with earlier findings. Finally, more load shifting occurs during peak weeks, indicating the tariffs induce the expected behavioral response.

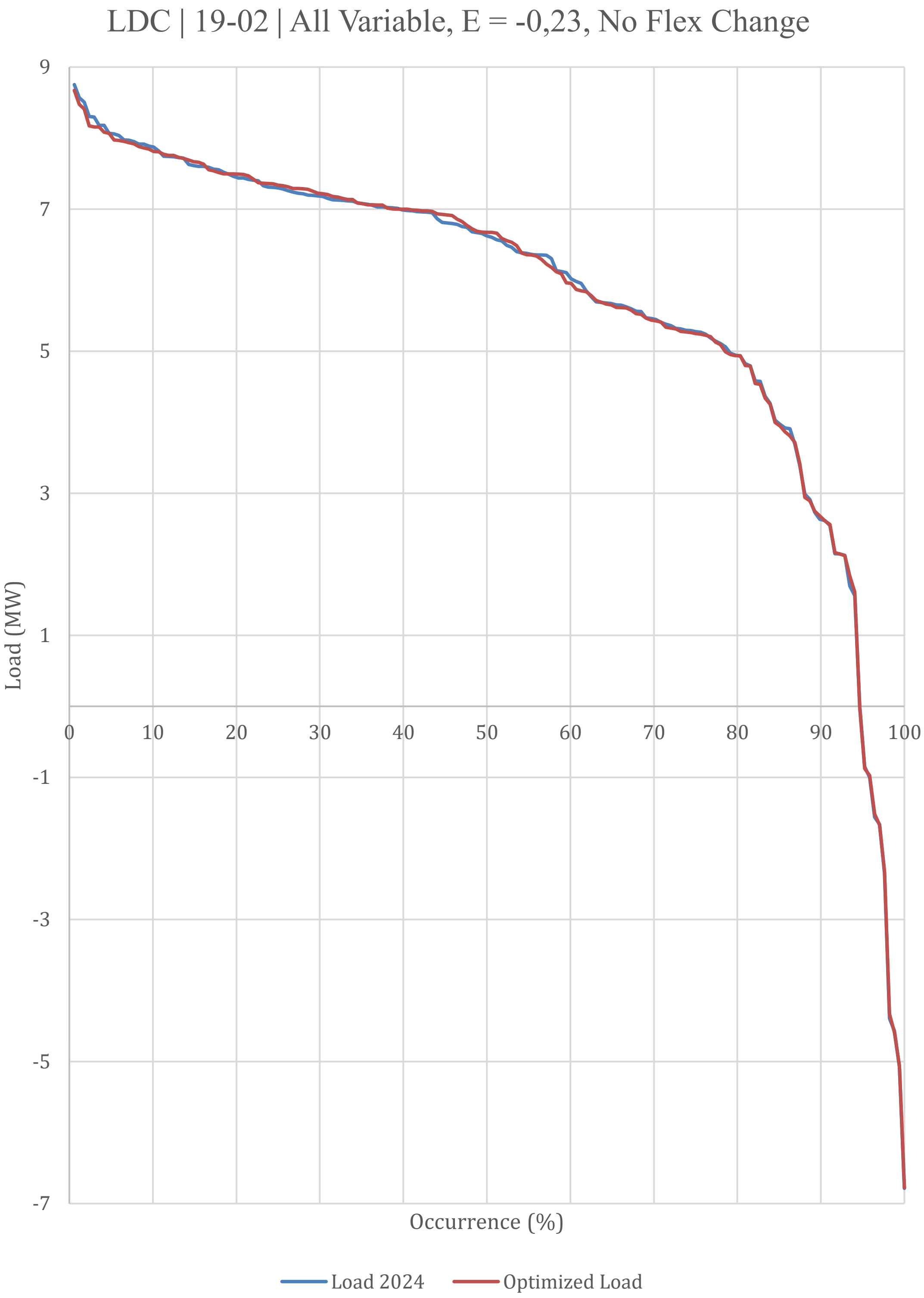


Figure 34: Load Duration Curve average week, lowest absolute peak reduction

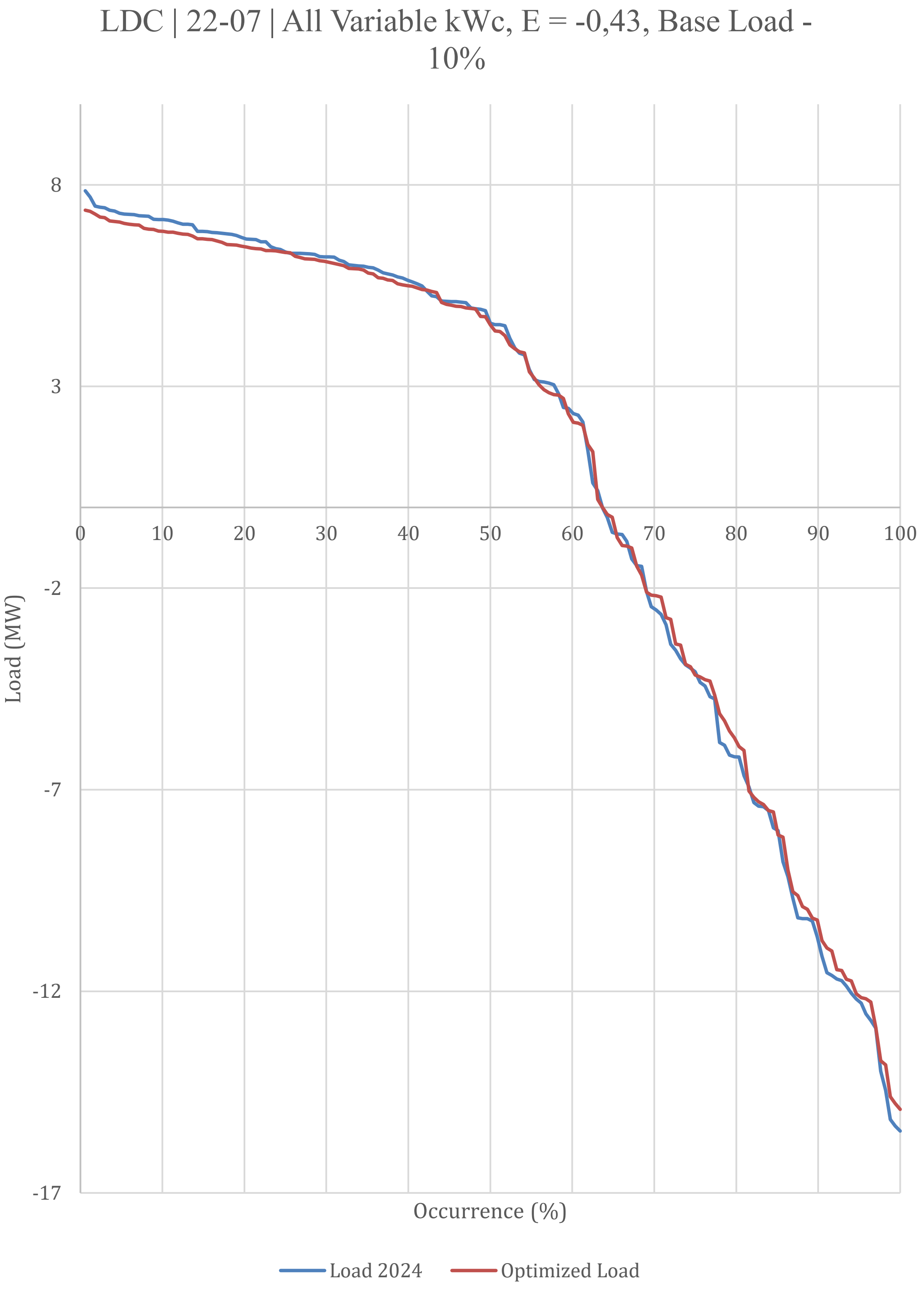


Figure 35: Load Duration Curve average week, highest absolute peak reduction

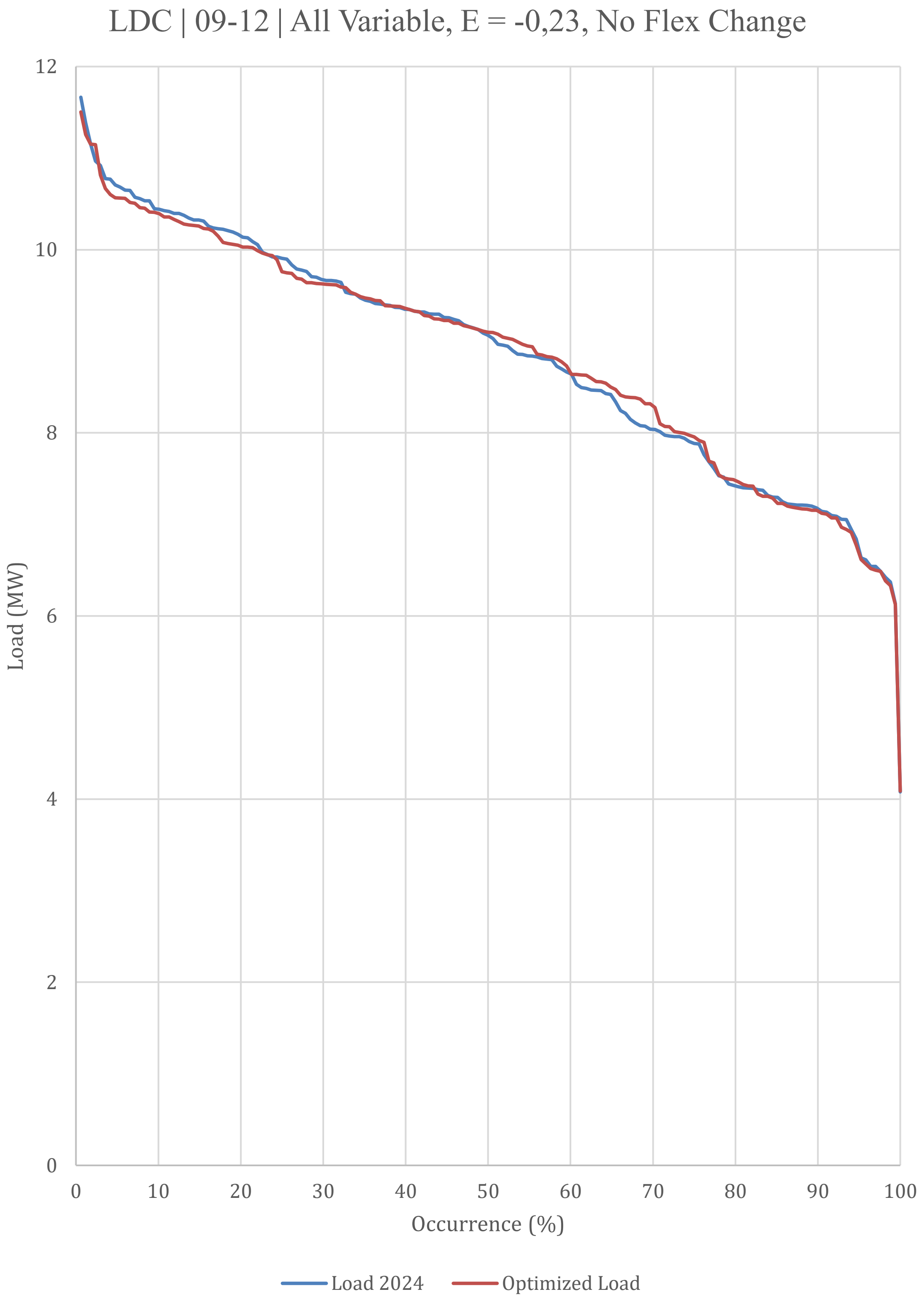


Figure 36: Load Duration Curve peak week, lowest absolute peak reduction

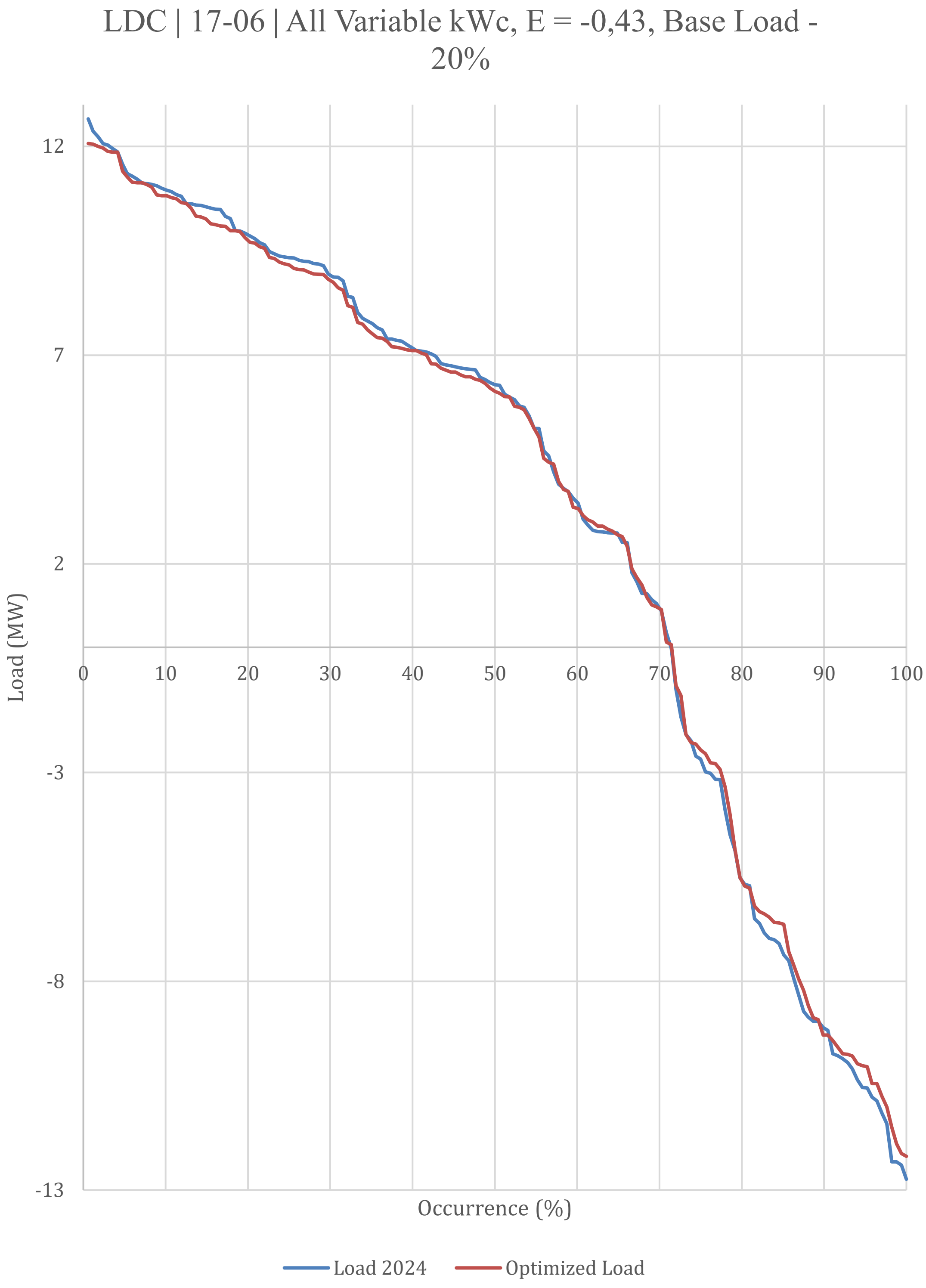


Figure 37: Load Duration Curve peak week, highest absolute peak reduction

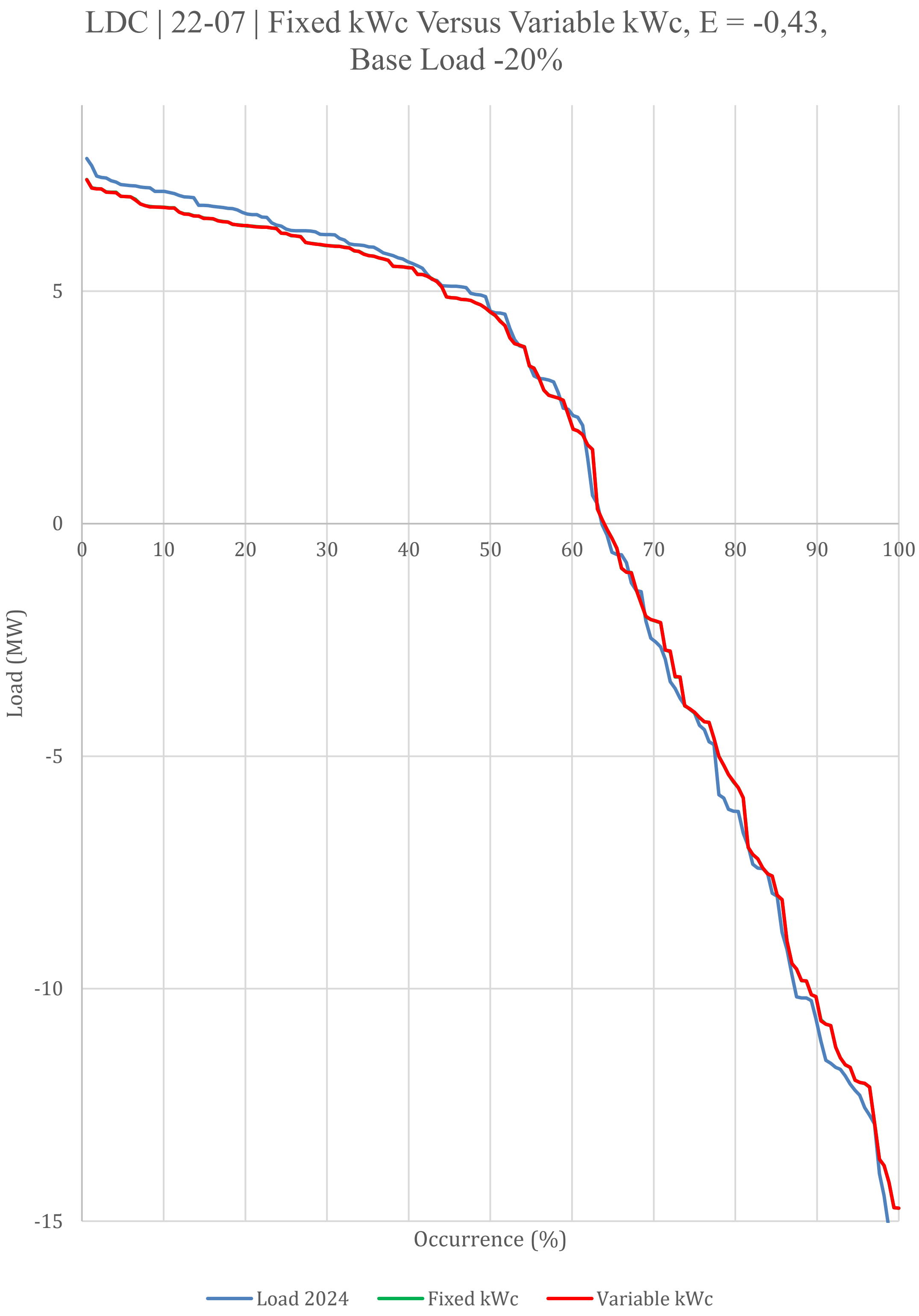


Figure 38: Load Duration Curve fixed versus variable contracted power tariff scenario

4.4 Synthesis

Now the results from the scenario analysis will be synthesized. The third sub-question concerns the effects of the ToU contracted power tariff on grid congestion and the adjusted load factor. The implication of the results on both criteria will be explained separately.

4.4.1 Reducing grid congestion

In this study, the reduction of grid congestion is operationalized as both absolute peak reduction and relative peak reduction. For the ToU contracted power tariff to be successful, it should reduce peaks, thus reducing grid congestion.

The results from Appendix E.2 and Tables 7 and 8 show that the introduction of the ToU contracted power tariff on average leads to slightly higher peak reductions. Most peak reduction is explained through the commodity costs, and the combination of the ToU volumetric and peak tariff. There are even two extreme scenarios where the absolute peak reduction is higher without the ToU contracted power tariff, but in these scenarios the relative peak reduction is highest, hinting at peak shifting. In general, absolute peak reductions remain smaller than relative peak reductions, meaning the ToU contracted power tariff incentivizes load shifting rather than peak reduction.

The ToU contracted power tariff seems to have a larger effect on the load shifting, than on the peak reduction, as is shown in Appendix E.2. The results again indicate that the ToU contracted power tariff primarily shifts load and has a marginal effect on peak reduction. The peak reduction caused by the ToU contracted power tariff is likely to be explained only by the increase in load shifting, which forces the load to a lower level if it then reaches an upper bound constraint in another hour. The comparison of scenarios with a ToU volumetric and peak tariff, and with and without a variable contracted power tariff also show that it only explains a small part of the total peak reduction. The largest added effect from the contracted power tariff is an extra absolute peak decrease of 0,076 percentage point, which is considered limited.

In conclusion, the introduction of a ToU contracted power tariff does reduce peaks in electricity consumption, but only marginally. As the commodity costs are the main driver in load changes, and with the ToU volumetric and peak tariffs in place, the ToU contracted power tariff has limited added benefit.

4.4.2 Improving the adjusted load factor

The adjusted load factor is operationalized as dividing the average load of the system by the 95th percentile of load. This performance indicator is chosen in line with the found criteria in Section 2.1.1. The ToU contracted power tariff can be considered successful if it improves the adjusted load factor.

The opposite is true, however. Though the ToU contracted power tariff improves the adjusted load factor ever so slightly in some scenarios, it reduces it in others. On average, the adjusted load factor is reduced by 0,005 percentage points in the conservative scenarios, and by 0,128 percentage points in the optimistic scenarios. Though these reductions are not very significant, it does show how the ToU contracted power tariff strictly does not help to improve the adjusted load factor. Instead, it increases the peaks in the 95th percentile and has limited effects on the baseload. The electricity consumption thus becomes more volatile because of the contracted power tariff.

In terms of the adjusted load factor, the ToU contracted power tariff cannot be considered successful. The results indicate that the tariff does mitigate congestion, albeit ever so slightly and at the cost of the adjusted load factor

4.4.3 Robustness of results

The direction of the main results remains robust over all elasticity and baseload assumptions. Across all scenarios the ToU contracted power tariff reduces relative peaks and has a marginal effect on the adjusted load factor. Negative effects on the adjusted load factor are found across varying scenarios, with varying elasticities and baseload reductions. Only in extreme cases does the ToU contracted tariff cause new system peaks as a result of synchronous load shifting.

The robustness of these conclusions is reinforced with the analysis of separate cost component effects presented in Appendix E.2. Scenarios with only the commodity price or only the ToU contracted power tariff show that the majority of peak reduction is already explained by the commodity costs and by the ToU volumetric and peak tariffs. The contracted power tariff contributes ever so slightly on top of these existing price signals. The consistency in the direction and magnitude of the results across all tariff configurations show that the main conclusions reflect the structural effects of the ToU contracted power tariff, and are not dependent on a single parameter choice.

Chapter 5: Conclusion & discussion

In this section the findings of this study are summarized, to draw a conclusion and present policy advice. Then the limitations of the study are discussed, from which recommendations for future research are derived.

5.1 Conclusion

Grid congestion is a pressing problem in the Netherlands, delaying economic growth and the energy transition. Grid expansion is not a feasible short-term solution, meaning other solutions such as implicit demand response through grid tariffs are necessary. Through the use of economic theory and a literature review it was determined that there must be a new perspective on grid tariffs, which may help to resolve grid congestion in the Netherlands.

Time-of-use (ToU) grid tariffs may be a step in the right direction to solve grid congestion. It is near certain that a volumetric tariff and a peak tariff will adopt a ToU structure for large-scale electricity users, but it is uncertain whether implementing a ToU contracted power tariff will prove beneficial. Therefore, the main research question that has guided this study was formulated as follows: "*How can Time-of-Use contracted power tariffs contribute to reducing grid congestion and improving efficient grid usage in the Dutch distribution grid, given modelled large-scale electricity user behavior?".* To answer the main research question, three sub questions were formulated.

First an understanding was created of the underlying principles of grid tariffs. The system efficiency principle, operationalized as peak reduction and efficient grid usage (by means of an adjusted load factor), was found most important in the context of grid congestion, and was thus taken as the focal point of the analysis. Then it was explored how large-scale electricity consumers respond to price signals, to understand the effects of new tariffs on the system efficiency principle. This was done by means of a literature review, where mostly cost-minimization and price elasticity approaches were found. A combination of these approaches was adopted, resulting in a cost-minimization constrained by historical consumption data. The optimization redistributed energy while minimizing costs based on transport tariff costs, commodity costs and flexibility. This model was then used to determine the impact of a ToU contracted power tariff.

From the scenario analysis it was found that, though the ToU contracted power does lead to an increase in both absolute and relative peak reduction, it does so only marginally. The largest influence comes from the commodity price, and most of the leftover peak reduction is attributed to the ToU volumetric and peak tariff. The ToU contracted power tariff has more of an effect on the timing of peaks, rather than actual peak reduction. This is not entirely unexpected, as there is no inherent penalty for higher contracted capacities, but only a penalty for the timing of a contracted capacity. The tariff thus provides incentives shifting peaks to other moments, instead of reducing peaks. Any peak reduction is attributed to load shifts to hours with a lower upper limit constraint.

The results have also shown how the average impact of the ToU contracted power tariff on the adjusted load factor was both negative and limited. Though there were more scenarios in which the adjusted load factor was impacted positively, the average impact over all scenarios is negative. This can also be explained by the fact that the contracted power tariff mainly incentivizes load shifting. The resulting synchronization of peaks increases high-load percentiles, without substantially affecting the average load, thus decreasing the adjusted load factor. The results therefore show that introducing a ToU contracted power tariff does not reliably improve adjusted load factor.

In an in-depth analysis, shown in Appendix C, different tariff configurations were tested on two different grid categories. First this analysis showed that the ToU contracted power tariff still has little influence on the system efficiency principle, but it also provided more fundamental insights. From the analysis it could be concluded that different grid tariff structures work for different grid categories. The 'TS' grid category is characterized by flatter load profiles, meaning the ToU tariffs can increase peaks in electricity consumption. The analysis has also shown how a yearly ToU structure may be too rough to address peaks in different grid categories, leading to unnecessary penalties and a decrease in economic efficiency. For future research it is thus important to understand the characteristics of grid categories, to then implement custom solutions.

In conclusion, in this study, under all modelled assumptions, it was found that the introduction of a ToU contracted power tariff contributes only marginally to peak reduction, unreliably increases the adjusted load factor and therefore does not reliably improve system efficiency. The tariff primarily incentivizes shifts in the timing of peaks, rather than actual peak reduction. This limits the effectiveness as an instrument for congestion management and system efficiency improvement. Though the tariff may improve on certain principles such as cost reflectiveness and cost recovery, it does not reliably improve the system efficiency principle and does not reduce grid congestion.

In the context of grid congestion in the Netherlands, the findings suggest that there must instead be a focus on other means of implicit demand response. For example, more research can be done to the other types of grid tariffs found in the literature review on the types of existing grid tariffs. Alternatives must be found that align better with the objectives of a successful energy transition, without imposing unnecessary complexity on electricity users.

5.2 Recommendations

The following recommendations are addressed to the Dutch distribution system operators, such as Stedin, and to the Dutch regulatory authority (ACM). The recommendations are derived from the results of this study and focus on the design of grid tariffs as a means to reduce grid congestion and on improving analysis methods to estimate demand response.

5.2.1 Recommendations for grid tariff design

In designing grid tariffs as means to reduce grid congestion, the fundamental characteristics of congestion must be accounted for. In general, these characteristics are location, time and peak reduction. Grid congestion is mainly a locational and temporal problem, characterized by peaks in electricity usage. In the design of tariffs these three dimensions must thus be addressed for effective solutions to grid congestion.

The ToU contracted power tariff contains a temporal dimension, but it lacks the other dimensions required for effective congestion management. The tariff primarily incentivizes load shifting, but does not actively incentivize peak reduction. Based on the results of this study, it is therefore recommended that future grid tariff design puts more emphasis on the peak reduction characteristic. If tariffs are to reduce grid congestion, they must directly penalize peaks, rather than cause them to shift to other moments. The ToU peak tariff is an example of a tariff that targets peak reduction specifically. There are various types of grid tariffs that also mainly incentivize peak reduction, from which valuable lessons can be drawn.

One other thing to consider is that ToU tariffs impose a pricing structure for an entire year, even though only rarely occurring system peaks must be reduced. As could be seen from Figure 33, there is only a single week that shows significant peaks, with some outliers in other moments of the year. It is thus the question whether imposing this structure for an entire year is a justified means if it must only influence a few moments in the year. In the case of the ToU contracted power tariff, it is unlikely that this is worth it due to its limited effects and its severe complexities. The tariff structure seems to be too complex and not effective enough to justify its implementation for an entire year. It would instead be fairer to target peaks directly, preventing unwanted effects and unnecessary complexities. That is, if peak reduction is taken as the most important criterion for a grid tariff. However, forming a conclusion on the fairness of ToU tariffs would require a separate analysis, for which these insights may form the basis.

Currently any locational dimension is absent from most grid tariffs. However, in several European countries location-dependent tariffs have already been adopted, indicating the feasibility of locational grid tariffs from a regulator's perspective. Given that grid congestion is a location specific problem, it is well worth exploring the possibilities. It is thus recommended that location-dependent grid tariffs are further explored, and that lessons are drawn from grid tariff design abroad. The introduction of location-based tariffs should always be balanced against other principles, such as non-complexity and equity.

The results of this study contribute to the ongoing policy discussions regarding congestion management and the role of grid tariffs. As mentioned, regulators allow room for redesigning grid tariffs to contain temporal or locational components, to better address cost reflectivity and system efficiency. This study adds to this discussion by providing insights into how the ToU contracted power tariff influences consumer behavior and peak demand. These insights can support policymakers and regulators in evaluating future tariff structures aimed at improving system efficiency, and it is recommended that future tariff reforms are assessed on their actual effects, rather than expected effects.

It is also important to emphasize the risk of complexity in the design of congestion-oriented grid tariffs. The ToU contracted power tariff serves as an example of a grid tariff where its effectiveness is undermined by its complexity. Complexity in grid tariff creates room for unwanted strategic behavior, and can impose significant burdens on electricity users. Such effects reduce the effectiveness of the tariffs, and may even cause unintended system behavior. It is advisable that future grid tariff designs build upon existing components, while incorporating dimensions such as location in a manner that is understandable and transparent.

Lastly, it must be noted that it is impossible for a single grid tariff to optimize all tariff principles. Trade-offs between cost reflectiveness, system efficiency, non-discrimination and non-complexity are unavoidable. Thus, within the context of the Dutch energy transition, it is advisable that priority is given to grid tariffs that are targeted, simple and provide stable and understandable price signals to mitigate grid congestion. This is regarded as the best way of implementing implicit demand response and furthering the Dutch energy transition.

5.2.2 Recommendations for use of data

One of the most significant potential improvements to the created model is a more accurate means to estimate demand elasticities. During this study, it was not possible to obtain empirically grounded elasticity values. However, given the extensive data available within Stedin, and presumably within other Dutch distribution system operators, such estimates should be feasible in the future.

Currently, a substantial amount of valuable data is dispersed across various departments within Stedin, and therefore seems to remain insufficiently exploited. Combining these data sources could potentially yield much more accurate insights into consumer behavior and demand response. It is thus recommended that Stedin and other DSOs explore the opportunities for cross-departmental collaboration and data use, to fully utilize the available data.

It is also recommended that distribution system operators further expand on the demand estimation method created for this study. By incorporating improved empirical estimates of flexibility, future analyses could provide even more valuable and reliable assessments of the effects of new grid tariff designs. These improvements would help to strengthen the discussion surrounding grid tariffs and provide support for regulatory decision-making in the context of grid congestion.

5.3 Limitations

To interpret the results correctly, several limitations of this study must first be addressed. In this section, the limitations of this study and their cause and substantiation are discussed. Possible improvements for these limitations will be addressed in the next section.

The first limitation of this study lies in the commodity costs, and the lacking revenue from balancing or congestion markets. In reality, large-scale electricity users may possess contracts with a constant commodity price, where it does not vary over time. The reason for the assumption that all electricity consumers are exposed to variable commodity pricing is that there was not enough data within Stedin to support consumer-specific commodity price approaches. However, the commodity price can also be interpreted as a stochastic driver in the optimization, capturing cost uncertainty rather than exact market outcomes. Similarly, the exclusion of balancing revenues is considered acceptable, as their inclusion would increase model complexity while being unlikely to improve on the analysis.

The second limitation in the analysis lies in how the costs for flexibility are modelled. The costs for flexibility are a penalty for deviation from the reference profile. The elasticity values used in the formula of the flexibility costs was adopted from literature on long-term price elasticity of industrial electricity consumers and was compared to other elasticities from other studies. It was found that the elasticities were all in a similar range, thus substantiating the made choices. However, elasticities are not a single dimensional value, as they may vary over time, place and type of consumer. It was therefore attempted to estimate elasticities empirically, but with the data provided by Stedin this was not possible.

The consequence of homogeneous elasticities across all consumers is that the cost minimizing behavior of all consumers is nearly similar. The reference load is still a determining factor, providing a form of heterogeneity, but only slightly. This leads to an overestimation of total load shifting, and an underestimation of absolute peak reduction. This is because, without constraints, all consumers shift their load to the same moment. However, due to the upper limit constraints, consumers are limited in the extent to which they can shift peaks, thus safeguarding extreme peak synchronization. Also, extreme peak synchronization should lead to a significant increase in the relative peak reduction. This was not found in this study, proving the analysis yields useful results despite this limitation.

Third, the deviations in the baseload were only chosen as a range rather than being derived from empirical or academic sources. It is not certain if the choices for baseload reductions are valid, and whether consumers are physically able to adjust their baseload to those levels. However, since the model does not aim to accurately forecast future energy demand of specific consumers, but rather to estimate aggregated load responses, the chosen range is considered valid. Also, as the original baseload constraints are based on empirical data, the assumed deviations remain reasonably close to reality.

Fourth, several behavioral mechanisms are not modelled. The model does not account for strategic behavior related to maintaining contracted capacity. For example, if the contracted capacity at a certain hour is lowered, it is unlikely that it can be increased in the near future due to grid congestion. The absence of this risk adverse behavior overestimates the already subtle effect the ToU contracted power tariff has.

Fifth, the time horizon in the optimization is set to 24 hours. This is an important simplification in the analysis of the contracted power tariff, because the structure of the contracted power is determined for a year. In reality, consumers could therefore shift electricity demand to other days, weeks or months. Extending the horizon would therefore be more realistic in theory but also suffers from some limitations and would be computationally infeasible within the scope of this thesis. For example, it would assume consumers have access to commodity prices ahead of time, it would try to shift all load to weekends, and running the model would take eight times longer on average, which is not feasible in the given scope. Therefore, the most feasible option was to set the horizon to 24 hours.

Another limitation of this study concerns the use of a static representation of the electricity system and electricity demand. Changes in the system, such as long-term developments like grid reinforcements, changes in the generation mix and increasing electrification are not taken into account in this study. The results therefore primarily reflect the short-term effectiveness of grid tariffs under current network conditions. However, as the limited effectiveness of the ToU contracted power tariff is seems to mainly be driven by the structure of the tariff, due to its incentivization of peak shifting rather than peak reduction, it is unlikely that future system developments would significantly alter the outcomes of the analysis.

Lastly, the results in this study are based on a case study on the medium-voltage grid in the Maasvlakte area. Though there is a wide variety of large-scale electricity users in this area, it is not a given that the area is fully representative of other grid areas with different consumers. In the in-depth analysis two more grid categories were analyzed, but there may always be differences in grid areas and grid categories, which could not be analyzed. However, the qualitative mechanisms identified of the ToU contracted power tariff are expected to be broadly applicable.

5.4 Future research

In this section, recommendations for future research are presented. A distinction is made between recommendations for the future of demand response modelling, and the future of the analysis of specific grid tariff designs.

5.4.1 The future of demand response modelling

The literature review conducted at the beginning of this study showed that there is substantial room for improvement in modelling demand response. In particular, future models should account for heterogeneity of consumer groups, take into account temporal differences in response, and factor in elasticities. That is, if demand response is modelled at all in the analysis of grid tariffs. In this study an attempt was made to incorporate several of these improvements in the created demand response estimation method. In this new method, time-dependent responses, heterogenous feasibility ranges and elasticities were included. However, as discussed in the limitations in Section 5.3, there is room for further improvement.

Future research should first and foremost focus on empirical estimations of demand elasticities. These elasticities would substantially improve the model and would improve future analyses of grid tariffs. More accurate elasticities allow for better distinctions between consumer segments and would bring behavioral responses closer to reality.

Further improvements to the model concern incorporating more consumer specific inputs, such as the electricity contracts by each consumer. Also, including the revenues from balancing markets or congestion markets would be a valuable extension, especially in the context of more realistic behavioral modelling. Also factors such as strategic behavior and growth in electricity demand are important factors. However, the incorporation of these features must remain appropriately standardized, to ensure the scalability of the model.

Lastly, an important direction for future demand response modelling concerns the extension of the rolling horizon. In the current model, energy is redistributed over days, thus not allowing for shifts in energy usage between days. Particularly because several tariff components apply different weighing factors across months, thus incentivizing monthly load shifting, this addition for future research is considered important.

5.4.2 The future of grid tariff analysis

The results have shown that the ToU contracted power tariff primarily leads to peak shifting, rather than peak reduction. Though a wide variety of tariffs are available, such as tariffs with a peak reducing focus, many of these designs have not been properly researched yet, and it is unclear how they should be classified in terms of their congestion-management properties. It would be valuable to develop an overview of grid tariff designs, in which tariffs are classified according to their dominant behavioral effects, such as distinguishing between peak-shifting and peak-reducing tariffs. A taxonomy of grid tariffs like this would allow for faster assessments of whether a grid tariff is suitable for addressing specific congestion problems.

In addition, further research on forms of implicit demand response remains necessary. Relatively little research links the effects of grid tariffs to the physical state of the electricity network. This linkage is increasingly important with the increasing complexities of the electricity grid as a result of the energy transition. Future research that explicitly integrates economic incentives, behavioral responses and physical network constraints could advance the analysis of congestion-management related solutions and provide more concrete and implementable policy insights.

Related to implicit demand response, the analysis of the ToU contracted power tariff or other tariffs could be expanded upon by analysing synergies with other means of congestion-management. Such means include alternative transport rights, congestion markets and technical solutions such as energy hubs and cable pooling. Potential synergies could improve the effectiveness of the ToU contracted power tariff, possibly making it a better solution than appears from the results of this study.

Lastly, though the results of this study show that the ToU contracted power tariff score1s poorly on the system efficiency principle, it may perform more favorably with respect to other principles. For a comprehensive assessment of the effectiveness of the ToU contracted power tariff, the analysis should be extended to these additional principles. However, in the specific context of the Netherlands, and the severity of grid congestion, it remains an open question whether such an extension is justifiable.

Chapter 6: Reflection

The reflection chapter is subdivided in two sections. First the academic reflection is presented, then the personal reflection is presented.

Academic reflection

This project was both challenging and educational. This is particularly because of the open-ended nature of the research question. The project started with Stedin's question whether the introduction of the time-of-use (ToU) contracted power tariff would be a valuable option in reducing grid congestion. Especially the effects of the tariff in a real grid were of interest to Stedin. From the start, no established analytical method, performance criteria or comparable studies were available. Thus, I had to define the scope and methodological approach myself, while ensuring an academically sound, and for Stedin relevant project, that would be feasible in the available time.

Defining the scope was approached from two directions. On the one hand, existing and grey literature was analyzed to find relevant approaches and performance criteria. On the other hand, ongoing work within Stedin related to congestion management was explored. Both approaches yielded limited guidance for this specific study, thus requiring me to develop a new analytical approach.

Initially, my chosen scope of the proposed method was too broad. In the early stages of the project, attention was spent on legal frameworks, interpretations of legal frameworks and literature to understand the principles for grid tariff design. I wanted to include all principles in the analysis, which proved to be too ambitious. Therefore, a specific focus was chosen on the ability of tariffs to reduce grid congestion, by means of analysing the adjusted load factor and peak reduction. This focus should have been chosen earlier, as it would have allowed for a more detailed analysis on this specific principle. It is a personal tendency to delay scoping in favor of a wide scope, which I recognize as an area of personal development.

Following the scoping phase, the main challenge was to design a new method to analyze the tariffs, that was detailed, scalable and compatible with a network analysis model. This process involved discussions with colleagues at Stedin, reading academic literature on demand response and a synthesis of these inputs. The final product was a cost-minimization model constrained by historical consumption data. Initially the intention was to incorporate more input from large-scale electricity users, but access and responsiveness of these stakeholders was limited. Nevertheless, insights from a single large-scale electricity user were combined with input from Stedin and literature and significantly contributed to a better understanding of consumer behavior.

I regard the model I have created as an innovative model that is an important step in a new direction. The main power of the model lies in how it is grounded in historical data, and how both academic insights and insights within Stedin are combined. It aligns with Stedin's internal data structures, allowing a user-friendly design where the only user-input is an EAN code for a connection. The model outputs were structured to be directly compatible with the Vision network analysis tool, allowing for easy integration with existing grid analyses. The created model is thus a model that is easy to be used within Stedin, and more importantly, can easily be expanded upon. The model is now namely mostly fitted to analyze the theoretical effects of grid tariffs on consumer behavior but is not yet in a stage where it can realistically predict future electricity demand. The model is thus very well suited for the analysis of this thesis, but can be expanded upon for further use in other areas within Stedin. Especially the incorporation of empirically estimated elasticities would improve the model greatly.

The development of the model required skills that were either new for me, or that I had not used recently, particularly with respect to programming in Python, especially in the Databricks environment. Also, the access to the required data and digital environment within Stedin took longer than expected. Therefore, the development and testing of the model were initially limited to fictitious scenarios. These delays reduced the time available for the final scenario analysis but also emphasized the importance of being able to be flexible with respect to iterative development and organizational constraints.

A specific methodological challenge concerned the estimation of price elasticities, which were used to calculate the costs of flexibility. Initially I wanted to estimate elasticities empirically based on historical consumption and price data. After multiple statistical analyses, it showed that this approach was not statistically meaningful. Elasticities were therefore introduced as scenario parameters instead. Though this is a pragmatic solution, the structure of the model remains suitable to incorporate empirically estimated elasticities, which may prove interesting if more data becomes available in the future.

Despite the reduced time for the final analysis, I put additional effort into strengthening other aspects in the study. Especially the theoretical background of grid tariffs and the mathematical formulations of the model were expanded upon, to ensure a strong theoretical basis and transparency and reproducibility of the model. I also put more emphasis on the verification and validation of the model, given the novelty of the modelling approach.

The final analysis with the completed model progressed efficiently. However, the broad initial design of the model resulted in an abundance of possible outputs, which obscured the most relevant performance indicators. This is another instance of a lack of scoping, which I am to work on in the future. After returning to peak reduction and adjusted load factor, the analysis proceeded in a structured and coherent manner.

Overall, this project has taught me the importance of early problem formulation, decisive scoping and ownership of methodological choices, especially under uncertainty. Delaying choices to preserve flexibility often resulted in inefficiencies later in the project. In future projects I would aim to make more decisions earlier, with the understanding that choices can be revised and learned from later. The project also highlighted the value of regular mental sparring with peers and supervisors. My objective for future projects is to strike a balance between discussion and timely decision-making.

Personal reflection

This thesis did not go without complications. However, it was precisely these complications that allowed me to learn a great deal. In this section I will give a personal reflection on my time working on this thesis.

At the start of the thesis I felt a bit overwhelmed with the broadness of the topic. Analyzing grid tariffs in a physical grid was no easy task. I decided that I could use all the help I could get, so started with exploring existing analysis methods within Stedin to understand large-scale electricity consumer behavior and to find a network model to perform the analysis in.

Finding a method to estimate behavior was troublesome. Within Stedin, there were no models capable of estimating behavior on the scale I expected to need for my analysis. Most methods were only suitable for predicting how aggregated loads would evolve in the future, without allowing for specific influences such as grid tariffs. At the same time, the methods I found in literature were too specific for my analysis. When a colleague showed me the concept of the flexpotential, which is used to contact large-scale electricity users to see if flexibility can be contracted, an idea popped into my head. A cost-minimization based on historical consumption data. This idea was further fleshed out during meetings with supervisors, colleagues and researchers at the Delft University of Technology.

Finding a network analysis tool also took more time than I would have liked. Within Stedin, a wide variety of network analysis tools is used, with some tools being very complex. I had tried my hand at some of these tools, without much success. After speaking with a significant number of colleagues, a colleague showed me Vision, an easy to understand and suitable tool for my analysis. Compared to the other tools I used, such as PowerFactory, this tool was the most user-friendly and provided the exact data I needed to conduct my analysis.

With the chosen behavior estimation method and network analysis tool, I started to build my model. This model had to be created in a specific online environment within Stedin. My access to this environment took very long however, because it was not clear how access to this environment had to be submitted and granted. Without access to the platform, I lacked full access to the available data requiring me to design my model based on assumptions about the data structure. Actual tests with the model were thus delayed, taking away from the time I had planned to spend on the analysis.

Due to the delays, I had to let go of some ideas I had for the model and final analysis, such as stochastic elasticities and strategic behavior of consumers. However, due to the delays and having to make certain choices, I did learn to get creative with the data I had available and got very efficient with handling the data from my model. Thus, though it may have taken away from the analysis I had originally planned, I did learn a lot on a personal level. This experience has taught me the importance of cooperation and scoping, which I will keep in mind for future projects.

After having finished the main analysis of this thesis, I conducted another analysis on the harmonization of grid tariffs, which can be found in Appendix C. During this analysis I had similar problems, for example because the dataset my original model used was deleted and thus unusable. Also, the volumes of the volumetric tariff were hard to come by. These issues required me to consult with various other colleagues. While such issues were occasionally frustrating, they also led to valuable discussions with people I had not yet met.

Regardless of some frustrating moments, various other aspects did go well within Stedin. I got to meet a lot of interesting people and learned a great deal from them. I have seen a lot within the company, even joining an excursion to see various transformers. The supervision from both Stedin and the Delft University of Technology was always pleasant and always helped me through the mentioned frustrating moments. For which I am truly thankful.

To summarize, this thesis period was a period of learning through trial and error, a period of meeting a lot of new people, and a period of personal development. Though some moments were frustrating, I have learned a great deal from them. This period has thus provided me with more than just knowledge on the subject, and has provided me with personal development, friends and good lunches.

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Appendix

Appendix A: Overview of grid tariff structures

There are various ways in which grid tariffs can be structured. Each of these ways has their own advantages and disadvantages. In the study of Vaughan et al. (2023), a large list of measuring units and tariff determination methods is presented. This list will be expanded upon, and every component of the list will be explained in more detail. It must be noted that near infinite grid structures are possible with very subtle differences and nuances, so only the most important considerations are mentioned.

In general, a grid tariff is based on a measuring unit and a way to set the price for this measuring unit. Five types of measuring units have been identified by Vaughan et al. (2023). A tariff can contain a fixed tariff, for which a sum is paid to the grid operator per time unit, a volumetric tariff, where a sum is paid per kilowatt hour of transported electricity, or a tariff can be paid for a capacity, where a sum is paid per kilowatt of capacity used. Two other measuring units are minimum bills and gradual increased fixed prices. Minimum bills refer to a system where there is a fixed, kilowatt or kilowatt hour measuring unit, but with a minimum threshold. If the calculated tariff is below this threshold, it will be increased to match this threshold (McLaren et al., 2015). Gradual increasing fixed prices refer to the gradual increase of fixed charges, but are not explained in more detail.

The ways in which the price of these measuring units can be determined can be summarized in four types, namely time, non-uniformity, multi-phase and other (Vaughan et al. 2023). Each type and determination method will be explained separately.

Time

Tariff structures that introduce a time dependency for the height of the tariff fall under the time category. Tariff structures that implement such a dependency are time of use tariffs, real-time-pricing tariffs and peak load contribution.

Time of use (ToU)

With ToU tariffs, the peak and off-peak hours of the electricity grid are determined, with the height of the tariff increasing during peak hours (Beaufils & Pineau, 2019). In this way, grid usage during off-peak hours is incentivized, possibly reducing the height of the peak. This property only works with capacity based and volumetric based tariff, whereby the price for each kilowatt or kilowatt hour changes depending on the time of day. The prices for off-peak and peak moments are calculated in such a way that total revenue is constant.

A capacity-based time of use tariff has been implemented in the Netherlands for the transmission grid (ACM, 2024). Every 15 minutes, the total capacity usage per connected user is calculated (kW max), whereby the highest usage each month is used to calculate the height of the tariff. If the highest peak was measured during an off-peak moment, for example in June at 4:00, the measured usage at that time is multiplied by 0,6 before calculating the tariff. If the peak was measured during a peak moment, the measured capacity is multiplied by 1. In the best case, this means that, during off-peak moments, 1,67 times more capacity can be used for the same price. This type of tariff is a combination of ToU and peak demand charges, of which the latter will be explained later.

Real-time pricing (RTP)

This type of pricing is often used in the context of the commodity price of electricity, but it can also be used by grid operators (Hofmann et al., 2025). In real-time contexts, something is communicated at (approximately) the same time as the to be communicated event happens. In terms of grid tariffs, this can mean that the status of the grid determines the height of the tariff. Instead of predetermined off- or on-peak moments, these moments are purely determined by the actual grid usage. Though this type of grid tariff is very granular and very cost-reflective, it brings along with it a lot of complexity (Beaufils & Pineau, 2019).

Peak load contribution

During moments of low grid usage, individual consumer peaks are not always as relevant. It is then more effective to determine the contribution of a specific consumer to grid wide peak usage. The tariff is then determined by the peak a consumer has while the network peak occurs (Nijhuis et al., 2017). This ensures that users with a high peak during off-peak hours are not penalised for this peak. In the example given by Nijhuis et al. (2017), the highest grid usage during peak moments is measured and used to determine a yearly tariff.

Non-uniformity

Tariffs that are not fixed but do change according to non-uniform principles fall under this category. Such tariff structures are Ramsey pricing, critical peak pricing, variable pricing and low-income pricing.

Ramsey pricing

Ramsey prices concern the price elasticity of demand (Trong & Yang, 2023). The price elasticity of a good determines how much the demand for that good changes as a result of a change in price. Demand is inelastic when it responds slightly to changes in price, while demand is elastic when it changes significantly as a result of price differences. According to the theory of Ramsey pricing, a difference in tariffs should be made according to the elasticities of demand for electricity (Trong & Yang, 2023). Consumers with an inelastic price elasticity pay a higher tariff than consumers with an elastic price elasticity. This pricing method is also called ‘second-best pricing’, as it ensures cost recovery without moving too far away from the first best alternative, which was marginal cost pricing (Bergaentzlé et al., 2018).

This method is rarely used, as it is very complex to properly understand the price elasticities of different demand groups (Trong & Yang, 2023). Demand elasticities may vary over time and are often different between multiple different consumer types. This pricing method also necessitates a form of discrimination, which is undesirable.

Low-income pricing

With low-income pricing, low-income consumers are exempted from certain payments (Batlle et al., 2020). This tariff structure seems to be functioning more as an addition to existing structures, rather than a tariff structure on its own (Brown et al., 2015).

Multi-phase

Tariffs that differ in rate in height across multiple phases are categorized under the multi-phase category. Four multi-phase tariff structures have been identified.

Critical Peak Pricing (CPP)

CPP is a variant of ToU tariffs, where there is a usual fixed price per kilowatt or kilowatt hour, which is only altered at certain critical event days (Beaufils & Pineau, 2019). A higher price during a critical peak moment should disincentivize grid usage to reduce the height of the peak. The time, duration and number of critical peak periods in a year are predetermined, but the actual dates are not (Hofmann et al., 2025). Connected parties are typically notified of a critical peak period a day ahead (Wang & Li, 2016).

Variable Peak Pricing (VPP)

VPP is very similar to CPP, with two main differences. VPP does have predetermined dates on which there will be a critical event, and the tariff that is paid varies dynamically instead of being fixed (Hofmann et al., 2025).

Critical Peak Rebates (CPR)

CPR or Peak Time Rebates structures are explained by Hu et al. (2014), and are practically the inverse of CPP. Rather than increasing the tariff during predetermined peak moments, consumers that lower their consumption during these peak moments are rewarded. The rebate refers to the payment they receive for lowering their grid usage.

Paris-Metro Pricing (PMP)

PMP stems from metro ticket prices in Paris. Two similar metro carts on the same line were priced differently, so that one of the carts would be less crowded, leading to a higher perceived quality of service (Ros & Tuffin, 2004). This method is often used in online networks. As explained by Ros & Tuffin (2004), under a PMP a network is divided into independent subnetworks. The tariff is different for each of these subnetworks, with networks that are prone to congestion having higher tariffs. This should lead to lower electricity usage and thus less congestion. Though this method is easy to implement, it does lead to price discrimination. It seems to be very similar in execution to zonal pricing.

Other

These are tariffs that cannot be categorized in the earlier categories. Seven such tariff structures have been identified.

Zonal pricing

Zonal pricing is most often regarded in the context of electricity markets (D. M. Brown, 2023). It occurs when parts of an electricity grid become isolated, for example due to congestion. If the generators in the isolated area produce electricity for a different rate than generators in the rest of the grid, two separate electricity prices emerge (Gianfreda & Grossi, 2012). Though there seems to be no empirical evidence of zonal grid tariffs, the theory would be the same. Grid tariffs are determined per zone or area (Vaughan et al., 2023), with areas for example experiencing more congestion having higher tariffs to disincentivize electricity demand and better reflect network costs.

MW-mile

MW-mile or AMP-mile pricing also takes location into account, but in a different way than zonal pricing. Now, a fixed network cost is based on the location and impact of loads and generation on the system (Sotkiewicz et al., 2006). If electricity must travel farther, and through congested areas, it has a larger impact on the grid, and thus a higher tariff is charged. This type of tariff structure is in use in Sweden, where the tariff is based on the latitudinal position of the network user (Hinz et al., 2017). There are various variants of this pricing method (Kharbas et al., 2011), but these will not be discussed further.

Postage stamp pricing

The opposite of zonal pricing and MW-mile is postage stamp pricing. With postage stamp pricing, groups of customers pay a uniform network tariff, regardless of differences in the future costs they may impose on the network (Kemp et al., 2014). In simpler terms, consumers pay the same rate over the entire grid, irrespective of their location in the grid.

Peak demand charges

With peak demand charges, the highest used capacity is measured every time interval, with the highest measurement being used per month or year to set the price (Hofmann et al., 2025). This type of tariff is like the peak tariff in the Netherlands. Here the used capacity is measured every 15 minutes, where the highest measurement is used to calculate a monthly tariff (Stedin, n.d.-b).

Capacity-based

Capacity-based tariffs are determined by measuring a customer's annual peak demand, after which customers are grouped into tiers linked to different tariff levels (Nijhuis et al., 2017). The difference with peak demand charges is that now customers are grouped into tiers.

Capacity subscription

Consumers subscribe to a fixed capacity, being allowed to only use capacity up to the subscribed level (Bjarghov et al., 2022). A price per kilowatt of subscribed capacity is paid. If consumers exceed the subscribed capacity, various measures can be taken by the grid operator. There can be a physical limitation, such as with a fuse, there can be a financial penalization, a transfer to a higher subscribed level, or simply a warning (Enexis Netbeheer, n.d.-b; Bjarghov et al., 2022). This tariff structure is generally only used with capacity, as the name suggests, but theoretically there could also be a subscription to an amount of kilowatt hours.

This type of tariff is in use in the Netherlands for large-scale electricity users. Consumers can contract an amount of capacity and pay for each contracted kilowatt. Generally, a warning is given if the contracted amount is exceeded, but if this happens in an area with congestion, the contracted amount is increased (Enexis, n.d.-b).

First connection charges (FCC)

FCC relates to the tariff paid for a connection to the grid. These charges can either be shallow or deep (Mateo et al., 2018). Shallow charges only consider the costs of the new connection that is built. Deep connection charges also take the necessary grid reinforcement into account that is necessary to realize the new connection (KEDS, 2022).

Appendix B: Load shifting

Table 25: Load shifting average week 19-02 - 25-02, in MW

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
Base	4,672	4,778	5,258	5,353	7,407	7,539	8,263	8,418
-10%	8,386	8,546	9,905	10,068	13,090	13,296	15,358	15,603
-20%	10,174	10,334	12,135	12,300	16,029	16,270	19,163	19,433

Table 26: Load shifting peak week 17-06 - 23-06, in MW

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
Base	5,840	5,903	6,523	6,620	8,267	8,361	9,220	9,332
-10%	10,843	10,938	12,066	12,180	15,383	15,522	16,901	17,055
-20%	13,032	13,128	14,473	14,593	18,886	19,028	20,942	21,106

Table 27: Load shifting average week 22-07 - 28-07, in MW

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
Base	9,358	9,423	10,356	10,320	12,931	12,989	14,069	14,133
-10%	15,785	15,881	17,018	17,114	21,018	21,147	22,537	22,649
-20%	19,592	19,704	21,310	21,441	27,364	27,521	29,482	29,672

Table 28: Load shifting average peak week 09-12 - 15-12, in MW

Elasticity	-0,23				-0,43			
Config. Base load	All fixed	kWc variable	kWc fixed	All variable	All fixed	kWc variable	kWc fixed	All variable
Base	10,387	10,449	10,861	10,917	15,532	15,602	16,166	16,237
-10%	13,180	13,248	13,873	13,941	20,159	20,248	21,137	21,219
-20%	14,155	14,214	14,882	14,947	22,152	22,237	23,216	23,292

Appendix C: In-depth analysis: harmonization and cost unit redistribution

Not all large-scale electricity users are exposed to the same grid tariff structure. Where most large-scale electricity users are exposed to a volumetric tariff, peak tariff and contracted power tariff, there are some grid categories exempted from paying the volumetric tariff., Within Stedin there is a question of whether or not it would be beneficial for these consumers to also be exposed to the volumetric tariff, which is also referred to as tariff harmonization. Here it would be deemed beneficial if this exposure would lead to higher system efficiencies and peak reductions. This analysis is in essence the same as the main analysis of this thesis, but now the influence of the Time-of-Use (ToU) volumetric tariff as an addition to the contracted power tariff and peak tariff will be analyzed. The same model as from the original analysis is used. In this analysis all tariffs are assumed to be ToU.

Appendix C.1: New distribution of cost units

In introducing a new tariff, the tariff level must be determined first. Tariff levels are determined by looking how much of the total allowed revenue a tariff is allowed to recover. The amount a tariff can recover is predetermined in a cost unit distribution. As an example, for the analyzed medium-voltage grid category from the main analysis, the cost unit distribution was 50% for the volumetric tariff, 25% for the peak tariff and 25% for the contracted power tariff. This means that the volumetric tariff recovered 50% of the total revenues from that specific grid category, with the peak tariff and contracted power tariff recovering the other half.

Consumers relevant in this analysis have not yet been exposed to volumetric tariffs, meaning there is not yet a tariff level or recovery rate. To determine these levels, first the total revenue from a specific grid category (R_c^{total}) must be calculated, consisting of the revenues from each tariff. This calculation is based on existing data. For this analysis 2024 is used as the reference year. Revenues for each tariff consist of the measured volumes times the original tariff level, as per equation 1.

$$R_c^{total} = (V^{kWh} * T^{kWh}) + (V^{kWmax} * T^{kWmax}) + (V^{kWc} * T^{kWc}) \tag{1}$$

With the total revenue calculated, it can be determined how much of that revenue can be recovered from a specific tariff (R_c^x) based on a new cost unit distribution. This is shown for the volumetric tariff, peak tariff and contracted power tariff in equations 2, 3 and 4, respectively. Here D_c^x stands for the percentage of the total revenue a tariff carries. The sum of all distribution percentages must always equal 100%, as per equation 5.

$$R_c^{kWh} = R_c^{total} * (\frac{D_c^{kWh}}{100}) \tag{2}$$

$$R_c^{kWmax} = R_c^{total} * (\frac{D_c^{kWmax}}{100}) \tag{3}$$

$$R_c^{kWc} = R_c^{total} * (\frac{D_c^{kWc}}{100}) \tag{4}$$

$$D_c^{kWh} + D_c^{kWmax} + D_c^{kWc} = 100 \tag{5}$$

With the total allowed revenue per tariff known, the tariff level itself (T_{new}^{x}) can be determined. For this analysis, this has been determined by dividing the calculated revenue by the original volumes for each tariff. This is shown in equations 6, 7 and 8 for the volumetric tariff, peak tariff and contracted power tariff, respectively.

$$T_{new}^{kWh} = \frac{R_c^{kWh}}{V^{kWh}} \tag{6}$$

$$T_{new}^{kWmax} = \frac{R_c^{kWmax}}{V^{kWmax}} \tag{7}$$

$$T_{new}^{kWc} = \frac{R_c^{kWc}}{V^{kWc}} \tag{8}$$

Now that the new tariff levels can be determined with this method, the new distribution levels must be determined. This will be explained in the next section.

Appendix C.2: Scenario setup

In this section the scenario setup for the harmonization and cost unit redistribution will be explained. First the chosen scenarios and corresponding tariff levels are explained, then the further details such as week choice and consumer selection are presented.

Tariff levels

For this analysis, two grid categories will be examined. These are the 'TS' grid category, containing connection capacities larger than 10.000 kVA, and the 'Trafo HS+TS/MS' grid category, containing connection capacities from 1.750 kVA to 10.000 kVA. Prior to a redistribution of cost units, revenue was collected by 50% from the peak tariff, and 50% from the contracted capacity tariff.

For the sake of this analysis, which aims to understand whether it is beneficial to introduce the volumetric tariff and find another cost unit distribution for the sake of peak reduction and adjusted load factor, a scenario analysis will be conducted with varying distributions. For this analysis it has been chosen to create separate scenarios where each of the three tariffs recovers half of the total revenue, and a scenario with equal distribution. This leads to the scenarios presented in Table 29.

Table 29: Scenarios for harmonization analysis

Scenario name	Cost recovery per tariff		
	Volumetric (kWh)	Peak (kWmax)	Contracted capacity (kWc)
Base case	0%	50%	50%
50 25 25	50%	25%	25%
25 50 25	25%	50%	25%
25 25 50	25%	25%	50%
33 33 33	33%	33%	33%

The resulting tariff levels for each tariff and scenario, following the established methodology, are presented in The original tariff levels are sourced from Stedin (n.d.-b).

A distinction must be made in these grid categories because different volumes and original tariff levels apply to these categories. The original tariff levels are sourced from Stedin (n.d.-b).

Table 30: Tariff levels for each scenario and grid category in euros

	Grid category					
	HS+TS/MS			TS		
Tariff Scenario	Volumetric (kWh)	Peak (kWmax)	Contracted capacity (kWc)	Volumetric (kWh)	Peak (kWmax)	Contracted capacity (kWc)
Base case	0	5,3286	3,1739	0	3,9621	2,7295
50 25 25	0,0134	2,6643	1,5870	0,0101	1,9811	1,3647
25 50 25	0,0067	5,3286	1,5870	0,0051	3,9621	1,3647
25 25 50	0,0067	2,6643	3,1739	0,0051	1,9811	2,7295
33 33 33	0,0089	3,5524	2,1159	0,0068	2,6414	1,8197

Chosen consumers

For each grid category, separate consumers have been chosen based on the data provided by Stedin. Same as in the original analysis, consumers are here defined by their connection to the grid. In this section an overview will be presented of the chosen consumers per grid category and the total amount of consumers that have been calculated.

For the HS+TS/MS grid category a total of 18 connections has been chosen, which consists of three connections per the following categories: bakery, manufacturing plant, office, logistics company, shipyard and horticulture. This represents fewer consumers as compared to the main analysis. This is because it was difficult to make a broad selection of consumers with the given timeframe. Yet, with the chosen categories a wide variety of consumer types have been selected, approximating a representation of the electricity grid.

For the TS grid category, a total of 35 connections has been chosen, also consisting of three connections per category, except for the cold storage facility category. The included categories are waste treatment, chemical industry, data centre, distribution centre, cold storage facility, rail infrastructure operator, refinery, port terminal, horticulture, food production and hospital. With this selection of categories, a representation of the variety in the grid category was approximated.

It must be noted that the chosen consumers do not represent an actual part of the grid. Such a selection would require insights into the distribution of types of consumers in each grid category, which was infeasible in the given timeframe. Therefore, the selections represent variety instead of an actual grid.

Chosen scope

For this analysis the scope is like the scope in the main analysis. Thus, four weeks are analyzed, which are week 8, week 25, week 30 and week 50 of 2024. In the context of the chosen grid categories these weeks are random. It was not possible in the given timeframe to redetermine the average and peak weeks in the relevant grid categories. Therefore, a random selection of weeks was made.

Chosen performance indicators

For this analysis, the same performance indicators as in the original analysis are chosen. These are absolute peak reduction, relative peak reduction and adjusted load factor. Load shifting is included to further understand the obtained results.

Appendix C.3: Results of scenario analysis

The results of the scenario analysis, where the effects of new cost unit distributions are analyzed, will be presented in this section. Results from both grid categories are presented separately. The results presented in the tables below contain colors. A green color is assigned to a result that is deemed desirable, and a red color is assigned to undesirable results.

HS+TS/MS grid category

Before presenting the results, the reference loads from this grid category are presented in Figure 39. From this figure it can be seen that the week with the highest peaks is week 50. It is therefore important that in this week the peak reductions are highest, these reductions reduce the system peak.

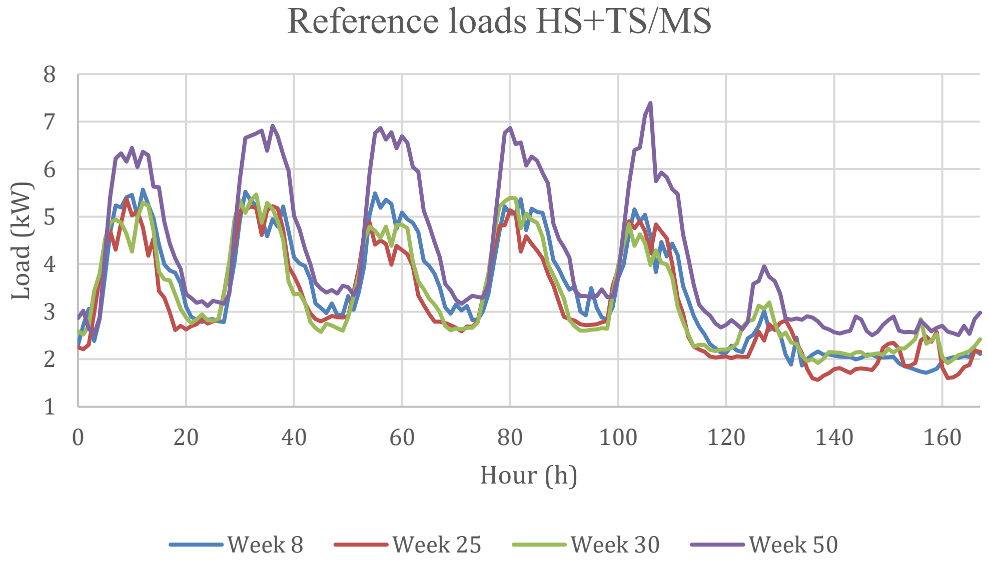

Figure 39: Reference loads HS+TS/MS

For the absolute peak reduction, shown in Table 31, it can be concluded that for the week with the highest peaks, week 50, the best configuration is ’50 25 25’, meaning the volumetric tariff has the largest influence. When looking at the overall score for each week, the best configuration is ’25 50 25’, where the peak tariff has the largest influence.

Table 31: Absolute peak reduction HS+TS/MS

Week	Reference peak	Base case	50 25 25	25 50 25	25 25 50	33 33 33
Week 8	5,570	-0,0575	-0,0895	-0,0699	-0,0786	-0,0786
Week 25	5,374	-0,1256	-0,1447	-0,1333	-0,1383	-0,1383
Week 30	5,467	-0,507	-0,3424	-0,334	-0,3399	-0,3399
Week 50	7,393	0,1526	0,1566	0,1549	0,1553	0,1553
Total		-0,5375	-0,42	-0,3823	-0,4027	-0,4015

Table 32 shows that the base case leads to the most relative peak reduction, except for in week 50, which is the week with the highest peaks. It can also be seen that for week 8 there is a higher relative peak. This is because the original peak occurs on a moment with a lower weighing factor, meaning load is shifted to this hour.

Table 32: Relative peak reduction HS+TS/MS

Week	Reference peak	Base case	50 25 25	25 50 25	25 25 50	33 33 33
Week 8	5,570	-0,0575	-0,0895	-0,0699	-0,0766	-0,0786
Week 25	5,374	0,1819	0,1727	0,178	0,1761	0,1756
Week 30	5,467	0,1856	0,1559	0,1715	0,1675	0,1649
Week 50	7,393	0,1526	0,1566	0,1549	0,1547	0,1553
Total		0,4626	0,3957	0,4345	0,4217	0,4172

For the adjusted load factor the overall best approach is keeping the tariff at the base case scenario, as seen in Table 33. Also, in most cases the adjusted load factor increases as a result of the ToU tariffs.

Table 33: Adjusted load factor HS+MS/TS

Week	Reference efficiency	Base case	50 25 25	25 50 25	25 25 50	33 33 33
Week 8	64,523	66,354	66,553	66,446	66,494	66,510
Week 25	61,967	63,099	62,699	62,892	62,848	62,813
Week 30	63,096	62,314	62,257	62,269	62,268	62,265
Week 50	61,761	63,253	63,306	63,229	63,261	63,261
Total		255,020	254,815	254,836	254,871	254,849

As shown in Table 34, the most load shift occurs when the volumetric tariff has the largest influence. This is because the volumetric tariff directly influences the energy price and thus provides a stronger incentive to shift load between hours. This is as expected and is in line with the reasoning from the main analysis.

Table 34: Load shift HS+MS/TS

Week	Base case	50 25 25	25 50 25	25 25 50	33 33 33
Week 8	10,731	11,632	11,175	11,189	11,329
Week 25	15,351	15,720	15,349	15,422	15,492
Week 30	15,499	15,728	15,526	15,555	15,603
Week 50	16,429	16,683	16,546	16,565	16,598
Total	58,010	59,763	58,596	58,730	59,021

TS grid category

Figure 40 shows the reference loads from the TS grid category. Here it can be seen that week 30 is the week with the highest peaks, meaning it is most important that peaks are reduced in this week. It can also be seen that the load patterns do not follow a day-night pattern such as the one seen in Figure 39. The consequences of this phenomenon will be explained later.

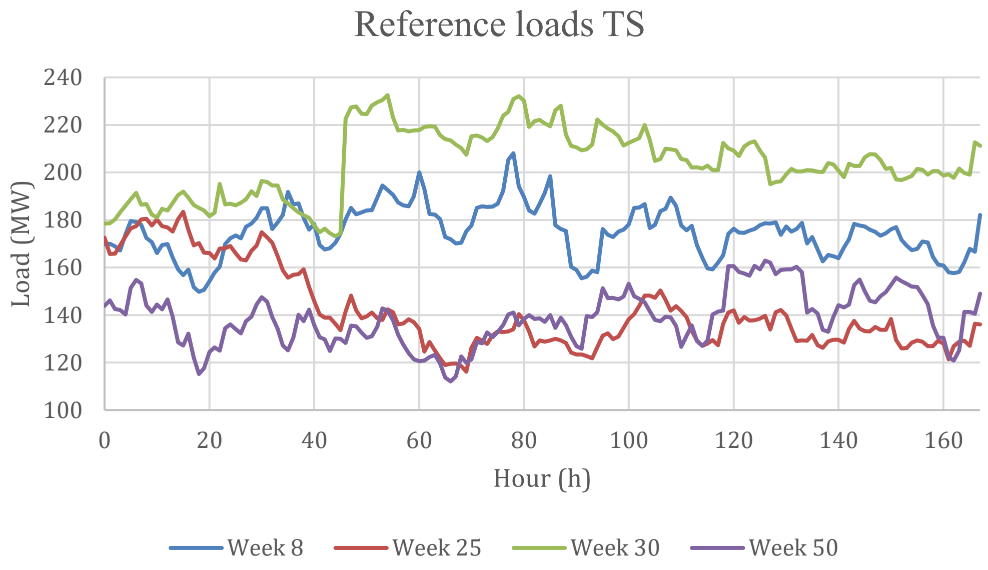

Figure 40: Reference loads TS

Looking at Table 35, the absolute peak reduction is overall highest in the scenario where the peak tariff has the largest influence. However, in Week 30, where the peak is highest, it is again the configuration with the volumetric tariff as the largest influence where there is the largest peak reduction. However, in this week, peaks are always higher than compared to the base case without ToU tariffs.

Table 35: Absolute peak reduction TS

Week	Reference peak	Base case	50 25 25	25 50 25	25 25 50	33 33 33
Week 8	208,089	1,660	0,831	1,235	1,258	1,109
Week 25	183,433	-15,023	-15,954	-15,387	-15,602	-15,651
Week 30	232,523	-17,040	-15,722	-15,875	-15,875	-15,823
Week 50	162,902	-4,246	-4,196	-4,233	-4,208	-4,212
Total		-34,649	-35,040	-34,259	-34,426	-34,577

Table 36 shows the relative peak reduction and shows how generally the base case leads to the most relative peak reduction, except for in week 30. Weeks with higher peaks lead to larger absolute peak changes, as similar relative load shifts lead to larger absolute peak reductions.

Table 36: Relative peak reduction TS

Week	Reference peak	Base case	50 25 25	25 50 25	25 25 50	33 33 33
Week 8	208,089	7,809	6,979	7,400	7,363	7,244
Week 25	183,433	-13,833	-14,287	-14,011	-14,116	-14,140
Week 30	232,523	7,510	7,604	7,548	7,571	7,575
Week 50	162,902	11,665	11,641	11,656	11,650	11,649
Total		13,152	11,937	12,593	12,468	12,328

The influence on the adjusted load factor seems more random, with the overall best scoring scenario being the ’33 33 33’ scenario, as shown in Table 37. From this table it can be seen that it is generally dependent on the week which configuration works best, showing there is no ‘one-size-fits-all’ configuration for the adjusted load factor. Also, as compared to the reference efficiency, introducing ToU tariffs has varying effects on the adjusted load factor.

Table 37: Adjusted load factor TS

Week	Reference efficiency	Base case	50 25 25	25 50 25	25 25 50	33 33 33
Week 8	90,121	89,155	88,940	89,002	89,039	90,121
Week 25	79,063	81,208	81,359	81,229	81,278	81,289
Week 30	88,615	88,579	88,511	88,525	88,524	88,322
Week 50	86,048	87,001	86,997	86,994	87,004	86,999
Total		345,943	345,807	345,751	345,845	346,730

Table 38 shows how the load shift is in this case generally highest in the ’33 33 33’ scenario, with the scenario with the volumetric tariff as the highest influence being second. It thus shows how load shift is highest whenever the volumetric tariff at least some influence.

Table 38: Load shift TS

Week	Base case	50 25 25	25 50 25	25 25 50	33 33 33
Week 8	391,501	411,568	401,342	401,947	405,082
Week 25	499,396	502,134	495,612	497,168	498,300
Week 30	563,955	569,768	564,690	565,308	604,410
Week 50	411,900	415,828	413,732	414,086	414,570
Total	1866,753	1899,298	1875,376	1878,509	1922,362

Synthesis of results

Peak reduction

Overall, it can be concluded from the scenario results that generally the ’25 50 25’ configuration leads to the most absolute peak reduction. However, when addressing grid congestion, it is most important to target the highest peaks in the system. In the weeks with the highest peaks, it is the ’50 25 25’ configuration that has the most influence.

Configurations with a larger volumetric component generally cause the most load shifting, an important detail in the explanation of why this scenario causes the most peak reduction. Due to the nature of the model, where the upper limit is determined by historical data, load shifting often leads to peak reduction due to varying upper limits. This is illustrated in Figure 41. The upper limit limits the amount of energy that can be consumed in the cheaper hour (hour 21). However, due to the fact that this hour is now cheaper as a result of the ToU tariffs, the load from the expensive hour (hour 20) now shifts to the cheaper hour, reducing the peak in hour 20. This is how load shifting causes peak reductions in the created model. Especially in peak weeks, it is likely that the loads are already close to the upper limit, which is an advantageous circumstance for the volumetric tariff.

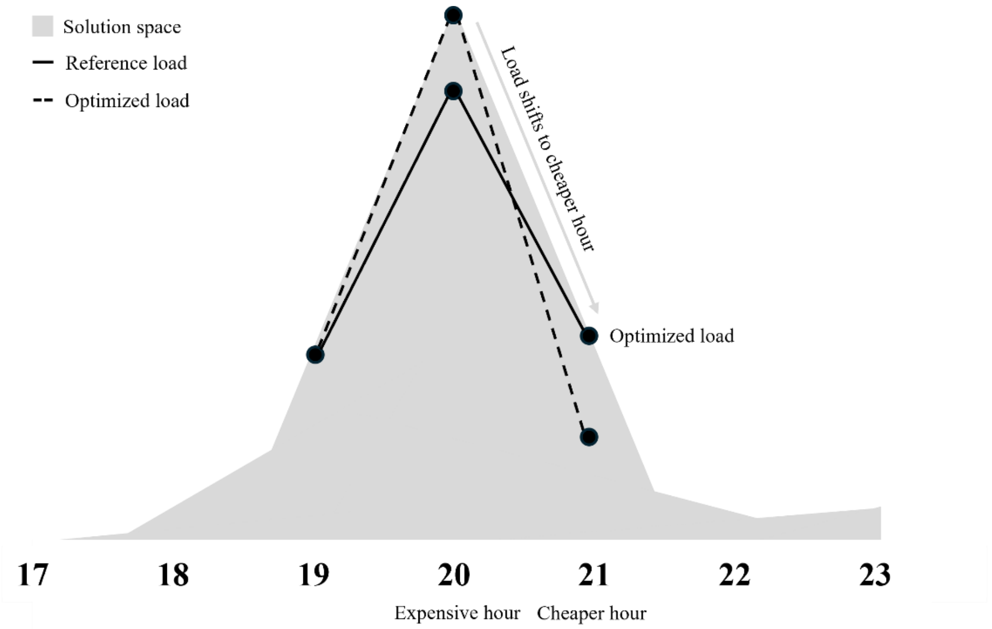

Figure 41: Fictitious example of load shifting causing peak reduction

It can also be seen how the introduction of ToU tariffs leads to increased peaks, even in weeks with system peaks. This is especially so in the case of the TS grid category. This phenomenon can be explained by the fact that the profiles in the TS grid category are generally flatter, and because some peaks occur during moments of low weighing factors. For example, the peak in week 25 of the TS grid category occurs in June at 15:00. During this moment there is a weighing factor of 0,1, meaning consumers are incentivized to further move load to this hour. Two general rules can be deducted from this phenomenon, which is first that profiles that were originally flat, will by definition create peaks in usage with ToU tariffs, and that profiles that have peaks during cheaper hours will increase their peaks in such hours.

Adjusted load factor

For the adjusted load factor it is more difficult to draw a singular conclusion. From this analysis it mostly shows how the best configuration for the adjusted load factor is largely dependent on the week, and there seems to be little correlation between the peak reduction and the adjusted load factor. The lack of correlation is explained by the fact that the adjusted load factor is determined with the 95th percentile of peaks, meaning singular peak reduction does not automatically lead to a higher adjusted load factor, as more peaks may have appeared.

It can be seen that the grid category is relevant in whether ToU tariffs lead to a higher adjusted load factor. For the HS+TS/MS grid category, the adjusted load factor generally increases as a result of ToU tariffs, whereas for the TS grid category the influence on the adjusted load factor is not as clear. This can be explained by the rule that flatter profiles become more variable with ToU tariffs, pushing average loads and peaks further apart, thus generally decreasing the adjusted load factor.

Appendix C.4: Conclusion and recommendation

In this short analysis two grid categories have been exposed to varying tariff configurations, to understand which configuration is best for increasing the system efficiency, which covers both peak reduction and increased adjusted load factors. The grid categories ‘Trafo HS+TS/MS’ and ‘TS’ were analyzed, with the same model as used in the original analysis from this thesis. Now a short overview of the main conclusions and recommendations as a result of this analysis will be presented.

First, it can be concluded that the ‘50 25 25’ configuration leads to the most absolute peak reduction during peak weeks. However, it must be noted that the nature of the model has a large influence on this outcome, as explained previously. Overall, it is the ’25 50 25’ configuration that scores best if the weekly results are added to each other. This is in line with the reasoning from the main analysis.

When it comes to the adjusted load factor, it seems there is no one-size-fits-all solution. It is dependent on the week type what tariff configuration will have the most influence. Based on the results of this analysis, ToU tariffs in grids characterized by flat profiles appear less effective for the adjusted load factor as they may increase load variability. It is therefore recommended to explore other means of increasing the adjusted load factor of grid categories characterized by flat load profiles, or by reevaluating the structure of weighing factors to align better with the profiles of a specific grid category.

In various cases, especially in the TS grid category, the introduction of ToU tariffs leads to an increase in peaks. It has been observed that this happens for two reasons. First, if a profile is originally flat, ToU tariffs will increase the variability of the load profile, thereby causing new peaks. Second, if peaks are originally measured during cheap hours, more load will shift to these hours leading to higher peaks. However, peaks in cheaper hours generally do not determine the yearly peak, lowering their relevance in the context of grid congestion.

Following these observations, it is not certain that ToU tariffs have the desired effects in grids that are characterized by flat profiles, such as the TS grid category. For grids such as these, it is often a handful of peaks that must be reduced in a given year, meaning a ToU structure for an entire year reduces the adjusted load factor seems excessive. Also, the influence on the adjusted load factor is less reliable, as more variable profiles generally lead to lower efficiencies. It is therefore recommended to look into other solutions than ToU tariffs in cases such as for the TS grid category.

Appendix C.5: Limitations

There are some limitations to this analysis that must be mentioned. These will be explained in this section.

First, only a handful of connections have been used for the analysis, which each have varying connection capacities. Due to the variability in connection capacities, it is uncertain how much one connection contributes to the system peak, and how this influences the relevance of other connections. Regardless, the effects of the tariffs are visible, and are expected to be similar even with more realistic connection groups. It must also be noted that only a single year is analyzed, and that the analyzed weeks may not be representative. These were necessary evils, as time constraints did not allow for a better week choices or better connection selections.

The method of recalculating tariff levels assumes that the consumption volumes are static. In reality, changing tariffs may lead to changing volumes. The calculated tariff levels may therefore not fully reflect the tariff levels that would emerge in reality. However, this method of calculating tariff levels was found fitting, as the model concerns a redistribution of energy and rarely leads to differing volumes.

Redelivery of power is not included in this analysis, same as in the original analysis of this thesis. This can impact the results, because in physical networks redelivery may lead to reduced aggregated loads. This power can for example be used to a consumer close by, preventing use of the grid in other areas, thus reducing the load at certain points.

Lastly, this analysis concerns an aggregation of connections that are not physically within the same grid area. Due to the limitations of Vision, the network analysis tool used in the original analysis, it was not possible to model a real network segment. Congestion problems are often local, meaning peak reductions do not necessarily translate to reduced congestion in this analysis.

Appendix D: Statement of Artificial Intelligence use

While preparing this work, ChatGPT-5.2 has been used to improve readability of text, and support with programming in Python. After using this tool/service, I reviewed and edited the content as needed and I take full responsibility for the content of my model and thesis.

Delft, March 11 , 2026