MASTER

Underground trading
a study on market-based congestion management in the distribution grid

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Award date:
2018

Underground Trading

A study on market- based congestion management in the distribution grid

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1 – 3 – 2018

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Summary

The energy transition is putting a strain on the distribution grid due to unpredictable and intermittent (renewable) generation, and electrification in general. This results in an increased chance of congestion in the distribution grid. We consider the application of a congestion management tool for the distribution grid that operates on the intraday market. The intraday market in the Netherlands is a continuous spot market without a fixed price. The tool allows the Distribution System Operator (DSO) to search for buy and sell orders in a bulletin-board style intraday market. Sorting by location allows the DSO to find unmatched buy and sell orders that can relieve congestions in the distribution grid. The difference between the buy and sell price is, in this case, called the congestion spread. By paying this congestion spread, the DSO can match an unmatched buy and sell order and relieve congestion in their grid without affecting the balancing in the grid or taking up a position in the market. The congestion management tool is analyzed based on a part of the Stedin grid that is currently experiencing congestion. The grid section consists of a 50kV to 10kV transformer substation, and 4 outgoing feeders. Every node is a 10kV to 400V transformer. The customers on these feeders are varied and consist of households, industry and horticulture parties. The analysis is done for a period of 6 years, from 2018 to 2023. For the loading of the grid, a high and low development scenario is used, and for the development of the market a forecast is made based on intraday market development in Germany.

In the high-development scenario the total congestion per year develops very strongly. In 2023, transformer congestion occurs in a total of 55% of the time, with an average congestion size of 133% of maximum capacity on the transformer. In the low-development scenario, there is congestion 3% of the time, and the average size of the congestion is much lower with only 108% of maximum capacity.

When looking at whether congestions were solved, the high-development scenario has a slight increase in how many of the congestions were traded, but how many congestions were actually solved decreases strongly. This is the result of the large size of the congestions that are too large to be solved. In the low-development scenario, the fraction of congestions that were solved is much higher, but the maximum is in 2021 (~50%). Afterwards, the congestions have also grown too large in some cases and less will be solved.

In terms of cost for Stedin, it varies strongly depending on the scenario but is always much lower than the alternative grid reinforcement solution. Therefore, the question is not so much about cost but whether the tool is reliable enough.

In addition to the original analysis of the congestion management tool, 3 case-studies were developed to look at certain developments in the overall market structure that could have an influence on the effectiveness on the tool.

The first case-study looked at the time of trading for a potential operational model to see how different times influence the cost. This showed that depending on which time a trade occurs, the cost can increase up to 80%. This shows the value of more accurately predicting congestion.

The second case-study looked into time-of-use grid tariffs and the intended peak-shaving effect. This significantly increased the effectiveness of the tool, especially in the high-development scenario. The total solved congestions is now 26% and 56% for the high and low scenario respectively.

The final case-study looked into greater market participation and flexibility that is more distributed as a result. This case study resulted in a total amount of solved congestions of 13% and 77% for high

and low development. Additionally, the average cost decreased due to an increase in the possible trades to choose from.

The conclusion is that the congestion management tool can be effective, but not as a stand-alone solution. Together with other ongoing developments that result in peak-shaving effects and increased market participation, the tool can add value. Mostly to solve congestions that were not predicted and pop-up last-minute. This makes sense because the intraday market is last-minute by definition so that is how a tool on that platform should be treated.

Finally, this thesis looked at the potential impacts of the congestion management tool and of time-of-use grid tariffs on the wider electricity system and its actors and there are two things that were addressed.

First of all, the socialization of cost. When the cost of operating the grid is no longer shared equally but divided with flexible tariffs as well as real market prices, it is a real possibility that the people that are hurt are the ones that are already struggling more than others. It is of crucial importance that if flexible grid tariffs and market prices are introduced, it is done in such a way that the people that struggle to adapt to this are supported, not left behind.

Secondly, the incentives on market parties and the grid operator should be considered. For grid operators it is important that they have the incentive to manage the grid as efficiently as possible. But if they get paid for congestion through flexible tariffs, this might disappear. It is important to maintain this incentive some other way. For market parties, the congestion management tool might incentivize them to artificially raise prices when there is congestion or even create congestions. This can be mitigated partly by increased competition, but mostly it should be done by making sure that the congestions solved with this tool are not easily predictable, which is another argument why it should be a last-minute solution.

1. Introduction

Electricity security is one of the pillars of the modern-day society. Without electricity, communication, and transportation, economic activity will all come to a screeching halt. For example, on January 17th 2017, a black-out in the Amsterdam region which lasted for less than four hours resulted in tens of millions in economic damages [1], and even two deaths [2]. Therefore, the critical task of the grid operator, to ensure that electricity is supplied reliably to where it is needed, is extremely important. With the changing energy landscape, this task is becoming both more challenging and expensive.

An issue that affects the reliability and security of our electricity supply is congestion in the grid. Congestion occurs when more electrical power is transported over a cable or line than it was designed to carry. This can happen when production or consumption of electricity increases, either in total or just in specific moments. Consequently, electrical equipment, such as a cable or transformer, gets damaged, breaks or is switched off to prevent further damage. This can result in black-outs such as the one in Amsterdam. Ideally, congestion is prevented by building the grid in such a way that there will always be enough available capacity. However, congestion may still occur or may be predicted to occur in the future. The practice of preventing this is called congestion management.

Congestion management in the Netherlands is only structurally practiced on the transmission grid by TenneT, the transmission system operator. They use the market to manage occasional congestion on high voltage lines and country interconnectors. Currently, distribution system operators (DSO) such as Stedin are only allowed to practice congestion management for short-term emergencies, as their grids are designed to always have enough capacity to prevent congestion. In practice, this requirement is becoming harder and harder to fulfill and costs are quickly rising.

Electricity production is becoming more intermittent and distributed due to the increase in sustainable electricity generation. Intermittent electrical generation is generation that is not continuously available due to external factors that cannot be influenced, most often the weather. Distributed generation is generation that is not centralized in a few locations and connected to the high-voltage grid (like is often the case with gas or coal fired power plants), but is instead scattered geographically and in different voltage levels. Being intermittent and distributed is common with renewable generation such as wind and solar.

The peak loads on the grid become higher and more erratic, making the expansion of the distribution grid more expensive and underutilized at the same time. In particular with renewable generation such as solar, which often overlaps with moments of low electricity use. Together with the overall electrification of society through the use of, for example, electric cars, this makes a strong case for congestion management in the distribution grid to prevent high societal costs that accompany grid strengthening.

The issue then becomes exploring how congestion management in the distribution grid should be implemented. Congestion management has many different variations, but what they all have in common is that they provide flexibility to the grid operator. Flexibility can be procured through direct control of assets, free markets or anything in between. Transportation capacity can be auctioned separately, it can be a boundary condition in other optimization processes or only be considered when it becomes a scarce commodity. Countless combinations of mechanisms can be proposed that all have their own advantages and hurdles to overcome, some which will be treated later in this report.

This research will focus on using bilateral trading to resolve grid congestion issues, a form of this type of solution is currently being developed by Stedin and Energy Trading Platform Amsterdam (ETPA). This congestion management tool will allow the DSO to perform congestion management within an existing intra-day market. Up until now, congestion management pilots, and programs to procure flexibility, have often taken place within a niche environment. This means that the program is physically and/or regulatory disconnected from the real-world situation; the program is very useful for testing different concepts and innovations, but may not always translate into the real-world situation. This congestion management tool is the first project where congestion management in distribution grids will be applied on a platform that is active on the national electricity market.

This connection to the real market makes the congestion management tool more than just a technical solution of how to solve congestion on the distribution grid. The current regulatory framework and market design is designed to function within the old regime of centralized fossil fuel electricity generation. A good congestion management solution for the distribution grid should focus on both the technical aspects, as well as the socioeconomic context in which it should function. Because the current market is designed based on the old energy landscape, there will be regulations and role divisions in place that will make it hard for congestion management in the distribution grid successful. Therefore this research will focus on both the technical as well as the regulatory and market aspects of congestion management in the distribution grid.

Research questions

In the end, the goal of this research is to determine how congestion management based on market principles can be introduced to the distribution grid, what the financial consequences will be, and how its development will work in conjunction with other developments in the market and the regulatory landscape. To do this the main research question will be:

What could be the role of market-based congestion management in the future electricity system?

Because it is important to look at all aspects to properly answer this research question, these aspects are clearly highlighted in the following research sub-questions:

1. ***What is the reliability of market-based congestion management in effectively solving congestions?***
2. ***What is the financial cost of market-based congestion management?***
3. ***What is the market and regulatory context in which market-based congestion management is applicable?***

These sub-questions ensure that the entire depth of this problem is considered. Because of the interconnectedness of the entire system, all these aspects should be looked at and all kept in mind throughout the research. These research questions reflect the technical workings of the concept, the economic aspects and the wider societal context in which it will be implemented.

2. Methodology

Since this thesis will fulfill the academic requirements for two masters, it is important that a certain technical depth is present, as well as a wider context that places the problem within a greater technological and societal transition. The basis of this research is a quantitative model that uses data from the DSO Stedin and market-based platform ETPA to quantify the possibilities of congestion management through bilateral trading. The results of this model will be analyzed and compared with alternative solutions, as well as interpreted within the context of market and policy developments within the energy sector.

The model will be applied to a grid area of Stedin called *Zuidplaspolder*. The reason that this grid area is chosen for a case study is that congestion is currently a problem there. Stedin is looking for an intermediate solution in this area that can span the time until a more permanent solution is available, which will be in 2023.

The reason that a quantitative approach is chosen is that this is currently very relevant for Stedin. They are at a point where decisions need to be made about how their grids need to be operated in the future. For something such as congestion management in the market, the idea has been qualitatively researched, but exactly how it will turn out in practice is largely unknown. After this research is completed, there will still be many uncertainties but cost ranges and the main factors upon which they depend will be more clear. Stedin can use this as a basis for further analysis and actual decision making. Besides cost, also the reliability with which congestions can be solved will be quantified.The qualitative analysis of the model results is important because the problem of congestion management and the intraday market cannot be seen separately from other developments. The entire energy system is in transition and choices made for congestion management will affect other markets and actors on the grid. Therefore, it is important to look at general policy and market developments and how they relate to congestion management and the specific solution in this research.

The model was written in Python 3. It is original work with the use of several existing Python libraries: pandas [3], NumPy [4], PyPSA [5], matplotlib [6], and datetime. The working of the model is mostly based on the congestion management tool from ETPA that is currently under development, but adapted on several points because it is not yet an operational model. Original data is used from the ETPA trading platform and the Stedin historical loading data. The modifications that were done to the data to account for different future scenarios were made on the basis of literature research and expertise within Stedin. Reports from different parties that have investigated future developments in grid loading, sustainable energy sources and intraday market development were used. Expertise from Stedin on grid operation and asset management were also used.

The qualitative analysis of results was based mostly on literature research and research using publicly available sources such as policy documents, government reports, and market studies. Additionally, discussions with policy and regulation experts within Stedin provided insight in current developments in the regulatory landscape. Perspectives obtained from market parties (such as aggregators) were also taken into account.

The methodology used in this research has as the main advantage that real-world data is used as a starting point. This means that the results are directly applicable to real-world scenarios, and should be widely generalizable. However, especially for the future scenarios, assumptions had to be made in order to make the data suitable for analysis and the applicability of the results depends on whether and how far these assumptions hold. Throughout the report, the assumptions that were made will be clearly noted and their impact described.

3. Historical overview

This background section will contain background information on the Dutch electricity grid, the electricity market, congestion, congestion management and finally about the Energy Trading Platform Amsterdam (ETPA). Figure 1 shows the historical and current overview in a graphical way.

3.1. The Dutch Electricity Grid

The first real power plant in the Netherlands was opened in 1886 in Kinderdijk, close to Rotterdam [7]. Before that, there were only individual electricity installations which were used to provide electricity to individual customers such as shops, hotels, and sometimes houses [8].

Around 1910 the Dutch electricity systems became more connected, as separate power plants would be connected to the same grid. First on a regional level, and after the second world war on a national level. During this time the voltages on which connections were also increasing. The first 50 kV high-voltage connection in the Netherlands was in operation in 1919. The voltage used kept gradually increasing as this decreases losses. In 1969 the first 380 kV connection was put into operation, which is still the highest operational voltage in the Netherlands today [9].

3.1.1. Development of operation

Initially it had mainly been private entrepreneurs that were investing in electricity. But from 1902, many municipalities started electricity companies to provide their municipalities, and later on surrounding areas as well, with electricity. Later on, the provinces were the ones to provide guarantees for the municipal companies to expand their network into areas that were previously not financially feasible to connect. This was done because electricity was starting to be considered as a basic utility that everyone should have access to.

After the different regional and provincial networks had continued to expand, the next step was taken in 1949. This year an organization for collaborating energy producers (SEP) was founded. In 1953 this cooperation had led to the coupling of all the regional grids into a national grid. In the following decades the national government took a more prominent role to force a focus shift from expansion to optimization. In 1982 the national economic optimization (LEO) was introduced, a calculation for optimal economic dispatch. This decade is also the time that there is increasing environmental concern and distributed generation is starting to increase, especially in industry. [10]

3.1.2. Liberalization

In 1998 the stepwise liberalization of the Dutch electricity sector is started with the introduction of a new ‘electricity-law’. At this point, individual consumers do not have a choice in who is their electricity supplier. This is because the same company operates the grid and generates the electricity in the region where you live. The liberalization means that the electricity companies have to split their generation and grid operation activities, and that new electricity suppliers can enter the market. This was done to increase competition, which should benefit the consumer. In contrast to their electricity supplier, consumers cannot choose their own grid operator as this is a natural monopoly due to the extremely high infrastructure cost. Because of this nature of grid operation, grid operators are not allowed to conduct market-related activities as part of their daily operation, only in experimental and pilot projects.

Recently, a new electricity law has been adopted. The role of the grid operators was a major point of discussion. Whether the grid operators get more freedom to innovate, or if this is left to the market? In the end the government to define the role of the grid operator more clearly, and for them to stay away from market activities as much as possible. For all activities, the DSO has to keep in mind that it should directly benefit the consumer. The grid and the liberalized energy market, which are only relatively new themselves, now have to undergo another big overhaul. From a static grid, where only large companies play a role on the market, to a dynamic grid and market where all players participate in order to make the best possible use of our renewable energy.

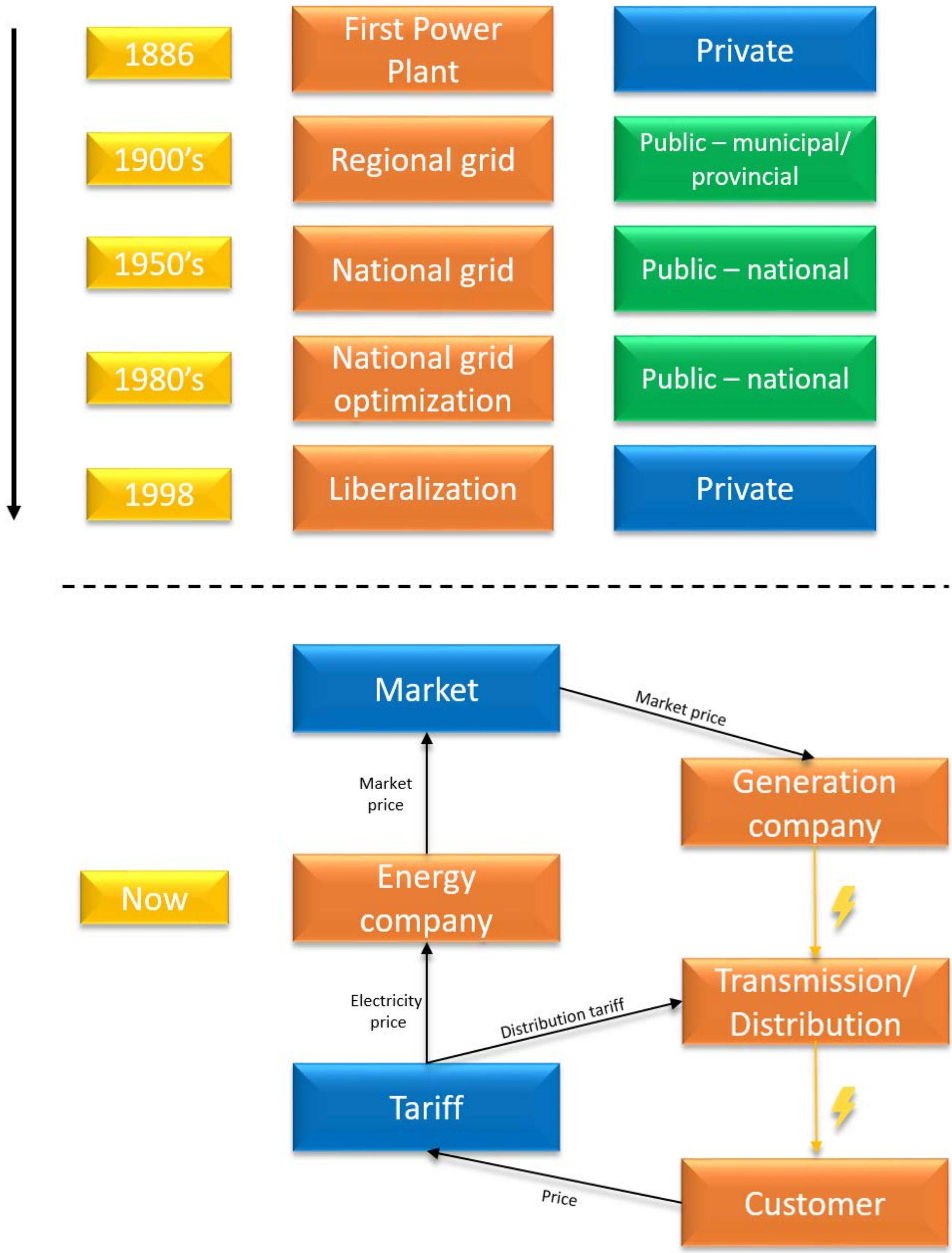


Figure 1: Timeline of electricity system development and overview of current situation

4. Theoretical background on electricity market design

The electricity market in the Netherlands is the basis for the congestion management tool of Stedin and ETPA. Therefore, it is important to have a good understanding of how this system functions. This basic understanding of the electricity market design will form the basis of further analysis of congestion management within this market.

The first part will give a general explanation of electricity markets, how they can be structured and what it contains. Secondly, the Dutch electricity market will be placed within this framework, with a focus on the parts that are relevant for congestion management in the distribution grid. Based on this understanding of the Dutch electricity market, the problems and hurdles that exist will be identified. The design of the different markets has inherent features, and some of these might clash with the goal to manage congestion through markets. What are these features, and how are they anchored within the market design. These problems and features will be used for continued analysis of the congestion management tool.

4.1. Architecture and structure of electricity markets

The design of the electricity market can be divided into two different categories, the market architecture and the market structure [11]. The electricity market as a whole consists of several different submarkets that fulfill different functions but are all interconnected. How many submarkets there are, and what type of markets they are is what is called the <u>market architecture</u>. The rules regulating the different markets such as tariff setting, price limits and reserve capacity requirements are all a result of what is called <u>market structure.</u>

4.1.1. Market architecture

As mentioned, the market architecture determines the number and type of the submarkets within the larger market. On the market, electricity is traded as a commodity but there are some aspects that make the electricity market unique. The electricity market has to deal with a physical aspect that goes much faster than any other market [12]. This introduces an important time aspect to the market. To catch this time aspect, the electricity market has several forward markets. These markets trade electricity for a certain point in the future. Usually there are several markets that allow for trading of electricity years in advance all the way until minutes from the time of operation.

There are two main considerations to be made considering the architecture of the forward markets.

- The number of markets, and on what time-scale they operate
- Is it a mediated or bilateral market

The decision on how many markets to run is based on the linkages between different markets. The different markets influence each other, and at some point it might be better to integrate two separate markets into one. This is usually a trade-off between efficiency and transparency. A multi-product market that integrates several markets is usually more efficient, but also more complex and therefore less transparent. Market linkages will be explored a little more in-depth later.

The second decision is on whether to run a mediated market or a bilateral market. A bilateral market is a market where two parties trade directly with each other. In a mediated market, both buyers and sellers trade through an intermediary party/institution. There are several versions of both types of markets, but in general bilateral markets are more unorganized and decentralized than mediated markets which are more centralized. Stoft [11] gives an overview of different types of bilateral and mediated markets in Figure 2.

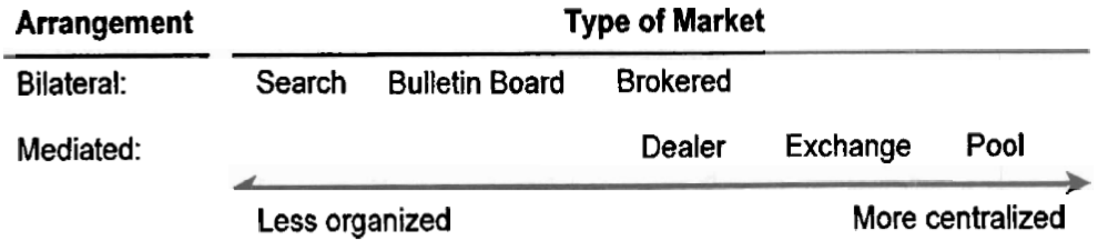


Figure 2: Different types of mediated and bilateral markets from less to more organized [11]

A short explanation of the different market types:

- *Direct search*: a market that is very unorganized. Buyers and sellers must seek each other out themselves by whatever means they choose themselves [13]. This could be through advertisements on relevant platforms. In the electricity market it is more likely that this would be done through directly approaching counterparties and utilizing existing networks.
- *Bulletin board*: Similar to a direct search market, but the buyers and the sellers have a common platform where they try to find each other.
- *Brokered*: In brokered markets, brokers offer services to buyers and sellers to help them find trading partners.
- *Dealer*: A dealer market is similar to a brokered market, but a dealer “trades for his own account” [11]. Instead of a brokerage fee, he buys for a lower price than he sells for.
- *Exchange*: An exchange is a place where all the participants in the market come together in one place, and there is no need to search for the best price across different dealers [13]. This makes an exchange fast and trustworthy, but also more regulated and inflexible [11]. The quickness of an exchange is especially useful for fast trading closer to time of operation in electricity markets.
- *Pool*: A pooled market is the most organized type of market. All the participants bid in the price for which they are willing to buy and sell. Based on a centralized market clearance, one price and volume is determined at the point where the supply and demand curves intersect.

Besides forward markets, which is the main form of market discussed in this research, there are some other markets as well that are relevant to the electricity system. They are referred to at some points throughout, but they are not as relevant in congestion management.

- Real-time markets
- Transmission or capacity markets
- Ex-post markets

Real-time markets are markets that do not trade for a point in the future, but are immediate or at least as fast as physically possible. This type of market is mostly used for the balancing market, as this requires real-time matching of supply and demand. Transmission markets are markets which do not trade in electricity, but the right to transport it over the grid. Finally, ex-post markets allow parties to trade electricity after the time of operation. This is useful to trade away imbalances and deviations from the original day-ahead market clearance.

Market linkages

Market linkages are a factor that plays a large role in determining the market architecture of an electricity market. A market linkage is a connection between two markets or between products within the same market. What happens in one market to, for example, the price will influence the other market. An example of a linkage is between the market for electricity and the market for transmission rights. Because electricity needs to be transported, activity on the electricity market has direct consequences for a transmission rights market.

Other examples of market linkages are linkages in time and location. If electricity is expected to be more expensive in a forward market closer to time of operation, more electricity will be sold in the current forward market which raises the price. If electricity is expected to be cheaper in the future, most parties will wait with buying. This dynamic causes the current price to converge towards the expected future price. This is how the prices in the different forward markets link together. Geographical linkages exist because the cost of transportation from point A to B is linked to the cost of transportation from C to B, or B to C.

4.1.2. Market structure

As mentioned before, market structure are rules and regulations on how the market architecture is utilized. Stoft [11], distinguishes five areas where policy makers should play a role in providing effective market structure. The five areas will be explained and their relevance for congestion management in the distribution grid discussed. The five areas are:

- Reliability requirements
- Transmission
- Demand elasticity
- Long-term contracts
- Supply concentration

Reliability requirements: The operator of the grid is responsible for providing a reliable grid. The main tools for the grid operator are operating an imbalance market, requiring operating reserves from generators, and investing in new grid infrastructure. With all these things, trade-offs between cost and reliability need to be made, and the right incentives need to be put at the right places.

Transmission: Transmission capacity that is available has influence on prices and can create market power through scarcity. In low and medium voltage this is usually called *Distribution.* In a situation where available transportation capacity is not enough for the demand, a system has to be in place that can divide the available capacity. Usually this system will involve some way of increasing the price of transportation. How these costs are divided will then again have an effect on investment incentives. If the cost falls on the grid operators, this will function as an incentive to invest in new grid infrastructure. If the cost falls on the electricity producers, this will function as an incentive to think critically about location of new generation capacity. Market structure is what determines what the rules surrounding transmission capacity are, and therefore determines these underlying market party incentives.

Demand elasticity: Demand elasticity is the reaction from the demand side on price variations in the electricity price. Right now, in many electricity markets all over the world this is very low due to a number of reasons:

- No real time rates, there is simply no price variation on the demand side
- Little capacity to respond to price variations
- Risk aversion

This is an important part of the market structure that certainly has to be looked into regarding the energy transition.

Long term contracts: Long term contracts require generators to sell a certain part of their production for a fixed price over a period of time. The advantage of this is that it decreases the market power of large generators, as they cannot use this electricity to potentially influence market prices on more short-term forward markets. The requirements for long-term 'vested' contracts is a matter of market structure.

Supply concentration

The supply concentration is about how large suppliers are in relation to the entire sector, this is an indicator of how oligopolistic an industry is. If suppliers are too large, they might have too much power in the market. An adequate market structure can ensure no single supplier holds too much power, while still making sure they can earn a profit and utilize economies of scale.

These 5 areas are places where good and adequate rules and regulations are needed to make sure the market functions as desired. For congestion management in distribution grids, 3 of these areas are especially important. These are *reliability, transmission*, or in this case distribution, and *demand elasticity*. The way transportation capacity and electricity are priced towards the demand side are crucial for how the distribution grid is used, and this is what causes congestion in the first place. Therefore, these two areas will be the main focus areas going forward.

5. Dutch electricity market design

5.1. Market architecture

Chapter 3 introduced the liberalized electricity market, but what exactly is it in the Netherlands? The electricity market consists of several different sub markets, roles and actors that all fulfill a specific function. In order to know where changes need to be made, it is important to understand how the situation is currently.

Since 2004, the Dutch electricity market is liberalized after a stepwise process which started in 1998, meaning that consumers are free to choose from which supplier they will buy their electricity. As mentioned previously, companies are no longer allowed to be both energy generators and grid operators. This gives a clearer division in roles in the electricity market. On the market side there are 2 different roles: electricity producer and electricity supplier. Electricity producers are companies that have physical assets to generate electricity. Electricity suppliers are companies that supply electricity to their customers. Since both of these roles are on the market side, they can be fulfilled by the same company, but this is not necessary. If an electricity producer is not an energy supplier, they can sell their electricity on the electricity market. On the other hand, a supplier does not have to be a producer either and they can buy the electricity they need to supply their customers from the market as well.

On the grid side, there are the DSOs such as Stedin. In total there are 6 DSOs in the Netherlands that together are responsible for the low and medium voltage grid in the Netherlands. This is the grid operating on everything until 50 kV. Each DSO has their own region in which they operate the grid. The second role at the grid side is that of transmission system operator (TSO), they operate the high voltage grid. Since this grid covers much larger distances and connects all the regional grids together, there is only one TSO in the Netherlands, this is TenneT. Besides the operation of the grid, TenneT is also responsible for the balancing of the entire grid. This means that they have to make sure the grid frequency of 50Hz is maintained at all times. This is done by matching supply and demand in real time. Exactly how they do this will be discussed later. Because all the regional grids are directly under the high-voltage grid, the balance of the medium and low voltage grid will be automatically maintained if TenneT balances the grid, and the DSOs do not have to balance their own grid.

The balancing of the grid is something that comes back in all markets. All parties on the grid have *balance responsibility.* This means that they are expected to specify how much electricity they will feed into and extract from the grid each day. This is done through *program responsible parties*. They are the large electricity suppliers, producers, and other large players. These players are responsible that they communicate in advance their schedules with TenneT, help TenneT to balance out the grid if needed and pay fines if they deviate from the agreed upon schedules. How these schedules look is determined in the different markets that will be discussed next.

Figure 3 shows the different markets that are active at different times with regards to the day of operation (N). The goal of the markets is to trade electricity, while maintaining a balance between supply and demand. The different market mechanisms will be explained in turn.

Earlier	N-1	Day of operation (N)	N+1	Later
• OTC (bilateral contracts)	• Day-ahead market • (OTC)	• Intra-day market • Imbalance market • (OTC)	• Ex-post trading	• Financial settlement of imbalance

Figure 3: Different electricity trade market mechanisms over time.

5.1.1. Over the counter

First, there are the *bilateral contracts*, usually called *Over The Counter* (OTC) contracts. These are agreements between a buyer and a seller to exchange electricity for a specific period. The advantage of these agreements is that they offer price stability, which for some parties is necessary to perform long-term planning [14]. Inherently, bi-lateral contracting carries a risk by committing to a price while not knowing how the market will develop [15]. Because a bilateral contract is a contract between two parties for a specified amount, balancing is guaranteed as long as both parties stick to the contract. Over the counter trading can occur at any time before the moment of operation when two parties come to an agreement. Over the counter trading is by definition a bilateral trade between two partners, it differs in how organized it is. It is possible for partners to find each other directly, making it a *direct-search* market [16]. Services for OTC trading might also be offered by organized markets, making it a *brokered* market [17].

5.1.2. Day-ahead auction

The second trading opportunity is at the *day-ahead auction*, which lasts until 12:00 on the day before operation. During this time buyers and sellers can put in orders for a certain timeframe, capacity and price. After market closure, all the buy orders are aggregated into a demand curve and all the sell orders are aggregated into a supply curve. This supply curve is also called the *merit order.* Generators are willing to produce electricity at a price that is equal to their marginal cost (variable cost such as fuel and operating cost). For most renewable generation, the marginal cost is very low because they don’t have fuel cost and they will usually be first in the merit order.

The point where the demand and supply curves intersect determines the market clearing price and market clearing quantity (see Figure 4). The results of the market clearing are checked by TenneT and the Distribution System Operators (DSO) for congestion and other problems. If this is approved, all the parties are sent their so-called E-programs which specifies their consumption and production pattern throughout the day. As long as parties stick to their E-program, the balance in the grid will be maintained.

Because the electricity supply and demand is gathered in a single place and cleared on a central market clearance, the day-ahead market is a *pooled market*. It is the most organized market in the Dutch system.

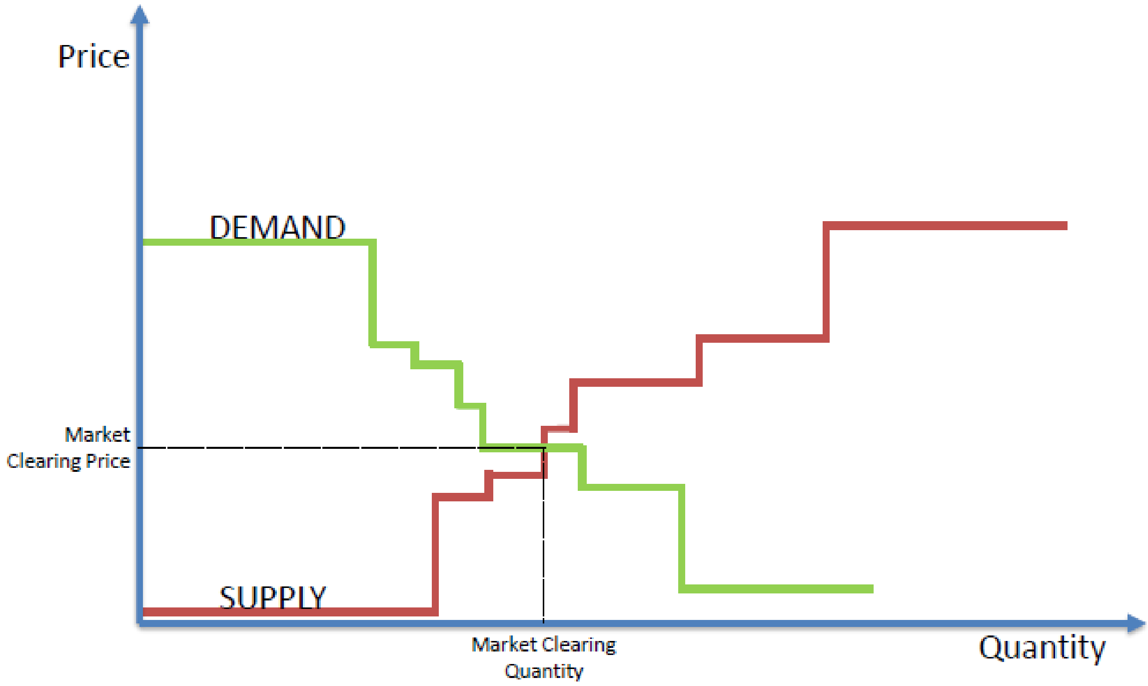


Figure 4: Clearing of the day-ahead market

5.1.3. Intraday market

It is easy to imagine that the specified amounts of electricity that are to be supplied and extracted from the grid are not accurate days before it actually occurs. Especially for energy companies representing aggregated consumers which have no direct control over their customers this is hard. Based on profiles they can make reasonably accurate predictions of the demand of their customers, but there will always be deviations. Furthermore, the weather has a large influence on the amount of renewable electricity supplied to the system and is hard to predict as well. Therefore, many parties will inevitably deviate from their programs as they are known by the TSO (TenneT). The intraday market exists to give trading parties the opportunity to adapt their E-program and in that way reduce the amount balancing to be done by the TSO. This will also reduce the imbalance fees that have to be paid by the parties that would otherwise be fined for deviation from their E-program.

The *intraday market* runs from approximately 16:00 (after the day-ahead market is cleared) until a 15 minutes before real-time. On the intraday market, market parties can trade electricity if they want or have to deviate from the original market clearing quantity. For some parties this is a necessity as they would otherwise be forced to deviate from their E-program. For other parties, that are more flexible, it is an opportunity to make or save some money. Contrary to the day-ahead market, the intraday market works by matching buyers and sellers directly for a price they are both willing to pay. There is no central market clearing which results in a single clearing price and quantity. Instead, trades are cleared on an individual basis making it bilateral trading, more similar to over-the-counter trading. Contrary to OTC, it is not a direct search market. Because it works relatively close to real time, a more organized approach is needed. The intraday market can best be qualified as a *bulletin board* market. It offers a place where buyers and sellers can find each other, and the services to quickly clear a trade. However, an intraday market stands or falls with the amount of traders and volumes traded, because it is not mediated. In other words, the market liquidity. Some background on what market liquidity is and means in this case can be found in

Appendix I.

5.1.4. Imbalance market

If, after participating in all these markets, a party still produces or consumes more than is the result of the market, they are forced to buy or sell the deviation to TenneT. TenneT will pay or charge them the imbalance price. This is a very volatile price and usually it will not be financially beneficial.

TenneT does not own any generation themselves, and they need to acquire or sell the electricity needed to balance out the grid somewhere else; this is the imbalance market. On this market, large producers are contractually obligated to make offers to up or downscale their production very quickly. TenneT can use this capacity to balance the grid. The costs that TenneT incurs when they use this market are put on the program responsible parties through the imbalance prices. As mentioned before, this is usually a costly affair. The imbalance market is an *exchange market* with a single dealer: TenneT.

5.1.5. Ex-post trading

Ex-post trading is a trading mechanism which allows parties that had imbalances to trade them after the moment of operation until 10AM the next morning [18]. For example, during one quarter of an hour on 17/09/17 the imbalance price for selling electricity was be €31.04/MWh while buying electricity from TenneT at the imbalance price was €59.48/MWh. Both parties can save quite some money if they trade with each other at the mid-price. Because even though both parties were not in balance, their imbalance was in the opposite direction and can therefore cancel each other out. Ex-post trading is not yet common in the Dutch market, but when done it is traded *bilaterally*.

5.2. Market structure

As explained previously, market structure is about the regulatory framework in which the different markets function. The three focus points of structure for congestion management are: reliability, transmission, and demand-side elasticity are discussed here.

5.2.1. Reliability

The reliability of the grid is one of the most important factors and is the responsibility of the grid operators. TenneT is responsible for the balancing of the whole grid and operation of the high-voltage grid. Stedin and the other DSOs are responsible for the operation of medium and low-voltage grids. The trade-off between cost and reliability was mentioned in the chapter on market structure, and the balance of this trade-off is shifting. Currently the trade-off for the DSO is still strongly in favor of reliability, and grid strengthening is the default response to an increase in maximum capacity. If flexibility is to be an option in the operation of the distribution grid, this trade-off needs to be re-evaluated. Flexibility has great saving potential but will almost always be less reliable, simply because it complicates the operation. An important for question for Stedin will be how they will re-evaluate this reliability and cost trade-off.

5.2.2. Transmission (Distribution)

In the previous section, there has been no mention of a transmission or capacity market. This is because this does not exist in the Netherlands. The Dutch electricity grid functions under the with the concept of 'the copper plate' in mind. What this means is that markets operate under the assumption that there are no limitations on transportation capacity of electricity. Transportation capacity is not a scarce resource and is therefore not traded, and entirety of the Netherlands is a single price zone. It does not matter where your electricity comes from, or where you are situated, the electricity price is the same.

Because of the copper plate principle, the grid operator is given the responsibility that there is actually enough transport capacity available at all times. In the Netherlands, this is anchored in the law with the right to non-discriminatory access to the electricity grid [19]. Both the national, as well as the regional grid operators in the Netherlands have this responsibility.

Of course the grid operator does need to be paid in some way, otherwise they would be unable to maintain or expand the grid. Dutch electricity consumers pay several tariffs to their grid operator. For most consumers, the tariffs are partly fixed and partly capacity based. The capacity part is based on the maximum amount of electricity that can be transported through the connection, this value is measured in Amperes. For the larger consumers, anyone who needs a connection larger than 3x80A, there are special tariffs that are also based on which voltage level you are connected to. Large consumers that are connected to the low voltage or high voltage grid have tariffs based on capacity. Only for large consumers connected to the medium voltage level there are tariffs based on consumption, meaning they pay to the grid operator based on the amount of electricity they use. According to regulation specialists at Stedin this practice is likely to be abandoned soon. The reasoning being that for Stedin the amount of electricity transported on their grid does not matter much, the limiting factor is the total flow of electricity at a single time [20].

The capacity tariffs are not variable, your capacity tariff is based on the single moment with your highest consumption regardless of what capacity was used during the rest of the year. This is usually called your *kWmax.*

5.2.3. Demand side elasticity

As mentioned previously, demand side elasticity is the willingness of customers to respond to price deviations. Currently, there is virtually no demand side elasticity in the Dutch electricity grid. All small and many larger customers have contracts with energy companies that supply them with electricity for a fixed price per kWh, so there are no *real time rates* for small consumers. Recently, more small factories and energy intensive industries such as horticulture are switching to becoming active players on the electricity market. But still for most customers this means that there are not even any price variations for to respond to. Even if there would be price variations, the actual elasticity might still be low due to a lack of capacity to respond to the price deviations and a risk aversion of the customer. The capacity to respond means that it would take too much time, effort, and knowledge to respond to price variations.

6. Congestion and Congestion management

6.1. Congestion

In a liberalized environment, the goal is to create a competitive market. In theory, the market is cleared for the whole grid, resulting in a single market clearing price for the entire market. However, the physical grid is limited in the capacity that it can transfer between two points. Therefore, the result of this competitive market clearing is not always physically executable. If the capacity carried on a line or a cable exceeds the limits of said line/cable, congestion will occur.

Congestion on the electricity grid is not like other types of network congestion such as road congestion. When the number of cars on the road exceeds the capacity of the road, traffic will slow down and in some cases, stop completely. Due to the physical nature of electricity, this will never happen in an electricity grid, current will always keep flowing [21]. To resolve congestion, action has to be taken at the generation and/or demand side. If timely action is not taken, there are 2 constraints that, when violated, could destroy grid components or cause imbalance in the grid, possibly leading to cascading blackouts in worst-case scenarios [22].

1. Thermal constraints
2. Stability limits

Due to the resistance in the electrical wires, energy will be dissipated in the form of heat losses. The thermal limit of a wire (in combination of the thermal properties of the insulation, if any, and the ambient temperature) determines the maximum capacity of the line or cable. If a wire is overloaded for an extended period of time it will become permanently damaged. Similar unwanted effects occur when overloading transformers. The thermal losses are proportional to the square of the magnitude of the current passing through a grid asset, and are therefore dependent on both real and reactive power flows.

The stability limits on a line have to do with the voltage drop and phase shift over that line. Reactive power injections are used to support the voltage magnitude of the grid. This causes a phase shift in the voltage. If the system cannot provide the necessary reactive power to the lines, the voltage will become unstable and eventually collapse resulting in a blackout [23] [24]. In long power lines, the stability limit is usually more important. In shorter power lines/cables, like in the Netherlands and distribution grids in general, the thermal limit is usually leading. As the focus of this research is on distribution systems and not on transmission systems, stability is not a problem and the focus will be on the thermal limits. If stability limits do turn out to be a problem, this will come forward in the power flow analysis.

In transmission grids, the resistance (R) of the lines is usually negligible compared to the reactance (X). This causes the reactive power to have a large influence on the voltage. Because of the shorter distances in the distribution grid, the resistance is much more important and cannot be neglected.

Another difference with traffic congestion is that how electrons flow on the grid cannot be steered. Only the injection and extraction points can be determined, the flows are determined by the physical characteristics of the network (impedance of lines and equipment). The flows can be calculated using a power flow analysis. A power flow analysis becomes rapidly more complex when more nodes and interconnections are added. This adds another level of complexity of to the congestion management problem, and makes it anything but straightforward.

To summarize, congestion is a violation of limits on a particular line or cable, either thermal limits or stability limits. In the case of congestion in the distribution grid the main problem is the violation of thermal limits. Whether they are violated depends on the impedance of the line and the current flowing.

6.2. Congestion management

How congestion is currently dealt with is something that is different in the high-voltage transmission network (managed by TenneT) and the distribution network (low/medium voltage, managed by the 6 DSOs).

After the clearing of the market, the risks of congestion in the system are calculated using power flow calculations. When a congestion risk is identified, the market is cleared again considering these limitations until a satisfactory solution is reached without congestion in the system. This is only done for the transmission grid and not the distribution grids. The DSOs will have to solve things differently.

Even after this check, the demand, and increasingly the supply of electricity are unpredictable. There might be much more wind than expected, the demand might be lower, or there could even be a failure in a grid component. Because the high voltage grid no longer has enough capacity at all times, there is a chance that congestion will happen. When this is the case, TenneT uses a mechanism called *Basic System Redispatch* to deal with a congestion risk [25].

When a congestion risk is identified during the day of operation, TenneT will use the imbalance market to solve the congestion. Producers in the congested area will bid how much they are willing to pay to produce less than they were originally scheduled to, or consume more within the same area. Producers in non-congested areas can put in an order for what price they are willing to produce extra, or consume less. TenneT will call upon these orders arranged in increasing price order until the congestion risk has been resolved [25]. This is what Basic System Redispatch is. Additionally, TenneT can call for market restrictions during which parties in a certain area are requested not to deviate from their cleared schedules (E-program) [26]. This is a process in which only professional parties participate and is therefore quite easy and straightforward compared to the distribution grid. Congestion in the medium and low voltage grids is far more challenging because it involves millions of smaller connections that are harder if not impossible to influence or control.

At this moment, congestion in the distribution grid hardly occurs because it is still the case that the grid is designed to have enough capacity to deal with peak power. If there is a threat that somewhere the peak demand will be larger than the grid capacity, capacity is simply increased [27]. As a result, the majority of the time the distribution grid is vastly underutilized, because this peak capacity is not often needed. This is the basis of why congestion management is considered worthwhile. If implemented successfully, the grid will be used much more effectively, resulting in a societal benefit. the authors in [28] note that a congestion management system for the distribution grid could "postpone or even avoid the need for more costly network capacity upgrades".

Soon, demand for electricity will increase further because of the general electrification of society (electric vehicles, heatpumps, electric cooking). Additionally, production of electricity will become more unpredictable due to the integration of renewable electricity sources such as wind and solar. This has already caused problems in Groningen where a steep increase in solar power caused congestion in the distribution grid [29].

This makes it clear that congestion and congestion management in the distribution grid is indeed a relevant problem and having a good alternative solution for this will make for a more efficient and cost-effective grid.

Ecofys [30] researched the savings that could be made by using congestion management in the distribution grid. They researched three different scenarios with three different dominant technologies (Electric vehicles – EV, heat pumps – HP, photovoltaics – PV) The possible savings were compared to a scenario without congestion management. Because all scenarios deal with a significant increase in electricity demand, no congestion management means large investments in strengthening the grid infrastructure. It turns out that especially the scenario with EV and heat pumps shows great potential with savings between 31% and 47% compared to a scenario without congestion management. This results in a saving of around 150 €/year/household for the EV scenario and a saving of around 80 €/year/household for the HP scenario. These technologies result in cost savings because they provide much flexibility that can be used to manage congestion. A PV dominated scenario results in much less cost savings (€/year/household) because they only provide flexibility through curtailment, and this loses money as well. The costs that are considered in the study by Ecofys are divided into three categories.

1. Flexibility costs – costs of software and technology to make flexibility options possible.
2. Grid costs – costs to increase the grid capacity in low, medium and high voltage grid. Also, the grid loss costs.
3. Generation costs – costs to have the needed generation capacity available and the operational costs. If curtailment of the solar panels is needed, those losses are counted into this category as well.

All the costs are also discounted over time using an annuity factor. Figure 5 shows the difference in cost for the different scenarios. The two main factors that contribute to the cost-saving with congestion management are:

- Less need for the building of extra grid capacity in medium voltage networks.
- Less need for extra generation capacity.

The first factor follows logically from earlier parts of the report. The reason that less generation capacity is needed, is that the overall peak demand is lower due to congestion management. Therefore there is less need for extra generation capacity, even though overall demand is increasing. The reason that a PV dominated scenario does not realize as much cost savings is that hardly any extra generation is needed because PV is already extra generation in itself, resulting in little difference between a scenario with and without congestion management.

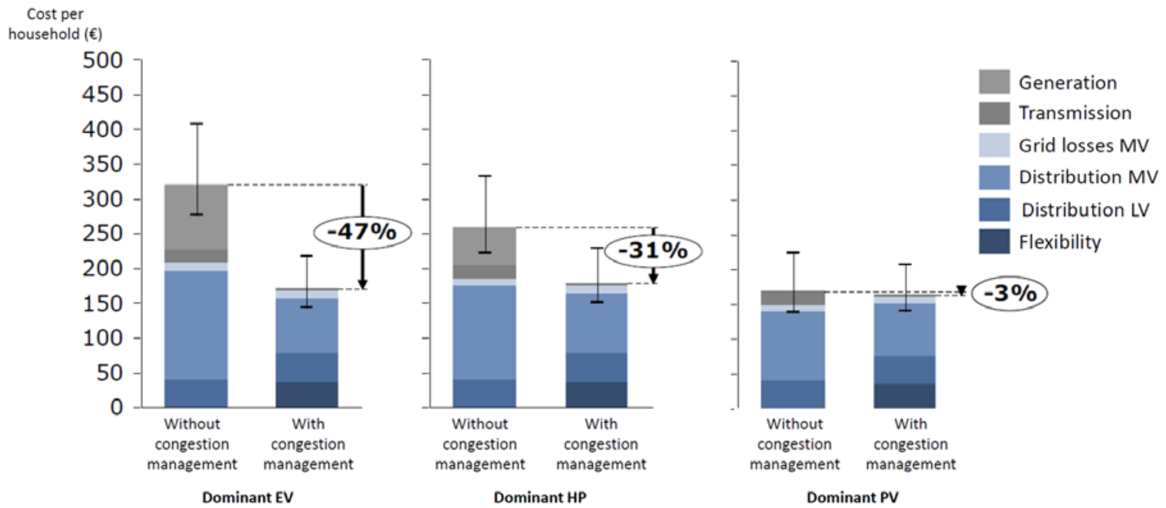


Figure 5: annual additional cost per household compared to now. With and without congestion management in different scenarios [30]

To summarize, congestion management will become more important in the future and potential savings will increase. Congestion management is performed differently in the transmission and distribution grid, but the overall solution of congestion will always come back to flexibility. If there is flexibility to shift electricity use and production in time or geographical location, congestion can be solved.

6.3. Flexibility

Flexibility is not only a solution for congestion. There are three basic tasks of a grid operator, and flexibility can play a role in all of them because they will become harder in the changing electricity landscape. This again underlines that congestion management is not something that is independent of the rest of the grid. What happens in one part of the grid will always have an influence somewhere else. The three main tasks of grid operation and their relation to flexibility are:

1. Delivery of electricity

In the old system, generation of electricity follows demand. At the moments demand is higher, the power plants can produce more electricity. With intermittent renewable sources, this is no longer possible. Flexibility is needed on both demand and supply side to still match supply and demand.

2. Balancing of the system

Electricity grids need to be balanced at all times, meaning that the supply and demand should be equal. This has to be balanced in real-time by the high-voltage grid operator TenneT. Because this can be a matter of seconds, large generation facilities in the Netherlands have the obligation to help TenneT with this balancing. Again, because of the intermittency, it is much harder for renewable sources to provide reliable balancing capabilities to TenneT.

3. Congestion

Because the grid was mostly designed for centralized generation, distributed generation puts pressure on parts of the system that were not designed for it. Additionally, renewable sources might cause unexpected high spikes in generation. This can cause overloading of lines, cables and transformers in the grid, but often only on a small number of occasions.

There are many ways in which flexibility can be procured from the system, and the market is just one of them. This research focuses on the market and the role it can play in congestion management. It is important to still recognize that this is only one possible solution to a part of the bigger transition.

7. Congestion management in Distribution grids

In the last section, congestion management in general and its current status has been discussed. When looking at congestion management in distribution grids specifically, there is no consensus on how it should be applied, and this will strongly depend on context and future developments. In cases that it has been applied, it has been for individual cases and temporary until a new connection can be realized . An example of this is the congestion management that took place in the Westland area, where horticulture companies had to offer to scale down production on a specifically designed online platform [31].

The next section will go into three ideas on how congestion management in distribution grids can be organized. They are not necessarily mutually exclusive and could find application side by side. They do, however, work distinctively different and have advantages and disadvantages. Based on this general explanation of how they work, they will be analyzed in conjunction with the ongoing developments on the regulatory side of the electricity market.

The three different mechanisms are the following:

1. Congestion management based on grid tariffs
2. Congestion management based on local markets
3. Congestion management using the ETPA congestion management tool

The first two will be described here while the last one will be described in the next chapter.

7.1. Congestion grid tariffs

A congestion tariff is a tariff installed because of limited transportation capacity and increases the price of electricity produced somewhere else relative to production closer to the point of consumption. This decreases the transported quantity at the congested point to within the acceptable limits. In theory there is always a single optimal congestion tariff, which can be seen in Figure 6. Three different methods to determine the congestion tariff are discussed. For now it will remain a theoretical construct. How it can practically be implemented in the Dutch electricity market will be analyzed later in this report.

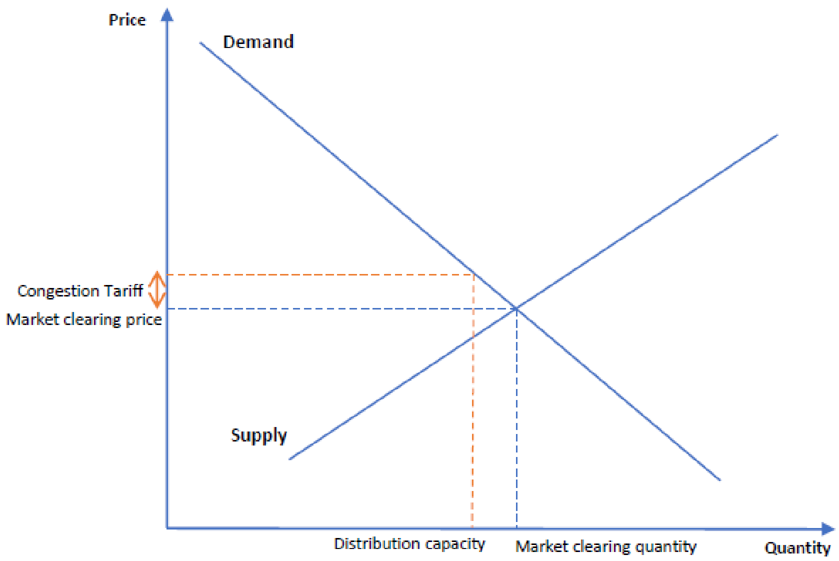


Figure 6: Congestion tariff working principle

The three methods to determine the congestion tariff are:

1. Dynamic grid tariff
2. Advance capacity allocation
3. Distribution grid capacity market

Before they are discussed, first the concept of *locational marginal pricing* will be discussed.

Congestion pricing is based on the principle of locational marginal pricing (LMP). LMP is not applied in the Netherlands but it does form the basis of the congestion tariffs in the next section.

Congestion pricing prices the transmission rights between different locations if there is a limit in transmission capacity. It determines the locational price of power and according to economic principles, these are the only efficient/competitive prices.

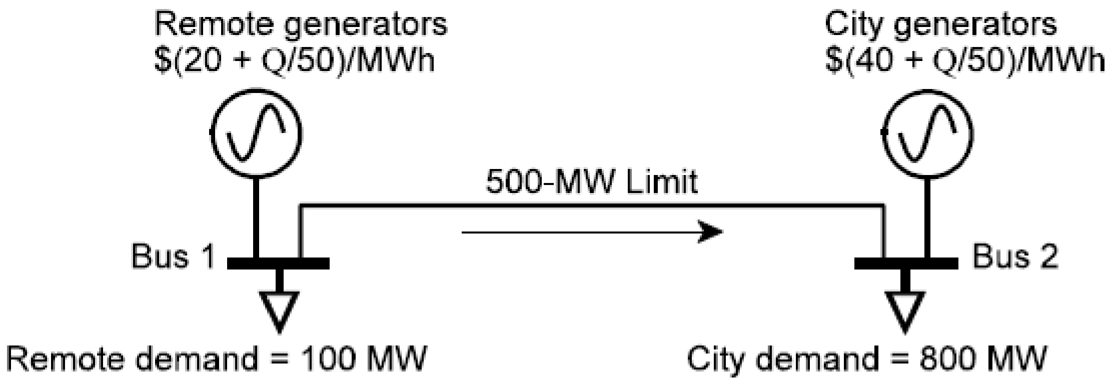


Figure 7: 2 bus power system example [23]

Figure 7 is an example 2-bus system, with prices depending on quantity (Q). If the limit on the line is ignored, all the demand will be supplied by the remote generators (900 MW at price 20+(900/50) = 38$/MWh). The city generators can be completely turned off. However, there is a limit of 500 MW on the line. This means that the price at bus 1 will be 20+(600/50) = 32$/MWh, and the price at bus 2 will be 40+(300/50) = 46$/MWh. In other words, customers at bus 2 are willing to pay extra in order to get the electricity from bus 1. Competitive forces will drive up this price to match the price that is already paid at bus 2 ($46) resulting in a transmission price of 46-32=$14/MWh. The locational price is always equal to the marginal cost of supplying an extra MW at that location, Figure 8 shows both solutions. In the no-limits solution all electricity is supplied by the remote generator at a price of 38$/MWh. At the limited solution there is a price difference due to the scarcity of transportation capacity. In the city they pay 32$/MWh plus a transmission price or the price of the city generators, which both is $46/MWh.

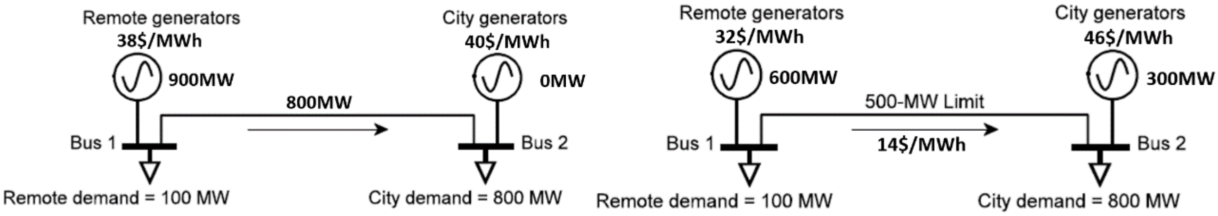


Figure 8: Solutions without (left) and with (right) transportation capacity limit.

7.1.1. Dynamic grid tariff

With this mechanism, a congestion tariff would be set that would keep the total demand just below the network capacity [28]. The DSO determines the tariff based on predictive models, historic demand and smart meter feedback [32]. The tariff is communicated by the DSO and the aggregators adapt their market position based on the increased price. If the DSO calculated the tariffs correctly, the resulting total demand will be equal to or smaller than the network capacity. The main advantage is that the communication from the DSO is simple. The disadvantages are that this is very complex to implement for the DSO and comes with many uncertainties because it assumes perfect information on the side of the DSO. If the estimation of the DSO is wrong, congestion might still occur and alternative mechanisms (e.g. load curtailment) must take effect and need to be possible.

7.1.2. Advance Capacity allocation

Instead of trying to set a tariff that will hopefully drive down the demand by the correct amount, advance capacity allocation reverses the order and divides the capacity [28] [32]. In the planning stage, the DSO and the aggregators make contractual agreements on which aggregator gets what share of the available capacity. Every day, the DSO determines the capacity that is left after the fulfillment of the baseload demand. This capacity is allocated to the different parties that would want to use it per previous contractual arrangement. Afterwards, it can also be traded in a capacity marketplace. The advantages are that the communication from the DSO is still simple, it communicates the available capacity and only comes into play again in the settlement stage. The market players will experience an increased complexity as they must not only optimize their own schedule, but need to trade in the capacity market. The capacity market would have only one supplier, namely the DSO. When all trades are settled, the price paid to the DSO is the network tariff. A problem with this system is that what parties are willing to pay in a certain time slot depends on what is allocated in previous and next time slots. Iterations are needed to solve this.

7.1.3. Distribution grid capacity market

An iterative process is used to determine the optimal congestion tariff. Initially the market parties perform their optimization without a congestion tariff, and communicate this with the DSO. The DSO analyzes the solution and sets a price for the distribution capacity (this is essentially the congestion tariff). The market parties then re-evaluate their positions considering this price. This process continues until it converges. This method requires multiple stages of communication and transfers complexity to the market. An issue is the time it takes to converge to a solution, in some situations this might take long and interfere with the normal market clearing [28] [32].

Besides these three, Liu et al [33] introduce a method based on locational marginal pricing to determine the grid tariff. Aggregators are asked to submit their day-ahead market bids and offers to the DSO before the actual market clears. The DSO clears the market artificially using historical prices because the actual prices are not yet known at that point. If congestion occurs at some point and time, the locational marginal price (LMP) is calculated. This price represents the marginal cost of increasing the power at that location and time, and is calculated using the power flow equations. The difference between the LMP and the predicted price is the distribution congestion price (DCP). This the tariff that the DSO will set for this location and time. In other words, the congestion tariff. Essentially, this is the same mechanism as the Distribution grid capacity market, only within a single iteration.

As long as the DSO is welfare maximizing and under perfect competition assumptions, all the solutions mentioned above will result in the same optimal situation and the same congestion tariff. The reality will of course be much more unpredictable.

7.2. Local flexibility markets

An alternative to the congestion tariffs is a method introduced by Torbaghan et al [34] [35]. They introduce the concept of *Local Flexibility Markets (LFM)* (Figure 9). On this market, which could operate both in the day-ahead and the intra-day market, aggregators make flexibility offers and the DSO makes flexibility requests. This market has its own market operator which clears the market. In the day-ahead market, congestion risks that are already identified will be solved as much as possible. Of course, new congestions risks might come up during the day. In this case, the intra-day market is used to find the necessary flexibility offers. If possible congestion risks cannot be solved in the day-ahead and intraday market, real-time dispatching is used. This consists again of two steps: voluntary profile management and compulsory profile management. Before the determined critical time, the DSO will negotiate with the aggregators to solve the congestion risk. When a critical time is reached and no solution found, the DSO will switch to compulsory profile management which means that the DSO will make autonomous decisions to adjust loads and generation.

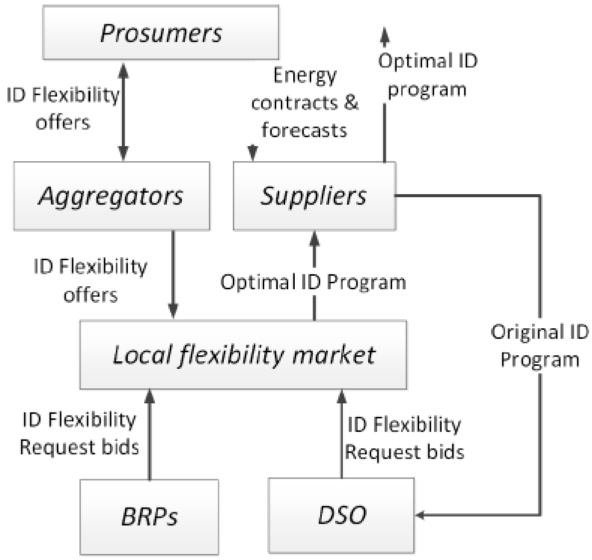


Figure 9: Intra-day market of the local flexibility market as proposed by Torbaghan et al. [34]

Torbaghan et al introduce the idea of trading flexibility. The concept of flexibility instead of buying/selling makes it easier to grasp what is happening physically. When a party offers *positive flexibility*, it means that they are willing to buy electricity and either increase their consumption, or reduce their production. They act as an electricity sink. When negative flexibility is offered, they work as a source by producing more electricity or consuming less electricity. This makes the direction of the trades clearer; the market parties are always the ones offering flexibility and the DSO is always procuring flexibility. In addition to using the local flexibility market for congestion management, the BRP also can use the intraday market for balancing. It turns out that combining these two functionalities increases the total social welfare.

8. Energy Trading Platform Amsterdam

Energy Trading Platform Amsterdam (ETPA) has developed a cloud-based software platform where market parties can trade, with a focus on the intraday market. ETPA differentiates itself from other spot markets in its accessibility and transparency [36]. ETPA allows for trading in 15 minute intervals with small capacities down to a minimum of 100kW. Besides that, membership fees for ETPA are only €150 per month whereas the annual fees of the EPEX marketplace (the largest in the Netherlands) can be up to €34.000 [37]. In terms of transparency, ETPA gives insight into what is traded and for which price in which time slot, something that is not possible on the EPEX.

The prediction is that low-barrier access into the electricity market will become much more important in the near future due to the increased need for flexibility to solve problems in the grid. More and more small and unpredictable sustainable electricity sources are being connected to voltage levels in the distribution rather than the transmission grid. This is a need that ETPA is trying to fill by allowing also these small players a platform on which they can trade their electricity and balance their position.

The platform is simple in its setup. Every order has 4 properties that need to be specified by the trader:

- Define a buy-order or a sell-order.
- The beginning and end time of the order.
- The capacity of the order in MW.
- The price of the order in €/MWh.

Let's say a trader defines a buy-order of 5 MW between 2pm and 3pm for €30/MWh. When the order is confirmed there are two options:

1. There is a matching order already available in the order book that can sell the electricity at the asked price or lower for the specified time-slot. In that case the orders are matched straight away and the electricity is traded.
2. There is no matching order available. In this case, the order is placed in the order book at the appropriate time and price. The order will stay in the order book until either the order is matched, or it is cancelled, or it is 15 minute before the start time of the order, at which point it is automatically cancelled.

Figure 10 gives an example of what the order book could look like at any given moment. Notice that there is a difference between the highest buying price and the lowest selling price. This number is called the spread. When the spread is 0, the buy and sell price are the same and that trade will occur. Quantities do not have to match in the platform. Looking at the figure, this means that if the first sell order would drop their price to €40/MWh, half of their order would be matched with the opposing buy-order (buying 5 MW at 40€/MWh). The buy order would disappear and 5 MW of the sell order would remain in the order book.

Buy/Sell	Quantity [MW]	Start	End	Price [€/MWh]	Spread [€/MWh]	Price [€/MWh]	End	Start	Quantity [MW]	Buy/Sell
Buy	5	14:00	15:00	40	5	45	15:00	14:00	10	Sell
Buy	5	14:00	15:00	35		50	15:00	14:00	5	Sell
Buy	5	14:00	15:00	30		60	15:00	14:00	5	Sell
Buy	1	15:00	16:00	35	5	40	16:00	15:00	10	Sell
Buy	1	15:00	16:00	34		43	16:00	15:00	1	Sell
Buy	5	15:00	16:00	30		50	16:00	15:00	5	Sell

Figure 10: Simplified visualization of how the platform works

8.1. ETPA congestion management tool

Together with the Dutch DSO Stedin, ETPA is developing a congestion management tool that will function within the intra-day market environment of the ETPA platform. The goal of the tool is to allow Stedin, or any other DSO, access to the order book and to stimulate trades that will be beneficial for the congestion management of Stedin. The anticipated effect of the tool is that consumption and/or production of electricity will be moved from a place with congestion risk to a place where distribution capacity is still plentiful.

Of all the orders that are in the order book, a congestion spread is calculated. As seen previously, a spread is the price difference between a buying and a selling order. A congestion spread has the added characteristic that it is a spread between an point with congestion (risk) and one where capacity is still available. These congestion spreads, and the accompanying locations are available to the DSO (not to other market parties). The DSO can review the available congestion spreads and determine whether they are a viable solution to a congestion problem. If they are, the DSO can decide to match the two orders by covering the difference in price. This way, generation or consumption capacity is moved from an area with a risk for congestion to another area [38]. Later, in this thesis, we will investigate whether this type of congestion mechanism is cost-effective for the DSO, i.e. it can be realized at a fraction of the cost of increasing the distribution grid capacity via reinforcements.

It is important to realize exactly what this means in terms of how electricity is generated or consumed. Let's say that a feeder coming from a 10vkV substation is congested because too much electricity is fed back into the grid. This can be solved in 2 ways, either less electricity is produced or more electricity is consumed on the feeder itself. Both of these things mean that less electricity is fed back into the grid. This seems like two completely different actions, but in the order book they would both be buy orders (see Figure 11). That consuming more is a buy order makes sense, but in order to produce less a buy order is needed. This is because the electricity otherwise produced by you, must now be bought from someone else. A sell order would only be needed if the congestion on the feeder would be caused by too much extraction from the grid. In that case it would be solved by producing more or consuming less on the feeder, both of which are sell orders in the order book.

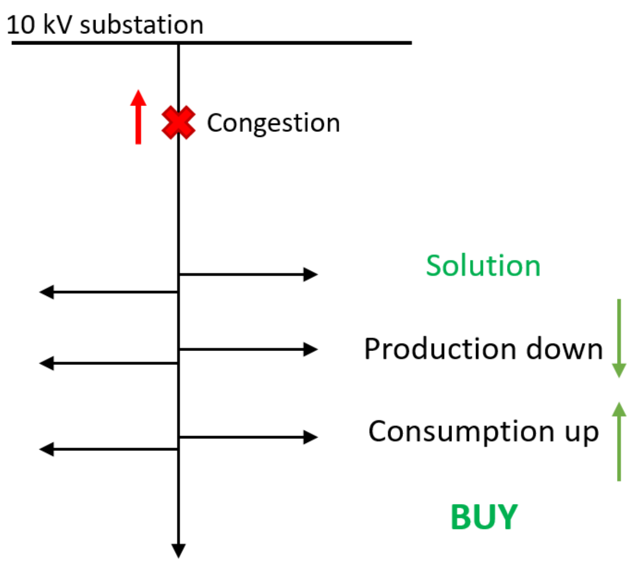


Figure 11: Example of simple congestion in a feeder in a radial system

Note that through this method, capacity is moved geographically and not over time, meaning that two different a parties must be willing to change their positions. This ensures that balance between supply and demand is maintained at all times. However, it does mean that a party might correct their position at a later point in time if they still want to consume or produce the electricity used for congestion management previously, potentially pushing the congestion forward. This is also different from other types of trading, such as the imbalance market. There the starting situation is an unbalanced supply-demand situation for a given trading interval. The trade is meant to restore the balance to the system, so a trade in only one direction (buy or sell) is used. This shifts the system to a more balanced situation. With congestion management, the starting point is a balanced system, and a trade needs to be balanced by a counter-trade to ensure no imbalances occur. This is important for the DSO as they are not allowed to take up a position in the market themselves. This method allows them to trade without actually trading themselves.

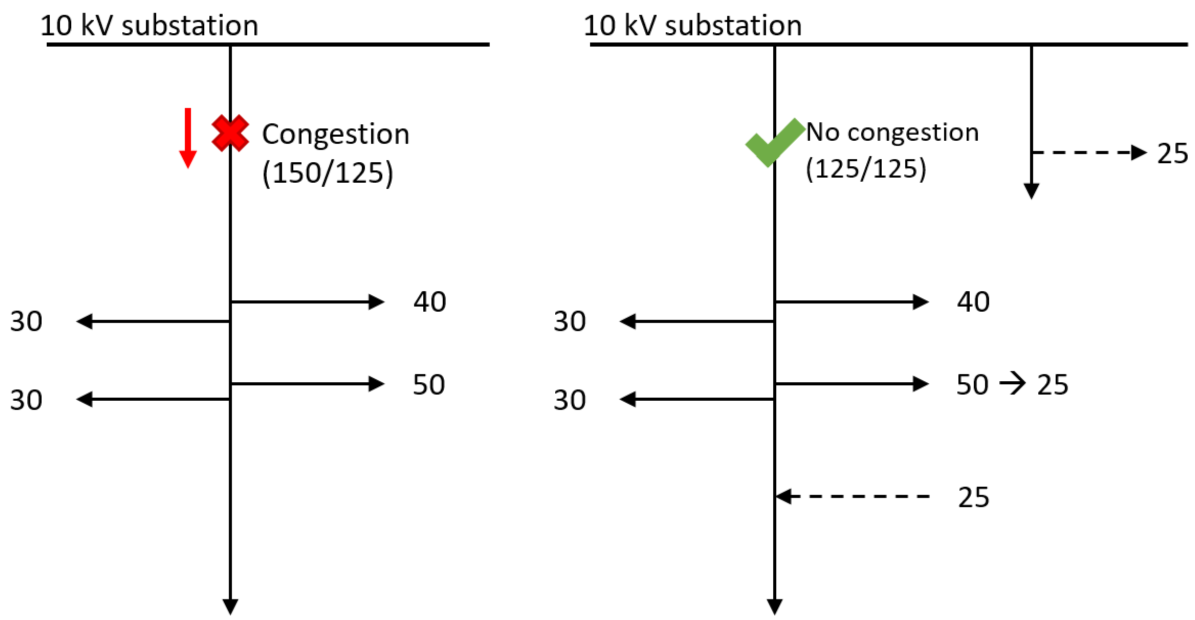


Figure 12: Example of solving a congestion in feeder (left), new situation has no congestion (right). Congestion is solved by reducing consumption or increasing production in the congested feeder. All numbers in MW.

To illustrate this with an example, Figure 12 shows how a congestion in a feeder might be solved. Too much power is being consumed in the feeder, namely 25 MW more than the capacity. This can be solved by either increasing the production of electricity, or decreasing the consumption, as illustrated. In order to maintain the balance in the grid, somewhere else the consumption must be increased (or production decreased). It is necessary that this second action happens upstream from the congested feeder, otherwise the situation on the feeder would remain the same.

For this tool to work properly it is important that trading parties combine their orders with location data. Without location data it is impossible for the DSO to know which order can be used to solve a congestion problem. Additionally, it is important that the market has enough liquidity to reliably solve congestion problems when they arise. How much liquidity is 'enough' liquidity is one of the objectives of this research.

9. Market analysis

Up until now, general market architecture and structure has been discussed, as well as congestion and congestion management. The next section will combine these things to explain how current market architecture and structure cause problems for the effectiveness of congestion management through the market and the procurement of flexibility in general. Some developments are already underway in the market that will help solve or alleviate some of the issues that exist. These will be introduced next. The following chapters will go into the model and the simulations of the proposed congestion management tool. Based on the results of these simulations, further analysis of the problems and trends in this chapter will be done in chapters 15 to 17.

9.1. Problems resulting from architecture and structure

The need for new ways of congestion management is becoming more obvious as grid operators start encountering it more and more. But as is often the case with innovation, regulatory frameworks lag behind the changing real life situations. This section will take a look at the Dutch market architecture and structure and where it is unsuitable for more innovative ways of congestion management in the distribution grid.

Three problems are defined that relate to the market structure and have an effect on whether a solution for congestion management in the distribution grid will be successful. The problems are defined based on problems that are commonly identified within research and policy documents, and personal understanding of how they will influence the congestion management issue. The three problems are separate, but all closely interrelated as well. The three problems are:

- Lack of demand side response.
- Disconnect between electricity price and network usage.
- The “copper plate” assumption.

9.1.1. Lack of demand side response

Demand side response means that electricity demand responds to changes in price or availability on the supply side. The lack of demand side response is the result of three things: consumers are not exposed to real time rates, there is a lack of capacity or willingness of the consumer to respond, and risk avoiding behavior by the consumer. This was touched upon in section 4.1.2. Lack of demand side response is a problem because it is one of the main drivers behind the increased congestion risk in the distribution grid. Congestion problems are caused by increased renewables and distributed generation, combined with electrification in general. Because of these renewables, electricity cannot follow demand as it used to do with fossil fuel generation.

That demand follows generation of electricity more closely is important for the energy transition in general. It will decrease the need for expensive storage, and the need for conventional generation to always be available to provide electricity when renewables are not enough. However, demand side response does not automatically solve congestion problems. Generation and consumption will continue to be erratic, and this can still cause problems in the transmission and distribution grids. Demand side response is a prerequisite for many solutions proposed for the congestion management problem, both when load-shifting in time and in geographic location.

9.1.2. Disconnect between electricity price and network usage

In the traditional system, where generation is centralized and based on fossil fuels, the electricity price is a direct indicator of how heavily the grid is loaded. As the electricity demand increases, the price will increase because more expensive generation will have to be turned on. In the new electricity system, with renewable and distributed generation, this linkage is disappearing or even reversing [39].

Because the marginal cost of renewable electricity is usually low, an increased supply of renewable electricity means a decrease in price and not an increase. Additionally, in the low and medium voltage grids, congestion problems might occur because of distributed generation. In this case the problems are completely unrelated to the (system-wide) electricity price, since they are very localized.

This is a problem because it means that even if price variations in the wholesale market are put through to the customers and there is demand elasticity, this does not necessarily solve congestion problems. Additionally, real time pricing could increase the volatility in the grid due to unpredictability of retail customers [40].

In Verzijlbergh et al. [28], a good example is provided of how this disconnect between price and use can cause congestion problems. It was found that a large share of variable renewable energy sources, such as wind, combined with cost-minimizing electric vehicles could cause an increased peak load and risks of congestion. Because regular base-load electricity demand is very inelastic, the electricity price will not greatly influence the base load demand. This can be seen in Figure 13, where a strong increase in wind generation has no influence on the network loading. When electric vehicles that trigger at a low electricity price are added to this equation, congestion risks occur. If the vehicles start charging at a moment when there already is a high base-load demand (e.g. early evening), this will result in an even higher peak and a risk of congestion.

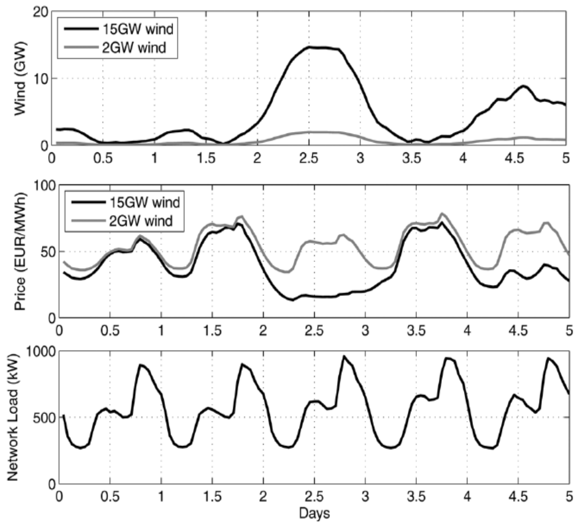


Figure 13: demand, wind supply, price, and network/system load profiles [28]

9.1.3. The "copper plate" assumption

The "copper plate" is an assumption stating that that the entire Dutch electricity system is one large copper plate to which all customers and generation producers are connected. There is unlimited transportation capacity between any two points on the copper plate. It is the responsibility of the national and regional grid operators to ensure that this is really the case.

Because the energy transition comes with higher electricity use and higher peak use as well, the cost of maintaining this copper plate principle are increasing ever faster [30]. This copper plate assumption also means that the entirety of the Dutch grid is a single price zone. The idea that capacity must always be large enough to accommodate every peak is losing ground, simply because it is so expensive to maintain.

If transportation capacity is no longer unlimited, it becomes a scarce resource. Therefore, some method needs to be chosen on how the available capacity is going to be divided amongst the ones that want to use it, or else congestion will certainly occur.

9.2. Solutions – General trends

In order to make a good analysis of the effectiveness of the proposed congestion management tool in the context of wider market and policy developments, this section will look into some trends in the marketplace and policy landscape. These are either developments that are already happening or actively being talked about in the Netherlands, and many other places in Europe for that matter. They will shortly be introduced and, where possible, related to the problems that were identified previously. The trends are:

- Time-of-use tariffs
- Real cost of electricity
    - Smart meters – home automation
    - Net metering
    - Aggregators
- Prediction of electricity demand and better transport programs

9.2.1. Time-of-use tariffs

The concept of congestion tariffs has been introduced earlier in the report and the economic principles behind it explained. A proper implementation of this idea could improve all three of the mentioned problems. The question is how to bring this theoretical concept into practice.

Currently, tariffs that are paid by consumers to the grid operator are largely based on the maximum power that a party takes from the grid in a year, and this can undermine the business case for flexibility. When electricity prices (or perhaps in the future congestion management) demand a higher capacity than would otherwise be used, there is a risk that the tariffs paid increase for the whole year, because a single moment with the highest demand determines the grid tariffs for the entire year. According to a report by Berenschot, this is an unwanted effect since this works against natural market mechanisms that help stabilize the grid. Furthermore, these tariffs only apply to consumers, creating an uneven playing field [41].

CE Delft also wrote a report on flexible transportation tariffs [42]. They note that flexible tariffs will nudge consumers to better spread their use of the grid, by increasing the tariffs at high demand moments as well as giving an incentive for saving in general. They also note that for a really variable tariff based on time and capacity, more developments in smart metering are needed. This shows that many developments are connected one way or another. The Berenschot report also gave a recommendation on what is the best way to introduce flexible tariffs in the Dutch market. Their conclusion is that time and location based flexible tariffs, similar to the congestion grid tariff discussed in section 7.1 will be the most successful. They also recognize that implementation of these tariffs is complex. They propose a transitional period where there are peak and off-peak hours (which some people in the Netherlands have in the form of a day/night tariff). This can then gradually be increased in specificity when data and predictive capabilities increase.

The new law ‘voortgang energietransitie’ has been approved in the beginning of 2018 and this is the start of updating the Dutch market structure and policy for the energy transition [43]. DSOs have been actively lobbying for changes with their branch organization (Netbeheer Nederland). Among these wanted changes is the ability to use more flexible tariff setting [44] [45]. Furthermore, the minister of Economic Affairs and Climate has also written a letter in which he stresses the importance of flexibility in the grid and his intent to keep improving legislation to make the energy transition possible [46].

Time-of-use tariffs is something that will likely be implemented, but when and in what form? If implemented correctly and successfully it will help in fixing the disconnect between electricity use and network usage as well as it being a step away from the ‘copper plate’ principle.

9.2.2. Greater participation in the market – Real cost of electricity

The second development that is important for the congestion management tool is the participation in the market, especially by smaller consumers. Currently it is still fairly complicated and time-consuming for smaller parties to actively participate in the market because of reasons mentioned in section 9.1.1. However, there are several developments that will make this easier in the future.

First of all are *smart meters*. These are meters that have much more functionality than traditional meters and can be connected to smart home energy management systems. The idea is that this will greatly increase the awareness of consumers of their consumption and production, but also the price. Smart meters are a prerequisite for many other developments such as flexible tariff setting. In February 2017, 3 million households in the Netherlands already had smart meters. The goal is that 80% of households have a smart meter by the end of 2020 [47]. Unfortunately, the step from having a smart meter to having a smart energy management system in your house is quite a large one. Only about 10% of the people that have a smart meter, also have smart energy management systems [48].

Secondly, *net-metering* is a policy that was adopted by the Dutch government to stimulate the adoption of renewable energy such as solar panels in homes. Currently, consumers that feed electricity into the grid can just subtract this from their total electricity usage over a year. This is irrespective of when they produced this electricity. Of course this is a great stimulus for the adaptation of renewable energy production, but it can – on the other hand – be problematic for the grid. This is because times of high generation often coincide with times of low usage. For example, during the day there will be low demand but high generation of solar energy from a residential consumer. This means that during the day electricity will be fed into the grid, and in the evening electricity will be consumed. This causes double the stress on distribution infrastructure. In reality, the best thing would be for consumers to use as much of the electricity that they produce themselves. Because if it is all fed into the grid at the same time, problems will occur. The Dutch government will repeal the net metering policy and replace it with something that more accurately reflects electricity prices and status of the grid [49]. Consequently, behind the meter storage will become more attractive for consumers which will further increase their flexibility.

Finally, *aggregators* will make it easier for consumer to become active participants on the electricity market. The electricity market is complicated and for most people it is not worthwhile to actively participate individually. Aggregators will take groups of consumers, or fleets of electric vehicles, or any other type of flexibility and optimize and trade for them. Among horticulture farmers this is already becoming quite normal with parties such as Agro Energy [50]. But also on household level and with many other types of customers, there are examples of projects where aggregators play a large role [51] [52].

All these developments will increase the participation of smaller consumers on the electricity market, and increase the availability of flexibility in the low and medium voltage levels. This will strongly contribute to the *"lack of demand side response"* problem mentioned earlier.

9.2.3. Prediction of congestion

In order to prevent congestion it is important that a DSO knows in advance when and where congestion will occur. Previously, the E-programs have already been introduced that show, on a national level, how much electricity a party produces or consumes. There is a second type called the T-program. The T-program details not how much electricity is consumed and produced by each party, but rather how much capacity will flow to each point in the grid. For a DSO, the T-program is much more important than the E-program. The latter is important when balancing the grid, the task of TenneT, and the former is important for congestion management.

Currently, there are no repercussions for customers that provide inaccurate data, and this makes it hard for the DSO to make an accurate T-program. Furthermore, small consumers (like households) are not obligated to submit a T-program. Instead, their electricity companies provides it for them, but since this is done in bulk, all the location data is lost [53]. These things make it hard to make accurate T-programs, but this hasn't been a big problem as congestion wasn't a common occurrence.

With developments that have been mentioned in previous sections, electricity supply and demand have become more erratic. And for solutions like the ETPA congestion management tool to work, it is necessary to have more accurate predictions of when and where congestion will take place. The same goes for determining flexible congestion tariffs. Prediction of electricity supply and demand is very valuable information on the electricity market, and it is no surprise that this is something that many parties are investing in [54]. Stedin has also invested in software to make better predictions, but they currently lack the data and expertise to make optimal use of this software. Furthermore, because of the valuable nature of this information, it is also not openly shared by market parties. It is up to the government to design regulation that will allow the DSO to make use of this more accurate information without disturbing the market.

9.3. Conclusion

Figure 14 gives an overview of the market structure as discussed until this point. Starting from the 3 relevant policy areas that were identified in chapter 5.2, and extended with the problems and developments identified in this chapter. The problems are not problems per se, but characteristics that could be problematic in relation to the energy transition and congestion management in the market. The next chapters will go into the congestion management tool simulations. Afterwards these developments will be integrated in the model. This will make it possible to analyze the functioning of the congestion management tool in a changing electricity market.

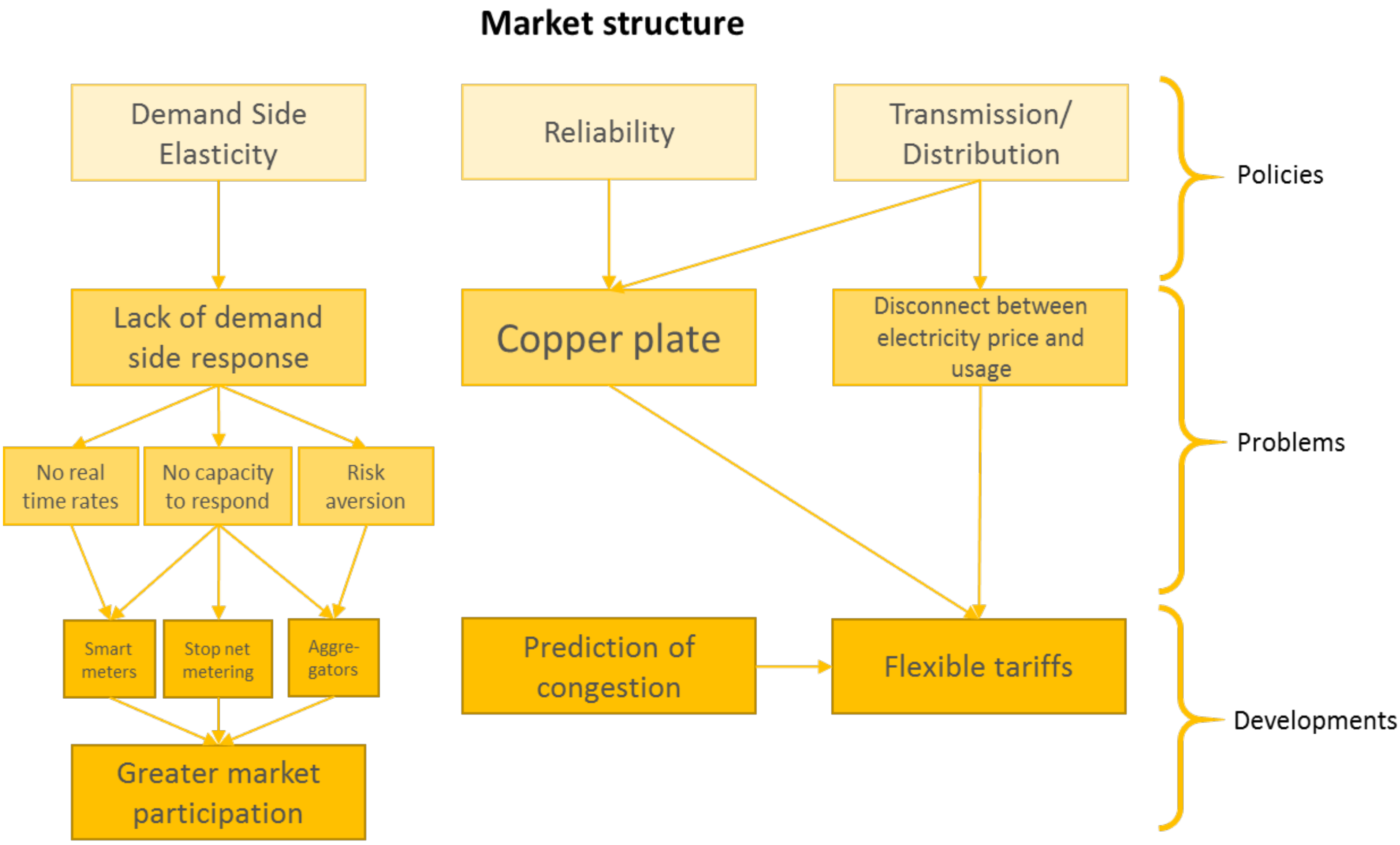


Figure 14: Overview of market structure, structure problems, and structure developments

10. Technical case study

At this point, all the concepts related congestion management and electricity market design have been introduced in chapters 5 to 9. In the next chapters these two paradigms will be combined in the model that will simulate the congestion management tool and quantify its technical and financial impact. As mentioned in the introduction the case study will be performed on a part of the Dutch grid in the *Zuidplaspolder* area, which is located between Rotterdam and Gouda. This part of the grid experiences congestion and will continue to do so until the a more permanent solution is finished in 2023.

10.1. Introduction

In order to assess the viability of the ETPA congestion management tool, a model is developed to simulate its future functionality. The model is based on real data from two sources. The first data source is the historical loading of (part of) the Stedin grid. The second data source is all the trading and order book data from ETPA. Because the data is from real-life sources, it will not contain everything we need to perform the research. It will be necessary to make certain assumptions to be able to work with the data. What these assumptions are and how they might influence the results will be discussed as well. Initially a base case scenario is analyzed where the data (from the year 2017) is taken as it is and only slight modifications will be made. Subsequently, every year up until 2023 is analyzed to give an insight on how the concept will develop when trading and loading of the grid changes with time. For each year a high development and a low development scenario are used.

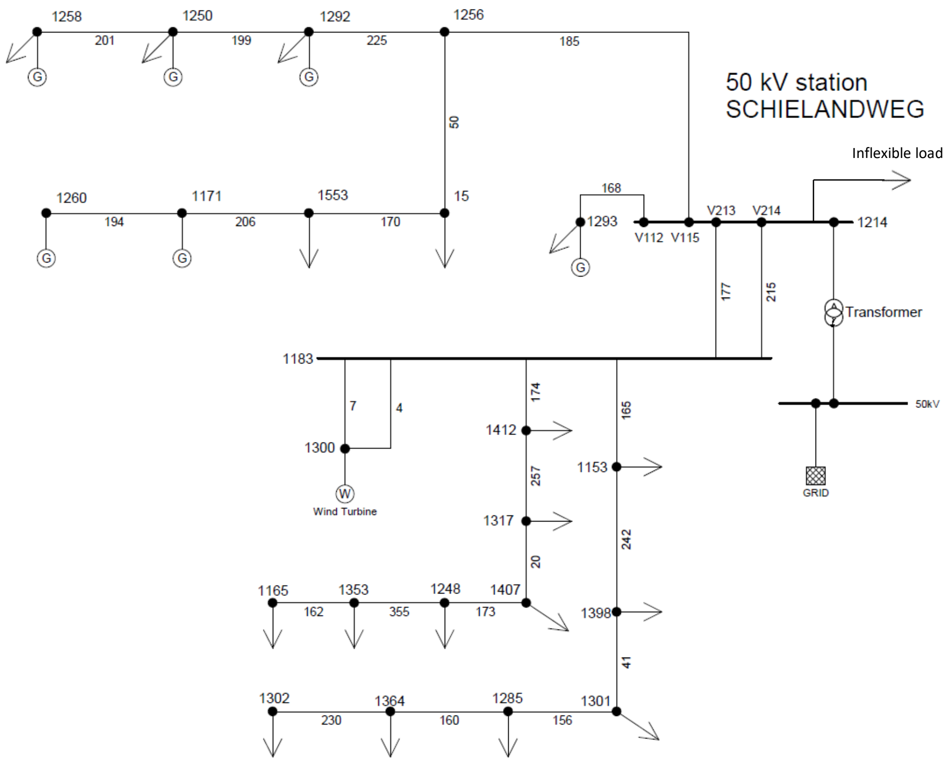


Figure 15: Model of analyzed part of the grid of the Dutch DSO Stedin

For the model, not the entire grid of the Zuidplaspolder region is analyzed as this would put a large computational strain on the model. A selection is made that includes the areas of the grid with the most flexibility, mostly in the form of horticulture and renewable generation.

Figure 15 shows the section of the grid that was used for the model. It consists of the main busbar of the *Schielandweg* substation (50 kV->10 kV) and 4 outgoing 10 kV fields (v112, v115, v213 and v214). *Schielandweg* is one of the substations in the *Zuidplaspolder* area. These fields were chosen on the basis of the type of connections connected to the field and also the reliability of the data (see Appendix II). Field 112 is connected to a single horticultural party that mainly produces electricity. Field 115 is also mainly connected to horticultural parties, although they are slightly smaller than the one on field 112. Fields 213 and 214 both connect to a different substation. On this substation, 4 outgoing fields are modelled. Two of them connect to a series of three wind turbines located in the industrial area that the other two fields connect to (node 1300). All the generators (labeled G) are combined heat and power generation at horticultural parties. Thus, the total modelled grid consists mainly of industrial and horticulture areas. This is important as these are the places from where it is most likely possible to procure flexibility in the short-term.

It is important to note, that for the transformer connecting the 10 kV busbar to the 50 kV busbar, the entire downstream grid is taken into account, not just the fields mentioned above. This is done to ensure that congestions appearing on the transformer show up. If only the small part of this grid is connected to the transformer, it would never be congested since it is meant for a much larger grid and thus a larger capacity.

10.2. Purpose of the model

The goal of this model is to create a proof of concept to test whether congestion management through the use of the ETPA congestion management tool is possible and to get a sense of the cost and reliability of it. This is done through the use of real network and market trade data in order to not only test the theoretical concept but also to see how it might behave in the real world.

10.3. Data

There are two main data inputs for this model:

1. The order book data from the ETPA intraday platform.
2. The historical loading data of the grid as measured by Stedin

The order book data from ETPA is an Excel file with about 1.2 million rows and 23 columns. The data used involves mainly times, volumes, prices, ID's, and of course whether an entry is a buy or a sell order. The data used starts on 19/1/2017 and ends on 2/10/2017. The starting date is so chosen because this is the moment that the market maker started and thus ensured a steady flow of orders in the book. The market maker is a party that is always willing to both buy and sell, thus ensuring that trade is always possible if at least one more party puts in an order. The end date is when the data processing was started and from thereon forward the data source had to be kept consistent.

ETPA is mainly an intra-day platform but day-ahead trading and, in the later months ex-post trading, are also possible. These orders are filtered from the system as they cannot be used for congestion management because they are either too early, or too late. Furthermore, orders that were actually traded are also filtered out because they would not have been available for congestion management.

The data from Stedin is taken from the *his* database, this is the database with all historical measurements from the entire Stedin grid. The resolution varies from 10 second values to 1 hour averaged values. Because the higher resolution values are saved for a shorter time, the 1 hour values are used because almost an entire year is necessary. This is also the most convenient because the trading orders are mostly for a period of one hour.

Which physical quantities are measured varies for every station as the kind of measuring equipment available also differs. For the *Schielandweg* substation, measuring equipment is present on each outgoing field from the main busbar. Unfortunately this equipment is rather rudimentary and only has non-directional current measurement for the feeders (Figure 16). Only for the transformer directional capacity measurements are available. Therefore the feeder measurement data will need further pre-processing before it can be used in the model.

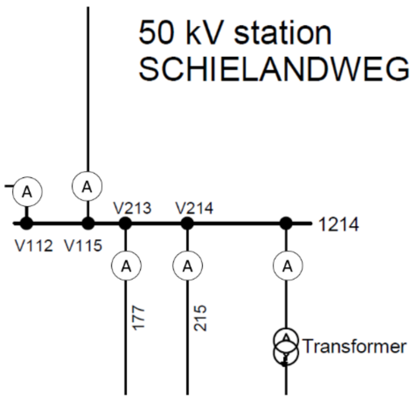


Figure 16: Locations of current measurement devices in grid

11. The model

In this section the workings of the model will be described and illustrated. As mentioned before, the purpose of the model is to test the conception management tool created by ETPA. This is done by running power flow analysis on the grid over a period of time. If a congestion is detected in the grid, the ETPA data will be checked to see if a trade can be made. The model is programmed in Python.

The model takes the viewpoint of the DSO, but it is also an 'all-knowing' model that is able to look through every order available when a congestion is detected. In reality, the DSO might not know exactly when a congestion will occur, so a trade-off between cost and congestion risk needs to be made. A choice needs to be made not only on where to trade, but also on when to do it. This sort of operational model could be the next step of this model, but will need a predictive power for which the data was not available for this model.

11.1. Data processing

As mentioned, the only input data available from the grid was data on the current in the outgoing fields. But for the congestion management tool to work it is necessary to know all the branch currents between the nodes. Furthermore, current is not an input for a power flow analysis but an output. The inputs for a power flow analysis are [55]:

- Grid topology:
    - Nodes in the grid
    - Physical parameters of cables/lines and transformers
- 2 of following 4 quantities at every node:
    - Real power (P)
    - Apparent power (Q)
    - Voltage magnitude
    - Voltage angle

Nodes and cables/lines/transformers are determined by the grid topology as given previously. Generation and load give the P and the Q. The generation and load in this part of the grid come from the base-case situation as is given by Stedin. For this base-case scenario, all the generation and loads are available for every load so a power flow analysis can be run on the base case situation. This gives branch currents for all the cables in the grid. Since the historical loading data does not give the loading and generation at each node, but only the current in the feeder, a load flow cannot be run directly on the historical loading data. Therefore, the feeder currents from the historical loading data are compared with the feeder currents from the base-case power flow. Based on this comparison, the loading and generation of the individual branches is determined proportionally. Then the power flow can be run to determine the rest of the currents.

For example, say that in the base case it is given that the capacity connected to two nodes is 0.4 and 0.6 MW (Figure 17). When running the power flow this will result in a total current of about 100A (in reality it will be slightly more because of losses). This 100A can be compared to the loading data available for the year 2017. If for a certain hour 110A is measured on this field, the loads on this field should also be multiplied by 1.1. In this case a loading of 0.66 MW and 0.44 MW would be entered into the power flow computation. The power flow can then be done and all the branch currents re-calculated. The assumption made here is that the ratio of loading between the different nodes stays the same. In reality, the ratio of loading between the different nodes might change but there are no measurements of this.

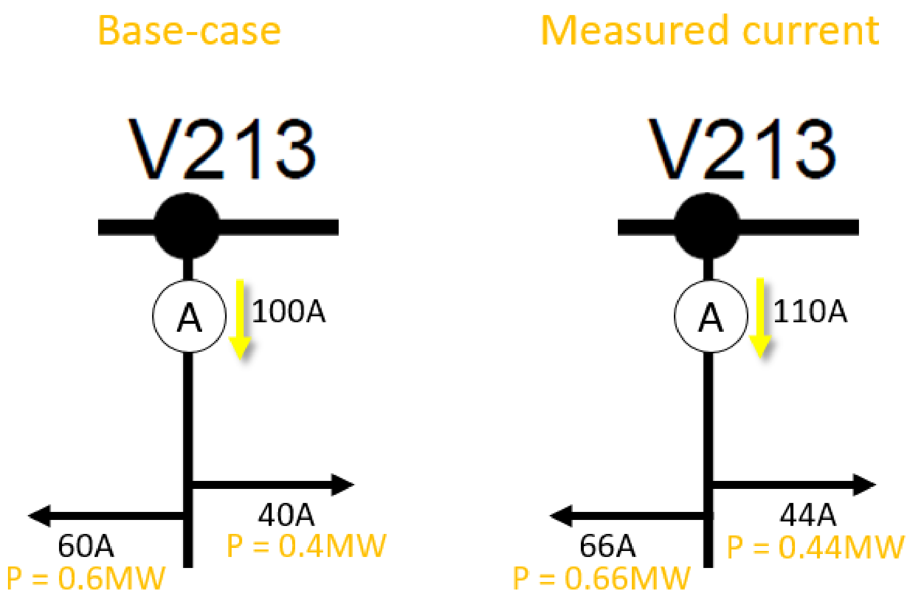


Figure 17: Illustration on how measured current is used in power flow calculation

Now that the Stedin data can be used in the model, the ETPA data also needs to be adapted slightly. In order to use the ETPA data to solve congestion in our grid, location data is needed for every order. Because the congestion management tool is not yet in operation on the ETPA platform, location data is not available for the orders in this database. Therefore, all the traders that have put orders in the order book are assigned to a node within the grid. Where possible they are assigned to a node that corresponds with their actual profile. For example, a trader in wind energy was assigned to the node where the wind turbines in this grid are. The exact locations of all traders is not very important. The only one that needs special attention is the market maker. Because it is always possible to trade with the market maker, the location of the market maker is outside of this grid (on the 50 kV side of the transformer). This symbolizes all the other traders in the national market. The assumption that is made here is that, if the actors in the grid were trading on the ETPA platform they would do so in a similar way to the traders that are active on the platform right now.

11.2. PyPSA

For the power flow analysis in this model, the software package PyPSA is used [5]. This is a package that enables easy power flow analysis based on inputs from csv files or inputs directly from the code.

11.3. Model workings

The way the model is organized is that the grid data about the nodes, lines/cables and generators is loaded into PyPSA through CSV files. The loads are loaded into PyPSA through the code. This is done because the power taken from the nodes needs to be varied over time. Variations in the generator injections into the nodes are also modelled through the code in the form of negative loads to make sure only one variable needs to be changed. Furthermore, pandas, a data analysis library, is used to handle all the data in Python.

Figure 18 shows a flow chart of how the model works. Initially all the data is loaded into the model and nodes are assigned to all the orders from the order book. After this, the main part of the model is started. This is based on a list of times with a resolution of 1 hour. For every hour there is a list of how much power is injected or withdrawn from each node, and this is the basis of the rest of the model. As visible in the figure, there are 2 main lines to check for congestion. This is done because for the transformer power measurements are directly available and it does not need to be included in the power flow analysis. The apparent power measurement at the transformer is compared directly to the capacity to determine if there is a congestion. This is done first because all of the current congestion problems are situated at the transformer, not the feeders.

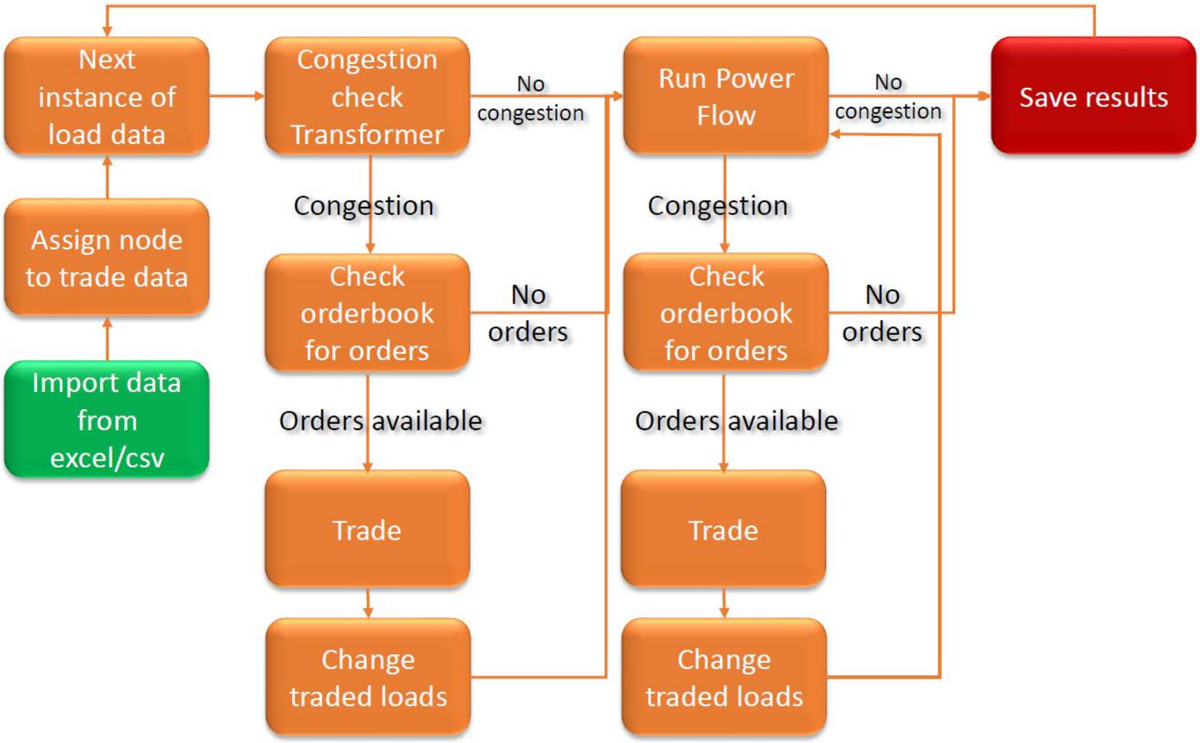


Figure 18: Process flow chart of congestion management model

If a congestion is found, the following steps are the same whether the congestion was found in the transformer or in one of the branches. The timestamp from the congestion is taken and an order book is reconstructed that contains all the orders for that hour. Based on the location and direction of the congestion it is determined where a buy and sell order should take place. The order book is filtered for this location and, if orders are available, the highest buy or lowest sell order is selected. This is then matched with an order from the market maker that was available at that time.

Some difficulty in matching the orders comes from the fact that there are two times that have to be taken into account. First there is the time for which the order is placed, for example a buy order from 14:00 until 15:00. Because the model is 'all-knowing', the time at which an order was placed and removed is also important. A trader might first place this order at 09:00 in the morning. Every time

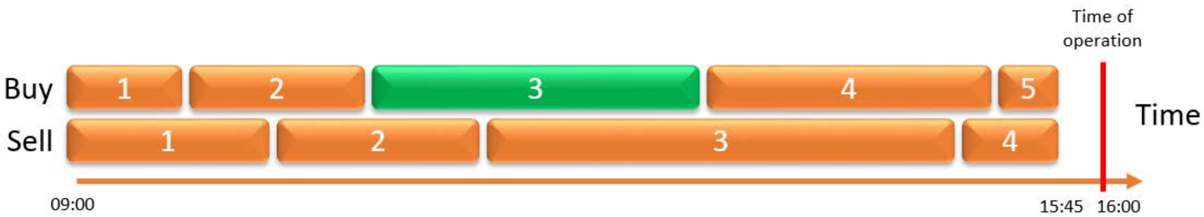


Figure 19: Timeline of orders for 16:00.

the trader updates the price, a new order is placed and the old one removed. Figure 19 shows the timeline of all the buy and sell orders placed for 14:00-15:00. If the DSO would decide that they want to use buy order 3, it has to be matched with either sell order 2 or sell order 3 which are overlapping in time. Sell order 1 or 4 might have a better price, but this would not have been a possible trade and will not accurately reflect the possibilities of this tool. Appendix III shows a more extensive 'mock code' of the model.

The trades being made are capped at 3 MW per hour because trading any more than that is unrealistic in terms of how much flexibility is actually available in the grid. Trading more would also cause big congestions in feeders, this is also addressed further in section 13.2.2.

11.3.1. Example

To give a better idea of how the model works, an example will be provided for one time and everything that happens for that particular time. Let's look at January 25th at 11am for the year 2022. The model starts by entering the time-varying loads into the PyPSA network.

time	L1250	L1258	L1292	L1553	L15	L1293	L1317	L1412
25-01-2022 10:00	0.699785	0.659943	1.665787	0.311106	0.114506	-2.13365	0.097982	0.154321
25-01-2022 11:00	**0.699938**	**0.659998**	**1.665686**	**0.310916**	**0.114436**	**-2.07035**	**0.095049**	**0.149701**
25-01-2022 12:00	0.70168	0.660625	1.664531	0.30875	0.113639	-2.09411	0.091168	0.143589

The next step is to check the transformer congestion at that time, the limit is S = 30MVA.

Time	S [MVA]	Q [MVAr]
25-01-2022 11:00	32.68973	4.445803

There is transformer congestion so a value for P is calculated that needs to be traded in order to solve the congestion. This is done by using Pythagoras' theorem to determine by how much P has to decrease to decrease S to 30, this value is Ptrade = 2.72 MW.

The order book for this moment is selected, and the orders that are in the right location on the grid are selected and sorted by price. In this case, order 0 and order 1 are the same, so they are sorted based on the time they were entered into the order book.

#	Start	End	Buy/sell	**quantity**	**Price**	Trader company
0	25-01-2022 11:00	25-01-2022 12:00	Sell	**10**	**133**	15
1	25-01-2022 11:00	25-01-2022 12:00	Sell	**10**	**133**	13
2	25-01-2022 11:00	25-01-2022 12:00	Sell	**1**	**150**	4

This shows that the first order has enough quantity to trade the entire capacity that is necessary. Next, the buy order book is determined with orders that are available at the same time as order 0 of the sell order book. It is sorted from high prices to low prices to get the smallest spread.

#	Start	End	Buy/sell	**quantity**	**Price**	Trader company
0	25-01-2022 11:00	25-01-2022 12:00	Buy	**5**	**105**	6
1	25-01-2022 11:00	25-01-2022 12:00	Buy	**5**	**90**	6
2	25-01-2022 11:00	25-01-2022 12:00	Buy	**5**	**90**	6
3	25-01-2022 11:00	25-01-2022 12:00	Buy	**5**	**67**	6
…	…	…	…	**…**	**…**	…

The buy order book only has orders from trader 6, which is the market maker. This is because it is the only trader that is on the high voltage side of the transformer and represents the rest of the market. Because the quantity of the first order is higher than Ptrade the first order can also trade the entire volume that is needed. A trade is made between the buy and sell order, and the change in the grid configuration is added into the PyPSa library to run a power flow. The branch currents are calculated and these show that there is congestion on 2 cables deeper in the grid, cable 50 and 70.

Time	cable	current	load %	nominal current
2022-01-25 11:00:00	**50**	315.4182	**108.76**	290
	170	321.9204	**111.01**	290

The same process is started and it is checked if it is possible to make a trade to solve the congestion on cable 50. This time order books are constructed that contain orders on both sides of the congestion. This turns out to be possible and the first trade solves the congestion on both cables. This is illustrated in the table below which shows every power flow iteration made.

Time	#	I – 50	I - 170
2022-01-25 11:00:00	**0**	315.4182	321.9204
	1	283.0475	289.5535

All the trades for this hour now look like this

Time	#	Company	Bus	Buy/sell	Volume [MWh]	Buy price [€]	Cost Stedin [€]
2022-01-25 11:00:00	**0**	15	1553	SELL	2.72	361.4	76.08
	1	9	1171	BUY	0.6095	18.29	-
	2	6	0	SELL	0.6095	76.19	57.90

Buy orders for the transformer congestion trade are not shown because they occur outside of the grid. Looking back at the order books it can be seen that this is correct. The traded volume was 2.72 MW and the congestion spread that Stedin pays is €28 (€133-€105). So the cost for Stedin would be 28*2.72 = €76.16. The table shows €76.08, this is a small error because the model works with unrounded values. By similarly constructing the order books for the feeder congestion, that price can also be checked. Whether partial trades like this are actually possible depends on the trader and their assets, for this research it was assumed partial trades are always possible.

12. Future Scenarios

The electricity landscape is in an incredible state of flux. There is an ever increasing capacity of renewable generation installed, and new technologies of transportation and heating make the future unpredictable. The electricity market is also very uncertain as there are different platforms and different types of markets on which electricity is traded. It is still uncertain what the dominant market will be in the future.

Nevertheless, it is important for Stedin to know if a congestion management tool like this one is, or will ever be, a viable solution to solve congestion problems. Therefore, it is not enough to only look at the 2017 data. An attempt will be made to give insight into what the congestion management tool can do in the years up until 2023. This is the year that the new substation will be finished and there will be no more congestion problems in the *Zuidplaspolder* because the capacity can then be distributed over two substations.

To construct different scenarios, a number of data sources will have to be adapted:

1. The loading on the 50 kV-10 kV transformer.
2. The loading of the outgoing fields in the grid.
3. The trading data of the ETPA platform.

The adaptation of the first two sources is based on a research report by Stedin and an independent consultancy. They have developed several scenarios on how the capacity in the *Zuidplaspolder* area will develop in the years 2016-2035 [56]. For every year they have made a prediction on how the existing capacity will develop, and also how much new capacity will be installed. There is a low, middle and high scenario. For the scenarios of this report, only the middle scenario was chosen. Furthermore, a distinction is also made between developments in the horticulture, industry, and urban areas. From this report, factors were extracted that were multiplied with the existing data to get input for every year until 2023. For the loading on the transformer, one multiplication factor was determined considering both new capacity and development in existing capacity. Another factor was determined only looking at how the existing capacity would develop. The scenario that looks at existing development is considered to be more viable. Many of the development plans in the 'all development' scenario are still highly unlikely as some customers have already found different solutions. For example, one large horticulture farmer for roses will be getting a dedicated cable to a different substation and will not be connected to the *Schielandweg* substation.

According to Stedin, any new connections to the station would require a new cable. Therefore, for the loading on the outgoing fields, only the development of the existing capacity was considered.

12.1. Trading data for scenarios

For the development of the volumes in the intraday market, scenarios were created based on the German market. In Germany, the strong increase in renewable energy generation resulted in a strongly developed intraday market and not, as many expected, more trade on the imbalance market [57]. The reason for this is that because the intraday market is more developed, many of the problems that would be solved by the imbalance market are prevented in the intraday market. The scenarios for the Dutch intraday market were based on the assumption that the Dutch market will go through a similar process in the near future.

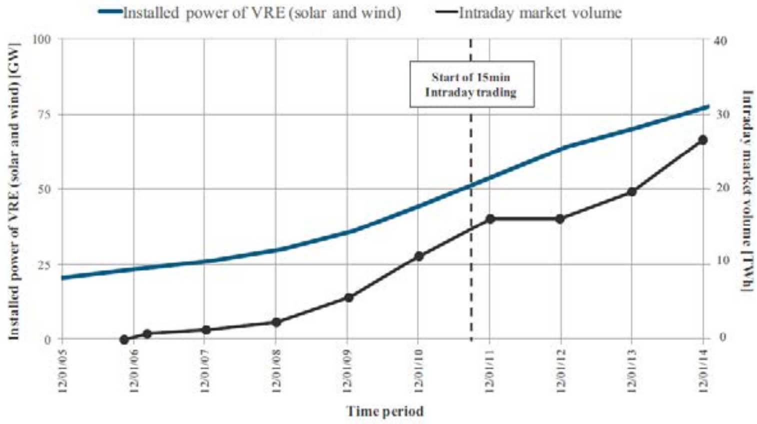


Figure 20: Simultaneous development of RES (electricity from wind and solar only) and intraday trading volume in Germany [58].

Figure 20 shows the simultaneous development of Renewable Energy Sources (RES) in Germany, and the development of intraday trading volume [58]. Instead of plotting them over time, I plotted them against each other and extracted the trend line formula (Figure 21). Based on data from the Netherlands about RES from the national energy outlook [59] and intraday trade in 2016 from EPEX [60], the offset of the trend line was changed to fit the Dutch scenario (where the total volumes are lower). The trend line formula used for the Netherlands is: $y = 0.1209x – 3.2315$ (see Figure 21). Where y is the intraday volume in TWh, and x is the available capacity from renewable energy sources. This gives the factors as seen in Table 1.

Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
multiplication factor	1	1.61	2.22	2.83	3.92	5.01	6.09

Table 1: Multiplication factor of intraday volume per year, based on 2017.

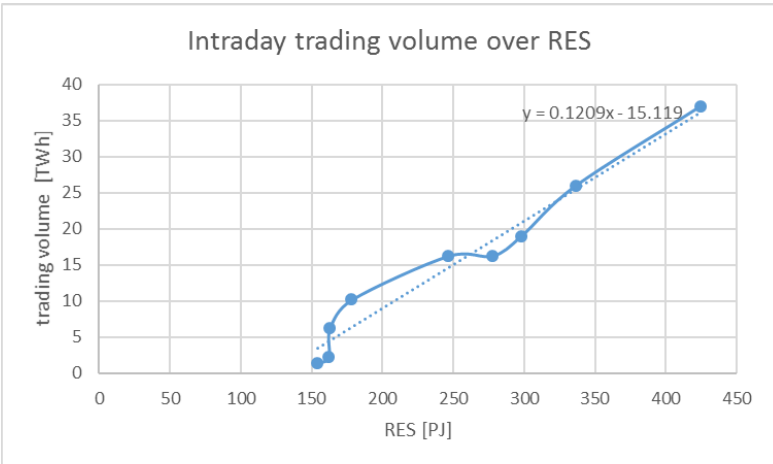


Figure 21: Intraday trading volume plotted against RES development in Germany

To get from these factors to more orders in the order book, several steps are taken. The order book is looked at separately for buy and sell orders, and also per hour of operation. For every hour of operation, the total volume in the current order book is determined and this is multiplied by the factor for that year. Additionally, the distributions for price and volume are determined; Figure 22 shows how often a certain buy and sell price occurred. Random prices and volumes are picked from the distribution until the new volume for that hour is reached. This is done for all 24 hours and all these orders get assigned a physical location on the grid. All the orders are added to the existing order book to form the order book for one of the future scenarios.

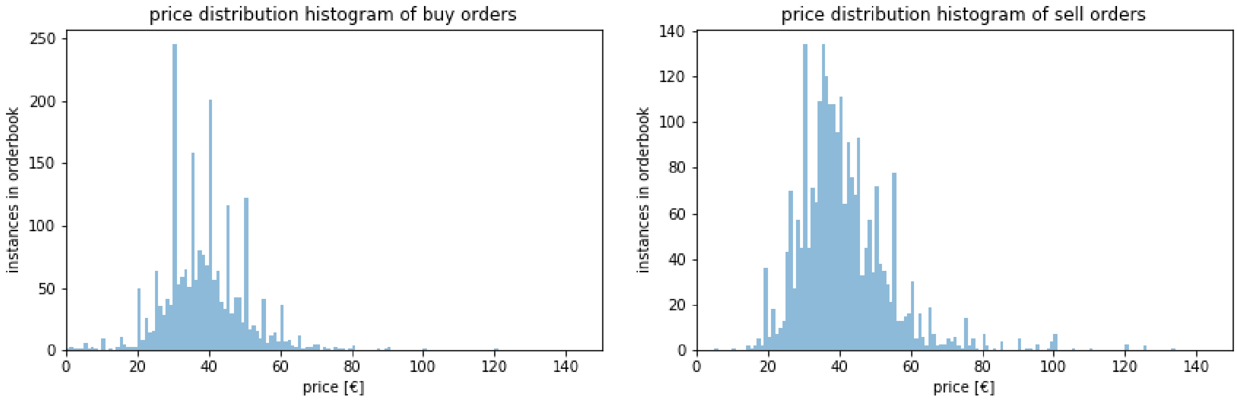


Figure 22: Histograms of buy (left) and sell prices (right)

The trading volumes of the market maker were not taken into account for the development of these scenarios. Because they already have buy and sell offers at every hour, their trading volume is unlikely to change as much as it does for other traders.

Something to consider is that the developments in the Dutch and German intraday market are based on how much trade there is. The congestion management tool does not work with trades, but with unmatched orders. The implicit assumption made is that the amount and volume of orders develops in a similar way to the actual trade. It is hard to say if this is valid, but it would be an interesting subject for future research.

13. Results

A total of 13 sets of results have been produced by the model. This is the base case and 2 different scenarios for each of the 6 future years analyzed. The results of the scenarios are based on the 6 years from 2018 to 2023. For every year, the model ran twice: once under the premise that both the existing and new capacity develop according to the middle scenario from the study by Stedin; the second run assumes that no new capacity is added to the grid, but is based only on the development of existing capacity. This also results in an increase in total capacity, but much less than under the assumption that all possible capacity is developed. This is done because it is unlikely that so much capacity will actually be added to the grid, and the second scenario shows what happens in a more modest development scenario. The difference is so large that different limits for what constitutes congestion are used. For the 'all development', 40 MW and up is considered congestion. This is the limit that was recently changed by Stedin and Liander and steps away from the N-1 preference (It is not a hard requirement for DSOs). The 'existing development' scenario uses the original N-1 limit of 30 MW because this is preferred by Stedin if possible.

First the results of the base case are discussed shortly. Then the scenarios will be discussed on three different themes.

1. The congestion that occurs in the grid, on the transformer and on the individual feeders.
2. The trades that have been made on the ETPA platform and whether they solve the congestions that occur.
3. The cost for Stedin of this method.

Afterwards, the results and cost will be compared to the more conventional solution of putting new cables in the ground.

13.1. Base Case (2017)

The base case reflects the situation with unaltered grid and ETPA data (with only the physical location of the traders assigned). It gives an idea how the congestion management tool would work

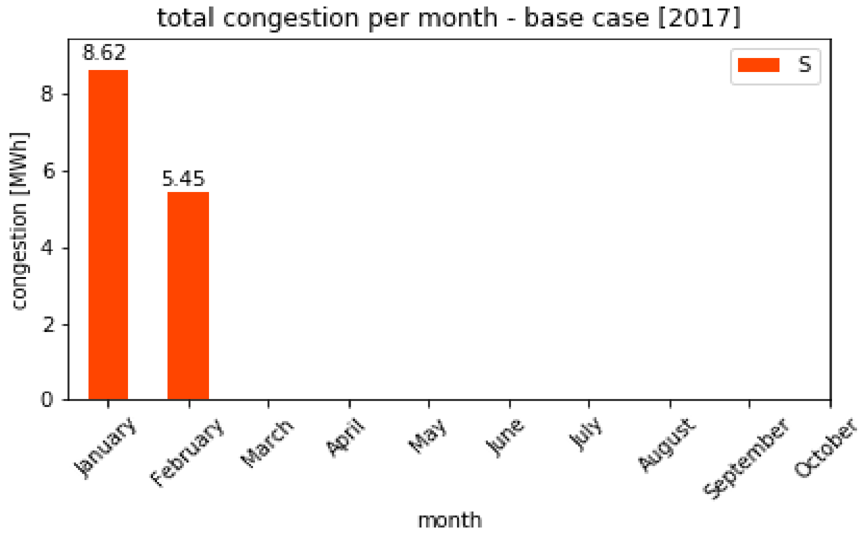


Figure 23: Transformer congestion per month in 2017

in the current situation. Unfortunately there is no trading data for December and the data for January is incomplete; these are the months with the most congestion. Figure 23 shows that all the congestion in 2017 so far takes place in the months January and February. This shows only the congestion on the transformer. This is because in 2017 no congestion took place in the feeders deeper inside the grid.

	Congestion hours	Hours traded	Hours solved	Solved [%]
Base_case	18	5	5	27.8

Table 2: Trade statistics base case

In the base case scenario, there is a total of 18 congestion hours. During 5 of these 18 hours it was possible to make a trade that relieves the congestion. All of these trades did in fact solve the congestion. This is possible because all the congestions occurring are relatively small (max 2.11 MW). When analyzing the future scenarios it will become clear that this will not always be the case.

	Average cost [€/MWh]	Highest cost [€/MWh]	Lowest cost [€/MWh]	Total cost Stedin [€]
Base_case	14.35	68.00	1.00	65.96

Table 3: Costs of congestion management for Stedin

As Table 3 shows, the total cost for Stedin for solving the congestion problem in 5/18 cases costs a total of €65.96 for the studied period of 10 months. This is a very small amount of money compared to the normal cost of operating the grid, let alone the cost of realizing a completely new cable (see section 13.3). However, the cost is also very unpredictable. Just for these 5 trades, the difference in price between the lowest and highest is a factor 68. This makes it so that the price that needs to be paid by Stedin varies strongly.

Additionally, with less than 30% of the congestions solved, the question is whether this will actually qualify as a real solution. From the results of this base case it seems that the congestion management tool can offer a cheap solution, but whether it can become reliable enough to be applied in a critical infrastructure such as the electricity grid is questionable.

13.2. Scenarios

As mentioned previously, the 12 different model runs will be analyzed based on the congestion in the grid, the trades being made to solve the congestion, and the cost incurred by Stedin to solve the congestions.

13.2.1. Congestions

The first thing to look into for all the different scenarios is how much congestion will effectively take place. Figure 24 shows the total hours of congestion in all 12 model runs. It becomes immediately clear that when both the development of new grid connections as well as the development of existing grid connections is taken into account, the amount of congestion increases quickly.

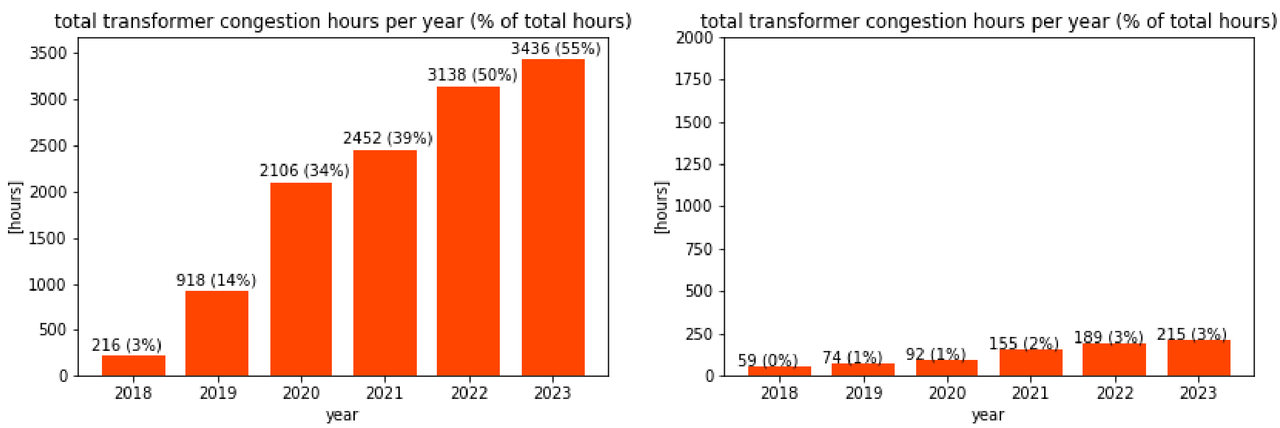


Figure 24: Total transformer congestion hours in the 'all development' (left) and 'existing development' (right) scenario

According to the assumptions of this study, in 2022 there will be as many congestion hours as non-congestion hours.

When only looking at the development of the existing capacity, the amount of congestion is much smaller and only goes up to about 9 days of total congestion (in a period of about 10 months). When looking at how much MWh of congestion there is, this increases even more strongly. Not only do the amounts of congestions increases, but the average size of a congestion (how many MW above the limit) increases as well (see Table 4).

AVERAGE CONGESTION SIZE [MW]	**2018**	**2023**
ALL DEVELOPMENT SCENARIOS	3.1 MW	13.2 MW
EXISTING DEVELOPMENT SCENARIOS	1.1 MW	2.3 MW

Table 4: Average congestion sizes (MW over the limit) of transformer congestions

Besides the congestion on the transformer, the model also checks for congestion in the feeders. It turns out that in all the scenarios, there is no congestion in the feeders as a direct result of the normal grid operation. However, it does occur that congestion in the feeders is the result of a trade made to solve congestion on the transformer. A trade made to solve feeder congestion could have the opposite effect as the trade to solve transformer congestion. This is not necessarily the case as a feeder congestion can also be solved with a trade behind the transformer, but on different sides of the congested cable. In an operational model it would be important to check for this before a trade is made. But for this model it would require many more iterations or an optimal power flow solution that is out of the scope of this thesis. The feeder congestion is simply registered and analyzed to see what the limitations of the model are in terms of creating feeder congestions.

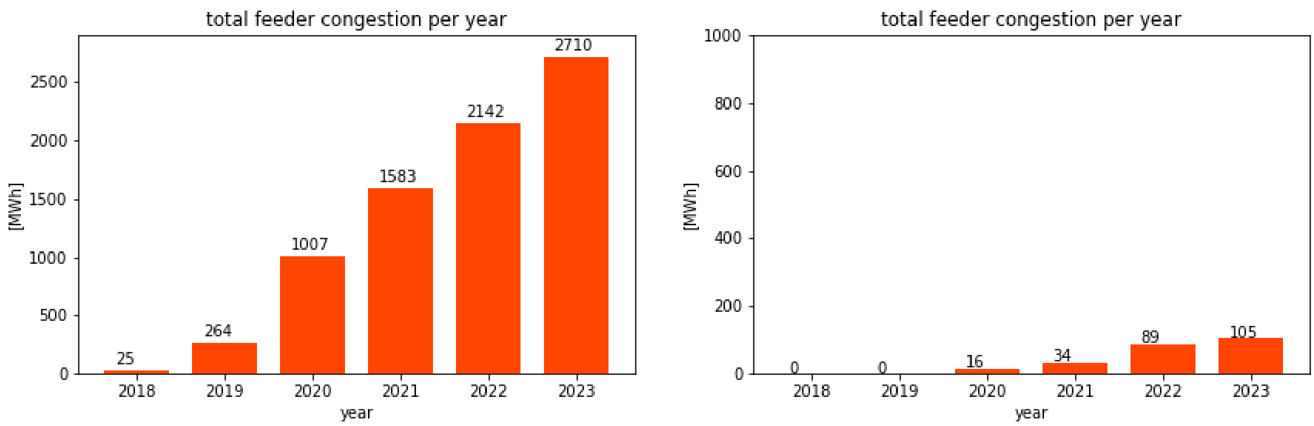


Figure 25: Total feeder congestion hours in the 'all development' (left) and 'existing development' (right) scenario

Figure 25 shows the feeder congestion in MWh that occurs in the different years in both scenarios. The feeder congestion that occurs in the ‘all development’ scenario is a lot more than the feeder congestion in the ‘existing development’ scenario. This is a direct result of the fact that the transformer congestions are much larger in the former scenario. Because the congestion is larger, the trades being made to attempt to solve the congestions are also larger. This results in more congestion in the feeders.

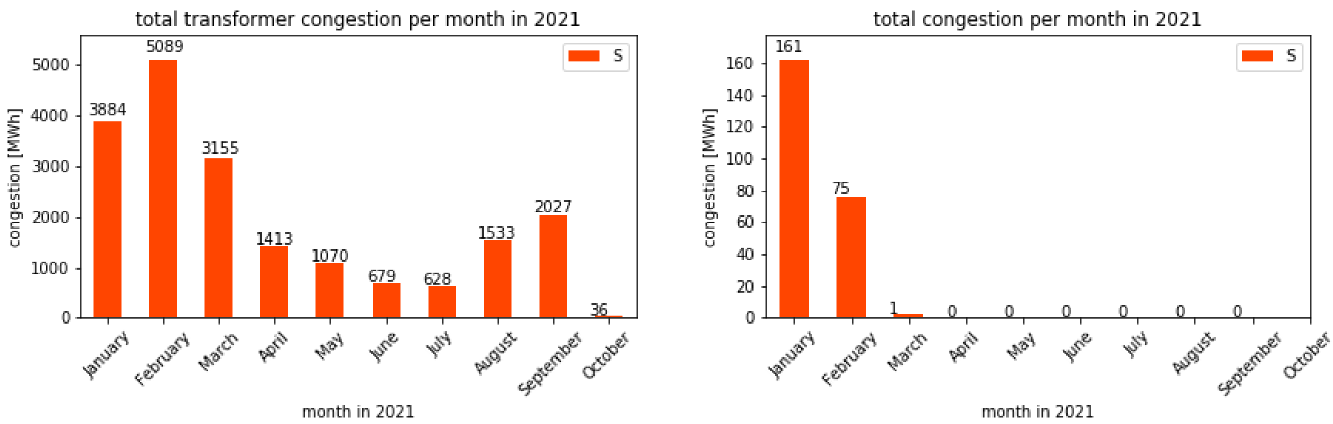


Figure 26: Monthly transformer congestion in the 'all development' (left) and 'existing development' (right) scenario in 2021

Besides the development over the years, it is also interesting to look at how the congestions occur within the year. Unfortunately not all data was available for the period of an entire year, and only January till October are represented in these figures. For January, only 12 days (19-31) are represented, and For October only 4 days are represented. Figure 26 shows that, as can be expected, congestion is much higher in the winter months, and lowest in June and July. With the development of only existing capacity, the grid is congestion free for a large part of the year.

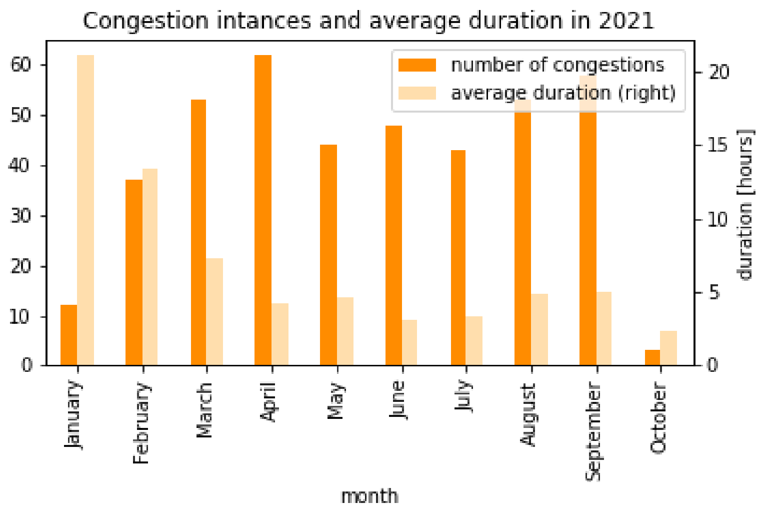


Figure 27: Number of congestions and average duration of congestions

For Stedin it is important to know not only how much congestion there is and when it occurs, but also how many instances of congestion there are and how long every congestion takes. Figure 27 shows for every month in 2021 the total number of congestions in that month (left y-axis), and the average duration, in consecutive hours, of each congestion (right y-axis). It is interesting to see that in the months with the most total congestion (January and February), there is a relatively small number of instances of congestion but with a much longer duration. In the spring and summer months the opposite is visible where there are many more instances of congestion but with much shorter durations.

After analyzing the congestions that occur over the year and the month, the most important conclusions about the occurring congestions in the grid are:

- The number of congestions increases steadily over the years.
- For the scenario where all the development is taken into account, the total amount of congestions is much higher (by a factor of 16). The average size of the congestion is also much higher (13.2MW vs 2.3MW).
- Most congestion occurs in the winter months
- In winter, the congestions are longer subsequent periods, whereas in spring and summer there are more, however shorter, instances.

13.2.2. Trades

The second step of the model is to see how often trading occurred, and how many congestions actually got solved; this is shown separately for the transformer and feeder congestion.

13.2.2.1. Transformer

Figure 28 gives an indication of how trades have occurred over the day. This shows that almost all trades occur around office hours. The reason for this is that since ETPA is a very young trading

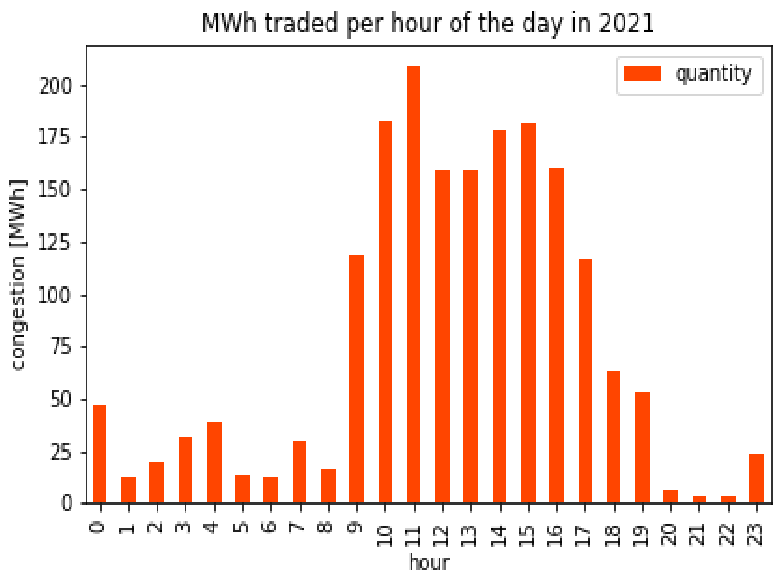


Figure 28: Total volume in MWh traded per hour of the day

platform, most trading is done manually. When the platform matures further, more trading will be done continuously and through trading algorithms. This will likely make the amount of electricity traded correlate more with situations that make consumption or prediction hard to predict, such as unforeseen weather circumstances.

Consequently, the question is whether these trades have actually solved the congestions. To give an answer to this question, three factors are looked at. Firstly, for how many of the total congested hours a trade was made by the model? Secondly, if a trade is made, has it actually solved the congestion? And finally, how many congestions were completely solved?

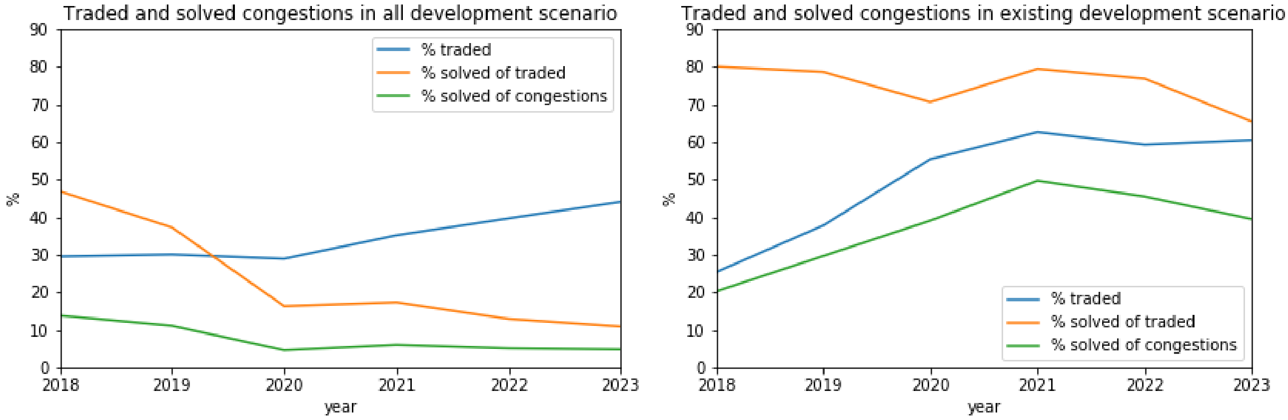


Figure 29: Traded and solved transformer congestions in the 'all development' (left) and 'existing development' (right) scenario

Figure 29 Gives the development over the years for these three factors. For the 'all development' scenario in 2018, for 30% of the congested hours a trade was made to try and solve the congestion (blue line). 47% of all these trades actually succeeded in solving the congestion problem at that particular hour (yellow line). In the end, for 14% of all the congestions a trade was done that solves the congestion problem completely (green line), and 15.5% of all congestions were partially solved. When looking at the development over time, the percentage of congestions where trades happen increases to a maximum of 44% in 2023. This comes from the quick development that was simulated on the intraday market. The amount of congestions actually solved, however, is only about 5%. The reason for this is that the average size of the congestions increases strongly (Table 4). Therefore, even when a trade is made, it is less likely to solve the congestion (the trades on every node are capped at 3 MW per trading hour to limit congestion forming in feeders).

The right side of the figure gives the information on the scenarios with only development on existing capacity, and it looks less clear. The percentage of congestions traded actually starts slightly lower at about 25%. But the percentage of these trades that solves the congestion is much higher at 80% giving a total solved percentage of over 20%. Over time, the percentage of congestions that are traded increases to a maximum of 63% in 2021, after which it falls off slightly. The percentage of trades that is actually solves is rather erratic, but seems to be on a slightly downwards trend. It reaches its lowest point in 2023 with just 65.5%. The total number of congestions solved also has its maximum (50%) in 2021. In the existing scenario, the growing intraday market is better able to keep up with the congestion growth. But at the end of the horizon, a similar trend to the 'all development' scenario occurs. The data for Figure 29 can be found in Appendix IV.

In general, the increased congestion occurs on three fronts. The number of congestions increases, the average size of the congestions increases (in both scenarios, but much more in the 'all development' scenario), and the duration of the congestion increases. The increased activity on the intraday platform deals very well with the increased number of congestions, showing the strong increase in how many of the congestions were traded. The duration of congestion is also not a problem as long as orders are available. The size of the congestions is a problem, the model can only deal with it until a certain point because of the limits on how much can be traded on every node before congestion occurs in the feeders.

13.2.2.2. Feeders

Besides the congestions in the transformer, congestion also occurs in the feeders. As seen before, this is always the result of a trade to solve the congestion in the transformer. This cannot always be handled by some of the feeders.

	CONGESTED HOURS	% TRADED	% SOLVED OF ALL TRADES
2018	8	12.5	**100**
2019	64	0	**0**
2020	240	2.9	**100**
2021	349	0.6	**100**
2022	485	1.6	**87.5**
2023	575	1	**83.3**

	CONGESTED HOURS	% TRADED	% SOLVED OF ALL TRADES
2020	4	0	**0**
2021	16	31.2	**100**
2022	20	10	**100**
2023	22	22.7	**80**

Table 5: Traded and solved congestions in the grid feeders for the all development (left) and existing development scenario (right).

Table 5 shows similar data to the transformer congestions, but this time for the feeder congestions. While the total congestion hours are much lower, the percentage traded is also low. This is because a congestion on the transformer needs a sell order anywhere in the downstream grid. A feeder congestion order on the other hand requires a buy or sell order downstream from the congested point. If this is far back in the grid, this might only be 1 or 2 nodes. This makes the chance of having a suitable order much smaller. However, if there is an order available the chance that the congestion is actually solved is high (>80%).

This shows that in the case of the feeder congestion, the development of the intraday market is not yet enough to make a large impact on the number of congestions that can be traded. On the other hand, the congestions are still a lot smaller, so if a trade is possible the chance of solving the congestion is high.

13.2.3. Cost

The last, and one of the most interesting results, is regarding the prices of the trades. In the end, Stedin will have to make a financial decision on how it can best serve its customers. Therefore, the

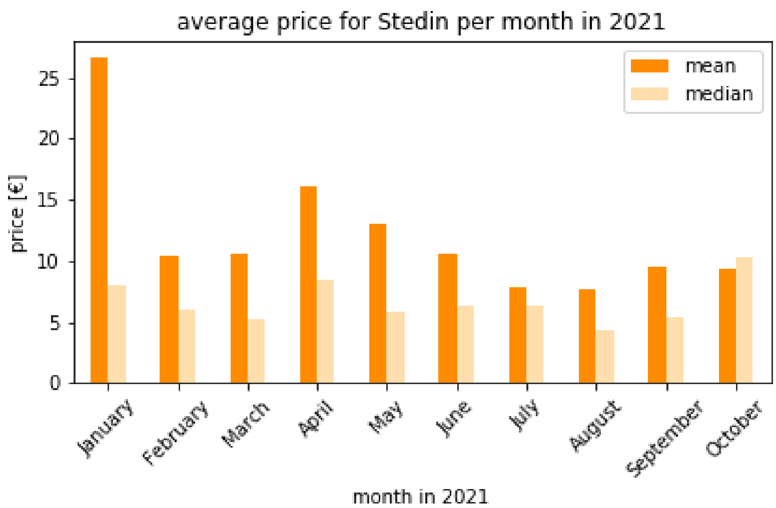


Figure 30: Mean and median prices [€/MWh] of congestion spread covered by Stedin

model has also analyzed what the cost for Stedin would be for every trade. This gives insight in how a solution like this compares to a more traditional solution of grid-reinforcement.

Important to remember here is that, when talking about price or cost in regards to Stedin, this does not refer to the buy or sell prices of the orders in the order book. Instead it refers to the *congestion spread*, or the price difference between the matched buy and sell orders. Figure 30 shows both the mean, as well as the median of this congestion spread in every month. It shows that median is much

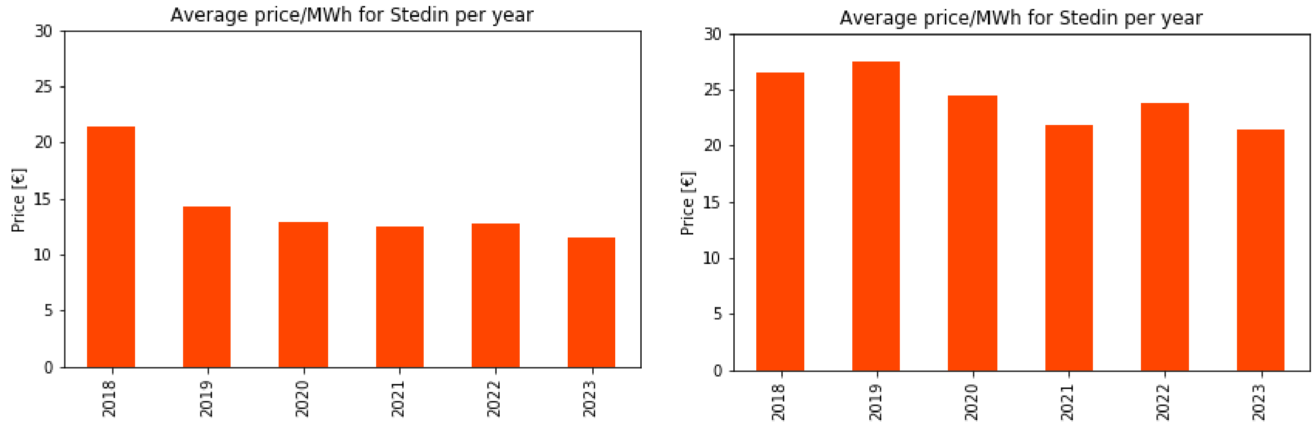


Figure 31: Average cost/MWh for Stedin for all trades made in a year in the 'all development' (left) and 'existing development' (right) scenario

more stable and lower than the mean. This means that the distribution of congestion spreads paid by Stedin is positively skewed, meaning that most values are to the left of the mean, but there are some instances where Stedin has to pay a very high price. This makes the mean much higher than the median (especially in January). This shows that even though prices might be usually low, sometimes there will be outliers. This is something that Stedin will have to take into account.

When looking at the average congestion spreads over the years (Figure 31), it shows that in 2018 it is slightly higher at just above 20€/MWh and afterwards it steadies out at around 12.5€/MWh. The 'existing development' scenario has a slightly higher price, and also stays higher. This indicates that the amount/volume of trades does have an influence on the average price.

Finally, it is time to look at the total cost for Stedin. It is quite obvious that the cost for the 'all development' scenario is much higher than for the 'existing development' scenario. Even though the prices for the latter are higher, it does not cancel out a much smaller traded volume.

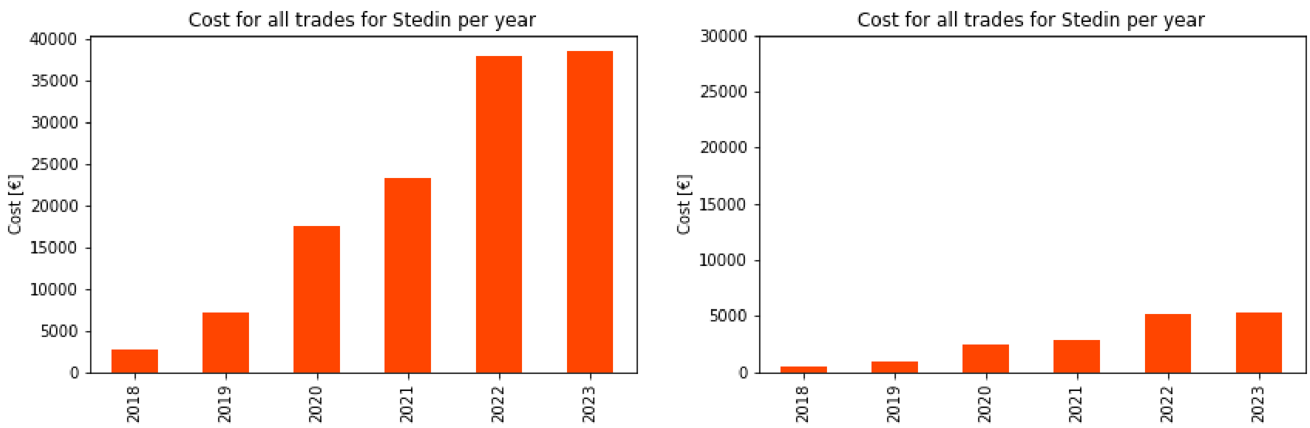


Figure 32: Total cost to Stedin for all trades made in a year in the 'all development' (left) and 'existing development' (right) scenario

Over the entire 6-year period, the total cost for Stedin in the two scenarios is:

Total Cost for Stedin 'All development'	Total Cost for Stedin 'Existing development'
€127,427.99	**€17,188.04**

13.2.3.1. Full year cost

The cost in the previous paragraph is only about the volume traded, meaning not all congestions are solved. Additionally, the model only has data for a period from January to October. So it is time to take a look at what the total cost would be if we look at the average prices per year and extrapolate that to the total congestion volume of each year. Additionally, the congestions in the missing months (October-December) are taken into account as well. This can be seen in Figure 33.

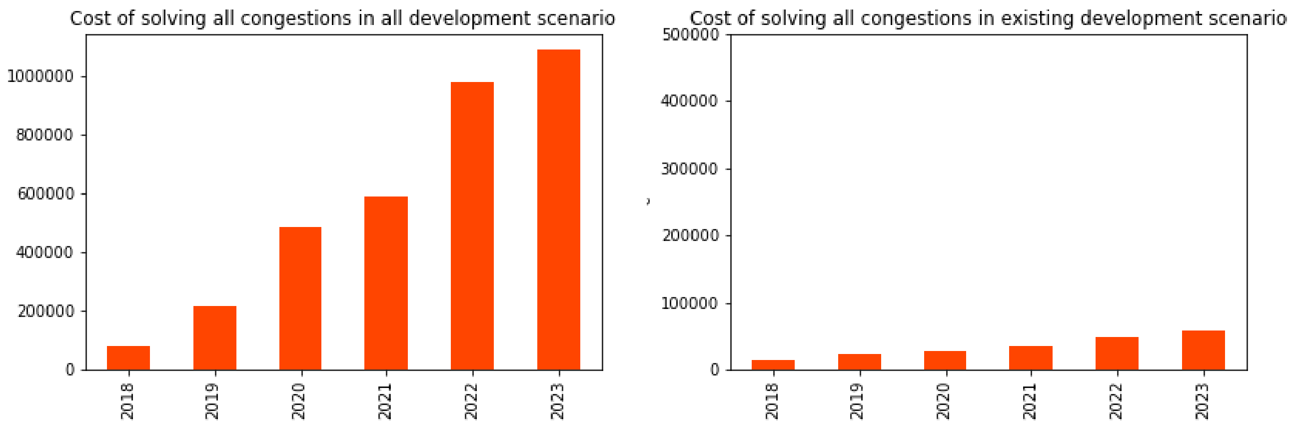


Figure 33: Cost for Stedin for solving all congestions in a year in the 'all development' (left) and the 'existing development' (right) scenario

Solving all the congestions in an entire year, increases the cost tremendously. Especially in the 'all development' scenario this difference is enormous. Remember that in this scenario only about 4% of the congestions in 2023 are solved. Add to that that the model only looks at about 9.5 months of trade excluding the strongly congested months of November and December (Figure 34).

Total Cost for Stedin 'All development'	Total Cost for Stedin 'Existing development'
€3,429,532.80	**€203,988.14**

Table 6: Total cost for Stedin for the entire 6 year period, as well as solving every congestion

Table 6 shows that the total cost for Stedin has strongly increased for the entire year. For a single year, the largest difference is in 2023. The total cost for the trades made in the model is €38,502.23 in 2023, but extrapolated to trading all congestions in 2023 this becomes €1,088,440.75. However, even if this were a financially attractive option, it is impossible to realize as the congestions on the transformer are simply too large to solve without creating massive feeder congestions.

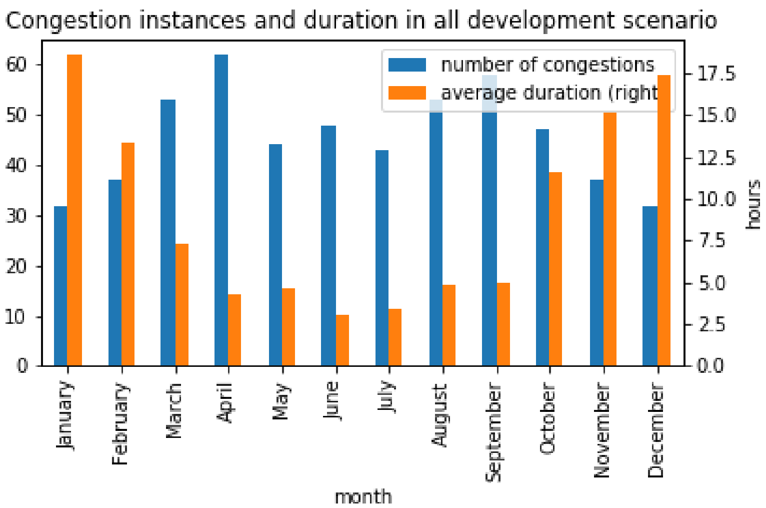


Figure 34: Congestion instances and duration for entire year

13.3. Comparison to traditional grid reinforcement scenario

There has been congestion in the *Zuidplaspolder* area which is expected to increase in the coming years, as was just analyzed in the model. A plan has been approved that will provide a long-term solution and resolve the congestion. This involves building a new sub-station which will be finished in 2023; therefore a solution is needed for the years until then. The option of using the ETPA congestion management tool is what we have analyzed here. The other option has been investigated by Stedin and it involves making a short term investment in a different substation that can carry some of the capacity of the *Zuidplaspolder* area.

In the analysis in this thesis there were different total costs for Stedin. Varying between €17,000 for only the trades made in the 'existing development' scenario to €3.4 million for solving all the congestions in the 'all development' scenario. Unsurprisingly, the total cost of this solution varies strongly with how much congestion there is and how much trade; Table 7 shows the different total costs. Especially the 3.4 million is much higher than all the other costs. Again, this is because the congestions are so large.

scenario	Model/ all development	Model/ existing development	All congestions/ all development	All congestions/ existing development
Cost [€]	€127,000	€17,000	€3.4 million	€204,000

Table 7: Total cost for Stedin in the two scenarios and when all congestions are solved (2018 – 2023)

Unfortunately, it also became clear that for the 'all development' scenario it will be impossible to solve all the congestions. For that the congestion is simply too much. In the 'existing development' scenario the congestions are much smaller and less, but nevertheless only a maximum of half of the congestions has been solved. But if all congestions are solved it will cost a little over €200k, which is significantly cheaper than the investment cost of the alternative solution.

The question thus is not about 'what is the cheapest alternative?', but becomes about making a trade-off between reliability/predictability and cost. The traditional grid strengthening has the main advantage that the available capacity is set and will prevent congestions in the transitional period. Although this cannot be guaranteed as a congestion could still happen, the chances are greatly reduced. The main advantage of the congestion management tool is that it is much cheaper but it is much more uncertain that it will actually solve all congestions.

What is exactly the goal for Stedin? Is it absolutely necessary that all the problems get solved, or is it already worthwhile to solve part of the problem and 'keep it under control'? In the next sections more alternative scenarios will be developed that can give more of an understanding of the effectiveness of the tool under different future developments. The cost versus reliability trade-off will remain central throughout the rest of the study.

One thing that has to be added is that there is always a risk of gaming, either in the form of price fixing or, if localized, monopolistic market power. If this comes into play, prices will start to deviate strongly from what is modelled here and the tool could become very expensive. More on gaming and its risks will be discussed in chapter 17.

14. Conclusion of model results

The results of the 2 scenarios ran on the model were analyzed on three main criteria: the congestions, the trades, and the price. The most important conclusions are summarized here:

Congestions

- The number of congestion hours increases steadily over the coming 6 years.
- The number of congestions is much higher in the 'all development' scenario, compared to the 'existing development' scenario (as expected).
- In winter the number of congestions is lower, but the duration is much longer. In summer this is the other way around.
- The size of the congestions (MW above limit) grows increasingly larger over the years, and is much larger in the 'all development' scenario.

Trades

- Impact of increased trade is seen, but fails to keep up with increased congestion.
- Increased number of trades cannot deal with larger size of congestions.
- Feeder congestion is a result of trades to resolve transformer congestion
- Feeder congestion is harder to solve as a result of more limited locations for trade.

Price

- The average congestion spread (cost for Stedin) decreases with more trade and averages out at around €12.5/MWh.
- The distribution for congestion spread is positively skewed so there are outliers with very high prices.
- There is a large difference in cost between the 'all development' and the 'existing development' scenario (this follows logically from increase in the number and size of congestions).

14.1. Main problems

Here, some of the problems and results of the model will be analyzed that can later be related back to the more general market design and policy problems that were mentioned in chapter 9. The main and most obvious problem is that the tool was unable to solve all, or even most of the congestions. 4 main problems that lead to that are identified.

1. **Too many congestions and too large congestions.**

The model shows that the number of congestions that can be solved, or at least traded can be increased strongly through development of the intraday network. The problem lies at how large the congestion is. Unfortunately, these two development do go hand in hand. As a result of the model design, the pattern of loading on the grid stays the same and this seems a fair assumption if the grid composition does not change substantially and the utilization does not change radically. When an entire loading pattern shifts upwards, new small congestions are added. The problem is that existing congestions will also become larger. This means that an increasing number of total congestions automatically means there are also more large congestions that are hard to solve (This trend is qualitatively illustrated in Figure 35).

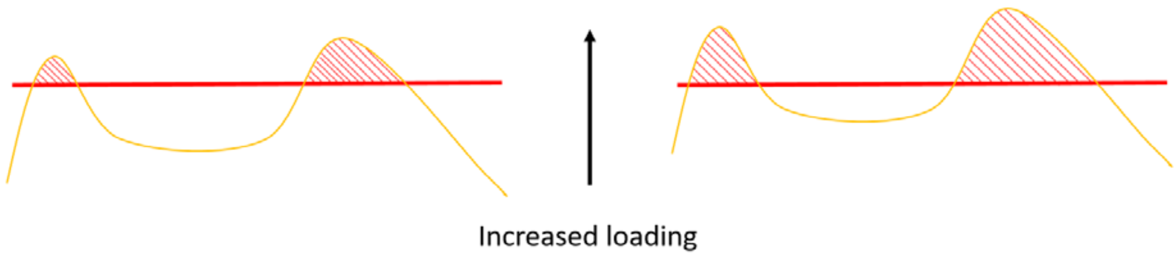


Figure 35: Simultaneous increase in congestion numbers, size, and duration due to general upward shift of loading profile.

2. Not enough orders, and orders are on average too large.

The next issue relates to the number of traders and the size of the orders. In the model there are about 15 active traders, all assigned to a different node. In reality, there could be several different traders behind every node since every node is a 10 kV substation. Of course, this is a future scenario as right now even the 15 traders is more than there are in reality. The number of traders also relates to the size of the orders in the order book. Because most traders in the order book right now are fairly large, their order size is also fairly large (usually several MWh). In a small grid like the one in this case study, many of the congestions are fairly small. It might be beneficial to have a larger number of orders, that are each smaller in size. This might also help with solving congestions in feeders as they arise.

3. Hard to predict when congestion will occur and what the best moment to trade is.

The last problem is related to the operational strategy of the congestion management tool. The model works in such a way that the best price is found that would have been possible for a certain hour. Of course, this is only possible because the model works as an 'all-knowing' model and all the orders are already known beforehand. If the tool would actually be used in operation, this would not be the case, and results in an extra challenge of determining what the right moment of trade would be. This is where accurately predicting the load comes into play, because the sooner a potential congestion is identified, the lower the cost most likely will be. Even when a congestion might be known, it could still be hard to know when a trade should be made. As seen during the result analysis, the prices can have large outliers making it unpredictable and sometimes very expensive.

All of the previous problems relate back to another question that is important for Stedin (and all DSOs in general) to answer: How important is it that all congestions are solved? The limits that are used are not actual limits of assets, but operational limits set to maintain the traditional N-1 security standards. Right now there is already congestion occurring, not only here but in multiple locations in the entire Stedin grid. This shows that this is not a critical problem that directly threatens the electricity supply. Of course, it does influence the overall reliability of the grid. Does this mean there is value in containing/mitigating the congestion problem instead of solving it? Or does the size of the congestion not really matter, only whether it is solved or not?

4. Inability of actors to perform normal operation when there is too much congestion.

Another problem related to the size of the congestions is related to the normal operation of the actors on the grid. When a trade is made to relieve congestion, this has an impact on the planned normal operation of the traders. Whether this be a horticulture farmer, a small factory or an aggregator of electric vehicles. It is likely that this change will have an impact on the future plans of that actor. For example, if the aggregator cannot charge the EVs or the factory cannot operate in a certain hour because they traded away their electricity for that hour, they will still have to do it at some other time. When there is so much congestion in the grid that this will likely result in a congestion again, this becomes problematic for the actors. This will either drive up the prices quickly, or the flexibility will simply not be offered anymore at all. Either way, it will result in a dysfunctional congestion management tool.

It is uncertain where the limit of how much congestion can be solved and thus how much capacity can be supplied by the entire system. There is a theoretical upper limit when all load is spread evenly resulting in a constant loading at max capacity. This would utilize the grid 100% at all times. It will be very hard, if not impossible to achieve this goal in reality. In reality, the limit will be much lower and will depend on the flexibility offered on the trading tool.

15. Analysis of problems

The next step is to look into the problems and see what causes them? Can the cause of this problem be related back to certain policies or market designs that are now present in the market, such as the ones we saw in chapter 9? The next step is to see if certain adaptation can be made in the model to show how this might affect the effectiveness of the tool.

The model has several parameters that can be changed in order to change the outcomes in terms of effectiveness and cost of solving the congestion. In total 8 parameters have been identified in 3 different categories that can be tweaked to change the outcome.

	ETPA ORDERS	CONGESTIONS	MATCHING
PARAMETER	Number	Number	Time of matching
	Size	Size	
	Price	Distribution	
	Time		

Table 8: The 8 parameters that can be modified to change the effectiveness and cost of solving congestions in the model.

The first category that can be modified is the order book of buy and sell orders. Within this order book, the number of orders, the size and the price can be changed. Additionally, the distribution of the orders throughout the day or the year can also be changed.

Secondly, the congestions itself can be changed in number or size of the congestion. Furthermore, the load shape of the congestions could be changed, meaning that the total power injected to or extracted from the grid stays the same, but distributed differently over time.

Finally, the order matching mechanism of the model can be changed. At this moment the model works in such a way that two orders are matched for the best possible price. In reality a DSO will not always be able to find this best price (see problem 3 in section 14.1). Matching could also be done based on a certain time (e.g. 1 hour before the congestion), or at a different price (highest price for Stedin instead of lowest).

15.1. Problem 1: Too many congestions and too large congestions

Because the number and size of congestions are too large to be handled by the tool as it is currently, changes could be made to improve this. As mentioned previously, the size of the congestions is a larger and more urgent problem than the number of congestions. That the congestions become so large is a result of the fact that the load shape stays the same throughout the yearly developments. This relates back to the market structure problem of the '*Copper plate*'. The copper plate makes the whole of the Netherlands a single price zone making it so that electricity stays the same price regardless of location. There is no incentive to no longer use a line/cable that is (almost) congested, and congestions can keep growing.

The direct solution for this is to introduce flexible congestion tariffs (chapter 7.1). All DSOs in the Netherlands agree that a change in tariff setting to more flexible tariffs is desirable [44] [20], but the way in which this should be done is not set in stone. The main discussion is on who should bear the extra cost of these tariffs, only the people affected or should some sort of cost socialization take place? The general goals of such flexible tariffs are clear, it should be an incentive for consumers to spread the use of the electricity infrastructure more evenly by moving capacity from busy moments (that will be expensive) to more quiet moments such as the night. This is generally called peak shaving. The flexible tariffs, together with the planned repeal of the net metering [49], will make private electricity storage more attractive. This again will be a new source of flexibility.

15.1.1. Model adaptation

The assumption is that the flexible tariff setting will make transporting electricity increasingly more expensive if the situation on the grid becomes more dire. The effect of this will be modelled using the following parameter from Table 8:

- Distribution of congestions

The model will be adapted by peak-shaving all the congestions above 3MW and putting this capacity in less critical moments (valley filling), for instance at night. This simulates high tariffs at times of potential congestion. The idea is that these high tariffs cause the use of the grid to shift to a different time ensuring that congestions will not get as large as they are now.

15.2. Problem 2: Not enough trading orders, and orders are too large on average.

This problem is a result of the type of traders that are currently active on the electricity market. The electricity market is a complex place that requires expertise and investment to participate in. Because of this, it are currently larger players that have the capital to make these investments and the scale that makes it worthwhile. This results in the orders being relatively large in size, while often for congestion management in the distribution grid only a fraction is needed.

This relates back to the problem of *'Lack of demand side response'* that was discovered earlier. There are 3 reasons that result in the lack of demand side response:

1. No real time rates
2. Lack of capacity and/or willingness to respond
3. Risk aversion

Several changes in market design and policy are already under way that aim to improve these three factors. The flexible tariff setting will help to show the real price of transportation. Platforms such as ETPA, that aim to make the electricity market more accessible for smaller players, help to bring the real price of electricity to the customer.

The second problem relates to the challenges in making effective use of available flexibility by customers and the technological challenges posed by this. The introduction of the smart meter, and the wider development of automation of processes in households, factories and businesses will make it easier to respond to price signals coming from the market without the need of large investment or expertise.

Thirdly, the use of so-called aggregators makes individual customers part of a collective. This spreads the risk while at the same time allowing for enough scale to make it worthwhile to invest in expertise.

15.2.1. Model adaptation

The model adaptation will not only assume increase in intraday trading because of renewable development but also increased use of existing flexibility in households and businesses/factories. The following parameters will be changed:

- Number of orders
- Size of orders
- Time of orders

Instead of pulling the size of the order from the current distribution of orders, the development will consist of all orders of 0.5kWh. It is possible for multiple orders to be available on the same node though.

15.3. Problem 3: Hard to predict when congestion will occur and what the best trading moment is

The third problem relates to the operation of the tool by Stedin or a different DSO. When operating the tool in real-time, there are two uncertainties that do not exist in this model. First, the model knows exactly when a congestion will occur and how big it is. The second one is that the model knows what the best time is to make a trade in order to have the lowest possible cost. In reality Stedin has very little idea of when congestions might occur. The predictions are based on historical data and on transportation programs (T-program) that large parties have to supply. However, there is no penalty for not sticking to the T-program, or not providing a T-program at all [61], meaning that the ones provided are often inaccurate. With more renewable energy in the system, it will become even harder to provide accurate T-programs (unless penalties are introduced, as is the case for E-programs, which will incentivize market parties to invest in state-of-art forecasting tools). This will be counteracted somewhat by more automation and better measurements which make it easier to share all the available data. Knowing as soon as possible how much capacity will flow at what point is essential for effective and cost-efficient congestion management.

15.3.1. Model adaptation

The model adaptations will be used to quantify the importance of having good predictions and information about when and where congestion will occur. The parameter that will be changed to do this is:

- Time of matching of the orders

Right now, the best price is found for a certain hour and this is the trade that is made. For the adaptation also the most expensive point of matching will be found to show how expensive it could possibly be. Additionally, the model will match the orders at 15 minutes to an hour before time of operation to show what the cost would be like if the congestion is only known shortly beforehand. Together these two adaptations can give a sense of how important it is to make accurate predictions about when and where congestion will occur.

15.4. Problem 4: Inability of actors to perform normal operation with too much congestion.

This problem is strongly dependent on the individual actors and what the nature of their flexibility is. In many flexibility programs, user demand is optimized over time to create an as even loading as possible on the grid. This tool however, does not optimize, but works on a case by case basis, meaning that there is always a risk that by solving a congestion through trade, different congestions get created because an actor still wants to fulfill their demand at a different time. This can be solved by using market restrictions, which are already used by TenneT on the transmission grid. A transportation restriction allows a DSO to forbid market parties to deviate from their operation schedule as known at that point.

Market restrictions should not have to be used too often because, as the problem states, it will interfere with the normal operation of actors on the grid. This problem puts a limit on the use of this tool that might occur before the technical limits of the grid or the amount of trade that would be possible on the trading platform. The model does not have a way to model this, but it is important to look into this. This problem will be considered during the other model adaptations. This might not give definitive answers but will at least provide insight into how often normal operation of actors is interrupted through the use of this tool by Stedin.

15.5. Conclusion

Moving forward, for 3 of the 4 problems mentioned above, model adaptations will be made to give an idea how certain developments in policy and market structure will affect the effectiveness of this tool. The final problem is hard to integrate into the model and will be analyzed together with the model adaptations of the other problems.

Figure 36 shows how the market structure developments from chapter 9.2 combine with the different congestion management tool problems identified in this chapter. In the next chapter these adaptations will be conducted and the results analyzed. As mentioned, problem 4 does not have a separate model adaptation but will be taken into account with the other adaptations.

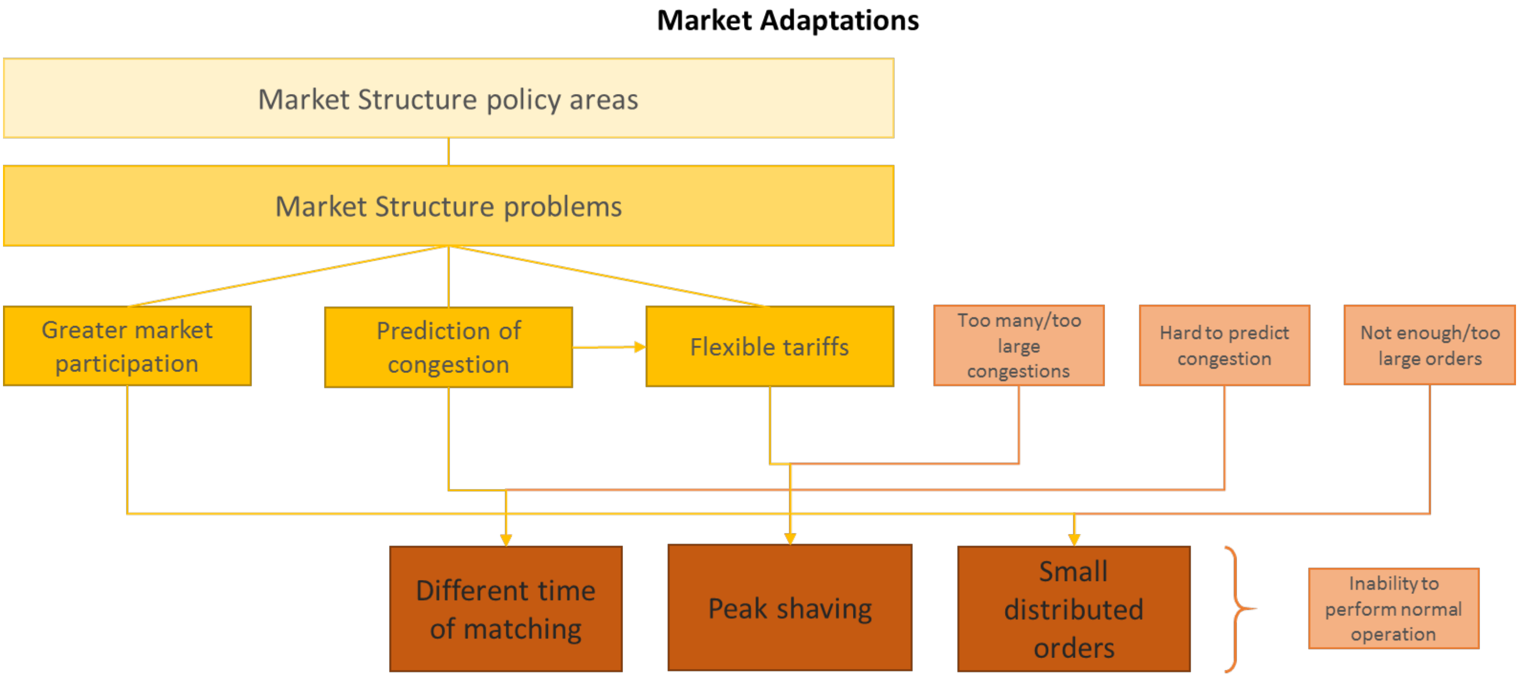


Figure 36: Graphical representation of how market structure developments (left) and congestion management tool problems (right) are combined into model adaptations

16. Future market structure analysis

In this section the results of the model adaptations for the different problems are discussed. Initially, the model adaptations are run separately and in the end they are combined. The adaptations are not run for every year since the effects are expected to be similar for every year. The year 2022 is chosen because the changes will already be pronounced, but 2023 is not possible. For the 'all development' scenario it is not possible to completely peak-shave in 2023 (see Table 9).

16.1. Problem 1

For this problem, congestion tariffs and some other policy plans are simulated by modelling peak shaving into the congestion patterns. This means that all the congestions above 3 MW are downsized to that value and the excess capacity is being spread among uncongested times.

YEAR	CONGESTION >3MW [MWH]	LOADING <40MW [MWH] (VALLEY)
2018	203	94,114
2019	2,269	69,351
2020	9,060	51,171
2021	13,149	46,168
2022	27,078	35,504
2023	36,281	30,774

Table 9: Total MWh that must be 'peak-shaved' and total MWh available in 'valleys' for the 'all development' scenarios

Table 9 shows that in 2023 it is not possible for all the large congestions to be peak-shaved. Even if every hour that is below max capacity is set at 40 MW, there will still be congestions that are over 3 MW, and can thus likely not be solved without creating congestion in the feeders.

During the initial analysis of the model results, three sections of the results were analyzed: congestions, trades and cost. This same order will be used to analyze the results of the model adaptations. This makes it easier to compare the results. Additionally, the effects of the results on problem 4 will be looked at. Instead of rerunning the analysis for all years again, the year 2022 will be taken as the basis for the comparison. For this year, both the 'all development' and the 'existing development' scenarios have been run to compare.

16.1.1. Congestions

Peak shaving only resulted in changing the loading of the congestions and non-congestions. No congestions were removed, or the other way around. The number of congestion instances and the duration of the congestions is still exactly the same. Things that have changed are the total volume of congestion in MWh and the average size of the congestions.

Model runs 2022	**All development**	**Existing development**	**All development – peak shaving**	**Existing development – peak shaving**
Congestion [MWh]	35,544	356	8,753	304

Table 10: Total MWh of congestion in different model runs of 2022

Table 10 shows the total amount of congestion for the different model runs on the year 2022. The 'all development' scenario on the original dataset clearly has the most congestion. The peak shaving scenarios are lower in both cases, but the difference is much larger for 'all development'. Table 11 paints a similar picture by showing a large decrease in average congestion size for the 'all development' scenarios and a relatively small decrease for the 'existing development' scenarios.

Model runs 2022	**All development**	**Existing development**	**All development – peak shaving**	**Existing development – peak shaving**
Average congestion size [MWh]	11.3	1.9	2.8	1.6

Table 11: Average congestion size in different model runs of 2022

16.1.2. Trades

The trading and actually solving of the congestions is hopefully where peak-shaving can make the largest contributions. Because the model limits trades at 3MWh in order to prevent congestion in the feeders, peak-shaving should result in a larger ability by the model to solve the congestions.

Table 12 does indeed confirm that the peak-shaving results in a strong improvement in the overall solving of congestions on the grid. It can be seen that the hours of congestion and the hours that were traded are still the same as in the original model runs. How much of the traded hours were actually solved increased drastically. For the 'all development' the percentage of trades that actually solve the congestion increases from 13% to almost 65%. For the 'existing development' scenario this increase is from 76.8% to almost 95%, meaning that almost all congestions are solved if relevant orders are available in the order book. In the peak-shaving scenarios the overall solved percentage is 25.7% and 56.1% for the all and existing scenario respectively.

	Congestion hours	**Traded hours**	**Unsolved hours**	**Solved hours**	**Traded [%]**	**Solved of traded [%]**	**Solved [%]**
2022 'all'	3138	1245	1083	162	39.7	13	5.2
2022 'all' peak-shaving	3138	1245	440	805	39.7	64.7	25.7
2022 'existing'	189	112	26	86	59.3	76.8	45.5
2022 'existing' peak-shaving	189	112	6	106	59.3	94.6	56.1

Table 12: Trading results from all the 2022 runs

Overall, the improvements made through peak-shaving are very significant. The peak-shaving greatly increased the likelihood of a congestion being solved if it is traded, but the total amount of congestion that is traded is still the same. To improve this, there needs to be development on the intraday market.

16.1.3. Cost

In terms of cost for Stedin, nothing changed to the original scenario. This is because in the original scenario, the maximum trade was also restricted to 3 MW. However, there are changes to the hypothetical cost if all the congestion would have been traded in the entire year (Table 12). In the original model run, the costs for the full year of 2022 are almost 1 million euros. In the peak-shaving scenario this amount is roughly halved. Unfortunately, in the case of the entire year 2022 runs into the same issue as 2023, namely that there are not enough uncongested hours to peak shave all of the congestion. This was not the problem in the original data set because the missing months (October-December) have much more congestion than the summer and spring months. For the 'existing development' scenario, the costs are also reduced, but not as much.

Model runs 2022	**All development**	**Existing development**	**All development – peak shaving**	**Existing development – peak shaving**
Total cost [€]	979,714.23	49,352.00	481,537.29	38,981.39
Difference			-51%	-21%

Table 13: Total cost to solve all congestions over the whole of year 2022

16.1.4. Relation to problem 4

In terms of the ability of actors to perform their normal operation, this model adaptation gives some good insight into why this is a legitimate problem. In the 'all development' scenario it is shown that the amount of congestion is too much in 2023 to even do peak shaving to 3MW congestions. Even in 2022 there is not much free capacity to spare after peak-shaving all the congestions. It is not hard to see that it would be quite hard, probably impossible, to realize a flat loading profile throughout the whole year.

For 2022, the free capacity left after peak-shaving is 8,426 MWh. There is also still congestion, since they were only limited to 3MW and not completely peak-shaved. The total congestion is 8,753. Due to the nature of the tool, the free capacity is not necessarily needed to solve the congestion because it moves capacity geographically and not in time. However, this does not mean that it will not also be moved in time. Imagine that a horticulture farmer decides to use less electricity because he could sell it for a good price. In practice this probably means that he will use the electricity at some other time anyway to ensure that he can still run his operation. This goes for the horticulture farmer, but also for a factory or someone charging an electric vehicle. As already concluded, it is impossible to create a flat profile continuously for an entire year. It might not be possible or very expensive to move capacity in time because almost every time this creates a new congestion. This will mean that the congestion tariffs will become very high as there is a high demand for transportation capacity almost continuously and not enough supply, creating a shortage and thus high prices. This is an issue where storage can play a role, but that is outside of the scope of this research.

It is now clear that the operation of the actors on the grid will limit the usability of the tool before the actual technical limits of the tool. This is the case for any flexibility measure, since there is always capacity that needs to be moved in time. The difference is that it is less obvious as the tool does not do optimization over time, so this will be a task of the normal market. The question still is where this limit exactly is?

16.1.5. Conclusions

In general, this model adaptation clearly improves the performance of the tool. Previously all congestions would increase in size over the years. This meant that for every new small congestion, congestions existing in a previous year would become a larger congestion. With the model adaptation the large congestions are kept relatively small.

This confirms the conclusions of the initial analysis that the problem lies mostly at the size of the congestions and not the number of congestions. Because if the number of congestions would be decreased, it still does not mean that a trade would be possible at the times that are leftover. To solve this part of the problem, the solution lies at the intraday trading volume.

This result also points in the direction that flexibility is a solution that has to come from multiple sources and not just one. It is unlikely that congestion tariffs or storage can solve everything, but neither can this congestion management tool. Therefore, it is likely that multiple solutions will have to be implemented in tandem.

16.2. Problem 2

For this adaptation, the order book of the trading platform was changed. There are several reasons to believe that flexibility that is already present in the grid, from small and large users, will be used more in the future. The use of aggregators, smart devices and storage will allow for more optimization possibilities in the low and medium voltage grid.

In the original model, order book was updated based on predictions for intraday development. The size of the new individual orders was based on the distribution of existing orders in the order book. Because currently most traders are relatively large companies that are familiar with electricity trading, many of the orders are quite large. In the scenario where more flexibility in the low voltage grid is utilized, the orders will become smaller. This was modelled by creating an order book of orders of the same capacity, but making every new order the size of 0.5MWh. This will result in a more even spread of the available capacity over the grid, and simulates smaller users or aggregators offering flexibility.

16.2.1. Congestions

The transformer congestions in this adaptation do not change, since only the orders were changed. The feeder congestions do change since they are often the result of trades to resolve the transformer congestion. Since the orders are smaller and more spread out throughout different nodes in the grid, the feeder congestion decreases. Table 14 shows that both the number of congested cables as well as the total congestion size decreases strongly. This shows that it is dependent on how and where the trade is what the actual limit is in trade size. In an operational model it would be important to implement some form of iterative process or optimal power flow. The limit could then be determined on a case by case basis.

	Original model – 2022	Adaptation 2 – 2022
Congested cables	485	155
Total congestion [MWh]	2142	335

Table 14: Total number of congestions and total congestion in original model run and adaptation 2 for 2022

16.2.2. Trades

Table 15 shows the trading results from the adaptation compared to the original for the year 2022. What is most important to notice is that the percentage of congestions that were traded went up to 100% in both cases. In every congestion instance it was possible to make a trade on the platform to relieve or solve the congestion. The solving percentages went up to 13% and 77.2% for the 'all development' and 'existing development' scenario respectively.

What is interesting to see is that the percentage 'solved of traded' stays nearly identical. There are two reasons for having an unsolved trade: the congestion is too large (>3MW) to be solved through trade, or there is not enough capacity available to solve the entire congestion. From the fact that these percentages stay roughly the same, it can be concluded that the latter hardly happens. The 'solved of traded' percentage is based purely on the distribution of congestion sizes (what percentage of congestions is below 3MW). If the congestions are randomly selected, the distribution should stay the same and that is what we can see.

	Congestion hours	Traded hours	Unsolved hours	Solved hours	Traded [%]	Solved of traded [%]	Solved [%]
2022	3138	1245	1083	162	39.7	13	5.2
2022 - 0.5MWh	3138	3138	2730	408	100	13	13
2022 existing	189	112	26	86	59.3	76.8	45.5
2022 existing 0.5 MWh	189	189	43	146	100	77.2	77.2

Table 15: Trading results comparing original 2022 scenario with order book of 0.5MWh orders

In adaptation 1 (peak-shaving), the results showed a large improvement in the solved trades for the 'all development' scenario and a small increase in the solved trades for the 'existing development' scenario. In this case, it is the other way around as the first only increases about 8% and the latter increases over 30%. This goes back to the two different problems that are tackled. The size of the congestions and the number of orders in the order book. An increased number of orders does little to help solve congestions that are too large to solve. And a decrease in congestion size does little when they aren't that big in the first place, but have no available matching orders. This indicates that a combination of the two solutions might grant good results.

16.2.3. Cost

The second step is to look at what the cost is for Stedin in total, both for the model run and extrapolated to the whole year. Table 16 shows that in the model run, both scenarios become more expensive. This is obvious, as many more trades are made with the 0.5MW orders. On the other hand, when the average price per MWh is taken and this extrapolated to all the congestion in the whole year, the price drops significantly. The reason for this is that with many more orders available in the order book, the congestion spread becomes smaller, and therefore the price per MWh decreases. So when taken for the same amount of congestion, the cost will decrease significantly.

Model runs 2022	**All development**	**Existing development**	**All development – 0.5MWh orders**	**Existing development – 0.5MWh orders**
Cost model run [€]	38,007.77	5,179.58	57,351.45	6,492.02
Difference			+51%	+25%
Cost whole year [€]	979,714.23	49,352.00	495,989.91	43,711.18
Difference			-49%	-11%

Table 16: cost for model run and cost for whole year, compared between original simulation and 0.5MWh order simulation

16.2.4. Relation to problem 4

This adaptation considers the situation where many smaller flexibility sources are available in the grid. The actual congestions do not change and this means that it is still relevant to see how these smaller actors might also still fulfill their electricity needs. Many of these small flexibility sources could come from things like aggregated electric vehicles or heat pumps. Besides looking at how much non-congested time is available in the year, it is also important to look at when it is available.

When the flexibility of an electric vehicle is used, by for example discharging, it has to be recharged at some point as well. However, when there is continuous congestion during the winter, this is not possible. If the car cannot be charged in a reasonable timeframe, not only is the actor unhappy, the source of flexibility is also gone. This stresses the importance of taking a look again at the duration and occurrences of congestion.

As seen previously, the 'all development' scenario presents a clear problem in this regard. In January, congestions last an average of about 20 hours, and are maybe interrupted by 1 or 2 hours of non-congestion. This obviously presents little chance for actors to do fulfill their needs. But also in the 'existing development' scenario, the congestion is concentrated around the winter months. The average duration of a congestion in January is about 10 hours. This is a long time, but more workable because still half of the alternative. This shows that even though there might be a lot of capacity at one moment, there might not be when it matters. It might be a good idea to look into the nature of flexibility that is available and how time-flexible it is.

16.2.5. Conclusions

This adaptation related to the size of the orders has shown two things. Firstly, if there are constantly orders available in the order book, it is easy to solve congestions as long as they are not too large. Secondly it has shown the relation between market liquidity and cost. With a constant availability of orders, the prices will decrease significantly because there is a choice. This adaptation has at the same time shown the potential in terms of how much trade is possible, as well as the limitations in terms of how much can be traded. Finally, it also showed that more smaller options make it possible to trade more total volume without creating feeder congestion.

16.3. Problem 3

This problem related to the nature of the model as being an 'all-knowing' model and the importance for Stedin and other DSOs to being able to make accurate predictions on where and when to make trades to relieve congestion. In the original model runs, the best possible trade for a certain time of operation was chosen. This is only possible with perfect information, as the model has. In reality, this perfect information is not available to the DSO and actually is minimal. To quantify the effect of having perfect information versus no information, the matching algorithm of the model has been adapted.

The original matching algorithm works as follows:

1. All orders are divided into upstream and downstream from the congestion.
2. The buy orders or the sell orders are filtered out of both depending on the direction of the congestion.
3. The buy orders are sorted high to low, and the sell orders are sorted low to high.
4. The first order from the downstream side is selected (because this side is always smaller than upstream which contains the rest of the grid).
5. It is matched with the upstream order that results in the smallest spread and thus cost to Stedin.

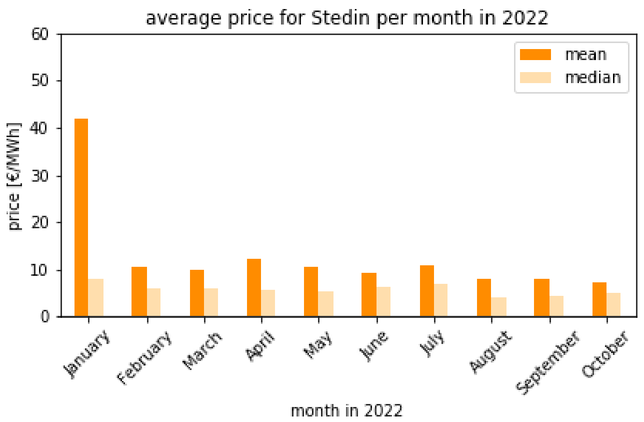
Two changes are made to this matching in this adaptation, and both are run on the model separately:

1. Instead of the first downstream order, the last one is selected. In other words, the lowest buy order or the highest sell order. It is still matched with the best upstream order, but this will likely still result in a much higher price.
2. Instead of taking all the orders for a certain hour of operation, only the orders that are available within an hour of operation are available.

These two changes will give insight in what the variations in cost to Stedin could be and thus the value of accurate transportation programs. The second change gives an idea of what the cost to Stedin would be when there are no good transportation programs and Stedin could only predict congestions very close to real-time. All the new orders that were generated for the different years have a long time in the order book so will all show up in the second change scenario. However, it does give insight in the pricing patterns of the market maker.

16.3.1. Cost – match expensive orders

When looking at the results of this model adaptation, only the cost for Stedin are interesting. Nothing was changed in the loading of the grid, or the orders in the order book. The congestions or trades will not change. Only which orders were matched, and therefore the price, has changed.



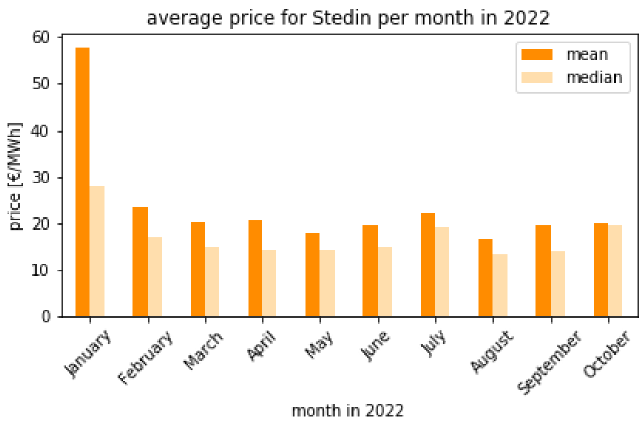


Figure 37: Average price that Stedin has to pay per MWh in the original (left) model and in the expensive order matchmaking (right).

Figure 37 shows the average mean and median prices paid by Stedin (congestion spread) to match orders for congestion management. The general pattern in pricing stays the same, but overall the averages rise significantly. The median rises from all values below €10 to values between €15 and €30 per MWh.

Model runs 2022	**All development**	**Existing development**	**All development – expensive**	**Existing development – expensive**
Cost model run [€]	38,007.77	5,179.58	67,800.75	8,106.22
Difference			+78%	+57%
Cost whole year [€]	979,714.23	49,352.00	1,894,267.50	93,042.37
Difference			+93%	+89%

Table 17: Increase in cost of congestion management with matching expensive orders

Table 17 shows the difference in cost that occurs when the all-knowing model does not search for the cheapest order, but for the most expensive one. The cost for Stedin will significantly increase when the ‘wrong’ moment for congestion management would be chosen. This shows the importance of finding out when a trade should be made in an operational version of this tool.

16.3.2. Cost – match 1 hour before hour of operation

Now that it is clear that there is a large variation in cost depending on what time the trade occurs, what is the value is of accurate prediction of congestion? As talked about before, inaccurate T-programs are now one of the reasons that make it hard for the grid operator to make good predictions on where congestion will occur.

Figure 38 shows the mean and median prices per MWh that Stedin has to pay for congestion management trading in the original model and when the orders were matched a maximum of 1 hour before. Similarly to the expensive matching, the matching 1 hour before time of operation increases the averages while also keeping the pattern similar. Only the April mean seems to be rather different from the original, similarly to January this is the result of outliers that result in a few very expensive trades.

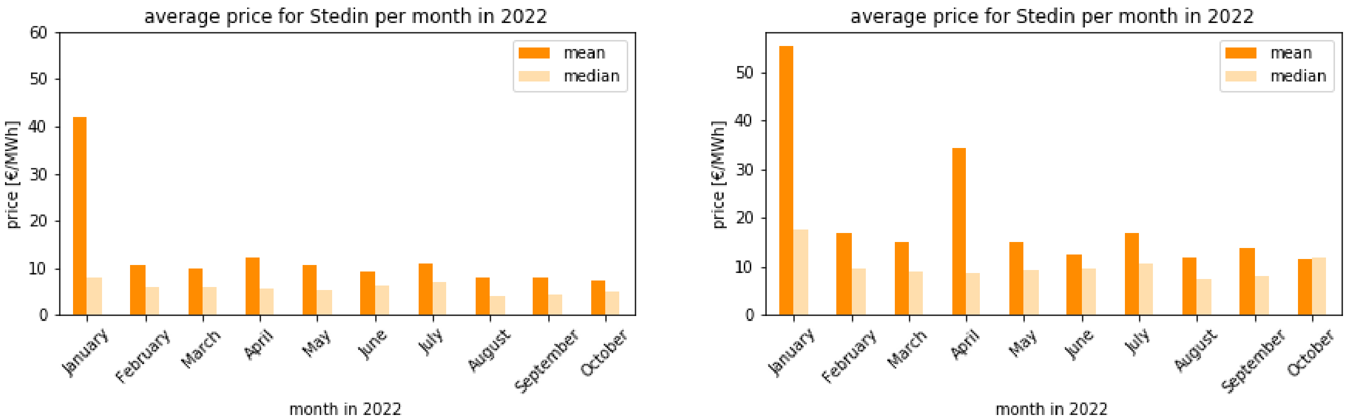


Figure 38: Average price that Stedin has to pay per MWh in the original (left) model and in the 1 hour-ahead matchmaking (right).

When looking at the total cost for Stedin for both the model and for the entire year (and solving all congestion), the increase is also quite large. It is not as much as using the most expensive matches but still between 40% and 76% increase. This is also the potential value for accurate predictions of congestion, and to get that, accurate T-programs are essential.

Model runs 2022	**All development**	**Existing development**	**All development – 1 hour**	**Existing development – 1 hour**
Cost model run [€]	38,007.77	5,179.58	54,330.76	7,269.57
Difference			+43%	+40%
Cost whole year [€]	979,714.23	49,352.00	1,603,726.27	87,068.51
Difference			+64%	+76%

Table 18: Increase in cost of congestion management with matching 1 hour before time of operation

16.3.3. Relation to problem 4

At first sight, this problem is more related to the operation of the tool from the perspective of Stedin, and not so much to the operation of individual actors in the grid. However, these two do have an interaction. How and when Stedin decides to trade has influence on how the actors can fulfill their normal operation.

This becomes especially relevant if Stedin (and other DSOs) would gain the ability to issue market restrictions. This means that after they have made a trade to solve congestion in a certain area, actors in this area of the grid cannot make any trades in one of the two directions because this would recreate the congestion that Stedin just solved. Therefore, if they haven't traded yet, the actors would have to stick to their original plan in this timeframe. This does not only influence actors that participate in congestion management, but all actors in a grid area.

In light of this, it would be most beneficial for actors that Stedin would either trade far away from the hour of operation or close to it. In the first situation, actors will have time to optimize their portfolio around the hour(s) where restrictions exist. If a restriction is called close to the time of operation most actors will have already done the trading they want to do for that hour. In other words, when Stedin decides to use the tool has an effect on all actors in the congested grid area.

Market restrictions will also not always be effective. For example if a wind turbine cannot meet its predicted (sold) output, it will have to buy extra capacity on the intra-day market. It will be impossible for the turbine to meet its required output at times of wind unavailability, so it can not stick to its original plan, with or without transportation restriction. If market restrictions are necessary it is crucial to look critically at how to implement them, as not to unfairly hurt actors with inflexible assets.

16.3.4. Conclusions

In this model adaptation, the quantitative effects of the moment of using the congestion management tool were studied. This is necessary to gain clear insight into the range of the cost for Stedin dependent on when they know a congestion occurs and when they decide to trade. The findings show that the most expensive moment of trading results in an overall increase in price of about 50%-100%. Furthermore, when trading time is restricted to 1 hour before the time of operation, the best price results in a price increase of 40%-75%. This shows that 1 hour before time of operation is not the worst time to trade, but also far from the best. These strong increases in price definitively show that more reliable T-programs are worthwhile to limit the cost of this tool.

Something that is outside of the scope of this research, but is a question worthy of investigation is what then is the best time to trade. It would be interesting to see if it is possible to discern a pattern in the congestion spreads and find out how the best time to trade changes throughout the day, seasons or years.

16.4. Problem 4

For problem 4, no separate model adaptation was made. Instead, the effects of the different adaptations on problem 4 were considered. Problem 4 deals with the (in)ability of grid actors to perform their normal operation in the face of congestion in their grid area. It became clear that this puts a limit on the extent to which this tool can be used. At some point there is so much congestion that it becomes impossible for actors to perform their normal operation. Often, this point will be reached before the technical/market limitations of the tool. Therefore, it is important to consider this when deciding if this congestion management tool is viable in a certain situation. When this is not done properly, the risk is that actors will no longer offer their flexibility (they are no longer flexible) or that prices increase strongly. There are several factors to consider:

- The amount of congestion, and amount of non-congestion.
- The duration of congestions and non-congestions (weekly, seasonal variations).
- The type of actor and how flexible their demand/supply is in time.

When it is the case that congestions last almost continuously for days, it becomes very hard to relieve. An electric car can be charged at 2am or at 5am, but not in three days. A factory on the other hand, might be able to shift their capacity around over several days. The type of actors in the grid determine the nature of the flexibility and how it can be used.

In general, considering this problem, the usability of the congestion management tool seems limited to small, short duration congestions. When reconsidering Figure 35, this shows that as long the loading of the grid is consistent and predictable like this, the tool has limited usability. If the graph as a whole shifts upwards, durations of congestions increase as well as the size and number of the congestion. This quickly limits the tool because of congestion creation in the feeders and hindering actors in their operation. When encountering these problems more robust solutions are probably warranted.

When loading of the grid becomes less predictable and more erratic, a development which many predict due to increase use of electricity and sustainable sources, the tool becomes more useful. The strength lies in dealing with these sort of unexpected changes in the grid use that haven't been dealt with by solutions such as the grid tariffs.

16.5. Combined model adaptations

Besides the discussed adaptations, one extra model adaptations was run. A combination of adaptation one and two, with both peak-shaving the congestions and the 0.5MWh orders in the order book. The trading results of this model adaptation are shown in Table 19. It shows that with this combination, the problem on the congestion side as well as on the order book side was solved. This can be seen from the fact that now practically all congestions are solved.

	Congestion hours	**Traded hours**	**Unsolved hours**	**Solved hours**	**Traded [%]**	**Solved of traded [%]**	**Solved [%]**
2022 'all'	3138	1245	1083	162	39.7	13	5.2
2022 'all' - 0.5MWh & peak shaving	3138	3138	4	3134	100	99.9	99.9
2022 'existing'	189	112	26	86	59.3	76.8	45.5
2022 'existing' - 0.5 MWh & peak shaving	189	189	0	189	100	100	100

Table 19: Results of combined adaptation of peak-shaving and small orders

16.6. Conclusion

The main conclusions about the model adaptations are summarized here:

- Peak shaving: in the 'all development' scenario, peak shaving is not viable in later years because the congestions are too large. Peak shaving does result in significant improvements in how many of the traded congestions were actually solved.
- Demand-side response: An increase in flexibility offering from smaller users that results in more evenly spread availability greatly increases the trades made. All congestions were traded in this adaptation, but many were too large to solve. Increased number of smaller orders also significantly decreases cost.
- Congestion prediction: Time of trading has a large influence on the total cost for the DSO (Stedin), up to twice as expensive. Trading close to time of operation is also significantly more expensive. This shows the value of accurate predictions of congestions.
- Grid actor operation: operation of actors is limited by how they can move their need for capacity in time. It is important to consider the type of flexibility and how time-flexible it is. In general, the tool is most useful for congestions that are short and small.

17. Reflection on national market

In the end, the goal is for the grid is to end up in a place where demand is equal to supply, the grid is balanced and there is no congestion in the grid. There are several ways to achieve this, some of them have been discussed in this report. All solutions theoretically end up in the same place with the same electricity prices and grid loadings (see chapter 7 and 8). The different methods can be less or more effective in managing some parts of the problem and achieving this theoretical solution. However, this is not the only side to the problem. The cost and accompanying incentives of solutions can be vastly different for different parties, this is what is reflected upon in this chapter.

17.1. Socialization of cost

Throughout this report, the copper plate and the unified price for the entire country that comes with it has been judged unsustainable. It is true that continuously expanding the grid will end up very costly for the entire society, so undoubtedly it is a good thing for consumers to be aware of when they consume and produce electricity. However, there is also a large advantage to the copper plate and that is that mostly everyone can afford electricity. The cost of grid investments and maintenance is socialized over all those who are connected to the grid. With flexible grid tariffs this would no longer be the case and it is important to keep in mind what the effects of that would be. In addition to that, if consumers are also charged the actual market price of electricity, the price becomes even more volatile. The cost socialization is mainly important for individual consumers as they run the risk of not being able to afford electricity. The next step is to determine what the risk groups are of this change in tariffs. Because the price of electricity will, with grid tariffs, depend on both location and time the most important factors to consider are the following:

1. What area does the consumer live in?
    a. An area of the grid where congestion is likely.
    b. An area of the grid where congestion is unlikely.
2. What are their capabilities to react to price signals?
    a. Strong capabilities to react to price signals.
        i. Technical know-how to understand market.
        ii. Financial means to invest.
    b. Weak capabilities to react to price signals.
        i. Limited understanding of market
        ii. Limited financial means to invest.

Considering the area where a consumer lives, electricity will be cheaper if you are located closer to a place where electricity is generated. Therefore, places with likely congestion are urban centers as they are usually further away from (centralized) generation, and the cost of replacing and reinforcing infrastructure is much higher. Places where congestion is unlikely are places close to generation as they depend less on the grid, and newly developed areas where the infrastructure is newer. When looking at time

When looking at the above factors, the consumers that will most likely be negatively influenced by the introduction of flexible tariffs are the ones who live in an area where congestion is likely, and who have weak capabilities to react to price signals. The people that have weak capabilities to react to price signals are probably people with lower education levels and income. They are less likely to have sufficient understanding of how the market and tariffs work to react to signals properly. Even if they have the knowledge, they will lack the financial means to make investments in smart devices, storage, and other ways to make reacting to price signals possible in the first place.

In other words, when the cost of operating the grid is no longer shared equally but divided with flexible tariffs as well as real market prices, it is a real possibility that the people that are hurt are the ones that are already struggling more than others. It is of crucial importance that if flexible grid tariffs and market prices are introduced, it is done in such a way that the people that struggle to adapt to this are supported, not left behind.

17.2. Incentives for grid operators and market parties

With the copper plate assumption in place, the incentives are clear. It is the job of the grid operator to supply electricity to the market parties as efficiently as possible, and the incentives for the market parties are to consume electricity whenever and wherever. The problem with picking a congestion management solution is that they often place contradicting incentives on market parties and the grid operator.

The previous section already showed part of the problem with flexible tariffs, but it is not the whole story. When looking at larger consumers, such as horticulture or factories, it might be considered fair that the cost of electricity is something they consider when choosing where to locate. Otherwise the grid operator might have to spend several millions just to connect a single party to the grid, and this will have to be paid by everyone. They also have the capabilities and means to optimize their own electricity use. The flip side of the coin is that flexible tariffs might put the wrong incentive on the grid operator. When a grid operator essentially gets paid when there is congestion, why would a grid operator want to prevent congestion?

The solution of congestion management in the market as studied in this report has essentially switched incentives. In this case the grid operator pays for congestion management and thus the incentive to prevent congestion is still intact. However, it does mean that the market parties get paid if they can solve congestion. This has the potential to give the market parties the perverse incentive to first create congestion and then get paid to resolve it. Or even locate themselves in areas that are known to have congestion to profit from this, and gaming the system. Either way, when choosing a congestion management solution it is important to consider the incentives this places on different parties, and if these are the wrong ones, how this can be prevented. The European commission, in their guideline on capacity allocation and congestion management, say that a congestion management methodology must: *"provide incentives to manage congestion, including remedial actions and incentives to invest effectively"* [62]. They clearly recognize the problem but give no clear direction yet on how to put this into practice.

17.3. Gaming

It has been mentioned in multiple places in this report that gaming is a significant risk, especially concerning the congestion management tool. 'Gaming', or 'Gaming the system', is the practice of using the rules and procedures in a way that they were not intended to be used, in order to gain advantage. In this particular case there are several things that could happen, a market party could:

1. Set a higher price than they would normally because the DSO will pay the spread regardless if they have to.
2. Plan generation/consumption that they never actually intended in order to make the DSO pay them, which is also known as the increase-decrease game [63].
3. Locate themselves in a congested area to profit of congestion problems.

When a grid operator pays market parties to change their electricity consumption and generation, there is an incentive for these market parties to misuse this if they can. The prerequisite for the market parties is that they need to know reasonably sure that congestion is actually a problem in this area, otherwise they will only hurt themselves. The first method of gaming can be counteracted somewhat by a higher liquidity in the market, because this gives the grid operator the option to choose from more prices and flexibility suppliers as long as they are not colluding.

However, when market parties intentionally move their consumption to congested times and areas, liquidity alone is not a fix. The only solution for this is not letting market parties know ahead of time when and where congestion is expected. This again is an argument why the congestion management tool is not as useful for structural congestion. Because structural congestion is repetitive, market parties can find out themselves what the congested areas and times are. In an interview with Energeia, two associate professors from the Technical University of Delft identify this problem and state that flexible tariffs should be the alternative [64]. They also identify that the implementation of flexible tariffs is hard and has a long way to go. Because it is so hard to implement flexible tariffs, congestion management in the market is not a bad solution, but the value of the congestion management tool lies especially in the last-minute variations that will undoubtedly arise. Because congestion will be more unpredictable in these last-minute cases, gaming will play much less of a role.

A document from the ACM (Dutch consumer regulatory authority) shows that they are aware of the challenges they face when regulating the energy transition. The cost reliability trade-off that has to be made by Stedin has been mentioned at different points in this report. The ACM introduces a triple trade-off between cost, reliability, and sustainability. Their view on this trade-off is that they want more sustainability per euro spent [65], showing that they are willing to make cost a consideration instead of putting the focus solely on reliability. Additionally, they are also investigating the possible redistribution effects of flexible tariffs as mentioned in 17.1.

To conclude, even though all the different congestion management solutions have the same goal, their effects on individuals are very different. Congestion management in the market makes sure that the grid operator manages its grid as effectively as possible, but might give perverse incentives to market parties and possibilities of gaming. Flexible tariffs on the other side give the right incentive to market parties, but there is a risk that some consumers will be affected unfairly. Also, flexible tariffs take away the incentive for the grid operator to critically look at their operation since they essentially get paid for congestion. These concerns should not be a reason to not implement these solutions, but a reason to consider carefully how and under which conditions to do so.

A way in which to deal with the unfair distribution of cost could be to subsidize flexibility solutions so that investments are possible for more people. Furthermore, if the responsibility for optimizing consumer consumption is taken away from the individual and put with a third party such as an aggregator, this will make it much easier for individuals. To give the proper incentives to grid operators, the allowed uses of flexible tariffs income can be restricted to make sure they still want to manage their grid effectively. In the end, it is the task of the government, the ACM, and the grid operators to come up with the best way to give these solutions a place within the future electricity system. Implementing flexible tariffs in a careful manner that accounts for the problems mentioned here, combined with congestion management in the market to deal with unpredicted congestions will go a long way towards being a solution that is both adept at tackling congestion in a cost-effective way while making sure there is still a fair market where everyone can access the basic need that electricity is.

18. Conclusion

This research has looked into market-based congestion management from both a technical as well as a market design and transition perspective. The research questions were the following:

What could be the role of market-based congestion management in the future electricity system?

1. ***What is the reliability of market-based congestion management?***
2. ***What is the financial cost of market-based congestion management?***
3. ***What is the market and regulatory context in which market-based congestion management can or should fit?***

The focus of the research has been on congestion management in the distribution grid based on a continuous intra-day market with bilateral trading. In order to answer these 3 sub-questions, first the conclusions of the technical model will be discussed. Afterwards these will be placed within the context of market structure developments as discussed throughout this report.

To put it succinctly, the results of the initial model runs showed that the trading was unable to solve all the congestions in the distribution grid. Nonetheless, it was shown that a congestion management tool is likely to be much cheaper than the alternative of placing a temporary cable. In the current state of the trading platform, with the type of congestions experienced, and the market development, the reliability is probably too low to use the congestion management tool as an actual solution.

The main problems concern the *size, duration,* and *frequency* of congestions, as well as the insufficient development of the intraday market. All three characteristics of congestion increase concurrently when the congestion is structural and if loading patterns stay the same. Congestion size is the biggest problem of the three as far as ability of the tool to deal with it is concerned. If the congestion is too large, it cannot be solved without creating new congestion in the feeders. The duration and frequency of the congestion can be dealt with by the tool, as long as there is enough capacity available in the intraday market. The problem however is that the actors in the congested grid area will be unable to perform their normal operation if the grid is congested too often or too long. Concerning the development of the intraday market, the main problem is that availability of flexibility is too concentrated in terms of time and location, with flexibility offerings that are larger than they need to be.

Several model adaptations were introduced to see how certain market structure developments would influence the effectiveness of the congestion management tool. The model adaptations were the following:

1. *Peak shaving*, as a result of possible introduction of flexible tariffs
2. *Distributed orders* in the intraday market, as a result of more incentives and capabilities for market parties to supply flexibility.
3. *Different time of matching* to quantify the influence of better ability of the DSO to predict congestion

Peak shaving showed large improvements in how many of the traded congestions were actually solved, whereas the distributed orders resulted in much more frequent trading. When both of the model adaptations are combined it is possible to solve all congestions that occurred up to the year 2022 for both the ‘all development’ and the ‘existing development’ scenarios. The different time of matching showed that the cost of applying this tool by the DSO can go up to 76% more, if congestion cannot be accurately predicted and needs to be traded very close to real-time.

The results showed that the congestion management tool can be much more effective if it is not a stand-alone solution to congestion but part of a larger solution, including peak-shaving mechanisms, ways to increase flexibility in the market, and accurate prediction of congestions.

At the beginning of the report, market design principles were introduced and three areas where policy should play a role, that are relevant for congestion management were identified. These three are *Reliability requirements, Transmission* (Distribution), and *Demand elasticity*. Now it is time to come back to these and see how these could be changed and the effect it will have on the use of the congestion management tool.

Regarding the reliability requirements and the distribution grid investments, the conclusions is that it should no longer be solely about reliability. There has to be a possibility to make a trade-off between reliability and cost; it is strongly interwoven with distribution capacity. Flexible congestion tariffs will be needed to step away from the idea of the copper plate and this opens up possibilities for grid operators to effectively use other alternatives such as the congestion management tool. There are already several developments underway that will increase demand side elasticity in the grid. Some of them come from the new market actors, such as aggregators. Others are more regulatory, such as the changes to net-metering, and smart meter rollout. These are areas where policies are already changing to make more flexible grid operation possible. It is important that these changes are stimulated and made possible by policy, and both the government and the ACM (Dutch consumer regulatory authority) are committed to this.

For policymakers there are more considerations besides enabling more effective grid utilization. Three areas were identified that deserve specific attention while implementing changes in the structure of the electricity markets:

1. *Socialization of cost* is no longer a given without the copper plate. However, fair access to electricity must remain possible for everyone.
2. *Incentives on DSO and market parties* will change. Market parties should consider the cost of their grid connection, DSO must be incentivized to manage grid effectively.
3. *Gaming* is a risk when market parties get paid to solve congestion.

In the end, the role of market based congestion management (on the intra-day market) will be to manage congestion close to real-time. When the whole electricity infrastructure steps away from the copper plate principle, there will be a need for congestion management. Peak shaving, storage and other ways of demand response will, together with better prediction of congestion, do their best to match supply and demand while observing the technical limits of grid assets. In implementing these measures it is important to take into account that the right incentives are placed in the right places and that electricity will stay available for everyone. Market-based congestion management will come in to deal with last-minute variations that will always occur due to the erratic nature of renewable generation and the unpredictability of consumers. Dealing only with last-minute non-structural variations will also significantly decrease the risk of gaming.

18.1. Recommendations for Stedin

For Stedin, the decision they have to make is whether they want to use market-based flexibility as a tool for congestion management. As mentioned, this is not simply a question of cost but a trade-off between cost and reliability. Subsequently, this cost and reliability again depend on several factors, some of which have been explored in this research.

It is important to realize that market-based congestion as modelled in this research is only one of the ways in which flexibility can be procured through the market. And the intraday market explored is again only one of the ways in which to procure flexibility. The market and the energy landscape will go through many developments in the coming years, and how the developments play out will influence the reliability cost trade-off.

The congestion management tool has turned out to be cheap compared to the grid reinforcement alternative. Unfortunately, the reliability is currently not high enough to have the trade-off decision made in its favor. Fortunately, other ways of procuring flexibility from the market can exchange some of the cost advantages for a higher reliability. An example of this are bilateral contracts with flexibility suppliers. A fixed price could be set for flexibility to get exclusive rights during certain periods. Or there could only be a contractual obligation to provide flexibility at no prescribed price in a market platform, to retain some form of market economics. This way Stedin would likely pay a higher price, but is also more secure in the availability of flexibility. This would be similar to how TenneT currently organizes the imbalance market by contracting capacity of generators that have to be available within a certain timeframe.

Figure 39 represents the way in which the cost-reliability trade-off is currently made. The horizontal line (trade-off barrier) signifies that the cost is essentially not a factor in the decision making process. A certain reliability (copper plate) must be guaranteed, only afterwards the cost can be a consideration. Traditional grid reinforcement is above this barrier, but is and will continue moving further to the right and becoming more expensive. Complete market-based congestion management is much cheaper but cannot guarantee the reliability that is demanded by the copper plate assumption and thus is below the trade-off barrier.

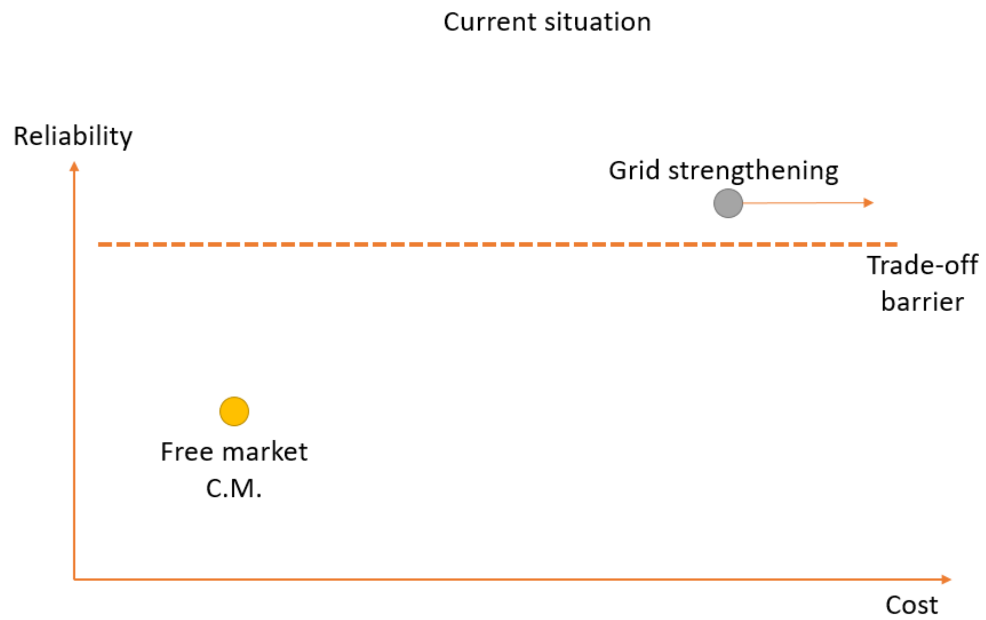


Figure 39: Current cost reliability trade-off made by DSO

Figure 40 shows how the cost-reliability trade-off could look in a future scenario, assuming that policy will indeed allow it. The trade-off barrier in this case is no longer horizontal but slightly tilted. This means that cost has become a direct consideration, and that a lesser reliability might be acceptable if the cost-savings are large enough. Free market congestion management will still not be reliable enough at this time, but other ways of procuring flexibility from the market, that are a little more costly, might already be. If Stedin and other DSOs were to use these types of flexibility, this is an incentive for market parties to invest in flexibility, thus increasing the total pool of flexibility in the market. When this pool becomes large enough, then free market congestion management might become an option.

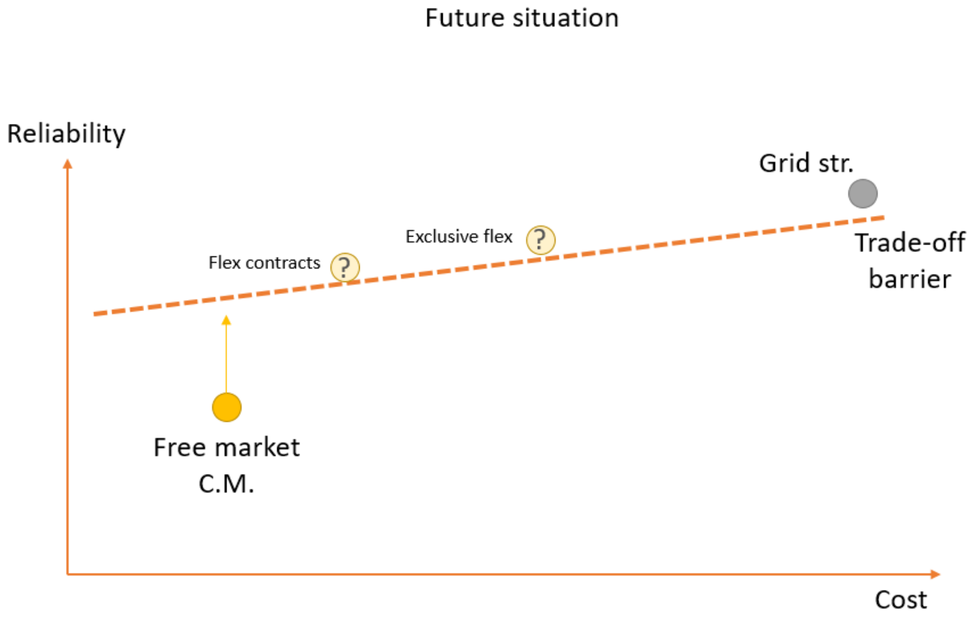


Figure 40: Potential future cost reliability trade-off

For Stedin to determine where on this two-dimensional field a certain solution is, will likely be a case by case decision. Depending on the type of flexibility there is in the market, the type of congestion and the liquidity of the market. There are things that Stedin can and should do to make this process easier and standardize it.

First, determine what kind of congestions there are, are they structural or occasional? Is it predictable or unpredictable? Determining what kind of characteristics are valuable will help to quickly identify new congestion areas. Secondly, what is the value of solving congestion versus mitigating it? There are many limits and safety margins on electrical components in the grid. When is there a congestion and is there value in making a congestion smaller, or is it only worthwhile if a congestion is completely gone?

This research has given an idea of what would be necessary to make the free-market congestion management tool move closer to the barrier. It is now up to Stedin to determine what exactly the variables are and to keep track of the position of different solutions in this field. First of all, it is important to gain insight in how much more expensive grid reinforcement is becoming because this will give the business-as-usual scenario. The problems identified in this study give a starting point for the variables to keep track of:

- Congestion type
    - Frequency
    - Duration
    - Intensity
- Flexibility
    - Volume in the market
    - Distribution of flexibility

The goal for Stedin should be to assign target values to each of the above variables that correspond to a certain type of solution. This could form the basis of making a decision as to which congestion management solution should be chosen. Of course, the selection criteria would have to be re-evaluated on a case by case basis since the actors present on the grid will play a large role in any chosen solution. Furthermore, the criteria per variable can change based on the value of another variable. For example, with a large volume in the market it is possible to handle larger congestions than with only a small volume.

Because the problem is the congestion, it would make sense to start with the congestion in relation to the grid and then relate it to the flexibility that is available. A conceptual example of how three of these criteria could be evaluated is given in Figure 41. In this example Stedin would identify or predict a congestion in a certain grid area. The first step is to evaluate the grid and how much congestion could be handled, this research showed that at some point a congestion becomes too large to handle. The second step could be to look at the actors that are on the grid and what kind of duration of congestion they could handle. If it becomes longer, dedicated flexibility sources might be needed, and if it becomes even longer, this might become too expensive. Only then the (potential) market is evaluated. With too little flexibility potential, grid reinforcement will be needed. If some flexibility is available it might be necessary to secure it through contractual means, and only with a large pool of flexibility providers a free market solution might be possible.

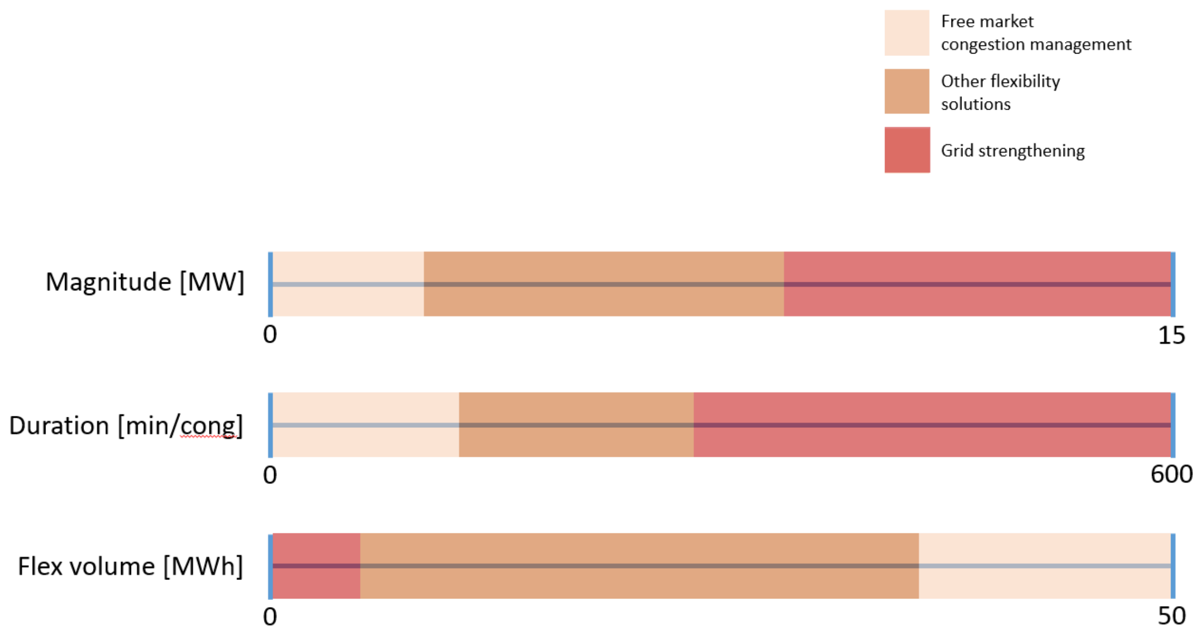


Figure 41: Example of congestion management solution evaluation.

This way Stedin can make a more informed and objective decision about what a suitable solution is in a certain situation. It will be important to quantify the situation because this way Stedin can build up working knowledge on how to deal with congestion and continuously optimize their decision making process. It is hard to come up with a standardized checklist to make these decisions, but a framework is necessary to at least homogenize the decision making. This thesis contributes towards this goal.

19. Discussion

This study was performed to give a distribution system operator a better insight in the practical implication of the congestion management on a bilateral intraday trading platform. The results gave clear insight and quantified the possibilities of the tool. On the other hand, there are still many variables related to the development of the markets and the grid connection capacities that make the results uncertain. Although the questions of which developments will take place and how still stand, the effects that certain developments have shown on the effectiveness and costs of managing congestion, are reliable. Something that could have made the results even more robust is if the model was run multiple times with different sets of generated data for future scenarios. This would have made it possible to further explore and quantify the uncertainty. Due to time constraints this was not done. Another limitation is the data from the ETPA trading platform. Since this trading platform is still very young, the way trade happens on the platform might still fundamentally change meaning that the intraday market development data is built on an unstable basis.

Still, the results are relevant since it is the first time that the possibilities of market-based congestion management in the distribution grid were researched and quantified with real-world data. For Stedin this will be a starting point allowing them to more objectively compare congestion management solutions. This will be crucial for a future electricity grid that is operated cost-effectively.

19.1. Future Research

It is important that Stedin and other DSOs will keep evaluating and researching variables that determine the success of market-based congestion management. This will allow them to make a well informed decision on the cost-reliability trade-off. If they want to use a market-based congestion management tool, they should also invest in making it into an operational model. Instead of looking back at existing data, this model should be able to support grid operation decisions based on real time information about the grid and the market.

For academic research several topics would be interesting to investigate further. Even though the outgoing feeders from the transformer busbar were taken into account, more research on congestion in the feeders and even in the low-voltage grid would be interesting. Many parts of the Stedin grid are not extensively monitored yet, as this data becomes available the nature of congestion and the effects of the market can be more accurately investigated. Another interesting topic would be to look into the intraday market itself. There's a lot more to find out about electricity trading on the intraday market and the relation to the energy transition. Research on the intraday development and renewable energy sources was used. The next step could be to see what the influence is of general electrification (for heat and transport) a nd the addition of smart devices in homes. Will this give another boost to the intraday market, or will most of it be optimized in earlier markets?

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Appendix I

Market Liquidity

Definition

market liquidity is a market's ability to purchase or sell an asset without causing drastic change in the asset's price.

Liquidity

In order to make a judgment about whether or not a market platform is suitable to solve congestion problems in the grid, it is important to know something about how reliable the platform can solve the congestion problem. A good indicator of whether a market can reliably do this, is the liquidity of the market. However, liquidity is a concept that is hard to define and even harder to measure.

A definition of liquidity is how quickly and cheaply an asset can be converted into cash [66]. In a market, liquidity means that an asset can be purchased or sold without causing a large change in the price of the asset. The problem is that this can never be measured directly, because it would require knowledge on what would have happened to the price if a certain trade did not occur to begin with. Therefore the liquidity of a market is usually determined by a combination of different indicators that can be measured. Three measures that are most commonly used are spread, depth, and resiliency. Spread is the price difference between the bid and the offer. Depth is about the quantity in the market and indicates an ability to absorb large trade volumes. Resiliency is about how quickly the spread and depth of a market can recover after a shock [67]. This concerning an electricity makes it a bit more specific, but these general principles still hold.

In a paper from 2013, Hagemann and Weber analyze the liquidity of the German intraday market [68]. This paper analyzes how liquidity can be determined by looking at specific indicators in the context of the intraday electricity market. Because the ETPA congestion management platform is also functioning on the intraday market, this is good starting point for determining what liquidity would mean in this context.

As a starting point, let's look at what the intraday market does and when trades happen. The intraday market opens as soon as the day-ahead market closes and all positions are settled. It allows parties to make changes in their position closer to real-time. Intraday trading is only needed when new information becomes available, and the situation as it was in the day-ahead market changes. Of course this always happens, but the extent differs. There are two different types of traders on the intraday market, patient and impatient ones. Patient traders trade by putting buy and sell orders into the order book. Impatient traders will trade as soon as the need arises for the best price that is available in the order book at that moment.

Hagemann and Weber use two different theories of how the market could function as a starting point for their analysis. They call these models the fundamental model and the trading model. The fundamental model assumes perfect information and a perfect competition. All the market participants are risk-averse in this situation. The trading model does not have perfect information, and there are also significant transaction costs. The goal of the market participants is profit maximization.

For both models the starting point for the intraday market is the same. In the day-ahead market, the price and quantity is determined by the merit order of generation (combined with demand). The spread will be formed by the generation that is more expensive than the day-ahead price on the one side. On the other side are the generators that are running based on the day-ahead clearance, but are willing to turn off if they can buy electricity cheaper than their marginal cost (see Figure 42). In the fundamental model, all the power plants will offer all their available trading capacity in the order book. All the impatient parties will only trade with the patient parties, making the spread larger as more trades are made. This would also determine the maximum liquidity at the opening of the intraday market, and it would only decrease from there. In the second model, the other market parties (the impatient traders) might act as patient traders in order to maximize their profits. They will put in orders that are within the current spread, making the spread smaller. In their analysis, Hagemann and Weber determine that the second model more accurately reflects the reality in the German intraday market. Because of the similarities with the ETPA congestion management platform, the focus will from now on be more on the second model. This is the starting point, and from here the different indicators of liquidity can be discussed and how they might affect this picture.

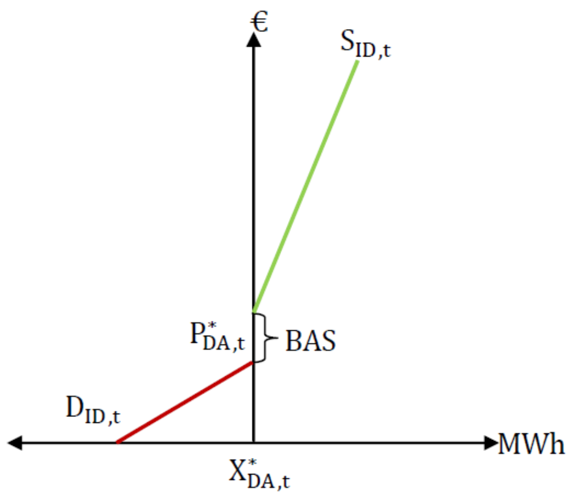


Figure 42: The bid-ask spread (BAS) at the opening of the intra-day market [68].

As mentioned, the three dimensions of liquidity are spread, depth and resiliency. Besides these three, three more factors are discussed. These are price volatility, delay & search costs, and trading activity. These six factors will now be discussed and how they might behave under the trading market model.

Spread

Also called tightness, the spread is the difference between the highest buy price and the lowest sell price in the order book. As mentioned before, the initial spread is determined by the power plants that were not dispatched in the day-ahead market (offering their electricity at their marginal cost and perhaps a profit margin), and the power plants that were dispatched (offering to buy electricity below their marginal cost so they can turn their generators off). When new information is available and market parties are looking to update their position, they might act as patient traders as well and put orders in the order book to maximize their profit. These orders will usually be between the current spread. This means that when more trading activity happens, the spread will become smaller.

Market resilience

Market resilience is defined as the ability of the market to 'bounce back' after a shock. This means that if something happens that will have a large impact on the price, the price should be able to restabilize to previous levels. This should be able to happen because the impatient traders will put in orders as well allowing for the order book to rebalance. In the fundamental model this would be impossible, because all the orders are in the order book from the start and no new ones will be added by impatient traders. In practice, the level of resilience will depend on the number of traders and how active they are.

Market depth

The depth of the market is determined by the slope of the demand and supply curves. This determines how much the price changes when a trade is made. If the curves are very steep, trading will have a large impact on the price. This means the market depth is not high. The depth of the market is determined by several factors. On the one hand, power plants might not offer all their residual power immediately but wait for opportune moments. This could result in a lower market depth. The depth also depends on the shape of the supply (merit order) curve. During different times of the day (peak or off-peak), the market might be situated at a different part of the curve which might be steeper or less steep.

Price volatility

Price volatility is somewhat similar to market depth in the sense that it also relates to the steepness of the supply and demand curves. But whereas depth is an idea of how much quantity is available for trading in total, price volatility is about how quickly the price changes if a trade is made. When the underlying merit order of the generation is steep, the price volatility will be high as well. If the day-ahead prices are very high, this indicates that the market clearing happened at a steep point in the merit order (supply) curve. This will likely result in a high price volatility. The volatility can be decreased by traders increasing the liquidity by putting orders in the book. Total trading activity also has an effect on price volatility. With more trades happening, the liquidity and depth of the order book will decrease and steeper parts of the merit order curve will be reached causing a greater volatility. However, this effect will be somewhat mitigated by imbalances from market parties in opposite directions. These will cancel each other out without affecting the volatility.

Search and delay costs

In a market with imperfect information, market parties might delay trading if they think they will be able to make a better deal later. This is a risk that they take which might or might not pay off. However, this also affects the liquidity of the market because it might decrease the number of orders available at any given time. This might result in market parties that are waiting for the other one to make a move in order to profit from the extra information. This might decrease the overall liquidity.

Trading activity

Trading activity has two dimensions, the number of trades and the total trading volume. The need for trading intra-day comes from new information and changing situations after the market clearing of the day-ahead market. If nothing were to change from the day-ahead clearing to the actual situation, there would be no intraday trading at all. This also means that the liquidity of the market, but also the need for a very liquid market differs from day to day.

Liquidity on the ETPA platform

At this moment, the intraday trading platform of ETPA is still in the start-up phase. Therefore it will be hard to compare it directly to the German intraday market which is already very well developed. However, the ETPA data will give an insight in how a starting intraday market is developing and what the different indicators of its liquidity look like. This can be taken as a basis for further development to see how this platform could help congestion management in a future state, but still grounded in reality.

Bid-ask spread

The bid ask spread in the order book has several different dimensions. At a certain point in time the order book contains several buy and sell orders. Time of production/consumption is a very important factor for electricity. Therefore, this also a criteria in the order book. Only orders which have the same time of operation can be traded. This is necessary to maintain the balance in the grid. The bid-ask spread can now be determined based on the entire situation of the order book, with all times. Or it can be determined based on for which hour it is traded. This is different, because for a certain time slot, let’s say from 14:00 until 15:00, the spread is different at 07:00 and at 13:00.

Appendix II

Grid and actor analysis

Location: 50 kV → 10 kV substation *Schielandweg*

In this section, the substation called *Schielandweg* will be discussed in detail. The substation converts power at 50 kV to power at 10 kV and distributes it further in the town of Waddinxveen and the surrounding areas. The station consists of the following measured components:

- 3 transformers to transform the voltage from 50 kV to 10 kV.
- 4 busbars (2 sets of 2).
- 4 coupling fields to couple the busbars.
- 21 outgoing fields (11 on busbars 1A en 1b, 10 on 2A en 2B)

All the outgoing fields will be analyzed based on their historical data and loading profiles. Furthermore their geographical location and the kinds of customers will be determined in order to make an estimation on the kind and amount of flexibility they could provide when solving a potential congestion problem.

This substation is a meshed network, meaning that there are many interconnections between the outgoing fields. In practice however, it is operated radially meaning that all substations are only fed from one direction. During faults or maintenance it is possible to feed from a different direction. The following things will be looked at for every field, or sometimes multiple fields are grouped together.

- Geographic location
- Schematic of the field and other connected fields.
- Loading of the field
    - Throughout the week/day
    - Cumulative loading
- Type of customers connected and relation to load shape.
- Congestion or congestion risk?
- Flexibility potential

It is important to take into account that there is no directional current measurements. Therefore no difference can be seen between if a field is generating electricity, except that the current goes through 0. But because it are aggregated measurements over 15 minutes this is easy to miss.

Field 101 & 102

These fields connect to a smaller substation called *Hefbrug*, which has 5 outgoing field itself. All these fields are again connected to other outgoing fields from *Schielandweg*. One is connected to a different 10 kV substation called *Bloemendaal* (BLD), in Gouda. The current limits for both of these fields are 545 A.

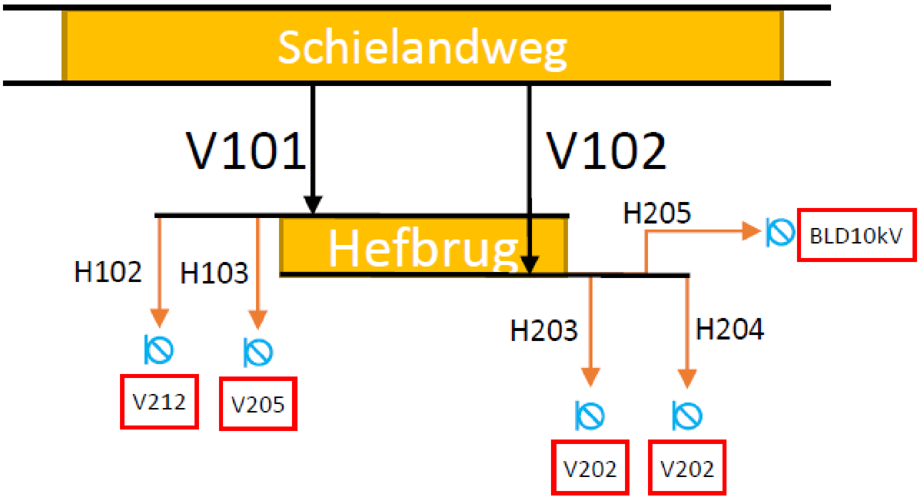


Figure 43: Schematic of outgoing fields 101 and 102

Geographically, one of the outgoing fields from *Hefbrug* goes to a small rural area east of Waddinxveen which is mostly agriculture, but no horticulture. The rest go to the urban areas in the north of Waddinxveen.

Loading

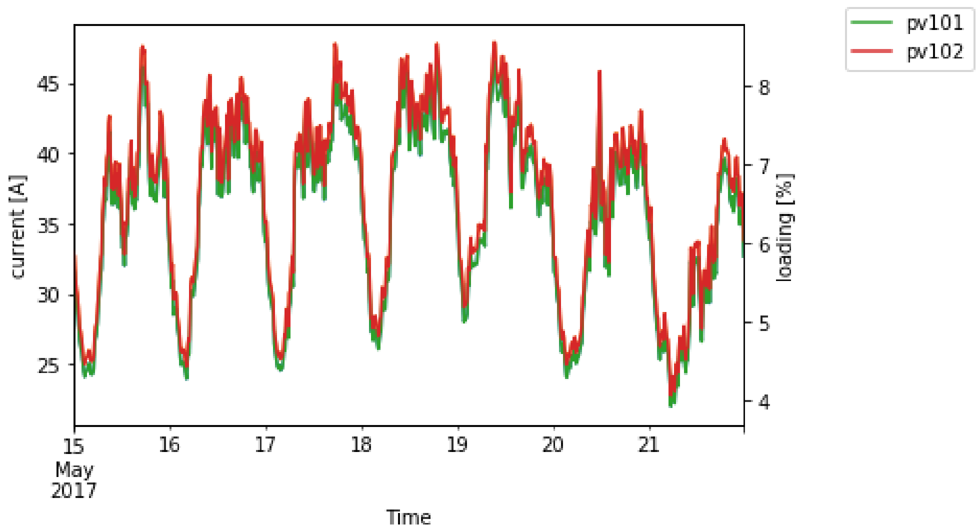


Figure 44: Loading of outgoing fields 101 and 102, absolute and percentual

When looking at the loading of these outgoing fields over a week in May, it looks like what would be expected of a loading in a mostly urban area with a small peak in the morning and a peak in the evening. However, the loading only falls back slightly during the day so the peaks are not very pronounced. Also the loading on Saturday stays rather high. These two things indicate that there is some different loading mixed in as well. This could be the influence of the agricultural area, or perhaps from a retail area that is connected as well. Both fields are loaded between 25A and 50A for the majority of the time which is still under 10% of the capacity of the cables.

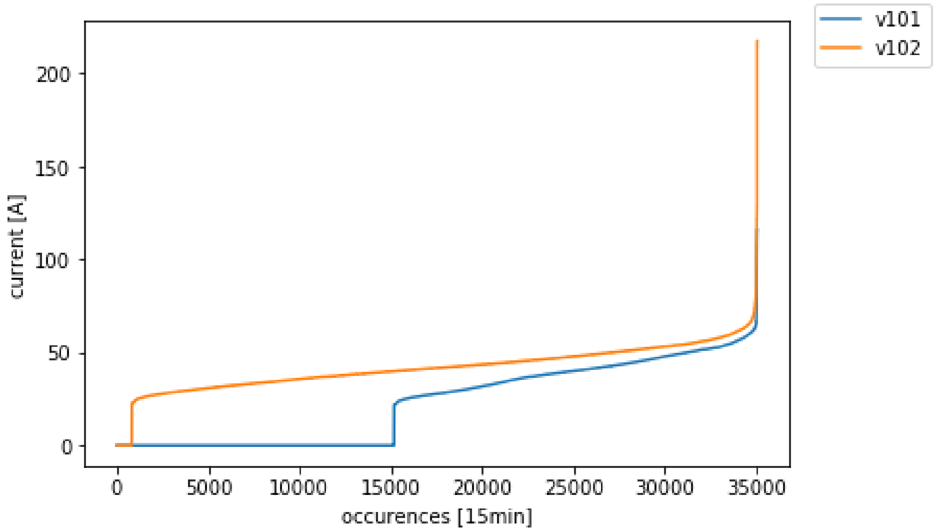


Figure 45: cumulative loading of fields 101 and 102

Figure 45 shows the cumulative loading of fields 101 and 102 over an entire year. This confirms that it is loaded below 50A for the majority of the time throughout the year. It also shows that there are some peaks, but only very few. Something that wasn't visible in the normal loading is that field 101 has been turned off for about 15.000 quarters (~156 days) in the past year. This means that the outgoing fields would have to been fed completely through field 102 or through other connections in the meshed network.

Congestion

The loading graphs already showed that there is no overloading during the week or anywhere in the year. But this graph is to visualize how far away a field is from overloading. On the y-axis is shown the percentage of time during the past year a cable was overloaded, if the limit of the cable was such as shown on the x-axis. This again confirms that field 101 and 102 are very far away from overloading.

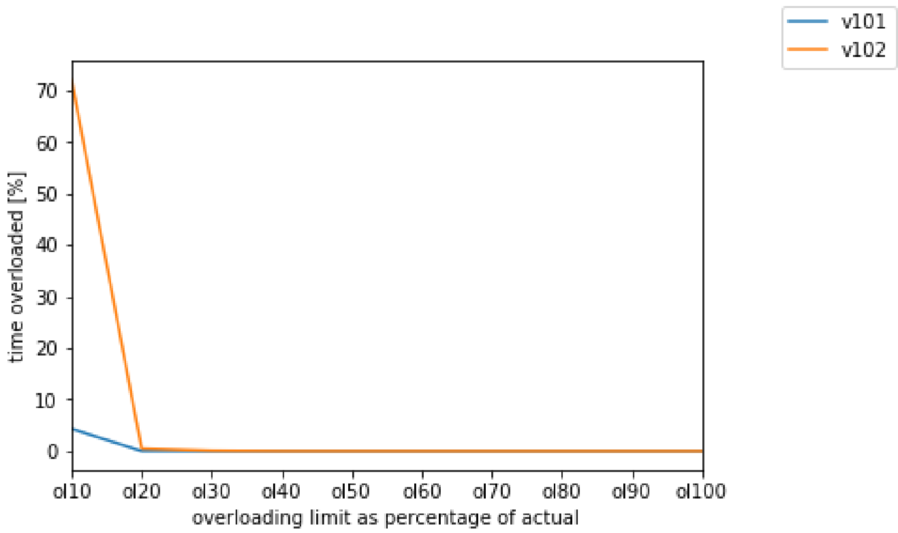


Figure 46: Percentual congested time with different current limits as a percent of actual limit

Flexibility

These fields are not a congestion risk, but they could be very suitable as a place where capacity can be moved towards since there is a lot of capacity available. However, urban areas are harder to use flexibility in because you are dealing with many customers. Perhaps the agricultural area has flexibility that is easier accessible.

These fields are grouped under:

- Agriculture
- Residential

Maintenance

For part of the year, there was maintenance on field 101, resulting in a lower loading that can be seen in these graphics. Since the loading of field 102 does not spike, part of the field was probably fed from a different feeder.

Field 103 & 105

Similarly to fields 101 and 102, fields 103 and 105 form a double connection to a smaller substation called *Ekster*. From this substation there are 6 outgoing fields which are operated radially but are connected to other fields as well. The maximum current for both fields is 575A.

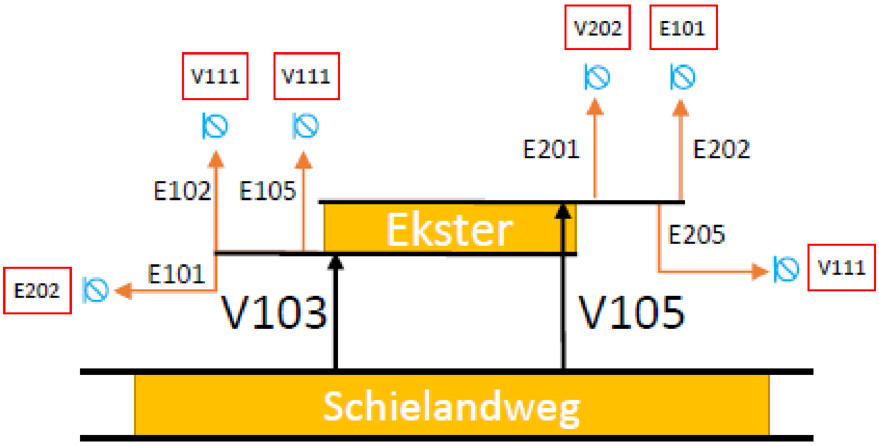


Figure 47: Schematic of outgoing fields 103 and 105

Geography and customers

The outgoing fields from the *Ekster* substation go mostly to urban areas in the Southwest of Waddinxveen. In the area are however also some retail areas, a large school, and one relatively small horticulture area.

Loading

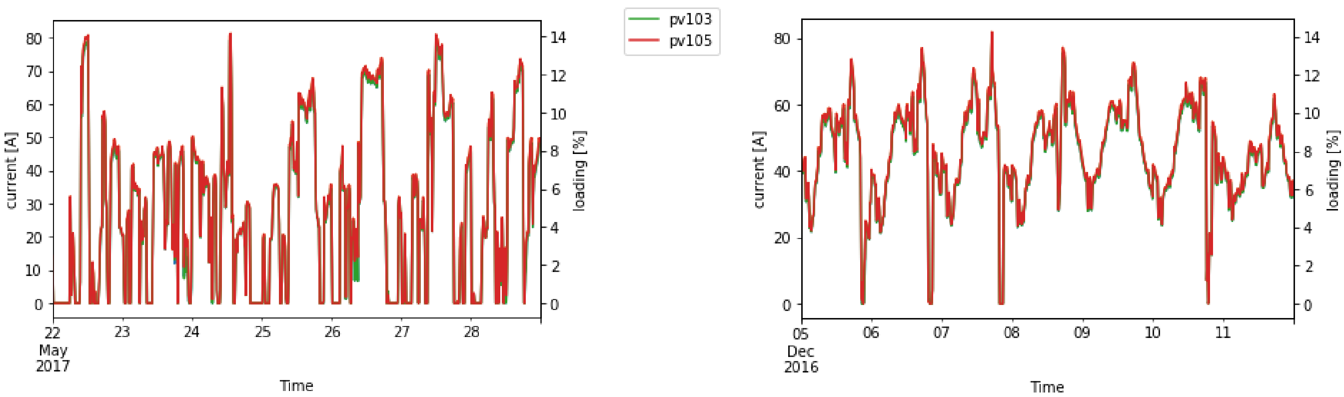


Figure 48: Loading of fields 103 and 105 in a week in May 2017 and December 2016

Figure 48 shows the loading of 2 different weeks, one in December and one in May. It shows that in half a year, the loading in the field has become much more erratic. In December it was still quite structured, but in May it has become very unstructured. The most likely explanation would be that the horticulture area has increased their electricity generation. This means that at points were the current is 0, the cogeneration is providing all electricity for the rest of the field, and this field is probably also supplying electricity into the grid. However, it is hard to say when exactly. Figure 49 shows the cumulative loading, which shows that there is not so much time where the loading was 0. This shows that the loading as seen in the week in May is only a relatively new phenomenon.

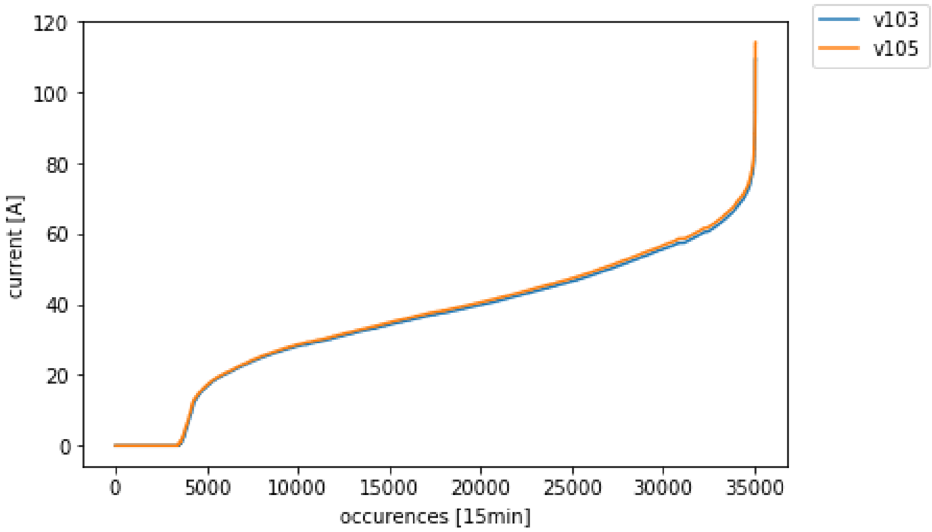


Figure 49: Cumulative loading of fields 103 and 105

Congestion

Fields 103 and 105 have not experienced congestion in the past year, they have very rarely exceeded even 15% of maximum capacity.

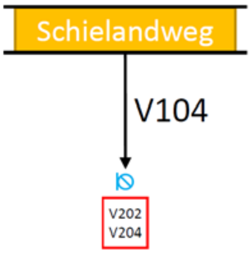
Flexibility

These fields have the potential to play a role in congestion management. There is plenty of capacity available and there are parties connected that could relatively easily play a role. The horticulture area has the ability to generate electricity and usually has flexibility in its portfolio. Additionally, the larger consumers such as schools and supermarkets could also play a role.

Category:

- Residential
- Horticulture
- Other

Field 104

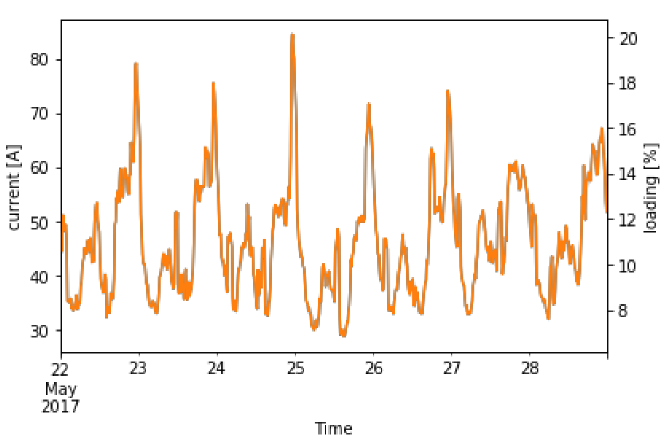


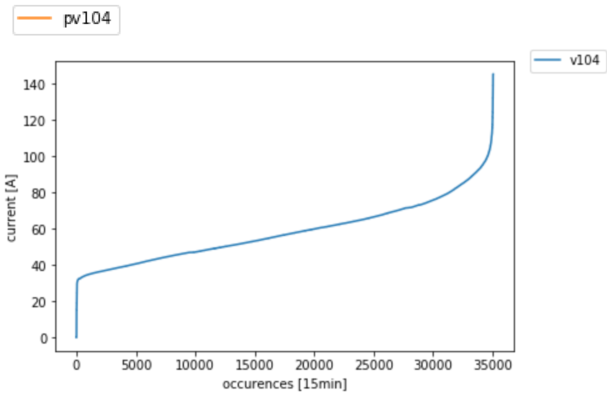
Field 104 is just a single outgoing field directly from the main *Schielandweg* station. It is connected to the 202 and 204 field. The maximum current for this field is 420A.

Geography and customers

This field connects part of the northern neigbourhoods of Waddinxveen, together with the fields coming from the *Hefbrug* substation. The connected area consists only of urban living areas.

Loading





From the loading it is clear that there are only residential areas connected to this field. There are small peaks in the morning, a large peak in the evening and consumption drops during the day. In the weekend electricity use is more spread out. From the cumulative loading it can be seen that the loading is almost always between 30A and 80A, with some peaks slightly higher going to about 140A.

Congestion

The loading of this field rarely goes above 20%, so congestion is not a problem.

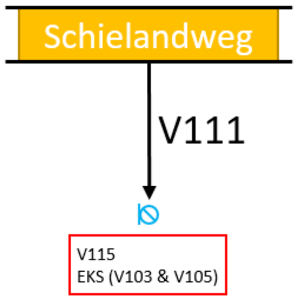
Flexibility

Since this is a purely residential area, it will be hard to acquire flexibility from this area. It might be possible in the future if new electrical technology such as electric cars and heatpumps that can be used through an aggregator.

Category:

- Residential

Field 111

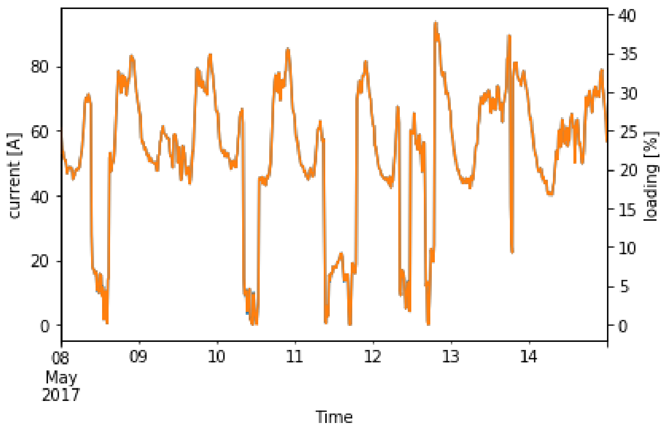


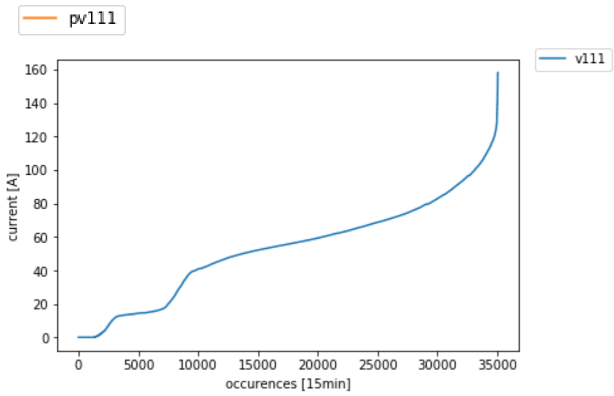
Field 111 connects to field 115, and to 3 fields connected to the *Ekster* substation. The maximum current for this field is 240A.

Geography and Customers

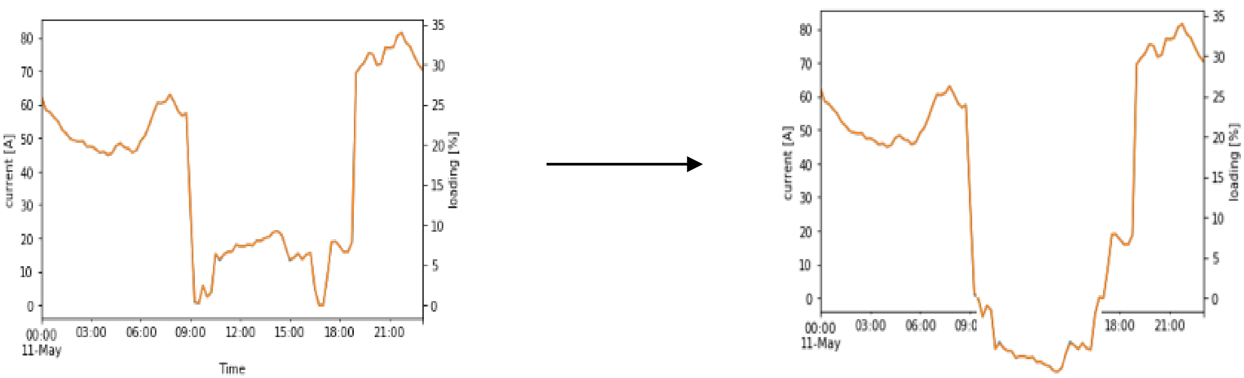
Field 111 connects to part of the Zuidplas neighbourhood in the southwest of Waddinxveen. Additionally it connects quite a large number of horticulture outside of Waddinxveen.

Loading

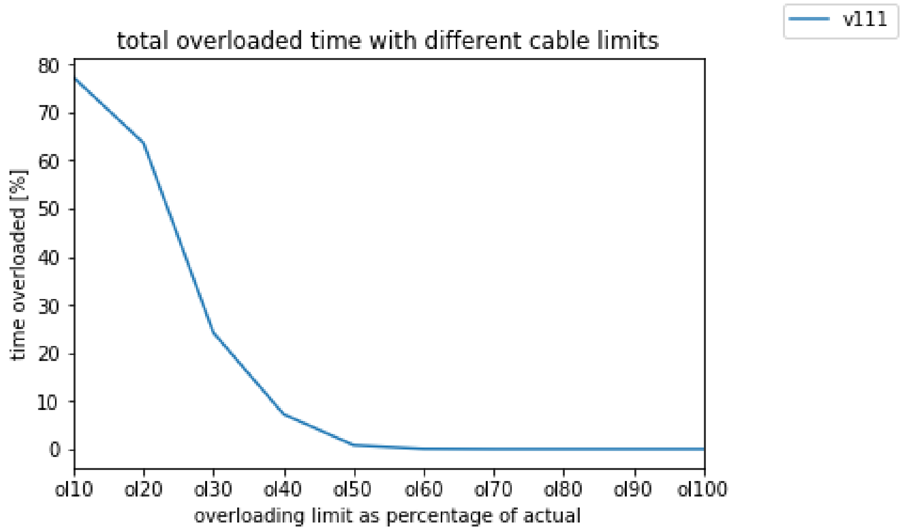




The loading of field 111 is a combination of the horticulture present in the area and the residential area. The general trends look like that of a residential area, but there are some drops to zero which indicates that there is also electricity generation from the horticulture area. The cumulative curve shows that the loading is slightly stepwise. There is a step slightly below 20A and then it jumps up to around 40A from where it gradually increases like a curve expected in a residential area. This could perhaps relate to settings of the cogeneration. When looking at may 11th during the day the graph touches 0, goes to 20 and later goes back to 0. It is easy to see that this part could be mirrored in the x-axis and actually is generation.



Congestion



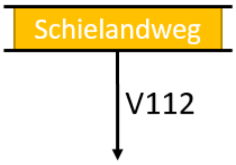
This field is still not loaded anywhere near the maximum capacity. However, there are regular peaks reaching about 40% of maximum capacity. With a large horticulture area already connected, there is potential for congestion in the future. When there are plans for increasing capacity of cogeneration it will not be hard to reach the rather limited capacity of 240A.

Flexibility

It is likely that the horticulture area has flexibility available that could be used in congestion management.

Category:

- Residential
- Horticulture



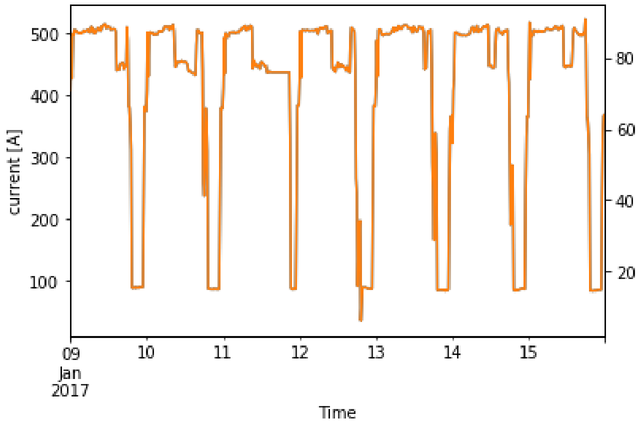
Field 112

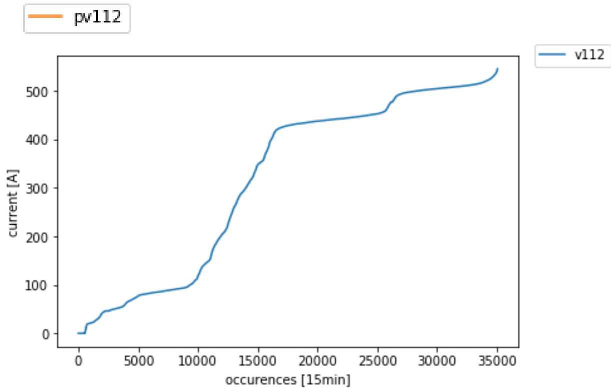
Field 112 is the only completely radially connected field in the grid, it is the only way to reach the customers in this area. The maximum capacity of the field is 575A

Geography and customers

This field only connects a single customer on the A. Kroesweg 34C. The connection is to a horticulture firm, just like all the other connections on this street.

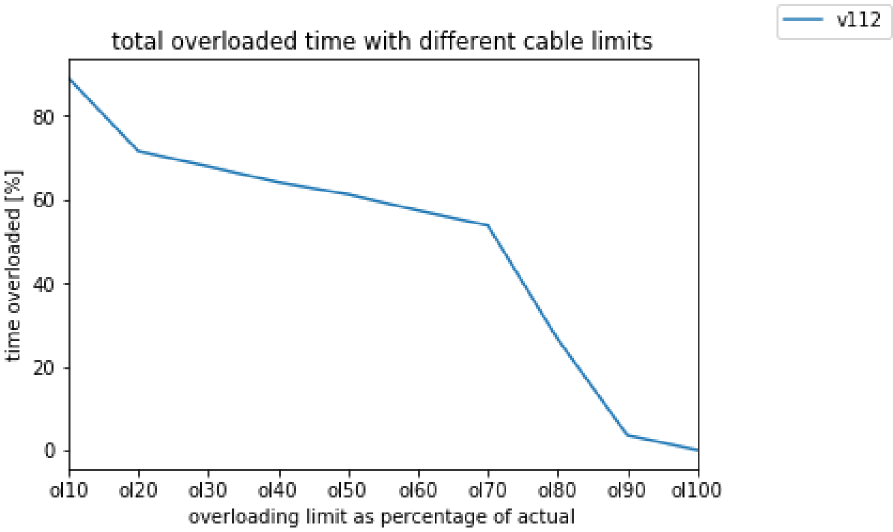
Loading





The loading of the field seems rather stepwise with steps of about 50A. The most common values are around 100A, 450A, and 500A. This can also be seen in the cumulative graph. This makes sense because it probably reflects the settings of the cogeneration of the single customer on this field. Probably all the loading that can be seen here is feeding electricity back into the grid. The loading is more erratic in winter than it is in May. This is probably because more heat/electricity is needed in the operation of the greenhouses, giving less consistent feeding to the grid.

Congestion



This field is the most heavily loaded field of the entire substation. The figure shows that over half of the time, the field is loaded for at least 70%, and it is even loaded over 90% in some occasions. There is no congestion now, but there is not much room for increases either. However, since this is only a single customer, they are probably aware of the limitations of their connection and a congestion problem will not occur unwarned.

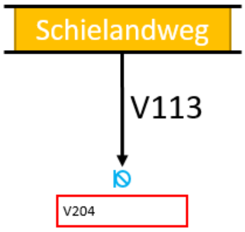
Flexibility

With such a single large customer on this field, there is a lot of flexibility available. The question is whether a single customer like this will function well in a market environment since they essentially monopolize the cable. They can play a role on the market by helping with congestion problems in other areas. But congestion on this specific field should be contractually avoided otherwise they could theoretically ask any price on the market to reduce capacity.

Category:

- Horticulture

Field 113

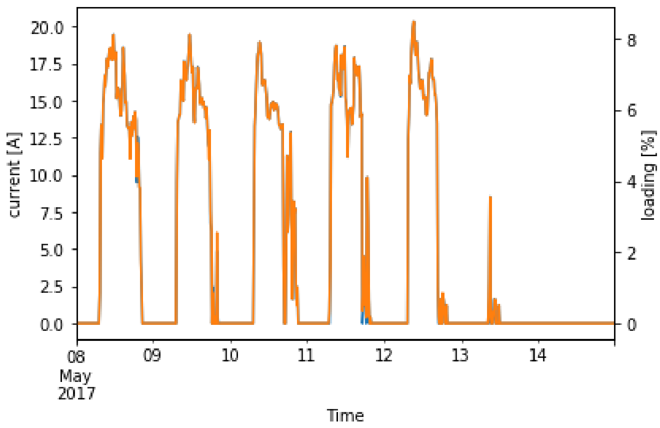


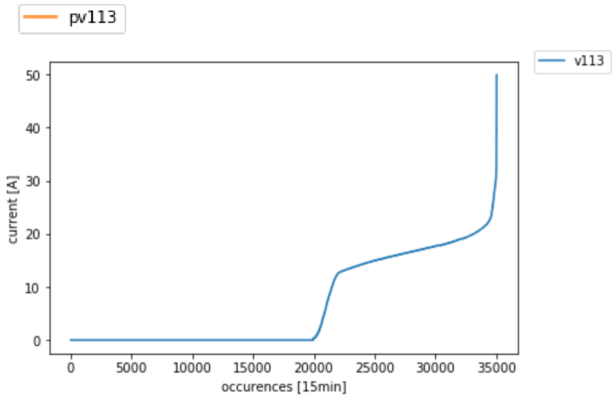
Field 113 is connected to field 204 in two points. The maximum current for the field is 240A.

Geography and customers

Field 113 connects a small residential area and the largest part of the industry complex in the north-east of Waddinxveen.

Loading





The loading of the field is quite structured. It is mostly only loaded during the day on workdays. The total loading is mostly around 17.5 to 20A, this can also be seen in the cumulative curve. Because it is mostly connected to an industrial area, it makes sense that the loading on weekends is less, but not that it is completely 0. Also because there is a small residential area connected. Either there must be generation available within the field, or this field is fed from another direction during off-peak hours.

Congestion

As can be seen from the loading graphs, the total loading does not even reach 10% of the maximum capacity, so congestion is not a problem on this cable. However, since it seems that this cable does not provide electricity for this area at all times it does not really give insight in the total consumption of this area. Therefore it is possible that the limit of this cable can be reached much easier than it seems right now.

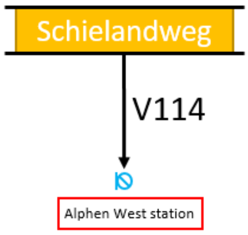
Flexibility

Usually, small industry complexes like these do not have much flexibility. Or they might have it, but do not have the means to make use of it. This means that if they have the opportunity to trade flexibility they might be willing to make an investment to allow them to do it (eg. A battery). However, this is not as straightforward as for horticulture companies which often have cogeneration already available and trading on the imbalance market is already a known source of income for them. Nevertheless, there might be some flexibility available that is less easily accessible than from horticulture, but easier than flexibility from residential areas.

Category:

- Residential
- Industry

Field 114

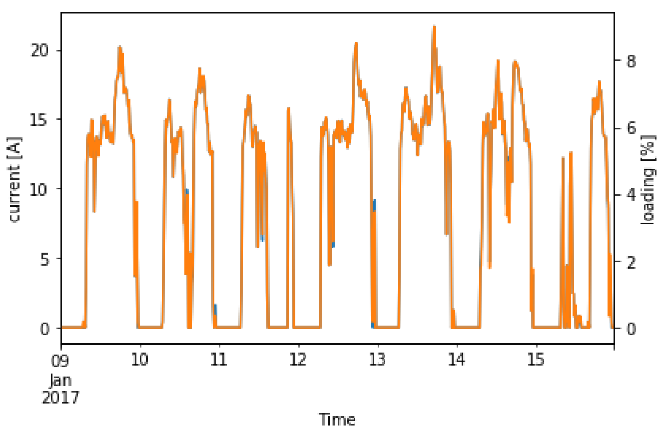


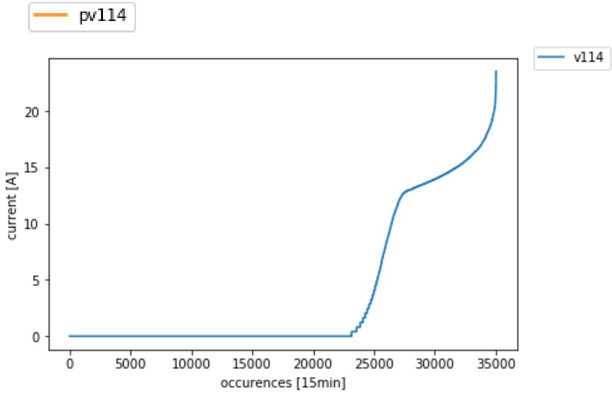
Field 114 is not connected to any other fields from the Schielandweg substation, but it is connected to the Alphen West station. The maximum capacity of the cable is 240A.

Geography and customers

Field 114 connects all the customers on the Noordeinde street. This street runs along the west side of Waddinxveen and runs all the way up to Boskoop. This is where it also connects to Alphen west, which is a 150kV-50kV substation from Liander.

Loading





The loading graphs show that this field is loaded mostly during the day, but still fairly irregular. The maximum loading hardly ever goes above 10% of the maximum loading of the line. This is a loading during the winter. When looking at a load profile from May, the loading will actually be much less with only very short and low peaks every other day. This indicates that this cable is only used when the demand is high, as more electricity is used in winter generally. When checking, it showed that that during a time when the current was 0, the connection to the other field was still open. This strongly suggests that there is generation in this field which supplies the total supply at these times. However, it seems that this is mostly a residential area with not much noticeable generation available.

Congestion

Congestion is not a problem in this field at this moment.

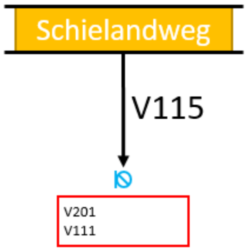
Flexibility

This is most a residential area, but perhaps the connection to the Alphen west field gives it a larger role to play. This is something to keep in mind for during the power flow studies.

Category:

- Residential

Field 115

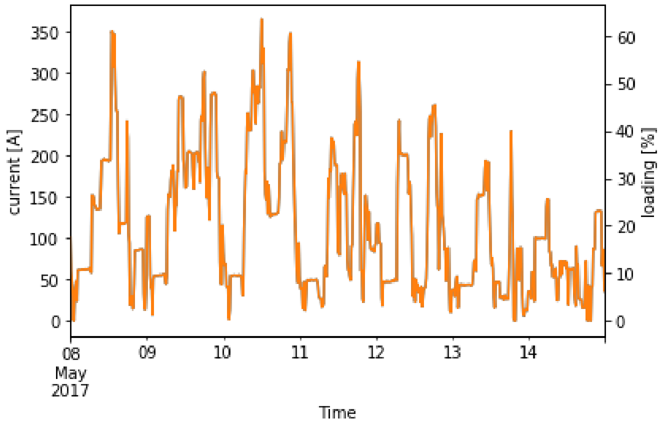


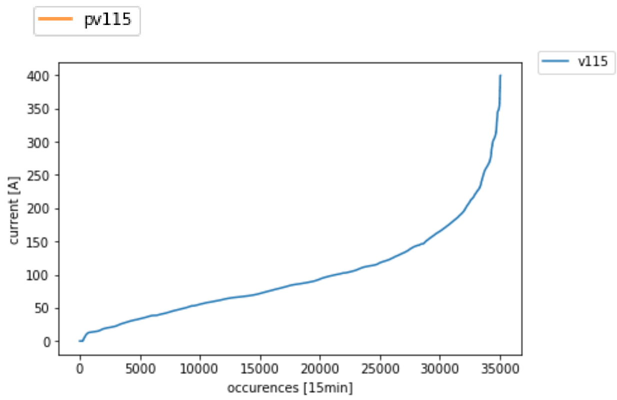
Field 115 is connected to field 201 and 111. The maximum capacity is 575A.

Geography and customers

Field 115 is also a field that connects to the horticulture area around the A Kroesweg, located to the south-west of Waddinxveen.

Loading





The loading of field 115 is highest during daytime, and drops during the weekend. The peaks seem to be centered around the morning and the evening but the overall profile is very up and down. This leads to the cumulative curve being very smooth, since there are no clear steps in the loading. The loading seems to be around 20% for the majority of the time, but peaks go to 60-70%. The loading is not 0 very often, but it is close to it often. This could mean there is a lot of switching between supplying and generating electricity, similarly to what can be seen in field 111.

Congestion

At the moment there is no congestion in the field. But if there are plans this could change quickly because cogeneration can have a large impact.

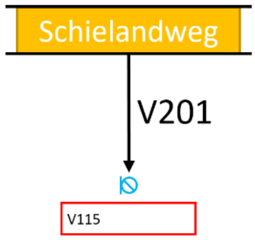
Flexibility

This field can play a large role in providing flexibility, and has flexibility available to solve its own congestion problems.

Category:

- Horticulture

Field 201

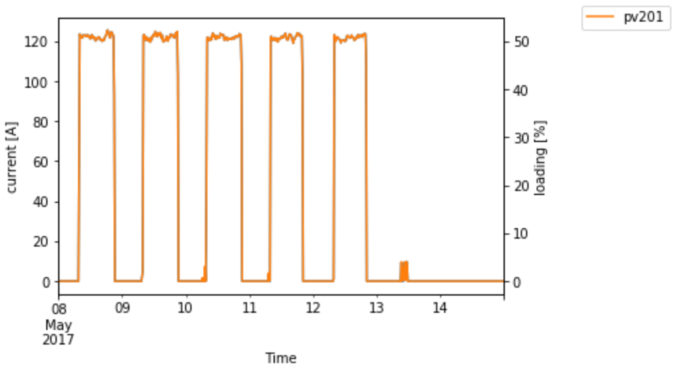


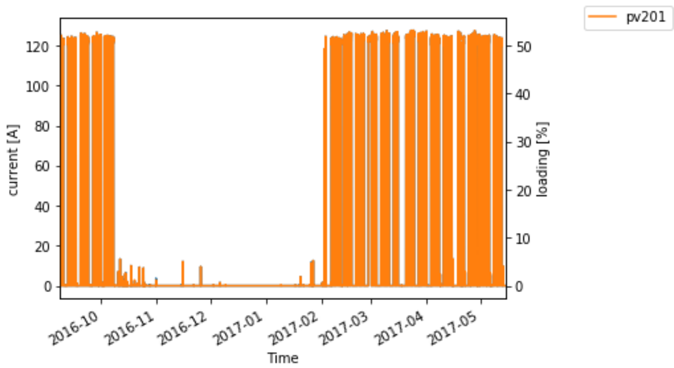
Field 201 is connected to field 115. The maximum capacity is 240A.

Geography and customers

This field connects to a small part of the same horticulture area as field 115. However, it connects only a single large horticulture customer. The other customers are agriculture without greenhouses.

Loading





As can be seen in the figure, the loading of this field is very regular. During the day, the loading of the cable is 120A consistently. During the night and the weekends the loading is 0, with some minor exceptions. Additionally, during the winter months there is almost consistently no loading either. A structured profile like this suggests that it is mainly the result of the actions of a single customer, similarly to what can be seen in field 112. However, there are some other customers connected as well. During the day they could be covered by the variations around the 120A. However, it seems unlikely that their consumption at night, during the weekends and the entire winter is 0.

Congestion

The loading of the field is either 0% or around 50%, without any meaningful peaks above that. This means that the connected capacity can be increased without risking any congestion.

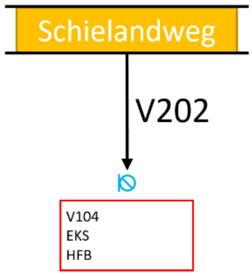
Flexibility

Again, this field has some horticulture connected, which probably has cogeneration available. The loading profile does not indicate that it is very flexible, but this could be the result of convenience and not a lack of flexibility options.

Category:

- Horticulture

Field 202

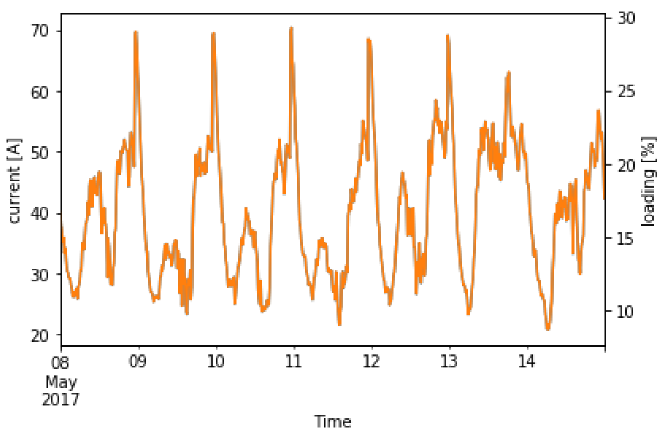


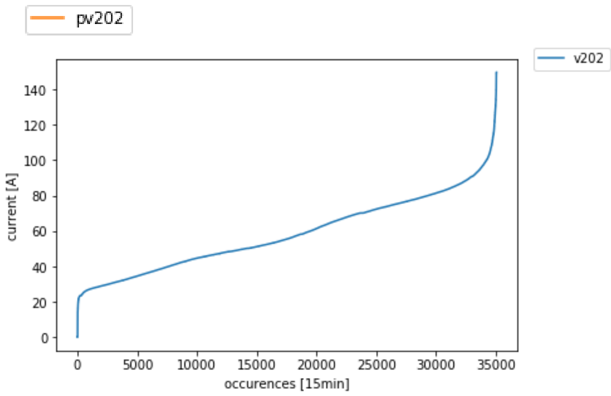
Field 202 is connected to field 104, and to the *Ekster* and *Hefbrug* substations. The maximum loading of the field is 240A.

Geography and customers

This field connects part of the residential area in the north of Waddinxveen. The majority of the customers in this field is residential

Loading





The loading of the field is consistent with that of a residential area, with peaks in the morning and evening. Additionally the loading never drops below 20%, which indicates no shifts to and from generation. This means that there is no significant generation in this field which at any point could be greater than the consumption.

Congestion

Congestion is not really a problem yet, but the peaks are very high compared to the average loading. This could pose a problem if the overall electricity use continues to grow in this residential neighborhood through use of e.g. electric vehicles.

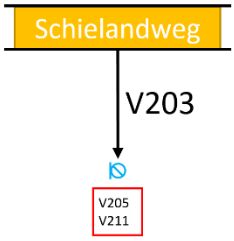
Flexibility

This seems to be a traditional residential area with little flexibility options. When electricity use starts to increase, the flexibility options will likely increase as well.

Category:

- Residential

Field 203

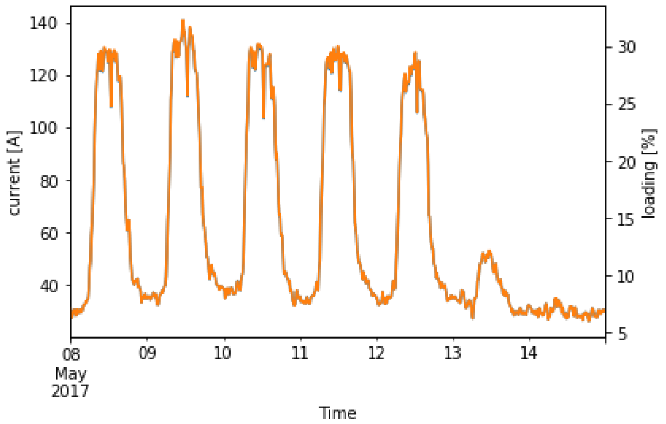


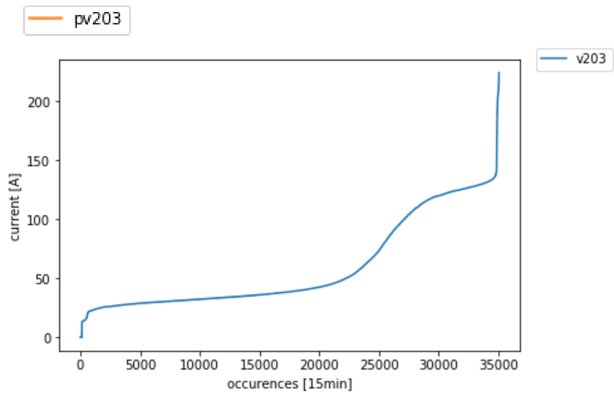
Field 203 is connected to the fields 205 and 211. The maximum capacity of the field is 435A.

Geography and customers

This field connects a large business park in the south of Waddinxveen. The customers are mainly offices and logistics centers because of a location close to the highway.

Loading





The loading of the field is consistent with the customer profile. There is a consistent loading during weekdays. During the night and weekends this falls back to a minimum baseload. The loading does not indicate the presence of large amounts of generation.

Congestion

The baseload is at around 5-10% of the maximum capacity of the field. The loading during the day is around 30%. There are hardly any peaks above this loading. There is no risk for congestions at this moment.

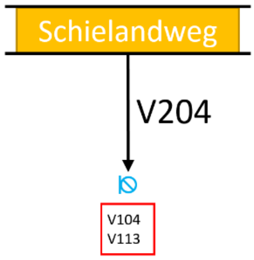
Flexibility

The customers in this field do not seem to make use of their flexibility at this moment, and their might be very little. However, companies might have the financial means to make investments in flexibility options if this could be beneficial.

Category:

- Industrial

Field 204

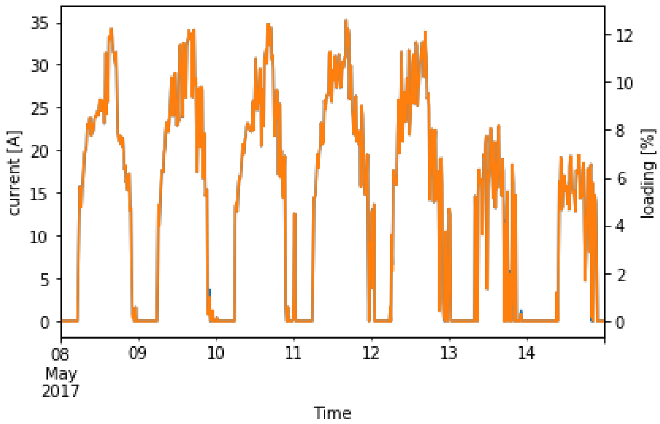


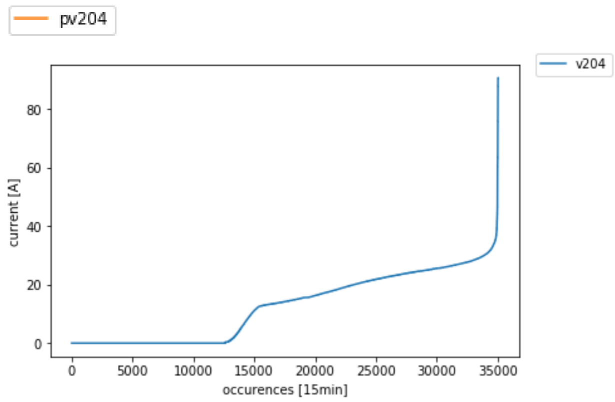
Field 204 is connected to fields 104 and 113. The maximum capacity of the field is 280A.

Geography and customers

The field covers a small area in the north of Waddinxveen. It is a combination of a small part of the business park situated there, and some apartment complexes.

Loading





The field has a similar loading to field 203, which is also connected to a business park. The difference is that this field falls back all the way back to zero during off-peak hours instead of remaining at base load. This suggests that there might be some generation available in the field to supply during these off-peak hours. The loading during peak hours is around 10-15% of the maximum capacity, depending mainly on the season.

Congestion

There is no congestion in this field.

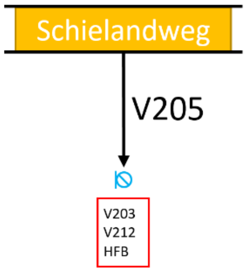
Flexibility

There seems to be some kind of generation already available which can provide for off-peak hours. Perhaps this flexibility can be used for congestion management as well.

Category:

- Industrial
- Residential

Field 205

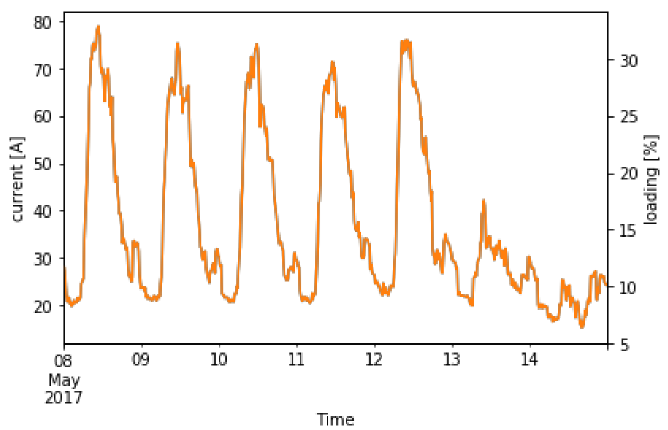


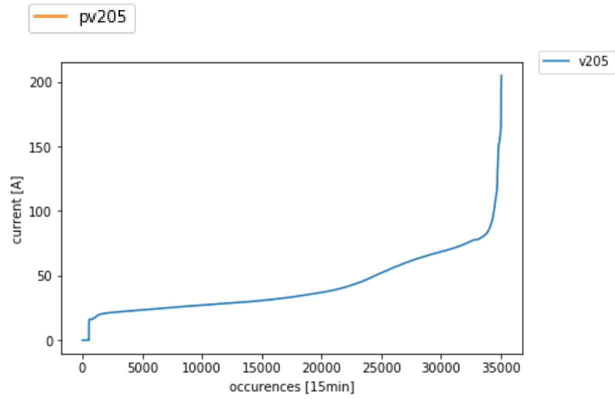
Field 205 connects to fields 203, 212, and to the Hefbrug substation. The maximum capacity of the field is 240A.

Geography and customers

This field connects a business park/industrial area in the south-west of Waddinxveen. There are some residential customers connected as well.

Loading





The Loading of this field strongly resembles that of field 203, with high peaks during weekdays and a low baseload at night and in the weekends. This field has more residential customers, which gives a small peak later in the evening and during the weekends.

Congestion

The base load uses about 10% of maximum capacity, and the peaks go to 30% of maximum capacity. This indicates that there is no indication that congestion will happen soon.

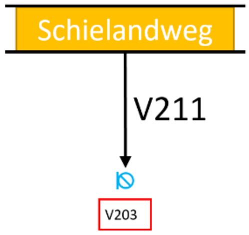
Flexibility

Similarly to field 203, there is not much flexibility available now but it is a good place to introduce flexibility because of the customer base and the capacity available on the cables.

Category:

- Residential
- Industrial

Field 211

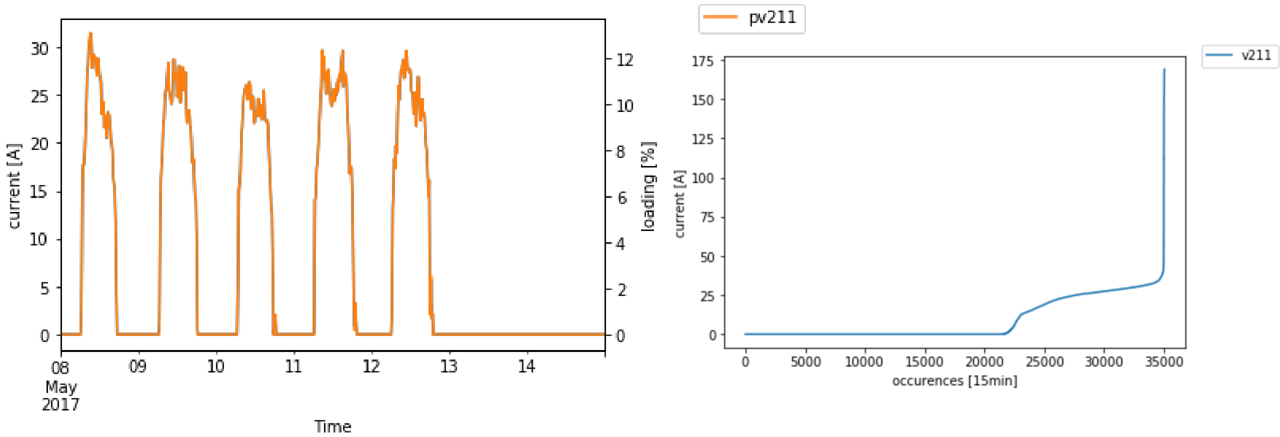


Field 211 is only connected to field 203. It has a maximum capacity of 240A.

Geography and customers

This field connects a part of the business park of which the rest is covered by field 203.

Loading



The loading of this field is very similar to that of field 204, except that there is no loading at all during the weekends. This raises similar questions to other fields which have such long downtime. How is the electricity supplied in the off-peak hours? Is it through generation, other fields, or is there really no electricity consumption at all.

Congestion

There is no congestion in this field, even during peak hours the loading is below 15% of maximum capacity.

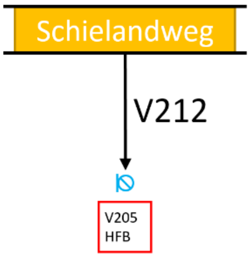
Flexibility

Similar to other fields connected to business parks, with flexibility possibilities.

Category:

- Industrial

Field 212

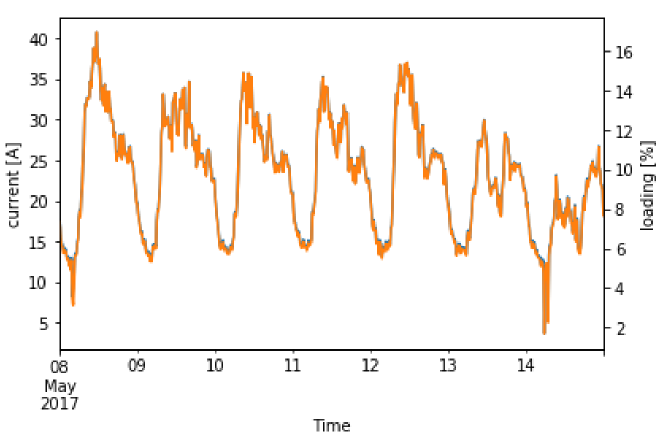


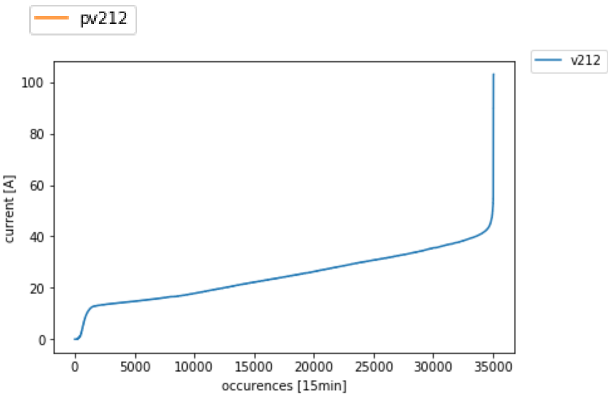
Field 212 is connected to field 205 and the *Hefbrug* substation. The maximum capacity of the field is 240A.

Geography and customers

This field connects a residential area in the east of Waddinxveen, just below the *Schielandweg* main station. It also has another small part of a business park connected to it.

Loading





The loading of this field is very similar to other fields that combine residential and industrial areas, such as field 205. The fact that the difference between the baseload and the peak is smaller than in field 205 shows that the contribution of the residential customers is relatively high. The contribution from the business park is shown by the fact that the peak during the day is higher than the peak at night.

Congestion

There is no congestion in this field. At peak load, less than 20% of the maximum capacity is in use.

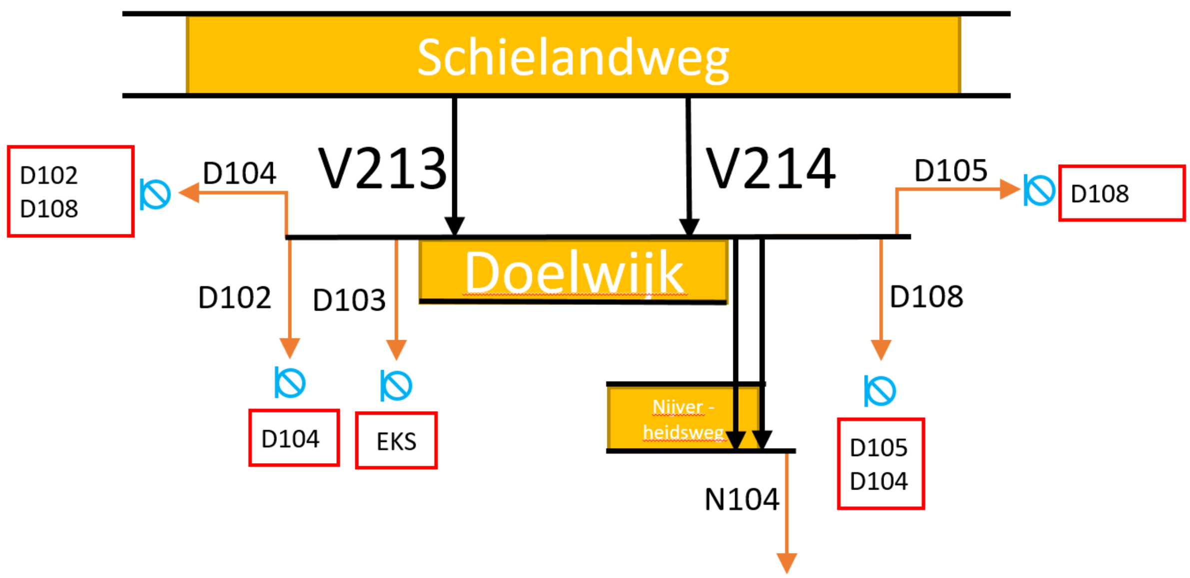
Flexibility

The same as for the other residential areas applies. Not much flexibility is available and investing might nog be viable for the residential area. The possibilities in the industrial area are better.

Category:

- Residential
- Industrial

Field 213 and 214

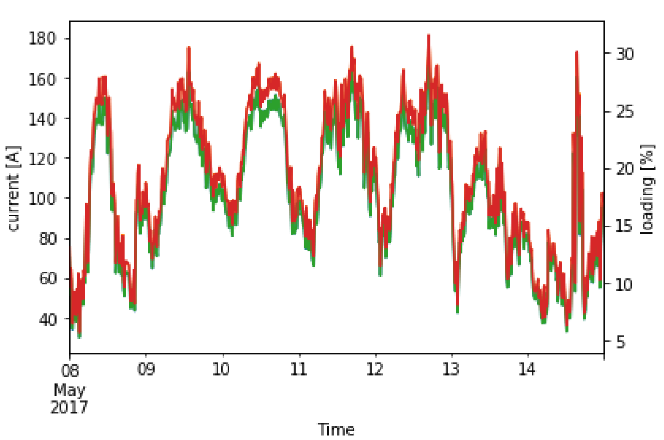


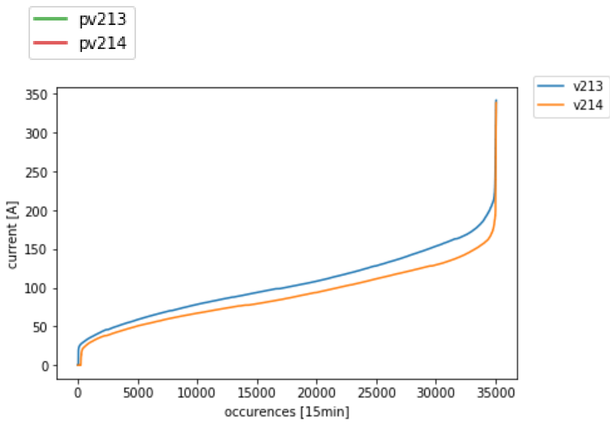
Field 213 and 214 connect to the third of the smaller substations that are connected to the *Schielandweg* station called *Doelwijk*. This substation has 5 outgoing fields of which 4 are only connected to each other. Field D103 is connected to one of the outgoing fields of the *Ekster* substation. Additionally, another smaller substation called *Nijverheidsweg* is connected to the Doelwijk substation. This small station is connected to the 4 wind turbines that are located here. The maximum capacity of field 213 and 214 is 575A each.

Geography and customers

These fields connect an industrial area called *LogistiekPark A12*. This is a logistics oriented industrial area situated next to the highway to the south of Waddinxveen. It consists mainly of transportation and distribution centers. There is generation available in the form of 4 wind turbines.

Loading





The loading of the field is what can be expected of an industrial area with high peaks during the day and a lower baseload at night. The load does not drop very low during the nigh which might suggest activity throughout the night which is not unexpected for logistics centers. The 4 wind turbines never produce enough electricity that the field is generating electricity as a whole. The peak loading of the fields is around 30%.

Congestion

There is no congestion in the field. Perhaps if many new customers are connected or if the companies start investing heavily into electric transportation congestion could become a problem.

Flexibility

Flexibility is available with the wind turbines, but these are just a small percentage of the total loading of the field. Perhaps investments can be made into renewable generation such as solar panels on the roofs and storage to provide the flexibility.

Category:

- Industrial
- Renewable generation

Conclusions

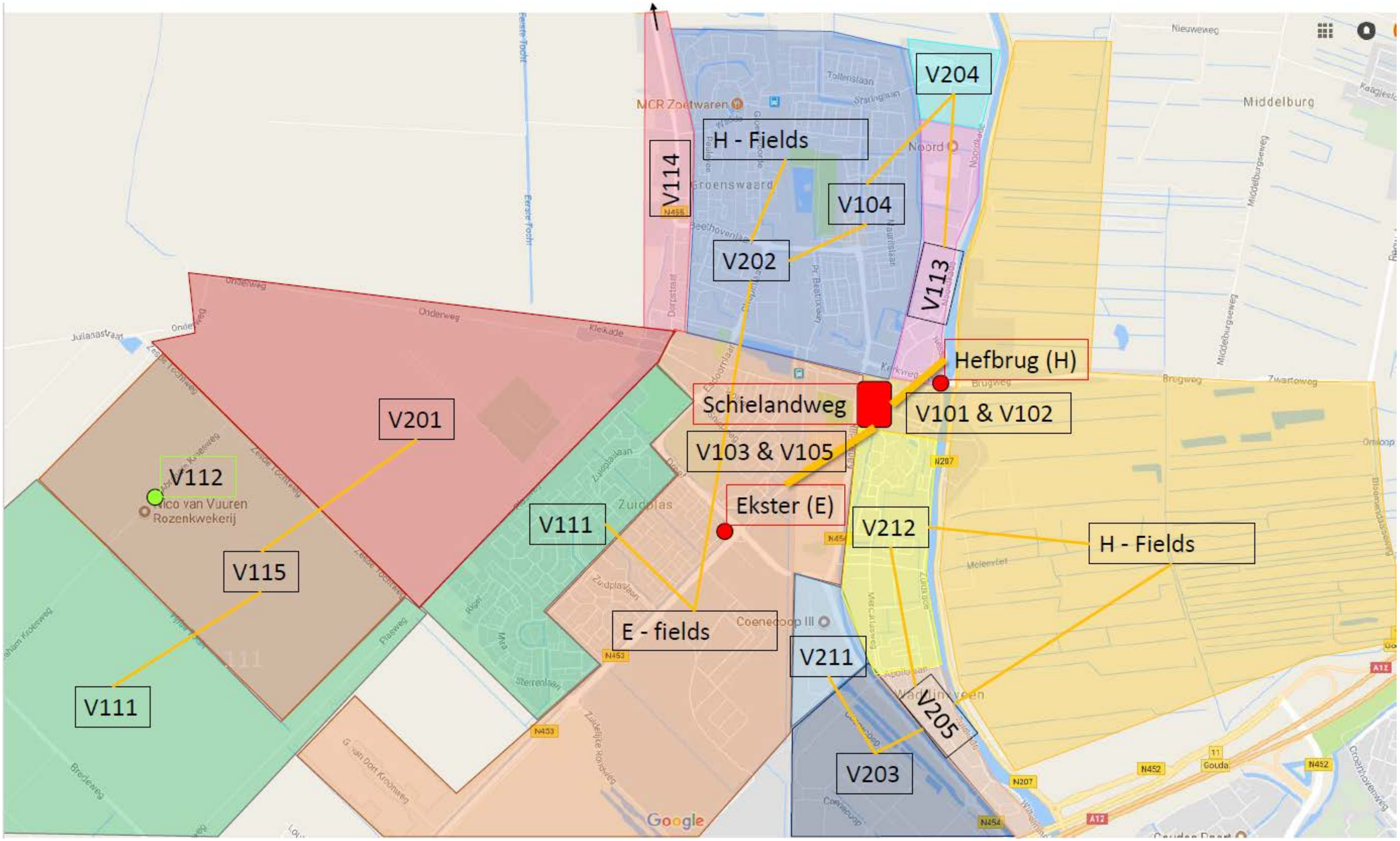
Having analyzed all the outgoing fields gives insight into the consumption patterns of the different types of actors. The next step is to analyze how these different actors can play a role in a potential congestion management market. The table below shows the division of the different categories.

Field\category	Residential	Industrial	Horticulture	Renewable generation	Agriculture	Other
101 & 102	■				■	
103 & 105	■		■			■
104	■					
111	■		■			
112			■			
113	■	■				
114	■					
115			■			
201			■			
202	■					
203		■				
204	■	■				
205	■	■				
211		■				
212	■	■				
213 & 214		■		■		

Residential, industrial, and horticulture are clearly the three largest actors in the different fields. Each of these three categories has a field where it is the only actor present. There are fields that combine residential and industrial, and fields that combine residential and horticulture. There are no fields that combine industrial and horticulture or fields that combine all three.

Something else that is of crucial importance in the operation of this network is the fact that it is a meshed network, but operated radially. This means that there might be switching options that can solve congestions before trading on the market is necessary.

In the figure on the next page the different outgoing fields are sketched schematically on a map. This gives an indication of how the different fields are connected. The narrow yellow lines between the different fields indicated where they are interconnected. But since the fields are operated radially, these connections are usually open. Field 213 and 214 are outside of the figure because they are much further to the south.


V204
H - Fields
V114
V104
V202
V113
Hefbrug (H)
Schielandweg
V101 & V102
V201
V103 & V105
V112
Ekster (E)
V111
V212
H - Fields
V115
E - fields
V211
V111
V205
V203
MCR Zoetwaren
Groenswaard
Noord
Middelburg
Nico van Vuuren Rozenkwekerij
Zuidplas
Coenecoop III
Google

Appendix III

Mock code

```
#import ETPA orderbook data
etpa1 = pd.read_excel('orderbook.xlsx')

#import the time-varying data for the loads of the grid
pset = pd.read_excel('loading_feeders_2022.xlsx', sheetname = 'pset', index_col='time')
qset = pd.read_excel('loading_feeders_2022.xlsx', sheetname = 'qset', index_col='time')

#import the names and positions of the different loads
loads = pd.read_excel('loads_total.xlsx')

#import the limits and positions of the cables
lims = pd.read_excel('cablelimits.xlsx')
feeders = pd.read_excel('Feeders.xlsx')

#import S-values of transformer
trafoS = pd.read_excel('trafoS.xlsx', index_col='time')


#Iterate through orderbook and assign position in grid to each order
bus = []
for index, row in etpa.iterrows():
    if row.trader_company == 6:
        bus.append(0)
    elif row.trader_company == 2:
        bus.append(1260)
    elif row.trader_company == 5:
        bus.append(1165)
    elif row.trader_company == 14:
        bus.append(1300)
    elif row.trader_company == 1:
        bus.append(1302)
    elif row.trader_company == 3:
        bus.append(1258)
    elif row.trader_company == 12:
        bus.append(1250)
    elif row.trader_company == 11:
        bus.append(1364)
    elif row.trader_company == 7:
        bus.append(1285)
    elif row.trader_company == 8:
        bus.append(1353)
    elif row.trader_company == 9:
        bus.append(1171)
    elif row.trader_company == 15:
        bus.append(1553)
    else:
        bus.append(0)
etpa2 = etpa.assign(bus=pd.Series(bus))
```

```python
#Iterate through every hour of the time-varying loads
for index, row in pset.iterrows():

    #PyPSA - import the buses, generators and lines from csv files.
    network = psa.Network()
    network.import_from_csv_folder("PyPSA\\total\\2022")

    #add the time-varying load to the PyPSA network topology
    time = row.name
    for index, row2 in loads.iterrows():
        loadname = "L{}".format(row2.bus)
        p = pset.loc[time,loadname]
        q = qset.loc[time,loadname]
        network.add("Load",name = loadname ,bus=row2.bus , p_set=p, q_set=q)

    #Determine if there is transformer congestion at this time
    S_time = trafoS.S.loc[time]
    Q_time = trafoS.Q.loc[time]

    if S_time >= S_max:
        tradeS = sqrt(S_time^2 - Q_time^2) - sqrt(S_max^2 - Q_time^2)
        #maximum trade is determined at 3MWh, otherwise downstream congestion would be too large
        if tradeS > 3:
            tradeS = 3

    #As long as the amount to be traded is not 0, start the function that tries to solve the transformer congestion
    while tradeS != 0:
            solve_Scong(tradeS, etpatijd, traded, tradedmax)

    #determine network topology and run the first powerflow.
    network.determine_network_topology()
    powerflow(network)

    #start function to calculate branch currents
    Icables = calcI(vmag_pf,vang_pf)

    #check which cables are congested - compare calculated branch currents with nominal values
    congested_lines = checkcongestion(Icables)

    #as long as there are congested lines, and they haven't been tried to be solved yet:
    while congested_lines.shape[0] != 0 and keep_solving:
        solvecongestion(indexcongline, bus0congline, bus1congline, currentcongline,
                                                nomcurrentcongline, etpatijd, solve_cable, traded, tradedmax)

        #rerun powerflow after every trade to determine new situation
        network.determine_network_topology()
        powerflow(network)

        #calculate branch currents and determine congested cables
        Icables = calcI(vmag_pf,vang_pf)
        congested_lines = checkcongestion(Icables)

    #save all the results
    trades = {'trader_company':trade_comp, 'bus':trade_bus, 'buy_sell':trade_buysell, 'quantity':trade_quant,
                'total_price':trade_price, 'start':trade_start, 'end':trade_end, 'price_Stedin':trade_priceStedin}
```

```python
#Congestion solving function

#solve a congestion, return value is a changed orderbook where the traded volumes are removed
def solvecongestion(index_line,bus0,bus1,cur,nomcur,etpanew, solve_cable, traded, tradedmax):

    #get all the buy and sell orders for a certain moment 'time' which is a global value defined outside of this function.
    buygood, sellgood = spreaddevelopment(time)

    #define the voltages of all the lines on bus0 and bus1 coming from the global values. bus 0 must always be upstream from bus1
    Vbus0 = vmag_pf[bus0]
    Vbus1 = vmag_pf[bus1]


    #determine the direction of the current. if the current is upstream, a BUY order is necessary downstream from congested point
    deltaV = float(Vbus0-Vbus1)
    if deltaV < 0:
        BUY = True
    elif deltaV > 0:
        BUY = False


    #determine on which feeder the congested line is
    cong_feeder = lims.Feeder.loc[index_line]
    #what buses are on the congested feeder
    x = feeders2[cong_feeder]
    #what is the index of bus1 of the congested line on the total feeder
    z = pd.Index(x).get_loc(bus1)

    #take all the buses that are downstream from bus1 of the congested line, and drop na's
    bus_congorders = x[z:]

    #if a buy order is necessary the orderbook must contain buy orders down- and sell orders upstream.
    if BUY:
        #iterate over all rows in the buy orderbook
        for index2, row2 in buygood.iterrows():
            #check if the bus of the order is present in the list of all useable buses. if not, drop it.
            if any(bus_congorders != row2.bus):
                buygood = buygood.drop(index2)

        #do the same for the sell orders but the other way around. drop it if it is at a downstream bus.
        for index2, row2 in sellgood.iterrows():
            if any(bus_congorders == row2.bus):
                sellgood = sellgood.drop(index2)

    #if a sell order is necessary the orderbook must contain sell orders down- and buy orders upstream.
    elif not BUY:
        #do opposite from above


    #sort orderbooks by price. high -> low for BUY. low -> high for SELL. reset the index.
    buygood = buygood.sort_values(['price'], ascending = False)
    sellgood = sellgood.sort_values(['price'])
```

```
#Trade on ETPA
    #determine what volume should be traded based on the absolute current overloading.
    deltaI = cur - nomcur
    P_trade = (deltaI*Vbase*np.sqrt(3)*1.05)/1000000
    if P_trade > 3:
        P_trade = 3

#select a buy order and filter orders from the sell orderbook that can be matched
    if BUY:
        tijdstart = buygood['order_creation'][0]
        tijdeinde = buygood['transaction_date'][0]
        sellgood = sellgood.loc[((sellgood['order_creation'] >= tijdstart) & (sellgood['order_creation'] <= tijdeinde)) |
                                ((sellgood['order_creation'] <= tijdstart) & (sellgood['transaction_date'] >= tijdstart))]
    elif not BUY:
            #Do opposite from above

 #Stop if there are no suitable buy or sell orders in the orderbook for this congestion.
    if (buygood.shape[0] == 0 or sellgood.shape[0] == 0 or tradedmax) and already_done == False:
        already_done = True


    elif already_done == False:

        #determine for the selected buy and sell orders what the quantities are, and which is the smaller one.
        if buygood['quantity'][0] < sellgood['quantity'][0]:
            quant = buygood['quantity'][0]
            smallisbuy = True
        else:
            quant = sellgood['quantity'][0]
            smallisbuy = False

        #If the amount to be traded is smaller than the lowest quantity, the whole trade can be made at once
        if quant > P_trade:

            #remove traded orders from orderbook
            trade_index_buy = etpanew.loc[(etpanew['order_id'] == order_id_buy)].index
            trade_index_sell = etpanew.loc[(etpanew['order_id'] == order_id_sell)].index
            etpanew.loc[trade_index_buy,'quantity'] = (buygood['quantity'][0]-P_trade)
            etpanew.loc[trade_index_sell,'quantity'] = (sellgood['quantity'][0]-P_trade)

            #add load with value of trade to the network before rerunning powerflow
            #buying is negative load
            network.add("Load",name = 'L{x}_{y}_{z}'.format(x = trade_index_buy[0], y=index_line, z=P_trade) ,
                        bus=buygood['bus'][0] , p_set=P_trade)
            network.add("Load",name = 'L{x}_{y}_{z}'.format(x = trade_index_sell[0], y=index_line, z=P_trade) ,
                        bus=sellgood['bus'][0] , p_set=-P_trade)

            #save trade
```

```
        else:
            #the order is smaller than the quantity to be traded
            order_id_buy = buygood['order_id'][0]
            order_id_sell = sellgood['order_id'][0]

            trade_index_buy = etpanew.loc[(etpanew['order_id'] == order_id_buy)].index
            trade_index_sell = etpanew.loc[(etpanew['order_id'] == order_id_sell)].index

            #remove traded instance from orderbook
            if smallisbuy:
                etpanew = etpanew.drop(trade_index_buy)
                etpanew.loc[trade_index_sell,'quantity'] = (sellgood['quantity'][0]-quant)
            else:
                #trade
                etpanew = etpanew.drop(trade_index_sell)
                etpanew.loc[trade_index_buy,'quantity'] = (buygood['quantity'][0]-quant)

            #add Load with value of trade to the network before rerunning powerflow
            #selling is negative Load
            network.add("Load",name = 'L{x}_{y}_{z}'.format(x = trade_index_buy[0], y=index_line, z=P_trade),
                        bus=buygood['bus'][0] , p_set=quant)
            network.add("Load",name = 'L{x}_{y}_{z}'.format(x = trade_index_sell[0], y=index_line, z=P_trade),
                        bus=sellgood['bus'][0] , p_set=-quant)

            #save trade

#return the new orderbook, amount of trades and if the maximum amount was traded
    return etpanew, traded, tradedmax

def solve_Scong():
    #Similar to above with slight adaptations to make suitable for transformer congestion.
```

Appendix IV

Traded and solved congestions – all model runs

	Congested hours	Traded hours	Unsolved hours	Solved hours	% traded	% solved of congestions	% solved of traded
2018	216	64	34	30	29.6	13.9	46.9
2019	918	276	173	103	30.1	11.2	37.3
2020	2106	610	510	100	29	4.7	16.4
2021	2452	863	713	150	35.2	6.1	17.4
2022	3138	1245	1083	162	39.7	5.2	13
2023	3436	1505	1348	167	44.1	4.9	11

Transformer congestions – all development scenario

	Congested hours	Traded hours	Unsolved hours	Solved hours	% traded	% solved of congestions	% solved of traded
2018	59	15	3	12	25.4	20.3	80
2019	74	28	6	22	37.8	29.7	78.6
2020	92	51	15	36	55.4	39.1	70.6
2021	155	97	20	77	62.6	49.7	79.4
2022	189	112	26	86	59.3	45.5	76.8
2023	215	130	45	85	60.5	39.5	65.4

Transformer congestions – existing development scenario

	Congested hours	Traded hours	Unsolved hours	Solved hours	% traded	% solved of congestions	% solved of trades
2018	8	1	0	1	12.5	12.5	100
2019	64	0	0	0	0	0	0
2020	240	7	0	7	2.9	2.9	100
2021	349	2	0	2	0.6	0.6	100
2022	485	8	1	7	1.6	1.4	87.5
2023	575	6	1	5	1	0.9	83.3

Feeder congestions – all development scenario

	Congested hours	Traded hours	Unsolved hours	Solved hours	% traded	% solved of congestions	% solved of trades
2020	4	0	0	0	0	0	0
2021	16	5	0	5	31.2	31.2	100
2022	20	2	0	2	10	10	100
2023	22	5	1	4	22.7	18.2	80

Feeder congestions – existing development scenario