PRICING HEAT IN AN OPEN HEAT NETWORK

Research into the application and effects of several pricing mechanisms and transmission loss allocation methods on the performance of a competitive wholesale market

by Joris Guichard

TU Delft

Delft University of Technology

Master's Thesis

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Research into the application and effects of several pricing mechanisms and transmission loss allocation methods on the performance of a competitive wholesale market

by

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PREFACE

Dear reader,

In front of you lies the Master's Thesis representing my final work as a student at Delft University of Technology. It can be described as the end of an eventful era, in which I have learned scientific and social skills, but was also given the opportunity to discover new things and evolve as a person. From my bachelor's onwards, I really had to grow into the 'studying' part of being a student, for several reasons. With perseverance and hard work I eventually picked that up and even managed to score a more than nominal amount of ECTS in the final year of my bachelor's. I was able to carry this through during my master's and wanted to end it on a high.

However, I've learned that highs become all the more appreciable when alternated by lows. I wanted to do a research project in which I could apply my modelling skills inside a sound theoretical context. Although I loved the subject, I noticed that the process of scoping this project and defining its context was more difficult and troublesome than I expected. This was partly attributable to the fact that some parts were unexplored territory, simultaneously making it very interesting. This resulted in my graduation process being a bumpy ride, but in the end I can say that I am happy with the end result. However, credits should go to several people as I could not have done it on my own.

Firstly, I want to thank Jesse Hettema and Frank van der Linden for giving me the opportunity to perform my research at energy company Eneco. The process of scoping was not straightforward, but thanks to our regular coffee meetings and occasional table tennis breaks you were able to steer me in the right directions. The result was this (rather exploratory) research, which will hopefully lay the foundation for future students to elaborate upon and provide you with even more knowledge in anticipation of the Heat Roundabout project.

Secondly, I want to thank my graduation committee at the Faculty of Technology, Policy and Management. Zofia Lukszo, Laurens de Vries and Pieter Bots, thank you for the feedback you provided me with, and for your support and understanding in the more difficult times. I want to thank Pieter in particular, since you have dedicated so many hours to helping me with defining and redefining the project, designing and modelling the algorithm and reporting it all. You have taught me a lot.

Last but not least, I want to thank all my friends and family that were around me the last year and supported me during this process. Also thanks to all my fellow interns at Eneco that I saw on a daily basis for the good conversations, support and fun that we had.

"All good things come to an end."

I hope you enjoy reading my Master's Thesis.

Joris Guichard,

August 15th, 2018

SUMMARY

Since heating forms a significant share of the Dutch primary energy consumption, it has been acknowledged as one of the most promising areas in which emissions can be cut back and the share of renewable energy can be increased. The Ministry of Economic Affairs has expressed this in the 'Heat Vision' by advocating a transformation of the natural gas provision system to a collective heat provision system. A relatively large share of the national heat consumption but also heat losses occur in the Province of Zuid-Holland, due to the presence of large industrial complexes such as the Port of Rotterdam and greenhouse horticulture. The Province recognises this supply and demand 'mismatch' and identifies it as an opportunity to integrate both by means of a regional heat network, also known as the 'Heat Roundabout'. The general objective of this regional heat network is to create a more sustainable (built) environment at the lowest possible social costs, by connecting existing district heating networks to different types of heat sources. Inherent to this objective is that the current heat provision system should evolve into a more 'open' network that facilitates the connection of potential new heat sources and create a more level playing field, while increasing transparency and economic efficiency.

District heating networks currently still lack competition due to a high degree of vertical integration, while long-term bilateral contracts are the main structure governing transactions between producers and suppliers. In order to achieve the objectives of the Heat Roundabout, the market should be organised differently. Although open heat networks are quite a novel phenomenon, a lot of exploratory research has been done, identifying the nodal pool model as most suitable for such a network and should fit the characteristics of heat best. One of those unique characteristics are the transmission losses, which are relatively large with heat and are not a function of the actual flows, as opposed to other energy carriers. Also, cost recovery of generation assets remains one of the obstacles that are inherent to organising a regional heat market according the nodal pool model. It is unknown how to deal with these transmission losses and in what way heat should be priced in order to allow for cost recovery while simultaneously pursuing affordability. This research therefore aims to increase the understanding of the effects of different pricing mechanisms and cost allocation methods on the performance of a heat market by answering the following main research question:

How would the application of Locational Marginal Pricing (LMP) to an open heat network affect the overall performance of this market, compared to alternative pricing mechanisms?

In order to facilitate a comparison of different pricing mechanisms on the overall performance of a heat market, market performance indicators were formulated based on insights obtained by an extensive exploration of the current system and the challenges relating to the Heat Roundabout project. From this exploration it was found that the main challenges amount to finding a balance in the trade-off between affordability and cost recovery, and to the allocation of transmission losses based on several principles that relate to fairness. This research focused on the overall market performance, not considering the actual investment decision. Therefore fixed costs of generation assets were not considered, and cost recovery was interpreted such that the pricing mechanisms would allow for a market surplus based only on the variable costs of generation.

In addition, a network model is required in which the economic dispatch can be determined. This model should facilitate the application of different pricing mechanisms and transmission loss allocation methods. Therefore, the model is twofold: it consists of a network model that determines the economic dispatch by means of linear optimisation and allows for simulating several existing

pricing mechanisms, and of an algorithm entailing an ex-post economic procedure capturing an alternative pricing mechanism that is proposed, including a transmission loss allocation method.

Due to the unique characteristics of heat and the relatively large amount of transmission losses, it was chosen to focus mainly on these transmission losses, and not on transmission congestion. Therefore storage and transmission constraints are assumed absent in the network model. Transmission losses in heat networks are a function of the difference between the outside temperature and the pipeline temperature, as well as the diameter and length of the pipeline. Although these differences tend to fluctuate following the different seasons, on an annual basis transmission losses are assumed constant in the network model. To build an understanding of the market performance, a relatively simple network was modelled of which the topology is mainly linear, comprising six nodes, five generators, five loads and five transmission segments where losses occur.

To explore and compare the effects of different pricing mechanisms on the market performance fifteen experiments were performed by combining:

- Five pricing mechanisms (incl. transmission loss allocation method if applicable);
- Three scenarios.

Four conventional pricing mechanisms were formulated: average cost pricing (ACP), system marginal pricing (SMP), locational cost pricing (LCP) and locational marginal pricing (LMP). Both average cost-based pricing mechanisms ACP and LCP were expected to perform best in terms of affordability, while both marginal cost-based pricing mechanisms SMP and LMP were expected to perform best in terms of cost recovery. In addition, an alternative pricing mechanism was developed to investigate if it would improve the market performance compared to the other pricing mechanisms: 'locational hybrid pricing' (LHP). This pricing mechanism was translated to an algorithm, and based on the starting points:

1. That it should find a balance in the trade-off between affordability and cost recovery;
2. That it should honour the fairness principle;
3. That it should reflect locational dependence of generation by assigning value to upstream generation (due to the unidirectional flow of heat);
4. That it should reflect locational dependence by incorporating costs of transmission losses;
5. That it should provide appropriate economic marginal signals to the market;
6. That it should be applicable to a network model in any possible configuration.

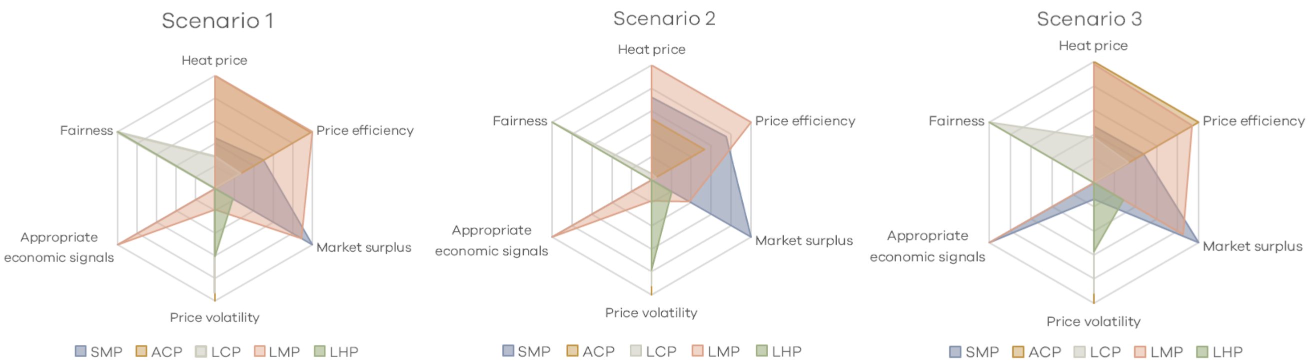
In terms of the allocation of transmission losses, a conventional method was formulated that mutualises all incurred costs over the entire system (loads) by including them in the system price, and applied to ACP. In addition, an alternative method was developed that allocates losses to the loads on the basis of their individual contribution to said losses, also based on the starting points mentioned above. This method was applied to LCP and LHP and also integrated into the algorithm. No transmission loss allocation method was applied to SMP and LMP.

The scenarios were formulated by varying three different parameters that are relevant in district heating systems. It was chosen not to perform a full factorial experiment design, since the purpose was not to evaluate the market performance's sensitivity to these parameters, but rather to provide a proof-of-concept of the model and show that it can be run in different scenario conditions, as well as to explore if the pricing mechanisms' relative performance changes or not.

Parameter	**Unit**	**Scenario 1**	**Scenario 2**	**Scenario 3**
Degree days	#	**2.902** (2012)	**2.675** (2015)	2.902 (2012)
Load sizes	%	100	100	**110**
G11 max. capacity	GJ	98	98	**298**

The results show that SMP and LMP both perform best in terms of cost recovery, as was expected, by creating the largest market surplus. ACP and LCP do not allow for any market surplus at all, while the LHP alternative comes in between by creating a relatively small market surplus. This holds in all scenarios. In terms of affordability it was found that ACP performs best in scenarios 1 and 3, characterised by relatively high demand i.e. more scarcity, closely followed by LMP. The combination of relatively small demand and the absence of any transmission loss allocation method however resulted in SMP and LMP performing best in scenario 2, yielding lower and more efficient prices than ACP on average. This is because the transmission losses are assumed constant and weigh more heavily on the total system costs in times of low demand.

The transmission loss allocation method that was developed in this research ultimately has a negative effect on the affordability, as became clear from the results of LCP and LHP. Compared to the other pricing mechanisms, LCP and LHP manage to perform better in terms of price volatility and honouring the fairness principles, however it was also found that the allocation methods produce inappropriate economic signals to the market because it allows for reducing prices by increasing volumes, and therewith total system costs.



Based on the results, it is concluded that LMP performs most consistently on both affordability and cost recovery, followed by ACP and SMP. The LHP alternative that was developed performed worst overall. It resulted in large differences between upstream and downstream nodes, giving the former large advantages over the latter. Referring to the starting points of LHP however, it is concluded that it satisfies most of them but only fails in (5) providing appropriate economic signals to the market. In general, the most important insights that were obtained are:

- SMP and LMP always allow for a certain market surplus, the opposite is true for ACP and LCP;

- LHP allows for a market surplus when following the perspective of the most upstream load in the generation assignment process;
- LMP and SMP do not include the costs of transmission losses and therefore prices may become lower and more efficient than ACP prices, given that ACP mutualises those costs;
- The principles used in the transmission loss allocation method cause large differences between downstream and upstream nodes for LCP and LHP;
- Pricing and allocating transmission losses on the basis of average costs creates economically sub-optimal incentives.
- The fixed nature of transmission losses reveal a strong dilemma between fairness on the one hand and economically efficient incentives and affordability on the other.

Ultimately this research has shown that different pricing mechanisms have divergent effects on the performance of an open heat market, and that its organisation is everything but trivial. The network that was modelled was however small and conceptual by nature. To add to the insights gained in this research and better put them into context of the Heat Roundabout it is recommended for future research to expand the network and incorporate transmission constraints and storage. To improve the understanding of the effect of different scenario conditions it is also recommended to systematically explore the sensitivity of the market performance to more variations of the scenario parameters. Since the algorithm has been designed such that it is applicable to a network in any configuration, it would also be interesting to explore if its performance can be improved by other ways of pricing generation and pricing/allocating the transmission losses by adapting several procedures in the algorithm.

CONTENTS

1. INTRODUCTION 1
1.1 Background 1
1.2 Problem exploration 2
1.3 Problem statement 4
1.4 Research questions 5
1.5 Research approach 6
2. TOWARDS AN OPEN HEAT MARKET 10
2.1 Theoretical exploration 10
2.2 System description 13
2.3 Performance indicators 19
3. MODEL CONCEPTUALISATION 24
3.1 The Nodal Pool model 24
3.2 Conventional pricing mechanisms 27
3.3 A hybrid pricing alternative 31
4. NETWORK MODEL 38
4.1 Model purpose and data requirements 38
4.2 Optimisation problem 41
4.3 Network configuration in Linny-R 42
4.4 Model verification 47
5. LOCATIONAL HYBRID PRICING ALGORITHM 54
5.1 General principles of the pricing algorithm 54
5.2 Mathematical basis 55
5.3 Designing the algorithm 58
5.4 Verifying the algorithm 61
6. EXPERIMENTS 66
6.1 Scenario parameters 66
6.2 Set-up of the experiments 67
6.3 Results of the experiments 70
7. DISCUSSION OF THE RESULTS 82
7.1 Relative performance of pricing mechanisms 82
7.2 Reflection on results 83
8. CONCLUSIONS & RECOMMENDATIONS 86
8.1 Main research findings 86
8.2 Contribution of this research 87
8.3 Recommendations 87
8.4 Reflection on research process 88
REFERENCES 90
APPENDICES 93

FIGURES

Figure 1 - Breakdown of Dutch energy consumption 2015. Figure is based on *Samenwerkingsverband Duurzame Warmte en Koude Zuid-Holland (2016*) 1
Figure 2 - Research flow diagram 6
Figure 3 - Model scheme 8
Figure 4 - Market design in infrastructures framework; based on Groenewegen (2005) 11
Figure 5 - Physical elements of a heat network 14
Figure 6 - Existing and planned heat infrastructure in Zuid-Holland 15
Figure 7 – Value chain of a heat network 16
Figure 8 - The current heat market organisation; based on *de Vries et al. (2010)* 16
Figure 9 - Field of stakeholders and their relations 17
Figure 10 - An integrated view of the current heat provision system by combining all components 20
Figure 11 - Nodal pool market organisation. Based on *de Vries et al. (2010)* 25
Figure 12 - Illustration of marginal pricing 27
Figure 13 - Composition of a locational marginal price 30
Figure 14 - Illustration of compensatory generation due to transmission losses 30
Figure 15 - Fictive economic dispatch (starting point) 34
Figure 17 - Assigning generation according 2nd perspective 35
Figure 16 - Assigning generation according 1st perspective 35
Figure 18 - Pricing of transmission losses by most expensive upstream generator 36
Figure 19 - Allocation of transmission losses to loads in proportion to their individual contribution to each loss 36
Figure 20 - Model scheme including data requirements 40
Figure 21 - Node configuration 42
Figure 22 - Load configuration 43
Figure 23 - Generation configuration 43
Figure 24 - Transmission configuration 44
Figure 25 - Network model in Linny-R 46
Figure 26 - Load curve 47
Figure 27 - Load duration curve 48
Figure 28 - Generation curve 48
Figure 29 - Generation duration curve 49
Figure 30 - Transmission loss curve 50
Figure 31 - Loss duration curve 50
Figure 32 - Locational hybrid prices in time-step 6070, including loss cost components 62
Figure 33 - Locational hybrid prices in time-step 897, including loss cost components 62
Figure 34 - Scatterplots of average outside temperatures and daily demand volumes 2012 and 2015 in same district heating network 66
Figure 35 - Histogram showing demand volumes and their occurrences annually (2012) 67
Figure 36 - Load duration curves for dataset in 2012 with reduced size (n=100) and original size (n-8784) 68
Figure 37 - Load duration curves of raw data in all scenarios 69
Figure 38 - Average annual heat prices in all scenarios 70
Figure 39 - ACP and SMP during high demand in scenario 1 70

Figure 40 - ACP and SMP during low demand in scenario 1 71
Figure 41 – LCPs per load during high demand in scenario 1....71
Figure 42 - LHPs per load during high demand in scenario 1 72
Figure 43 - Average annual LMPs per load in all scenarios including changes relative to scenario 1 72
Figure 44 - Average annual heat price efficiency in all scenarios 73
Figure 45 - Relationship between prices and price efficiency between SMP and ACP during low demand in scenario 1 74
Figure 46 – Average LCP price efficiency per load in scenario 1 and 2....74
Figure 47 - Average LHP price efficiency per load in scenario 1 and 2....75
Figure 48 - Average annual LHPs per load in scenario 1 and 2, including relative changes....75
Figure 49 - Annual market surplus in all scenarios....75
Figure 50 - Size of surplus relative to total costs of generation for SMP, LMP and LHP in all scenarios...76
Figure 51 - Market surplus mutations for SMP, LMP and LHP in scenario 2 and 3....76
Figure 52 - Market surplus vs generation curve for SMP, LMP and LHP in scenario 1 and 3....77
Figure 53 - Historical price volatility in all scenarios....78
Figure 54 - Prices for load 1 during high demand for all pricing mechanisms in scenario 1....78
Figure 55 - Price volatility for load 1 during high demand for all pricing mechanisms in scenario 1 79
Figure 56 - Price volatility for all loads during high demand in LHP in scenario 1 79
Figure 57 - LMP historical price volatility mutations per load in scenario 2 and 3....79
Figure 58 - LMPs for Load 1 during low demand in scenario 1 and 3....80
Figure 59 - Positive or negative scores on scenario-insensitive indicators for all pricing mechanisms....81
Figure 60 – Spider web charts with results in all scenarios scaled at 0-1 range....86

TABLES

Table 1 - List of research sub questions 5
Table 2 - List of market performance indicators....22
Table 3 – Comparison of most important facets of current and intended market model (Werkgroep Warmte Koude Zuid-Holland, 2015)....26
Table 4 - Summary of conventional pricing mechanisms showing benefits, drawbacks and loss allocation method (when applicable)....32
Table 5 - Price of generation resulting from both perspectives....35
Table 6 - Input data requirements for network model in Linny-R 39
Table 7 - Output data for network model in Linny-R....39
Table 8 - Variable costs and maximum capacities of generators....44
Table 9 – Elements of network model in Linny-R....45
Table 10 - Demand volumes in time-step 6070 (minimum) and time-step 897 (peak) 51
Table 11 - Transmission losses in time-step 6070 (minimum) and time-step 897 (peak)....51
Table 12 - Generation volumes and costs of dispatched generators in time-step 6070 (minimum) and 897 (peak)....51
Table 13 - System marginal prices in time-step 6070 and 897 52
Table 14 - Average cost prices in time-step 6070 and 897 52
Table 15 - Locational marginal prices in time-step 6070 and 897....52
Table 16 - Locational cost prices (excluding transmission losses) in time-step 6070 and 897 53
Table 17 - Locational cost prices of transmission losses in time-step 6070 and 897....53
Table 18 - List of main tasks of pricing algorithm....54
Table 19 - Pseudocode for the assignment of dispatched generation to transmission losses....59
Table 20 - Pseudocode for the assignment of dispatched generation to loads 60
Table 21 - Pseudocode for the allocation of the transmission losses to the loads 61
Table 22 - Computed costs of transmission losses in time-step 6070 and 897....62
Table 23 - Updated generation volumes after assignment to transmission losses....63
Table 24 - Assigned generation volumes from generators to loads and resulting price of generation in time-step 6070....63
Table 25 - Assigned generation volumes from generators to loads and resulting price of generation in time-step 897....63
Table 26 - Computed net total demand for each transmission loss in time-step 6070 and 897....64
Table 27 - Computed net individual contribution of each load to each transmission loss in time-step 6070 65
Table 28 - Computed net individual contribution of each load to each transmission loss in time-step 89765
Table 29 - Comparison between LHPs computed manually and generated by algorithm in time-step 6070 and 897....65
Table 30 - Weight factors for degree days in different months....66
Table 31 – Overview of quantified scenario parameters in all scenarios 69
Table 32 – Overview of fifteen different experiments that comprise the experiment design 69
Table 33 - Scorecard overview of results in all scenarios....82
Table 34 - Overall ranking of pricing mechanisms based on scorecard....83

1. INTRODUCTION

1.1 Background

The Paris climate agreement that was drafted in 2015 and effective as of November 2016 pursues to limit global temperature rise to a maximum of two degrees Celsius, while reaching global peaking of greenhouse gas emissions as soon as possible (UNFCCC, 2016). This agreement is now binding, and prescribes a leading role to more developed countries who have to adopt these goals into their own national policies. In terms of these emissions- and renewable energy targets, the Netherlands is lacking behind (Ministry of Economic Affairs, 2016). Research has shown that in order to reach the goals set out in the Paris agreement, our national CO_2 emission levels should be reduced by 80 - 95% in 2050, compared to the reference year 1990. Breaking down our primary energy consumption and CO_2 emissions it becomes clear that 44% and 41% can be attributed to **heating**, respectively. Within our heat provision system 80% of this energy is being provided by natural gas, which remains our primary fuel for the purpose of heating (Hoogervorst, 2017).

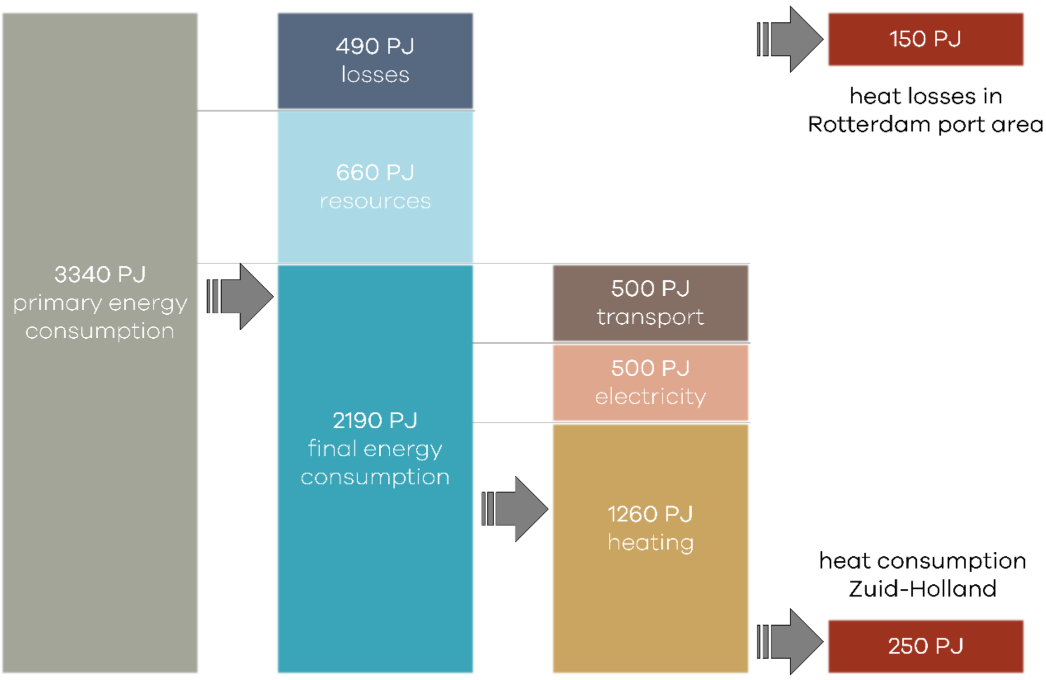


Figure 1 - Breakdown of Dutch energy consumption 2015. Figure is based on *Samenwerkingsverband Duurzame Warmte en Koude Zuid-Holland (2016)*

Evidently these statistics reveal significant opportunities in this corner of our national energy consumption in terms of cutting emissions. This has been acknowledged by the Dutch Minister of Economic Affairs, who recently expressed the 'Heat vision' (*Warmtevisie*), entailing the government's newly adopted stance toward our heat supply. Effectively it includes dramatically reducing our dependence on natural gas, as our domestic production slowly diminishes and further dependence on gas imports from politically unstable regions is considered undesirable (Kamp, 2015). Transforming our natural gas provision system to a collective heat provision system is therefore regarded as a policy priority, inherent to this vision.

Figure 1 illustrates that the Province of Zuid-Holland - home to large industrial complexes such as the Port of Rotterdam and big greenhouse horticulture - accounts for almost 20% of the national heat consumption, while more than 30% of losses in our primary energy consumption occur in the Rotterdam port area. The Province of Zuid-Holland recognises this supply and demand 'mismatch' and identifies it as an opportunity to integrate both by means of a regional heat network, also known as the 'Heat Roundabout' (Programmabureau Warmte Koude Zuid-Holland, 2015). Connecting existing district heating networks to industries' surplus heat production - that currently is still often emitted as a by-product - would be a start in cutting unnecessary losses and increasing overall energy efficiency. However, the ambition reaches beyond that as eventually the aim is to drive out fossil energy sources altogether, making place for renewable sources such as geothermal energy. The general objective of this regional heat network can be captured in short as: "*creating a more sustainable (built) environment at the lowest possible social costs*". In the pursuit of replacing natural gas altogether, four different sources for our future heat supply have been identified as most promising with respect to an integrated heat network (Werkgroep Warmte Koude Zuid-Holland, 2015):

- Geothermal energy;
- Residual heat (e.g. industrial waste heat);
- Local renewable sources;
- Power-to-heat.

Although the Dutch government supports this enormous project, our national heat provision was historically built upon our natural gas provision system. In this respect, path dependence raises difficulties in shifting from a natural gas provision system to a collective heat provision system, as lumpy investments are needed for the necessary infrastructure, accompanied by a high degree of uncertainty and thus risks. Nevertheless, district heating networks are not a novel phenomenon in the Netherlands. In 2009, Schepers & Van Valkengoed (2009) conducted a study on behalf of CE Delft in which they mapped all district heating networks already present in the Netherlands. Especially in the larger cities relatively large district heating networks are already present, such as Rotterdam, Leiden and The Hague. Networks in these cities will all take part in the Heat Roundabout project, as they are all located in the Province of Zuid-Holland. As an integral part of the aforementioned Heat vision, one of the key objectives of the Heat Roundabout project is to accelerate growth of the amount of consumers connected to district heating in the province (Programmabureau Warmte Koude Zuid-Holland, 2015).

1.2 Problem exploration

Inherent to the objectives of the Heat Roundabout project is the notion that the current heat provision system should evolve into a more 'open' network[1] with stronger market forces, in order to facilitate the connection of potential new heat sources as well as to create a level playing field while increasing transparency and economic efficiency. This vision somewhat resembles the liberalisation of the electricity and gas markets. But as the liberalisation process of those other energy markets at the time already showed, it is difficult to transform an existing market as a market design is often affected by 1) its starting conditions, 2) the physical, economic and institutional environment, 3) goals of the government and other actors involved and 4) the concepts of delayed feedback and bounded rationality (Correljé, de Vries & Knops, 2010). These aspects will be elaborated upon in chapter 2.

[1] An open network in this context is meant as a certain energy infrastructure which multiple producers and/or suppliers have access to. This is often called 'Third Party Access', or TPA.

Moreover, achieving this intended transformation of the existing heat provision system will be extra difficult as open heat networks are still a novel phenomenon, and for that reason there is a lack of available case studies. Nevertheless, a lot of exploratory research has already been done recently. These studies were performed and commissioned by different types of companies and organisations that are related to the heat chain. Ecofys (2015) has evaluated the possibility of open heat networks on behalf of Eneco, where they assessed three different market models on affordability, sustainability and reliability. In these market models Ecofys made a distinction between 1) TPA for producers, 2) TPA for suppliers and 3) TPA for suppliers with unbundling of network ownership. They concluded that a strong form of TPA for producers is most feasible in terms of stimulating the use of residual heat and renewable heat, provided that the main transmission network of the Heat Roundabout will actually be realised. Whether unbundling of network ownership is desirable depends on a trade-off between affordability and transparency, on which is noted that unbundling would probably increase heat prices and complicate the rise of decentral/local heat sources. Similar research has been done by PricewaterhouseCoopers Advisory (2015) on behalf of Nuon, drawing similar conclusions but attribute an important role to local governments in terms of participating in distribution networks in order to reach a certain degree of independency on the network.

Berenschot (2015), commissioned by network company Alliander, took a more integral approach and carried out a study into the potential of open heat networks in light of making the built environment more sustainable. They involved relevant stakeholders by means of workshops and concluded that TPA on a wholesale level would stimulate renewable and innovative heat production. Although Berenschot point out the importance of freedom of choice of the heat supplier experienced by consumers, they state that TPA on retail level would only be effective beyond a certain order of magnitude of a regional heat market. Additionally the concern of security of investment is coupled to the potential introduction of TPA, since a competitive market doesn't necessarily guarantee a long-term cash flow for investors as opposed to long-term bilateral contracts. In this light, Berenschot point out that more research is needed.

The Municipality of the Hague commissioned a study into the optimal market model for the local district heating network in the Hague, in which they compared existing district heating markets from New York, Copenhagen and Vienna. In their findings they attribute a leading role to the local government with respect to development and investment in the infrastructure, separating it from exploitation. In their optimal market model, which is meant to rapidly achieve an increase of customer connections and is not necessarily regarded as the desirable end-state model, TPA is advocated only on the production side as well (HWI, 2015).

Werkgroep Warmte Koude Zuid-Holland (2015), a workgroup commissioned by the aforementioned Program Agency consisting of incumbent parties from across the entire heat chain, have elaborated on their research into a feasible market model somewhat more than others. They found that the Nodal Pool model fits the characteristics of heat best, since transmission losses and CO_2 contents can eventually be included in the optimisation. In this market structure, the role of an independent system operator would be very large, as they would be responsible for dispatch and balancing via a central market place using optimisation algorithms. In their view, ownership doesn't necessarily have to lie with this system operator as well. They present two possibilities for recovery of investment costs for current network owners: 1) transport costs based on connected MW_{th} or

2) transport costs based on actual output GJ. The former would account for more security of investment than the latter, but a combination of both is also possible.

Apart from the aforementioned research (commissioned by mostly parties already incumbent in the respective heat markets) that focused specifically on the possibility of TPA to the network, relevance can also be derived from more policy related sources. Hoogervorst (2017) performed a study on behalf of the Dutch *Planbureau voor de Leefomgeving* in which the Dutch government's vision regarding carbon neutral heat networks is drawn, including potential policy instruments the government can utilise to achieve this vision. The Ministry of Economic Affairs (2016) has written a report that discusses the Dutch energy transition on a more aggregated level, of which a more renewable heat provision system is an integral part. Ecorys, Innoforte, Energy Finance Institute et al. (2016) have evaluated the 'Warmtewet' against policy targets regarding the Dutch heating system and also analysed potential future market structures for heat. Ultimately, recently written theses by van Woerden (2015), Oei (2016) and Bijvoet (2017) can provide additional important insights that they have already collected during their research into open heat networks.

1.3 Problem statement

After an exploration of the problem situation and relevant literature in the previous paragraph, several knowledge gaps can be distilled that point to interesting areas for elaborated research. Succinctly, most of the research that has already been performed point to the possibility of the introduction of Third Party Access onto a heat network that is originally 'closed' and governed by means of long-term bilateral contracts between producers and (vertically integrated) suppliers, such as Eneco. Moreover, Werkgroep Warmte Koude Zuid-Holland (2015) have identified the Nodal Pool market model as most promising and suitable for a regional heat network. However they state that still several important questions remain that require further research, reinforced by the fact that this particular market model has never before been applied to a heat network. This opens up opportunities to investigate this specific market model more deeply, considering the unique characteristics of heat compared to other utilities. The relevant knowledge gaps following from this are formulated as:

- There is a lack of insight into the overall system performance when applying the Nodal Pool model and locational marginal pricing to a regional open heat network compared to other possible pricing mechanisms;
- There is a lack of understanding of how to deal with the costs inherent to the characteristics of heat in the organisation of a competitive (wholesale) heat market;

These knowledge gaps can be translated to a comprehensive problem statement, forming the starting position of this thesis and the basis for relevant research questions:

There is a lack of knowledge regarding the optimal design of a regional heat market in the context of the heat roundabout in the Province of Zuid-Holland. Specifically, more knowledge is required about how the Nodal Pool model performs in different scenarios, comparing alternative pricing mechanisms.

While the aforementioned exploratory research and studies found in the literature point to many uncertainties still present in the context of the application of a market model that facilitates open heat networks (ultimately aiming to create a sustainable built environment that is carbon neutral in 2050), the Heat Roundabout project is still shaping up at the time of writing this thesis. In this light, the research is demarcated in such a way that the performance of different market organisations can be explored without considering the exact specifics of the existing – and still to be constructed – networks. The existing system will however be used as a case study for the purpose of conceptualising a model later on. In this light, the research will be focused on the wholesale market, also considering that the problem owner and commissioner of the research is Eneco, aiming to increase their knowledge regarding this market in different market organisations.

Referring to the problem statement that was mentioned above, the general objective of this thesis is:

To identify the most attractive pricing mechanism for a regional competitive heat market in the context of the Heat Roundabout.

In order to achieve this objective, a heat network will ultimately be represented by a running (economic dispatch) model. By means of such a model the performance of the Nodal Pool market model can be investigated by simulating different scenarios and investigating different pricing mechanisms. Naturally, findings from the simulations will be translated to workable recommendations.

1.4 Research questions

The main research question logically follows from the problem statement identified in section 1.3 and is as follows:

How would the application of Locational Marginal Pricing (LMP) to an open heat network affect the overall performance of this market, compared to alternative pricing mechanisms?

This question can be broken down into the following sub-questions, providing structure and a clear demarcation of the system to be analysed:

1.	What relevant characteristics differentiate heat and heat provision systems from other utilities?
2.	What are the relevant characteristics of the Nodal Pool market model?
3.	In what way can the Nodal Pool model and Locational Marginal Pricing be applied to a heat network?
4.	What is the effect of Locational Marginal Pricing and alternative pricing mechanisms on the system performance of the wholesale market in different scenarios?

Table 1 - List of research sub questions

1.5 Research approach

In order to derive answers to the research questions from section 1.4, a structured approach will be followed during this thesis. Textbook systems engineering processes defined by Sage & Armstrong (2000) usually consist of three phases: Formulation, Analysis and Interpretation. During this research this approach has been slightly adapted. It is depicted in figure 2 and will consist of the following phases, comprising the outlined activities:

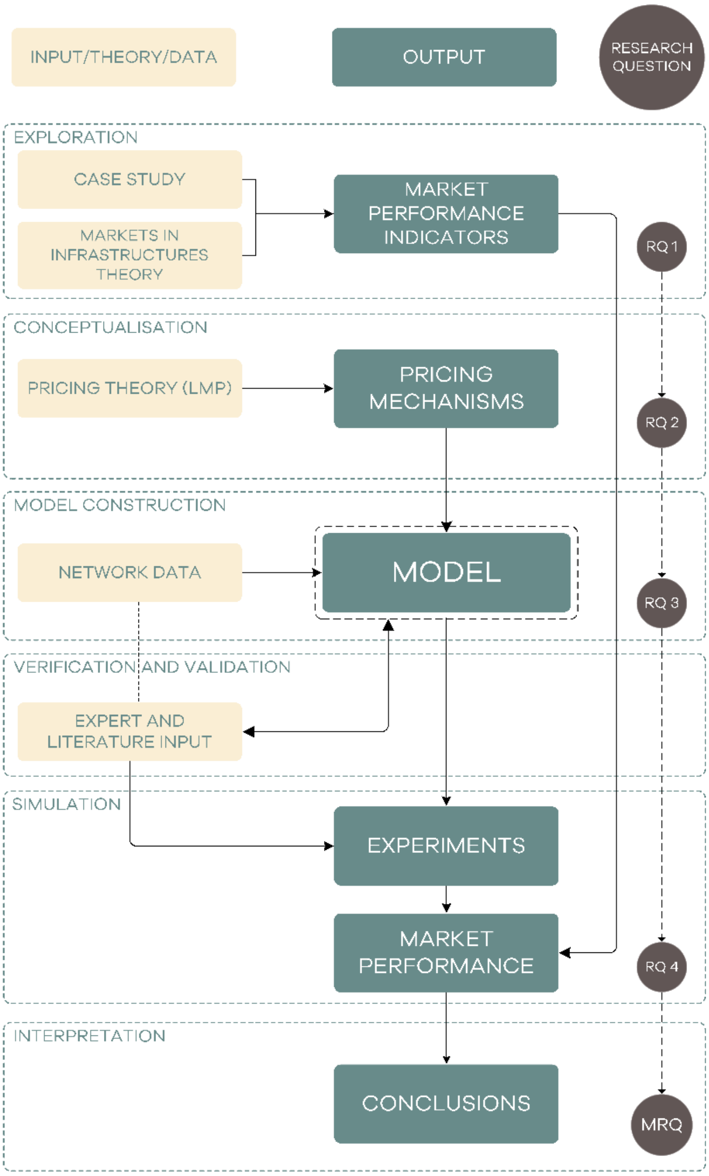


Figure 2 - Research flow diagram

1.5.1 Exploration

The first phase intends to explore the distinct qualities of heat and heat systems compared to other utilities by means of a literature study, as well as to collect information regarding the objectives underlying the choice for the nodal pool model as market configuration for an open heat network. This includes theory dealing with market design in infrastructures, based on Groenewegen (2005), applied to the existing heat networks in Zuid-Holland which will be used as a case study. The exploration essentially has been partly done in section 1.2, elaborated in section 2.1 in which also the focus of this research with respect to the theory and the accompanying methods is further discussed. Ultimately, based on the insights gathered and on the formulation of an answer to the first research question, relevant performance indicators on which potential alternative pricing mechanisms can be tested will be specified upon completion of this phase.

1.5.2 Conceptualisation

The conceptualisation phase firstly intends to identify the most important characteristics of the nodal pool model in view of applying it to a model of a heat network. In this light, the emphasis is on the working principle of nodal pricing as well as the second research question about how it can be applied to a heat network as a pricing mechanism. In the further conceptualisation, several alternative pricing mechanisms that are known from practice will be discussed, while a new pricing alternative is proposed for the purpose of investigating how it performs on the market performance indicators in relation to the other pricing mechanisms.

1.5.3 Model construction

This phase comprises the specification of a network model, that aims to facilitate the comparison of different pricing mechanisms and their performance on the wholesale market based on the performance indicators. Economic performance is often strived for by minimisation of production costs, as pointed out by Groenewegen (2005). Since not all production units in such a network have the same production costs, the challenge inherent to cost minimisation is the optimal allocation of the total demand among the production units (Lukszo, 2015). In other words, the least-cost economic dispatch should be determined by the model, asking for an optimisation model.

In most cases these production units are also characterised by their own respective start-up time and –costs, as well as ramping time and –costs. Such production systems usually also include temporary storage facilities that can buffer heat when it is cheap while discharging it when prices rise again. Including these parameters would amount to a Unit Commitment (UC) problem, as described by Tahanan, van Ackooij, Frangioni, & Lacalandra (2015), which are solved with Mixed Integer Linear Programming (MILP). However, this research places the emphasis on the effect of different pricing mechanisms and inherent cost allocation methods *given* a certain allocation of demand over the production units, while focusing on the distinctive properties of transmission losses with heat systems. Within this scope, as time-dependence is assumed absent, this problem will therefore be framed as a classic Economic Dispatch (EC) problem, which will be solved by means of Linear Programming (LP). The software tool Linny-R will be used to solve this problem, as it provides a sophisticated and user-friendly environment in which production systems can be modelled as processes that have products as input and output (Steep Orbit, 2013). In the construction of this model, several choices will be made relating to the configuration of the network, discussed in chapter 4. This will be done according to several data relating to the infrastructure of the network, which will also be discussed in chapter 4.

In addition to the network model, the proposed pricing alternative will be translated to an algorithm that performs the ex-post pricing of heat and the allocation of transmission loss costs to the loads. The choice for an algorithm is explained by the fact that Linny-R merely determines the least-cost dispatch by minimising total system costs, not considering pricing mechanisms potentially in place. Therefore Linny-R is not suitable for the determination of prices and allocation of incurred costs. Algorithms on the other hand are an algebraic tool that allow for conditional programming that may include multiple iterations, and are a relatively effective instrument to describe a certain problem in a logically oriented way. Besides, they provide the possibility to process large amounts of data in an efficient manner.

Different mathematical tools can be used for the construction of such an algorithm. In this thesis Maple has been chosen, as it includes built-in packages such as GraphTheory, which will be helpful in reproducing the network model from Linny-R into Maple, as well as several other powerful pre-specified functions that increase the usability in light of this particular subject (Maplesoft, n.d.). Based on the principles and choices discussed in the conceptualisation in chapter 3, this algorithm will be presented in chapter 5. It should be noted that the entire model, corresponding to the circled model 'block' from figure 2, thus consists of multiple different iterations which are clarified in the model scheme in figure 3.

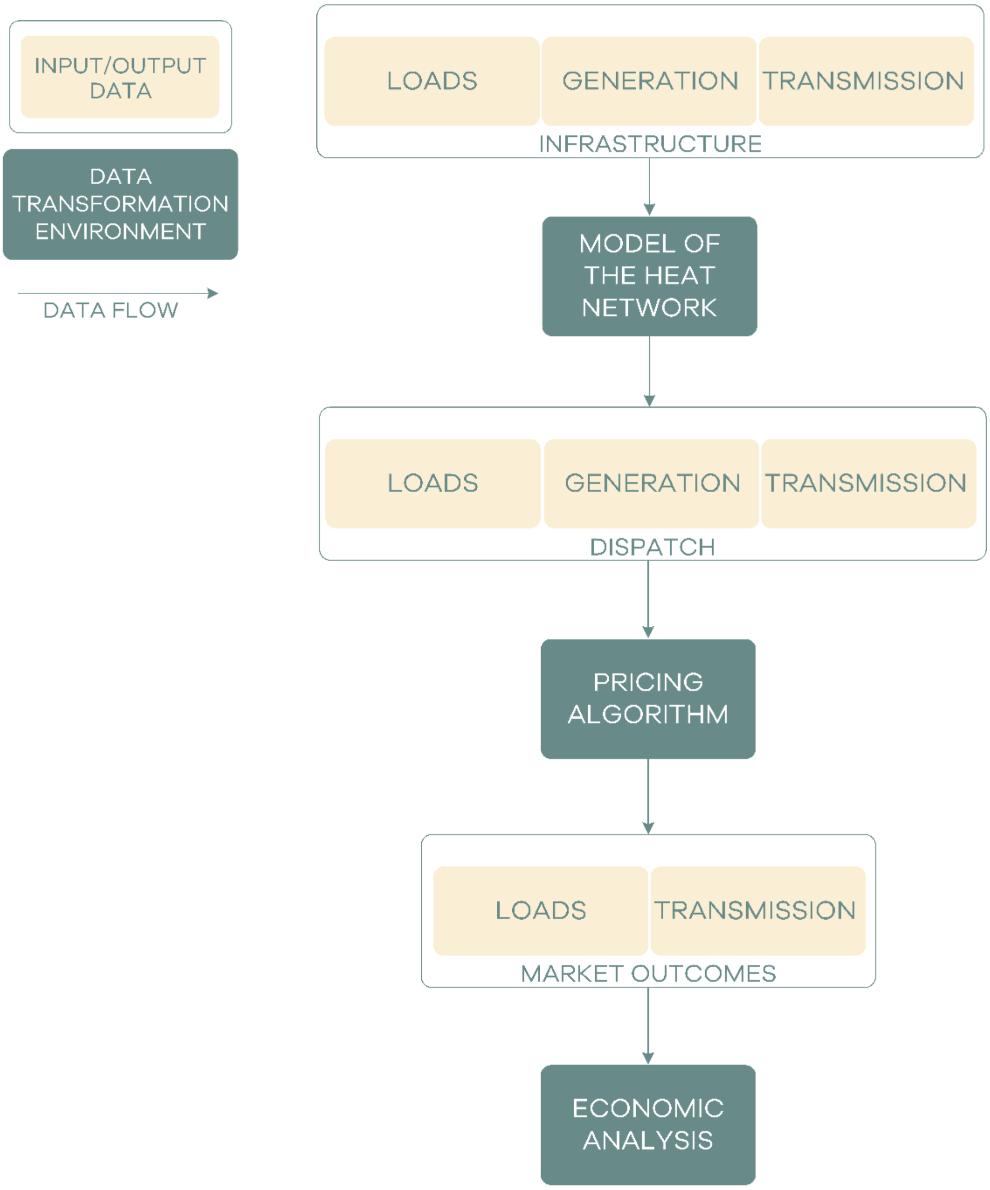


Figure 3 - Model scheme

1.5.4 Verification

Once the network model and the algorithm have been constructed, it will be verified that they both work correctly on the basis of the data used. The network model will be verified by explaining its behaviour that is generated by and based on the input data, while the data generated by the algorithm will be verified by checking the calculations manually in two extreme value cases on the basis of the proposed principles underlying the algorithm. This phase will be performed and presented in chapters 4 and 5, following the network model and the algorithm.

1.5.5 Simulation

For the purpose of simulating the wholesale market and alternative pricing mechanisms, this phase deals with the set-up of several scenarios. These scenarios will be formulated by specifying several variables relating to the input data of the network model of which the values are varied in each scenario. Ultimately, three different scenarios will be presented in which the market can be simulated. In combination with the different pricing alternatives, this will produce a certain amount of experiments that should produce insights into the market performance and enable the answering of research question 4. The design of the experiments is discussed in chapter 6, as well as the results following from the simulations.

1.5.6 Interpretation

Lastly, the results will be interpreted by consulting the experiments' performances on the specified performance indicators, and discussed in chapter 7. The insights obtained from these results will be translated to relevant conclusions and provide the means to answer the main research question in chapter 8, followed by some suggestions for further research.

2. TOWARDS AN OPEN HEAT MARKET

In this chapter firstly several strands of the literature relating to market design and locational marginal pricing are explored, after which the focus of this research will be presented. Secondly, for the purpose of producing an answer to the first sub-question, the most important characteristics of heat and heat provision systems will be discussed on the basis of a case study of the current heat provision system in Zuid-Holland. Ultimately, insights obtained from this system description will lead to the formulation of several market performance indicators in the final paragraph.

2.1 Theoretical exploration

2.1.1 Market design

As was already briefly mentioned in section 1.2, market design is often affected by (Correljé, de Vries & Knops, 2010):

1. its starting conditions;
2. physical, economic and institutional environment;
3. goals of the government and other actors involved;
4. delayed feedback and bounded rationality.

In this light, it is emphasised that the restructuring of a market is a dynamic process as markets are never in equilibrium. The market 'design space' is hereby constrained by the *starting conditions* of the market which are (partly) determined by the *physical, economic and institutional context* of the system. This design space is comprised of different design variables, as described by Correljé & de Vries (2008). Depending on the *objectives of the government* and other policy makers these variables are chosen in such a way that the right incentives are put in place, creating the environment in which market parties can operate and make their decisions, ultimately producing the desired market outcome (Williamson, 1998). The dynamics of the market design or restructuring process are also illustrated by the concepts of *delayed feedback* and *bounded rationality*. Inherent to this process is a certain time delay after which the market outcomes are being fed back into the restructuring or design process, making it impossible to design the 'perfect' market. Additionally, bounded rationality describes the notion that market actors are expected to act rationally but sometimes may fail to do so due to incomplete information or act unexpectedly out of e.g. opportunism (Williamson, 1998). These phenomena thus strongly impact the market outcomes and indirectly the process of restructuring a market.

As Groenewegen (2005) explains in his paper, the notion that the introduction of 'more market' and less government when designing a market leads to higher economic efficiency doesn't always uphold. This notion can strongly be attributed to the domain of economics, as it essentially advocates minimisation of (production) costs. This domain refers to the production of goods and services seen from the macro-level, meso-level and micro-level (Groenewegen, 2005). But when dealing with large infrastructures, economics is not the only domain that is of influence on the performance of the market that was designed.

The domain of institutions, as opposed to economics of production, focuses on minimisation of transaction costs. The institutional domain is therewith comprised of institutions on different levels as well; informal institutions, formal institutions and the level of institutional arrangements. This is the domain that touches upon the essence of market design: coordination of transactions. But both domains are interrelated to the technological domain, according to Groenewegen (2005) “being the basic understanding of how to engineer the physical environment” (p. 2), followed by the technical artefacts and operationalisation of the system located at the lower levels in this domain. Ultimately, different types of actors, both public and private, play an important role in the system and interact with all the components, and each other. Markets in infrastructures therefore comprise systems that are characterised by being multi-disciplinary, multi-level and multi-actor. Following from these notions is a comprehensive framework by Groenewegen (2005), presented in figure 4, by which systems of markets in infrastructures can be described and designed.

Both strands from the literature emphasise the dynamic nature of the market restructuring process and the interrelatedness of all components that are inherent to the functioning of an energy market. In section 1.2 however it was already pointed out that a certain market model was identified to fit the heat market best: the nodal pool model. This means that a large part of the theoretical design space of the heat market has already been filled in. In other words, the nodal pool market model is assumed to be in place, while the focus is put on the effect of different pricing mechanisms and cost allocation methods on the performance of the market. Therefore a more static approach is used with respect to the market design, not considering the aforementioned concepts of bounded rationality, delayed feedback and transaction costs. In this sense, the emphasis lies more on the ‘product’ than on the process of market design.

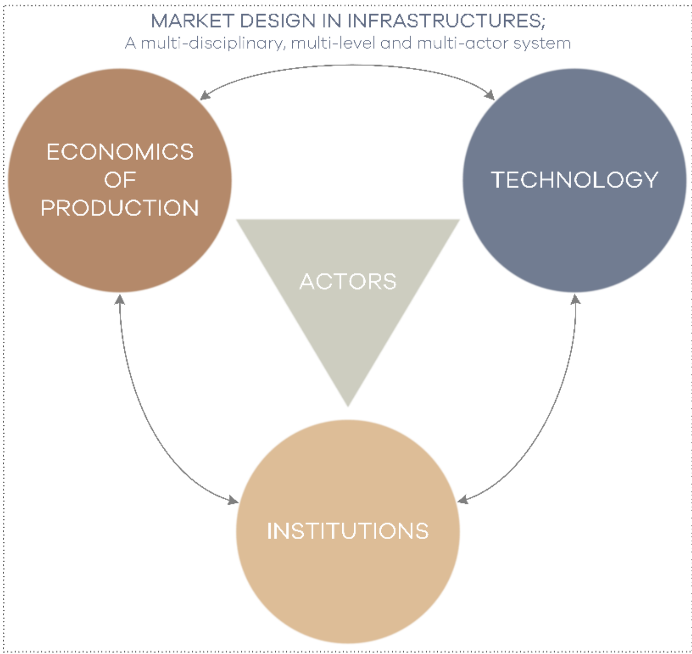


Figure 4 - Market design in infrastructures framework; based on Groenewegen (2005)

2.1.2 Focus of this research

Although a static economic perspective is chosen in this research, the market would realistically still be influenced by its context. The definition of this context can therewith not be disregarded when building a model of a heat network. In addition, in order to enable the evaluation of the market performance and eventually reflect on the current situation, it is important to identify the objectives that underlie the nodal pool market model in light of applying it to a regional open heat network. Therefore the system will first be described on the basis of the aforementioned framework by Groenewegen (2005) (figure 4), in order to define the context of the model considering all relevant components, and identify the most relevant objectives inherent to creating a large-scale open heat network, so that these can be translated to performance indicators on which the market outcomes from the model can be tested. It should be noted that not all components will be described in full detail, as was already mentioned that not everything from the framework is relevant in this study (referring back to e.g. transaction cost economics from the institutional domain). Nevertheless, the components of which the framework is comprised provide a categorical way of analysing the system to which the heat market is inherent.

Central in the approach is the effect of different pricing mechanisms and cost allocation methods on these performance indicators, when applied to heat networks. This presents an interesting field of research as heat has certain unique characteristics compared to other energy carriers, which will be elaborated on in the next paragraph. While nodal pricing is usually applied to electricity networks as described in the theory, it originates as a method for managing transmission congestion, which is actually one of the market design variables (de Vries et al., 2010). Also known as Locational Marginal Pricing (LMP), nodal prices reflect the (least) *marginal cost* of supplying the next increment of demand at a specific location (node) in the network, taking into account both supply bids and demand offers, and the physical aspects of the transmission system (constraints) (Phillips, 2004; Treinen, 2005). These marginal costs may thus be comprised of costs inherent to generation, costs inherent to transmission losses and costs inherent to transmission congestion.

According to economic theory, marginal costs are the most efficient prices that all consumers should pay, while LMP should be able to give appropriate incentives for investment in transmission capacity in the segments of the network where most congestion occurs (Rau, 2000). According to Rau (2000) however such is not always the case, as consumers on a certain node are asked to pay more due to congestion and/or losses arising from the increased consumption of others located on another node that geographically may not even be reachable by the same generator. For this reason they suggest allocating transmission losses and congestion by an approach based on responsibility.

Integrated pool-operated markets usually neglect network constraints and network losses when clearing the market on an hourly basis, after which the costs of congestion and losses are determined and allocated by re-dispatching or by ex-post economic procedures (Conejo, Arroyo, Alguacil, & Guijarro, 2002). In theory, a certain pricing mechanism can result in the dispatch to be altered due to allocated costs arising from e.g. congestion or transmission losses. Re-dispatching as a result of a pricing mechanism or cost allocation method in effect requires nonlinear programming. In this thesis however, the optimisation tool that is used for the market clearing process only allows for linear programming. Therefore, the least-cost economic dispatch based on the supply-bids (consisting of variable costs) and demand offers (assumed perfectly inelastic) will be used as a starting point, and it is assumed that potential pricing mechanisms in effect will not alter this dispatch. This means that those pricing mechanisms are purely ex-post economic procedures and that the dispatch will always be economically efficient.

Because of the unique properties of heat, focus is put on the **transmission losses** and different ways to allocate them more fairly. Transmission (capacity) constraints are hereby disregarded. This does not necessarily mean that congestion is completely absent in the system: the flow direction (which is fixed with heat) is also considered a network constraint and therefore congestion can occur nonetheless. Although LMP originates as a transmission congestion management method, it can still create locational price differences due to this flow direction in the absence of transmission (capacity) constraints.

Transmission losses can be allocated more fairly using algorithm(s), as was also done for electricity networks by Conejo, Arroyo, Alguacil, & Guijarro (2002) who compared four different procedures. They state that no unique or ideal procedure exists but that loss allocation algorithms should have most of the desirable properties listed below:

1. To be consistent with the results of a power flow;
2. To depend on the amount of energy either produced or consumed;
3. To depend on the relative location in the transmission network;
4. To avoid volatility;
5. To provide appropriate economic marginal signals;
6. To be easy to understand;
7. To be simple to implement.

Summarising, a relatively static economic approach is used in this research in terms of the market design, not considering transaction cost economics and the dynamics of the market design process but focusing on the product of the market design by comparing different pricing mechanisms – including LMP – on aspects that relate to the performance of the market, e.g. economic efficiency and transparency. In addition, a method for the allocation of transmission loss costs will be developed based on the fairness principle, while considering the most relevant properties that were summed up above.

2.2 System description

This paragraph will discuss the current market organisation from the perspective of the framework by Groenewegen (2005), for the purpose of providing an answer to the first research question. Before heat can be consumed it first has to be generated, transported, possibly stored (temporarily) and ultimately supplied to the end-consumer. In essence, these are the activities that are being performed throughout the heat chain, adding economic value along the way. All these activities are being performed by different entities, who all act according to a certain set of rules that were agreed upon when designing the market as it is now. This set of rules is meant to govern transactions that occur in the market. Naturally, this all occurs inside a physical environment providing the necessary infrastructure to make all of the above possible.

2.2.1 Physical/technical system

Physical characteristics of heat as a utility

Firstly, there are certain aspects regarding heat that resemble those of electricity and natural gas. Heat however also has certain unique characteristics that differ from other energy carriers:

- Heat resembles *natural gas* in the sense that the energy flows in only one direction. Also storage is relatively cheap, while there is more short-term storage inherent to the actual transport networks, also called ‘line-packing’ (Den Ouden et al., 2015);

- Heat resembles *electricity* in the sense that it allows for generation from different types of energy carriers, as well as generation from multiple decentral locations. Generation could even occur inside households (Den Ouden et al., 2015);
- Heat distinguishes itself as a utility in the sense that it can have different qualities and applications depending on the temperature levels. Heat is essentially being carried using water as a medium that never leaves the system, featuring relatively larger losses when being transported over longer distances. In general, transport capacities are determined by the temperature difference between the supply and return flows. The amount of losses depend on the temperature difference between the water flows and the outside temperature, as well as the length and diameter of the pipelines. Therefore the infrastructure has to be well isolated. Additionally, heat networks consist of both supply- and return-pipelines. These characteristics make them relatively more expensive than other energy infrastructures. All these aspects highlight the increased dependence on location of generation, which becomes much more important in a larger scale heat network as opposed to other utilities.

Composition of heat networks

Generators and buffers, primary networks (transmission), secondary networks (distribution) and the actual connections to the network (consumption) essentially form the main elements that are present throughout the physical heat chain and are displayed in figure 5. The figure also shows the losses occurring in the networks, usually amounting to 15 to 25 percent of the supplied heat (Hoogervorst, 2017; Menkveld et al., 2017). This differs from heat network to heat network, mostly depending on the type of connected consumers. Figure 6 shows a map of the entire existing infrastructure in the Province of Zuid-Holland, as well as the (provisionally) planned infrastructure for the Heat Roundabout.

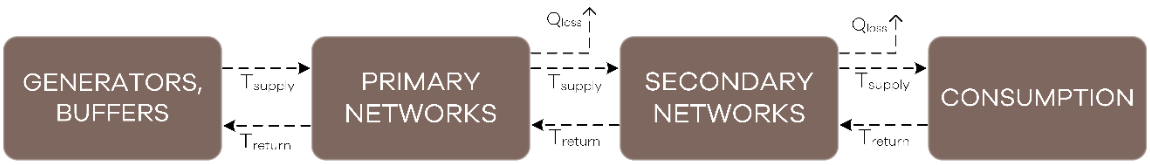


Figure 5 - Physical elements of a heat network

The map shows two already existing primary networks, transporting residual heat from a waste incineration plant in the Port of Rotterdam to the secondary networks through which heat is distributed over households in and around the city of Rotterdam. Additional secondary networks can be found in other relatively large urban areas like The Hague, Leiden and Pijnacker-Nootdorp/Ypenburg, but also in more rural areas that house a lot of greenhouses, like Lansingerland (also known as the 'B-triangle'). What becomes clear from this image is that the distances that potential new transmission infrastructure as part of the Heat Roundabout will have to cover are relatively large, compared to the existing infrastructure. Also natural gas-based CHP now still accounts for a significant share of the heat supply, whereas the aim is to gradually substitute this for more sustainable types of generation, such as residual heat and geothermal sources, given the potential future possibility for new generators to be given equal access to the network.

2.2.2 Institutions

Paramount to the proper functioning of complex technological systems, such as the heat provision system, are certain mechanisms that coordinate the behaviour of the participants in those systems. These coordination mechanisms can be described as "durable sets of agreements between parties that are part of a complex (technological) system, which have the form of formal and informal rules and organisational arrangements", according to Koppenjan & Groenewegen (2005). Relating to the heat market, these rules and agreements are thus different types of institutions that govern the interactions between market participants.

As already mentioned in sub-section 2.1.2 though, institutions and the process of designing for institutional change are not pivotal in this thesis. The most relevant form of institutions is the current **governance structure** that is in place. In this light, the current heat market is actually characterised by long-term contracts between producers and suppliers. Wholesale prices for heat are currently captured in these long-term contracts, while retail prices are regulated. These long-term bilateral agreements provide a certain amount of security for both parties. However, with it comes a long-term commitment which can be experienced as an entry barrier by potential new entrants to the market that might be characterised by a more intermittent type of heat supply. In addition, heat suppliers are mostly vertically integrated companies as they also own and operate their own distribution networks, and in some cases even transmission networks, giving them a natural monopoly position. These properties might allow for cost recovery of assets due to the long-term security, however they also highlight the lack of competition in the current organisation of the heat market, and with it the absence of incentives to maximise economic efficiency.

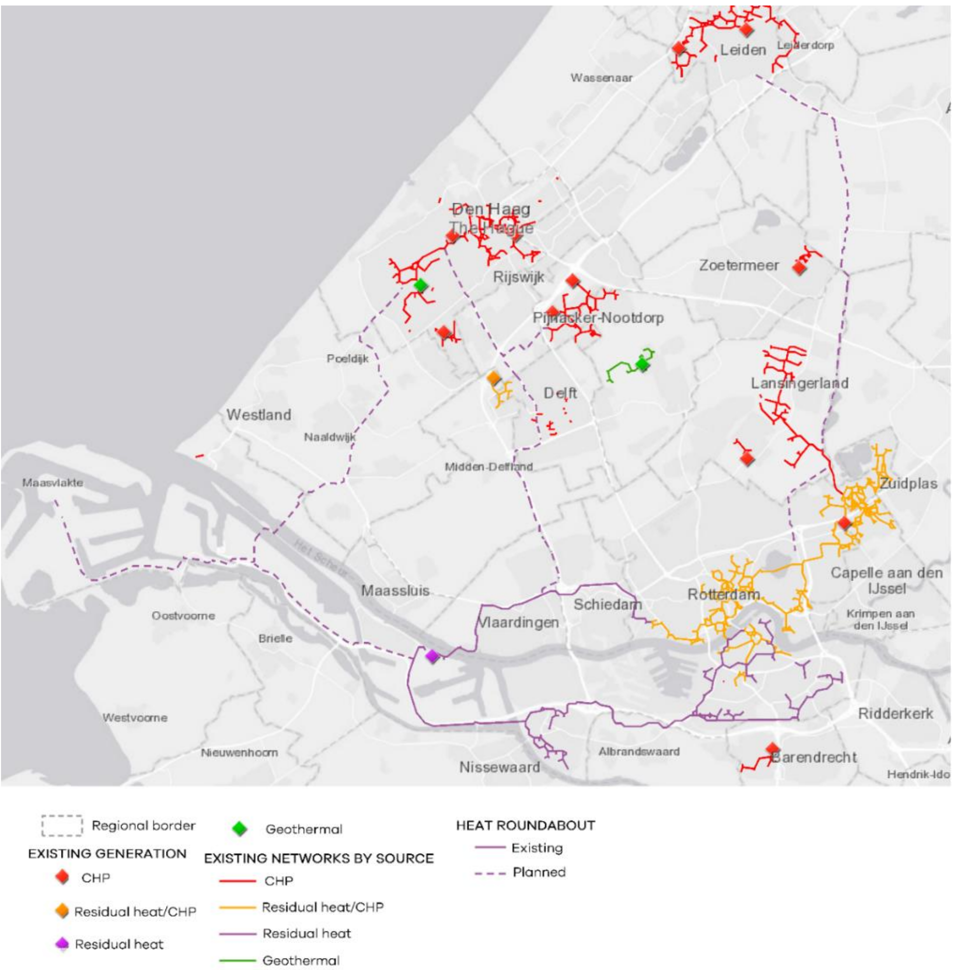


Figure 6 - Existing and planned heat infrastructure in Zuid-Holland

2.2.3 Economics of production

From an economic point of view the system is essentially built up from supply and demand, while transport and distribution & retail connect both ends of the value chain. Figure 7 displays the value chain in which the dotted arrows represent the money flow. From the figure it is derived that the aforementioned tariff regulation fixes the variable maximum retail price for (small) consumers at a little less than €23 per GJ, therewith setting the margin ceiling over the entire chain (ACM, n.d.).

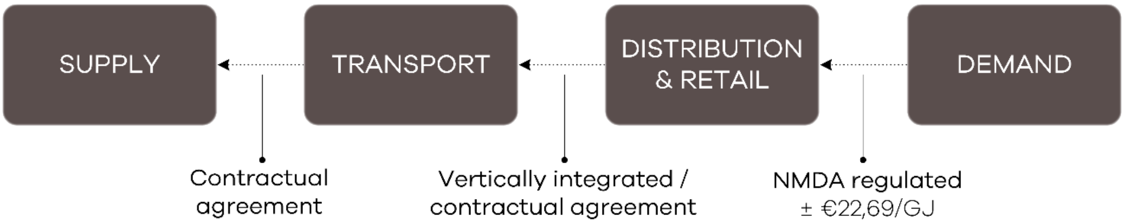


Figure 7 – Value chain of a heat network

Again it is emphasised that the current heat market is relatively 'closed', considering the natural monopolies downstream of the value chain and the fact that trading is mostly dictated by long-term bilateral contracts with the producers upstream in the value chain. The system can thus be described as a strongly decentralised market, without an independent system operator, controlling itself by means of 'self-dispatch' according to contractual agreements. This has been highlighted by a breakdown of the value chain in its institutional environment in figure 8 below.

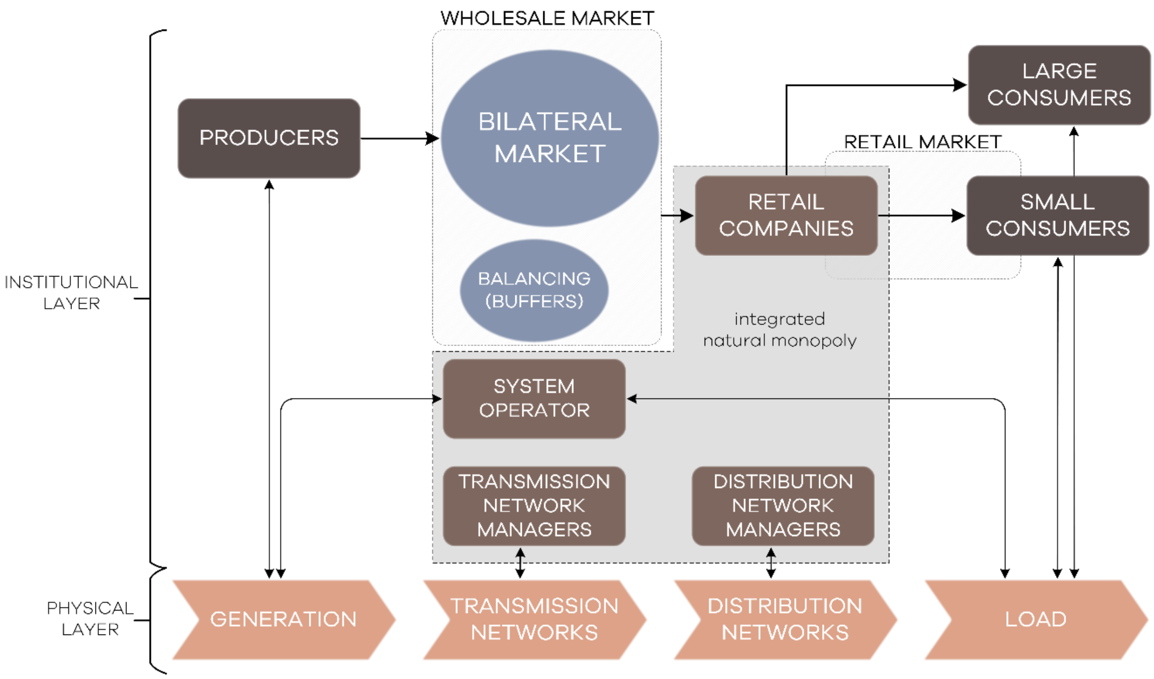


Figure 8 - The current heat market organisation; based on *de Vries et al. (2010)*

2.2.4 Actors

Along the heat value chain different types of stakeholders can be distinguished. As already mentioned earlier, the heat market has not been liberalised i.e. is characterised by vertical integration of retail and distribution, and in some cases also transmission. The system can be divided into five different types of stakeholders:

1. Government/Policy maker
2. Producers
3. Retailers/Distributors
4. Consumers
5. Market-/Enforcement-authority

The entire field of relevant stakeholders that apply to the heat provision system are displayed in figure 9, also capturing their interrelations and most important responsibilities. Each category will be explained in more detail following after the figure.

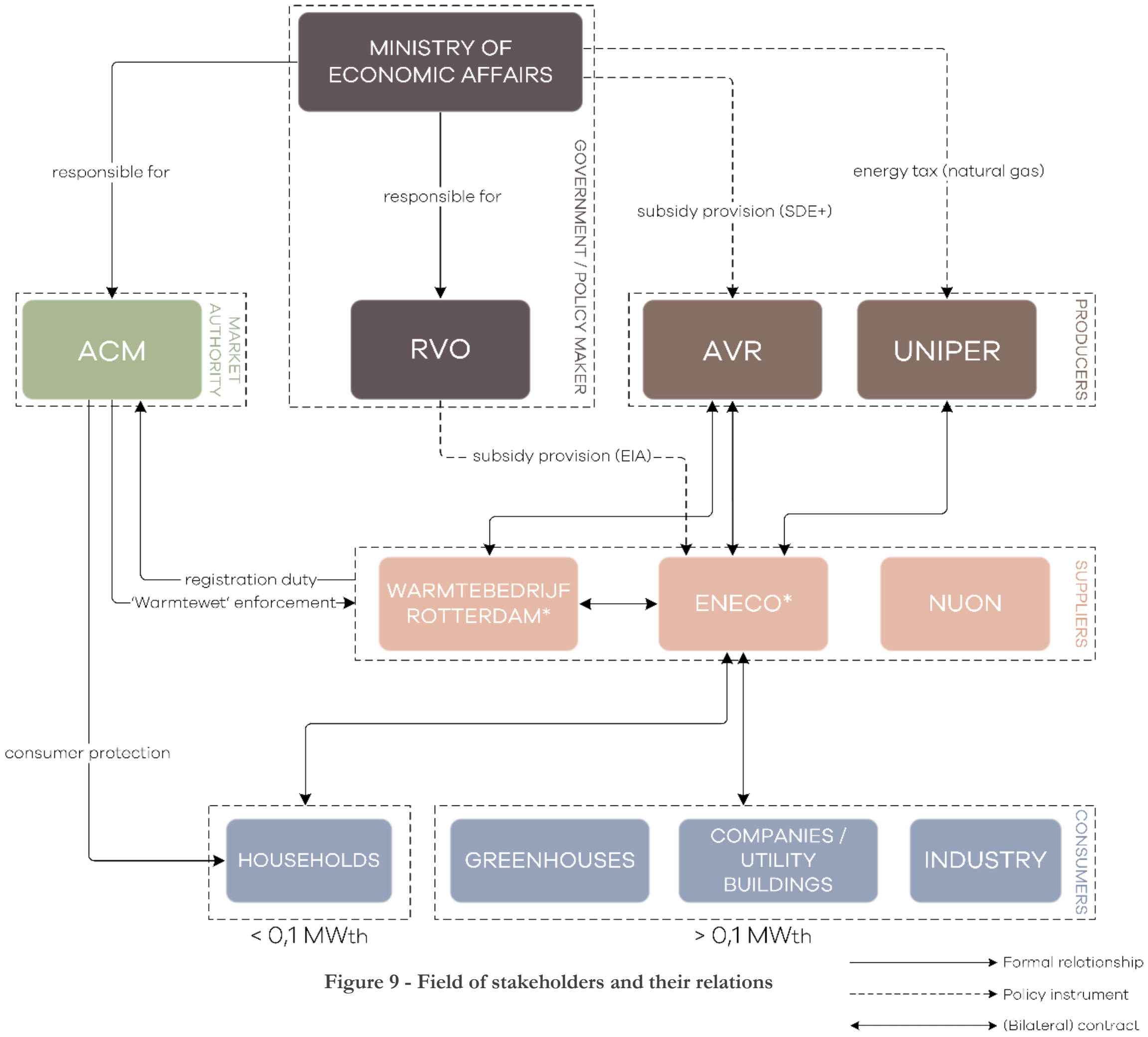


Figure 9 - Field of stakeholders and their relations

Government/Policy maker

The most important governmental entity relating to the value chain is the *Ministry of Economic Affairs*. The Ministry of Economic Affairs develops policy that stimulates innovation and sustainability by creating a healthy investment climate that facilitates enterprising (Rijksoverheid, 2017). As an intrinsic part of this vision creating a more sustainable energy system is also amongst their responsibilities. In utility markets policy makers strive for affordability, acceptability and availability, i.e. economic efficiency, reduction of emissions and security of supply. With respect to the heat market, this organisation uses two different instruments to steer towards more renewable energy:

1. Fiscal instruments (e.g. taxes)
2. Subsidy

Another governmental organisation, a subsidiary of the Ministry, is the *Rijksdienst voor Ondernemend Nederland* (RVO). As part of the Ministry, the RVO was created in 2014 to perform tasks similar to those just described with respect to the Ministry itself (RVO, 2017). Regarding the heat market, the most important tasks of the RVO are the provision of a fiscal instrument to stimulate investment in renewable technology that resembles tax deductions, and the granting of subsidies.

Producers

The producers that are in the current system may differ from each other in terms of what resources they use for the generation of heat. In other words, we can distinguish different types of production assets in the existing system:

- Natural gas boilers
- Combined Heat and Power plants (CHP)
- Industrial sources, e.g. waste incineration plants (WIP)
- Geothermal sources
- Biomass plants

In the current situation, the most important producers are AVR and Uniper. AVR is a waste processing company (WIP), while Uniper mostly owns natural gas based assets (CHP and boilers). Depending on the type of generation, producers may be eligible for subsidies or – contrarily – may be obliged to pay taxes on the fuels being used. While some producers in this network regard heat as their primary product whereas others consider it as a by-product of other production processes, their goal is ultimately to guarantee the continuity of their businesses by making profits, or at the minimum earn back the investments in their production assets. In other words, their main goal in this market can be identified as being cost recovery.

Retailers/Distributors

In the province of Zuid-Holland the largest supplier is Eneco, followed by Nuon. This actually applies to the entirety of heat networks in the Netherlands, according to research done by CE Delft, in which they made an inventory of large- as well as small-scale heat networks in the Netherlands (CE Delft, 2009). More recent research by Hoogervorst (2017) confirms this. Both suppliers own and operate their own distribution networks, whereas Eneco also owns and operates their own transmission network in Rotterdam. Regarding transmission networks we can identify Warmtebedrijf Rotterdam (WBR) as somewhat of an 'abnormality' in this category, since they operate their own transmission network in Rotterdam, yet do not actually own distribution networks. Hence they do not directly supply heat to end-consumers. Nevertheless, they sell heat to Nuon and Eneco, and in this light will be considered as 'intermediate demand', while offering transport services. Therefore WBR will be considered in the same category. As mentioned before, trading between this group and the producers occurs on the basis of long-term contracts, in which prices have been negotiated and fixed. In their turn, consumers are being charged a fixed regulated tariff as well. This creates a certain amount of security and predictability in terms of cash-flow for retailers, which is desirable as they aim to recover costs of investments in e.g. distribution infrastructure.

Consumers
Consumers comprise many different types, e.g. households, companies or utility buildings, greenhouses and industry. Regardless of this, the most important distinction relevant in this thesis is the load capacity. Large consumers and small consumers can hereby be distinguished by means of the boundary of 0,1 MWth with respect to their load connections. This distinction is made because of the *Warmtewet* legislation (ACM, 2014; Ecorys et al., 2016). Due to the absence of freedom of choice (due to the natural monopoly of suppliers) they are protected by means of the maximum tariff regulation, discussed earlier. The absence of this freedom of choice has been criticised by this group. Since consumers do not have the possibility of choosing an alternative they want more attractive prices, or at least demand more transparency into the costs made along the heat chain on which the prices are based.

Market-/Enforcement-authority
The *Authority for Consumers and Markets* (ACM) is the most important independent market authority that is responsible for the enforcement of legislation and regulation applicable to the heat market. In essence, they strive for a level playing field and protect consumer interests. Legally speaking, ACM is part of the Ministry of Economic Affairs (ACM, 2017). For the sake of transparency, suppliers are also imposed to comply with a registration duty by the ACM.

2.3 Performance indicators

2.3.1 Reviewing the current market organisation

The analyses from the previous section revealed the components inherent to the heat provision system, combined in figure 10, and enable the formulation of an answer to the first research question:

What relevant characteristics differentiate heat and heat provision systems from other utilities?

The most important observation that can be made is that the heat provision system as is can be described as a decentralised market that lacks competition on both ends of the value chain. Due to the physical characteristics of heat, its transmission is rather expensive resulting in an increased location dependence of generation. The current system is thereby supplied by only two large producers, as seen in figure 9, revealing this lack of competition and thus the current producers' relatively large amount of market power. Long-term bilateral agreements between them and suppliers present the main governance structure of transactions and provide both incumbents with an amount of security, however raises entry barriers for potential new entrants to the market. This also reinforces the lack of competition and additionally results in a lack of transparency, since wholesale prices are captured in these contracts. Retail prices are regulated as suppliers enjoy a natural monopoly position due to their vertical integration, also revealing the lack of competition on the other end of the chain.

While heat as a utility is starting to compete more and more with the conventional natural gas provision system, it is obvious that the government feels responsible for creating a market in which the three main general policy goals are guaranteed: availability, affordability and acceptability (AAA). Unfortunately, in most cases these goals intrinsically compete with each other as there are some inherent trade-offs. The bilateral long-term agreements for example may provide producers

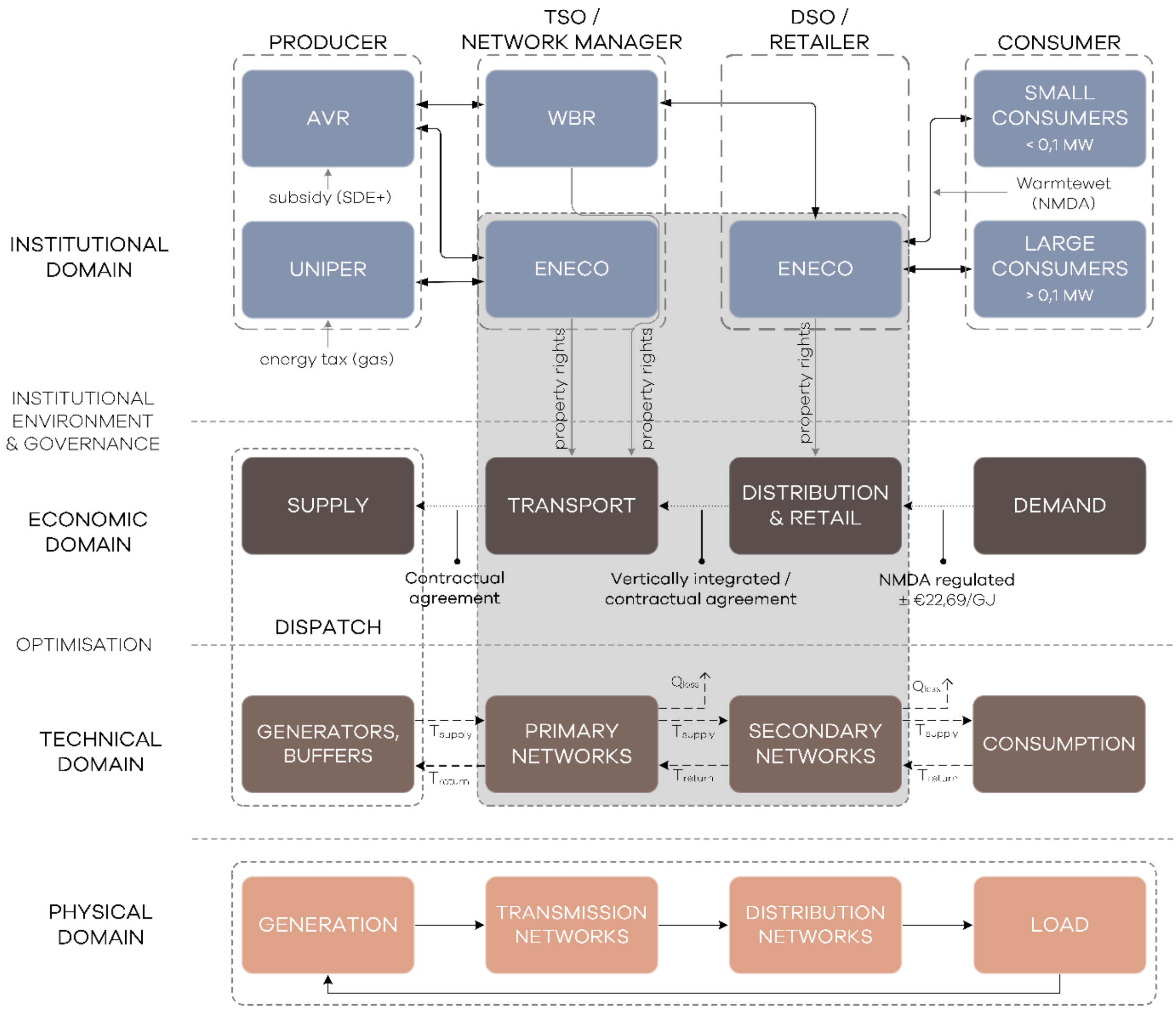


Figure 10 - An integrated view of the current heat provision system by combining all components

with a steady and predictable cash-flow with which they can earn back investment costs and guarantee reliability and security of supply, however they give no (dynamic) incentive to increase efficiency or reduce environmental impact, apart from the fiscal instruments and subsidy in place. In addition, as these wholesale prices are captured in contracts long-term, there is no transparency for consumers and combined with the lack of freedom of choice of their supplier this can be perceived as unfair. The observations made in this section emphasise the gap between the current situation and the overall goal of the government in terms of creating a regional heat network, recalled from chapter 1: "*creating a more sustainable built environment at the lowest possible social costs*" (Werkgroep Warmte Koude Zuid-Holland, 2015).

2.3.2 Identification of market performance indicators

The overall goal of a regional heat network just mentioned can effectively be broken down into two general components, relating to the AAA policy objectives:

- Decreasing the environmental impact (*acceptability*), while;
- Increasing economic efficiency (*affordability*).

These overall objectives of a regional heat network have thus been the starting point in the search for a suitable market model done by the concerning task force *Werkgroep Warmte Koude Zuid-Holland (2015)*. As the nodal pool model has come out of this search as most promising and fitting in terms of facilitating these objectives, the following desirable properties have been identified on their account:

- Accessible
- Transparent
- Optimisable
- Steerable

Accessibility and transparency would intrinsically already be accounted for (to a great extent) in organising the heat market according the (integrated) nodal pool model, since it would be accompanied by introducing some form of TPA that would grant all generators equal access to the network while an independent system operator would determine the most economically efficient dispatch based on supply-bids by producers, all occurring through the integrated pool. The economic dispatch would hereby be determined according the merit order, also accounting for price optimisation. In addition, CO_2-contents of generation could be given a price that would be added to the respective supply-bids, providing the desired steerability towards reduced environmental impact.

Nevertheless, apart from the potential of organising an open heat market by means of the nodal pool model in light of these properties, the security of investments of producers i.e. their cost recovery in this open market remains an obstacle for which no solution has been found yet. Therefore the most relevant aspects to consider have been identified as being the friction between economic efficiency on the one side, and cost recovery of generation assets on the other. In section 2.1.2 however it was already explained that the economic dispatch is assumed to be economically efficient at all times, and that it would not be altered by potential pricing mechanisms in effect. Economic efficiency hereby becomes a starting point, while focus is shifted to affordability i.e. price effects. In terms of cost recovery, the goal is to recover both fixed and variable costs of the generation assets by means of sufficient producer surplus. A lack of insight into the fixed costs of such generation assets at the time of writing this thesis makes it impossible to determine if and to what extent this goal is met. Comparing the amount of producer surplus generated by the market, in this case thus solely based on variable costs, does however give an indication of how different pricing mechanisms relate to each other in terms of leaving room for such a surplus.

Ultimately, the model will enable an assessment of different pricing mechanisms and cost allocation methods on the basis of the performance indicators presented in table 2. Apart from the evaluation of the market outcomes on the indicators relating to affordability and cost recovery, the allocation methods will additionally be evaluated on the basis of fairness by revisiting the most relevant principles with respect to loss allocation procedures as identified in sub-section 2.1.2. Naturally, the results of the alternatives will be assessed quantitatively by operationalising these indicators. Some performance indicators however are difficult to operationalise, and will be reflected on qualitatively in the next sub-section. The performance indicators that have been identified as most relevant in this research are thus based on the trade-off between affordability and cost recovery, supplemented by the loss cost allocation principles by Conejo et al. (2002).

	Goals	Performance indicator
Affordability	Lower heat prices	€/GJ
	More efficient prices	% (difference between prices and average costs)
Cost recovery of generation	Sufficient market surplus	€ (difference between net total collection and net total generation costs)
Loss allocation principles	Less price volatility	% (historical volatility expressed as variance)
	Appropriate economic marginal signals	-
	Based on fairness principle	-

Table 2 - List of market performance indicators

2.3.3 Explanation of loss allocation principles

Operationalisation of the performance indicators from this category is less straightforward than of those dealing with affordability and cost recovery of generation. In order to ultimately improve the validity of the results, they should however be measurable in a consequent manner, whether it is quantitatively or qualitatively. Therefore the three performance indicators associated with the loss allocation principles will be explained and specified in more detail below.

Price volatility

In an open heat market, prices are not regulated or captured in bilateral contracts any longer but determined by the market operator based on supply and demand bids. This may cause prices to fluctuate more unpredictably which e.g. potential investors in generation capacity might experience as undesirable. Different loss allocation methods can potentially increase this effect and cause even more volatile prices. While price volatility can be measured in different ways, the aim of this study - and this market performance indicator in particular – is to enable a valid comparison of the effect of different pricing mechanisms and accompanying loss allocation methods on the price volatility. Therefore a commonly used method is taken, yielding the historical volatility by first calculating the logarithmic returns over a time period of one year on an hourly basis, and subsequently taking the standard deviation of these logarithmic returns over the same time period (Zareipour, Bhattacharya, & Cañizares, 2007).

Appropriate economic marginal signals

In competitive markets that use marginal cost-based pricing automatically the incentive is in place to reduce costs, as market participants compete with each other for market power by trying to drive their costs to marginal cost levels, which is the least expensive option that still enables cost recovery. Projecting this on the loss allocation principles, economic signals in place in the market are thus considered appropriate when they actually result in economic efficiency, and not encourage market participants to increase volumes for the sake of reducing prices.

Fairness principle

It should be noted that fairness can be perceived in different ways, as the notion itself is rather arbitrary and subjective by nature. In light of this study, the interpretation of fairness is based on the first three loss allocation principles by Conejo et al. (2002) as described in sub-section 2.1.2. In essence, this means that transmission losses should be allocated to those loads that cause the losses, while considering their relative contribution to said losses in relation to other loads in the network. By allocating all transmission losses to the loads, generators should be able to be compensated economically for their compensatory generation. The exact translation of these principles to an allocation procedure will be explained in more detail in sub-section 3.3.3.

3. MODEL CONCEPTUALISATION

Conceptualising the model will be done firstly by exploring the most relevant characteristic of the Nodal Pool model and answering the second sub-question. After this exploration and a discussion of the differences between the Nodal Pool model and the current bilateral market organisation, several conventional pricing mechanisms are formulated and discussed. Ultimately, on the basis of a theoretical evaluation of those pricing mechanisms, an alternative pricing mechanisms is developed and discussed in the last paragraph.

3.1 The Nodal Pool model

The Nodal Pool model strongly differs from the current bilateral market organisation in most areas. The general intention of a potential shift to this particular market model is to create a more 'open' and transparent heat market, in which costs can be minimised and renewable sources are given a fair chance. Paramount to this vision is to effectuate more equal access to the heat networks (Werkgroep Warmte Koude Zuid-Holland, 2015). As was also discussed in section 2.4, these desirable properties were at the root of the choice for the nodal pool model and the corresponding locational marginal pricing mechanism. However, alternative pricing mechanisms might exist that could perform as well or even better on the identified performance indicators. For the purpose of facilitating the evaluation of potential alternative pricing mechanisms against locational marginal pricing in the nodal pool model this paragraph is therefore dedicated to first answering the second research question:

What are the relevant characteristics of the Nodal Pool market model?

3.1.1 Market organisation

As opposed to the current market organisation, the nodal pool model would transform the heat market from a decentralised to a completely integrated market, characterised by a mandatory pool through which all heat is traded, improving transparency and the possibility of central optimisation. For the operation of this integrated pool a new independent system operator (ISO) would be introduced. In order to actually 'open' up the network, facilitate fair and equal access and competition amongst producers, some form of TPA would be introduced as well. This would cater to potential producers with a more intermittent type of heat supply, e.g. industrial sources that consider heat as a by-product or large professional consumers with cases of surpluses or excess production ('prosumers'). Additional unbundling of transmission networks would theoretically secure equal and non-discriminatory access to the networks even more, however the unbundling process would most likely prove very costly as current transmission networks are owned and operated by multiple different energy companies. In this sense, as long as the form of TPA to be introduced is strong enough, this will not be necessary. Compared to the current bilateral market organisation as was shown in figure 8 a transformation to the nodal pool model would thus include several significant changes, shown in figure 11.

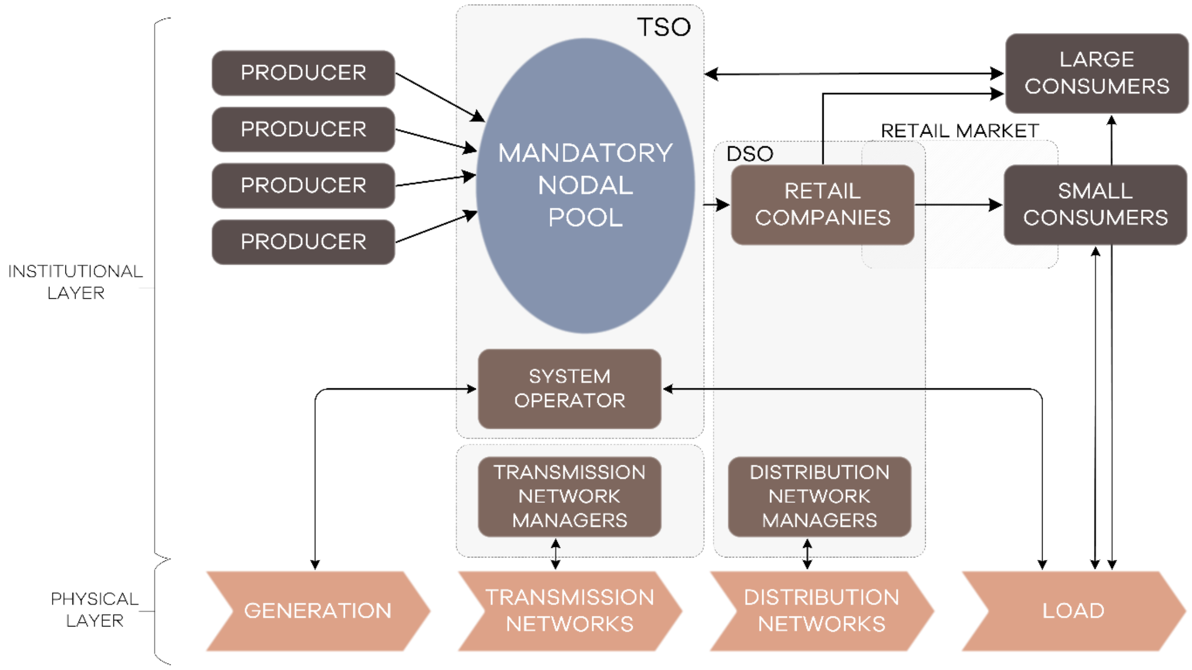


Figure 11 - Nodal pool market organisation. Based on *de Vries et al. (2010)*

3.1.2 Market clearing process

The mandatory pool through which all heat is traded calls for an independent system operator, as already mentioned, and is responsible for clearing the market and thus determining the dispatch. The latter occurs by means of economic optimisation, based on the offered volumes and costs of generation from the respective producers by order of merit. Any producer that falls outside of the market clearing and is not dispatched would automatically be included in the back-up reserve. As these supply bids are binding, any deviation from it would mean that the producer(s) responsible will be charged for this deviation, while producers from the back-up reserve would be dispatched and paid for their back-up services. The market clearing process and role of the ISO somewhat resembles the electricity market, however in this case transmission networks aren't necessarily owned as well by the ISO, as is the case in the electricity market. The market clearing process is summed up below:

1. The system operator makes an analysis of the expected day-ahead demand volume per location (node);
2. Based on this information, the system operator drafts certain terms and conditions with respect to e.g. supply temperatures producers will have to meet up to;
3. Subsequently, producers will submit their bids, incorporating offered volumes and costs of generation;
4. The system operator collects all bids and runs the optimisation, accounting for possible costs resulting from the physical aspects of the network, such as the aforementioned transmission losses and/or congestion.
5. The resulting economic dispatch is being communicated to the producers by the system operator, binding them to their respective bids.

3.1.3 Preliminary conclusions

In the preceding sub-sections an attempt has been made to illustrate the concept of the Nodal Pool market model and explain its most general and relevant properties when applied to the heat market. In order to facilitate the answering of the second sub-question as mentioned in the beginning of this section and to increase the understanding of the market model with respect to the current bilateral market organisation, table 3 displays a comparison of both market models on the most important characteristics. The most noteworthy facets that surface from this comparison firstly include that locational marginal pricing captures the entire volume of heat i.e. supply/demand in the central optimisation, as well as potential congestion and losses that may cause locational price differences, as opposed to a bilateral market. Secondly, the role of a potential new independent system operator would become relatively important, being responsible for the market clearing process and the determination of the resulting dispatch. Another important conclusion that can be drawn from this is that a possible implementation of the Nodal Pool model would not require any particular starting situation, pointing to the observation made earlier that transmission network ownership by incumbent parties wouldn't necessarily need to be unbundled.

	Bilateral	**Nodal Pool**
Spot market volume	Small	100% of supply/demand
Price mechanism	Bilateral contracts	Day ahead auction (supply-based)
Transport losses included in optimisation?	Yes (natural gas), No (electricity)	Yes, 100%
Congestion included in optimisation?	Not usually (inefficient)	Yes, between nodes
Pricing	Per contract	Per node
Roll/importance SO	Medium/large	Very large
Revenue for transport network owner from:	Open season + auctions	Difference between nodal prices and transport tariffs
Contra-indication	Situations with lots of congestion	Desire for bilateral (physical) deals
Required starting situation	From scratch	From scratch

Table 3 – Comparison of most important facets of current and intended market model (Werkgroep Warmte Koude Zuid-Holland, 2015)

Lastly, the contra-indication i.e. the desire for bilateral (financial) deals emphasises the absence of the security of investments and decreased predictability of cash flows experienced by producers and network owners in case of an open heat network. This can be experienced as a drawback of this market model, but can be mitigated by allowing for financial contracts or financial transmission rights (FTR), enabling market parties to hedge themselves against the risk of large unpredictable differences in wholesale prices that might occur throughout the network (Lyons, Fraser, & Parmesano, 2000; Werkgroep Warmte Koude Zuid-Holland, 2015). Again, it becomes clear that cost recovery presents an uncertainty and thus important performance indicator in light of this study.

3.2 Conventional pricing mechanisms

In light of the pricing mechanisms presented in this section, including locational marginal pricing (as conventional in the nodal pool model), it should be noted that the least-cost economic dispatch as determined by the optimisation software shall remain the starting point for these (ex-post) pricing mechanisms, and will thus not be influenced or altered by them. Additionally it is stressed that, while at this point they have not been included in the process of determining the economic dispatch, **fixed costs of the production system are not included in the pricing of heat**. They will however be briefly reflected upon in the discussion of the pricing mechanisms following hereafter.

3.2.1 System marginal cost pricing

Working principle/price determination

The most basic form of marginal pricing when applied to an energy production system is described by determining the intersection between the supply-curve, which is formed by all supply-bids as discussed in sub-section 3.1.2, and the (perfectly inelastic) demand curve. By this intersection the market clearing price i.e. system marginal price (SMP) is obtained, equal to the variable costs of the marginal generator.

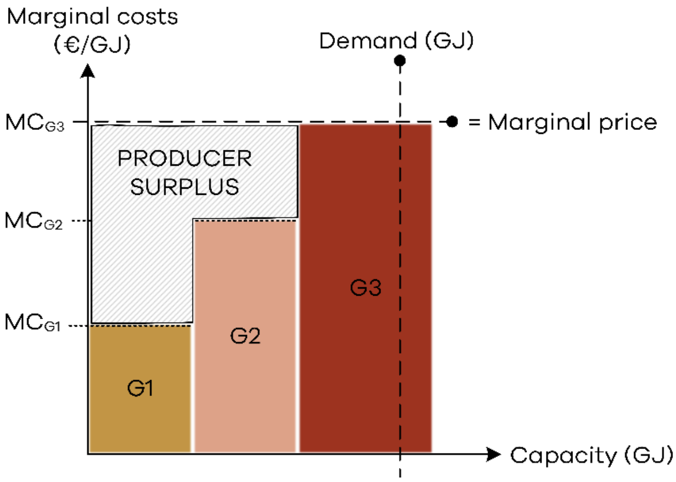


Figure 12 - Illustration of marginal pricing

Transmission loss allocation

Transmission losses are usually captured in the SMPs when they are a function of the demand. In the case of heat however, since they are assumed constant and do not change when system demand (marginally) increases, losses are not allocated or reflected in the SMPs.

Qualitative expectations

As the name already reveals this will set the price for the entire system, thus neglecting locational differences and creating a margin for all producers that are able to produce against lower variable costs than the SMP, also called the producer surplus as illustrated in figure 12, with which they can recover the (fixed) costs of e.g. their investments. While the marginal generator is unable to realise profits, assuming no strategic bidding occurs and its bid equals its variable production costs, this installs an incentive for all producers to increase their efficiency and minimise production costs (Li, Sun, Zhang, & Wallin, 2015). By neglecting locational price differences, it however fails to consider the costs of the transmission losses occurring throughout the network. It can be expected that marginal pricing thus will not perform particularly well on the fairness principle with respect to the allocation of these costs and lacks the incentive to minimise those transmission losses. Volatility in prices on the other hand is expected to be relatively low, since there is one system price.

3.2.2 Average cost pricing

Working principle/price determination

Another potential pricing mechanism is a form of cost-based pricing and entails the determination of the system price based on the entire system's average costs. Normally, average cost pricing captures the average of both fixed and variable costs of the system. As mentioned, fixed costs are not included in this research. This form of pricing can hence be better described as average *variable* cost pricing, but will be called average cost pricing in the rest of this thesis. Again, no locational differences are considered and the entire system is being charged the same price. This very basic form of average cost pricing can be described as the total system production costs divided by the total system demand;

$$ACP = \frac{\textbf{\textit{System production costs}}}{\textbf{\textit{Total demand}}} = \frac{C(Q_{G_{tot}})}{Q_{D_{tot}}} \tag{1}$$

Where:

$$ACP = average\ cost\ price\ of\ an\ amount\ of\ heat\ for\ all\ loads\ \ (€/GJ)$$

Transmission loss allocation

As will be explained in more detail later, additional generation is included in the dispatch for the compensation of transmission losses, naturally causing additional production costs. As the formula above acknowledges, these costs are hereby incorporated in the average cost prices, i.e. socialised over the entire system. The average cost prices are thus influenced by the variable costs of the generators, their respective produced volumes i.e. market share and the amount of transmission losses.

Qualitative expectations

As opposed to marginal pricing, where every generator able to produce against lower variable costs than the most expensive generator that was dispatched receives part of the surplus, (more) generators will more often be unable to recover their (fixed) costs, depending on the generators' variable costs and dispatched volumes. Averaging the entire system's production costs by following the formula above will simply amount to a surplus equal to zero, emphasising this. It should be noted that the exclusion of fixed costs might result in an ACP being lower than the variable production costs of some generators that were dispatched. In reality, as average cost pricing usually does include fixed costs, this would be most unlikely as generators would otherwise have no incentive to actually produce. The spread of variable costs among the system will also largely influence the volatility of the prices on the short-term, however on the long-term the system will expectedly approach one average price. Additionally, as the costs of the transmission losses are socialised, this mechanism also fails to give an incentive to minimise the transmission losses in the system and neglects to consider the fairness principle in terms of allocating its costs. Although fixed costs are disregarded at this point, in reality they are often included in regulated utility prices. As more of these fixed costs are allocated to the utility charge, this would naturally move the utility price towards average total costs (Procter, 2014).

3.2.3 Locational cost pricing

Working principle/price determination

This pricing mechanism can be described as another form of average cost-based pricing and yields the exact cost prices by considering the actual flows from generators to loads. These flows are extracted from the economic dispatch as determined by Linny-R. The generation costs are essentially also averaged, as with ACP, but in this case a distinction is made as to from which generator(s) the heat demanded by a certain load actually originates from, creating locational price differences. The price of heat for a certain load can thus be described as the average variable costs of the generated heat that is supplied to that load, also captured in formula 2.

$$LCP_j\ (excl. losses) = \frac{Sum\ of\ required\ production\ costs\ of\ generators\ supplying\ load\ j}{Demand\ of\ load\ j} = \frac{\sum_i C(Q_{G_{i,j}})}{Q_{D_j}} \quad (2)$$

Where:

$$LCP_j\ (excl. losses) = locational\ cost\ price\ of\ an\ amount\ of\ heat\ for\ load\ j\ (excluding\ losses)\ \ (€/GJ)$$

$$C(Q_{G_{i,j}}) = generation\ costs\ of\ heat\ supplied\ from\ generator\ i\ to\ load\ j\ (€)$$

Transmission loss allocation

As the formula already revealed, the LCPs as just described not yet include the costs of the transmission losses. Costs of those transmission losses are however calculated in exactly the same manner (transmission losses in the network model can essentially be seen as additional 'loads' with a constant demand). The allocation of those costs to the loads will be done ex-post by means of the algorithm following the same allocation principles as discussed earlier, after which the final LCPs are derived.

Qualitative expectations

Locational cost pricing essentially is a very transparent way of pricing, as the prices equal the exact costs that were incurred for the production and supply of an amount of heat to a certain location. The lack of incentives however very much resembles the case of average cost pricing, only augmented by even less legitimate competition due to the local nature of heat in combination with the locational price considerations. Without additional instruments, it thus lacks the incentive to minimise costs and the possibility for producers to recover their (fixed) costs. Volatility is expected to be low and prices to be maximally efficient. Without additional ex-post allocation of transmission loss costs to the consumers, the market surplus will logically be negative as generators are not financially compensated for their additional generation compensating for those transmission losses.

3.2.4 Locational marginal pricing

Working principle/price determination

The nodal pool model uses a particular pricing mechanism that resembles marginal pricing but in this case does incorporate locational differences. The differences in prices that are captured by means of locational marginal pricing may be attributed to two events:

1. Transmission congestion
2. Transmission losses

Contrarily to the electricity market as currently organised in the Netherlands, which uses a form of marginal pricing as explained in sub-section 3.2.1, the price may thus not be similar across the entire heat system. Locational dependence of generation assets is much more inherent to the heat system, attributable to heat flowing unidirectional in the network and the accompanying transmission losses. The locational differences in prices and corresponding dependence of the location of generation assets can be thus be explained by additional costs, attributable to the two events mentioned above. Adding all together, the heat price at a given location (node) is composed of three components (Phillips, 2004; Treinen, 2005), illustrated in figure 13.

Figure 13 - Composition of a locational marginal price

The first component has already been discussed, as the second component can be explained by recalling the merit order. Given a situation where in theory the cheapest generator in the system would own enough generation capacity to supply a certain load all of its demanded heat, but the network's transmission capacity is constrained at an insufficient amount to actually deliver this heat from the cheapest generator to said load; this would mean that another (more expensive) generator, located elsewhere in the network, would need to jump in to supply the remaining heat that could not be transported from the cheapest generator to the load on account of so-called transmission congestion. These additional costs (difference in variable costs between the two generators) comprise the second component of an LMP.

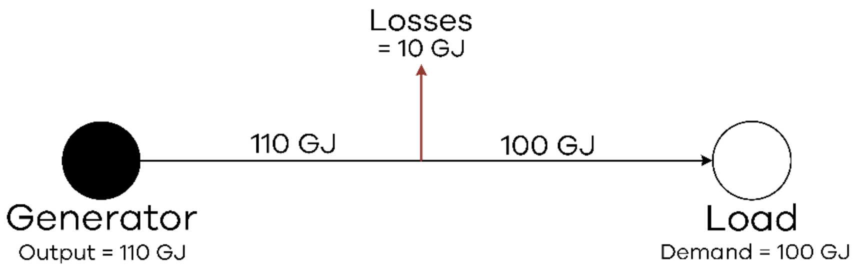


Figure 14 - Illustration of compensatory generation due to transmission losses

The last component of the LMP comprises the marginal costs of transmission losses. As already explained in section 3.1, larger scale heat networks are characterised by significant transmission losses. These losses have to be compensated for by extra generation, as illustrated in figure 14, bringing additional costs. These costs are incorporated into the LMP, so that producers can be compensated for their compensatory generation. Summarising, an LMP can be formulated as *the marginal cost of supplying the next increment of demand at a specific node in the network, taking into account supply-bids and demand offers and the physical constraints of the transmission network* (Phillips, 2004; Treinen, 2005).

As mentioned in sub-section 2.1.2, this research focuses exclusively on the transmission losses and their potential cost allocation methods. Transmission congestion is not considered in the conceptualisation of the model and would otherwise already be accounted for in the economic dispatch on account of the optimisation software used in this research. Referring back to the formulation of an LMP based on Phillips (2004) and Treinen (2005) above, LMPs can be determined relatively easily using the network model that will be presented in the next chapter. This enables the provision of an answer to research question 3:

In what way can the Nodal Pool model and locational marginal pricing be applied to a heat network?

By running the least-cost economic dispatch for a certain demand scenario and subsequently adding one increment of demand (+1 GJ) to each node one by one, the LMPs are obtained by calculating the difference in total system costs in each demand scenario. This way, locational marginal pricing can thus be applied to a heat network, given that it is represented in an optimisation model that performs the least-cost economic dispatch correctly.

Transmission loss allocation

In theory, as just explained, all costs needed to supply a load with an additional increment of demand should be reflected in the LMPs, including those attributable to potential congestion and/or losses. Since losses for heat are assumed to be fixed and not a function of the demand, expressing the marginal costs of those losses becomes more difficult. In this research, transmission losses would always be accounted for already in the optimisation model, meaning that its costs are not allocated or reflected in the LMPs of the loads.

Qualitative expectations

As with conventional marginal pricing, this mechanism is marginal cost-based. In theory it should therefore be able to lead to even higher economic efficiency and achieve more social optimality in a competitive market where marginal pricing is done locational. It can thus be expected that simultaneously cost recovery will become more difficult as the market surplus will shrink compared to (system) marginal pricing, also considering that the general objective of LMP is to maximise economic efficiency by incentivising (variable) cost minimisation. This mechanism has already proven to be efficient when applied to electricity markets that are characterised by relatively large thermal losses and congestion, again assuming no strategic bidding occurs (Xu & Low, 2015). Heat losses behave differently compared to thermal losses in electricity networks however, as was mentioned already and will be explained in more detail in the following section. Increasing an electrical power flow over a certain line due to e.g. congestion elsewhere thus induces additional losses *relative* to that power flow, making it easy to determine the marginal costs of these transmission losses. In the case of heat, due to their *fixed* character, it is difficult to express the exact marginal costs of transmission losses in the locational marginal prices, undermining the economic marginal signals that marginal cost-based pricing intends to give in terms of minimising these losses. Logically, this also means that LMP expectedly fails to honour the fairness principles.

3.3 A hybrid pricing alternative

The pricing mechanisms discussed in the previous section all have their benefits and drawbacks in terms of their expected impact on the market performance. The two marginal cost-based pricing mechanisms will most likely result in a larger producer surplus, whereas the other two pricing mechanisms are mainly beneficial for affordability in terms of creating lower and more efficient wholesale prices. In terms of the allocation of transmission losses, only locational cost pricing is eligible for considering the fairness principle. In combination with locational marginal pricing these are the only two pricing mechanisms actually assigning value to the locational dependence of generation by accommodating locational price differences.

Pricing mechanisms	Loss allocation method	Benefits	Drawbacks
System marginal cost pricing	N/A	Easy, incentivises cost reduction, predictable, creates producer surplus	Fails to allocate losses, marginal signals do not apply to loss costs, market prices can be high
Average cost pricing	Losses are socialised over entire system	Easy, market prices low, low volatility, losses are captured in prices	Creates no producer surplus, losses allocated but not fairly, lacks economic signals, ACP can be lower than variable costs of some generators
Locational marginal pricing	N/A	Incentivises cost reduction, increases efficiency by considering locational differences, creates producer surplus	Marginal signals do not apply to loss costs, cost recovery can be more difficult
Locational cost pricing	Losses are allocated to loads in proportion to their relative contribution to those losses	Market prices low and transparent, low volatility, losses allocated according fairness principle	Creates no producer surplus, lacks economic signals

Table 4 - Summary of conventional pricing mechanisms showing benefits, drawbacks and loss allocation method (when applicable)

In addition to these four pricing mechanisms discussed in the previous section, summarised in table 4, this section will propose a potential alternative pricing mechanism for the purpose of investigating if it improves the market performance compared to the previously discussed alternatives. The starting points for this alternative pricing mechanism are:

1. That it should find a balance in the trade-off between affordability and cost recovery;
2. That it should honour the fairness principle;
3. That it should reflect locational dependence of generation by assigning value to upstream generation due to the unidirectional flow of heat;
4. That it should reflect locational dependence of generation by incorporating costs of transmission losses;
5. That it should provide appropriate economic signals to the market;
6. That it should be applicable to a network model in any possible configuration.

3.3.1 Key assumptions

Ultimately this alternative pricing mechanism can be described as a 'hybrid' form of pricing, showing resemblance with both average cost pricing and (locational) marginal pricing. LMPs are usually comprised of the three cost components as explained in sub-section 3.2.4, and derived by determining the cost of the next increment of demand at a certain node, thus based on marginal costs. In the absence of any transmission losses or congestion, the marginal costs of the next increment of demand thus equal the variable costs of the marginal generator/next generator to be dispatched and form the basis of the unconstrained market clearing price (Phillips, 2004). In this research, as mentioned, the least-cost economic dispatch that is determined in the optimisation is the starting point for all pricing mechanisms, meaning that this hybrid pricing mechanism also will not alter the dispatch but merely (re-)allocate the incurred costs inherent to said dispatch, i.e. an ex-post economic procedure.

In sub-section 2.2.1 it was already discussed that heat shows several distinct characteristics compared to natural gas and electricity, one of those being the nature of the transmission losses occurring throughout the network. Thermal losses in electricity networks firstly become significant only over relatively longer distances, whereas these often occur as a *percentage* of the power flow due to so-called penalty factors inherent to the transmission lines (Phillips, 2004; Treinen, 2005). As already mentioned in the previous section, an increased power flow over a certain line thus induces additional losses relative to that power flow.

The amount of heat losses however depend on the relative temperature difference between the supply pipeline and the outside temperature, as well as the diameter and length of the pipeline, while the transport capacities are determined by the temperature difference between the supply- and return pipelines. Naturally, the outside temperature is deemed an external factor while diameter and length are, once chosen, fixed. Increasing the temperature difference between the two pipelines thus would increase the transport capacities, but would usually result in a larger amount of losses along the way as the temperature difference between the supply-pipeline and the outside temperature increases in parallel, revealing a trade-off. As these pipeline temperatures are usually chosen in anticipation of the forecasted outside temperatures and heat demand, the amount of losses is a result of this trade-off rather than of the heat flow, which complicates the determination of the marginal costs of transmission losses. In order to deal with these characteristics, heat losses will therefore be averaged annually to obtain a certain amount of losses inherent to each pipeline. This amount, as opposed to thermal losses in electricity networks, is assumed a constant, which can additionally be explained by the fact that in order to maintain the pipelines' transport capacities, its temperature should be kept at a constant level as well. In other words, when increasing the amount of demand incrementally in a heat network, the amount of losses does not increase relatively to the demand but remains the same. This forms the starting point of the proposed allocation method that will be discussed in sub-section 3.3.3.

Using the least-cost economic dispatch as a constraint, the prices obtained by this hybrid pricing mechanism will thus again consist of the same two components considered in locational marginal pricing as:

- Costs of generation;
- Costs of transmission losses.

3.3.2 Choices regarding assignment of generation

The first component will be approached somewhat different than with locational marginal pricing, underlying the rationale of increasing the efficiency of the prices and thus intrinsically decreasing the possibility of cost recovery, referring to the inherent trade-off between both. Essentially, all generated heat from all generators that were dispatched will be 'assigned' to the loads in the network. All generators assigned to a certain node hereby form a so-called 'nodal merit order', meaning that the generator with the highest variable costs will set the price of generation for that node. In theory, this would result in less generators actually being able to enjoy a surplus (less frequently), as prices with respect to the generation would be closer to the actual variable costs incurred for said generation at most locations, depending on how this generation is assigned. The most relevant choice to be made with respect to this component as assumed in this hybrid pricing alternative thus relates to the way in which the aggregated generation that was dispatched is being allocated over the respective loads i.e. how the generators are assigned to those loads.

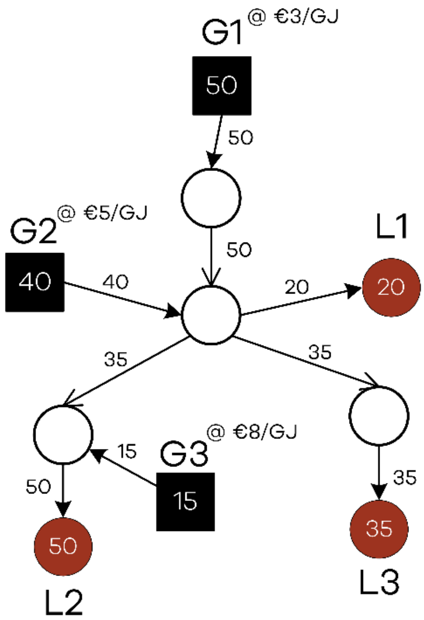


Figure 15 - Fictive economic dispatch (starting point)

An important factor that already constrained the determination of the least-cost dispatch (being used as starting point for this process) is the unidirectional flow of heat in the network, and should therefore also constrain this assignment process. In the end, generators can only provide heat to loads located at nodes downstream of themselves, or at the same node. Therefore two different options are proposed. The assignment of generation could be viewed from either;

1) The perspective of the most **upstream load**, or
2) The perspective of the most **downstream generator**;

Where in both perspectives **each node's resulting price of generation will be set equal to the variable costs of the most expensive generator assigned to that node**. To illustrate, a fictive economic dispatch has been shown in figure 15 and will be used to explain the consequences of both perspectives as shown in figure 16 and 17, respectively. This fictive network consists of four nodes, three generators and three loads. Loads are numbered in their respective order from upstream to downstream. Concerning the latter it should be noted that, although loads L2 and L3 seem to be located at the same level in the network, L2 is regarded more upstream than L3 because it has an additional local generator, making L3 completely dependent on the other generators upstream in the network.

Now it can be expected that both perspectives result in different consequences:

1. The perspective of the most upstream load implies that the load located at the node most upstream in the network is given priority in the assignment of the least expensive generation, followed by the other loads according to an ordering from upstream to downstream. It is shown in figure 16, from which can be observed that L1 has been

assigned generation from only G1, being the cheapest generator, after which L2 was assigned its remaining generation supplemented by G3 (which can physically only supply L2) and G2. This process ultimately results in L3 being assigned with the only generation left unassigned that can physically be supplied to L3, from G2. Evidently, this means that in most cases more downstream loads will experience higher prices than upstream loads, illustrated in table 5, which might be experienced as unfair as loads have no influence in their respective location in the network. On the other hand, this perspective can be argued by the rationale that loads 'higher' up in the network have less generators located upstream of them that can supply them than loads 'lower' down in the network, automatically making them more dependent on a smaller amount of generators.

2. The perspective of the most downstream generator would imply that the most downstream generator would be given priority in the allocation of its generation that was dispatched by the ISO to the loads, followed by the other generators according an ordering from downstream to upstream. This is illustrated in figure 17, where generator G3 is allowed to allocate its heat first followed by G2 and G1. G3's entire generated volume is hereby assigned to L2, being the only load physically able to receive heat from G3. Generator G2 then is next in this process followed by G1, both physically able to supply any load. It can be observed that the heat from these respective generators is not allocated evenly, but in proportion to the net remaining demand of the respective loads. Theoretically it can be expected that this would have a more dampening effect on the price differences throughout the network and decrease volatility, as the generated heat would be distributed more evenly and fairly in comparison with the first perspective.

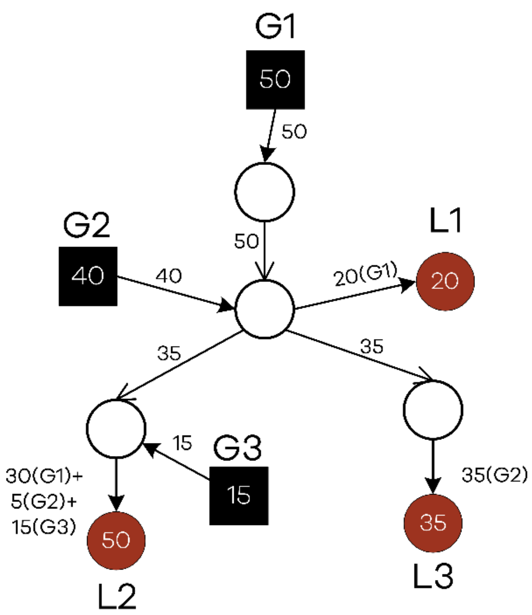


Figure 17 - Assigning generation according 1st perspective

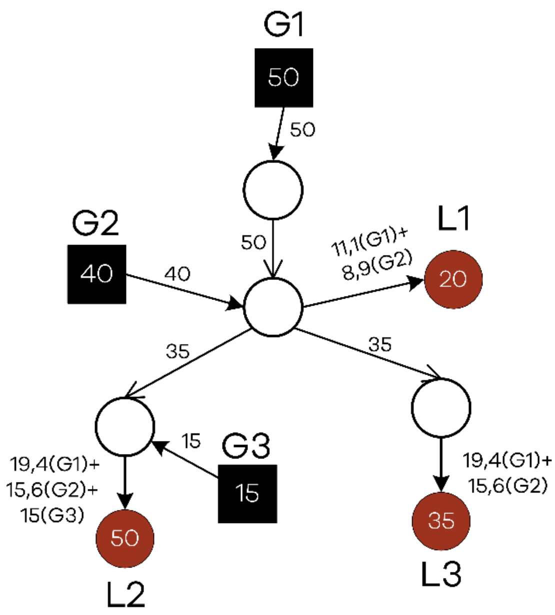


Figure 16 - Assigning generation according 2nd perspective

	L1	L2	L3
Price of generation (1st perspective) (€/GJ)	3	8	5
Price of generation (2nd perspective) (€/GJ)	5	8	5

Table 5 - Price of generation resulting from both perspectives

3.3.3 Choices regarding allocation of transmission losses

The second component comprises the costs of the transmission losses. For the allocation of these costs again different possibilities exist, closely resembling the two perspectives mentioned earlier. The first choice relates to the determination of these costs i.e. pricing of the respective transmission losses. By following the starting points of this hybrid pricing alternative, we assume that generation located upstream is given more value than that located downstream, as it is able to supply a larger share of the network referring to the constraining flow direction and as already mentioned. Inverting this rationale while considering the transmission losses, we assume that transmission losses occurring downstream in the network in turn are more costly than those occurring upstream in the network. After all, the former indirectly also contribute to the latter, again referring to the unidirectional flow of heat.

To this respect, we assume that the most expensive generators have been dispatched last in order to compensate for the transmission losses occurring all the way downstream in the network, i.e. transmission losses are considered last in the merit order. In essence they can be regarded as a perfectly inelastic consumer with a constant demand. Again, this reasoning is followed from downstream to upstream in pricing the rest of the transmission losses. In other words, the transmission losses are priced according the opposite merit order as determined in the economic dispatch by the optimisation software. Situations might occur in which a transmission loss is allocated to multiple generators, if one generator is unable to compensate for the entire loss volume with its generated heat alone. In this case, as opposed to with the pricing of generation, the costs of that transmission loss are determined at the average (variable) generation costs of all respective generators that were assigned to it (and not at the variable generation costs of the most expensive generator assigned to it). This has been done from the viewpoint of increasing transparency and fairness, whereas consumers are not asked to pay more than the exact costs that were incurred. A drawback of this however is that no signal is given to minimise these losses.

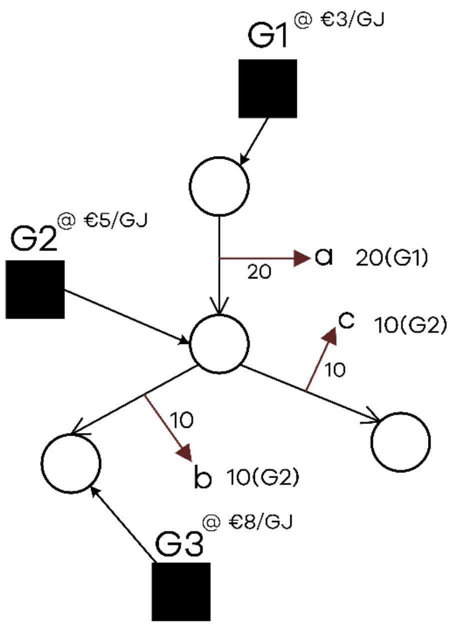


Figure 18 - Pricing of transmission losses by most expensive upstream generator

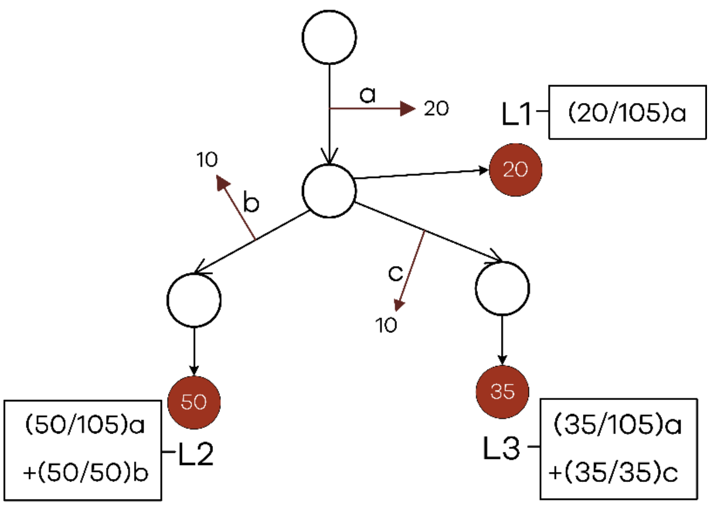


Figure 19 - Allocation of transmission losses to loads in proportion to their individual contribution to each loss

In figure 18 the transmission losses associated with the same fictive economic dispatch from figure 15 have been shown. Following the aforementioned rationale, segment “a” is thus priced by generator “G1”, being the only generator physically able to compensate for these losses, while segments “b” and “c” are priced by generator “G2”, being the most expensive one that can physically compensate for these losses. As the costs of transmission losses are now determined, the second choice relates to the actual allocation of these costs over the respective loads. With respect to honouring the fairness principle, this process has been chosen such that it actually very much resembles the second perspective that was discussed in the context of the assignment of generation. Recalling said perspective, this essentially means that the loads will be charged for their own individual net contribution to each transmission loss. More specifically, the costs of each transmission loss will be distributed over all loads that induce the loss *in proportion to their respective consumption, while respecting the results of the generation assignment process*. This has been illustrated in figure 19, showing that L1, L2 and L3 are all charged for loss “a” in proportion to their demand. In the cases of losses “b” and “c”, loads L2 and L3 are solely charged respectively as they are the only load contributing to that respective loss.

4. NETWORK MODEL

This chapter will start by formulating the purpose of the model and identify the data that is required. Following is the formulation of the optimisation problem that is solved by the model, after which the actual configuration of the network will be presented and discussed. Ultimately, the network model will be verified in the last paragraph.

4.1 Model purpose and data requirements

4.1.1 Modelling question

Since it is unclear what the effects of different pricing mechanisms would be on the performance of the heat market, it presents an interesting area for quantitative research. This requires a quantitative model of which the purpose is to facilitate the answering of research question 4, as specified in the introduction of this thesis;

"What is the effect of Locational Marginal Pricing and alternative pricing mechanisms on the system performance of the wholesale market in different scenarios?"

Ultimately the model should thus provide the means of answering this question. Since the Nodal Pool model aims to transform the heat market into a more open heat market with more cost efficient central optimisation, in which producers of heat are granted equal access to the networks, the focus will lie on the wholesale market with respect to the quantitative model. On the basis of the performance indicators that were specified in section 2.3.2 the model should thus be able to facilitate a comparison of the wholesale market performance under different pricing mechanisms in several scenarios. As the model scheme (figure 3) already revealed, the model study firstly requires a running network model in which the economic dispatch can be determined.

4.1.2 Data requirements

This model will be specified with the software tool Linny-R, as discussed in section 1.5. Since the model aims to represent a physical network, composed by a certain infrastructure, several data is required that covers the latter. This input data comprises the aspects displayed in table 6. It shows that the network is characterised by a load infrastructure, generation infrastructure and transmission infrastructure. Although absent in the table, the actual nodes at which the loads and generation assets are located naturally are incorporated in the network model as well, they however do not require any data.

As will be explained in more detail in section 4.3, several choices have to be made regarding the actual configuration of the network, and thus the application of the data relating to table 6. The data that is used in the network model is taken from the report "Monitoring heat" by Statistics Netherlands (CBS) and Energy Research Centre of the Netherlands (ECN), describing the role of district heating in the Netherlands based on collected information and empirical data from existing district heating networks in the year 2015 (Menkveld et al., 2017). Additionally, data was obtained from energy company Eneco, regarding district heating networks owned by Eneco. Appendix A elaborates on how the data was adapted and used in the network model.

	Input variable	Mathematical notation
Load infrastructure	Location (node)	-
	Demand volume	Q_{demand}
Generation infrastructure	Location (node) + type	-
	Max. capacity	$Q_{generation}^{max}$
	Variable costs	$VC_{generation}$
Transmission infrastructure	Flow direction	-
	Max. flow	Q_{flow}^{max}
	Loss volume	Q_{losses}

Table 6 - Input data requirements for network model in Linny-R

Once the network model has been constructed and the input data has been integrated in it, the dispatch can be determined by letting Linny-R perform the optimisation. This ultimately yields the necessary information regarding the economic dispatch, i.e. which producers are being dispatched with the corresponding generation volumes in order to meet the demand volumes, as well as to compensate for potential transmission losses. In addition, Linny-R also yields the total costs associated with the production of the corresponding generation assets, as well as heat prices corresponding to four out of five pricing mechanisms; system marginal prices, system average cost prices, locational cost prices and the locational marginal prices. The latter are obtained by re-running the model in each demand scenario with an additional increment of demand (+1 GJ) appointed to each load, as explained in sub-section 3.2.4. Furthermore, the model presents the exact transmission flows and losses inherent to each segment of the transmission network, as well as its cost prices in the corresponding pricing mechanism. Ultimately, (part of) the output data (table 7) generated by Linny-R will form the input for the algorithm that will calculate the heat prices according to the proposed hybrid pricing alternative.

	Output variable	Mathematical notation
Load infrastructure	System marginal price	SMP
	Average cost price	ACP
	Locational cost price (demand)	LCP_D
	Locational marginal price	LMP_D
Generation infrastructure	Generation volume	Q_G
	Total costs of generation	TC_G
Transmission infrastructure	Transmission flows	Q_f
	Transmission losses	Q_l
	Cost price (transmission losses)	CP_l

Table 7 - Output data for network model in Linny-R

In figure 20 all the elements relating to the quantitative research come together in the model scheme. As all data requirements and output have now been captured in the 'blueprint' of the quantitative research, the actual configuration of the network in Linny-R will be discussed in section 4.3 on the basis of the data requirements from table 6.

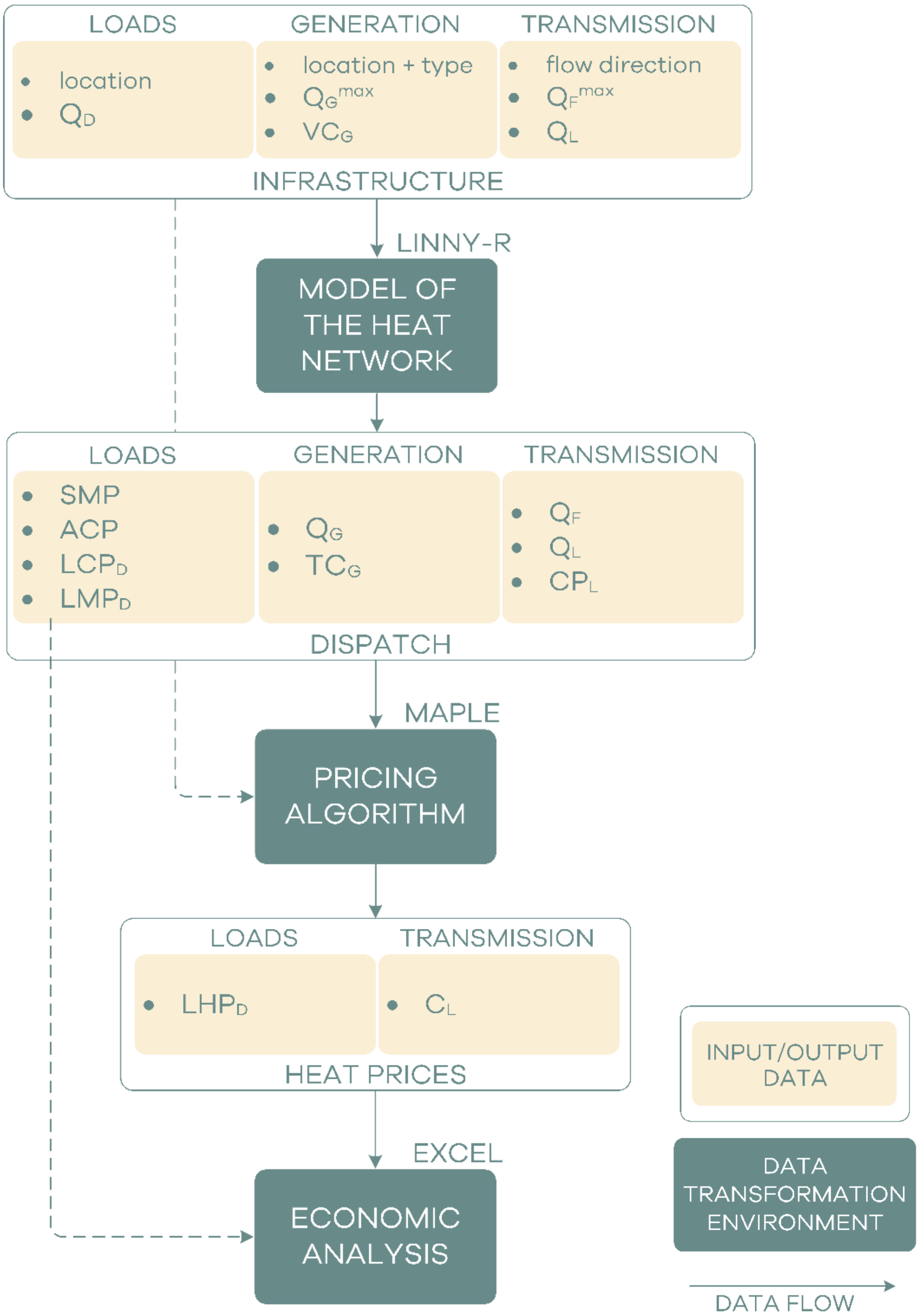


Figure 20 - Model scheme including data requirements

4.1.3 Design variables

Summarising, given a certain network model, the design variables relevant for this study can already be extracted from the concerning research question and amount to:

1. Pricing mechanisms
2. Scenario parameters

Whereas the five pricing mechanisms have already been discussed, the scenario parameters can relate to any of the input variables shown in table 6. In this study only *demand volumes* and *maximum generation capacities* will be used in light of creating different scenarios. Why these parameters are chosen and how they are combined into scenarios exactly will be explained in further detail in section 6.1 and 6.2, respectively.

4.2 Optimisation problem

As already discussed in section 2.2.1, the optimisation problem is framed as an Economic Dispatch (ED) problem. Optimisation problems are usually comprised of three main components (Lukszo, 2015; Tahanan et al., 2015):

1. Objective function
2. Decision variables
3. Constraints

This section will therefore describe the optimisation problem that is solved by the built-in solver from Linny-R (using a branch&bound algorithm) on the basis of the infrastructural elements discussed in the previous section.

4.2.1 Objective function

Obviously the objective is to minimise the total system costs. For each time-step, the objective function will thus be:

$$\min C(Q_G) = \sum_{i=1}^{n} C_i(Q_{G,i}) \tag{3}$$

where:

$$C_i(Q_{G,i}) = VC_{G,i} * Q_{G,i} \tag{4}$$

4.2.2 Decision variables

The decision variables are essentially comprised of the output levels of the different generation units:

$$Q_{G,i} \ \forall i, \ i = 1 \dots n \tag{5}$$

4.2.3 Constraints

Constraints bind the solution space and can be divided into two categories: equality constraints and inequality constraints. The equality constraint applicable to most economic dispatch problems is the energy balance, which in this case prescribes that the total generation output should be equal to the total demand plus the total amount of transmission losses:

$$\sum Q_G = \sum Q_D + \sum Q_l \tag{6}$$

where:

$$\sum Q_G = \sum_{i=1}^{n} Q_{G,i} \tag{7}$$

and:

$$\sum Q_D = \sum_{j=1}^{n} Q_{D,j} \tag{8}$$

and:

$$\sum Q_l = \sum_{k=1}^{n} Q_{l,k} \tag{9}$$

In addition to the equality constraint, we can distinguish one inequality constraint that is relevant for this economic dispatch problem. This constraint prescribes that the generation level of each unit can only vary between zero and its respective max. capacity:

$$0 \leq Q_{G,i} \leq Q_{G,i}^{max} \tag{10}$$

4.3 Network configuration in Linny-R

The network can be configured in endless different ways. One option is to model the existing and planned heat transmission networks. Large parts of the intended infrastructure of the Heat Roundabout however are still not decided on, already making this less feasible. Apart from this, the overall goal of the model study is to demonstrate how different pricing mechanisms could be implemented in a heat network and learn the effects on the performance of the market in different scenarios. Understanding the market outcomes of a rather simple and small network under these conditions first can in turn enable the extrapolation to those in other network configurations. Without loss of generality and for reasons of time, scope and practicality therefore it has been decided to model a fictive network that incorporates some diversity with respect to the configuration and topology of the nodes, loads and generators.

The network model will consist of six nodes, all at which either generator(s), load(s), both or neither can be located (figure 21). Nodes will be numbered according their order from downstream to upstream. Chapter 5 will provide an additional explanation as to why this ordering is done this particular way. Below the exact infrastructure of the network will be explained. Recalling the working principles of the Linny-R software it should be stressed that for the model to work properly, it must be configured by placing *products* (ovals in Linny-R) only as inputs and/or outputs of *processes* (squares in Linny-R), connected by means of *links*. These three elements are the building blocks of the model in Linny-R.

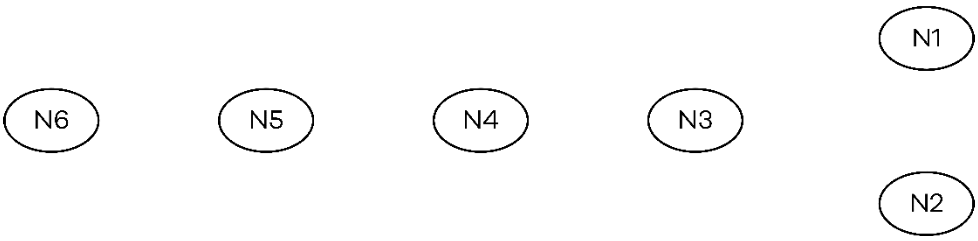


Figure 21 - Node configuration

4.3.1 Load infrastructure

The load infrastructure will consist of five loads, spread out across the network. They will be numbered according to the nodes at which they are located, shown in figure 22. Loads have a certain hourly heat demand volume. The load infrastructure can thus be described as a set of loads $\{j\}$ that all have their own demand volume Q_D at a certain time t:

$$Q_{D,j,t} \; \forall j, \; j = 1,2,3,4,6 \tag{11}$$

As already mentioned in sub-section 4.1.2, the data being used is elaborated upon in appendix A. Hourly demand volumes used for all loads are captured by the appendix as well.

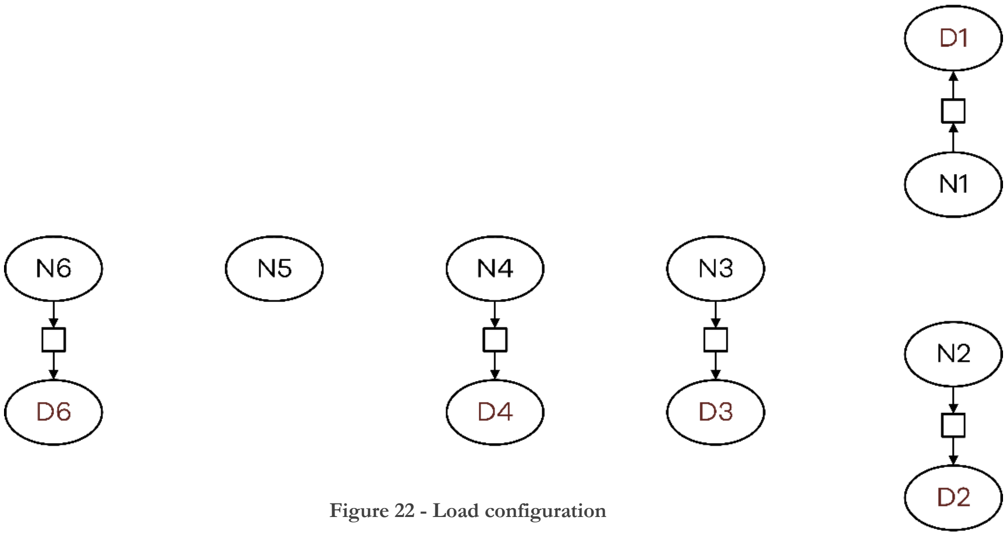


Figure 22 - Load configuration

4.3.2 Generation infrastructure

The generation infrastructure will consist of five generators in total, shown in figure 23. They will be numbered in chronological order relating to their position on the network from upstream to downstream, starting from seven, thus continuing the numbering from the last respective node. As opposed to the load infrastructure, there is no specific reason behind this numbering process. Generators have a certain generation volume that is bound to their respective max. output capacity. They can all be characterised by their own respective variable generation costs. The generation infrastructure can thus be described as a set of generators $\{ i \}$ that all have a certain generation volume Q_G at a certain time t, according to their variable costs VC_G bound to a max. output capacity $Q_G{}^{max}$:

$$Q_{G,i,t} \; \forall i, \; i = 7 \dots 11 \tag{12}$$

$$Q_{G,i}^{max} \; \forall i, \; i = 7 \dots 11 \tag{13}$$

$$VC_{G,i} \; \forall i, \; i = 7 \dots 11 \tag{14}$$

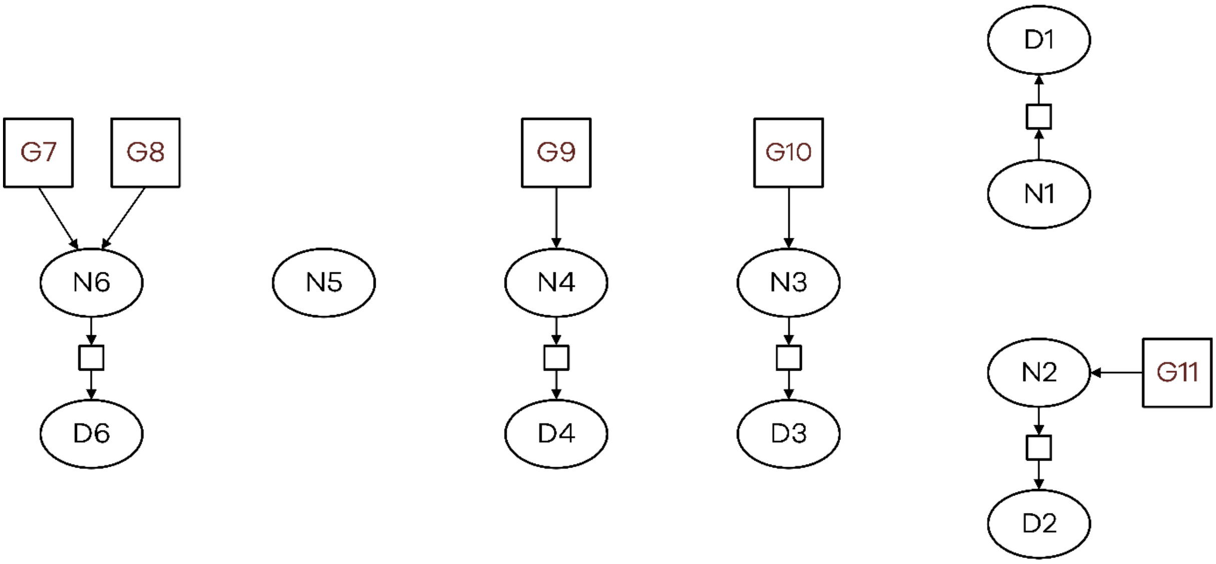


Figure 23 - Generation configuration

The maximum generation capacities and variable costs of the generators again are based on the data discussed in appendix A. Table 8 summarises the aforementioned properties belonging to each generator.

Generator	Variable costs (€/GJ)	Maximum capacity (GJ)
G7	3	1.703
G8	7	2.335
G9	8	196
G10	10	888
G11	5	98

Table 8 - Variable costs and maximum capacities of generators

4.3.3 Transmission infrastructure

The transmission infrastructure is essentially comprised of transmission lines that connect the nodes, shown in figure 24. As there are six nodes in the network, this logically means that there will be five pipelines between them. They will be numbered by the numbers of both nodes that they connect in such a way that designates the flow direction. Transmission pipelines normally have a certain max. transmission capacity. In this research however these max. capacities are taken infinite, recalling that congestion is not central in this thesis. For the sake of completeness this attribute will be noted nevertheless. Every transmission pipeline can be characterised by a certain amount of transmission losses, depending on their length, and the difference between its own temperature and the outside temperature, as was already explained in sub-sections 2.2.1 and 3.3.1. These transmission losses are assumed a binary constant, meaning they either occur at a fixed level, or they don't occur at all. The transmission infrastructure can thus be described as a set of pipelines $\{\, k \,\}$ that have a certain transmission flow Q_f and a certain amount of transmission losses Q_l at a certain time t:

$$Q_{f,k,t}\ \forall k,\ \ k = \{\,\{6,5\},\{5,4\},\{4,3\},\{3,2\},\{3,1\}\,\} \qquad (15)$$

$$Q_{l,k,t}\ \forall k,\ \ k = \{\,\{6,5\},\{5,4\},\{4,3\},\{3,2\},\{3,1\}\,\} \qquad (16)$$

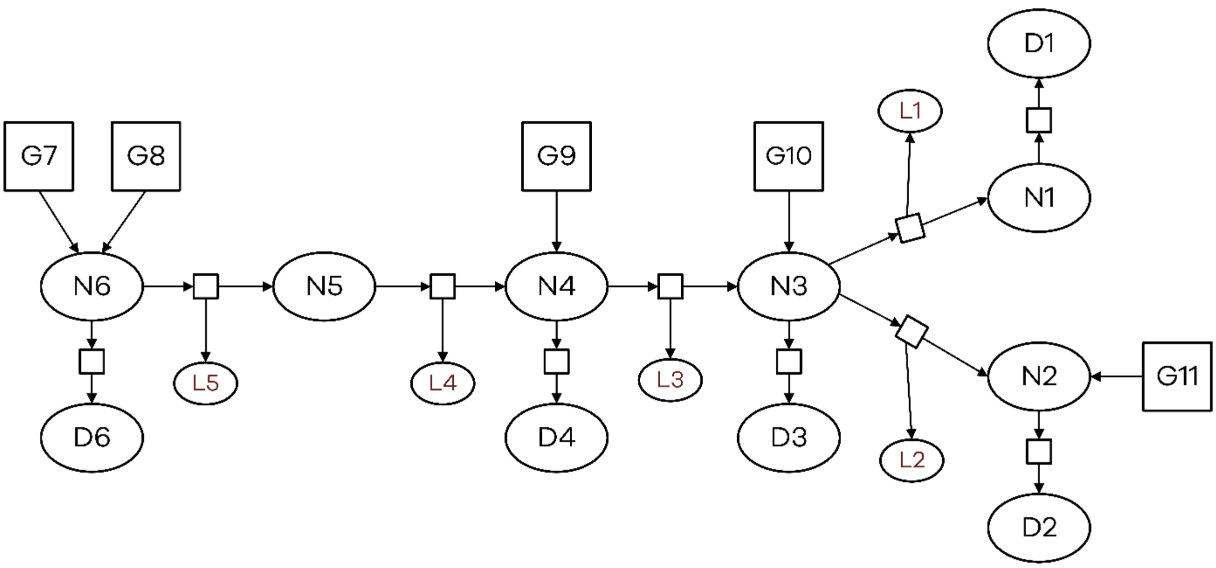


Figure 24 - Transmission configuration

It can be seen that node N5 actually has no generators or loads connected to it. Deleting this node and adding losses L5 and L4 together in the model would not have changed the results. Still it has been chosen to include such a node in view of verifying that the algorithm presented in the next chapter works in every potential network configuration, and increase its robustness. The set of transmission pipelines also reveals that there is a junction at the third node in the network. Figure 25 shows the network as modelled in Linny-R. It shows that the transmission segments have been modelled in a relatively complicated and more devious way than suggested above in figure 24. The reason for this is twofold: firstly, as nodes have been modelled as products, the Linny-R software prescribes that products can only serve as input or output for processes, pointing to the necessity of a transport process connecting each node, instead of just modelling the transmission pipelines as links; secondly, it relates to the assumption that was made with regard to the transmission losses (being modelled as products), prescribing that losses should only occur when actual heat flows across a transmission pipeline. As Linny-R lacks a built-in binary variable that could organise this, the transmission losses are modelled by means of a dummy-process whose bounds depend on the actual process that represents the heat transport flow over each respective transmission segment.

The table below captures the entire infrastructure of the network, categorised by the three elements of which the model in Linny-R is comprised. It should be noted that the demand volumes corresponding to the loads and transmission loss volumes corresponding to the transmission segments are modelled as products with only incoming links. The actual nodes in the network are modelled as products with both incoming and outgoing links, for which Kirchhoff's law applies[2], making them transhipment nodes.

Category	**Function**
Product (circles/ovals)	It represents the demand of a load
	It represents the losses of a transmission segment
	It represents a transhipment node
Processes (squares/rectangles)	It represents a generator
	It represents a load
	It represents a transport process or a loss (dummy-)process
Links	It acts as the connection between product and process

Table 9 – Elements of network model in Linny-R

[2] Kirchhoff's law prescribes that the sum of inflow and outflow of a node in a certain network is zero.

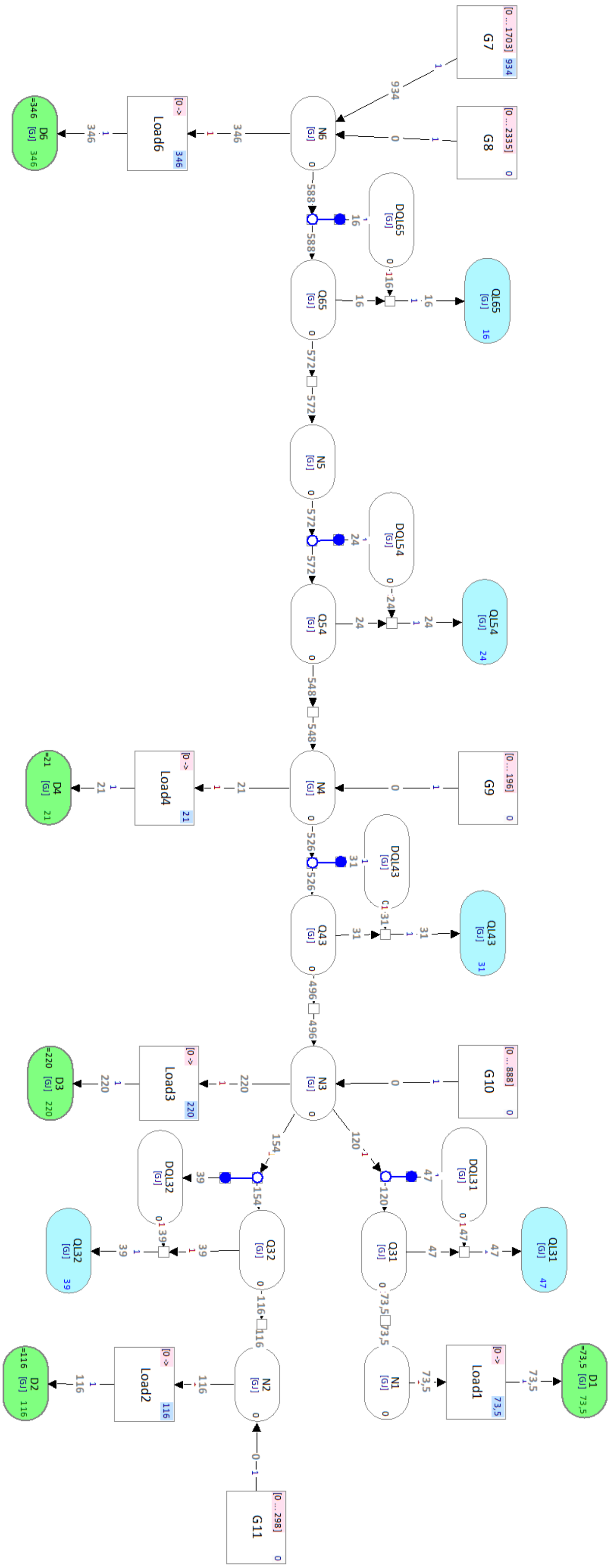


Figure 25 - Network model in Linny-R

4.4 Model verification

This section aims to verify that the network model has been constructed and integrated into the software tool in conjunction with the conceptualisation, and that the output is being generated in the correct way. Also it will be verified if the heat prices corresponding to the conventional pricing mechanisms are calculated correctly. This will be done by means of a demonstration case, following the general structure of the model scheme from figure 20.

Firstly, by explaining the behaviour of the network model over an entire year by means of the generation curve and the transmission loss curve, it will be verified that the economic dispatch is accurately determined on the basis of the load curve that is used as input data. Subsequently, it is checked that the heat prices corresponding to the four conventional pricing mechanisms are correctly generated by Linny-R by taking two time-steps representing the extreme values of the input data.

4.4.1 The load curve

Section 4.2 and appendix A already explained how the available data was adapted and implemented in the model with respect to the network configuration. For the demonstration case, we will first inspect the model behaviour by running it on the basis of the hourly demand data for a timespan of one whole year. Figure 26 shows the corresponding unsorted load curve, in which the hourly total demand volume of all loads in the network combined have been plotted over a time span of 8784 hours[3]. The network model should essentially be able to determine an economically optimal dispatch on the basis of this load curve.

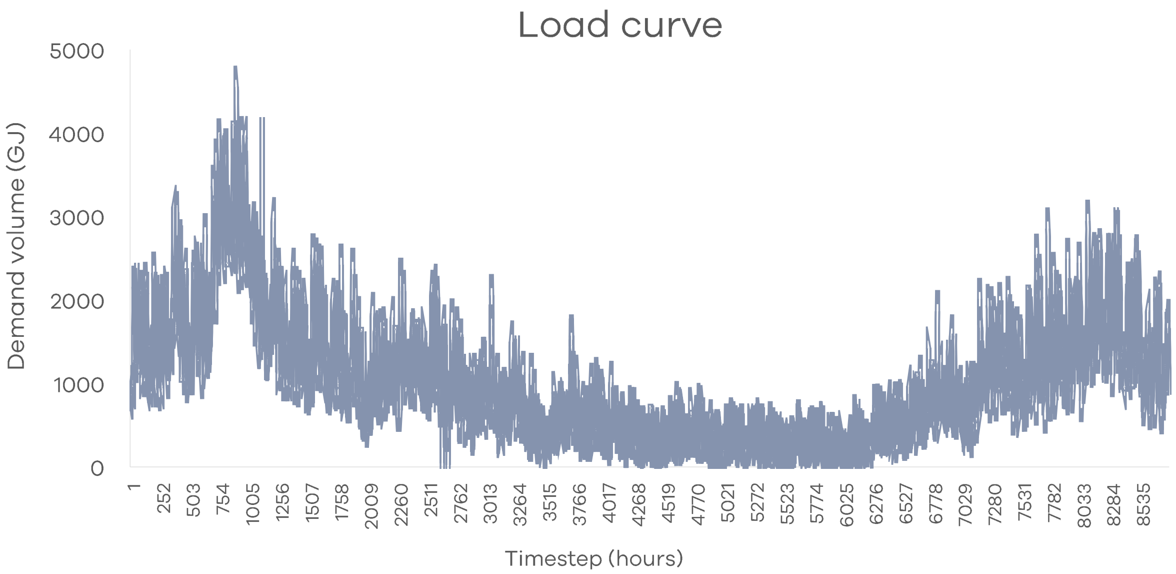


Figure 26 - Load curve

The load curve clearly shows the seasonal fluctuations, as the demand for heat is directly correlated with the outside temperature. Peak demand can be found in the first months of the year, whereas naturally demand drops significantly during the summer months. The expectation is thus that the most expensive generators in the network will only be dispatched in times of relatively high demand, assuming that the least expensive 'base-load' generators have adequate generation capacity

[3] The hourly demand data is from 2012, which was a leap year and thus had 366 days instead of 365

and that they are located upstream (referring to the unidirectional flow constraint). The load curve can also be sorted by the duration of the respective amount of aggregated demand that is present during the year. Figure 27 displays this load duration curve, from which becomes clear that during a very small period of the year, the demand volume nearly doubles relative to the 'base-load'.

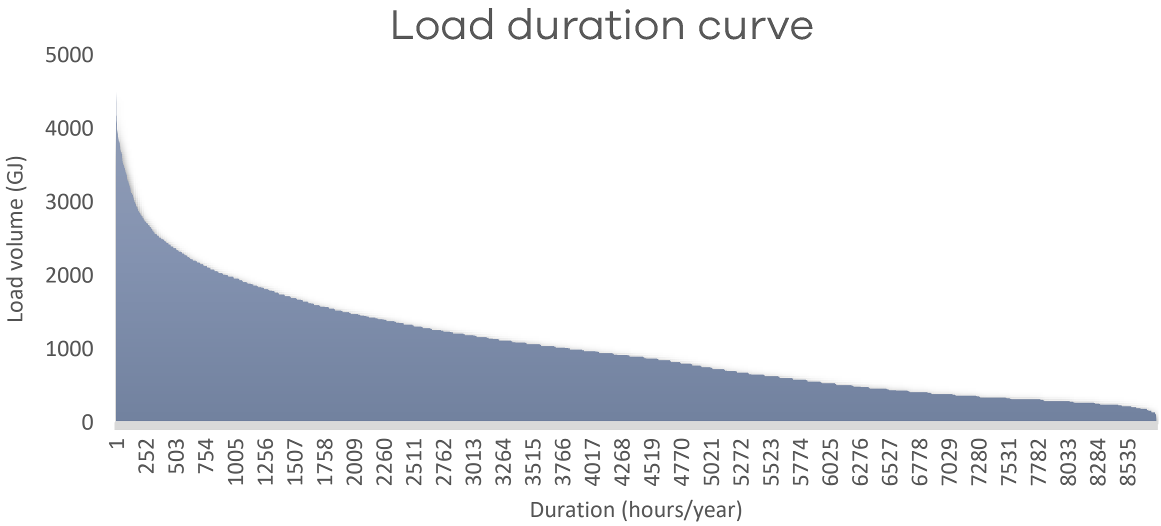


Figure 27 - Load duration curve

4.4.2 The generation curve

The economic dispatch is determined by having Linny-R run the optimisation. The generation output for all dispatched generators has been plotted in the form of a generation curve and is displayed in figure 28. The legend shows the generators in the order of their respective variable generation costs (i.e. in the merit order). The curve's behaviour seems to match with the load curve from figure 26, while it is clearly visible that the least costly generation units run during the largest part of the year, and vice versa.

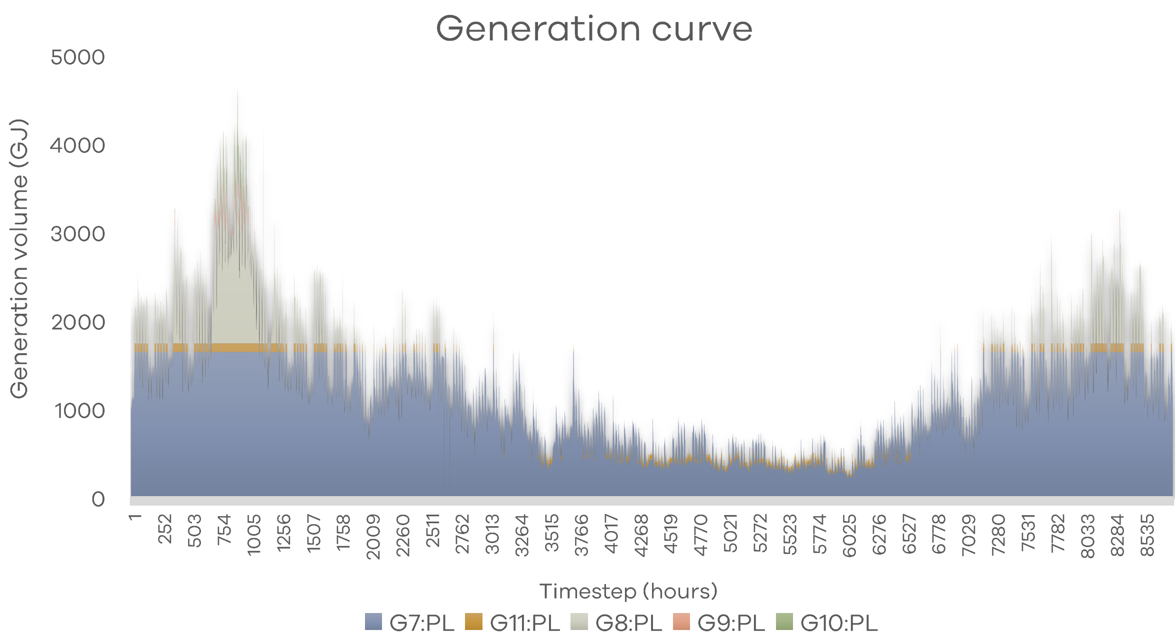


Figure 28 - Generation curve

Again, we can verify this by sorting the generation output of the respective generators by the duration of their respective output volumes, yielding a generation duration curve. This curve is displayed in figure 29, in which can be observed that indeed generator G7 runs throughout the whole year and thus provides the base-load, while G11 is also dispatched during a large part of the year providing node N2 with cheap local generation. The most expensive generators G9 and G10 are only being dispatched during the real demand spikes, matching the sorted load duration curve and expectations.

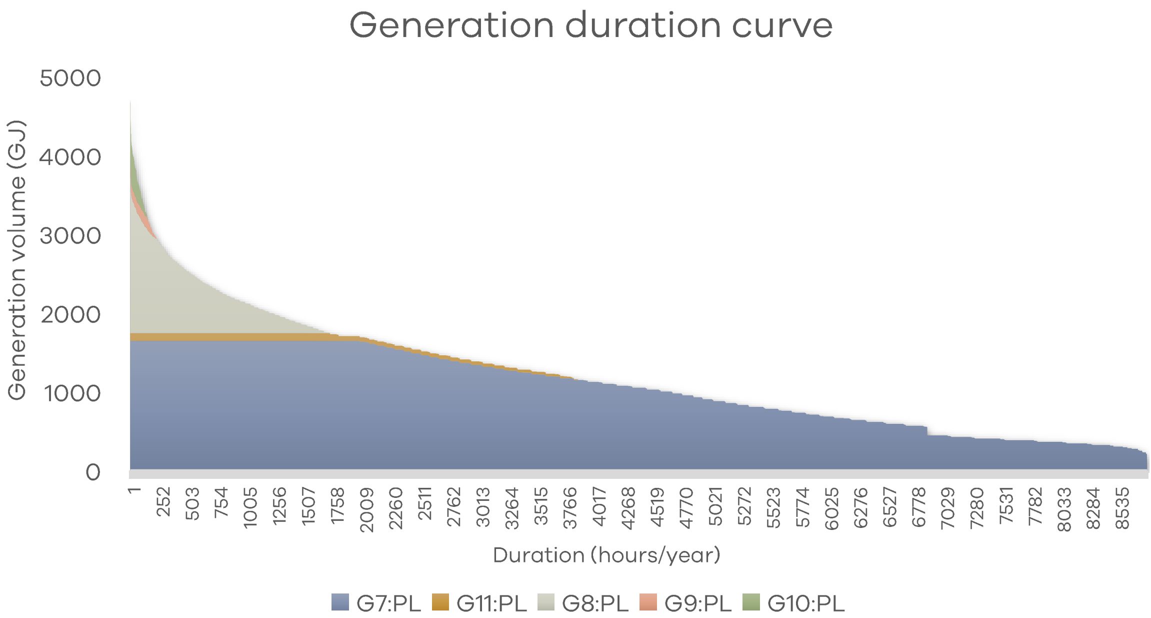


Figure 29 - Generation duration curve

A final observation from the generation duration curve is the sudden vertical drop somewhere around 6.800 hours. To explain this, we have to refer back to the energy balance from section 4.2, stating the sum of generation should be equal to the sum of demand volume plus transmission losses. This means that the generation duration curve cannot be explained by the load curves solely, as part of the generation volume is lost in the form of transmission losses. The sudden drop in the generation duration curve can thus be explained by one or more transmission segment(s) not being used for transport during 100% of the year, while the verticality of the drop is attributable to the binary constant nature of the assumed losses. This should however be verified by plotting an additional graph capturing the transmission losses and their respective duration.

4.4.3 The transmission loss curve

This additional graph has been plotted in figure 30 showing exactly when losses occur on which transmission segment. According to the conceptualisation of the transmission infrastructure from sub-section 4.3.3, transmission losses should either occur on a constant level, or not occur at all. This behaviour is verified by the graph in the figure, referring to the horizontal lines and sudden vertical drops in the graph. While most transmission losses occur during the entire year, especially the transmission segment between node N3 and node N2 shows some divergent behaviour. Again, when consulting the load and generation curves at the corresponding time-span, this behaviour can mostly be observed in times of relatively low demand. The fact that this behaviour is so clearly visible for node N2 can be explained by generator G11 being located at said node. In times of low demand, this generator thus has enough capacity to solely meet the demand of Load 2, abating the need for additional heat transport.

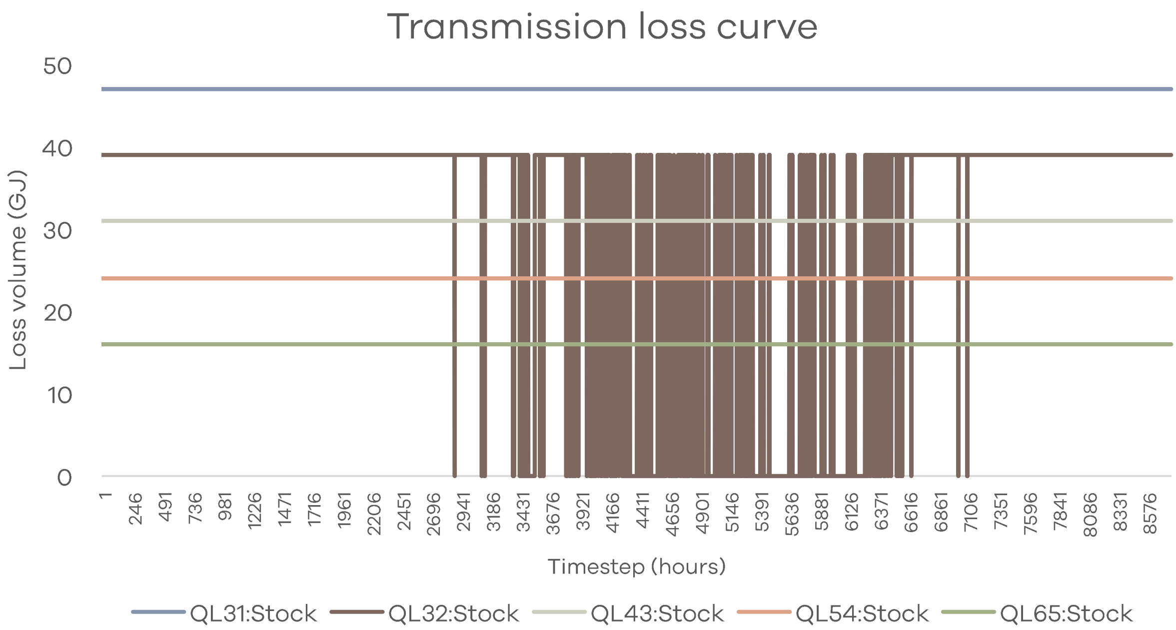


Figure 30 - Transmission loss curve

Again, we can verify this by sorting the amount of transmission losses by the duration of their occurrence. Figure 31 shows this loss duration curve, clearly showing that the aforementioned transmission segment between N3 and N2 is indeed not being used for transport during approximately 20% of the year, explained by the available local generation at node N2. The drop in the graph, where said transmission segment becomes unused, corresponds to the sudden drop from the generation duration curve in figure 29. The network model in Linny-R thus seems to behave as expected beforehand, suggesting that it has been modelled correctly.

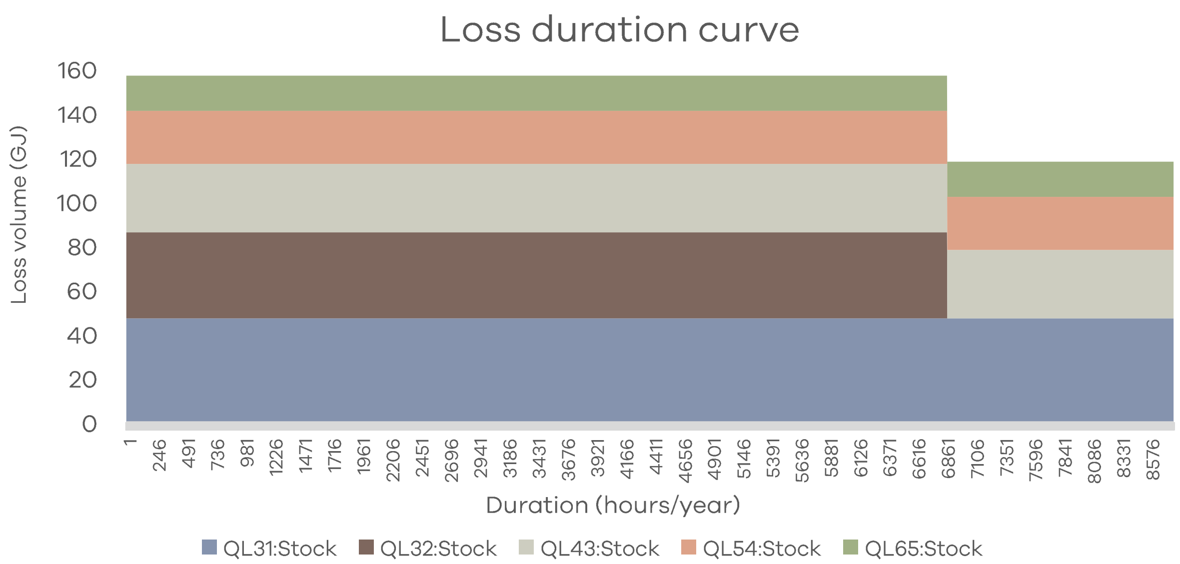


Figure 31 - Loss duration curve

4.4.4 Heat price calculation

For the verification of the heat price calculation corresponding to the pricing mechanisms conceptualised in section 3.2 and 3.3, two extreme values are taken from the input data, i.e. a minimum demand sample and a maximum demand sample. These moments occur at time-step 6070 and 897, during a day in the second week of September and the first week of February, respectively. The demand volumes corresponding to both samples are presented in table 10, from which it can be observed that demand volumes for each load differ with a factor of approximately 41 between the minimum and the maximum sample. In essence, all loads feature roughly the same demand pattern due to the way the available demand data was used.

		Load 1	Load 2	Load 3	Load 4	Load 6	Total
MIN (6070)	**Demand (GJ)**	10	16	31	3	49	111
MAX (897)	**Demand (GJ)**	430	676	1.291	123	2.031	4.553

Table 10 - Demand volumes in time-step 6070 (minimum) and time-step 897 (peak)

Table 11 shows the transmission losses occurring throughout the several transmission segments in both situations. From this it can be observed that all transmission segments are being used except for QL32 in the minimum demand sample, explained by the presence of local generator G11 at node N2 which is able to solely supply the load located there.

		QL 31	QL 32	QL 43	QL 54	QL 65	Total
MIN (6070)	**Losses (GJ)**	47	0	31	24	16	118
MAX (897)	**Losses (GJ)**	47	39	31	24	16	157

Table 11 - Transmission losses in time-step 6070 (minimum) and time-step 897 (peak)

Besides the transmission losses, additional information regarding the economic dispatch is displayed below in table 12, showing the generators in the merit order and their respective dispatched generation volumes and accompanying generation costs in both samples. Since the least-cost dispatch forms the starting point for all pricing mechanisms, this information is relevant in light of verifying that heat prices are being calculated correctly.

	Variable costs (€/GJ)	Installed capacity (GJ)	Dispatched volume (GJ)		Generation costs (€)	
	-	-	MIN (6070)	MAX (897)	MIN (6070)	MAX (897)
G7	3	1.703	212	1.703	637	5.109
G11	5	98	16	98	82	490
G8	7	2.335	-	2.335	-	16.345
G9	8	196	-	196	-	1.568
G10	10	888	-	378	-	3.781
TOTAL			229	4.710	720	27.293

Table 12 - Generation volumes and costs of dispatched generators in time-step 6070 (minimum) and 897 (peak)

From the table it can be observed that in the maximum demand sample generator G10 still is not dispatched fully but has some capacity left. The sum of demand and transmission losses in this sample however is equal to the sum of dispatched generation volume, verifying that the energy balance is honoured and that the network is indeed slightly over-dimensioned in order to provide security of supply.

System Marginal Prices

As table 12 shows, generator G11 is the marginal generator in the minimum demand sample while G10 is the marginal generator in the peak demand sample. The system marginal prices should thus correspond to both generators' respective variable costs, verified in table 13.

		Load 1	Load 2	Load 3	Load 4	Load 6
MIN (6070)	**SMP (€/GJ)**	5	5	5	5	5
MAX (897)	**SMP (€/GJ)**	10	10	10	10	10

Table 13 - System marginal prices in time-step 6070 and 897

Average Cost Prices

The average cost prices that were generated for both samples are shown in table 14. As with the system marginal prices, the average cost price applies to the entire system. Since transmission losses are hereby socialised over all loads, disregarding their potential relative contribution those losses, the average cost price is calculated by dividing the total generation costs by the total demand volume of the system. This is again verified by the generated prices shown in the table below.

		Load 1	Load 2	Load 3	Load 4	Load 6
MIN (6070)	**ACP (€/GJ)**	6,5	6,5	6,5	6,5	6,5
MAX (897)	**ACP (€/GJ)**	5,9	5,9	5,9	5,9	5,9

Table 14 - Average cost prices in time-step 6070 and 897

Locational Marginal Prices

The locational marginal prices that were generated in both samples are shown in table 15. Since in both samples no changes in the accompanying transmission losses occur, these prices should correspond to the variable costs of the generator needed to supply each respective load with an additional increment of demand, i.e. the change in system costs. This is verified by the prices in table 15, from which it can be observed that prices are the same for all loads in both samples, except for Load 2 in the minimum demand sample. This is explained by the presence of local generator G11 that is located at the same node. Although its variable costs are higher than those of G7, supplying the rest, clearly it is a less expensive option to avoid the additional transmission losses on the segment would G7 supply Load 2 as well instead of G11. In the maximum demand sample the most expensive generator (G10) is marginal for all nodes, as all other generators have already been fully dispatched, which is also verified by the ED-data from table 12.

		Load 1	Load 2	Load 3	Load 4	Load 6
MIN (6070)	**LMP (€/GJ)**	3	5	3	3	3
MAX (897)	**LMP (€/GJ)**	10	10	10	10	10

Table 15 - Locational marginal prices in time-step 6070 and 897

Locational Cost Prices

The locational cost prices for both samples are shown in table 16. Costs of transmission losses are not yet included in these LCPs, as their allocation can be done only by the algorithm that will be presented in the next chapter. In the minimum demand sample it can be observed that the LCPs are similar to the LMPs, since generator G11 solely supplies Load 2 while the other loads are all supplied by generator G7. All loads thus receive their heat from only one generator, i.e. no heat received by loads has 'mixed' origins, which means that the locational cost prices should equal the variable costs of those respective generators. In the maximum demand sample, where all generators have been dispatched, this is clearly not the case. All loads hereby receive their demand volume from multiple different generators, which is verified by the fact that the LCPs are not equal to the variable costs of one particular generator. What stands out in this sample is that prices appear to decrease gradually by going from downstream (Load 1) to upstream (Load 6), with the exception of Load 2. This can be explained by the fact that the generators located upstream are simply less expensive than those downstream, again with the exception of local generator G11 at the node where Load 2 is located being the second cheapest generator.

		Load 1	Load 2	Load 3	Load 4	Load 6
MIN (6070)	**LCP (€/GJ)**	3	5	3	3	3
MAX (897)	**LCP (€/GJ)**	6,3	6,1	6,3	5,6	5,3

Table 16 - Locational cost prices (excluding transmission losses) in time-step 6070 and 897

The locational cost prices of the transmission losses are calculated in the same manner as those of the loads, and are shown in table 17. In the minimum demand sample transmission segment QL32 supplying Load 2 is not in operation, explaining why its price is equal to zero. It can be observed that in the maximum demand sample the transmission losses' prices correspond to the LCPs of the loads that are located downstream of those respective transmission segments, again with the exception of Load 2. This is explained by the same reason as mentioned in light of table 16.

		QL31	QL32	QL43	QL54	QL65
MIN (6070)	**LCP (€/GJ)**	3	-	3	3	3
MAX (897)	**LCP (€/GJ)**	6,3	6,3	5,6	5,3	5,3

Table 17 - Locational cost prices of transmission losses in time-step 6070 and 897

Summarising, it has been verified that the heat prices corresponding to the four conventional pricing mechanisms are calculated in the correct way. In the case of locational cost pricing however the heat price calculation is not yet done, as it should be supplemented by a calculation that allocates the costs of the transmission losses over the loads. As already mentioned, this will be done by the algorithm that will be discussed in the chapter that follows after this.

5. LOCATIONAL HYBRID PRICING ALGORITHM

In this chapter the locational hybrid pricing alternative will be given shape and translated to an algorithm. The first paragraph will discuss the general principles of the algorithm and identify the main tasks it has to perform. Subsequently, the mathematical basis of the required output will be formulated so that it can be translated to pseudocode in the paragraph that follows. Ultimately, the algorithm will be verified in the last paragraph.

5.1 General principles of the pricing algorithm

Based on the key assumptions that were presented in sub-section 3.3.1 an alternative 'hybrid' pricing mechanism was proposed. As already mentioned, this pricing mechanism shows resemblance with both marginal cost pricing and average cost pricing, and should be considered as an ex-post economic tool as it takes the least-cost economic dispatch as determined in Linny-R as a starting point, not altering it. In the same sub-section it was concluded that prices generated by this pricing mechanism consist of two general components:

1. Price of generation
2. Price of transmission losses

The following sub-sections will describe the mathematical basis of this pricing mechanism that will subsequently be translated to an algorithm. Referring to the aforementioned two price components, and the key principles discussed in section 3.3 the algorithm is required to fulfil the following main tasks:

Price component	Main task of algorithm
Price of generation	1. Assign dispatched generation to loads
Price of transmission losses	2. Assign transmission losses to dispatched generators
	3. Allocate transmission losses to loads

Table 18 - List of main tasks of pricing algorithm

In light of the first main task, as discussed in sub-section 3.3.2, two 'perspectives' were proposed with respect to the approach regarding the assigning of the dispatched generation to the loads. It was expected that the (2^{nd}) perspective of the most downstream load would have a more dampening effect on the prices throughout the network, while the (1^{st}) perspective of the most upstream load would create more disparity and volatility. The latter however does places more emphasis on the locational dependence of generation inherent to the flow directions in the network, which can theoretically result in stronger economic investment signals. For the construction of the algorithm therefore the (1^{st}) perspective of the most upstream load is chosen to be incorporated.

5.2 Mathematical basis

5.2.1 Price composition

As explained the heat prices obtained by the hybrid pricing alternative consist of two components: 1) the price of generation and 2) the price of transmission losses. It has to be noted that costs are not necessarily the same as prices, however costs form the basis of the prices that will be calculated by the algorithm. Therefore it is important to first define these two cost components in terms of how they are constructed mathematically. In mathematical terms, the different types of costs that can be attributed to a certain load j would be as follows:

$$VC_{heat,j} = \frac{C_{generation,j} + C_{losses,j}}{Q_{demand,j}} \tag{17}$$

where:

$$VC_{heat,j} = Variable\ costs\ of\ heat\ for\ load\ j\ (€/GJ)$$
$$C_{generation,j} = Costs\ of generation\ for\ load\ j\ (€)$$
$$C_{losses,j} = Costs\ of\ losses\ for\ load\ j\ (€)$$
$$Q_{demand,j} = Demand\ volume\ of\ load\ j\ (GJ)$$

Firstly, the costs of generation are built up as follows:

$$C_{generation,j} = \sum_i TD_{i,j} \cdot VC_{G,i} \tag{18}$$

where:

$$TD_{i,j} = q_{i,j} \tag{19}$$

if i is located upstream of j, calculated according to the merit order until:

$$\sum q_{i,j} = Q_{D,j} \tag{20}$$

where:

$$TD_{i,j} = q_{i,j} = the\ amount\ of\ heat\ transported\ from\ Generator\ i\ to\ Load\ j\ (GJ)$$

As the merit order essentially comprises all (available) generators based on their respective variable costs in ascending order, it can be expressed as a vector:

$$(a_1, \ldots, a_n) \tag{21}$$

such that:

$$VC_{a_i} \leq VC_{a_{i+1}} \tag{22}$$
$$i \neq j \rightarrow a_i \neq a_j \tag{23}$$
$$a_i \in \{1, \ldots, N\}\ \forall i \tag{24}$$

Secondly, the costs of transmission losses are calculated according the opposite merit order, following the assumed principles as explained in sub-section 3.3.3, being allocated to the most expensive generators. Hence, we can define these costs as:

$$C_{losses,j} = f_{loss}(Q_{L,k}, N) \tag{25}$$

$$f_{loss}(q,i) = \begin{cases} f_{loss}(q, i-1) & if\ Q_{a_i} = 0 \\ VC_{a_i} \cdot q & if\ Q_{a_i} \geq q \\ VC_{a_i} \cdot q + f_{loss}(q - Q_{a_i}, i-1) & otherwise \end{cases} \tag{26}$$

5.2.2 Required output

In principle, these definitions of the different cost components form the mathematical basis of the algorithm. In principle, the algorithm is thus only required to calculate two components in order to derive the wholesale prices per node. As already mentioned, costs may not merely be regarded the same as prices when applying marginal pricing mechanisms. The latter prescribes that the (marginal) price of generation is equal to the variable costs of the *marginal generator*. Since the assumed principles regarding the price of generation require so-called 'nodal' merit orders, we therefore redefine this first price component and adapt equation 17 accordingly. Ultimately, this yields the following output required by the algorithm:

$$LHP_j = P_{generation,j} + \frac{C_{losses,j}}{Q_{demand,j}} \tag{27}$$

where:

$$P_{generation,j} = \max(VC_i : Q_i > 0)$$
$$= Variable\ costs\ of\ the\ most\ expensive\ generator\ assigned\ to\ load\ j\ (€/GJ)$$
$$LHP_j = Locational\ hybrid\ price\ for\ load\ j\ (€/GJ)$$

Since we only defined the price composition of an amount of heat for a certain load in the most general sense, we will eventually have to translate this to an algorithm in which this is defined for all loads. In light of the principles assumed and discussed in section 3.3, including the key assumption that it should be reproducible and thus applicable to a network in any possible configuration, both components of the required output will be expressed mathematically enabling the design of an algorithm.

In light of the first price component the most important choice amounted to the assignment of the dispatched generation according to the perspective of the most upstream load, i.e. giving upstream loads precedence in this process. This process determines the nodal merit orders and should thus yield the 'marginal' generator for each load. As was explained, the flow direction in the network constrains this process, as generators can only physically provide heat to loads that are located at nodes downstream of themselves, or at the same node. The set of generators will henceforth be expressed in a vector that orders them from upstream to downstream while considering their variable costs:

$$g_i \in \{1, \dots, N_G\} \tag{28}$$

where:

$$i \neq j \rightarrow g_i \neq g_j \tag{29}$$
$$i > j \rightarrow then\ generator\ g_i\ is\ downstream\ of\ generator\ g_j,$$
$$or\ on\ the\ same\ node\ but\ has\ larger\ variable\ costs\ than\ generator\ g_j$$

The same can be done for the loads (demand) that are present throughout the network:

$$d_i \in \{1, \dots, N_D\} \tag{30}$$

where:

$$i \neq j \rightarrow d_i \neq d_j \tag{31}$$
$$i > j \rightarrow then\ load\ d_i\ is\ downstream\ of\ load\ d_j$$

The second main task the algorithm has to execute comprises the assignment of transmission losses to generators. As was already discussed, this process happens according the opposite merit order, assigning them to the most expensive generators first. This was also shown by equation 26, from which can also be derived that a certain transmission loss can be assigned to multiple generators, in the cases where one generator has insufficient generation output to account for the entire transmission loss. In view of the algorithm, this calls for a definition of all loss-segments present in the network, ordered from upstream to downstream:

$$l_i \in \{1, \dots, N_L\} \tag{32}$$

where:

$$i \neq j \rightarrow l_i \neq l_j \tag{33}$$

$$i > j \rightarrow then\ transmission\ loss\ l_i\ is\ downstream\ of\ transmission\ loss\ l_j$$

Subsequently, the third and final main task of the algorithm aims to allocate the costs of the transmission losses that were just determined to the loads that induce them in proportion to their net consumption. In this sense, *net* consumption of a load means that additional heat received by a load from a location located downstream of a transmission loss segment, i.e. heat that does not actually contribute to said loss segment, should be deducted from the loads initial consumption in order to obtain its net consumption with respect to said transmission loss. In light of the aforementioned it is helpful to define an additional variable incorporating the constraining flow direction that verifies if a path exists from a certain generator, loss segment and/or load in the network. This variable is specified as a binary indicator:

$$u(i, j) \in \{0,1\} \tag{34}$$

where

$$u(i, j) = 1\ if\ there\ is\ a\ path\ from\ i\ to\ j, and\ 0\ otherwise$$

5.3 Designing the algorithm

The algorithm is required to produce the output as discussed in the previous sections, while incorporating the corresponding choices that were made in section 3.3. While the required output relating to the hybrid heat prices is twofold (equation 27), they are derived by performing three consecutive main tasks. Once a certain amount of generation (and its corresponding costs) have been assigned to a load or transmission loss, it cannot be assigned again, naturally. How these tasks are performed chronologically will thus influence the outcomes, pointing to the importance of the order in which the main tasks are programmed in the algorithm. Recalling the notion from sub-section 3.3.1 that transmission losses essentially are assumed most costly in the network, they should therewith be assigned first in the algorithm. This would amount to the main tasks being performed by the algorithm in the following order:

1. Assign transmission losses to dispatched generators;
2. Assign dispatched generation to loads;
3. Allocate costs of transmission losses to loads.

In the following sub-sections these main tasks are translated to pseudo-code, accompanied by some explanatory annotations.

5.3.1 Assigning transmission losses to dispatched generators

The pseudocode corresponding to the assignment of the losses to the dispatched generators is displayed in table 19. Annotations are presented below in a manner that they correspond to the numbering in the pseudocode.

1. For all generators make an auxiliary variable representing their remaining generation and set it equal to their initial generation output.
2. For all loss segments make an auxiliary variable representing their heat volume still to be accounted for and set it equal to their initial amount of heat losses. Also make a variable that represents the costs of those loss segments and set it to zero;
3. For all generators set the variable representing transmission from generators to losses to zero if there is no path between the generator and loss segment or if the generator's output volume is zero or if the amount of losses is zero;
4. Otherwise, if the amount of losses still to be accounted for is smaller than or equal to the remaining generation output of the generator set the transmission from the generator to the loss segment equal to the amount of losses, add the amount of losses multiplied by the marginal costs of the generator to the costs of the loss segment, subtract the amount of losses from the generation output of the generator and set the remaining amount of losses to be accounted for to zero;
5. Otherwise, set the transmission from the generator to the loss segment equal to the amount of remaining generation output of the generator, add the amount of remaining generation output multiplied by the marginal costs of the generator to the costs of the loss segment, subtract the remaining generation output of the generator from the amount of losses still to be accounted for and set the remaining generation output of the generator to zero.

1.	$FOR\ i = 1\ to\ N_G$ $\quad Q_{RG,i} := Q_{g_i}$ $END\ FOR$
2.	$FOR\ i = N_L\ to\ 1$ $\quad q := Q_{l_i}$ $\quad C_{l_i} := 0$
3.	$\quad FOR\ j = N_G\ to\ 1$ $\qquad IF\ u(a_j, l_i) = 0\ \lor Q_{RG,a_j} = 0\ \lor q = 0\ THEN$ $\qquad\quad TL_{a_j,l_i} := 0$
4.	$\qquad ELSE\quad IF\ q \leq Q_{RG,a_j}\ THEN$ $\qquad\qquad TL_{a_j,l_i} := q$ $\qquad\qquad C_{l_i} := C_{l_i} + \left(TL_{a_j,l_i} \cdot VC_{a_j}\right)$ $\qquad\qquad Q_{RG,a_j} := Q_{RG,a_j} - q$ $\qquad\qquad q := 0$
5.	$\qquad\quad ELSE$ $\qquad\qquad TL_{g_j,l_i} := Q_{RG,a_j}$ $\qquad\qquad C_{l_i} := C_{l_i} + \left(TL_{a_j,l_i} \cdot VC_{a_j}\right)$ $\qquad\qquad q := q - Q_{RG,a_j}$ $\qquad\qquad Q_{RG,a_j} := 0$ $\qquad\quad END\ IF$ $\qquad END\ IF$ $\quad END\ FOR$ $END\ FOR$

Table 19 - Pseudocode for the assignment of dispatched generation to transmission losses

5.3.2 Assigning dispatched generation to loads

The pseudocode corresponding to the assignment of the dispatched generation to the loads is displayed in table 20.

1. For all loads make an auxiliary variable representing the remaining demand volume to be accounted for and set it equal to their initial demand volume. Also make a variable representing the marginal price of generation for the load and set it to zero;
2. For all generators set the transmission from generators to loads to zero if there is no path between the generator and load or if the generator's remaining output volume is zero or if the demand volume of the load is zero;
3. Otherwise, if the amount of demand volume still to be accounted for is smaller than or equal to the amount of remaining generation output of the generator set the transmission from the generator to the load equal to the demand volume of the load, set the marginal price for the load equal to the marginal costs of the generator, subtract the demand volume from the remaining generation output of the generator and set the remaining demand volume to be accounted for to zero;
4. Otherwise, set the transmission from the generator to the load equal to the remaining generation output of the generator, set the marginal price of the load equal to the marginal costs of the generator, subtract the remaining generation output of the generator from the demand volume of the load still to be accounted for and set the remaining generation output of the generator to zero.

1.	$FOR\ i = 1\ to\ N_D$ $q \coloneqq Q_{d_i}$ $P_{d_i} \coloneqq 0$
2.	$FOR\ j = 1\ to\ N_G$ $IF\ u(a_j, d_i) = 0\ \vee Q_{RG,a_j} = 0 \vee q = 0\ THEN$ $TD_{a_j,d_i} \coloneqq 0$
3.	$ELSE\quad IF\ q \leq Q_{RG,a_j}\ THEN$ $TD_{a_j,l_i} \coloneqq q$ $P_{d_i} \coloneqq VC_{a_j}$ $Q_{RG,a_j} \coloneqq Q_{RG,a_j} - q$ $q \coloneqq 0$
4.	$ELSE$ $TD_{a_j,l_i} \coloneqq Q_{RG,a_j}$ $P_{d_i} \coloneqq VC_{a_j}$ $q \coloneqq q - Q_{RG,a_j}$ $Q_{RG,a_j} \coloneqq 0$ $END\ IF$ $END\ IF$ $END\ FOR$ $END\ FOR$

Table 20 - Pseudocode for the assignment of dispatched generation to loads

5.3.3 Allocating costs of transmission losses to loads

The pseudocode corresponding to the allocation of the transmission losses to the loads is displayed in table 21. It should be noted that this main task is divided into two sub-tasks. First, the net amount of demand volume attributable to each transmission loss is determined. Second, vice versa, the net contribution of each load to each transmission loss is calculated, yielding the exact costs attributable to each load.

1. For all loads add the demand volume to the net total demand downstream of the loss segment if there is a path from the loss segment to the load. Do this for all loss segments;
2. For all generators, if there is a path from the loss segment to the generator; for all loads, if there is a path from the generator to the load then subtract the transmission from the generator to the load from the net total demand downstream of the loss segment.
3. For all loads make an auxiliary variable representing its individual net demand downstream of the loss segment and set it to its initial demand volume if there is a path from the loss segment to the load. Do this for all loss segments.
4. For all generators, subtract the heat transported from the generator to the load from its individual net demand downstream of the loss segment if there is a path from the loss segment to the generator.
5. Multiply the total costs of the loss segment by the share of the load in the net total demand downstream of the loss segment and add it to the total costs of losses attributable to the load (defined as CL).
6. Now that all components of the required output from sub-section 5.2.2 have been calculated, we can bring them all together to obtain the locational hybrid prices, while the variable representing the transmission flows from generators to loads, needed for the ex-post settlement of transactions, has already been calculated during the generation allocation process in the algorithm.

1.	$FOR\ i = N_L\ to\ 1$ $\quad FOR\ j = 1\ to\ N_D$ $\quad\quad IF\ u(l_i, d_j) = 1\ THEN$ $\quad\quad\quad \mid Q_{D_{tot,l_i}} := Q_{D_{tot,l_i}} + Q_{d_j}$ $\quad\quad END\ IF$ $\quad END\ FOR$
2.	$\quad FOR\ j = 1\ to\ N_G$ $\quad\quad IF\ u(l_i, g_j) = 1\ THEN$ $\quad\quad\quad FOR\ k = 1\ to\ N_D$ $\quad\quad\quad\quad IF\ u(g_j, d_k) = 1\ THEN$ $\quad\quad\quad\quad\quad \mid Q_{D_{tot,l_i}} := Q_{D_{tot,l_i}} - TD_{g_j,d_k}$ $\quad\quad\quad\quad END\ IF$ $\quad\quad\quad END\ FOR$ $\quad\quad END\ IF$ $\quad END\ FOR$ $END\ FOR$
3.	$FOR\ i = N_L\ to\ 1$ $\quad FOR\ j = 1\ to\ N_D$ $\quad\quad IF\ u(l_i, d_j) = 1\ THEN$ $\quad\quad\quad \mid q := Q_{d_j}$
4.	$\quad\quad\quad FOR\ k = 1\ to\ N_G$ $\quad\quad\quad\quad IF\ u(l_i, g_k) = 1\ THEN$ $\quad\quad\quad\quad\quad \mid q := q - TD_{g_k,d_j}$ $\quad\quad\quad\quad END\ IF$ $\quad\quad\quad END\ FOR$ $\quad\quad END\ IF$
5.	$\quad\quad \mid CL_{d_j} := CL_{d_j} + \frac{q}{Q_{D_{tot,l_i}}} \cdot C_{l_i}$ $\quad END\ FOR$ $END\ FOR$
6.	$FOR\ i = 1\ to\ N_D$ $\quad FOR\ j = 1\ to\ N_G$ $\quad\quad \mid LHP_{d_i} := P_{d_i} + \frac{CL_{d_i}}{Q_{d_i}}$ $\quad\quad \mid q_{j,i} := TD_{g_j,d_i}$ $\quad END\ FOR$ $END\ FOR$

Table 21 - Pseudocode for the allocation of the transmission losses to the loads

5.4 Verifying the algorithm

The algorithm has been implemented in Maple following the design discussed in the previous section. In order to verify if the implementation into Maple has been done correctly, the same two time-steps (min. and max. demand) used in the verification of the network model will be taken and processed by the algorithm, which yields the locational hybrid prices. Subsequently, these LHPs will be checked by means of a manual calculation in which the general (chronological) structure of the algorithm is followed. The LHPs that were generated by the algorithm are shown in figures 32 and 33 in the minimum and maximum demand sample, respectively. The figures show the composition of the LHPs in terms of the cost components attributable to the transmission losses and to the generation. Since the dispatch remains unchanged and the verification process involves the same two time-steps, the ED-information from tables 10, 11 and 12 will occasionally be referred to throughout the verification process.

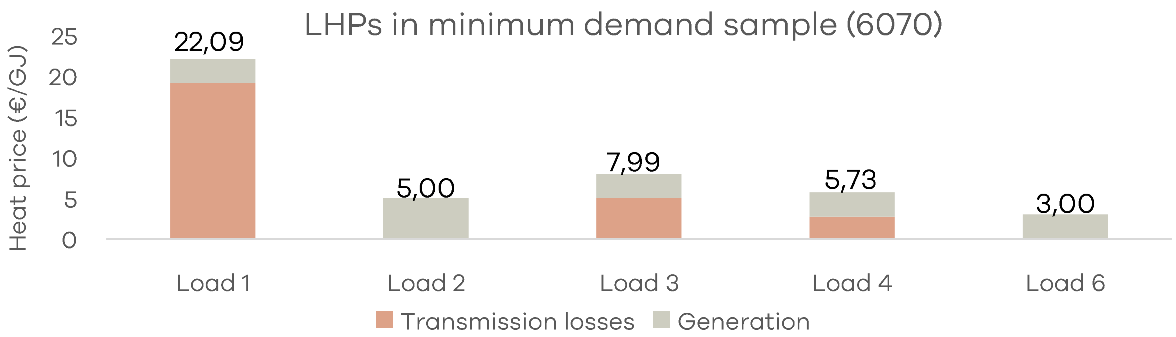


Figure 32 - Locational hybrid prices in time-step 6070, including loss cost components

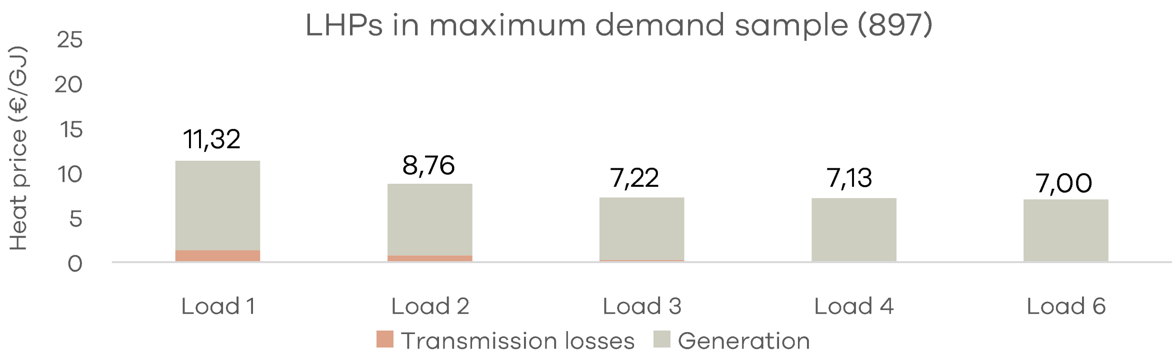


Figure 33 - Locational hybrid prices in time-step 897, including loss cost components

5.4.1 Verifying the assignment of transmission losses to generators

As was noted in section 5.3, the order in which the algorithm performs the main tasks prescribe that we first start with the process of pricing the transmission losses for both samples. Consulting tables 11 and 12, it can be concluded that all transmission losses occurring in the minimum demand sample are assigned to generator G7, being the only generator physically able to compensate for those losses. In the maximum demand sample, where all generators were dispatched, every transmission loss is assigned to the most expensive generator physically able to compensate for it. This yields the computed costs of all transmission losses in both samples, shown in table 22, verifying that this step is performed correctly by the algorithm.

		QL 31	**QL 32**	**QL 43**	**QL 54**	**QL 65**
MIN (6070)	**Costs (€)**	141	-	93	72	48
	Assigned to:	G7	-	G7	G7	G7
MAX (897)	**Costs (€)**	470	390	248	168	112
	Assigned to:	G10	G10	G9	G8	G8

Table 22 - Computed costs of transmission losses in time-step 6070 and 897

5.4.2 Verifying the assignment of generation volumes to loads

Next is the process of assigning the dispatched generation volumes to the loads. Before this process can commence, generation volumes of the dispatched generators should be 'updated' since volumes previously assigned to the transmission losses cannot be assigned again. Taking the ED-information from table 12 as a starting point while considering the volumes of the transmission losses from table 11, the updated information is displayed in table 23.

	Dispatched volume (GJ)		Volume assigned to losses (GJ)		Remaining volume for loads (GJ)	
	MIN (6070)	MAX (897)	MIN (6070)	MAX (897)	MIN (6070)	MAX (897)
G7	212	1.703	118	-	94	1.703
G11	16	98	-	-	16	98
G8	-	2.335	-	40	-	2.295
G9	-	196	-	31	-	165
G10	-	378	-	86	-	292

Table 23 - Updated generation volumes after assignment to transmission losses

The principles regarding the assignment of generation were chosen such that upstream loads are given precedence with regard to the least expensive heat, followed by downstream loads. In the minimum demand sample this process is relatively straightforward since all loads can physically receive their heat from only one generator, following from the ED-information and as already discussed. In this light, the price of generation for each load equals the exact cost price of the generated heat, corresponding to either G7 or G11's variable generation costs.

In the maximum demand sample, this assignment process is less straightforward - since all generators are dispatched - and starts with Load 6, proceeding its way down the network ending with Load 1. The volumes assigned from each generator to each load in the minimum and maximum demand sample are displayed in table 24 and 25, respectively. The most expensive generator of all generators assigned to each load hereby sets the price of generation, also shown by the tables in both time-steps. The second task of the algorithm has hereby also been checked and verified.

MIN (6070)	Load 1	Load 2	Load 3	Load 4	Load 6
G7	10,5	-	31,5	3,0	49,5
G11	-	16,5	-	-	-
G8	-	-	-	-	-
G9	-	-	-	-	-
G10	-	-	-	-	-
Price (€/GJ)	3 (G7)	5 (G11)	3 (G7)	3 (G7)	3 (G7)

Table 24 - Assigned generation volumes from generators to loads and resulting price of generation in time-step 6070

MAX (897)	Load 1	Load 2	Load 3	Load 4	Load 6
G7	-	-	-	-	1.703
G11	-	98	-	-	-
G8	-	552	1.291	123	328
G9	138	26	-	-	-
G10	292	-	-	-	-
Price (€/GJ)	10 (G10)	8 (G9)	7 (G8)	7 (G8)	7 (G8)

Table 25 - Assigned generation volumes from generators to loads and resulting price of generation in time-step 897

5.4.3 Verifying the allocation of transmission losses to loads

Lastly, the computed costs of the transmission losses from table 22 will have to be allocated to the loads, in conjunction with the assumed allocation principles. This process starts by determining the *net* total demand volume of all loads contributing to a transmission loss. For the minimum demand sample again this is relatively straightforward, since all loads that contribute to transmission losses receive their heat from G7, which is located at Node 6 upstream in the network. In the maximum demand sample however, heat that was generated and assigned *downstream* of a certain transmission loss should be excluded from the net total demand corresponding to that transmission loss, as it physically cannot flow over the concerning transmission segment. By consulting the network model and the assigned generation volumes shown in tables 24 and 25, the net total demand can be determined for each transmission loss. Naturally, the same adaptation should be applied when determining each load's individual contribution to a transmission loss. The computed net total demand for each transmission loss is displayed in table 26, also showing which loads contribute to each transmission loss. From the table it can be observed that the net total demand corresponding to QL 54 and QL 65 is lower than that corresponding to QL 43. This is attributable to G9 and G10's location in the network, located downstream of the former, resulting in their assigned generation being netted i.e. subtracted from the total demand corresponding to QL 54 and QL 65.

	Transmission losses	QL 31	QL 32	QL 43	QL 54	QL 65
MIN (6070)	**Contributing loads**	Load 1	-	Load 1 & 3	Load 1, 3 & 4	Load 1, 3 & 4
	Total demand (GJ)	*10*	-	*42*	*45*	*45*
	Net total demand (GJ)	10	-	42	45	45
MAX (897)	**Contributing loads**	Load 1	Load 2	Load 1, 2 & 3	Load 2, 3 & 4	Load 2, 3 & 4
	Total demand (GJ)	*430*	*676*	*2.399*	*2.522*	*2.522*
	Net total demand (GJ)	430	676	2.008	1.967	1.967

Table 26 - Computed net total demand for each transmission loss in time-step 6070 and 897

The last step in the allocation process is the determination of the loads' net individual contribution to each transmission loss as part of the net total demand from table 26, and subsequently allocate the concerning costs accordingly. Again, by consulting the assigned generation volumes from tables 24 and 25 and the network model, as well as the initial demand volumes from table 10, this is calculated for each load. By multiplying the computed costs of each transmission loss from table 22 by each load's net contribution to each transmission loss, the total costs allocated to each load are obtained. The results for both samples are shown in tables 27 and 28. In both tables the total allocated costs have also been expressed as a variable cost component by dividing the total costs by the loads' respective demand volume at both time-steps. Since Load 6 never contributes to any transmission losses, it has been left out of both tables.

MIN (6070)	QL 31 (GJ)	QL 32 (GJ)	QL 43 (GJ)	QL 54 (GJ)	QL 65 (GJ)	Allocated costs (€)	Per GJ (€/GJ)
Load 1	10/10	-	10/42	10/45	10/45	192	18,2
Load 2	-	-	-	-	-	-	-
Load 3	-	-	31/42	31/45	31/45	153	4,9
Load 4	-	-	-	3/45	3/45	8	2,7

Table 27 - Computed net individual contribution of each load to each transmission loss in time-step 6070

MAX (897)	QL 31 (GJ)	QL 32 (GJ)	QL 43 (GJ)	QL 54 (GJ)	QL 65 (GJ)	Allocated costs (€)	Per GJ (€/GJ)
Load 1	430/ 430	-	138/ 2.008	-	-	487	1,1
Load 2	-	676/ 676	578/ 2.008	552/ 1.966	552/ 1.966	540	0,8
Load 3	-	-	1.291/ 2.008	1.291/ 1.966	1.291/ 1.966	343	0,3
Load 4	-	-	-	123/ 1.966	123/ 1.966	17	0,1

Table 28 - Computed net individual contribution of each load to each transmission loss in time-step 897

Both components of the locational hybrid prices have now been calculated for both time-steps. The final LHP for each load in the minimum and maximum demand sample can now be obtained by summing up the computed price of generation from tables 24 and 25, respectively, and the computed price of the transmission losses from tables 27 and 28, respectively. In order to verify if the algorithm has been programmed according the conceptualisation and functions correctly, the computed LHPs are compared to the LHPs that were generated by the algorithm in Maple. Table 29 shows those LHPs, from which a slight deviation between both can be observed. While it is verified that the assignment of generation and the pricing of the transmission losses are performed correctly, apparently this deviation is caused by the allocation of transmission losses to the loads. This is due to the fact that the algorithm rounds off the numbers relating to the demand volumes of the loads. Although this reveals an imperfection in the algorithm, the deviations are so minor that they are regarded negligible with respect to their impact on the results.

		Load 1	Load 2	Load 3	Load 4	Load 6
MIN (6070)	**LHP (algorithm) (€/GJ)**	22,09	5,00	7,99	5,73	3,00
	LHP (manual) (€/GJ)	21,24	5,00	7,88	5,67	3,00
MAX (897)	**LHP (algorithm) (€/GJ)**	11,32	8,76	7,22	7,13	7,00
	LHP (manual) (€/GJ)	11,13	8,79	7,27	7,14	7,00

Table 29 - Comparison between LHPs computed manually and generated by algorithm in time-step 6070 and 897

6. EXPERIMENTS

The different pricing mechanisms will be tested and compared in three scenarios that will be presented in this chapter, together forming the experiments. The scenarios are formed by varying several parameters that are expected to impact the results and thus the performance of the market. How these parameters are chosen, and subsequently how the experiments are set-up in light of running them in the model will be discussed in the following sections.

6.1 Scenario parameters

The scatterplots in figure 34 show the relation between the average outside temperature and the daily heat demand, from which a negative correlation can be observed. More specifically, every year is comprised of a certain number of *degree days*. This is a common term often used by e.g. heat suppliers, and was created to assess the impact of varying outside temperatures in calculations with respect to e.g. the energy consumption. It is defined as a non-negative unit representing the difference between the reference temperature (18°C, below which is assumed (central) heating is needed) and the average temperature measured over an entire day (EIA, 2017).

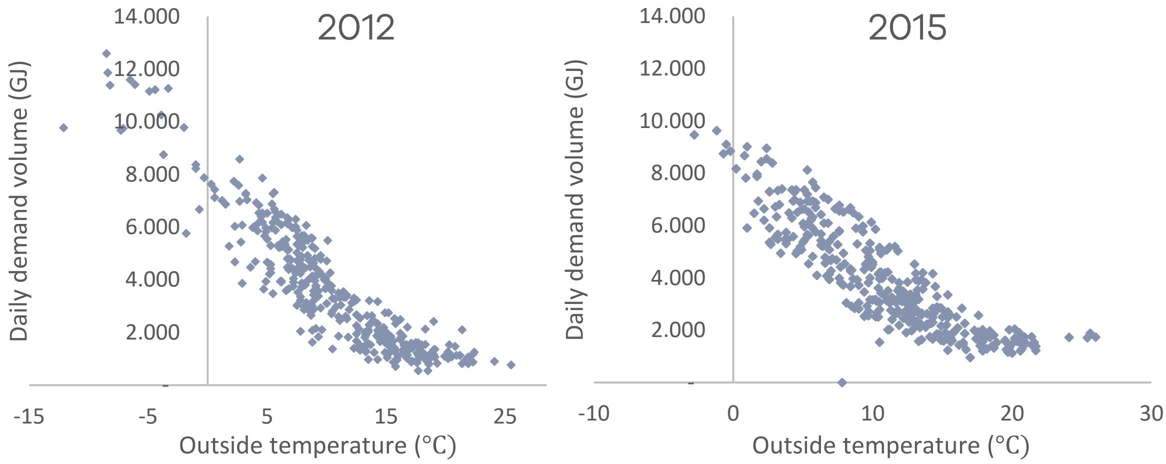


Figure 34 - Scatterplots of average outside temperatures and daily demand volumes 2012 and 2015 in same district heating network

Logically, a higher number of degree days results in a higher amount of energy used for heating. In order to correct for seasonal influences such as heating due to solar irradiation or cooling by wind, and improve the unit's explanatory ability, degree days are assigned a weight factor (van de Bree & Ramaekers, 2013), shown in table 30 as applicable in the Netherlands.

Months	Weight factor
April – September	0,8
March & October	1,0
November – February	1,1

Table 30 - Weight factors for degree days in different months

Different years can thus be analysed and compared on the basis of their weighted degree days. As the climate is warming, it has been discovered that a trend has emerged pointing to a decreasing amount of yearly weighted degree days (Wever, 2008). In this respect, it becomes increasingly important and helpful for potential investors in generation assets to obtain better insights into the performance of an open heat market in a scenario with relatively few weighted degree days.

Secondly, as already discussed in section 1.1, district heating systems are regarded as a more sustainable and environmentally friendly alternative than the conventional natural gas system. Despite of the amount of degree days experiencing a decreasing trend, district heating networks therefore are expected to grow over time in terms of the amount of connected consumers, i.e. the *size of the loads*.[4] In order to research the impact of an increasing amount of connected consumers on the market performance indicators, the size of the loads is taken as a second scenario parameter.

Thirdly, it is possible that potential investors will anticipate a potential load size increase over time. In an open heat market, it is expected that investments will most likely be made in relatively efficient assets that will come high up in the merit order, in light of maximising its annual time in operation, and therewith market share. Depending on the pricing mechanism in place, this would theoretically improve chances of obtaining a surplus and recovering its costs. In order to simulate this investment in additional capacity and the corresponding impact on the market performance indicators, the *generation capacity of local generator G11* (second in the merit order and now still has low capacity) is therefore chosen as a third parameter that will be varied in potential scenarios.

6.2 Set-up of the experiments

6.2.1 Reduction and normalisation of datasets

The dataset entailing the demand volumes of a load in a certain year normally comprise 8760 time-steps. During a leap year, as section 6.1 showed where data from 2012 was used, this dataset even amounts to 8784 time-steps. From the same section it became clear that the size of those datasets does not present any issues for the network (optimisation) model. It would however take the algorithm extremely long to compute so many time-steps in multiple scenarios, which presents an obstacle with respect to the time scope of this research. Therefore, without loss of validity, it has been chosen to reduce the datasets of each scenario from n=8784 or n=8760 to n=100, while maintaining its representativeness as much as possible. This will be done by sorting each dataset by the hourly demand volumes and construct a histogram that captures the sorted demand volumes over a bin range of 100 steps and the corresponding frequencies of their occurrence. For each bin the maximum value is taken, which means that the actual demand volumes are systematically slightly overstated. This enables a relatively simple ex-post extrapolation to an entire year again afterwards. The histogram obtained is shown in figure 35.

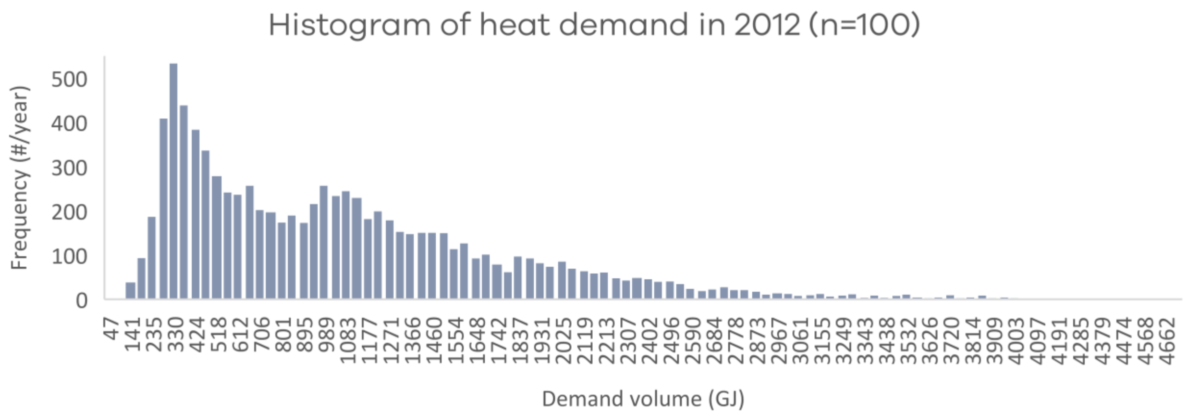


Figure 35 - Histogram showing demand volumes and their occurrences annually (2012)

[4] In this light a distinction is made between the hourly demand volumes of the loads and the size of the loads; the hourly demand volumes are a product of the outside temperatures throughout a year, whereas an increased load size is simulated by multiplying the respective hourly demand volumes with a certain growth factor. The existing demand patterns from the demand volume data hereby remain unchanged.

The load duration curve of the simplified dataset has been shown in figure 36, next to the original load duration curve. It has a more cascading shape and lies above the original curve due to the reduced size, and because it slightly overstates the original data since the maximum of the bin was taken.

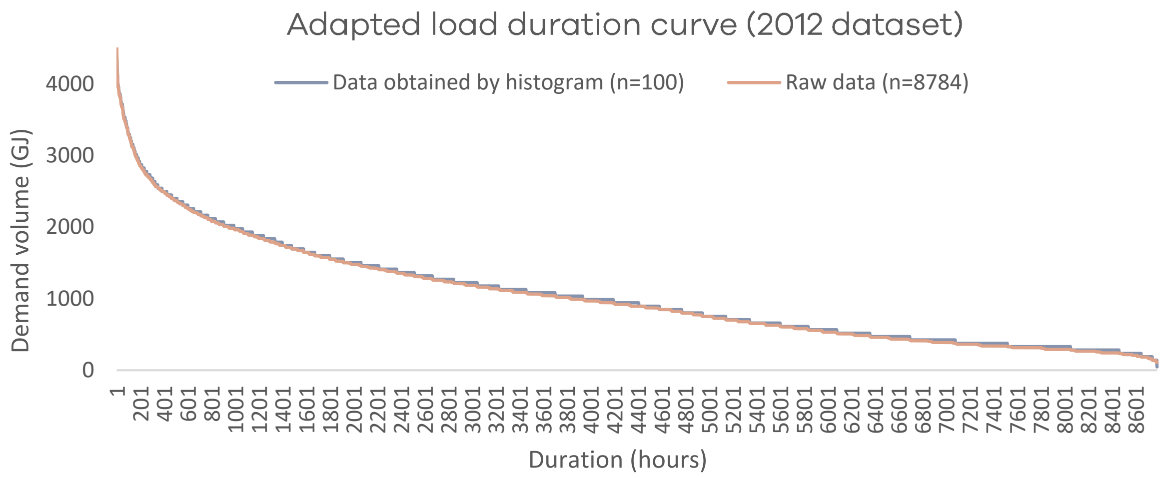


Figure 36 - Load duration curves for dataset in 2012 with reduced size (n=100) and original size (n-8784)

As was explained in the previous section, different years can be compared on the basis of their weighted degree days, one of the scenario parameters. In the same sub-section however, it was also discussed that district heating networks experience yearly growth in terms of the amount of connected consumers. In order to research the impact of the amount of degree days (independent variable) on the market performance indicators, first a valid comparison between both years should be facilitated by correcting for the aforementioned growth of said district heating network.

Therefore both datasets will first be normalised on the basis of figure 34, showing the negative correlation between the average daily outside temperature and the corresponding total demand during those days. The datasets are taken from the year 2012 and 2015, counting 2.902 and 2.675 weighted degree days, respectively, and stem from the exact same district heating network. The relation between the average outside temperatures and the corresponding heat demand is considered over the full year and expressed in a slope coefficient for both datasets. The difference in slope coefficients between both datasets hereby explains the growth in the amount of connected consumers, revealing a growth of approximately 7,15% in 2015 relative to 2012. Subsequently, the demand volumes of 2015 are corrected for growth by means of this growth percentage. This process is elaborated upon in appendix B. It should be noted that, with respect to this correction, validity cannot be fully guaranteed as the possibility of biases remains, e.g. regarding the *type* of connected consumers; Utility buildings or businesses that may have joined the network have different demand profiles than e.g. households and may undermine the validity of this comparison.

6.2.2 Construction of scenarios

By assigning values to and make combinations of the identified scenario parameters, scenarios can be constructed. Since the aim is to provide a proof-of-concept rather than investigate the sensitivity of KPIs to certain scenario parameters and considering the relatively large amount of computation time needed by the algorithm as mentioned in the previous section, it has been chosen to formulate three different scenarios instead of creating a full-factorial experiment design. Values for the parameter *degree days* are already known, as demand data from both 2012 and 2015, counting 2.902

and 2.675 weighted degree days respectively, were available at the time of this research. In order to prevent distortion of the results by other parameters, both years are hereby defined as separate scenarios, assigning data from 2012 to scenario 1 and the (normalised) data from 2015 to scenario 2, while keeping the other two scenario parameters unchanged. In the third scenario, the data from year 2012 is used again while a combination is made between the other two scenario parameters, *size of the loads* and the *generation capacity of G11*. This can be argued by the fact that an increase in load sizes, and thus increase in the aggregated demand in the system, is likely to be anticipated by potential investors in additional capacity. In this scenario, all loads are increased in size by ten percent i.e. assigned an additional ten percent of demand volume in each time-step relative to the demand volume from 2012, while G11 is assigned an additional 200 GJ of generation capacity. The three scenarios are summarised in table 30. The load duration curves corresponding to each scenario have been displayed in figure 37.

Parameter	Unit	Scenario 1	Scenario 2	Scenario 3
Degree days	#	**2.902** (2012)	**2.675** (2015)	2.902 (2012)
Load sizes	%	100	100	**110**
G11 max. capacity	GJ	98	98	**298**

Table 31 – Overview of quantified scenario parameters in all scenarios

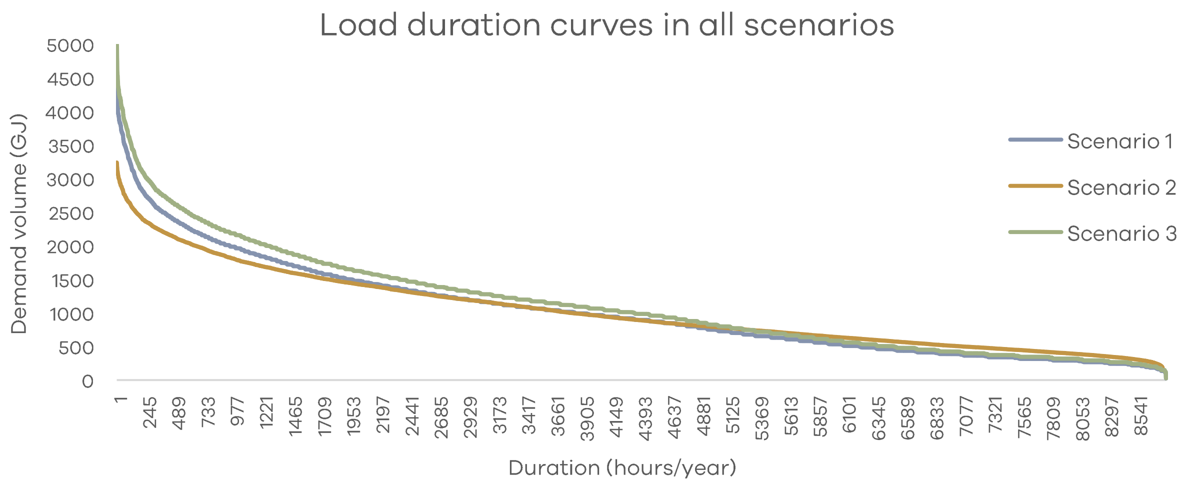


Figure 37 - Load duration curves of raw data in all scenarios

6.2.3 Experiment design

By investigating five pricing mechanisms in three different scenarios, the experiment design ultimately amounts to fifteen different experiments, summarised in table 32.

Scenario / **Pricing mechanism**	Scenario 1	Scenario 2	Scenario 3
System Marginal Pricing	X	X	X
Average Cost Pricing	X	X	X
Locational Cost Pricing	X	X	X
Locational Marginal Pricing	X	X	X
Locational Hybrid Pricing	X	X	X

Table 32 – Overview of fifteen different experiments that comprise the experiment design

6.3 Results of the experiments

The results of the pricing mechanisms in each scenario will be presented in this section on the basis of the six market performance indicators. It should be noted that some performance indicators may be 'load-specific', such as the *average heat prices*, *price efficiency* and *price volatility*. To derive the aggregated results, the overall score was taken by averaging the score of all loads in the network. In most cases however these will be elaborated upon by looking at the individual loads as well.

6.3.1 Heat prices

Average annual heat prices for all pricing mechanisms in all three scenarios are shown in figure 38.

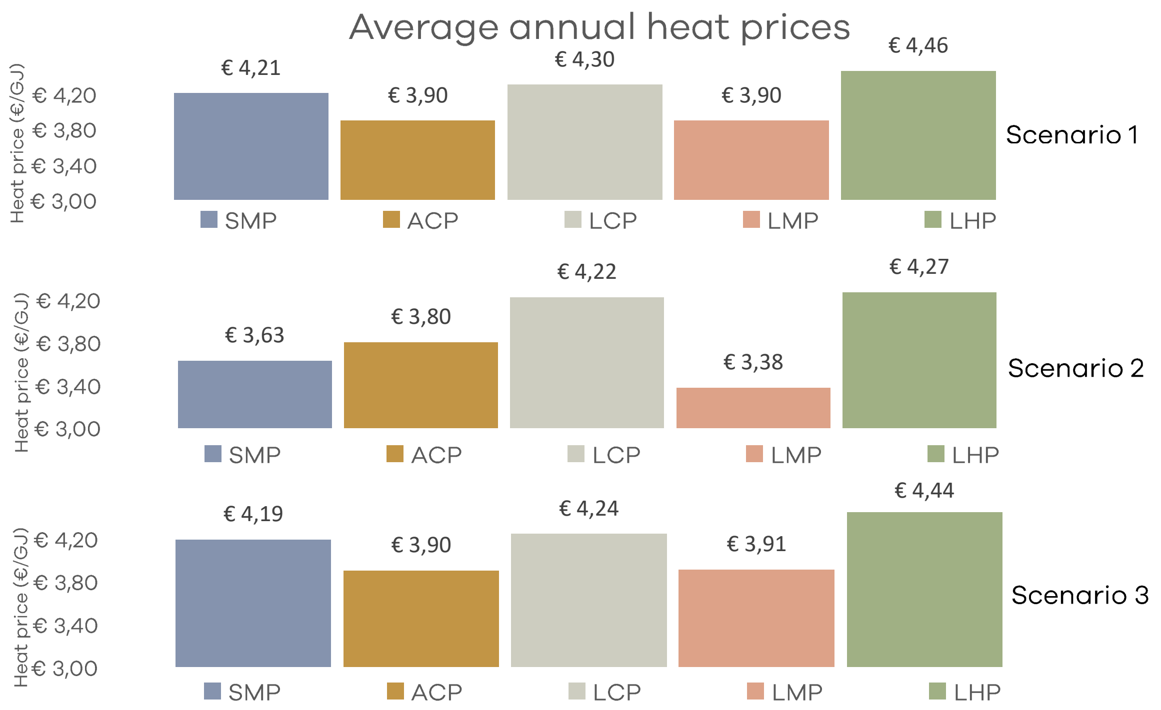


Figure 38 - Average annual heat prices in all scenarios

In the comparison of these average heat prices it should be kept in mind that some pricing mechanisms include the allocation of transmission losses (ACP, LCP and LHP) whereas others do not (SMP and LMP). The figure shows that SMP yields higher average heat prices than ACP in scenarios 1 and 3, which is to be expected since SMP is marginal cost-based and therefore creates a surplus. Figure 39 shows SMP and ACP in two cold weeks, characterised by relatively high demand and confirms that SMPs rise above the ACPs when demand increases to a certain level.

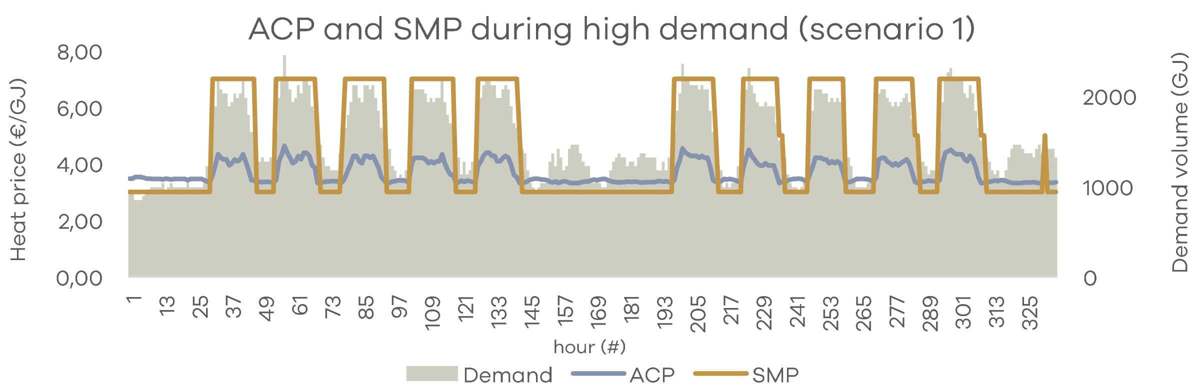


Figure 39 - ACP and SMP during high demand in scenario 1

It can also be seen that the opposite is true in scenario 2, where the average SMP becomes lower than the average ACP. Since scenario 2 is characterised by fewer degree days, this can be explained by lower demand situations in general. This is confirmed by figure 40, showing that this is also true for a low demand situation in e.g. scenario 1. In this case, ACP is able to rise above SMP because of the inherent transmission loss mutualisation over the system, and the absence of transmission loss allocation in SMP. Because of the consistently lower demand resulting in the cheapest generator becoming marginal more often, SMP therefore turns out lower than ACP on average in scenario 2.

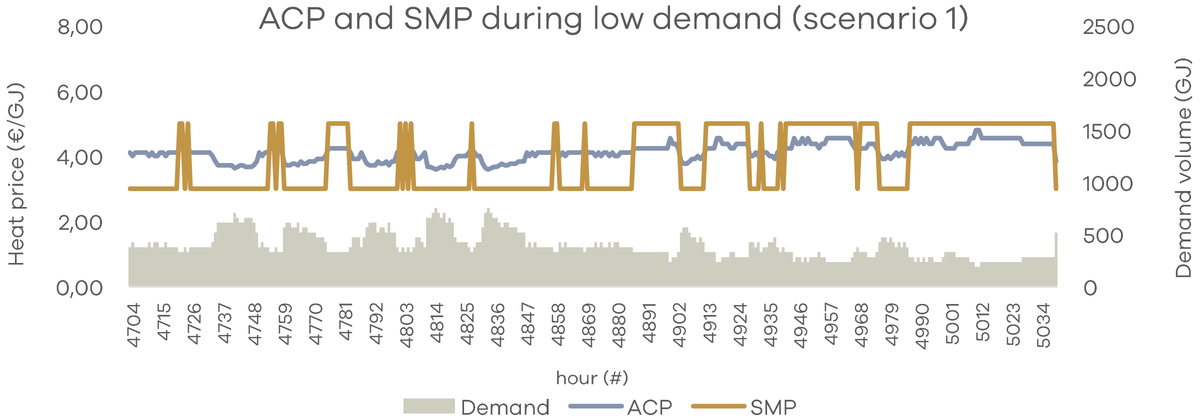


Figure 40 - ACP and SMP during low demand in scenario 1

From figure 38 it can also be noticed that the LHP alternative ultimately results in the highest heat prices in all scenarios, closely followed by LCP. This is explained by the transmission loss allocation method inherent to these pricing mechanisms, which drives up price averages especially for the loads that are located more downstream in the network. In order to properly show this effect for LCP, a high demand situation has been plotted in figure 41 where multiple generators are dispatched and the differences between downstream and upstream are more noticeable. The figure clearly shows that especially Loads 1 and 2 are charged more for the transmission losses than the other loads, resulting in higher prices.

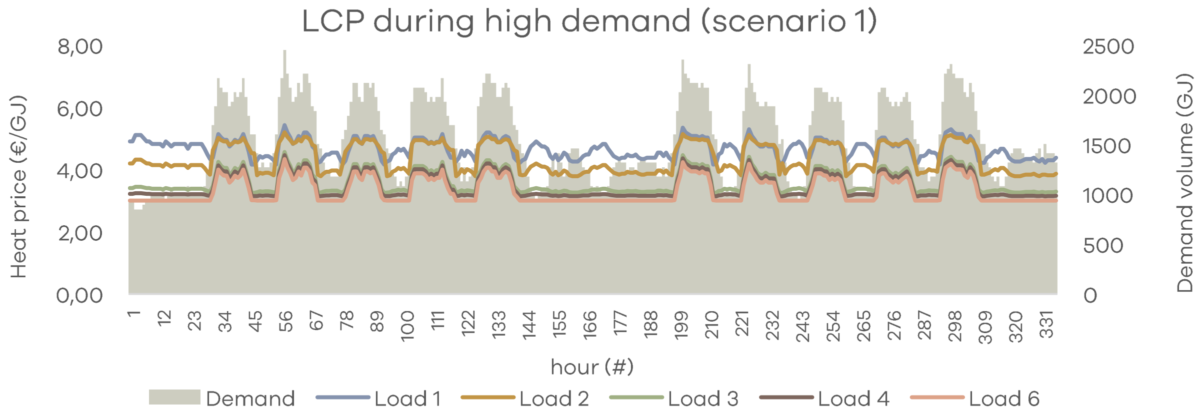


Figure 41 – LCPs per load during high demand in scenario 1

Although LCP and LHP incorporate exactly the same transmission loss allocation method, the most significant difference between both pricing mechanisms is the pricing of the actual generation. Whereas LCP charges loads with the actual (average) cost prices of the generated heat delivered to those loads, LHP ensures that the cheapest generators are assigned from upstream to downstream while the most expensive generator assigned to each load sets the price of generation. As can be expected, this should result in even larger differences between upstream and downstream due to the differences in variable costs of the generators. This is confirmed by figure 42, showing LHP during the same demand situation as with LCP in figure 41. The assignment principles of LHP are hereby also reflected by looking at Load 6. Since it is the most upstream load, it does not contribute to any transmission losses. Still its LCP occasionally shows an increase due to the other generator at that node being dispatched, in addition to the cheapest generator already in operation. Its LHP however remains constant at the variable cost level of the cheapest generator, because it will always get precedence in the assignment of the least expensive generation.

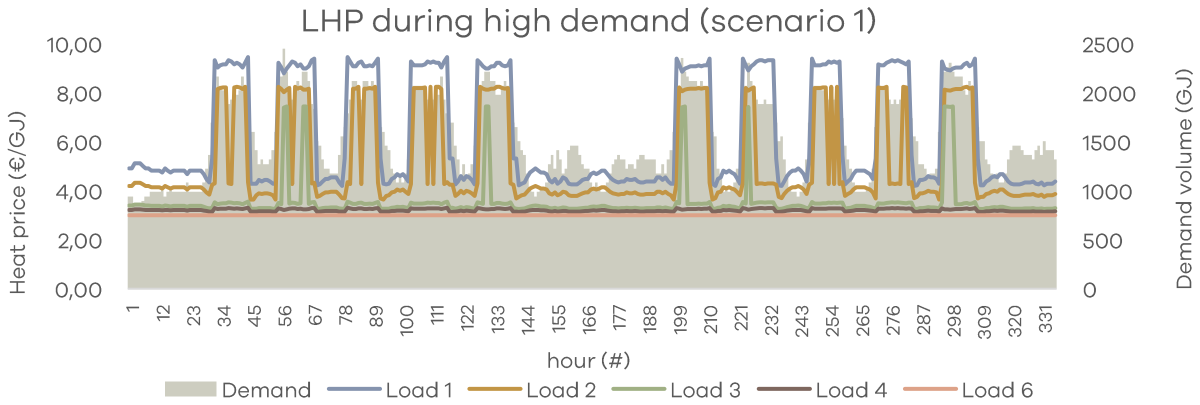


Figure 42 - LHPs per load during high demand in scenario 1

Whereas scenario 2 was characterised by a smaller amount of aggregated demand, in scenario 3 demand volumes were increased by ten percent. The average heat prices resulting from this are equal to are slightly lower for most pricing mechanisms, with the exception of LMP. To explain, the differences are exposed by considering the average LMPs per load instead of on an aggregated level shown in figure 43. It can be seen that there actually are no differences among the loads' LMPs, except for Load 2. This is because of the linear network configuration and the absence of any transmission constraints. The fact that only Load 2's LMP differs from the other loads is explained by its local generator, enabling it to occasionally abate the need for additional heat from other generators. The average LMP for Load 2 is higher than the for the other loads in all scenarios because that local generator is the second cheapest in the network. This means that in relatively low demand situations the benefits of providing Load 2 with the cheapest generation available in the network do not weigh up to the additional costs of transport over that segment. In high demand situations however these differences tend to converge, which is reinforced by the additional generation capacity assigned to that local generator in scenario 3. This is confirmed by the figure showing that Load 2's LMP decreases while the other loads' LMPs increase.

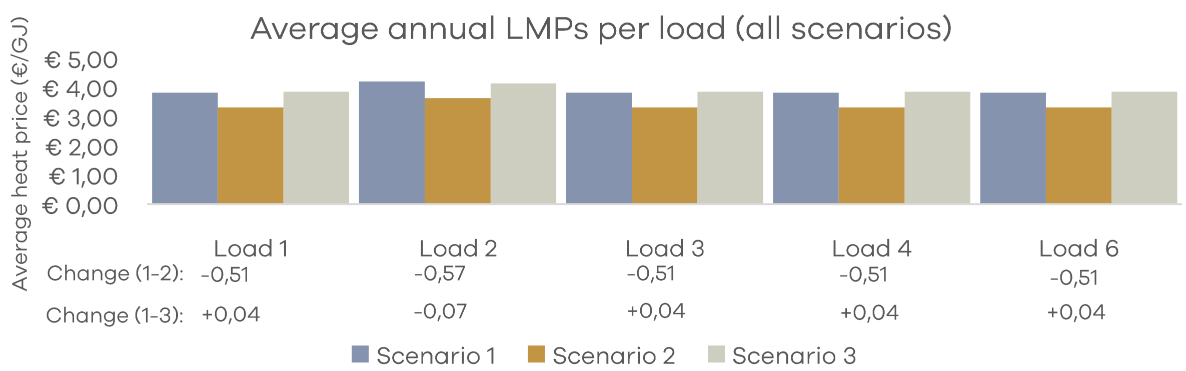


Figure 43 - Average annual LMPs per load in all scenarios including changes relative to scenario 1

6.3.2 Price efficiency

The efficiency of the heat prices, shown in figure 44, was defined in such a way that it represents the percentage difference between the heat price of a certain pricing mechanism and the average system costs of the demand, i.e. the ACP. Since ACP is the reference, its efficiency will always be zero. In ACP total system costs are divided over the total demand, which means that costs of transmission losses are covered in the ACPs as well. Theoretically, this would yield maximally efficient prices considering that they are the actual cost prices. This would imply that heat prices as a result of other pricing mechanisms would always be less efficient than the ACPs. Nevertheless, it can be observed from the figure that the LMPs in scenario 1 and 2 and the SMP in scenario 2 are more efficient on average than the actual ACPs.

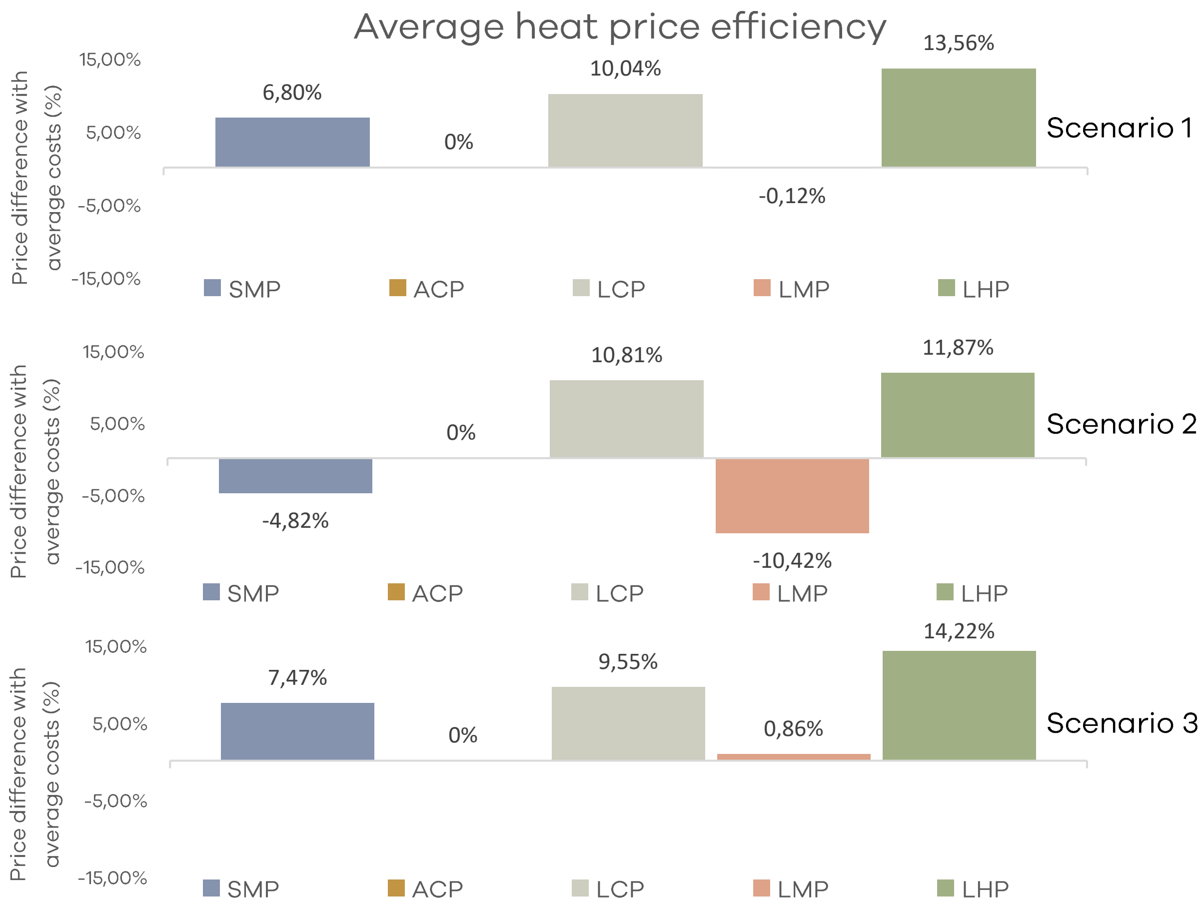


Figure 44 - Average annual heat price efficiency in all scenarios

As with the average heat prices, this is explained simply by the fact that both SMP and LMP occasionally yield prices lower than the ACPs due to the absence of a transmission loss allocation method, whereas ACP incorporates those costs by mutualising them over the loads. Essentially this means that when a heat price resulting from either SMP or LMP decreases below the ACP, it becomes more efficient than the ACP, i.e. the percentage difference becomes negative, which is illustrated in figure 45 showing this relationship. This is reinforced by low demand situations because the costs of the (constant) transmission losses become a more significant part of the total system costs, which can also be seen in the figure. That also explains why scenario 2 shows a strong decrease in the percentage difference of SMP and LMP with ACP, i.e. an increase in average price efficiency.

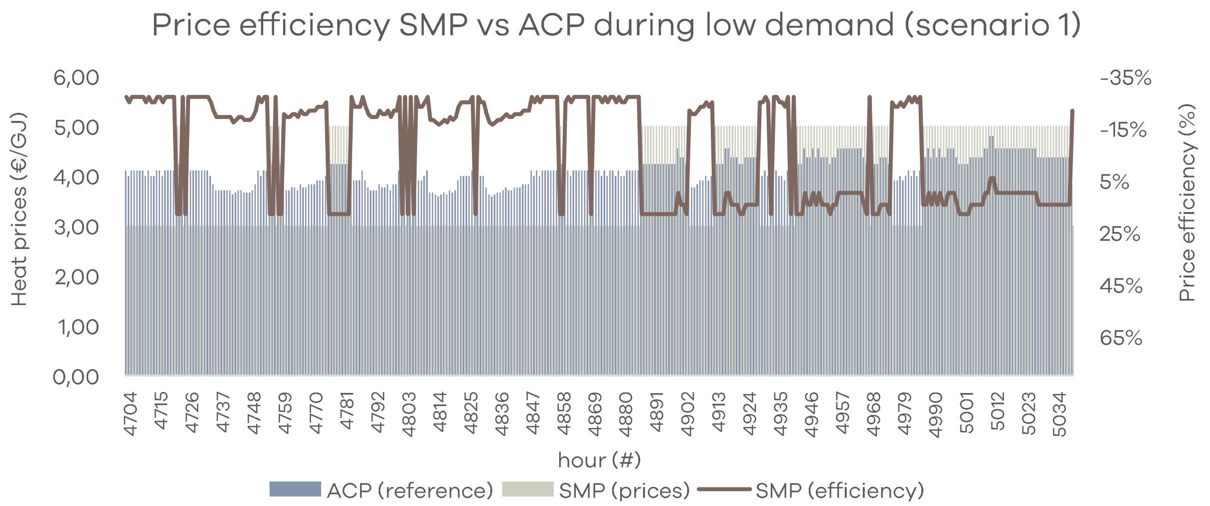


Figure 45 - Relationship between prices and price efficiency between SMP and ACP during low demand in scenario 1

In contrast to SMP and LMP, the transmission loss allocation method applied to LCP and LHP results in those respective heat prices being least efficient compared to ACP. Whereas most pricing mechanisms show an improvement in efficiency in scenario 2, LCP forms an exception. This can only be explained by considering the individual loads' price efficiencies, shown in figure 46. It can be seen that most loads actually see an improvement, except for Load 1 and 2. According to the transmission loss allocation method those downstream loads are charged for a larger share of the transmission losses than upstream loads. Due to the smaller demand volumes in scenario 2 those allocated costs thus weigh more heavily on their heat prices than in situations with higher demand.

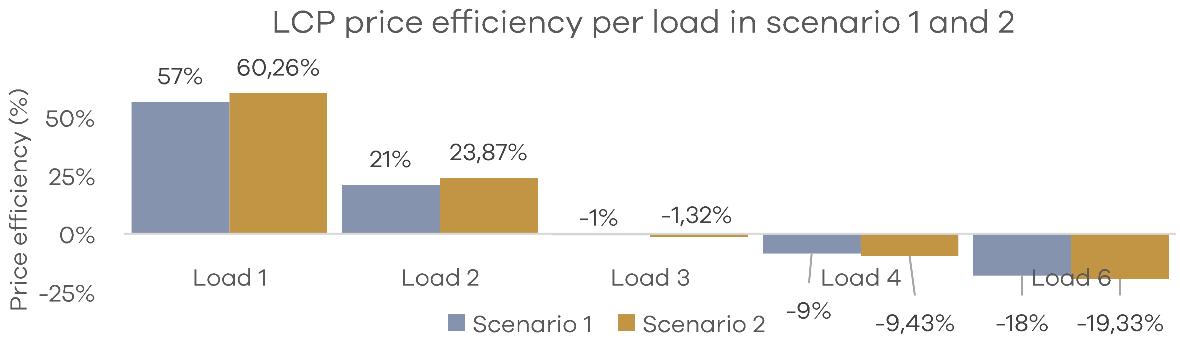


Figure 46 – Average LCP price efficiency per load in scenario 1 and 2

Since LCP is not the only pricing mechanism that includes the transmission loss allocation principles, the question now arises why LHP as opposed to LCP does in fact experience an increase in price efficiency on average in scenario 2, compared to scenario 1. Again, by looking at the exact price efficiencies per load in both scenarios this can be explained. As figure 47 shows, in this case Loads 1, 2 and 3 actually experience an increase in price efficiency compared to scenario 1. The opposite is true for the upstream Loads 4 and 6, although their LHPs remain more efficient than the reference ACP.

In this case, this is not explained by the transmission loss allocation but by the way that LHP assigns the generators to the loads. Since there is less demand in scenario 2, cheaper generators supply the base-load during a larger part of the year. As upstream loads are assigned the cheapest generation

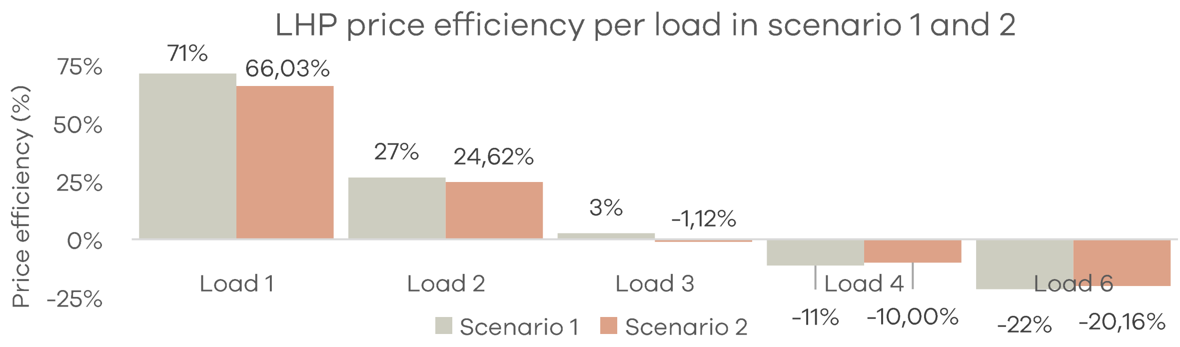


Figure 47 - Average LHP price efficiency per load in scenario 1 and 2

first, they do not notice that much difference because they would receive the cheapest generation anyway. Those differences become more noticeable however when going downstream, which is confirmed by figure 48 showing the differences in average heat prices per load in both scenarios. Ultimately, this effect causes the overall average LHP in scenario 2 to decrease stronger than the overall average LCP does (relative to the ACP), explaining why price efficiency in LHP hereby increases on average while in LCP it decreases.

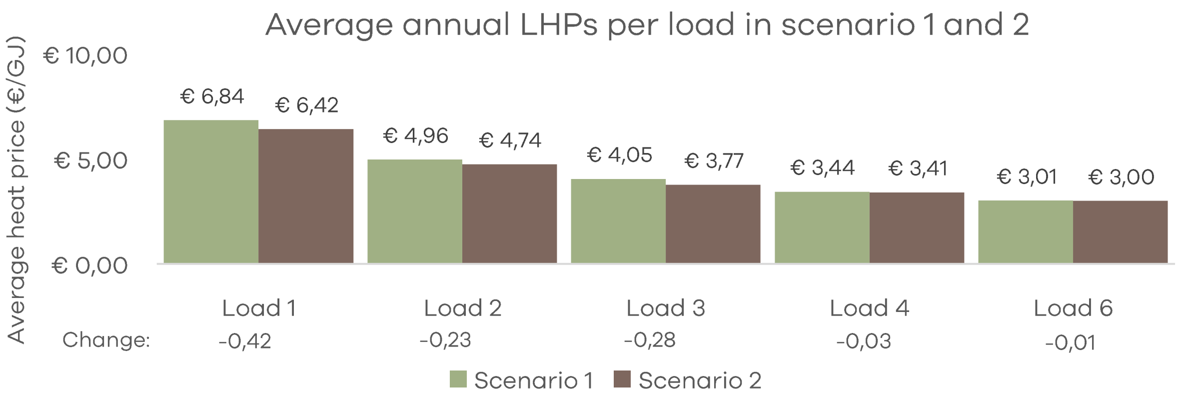


Figure 48 - Average annual LHPs per load in scenario 1 and 2, including relative changes

6.3.3 Market surplus

The market surpluses resulting from the different pricing mechanisms in all scenarios are shown in figure 49. From the figure it can be observed that in both ACP and LCP the market surplus is equal to zero, in all scenarios. This is because in these pricing mechanisms the actual cost prices are charged, not leaving room for any margins. The difference between both is that ACP results in

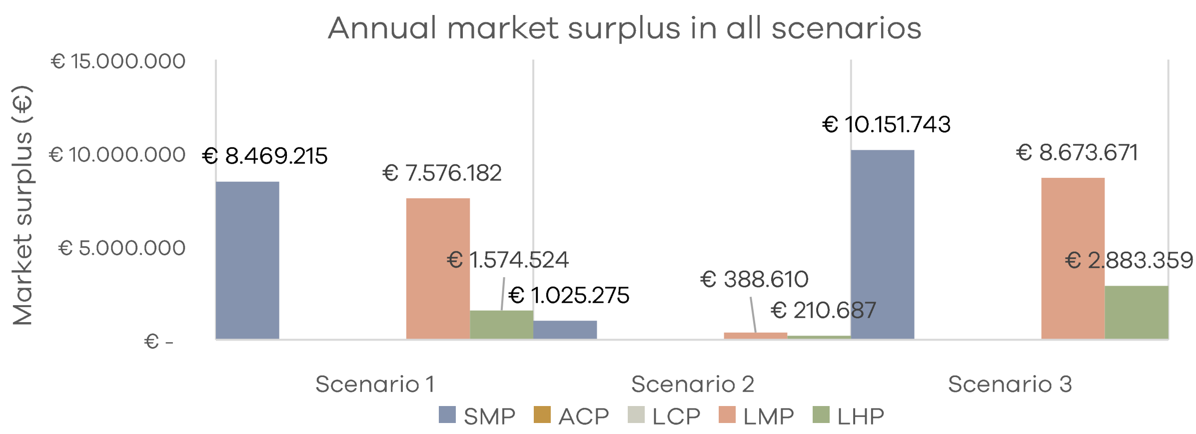


Figure 49 - Annual market surplus in all scenarios

one average cost price applicable to the entire system, whereas LCP considers locational differences including the loads' respective contribution to transmission losses.

All scenarios result in SMP yielding the largest market surplus, closely followed by LMP. This can be explained by both pricing mechanisms being marginal cost-based, intrinsically creating margins as a result of the differences in variable costs of the dispatched generators. The actual size of the surpluses generated by SMP, LMP and LHP relative to the total costs of generation can be consulted in figure 50, showing that SMP and LMP add approximately a quarter of those costs to the total system costs, i.e. to the (intermediate) consumers' bill.

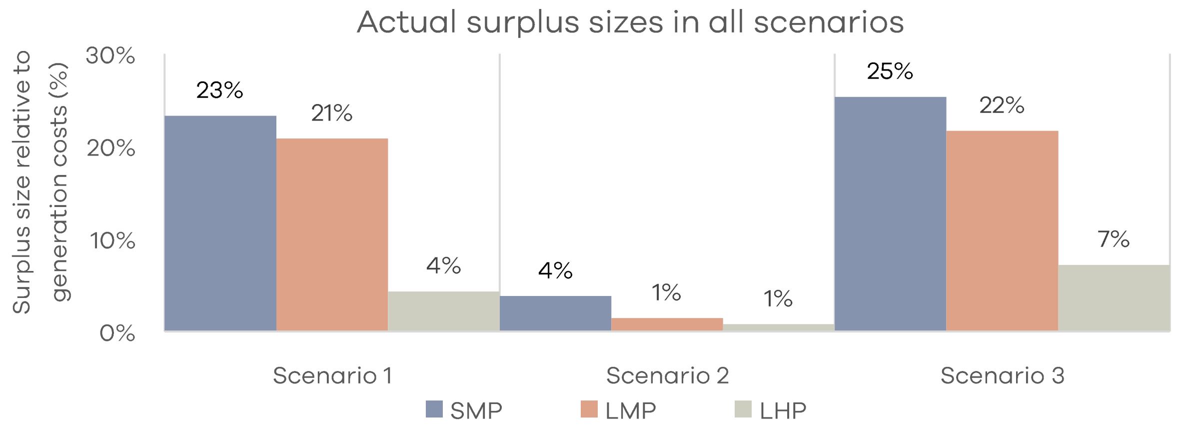


Figure 50 - Size of surplus relative to total costs of generation for SMP, LMP and LHP in all scenarios

As figure 51 shows, all three pricing mechanisms see a strong reduction of the surplus in scenario 2. Again this is simply because of the smaller demand volumes in that scenario, implying that the expensive generators are in operation during a smaller part of the year and thus less often create this margin from which the cheaper generators can profit. Although smaller than SMP and LMP, the LHP alternative also yields market surpluses in all scenarios. This can be explained only by the assignment of generation process inherent to the algorithm. In the end, the price of generation for a certain load is determined by assigning the variable costs of the most expensive generator that was assigned to that load, creating a margin for the other (cheaper) generators assigned to that load. It can also be seen that scenario 3 causes the surplus of LHP to almost double in size. This is explained by the induced scarcity due to the increased load sizes, causing shifts in the aforementioned assignment of generation resulting in more loads being assigned a more expensive generator.

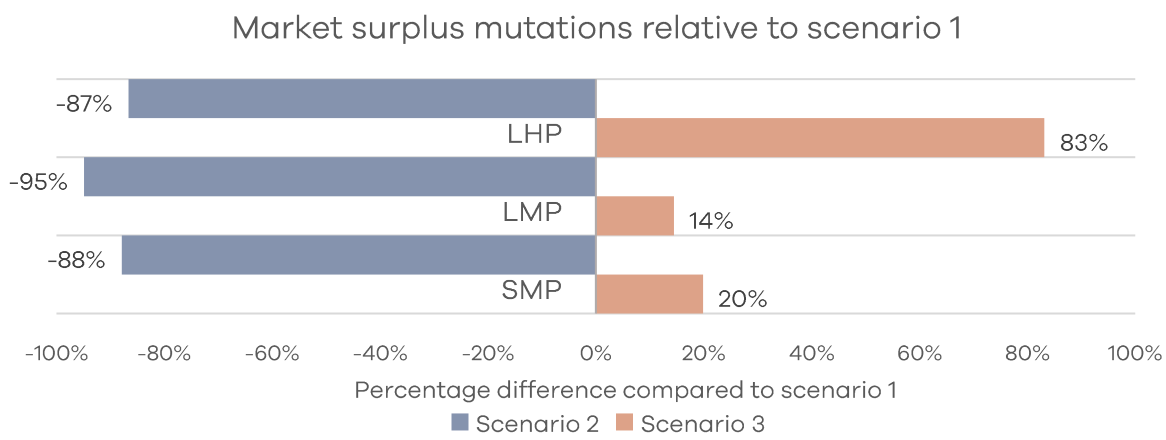


Figure 51 - Market surplus mutations for SMP, LMP and LHP in scenario 2 and 3

Figure 52 shows the behaviour of the market surplus of SMP, LMP and LHP in scenario 1 and 3 set against the aggregated generation curve during two weeks including the peak demand moment (897th hour). The relationship between the surplus and the generation curve becomes visible when looking at both the plotted SMP and LMP surplus curves, showing rises and falls when changes in the marginal generator occur in cases of increasing or decreasing demand, respectively. Despite the additional generation capacity for G11 in scenario 3, also visible in the figure below, the increased load sizes cause the most expensive generators to be dispatched more often, as for instance around the 945th and 970th hour. The surplus curve corresponding to LHP shows more variability due to the locational differences resulting from the assignment of generation principles, but clearly shows more peaks compared to scenario 1.

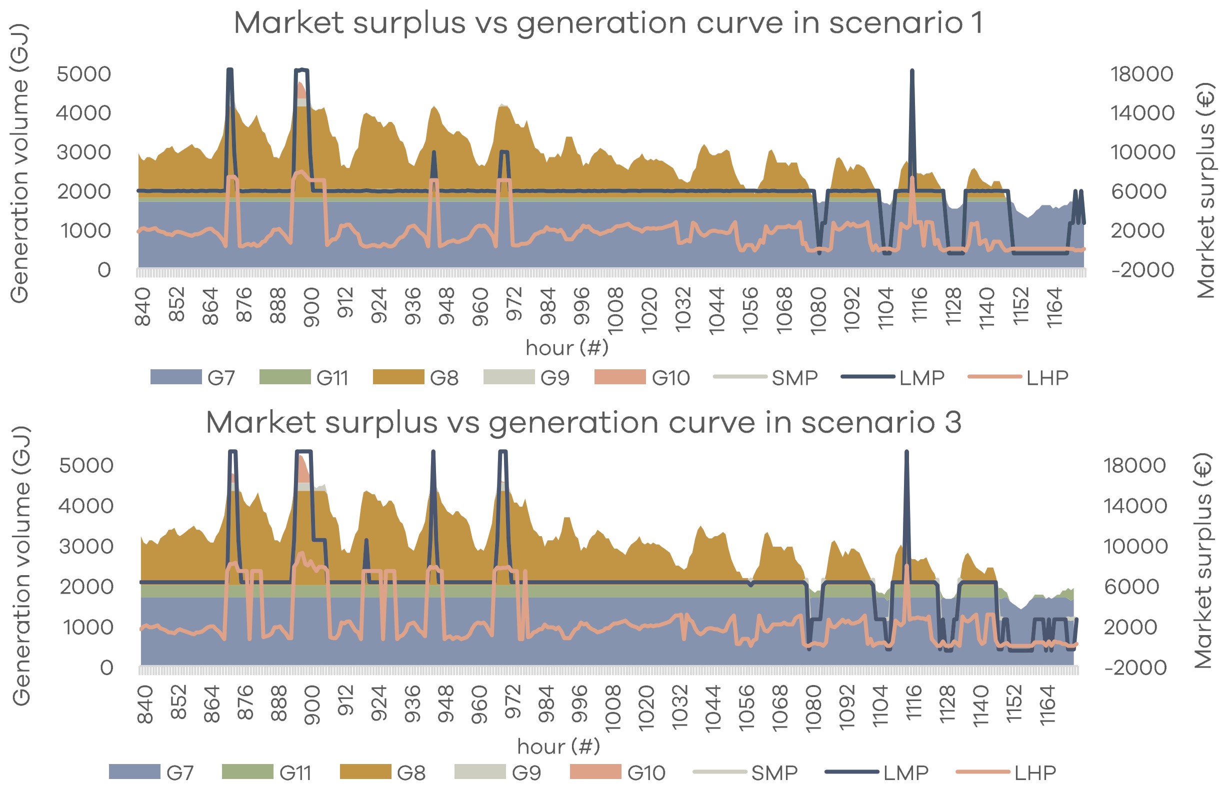


Figure 52 - Market surplus vs generation curve for SMP, LMP and LHP in scenario 1 and 3

6.3.4 Price volatility

Figure 52 shows the average historical price volatility resulting from the different pricing mechanisms in all scenarios, from which can be seen that SMP and LMP cause prices to be most volatile. Since both are marginal cost-based pricing methods, price variance in these pricing mechanisms can become relatively high due to the changes in marginal generator following the changes in demand. Larger differences in variable costs of the generators throughout the merit order naturally result in larger variance of prices, i.e. more price volatility. Both average cost-based pricing mechanisms logically cause prices to be least volatile. The fact that ACP yields less volatile prices than LCP is explained by the locational dependence of generation and the transmission loss allocation inherent to LCP, whereas ACP maintains one system price and mutualises those transmission losses.

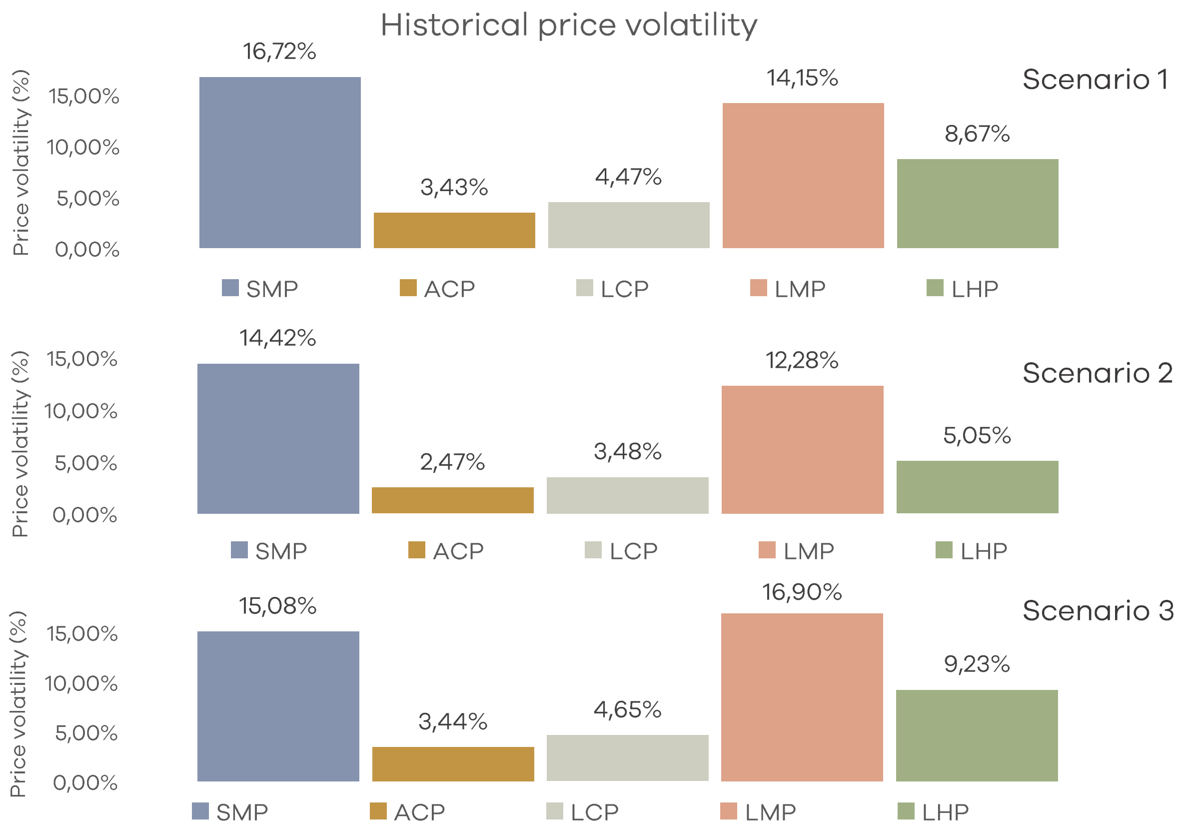


Figure 53 - Historical price volatility in all scenarios

To highlight the variance in prices caused by the different pricing mechanisms, prices for Load 1 during two weeks with relatively high demand have been plotted in figure 54, while the computed volatility corresponding to that time-frame has been plotted in figure 55. In figure 53 it can be seen that the LHPs for Load 1 tend to rise above the SMPs. Additionally, the range along which those LHPs for Load 1 vary seems larger than that for SMP. This is solely attributable to the allocation method and the fact that Load 1 is located entirely downstream and therefore is charged most for the transmission losses. As figure 54 also acknowledges, this results in the LHPs for Load 1 to sometimes become more volatile than the SMPs. The average historical price volatility resulting from LHP nevertheless turns out much lower than that of SMP or LMP, pointing to significant differences between downstream and upstream caused by LHP and its transmission loss allocation.

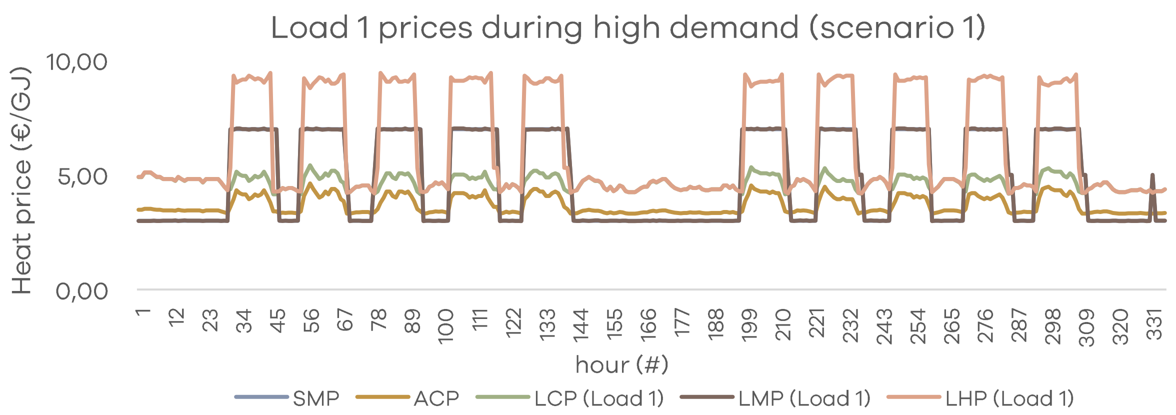


Figure 54 - Prices for load 1 during high demand for all pricing mechanisms in scenario 1

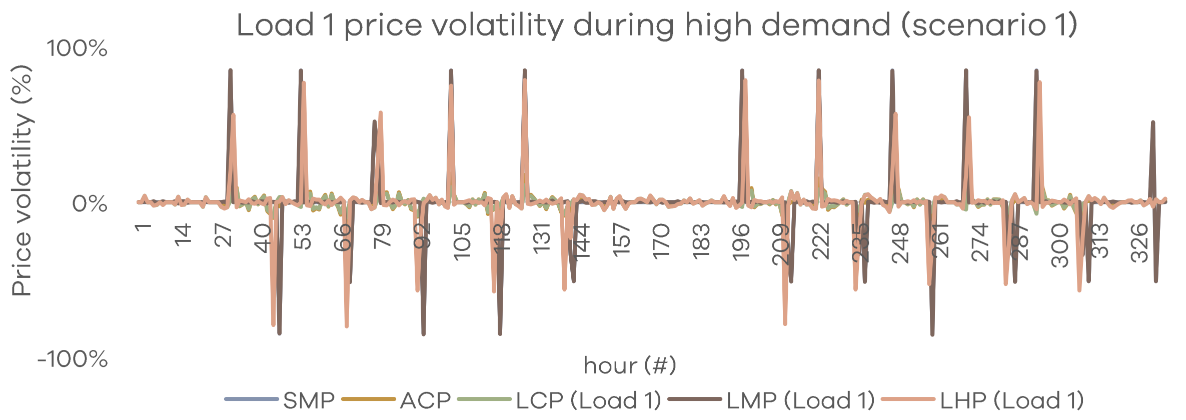


Figure 55 - Price volatility for load 1 during high demand for all pricing mechanisms in scenario 1

To explain this, the LHP price volatility for all loads has been plotted in figure 56 during the same time-frame. It can be seen that Load 1, 2 and 3 experience the most price volatility while Load 4 and 6 experience hardly any price volatility at all. LHP thus causes large differences between downstream and upstream in terms of price volatility experienced by the loads, which are only magnified by the inherent transmission loss allocation method. This explains why historical price volatility for LHP on average turns out lower than that for SMP or LMP.

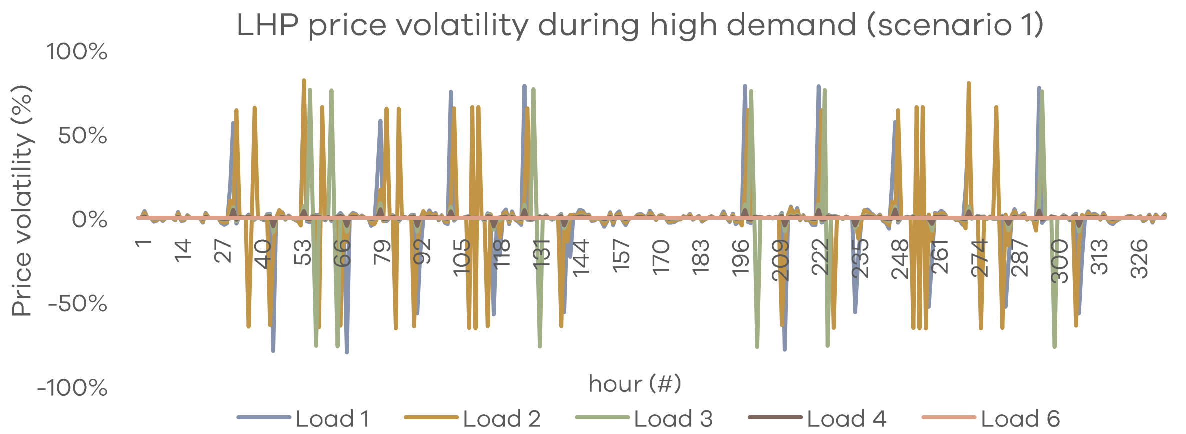


Figure 56 - Price volatility for all loads during high demand in LHP in scenario 1

An additional observation made by looking at the results from figure 53 is that LMP price volatility on average appears to increase disproportionately to the other pricing mechanisms in scenario 3. As figure 57 shows, this increase actually applies to all loads except for Load 2.

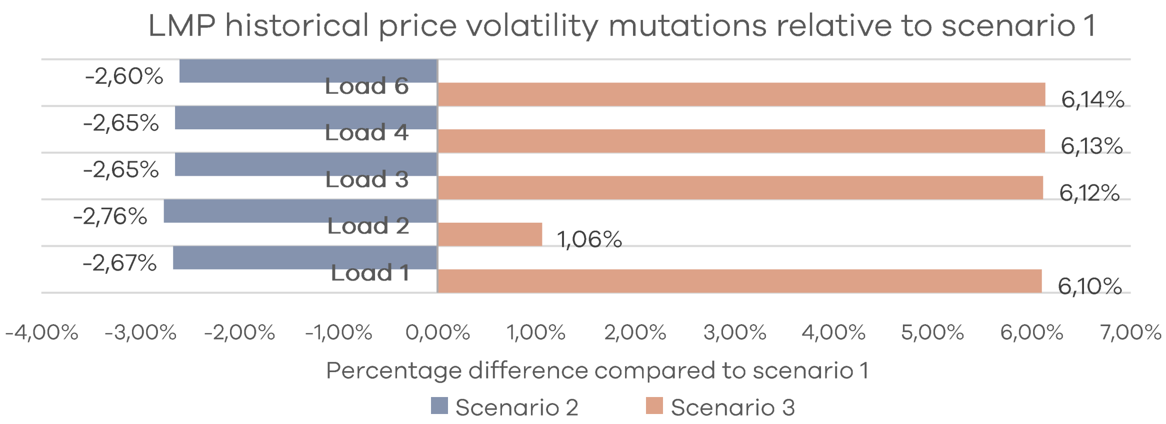


Figure 57 - LMP historical price volatility mutations per load in scenario 2 and 3

This is most likely explained by the additional generation capacity assigned to G11. The additional capacity of local generator G11 hereby creates more room for considerations between an economically optimal dispatch where G7 solely supplies the whole network and one where the transmission losses on segment N3-N2 are avoided and corresponding Load 2 is supplied by the slightly more expensive local generator G11. In low demand situations this causes a shift in cheap generation between the loads more often. Especially when approaching the tipping point between the two situations just explained, this sometimes even results in the other loads' LMP becoming equal to the variable costs of G11. Since G11 is a local generator, this implies a shift in G7's heat from Load 2 to the other loads as G11 is dispatched instead. This ultimately creates more price variance, especially for the other loads. Since there are no differences in LMPs between the other loads than Load 2, this has been illustrated in figure 58 by plotting the LMPs for Load 1 only. It can be seen that its LMP sees more variability in scenario 3, and becomes equal to the variable costs of G11 (€5/GJ) more often. This causes the historical price volatility to increase so much on average.

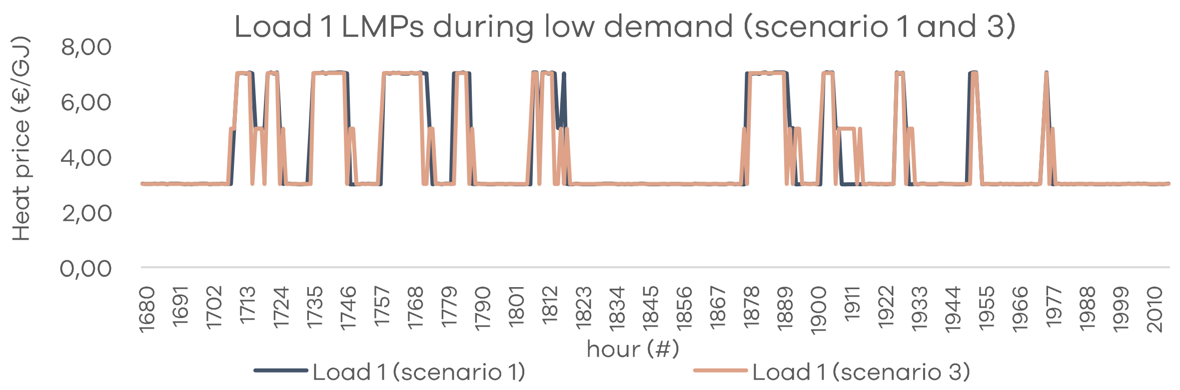


Figure 58 - LMPs for Load 1 during low demand in scenario 1 and 3

6.3.5 Appropriate economic marginal signals

Firstly, it should be noted that the economic signals experienced by the market remain unchanged in different scenarios and are more likely to be dependent on the respective pricing mechanism and loss allocation method in place. Essentially, only marginal cost-based pricing mechanisms SMP and LMP give appropriate economic marginal signals. The average cost-based pricing mechanisms ACP and LCP, as well as the hybrid LHP alternative still allow for prices to become excessively high in (although rare) situations where transmission loss volumes are large compared to – or even exceed – the demand volumes of the loads. This is solely due to the transmission loss allocation, done on the basis of average cost pricing, which intrinsically incentivises loads to increase their demand volumes in order to cut down heat prices. Naturally, this is considered inappropriate as it would simultaneously increase system costs altogether, decreasing economic efficiency. In this light, ACP gives the least inappropriate incentives out of the three pricing mechanisms just mentioned, given that the mutualisation of the transmission losses incorporated into one system price somewhat dampens these rare price spikes in times of low demand.

6.3.6 Fairness principle

The same applies to the fairness principle, also insensitive to potential scenarios but solely dependent on the pricing mechanism and transmission loss allocation method in place. Essentially, as already concluded during the conceptualisation of the different pricing mechanisms, only LCP and LHP incorporate the fairness principle in the allocation of transmission losses. ACP uses cost mutualisation disregarding loads' potential contribution to the losses. Although in theory costs of losses should be reflected by SMP and LMP, as stressed before losses are assumed constant and depend on whether a certain transmission segment is used or not. This means that its costs are not reflected in the SMPs or LMPs and therefore, as defined in this research, both pricing mechanisms disregard the allocation of transmission losses altogether. Summarising, all pricing mechanisms are assigned a positive or negative score on both scenario-insensitive market performance indicators, resulting in the following:

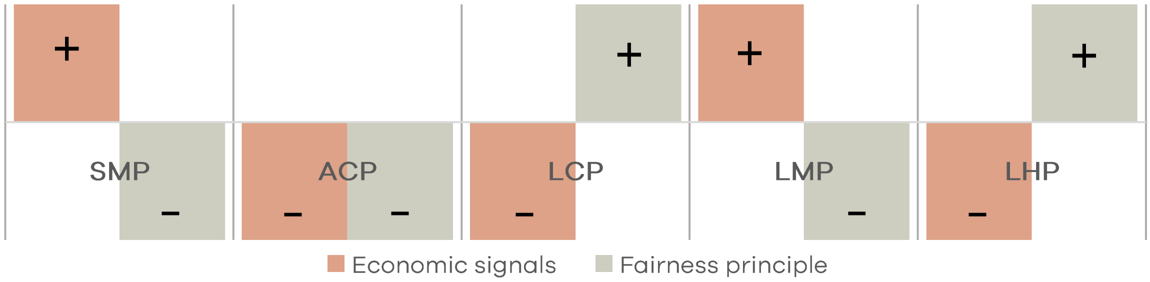


Figure 59 - Positive or negative scores on scenario-insensitive indicators for all pricing mechanisms

7. DISCUSSION OF THE RESULTS

This chapter will discuss the results from the experiments. On the basis of these results and by reflecting on the methodological choices and assumptions that have been made throughout this research, relevant insights will be formulated. Ultimately, these insights will be used to provide an answer to sub-question four:

What is the effect of locational marginal pricing and alternative pricing mechanisms on the system performance of the wholesale market in different scenarios?

7.1 Relative performance of pricing mechanisms

The results from all experiments have been displayed in table 33 by means of a scorecard. The market performance indicators that are used in this research are mostly based on the trade-off between affordability and cost recovery, supplemented by three indicators that are considered relevant with respect to the allocation of transmission losses. Although the market performance indicators have not been weighted in this research, some are regarded more important or impactful than others.

Scenario 1	**SMP**	**ACP**	**LCP**	**LMP**	**LHP**
Market surplus (M €)	8,5	-	-	7,6	1,6
Average heat price (€/GJ)	4,2	3,9	4,3	3,9	4,5
Price efficiency (%)	6,8	-	10,0	-0,1	13,6
Price volatility (%)	16,7	3,4	4,5	14,2	8,7
Scenario 2					
Market surplus (M €)	1,0	-	-	0,4	0,2
Average heat price (€/GJ)	3,6	3,8	4,2	3,4	4,3
Price efficiency (%)	-4,8	-	10,8	-10,4	11,9
Price volatility (%)	14,4	2,5	3,5	12,3	5,1
Scenario 3					
Market surplus (M €)	10,2	-	-	8,7	2,9
Average heat price (€/GJ)	4,2	3,9	4,2	3,9	4,4
Price efficiency (%)	7,5	-	9,6	0,9	14,2
Price volatility (%)	15,1	3,4	4,7	16,9	9,2

Table 33 - Scorecard overview of results in all scenarios

Cost recovery of the generators hereby has been considered as one of the biggest obstacles from the start of the discussions between all involved parties about how to organise an open heat market. Retail prices for heat are regulated in the Netherlands as yet, at approximately €23 per GJ (ACM, n.d.; Ecorys et al., 2016). The wholesale prices generated by the experiments in this research do not nearly approach those regulated retail prices, and thus leave considerable margins to be gained from wholesale market (supplier) to retail market (consumer). Therefore the market surplus is considered more important in this research, especially in light of the difficulties and uncertainties concerning cost recovery of the generators. Since the heat prices and corresponding price efficiencies are inherently connected, no distinction is made between both in terms of importance.

Both are however considered more relevant than price volatility. This order of relevance has been adopted in the scorecard.

As expected, the scorecard shows that SMP is most beneficial for the market performance in terms of cost recovery since it creates the largest market surplus in all scenarios, closely followed by LMP. In terms of affordability however, ACP and LMP both perform better. By combining all scores on each indicator from all scenarios the pricing mechanisms can be ranked, shown in table 34. It can be seen that LMP actually performs best and most consistently, despite the absence of any transmission loss allocation method i.e. honouring the fairness principle. Consequently, the results have shown that affordability and cost recovery do not necessarily exclude each other.

All scenarios combined		**SMP**	**ACP**	**LCP**	**LMP**	**LHP**
Cost recovery	Market surplus	1	4	4	2	3
Affordability	Average heat price	3	2	4	1	5
	Price efficiency	3	2	4	1	5
Transmission loss allocation	Price volatility	5	1	2	4	3
	Appropriate economic signals	1	2	2	1	2
	Fairness principle	2	2	1	2	1
	Overall ranking	**3**	**2**	**4**	**1**	**5**

Table 34 - Overall ranking of pricing mechanisms based on scorecard

7.2 Reflection on results

7.2.1 Interpretation of market performance

On the trade-off between affordability and cost recovery several things should be noted. Firstly, the case of LMP demonstrated that heat prices may become lower and more efficient than those produced by ACP, on average. As opposed to ACP however, LMP still allows for a market surplus. As a result of the differences in variable costs between the generators, this market surplus is generated mainly in times of relatively large demand, i.e. when more expensive generators are dispatched. In these situations, LMPs may become a lot higher (and thus less efficient) than the ACPs, as was shown in figure 54. These times of 'scarcity' represent less than 20% of an entire year, meaning that those higher prices are disproportionately reflected in the annual price averages. In parallel to this, the larger demand volumes in those times of scarcity result in a considerable market surplus. It was found that the actual size of this surplus could amount to almost 25% of the total generation costs, essentially meaning that total (variable) system costs are overstated by this amount. These costs were not included in the consideration of affordability. In other words, in terms of the generators, only the producer surplus was considered, whereas in terms of the consumers, consumer surplus was neglected and only price effects were considered. ACP for instance would have become more affordable on average if those costs i.e. the consumer surplus would have been included, while LMP would have become less affordable. On the other hand, LMP does succeed in producing more economically efficient signals to the market than ACP, since prices reflect this scarcity better and thus incentivise consumers to decrease their demand.

Secondly, an important remark concerns the fact that fixed costs of the generators were neglected in this research, as only variable costs were considered. These variable costs of the generators were chosen quite arbitrarily. It was also not considered how the respective market surpluses, thus solely based on variable generation costs, should be allocated over the generators. This is a limitation that is illustrated by the observation that the ACPs become lower than the variable costs of some generators, which in theory would result in them not even being able to earn back their variable costs. Realistically, this makes it impossible to draw clear conclusions with respect to actual cost recovery of their assets. Also, a sufficient market surplus was identified as being a goal. In the results however, pricing mechanisms producing a larger market surplus are regarded to perform better in terms of this goal than those producing a smaller (or no) market surplus. More realistically, it should regarded as a means to improve cost recovery whereas in reality also other mechanisms exist that can help improve cost recovery, such as e.g. a fixed tariff. Therefore, despite being formulated as an indicator, the market surplus actually has little representativeness in terms of the performance of the market. This should be taken into account in the interpretation of the results, as it only provides insight into how different pricing mechanisms relate to each other in terms of allowing for **variable** cost recovery from an aggregated viewpoint, and not from the viewpoint of individual generators.

7.2.2 Transmission loss allocation

The transmission loss allocation method that was designed and applied to LCP and LHP succeeds in honouring the fairness principle and in preventing too much price volatility, but also produces economically sub-optimal incentives, since prices can be decreased by increasing demand volumes and thus system costs. It also results in the highest and least efficient prices. These findings reveal a dilemma arising from friction between fairness on the one hand and economically efficient incentives and affordability on the other. Since the transmission losses have such a constant character, they might also be considered as fixed costs and be socialised over the entire system. From the viewpoint of fairness however this is considered sub-optimal. The proposed allocation method associates those costs with the actual heat demand from the viewpoint of fairness, but the absence of a relation between the actual heat demand and the amount of losses induced makes it very difficult to both incentivise cost reduction as well as to guarantee fairness. As a result, a 'fair' allocation of these losses can theoretically also result in the system becoming unstable, because costs of those losses are fixed while demand is variable, meaning that those costs could only be minimised by increasing demand. In other words, some nodes might want to avoid those losses if demand is too low, resulting in extremely high prices for other nodes. The ratio between the demand volumes and loss volumes hereby forms a crucial aspect to be considered as part of this dilemma. Loss volumes should hereby not be able to rise above the aggregated demand of the system. Nevertheless, the results have shown that this can occur during approximately two percent of the year where prices rose excessively. An option to mitigate this is to introduce a price cap that regulates a maximum relative loss cost component into the heat price that protects loads during these situations, assuming that generators are still able to earn back their variable costs over an entire year.

Additionally, the interpretation of the fairness principle as was done in this research has shown to cause large differences between downstream and upstream nodes, where upstream nodes essentially always have the advantage over downstream nodes. In the case of LHP, this is magnified because the upstream nodes are also given precedence in the assignment of cheaper generation. Although loads as formulated in this research represent large suppliers, they realistically are unable to choose their own location in a certain regional network because of the natural monopolies in place. Therefore this can be perceived as unfair instead. Would the other perspective have been chosen with respect to the assignment of cheap generation in LHP, then these differences would have become much smaller as they would then be caused by only the transmission loss allocation.

7.2.3 Other methodological choices

Several other methodological choices were made during this research that should be considered in the interpretation of the results. For instance, the network that was modelled is rather simple and linear in terms of its topology. In the case of LMP, only Load 2 experienced a different heat price because of its local generator. If the network would have been larger and characterised by more 'branches', i.e. less linear, certain transmission segments might have been avoided or other generators might have been dispatched in the optimisation which would lead to more locational differences reflected by the LMPs. This would have been improved even further by also including transmission constraints and storage. Based on the assumptions made in this research, referring to the economic dispatch being regarded as a starting point and unaltered by potential pricing mechanisms, this would not have changed the relative performance of those pricing mechanisms.

Also the way in which the data was used results in all loads being characterised by exactly the same demand pattern, since demand volumes from one particular district heating network were extrapolated to the other loads on the basis of their relative sizes. Realistically, loads are more distinguished in terms of their demand pattern due to e.g. different types of connected consumers in different areas. In addition, the datasets were reduced in size for the purpose of computational efficiency in light of the algorithm. By extrapolating again afterwards the actual demand volumes are hereby overstated by a certain percentage error. This error is made systematically, since this was done for all datasets, and therefore would not have influenced how the pricing mechanisms perform relative to each other.

Overall, based on the results, it can be concluded that LMP performs most consistently on both cost recovery and affordability, followed by ACP and SMP. The transmission loss allocation method was designed according the rationale that generators should be economically compensated for their generated heat that is lost in the system by considering the loads' relative contribution to those losses. Although this method is average cost-based, combining it with a semi marginal cost-based pricing mechanism into the LHP alternative was expected to benefit cost recovery compared to LMP. Despite not reflecting the costs of the transmission losses or considering the fairness principle, the LMP results have refuted this. The limitations that were discussed however also showed that based on this research it is difficult to arrive to un unambiguous and definitive answer to sub-question four. This research has rather provided the tools to enable the answering of the sub-question methodologically, while generating several important insights that relate to the sub-question:

- SMP and LMP always allow for a certain market surplus, the opposite is true for ACP and LCP;
- LHP allows for a market surplus when following the perspective of the most upstream load in the generation assignment process;
- LMP and SMP do not include the costs of transmission losses and therefore prices may become lower and more efficient than ACP prices, given that ACP mutualises those costs;
- The principles used in the transmission loss allocation method cause large differences between downstream and upstream nodes for LCP and LHP;
- Pricing and allocating transmission losses on the basis of average costs creates economically sub-optimal incentives.
- The fixed nature of transmission losses reveal a strong dilemma between fairness on the one hand and economically efficient incentives and affordability on the other.

8. CONCLUSIONS & RECOMMENDATIONS

8.1 Main research findings

As introduced in the beginning of this thesis the challenge of arranging an open heat market according to the Nodal Pool model in the context of the Heat Roundabout project, while extending the focus on the unique character of the transmission losses for heat, led to the following main research question:

How would the application of Locational Marginal Pricing (LMP) to an open heat network affect the overall performance of this market, compared to alternative pricing mechanisms?

From the results of the experiments that were performed, displayed in the spider web-charts in figure 60, it was found that the application of LMP, despite not including any transmission loss allocation method, still positively affects the wholesale market performance most consistently compared to the other pricing mechanisms. Both LMP and SMP produce more appropriate economic signals to the market than the other pricing mechanisms, because they do not allow for increasing demand and thus system costs in order to decrease prices. Since the transmission losses are fixed and not a function of the demand, the absence of any allocation method in LMP proves less of a problem in terms of sound economic signals and affordability, but rather in terms of fairness. However, both SMP and LMP also produce the largest price volatility compared to the other pricing mechanisms. It was also found that for some nodes LMPs can become equal to the variable costs of a generator that physically cannot even reach them. This means that LMP can still provide the wrong investment signals to the market, which was one of the motives for Rau (2000) to suggest allocating transmission losses by an approach based on responsibility or fairness.

As became clear during the exploration, it proves difficult to accurately express the marginal costs of transmission losses due to their fixed and constant character. Therefore an alternative pricing mechanism and a transmission loss allocation method was sought based on the starting points:

1. That it should find a balance in the trade-off between affordability and cost recovery;
2. That it should honour the fairness principle;
3. That it should reflect locational dependence of generation by assigning value to upstream generation (due to the unidirectional flow of heat);
4. That it should reflect locational dependence by incorporating costs of transmission losses;
5. That it should provide appropriate economic marginal signals to the market;
6. That it should be applicable to a network model in any possible configuration.

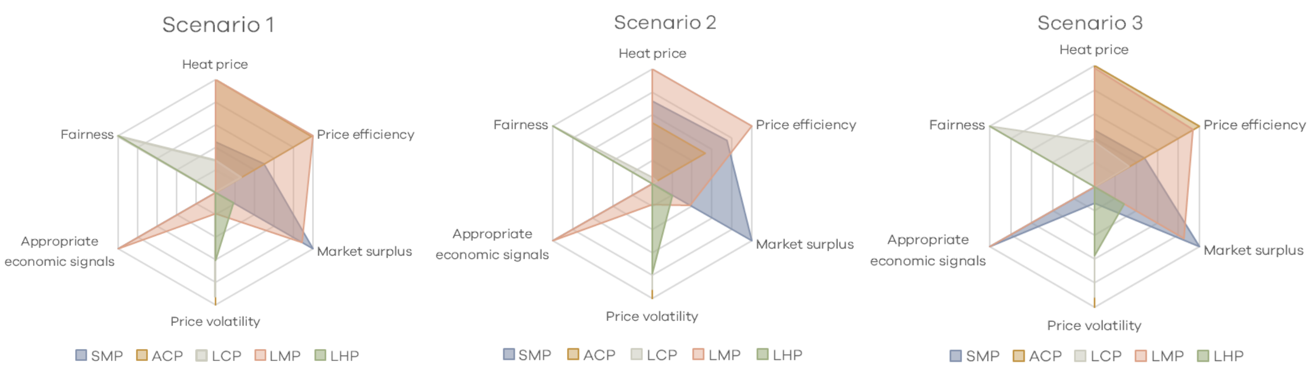


Figure 60 – Spider web charts with results in all scenarios scaled at 0-1 range

It can be concluded that the LHP alternative satisfies most of these starting points but fails to (5) provide appropriate economic marginal signals to the market. Considering the limitations of the indicators representing the market performance discussed in the previous chapter, LHP succeeds in reflecting the locational dependence of generation and incorporates all incurred costs of the transmission losses. As a result, this alternative pricing mechanism produces large differences between upstream and downstream nodes. It was also found that the allocation of transmission losses on the basis of fairness reveals a strong dilemma dealing with fairness, appropriate economic incentives and affordability.

Overall, considering the limitations of this research that were discussed in the previous chapter, the main conclusion is that different pricing mechanisms and loss allocation methods result in divergent effects on the performance of an open heat market. The model that was used was rather conceptual by nature. The research objective that was formulated in the introduction is hereby partly fulfilled:

To identify the most attractive pricing mechanism for a regional competitive heat market in the context of the Heat Roundabout.

Despite the fact that this research produced several useful preliminary insights in terms of how different pricing mechanisms perform in relation to each other and how to deal with costs inherent to the unique characteristics of heat, it is found that no definitive answer to the main research question can be formulated based on this research only. For the purpose of translating the insights from this research to the context of the Heat Roundabout, additional research is needed.

8.2 Contribution of this research

By means of the research presented in this thesis insights have been generated into the relative performance of different pricing mechanisms when applied to an open heat network. Apart from these insights, this research contributed by providing the methodological tools to explore the effects of those pricing mechanisms in the form of a running network model that is able to determine the economic dispatch under different scenario conditions.

In addition to the network model, a working algorithm was designed that incorporates an alternative pricing mechanism and includes the allocation of transmission losses. This algorithm has been designed so that it can be applied to a network model in any configuration. Different perspectives have been formulated that can be applied to either the pricing of generation or the pricing and/or allocation of transmission losses.

8.3 Recommendations

This research produced several important insights regarding the system performance of a conceptual open heat market. The differences that exist between the different pricing mechanisms show that the organisation of an open heat market is not trivial and accordingly it is recommended for Eneco to carefully consider this. The network that was modelled however was rather small and linear by nature, showing no real locational differences when applying LMP. To add to the insights gained in this research and to better put them into the context of the Heat Roundabout, it is therefore recommended for future research to expand the network and incorporate transmission constraints and storage in order to investigate the changes in market dynamics. In addition, since only three scenarios were formulated with three scenario parameters, it is recommended to systematically explore the sensitivity of the market performance indicators to more variations of these parameters.

One fundamental assumption that was made in this research was that the least-cost dispatch based on only variable costs was used as a starting point and assumed most economically efficient, while the pricing mechanisms were only considered as an ex-post economic (allocation) procedure. In future research, it is recommended to incorporate pricing mechanisms into the actual optimisation model. With such a model it can be investigated if some pricing mechanisms might result in a different allocation of resources. In combination with the additional consideration of the consumer surplus, as opposed to just looking at price effects, this should enable the investigation of which pricing mechanism is most economically efficient, which ultimately is one of the drivers of the heat roundabout project.

In addition, including fixed costs in a future model study would increase the validity of the market outcomes produced by different pricing mechanisms. From the viewpoint of Eneco this would be interesting considering that it could enable the answering of questions relating to the investment decisions, e.g. how the feasibility of investments in generation assets would compare in different pricing mechanisms and at which location in a regional heat network such investments would be most lucrative.

With respect to the LHP alternative, future research could explore the effect of incorporating the other perspective regarding pricing of generation on the market performance. It would also be interesting to test different transmission loss allocation methods on the system. In this light it is recommended to refine the corresponding algorithm and increase its efficiency, so that it needs less computation time and enable the calculation of a larger and more valid dataset in the context of a larger network.

8.4 Reflection on research process

As was concluded in section 8.1, the objective of this thesis was only partly fulfilled. This can be attributed to several shortcomings of the research design and process. Firstly, the research has proven to be rather extensive, and has practically been done in two main iterations. In the beginning of the process the general objective was to identify the most attractive market model from the viewpoint of Eneco. The research was widely scoped at first, and after an extensive exploration the focus shifted more towards pricing mechanisms and the allocation of costs, rather than also including other design choices comprising a market model as a whole. Following from other exploratory research into the optimal market design of the heat roundabout, the research question was formulated mainly from the viewpoint of applying LMP to this regional heat network. This led to the development of a tool, in the form of a network model and an algorithm, that would need to incorporate LMP. Inconsistencies in the research design most likely started in this first iteration, as it proved difficult to translate a pricing mechanism, that is originally meant as a congestion management method in electricity networks, to the context of a heat network, considering the different properties of both utilities. This led to a wrong interpretation of LMP as a pricing mechanism, while it had already been integrated into the algorithm. A better understanding of LMP theory could have prevented this, whereas the inclusion of transmission constraints could have improved the validity of the application of LMP. The 'costs' of this work were however not sunk costs, as the wrong interpretation of LMP led to the further development of an alternative pricing mechanism, i.e. the LHP alternative.

Another inconsistency is attributable to the fact that in this first iteration the research approach was not formulated clearly enough, in terms of how the results generated by the model would be compared. The results were reflected on from the perspective of the 'consumers' and 'producers', but clear and unambiguous performance indicators were missing. At this point a second iteration commenced, in which the model or tool was (practically) unaltered while sub-questions, performance indicators and the resulting interpretation of results had to be reverse engineered or 'repaired'. In this process I noticed how important it is to let the research question be leading for the subsequent formulation of performance indicators and choosing an appropriate tool or method. An example is the formulation of a research question relating to how pricing mechanisms compare to each other in terms of economic efficiency, while the model that was built and used made this irrelevant since it was only able to determine an economic dispatch on the basis of variable costs, and not altered by potential pricing mechanisms. Another example is the inclusion of cost recovery, that was identified as a driver of the research in the exploration phase, whereas in the course of the research it became clear that a lack of insight into the fixed costs of such generation assets would make it impossible to draw clear conclusions with respect to cost recovery. This could have been prevented by investigating if insights in these fixed costs were available at all in the exploration phase, and instead disregard them out of the scope or make assumptions based on available theory.

An additional remark concerns the choice for building an algorithm as a means of incorporating a pricing mechanism. This was a rather bold choice, since my programming skills had to be developed during this process. It proved a difficult challenge and cost a lot of time, indirectly leading to more simplifications and assumptions in the specification of the hybrid pricing alternative and search for an optimal allocation of transmission loss costs. Ultimately I've experienced the difficulty, and inherently learned the importance, of aligning the research question(s) and scope with the criteria and method to be used in view of improving the line of argumentation and inherently the quality of such an extensive research. Focus could have been put more on the cost allocation methods and less on the challenge of an optimal market design in the context of the heat roundabout, and the identified hurdle of balancing cost recovery with economic efficiency or affordability, to improve the quality of this research. Nevertheless, this research contributed by presenting a novel cost allocation method that can be further improved, and simultaneously produced insights into the relative performance of different pricing mechanisms when applied to a conceptual heat market, taking into account the shortcomings of the indicators that reflect the performance of such a market.

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APPENDICES

A. NETWORK MODEL CONFIGURATION

B. SCENARIO DATA

C. PRICING ALGORITHM IN MAPLE

A. NETWORK MODEL CONFIGURATION

Reproducing an existing heat network in a most realistic and valid way was not part of the objective in this thesis, due to the scope of the research and the lack of available data. Intrinsically, this means that a lot of assumptions are made with respect to the configuration of a network model. These assumptions are however partly based on the existing and planned infrastructure as was presented in figure 6, and partly based on actual historical data that originates from existing networks.

A.1 Load infrastructure

As was displayed in table 3 and discussed in sub-section 4.1.2 the most relevant properties of the load infrastructure as formulated in this research are the loads' locations in the network and their demand volumes. The process of choosing the loads and their locations was guided by figure 6, mapping the current and planned infrastructure regarding the Heat Roundabout project including all major heat networks in the Province of Zuid-Holland. It was chosen to model a network of six nodes containing five loads, based on five of the largest district heating networks currently present in Zuid-Holland.

Node:	**Load:**	**Based on district heating network:**
Node 1	Load 1	Leiden
Node 2	Load 2	The Hague
Node 3	Load 3	Lansingerland ('B-driehoek')
Node 4	Load 4	Rotterdam (Nuon)
Node 5	-	-
Node 6	Load 6	Rotterdam (Eneco)

The process of choosing a location for the loads was argued from the perspective of Rotterdam, where the only existing transmission networks are located and heat is transported from mainly the waste processing plant (AVR) located in the Port of Rotterdam. This resulted in Load 6 being placed on the first node (6) upstream in the network. Although the topology of the network model, best described as mostly linear yet with a tree element in the tail-end, does not correspond to the existing and planned networks, the locations of the other loads and the district heating networks which they are based on were taken into account as much as possible in their placement in the model. Hence, it can be observed that Leiden and The Hague, both relatively farthest away from Rotterdam, are placed at the last two nodes (1 & 2) located at the tail-end downstream in the network model.

In the case of the hourly demand volumes that have been used in the network model, the only usable data available was from the district heating network in The Hague and obtained from energy company Eneco. For confidentiality reasons this data will not be made public. This data has been used as a reference in the process of assigning hourly demand volumes to the other loads in the network model. Despite the absence of data regarding hourly demand volumes for the other district heating networks, the *yearly* amount of delivered heat in all existing Dutch district heating networks was indeed available and obtained from the report *Monitoring Heat 2015* by Menkveld et al. (2017).

By combining the two sources of data, a distribution key was made with respect to the allocation of hourly demand volumes to the other loads, shown in the table below. This was done by considering the yearly delivered heat volumes in every district heating network and express it as a percentage of the yearly volume delivered in the district heating network of the Hague, of which the hourly volumes are known. Subsequently, hourly demand volumes for the other loads were proportionately calculated by multiplying the hourly demand data from The Hague by those respective percentages. Since the hourly demand data from The Hague was hereby used as a reference, this results in the hourly demand volumes of the other loads always being a certain multiple of the former. This means that all loads are characterised by the same demand pattern at each time-step.

Load (based on)	Demand in 2015 (GJ)	Share of total demand (%)	Share relative to Load 2 ('The Hague') (%)
1 – 'Leiden'	700.000	9	64
2 – 'The Hague'	1.100.000	15	100
3 – 'Lansingerland'	2.100.000	28	191
4 – 'Rotterdam (Nuon)'	200.000	3	18
6 – 'Rotterdam (Eneco)'	3.300.000	45	300
Total	**7.400.000**	**100**	-

A.2 Generation infrastructure

The most relevant properties of the generation infrastructure are their locations in the network, their maximum generation capacity and their variable costs of generation. In order to produce some diversity with respect to the merit order, it was decided to model five generation assets characterised by divergent amounts of generation capacity and generation costs. Firstly, the aggregated installed generation capacity was dimensioned at approximately one hundred and seven percent of the peak demand and the average losses. The generation infrastructure has thus been overdimensioned slightly in order to avoid shortages that might cause errors in the optimisation software. Subsequently, the aggregated generation capacity was allocated on the basis of an estimation of the generation assets currently installed in the province of Zuid-Holland, distinguished by type of asset i.e. fuel. This estimation was based on data by Menkveld et al. (2017) regarding the distribution of installed generation capacity nationwide in the Netherlands. Since Zuid-Holland is characterised by relatively large amounts of residual heat due to the presence of the AVR waste processing plant in the Port of Rotterdam, as well as a relatively new geothermal plant in the Hague, these numbers were adapted to come to the estimated distribution of types of generation assets as shown in the table below.

Type of asset	Nationwide (%)	Zuid-Holland (estimation) (%)	Installed capacity (GJ)
CHP	67	45	2.335
Natural gas	7	17	888
Biomass	15	4	196
Residual heat	12	33	1.703
Geothermal	-	2	98
Total			5.220

The process of choosing the respective locations of the generation assets again was somewhat guided by figure 6. As the figure shows, the district heating network in and around Rotterdam is mainly supplied by the waste processing plant AVR and a large CHP plant. Since both also account for the largest share of the aggregated generation capacity, they have been placed at node 6, most upstream in the network, so they could physically supply any load in the network. The generator with the least amount of generation capacity presents the geothermal plant located in The Hague, positioned at node 2 as a local generator. Residual and geothermal heat are usually characterised by low variable generation costs due to the absence of fuel costs, and therefore both generators were assigned relatively low variable costs in the network model as well. The other two generators were positioned at node 4 and 3 and assigned relatively higher variable generation costs, leaving node 1 without a generator and node 5 as a transhipment node, thus creating some diversity with respect to the topology of the network and the merit order. This ultimately results in the following:

Node:	Generator:	Based on:	Variable costs (€/GJ):
Node 1	-	-	-
Node 2	Generator 11	Geothermal	5
Node 3	Generator 10	Natural gas	10
Node 4	Generator 9	Biomass	8
Node 5	-	-	-
Node 6	Generator 7	Residual	3
	Generator 8	CHP	7

A.3 Transmission infrastructure

The transmission infrastructure comprises the set of segments connecting the nodes, of which the most relevant properties are their transmission capacities and transmission loss volumes. As the focus of this research lies on the transmission losses and not transmission congestion, transmission constraints are assumed absent and therefore the maximum transmission capacities are set at infinite. Despite the fact that several aspects of the network model configuration are derived from the existing district heating infrastructure in the Province of Zuid-Holland, the aim partly is to provide a proof-of-concept of the pricing algorithm that was designed. This makes the model study rather conceptual by nature, using a simple network of which the topology, as mentioned earlier, is rather linear and simple as well.

For the determination of the transmission loss volumes specific to each segment a distinction was made on the basis of the distances existing between the district heating networks on which the different loads discussed in A.1 were based. A longer distance hereby means a larger transmission loss volume and vice versa. Firstly, the average aggregated transmission loss volume of the entire network was calculated. According to Menkveld et al. (2017) transmission losses for heat averagely amount to fifteen percent of the heat flows throughout a network. Multiplying the average demand by this percentage amounts to an aggregated transmission loss volume of 158 GJ. This aggregated volume was subsequently distributed over the different transmission segments by means of a distribution key based on the assumed distances. This results in the following:

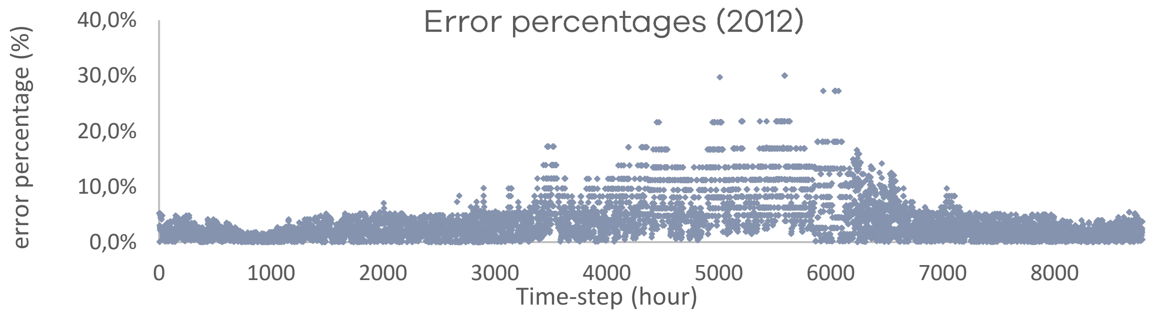
From (node)	To (node)	Transmission segment (name)	Share of total losses (%)	Loss volume (GJ)
6	5	QL65	30	47
5	4	QL54	25	39
4	3	QL43	20	32
3	2	QL32	15	24
3	1	QL31	10	16
		TOTAL	**100**	**158**

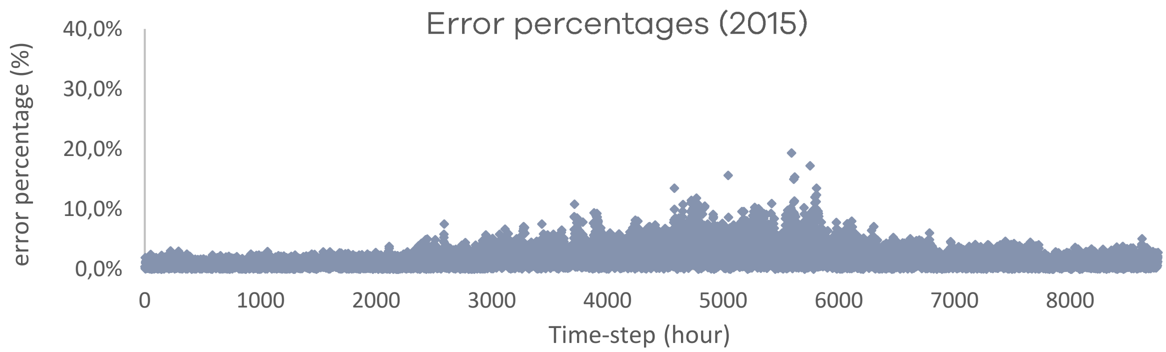
B. SCENARIO DATA

The scenarios that were developed and simulated in this research are based on two different datasets: hourly demand volumes from the same district heating network in the year 2012 and 2015. For the purpose of computational efficiency in view of the algorithm, these datasets are reduced in size. In the case of the dataset of 2015, also a correction for growth of the network is performed by normalising the data on the basis of the correlation between the demand volumes and the outside temperatures.

B.1 Reduction of datasets to n=100

The datasets from 2012 and 2015 entail 8784 and 8760 pieces, respectively. Both are reduced in size to n=100 by constructing a histogram, taking the maximum of the bin. This means that the actual hourly demand volumes are inevitably overstated by a certain error margin when extrapolating again to the original size of a whole year afterwards. The figures below show the error percentages throughout the year in both datasets, in which it can be observed that they become larger during months in which the temperature is relatively high, i.e. in times of low demand.





Ultimately, the dataset from 2012 is characterised by an average error of 3,9 % whereas the dataset from 2015 has an average error of 2,1 %. Since these errors are made consequently, it does not influence the comparison of the different pricing mechanisms in these scenarios.

B.2 Network growth correction by data normalisation

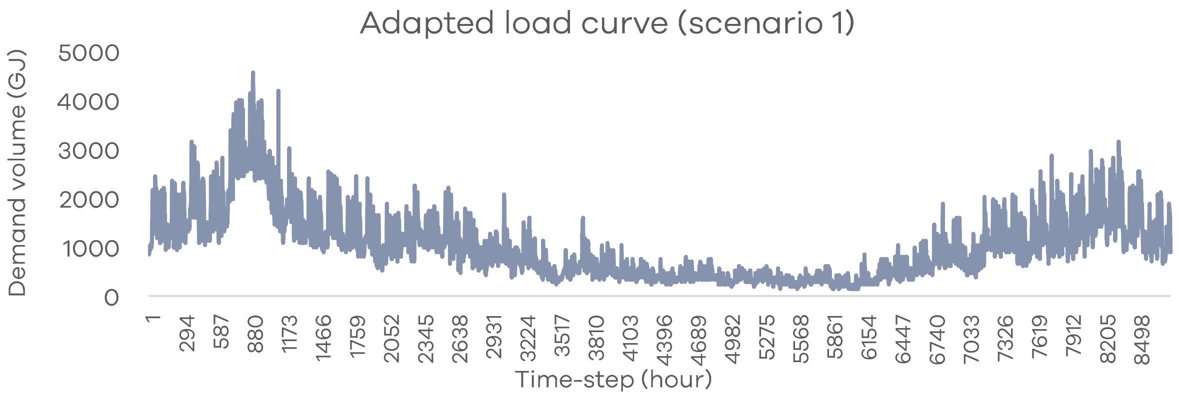
In order to correct for natural growth of the amount of connected consumers in the district heating network from which the data stems, the demand volumes from the dataset of 2015 are normalised on the basis of the correlation with the outside temperatures. The average temperatures were taken from KNMI (n.d.), and coupled to the corresponding demand volumes. Since these average temperatures were daily and demand volumes hourly, demand volumes were summed in order to obtain the total amount of demand volume applicable to each day and match time-frames of both variables. This is done for the entire datasets from 2012 and 2015. This enables the calculation of the aggregated slope coefficients between the total daily demand volumes and the average daily outside temperatures. These have been displayed in the table below, also showing that the difference in slope coefficients amounts to a growth percentage of 7,15 % in 2015 relative to 2012.

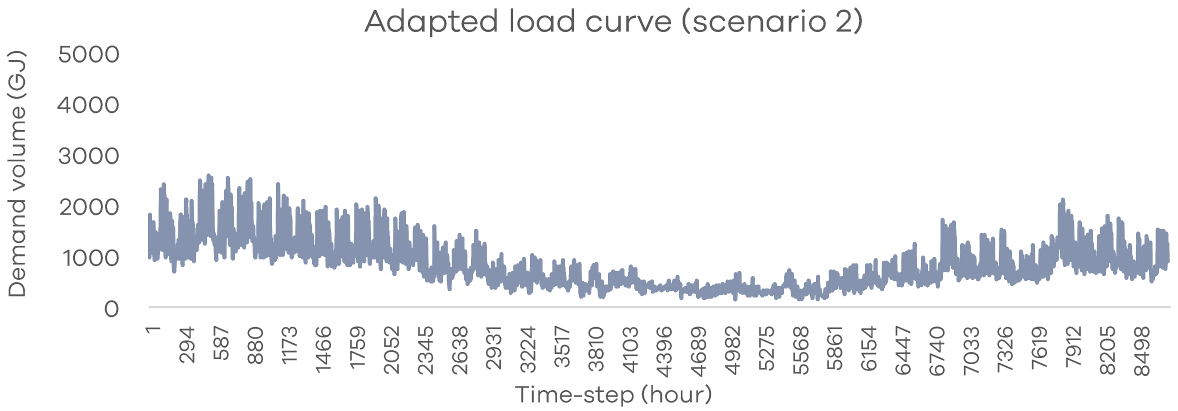
	Dataset 2012		**Dataset 2015**
Slope coefficient	-349,5		-326,2
Difference		23,3	
Growth percentage			7,15

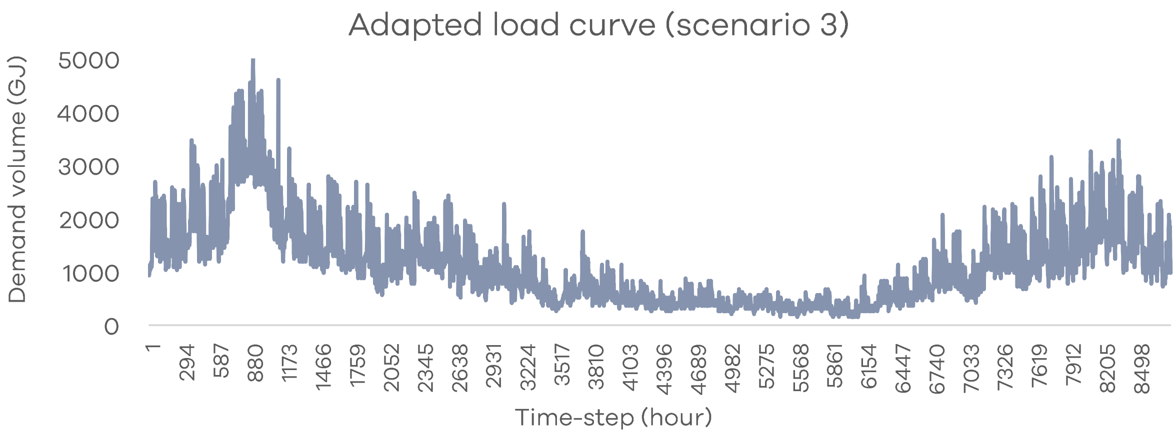
Consequently, the hourly demand volumes of the 2015 dataset are thus corrected for growth by decreasing them by the same growth percentage of 7,15 %.

B.3 Load curves for all scenarios

As was discussed in B.1, the extrapolation to an entire year again afterwards brings about a slight error percentage with respect to the original data due to taking the maximum of the bin in the construction of the histograms, in the process of reducing the datasets. Although this does not influence the comparison of the pricing mechanisms as central in this research, the adapted datasets thus yield slightly different load curves in all scenarios. These have been displayed below for all scenarios.







Adapted load curve (scenario 3)
Demand volume (GJ)
5000
4000
3000
2000
1000
0
1
294
587
880
1173
1466
1759
2052
2345
2638
2931
3224
3517
3810
4103
4396
4689
4982
5275
5568
5861
6154
6447
6740
7033
7326
7619
7912
8205
8498
Time-step (hour)

C. PRICING ALGORITHM IN MAPLE

In this appendix the code as programmed in MAPLE capturing the hybrid pricing alternative is documented. For the algorithm several procedures were specified for the sake of computational efficiency. These are presented below as well.

C.1 MAPLE code – procedures

```
DetermineUpstreamGenerators := proc(k)
local vv, MF;
global UPG;
UPG[k] := [ ] :
  for vv from 1 to nops(Vertices(GG)) do
    if InDegree(GG, vv) = 0 and Distance(GG, vv, k) > 1 and Distance(GG, vv, k) < infinity then
      MF := MaxFlow(GG, vv, k) :
      if MF[1] > 0 then
        UPG[k] := [op(UPG[k]), vv] :
      fi:
    fi:
od:
end proc:
```

```
DetermineMarginalGenerator := proc(h)
local UPG2, o, M3, oo;
global UPGIndicator, UPG;

UPG2 := UPG[h] :
M3 := 0 :
for o in UPG2 do
if CG[o] > M3 then
M3 := CG[o] :
oo := o :
fi:
od:
return oo :
end proc:
```

```
DetermineCheapestGenerator := proc(G, j)
local o, M3, oo, UPG2temp;
global UPG2;

UPG2temp := UPG2[j] :
M3 := 100000 :
for o in UPG2temp do
if CG[o] < M3 then
M3 := CG[o] :
oo := o :
fi:
od:
return oo :
end proc:
```

```
SetNodalGeneration := proc(G, v)
local NB, nb;
global QG;

  if InDegree(G, v) > 0 then
    QG[v] := 0 :
    NB := Neighborhood(G, v) :
   for nb in NB do
     if InDegree(G, nb) = 0 then print(nb);
     QG[v] := QG[v] + QG[nb] :
     fi:
  od:
 fi:
end proc:
```

```
DownstreamGenerationOnCheck := proc(G, h)
 if QG[h] > 0 and nops(IncidentEdges(G, h, direction = outgoing)) = 0 then
   return QG[h] :
  else return 0 :
 fi:
end proc:
```

```
DownstreamConnectedCheck := proc(G, s, t)
  if Distance(G, s, t) ≥ 0 and Distance(G, s, t) < infinity then
    return 1; else
    return 0;
  fi:
end proc:
```

```
DownstreamGenerationOfLossCheck := proc(G, k)
 global QG, c;
 local k2;
  c := [ ] :
  if k > 1 then
  k2 := k - 1 :
  for k2 from 1 to k2 do
  if QG[k2] > 0 and nops(IncidentEdges(G, k2, direction = outgoing)) > 0 then
  c := [op(c), k2] :
  fi:
od:
fi:
return c :
end proc:
```

```
SumOfLossesUnderGenerator := proc(G, m, n)
 global QL, DownstreamGenerationOfLossCheck, DownstreamConnectedCheck,
 local LossSum, h, hh;
  h := op(n, DownstreamGenerationOfLossCheck(G, m)) - 1 :
 hh := op(n, DownstreamGenerationOfLossCheck(G, m)) - 1 :
  if h > 1 then
  LossSum[m] := 0 :
  for h from 1 to h do
 LossSum[m] := LossSum[m] + (QL[h]·DownstreamConnectedCheck(G, op(n, DownstreamGenerationOfLossCheck(G, m)), h)) :
 od:
 if not hh = (min(DownstreamGenerationOfLossCheck(G, m)) - 1 ) then
  LossSum[m] := LossSum[m] - (add(QL[mm], mm = 1 ..(op((n-1), DownstreamGenerationOfLossCheck(G, m))) - 1)) :
  fi:
 return LossSum[m] :
 else return 0 :
 fi:
end proc:
```

```
SumOfLoadsUnderGenerator := proc(G, m, n)
 global DownstreamGenerationOfLossCheck, DownstreamGenerationOnCheck, SumOfLoads,
 local hh, h;
  hh := op(n, DownstreamGenerationOfLossCheck(G, m)) :
 h := op(n, DownstreamGenerationOfLossCheck(G, m)) :
 SumOfLoads[h] := 0 :
for hh from 1 to hh do
 SumOfLoads[h] := SumOfLoads[h] + D[hh] - DownstreamGenerationOnCheck(G, hh) :
 od:
 if not h = min(DownstreamGenerationOfLossCheck(G, m)) then
SumOfLoads[h] := SumOfLoads[h] - (add(QG[hhh], hhh = min(DownstreamGenerationOfLossCheck(G, m)) ..( h - 1)) - add(QG[hhh], hhh = min(DownstreamGenerationOfLossCheck(G, m)) ..(n - 1))) + (add(QL[hhh], hhh = 1 ..(h - 1))
     - add(QL[hhh], hhh = 1 ..(n - 1))) :
 fi:
 return SumOfLoads[h] :
end proc:
```

```
MultipleDSGcalc := proc(G, k, j)
global Dn, D, DownstreamGenerationOnCheck, DownstreamConnectedCheck, SumOfLoadsUnderGenerator, SumOfLossesUnderGenerator, DownstreamGenerationOfLossCheck;
local DSGno, DSGlistOp;

DSGlistOp := 1 :
DSGno := op(DSGlistOp, DownstreamGenerationOfLossCheck(G, k)) :

Dn[j] := (D[j] − DownstreamGenerationOnCheck(G, j)) - ( ((D[j] − DownstreamGenerationOnCheck(G, j)) · DownstreamConnectedCheck(G, DSGno, j)) / SumOfLoadsUnderGenerator(G, k, DSGlistOp) · (QG[DSGno] − SumOfLossesUnderGenerator(G, k, DSGlistOp)) ) :

        while DSGno < max(DownstreamGenerationOfLossCheck(G, k)) do

          DSGno := op((DSGlistOp + 1), DownstreamGenerationOfLossCheck(G, k)) :
          DSGlistOp := DSGlistOp + 1 :

          Dn[j] := (Dn[j] − DownstreamGenerationOnCheck(G, j)) - ( ((Dn[j] − DownstreamGenerationOnCheck(G, j)) · DownstreamConnectedCheck(G, DSGno, j)) / SumOfLoadsUnderGenerator(G, k, DSGlistOp) · (QG[DSGno] − SumOfLossesUnderGenerator(G, k, DSGlistOp)) ) :
        od:
end proc:
```

```
SingleDSGcalc := proc(G, k, j)
global Dn, D, DownstreamGenerationOnCheck, SumOfLoadsUnderGenerator, DownstreamGenerationOfLossCheck, SumOfLossesUnderGenerator;
Dn[j] := (D[j]− DownstreamGenerationOnCheck(G, j)) - ( (D[j] − DownstreamGenerationOnCheck(G, j)) / SumOfLoadsUnderGenerator(G, k, 1) ) · (QG[op(1, DownstreamGenerationOfLossCheck(G, k))] − SumOfLossesUnderGenerator(G, k, 1)) :
end proc:
```

```
DetermineUpstreamGenerators2 := proc(G, j)
local vv, MF;
global UPG2;
UPG2[j] := [ ] :
  for vv from 1 to nops(Vertices(GG)) do
    if InDegree(G, vv) = 0 and Distance(G, vv, j) > 0 and Distance(G, vv, j) < infinity then
      MF := MaxFlow(G, vv, j) :
      if MF[1] > 0 then
        UPG2[j] := [op(UPG2[j]), vv] :
      fi:
    fi:
od:
end proc:
```

```
UpdateGeneratorData := proc(j)
local hhh, m;
global UPG, CG, QG, UPGIndicator;

if UPGIndicator in UPG[j] then
hhh := select(m→UPG[j][m] = UPGIndicator, [$ 1 ..nops(UPG[j])]);
UPG[j] := subsop(hhh = NULL, UPG[j]) :
 CG[UPGIndicator] := subsop(1 = NULL, CG[UPGIndicator]) :
 QG[UPGIndicator] := subsop(1 = NULL, QG[UPGIndicator]) :
fi;
end proc:
```

```
UpdateDataPriceCalc := proc(G, j, p)
 local hhh, m;
 global UPG2, CG, QGtemp;

if p in UPG2[j] then
hhh := select(m→UPG2[j][m] = p, [$ 1 ..nops(UPG2[j])]);
UPG2[j] := subsop(hhh = NULL, UPG2[j]) :
 QGtemp[p] := subsop(1 = NULL, QGtemp[p]) :
fi:
end proc:
```

```
MCGCalculation := proc(G, j)
global D, indD, CG, P, QGtemp, DetermineCheapestGenerator, UpdateDataPriceCalc, QFlow, n;
local QD, Gno, h;
|
if j in indD then
QD[j] := D[j] :
P[n][j] := 0 :

while QD[j] > 0 do
Gno := DetermineCheapestGenerator(G, j);

if  QGtemp[Gno] ≥ QD[j] then
P[n][j] := CG[Gno] :
 QFlow[n][Gno, j] := QD[j] :
QGtemp[Gno] := QGtemp[Gno] − QD[j] :
QD[j] := 0 :

if QGtemp[Gno] = 0 then
 for h from 1 to nops(Vertices(G)) − 5 do
  UpdateDataPriceCalc(G, h, Gno) :
od:
fi:

else
P[n][j] := CG[Gno] :
QFlow[n][Gno, j] := QGtemp[Gno] :
QD[j] := QD[j] − QGtemp[Gno] :

for h from 1 to nops(Vertices(G)) − 5 do
UpdateDataPriceCalc(G, h, Gno) :
od:

fi:
od:
fi:
end proc:
```

C.2 MAPLE code - algorithm

```
with(GraphTheory):
E := {[6, 5], [5, 4], [4, 3], [3, 2], [3, 1], [7, 6], [8, 6], [9, 4], [10, 3], [11, 2], [1, 12], [2, 13], [3, 14], [4, 15], [6, 16]} :
G := Graph(16, E);
G := MakeWeighted(G);

vp := [
[35, 37],
[35, 13],
[25, 25],
[18, 25],
[9, 25], [1, 25],
[0, 50],
[4, 50], [18, 50],
[25, 50],
[45, 13],
[35, 50],
[35, 1],
[25, 1],
[18, 1],
[1, 1]
]:
SetVertexPositions(G, vp) :
DrawGraph(G);
n := 4 :
nmax := 103 :
while n ≤ nmax do


GG := CopyGraph(G) :
for v in Vertices(GG) do
if OutDegree(GG, v) = 0 then GG := DeleteVertex(GG, v) :
fi:
od:
for v in Vertices(GG) do
ie := IncidentEdges(GG, v) :
if InDegree(GG, v) = 0 then
HighlightVertex(GG, v, blue) :
HighlightEdges(GG, ie, blue) :
fi:
od:
E2 := Edges(GG);
DrawGraph(GG);
```

```
with(FileTools) :
with(ExcelTools) :
data := JoinPath(["Excel", "Model data - edited.xlsx"], base = datadir);
M := Import(data);


Flow[[3, 1]] := round(M[n][2]) :
Flow[[3, 2]] := round(M[n][3]) :
Flow[[4, 3]] := round(M[n][4]) :
Flow[[5, 4]] := round(M[n][5]) :
Flow[[6, 5]] := round(M[n][6]) :
Flow[[7, 6]] := round(M[n][7]) :
Flow[[8, 6]] := round(M[n][8]) :
Flow[[9, 4]] := round(M[n][9]) :
Flow[[10, 3]] := round(M[n][10]) :
Flow[[11, 2]] := round(M[n][11]) :
```

```
QG[7] := round(M[n][7]) :
QG[8] := round(M[n][8]) :
QG[9] := round(M[n][9]) :
QG[10] := round(M[n][10]) :
QG[11] := round(M[n][11]) :

CG[7] := 10 :
CG[8] := 8 :
CG[9] := 5 :
CG[10] := 5 :
CG[11] := 12 :

CL[n][1] := 0 :
CL[n][2] := 0 :
CL[n][3] := 0 :
CL[n][4] := 0 :
CL[n][5] := 0 :

QL[1] := round(M[n][17]) :
QL[2] := round(M[n][18]) :
QL[3] := round(M[n][19]) :
QL[4] := round(M[n][20]) :
QL[5] := round(M[n][21]) :

D[1] := round(M[n][12]) :
D[2] := round(M[n][13]) :
D[3] := round(M[n][14]) :
D[4] := round(M[n][15]) :
D[6] := round(M[n][16]) :

DC[n][1] := 0 :
DC[n][2] := 0 :
DC[n][3] := 0 :
DC[n][4] := 0 :
DC[n][5] := 0 :

P[n][1] := 0 :
P[n][2] := 0 :
P[n][3] := 0 :
P[n][4] := 0 :
P[n][5] := 0 :
P[n][6] := 0 :

NP[n][1] := 0 :
NP[n][2] := 0 :
NP[n][3] := 0 :
NP[n][4] := 0 :
NP[n][5] := 0 :
NP[n][6] := 0 :
```

```
for v from 1 to max(indices(QL,'nolist')) do
UPG[v] := [ ] :
od
```

```
for e in Edges(GG) do
SetEdgeWeight(GG, e, Flow[e]);
od;
Edges(GG, weights);
DrawGraph(GG);
```

```
for v from 1 to 5 do
DetermineUpstreamGenerators(v);
od;

for i from 1 to 5 do
"TRACE: nu gaat de volgende verliespijp behandeld worden", i;
 QL[i];
Qrem := QL[i] :
Qrem;

while Qrem > 0 do
UPGIndicator := DetermineMarginalGenerator(i);
print(UPG[i]);
print(UPGIndicator);
print(DetermineMarginalGenerator(i));


 if QG[UPGIndicator] ≥ Qrem then
 CL[n][i] := CL[n][i] + (Qrem·CG[UPGIndicator]) :
 QG[UPGIndicator] := QG[UPGIndicator] − Qrem :
 Qrem := Qrem − Qrem :
 print(CL[n][i]);

    if QG[UPGIndicator] = 0 then
     for j from 1 to 5 do
       UpdateGeneratorData(j);
    od:
    fi:

   else
    CL[n][i] := CL[n][i] + (QG[UPGIndicator]·CG[UPGIndicator]) :
    Qrem := Qrem − QG[UPGIndicator] :

     for j from 1 to 5 do
       UpdateGeneratorData(j);
    od:

 fi:

od:
od:
```

```
for v in Vertices(GG) do
SetNodalGeneration(GG, v);
 od:


G3 := CopyGraph(GG) :
for v in Vertices(GG)  do
 if InDegree(G3, v) = 0 then
 G3 := DeleteVertex(G3, v) :
 fi:
 od;
 E := Edges(G3);
DrawGraph(G3);


 l := 1 :
 for e in Edges(G3) do
 SetEdgeWeight(G3, e, Flow[e]) :
 if GetEdgeWeight(G3, e) = 0 then
G3 := DeleteArc(G3, e) :
 fi:
 l := l + 1 :
 od;
 l := 1 :
Edges(G3,'weights');
 DrawGraph(G3);
```

```
TD[1] := 0 :
TD[2] := 0 :
TD[3] := 0 :
TD[4] := 0 :
TD[5] := 0 :
i := [indices(D,'nolist')] :

for k from 1 to nops(Vertices(G3)) − 1 do
 if QL[k] > 0 then
   if nops(DownstreamGenerationOfLossCheck(G3, k)) > 1 then
      for v from 1 to nops(Vertices(G3)) − 1 do

       if v in i then
        TD[k] := TD[k] + (D[v]·DownstreamConnectedCheck(G3, k, v)) − (DownstreamGenerationOnCheck(G3, v)·DownstreamConnectedCheck(G3, k, v));
        fi:  od:
        TD[k] := TD[k] + add(SumOfLossesUnderGenerator(G3, k, kk), kk = 1 ..nops(DownstreamGenerationOfLossCheck(G3, k)))−add(QG[kk], kk = min(DownstreamGenerationOfLossCheck(G3, k)) ..max(DownstreamGenerationOfLossCheck(G3, k)));

       else

        if nops(DownstreamGenerationOfLossCheck(G3, k)) = 1 then
        for v from 1 to nops(Vertices(G3)) − 1 do

         if v in i then
         TD[k] := TD[k] + (D[v]·DownstreamConnectedCheck(G3, k, v)) − (DownstreamGenerationOnCheck(G3, v)·DownstreamConnectedCheck(G3, k, v));
          fi:  od:
         TD[k] := TD[k] + SumOfLossesUnderGenerator(G3, k, 1) − QG[min(DownstreamGenerationOfLossCheck(G3, k))];

    else
     for v from 1 to nops(Vertices(G3)) − 1 do
      if v in i then
       TD[k] := TD[k] + (D[v]·DownstreamConnectedCheck(G3, k, v)) − (DownstreamGenerationOnCheck(G3, v)·DownstreamConnectedCheck(G3, k, v));
     fi: od: fi:

  fi:
print("TRACE check", TD[k]);
fi:
 od:
```

```
 for v from 1 to nops(Vertices(G3)) − 1 do
 if nops(DownstreamGenerationOfLossCheck(G3, v)) > 0 then
print("TRACE", v, SumOfLoads[v]);
  SumOfLoads[v] := SumOfLoadsUnderGenerator(G3, v, 1);
fi:
od:
```

```
for j in indices(D,'nolist') do
 if not j = max(indices(D, 'nolist')) then
  for k from 1 to nops(Vertices(G3)) - 1 do
   if DownstreamConnectedCheck(G3, k, j) = 1 and nops(IncidentEdges(G3, j, direction = incoming)) > 0 and QL[k] > 0 then

    if nops(DownstreamGenerationOfLossCheck(G3, k)) = 0 then

     DC[n][j] := DC[n][j] + ( (D[j] - DownstreamGenerationOnCheck(G3, j)) · CL[n][k] · DownstreamConnectedCheck(G3, k, j) / TD[k] );

    else

     if nops(DownstreamGenerationOfLossCheck(G3, k)) > 1 then

     MultipleDSGcalc(G3, k, j);
     DC[n][j] := DC[n][j] + ( Dn[j] · CL[n][k] / TD[k] );
     fi:

    if nops(DownstreamGenerationOfLossCheck(G3, k)) = 1 then

      if k > j and DownstreamConnectedCheck(G3, op(1, DownstreamGenerationOfLossCheck(G3, k)), j) > 0 then
      SingleDSGcalc(G3, k, j);
      DC[n][j] := DC[n][j] + Dn[j] · CL[n][k] / TD[k] :

     else
     DC[n][j] := DC[n][j] + ( D[j] · CL[n][k] / TD[k] );
    fi:
   fi:

  fi:
 fi:
 od:
fi:
od:
```

```
for v in Vertices(GG) do
DetermineUpstreamGenerators2(GG, v) :
print(UPG2[v]);
od

indD := [indices(D, 'nolist')];
indQG := [indices(QG,'nolist')];

for q in indQG do
QGtemp[q] := QG[q] :
print(QGtemp[q]);
od

 for j from 6 by -1 to 1 do
MCGCalculation(GG, j);
od

for j from 1 to 6 do
print(P[n][j]);
od
```

```
for v from 1 to 6 do
if v in [indices(D, 'nolist')] then

if not v = max(indices(D, 'nolist')) then

if D[v] > 0 then
print("NP van knoop check", v, "is");
NP[n][v] := evalf(P[n][v] + DC[n][v]/D[v]);
print(NP[n][v]);
fi:

else

if D[v] > 0 then
NP[n][v] := P[n][v]:
print("NP van knoop", v, "is", NP[n][v]);
fi:

fi:
fi:
od;
```

```
NPoutput[n] := [ ];
for j from 1 to 6 do
NPoutput[n] := [op(NPoutput[n]), NP[n][j]]:
od;

if n = 4 then
OutputNP := convert(NPoutput[n], Matrix) :
else
OutputNP((n - 3), 1 ..) := ⟨(op(1, NPoutput[n])), (op(2, NPoutput[n])), (op(3, NPoutput[n])), (op(4, NPoutput[n])), (op(5, NPoutput[n])), (op(6, NPoutput[n]))⟩;
fi:

print(n);
n := n + 1 :
od
```

Master of Science Thesis
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