Balancing market performance in a decentralized electricity system in the Netherlands

Reinier van der Veen - 1152211

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TenneT TSO B.V.
Contact author: reinier.vanderveen@gmail.com

Preface

This thesis has been written as part of the Master Thesis Project (spm5910), the final course from the master Systems Engineering, Policy Analysis & Management (SEPAM). This master forms the last two years of the five-year study Technische Bestuurskunde from the University of Technology in Delft (TU Delft). I originally started with this study because of my broad interest, but because I found the energy domain particularly interesting, I chose energy as the specialization subject for my master. For the same reason, I have chosen to graduate in the section Energy & Industry.

From April 2007 to September 2007, I have conducted the research described in this thesis at TenneT TSO B.V in Arnhem. The subjects of the Dutch balancing market design and domestic distributed generation, and the choice to study the effects of domestic DG on balancing market functioning in the Netherlands, originated from the Dutch project plan EOS-LT RegelDuurzaam, in which both TenneT and the TU Delft take part. Because of my interest in these subjects, the six months have passed quickly, and have led to a satisfactory result.

Due to the complexity and scope of the research, the thesis has become quite long. Readers who are interested in the current Dutch balancing market design should read Chapter 2. The results of the scenario analysis valuating the effects of domestic DG penetration on the operational performance of the Dutch balancing market can be found in paragraph 4.4 (the used scenarios are introduced in section 4.2.1, and the allocation methods in 4.2.4). Readers who are interested in the possible improvement of the current balancing market design for a Dutch electricity system with a high penetration level of domestic DG are advised to read Chapter 6. Chapter 7 contains the conclusions of this research and the recommendations based on the research.

Finally, I would like to thank my graduation committee: dr. ir. Laurens de Vries (first supervisor) for directing and commenting on my research, drs. Frank Nobel (external supervisor) for his daily comments and support at TenneT, and prof.dr.ir. Margot Weijnen (section professor) and ir. Martijn Jonker (second supervisor) for their supervision. Also, I want to thank prof.ir. Wil Kling and ir. Dennis Klaar from TenneT for giving me the opportunity to do my graduation project at TenneT.

Reinier van der Veen
October 10th, 2007

Summary

Considering the importance of security of electricity supply, its dependence on balancing market functioning, and the unknown effects of the introduction of distributed generation (DG) on a large scale, the following main research question is answered in this thesis report: *Which balancing market design will have a high operational performance for a large-scale penetration of distributed generation at households in the Dutch electricity system?*

The first step taken is the description of the current Dutch balancing market design and its current operational performance. This design consists of three main instruments: Programme Responsibility, the single-buyer market for Regulating and Reserve Power (RRP) and imbalance settlement. Programmer Responsibility requires Programme Responsible Parties (PRPs) to submit Energy Programmes to the Dutch TSO TenneT, in which they specify how much electricity will be injected into or withdrawn from the public grid through the grid connections for which they have taken up responsibility. Deviations from these planned volumes, called imbalances, are settled between TenneT and the PRPs against the imbalance price. The imbalance price follows from the single-buyer market for RRP, on which large market parties must offer available RRP, and which TenneT operates to solve system imbalances. Of particular importance to this research is that actual volumes of PRPs are determined by means of the Allocation process. For households, consumption is allocated by means of profiles, which substitutes continuous metering used for larger consumers and producers.

Secondly, requirements which the Dutch balancing market must meet are listed. These are complemented with requirements concerning the technical effects of DG and the introduction of smart meters posed to a future decentralized system. From these, a set of performance criteria are formulated.

Third, a thorough qualitative scenario analysis is performed. In this analysis, four scenarios are examined, all of which assume two million Dutch households to install a 1 kW_{el} DG unit each. Scenario A considers PV penetration, scenario B heat-led micro-CHP, scenario C electricity-led micro-CHP, and scenario D micro-CHP operated by the electricity supplier. Furthermore, two extreme allocation methods are studied: allocation by means of profiles and allocation by means of smart metering. The results show that scenario A has a negative net effect on the operational performance of the Dutch balancing market, while the micro-CHP scenarios have a zero to positive net effect. Scenario D has the largest positive effect. Allocation by metering always leads to a better result than allocation by profiling.

Fourth, from the analysis and literature six design options are identified that aim to anticipate and improve the operational performance of the Dutch balancing market design in a system with a lot of domestic DG. These are the postponement of gate closure time, the adjustment of the profile methodology, the embedding of smart metering provisions, the alteration of requirements for the offering of RRP, the reduction of the PTU length, and decentralized balancing control.

Fifth, an improved balancing market design is created on the basis of the estimated effects of the different design options. It is found that the implementation of the adjustment of the profile methodology and the embedding of smart metering provisions

will be useful in any case. The usefulness of the other options have been found to depend mainly on the DG portfolio emerging (postponement of the gate closure time; alteration of RRP requirements), the nature of the technical effects of domestic DG development (decentralized balancing control), and the manageability of large metering data flows (reduction of the PTU length).

By means of the conduction of the steps described above, the main research question is answered. The current balancing market design is capable of maintaining a sufficient operational performance level in case of large-scale domestic DG development, especially with respect to micro-CHP. This reduces the need and urgency for adaptation of the balancing market design. However, the created improved balancing market design can still improve the operational performance of the Dutch balancing market.

The implementation of the adjustment of the profile methodology and embedding of smart metering provisions will be useful in any DG scenario and allocation method. Therefore, it is recommended that these two design options are implemented whenever possible. Later on, when the emerging domestic DG portfolio has become more certain, the postponement of the gate closure time and/or the alteration of RRP requirements can be implemented. After that, the reduction of the PTU length should be implemented whenever experience with smart metering proves the manageability of large data flows, and decentralized balancing control should be implemented whenever the adverse effects of a high DG penetration level have become proven. This way, design options will only be implemented when they are sure to improve the operational performance of the Dutch balancing market at acceptable costs. This approach is enabled by the suitability of the current balancing market design even in a decentralized electricity system.

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Abbreviations

AC: Alternating current
APX: Amsterdam Power Exchange
CHP: Combined Heat and Power
DC: Direct Current
DG: Distributed Generation
DSM: Demand-Side Management
DSO: Distribution System Operator
DTe: Directie Toezicht Energie
ETSO: European Transmission System Operators
EU: European Union
GW: gigawatt
HV: high voltage
kW: kilowatt
LFC: Load Frequency Control
LV: low voltage
MCF: Metering Correction Factor
MRP: Metering Responsible Party
MV: medium voltage
MW: megawatt
OTC: Over-The-Counter
PRP: Programme Responsible Party
PTU: Programme Time Unit
PV: Photovoltaic(s)
RRP: Regulating and Reserve Power
SYC: Standard Yearly Consumption
SYG: Standard Yearly Generation
TSO: Transmission System Operator
UCTE: Union for the Coordination of Transmission of Electricity
VPP: Virtual Power Plant

1. Research problem

1.1 Background

The supply of electricity has become a normal, self-evident, utility service for households, companies and industries alike, the importance of which is clearly revealed when an outage occurs. But although electricity is being supplied almost without interruption to all consumers, the system responsible for electricity generation, transmission and distribution is rather complicated.

Electricity is provided to consumers by an electricity system: electricity generators produce electricity, which is transported via a high-voltage transmission network and low-voltage distribution network to electricity consumers. System reliability is difficult to maintain because electricity can not be stored in an efficient way. As an effect, the total electricity demand and the total electricity supply have to be balanced anew at each point in time. A shortage of production leads to outages, a surplus of production leads to system overload and tripping of power plants.

In the Netherlands, the balance of the electricity system is maintained by the Dutch Transmission System Operator (TSO), TenneT. In the Dutch electricity system there exist three (administrative) instruments that together form the Dutch mechanism for the restoration of system imbalances: Programme Responsibility, the single-buyer market for Regulating and Reserve Power (RRP), and the imbalance settlement (TenneT 2005). The combination of these three instruments is often referred to as the 'balancing market', although it has more of a mechanism than a market. Another provision that characterizes the Dutch electricity market is one that is connected to its liberalized state: the existence of independent grid operators & non-discriminatory grid access.

The Dutch balancing market design is relatively new; it has been in existence since the liberalization of the Dutch electricity market, which started in 1998 with the opening of the market for large electricity consumers and ended in 2004 with the opening of the market for small consumers. Although the balancing market design currently functions well, it remains the question if it can cope with large developments in the electricity sector. One future development that is generally considered to arise, and is broadly researched, is that of distributed generation (DG).

Distributed generation can generally be defined as “small-scale power generation plants, connected to the distribution network or at the customer side of the network” (Ten Donkelaar 2004, p. 323). For the purpose of this research, the definition of DG will read "small-scale power generation at households, coupled to the low-voltage grid", which is an important subset of the broader definition. Different distributed generation technologies with different characteristics exist (wind turbines, photovoltaic (PV) cells, micro-CHP, geothermal power, small hydro power), but PV cells and micro-CHP have the largest potential for residential application.

This research aims to investigate in what way the balancing market design will respond to a large-scale penetration of distributed generation in the Dutch electricity system.

Investigation of the relation between the functioning of the balancing market design and the growing integration of distributed generation into the Dutch electricity system will also shed light on how market conditions and system balancing provisions can accommodate for the large-scale introduction of DG in power systems with liberalized electricity markets.

1.2 Research introduction

In short, the balancing market design is arranged and operated in the following way. Following the EU Directive 2003/54/EG, The Dutch Electricity Act 1998 has implemented the free market conditions of independent grid operators & non-discriminatory grid access (European Union 2003; Ministry of Economic Affairs 2007). The Act also lays down the concept of Programme Responsibility, according to which connected parties are obliged to submit Transport Prognoses and Energy Programmes to TenneT. Such parties are therefore called Programme Responsible Parties (PRPs). The Grid Code, which has been set up by DTe in following of the Electricity Act, requires connected parties to offer available Regulating and Reserve Power (RRP) to TenneT (DTe 2006a). Every Programme Time Unit (PTU), which is 15 minutes long, TenneT matches system supply and demand by 'calling' RRP offered by PRPs to resolve the imbalance. On the market for RRP, all bids are ranked by price on a bid price ladder, from which the imbalance prices are derived and charged/paid to the relevant PRPs.

The current balancing market design appears to work satisfactorily: emergency power, which is only deployed when the balancing market can not cope with the system imbalance, had to be deployed during 165 PTUs in 2002 and during 163 PTUs in 2003. This is 0.47% of the time. In all the cases it concerned positive emergency power, meaning that only electricity shortages occurred (DTe 2004).

The large-scale introduction of DG into the Dutch electricity system is likely to have effect on the functioning of balancing market design. In this research, the focus lies on DG units at households because of the potentially large impact of these units. After all, there are over seven million households in the Netherlands (CBS website), and residential consumers with DG units installed at their houses will obtain an extra role of electricity producer. Even if we looked at this development only superficially, it would already become evident that potential consequences for the balancing market are large.

Considering the different elements of the balancing market, it will be more difficult for PRPs to accurately predict production and demand in their programmes when DG has penetrated at households, leading to a greater need for RRP. Another negative consequence could be that most DG units at households will not meet the requirements for RRP, but on the other hand controllable DG units could supply electricity to the grid when needed (made possible by intelligent switches and advanced control systems). Further, imbalance settlement with residential DG owners will probably be much more difficult. To settle balancing costs with these residential DG owners, either more fitting consumption profiles are needed, or meters have to be installed inside their houses. But fitting profiles will be hard to form, and meters and the resulting data traffic bring about extra costs and complexity.

Although the balancing market design has been working adequately in its years of operation, it can thus be expected that the performance of this design will be affected by the large-scale penetration of distributed generation at households in the Netherlands. The nature of the effects is unclear, however, because it is not certain in what form distributed generation will develop in the first place. Also, it is unclear what the effects are of the large-scale DG penetration on the technical and economical performance of the electricity system, and how the market will respond to this development. Therefore, suggestions for improvement of the balancing market design, so that it can cope with DG, can not be readily specified either. This possibly puts high threats on Dutch economy and society, which heavily rely on continuous electricity supply, and the balancing market design that makes this possible.

1.3 Problem statement

The balancing market design consists of the balancing market instruments Programme Responsibility, the single-buyer market for Regulating and Reserve Power, and imbalance settlement. Besides, the Dutch judicial framework with the condition of independent grid operators & non-discriminatory grid access is closely connected to the balancing market design. It is expected this design will be affected by the development of distributed generation at households in the Netherlands, but it unknown to what extent and in what way.

The main issue following from the problem description is the search for a balancing market design that has a high operational performance in a Dutch electricity system with a high level of distributed generation at households. It is the operational performance that is of interest: the Dutch balancing market design should effectuate the resolution of system imbalances in an efficient and effective way, a short-term view.

Also, it is interesting to find out what remedies or adaptations to the current Market Design could mitigate or even prevent possible negative effects of the DG development, or further improve market functioning. Finally, the way these adaptations should be implemented is of interest.

The **main research question** is:
Which balancing market design will have a high operational performance for a large-scale penetration of distributed generation at households in the Dutch electricity system?

The main research question is divided into the following **sub questions**:

1. What is the current state of the balancing market design in the Dutch electricity system?
2. Which requirements are posed to the balancing market design, and in what way will these requirements change if a large-scale DG penetration emerges at Dutch households?
3. In what way will large-scale penetration of distributed generation at households affect the balancing market design performance?
4. Which design options exist for a balancing market design in a decentralized system?
5. What balancing market design would best improve operational performance, and how should that design be implemented?

1.4 Research structure

1.4.1 Research scope

The research questions formulated above limit the scope to a large extent. This report has taken the subject of the Dutch balancing market design. This means that the real Dutch electricity markets (the APX day-ahead market, the intraday market, the bilateral market, the import capacity auction) are not considered any further than as parts of the environment of the balancing market. Furthermore, foreign electricity markets and the interconnection and trade with other countries are not taken into account either.

Then, by taking the subject of the balancing market, the attention of this research will also be directed to the system service of the balancing of system supply and demand. This means that other system services, transport services and grid operation are only considered when the system balancing function is involved.

Furthermore, as has become clear from the problem statement, the focus of the research will be on effects of DG penetration at households, by which wind power, small hydropower and CHP-plants are implicitly excluded. For the analysis of these effects, some simple DG scenarios will be used, which are derived from literature.

Finally, considering the effects of DG on balancing market functioning, attention will be directed toward the operational performance of the Dutch balancing market design. This way, the research will investigate the ability of the balancing market design to resolve system imbalances in an efficient and effective way, while neglecting longer-term effects on e.g. investment decisions of market parties.

1.4.2 Research model

The research is structured and conducted in a number of steps, each of which contribute to the answering of one or more sub question, so that in the end the main research question can be answered. This is represented in the research model in
Figure 1. First, the Dutch balancing market design will be described (sub question 1). By this, balancing market design variables are identified. Second, the balancing market design requirements will be formulated based on this description (sub question 2) from which performance criteria will be deduced. This leads to the set-up of some DG scenarios in the next step, which will be used to analyze the effects of large-scale DG penetration at Dutch households on the operational performance of the balancing market (sub question 3). Then, a set of design options for a new Dutch balancing market design anticipating DG penetration is formed (sub question 4). For this, a short look is taken at balancing market designs in other countries. Next, an improved balancing market is formulated from the set of design options. This improved balancing market design is expected to have a high operational performance in a system where DG has penetrated at Dutch households on a large scale. To realize this new balancing market design, an implementation plan is set up (sub question 5). Finally then, the main research question is answered and recommendations for the improvement of the Dutch balancing market design across time are given.

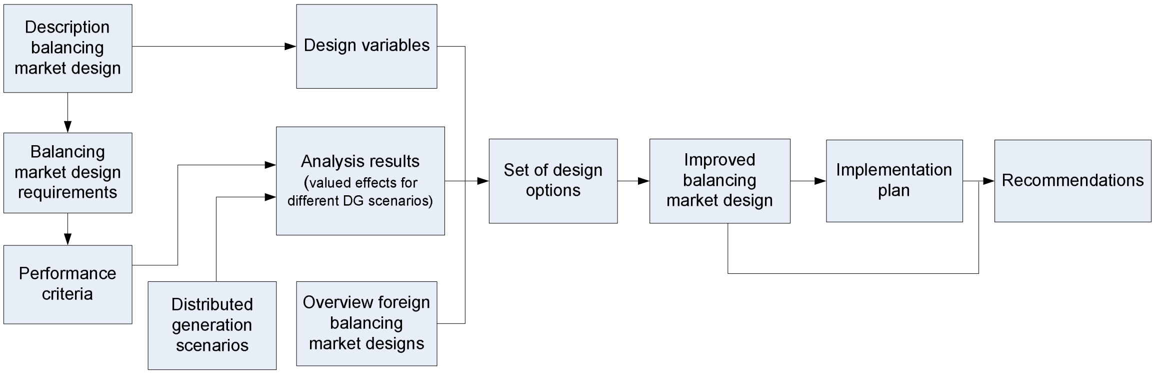

Figure 1: Research model

1.4.3 Research method

The research steps are intended to be executed in the following way. The description of the balancing market design will be made after the studying of documents about the Dutch balancing market structure and functioning. Also, balancing market design variables will be identified. After that, balancing market design requirements will be derived from the description. From those requirements, a set of performance criteria is formed, against which the operational performance of the Dutch balancing market will be valuated in a scenario analysis. For this analysis, some distinct and realistic distributed generation scenarios will be formed on the basis of literature. Then the analysis will be carried out by making qualitative estimates of the effects of the scenarios on the operational performance. The main analysis results are the net effects of the different scenarios on the operational performance of the balancing market.

Next, an overview of the design variables identified earlier is given. From that, six design options with a potential to improve the balancing market design are derived. These design options are further grounded and described by means of a comparison with foreign balancing markets, the use of an infrastructure theory, and the use of the analysis results. Then, an improved balancing market will be formed by considering the effects of the different design options on the performance of the Dutch balancing market in different DG scenarios. For this improved balancing market design, an implementation plan will be set up. This, in combination with the analysis results, will enable the formulation of recommendations considering the Dutch balancing market.

The research has been conducted at TenneT TSO B.V. This has given the author the opportunity to, next to the independent study of balancing market documents and DG literature, ask detailed questions about the balancing market to TenneT employees. Also, the contact with TenneT, in particular the supervision by drs. F.A. Nobel, has enabled the author to attend several B'con expert meetings about Allocation and reconciliation, conduct an interview with people from Eneco about the use of profiles, and to go to the final seminar about the European DG-GRID and ELEP projects.

Finally, the author thinks that the main research method chosen for the valuation of the effect of large-scale domestic DG penetration on the operational performance, i.e. the qualitative scenario analysis, is a good choice. The limited time and means in combination with the complexity of the subject excludes the possibility of a quantitative analysis. The use of a technical model to simulate the network effects of different DG scenarios will only shed light on a part of the system investigated in this research. Finally, the consultation of experts for the estimation of the effects is hard to execute, because not much people have a complete overview of the Dutch balancing market and sufficient knowledge about the (future) technical features of distributed generation and smart metering facilities.

1.4.4 Report structure

The structure of this report follows the research model, and is therefore based on the order of the sub questions as well. Each chapter takes a next step in the process towards answering the main research question; the Chapters 2 till 6 serve to answer the sub questions 1 to 5.

In chapter 2, the balancing market design will be described. To this extent, the Dutch electricity system will be considered first, indicating the position and the composition of the balancing market design in this system. Then, the three elements of the balancing market design are discussed consecutively, which also leads to the identification of balancing market design variables.

Chapter 3 serves to bring down the requirements that have to be met by the balancing market design of the Netherlands to a shorter set of performance criteria. Also, the system boundaries of the system to be analyzed are drawn.

Next, in Chapter 4 the analysis of balancing market design performance for a large-scale DG penetration at Dutch households is considered. To this extent, four DG scenarios are formulated, and two extreme allocation methods are introduced. The effects of domestic DG development are analyzed by valuating the performance criteria from Chapter 3 for each scenario and allocation method.

In Chapter 5, six design options for the Dutch balancing market design are derived from a list of design variables. These design options potentially improve the operational performance of this market design for a large-scale DG penetration, and are described in relation to the analysis results, literature, and a study of foreign balancing markets.

Then, in Chapter 6, the six design options are compared in terms of effects and suitability for a decentralized Dutch electricity system. Based on that, an improved balancing market that anticipates a high domestic DG penetration level will be created. Next, an implementation plan is set up for this improved balancing market design.

Finally, in Chapter 7 recommendations for the implementation of an improved balancing market design are given, the conclusions of the research are presented, a reflection on the research is given, and suggestions for further research are made.

1.4.5 Literature review

For the description of the Dutch balancing market, no scientific literature has been found. The description is based on several documents from TenneT (Nobel 2004; TenneT 2003, TenneT 2005; TenneT 2006; Wenting 2002) and on legislational and other documents from energy regulator DTe (DTe 2004; DTe 2005a; DTe 2005b; DTe 2006a; DTe 2006b). The requirements largely follow from the same sources. Information about the Allocation process and the profile methodology has been found in PVE (2002) and PVE (2003).

For the scenario analysis, a lot of literature has been consulted about distributed generation in general (Borbely and Kreider 2001; Chambers et al. 2001; Jenkins et al. 2000; Peças Lopes 2006), about PV in specific (Coppye et al. 2000; Denholm and Margolis 2006; Paatero and Lund 2006; Yogi Goswami 2003), and about micro-CHP in specific (Hawkes and Leach 2005; Peacock and Newborough 2006; Pehnt et al. 2006). Regarding information about the consumption patterns of Dutch households, the consumption profiles of Ecofys (2001) has been taken as a basis. The different smart metering and profiling options are based on Choudhury and Andrews (2002).

Concerning the discussion of possible balancing market design options, some information has been found on foreign balancing markets (ELEXON 2004; ETSO 2006; Glachant and Saguan 2007; Morthorst et al. 2007), but not much. The formation of design options and an improved design for the Dutch balancing market is again mainly based on the mentioned Dutch balancing market documents, although the coherence theory of Finger et al. (2005) provides an interesting viewpoint for forming and evaluating designs.

2. The balancing market design of the Netherlands

The first step in the process of finding an answer to the main research question given in Chapter 1 is to gather knowledge about the current state of the Dutch balancing market design (sub question 1).

First, a general description of the Dutch balancing market design is given in paragraph 2.1, along with a short introduction of its position in the Dutch electricity system. The three instruments of which the balancing market consists are introduced. Then, each of the three instruments of the balancing market are described in more detail in the next paragraphs: Programme Responsibility in paragraph 2.2, the single-buyer market for Regulating and Reserve Power in paragraph 2.3, and imbalance settlement in paragraph 2.4. Finally, the current operational performance of the Dutch electricity system is discussed in paragraph 2.5. In paragraph 2.2 to 2.4, important balancing market design variables will be identified. These will be used in Chapter 5 to derive design options that can be used to create an improved balancing market design that anticipates the large-scale development of distributed generation.

2.1 The Dutch balancing market design

In this paragraph, the Dutch balancing market design is introduced, and described in headlines. In 2.1.1, the position and structure of the balancing market are indicated. Then in 2.1.2, the Dutch balancing market design is introduced. After that, 2.1.3 handles the condition of independent grid operators & non-discriminatory grid access. This condition is of importance for the Dutch balancing market design, which is based on a free and competitive electricity market design. The last subsection 2.1.4 gives some definitions that are needed to describe the three instruments of the balancing market design in more detail in the next three paragraphs.

2.1.1 Position and structure of the Dutch balancing market

In this subsection, it is shortly indicated how the Dutch balancing market is positioned in the Dutch electricity system, what are the relevant actors in the balancing market design, what is the relevant regulatory regime, and how the market design is related to the condition of independent grid operators & non-discriminatory grid access. For a more extensive description of all these aspects, see appendix A.

The Dutch electricity system is defined in this research proposal as the system that comprises the generation, transmission, distribution and supply of electricity within the borders of the Netherlands, including the interconnection capacity available for electricity import and export. The Dutch electricity system can be viewed upon as having a physical layer and an economic layer (see Figure 2).

The physical layer consists of the Dutch electricity generation units (operated by electricity producers), the Dutch transmission network (operated by TenneT), Dutch distribution networks (operated by DSOs), and all Dutch electricity consumers. Electricity producers generate electricity, which is first fed into the high-voltage transmission grid. This transmission grid is owned and operated by TenneT, who is therefore called the Dutch Transmission System Operator (TSO). The transmission grid interconnects the large and central power plants and the distribution networks throughout the Netherlands, and therefore has a high transport capacity. Subsequently, the electricity flows through the distribution grids to reach the electricity consumers. These distribution networks are owned and operated by regional grid operators, or Distribution System Operators (DSOs).

The economic layer contains the arrangements for electricity trade. For the Dutch electricity system, these consist of a spot market, a bilateral market, a balancing market (which is actually a mechanism), and an import capacity auction. Together, these markets form the overarching 'Dutch electricity market'.

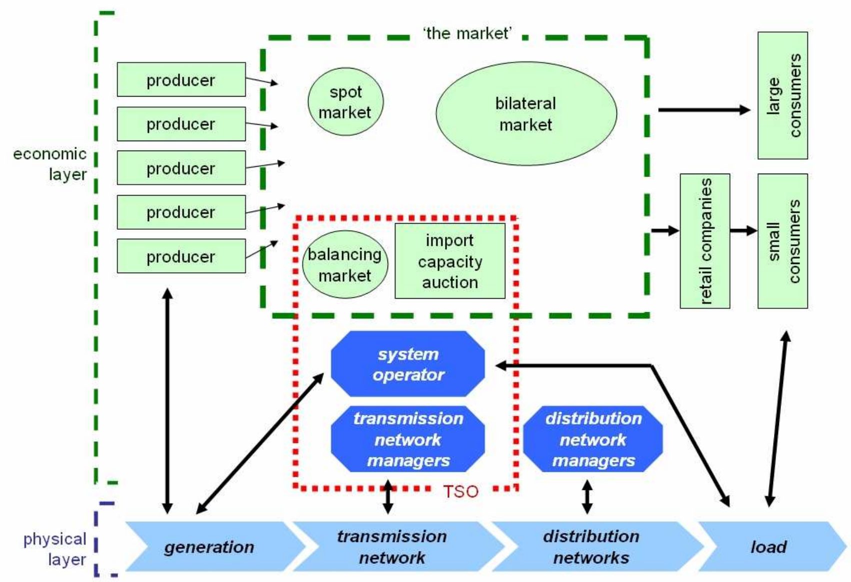

Figure 2: Demarcation of the Dutch electricity system (L.J. de Vries 2006, TPM, TU Delft)

For the restoration of imbalances in the Dutch electricity system, TenneT operates the so-called balancing market. Because the balancing market only solves the imbalance resulting from deviations from planned amounts of production and delivery, and market parties do their best to avoid the high imbalance costs, the balancing market normally has to deal with a relatively small amount of electricity. The proportion of electricity transport that is handled by the balancing market is currently 1.5-3.5 %.

Considering the relevant actor network for the Dutch balancing market design (see Figure 3), the electricity producers, TenneT, regional grid operators, electricity suppliers and electricity consumers can be seen as actors part of the electricity supply chain, if one takes the physical delivery of electricity as a starting point. Additionally, traders trade electricity in the market and Metering Responsible Parties do the metering, both of which can also be considered part of the value chain. Programme Responsible Parties exist by provision for these in the Dutch Electricity Act 1998, and have a central and crucial role in the Dutch balancing market. DTe is the Dutch regulatory authority for energy; the ministry of Economic Affairs is the relevant ministry. This Ministry has to take European regulation into account from the European Union. Finally, ETSO and UCTE are two European organizations for the coordination of European electricity systems, the first more directing to the markets and the second to the infrastructures.

The European Directive 2003/54/EG has been institutionalized in the Netherlands with the creation of the Dutch Electricity Act 1998. Article 31 of this Act requires that the grid operators together make a proposal to the board of management of the regulating authority for the conditions they will wield with respect to a number of technical and procedural issues (Ministry of Economic Affairs 2007). In response, the Grid Code, System Code, the Metering Code and the Information Code have been formulated (see Figure 4). The first two are the most important ones: the Grid Code describes the way in which grid operators should operate their nets, and the System Code describes how they should deliver system services. The Tariff Code is set up in response to article 36 of the Electricity Act. It determines how the costs of the Dutch electricity grid are distributed among network users by means of tariff structures for connection, transport and system services. Finally, it must be noted that the Codes, although induced by the Electricity Act, are a form of indirect regulation.

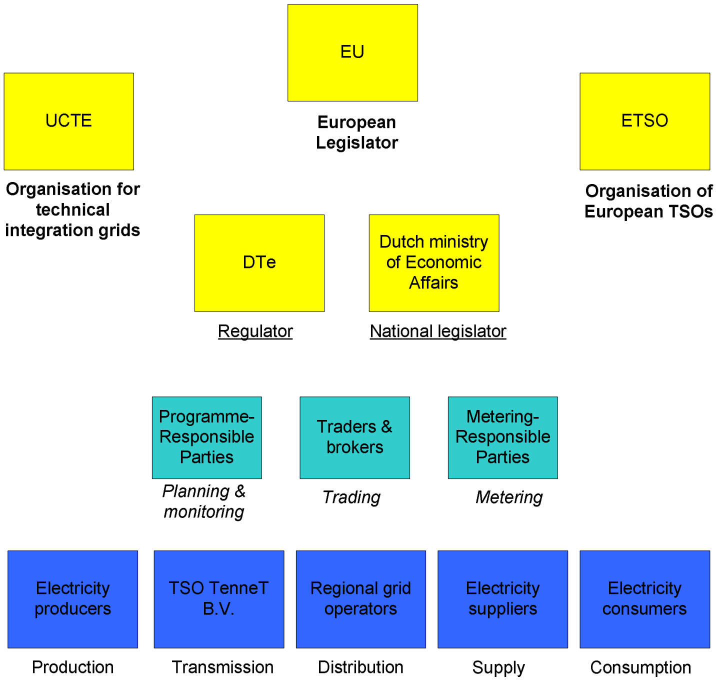

Figure 3: the network of actors for the Dutch electricity system

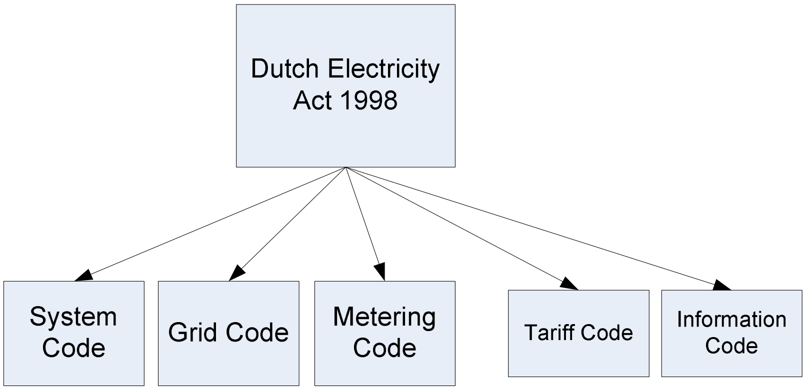

Figure 4: National regulation for the Dutch electricity system

2.1.2 Overview of the Dutch balancing market[1]

The Dutch balancing market design is the arrangement of the Dutch balancing market, including the roles and responsibilities of relevant actors and relevant regulations determining the market rules. The balancing market is actually not a market, but an institutional arrangement consisting of the instruments of Programme Responsibility, the single-buyer market for Regulating and Reserve Power, and imbalance settlement. In the Netherlands, the term 'onbalanssystematiek' is also being used, which could be translated into 'balancing mechanism'. Still, the term 'balancing market' is more generally adopted and is thought to better reflect the systems level of this institutional arrangement. The terms ‘balancing market’ and 'balancing market design' will be used interchangeably to indicate the combination of the three mentioned instruments[2].

In the liberalized and unbundled electricity market of the Netherlands, the activities of electricity production, transmission, distribution and supply are separated to create fair market conditions. The Electricity Act provides for the independency of grid operators (being both the national operator TenneT and the regional grid operators), so that trading positions of market parties are equal. In concrete, grid operators are not allowed to discriminate between market parties, and therefore have to provide non-discriminatory grid access.

One of the tasks of the Dutch TSO TenneT is to maintain the system balance in the Netherlands. In order to fulfil its responsibility for balancing supply and demand when actual electricity supply and/or demand deviate from the predicated amounts, TenneT makes use of the three balancing market instruments. Programme Responsibility is directly enforced by the Electricity Act; the bidding and dispatching of RRP and settlement of imbalances are laid down in the Grid Code and the System Code by DTe.

Programme Responsibility requires connected parties (electricity producers and consumers with a connection to the grid) to inform TenneT about the electricity volumes they will buy and sell for each Programme Time Unit (PTU) in the form of Energy Programmes (E Programmes), so that TenneT is able to maintain the system balance and settle imbalances justly. In practice, so-called Programme Responsible Parties (PRPs) have taken up this responsibility. To resolve the system imbalances, TenneT operates the single-buyer market for Regulating and Reserve Power (RRP), which is made possible by the obligation of large producers to offer available RRP. The imbalances are then resolved by TenneT through either calling (asking to dispatch) or automatically dispatching the needed amount of RRP. The deployment of RRP is taken up in the E Programmes, after which the imbalance of every PRP is settled with an imbalance price that resembles the dispatch price resulting from the market for RRP. This settlement process is called 'imbalance settlement'.

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[1] The explanation of the working of the balancing market is based on "The imbalance price mechanism per 01-01-2001, revised per 26-10-2005", TenneT 2005 (Dutch-only)

[2] One of these three instruments of the Dutch balancing market, the single-buyer market for Regulating and Reserve Power, has more of a market, although there is only one buyer, sellers who are obliged to offer, and a price that is mainly determined by the sellers. See paragraph 2.3.

As becomes clear from the above short description of the Dutch balancing market, Programme Responsible Parties have an important role in this market. This is shown in Figure 5.

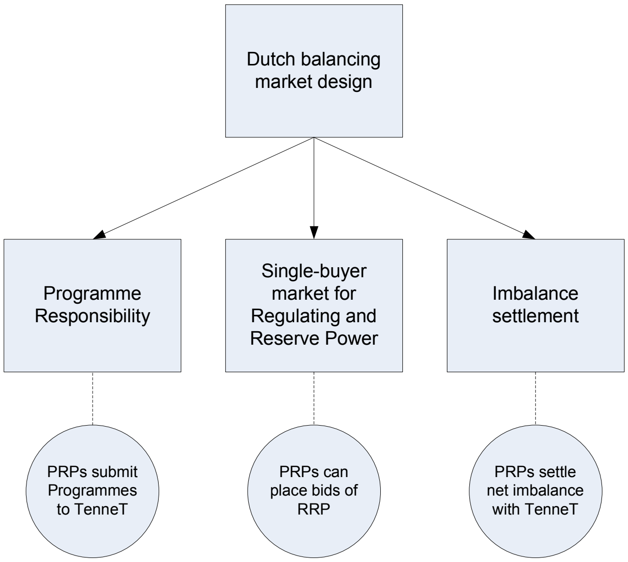

Figure 5: the Dutch balancing market design and the role of Programme Responsible Parties

According to their Programme Responsibility, Programme Responsible Parties (PRPs) have to submit E Programmes to TenneT, and keep to those E Programmes, so that the system imbalance is maintained. However, during virtually each PTU (which is fifteen minutes) a system imbalance will occur due to unexpected events or uncertainties.

This system imbalance will be resolved by the single-buyer market for RRP, on which producers or consumers have to offer available Regulating and Reserve Power. In practice, it is the PRPs who offer the RRP in name of the producers/consumers from which they have taken over Programme Responsibility. TenneT calls/dispatches the cheapest RRP to resolve the system imbalance.

Then, the system imbalance can be traced back to PRPs by comparing for each PRP the actual net electricity volume with the planned net electricity volume in the E-Programme. The actual net volumes cannot be determined exactly, which is why the total measured feed-in is allocated to the PRPs in the Allocation process, which is part of the imbalance settlement process. For deviations between planned net volumes and allocated net volumes, the PRPs pay/receive the imbalance price to/from TenneT, the last step in the imbalance settlement process.

Below in Figure 6, the current Dutch balancing market design is presented in a simplified way, by showing the actors, information products and physical elements in separate layers, and arrows showing the relationships and information flows.

In the bottom layer showing the physical elements, central generation units are used to generate electricity, which is transported via the high-voltage transmission network and the medium-voltage and low-voltage distribution network to feed the electric appliances of end-users. The solid lines in this layer represent the infrastructure of the Dutch electricity system. Metering facilities are used for metering production, transport and consumption of electricity.

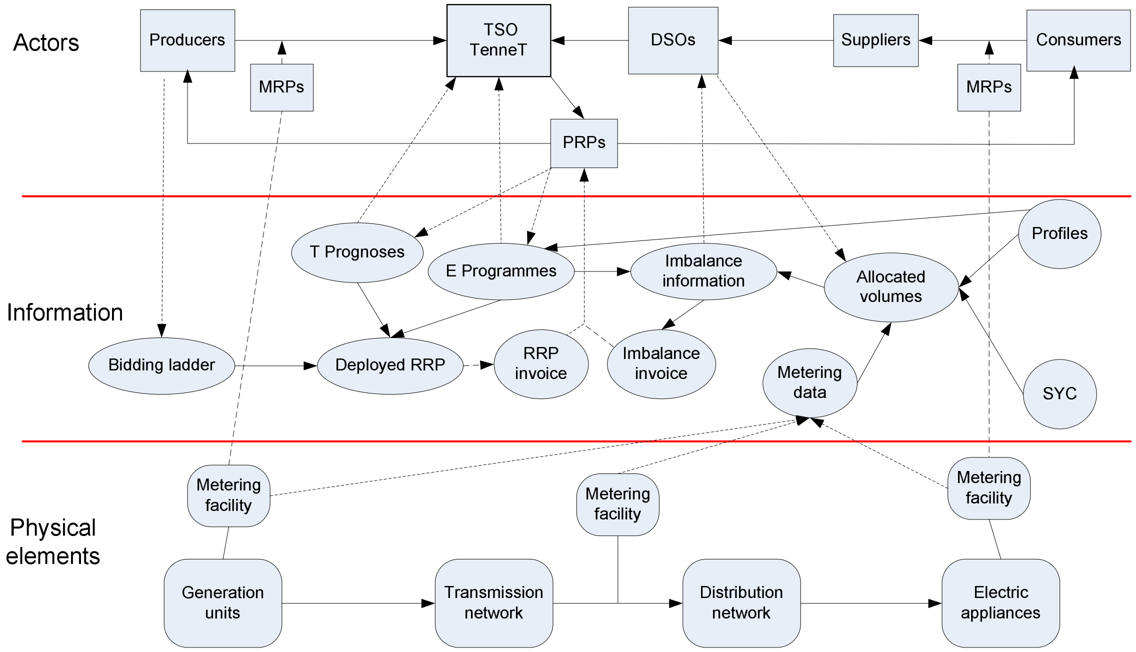

Figure 6: Actor-information-physical elements diagram of the Dutch balancing market design

The top layer shows the participants in the Dutch balancing market, with the solid arrows indicating relationships between the actors. Producers are directly connected to the transmission network, owned and operated by TenneT, the Dutch TSO. Consumers are connected to the distribution networks, which are owned and operated by the DSOs, with the suppliers as the usual intermediary between consumers and DSOs. PRPs have taken over Programme Responsibility of producers and consumers, and are registered by TenneT.

The middle layer presents an overview of the main information products. The solid arrows show which information products are used as an input for other information products. With help of the bidding ladder, it is determined which RRP is deployed when a certain amount of it is needed. Hereby, it is also determined what the imbalance prices are. How much is needed, depends on the system imbalance, as indicated by the totality of E Programmes, and the amount of transport restrictions, which follows from the T Programmes. The size of imbalance for each PRP is determined by comparing the allocated net volume of that PRP with the net volume specified in his E Programme, and in combination with the imbalance prices, this forms the imbalance information. RRP invoices and imbalance invoices can be set up with all this, and settled with the PRPs. Allocated volumes are determined with help of metering data, profiles and the SYCs.

The interrupted lines show the relations between physical elements, actors and information products, which will be discussed later on. Finally, remember that the diagram in Figure 6 is illustrative, but not complete. Especially the flow of information between different actors cannot be read from it.

The three instruments of the Dutch balancing market design, along with the role of PRPs and other actors in the Dutch electricity system, are described in more detail in the next three paragraphs.

2.1.3 Independent grid operators and non-discriminatory grid access

In the liberalized electricity market of the Netherlands, the traditionally vertically integrated distribution companies have been legally 'unbundled' into electricity suppliers and regional grid operators. Unbundling of the traditionally vertically integrated distribution companies has made sure that the activities of electricity production, transmission, distribution and supply are separated, i.e. not conducted by the same parties. The transmission network and distribution networks are owned by a single operator. In order for the electricity market to provide equal conditions to all producers, traders, suppliers and consumers, the grid operators should be independent. This is why the market condition of independent grid operators and non-discriminatory grid access is legally enforced, both in the European Directive 2003/54/EC and the Dutch Electricity Act 1998.

The balancing market rests on the principle of independent grid operators and non-discriminatory grid access, because it is a needed precondition for fair and equal competition, and the performance of the balancing market depends on market efficiency. The independency of regional grid operators is ensured by legal unbundling, while both regional grid operators and TenneT are not allowed to make profits from the provision of transport and system services, which removes profit making as a cause of discrimination.

2.1.4 Definitions of balancing market terms

Some definitions of balancing market-related words must be given now, in order to describe the three instruments of the Dutch balancing market design in more detail. These definitions are reproduced from several documents on the Dutch balancing market design (see footnotes). They will be used in the remainder of the report, without repeating its meaning, so they should be read carefully.

Grid operators

Both the national grid operator TenneT (the TSO) and the regional grid operators (the DSOs)[4]

Consumers

According to the European Directive 2003/54/EC, there is a differentiation between final consumers and wholesale consumers. But since the focus in this report is on household consumers, with the term ‘consumers’ will be meant here the final consumers, who utilize the electricity to satisfy their own demand[3]

Connection

A connection to the grid, either to the transmission network (for producers), to the distribution network (for consumers), or between two networks of a different voltage level[4]

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[3] European Union 2003

[4] Ministry of Economic Affairs 2007

Connected parties
Parties that are have a connection to the electricity grid, being both electricity producers (who are generally coupled to the transmission grid) and electricity consumers (who are generally coupled to the distribution grid)[5]

Programme Responsible parties (PRPs)
Parties who have the legal responsibility to formulate Energy Programmes and follow up these Programmes. They are either responsible for one or more connections, or are just traders of electricity volumes. Both types of PRPs have to be recognized as such by TenneT

Balance
The balance of one Programme Responsible Party, meaning the extent to which that Party keeps to its Energy Programme: if the actual net electricity volume does not deviate from the Energy Programme, the balance has been maintained

System balance
Balance between the total supply of and demand for electricity on the Dutch electricity grid[6]

System imbalance
Disruption of the balance between the total supply of and demand for electricity on the Dutch electricity grid[6]

Control power
Regulating Power, Reserve Power and emergency power

Regulating Power
All capacity made available to TenneT through bids which can be controlled by means of Load Frequency Control with a regulating speed of at least 7% per minute[6]

Reserve Power
All capacity that can be consumed under the agreed amount, or produced over or under the agreed amount, and offered to TenneT on a compulsory or voluntary basis, but not as regulating power[6]

Emergency power
Capacity that has been contracted by TenneT in order to maintain the system balance and that is deployed if no (sufficient) Regulating and Reserve Power is available[6]

Positive power
Regulating and reserve power that increases the electricity production or decreases the demand, and is therefore said to have a positive value[6]

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[5] DTe 2005a

[6] TenneT 2006 ('Implementation regulations for Grid Code and System Code')

Negative power
Regulating and reserve power that decreases the electricity production, and is therefore said to have a negative value[6]

Dispatch time
Period of time between the moment of request of Reserve Power and the start of delivery[6]

Response time
Period of time between the moment of deployment of Regulating Power and the start of delivery[6]

Regulating speed
Speed with which Regulating Power can be adjusted upwards or downwards, expressed as a percentage per minute of the offered capacity[6]

To supplete
To deploy positive Regulating and Reserve Power (in Dutch: 'opregelen')[7]

To absorb
To deploy of negative Regulating and Reserve Power (in Dutch: 'afregelen')[7]

PTU
Programme Time Unit (= 15 minutes)[6]

Day of execution
Day which contains the considered PTU, called the PTU of execution. For the PTU of execution, which is the actual time of delivery, E Programmes are made and Regulating and Reserve Power is offered.[6]

Day of preparation
Day before the day of execution[6]

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[7] According to a short TenneT note, this English word is the formal translation of the mentioned Dutch words

2.2 Programme Responsibility

Connected parties have Programme Responsibility, a concept taken up in the Electricity Act 1998 to increase efficiency and effectiveness of electricity delivery. Programme Responsible Parties (PRPs) have to deliver Transport Prognoses (T Prognoses) and Energy Programmes (E Programmes) to TenneT on the day before the day of execution, per Programme Time Unit (PTU). One PTU is 15 minutes. T Prognoses show the planned power flows through the PRPs' connection and assembly points; E Programmes reveal the planned net amount of electricity demanded or supplied.

For each operational PTU, TenneT compares the E Programmes of the PRPs with the actual net electricity volumes demanded or supplied. PRPs are charged the imbalance price (in €/MWh) for the difference, since that amount had to be corrected by TenneT through operation of the singe-buyer market for Regulating and Reserve Power. This is part of the imbalance settlement instrument.

According to article 31, lid 2 of the Electricity Act 1998, Programme Responsibility of connected parties can be assigned to another party, net operators excluded. One PRP can be responsible for multiple connected parties. PRPs must have been formally recognized by TenneT. To become an admitted PRP, a party has to meet conditions with regard to the availability of technical means to formulate and send in programmes, and the ability to follow strict time schedules for the sending of programmes in a prescribed electronic format (Wenting 2002). A PRP can either have a trade allowance or a complete allowance. A complete allowance holds that an allowed legal person may have Programme Responsibility for connections, while a trade allowance only gives the permission to trade between PRPs. In the PV register, publicized on the TenneT website, the PRPs are listed. There are currently 29 PRPs with complete allowance, and 21 PRPs with trade allowance.

The most important task for the PRPs is the formulation and submission of E Programmes. In contrast to T Prognoses, E Programmes are binding for PRPs, who must pay for every MWh of deviation. E Programmes can only be adapted until one hour before the PTU of execution.

In the E Programmes the PRPs must report the planned net volume exchange through its grid connections (in case of complete allowance) and the transactions agreed upon with other PRPs. Also import and export volumes must be reported.

One hour before the PTU of execution the E Programmes become final. The day after the day of execution, TenneT and the other grid operators collect metering data about the actual production and consumption, which are communicated to TenneT and are summed up for each PRP. Not all consumption (and production) can be measured on such a short notice, but this consumption is calculated and allocated to the PRPs with help of the known data by means of the profile methodology (see paragraph 2.4) in a process called Allocation[8]. By comparing the allocated volumes with the E Programmes, TenneT can determine the imbalance of each PRP for each PTU. This imbalance can then be settled.

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[8] The determination of the actual consumption and production is often called 'Allocation' as well, with a part known exactly by metering and a part allocated with help of the profile methodology. See paragraph 2.5.

The time schedule for the submission of E Programmes is relatively simple. An accepted E Programme takes effect on 0.00 a.m. of the day of execution, but altered E Programmes can be sent until one hour before the PTU of execution. However, alterations can only take effect every whole hour and therefore should at least be submitted one hour before that whole hour. Then, the day after the day of execution, the PRP receives information about the allocation, imbalances and imbalance prices, and the total imbalance costs with regard to the day before, at the latest at 17.00 p.m. (DTe 2005b). The time schedule for E Programmes is visualized below in Figure 7.

There is a more extensive time schedule for T Prognoses, because TenneT uses the T Prognoses of PRPs to perform a grid security analysis, to find and solve transmission restrictions in order to make the grid operationally 'n-1 secure'. This means that load disturbances will not lead to system overload. The target time of solving all the transmission restrictions and authorizing the T Prognoses is 17.00 p.m. at latest. If not all restrictions have been solved, TenneT or the regional grid operators may have to impose restrictions on the market (TenneT 2006). This can be seen in the time line for the bidding or RRP in Figure 9.

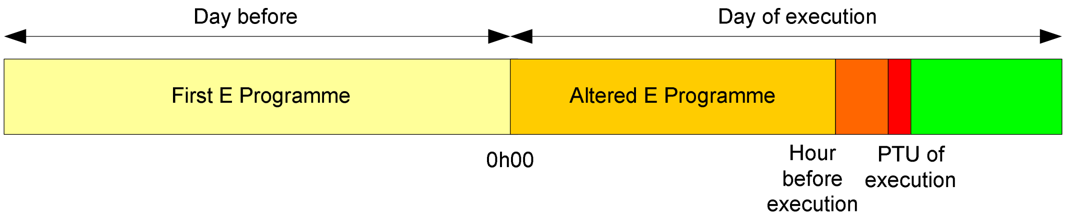

Figure 7: Time schedule for the submission of E Programmes

In the imbalance settlement process, only the net volume specified in the E Programme is of interest: deviations from this net volume (X MWh subtracted from or supplied to the grid) are settled. Allocation and the E Programmes are the components of the imbalance settlement: the transactions in the E Programmes are compared with the actual transactions resulting from the Allocation. Therefore, PRPs try to predict the consumption and production as good as possible for submission in the E Programmes, but also to predict the allocation so that they can adapt their E Programme to it. Also, the PRP can change his actual net volume as a response to the prediction he has made of the volume that will be allocated to him. This can be done by making deals on the OTC market or APX intraday market, or by producing more or less. Altered E Programmes should be submitted only if the net volume will be different, which also points to the possibility of 'internal balancing' by PRPs or connected parties even if the PTU of execution is less than an hour away. Sudden extra consumption can be compensated by suppletion of a production plant, for instance, keeping the same net volume. The bundling of connections by one PRP thus increases the ability to minimize imbalances. To what extent this happens is left to the market (Wenting 2002).

Seven design variables are derived from the above description of the Programme Responsibility instrument.

First, Programme Responsibility is an instrument that provides a way to allocate imbalance costs to market parties on the basis of E Programmes, and to enable TenneT to balance the system a-priori. A first design variable is concerned with *the presence of Programme Responsibility*. After all, this presence is not an indispensable ingredient for the ability to balance system supply and demand.

Second, the Programme Time Unit of fifteen minutes is not only used for the submission of E Programmes and T Prognoses, but also in the single-buyer market for Regulating and Reserve Power and for imbalance settlement. This makes *the length of the PTU* an obvious design variable.

Third, there exist specifications for the composition and submission of E Programmes. The Programme Responsible Party should specify the net electricity amounts subtracted and withdrawn in a predescribed way, and submit the E Programmes in the form of EDINE (Electronic Data Interchange in the Dutch Energy Sector) messages. The nature of these *E Programme specifications* forms another design variable.

Fourth, certain specifications exist for the composition and submission of T Prognoses as well. Like the E Programme specifications, they exist to make the Prognoses comparable, understandable, and quickly processable. The nature of *T Prognose specifications* is thus another design variable.

A fifth design variable is concerned with the *admission conditions for PRPs*. To gain a trade allowance of a complete allowance from TenneT, a party must meet conditions regarding the ability to formulate programmes justly and timely. These conditions could be changed.

Sixth, *the existence of a lower limit for the number of PRPs* is another design variable. Currently, there is no such limit. However, the existence of only a few PRPs might lead to too much influence (this will be explained in Chapter 5). The tendency of PRPs to take up responsibility for a larger number of consumers and producers, which improves their internal balancing capabilities, could lead to a reduction of the number of PRPs.

Seventh, the final time at which altered E Programmes can be submitted to TenneT, also called the *gate closure time*, is a design variable. Currently, the gate closure time is one hour before of the operational PTU, but to make sure that the altered E Programme takes effect, the E Programme should be submitted one hour before the last whole hour before the operational PTU. The gate closure time could be shortened to increase the balancing market efficiency, at the expense of higher administration costs, and perhaps restricted by technical and processing constraints.

2.3 The single-buyer market for Regulating and Reserve Power

Regulating and Reserve Power (RRP) are two forms of control power, which is only deployed for the purpose of resolving system imbalances. In the liberalized Dutch electricity market, RRP should be supplied by market parties. However, market parties can be reluctant to put aside surplus capacity because this does not provide them safe and constant revenues. That is why a provision is made in the Grid Code: Connected parties with contracted and provided capacity of more than 60 MW are obliged to offer all the available capacity that they can produce more or less and consume less to TenneT as RRP by means of bids; other connected parties are allowed to do so (DTe 2006a). In practice, the bidding of RRP owned by connected parties will be conducted by the PRPs who have taken over the Programme Responsibility of those connected parties. This set-up avoids complex transactions between TenneT, connected parties that offer RRP and their Programme Responsible Parties.

Regulating Power is a form of control power that is used for the balancing of electricity supply and demand within a Program Time Unit (PTU), which is 15 minutes. PRPs can offer Regulating Power to TenneT either voluntary or by contract. The Regulating Power has to be available within 15 minutes and TenneT must be able to operate it via the so-called Load Frequency Control (LFC), which requires a regulating speed of at least 7% per minute. This LFC implies that TenneT can automatically deploy the Regulating Power, whether positive or negative, by sending a 'regulating delta' (an electronic signal) (TenneT 2006). How quick Regulating Power can be 'called' is given by the response time. Like with Reserve Power, only volumes between 5 and 100 MW can be offered.

Reserve Power is not operated automatically, and often has a relatively large dispatch time. Another important difference with Regulating Power is that Reserve Power is deployed per whole generation unit for positive power. Negative Reserve Power can be partially dispatched per bid. Furthermore, it can only be offered to TenneT if the capacity is above 5 and below 100 MW (TenneT 2003). How quick Reserve Power can be dispatched is given by the dispatch time (see the definitions in 2.1.4).

As a backup, there is also emergency power. This is control power that has been contracted by TenneT in order to safeguard the system balance and that is deployed if the offered Regulating and Reserve capacity is insufficient. Specifications for the bids of these three forms of control power follow below.

For every PTU, PRPs/connected parties should bid available RRP. The bid price can be freely chosen. With the totality of bids, which can be adapted till one hour before the PTU of operation, the dispatch prices and the order of dispatch are determined. This is done by means of the bid ladder mechanism. The bid ladder contains bids of Regulating and Reserve Power with a dispatch time smaller than or equal to 15 minutes. The bids are ordered per direction, from the cheapest bid to the most expensive bid. The bids of negative power can be found on the left side of the ladder, and the bids of positive power on the right side. Bids of positive power are deployed by TenneT in order of increasing bid price, and bids of negative power in order of decreasing bid price. The dispatch price per direction (positive or negative) is the bid price of the marginal ('last') bid in that direction, needed to resolve the system imbalance in that direction (TenneT 2005). This means that positive bids are settled at the price of the highest bid deployed and negative bids at the price of the lowest bid deployed, for each PTU. In general, positive power is paid for by TenneT, and negative power paid for by the PRP. See Figure 8.

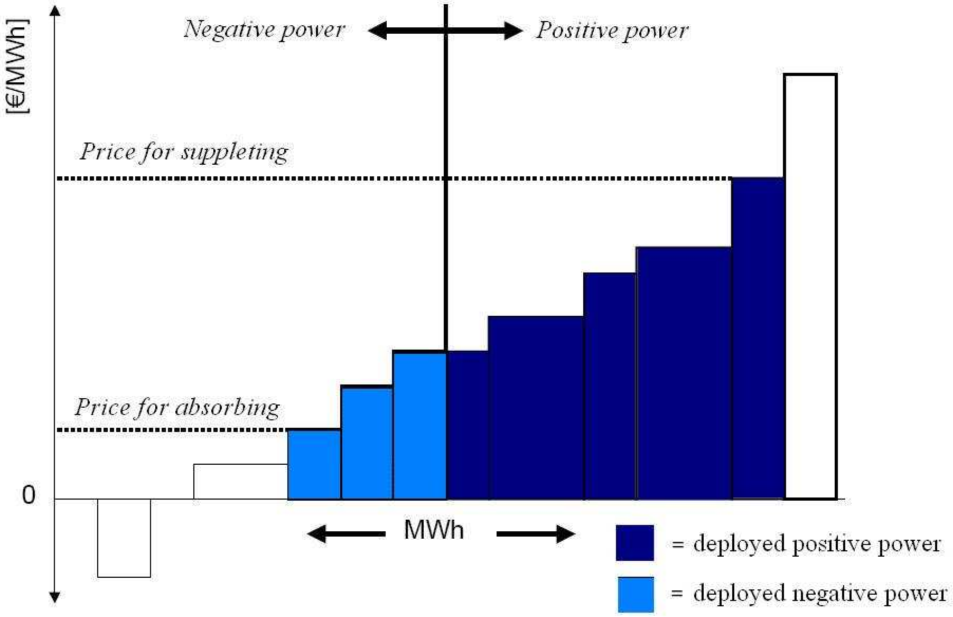

Figure 8: The bid ladder mechanism (DTe 2004)

In general, connected parties who have offered positive RRP that has been dispatched to solve an imbalance during a PTU are paid the dispatch price for positive power by TenneT, while connected parties who have offered negative RRP pay TenneT the dispatch price for negative power (for the relevant PTU). Suppliers of negative power will be willing to pay TenneT, because they have already sold the electricity and they will have lower fuel costs by the absorption of production capacity. The price for absorbing can also be negative; TenneT then pays for the absorption (TenneT 2005).

Once bids are made, the PRPs/suppliers of RRP are obliged to deploy the RRP when TenneT requests this. The deployment of RRP will be corrected in the E Programmes by TenneT. If the requested RRP is deployed, the relevant PRP receives the dispatch price for every MWh. If the requested RRP is not deployed, the dispatch price is not paid, and the PRP will have an imbalance for which he has to pay the imbalance price. Partial deployment will lead to partial pay-off and imbalance for the part not deployed.

TenneT will settle the dispatched amount of RRP with the relevant suppliers of RRP separately. For this purpose, TenneT sends bid information relevant to invoicing to the PRPs that have deployed RRP, who should formulate and send back invoices to TenneT every Wednesday. If the invoice amount is approved, the net sum must be paid within two weeks (TenneT 2006).

For guaranteeing that the system balance can be maintained at all times, a certain amount of Regulating, Reserve and emergency power is contracted. In 2002, 275 MW of

Regulating Power and 300 of MW emergency power has been contracted. Currently contracted RRP is of similar size. This ensures the availability of a minimum amount of Regulating Power, Reserve Power and emergency power.

Regulating Power is used primarily for solving system imbalances because of its low response time and its ability to be deployed partially. This is why the Reserve Power is often skipped on the bid ladder. Reserve Power is primarily used to solve transmission restrictions, and to free Regulating Power for possible new imbalance (TenneT 2005).

Suppliers of RRP or PRPs send *messages* to TenneT. These messages consist of a collection of *bids* of RRP. A bid covers the offering of RRP for one whole day. It consists of *bidding lines,* one for every PTU. Thus, a bid consists of 96 bidding lines. The number of bids in one RRP message is unlimited. In case a supplier of RRP/PRP does not have RRP available, he should still send a message, in which is specified that zero bids are made. New messages overwrite all earlier sent messages. For every bid of RRP, it should be specified for all of the PTUs of the implementation date how much capacity is made available for which price (TenneT 2003).

Messages of RRP are exchanged in a standardized format, which meets the EDI standard for the Dutch energy sector (EDINE[9]). The use of this format, plus the required attributes for the messages, makes that RRP messages are all alike, and can be processed by TenneT automatically. For the same reason, and to make sure the messages contain the right information, there are a number of requirements posed to the messages, bids and bidding lines.

For RRP messages, the supplier of the RRP and the PRP must be specified by means of an EAN code. The implementation date should also be given. This date must be between the current day and 7 days later.

Important attributes of the bids of RRP are the dispatch time and the regulating speed. The dispatch time should be given in minutes, and should be between zero and 10080 (7 days). The regulating speed must be given in %/minute, and should be between 7.0 and 100.0. For regulating power, the response time may not exceed 30 seconds (TenneT 2006)

The attributes of the bidding line are the capacity in MW and the bid price in €/MWh. The capacity of positive power must be an integer between 5 and 100; the capacity of negative power must be an integer between -100 and -5. The capacity has the value zero when there is none offered. The bid price should have a value between
-100,000.00 and 100,000.00 (TenneT 2003).

Until one hour after the closure of the day-ahead market (which is the day before execution at 1300 p.m.), the first bid can be made by a RRP supplier/PRP who wants to offer RRP for the next day. Then, TenneT will use the bid information to solve transport restrictions until 16.00 p.m., when authorization of the bids takes place. Subsequently, it is possible to make alterations in the bids from the moment of authorization until closure of the intraday market (1 hour before hour of execution). On the day of execution, the term for sending in altered bids of RRP always ends one hour before each PTU. The

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[9] Electronic Data Interchange in the Netherlands (EDINE) is a collection of specifications and agreements (TenneT 2006).

remaining hour before the PTU of execution is used by TenneT to solve remaining transport restrictions. This time schedule is presented in Figure 9.

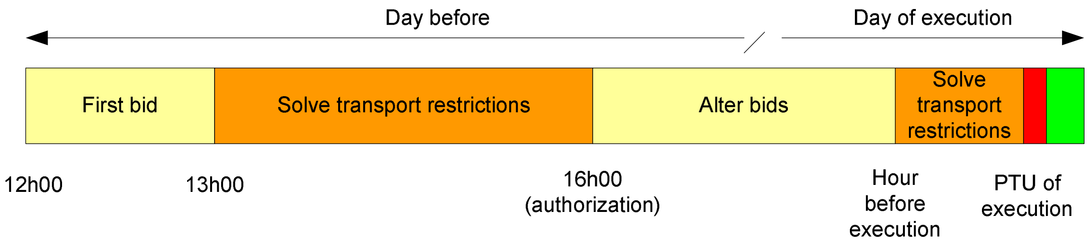

Figure 9: Time schedule for the single-buyer market of RRP (TenneT presentation)

In case the market for RRP is insufficient for solving the system imbalance, emergency power will be deployed. TenneT has contracted some 300 MW of emergency power, which serves to solve system imbalances that the market for Regulating and Reserve Power can not cope with. Thus, emergency power and its use do not fall under the market for RRP or under another market. In past operating years, deployment of emergency power was only necessary for a limited amount of PTUs. According to a note by TenneT, it is desirable that the contracted capacity is at minimum 20-25 MW. This capacity should be available exclusively to TenneT, during the whole agreed contract period. Furthermore, the dispatch time should be as small as possible, but not larger than 15 minutes. Finally, the offered capacity should be dispatchable for at least 60 minutes uninterruptedly. All these requirements make sure that emergency power can be used immediately and effectively for the resolution of a system imbalance that the market for RRP could not solve, in order to prevent emergency measures like the cancellation of electricity export or the switching off of consumer connections.

Six design variables arise from the above description of the single-buyer market for Regulating and Reserve Power.

First, it was mentioned that large parties with more than 60 MW production capacity are obliged to offer their available RRP. The *degree of compulsion of RRP provision* is a first design variable that follows from this obligation.

Second, the *structure of the bid ladder mechanism* is a design variable. This concerns the way bids of RRP are arranged on the bid ladder: bids of negative power are placed to the left in order of decreasing bid price and bids of positive power are placed to the right in order of increasing bid prices. The provision that bids of Regulating Power and bids of Reserve Power are not separated is also part of this structure.

Third, the *determination of dispatch prices* is a design variable that is concerned with the way the dispatch prices are derived. In the current design, these prices are the marginal prices for RRP, and separate prices are formed for positive and negative power.

Fourth, the *requirements for the offering of RRP* in the current balancing market design have been listed. They could be altered, for example be made more or less strict.

Fifth, a last design variable is concerned with the *level of contracting of control power*. As said, 300 MW of emergency power and 275 MW of Regulating Power was contracted in 2002, but the amounts could be increased or decreased to anticipate the future state of electricity system.

Sixth, the *requirements for emergency power* given above can be adapted as well.

2.4 Imbalance settlement

The third instrument of the Dutch balancing market is the imbalance settlement. Imbalance settlement consists of the settlement of imbalances of Programme Responsible Parties, and the preceding process of allocating actual production and consumption to each of them: Allocation. See Figure 10.

For the settlement of imbalances to take place, the imbalance volume of each PRP must be known, along with the imbalance prices. The imbalance costs for each PRP are then his imbalance in MWh multiplied by the imbalance price in €/MWh. For each PTU new imbalance prices and imbalance volumes are derived. The imbalance prices follow from the dispatch prices that are formed in the market for Regulating and Reserve Power; the imbalance volumes are the differences between the E Programmes and the allocated volumes.

The imbalance for a PRP is the deviation of the actual net volume supplied to or subtracted from the grid from the planned net volume specified in the submitted E Programme. The actual net volume supplied to or subtracted from the grid should be derived for each PRP by determining the electricity volumes that are injected by the producers the PRP has programme responsibility for and the electricity volumes that are withdrawn by the consumers the PRP has programme responsibility for. However, only the producers and consumers with a telemetry facility can be metered continuously. Household consumers, having relatively small grid connections and yearly consumption levels, are not metered continuously. This is where the Allocation process comes in.

In the Allocation process, the total amount of electricity fed into the different distribution networks is allocated to all connected consumers. For the continuously metered consumers, this is easy, and is done first. This leaves the total volume consumed by consumers that are not continuously metered. This remaining volume is allocated among these consumers by means of the profile methodology.

All consumers not continuously metered have been assigned a consumption profile, based on their consumption pattern. In combination with a Standard Yearly Consumption, an assumed consumption volume can be determined for them for each PTU. Then, the total consumption of 'profile consumers' is allocated to them on the basis of their relative assumed consumption levels.

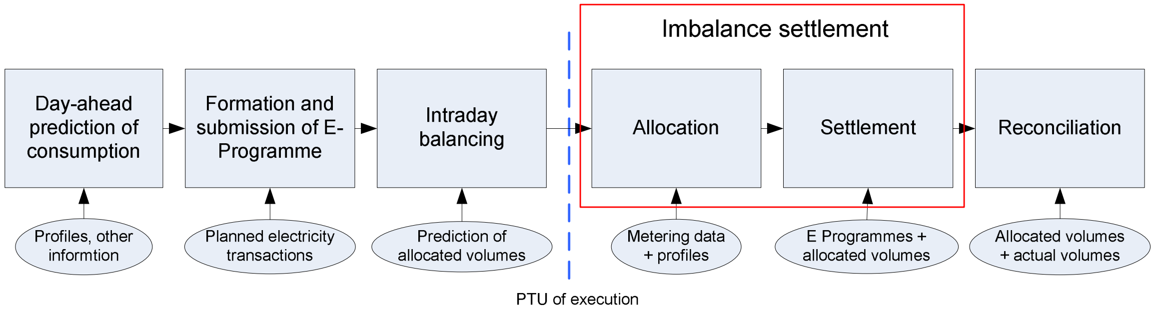

Figure 10: Follow-up of processes concerning the Programme Responsibility and imbalance settlement

2.4.1 Determination of the imbalance prices

As has been become clear by now, Programme Responsible Parties have to pay the imbalance price for every MWh their actual net electricity volume (resulting from the Allocation process) differs from the net volume stated in their E Programme, which stimulates them to minimize their imbalance. PRPs that have a positive net volume difference (PRP surplus) are expected to have sold this *to* TenneT. PRPs that have a negative net volume difference (PRP shortage) are expected to have bought this *from* TenneT (TenneT 2005). This stimulates market parties to have a surplus rather than a shortage, which is beneficial for maintaining the system balance.

The imbalance price is based on the dispatch price resulting from the single-buyer market for Regulating and Reserve Power. Like there is a dispatch price for positive power and one for negative power, there are in principal two imbalance prices for each PTU: one for PRPs who have a negative net volume difference and one for PRPs who have a positive difference. Which dispatch price is taken as a basis, depends on which of four situations applies to the operational PTU:

1. TenneT has only deployed negative power
2. TenneT has only deployed positive power
3. TenneT has both deployed negative power and positive power
4. TenneT has neither deployed negative power nor positive power

In the first situation the dispatch price for negative power is taken as a basis, and in the second situation the dispatch price for positive power is taken. In the third situation the price for positive power is used for PRPs having a negative net volume difference and the price for negative power for PRPs having a positive net volume difference. In the fourth situation, no dispatch prices have been set, because no RRP is deployed. In that case the imbalance price will be based on the 'middle price': the average of the lowest bid price for positive power and the highest bid price for negative power (Wenting 2002).

Finally, to obtain the imbalance price the dispatch price has to be increased or decreased with the 'incentive component'. If this component is zero, the imbalance price is the same as the dispatch price. The dispatch price is increased with the incentive component if the PRP has a negative net volume difference, and vice versa.

The incentive component is determined every week, and is coupled to the performance level of the Dutch balancing system. The performance level is found sufficiently high if two conditions are met:

A. The number of inadvertent exchanges over 5 minutes that per week, converted to MW, larger than 300 MW or smaller than -300 MW is less than 40.
B. The average per week of the inadvertent exchanges over 5 minutes is, converted to MW, both larger than -20 MW and smaller than 20 MW (TenneT 2005).

If these two conditions are met, the incentive component will decrease. It increases if the performance level decreases, thereby providing a larger stimulus for PRPs to have a surplus rather than a shortage, and less imbalance. In past operating years, the incentive component has been zero most of the time, which means that the above conditions are usually met. Moreover, it means that the imbalance prices have been equal to the dispatch prices most of the time.

The imbalances of PRPs are settled in the following way. The settlements of the imbalances between TenneT and each PRP are netted for every weak by multiplying for each PTU the imbalance price with the imbalance, and summing the outcomes. The net cash value is either paid by TenneT to the PRP or paid by the PRP to TenneT, depending on the sign of this value. Payments are made for each week. This happens after the invoice of that week is sent, which is 10 days after the last day of that week (see below). The yearly cash balance between the settlement of imbalances and the settlement of deployed RRP are settled in the system services tariff of the next year, as specified in article 3.9.9 of the System Code, thereby redirecting the remaining net balancing costs back to the market (TenneT 2005).

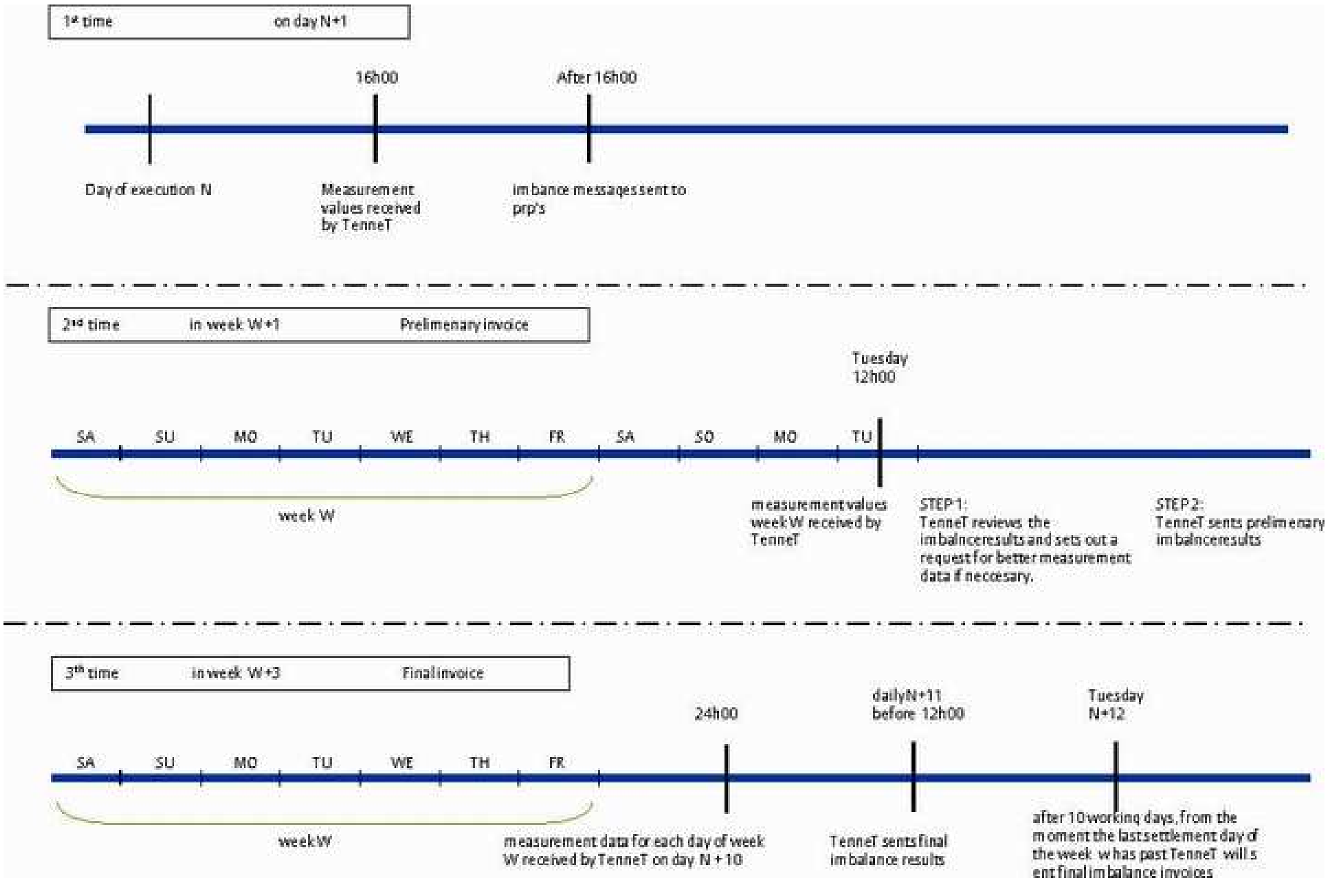

Figure 11: Time schedule information exchange for imbalance settlement (TenneT website)

The imbalance settlement process is also subject to a time schedule, see Figure 11. The imbalance is settled for every week, running from Saturday up to and including Friday. The day after the day of execution, the metering data must be received by TenneT before 16.00 p.m. Putting the metering data on-line is a responsibility of the individual PRPs, although the Metering Responsible Parties collect the metering data. After 16.00 p.m., the imbalance messages with imbalance information are sent to the PRPs. Then, in the next week, the temporal invoice is sent, after TenneT has received the metering data for the whole week, which should be finished by Tuesday at 12.00 p.m. TenneT can request better metering data if needed. Then, on the tenth day after the last day of the week of execution, TenneT has received the final metering data of every single day in the week of operation. When the tenth *working day* has past since the last settlement day of the week of operation (which is in the third week after the week of execution), the final imbalance invoices are sent to the PRPs.

Because the dispatch price for RRP is essentially the same as the imbalance price used for settling imbalances of PRPs, the bid prices asked by suppliers of RRP (which is done by the PRPs) reflect their attitude towards risks. The starting point for the imbalance settlement instrument has been the wish to assign a market-related price to imbalance by relating it to the settlement prices for deployed RRP (TenneT 2005). This way, the imbalance prices are determined by the market: PRPs who offer RRP consider both the possible benefits of being deployed and the possible costs of having to pay the imbalance price for their imbalance. Both will probably increase if the PRPs specify a higher bid price. PRPs have to bear in mind that if offered RRP with a high bid price is deployed, this also means that the imbalance price is high. Furthermore, it can be remarked that a PRP who is certain of his ability to prevent an imbalance and therefore submits a very high bid price, will probably not be deployed, because his RRP is at the end of the bid ladder. Finally, submitting very low prices with the intention to keep the imbalance price low is not attractive, because PRPs will lose money on the deployment of their RRP, which needs to be offered if it is available. It appears that opportunistic behaviour by PRPs is prohibited by this balancing market design.

To conclude, the imbalance settlement instrument, in combination with Programme Responsibility and the single-buyer market for RRP appear to give the right incentives to PRPs and other market parties to minimize their imbalances, but also to offer RRP. This makes the system balancing task of TenneT a lot easier: it only has to facilitate the transactions in the balancing market, solve the planned system imbalance by means of import and export, restore unexpected imbalance not solved by the market, and remove transport restrictions.

Now, the profile methodology will be discussed. The profile methodology is used to allocate the amount of consumed electricity to consumers from which no meter readings are known. It therefore forms an important part of the Allocation process, and thus also of the imbalance settlement. Besides, it is very relevant to this research because of the focus on households, which are normally all profile customers.

First, some definitions of key words in the profile methodology are given. The original Dutch words can be found in appendix B, as well as the foundation of the methodology in regulation.

2.4.2 Definitions for the profile methodology

The profile methodology
The regulatory provision of the existence, structure and use of consumption profiles for the prediction and Allocation of consumption by profile customers.

Profile customers/consumers
Profile customers, or profile consumers, are consumers with a 'dumb meter' (a meter that has to be read manually), and therefore have been assigned a consumption profile.

Consumption profile
A consumption profile assigns a consumption pattern to a profile customer. The profile takes the form of a series of fractions, one for each PTU in the year.[10]

Standard Yearly Consumption (SYC)
The expected yearly consumption of a consumer connected to the grid at standardized conditions and on the basis of a normalized year.[10]

Allocation
For each PTU, grid operators have to calculate the amounts of electricity PRPs have delivered through their nets. Most injected and withdrawn electricity flows are metered remotely and thus exactly known, but consumption by profile customers is not. The total consumption of profile customers is allocated among them with help of their consumption profiles and SYCs. This process is called the Allocation process.

Reconciliation
Settlement over a certain period on the basis of the difference between the calculated consumption of profile customers (Corrected Profiled Consumption) and the actual consumption with a weighted market price.[11]

Assumed Profiled Consumption (APC): the predicted consumption of profile customers by means of their consumption profiles and SYCs.
Corrected Profiled Consumption (CPC): the consumption of profile customers that is allocated to them by means of their profiles in the allocation process.
Metering Correction Factor (MCF): the factor that is determined by dividing the total consumption of profile customers by the APC[10]
Climate Correction Factor (CCF): a climate dependent factor used to correct the different profiles for climate influences. Up to current day, the MCF has been 1.[10]
Tariff Correction Factor (TCF): a multiplication factor that is applied per PRP per profile category when there are multiple tariff categories applicable in one profile category.[10]

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[10] PVE 2003 ('Profielenmethodiek Elektriciteit – Versie 3.04')
[11] PVE 2002 ('Reconciliatie Elektriciteitsmarkt')

2.4.3 Description of the consumption profiles

A consumption profile is used to assign a consumption pattern to a large group of connected electricity consumers from which the day-to-day electricity consumption can not be metered.

Large consumers generally have a telemetry facility, which daily transmits metering data electronically, so that actual consumption is known immediately. Since individual consumers only use relatively small electricity volumes, the installation of a telemetry facility at households has been found unprofitable. Because the level of consumption of different small consumers throughout time is rather similar, the electricity consumption of these similar consumers can be estimated by the Programme Responsible Party by means of the same consumption profile. Currently, nine consumption profiles have been agreed upon by the combined grid operators and PRPs, for different types of small consumers. One consumption profile is assigned to each connected consumer without daily metered consumption.

A consumption profile reveals the distribution of the yearly consumption over all PTUs of the year. It essentially consists of 35,040 fractions, one for each fifteen minutes in the year. In Figure 12, the profile fractions of profile E1A are plotted for four weeks across the year 2002 (Ecofys 2001). This illustrates the fluctuating consumption pattern of Dutch households.

Except for a consumption profile, each profile customer is assigned a Standard Yearly Consumption (SYC) as well. This SYC is based on the electricity consumption of the particular consumer in former years, and is renewed when a new and validated meter reading becomes known to the grid operator, by means of recalculation.

Now if a fraction of a particular PTU in the consumption profile is multiplied with the SYC, the result is the ‘assumed consumption’ in that fifteen-minute period of the year. The assumed consumption calculated for profile customers this way serves as the basis for the Allocation to profile customers.

As consumption profiles are used as an alternative to telemetry facilities, they can be considered a measuring instrument[12]. The totality of rules, specifications and applications for consumption profiles is referred to as the 'profile methodology'.

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[12] From http://www.verbruiksprofielen.nl/toelichting.asp, an information website from Ecofys. Viewed on May 23th, 2007.

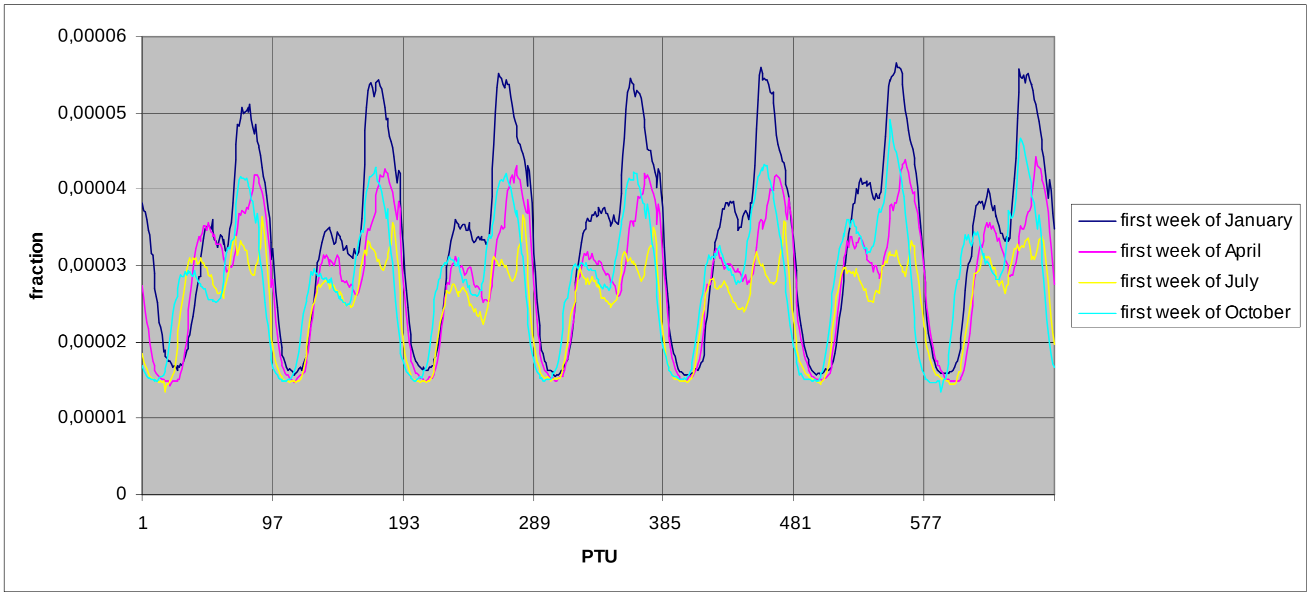

Figure 12: Fraction variation for profile E1A in four different weeks of 2002 (Ecofys 2001)

The profile methodology is laid down in the Metering Code. There are currently nine consumption profiles (profile categories). These are specified in the Metering Code, and are presented in Table 1. The rules concerning the profile methodology and their foundation in the Code are described in Appendix B.

Group	*Profile categories electricity*
E1	Consumers with a connection value smaller or equal to 3 x 25 Ampere **E1A** single-tariff **E1B** double-tariff night electricity **E1C** double-tariff evening electricity
E2	Consumers with a connection value above 3 x 25 Ampere up to 3 x 80 Ampere **E2A** single-tariff **E2B** double-tariff
E3	Consumers with a connection value above 3 x 80 Ampere, but with a contracted transport capacity smaller than 0.1 MW and not provided with a continuous metering facility conform the Metering Code **E3A** Operational Time ≤ 2,000 hours **E3B** 2,000 < Operational Time ≤ 3,000 hours **E3C** 3,000 < Operational Time < 5,000 hours **E3D** Operational Time ≥ 5,000 hours
Remark 1: The above is applicable to connections to the low-voltage grid *Remark 2: The Operational Time can be calculated if the SYC and the contracted transport capacity are known* *Remark 3: With 'evening electricity' slightly more hours have a reduced tariff than with 'night electricity'*	

Table 1: Overview of the existing profile categories

2.4.4 The use of profiles in the allocation process

The imbalance settlement serves to settle imbalances with PRPs, as revealed by differences between actual net volumes and planned net volumes specified in the E Programmes. In order for TenneT to settle the imbalance with each PRP, first the real volumes delivered to profile customers must be known for each PRP. These volumes can not be measured, which is why they must be derived from known electricity volumes and by means of the profile methodology.

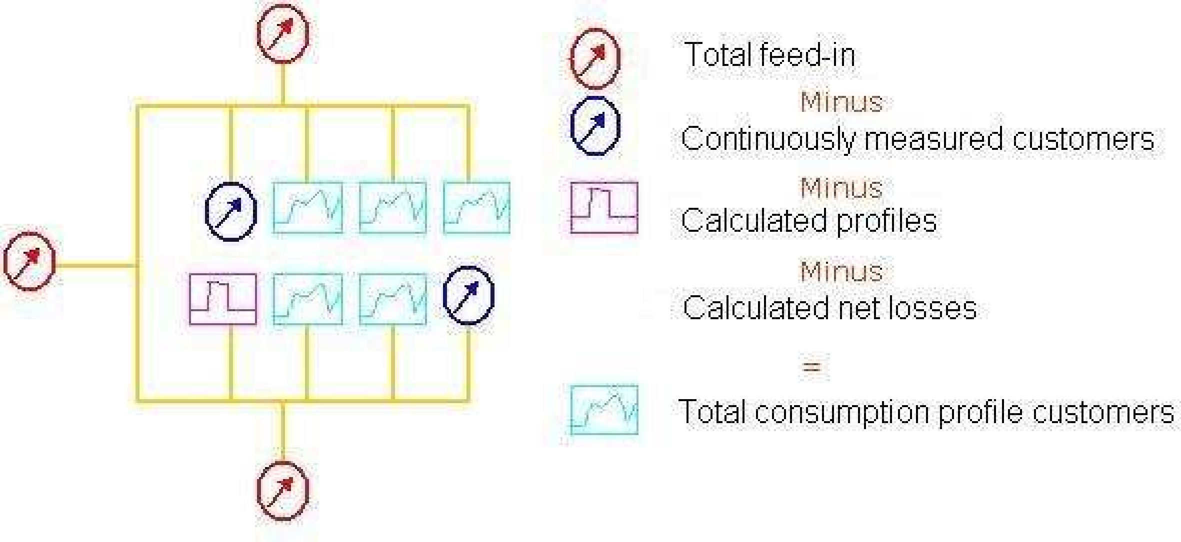

Figure 13: Determination of the total consumption of profile customers in one grid (website Ecofys)

For each PTU, grid operators need to calculate the amounts of electricity PRPs have supplied through their nets. This process is called 'Allocation'. Every regional grid operator can calculate the total consumption of profile customers connected to its grid by subtracting known consumption volume from the feed-in volume (import plus total production). Unlike the consumption of small consumers, these volumes are metered continuously. The total feed-in minus the continuously metered customers, minus the calculated profiles[13] (e.g. public lighting), minus calculated net losses, leaves the total consumption of all profile customers connected to the grid (see Figure 13). The calculation holds for both the whole national grid and the distribution grids, but profile customers are small consumers that are coupled to the distribution grids. Therefore, the calculation is made for every distribution grid, total feed-in being the total electricity volume supplied from the transmission grid through one or a few Grid Supply Points (which are metered). The total consumption of profile customers then refers to all the profile customers connected to the distribution grid under consideration.

The next step is to distribute this total consumption to the different profile customers by means of the profile methodology.

As said, the assumed consumption of a profile can be calculated by multiplying the relevant profile fraction with the SYC. If the assumed consumption volumes of all profile

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[13] The 'calculated profiles' are different from the consumption profiles discussed here, because they are assigned to consumption with a stable, highly predictable pattern, such as public lighting.

customers in the grid are added up, the 'Assumed Profiled Consumption' (APC) is obtained. The Assumed Profiled Consumption is now corrected with a factor, so that it matches the determined total consumption of all profile customers. This factor is called the Metering Correction Factor (MCF), and the distribution of the total determined consumption among profile customers is called the 'Corrected Profiled Consumption' (CPC). By multiplying the individual APC of profile customers with the MCF, their share of the total CPC is determined. The determination of the CPC is shown in Figure 14.
In the Corrected Profiled Consumption, the ‘actual’ consumption of all profile customers of every PRP connected to the relevant regional grid can be found. The regional grid operators are therefore now able to inform TenneT about the actual electricity delivery to profile customers belonging to one PRP, so that TenneT can make up the balance for each PRP and settle the imbalances.

A detailed calculation of the APC and the CPC can be found in Appendix B.

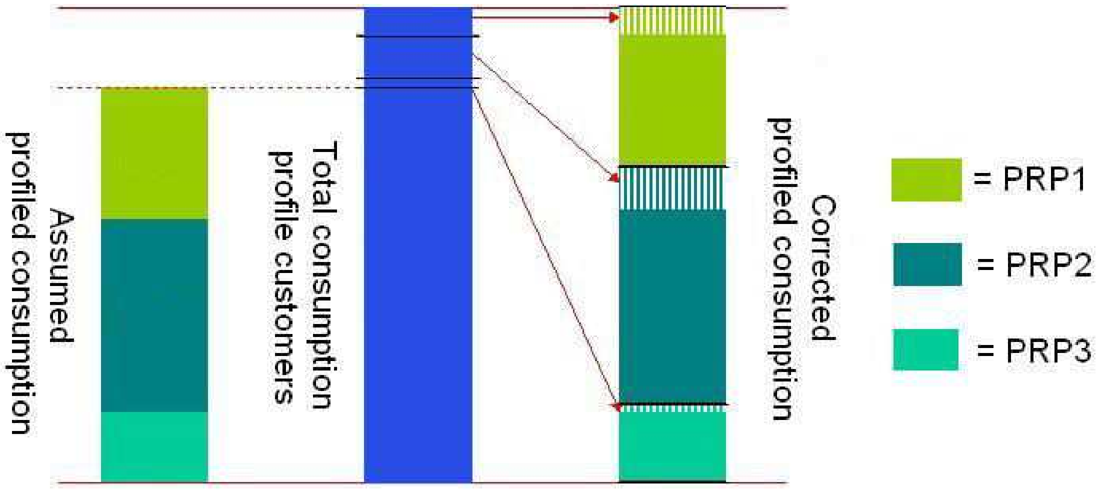

Figure 14: Determination of Corrected Profiled Consumption from Assumed Profiled Consumption

2.4.5 Reconciliation

Because the distribution of the total consumption of profile customers over the customers of the different PRPs is only estimated by means of the profile methodology, it is not exactly known if this total consumption is allocated justly between the different PRPs. Also, it is uncertain if the consumers have paid their supplier for the exact amount of electricity they have used. When the meter readings of the profile customers are metered once a year, however, the actual consumption becomes known and volume differences can be settled. This settlement is called 'reconciliation'.

Reconciliation is the settlement of the differences between the consumption allocated to the PRPs on the basis of the profile methodology and the actual consumption measured, between the PRPs, with a weighted APX price (PVE 2002). These differences become known whenever Metering Responsible Parties (MRPs) have metered and validated the actual consumption of profile customers, which has to be done at least once a year, as laid down in the Metering Code. Data about the actual consumption is sent to grid operators, PRPs and suppliers. Whenever known, the differences are settled between the PRPs, while suppliers settle with the profile customers, so that in the end every party has paid for the actually delivered electricity volumes.

The given description concerns the light variant of reconciliation, which is being used in the Dutch electricity system. It is conceivable that, next to volume correction, imbalance correction take place as well: the heavy variant. But "because the recalculation of the imbalance in hindsight is not feasible in a practical sense, the heavy variant is discarded" (PVE 2002). This means that the reconciliation process is not part of the imbalance settlement instrument (see Figure 10).

2.4.6 Implications of DG penetration for profile methodology

The research focuses on the performance of the balancing market design when a large-scale penetration of distributed generation (DG) emerges at Dutch households. Considering the fact that these households, even with their increased role of consumer-generator, still fall under the group of profile customers (according to the Metering Code), the profile methodology would play a larger role and its performance would become more important. The DG penetration will make the prediction of the net consumption of profile customers more difficult, even it were just for the fact that both household production and consumption would then influence the net consumption or net production. But also the use of limitedly predictable DG units could hinder accurate prediction of net consumption. Most important, generation would be unaccounted for when the current Allocation process would still be used. Thus, the formation of accurate E Programmes could become much more difficult and the net imbalances to be settled could become much higher when domestic DG would emerge at large scale.

The questions arise if new consumption profiles should and could be made for household consumers with a DG unit. Also, it can be considered if generation profiles could be made to account for domestic generation. The feasibility of all this will depend on the similarity in consumption and generation of households with a DG unit, the nature of which is also uncertain.

Another measure improving the balancing market design performance in this respect could be the requirement of daily readable meters for DG owners: smart meters. This might be an expensive option. On the other hand, it would not only solve the possible difficulties for Programme Responsibility, but also create the possibility for DG owners to participate in the market for Regulating and Reserve Power. Currently, however, only monthly metering is required for distributed generation coupled with a grid connection larger than 3 x 80 Ampere (which means for the low-voltage grid connections of 230 Volt that the connection capacity should be more than 55.2 kW). Most grid connections of profile customers are smaller, which means that smart meters do not have to be installed. Still, the Dutch Ministry of Economic Affairs has decided to do this, which is why this instalment is taken as an assumption for the analysis (see paragraph 3.4).

2.4.7 Design variables for imbalance settlement and entire balancing market

From the above description of the imbalance settlement instrument, new design variables are derived. Furthermore, some general balancing market design variables are derived, basing on the whole balancing market description in this chapter.

Regarding imbalance settlement, seven design variables are found.
First, the *determination of the imbalance prices* is a design variable that is concerned with the way the imbalance prices are derived. In the current design, the imbalance prices are based on the dispatch prices, depend on the system state, and are complemented with an incentive component. All this could be changed.

Second, the current allocation of imbalance costs is based on the individual imbalances of PRPs and on the actual electricity volumes measured and allocated by means of the profile methodology. The *base of allocation of system imbalance* is another design variable, because other possibilities exist. For instance, the total imbalance costs could be distributed evenly among market parties.

Third, the *length of the reconciliation period* is a design variable, because this length can be adapted when meter readings for households become known on a smaller time scale than once a year. The use of smart metering brings this possibility (see Appendix C and paragraph 3.4 onward).

Fourth, the *length of the period for the assignment of profiles* is a design variable concerned with the time period for assigning profiles to the profile customers and possibly using newly created profiles. Currently, not later than in the third week of January, April, July, and October, all grid operators combined submit a motivated proposal to the conference platform about the profiles that will be used in the next quarter of the year (see appendix B). The length might need to be altered as a consequence of increasing dynamics in residential consumption and production patterns.

Fifth, the *length of the period for the assignments of SYCs* can be adapted as well, and thus forms another design variable. In the current design, the Standard Yearly Consumption of a grid connection is determined by dividing the measured consumption for that grid connection over the smallest possible measured consumption period of minimally 120 days by the sum of the profile fractions in the consumption profile over the relevant period (see appendix B).

Finally, the *structure of the profile methodology* and the *provisions for smart metering* are two design variables considered with two alternative ways of Allocation: by means of profiles and by means of continuous metering. See section 3.3.2 and further.

Regarding the entire Dutch balancing market, two design variables are found.
The *nature of balancing control* is concerned with the level of hierarchy, or centralized control, in the Dutch electricity system. This depends on the involvement of government (by means of regulation) and TenneT in maintaining the system balance. The *level of interconnection with foreign balancing markets* is a last design variable. Currently, the Dutch balancing market is not connected with other balancing markets.
The total list of design variables for the Dutch balancing market formed in this Chapter can be found at the beginning of Chapter 5, where design options will be derived.

2.5 Current operational performance of the Dutch balancing market

Because emergency power is only deployed when the single-buyer market for RRP fails to solve the system imbalance during any PTU, the number of PTUs that emergency power has been deployed throughout the year is a good performance indicator for the performance of the single-buyer market for RRP. Emergency power had to be deployed during 165 PTUs in 2002 and during 163 PTUs in 2003. In all these cases it was positive emergency power (DTe 2004). In 2006, only in 35 PTUs emergency power has been deployed[14].

The net amount of Regulating and Reserve Power that is deployed for all PTUs in a year is an indicator for the size of system imbalances in the Dutch electricity system. For 2006, the net amount of RRP deployed for all PTUs is shown in Figure 15 [14]. It can be seen there that most of the time, the system imbalance appears to be rather small, and that larger imbalances (amounts of deployed RRP) occur less the larger the size of deployed RRP becomes. In numbers, during 3484 hours in 2006 (~40% of the time) there appears to have been a net system imbalance smaller than 50 MW (between -50 and 50 MW; number of PTUs divided by 4). Furthermore, negative net imbalances larger than 50 MW appear to have existed during 2987.5 hours (~34% of the time), and positive net imbalances larger than 50 MW during 2288.5 hours (~26% of the time). Negative imbalances appear to have occurred during 4759 hours (54.3%), and positive imbalances during 4001 hours (45.7%).

Having derived that the average measured electricity system load in 2006 was 11,851 MW[14] , and that the average amount of deployed RRP in 2006 was -11.13 MW, only 0.09 % of electricity flows/transactions appears to be settled by the RRP market. This is the average, however: for large imbalances, this is 1.5-3.5 % (see appendix A).

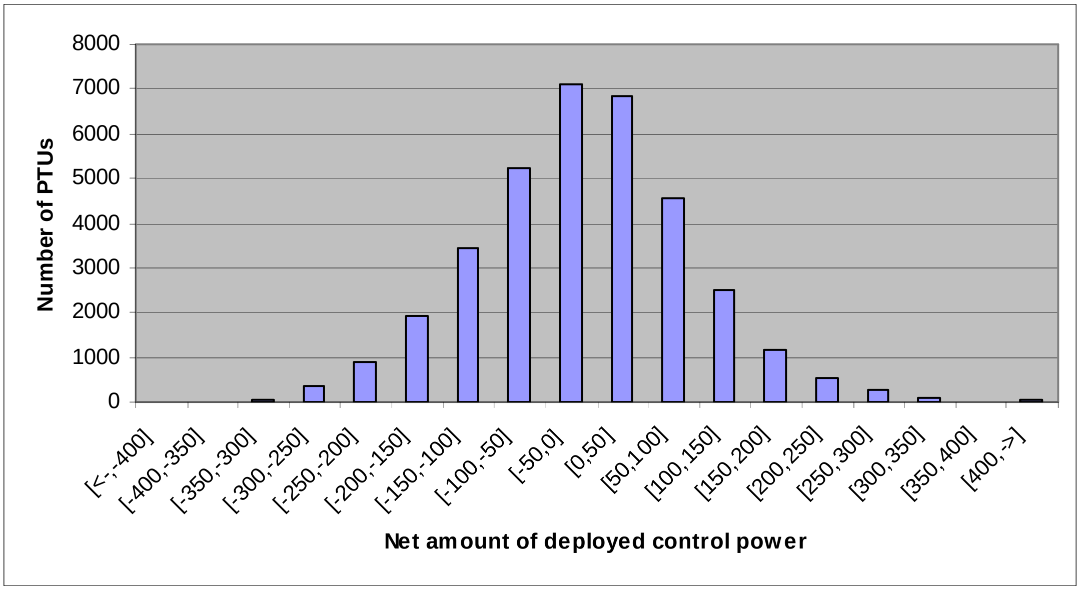

Figure 15: Deployment of control power in 2006 (TenneT website)

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[14] Derived from electricity system performance data retrievable on the TenneT website.

The regulating space, being the available production capacity minus the capacity that is utilized for electricity transactions and the own consumption behind the grid connection points, has been 4,215 MW[14] on average in 2006. The average net amount of RRP deployed in 2006 was only -11.13 MW. This means that, if we assume that all the regulating space has been offered as RRP, on average 0.3% of the offered RRP has been deployed. Of course, the actually deployed RRP will be larger than the net imbalance shows, because transport restrictions have to be solved as well, and not all available capacity is offered as RRP to TenneT (partly because it does not meet the requirements). Considering the fact that, in August 2003, the offered amount of RRP had dropped to below 700 MW during several days (DTe 2004), it looks like it that the RRP margin is much smaller than the regulating space, and thus not reassuringly large.

Table 2 presents the average monthly dispatch prices for deployment of RRP and imbalance prices for the imbalances of PRPs. The yearly averages are given as well. As is expected, the average dispatch price for positive power is much higher than the dispatch price for negative power. As is also expected, the average imbalance price for RRP shortage is higher than the imbalance price for RRP surplus, although the difference is much smaller. This small difference can be explained by the fact that the amount of RRP deployed each PTU has not been taken into account, while it influences the prices (see paragraph 2.3 and the causal diagram in Figure 18). The volume weighted mean imbalance prices for 2004 calculated by TenneT confirm this: for PRP shortage it was 71.0 €/MWh, and for PRP surplus it was 23.4 €/MWh (Nobel 2004).

To stimulate the PRPs to prevent imbalance, the imbalance price for RRP shortage should be significantly higher than the APX day ahead price, while the imbalance price for RRP surplus (which is paid to the PRP) should be lower. As can be seen in the table, this is just the case for the yearly average, but the volume weighted mean imbalance prices are expected to show a more significant difference.

Months (of the year 2006)	Dispatch price positive power (€/MWh)	Dispatch price negative power (€/MWh)	Imbalance price for RRP shortage (€/MWh)	Imbalance price for RRP surplus (€/MWh)	*APX day ahead price (monthly average base price; €/MWh)*
January	112.62	14.25	57.50	42.97	72.40
February	129.52	10.29	58.11	46.38	77.01
March	133.13	8.81	63.18	49.44	70.37
April	92.50	12.20	47.41	39.64	50.85
May	79.66	15.21	53.52	49.74	41.75
June	88.37	19.67	52.04	48.61	51.66
July	101.16	28.38	79.16	74.43	80.78
August	77.21	21.69	46.09	42.75	46.97
September	88.76	21.51	65.60	61.33	48.85
October	85.02	20.02	56.16	51.68	52.14
November	114.38	23.06	76.49	70.04	61.32
December	85.39	13.04	51.85	47.80	44.21
Yearly average	**98.98**	**17.34**	**58.93**	**52.07**	**58.19**

Table 2: Average dispatch prices and imbalance prices in comparison with the APX price in 2006 (website TenneT 2006; website APX 2006)

Price differences between Regulating Power and Reserve Power are not shown, but Regulating Power is generally more expensive than Reserve Power, because it should be deployed automatically and it should meet more strict requirements. Also, Regulating Power is used to solve the more unexpected system imbalances, which are more critical. This makes Regulating Power more important, and thus more valuable.

The number of times emergency power has been deployed, the involvement of the RRP market, and the average amount of deployed RRP all appear to be relatively low. The dispatch prices appear to give a good incentive to offer RRP, and the imbalance prices to avoid imbalances, seeing the effects on the size of system imbalance. This shows that the instruments of Programme Responsibility, the single-buyer market for RRP and imbalance settlement perform quite well.

More specifically, more negative RRP has been deployed than positive RRP, which means that the system was more often 'long' (total production was larger than total consumption) than 'short' (total production was smaller than total consumption). A diagram like Figure 15 Jasper Frunt has made for the years 2003, 2004 and 2005 (Jasper Frunt 2005, figure 5.7) shows a similar picture. This is the desired situation: it means that market parties are effectively stimulated by the higher imbalance costs for RRP shortages to have a RRP excess rather than a RRP shortage.

The RRP margin should be optimal, rather than maximal: a too high margin brings excessively higher costs for only a marginal gain in system reliability. Thus, the fact that emergency power has been deployed at some PTUs, does not have to mean that the operational performance of the current balancing market design is suboptimal. It is concluded here that the current Dutch balancing market performs satisfactorily in the current, centralized Dutch electricity system.

3. Balancing market requirements

In this chapter, the second sub question, 'Which requirements are posed to the balancing market design, and in what way will these requirements change if a large-scale DG penetration emerges at Dutch households?', is answered. With help of these requirements, a set of performance criteria is formed that will be used to analyze the effects of large-scale DG penetration at households in the next chapter.

This chapter starts with some definitions in paragraph 3.1. Then, requirements for the whole Dutch electricity system are discussed in paragraph 3.2. These are important for putting the analysis into perspective, and drawing boundaries for the analysis. After that, in paragraph 3.3 the performance criteria for the Dutch balancing market design are given. These are derived from a formed list of balancing market requirements, which is presented in appendix C. Finally, in paragraph 3.4 the system to be analyzed is delineated, and included factors and relationships are discussed for a future decentralized system.

3.1 Definitions

Performance Dutch electricity system
The overall performance of the whole Dutch electricity system, including technical, economical and environmental performance

Operational performance balancing market
The short-term performance of the balancing market, consisting here of short-term reliability and short-term economical performance

Regulating space
Is the available production capacity minus the capacity that is utilized for electricity transactions, minus the own consumption behind the grid connection points for that production capacity.

RRP margin
The difference between the offered amount of RRP and the deployed amount of RRP

System reliability
The guaranteed availability and quality of electricity supply to all consumers at all times

Short-term reliability
The efficiency and effectiveness of system balancing in the Dutch electricity system

3.2 Requirements for the Dutch electricity system

The goals-tree in

Figure 16 shows the most important system requirements (i.e., goals) for the Dutch electricity system. A high operational performance of this system, the main goal for this system, is split up into two different types of performance: economical performance and technical performance. This is not to say that environmental and social goals are not important, or do not play a part in this system. The structure of the goals-tree merely serves to show what type of goals are important for the Dutch electricity system, so that the goals for the balancing market specifying the operational performance for can be put into perspective. The effects of large-scale penetration of distributed generation on the environmental performance of the system will not influence the functioning of the Dutch balancing market as much in the short term.

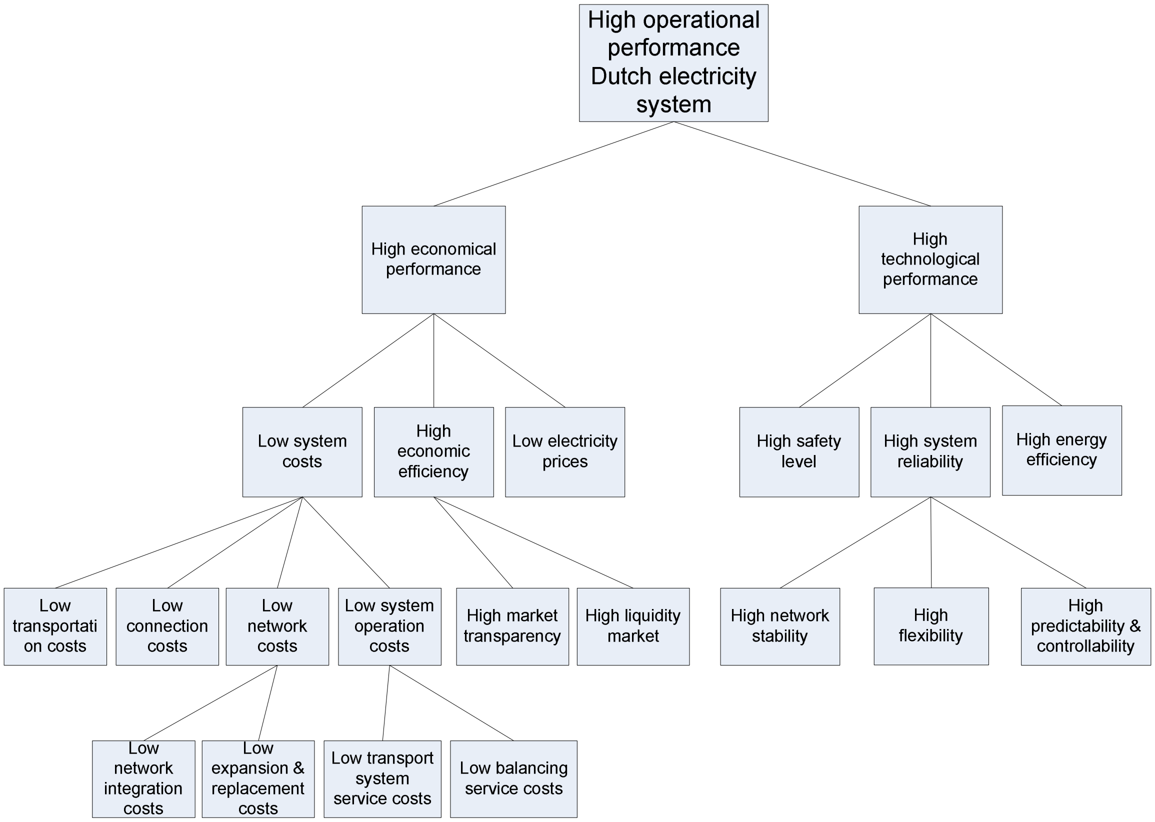

Figure 16: goals-tree for the Dutch electricity system

A high technological performance is reached by the realization of a high safety level of the system, high energy efficiency of the energy conversion processes, and high system reliability. Energy efficiency can be deemed an attribute of electricity generation units, power lines and other equipment, and therefore considered a technical goal. However, of interest to this research is the goal of high system reliability, which is divided here in a high network stability, high flexibility, and high predictability & controllability. System reliability is defined here as the guaranteed availability and quality of electricity supply to all consumers at all times. Under network stability is understood technical stability, power quality and redundancy of the network. High flexibility is reached when there is ample opportunity to reach system reliability, for instance by having enough reserve capacity and spare interconnection capacity. Finally, high predictability and controllability of electricity production and consumption is of importance for the ability to balance supply and demand, and is therefore an important requirement.

Looking at the goal of high economical performance, low system costs, high economic efficiency and low electricity prices are important sub goals. The Dutch government strives for low consumer prices, and low wholesale prices are important for the competitiveness of the Dutch electricity market. High economic efficiency is also advocated by government, because it will lead to lower costs and prices[15]. It can be pursued by increasing market transparency and liquidity (realized by a large number of market players), which will increase competitiveness.

System costs can be split up in transportation costs, connection costs, network costs, and system operation costs. These goals speak for themselves: transportation costs are the costs of transporting a certain volume of electricity, connection costs are the costs of making a grid connection for production or consumption, network costs are costs related to the physical infrastructure, and system operation costs are costs of operating the system. Network costs can be divided in network expansion and replacement costs, and the costs of integrating new technologies like distributed generation. This is of interest for the research, but most are the balancing service costs. System operation is mainly the task of the TSO TenneT, and consists of system services to safeguard safe and efficient electricity transport across all nets and to solve transport capacity restrictions (transport system services), and of system services to balance supply and demand on an national level (balancing services). With balancing service costs are meant all the costs made for operating the Dutch balancing market, which function it is to safeguard the system balance in an effective and cost efficient way.

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[15] In fact, this has been an important, if not the most important, reason to liberalize the electricity market, conform to the common belief that the market is more cost efficient than public provision.

3.3 Balancing market requirements

In this paragraph, the requirements for the Dutch balancing market design are considered. For this purpose, first a goals-tree for the balancing market is presented and described. This is put in subsection 3.3.1. Then, in 3.3.2, set of performance criteria for a Dutch balancing market is given and discussed. These performance criteria will be used to valuate operational performance of the balancing market in the scenario analysis in Chapter 4.

3.3.1 Goals for the Dutch balancing market design

As follows from the main research question, the main goal for the balancing market is a high operational performance. The operational performance of the balancing market depends on the effectiveness and efficiency with which the system balance is maintained, which is a short-term perspective. Furthermore, the most important sub-goals are concerned with the technical aspect of reliability and the economical aspects of market efficiency, costs and benefits. See the goals-tree in Figure 17.

For the goals-tree of the Dutch balancing market design, the operational performance is not divided in technical and economical performance such as in the goals-tree for the whole electricity system, but in a high operational performance for each of the three instruments the balancing market consists of: Programme Responsibility, the single-buyer market for Regulating and Reserve Power (RRP) and imbalance settlement. This division enables us to consider the instruments separately, which is useful for a detailed analysis of effects of DG penetration in the next chapter. It should be noted, though, that the goals included are technical and economical goals, which can be placed somewhere in the overarching goals-tree for the whole electricity system. As has been said in the last paragraph, balancing market goals fall primarily under ‘low balancing service costs’, ‘low network integration costs’, and ‘high system reliability’ and its underlying goals, while ‘high economic efficiency’ and ‘low electricity prices’ are relevant as well. This interrelation will come up again in paragraph 3.4.

First, a high operational performance of the Programme Responsibility instrument is strived for by increasing the accuracy of the E Programmes and decreasing its costs. A high accuracy of E Programmes can be achieved if demand and supply are predictable and controllable, if the intraday market is large enough to enable day-ahead balancing on this market by PRPs, and if PRPs have good possibilities for internal balancing. Low costs are both low costs for PRPs to formulate E Programmes conformable to the requirements of TenneT and low costs for TenneT to administer all the E Programmes for the purpose of maintaining the system balance and settling imbalances.

Secondly, a high operational performance of the single-buyer market for RRP can be achieved by high quality bids of RRP and by an optimal RRP margin. The goal of high quality bids consists of the sub goals of compliance with the bidding requirements of TenneT and a high number of bids, which will increase RRP market efficiency and system reliability. The RRP margin is the margin between the offered amount of RRP and the deployed amount of RRP[16]. The RRP margin should be 'optimal' in the way that it should be large enough to guarantee that system imbalances can be solved by the market for RRP, and that is should not so large that suppliers of RRP bear too high costs. After all, parties who have offered RRP which has not been deployed do not receive any compensation at all, even though they have missed revenues for not operating that capacity. Thus, the mentioned costs are 'opportunity costs': missed revenues.

Third, a high operational performance of the imbalance settlement process is achieved by a just distribution of imbalance costs, optimal imbalance prices and timely imbalance settlement. A just distribution of imbalance costs is reached when the process of Allocation effectively allocates the system imbalance to the PRPs responsible for it, which also leads to lower reconciliation costs. Also, a just settlement of the imbalance costs contributes to this goal. Next, the goal of optimal imbalance prices holds that these prices should be high enough to create an effective financial incentive for the PRPs to maintain their balance, but should not be so high that PRPs are faced with high imbalance costs beyond proportions. Then, timely settlement can be realized by the sub goals of high transparency and low costs of delays in settlement. Transparency can be aimed for by keeping the rules and the process as simple as possible, low costs of the unavoidable time delay in settlement by settling as quickly as possible.

Finally, a balancing market level aspect that is merely implicitly reflected in the goals-tree is the inclusion of the balancing costs in the final consumer electricity prices. If low electricity prices are to develop, costs for the operation of the various tasks and processes within the Dutch balancing market should be low, which can be realized through high efficiency of the processes.

While the imbalance costs are allocated to the PRPs according to their imbalances, there are also central costs made by TenneT for administration and operation of the bidding procedure for the market for RRP, the checking of E Programmes, and the imbalance settlement process. These costs are distributed evenly among parties, because these are institutional costs for the benefit of all. They should be as low as possible, which again can be achieved by simple procedures, although that should not be at the expense of balancing market efficiency or effectiveness.

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[16] The RRP margin should not be confused with the regulating space, which is the available production capacity minus the capacity utilized for transactions and minus the own consumption, and therefore is an indicator of available RRP. However, the amount of offered RRP is smaller than the available free production capacity. See paragraph 2.5.

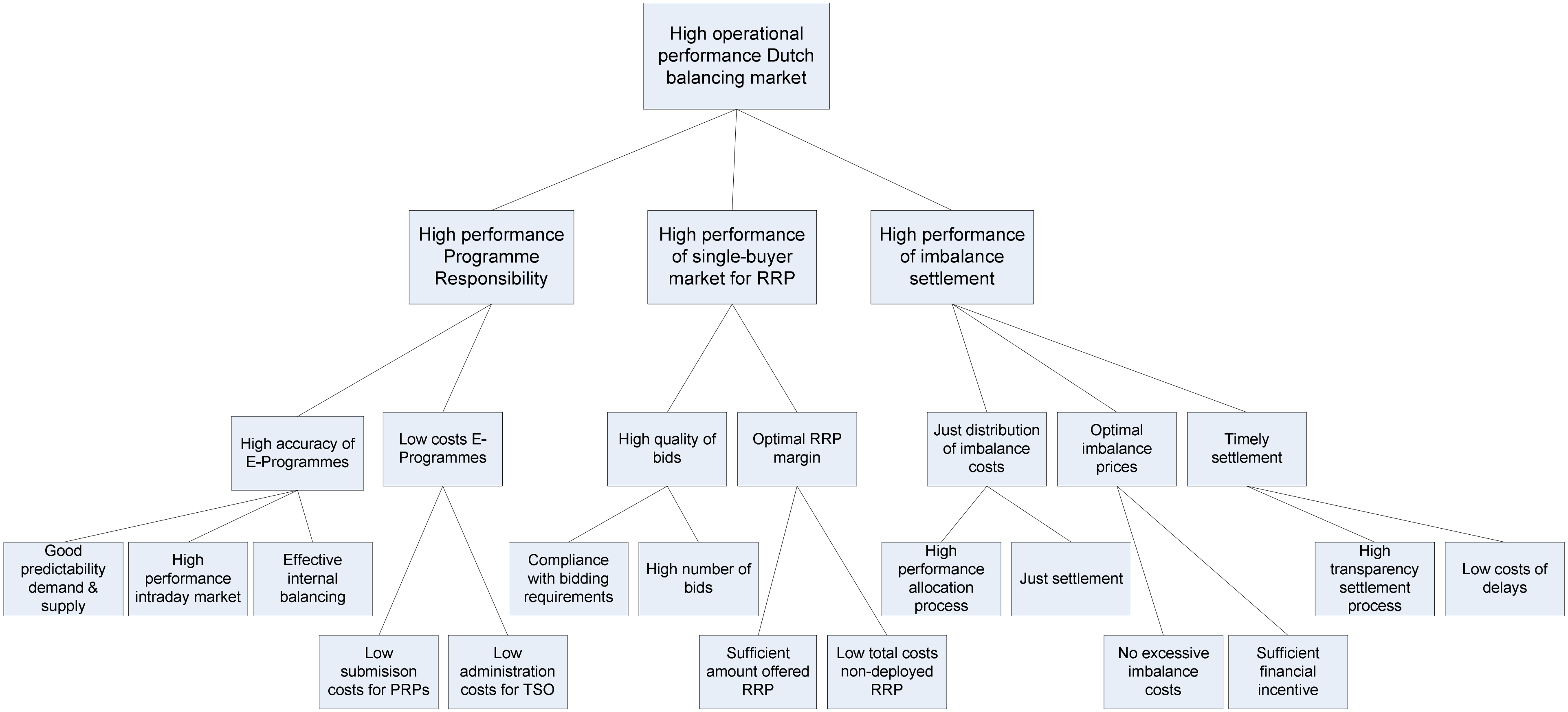

Figure 17: Goals-tree for the Dutch balancing market design

3.3.2 Set of performance criteria for the analysis

The goals reflected in the goals-tree for the Dutch balancing market above can be transferred into a list of requirements for the Dutch balancing market. This list of requirements represents the requirements that a Dutch balancing market design should meet in order to have a high operational performance, and can be found in appendix C.

The list of requirements is impractical for the valuation of the different DG scenarios in the next chapter. The system to be analyzed is too complicated to allow an exact valuation of those detailed requirements. For the same reason, quantification of the effects of different DG scenarios on the operational performance of the Dutch balancing market design is not feasible in this research either. What the analysis does allow is a qualitative valuation of the general effects. The valuation of some basic performance criteria, based on the requirements above, will therefore serve as the basis for valuation in the analysis.

The list of requirements is reduced to a short and general set of performance criteria; see the effects table in Table 3. This set is organized in criteria for the three different balancing market instruments. The additional metering requirements included in the list of requirements are considered under imbalance settlement, and the additional technical requirements under the market for Regulating and Reserve Power (see appendix C). First, the performance criteria will be explained. Then, the relative weights of these criteria for the operational performance of the balancing market are discussed.

The effect of DG penetration on the predictability of production and consumption concerns the relative influence of this penetration on the overall predictability of electricity production and consumption in the Dutch electricity system. The more predictable production and consumption are, the better generators, suppliers and PRPs can balance supply and demand a-priori. Furthermore, a good predictability leads to a higher accuracy of E Programmes. However, this accuracy is also determined by the possibility to shift consumption and generation, and to balance supply and demand internally after closure of the day ahead market. The costs of the Programme Responsibility instrument are determined by the number of altered E Programmes the PRPs submit. These include the extra costs TenneT has to make to maintain the system balance, which becomes harder when the initial E Programmes become more inaccurate.

For the single-buyer market for Regulating and Reserve Power, a first performance criterion is the network stability, which represents all the technical effects of the DG penetration on the functioning of the electrical infrastructure: the effect on available transport capacity, power quality (frequency and voltage stability, current levels, reactive power), and transient stability. This criterion also influences both the amount of RRP offered in the single-buyer market and the amount of RRP deployed, because it has effect on the possibilities of RRP provision and on the number and size of system imbalances. The amount of RRP offered, a second criterion, is also influenced by the availability of central power plants (which is determined by the match between system supply and demand over time) and the possibilities for the use of DG as RRP. An obvious third performance criterion is the amount of RRP deployed, which depends on the number and size of system imbalances, and also on the transport restrictions. The administrative costs of the RRP market will be high when the number of RRP bids is high.

The effects of domestic DG penetration on imbalance settlement are valuated with three performance criteria: the accuracy of the allocation, the imbalance costs, and the costs of allocation. The accuracy of allocation depends on the effectiveness of the allocation process, which can either be done with profiles (as is currently done) or by means of smart metering (see appendix C). This distinction is highly important for the performance of the imbalance settlement, and is discussed in sub paragraph 4.2.4. The imbalance costs depend on the amount of RRP (and emergency power) deployed, and on the liquidity of the RRP market. The costs of allocation are heavily influenced by the choice for an allocation method.

As can be seen in Table 3, the valuation of all the different performance criteria adds up to a score for the total effect of DG penetration on the operational performance of the Dutch balancing market. The effect on each criterion will be assigned a value from -10 to 10 depending on the magnitude of the effect and the direction, i.e. whether the effect is positive or negative. Of course, lower costs and a higher reliability level are positive. The valuation will be done for each of the four scenarios, and within each scenario for the two extreme allocation methods: allocation by metering and allocation by profiling (see Chapter 4).

It should be reminded that the *effects* of a large-scale introduction of DG at Dutch households are valuated. This means the relative change in value of the different performance criteria from the current situation without DG to a situation with DG.

Finally, the different performance criteria should be assigned different weights, because their contribution to the operational performance of the Dutch balancing market design is different. The criteria can be divided into reliability and economic criteria, as the ‘intermediate’ criteria “short-term economic performance” and “short-term reliability” indicate. The short-term economic performance consists of the costs of Programme Responsibility, the costs of the RRP market, the imbalance costs and the costs of allocation. Although the choice for weights are a bit trivial, it is clear that short-term reliability is more important than short-term economic performance, and therefore has a higher aggregate weight.

The individual performance criteria are given a weight on a 1 to 5 scale. A ‘1’ is assigned to the least important criteria and a ‘5’ to the most important ones. The accuracy of E Programmes, the network stability and the RRP offered are deemed most important. Costs are generally found least important, but imbalance costs are borne by the market players and affect market efficiency and the openness of the market, which is why this criterion is weighted higher.

Of course, the choice of weights influences the total effects of DG penetration calculated in the analysis, as do the values given to the different performance criteria. This should be remembered when considering the outcomes of the analysis, i.e. the aggregate effect of DG penetration scenarios on the operational performance of the Dutch balancing market design.

Performance criteria Allocation option	*weight*	**Scenario A**		**Scenario B**		**Scenario C**		**Scenario D**	
		profiling	metering	profiling	metering	profiling	metering	profiling	metering
Programme Responsibility effects									
Predictability production & consumption	*3*								
Accuracy E Programmes	*5*								
Costs of Programme Responsibility	*1*								
Single-buyer market for RRP effects									
Network stability	*5*								
RRP offered	*5*								
RRP deployed	*4*								
Costs of single-buyer market for RRP	*1*								
Imbalance settlement effects									
Accuracy allocation	*3*								
Imbalance costs	*3*								
Costs of allocation	*1*								
Effects Dutch balancing market									
Short-term economic performance	*6*								
Short-term reliability	*25*								
Operational performance balancing market design	*31*								

Table 3: Effect table for the valuation of balancing market performance criteria in different scenarios

The chosen effect valuation structure is arguable. First and foremost, it must be kept in mind that the used valuation method in the form of a weighted effects table is a very rough way of analyzing the effects of DG penetration on the operational performance of the Dutch balancing market design. A more detailed and quantitative valuation is deemed unfeasible here. However, this qualitative valuation will suffice for the answering the main research question of this research: Which balancing market design will have a high operational performance for a large-scale penetration of distributed generation at households in the Dutch electricity system? In general, the more negative the effects, the more changes in the current balancing market design are needed, and the more rigorous the nature of theses changes should be. If all effects would be positive, the current balancing market design could very well be the best one.

Furthermore, the chosen weights are based on information about the Dutch balancing market, but have not been validated by experts due to a lack of time. Besides, there are not that many experts with a good overview. Moreover, the choice of weights is a major simplification of the relative importance of balancing market aspects, and therefore a bit subjective.

A final remark regarding the effect valuation structure concerns the use of a -10 to 10 scale for the valuation of the effects. A smaller scale could have been chosen, but to the opinion of the author the possible differences in effects of different size for the four DG scenarios favour the use of a larger scale.

3.4 Definition of the system boundaries for the analysis

The analysis in the next chapter comprises the investigation of the effects of large-scale domestic DG penetration on the operational performance of the Dutch balancing market design. The effects will be valuated by means of the performance criteria listed above. In this paragraph, the system boundaries will be drawn by describing the relevant system factors and their relationships in a causal diagram. In addition, this causal diagram provides an additional handle for the analysis of the balancing market performance in a decentralized situation. Before the definition of the system boundaries, some system assumptions are made. By all this, the system to be analyzed, i.e. the Dutch balancing market design in several DG scenarios, is defined.

System assumptions
The following system assumptions are used. They are explained below.

- The system environment outside the system boundaries remains the same.
- The distribution of the costs and benefits of DG is considered to be settled justly.
- Household consumers with a DG unit will remain connected to the grid
- Every household will have a smart meter, with which meter readings can be read remotely at least every fifteen minutes, consumers can be remotely connected and (partially) disconnected consumers, and price and production/consumption information can be exchanged in both directions in real-time.

The system boundaries define the system to be analyzed. Outside these boundaries lies the system environment. It is assumed that the system environment remains the same. Thereby, also the current production capacity, transport capacity and electricity demand within the Dutch electricity system are assumed to remain (approximately) the same.

Second, it is assumed that the costs and benefits of DG are distributed justly among the stakeholders, and that a profitable market for DG units has arisen. It is assumed that this was a required precondition in order for the large-scale domestic DG penetration to arise. It must be remarked that this distribution does not include the still unknown technical effects of the large-scale integration of DG.

Household consumers with a DG unit are assumed to remain connected to the distribution grid, even though it might be possible for them to disconnect and generate precisely the amount of electricity they need for themselves. It is not realistic to assume that consumers want to be disconnected, because, considering the DG technologies included, PV-cells are intermittent and micro-CHP units bring along restrictions related to the heat demand.

Finally, it is assumed that every household will have a smart meter, with which meter readings can be read from distance every fifteen minutes, consumers can be connected and (partially) disconnected from distance, and price and production and consumption information can be exchanged in both directions. This assumption follows the aim of the Dutch Ministry of Economic Affairs (Energie Nederland 2007), see appendix C.

System boundaries

The system boundaries of the system to be analyzed will be defined here. It consists of the Dutch balancing market design in a decentralized situation and the effects of the DG penetration on this design. The system boundaries have already been set by means of the given requirements and performance criteria for the Dutch balancing market design, but will be defined here in terms of system factors and relationships. This is done by means of a causal diagram, which is presented in Figure 18. Shown are the expected interrelations without consideration of the analysis results.

A causal diagram consists of factors, arrows, and positive/negative signs. The factors are presented in ovals. The arrows and signs indicate the causal relationships between factors in the following way: If an arrow with a positive sign points from factor A to factor B, factor B will increase is factor A increases, and decrease if factor A decreases. If an arrow with a negative sign points from factor A to factor B, factor B will decrease if factor A increases, and vice versa. A question mark indicates that the causal relationship between the respective factors is uncertain or unknown.

'Operational performance balancing market' is the main output variable of the system, which the analysis aims to determine for different DG scenarios. As has been underlined in paragraph 3.3, this operational performance only incorporates the short-term economic performance and the short-term reliability of the Dutch balancing market design. Therefore it merely contributes to overall system reliability, a higher system variable. Other system variables included are the height of the electricity price and the network integration costs for the DG penetration. Higher integration costs will lead to higher electricity prices (and tariffs).

Two external variables are the penetration level of PV cells and the penetration level of micro-CHP. These factors originate from the DG scenarios in Chapter 4 and form the starting point of the analysis. The penetration level of PV or micro-CHP will have effects on the network integration costs, the power quality, operational flexibility of the electricity system, the predictability and controllability of production, and on the accuracy of profiles. Profiles will be less accurate in the prediction and allocation of production and consumption in a distribution network if more consumers have installed a DG unit. This is related to the limited predictability and controllability of PV cells and micro-CHP. Still, micro-CHP, and especially electricity-led CHP, is relatively predictable and controllable.

The factor 'system imbalance volume' represents the amount of system imbalance that occurs in the system, and reflects the ability with which PRPs are able to plan and keep to the E Programmes. It therefore is a determinant of system reliability. The amount is increased if production and consumption are less predictable and controllable, and if the network stability (affected by the DG technology) decreases. More system imbalance means that more RRP has to be deployed by means of the single-buyer market for Regulating and Reserve Power.

'System balancing costs' is the main economic factor in the system. It negatively influences the operational performance of the balancing market design, and also increases the height of the electricity prices.

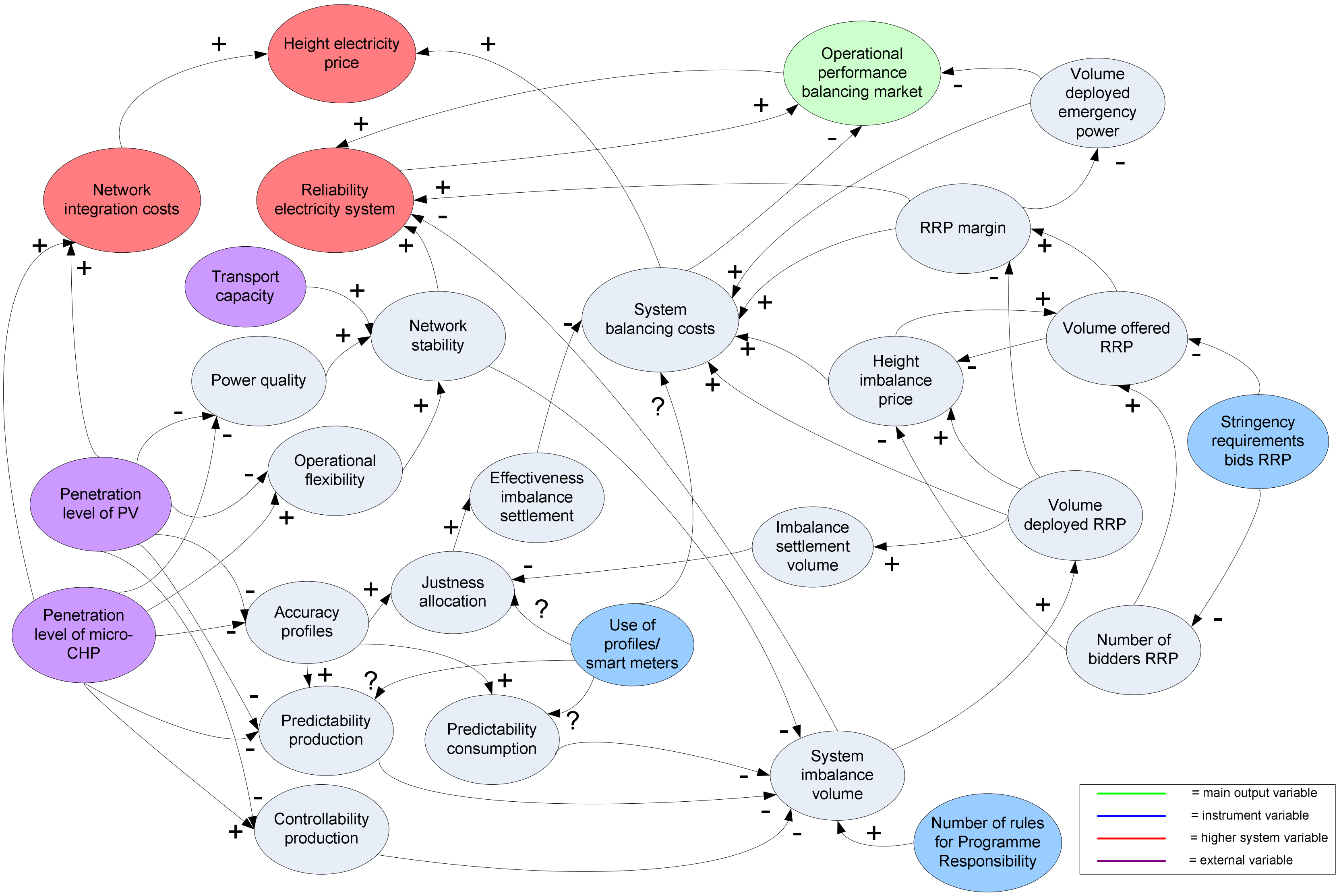

Figure 18: Causal diagram of the system to be analyzed, the Dutch balancing market design in different DG scenarios

The volume of the deployed RRP depends on the size of the system imbalance, and influences the imbalance costs for the PRPs, producers and consumers. The higher this volume, the higher the system balancing costs, which includes the imbalance costs. These higher imbalance costs are also indirectly caused by the higher volume that has to be settled with the imbalance settlement process. The justness of allocation will then be reduced. This in turn decreases the effectiveness of imbalance settlement, because the wrong distribution of imbalance costs is not settled in the reconciliation process.

Further, a higher volume of deployed RRP leads to a higher imbalance price by means of the bid ladder mechanism. This, in turn, will lead to more RRP being offered by PRPs who want to receive the higher dispatch price. This will however decrease the imbalance price again. The volume of deployed RRP and the volume of offered RRP together form the RRP margin, which is defined as the difference between the two. As stated by one of the requirements, this RRP margin should be optimal, because a higher margin leads to higher costs, but also to a higher system reliability level. Besides, the high costs of deploying emergency power are avoided.

Three instrument variables (variables which can be directly influenced by the relevant actors) are included in the causal diagram. The first is called 'Number of rules for Programme Responsibility', and is concerned with the requirements that should be met by PRPs for the formation and submission of E Programmes. It is argued that a higher number of rules for Programme Responsibility results in a higher system imbalance volume, because it will be harder to form correct E Programmes, and also to send in altered E Programmes. The second instrument variable is the stringency of the requirements for bids of RRP: the stricter the requirements, the lower the volume or RRP offered. Also, the number of bidders will decrease by a higher stringency, which will further decrease the volume of offered RRP, and is expected to increase the imbalance price. This is because the bidders will know that their bids have a higher chance to be deployed.

The third instrument variable is the use of profiles and smart meters. Although smart metering can replace the use of consumption profiles for the allocation of consumption, the two instruments are not mutually exclusive: using profiles can still have value when smart metering has become common practice. However, whether effects of the use of profiles and smart metering on the predictability of consumption and production, on the justness of the allocation and on system balancing costs will be generally positive or negative, is unclear. What will be the effects of DG penetration on the usefulness of different smart metering and profiling options forms an important part of the analysis.

The causal diagram presented and discussed above shows that the interrelations between the system variables are diverse and many, and can be expected to lead to dynamic system behaviour that is difficult to predict. The large-scale introduction of domestic DG and the roll-out of smart meters are the system changes of interest in the coming analysis. It is clear that the causal diagram is a strong simplification of the system. But because of this, it is useful as an illustration of the system boundaries, and as a handle for the analysis of the effects of domestic DG penetration on the operational performance of the Dutch balancing market design.

4. Analysis of the effects of DG penetration on balancing market performance

Before the definition of distributed generation used in the research is given and rationalized, it should first be underlined that the term ‘distributed generation’ not only has been given many definitions in both literature and in practice, there are also quite a few synonyms for distributed generation. Dispersed generation, embedded generation and decentralized generation are regularly used ones. Here, only the mostly used term ‘distributed generation’ and its abbreviation ‘DG’ will be used.

The term ‘distributed generation’ has been defined differently by different authors. It has been called “power generation co-located with demand” (Zerriffi, Dowlatabadi and Farrell 2005 p.63), “a generic term for small-scale electricity production technologies that can be located near the point of end-use” (Morgan, Apt and Lave 2005 p.42), and “small-scale power generation plants, connected to the distribution network or at the customer side of the network” (Ten Donkelaar 2004, p. 323).

As specified in the research introduction, an adapted form of the definition of Ten Donkelaar (2004) will be used for distributed generation: ‘small-scale power generation at households, coupled to the low-voltage grid’. This definition is used because the research is restricted to DG at households, which are usually connected to the low-voltage distribution network.

Different distributed generation technologies exist: PV cells, micro-CHP units, wind turbines, hydropower, geothermal power, and small-scale steam turbines. For the purpose of the research, attention will be drawn towards photovoltaics (PV) and micro-Combined Heat and Power (CHP). These two DG technologies have the largest potential for large-scale penetration at households, as is widely recognized by experts and researchers (e.g., Choudhury and Andrews 2002).

The focus lies here on distributed generation at households, sometimes defined as 'micro generation'. However, to avoid confusion with the concept of micro-CHP (also referred to as 'micro-cogeneration'), the terms used in this research are 'distributed generation at households' or 'domestic DG'. The large-scale introduction possibility, uncertain performance and production/consumption patterns, and different metering and profiling options make DG at households a very interesting subset of distributed generation.

In order to analyze the effects of large-scale DG penetration at Dutch households on the operational performance of the Dutch balancing market, the composed DG scenarios will reflect different directions in which domestic DG could develop in the Netherlands. Thus, the composed scenarios are limited in the following ways:

- Only photovoltaic cells (PV cells) and micro-CHP units are included, because they have the highest potential for households.
- Only DG installed at households is considered, not DG at supplier or grid operator sites, because that has different features and behaviour and is installed for other reasons (grid support, peak shaving and medium-scale electricity supply, instead of small-scale consumption).

In this chapter, first the definitions used are given in paragraph 4.1. Then, in paragraph 4.2, the used distributed generation scenarios are introduced (4.2.1), the plausibility of the scenarios is described (4.2.2), general changes in the system due to the domestic DG penetration are indicated (4.2.3), and the two allocation methods considered are introduced (4.2.4). Subsequently, the qualitative scenario analysis is described in paragraph 4.3. Finally, paragraph 4.4 gives the analysis results.

4.1 Definitions

The following terms are generally used in various sources, but 'official' definitions have not been found. The definitions below are tuned to the scope of the analysis.

Distributed generation (DG) unit
The distributed generation installation, being either a micro-CHP unit or a PV cell

Photovoltaic (PV) cell
A DG unit that converts photons in sunlight directly into electricity

Micro-Combined Heat and Power (CHP) unit
A DG unit that converts the chemical energy in natural gas into electricity and heat

Consumer-generator
A household consumer who has a DG unit installed in his house

Smart meter
An electronic meter with which meter readings can be read remotely at least every fifteen minutes, with which consumers can be remotely connected and (partially) disconnected, and price and production/consumption information can be exchanged in both directions in real-time[17]

Profile
Either a consumption profile, a generation profile, or a net profile, used to account for the consumption and/or production of the consumer-generator

Net profile
A profile that reflects the net production/consumption pattern of a group of consumer-generators throughout the year

Export
The injection of electricity into the distribution grid by consumer-generators

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[17] It is assumed that smart meters will have the mentioned features (see paragraph 3.5). Thus, the given definition is by no means a general definition of a smart meter.

Import
The withdrawal of electricity from the distribution network by consumer-generators

Bi-directional meter
A meter that registers the net production/consumption[18]

Import/export meter
A meter that registers the imported or exported electricity

Generation meter
A meter that registers the production of a DG unit

Net exchange
The net imported/exported electricity volume

Allocation by profiling
The use of profiles for the allocation of electricity volumes to profile customers, including the generation of consumer-generators

Allocation by metering
The use of smart metering for the allocation of electricity volumes to the former profile customers, including the consumer-generators, consisting of the transmission of meter readings for each PTU and the communication of real-time prices

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[18] This meter runs backwards if electricity is exported. This is generally referred to as 'net metering'.

4.2 Distributed generation scenarios

4.2.1 Introduction scenarios

Although the creation of realistic and useful distributed generation scenarios could take the form of a small study on its own, for the purpose of this research the use of some simple scenarios suffice. The used scenarios consider some distinct directions in which domestic DG in the Netherlands could evolve, so that the possible effects on the operational performance of the balancing market are analyzed in a more complete manner. The scenarios are presented below.

For all scenarios, it is assumed that the DG units emerged are distributed evenly among distribution networks in the Netherlands. Excess electricity is fed back into the distribution grid, while excess heat is either stored in a heat buffer or released into the environment. Furthermore, it is assumed that, considering the use of profiles and smart meters, all households have a smart meter, which are able to transmit the meter reading(s) every 15 minutes (see paragraph 3.4). Finally, it is assumed that two million DG units of 1 kilowatt (kW) have been installed at as many households in each scenario, which is approximately 30 % of all Dutch households. With '1 kW' is meant '1 kW' electrical power, officially indicated by 'kW_{el}'. When thermal energy is meant, the unit 'kW_{th}' will be used. The total production capacity of the DG is thus 2,000 MW.

Scenario A: PV cells
Two million households have a 1 kW PV cell. This means 30% of all Dutch household consumers has a PV cell. The PV cells are operated by the household consumers themselves, and do not produce any usable product heat.

Scenario B: Heat-led micro-CHP
Two million households have a 1 kW micro-CHP unit, using a heat-led operating strategy. This means that 30 % of all Dutch household consumers has a micro-CHP unit, which is primary operated to cover the heat demand and which generates electricity as a secondary product.

Scenario C: Electricity-led micro-CHP operated by consumer
Two million households have a 1 kW micro-CHP unit, operated by the consumer, using an electricity-led operating strategy. This means that 30 % of all Dutch household consumers has a micro-CHP unit, which is primary operated to cover the electricity demand and which produces heat as a secondary product.

Scenario D: Electricity-led micro-CHP operated by supplier
Two million households have a 1 kW micro-CHP unit, operated by the supplier, using an electricity-led operating strategy. This means that 30 % of all Dutch household consumers has a micro-CHP unit, which the supplier operates to primarily generate electricity for both the local household demand and regional/national system demand, and which produces heat as a secondary product.

4.2.2 Plausibility of the scenarios

The construction of the scenarios has been rather straightforward: they follow directly from distributed generation technologies, systems and configurations considered in literature and in real life. Photovoltaics (PV) and micro-Combined Heat and Power (CHP) are considered the two DG technologies with the highest potential for residential application (see e.g. Choudhury and Andrews 2002). Furthermore, heat-led and electricity-led control are two well-known operating strategies for micro-CHP with different implications for electricity production and consumption (see e.g. Hawkes and Leach 2005). Finally, control of the micro-CHP unit by the supplier is also considered, which could have very different implications for DG operation as well. The plausibility of the four scenarios is discussed in detail below.

Scenario A

Generally, solar power is thought to have the lowest potential of penetrating the electricity market. For an important part, this has to do with the high costs of the technology: investment costs are with 5,000-7,000 €/kW_{el} the most expensive DG technology (Pepermans et al. 2005). If this leads to a profitable investment, depends on the lifetime of PV cell, the solar radiation level, the efficiency of energy conversion, the consumer electricity price and the feed-in tariff. The development of PV cells depends for an important part on regulation: Germany, which its high feed-in tariff for solar power, had in 2006 1,930 MW of PV, against 46 MW in the Netherlands (Ummels 2006).

Next to cost regulation, cost reductions could help to introduce PV on a large scale. According to Gross, Leach and Bauen (2002), "PV appears to offer tremendous potential for long-term cost reduction through market growth and innovation over the next 10-20 years" (p.121). Technological developments could increase the electrical efficiency of the PV cell.

In de Noord, Beurskens and de Vries (2003) the development of PV in the Netherlands is assumed to lead to 1.2 GW in 2020, and 5.8 GW in 2030. Considering the capacity size of single cells, the assumed 1 kW PV cell is standard: the typical system dimensions are between 1 and 3 kW_p (Yogi Goswami 2003, p. 243).

Viewing all this, two million PV cells of 1 kW at Dutch households is a plausible scenario. When comparing this DG technology with micro-CHP, photovoltaics are more expensive but renewable, and therefore more likely to be introduced on the longer term.

Scenario B

The first thing to mention about the probability of micro-CHP penetration in the Netherlands is its apparent competition with conventional (condensing) boilers and district heating.

A precondition for micro-CHP penetration to arise in the Netherlands is that it should have added value compared to the current High Efficiency boiler (in Dutch: 'HR-ketel'), which already delivers a high energy efficiency for heat supply in households. As will be shown, the electricity generated by micro-CHP provides that advantage.

Also, micro-CHP should have added value in comparison with regional CHP, which generates electricity on a medium-voltage level, and generates heat for supply through district heating systems. According to Matthes and Cames (2000), micro-CHP is a fall-back option for when centralized CHP is not available, because the latter may be ecologically superior (Pehnt et al. 2006, p. 37). However, the heat pipeline infrastructure is expensive, and for consumers with relatively low heat demand heat distribution losses are significant.

Next, the probability of a penetration of two million 1 kW_{el} micro-CHP units at as many Dutch households can be considered.

According to Choudhury and Andrews (2002), "some authoritative estimates indicate a potential market in Europe for micro-CHP alone of 1 million units per year with an ultimate installed capacity of a similar scale to that of the present nuclear industry" (p.1). Moreover, scenarios with more than two million micro-CHP units in the Netherlands are considered in De Jong et al. (2006). Apart from that, Schneider (2006) states that the size of 1 kW_{el} is well-suited to single-family houses (Pehnt et al. 2006, p. 68). Apparently, a scenario in which two million Dutch households have a 1 kW micro-CHP unit is not unlikely.

When compared to photovoltaics, micro-CHP is already cost-competitive and can therefore be introduced in a shorter time frame, but its scope is more limited than PV. After all, natural gas is the favourable fuel for the production of electricity and heat in micro-CHP units, and when this fossil fuel runs out, micro-CHP can become prohibitively expensive.

The heat-led operating strategy is the strategy used by the small base of currently operating micro-CHP units. It is the most 'natural' operating strategy, because it increases the contribution of product heat to heat demand coverage compared to the contribution of the conventional boiler, so that the high energy efficiency advantage of micro-CHP is maximally utilized. Besides, a high amount of electricity is produced for own consumption and export, which cuts on the total energy costs for the consumer-generator.

Scenario C

The analysis of scenario C is partly based on that of scenario B, because both consider micro-CHP penetration at two million Dutch households. In fact, these two scenarios only differ in operating strategy, which will be possible to change: it will probably be possible for consumer-generators (or suppliers) to set the micro-CHP system in different modes, where a heat-led mode and an electricity-led mode are two obvious ones. This possibility has already been successfully used in a European Virtual Power Plant project, see Vaillant, Plug Power Holland and others (2005; p. 14). Consumers could switch between modes as a reaction to a changing export tariff, which is set by the electricity supplier.

Viewing the possibility of switching between operational strategies, this scenario is as probable as scenario B, in which heat-led micro-CHP penetration was considered.

Moreover, according to Peacock and Newborough (2006), the electricity-led operating strategy will gain in potential and attractiveness when the penetration level of micro-CHP increases: "At low penetrations, micro-CHP operation that provides ancillary benefits to the electricity industry is less likely and the heat-led control strategy would appear to be the most applicable. As both the micro-CHP and the embedded generation approach develop towards mass market, the implementation of alternative control strategies … will be desirable." (p. 1103). This effect can be explained by the increased operational flexibility thanks to technological development, and the increased opportunities for active participation in the electricity market. This participation could even be required for base-load power provision and/or the provision of balancing services in an electricity generation market that relies for a larger part on DG. Electricity-led micro-CHP operation is required for all this.

Scenario D

Scenario D assumes control of the micro-CHP units by electricity suppliers, but even in this case the control is not unconditional. Still, the supplier will be subject to constraints concerning heat provision to the consumer and limits to the waste of heat. The provision of electricity to the households is safeguarded: either the micro-CHP unit or the grid will deliver this.

When a supplier runs a micro-CHP unit for electricity provision to consumers, the ‘host’ consumer-generator will use a portion of the electricity generated as large as his momentary electricity demand. The electrical capacity of the unit, 1 kW, is always higher than the electricity demand of the average household (which has a maximum of 800 W[19]). Because on average 600 W of the available capacity is not needed for the own power consumption[20], and the supplier will mostly dispatch the full capacity, on average 600 W of power output can be injected into the grid by the supplier. This comes down to a total available micro-CHP capacity of 1.2 GW, the two million households with the installed micro-CHP systems already provided.
A problem can be the heat dumping that would occur if no attention were paid to the heat production of the micro-CHP units. But the supplier is perfectly capable of calculating the operational possibilities without causing any, or more than a certain amount of, heat dumping. The good predictability of heat and electricity demand enable this (see the analysis in paragraph 4.3).

In short, the electricity-led micro-CHP units controlled by electricity suppliers will allow these suppliers to dispatch additional production capacity for electricity trade in the day ahead market, the intraday market and/or the single-buyer market for Regulating and Reserve Power, without the lack of control present in scenario B and C. Thus, this scenario can be concluded to be plausible enough for consideration.

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[19] Taking an average household consumption of 3,397 kWh (see appendix A) and the consumption profile E1A from Ecofys (2001), the maximum momentary power demand is 791 W.

[20] The average power output for an average household is 388 W, based again on the consumption profile of Ecofys (2001) and an average household consumption of 3,397 kWh.

4.2.3 General changes due to domestic DG penetration

The nature and magnitude of the effects of domestic DG penetration are influenced by the specific DG development, as reflected by the scenarios, but also by the system environment: the exact technological features of the future Dutch electricity system, the economic status (e.g., height of the fuel prices), the institutional structure and the future level of reliability without DG. It is assumed that the system environment does not change from the current situation, so that only the effects of the DG penetration are considered (see paragraph 3.4).

The following general changes can be discerned within the system boundaries, for all of the DG scenarios. These changes are logical and have already been considered for the set-up of requirements and performance criteria, but are presented to underline the inherent changes domestic DG penetration brings about.

- *The changing role of household consumers with a DG unit*: The household consumers will become both a generator and a consumer, hence the use of the term: 'consumer-generator'. At each moment in time, a DG owner either is a net producer or a net consumer. Which role is larger can change frequently, also within a period of fifteen minutes.
- *Bi-directional flows and the larger role of DSOs*: As an effect of the introduction of DG, the distribution network will suddenly face bi-directional flows: electricity from central generation units to the household consumers, and electricity from distributed generation units to other consumers in the same or other distribution grids. The consequence is that the DSO no longer can suffice with passive network management, but has to start with active network management, in order to maintain the balance and prevent transport restrictions on the distribution network level.
- *The existence of a smart meter in every household*: As stated, the smart meters are able to transmit the meter reading every 15 minutes. Also the Metering Responsible Parties will change into Metering Data Companies (see appendix D). The existence and use of smart meters will change the Allocation process. To what extent smart metering and profiles are used is part of the analysis.
- *Change in consumption and production patterns*: Household consumers with a DG unit will have a different consumption pattern, because the use of the DG unit changes the availability and/or affordability of electricity. Also, a generation pattern will arise for the consumer-generators, resulting in a certain net exchange pattern.
- *Provisions for the feed-back of electricity* into the grid by household DG owners: This includes tariffs, technical standards, and regulations for the fair distribution of costs, benefits, roles and responsibilities. It is assumed that DG-related costs and benefits are distributed justly (see paragraph 3.4).

In appendix E, some general characteristics of distributed generation are given, and the technologies of PV cells and micro-CHP are described. This provides background information for the analysis in the next paragraph.

4.2.4 Allocation by profiling versus allocation by metering

The four composed DG scenarios each provide a different situation for a possible future state of a decentralized Dutch electricity system. Other factors are kept the same, as the assumptions of paragraph 3.4 show: the system environment is similar to the current one, the distribution of costs and benefits of DG introduction is already settled justly, and every household has a smart meter, with which meter readings can be read remotely at least every fifteen minutes, consumers can be remotely connected and (partially) disconnected, and price and production/consumption information can be exchanged in both directions in real-time.

Although the smart meters installed are able to perform the above functions, it has been left open whether or not these functions are used: the use of smart metering and profiling is part of this analysis (see paragraph 3.4). Basically, there are two different ways to allocate the remaining consumption among profile customers: by means of the profile methodology, or by means of smart metering. Currently, the profile methodology is used (see paragraph 2.4). Using smart meters for allocation will transfer the profile consumers into metered consumers.

For this analysis, two extremes in a continuum of allocation methods are considered in each scenario: allocation purely on the basis of profiles, and allocation purely on the basis of smart metering.

The use of profiles for allocation will be called *allocation by profiling* or 'profiling allocation method'. Meter readings will be collected with the smart meters, not continuously but at least monthly. Thus, the reconciliation period can be smaller than the current yearly meter reading. Finally, the use of multiple registers and fixed tariff periods could lead to some consumption and generation shifts in this allocation method without the use of smart metering.

The use of smart meters for allocation, in which meter readings are transmitted each PTU and real-time prices are communicated, will be called *allocation by metering* or 'metering allocation method'. This will result in perfect allocation, and provide full opportunities for generation and demand shifting, and the use of DG as RRP.

This distinction is made, because the two different allocation methods are expected to have different effects on the operational performance of the balancing market design: the costs of data collection and processing for allocation by metering will be high, but the added value of complete allocation, removing the need for reconciliation and perfectly allocating all imbalance costs, could be worth more.

In appendix D, a process model for both allocation methods is presented, along with a short explanation of the structure of processes and actor relationships. The most important insights are that profiles could still be useful for prediction even when the metering allocation method is chosen, that so-called 'aggregators' will execute the tasks of clustering DG-units into Virtual Power Plants for participation in the day-ahead market, intraday market or RRP market, and that a Metering Data Company will collect and process metering data, although the supplier is responsible for the management of the data.

Furthermore, there are also different types of profiles and smart metering systems possible. These are described in appendix D, where it also argued that there exist some logical combinations of profiles and metering systems, here called 'metering-profiling options'. These are:

a. *Bi-directional metering* and *net profiles*
b. *Import-export metering* and *import and export profiles*
c. *Gross generation metering* and *consumption and production profiles* (or possibly import and export profiles)
d. *Net generation metering* and *consumption and production profiles* (or possibly net profiles)

The four metering-profiling options are shown in Figure 19. These will not be considered one by one for each scenario, as with the two allocation methods. It will however be discussed which metering-profiling option should be chosen for each DG scenario, because this choice can affect the operational performance of the Dutch balancing market, albeit in a smaller way than the choice for an allocation method.

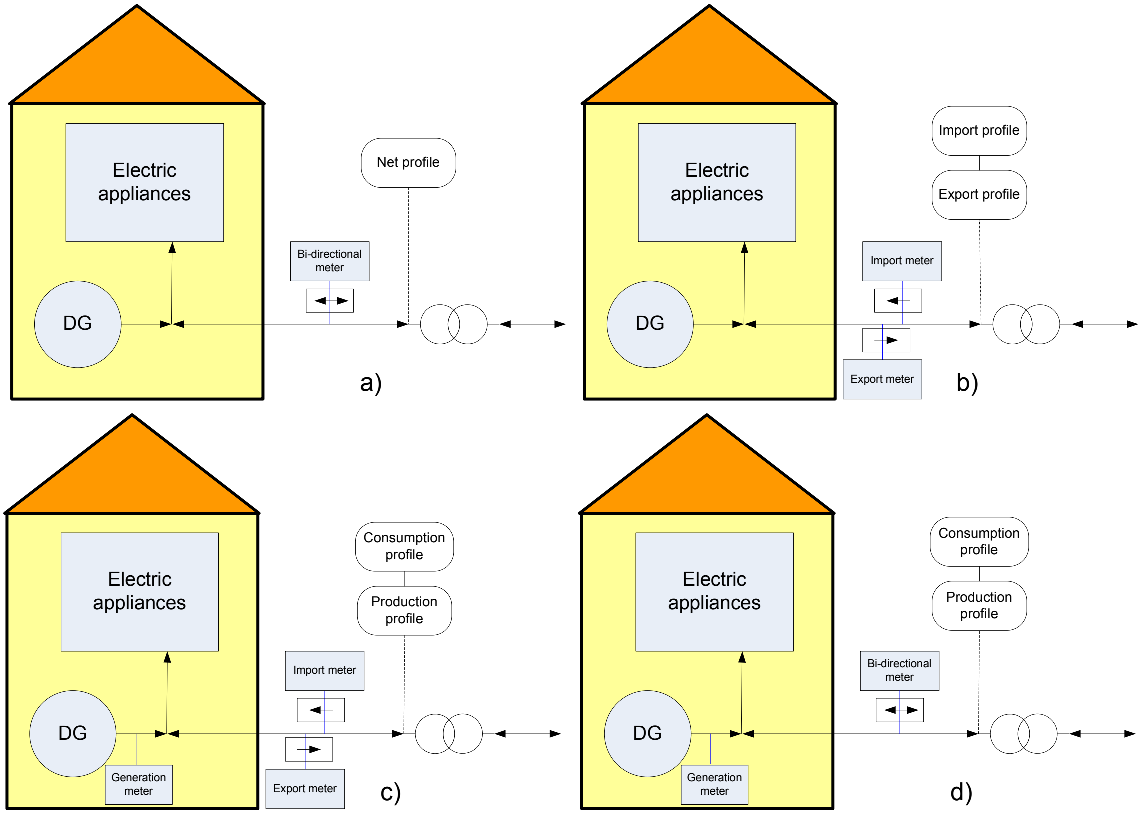

Figure 19: Four metering options with corresponding profiles: a) bi-directional metering, b) import-export metering, c) gross generation metering, and d) net generation metering

4.3 Analysis of the effects of DG on balancing market performance

The effects of each of the four distributed generation scenarios on the operational performance of the Dutch balancing market design will be analyzed by focusing on each of the three instruments of the balancing market separately and on allocation by profiling versus allocation by metering. To this extent, the performance criteria for the operational performance of the balancing market will be valuated qualitatively, as described in sub-paragraph 3.3.2. The performance criteria are given a value from -10 to 10, depending on the magnitude and the direction of the effect. The scenarios are considered in the order given in paragraph 4.2. Background information, including illustrations can be found in appendix G. The results are summarized in paragraph 4.4.

4.3.1 Scenario A: PV cells

Effects on Programme Responsibility

Predictability production & consumption

The predictability of generation for an individual PV cell is a different issue than the predictability of generation for a group of consumer-generators with a PV cell. Basically, the solar irradiance will increase and drop during the day following the orbit of the sun through the sky during the day, which results in a parabolic development of the momentary power output of a PV cell on clear days.

The daily electricity output is much higher on summer days than on winter days. Assuming a relation between rated power and actual power for the 1 kW_p PV cells in this scenario that is similar to that depicted as Figure G1 in appendix G, one PV cell will have a peak output of at best 750 W (75% of rated power) on cloudless summer days, down to 450 W (45% of rated power) on cloudless winter days.

The seasonal differences for momentary power output of PV cells leads to a specific energy output pattern over the year. The energy output of PV cells rises from January up to June, after which it drops again. November, December, January and February are the months with the lowest energy output in the Netherlands, with roughly only 20-40% of the output in the summer months, according to measuring data of PV cells in the Netherlands[21].

Seasonal differences are quite predictable, because it depends on sunshine hours and temperature, which can be rightly predicted well in advance. However, the formation of clouds is much harder to predict, while it has a large effect on PV power output. When clouds pass by and the solar beams are alternately blocked and unblocked, a high PV power output alternates with an almost zero power output. This can lead to large production variations in a matter of seconds, as can be seen in Figures G2 and G3.

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[21] See the website of Ton Peters, http://www.pv-solar24.info, viewed on July 26th, 2007.

However, for a group of geographically distributed PV cells, production is more predictable, because the integral fluctuations are smaller than the individual ones. According to Coppye et al. (2000), "the energy produced by N decentralized PV systems increases with a factor N, while the energy of the fluctuations on the output increases only by a factor √N" (p. 2). The predictability of production and consumption for this scenario is given a '-3': Although fluctuations are smaller on a system level, cloud coverage can still change the aggregate production pattern in the short to very short term. The relative size of this error compared to the system load is small, though. The value '-3' is given for both allocation methods, because a thorough analysis of production data enabled by smart metering has no use: the PV production pattern is predictable enough without.

Accuracy E Programmes

The reduced variation of PV production for the aggregate means that PRPs will be inclined to take responsibility for a large group of consumers with a PV cell (who are preferably not too close to one another). The predictability of PV production will lead to quite accurate E Programmes, but the accuracy can be increased by submitting altered E Programmes after closure of the day ahead market. Because E Programmes can be altered until one hour before the PTU of execution, PRPs will be able to submit altered E Programmes that reflect the latest weather predictions. However, it is not possible to shift PV generation. This brings the author to give this performance criterion the value '-3' for allocation by profiling, and '-2' for allocation by metering, because the consumption can be shifted more towards PV peak production periods by setting lower export prices and perhaps higher import prices in those periods.

Costs of Programme Responsibility

The costs of the execution of the Programme Responsibility instrument are relatively high for this scenario, because a lot of altered E Programmes will be submitted. This increases the administration costs for both PRPs and TenneT. Also, the efforts TenneT undertakes to balance system supply and demand, including the prevention of transport restrictions on beforehand, are higher. This is related to the limited accuracy of the E Programmes, on which TenneT bases its balancing efforts (the combined E Programmes reveal the deviation between system supply and demand that must be bridged by import, export and changes in production capacity). Since the E Programme accuracy is reasonable, only a '-4' is given for this performance criterion. The choice for an allocation method has no influence.

Effects on the single-buyer market for RRP

Network stability

There have been several studies that point to the conclusion that PV penetration on a scale similar to the one assumed in scenario A is manageable.

To start, Denholm and Margolis (2006) find that, even at a low flexibility of central plants of 60%, the intermittency impact of the total PV capacity would only become critical when it has reached about 20% of the peak load (page 2860). In the case of the Netherlands, which has a peak load of 17,376 MW (TenneT website 2006), the PV capacity should exceed the 3.5 GW to become critical. The 2 GW in this scenario is well away from that number.

Furthermore, the PV production peaks, which occur at off-peak hours, can be flattened by fine-tuning the PV panel orientation. Paatero and Lund (2006) find that an east-west panel orientation results in smoother PV production peaks that a more spread out over the day, but also in a lower total PV output. The flattening of the PV generation peaks might be needed to prevent undesirable technical effects of those peaks. A good trade-off might be to orientate PV panels differently at different households, in such a way that the production peak at summer mid-hours is as large as the total residential consumption in the distribution network.

Then, Paatero and Lund (2006) also studied the voltage rise effects and network losses arising from PV penetration. From that, it can be found that for scenario A only small voltage rises (> 1% of nominal voltage) will arise, and that the total network losses will reduce.

Finally, the option provided by the instalment of the smart meters to dim the connections would provide a fall-back option to balance system supply and demand at times of unmanageable PV peak production. Of course this measure would only be taken when consumer-generators would not respond to the instruction to shut off the PV cell, because this measure could lead to overloading of the domestic circuit.

Taking into account the sufficient network capacity, uncritical impact mentioned, possible mitigation of PV generation peaks, and limited voltage rise, it is concluded that the electricity system can technically cope with the 30% PV penetration at Dutch households. Only the times of peak production at summer days might bring difficulties. The performance criterion 'network stability' is valued with a '-2' for both allocation methods, noticing the potentially adverse effects of large export volumes (see under 'RRP offered').

RRP offered

In order to analyze the effects of PV penetration on the amount of RRP offered, first the change in the consumption pattern, in combination with the production pattern, of the two million households with a 1 kW_p PV cell should be taken into account. After all, its interference with the overall system load in the Dutch electricity system determines how large the electricity export and import volumes from/to the consumer-generators will become, and thus how much the system would depend on DG. The dependency on DG would generally decrease the amount of RRP offered, because PV is not suitable for RRP provision: PV is uncontrollable. The power output is determined by the weather, not by the operator.

Here too, the correlation between production and consumption can be examined for both individual PV cell owners and for the whole system with two million PV cell owners. The first reveals the effects on electricity import and export upon distribution network level, the second the effects upon the operation of the national electricity system.

Starting with individual consumer-generators, the production pattern of a consumer-generator with a 1 kW_p PV cell will combine with his consumption pattern to form a net exchange pattern: for every moment in time, the net exchange is the momentary power demanded minus the momentary power generated. If the momentary production is larger than the consumption, the consumer-generator will export the surplus electricity; if the consumption is larger, he will import the remaining electricity. On this individual level, the weather conditions play a very important role in determining the net exchange pattern.

The fit between household consumption and PV production is rather poor: PV production of a 1 kW_{el} cell exceeds the consumption level largely at midday, while it is much smaller at the start and end of the day. Furthermore, the fluctuations caused by passing clouds can result in sharp increases/decrease of electricity import/export rates on the distribution network level, and are limitedly predictable. Can the distribution network cope with this?

At least, the PV production reduces the electricity volumes that need to be imported to meet consumption. This reduction frees up transport capacity that may be needed for handling export volumes. However, for clear days in summertime the export rate can be three times higher than the import rate. Moreover, this will be true for all consumer-generators with a PV cell at the same time. In this scenario there are 2.3 times more ‘normal households’ than households with a PV cell, so when the instantaneous production is smaller than 2.3 times the instantaneous consumption, the excess electricity can delivered to the ‘normal’ household consumers connected to the same distribution network. The total transport volumes will then still be lower than in a situation without any distributed generation, and no electricity will flow back to the transmission network. However, for the warmest hours on clear summer days, production will be so large that a relatively small amount will flow back to the transmission network. The transmission network will probably be able to transport these reverse flows, because its load factor was already decreased significantly thanks to the PV penetration. Because the export volumes will be smaller than current import volumes, it is likely that the networks will have enough capacity to deal with the domestic electricity volumes. Also, the times and amounts will be predictable, which gives a first positive finding for the performance of the RRP market: it will at least be possible to plan and monitor the needed extra system balancing for PV penetration caused by its poor fit with residential consumption.

This brings us to the integrative effects of this scenario, considering the total production and consumption of all consumer-generators combined. First, it is noticed that PV output is highest in the summer and lowest in the winter. The PV output pattern throughout the year is hill-shaped, whereas the consumption output pattern is valley-shaped (both for individual consumer-generators and for the aggregate). See Figure 20. In other words, the yearly PV production curve and the yearly consumption curve are oppositely shaped. It appears that in summer, the PV contribution to household consumption can become 50%, while in winter it can be less than 10%. This makes reliance on PV production capacity for both stand-alone electricity provision and standard Regulating/Reserve Power even more unfeasible than the bad controllability of PV already makes it.

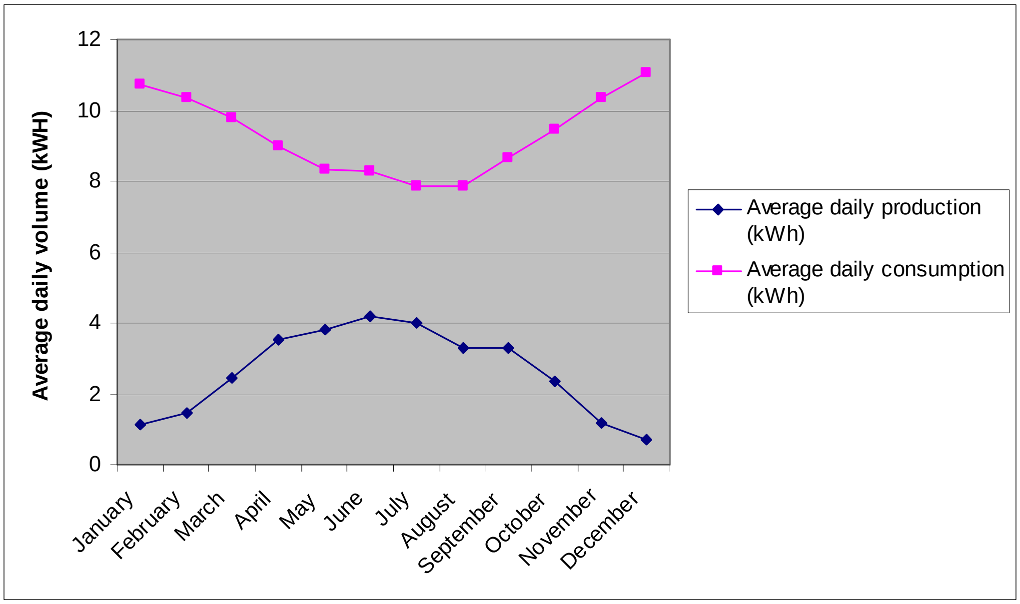

Figure 20: Shape of household consumption and PV production pattern throughout the year (Peters 2007; Ecofys 2001)

There are some measures that can simplify the balancing task in the PV scenario, though. First, it is possible to improve the fit between production and consumption, if consumer-generators with a PV cell adapt their consumption pattern to benefit from their own produced electricity. They would be stimulated to do this when the export tariff (feed-in tariff) is lower than the retail price they pay for imported electricity. Since this would require consumption shifts towards midday, mostly appliances like washing machines, dryers, and refrigerators would be eligible for this. Cleaning and cooling applications constitute on average 38% to household consumption[22], so this has a potential. Activities to effectuate electricity consumption shifts are generally called Demand-Side Management (DSM). This could be done by providing price signals to consumers and letting them react on those, but more effective is the automatic programming of appliances to switch on and off at preset times.

Although DSM would limit the decrease in system reliability resulting from the PV penetration, it will not be able to fully remove the high differences between consumption and production patterns in this scenario. However Haas et al. (1999) have found that photovoltaic users are willing to adapt their temporal consumption patterns to the production patterns of their panels, in order to maximize self-reliance (Pehnt et al. 2006, p. 113), which would improve the correlation between consumption and production at least partly.

In addition, Paatero and Lund (2006) have analyzed that by panel orientation the PV production shape can be significantly altered. As already noticed, it could pay to flatten the production curve at the expense of total PV production to increase system balancing possibilities.

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[22] See www.osbexact.nl/pages/206/Stap_0_Nulmeting.html, viewed on July 31th, 2007.

To conclude, the bad match between PV output and system load necessitates the shut down of central power plants at PV peak production times. As a consequence, less central production capacity is available as Regulating and Reserve Power. The PV capacity cannot make up for this, because the power output is not controllable. This makes the clustering of PV cells into Virtual Power Plants (see scenario B) a useless possibility. DSM and panel orientation can increase the availability of central plants for RRP provision by improving the match between production and consumption. The dimming of connections will only be used a last resort. With all this in mind, a value '-5' has been given to the performance criterion 'RRP offered'. Smart metering does not change the picture.

RRP deployed

As discussed under 'RRP offered', the PV penetration will reduce the match between system supply and demand, especially at the noon of summer days. But although the availability of central power plants and thus the amount of offered Regulating and Reserve Power might decrease, the amount of deployed RRP is primarily influenced by the occurring system imbalance and transport restrictions. The effect of PV penetration on the system imbalance is negative because of the lower predictability and the lower network stability. However, the amount of transport restrictions is reduced because of the distributed generation and consumption that replaces central production and transmission. Still, the negative effect on system imbalance is expected to be larger, which is why the value '-2' is given to this performance criterion. The use of smart metering changes this to '-1', because of the possibility to shut off PV capacity.

Costs of single-buyer market for RRP

The valuation of the costs associated with the operation of the single-buyer market for Regulating and Reserve Power basically are administrative costs to monitor the bidding ladder and derive dispatch prices. These costs will be higher if the offered amount and deployed amount increase, but the relative effect on the costs will only be marginal. The reduction in offered amount of RRP is higher than the increase in deployed RRP, so the value '1' is given to this performance criterion.

Effects on imbalance settlement

Accuracy allocation

First, the choice of a metering-profiling option is considered, because this will influence the accuracy of allocation for both allocation methods (and the allocation costs).

The export tariff will probably be lower than the retail price, because the value of exported electricity is lower: it has yet to be transported, it goes the other way, and PV power is generated at off-peak hours and in large bulks, which makes it more difficult to balance. In combination with the sharp fluctuations that are possible, this means that it is important to meter the import and export rates separately and exactly. However, for allocation by metering, exact metering data will be required as well, in order to maximize the benefits for allocating and balancing. So, either gross generation metering or import-export metering should be chosen as the metering-profiling option.

The difference between these two is whether or not generation is metered separately. The metering of domestic generation would be needed for the construction of a generation profile. The construction of a new, separate generation profile (or more for different panel orientations) is the obvious choice here, because it requires less work and is more workable. It requires less work, because the current consumption profiles can be maintained and the production does not have to be combined with consumption to form a net profile. It is more workable, because the production pattern from PV as predicted by the profile is immediately visible from the profile fractions, and adaptations can be easily made. The only disadvantage is that the system should be able to work with two profiles for one connection, instead of one (B'con 2007b), but that technicality will probably have been worked out by the time the large-scale DG penetration has arisen.

Thus, gross generation metering is concluded to be best metering option for scenario A, in combination with one production profile, and one or more consumption profiles (depending on consumer responsiveness to price signals or different tariff periods).

Because PRPs will likely take responsibility over a large group of consumer-generators, the allocation will be suboptimal. When a large part of the allocation error is caused by badly predicted PV production, this will not be visible in the allocation process making use of profiles, and all PRPs will share in the error. This way, other PRPs will face higher imbalance costs undeservedly, while the PRPs with the PV consumer-generators will have too low imbalance costs. However, the prediction of PV generation for the large groups of consumer-generators will be rather good, so this effect will be limited. This is why the value '-2' is given to 'accuracy allocation' for allocation by profiling.

For allocation by metering, the imbalances can be settled perfectly, because of the perfect allocation of actual production and consumption: it is exactly metered which PRPs have deviated how much from the net amounts in the E Programmes, as made possible by gross generation metering. Also, a reconciliation step is not needed anymore. Finally, all imbalance costs are allocated justly among the PRPs responsible. In total, the accuracy of allocation is improved significantly, compared to the current allocation. The value '6' is given for allocation by metering. This is not maximal, because the current allocation already works quite satisfactorily.

<u>Imbalance costs</u>

The imbalance costs are determined by the amount of control power deployed, the liquidity of the market for Regulating and Reserve Power, the RRP margin, and the amount of imbalances by the PRPs. The amount of control power deployed could very well stay the same: the lower short-term predictability is offset by the reduction of transport restrictions. The liquidity of the RRP market will decrease, however: the amount of offered RRP drops, while the number of offering parties stays the same (PV cannot be offered as RRP). Further, the relative amount of RRP deployed will become larger, which significantly increases the imbalance costs. Finally, the aggregate size of RRP imbalances will be somewhat higher as a consequence of PV penetration as well. Thus, the overall imbalance costs will increase. The estimated value of this effect is -5.

Costs of allocation

The costs of making new profiles appear to be relatively low: only one new production profile could suffice. Even though more production profiles might be needed for different panels, and a few new consumption profiles might need to be formed as well, the costs will remain limited and much lower than with allocation by metering. This can be derived from cost estimations by Choudhury and Andrews (2002), who estimate the costs for the creation of a new profile at €150,000-€750,000 and monitoring costs per profile around €150,000 per annum (p. 48), but the costs of data collection and processing at around an optimistic 75-190 euro per annum per connection (p. 49). Per consumer-generator the costs of one profile are thus 0.375 euro plus 0.075 euro per year at most, which is negligible compared to the costs of data collection and processing even when several profiles must be made and data costs in the profiling allocation method are added. When it is also considered that a generation profile is already likely to be constructed for the prediction of PV production by suppliers and PRPs, and that the shortening of the reconciliation period reduces financial risks, the costs of allocation by profiling are estimated to be similar to today ('0'). For allocation by metering, however, the removed costs associated with the reconciliation process and imperfect distribution of imbalance costs must be taken into account as well. These will reduce the costs of data collection and processing somewhat, so that the effect for this allocation method is valued to be '-8' (instead of -10).

4.3.2 Scenario B: Heat-led micro-CHP

As an introduction to the micro-CHP scenarios, the following must be said. Generally, four micro-CHP systems are considerable: a stand-alone micro-CHP unit, a micro-CHP unit with a supplementary boiler, a unit with a heat storage tank, and a unit with both. Furthermore, four micro-CHP technologies are considerable: reciprocating engines, fuel cells, Stirling engines, and ORC-based units. The possibilities of multiple micro-CHP systems and technologies complicate the analysis, but require discussion, because they influence the effects micro-CHP penetration could have. Moreover, they facilitate or hamper the mere possibility of residential micro-CHP operation. In appendix G, they are described in more detail.

In addition, there are some important notions, described in appendix G, relevant to the analysis of the micro-CHP scenarios. First, the heat-electricity consumption ratio for the average Dutch household is 4.3:1. By 2030, it could have become 2.1:1 due to better heat isolation and a higher electricity demand. This changes the relative suitability of the different micro-CHP technologies for Dutch households. Next, the micro-CHP unit will never be able to provide the entire domestic heat demand. This implies that a supplementary boiler is a necessary part of the micro-CHP system. Finally, it is important to stress that natural gas is assumed to be the fuel used for electricity and heat production in the micro-CHP systems.

This scenario assumes the large-scale domestic penetration of heat-led micro-CHP, which is the main micro-CHP type investigated, because heat is generally seen as the primary product of micro-CHP systems. There are however more types, which will be discussed in scenario C and D.

Effects on Programme Responsibility

Predictability production & consumption

To determine the predictability of production and consumption, it is useful to examine first how well electricity and heat demand patterns match originally, without any load/generation control. After all, in this scenario the domestic generation will be proportional to the heat consumption, which is aimed to cover up by operation of the micro-CHP unit. Again, it is useful to distinguish between individual household demand and aggregate demand.

Seasonal differences exist both for electricity demand and heat demand. Electricity consumption in the Netherlands tops in the winter and is lowest in the summer, also for the residential sector. Considering the heat consumption level, one can differentiate between three different time periods: winter, summer, and spring/autumn. Not surprisingly, the general residential heat consumption shows a similar course: heat demand is lowest in summer, and highest in the winter. Thus, to start, at least the seasonal changes for electricity and heat consumption are not opposing.

Important findings on the individual level are that heat consumption lies at a higher level than the electricity consumption, that both individual patterns show sharp fluctuations, and that, very roughly, both the electricity consumption pattern and the heat consumption pattern show a morning peak and an evening peak that do not overlap perfectly. See Figure 21, which is reproduced from Peacock and Newborough (2006). This picture shows the aggregate electricity and heat demand for 50 households on a January day. Heat demand is on a higher level than electricity demand, but shows the same shape in the form of a morning peak and an evening peak. However, the peaks do not overlap perfectly. According to Peacock and Newborough (2006), “The heat demand tends to lead the power demand, particularly in the morning as boilers commence operation prior to active occupation of the dwelling” (page 1096). Finally, it can be seen that, on the aggregate level, heat demand fluctuations are much smaller than individual heat demand fluctuations (see Figure G6 in appendix G), while electricity fluctuations are still visible.

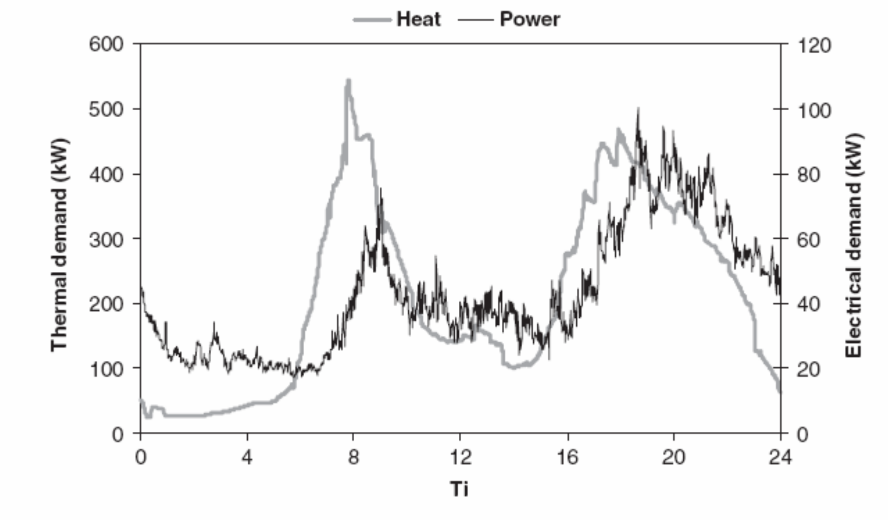

Figure 21: Aggregate heat and power demands from a group of 50 dwellings on a day in January (Peacock and Newborough 2006, fig. 2)

It can be concluded that residential heat demand is at least as predictable as residential electricity demand, which means that the effects of micro-CHP operation on production and consumption patterns are predictable as well. This holds even more for the aggregate. Finally, it can be deduced as well that the match between residential heat consumption and electricity consumption is reasonable. This has implications for the RRP offered and deployed. The predictability is valued with a '-2': the dependency of the net electricity exchange on the heat demand pattern and the operation of the micro-CHP system add some extra uncertainty, but both are rather predictable. Smart metering will improve the effect, because the analysis of generation and consumption data will lead to a better prediction: the value '-1' is given for allocation by metering.

Accuracy E Programmes

The good predictability of consumption and generation of consumer-generators with a heat-led micro-CHP system contributes to a high accuracy of the E Programmes PRPs submit. Moreover, the predictions can be made well in advance, which prevents any negative effect on intraday balancing opportunities. Finally, as will be discussed later on, there is enough operational flexibility if the micro-CHP system is equipped with both a supplementary boiler and a heat storage tank. This provides some possibilities for consumption and generation shifting, although they are limited to the extent that product heat from the micro-CHP unit is to be utilized. Shifting requires the use of smart metering, however. It is thought that the effect of a somewhat lower predictability is offset by the shifting possibilities, so that the overall effect is '0' for allocation by metering, but '-2' for allocation by profiling.

Costs of Programme Responsibility

This performance criterion is influenced by the amount of altered E Programmes, which is thought to rise very little as an effect of the slightly lower predictability. This also increases the balancing service costs of TenneT a bit. This is why the value '-2' is given for allocation by profiling. For allocation by metering, it will be possible to steer the production and consumption portfolio of a PRP a bit towards the net electricity volume specified in the E Programme, which makes the effect '-1' for this allocation method.

Effects on the single-buyer market for RRP

Network stability

For this performance criterion, first the choice of the micro-CHP technology can be considered in more detail. It has become clear that none of the micro-CHP technologies can cover the entire heat demand, but the ORC-based unit comes closest by far, because of its high heat-electricity ratio (see appendix G). The choice for a specific technology has consequences for the electricity production level in this scenario and thus for the electricity export level, but the latter is also determined by the relative use of product heat for heat demand coverage. This depends on the exact operating mode: if maximum heat would be produced at peak heat demand times, the electricity export level could become very high, especially for the fuel cell in the winter. However, the micro-CHP unit can be operated at part-load when the high export rate is undesirable, which is why the technologies with a high part-load performance and regulating speed are favoured: the Stirling engine, the low-temperature fuel cell, and possibly the ORC-based unit. If the technical features of the ORC-based unit will prove to be favourable, its high heat-electricity production ratio will be the most attractive for heat-led operation with respect to energy efficiency, and even more so if electricity export is to be prevented.

Peças Lopes et al. (2006) have examined the technical effects of DG integration in general. First and foremost, they indicate that DG is capable of providing ancillary services like Reserve Power, especially technologies like micro-CHP. The opportunities for provision of other ancillary services by DG are stated to be better for micro-CHP than for PV, although still limited.

Furthermore, Pehnt et al. (2006) mention several research projects concerning the technical effects of micro-CHP penetration, where the outcomes are generally positive. To start, a power flow calculation done by Pitz et al. (2003) showed that even under maximum micro-CHP penetration and minimum demand in the distribution circuit "the equipment (cables, transformers, etc.) would not be overloaded, the voltage would remain within the acceptable bandwidth, and the feed-in into the medium voltage grid would be manageable" (Pehnt et al. 2006, p. 204). Further, a power flow analysis by Arndt et al. (2004) has shown that a micro-CHP unit in every household, leading to a total capacity of 131.5 kW in the distribution network, only led to a maximum reverse power flow to the MV of 91 kW, compared to a maximum power flow of 200 kW without any micro CHP (Pehnt et al. 2006, page 204).

Moreover, Pehnt et al. (2006) mention that connection of plants is easier near transformers or in grids with high load density, where short-circuit levels are higher (p. 205). For the densely populated country of the Netherlands, this condition holds. Finally, a German research project by the Technical College of Darmstadt led to the conclusion that 1.5 kW_{el} could be installed at each household (or other consumer site) without causing problems regarding voltage variations (Pehnt et al. 2006, p. 206)

Regarding reactive control, the provision of reactive power by DG (and thus micro-CHP) is possible, but limited (see appendix F). However, the reduction of reactive control by central power capacity is also likely to be limited, for the oldest and least useful plants will be replaced by DG first.

Finally, the effect of micro-CHP penetration on network losses are positive, as can be expected from the reduction in electricity transport. According to the analysis of Arndt et al. (2004) for electricity supplied through the grid, losses are 50% less with micro cogeneration compared to the scenario without micro cogeneration, even when all buildings in a distribution grid where equipped with a fuel cell, and a lot of export would occur. However, it is also analyzed that losses do increase for high DG penetration levels if there are large reverse flows to the MV grid (Pehnt et al. 2006, p. 208). Noticing the reasonable match between domestic electricity generation and electricity demand, the possibility to limit electricity export rates, and the limited micro-CHP penetration level, this will not be the case in this scenario.

Summarizing, the system load will be reduced (due to the domestic generation and consumption), the power quality will reduce a bit, export volumes are manageable, and the transient stability will reduce somewhat (see appendix F). It is assumed that the reduced utilization of network capacity will limit the negative effects. The use of smart metering does not change this. This is why the value ‘-2’ is given, for both allocation methods.

RRP offered

The effect of heat-led micro-CHP penetration on the amount of offered RRP is basically determined by the effect on the match between system supply and demand. The match influences the availability of central power plants for RRP provision, and the value of clustering micro-CHP units into Virtual Power Plants (VPPs), which can either be used in the day-ahead and intraday market to increase a-priori balancing, or in the single-buyer market for RRP to increase the amount of RRP offered directly.

First, the match between residential consumption and production by consumer-generators was found to be reasonable under 'predictability production & consumption'. On the distribution and transmission system level, this should therefore lead in an overall reduction of the system load, and limited export volumes. This is confirmed by an analysis of Peacock and Newborough (2006), see appendix G. During the peak heat demand periods, the large penetration results in net electricity export for the entire distribution network, but this export is much smaller than the former peak load in the network, and also much smaller than the net export at PV production peak times in scenario A.

It is shown by Hawkes and Leach (2005) that the heat-led control of micro-CHP will cover most of the household electrical demand in the winter, autumn and spring, but not in the summer. This of course is caused by the very low heat demand in the summer. Especially when summers are getting hotter and central power plant production will be restricted due to cooling water limitations, extra micro-CHP power output to the grid would be desirable, but the minimal heat demand prevents this.

Furthermore, Peacock and Newborough (2006) state that "the resultant electrical load profiles placed on LV distribution transformers will be of reduced mean load but increased variability. This is likely to exacerbate supply/demand matching of central generation" (p. 1102). However, variations do not appear to be very different from current ones. Besides, the inclusion of boilers and heat storage tanks enable the flattening of electrical output and thus decrease of variation.

To conclude, the micro-CHP penetration will generally not lead to excessive amounts of export at certain periods, but just reduce the system load on an overall basis, which will increase the availability of central power plants for RRP provision in case the micro-CHP is installed on top of the existing production capacity. Variations will probably be too small to affect this. In hot summers however, the contribution of micro-CHP to electricity production will be minimal. This requires back-up capacity, possibly PV cells, which limits the size of the general positive effect of micro-CHP penetration in this scenario.

Second, the opportunities for clustering micro-CHP units into VPPs depend on the flexibility of generation and consumption of households with a micro-CHP system. Although the stable heat demand pattern limits the flexibility of micro-CHP generation significantly, the inclusion of the supplementary boiler and a possible heat storage tank makes some generation shifting possible. As is found above, a supplementary boiler is an essential part of the micro-CHP system when the unit has a 1 kW_{el} capacity, because the produced heat cannot cover the domestic heat demand. However, the produced electricity is large enough to satisfy the entire electricity demand of the average household.

The capacity of the supplementary boiler and the heat storage tank are an important determinant. If the boiler is capable of supplying the entire residential heat demand, the micro-CHP unit could theoretically operate at any time and output level. However, operation during off-peak heat demand periods removes both the energy efficiency and cost advantages of the micro-CHP system, if the product heat is dumped and the boiler supplies the required heat. This is where the heat storage tank comes in: it can store the heat produced by the micro-CHP unit until it is needed. As we look at the heat production patterns of a micro-CHP unit in Figure G6, and remember that the individual electricity demand pattern knows similar fluctuations, the opportunity and usefulness of heat storage becomes clear. When the micro-CHP unit is used to cover all electricity during an electricity demand ‘spike’, the excess heat can be stored until a heat ‘spike’ occurs, and then used to complement the heat production otherwise provided by the boiler.

With respect to demand shifting, it is can be beneficial to shift part of the electricity demand to peak heat demand times. The programming of cooling and washing equipment is most eligible for this, because they allow operation during other hours.

From the above can be concluded that a micro-CHP system with both a boiler and a heat storage tank provides the required generation flexibility that is needed for the use of micro-CHP units in system balancing. This use necessitates the formation of Virtual Power Plants (VPPs). According to Pehnt et al. (2006), "A virtual power plant consists of a number of geographically distributed power generation units – generally decentralized and low electrical capacity – which are integrated into one large operational unit by means of a joint control and operator interface" (p. 14). The VPPs could be used in different electricity markets, all influencing the amount of RRP offered.

The use of micro-CHP units in the day-ahead intraday market could increase the balancing of system supply and demand before the operational PTU has come. The required flexibility is present, but the use of smart metering is a precondition as well. By sending real-time prices to consumer-generators, and knowing the average household responsiveness to price signals thanks to a thorough data analysis made possible by smart metering, consumer-generators can be stimulated to change their consumption and generation in a matter of minutes. A programmed control system for individual micro-CHP systems that automatically responds to the price level is probably required too. That way, aggregators could operate VPPs to balance a PRP portfolio, or contribute to a-priori balancing by responding to high APX prices.

The use of micro-CHP as Regulating and Reserve Power also has potential. This would then focus on the Reserve Power, because the automatic control and high availability requirements of Regulating Power are not likely to be met by the heat-led micro-CHP units. Micro-CHP could be used as Reserve Power, because its regulating speed and dispatch time are probably high enough for the lower Reserve Power requirements. This is in correspondence with Peças Lopes et al. (2006), who stress that "CCGTs, diesel standby generators and perhaps micro-CHP were best placed to provide reserve services" (p.1194-1195). The minimum dispatch size of 5 MW requires the formation of VPPs. The aggregators of the VPPs could then transfer the multiple bids of consumer-generators into one RRP bid to TenneT, and check the response to a dispatch instruction from the meter readings provided by smart metering.

But although VPPs can be formed technically and can be useful for balancing, Roon (2003) states that VPPs are not economically viable at the moment: "Other than with virtual power plants based on larger individual generation units, under present-day conditions, the potentially higher proceeds of connected micro cogeneration plants do not justify the high expense for installation and management of a virtual power plant" (Pehnt et al. 2006, p. 16). Still, the installation and operation of VPPs consisting of residential PEM fuel cells has already been realized with success in a European project (Vaillant, Plug Power Holland and others 2005). So whenever the VPP concept becomes profitable it can be implemented. A final reservation is however provided by Pehnt et al. (2006), who think that the grid-relief and peak shaving caused by (heat-led) micro-CHP penetration already has a positive effect on system performance, and that thereby the relative benefits of VPPs are reduced (p. 217).

To conclude on the effects of heat-led micro-CHP penetration on the amount of Regulating and Reserve Power offered, the central back-up capacity needed for hot days offsets the reduced system load. This would keep the central production capacity available for RRP provision the same. However, the micro-CHP units can be clustered and used as RRP, so that the amount of RRP offered will increase. This increase could be low because of the possibly high costs of VPP formation and operation. Also, analysis of the metering data provided by smart metering could increase prediction and therefore decrease system imbalances. For allocation by metering, the value given is '2', but for allocation by profiling, the formation of VPPs will be impossible, which results in a value '0'.

RRP deployed

The RRP deployed depends on the system imbalance and the amount of transport restrictions. The amount of system imbalance will increase a bit by the somewhat lower predictability and network stability, but the large reduction of the network load is assumed to be higher. Therefore, the value for the performance criterion 'RRP deployed' is chosen to be '3'. If the metering allocation method is used, there is more opportunity to balance a-priori, internally balance and improve prediction due to data analysis, which will further reduce the amount of RRP deployed: the value given is '5'.

Costs of single-buyer market for RRP

The costs of operating the single-buyer market for RRP are mainly influenced by the amount of Regulating and Reserve Power offered and deployed: the lower these amounts, the lower the costs. The effect will be marginal, though. For allocation by profiling, there is less RRP deployed, so the value given is '1'. For allocation by metering, more RRP is offered but the amount of deployed RRP is even lower, so the value here is again '1'.

Effects on imbalance settlement

Accuracy allocation

With regard to the different metering-profiling options, the same line of reasoning as for PV penetration in scenario A can be used here. Because the generation pattern of the micro-CHP unit is generally the same for each consumer-generator, only one generation profile would be needed. The creation of a net profile or import and export profiles would incur extra costs, while the transparency of the electricity consumption and generation by households would be reduced. The newly created generation profile can be used together with the existing consumption profile, or with a new one, if the consumption pattern of consumer-generators is changed by the micro-CHP operation.

The use of generation profiles and consumption profiles would limit the choice for a metering option between gross generation metering and net generation metering (see appendix D and Figure 19). Again, the use of a bi-directional meter cannot be recommended: the likely difference between import price and export tariff favours the exact measurement of import and export, which a bi-directional meter does not provide. Finally, the costs of an import-export meter are only marginally higher than the costs of a bi-directional meter, understanding that the required functions of the smart meter incur much higher costs than the 'hardware' of the metering facility (see Choudhury and Andrews 2002). This favours the choice of the most accurate metering option, which is gross generation metering.

The effects of heat-led micro-CHP penetration on the accuracy of the allocation depend on the allocation method chosen. For allocation by profiling, there is no reason to believe that the micro-CHP would change this accuracy: the value set is '0'. For allocation by metering, the allocation will become exact, which has a large positive impact similar to the other scenarios: the value set is '6'.

Imbalance costs

The imbalance costs are determined by the amount of control power deployed, the liquidity of the market for Regulating and Reserve Power, the RRP margin, and on the amount of imbalances by the PRPs.

The amount of control power deployed will decrease, as shown by 'RRP deployed'. The liquidity of the RRP market depends on the allocation option. For allocation by metering, consumer-generators could participate in the electricity market, but only aggregators, who will probably be affiliated with the suppliers, will offer RRP by clustering micro-CHP units into VPPs. Thus, the liquidity of the RRP market will not change. Further, the RRP margin will increase, which reduces the dispatch prices and thus the imbalance prices. The amount of imbalances by the PRPs will reduce, because of the increased possibilities for PRPs to internally balance their portfolio. On overall, the effect on imbalance costs will be positive: '3' for allocation by profiling, and '4' for allocation by metering, because the higher amount of RRP offered will reduce the imbalance prices.

Costs of allocation

Considering the costs of allocation, the same can be said as for scenario A: the costs of data collection and processing for allocation by metering per consumer generator are much higher than the costs of creating and maintaining a new generation profile for micro-CHP: 75-190 euro per year, instead of 0.375 euro plus 0.075 euro per year for the new generation profile (Choudhury and Andrews 2002). Possibly, different generation profiles will be needed for different heat storage tank capacities and different micro-CHP technologies, and also the costs of data transfer for allocation by profiling will be incurred, but still the costs of allocation will be at least ten times higher for allocation by metering. However, the removal of the reconciliation process and the perfect distribution of imbalance costs will reduce the negative cost effect somewhat for this allocation method. The same values as in scenario A are given: '0 for allocation by profiling, and '-8' for allocation by metering.

4.3.3 Scenario C: Electricity-led micro-CHP operated by consumer

Heat-led operation can be viewed as one extreme in the spectrum of operating strategies of the micro-CHP system; electricity-led operation as the other. It is therefore very instructive to consider electricity-led micro-CHP operation. In this operating strategy, the micro-CHP unit is operated primarily to cover the domestic electricity demand. The micro-CHP system always includes a boiler and a heat storage tank, so that as much product heat is utilized as possible.

Effects on Programme Responsibility

Predictability production & consumption

In this scenario, predictability of the two million 1 kW_{el} DG units is worst of the three consumer-operated scenarios, because the generation pattern is neither determined by weather conditions (scenario A), nor by the residential heat demand pattern (scenario B), but by the residential electricity demand pattern. Electricity demand is not as dependent on weather conditions as is the heat demand for heat-led micro-CHP operation or is PV generation. This makes the potential for generation shifting higher in this scenario compared to scenario B. Because consumer-generators have a high operational flexibility, they also have large opportunities for minimizing their energy costs by operating the micro-CHP system on the basis of the prices for gas and electricity and the export tariff. This shows that the predictability of residential generation and consumption depends for an important part on the behaviour of the consumer-generator, in specific on their response to export tariffs and price signals.

Although production and demand are least predictable in this scenario, it still does not mean that they are totally unpredictable. Basically, the consumer-generators will still generate heat and electricity when they want it and therefore the consumption pattern will continue to resemble the old one.

Furthermore, full electricity-led control independent from heat demand would be very unrealistic, because that could lead to reliance on the supplementary boiler for heat generation to almost the current level. When that happens, the basic advantage of micro-CHP, the high energy efficiency, would have disappeared entirely. Besides, when the boiler is used more than necessary, this means that more product heat from the micro-

CHP unit is wasted, and that higher natural gas costs are paid. The consumer-generator can prevent this by smartly using of the capacity of the heat storage tank.

Finally, it can be expected that the consumer-generator will either try to cover its own electricity demand, or just maximize electricity output of his micro-CHP unit, depending on the height of the export tariff in comparison to the electricity generation costs. This means that the electricity generation pattern will either follow the electricity consumption pattern, or be maximal. The last option is not very likely, because it results in high energy costs for the households, while suppliers can prevent this situation by their price setting. Thus, electricity generation can be expected to follow consumption in this scenario, restrained by the heat production and consumption. For allocation by profiling, only different tariff periods will exist, and the generation will be as predictable as the consumption. For allocation by metering, the generation pattern depends on the consumer responsiveness to price signals from the supplier. When the micro-CHP unit is programmed by the consumer-generator to react on those, the predictability for this allocation method will be almost as predictable.

To conclude, the predictability of production and consumption will be a bit less for allocation by profiling due to some operational restrictions following from the utilization of heat produced by the micro-CHP unit, which is why the value '-2' is given. The predictability for allocation by metering will be lower due to the uncertainty of household responsiveness to price signals, which is why the value '-3' is given.

Accuracy E Programmes

Next to predictability, the ability to shift generation and consumption is also an important factor in determining the effect of electricity-led micro-CHP operation on the accuracy of the E Programmes.

Considering this ability, it is likely that the consumer-generators will be aware of the environmental and financial advantages of matching their own electricity production and consumption patterns (assuming a low export tariff), because this will have contributed to the large-scale micro-CHP penetration in the first place. Therefore, it can be expected that the consumer-generators will actively engage in both generation and demand shifting insofar the financial advantages (plus the possible satisfaction gained from environmental-friendly micro-CHP operation) exceed the costs and effort.

This engagement is also expectable from a business perspective. The high operational freedom of the consumer-generator in this scenario implies that he is also the owner of the micro-CHP system, and that he bears all the costs and revenues related to it. After all, a supplier will not be eager to invest in a micro-CHP unit that is limitedly predictable and controllable. To earn the investment costs of the micro-CHP system back, the consumer should take the opportunities in demand and generation shifting. The more opportunities he takes, the shorter the pay-back period, and the sooner the cost reductions obtained from active micro-CHP control are really profits.

Because the consumer-generators are expected to be quite responsive to price signals, Programme Responsible Parties have gained a new way to balance their electricity production and consumption portfolio. By stimulating households to generate less or extra electricity, sudden deviations from planned E Programmes can be tackled, so that the net exchange volume submitted can be maintained. Moreover, the shifting potential with micro-CHP is quite large, because 2 GW is 13% of the total available production capacity in the Netherlands[23]. However, smart metering is required to communicate prices and meter readings. Therefore, the value given for allocation by metering is '4'. For allocation by profiling, the unchanged predictability leads to an unchanged accuracy of the E Programmes: the value for this allocation method is '0'.

Costs of Programme Responsibility

The costs of the Programme Responsibility instrument are influenced by the amount of altered E Programmes and the resulting change in balancing service effort by TenneT. Because less altered E Programmes will be submitted, both the administration costs and the balancing service costs decrease, which is valued at '2' for allocation by metering and '0' for allocation by profiling, because demand and generation shifting is not possible there.

Effects on the single-buyer market for RRP

Network stability

With respect to the technical effects, the same technical effects of micro-CHP penetration as discussed for heat-led operation in scenario B apply here. For this scenario, the situation will only improve, because of the higher operational flexibility of the micro-CHP units. This increases the possibilities to control the units in such a way that adverse effects on power quality, transport capacity, and transient stability are minimized.

The utilization of the higher operational flexibility favours the choice for a micro-CHP technology with a good part-load performance and regulating speed. Furthermore, the electricity-led operation favours the use of a technology with a high electrical efficiency, avoiding ‘the production of thermal surplus’ (Peacock and Newborough 2006, p. 1103). Thus, the best choice for this scenario could very well be the low-temperature fuel cell, noticing that reciprocating engine have a bad part-load performance and that Stirling engines and ORC-based units have a too low electrical efficiency.

It is thought that the improved flexibility can partly counter the small negative net effect of micro-CHP on network stability as described for scenario B. Especially when consumer-generators just cover their own electricity demand, the use of the public grid is minimal, and only serves as a back-up for electricity provision and export channel for when export becomes attractive. However, the micro-CHP units still are connected to the grid, and must be synchronized to the grid. With regard to electricity export volumes, these would become lower compared to heat-led operation when only the household consumption is covered, but would become higher at times a profitable export tariff is in place. It is shown below that even at full-load operation of the micro-CHP units, export volumes will be manageable, and so this does not have a large influence. The value set for the effect on network stability is '-1'. This value is also given to allocation by metering, because the extra electricity export expected as an effect of smart metering are assumed to have a positive effect on available transport capacity but a negative effect on power quality, which cancel each other out.

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[23] The average available production capacity in the Netherlands in 2006 was 15,282 MW (TenneT website)

RRP offered

There are two hypothetical generation patterns worth considering: generation at maximum capacity (which is unlikely), and total coverage of own consumption (which is likely). From their examination, the effect on the amount of RRP offered can be qualified.

The case of domestic electricity demand coverage is the most simple. When consumer-generators generate the electricity they need and nothing more, the system load will decrease with about 6%[24]. See Figure 22. The removal of the residential consumption peak in the morning and particularly that in the evening in the system load for two million households means that the system load reduction is particularly significant during residential peak hours. The overall result of demand coverage by consumer-generators is therefore both a system load reduction and a reduction in variation.

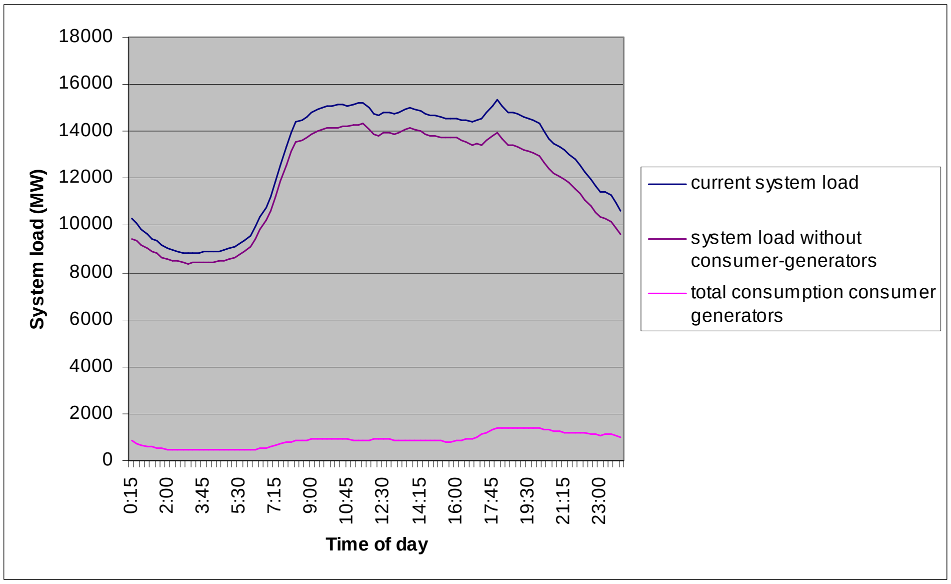

Figure 22: Contribution of consumer-generators to system load on February 1st 2006 (Ecofys 2001; TenneT website 2006)

The case of full-load operation is more difficult to examine, but also less relevant. When consumer-generators run their micro-CHP units at full-load and full capacity, the generation pattern will not look like the consumption curve in Figure 22, but will resemble the horizontal line y = 2,000. This will result in a continuous export rate which is as large as 2,000 MW minus the total consumption of the consumer generators, which will be 358 MW at minimum, 1,582 MW at maximum, and 776 MW on average, when based on the consumption profile for households from Ecofys (2001) and an average SYC of 3,397 kWh (see appendix A). What will be the effect here on the system load is less clear. The consumer-generators combined cause an aggregate production pattern that is high when domestic consumption is low, and vice versa. To what extent the export volumes flows back to through the ML/LV-transformer to the MV-network, depends on the consumption in the low-voltage distribution systems.

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[24] Household consumption in the Netherlands is 20% of total consumption, which means that the total consumption of consumer-generators for a 30% micro-CHP penetration is 6%.

When assuming that all remaining households are supplied with the export flows from the consumer-generators, the maximum reverse flow back to the MV networks will be 744 MW, while total household consumption can be as large as 5,536 MW (Ecofys 2001, TenneT website 2006).

The contribution of total household consumption to the system load is on average 23%[25]. When the micro-CHP units will run continuously at full-load and other households are supplied first with the export, the average aggregate load on the transmission system for all households together will drop from 2,715 MW to 715 MW, which is only 6% of the former system load, instead of 23% (Ecofys 2001, TenneT website 2006).

Next, the utilization of the operational flexibility by forming Virtual Power Plants and shifting household generation and demand should be considered. The opportunities of VPP formation and operation are improved compared to heat-led operation in scenario B because of the higher operational flexibility.

Still, the load shifting potential is limited by the heat demand, in combination with the electricity demand. According to Pitz et al. (2003), “the flexibility of adjusting power generation is greatest in spring and autumn when plants are typically operated for several hours per day. This is the best period for micro cogeneration plants to shift power generation to demand peaks and to also provide power control services” (Pehnt et al. 2006, p. 211). Operational flexibility in the summer is still limited due to the low heat demand, while the high heat demand in winter makes full operation of the micro-CHP unit in the morning and evening very profitable (see Figure G6). These seasonal differences partly increase the reliance on central power plants for back-up electricity provision again, and limit the larger potential of VPP operation in this scenario compared to scenario B.

Again, the use of VPPs can increase a-prior balancing and the amount of Reserve Power offered, thereby increasing the amount of RRP offered. However, again it is the question here if the benefits of VPPs will exceed the costs, especially since the effect on the amount of RRP offered without VVP operation is already positive. Pehnt et al (2006) agree that even without interconnection to VPPs, micro cogeneration tends to result in grid relief and peak shaving due to operation during system peak hours. “Thus, it is questionable whether the additional service benefit of connecting micro cogeneration units to virtual power plants is actually worth the additional effort and cost of communication and control" (p. 217).

Besides, the provision of Reserve Power would bring both complexity and risks for the consumer-generator, which can lead to added costs. After all, micro-CHP operation during periods of low heat demand increases the fuel costs if the heat storage tank is not sufficient. A high pay-off for the provision of Reserve Power could compensate for this, but the interconnection costs for the VPP, the aggregator fee and the share for other consumer-generators part of the VPP lower the pay-off significantly.

All the above shows that the availability of central power plans for RRP provision is generally increased by the introduction of electricity-led micro-CHP due to the lower

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[25] The average system load in 2006 was 11,851 MW (TenneT website 2006), while the average consumption of all households according to the 2002 consumption profile was 2,715 MW (Ecofys 2001, assuming 3,397 as the average household consumption)

system load. The reverse flows of exported electricity are too small to result in many temporal shut-downs. Moreover, the micro-CHP output is more independent from heat demand, which means that less back-up capacity is needed to replace this output during hot days. The opportunities to form and use Virtual Power Plants are larger, but the relative benefits will be lower here compared to scenario B. The value given for allocation by profiling is a '1', and for allocation by metering a '3', taking into account the still small reduction of system load and the need for smart metering to shift consumption and generation and operate VPPs.

RRP deployed

The amount and size of system imbalances for electricity-led micro-CHP penetration are expected to decrease somewhat due to increased possibilities of PRPs to internally balance their portfolio. Also, the amount of transport restrictions will decrease significantly in this scenario, which will reduce the amount of Reserve Power deployed. On the other hand, the smaller predictability and network stability will have a negative effect on the amount of RRP deployed. These negative effects are estimated to be fairly smaller than the positive effects, however. Thus, the overall effect will be rather positive. For allocation by profiling, the value given is '4', and for allocation by metering the value given is '6'.

Costs of single-buyer market for RRP

The amount of offered RRP is thought to increase, which increases the administrative costs of the single-buyer market for Regulating and Reserve Power. However, the decrease in the amount of deployed RRP is thought to be larger, which leads to an overall decrease of the costs. The net effect is similar to scenarios A and B, so the value '1' is given for both allocation methods.

Effects on imbalance settlement

Accuracy allocation

Considering the choice for a metering-profiling option, the creation of a new generation profile is again the logical choice: the generation pattern of electricity-led micro-CHP units is basically the same as the consumption pattern, and therefore as predictable. Differences between the consumption profile and the production profile can be caused by a certain responsiveness of consumer-generators to price regimes (in the profiling allocation method) or price signals (in the metering allocation method), which can be studied in advance as well. Although the mere coverage of own electricity demand would not lead to significant export, the use of an import-export meter can still be favourable for metering the import and export exactly. In combination with the need for generation data provided by a generation meter, gross generation metering would again be the logical option. However, for allocation by profiling exact metering of import and export is much less important, so that net generation metering could suffice. However, since it is not realistic to assume that the import tariff and export tariff will be equal, gross generation metering is preferred. This increases the costs of the metering facility only marginally, because the highest costs are attached to the smart metering technology and software.

The accuracy of the allocation process is not affected by the micro-CHP penetration when the profiling allocation method is used: it is assumed that each PRP will have the responsibility for a similar portion of the consumer-generators, making possibly larger deviations for that group irrelevant to the effectiveness of the allocation. For allocation by metering, the allocation will be perfect. This leads to the same values as for scenario B: '0' for allocation by profiling and '6' for allocation by metering.

Imbalance costs

The imbalance costs are determined by the amount of control power deployed, the liquidity of the single-buyer market for Regulating and Reserve Power, the RRP margin, and on the amount of imbalances by the PRPs. The amount of control power deployed is expected to decrease significantly, which decreases the imbalance costs. The liquidity of the RRP market will improve a bit for allocation by metering when aggregators participate on behalf of the consumer-generators, which lowers the imbalance costs a bit. The RRP margin will increase quite a bit, which reduce the imbalance costs by the lower imbalance prices derived. Finally, the imbalance size of PRPs will decrease only for the metering allocation method, because they can in that case balance generation and consumption more for themselves. This decreases the imbalance costs for that allocation method. Adding up, the value given to allocation by profiling is '5', and the value given to allocation by metering is '7'. The larger effect compared to scenario B is mainly caused by the larger RRP margin, but also by the decreased imbalances caused by the higher operational flexibility of electricity-led micro-CHP operation.

Costs of allocation

For the valuation of the costs of allocation, the exact same arguments can be brought up as under the other scenarios, so that the costs for allocation by profiling are similar to today (value '0'), and the costs for allocation by metering are much higher (value '-8').

4.3.4 Scenario D: Electricity-led micro-CHP operated by supplier

The main difference of this scenario in comparison to scenario C is that the operation of the micro-CHP unit is executed by the electricity supplier, instead of the consumer-generator. This means that the unit is switched on and off when the supplier wants it, subjected to some constraints agreed upon between supplier and household. This arrangement could remove the burden of financial risks and high investment costs on the households, and provide the suppliers maximum control over the micro-CHP units, not depending anymore on household responsiveness to price signals and having full operational flexibility even under allocation by profiling.

Effects on Programme Responsibility

Predictability production & consumption
The predictability of electricity generation of households with a micro-CHP system will in this scenario be maximal. However, the predictability of electricity consumption cannot be controlled, making the resulting net exchange still uncertain to some extent. Furthermore, the contribution of the group of households with a micro-CHP unit to total system load is limited. Still, a large positive valuation of the effect on this performance criterion is justified: a '7' is given. This value holds for both allocation options: the fact that in this scenario the communication portals provided by the smart metering facilities are used to control the micro-CHP units from a distance is independent from the choice between allocation by profiling and allocation by metering. The exact domestic generation is known for each PTU, which removes the largest uncertainty in predictability in this scenario.

Accuracy E Programmes
Thanks to operational control of the micro-CHP units by the suppliers, the operational flexibility, and thus the possibilities to shift generation are maximal. Therefore, possibilities to balance the electricity portfolio are high, and submitted E Programmes can be followed up more easily. This is only subject to some constraints related to the utilization of product heat in the households, which is settled between the consumer-generators and suppliers. Again, it must be taken into account that the micro-CHP contribution to the system is limited. The difference between the two allocation methods is here that for allocation by profiling, the consumption cannot be influenced by price signals, but this is of minor importance compared to the high operational flexibility. The value given for allocation by profiling is '6', and for allocation by metering '7'.

Costs of Programme Responsibility
Because the accuracy of initial E Programmes will be higher and the number of altered E Programmes lower, the administrative costs belonging to the Programme Responsibility instruments will be lower. Also, the balancing of system supply and demand and the resolution of transport restrictions by TenneT will be easier and therefore cheaper. The

value give here is '2' for allocation by profiling and '3' for allocation by metering, because the changes in these administrative costs will still be relatively small.

Effects on the single-buyer market for RRP

Network stability

Network stability will become somewhat lower compared to electricity-led micro-CHP units operated by the consumer-generator because the control by suppliers will result in a much more active operation of the micro-CHP units. Suppliers will switch these units on and off and ramp up and down much more often in order to maximize their profits and balance their portfolio. This results in larger and more frequent variations of the micro-CHP contribution, which will have a negative effect on the power quality and transient stability of the system. However, investigation of general technical effects of micro-CHP under scenario B indicates that the effects will probably still be manageable. The value for the network stability is therefore set at '-4'.

RRP offered

Generally, the micro-CHP control by the supplier will result in better a-priori balancing, because he aims to maximize his profits. When the day ahead market price or intraday market prices rises as a consequence of supply shortage, it will become more attractive to switch on/ramp up the micro-CHP units, which results in a smaller shortage of electricity. This will decrease the use for central power plants to balance system supply and demand, so that more central capacity is available for RRP provision.

Furthermore, the effect on the freeing of transport capacity will be largest for this scenario, because the suppliers will free transport capacity when it is needed, driven by the reflection of this in the electricity prices. For instance, when the capacity of the network is used almost entirely, the supplier could generate just enough electricity with the micro-CHP units so that whole the distribution network is supplied, freeing the transmission system from any electricity import or export. In addition, the system load is already reduced by the in-house generation and consumption of electricity.

The following control strategy provided by the full micro-CHP control illustrates both the increase in a-priori balancing and the decrease in system load. A group of micro-CHP units controlled by a supplier could be operated in such a way that the distribution load is flattened, like a study by Peacock and Newborough (2006) proved possible. In Figure 23, it is shown for a distribution circuit with 50 households and a micro-CHP penetration (1 kW_{el} units) of 76% that the electricity distribution load can be flattened by means of so-called ‘Aggregated Load Control’, which can be considered a sophisticated operating strategy, programmed into the micro-CHP systems. The predictable shape of the distribution load enables such a strategy, which significantly increases a-priori balancing on the distribution system level. The flattened load shape thus decreases the demand for back-up capacity, thereby increasing the availability of Regulating and Reserve Power.

The question remains to which extent the flattening of the distribution load will emerge, but the operation of micro-CHP units during periods with a high system load driven by the price mechanism will already move the system in this direction.

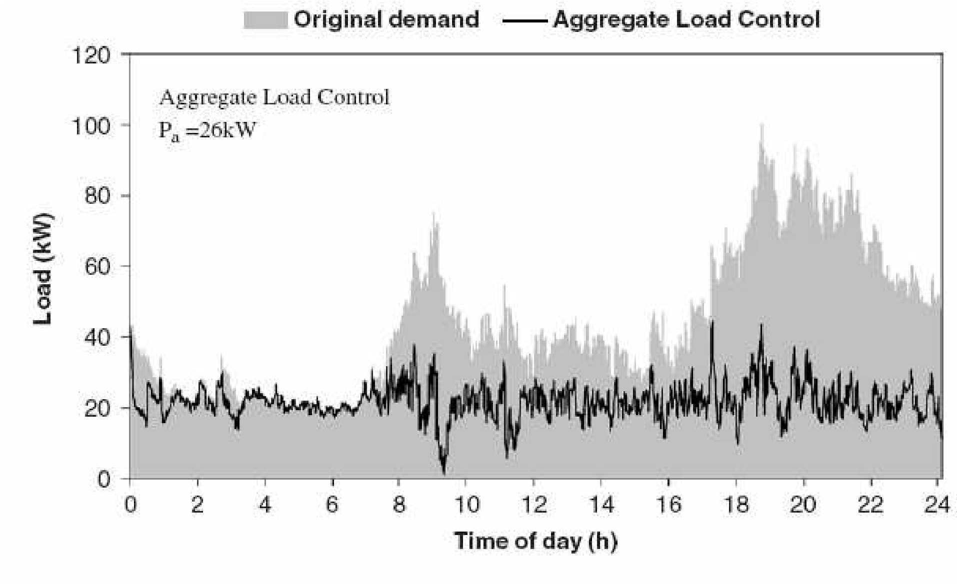

Figure 23: Effect of Aggregate Load Control on the network by 50 dwellings on a January day (Peacock and Newborough 2006, fig. 3b)

Finally, the opportunity to form and operate Virtual Power Plants is maximized here, and is in this scenario is the most straightforward: because the supplier has maximum control over multiple micro-CHP units, he can easily offer and deploy this as Reserve Power, or even as Regulating Power. The provision of Regulating Power could become possible, because the households have lost the control over their units anyway, so that automatic deployment by means of Load Frequency Control is achievable. Of course, the technical features of the micro-CHP must meet the requirements for bids of Regulating Power. The regulating speed and part-load performance of Stirling engines and low-temperature fuel cells could already be sufficient, and even more so in the future. According to Peças Lopes et al. (2006), "An innovative, low-cost means of scheduling automated mass responses from highly flexible small plant can be developed. If such a scenario does arise, it is likely that the scope for aggregation services will increase" (p. 1193). RRP should only be offered, however, when the dispatch of micro-CHP does not lead to waste of heat and/or household energy costs higher than agreed upon.

It thus appears that for this scenario, the benefits of VPP operation are most likely to exceed the costs, even though the a-priori and internal balancing made possible by the full operational flexibility and control minimizes the need for micro-CHP for RRP provision.

To conclude, the effect of supplier-control of electricity-led micro-CHP units on the amount of RRP offered is very positive, because of the increase of day-ahead and intraday balancing, increased availability of central power plants and RRP provision by micro-CHP. Because the suppliers are in control of the units, they also meter the generation continuously (with the generation meter), which removes DG generation from the pool of non-metered, profiled consumption and generation. This means that the choice for an allocation method does not make a large difference here. The value given is a '6'.

RRP deployed

The effect of this scenario on the amount of RRP deployed depends on the effects on network stability and predictability of production and consumption. The positive effect on production and consumption has been valued higher than the negative effect on network stability.

Then, this performance criterion is also influenced by the amount and size of system imbalances and transport restrictions. The amount of system imbalances will reduce thanks to the increased predictability and day-ahead and intraday system balancing, while the transport restrictions reduce due to the reduction of the system load caused by the micro-CHP penetration.

It is assumed that, compared to scenario C, the increase in predictability and balancing will just cover the negative effects on network stability. The difference between the two allocation methods is thought to be too small to notice, because it only takes effect indirectly via the possibility to shift consumption with smart metering, which is thought to be unexploited because of the generation shifting potential. The resulting value is '6'.

Costs of single-buyer market for RRP

The effect on the costs of the operation of the single-buyer market for Regulating and Reserve Power are zero: the increase in RRP offered is estimated to be as large as the decrease in RRP deployed.

Effects on imbalance settlement

Accuracy allocation

The effects of electricity-led micro-CHP penetration on the accuracy of the allocation process are the same as for the other scenarios. The fact that micro-CHP generation does not have to be accounted for by means of the profile methodology (as in the other scenarios) does not mean that the accuracy of allocation has been increased. The absolute allocation error will probably become smaller, but that is taken into account under 'imbalance costs'. The values given are '0' for allocation by profiling and '6' for allocation by metering, just like in the other micro-CHP scenarios.

Imbalance costs

The imbalance costs are determined by the amount of control power deployed, the liquidity of the single-buyer market for Regulating and Reserve Power, the RRP margin, and on the amount of imbalances by the PRPs. The amount of control power deployed is much lower, the liquidity of the RRP market does not change, the RRP margin is much larger and the amount of imbalances of PRPs reduce due to maximum operational control without additional unpredictability. This leads to much lower imbalance costs. The choice of allocation method does not lead to a change in the imbalance costs, because the possibility of consumption shifting (DSM) is thought to be unexploited, because the generation shifting suffices and is more reliable. This leads to the valuation of this performance criterion with an '8' for both allocation methods.

Costs of allocation

Regarding the choice for a metering-profiling option in this scenario, the choice for a profile considering household generation is still necessary here: although generation is metered as part of the supplier control, actual import and export are still not known under allocation by profiling. The creation of a generation profile is not necessary because of the generation metering. When the metering allocation method is chosen, consumption will be metered as well.

Again, an import-export meter appears necessary, because the supplier wants to know how much electricity is used by the household and how much is exported. This again has to do with the price for electricity import and the value of electricity generated in-house: the arrangement with the supplier in this scenario will probably encompass the payment of investment costs, operational costs and maintenance costs by the supplier, and payment of fuel costs by the household, in exchange for free electricity whenever electricity demand and micro-CHP generation coincide. The natural gas costs could be reduced as well, in this arrangement. Thus, gross generation metering will be used in this scenario as well.

Concerning the effect of this scenario on allocation costs, the choice for an allocation option has a relatively smaller cost impact. The costs of the profiling allocation option will be higher, because generation is continuously metered by means of the smart generation meter. This results in data collection costs for the supplier, but the operation of the micro-CHP also creates communication costs. The consumption is still allocated by means of the profile methodology, however. But that does not lead to half of the costs compared to allocation by metering, because there are some fixed costs like a communication infrastructure, data storage capacity, and data transport capacity. This is why the costs are estimated to be '-6' for allocation by profiling, and the usual '-8' for allocation by metering.

4.4 Results

In this paragraph the results of the analysis in paragraph 4.3 are presented and discussed. Table 4 lists the multiplied effects (the values given to the performance criteria times the weights) for each scenario and for both allocation methods. First, the general outcome is discussed. Then, the sensitivity of the outcome to changes in weights and values are indicated. After that, the limitations of the analysis are described. Finally, some general findings from the analysis are presented, including the largest uncertainties related to the effect of large-scale DG penetration on the operational performance of the Dutch balancing market design.

Performance criteria	*weight*	**Scenario A**		**Scenario B**		**Scenario C**		**Scenario D**	
Allocation option		profiling	metering	profiling	metering	profiling	metering	profiling	metering
Programme Responsibility effects									
Predictability production & consumption	*3*	-9	-9	-6	-3	-6	-9	21	21
Accuracy E Programmes	*5*	-15	-10	-10	0	0	20	30	35
Costs of Programme Responsibility	*1*	-4	-4	-2	-1	0	2	2	3
Single-buyer market for RRP effects									
Network stability	*5*	-10	-10	-10	-10	-5	-5	-20	-20
RRP offered	*5*	-25	-25	0	10	5	15	30	30
RRP deployed	*4*	-8	-4	12	20	16	24	24	24
Costs of single-buyer market for RRP	*1*	1	1	1	1	1	1	0	0
Imbalance settlement effects									
Accuracy allocation	*3*	-6	18	0	18	0	18	0	18
Imbalance costs	*3*	-15	-15	9	12	15	21	24	24
Costs of allocation	*1*	0	-8	0	-8	0	-8	-6	-8
Effects Dutch balancing market									
Short-term economic performance	*6*	-18	-26	8	4	16	16	20	19
Short-term reliability	*25*	-73	-40	-14	35	10	63	85	108
Operational performance balancing market design	*31*	-91	-66	-6	39	26	79	105	127

Table 4: Weighted effects DG scenarios on the operational performance of the balancing market

In the valuation, short-term reliability was estimated to contribute for about 80% to the operational performance, and short term economic performance for 20%. With weights adding up to 31 and a value scale from -10 tot 10, the maximum positive effect would be 310 and the maximum negative effect -310. Looking at the net results for the four scenarios, it becomes apparent that the overall effect of DG penetration on balancing market performance found is small (scenario B) to reasonably large (scenario D).

With respect to the relative outcome of different scenarios, scenario D leads to the best net result, followed by scenario C, scenario B, and scenario A. This holds both for allocation by profiling and allocation by metering. Further, the net result is positive for scenario D and C, positive for allocation by metering and negative for allocation by profiling in scenario B, and negative for scenario A. If the results would hold in reality, this means that the large-scale introduction of (1 kW_{el}) micro-CHP generally improves the operational performance of the Dutch balancing market, except for heat-led micro-CHP when allocation by profiling is used as the allocation method. The large-scale introduction of (1 kW_{el}) PV cells decreases the operational performance.

The difference in net result between to consecutive scenarios is largest between A and B, and smallest between B and C. This is logical, because scenario A and B differ in the DG technology used, while the only difference between scenario B and C is the operational strategy.

For all scenarios, allocation by metering brings a higher net result than allocation by profiling. This suggests that allocation by metering should always be chosen as the allocation method. However, the difference in each scenario between allocation by profiling and allocation by metering is rather small, on average only 36 ‘value points’ out of a range of 620. And because the exact costs of smart metering are one of the largest uncertainties, one should be careful to conclude that allocation by metering is always the better option.

In short, the rash conclusion from the results presented in Table 4 would be that large-scale penetration of electricity-led micro-CHP systems in households operated by the electricity suppliers should be strived for, and that the allocation should be executed by continuous metering of household consumption and production.

As a first comment on the analysis results, other effect valuations and/or other weights will give other net results, leading possibly to entirely different findings for the DG scenarios. The effects of some value and weight modifications on the net results will be discussed now, as a test for the validity of the outcomes.

First, it is interesting to look at a value modification for the costs of allocation in allocation by metering, because this allocation method always comes on top but the magnitude of this criterion is very uncertain. If ‘-10’ instead of ‘-8’ were the value for all scenarios, the effect on the net result would be negligible, but if the weight of this performance criterion is changed from 1 to 3 as well, the average difference in net result for the scenarios would be halved to 17 value points. However, allocation by metering would still be the best allocation option for all scenarios.

Second, the effects of DG penetration on network stability are rather uncertain, and thus interesting to examine. The effect of scenario D on the network stability is estimated to be most negative, because the use of DG in the electricity market would be largest there. If instead of the value ‘-4’ ‘-10’ were given, scenario D would still give the best results, but the difference with scenario C would be smaller. Moreover, the net result of the use of allocation by metering in scenario C would be just higher than allocation by profiling in scenario D. Of course, when the effect of all scenarios on the network stability would be zero, scenario D would stand out as the best scenario even more.

Next, it is instructive to watch the effect of the raise of every value in scenario A by one. When this is done, the net result of scenario A is still very negative: the increase in ‘value points’ of the net result would be 29 for allocation by profiling and 23 for allocation by metering.

Finally, the effect of weight modification is tested rather rigorously by changing all the fives in threes (which thus reduces the relative importance of the accuracy of E

Programmes, network stability and the amount of RRP offered, all criteria related to system reliability). This does neither change the relative outcome of the different scenarios, nor the favourability of allocation by metering and the height of its added value compared to allocation by profiling. This shows two things: that the outcomes are robust, and that the weight put on system reliability does not alter the absolute and relative outcomes very much.

From the sensitivity analysis can be concluded that the relative net results appear valid and robust. Allocation by metering indeed appears to be the best allocation method. The follow-up of scenarios in terms of the net effect on operational performance does not change, and the net result of scenario A stays negative, while the net results of the micro-CHP scenarios stay positive.

Even though the robustness of the analysis appears to be good, there can be named several limitations and reservations of its worth.

To start, short-term reliability was estimated to make up 80% of the operational performance, and short-term economic performance 20%. Thereby, it has been assumed that system reliability is four times more important than the cost competitiveness of the balancing market. But what exactly is the value of security of electricity supply is difficult to estimate. Besides, what is the contribution of the balancing market to this security is not crystal clear either. At least, the author thinks is it safe to say that security of supply is worth a lot, so the weight distribution is not totally wrong.

Second, the valuation of the performance criteria is only qualitative, which is related to the complexity of the system, making estimations difficult to make. As a result, it is difficult to make statements with the net results about the size of the effects of large-scale penetration of PV or micro-CHP at households.

Third, the used set of performance criteria is very short, and simplifies the balancing market and distributed generation penetration to a large extent. It is possible that the use of more and more detailed criteria would have led to different outcomes.

Finally, the outcomes say something about the operational performance of the Dutch balancing market design, which was defined to exclude social and environmental performance. The analysis of the effects of large-scale DG penetration on *system performance* should also include those. Under social performance could be understood the changes in prosperity, comfort and utility for the stakeholders, which includes the whole Dutch population and should therefore not be underestimated. The same can be said for environmental performance. One of the main advantages of PV and micro-CHP, its sustainability (PV) and its high energy efficiency (micro-CHP), were not taken into account. This is related to the fact that long-term effects were not considered in the scenario analysis. At least the inclusion of environmental performance can be expected to improve the positive effects of DG at households on the system performance of the Dutch electricity market. In concrete, the performance criteria would become less important, and the positive effects of DG penetration on environment and long-term security of electricity supply could make the net effect of micro-CHP penetration much more positive and the net effect of PV penetration positive instead of negative.

Having tested the robustness of the analysis results, the following general findings follow from scenario analysis.

1. **Scenario D has the highest net result**, followed by scenario C, scenario B and scenario A. Micro-CHP penetration has a positive effect; PV penetration a negative effect. For micro-CHP, electricity-led operation gives a higher result than heat-led operation, and supplier control is better than consumer-generator control.
2. The choice for **allocation by metering** always leads to a higher result than allocation by profiling, though the difference is generally modest.
3. The large-scale penetration of **PV cells** in households appears to have a rather negative effect on the operational performance of the balancing market. This is not to say that it can not be integrated in the system, but looking at the current balancing market performance and expected trends, it is advisable to install PV cells with a capacity smaller than 1 kW_{el}. After all, the large export rates were an important reason for the negative net result. The downside of this will be the lower contribution of PV to electricity provision.
4. For **micro-CHP systems**, the complementary installation of a boiler is a necessity and a heat storage tank is desirable especially when the units will participate in the electricity market. Stirling engines and low-temperature fuel cells are on overall the best micro-CHP technologies to choose due to their favourable technical performance and heat-electricity ratio. For heat-led operation the ORC based unit is most favourable when its properties will be proven good, and electricity export should be prevented for financial or technical reasons. For electricity-led operation, the low-temperature fuel cell is the best choice if a minimum of heat should be wasted and participation in the market is large.
5. With respect to new profiles, the creation of generation profiles should be chosen, because one can suffice for all consumer-generators and it is a straightforward and transparent option. Furthermore, exact metering of import and export saves more money than it costs compared to net metering, so **gross generation metering** is the best metering-profiling option, for all DG scenarios.
6. It will be possible to cluster DG units into **Virtual Power Plants**, but for PV cells this is pretty useless because of the uncontrollability of generation. VPPs consisting of micro-CHP units can participate in the day ahead market, intraday market and the single-buyer market for Regulating and Reserve Power, but the investment costs could very well be higher than the benefits. After all, the integration of micro-CHP lowers the prices due to a reduction of system load and peak shaving for allocation by metering. Scenario D offers the highest potential for the VPP concept, also for the use of micro-CHP as RRP.
7. **The net result of scenario D may be highest, its plausibility is not**: it requires a sound contractual arrangement between household and supplier to which both parties can agree, including a fitting allocation of costs and revenues and workable operating conditions. Moreover, the benefits supplier control could offer do not appear to be applicable to the situation: the micro-CHP investment can become affordable for the households, the operation understandable, the network stability is expected to be satisfactory, and the RRP margin will probably large enough already. Finally, this scenario would lead to much more market power in the electricity market, while DG control by households could increase the number of market players and liquidity in the electricity market.

The largest **uncertainties** found in the scenario analysis for the effect of DG penetration on the operational performance of the Dutch balancing market design are the following:

- The height of the **costs of allocation by metering**. The estimation of the added value of the metering of all households every fifteen minutes depends on the costs of data collection, transport, processing and storage. The scenario analysis shows that the difference in performance between allocation by profiling and allocation by metering is not that large, which makes the height of these costs an important consideration.
- The **manageability of metering data exchange**. When allocation by metering will be used, suddenly seven million more meter readings will be electronically transmitted every fifteen minutes. All these readings have then to be processed in order to allocate consumption and production to the relevant PRPs. It is not certain if these large data flows are manageable, while this manageability is crucial for allocation by metering.
- The **technical effects of large-scale DG penetration** in households. Especially the dynamic behaviour resulting from DG penetration, the change on reactive power provision and the effect of large export volumes are uncertain. Simulation studies can only analyze a simplified version of the system, while a large-scale DG penetration like considered in this research has not been realized in reality yet. Only the realization of such a penetration level will make the exact effects visible.
- The **costs of the formation of Virtual Power Plants** and the effect on balancing service and imbalance costs when participating in the Dutch electricity market. The latter depends on the operational performance of the VPPs.
- The **response of households to price signals**, and the consequences for the predictability of household production and consumption. This response influences the usefulness of allocation by metering in scenario B and C.
- The cooperation and support of stakeholders to supplier controlled micro-CHP penetration (scenario D), and the possibility of the construction of a **contractual arrangement** attractive to both the supplier and the household consumer. This determines the plausibility of the development of scenario D, which has the most positive effect on the operational performance of the Dutch balancing market.

5. Design options for the Dutch balancing market

The goal of this chapter is to formulate design options for the Dutch balancing market that have a potential to improve the operational performance of this market when a high penetration level of distributed generation in households has arisen. To this extent, six relevant and promising design options are derived from an overview of design variables for the Dutch balancing market in paragraph 5.1. Then, in paragraph 5.2 to 5.4, these options are discussed in relation to the analysis results, foreign balancing markets and literature (paragraph 5.2 to 5.4). In paragraph 5.5, the six design options and their specific meanings in this research are given.

5.1 Overview of design variables

The design variables for the Dutch balancing market presented below have been identified before in Chapter 2, and are shortly described there as well. Three design variables are concerned with the whole balancing market; the rest just with one balancing market instrument.

Balancing market as a whole:
- Nature of balancing control
- Level of interconnection with foreign balancing markets
- Length of the Programme Time Unit

Programme Responsibility:
- Presence of Programme Responsibility
- Admission conditions for PRPs
- Existence of a lower limit for the number of PRPs
- E Programme specifications
- T Prognose specifications
- Gate closure time

Single-buyer market for RRP:
- Degree of compulsion of RRP provision
- Structure of bid ladder mechanism
- Determination dispatch prices
- Requirements for the offering of RRP
- Requirements for emergency power
- Level of contracting of control power

Imbalance settlement:
- Determination imbalance prices
- Base of allocation of system imbalances
- Length of reconciliation period
- Length of period assignment profiles
- Length of period assignment SYC
- Structure of the profile methodology
- Provisions for smart metering

Most of the listed design variables are not relevant here, because they either are certain to decrease balancing market performance, or have no potential for improving this performance for an electricity system with a high domestic DG penetration level.

With respect to the general balancing market design variables, the variable *nature of balancing control* can be changed in two opposite directions. The adoption of hierarchical balancing control would lead to the removal of the RRP market and to full system imbalance resolution by means of contracted or own control power. There is no reason to consider this option, because the RRP market works fine. However, the adoption of **decentralized balancing control** could facilitate large-scale DG penetration when this penetration complicates the system balancing task, and increase the possibilities for DG as RRP. The *level of interconnection with foreign balancing markets* lies outside the scope of this research, but will also be hard to obtain considering the differences between the Dutch balancing market and foreign ones (see paragraph 5.3) and the limited interconnection capacity. Regarding the *length of the Programme Time Unit,* the increase of the PTU would probably reduce the balancing market efficiency. A decrease could improve this efficiency, but in that case it will be even harder to collect and process all metering data when allocation by metering is adopted. Also, the reasonable predictability of PV and micro-CHP makes this option of less value. Still, the **reduction of the PTU length** is considerable.

Considering the Programme Responsibility design variables, the *presence of Programme Responsibility* makes it possible to allocate the balancing costs among the responsible parties, which creates the incentives for parties to keep to a certain predefined net electricity volume and balance internally. Its removal is therefore highly undesirable. Furthermore, there is no reason to change the current *admission conditions for PRPs*, *E Programme specifications* or *T Prognose specifications*. After all, their usefulness does not depend so much on the technical state of the system as on the structure of the balancing market, including the used communication protocols and PTU length. The *existence of a lower limit for the number of PRPs* is also found irrelevant, because for a low number of PRPs the effects of DG penetration on imbalance and balancing costs and reliability will be the same as for a higher number. Finally, the design variable *gate closure time* can be important here. The **postponement of the gate closure time**, i.e. the reduction of the time between the final moment of submission of altered E Programmes and the operational PTU, can give PRPs more time to predict their net volume more accurately and to improve their own balance.

Concerning the RRP market design variables, the *degree of compulsion of RRP provision* is not worth considering here. After all, the voluntary offering of RRP will lead to a minimum amount of RRP offered, which will increase the imbalance costs and endanger system reliability. The augmentation of the compulsion from parties with at least 60 MW capacity to parties with e.g. at least 30 MW capacity will not be considered either, because the analysis has not revealed the need for this and because the offering of domestic DG as RRP is difficult due to required clustering and limited availability. Since the current RRP market functions satisfactorily, change of the *structure of the bid ladder mechanism* is undesirable. Likewise, there is no reason for a change in the *determination of dispatch prices*. For instance, taking the average bid price in each direction (instead of the marginal bid price) leads to smaller financial incentives and makes the offering of

RRP less attractive. The *requirements for the offering of RRP* is a design variable relevant to DG development, because the current requirements are directed to central capacity, **alteration of the requirements for the offering of RRP** could facilitate the bidding of DG as RRP. The change of the *requirements for emergency power* is not desirable, because these should be strict. Finally, adaptation of the *level of contracting of control power* appears unnecessary, because more than enough of it is contracted to solve the system imbalances that the RRP market cannot deal with (about 300 MW emergency power and 275 MW Regulating Power, while most system imbalances are between -300 and 300 MW).

Regarding the imbalance settlement design variables, a change of the *determination of imbalance prices*, such as using the same imbalance price for PRP surplus and PRP shortage when TenneT has deployed both positive and negative RRP, will decrease the effect of the financial incentives to PRPs to minimize their imbalance and to have a surplus rather than a shortage. The change of the *base of allocation of system imbalances* to one that is not grounded on PRP imbalances is highly undesirable for the same reason. The change of the *length of the reconciliation period* is of minor influence and importance, because reconciliation is removed when allocation by metering will be used, and its shortening will merely improve the accuracy of the financial incentives provided to PRPs. Next, the change of *the length of the periods for profile assignment* and *SYC assignment* will only have a marginal effect on balancing market performance compared to DG development. Besides, predictability of household consumption and production will be large enough to exclude the need to shorten these periods. Finally, the *structure of the profile methodology* and the *provisions for smart metering* are very relevant design variables in this research. The **adjustment of the profile methodology** would be required in case of large-scale DG development at least when allocation by profiling will be used, and the **embedding of smart metering provisions** at least when allocation by metering will be used. Still, both options can be useful no matter which allocation method is chosen.

In the above, six design options are deduced from the list of design variables. These options are worth considering for a new balancing market design that can improve the operational performance of the Dutch balancing market in a system with a high domestic DG penetration level. The next paragraphs will show that the design options follow not only from the balancing market description, but also from the analysis (postponement of the gate closure time, alteration of the RRP requirements; paragraph 5.2), from a comparison with foreign balancing markets (decrease of the PTU length, adjustment of the profile methodology, embedding of smart metering provisions; paragraph 5.3), and from literature (decentralized balancing control; paragraph 5.4). In the next paragraphs will also be described what these design options entail, so that an improved balancing market design can be formed in Chapter 6.

5.2 Design options following from the analysis

The results of the scenario analysis in Chapter 4 show which performance criteria are (supposedly) most negatively affected by DG penetration. This points to design options that have the potential to improve the effect of DG penetration on those same performance criteria.

As a first obvious remark, results from the analysis show that the current balancing market design is quite suitable for the integration of a large-scale DG penetration level already: the operational performance increases for micro-CHP. However, it decreases for PV, and it could be that another balancing market design is better suited for a decentralized electricity market and will result in an even higher operational performance.

Concerning a large-scale PV penetration as in scenario A, the negative effects of the uncontrollability of PV and its unfavourable generation pattern are difficult to take away, because these are inherent technological features. However, it was discussed in the analysis that the predictability of PV and the accompanying accuracy of E Programmes are improved by sending in altered E Programmes as late as possible. This suggests that the effects on these performance criteria can be improved by **postponement of the gate closure time**: the time at which PRPs must have submitted their final E Programme. The gate closure time could be decreased to thirty minutes before the PTU of operation, instead of one hour. This requires a fast and efficient handling of E Programmes by TenneT. The importance of this design option is recognized by Glachant and Saguan (2007), who state: "The temporal position of the gate closure is thus a key parameter of the design of the balancing arrangement, determining the volume of information available for decisions made on forward markets, and thus the level of uncertainty (pp. 7-8).

Concerning the effects of DG scenarios in general, balancing market design options cannot directly change the technological DG characteristics and thereby influence technical effects via the source. Indirectly, additional technical requirements for DG could me made, so that their integration will not lead to a damaging decrease in power quality or instability of the network. However, such a measure does not fall under the balancing market design. What can be done is the **alteration of the requirements for the offering of Regulating and Reserve Power**. To facilitate the participation of micro-CHP in the single-buyer market for RRP, the minimum bid size of 5 MW could be decreased, and the requirements for the minimum regulating speed and dispatch time could be relaxed as well. This can be done without adverse effects on the effectiveness of system imbalance resolution, but the requirements for central production capacity can become too weak as a side effect, which may be undesirable. Therefore, it might be a good idea to formulate a separate list of RRP requirements just for DG, so that possibilities and constraints of different types of available production capacities are taken into account.

5.3 Design options following from foreign balancing market designs

Not much documentation can be found about European balancing markets in other countries. This probably has to do with the short life of balancing market designs, which after all were created when countries liberalized their electricity sectors from the nineties onwards. Furthermore, this information is often inside knowledge that is mainly exchanged between the relevant organizations within the national electricity sectors. Normally, other actors have no interest. However, there is some investigation to combine national balancing markets to increase system reliability in the whole UCTE-grid. For this research, information about other balancing markets is interesting for the discussion of possible design options that could facilitate DG penetration in the Dutch market. Therefore, balancing markets of countries with already a large amount of DG would be particularly interesting. Micro-CHP is not implemented on a large scale yet, but according to Pehnt et al. (2006), the UK and Germany are two of the three European frontrunners in its development (the Netherlands is the third one). A lot of PV has been installed in Germany. This makes Germany particularly interesting, followed by the UK. However, other European countries will be examined shortly as well: Belgium and France, being neighbouring countries, and Italy, being the frontrunner in smart meter roll-out.

Germany

The German electricity system comprises four control zones, which together form the German control block. Each control zone is operated by one TSO. As in most European countries, the TSO operates the system and owns the assets. The German TSOs are EnBW Transportnetze AG, E.ON Netz GmbH, RWE Transportnetz Strom GmbH, and Vattenfall Europe Transmission (Morthorst et al. 2007, p. 70).

The German balancing market is quite similar to that of the Netherlands. Balance responsible parties (‘Bilanzkreisverantwortliche’) have to submit Programmes on a day-ahead basis, and imbalance is settled on a 15 minute base. A difference is that it is possible to change the Programmes until 45 minutes ahead, and sometimes even 15 minutes ahead. Another important difference is that a balancing responsible party, of which there are about 300 in Germany, pays the same imbalance price for a shortage as he receives for a surplus, irrespective of the status of the control zone. This however leads to strategic behaviour by balancing responsible parties, who at times profit from an intentional deviation from their Programme (Morthorst et al. 2007; presentation Dr. Ernst, RWE-TSO 2007).

Finally, Germany has a significant amount of PV power: about 410 MW in 2003 (compared to 41 MW in the Netherlands), which is caused for an important part by the high export tariff in place. This tariff was €0.57 in 2004, and is attributed to the distributed generator for twenty years after installation of the PV system[26]. As found out during a visit to RWE-TSO, PV power is handled together with wind power, which is balanced in a separate balancing market. With more than 20 GW of wind power, the total PV power is much smaller, and also much more predictable. The aggregate generation

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[26] http://www.senternovem.nl/duurzameenergie/projecten/den-projecten_ho-int/homehub_duurzame_energie.asp, viewed on July 14th, 2007.

pattern of the 410 MW PV capacity is accounted for by adaptation of the predicted generation pattern of the aggregate wind power production capacity (presentation Dr. Ernst, RWE-TSO 2007).

Except for the different time period for submission of Programmes, which already has been indicated as a design option, no design options suitable for the Dutch balancing market can be derived from the German balancing market, because it is largely the same.

United Kingdom (UK)

The regulation for the British balancing market consists of the Balancing and Settlement Code (BSC) arrangements, which were introduced in England and Wales in 2001 and in Scotland in 2005. The National Grid Company (NGC) is the British TSO, and PRPs are called 'BSC parties'.

Again, the main structure of the balancing market is the same: there is a form of Programme Responsibility for BSC parties, imbalance settlement, and something called the 'Balancing Mechanism', which is very similar to the Dutch single-buyer market for RRP. A first difference is that the UK has a Half Hourly Settlement Period, instead of the 15-minute PTU in the Netherlands, which makes balancing and imbalance settlement less efficient than in the Netherlands. Furthermore, participation in the Balancing Mechanism (RRP bids) is optional, while in the Netherlands parties with more than 60 MW are obliged to offer available RRP. Moreover, the minimum bid size is 1 MW, which is lower than the 5 MW in the Netherlands, while the system load is twice as large. Another difference is that the 'reverse price', i.e. the imbalance price for negative power when the system is long and the imbalance price for positive power when the system is short, is based on a forward market price derived from Power Exchange trades (ELEXON 2004; website NGC 2007).

Finally, the UK makes use of a profile methodology that is more complicated than the Dutch one. There are eight generic Profile Classes, of which two are for domestic consumers. According to a report from the International Energy Agency, "The amount of energy used by a non half-hourly metered customer in each half-hourly settlement period is determined by allocating a customer's total energy consumption according to the pattern dictated by their load profile. This is done by applying the appropriate regression coefficients to the appropriate out-turn regression variables." The regression coefficients are derived from a regression analysis. There are fifteen of them, representing five season types (winter, spring, summer, high summer and autumn) and three day types (weekdays, Saturdays, and Sundays). Finally, three types of regression variables are used to modify the profile shape on a daily basis, which are temperature variables, sunset variables and week-day variables (IEA-DSM 2007, p. 25-29).

The comparison of the British and Dutch balancing market designs provides the following observations. First, cancellation of the obligation of large parties to offer available RRP is not an attractive option, because it will reduce the amount of RRP offered and thereby the liquidity of the RRP market. Then, alteration of RRP requirements such as decrease of the minimum bid size has already been identified as a design option in the last paragraph. Next, removing the connection between 'reverse imbalance prices' and the dispatch prices in the Netherlands would reduce the efficiency of allocation of imbalance costs and decrease the quality of incentives to market parties.

Subsequently, the higher PTU length in the UK brings up a more interesting design option: **decrease of the PTU length**. The increase of the PTU length to 30 minutes in the Netherlands would decrease the overall precision of the balancing market instruments. However, the decrease of the PTU length to 10 minutes or 5 minutes could improve the overall accuracy and thus efficiency of the Dutch balancing market. To realize this decrease, it should still be possible for actors to perform their tasks in time, and the increased data flows should be manageable. Because E Programmes and RRP messages can probably be extended relatively easy, and the information and communication infrastructure will already be expanded to enable the use of smart metering, these two conditions can be met. The improved balancing market efficiency effectuated can be really important when a lot of DG capacity is installed that is able to ramp up and down very quickly. When rising balance costs (due to DG development) are distributed more accurately to the parties responsible, consumer-generators ‘guilty’ of imbalance are driven more to ‘listen to’ price signals given by the supplier.

Then, the description of the different profile methodology points to the design option of **adjustment of the profile methodology**. In order to account for domestic generation in the current Allocation process, the new profile(s) (at least one new generation profile) should be specified in the Metering Code, as should the assignment of a generation profile to either all profile customers or all households (normal households then getting a 'zero profile'). This design option is mainly important for allocation by profiling. The increase of detail and calculation in the British profiles found in the UK profile methodology is undesirable, because it would increase costs and complexity unnecessarily.

Belgium and France

According to Glachant and Saguan (2007), the balancing market arrangement in the Netherlands resembles a real-time market, while those in Belgium and France use balancing mechanisms (with penalties or an administrative fee) (p. 10). In Belgium, gate closure occurs a day ahead. "There are 16 different types of imbalance prices. These prices depend on the sign of the individual imbalance, the sign of the global imbalance, and the magnitude of the individual imbalance. Prices on these imbalances are computed with respect to the day ahead price on two markets outside of Belgium: APX in the Netherlands and PowerNext in France." (Glachant and Saguan 2007, pp. 10-11).

In France, there is no rolling gate closure. "The mechanism functions with four prices on imbalances, which depend upon the relationship between the global sign of the system imbalances and that of the individual imbalance. Imbalances with the same sign as that of the system are settled with a penalty defined by a constant (k) applied to the mean purchase price of energy to the TSO each half-hour" (p. 11).

Because of the fundamental difference between the balancing market of the Netherlands and those of Belgium and France, no suitable design options can be expected to follow from those markets. A rolling gate closure time and imbalance prices reflecting the real imbalance costs are needed for a balancing market that is really operated by the market, which is indeed the aim of the Dutch balancing market design.

Italy

Italy has just fully liberalized its electricity market in 2007, but it has already realized an enormous smart meter roll-out: Enel SpA, the dominant utility in Italy, has installed a smart meter at each of its 27 million customers in the period 2000-2005. These meters are fully electronic and truly smart: power can be turned off remotely, electricity transport capacity of a connection can be dimmed, and usage information can be read, among else. The meters communicate over low voltage power lines[27]. Currently, Enel uses the smart meters primarily for energy services like remote answering of complaints, quick repair of outages, and shutting off of customers failing to pay the bill, and less so for demand shifting (The Economist 2006).

It could not be found to which extent smart metering was used for the allocation of electricity consumption by Italian households. However, the differences between the Dutch and Italian electricity markets make the study of the use of smart metering in Italy less valuable anyway.

The Italian market model is a zonal model: There are multiple zones with each their own Energy market. The balancing of supply and demand also takes into account the balance within zones, because the interconnection capacity between zones is limited. The balancing market of Italy works with a regulated mandatory market for Regulating and Reserve Power, which is called Market for Dispatching Services (MSD), and is managed by TERNA, the Italian TSO. The settlement period for imbalances is a quarter of an hour. The selection of bids is made on the 'merit order criterion'. The height of the imbalance price for production units depends on the state of the zone imbalance and on the individual imbalance. It is the maximum/minimum price of the selected bids in the same way as for the Netherlands, and is the zonal clearing price when the individual imbalance is 'in the same verse' of the zone imbalance (ETSO 2006). This description shows that the Italian electricity system and balancing market are very different from those in the Netherlands. Therefore, useful design options cannot be derived from the Italian market.

Because the effect of price stimulation in Italy is limited by the zonal model, the more regulated RRP market and less efficient imbalance prices, benefits of smart metering and allocation by metering are likely to be very different from the Netherlands. This makes it less regrettable that specific design options coupled to smart metering were not found.

However, it can be said that the use of smart meters in a future decentralized electricity system in the Netherlands will probably require **the embedding of smart metering provisions** in the Dutch balancing market design. When allocation by metering will be chosen as the allocation method, the new Allocation process should replace the old one in regulation, specifying what will be the interval for collecting meter readings, and how reconciliation will change. Also, the already constructed new market model, which speaks of Metering Data Companies instead of MRPs, should be embedded in the balancing market design. When allocation by profiling is maintained, the role of smart metering will be smaller but should still be formalized. Important decisions concern the size of the reconciliation period, but perhaps also the nature of information exchange with the smart meters (what kind of information is exchanged).

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[27] http://en.wikipedia.org/wiki/Smart_meter, viewed on August 17th, 2007.

5.4 Design options following from literature

Given the small base of written documentation about balancing markets, it comes to no surprise that no literature has been found about balancing market designs. There is however a conceptual theory from the field of infrastructure policy that could point to some new design options: the coherence theory for infrastructures, as formed and used by Finger, Groenewegen and Künneke (2005).

The coherence theory focuses on the interrelations between the technical and institutional coordination of infrastructures. It defends the statement that there is "a need for coherence between both in order to safeguard a satisfactory functioning in terms of economic performance, guarantee of public values and technical system integrity" (Finger et al. 2005, p. 1). Considering the subject of this research, this suggests that large-scale DG penetration at Dutch households should be coherent with institutions, in order to achieve a high electricity system performance.

For coherence between the institutional coordination and technical coordination of an infrastructure, both should be based on the same coordination mechanism, and their scope of control should be coherent. There are three main coordination mechanisms: centralized, decentralized and peer to peer. Coherence in scope of control occurs when the scope of technical and institutional coordination are related to comparable system boundaries (Finger et al. 2005, p.13).

According to Finger et al. (2005), who have used liberalization of the electricity sector in general as a case study, the institutional coordination has become decentralized, while the technical coordination continued to be centralized: "In liberalized markets, the institutional coordination ideally fits the decentralized coordination mechanism with bottom-up control" (p. 16). Technical and institutional coordination are incoherent since liberalization, because the technical coordination did not change along with the institutional coordination (Finger et al. 2006, p. 17).

Remarkably, the large-scale introduction of domestic DG on its own can be argued to improve the coherence by increasing the decentralization of the technical coordination of the electricity infrastructure/system, and thereby levelling it with the decentralized institutional coordination. After all, the liberalization has brought competition in the electricity market, where electricity prices are determined by demand, supply and trade between market players. However, the technical system is still centralized: electricity is produced in large, central power plants, and then transported via the transmission network and the distribution network to the final consumer. A large-scale introduction of domestic DG would decentralize the technical coordination, because a part of the electricity generation would become decentralized. This better fits the liberalized market, because it introduces more players while reducing market shares. This reduces the market power of players and increases liquidity, which improves the market mechanisms. Furthermore, the reliance of consumers on the physical grid for electricity provision is reduced, as is the network load. Both increase the flexibility of the system, which fits a liberalized market controlled by the market instead of by regulation.

The scenario analysis supports this theoretical statement: the operational performance of the balancing market indeed increased due to the DG penetration (except for PV, which could be explained by the much lower flexibility it provides).

Concerning the Dutch balancing market, the fact that the current balancing market design functions satisfactorily leads to the statement that this design is coherent with the decentralized market and the centrally controlled technical system. Zooming in, Programme Responsibility and imbalance settlement can be called centralized, but are actually necessary for the electricity system and market to function. With respect to the single-buyer market for RRP, this market is regulated in the form of a single buyer and compulsory bidding by larger players, but these and the other rules are in place to let system imbalance be solved by the market as much as possible. The operation of the RRP market by TenneT is only logical, because it is the TSO that has the task to safeguard system supply and demand, and he has the tools to do this in the form of control of the transmission system (including LFC), operation of the auction for interconnection capacity, and emergency power contracts.

Although a large-scale penetration of DG will decentralize the technical system and therefore increase the coherence between institutional and technical coordination, the fit of the control of the balancing market, which is rather centralized, with the technical control of the whole system, which becomes more decentralized, decreases. This brings up the suggestion to introduce **decentralized balancing control** in the Dutch balancing market, by delegating some balancing service tasks from the TSO to the DSOs. In addition, according to Peças Lopes (2006), the potential of this design option follows from the characteristics and promising future of DG. They state: "In particular, the need to move from the fit and forget policy of connecting DG to electric power systems to a policy of *integrating* DG into power system planning and operation through active management of distribution networks is emphasised.” (Peças Lopes et al. 2006, p. 1190).

The desirability and usefulness of decentralized control of the balancing system in a decentralized electricity system reveals itself, if the implications of large-scale DG penetration for the tasks of the TSO are taken into account. At the moment, virtually all production comes from central power plants, which are continuously metered and directly coupled to the transmission system, and can therefore be accounted for in the system balancing service tasks easily. However, distributed generation is coupled to the distribution system, and even when it is continuously metered, it leads to much more complexity and non-transparency. The limited predictability and controllability and technical effects of the DG alter the system load pattern and overall predictability and controllability. All this make the decentralization of system balancing a logical step: DSOs can oversee the different, more complex state of the distribution networks, and make use of the DG to balance the distribution network. Besides, they can actively solve technical problems of DG, preventing a cascade through the whole system. This would greatly relieve TenneT’s system balancing task, which can then continue to focus on the transmission network level without too much difficulty.

5.5 Set of design options for the Dutch balancing market

In this chapter, six design options for the Dutch balancing market design have been identified that could improve the balancing market operational performance for a system with a high DG penetration level at Dutch households. These are:

- **Postponement of the gate closure time**
- **Reduction of the PTU length**
- **Alteration of the requirements for the offering of RRP**
- **Adjustment of the profile methodology**
- **Embedding of smart metering provisions**
- **Decentralized balancing control**

The design options are specified here in what are believed to be realistic and beneficial measures, so that the discussion of the design options and the formation of an improved balancing market design in the next chapter can be more specific.

Postponement of the gate closure time
The current gate closure time is one hour before the PTU of operation. The postponement of the gate closure time to half an hour before the PTU of operation might both be feasible and lead to a significant improvement of E Programme accuracy. This change of the gate closure time not only shifts the deadline for the submission of the final E Programmes, but also that for the T Prognoses (which specifies the use of network lines).

Reduction of the PTU length
The current PTU length is fifteen minutes. When this length is decreased to ten or even five minutes, the efficiency of the balancing market will be increased to a major extent by means of the higher accuracy of imbalance distribution. The feasibility depends on the manageability of data and the ability of actors to complete their tasks in time.

Alteration of the requirements for the offering of RRP
It was discussed above that the formulation of a separate list of RRP requirements for DG is most convenient, because current requirements are fine for central power plants but probably not for DG. Considering the offering of DG as reserve power, the regulating speed is expected to be large enough. However, the minimum bid size constraint could be decreased from 5 MW to 1 MW, so that only 1,000 DG units have to be bundled instead of 5,000. As only micro-CHP is suitable for RRP provision and this technology is subject to heat demand constraints, the RRP requirements for DG should allow for a limited availability and dispatch time. To this end, the RRP bids from DG should be required to specify exactly the available periods.

Adjustment of the profile methodology
For households that install a DG unit, a generation profile should be assigned in addition to a consumption profile. The generation profiles should be formed and specified in the Metering Code in the same way as consumption profiles. Instead of a Standard Yearly

Consumption, a Standard Yearly Generation (SYG) will be determined for each household. Possibly, multiple tariff categories will be used for generation as well, increasing the number of generation profiles and multiple (split) SYGs per consumer-generator. For allocation by profiling, the generation profile and SYG will be used to allocate household generation. Because the yearly reading could be reduced to monthly reading and reconciliation, profiles and SYCs and SYGs should perhaps be updated more often. For allocation by metering, the profiles can still be useful for forecasting, analysis and as a back-up for metering data generation.

Embedding of smart metering provisions

More than for the adjustment of the profile methodology, the interpretation of the embedding of smart metering provisions depends on the choice for an allocation method. When allocation by metering is chosen (which is best according to the analysis results), meter readings should be collected, transported, and used for exact allocation of residential electricity production and consumption every fifteen minutes. An efficient communication and information protocol should be designed for this. The total process should take at least less than fifteen minutes. Second, it should be regulated for which purposes the smart meters may be used, a provision that is also needed when allocation by profiling is used. In specific, it should be decided to what extent suppliers or DSOs can dim connections or shut off households completely by means of the smart meters. Finally, during an expert meeting of design group OG08 'Allocation and Reconciliation' on August 28th 2007, another important provision was mentioned: what should be done when metering data is missing, e.g. due to metering system failure? Because the allocation process will require a net exchange volume for every connection per PTU, this volume must be generated artificially when it is missing. It should be specified on what other data such 'data generation' should be based.

Decentralized balancing control

Giving a realistic specification for decentralized balancing control is the most difficult, because this design option has the largest and most complex implications. When considering this design option, we will think about a decentralized version of the current centralized balancing control. In this version, the total net production/consumption in a distribution network is complemented with an import or export stream from/to the transmission network in order to balance distribution system supply and demand. The DSOs will be thought to operate a smaller, simple distributed RRP market that only places RRP from the distribution network, i.e. domestic DG and larger DG, on the bidding ladder. Only when this distributed RRP market is insufficient, import/export from the transmission network will be considered, from which point the central balancing market takes over. It must be noticed that DG handled this way does not necessarily have to come from households. It could also include power plants coupled to the MV network, possibly operated by the DSOs themselves[28] or by market parties contracted by the DSOs.

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[28] This will then be DG built specifically for providing ancillary service like RRP provision, probably funded by government.

6. An improved balancing market design

The purpose of this chapter is to form an improved balancing market design for a Dutch electricity market with a high domestic DG penetration level. To this extent, the effects of the six design options identified in Chapter 5 on operational performance will be considered in paragraph 6.1, both separate and interaction effects. Then, the suitability of the design options is tested by means of four additional considerations in paragraph 6.2. After that, an improved balancing market design will be formed in paragraph 6.3. Finally, in paragraph 6.4, an implementation plan for this improved design will be described.

6.1 Effects of promising design options

Postponement of the gate closure time
The postponement of the gate closure time to half an hour before the operational PTU will increase the accuracy of the E Programmes especially when the predictability increases by time. This is up and foremost the case for large-scale PV penetration. For this scenario, the design option has probably a positive effect on the net result of the DG scenario (A). However, the disadvantage of this design option is that TenneT has less time to balance system supply and demand with full knowledge about planned electricity volumes. For PRPs, the shorter time to balance internally is compensated by the extra time to submit an altered E Programme. This will then lead to some more administrative work for TenneT.

Reduction of the PTU length
The reduction of the PTU length to 10 or 5 minutes will improve the accuracy and thereby the efficiency of the Dutch balancing market instruments. This in turn can improve DG predictability and controllability: because imbalance costs caused by DG operators are more specifically distributed to them, they will make sure that their operation becomes more predictable, by choosing a better technology or more predictable operating strategy, or by responding more consistently to price signals. For micro-CHP, this option could even effectuate that consumer-generators hand over control to the suppliers, to get rid of the financial risks and operational efforts. However, the reduction will also lead to increased data flows, which can be particularly problematic for allocation by metering.

Alteration of the requirements for the offering of RRP
The creation of a separate list of RRP requirements for DG makes it much easier to provide RRP in the form of DG. This will increase the amount of RRP offered in the single-buyer market for RRP, and decrease the imbalance costs. This is only applicable to the micro-CHP scenarios, where RRP provision is an option. This design option will further increase the positive net result of large-scale micro-CHP penetration on the operational performance of the Dutch balancing market, but its importance of course depends on the amount of DG participating in the RRP market. According to the scenario analysis, this amount will probably be small.

Adjustment of the profile methodology

The creation of generation profiles and SYGs, and the inclusion of their creation and use in regulations and daily practices will lead to relatively low costs, because this complements the current market design nicely. For allocation by profiling, this design option obviously has a large positive effect, because household generation can then be accounted for during Allocation. For allocation by metering, generation profiles can still be useful when a part of the smart metering system fails and metering data is missing. The execution of this design option is therefore expected to have a positive effect on the net results of the DG scenarios, although the effect for PV penetration can be zero.

Embedding of smart metering provisions

The instalment of enough data transfer, processing and storage capacity is of course only necessary when allocation by metering is chosen as the allocation method, and is then a prerequisite. Specification of the use of smart meter functionalities and data generation in case of missing metering data are actually also required provisions. If technological standards and operational and communication procedures are set up to tackle this in advance, this will avoid switching costs and costs arising from incompatibility problems and conflicts later on. In general, the embedding of smart metering provisions can make sure that smart metering is used the right way, improving the efficiency of the Allocation process and of participation of DG in the electricity market.

Decentralized balancing control

It is difficult to estimate what the effect of the introduction of decentralized balancing control is on the net result of DG scenarios on the operational performance of the balancing market. The costs of this design option will be large, because the whole institutional arrangement has to be adapted, control systems will be needed for all the DSOs, and coordination mechanisms for the tuning of balancing tasks between the DSOs and TenneT need to be installed. Besides, the execution will probably run into many technical and operational problems, which further increase the costs. For example, the existence of distributed imbalance settlement systems next to the national one could lead to excessively high imbalance costs for some distribution systems that would not have occurred in the current balancing market design. Another example is that PRP suddenly have to submit E Programmes to the relevant DSOs as well, which increases the amount of administrative faults and can therefore lead to more system imbalance. To minimize the problems, a well-thought decentralized balancing market design should be created, that can be implemented without endangering the system balance. If implemented successfully, it will improve the transparency of system balancing in the Netherlands, decrease potentially negative effects of DG integration, and add another level in system balancing. This will improve the effectiveness of the balancing market to solve system imbalances (so without having to use emergency power) and decrease imbalance costs. However, this only holds when DG can be managed and used as RRP, so for the micro-CHP scenarios. An additional benefit in micro-CHP scenarios is that DG offered as RRP does not have to compete with RRP from central plants, which increases the attractiveness of RRP provision.

Following a similar line of reasoning for VPPs by Pehnt et al. (2006), the added value of this design option is considered as the crucial factor for its assessment. The more negative the effect of large-scale micro-CHP penetration on the operational performance will be, the higher the added value of decentralized balancing control will be, the more attractive this design option is. As has been described in the analysis in Chapter 4, the general effect on operational reliability has been valued as positive. However, there is uncertainty about the nature of the technical effects, and also on the economic attractiveness of the creation of Virtual Power Plants, which might prevent the offering of DG as RRP. This would limit the positive effects of micro-CHP penetration to the general reduction of system load.

Finally, since scenario D appears to have the most positive net result and scenario B the lowest, this design option is more attractive for heat-led micro-CHP operation than for (supplier controlled) electricity-led micro-CHP operation, even though opportunities for RRP provision in scenario B are lower.

Interaction effects for design options

Important for the formation of an improved balancing market design consisting of a combination of the above design options are the possible interaction effects that occur when two or more design options are implemented simultaneously.

The postponement of the gate closure time to thirty minutes before the operational PTU is argued to be useful predominantly for large-scale PV penetration. This means that the alteration of RRP requirements and decentralized balancing control, which are directed to dispatchable DG, will probably not be implemented along with this design option. The need for adjustment of the profile methodology and embedding of the smart metering provisions depends on the allocation method chosen, which does not interfere with the system balancing tasks influenced by the change of gate closure time.

The reduction of the PTU length is quite complementary with the postponement of the gate closure time, because both decrease the time scale used. Quick handling of procedures required by the first probably enables the postponement of the gate closure time as well. Further, RRP requirements should perhaps be changed as a consequence, but not necessarily. Next, the profile methodology should definitely be adjusted: a profile fraction is needed for each 5 or 10 minutes, depending on the new PTU length. Regarding the embedding of smart metering, the reduction of the PTU length requires even more data transfer and processing capacity. Finally, this design option can complement the implementation of decentralized balancing control, especially when technologies with a quick regulating speed or that are relatively unpredictable are used.

The alteration of the RRP requirements is only useful for a large-scale penetration of micro-CHP. In this case, micro-CHP will be used to offer RRP, which requires allocation by metering, and embedding of smart metering provisions as well. The adjustment of the profile methodology is not needed. The implementation of decentralized balancing control can be really useful, but especially when adverse effects of the micro-CHP penetration are expected to be larger than anticipated in this research. This is the case when the individual capacity and/or the penetration level are larger than assumed here, negative effects are underestimated, and/or positive effects are overestimated.

The adjustment of the profile methodology is mainly useful when allocation by profiling will be used as the allocation method. For allocation by metering, domestic generation is exactly metered, and thorough data analysis by means of smart metering can substitute the use of profiles for prediction.

The embedding of smart metering provisions is more of a precondition when smart meters are installed in every household. This is particularly important when the metering allocation method will be used, which is according to the analysis in Chapter 4 favourable for a decentralized Dutch electricity system.

Decentralized balancing control should be implemented when the negative effects of large-scale DG penetration at Dutch households on system balancing capabilities are significant. The distributed RRP markets can naturally wield other RRP requirements, directed to the distributed generation that will be offered on them. This means that decentralized balancing control and the alteration of RRP requirements are complementary design options. A later gate closure time could have a negative impact here, because, although the task of TenneT of system balancing on the national level will be relieved, he must wait on the 'balancing states' of the different distribution networks that result from the balancing control by the DSOs. This causes a time delay for TenneT, which increases again the time needed for system balancing between gate closure time and operational time.

Summarizing this paragraph, in scenario A the change of the gate closure time should be implemented, while in the micro-CHP scenarios the alteration of RRP requirement should be implemented, in combination with decentralized balancing control when the negative effects of micro-CHP penetration are really significant. Furthermore, embedding of smart metering provisions should always be implemented (though is more important for allocation by metering), while the adjustment of the profile methodology should be implemented when allocation by profiling is chosen. Finally, the reduction of the PTU length is most useful for the balancing market when allocation by metering is chosen, because DG operators will than face more accurate imbalance costs. In case of allocation by metering, this reduction will still affect the continuously metered producers and producers. All this is shown in Table 5. Dark grey means that implementation of the design option is really beneficial; light grey that the implementation is limitedly beneficial, depending on the DG scenario emerged and the allocation method chosen.

	Allocation method	Decrease of gate closure time	Reduction of the PTU length	Alteration RRP requirements	Adjustment profile methodology	Embedding smart metering	Decentralized balancing control
Scenario A	profiling	■	░		■	░	
	metering		■			■	░
Scenario B	profiling		░		■	░	
	metering		■	░		■	░
Scenario C	profiling		░		■	░	
	metering		■	░		■	░
Scenario D	profiling		░		■	░	
	metering		■	░		■	░
Dark grey = largely beneficial ; Light grey = limitedly beneficial							

Table 5: Indication of the desirability of the design options for all scenarios and allocation options

6.2 Suitability of design options

When considering the adjustment of the current Dutch balancing market design in order to make it more suitable for the large-scale introduction of domestic DG, one should not only take into account the effects on the operational performance in a future decentralized electricity system, but also in the current centralized electricity system. The latter includes the effects on DG development, as different designs can change the attractiveness of investment in different DG technologies.

Furthermore, it is important what the relevant actors think of changes to the current balancing market design, especially when they can block it. Finally, the feasibility of the design option is important. This leads to four additional considerations for the design options:

- The effect of the design options on the performance of the *current* electricity system
- The effect of the design options on the probability of development of the DG scenarios
- Actor support of the design options
- Feasibility of the design options

Effect on the performance of the current system

The postponement of the gate closure time is the only design option that can have a significant positive effect on the operational performance of the balancing market in the current system. The alteration of RRP requirements, embedding of smart metering provisions and adjustment of the profile methodology are not applicable, because there is no domestic DG penetration and no smart metering roll-out. Decentralized balancing control for the current system is also useless, because there is not enough production capacity coupled to the distribution networks. The reduction of the PTU length can already improve the balancing market efficiency, if the larger information streams are manageable for especially the grid operators.

Effect on the probability of DG scenario development

In scenarios A, B, and C, the households are assumed to invest in and operate the DG units. The investment decision is based on investment costs, operational costs, revenues, and Return-On-Investment. The financial attractiveness of DG is not directly influenced by the design options, except in scenario D. In scenario D the supplier is thought to invest. When the opportunities for profit by active market participation are increased, investment will be more attractive to suppliers. This means that the alteration of RRP requirements, embedding of smart metering provisions, and decentralized balancing control will stimulate the development of scenario D.

Considering the indirect influence of design options, the change of the gate closure time will facilitate the development of the PV scenario, because predictability of PV output will improve, which in the end could increase the export price received by consumer-generators. For the micro-CHP scenarios, alteration of RRP requirements, embedding of smart metering provisions, and decentralized balancing control will facilitate micro-CHP penetration, although the last option could decrease the balancing market performance.

The adjustment of the profile methodology stimulates DG penetration without dependence on the smart metering development, which can be an advantage. The reduction of the PTU length will improve the efficiency of imbalance settlement, and therefore facilitate the development of predictable and controllable DG.

Actor support

To start, market parties will be happy with a postponement of the gate closure time, because they will gain more time to submit accurate E Programmes. The reduction of the PTU length can lead to more administrative work (for the creation of RRP messages and E Programmes), but the increased efficiency of settlement of deployed RRP and imbalances will probably lead to a much larger benefit. Alteration of the RRP requirements will be favourable to parties involved in DG operation because of the creation of a separate list of RRP requirements for DG. Furthermore, the adjustment of the profile methodology and the embedding of smart metering provisions are also options that facilitate the development of DG and smart meters, and are not expected to have disadvantages for the stakeholders. Finally, decentralized balancing control has the highest risk of being disadvantageous. For grid operators, the administrative balancing market costs can increase a lot, DSOs might be reluctant to obtain responsibility over the distribution system balance, and PRPs could face much higher imbalance costs when distributed RRP markets are used.

Summarizing, it is expected that the six design options will meet few to no resistance from electricity market participants, because in general these design options will only reduce costs and offer more opportunities for making profit.

Feasibility

The feasibility of the postponement of the gate closure time could be limited because of the timed needed by TenneT to finalize on the maintenance of the system balance. The alteration of RRP requirements, which takes the form of a separate list for DG, can be implemented easily. The same holds for embedding of smart metering provisions, in contrast to the implementation of the intelligent communication infrastructure needed for smart metering itself. The adjustment of the profile methodology will not change the basis structure, and will therefore be easy to implement as well.

However, the introduction of decentralized balancing control will probably pose many small and large problems. The whole institutional arrangement of the Dutch balancing market design has to be adapted in order to implement this design option. This is a difficult task on its own, but making the new arrangement work as satisfactorily as the current balancing market design can also become a large hurdle. An example of a potential problem is the decreased transparency of the system load balancing status for TenneT. Furthermore, the existence of multiple RRP markets might lead to excessively high imbalance prices due to the decreased offered amounts in each of them.

Finally, the reduction of the PTU length is feasible, but requires that the increased information from more frequent RRP messages, E Programmes and imbalance information is manageable for grid operators and market parties.

6.3 An improved balancing market design

With the six design options derived in Chapter 5, the description of the effects of these design options in paragraph 6.1, and the discussion of their suitability in paragraph 6.2, here an improved balancing market design will be formed that anticipates large-scale domestic DG penetration in the Dutch electricity system. Consideration of the implementation of an improved design before the DG penetration has arisen is the most crucial, because it can prevent negative effects on the operational performance of the Dutch balancing market, and will be based on incomplete information about these effects.

The six design options identified are the postponement of the gate closure time, the reduction of the PTU length, the alteration of the requirements for the offering of RRP, the adjustment of the profile methodology, the embedding of smart metering provisions, and decentralized balancing control. The formation of an improved design can be commenced by identification of the interdependency of the design options, based on the interaction effects described in paragraph 6.1.

The adjustment of the profile methodology and the embedding of smart metering provisions are options that are independent from the other options, because they are related to profiles, which can have a function in any future scenario, and to smart meters, which were assumed to be installed in every Dutch household. Next, alteration of the RRP requirements and decentralized balancing control are both DG-related design options and can improve each other’s effect, but the first can be useful on its own while the second needs the first to maximize the amount of RRP offered. Furthermore, the reduction of the PTU length and the postponement of the gate closure time are both time-related design options. It was said that they are complementary in the sense that they both decrease the time-scale and can improve balancing market efficiency, but also that simultaneous implementation can add too much burden to the balancing market since the reduction of the PTU length increases data flows and a later gate closure time decreases the time for TenneT to finalize on system balance maintenance. Finally, implementation of these last two design options also influences the value of the DG-related design options, and vice versa. For example, when the system imbalance costs are better distributed, possible negative effects of DG development will result in a lower attractiveness of further DG investment, making decentralized balancing control a less suitable option.

Ergo, only adjustment of the profile methodology and embedding of smart metering provisions can really be called independent design options, the other four are more dependent design options.

In paragraph 6.2 it has been shown that both actor support for and feasibility of the implementation of the design options are good (with decentralized balancing control as the exception). This is why the creation of the improved balancing market design will be based on the dependency of the suitability of design options on the emerging DG scenario and the chosen allocation method (see paragraph 6.1), and on the interdependency between design options (see above).

As the obvious starting point for the improved balancing market design, the *adjustment of the profile methodology* and the *embedding of smart metering provisions* can be put forward. Not only are these two the only independent design options, they also can be argued to be useful in any scenario. It is true that the adjustment of the profile methodology is most useful when allocation by profiling is chosen, but in case of allocation by means of smart metering the profiles can still be used for forecasting and data generation when data is missing. The embedding of smart metering provisions is most useful when allocation by metering is chosen, but the agreement on used smart metering functions and information exchange is also important for allocation by profiling. Finally, the investment in data transport capacity is desirable because allocation by metering has come up as the best allocation method, while the creation of generation profiles does not cost a lot of money. All of this leads to the conclusion that these two design options should be implemented whichever DG scenario will arise.

Then, for the anticipation of PV penetration, *the postponement of the gate closure time* has been identified as a suitable design option, because it enables PRPs with responsibility over PV owners to submit more accurate E Programmes. For the anticipation of micro-CHP penetration, *the alteration of RRP requirements* is a good option that increases the amount of DG that can and will be offered in the market for Regulating and Reserve Power.

Subsequently, the suitability of the *reduction of the PTU length* was argued to depend on the manageability of the larger metering data flows. When allocation by metering is chosen, the amount of metering data coming from the continuously metered households will already be enormous compared to the current situation, but in case of the change to a PTU of five minutes, the already large data flows will triple. Furthermore, the suitability of *decentralized balancing control* has been argued to depend mainly on the nature of the technical effects of large-scale domestic DG penetration. When these effects are very negative, the large increase in system imbalances can be countered by introducing system balancing control on the distribution system level.

Putting all the above together, and noticing that the DG technology emerging, the manageability of data, and the nature of the technical effects of DG penetration do not fixate each other, the improved balancing market design created here can be represented by Figure 24.

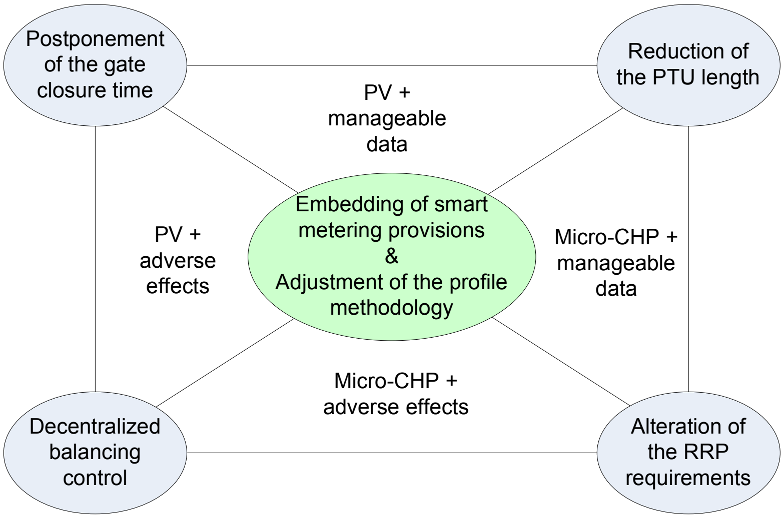

Figure 24: Improved balancing market design that anticipates a high domestic DG penetration level

As a validation to the above balancing market design, the different decentralized situations anticipated can all be argued to be possible. Adverse technical effects of DG penetration are possible for both micro-CHP and PV penetration, which increases the value of decentralized balancing control. Generally, reduction of the PTU length is a beneficial option, but the increase in metering data should be manageable. Both the manageability of metering data and the nature of technical DG effects are inherent technological features, which are quite independent of the emerging DG technology and the accompanying design option implemented. This shows that the emerging DG technology, the nature of the technical DG effects, and the manageability of metering data are indeed valuable as different criteria for the choice for implementation of an improved balancing market design. Thus, in total, there are eight possible situations: either micro-CHP or PV emerges as the leading DG technology, technical effects are either positive/insignificant or adverse, and metering data flows are either manageable or unmanageable. To these respond eight fine-tuned designs, all of which can be found in Figure 24. For the combinations of ‘adverse effects and unmanageable data’ and ‘non-adverse effects and manageable data’, the four small triangles show four of the fine-tined designs. For the combination ‘adverse effects and manageable data’, the two large triangles show two more fine-tuned designs. For the combination ‘non-adverse effects and unmanageable data’, the diagonal from the upper left corner to the lower right corner shows the last two fine-tuned designs: for micro-CHP penetration only the alteration of RRP requirements should be implemented next to the two centre ones; for PV penetration this is the postponement of the gate closure time.

Furthermore, it is interesting to notice that the possible combined development of both micro-CHP and PV in Dutch households on a large scale can be coupled to the remaining fine-tuned designs that can be formed with the improved balancing design shown in Figure 24. Such a combined development has not been included in the analysis, but is quite plausible: the Dutch government will want to stimulate PV for its sustainability and micro-CHP for its high energy efficiency. The two remaining large triangles in Figure 24 correspond to fine-tuned designs for situations of combined development where either technical effects are adverse or the amount of data is manageable. When both are the case, all design options are included. Finally, for the combined development of PV and micro-CHP where effects are not adverse and too large data flows are unmanageable, only the adjustment of the profile methodology and the embedding of smart metering provisions are really useful. After all, the predictability of PV in combination with the possibility to control micro-CHP to adjust the PV generation pattern makes the need of DG as RRP minimal, and thus the alteration of RRP requirements unnecessary.

Concluding on this, an improved balancing market design for the Dutch electricity system that anticipates large-scale domestic DG development at least includes the adjustment of the profile methodology and the embedding of smart metering provisions. Depending on the DG technology emerging, the postponement of the gate closure time (for PV) and/or the alteration of RRP requirements (for micro-CHP) should be implemented. Decentralized balancing control and the reduction of the PTU length could be implemented in advance as well, depending on the nature of the technical effects of domestic DG development and the manageability of large metering data flows.

6.4 Implementation plan

In this paragraph, a plan for the implementation of the improved balancing market design that anticipates large-scale DG penetration is described. This plan is based on the following line of reasoning. It is not possible to know for sure what the future may bring, and therefore which fine-tuned design should be chosen from the improved balancing market design formed in paragraph 6.3. Based on the situation (including the amount of knowledge), the design could be implemented in phases instead of entirely at one point in time. Finally, it can be worthwhile to carry out some other measures not part of the balancing market design that can facilitate the desired domestic DG development.

To start, it was argued above that a fine-tuned design should be picked for implementation from the general improved balancing market design depicted in Figure 24. The selection should be based on the DG technology emerging, the nature of the technical effects of DG penetration, and the manageability of metering data flows. On this moment, it can not be said which situation will arise, seeing that both the nature of technical DG effects and the manageability of large data flows have been identified as uncertainties, and that the nature of DG development is not certain either. After all, there is no experience with high DG penetration levels. Based on the conducted research, it is believed that the nature of DG development will become known first (due to specific governmental stimulation), followed by the manageability of metering data later on (thanks to the analysis of a first group of continuously metered residential DG owners), and finalized by the nature of the technical DG effects (after extensive and realistic performance studies).

To continue, the suitability of implementation of single design options also depends on other factors. First, *the adjustment of the profile methodology* can already be implemented before a large-scale domestic DG penetration has arisen, because the ‘metering campaign’ normally executed to create new profiles makes use of a limited group of connections. Currently, there is enough PV in the Netherlands to do this, but the campaign of course requires continuous metering with a smart generation meter. Second, t*he embedding of smart metering provisions* can best be implemented when there is agreement about communication protocols, smart metering functions, and operational procedures to be used. This can be based on experience with smart metering of the first households that have a DG unit. Third, the *alteration of RRP requirements* should obviously be based on the technical capabilities of DG. For the setting of a lower minimum bid size, it should be investigated which bid sizes in which quantities can still be handled by TenneT in the RRP market. Fourth, the suitability of the *postponement of the gate closure time* depends on TenneT’s ability to safeguard the system balance in all possible future DG scenarios. Fifth, for the *reduction of the PTU length*, next to the manageability of data flows, actors should also be able to perform their extended tasks adequately. Sixth, for *decentralized balancing control*, not only the nature of the technical DG effects is important, but also the amount of actor support (especially from the DSOs), the height of the switching costs, the change in balancing market efficiency, and the amount of arising technical and procedural problems.

It can be concluded that most aspects of the improved balancing market design can best be implemented on a favourable moment in the transition period towards a large-scale penetration of DG in Dutch households. The postponement the implementation of design options until more is known about the nature of change in the Dutch electricity system reduces the risks of implementing unsuitable or unsuitably tuned design options much more than is gained from immediate implementation.

Furthermore, it can be concluded from the above that probably the embedding of smart metering provisions should happen first, followed by the adjustment of the profile methodology, because these are useful in any situation. When the emerging domestic DG portfolio becomes more certain, the postponement of the gate closure time and/or the alteration of RRP requirements can be implemented. The first can best be implemented when PV is the dominating technology, or micro-CHP proves very predictable, while for the second micro-CHP penetration should be large and exact micro-CHP features should be known. Then, whenever experience with smart metering proves the manageability of large data flows, the reduction of the PTU length can be implemented. Finally, whenever the adverse effects of a high DG penetration level have become proven, this penetration is certain to arise, and expected costs and difficulties are acceptable, decentralized balancing control should be implemented.

Considering additional measures that can facilitate large-scale DG penetration, some important recommendations were made during the final seminar of the Europe DG-GRID and ELEP projects on June 5th 2007. Important ones are:

- Reinforcement of the distribution grids needed for DG integration. The need for this can be reduced by more active network management by DSOs.
- DSO should not be compensated through DG connection charges. To guarantee non-discriminatory network access, DG connection charges should be based on shallow costs (i.e. direct costs of the connection), because of the transparency and consistency of it, clear division of cost responsibilities and a non-discriminatory environment.
- DG integration costs should be socialized among consumers and DG operators through Use of System charges. These can also be negative when network savings are greater than the costs.
- Simplification and streamlining of authorisation, certification procedures and rules for DG. Procedures for DG should also be non-discriminatory, and should include standard interconnection contracts, based on size and/or technology.

As said, such additional measures can help steering DG development in the desired direction. This could enable an earlier implementation of the alteration of RRP requirements and/or the postponement of the gate closure time, because the DG portfolio of the expected domestic DG penetration would be certain at an earlier time. Furthermore, the enactment of DG connection standards and the institutionalization of fair distribution of costs and benefits could make sure that only DG with significant positive network effects are installed, thus preventing the need for implementation of decentralized balancing control. Finally, these measures can generally improve the positive effects of domestic DG development and decrease the negative ones, making the need for and added value of all design options smaller, but paradoxically also increasing the opportunities to implement them.

7. Conclusion

7.1 Recommendations

The created improved balancing market design anticipating a high domestic DG penetration level is recommended to be implemented on the basis of to-be-gathered knowledge about the nature of the emerging technological DG portfolio, the nature of the technical effects of DG, and on the manageability of large metering data flows. The best combination of design options in the improved balancing market design depends largely on those factors. Furthermore, it is recommended to implement the improved design in phases, because not all knowledge needed to make the implementation decisions can be obtained in the same time.

As a consequence, the embedding of smart metering provisions should happen first, followed by the adjustment of the profile methodology, because these two design options are useful in any situation. When the emerging domestic DG portfolio becomes more certain, the postponement of the gate closure time and/or the alteration of RRP requirements can be implemented. The first can best be implemented when PV is the dominating technology, or micro-CHP proves very predictable, while for the second micro-CHP penetration should be large and the exact micro-CHP features should be known. Then, whenever experience with smart metering proves the manageability of large data flows, the reduction of the PTU length can be implemented. Finally, whenever the adverse effects of a high DG penetration level have become proven, this penetration is certain to arise, and expected costs and difficulties are acceptable, decentralized balancing control should be implemented.

The most suitable actor for leading the eventual implementation of design options and for monitoring the electricity sector developments is probably the Dutch TSO TenneT. TenneT should monitor the progress made in the installation and operation of smart metering and domestic DG, and frequently evaluate the added value and feasibility of the implementation of the design options. To get the required information, and reach consensus with the relevant stakeholders (producers, suppliers, PRPs, DTe), this should be accompanied by frequent discussions of the need and desirability for change. As said, the actors will support the implementation of the design options.

It is recommended that grid operators, PRPs, electricity suppliers, metering data companies and other relevant parties should discuss the merits and demerits of a few profiles versus many profiles, but also those of allocation by profiling versus allocation by metering. Open discussion and decision-making is needed, because the required knowledge resides in the different stakeholders and the decisions affect all of them. Allocation by metering can be considered for implementation before all households have a smart metering facility. A possible plan is to install smart meters first at households that have a DG unit or are installing one, and to use allocation by metering only for the households with a DG unit. After all, this is the most unpredictable and interesting group, which will in the beginning be much smaller than the two million assumed in the scenario analysis.

Considering the embedding of smart metering provisions and the adjustment of the profile methodology, which should be implemented first and no matter what scenario will emerge, the following can be said.

The development of smart metering and the roll-out of smart meters should be closely monitored. All the smart meters installed should have the same characteristics, and the desired functions should be operative. To this extent, the Dutch Technical Agreement NTA 8130 is an important guiding document. The project group of the same name has formulated the different functions smart metering systems should have, and the (technical) requirements that are posed to these functions. Also, it has proposed to the Ministry of Economic Affairs to keep the project group alive, so that it can evaluate the content of the NTA 8130 at least once per year, and possibly make suggestions for action (NEN 2007). Such an arrangement would indeed help to make sure that the desirable functions are operative for all smart metering systems installed, so that allocation by metering will become possible.

As for the creation of new generation profiles for distributed generation in households, a trade-off should be made between accuracy of allocation and the complexity of the profile methodology. Especially when different micro-CHP units would be installed in Dutch households, different production patterns would arise that could be described by means of different profiles. Although the creation of profiles is relatively cheap (in comparison to smart metering), the increase of the number of profiles will make the process of the assignment and updating of profiles more difficult, and the Allocation process as well. The predictability of the integrative generation pattern for a group consisting of different micro-CHP units should be studied to make a good decision. This predictability will also influence the added value of allocation by metering, and is therefore useful information to base the choice for an allocation method on.

Finally, as new knowledge is gained about different DG technologies, and some have been proven to be inferior to others for technical or environmental reasons, the Ministry of Economic Affairs should adapt the DG stimulation arrangements (subsidies, taxes) accordingly, so that the desired DG development is economically driven. This will also reduce the risk that the early implementation of a balancing market design (option) will decrease the operational performance of the balancing market instead of increasing it.

If further DG penetration in general will have been proven to endanger system reliability, it will probably be most effective to let the costs, prices and charges related to DG installation and operation reflect the increased risks of system imbalance and failures. But, as the scenarios analysis indicates, such a penetration level will probably be very high, and may never be reached.

7.2 Conclusions

The answer to the main research question, *which balancing market design will have a high operational performance for a large-scale penetration of distributed generation at households in the Dutch electricity system*, is the following. The current balancing market design is capable of maintaining a sufficient performance level in case of large-scale domestic DG development. However, the implementation of the adjustment of the profile methodology, the embedding of smart metering provisions and DG-embedding regulation will be useful in any case. The usefulness of other options have been found to depend mainly on the DG portfolio emerging, the nature of the technical effects of domestic DG development, and the manageability of large metering data flows. Therefore, the created improved balancing market design anticipating large-scale domestic DG penetration advices the implementation of a specific combination of design options based on these factors.

The current Dutch balancing market design (*sub question 1*) can be said to be successfully embedded in the Dutch liberalized electricity market, because market parties are driven to prevent and resolve system imbalances. All three balancing market instruments, i.e. Programme Responsibility, the single-buyer market for Regulating and Reserve Power (RRP) and imbalance settlement, contribute to this. Looking at the current balancing market results, the Dutch balancing market design can be said to function satisfactorily: less than 3.5% of the system load has to be balanced in the RRP market.

For all three balancing market instruments a lot of detailed requirements exist. On the basis of a formulated list of requirements derived from balancing market documents, a shorter set of performance criteria has been formulated, together reflecting the operational performance of the Dutch balancing market design. These performance criteria have been ranked per balancing market instrument, and are all aspects of either short-term economic performance or short-term system reliability.

The effects of a large-scale penetration of distributed generation at Dutch households on the operational performance of the balancing market (*sub question 3*) have been analyzed by means of the qualitative valuation of the performance criteria for four DG scenarios and two allocation methods. The DG scenarios have assumed the penetration of two million 1 kW_{el} DG units at households: PV (A), heat-led micro-CHP (B), electricity-led micro-CHP operated by the households (C), or electricity-led micro-CHP operated by the supplier (D). The allocation methods considered have been allocation making use of profiles (allocation by profiling), and allocation making use of smart meters (allocation by metering).

The most important result from the scenario analysis is that from the four domestic DG scenarios considered, scenario A leads to a decrease in operational performance, while the micro-CHP scenarios lead to an increase. Scenario D causes the largest increase of operational performance, but the plausibility of this scenario is more limited. The decrease in scenario A is significant but not enormous, which also holds for the increase in scenario D. The positive effect of scenario C is small, while for scenario B the effects are minimal.

Furthermore, the choice for allocation by metering always comes out as the best allocation method. The best metering option appears to be gross generation metering, while the creation of new generation profiles for DG is the best profiling option.
Uncertainties uncovered by the analysis encompass the height of the costs of allocation by metering, the manageability of large data flows, the technical effects of large-scale DG penetration, the costs of Virtual Power Plants, the response of households to price signals, and the possibilities for mutually beneficial contractual arrangements between suppliers and consumer-generators.

There are a lot of design options for the Dutch balancing market design, but only six have been identified to potentially improve the anticipation for a large-scale introduction of domestic DG (*sub question 4*): The postponement of the gate closure time, the reduction of the PTU length, the alteration of the requirements for the offering of RRP, the adjustment of the profile methodology, the embedding of smart metering provisions, and decentralized balancing control.

An improved balancing market design has been formed for the Dutch electricity system, in order to anticipate the large-scale penetration of domestic DG (*sub question 5*). This exists of at least the embedding of smart metering provisions and the adjustment of the profile methodology. Possibly it also consists of the alteration of RRP requirements and/or the postponement of the gate closure time depending on the emerging DG portfolio, the reduction of the PTU length depending on the manageability of large metering data flows, and decentralized balancing control depending on the nature of the technical effects of domestic DG development. Additional measures like grid reinforcement and formation of DG standards can complement the implementation of the improved design to stimulate the desired domestic DG development.

Furthermore, it is recommended to implement the improved design in phases, because of the gradual increase in knowledge needed to make the implementation decisions. To this extent, studies of the use of smart metering and the behaviour of consumer-generators will help. For good monitoring by TenneT, especially with respect to the more far-reaching design options like the reduction of the PTU length and decentralized balancing control, discussion and open decision-making with the relevant actors is advisable. The more information is gathered, the better the decisions whether or not to implement which design options, the smaller the risks that the implementation will not or insufficiently increase the operational performance of the Dutch balancing market in a future electricity system with a high domestic DG penetration level.

7.3 Reflection

The research and in particular the analysis have some shortcomings that limit the validity of the conclusions drawn in the last paragraph. The main shortcomings lie in the limitations of the qualitative scenario analysis used to determine the effect of large-scale domestic DG penetration on the operational performance of the Dutch balancing market. Most important, the qualitative valuation is much less valuable than a quantitative valuation, because the magnitude of the qualitative effects cannot be compared to e.g. foreign balancing markets. Furthermore, the effects-approach in this research does not reveal how large the effects of DG penetration are in relation to the operational performance level of the Dutch balancing market. These two limitations significantly reduce the possibilities to draw conclusions and limit their value.

Other restrictions of the qualitative analysis are related to the use of a small number of DG scenarios, allocation methods, and performance criteria. Although the use of extreme variants of DG scenarios and allocation methods are suitable to reveal the possible range of effects of large-scale DG penetration, it is possible that scenarios or methods unconsidered have unexpected effects. In particular a DG scenario combining PV and micro-CHP is worth mentioning in this respect. In addition, a hybrid form of allocation by metering and allocation by profiling might combine accurate allocation with low allocation costs. Finally, the performance criteria used might be incomplete, overlap partially, or could have badly chosen weights. The abstract level of the performance criteria might conceal the real contributing factors to the effects of domestic DG penetration, blurring the outcomes and reducing the insights gained.

Furthermore, in the analysis the system environment has been assumed constant. In reality this will not be the case. The electricity and heat demand, the central production portfolio (sizes and technologies), the grid capacity, fossil fuel prices, and the actor field, among else, will all probably change. Since these changes are likely to alter the effects of large-scale domestic DG development, the assumption further limits the validity of the analysis.

Finally, a last important limitation of the analysis is the restriction to 1 kW_{el} DG units and a penetration level of two million households in the Netherlands. It can be expected that larger DG production capacities and larger penetration levels will increase the effects of DG penetration on the operational performance of the Dutch balancing market. Moreover, it is conceivable that the net result will suddenly change from positive to negative or vice versa for changing capacities and/or penetration levels.

As a last remark, the question can be posed whether or not another research method should have been chosen for the conduction of this research. However, the limited time and means in combination with the complexity of the subject excluded the possibility of a quantitative analysis on beforehand. Furthermore, the use of a technical model to simulate the network effects of different DG scenarios would only shed light on a part of the system investigated in this research. Finally, the consultation of experts for the estimation of the effects would be hard to execute, because not much people have a complete overview of the Dutch balancing market, let alone sufficient knowledge about the (future) technical features of distributed generation and smart metering facilities.

7.4 Suggestions for further research

From the above conclusions and reflection some suggestions for further research evolve. These are listed here, separated in suggestions related to the research methods used in this research and suggestions for more detailed research on other subjects.

- Valuation of the absolute operational performance of the current Dutch balancing market design, so that the relative effect of domestic DG development becomes known.
- Performing a quantitative version of the scenario analysis conducted in this research, which will be more precise, instructive and comparable.
- The validation and possible improvement of the used list of performance criteria and the used weights by means of an expert group session.

- The removal of the uncertainty related to the technical effects of large-scale domestic DG penetration, by means of more detailed simulation studies and (preferably) close examination of network effects of the introduction of domestic DG in reality.
- The analysis of DG scenarios that assume a high penetration level of both PV and micro-CHP in either the same households or in different ones. This will shed more light on the possible effects of a large-scale domestic DG penetration.
- Investigation of the costs and possibilities of smart metering, especially concerning the collection of meter readings every fifteen minutes.
- Investigation of the costs and possibilities of the formation and use of Virtual Power Plants in the Dutch electricity market, including the use of DG as Regulating and Reserve Power.
- A study of the response of households to price signals given by suppliers to change residential consumption and/or production patterns. Both the level of response and the predictability of response are of interest.
- Investigation of the possibilities for realization of scenario D, i.e. the operation of domestic micro-CHP units by electricity suppliers.
- Investigation of the feasibility of residential control systems for micro-CHP units that can be used by consumer-generators to program the micro-CHP unit to switch on and off automatically based on price signals and heat provision constraints.
- A study of the possibilities of domestic electricity storage. Electricity storage has not been considered in the research at all, because of its prohibitively high costs and limited capacity. However, technological development could improve the opportunities for domestic electricity storage. This could greatly reduce electricity export rates and fluctuation of the export volumes from households with a DG unit installed, and further increase flexibility of DG operation and opportunities for generation and demand shifting.

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NGC, www.nationalgrid.com/uk/
TenneT, www.tennet.nl

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Appendices

Appendix A: The Dutch electricity system

Structure of the Dutch electricity system

The Dutch electricity system is defined in this research proposal as the system that comprises the generation, transmission, distribution and supply of electricity within the borders of the Netherlands, including the interconnection capacity available for electricity import and export. The Dutch electricity system can be viewed upon as having a physical layer and an economic layer (see Figure A1).

The physical layer consists of the Dutch electricity generation units (operated by electricity producers), the Dutch transmission network (operated by TenneT), Dutch distribution networks (operated by DSOs), and all Dutch electricity consumers. Electricity producers generate electricity, which is first fed into the high-voltage transmission grid. This transmission grid is owned and operated by TenneT, who is therefore called the Dutch Transmission System Operator (TSO). The transmission grid connects the large and central power plants and the distribution networks throughout the Netherlands, and therefore has a high transport capacity. The electricity subsequently flows through the distribution grids to reach the electricity consumers. These distribution networks are owned and operated by regional grid operators, or Distribution System Operators (DSOs)[29].

The economic layer contains the arrangements for electricity trade. For the Dutch electricity system, these consist of a spot market, a bilateral market, a balancing market (which is actually a mechanism), and an import capacity auction. Together, these markets form the overarching 'Dutch electricity market'.

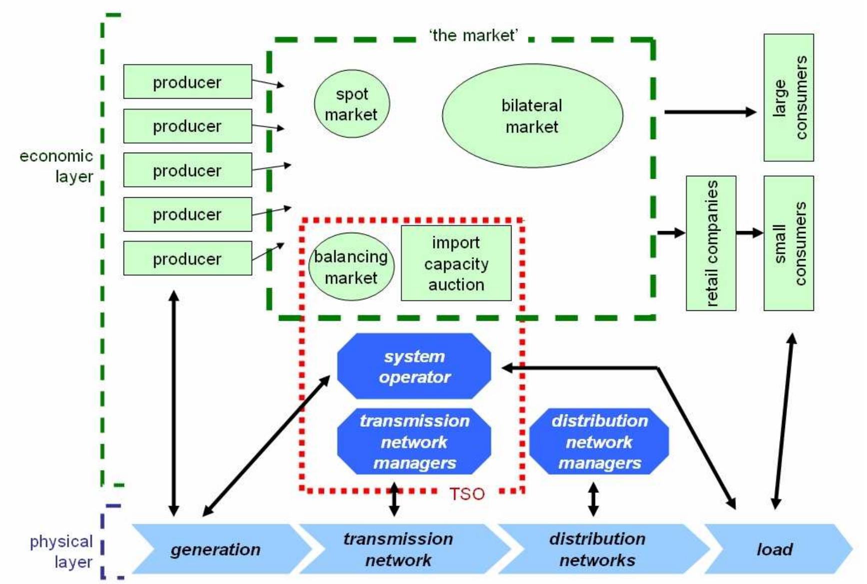

Figure A1: Demarcation of the Dutch electricity system (L.J. de Vries 2006, TPM, TU Delft)

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[29] The name 'distribution system operator' is a bit misplaced, because the regional grid operators do not perform many system services as does the Dutch TSO TenneT for the balancing of system supply and demand and the resolution of transport restrictions. However, they still are grid operators like TenneT (albeit on a smaller level), and their system operation tasks might be increased in the future, when, among else, the share of distribution generation increases.

The bilateral market, also called Over-The-Counter (OTC) market, where electricity is traded by contract, is currently the largest electricity market. Electricity producers and suppliers often sign contracts to safeguard the trade of electricity for a certain price for a longer time.

The name 'spot market' is confusing, because on this market electricity is traded one day ahead of the actual time of delivery. It is therefore also called 'day ahead market', which will be used here as well. The day-ahead market takes places at the Amsterdam Power Exchange (APX). Its role in the Dutch electricity market is limited: only 14.5% of the traded electricity in 2005 was traded on the APX (EnergieNed 2006).

Because there is a limited interconnection capacity available for cross-border trade of electricity between the Netherlands and neighbouring countries (Belgium and Germany, in the near future also Norway and Great-Britain), this capacity is auctioned by TenneT on an hourly basis. Compared to the daily electricity amount traded, the interconnection capacity is limited: at maximum 3850 MW is available for trade, while the load of the national grid can at times be higher than 15,000 MW. The imported electricity is trade via the APX.

Until one hour before the time of delivery, electricity can still be traded, mainly by Programme Responsible Parties to balance their supply and demand. This can take place on the APX or directly between parties. The attached market is also called the intraday market.

As a last resort for maintaining the system balance in the Dutch electricity system, TenneT operates the so-called balancing market. Because the balancing market only solves the imbalance resulting from deviations from planned amounts of production and delivery, and market parties do their best to avoid the high imbalance costs, the balancing market normally has to deal with a relatively small amount of electricity.

Regulatory regime for the Dutch electricity system

Like every other electricity sector, the Dutch electricity sector has been governmentally owned since its origin, up to the nineties. The common belief in the efficiency of the market has led to international enforcement of the liberalization of the electricity sector by European Directive 96/92/EG, replaced later by Directive 2003/54/EG. This Directive aims to establish an internal market for electricity within the European Union, of which liberalization is an essential precondition.

Before 1998, the Dutch electricity sector was owned and operated by the government. The liberalization of the Dutch electricity market started in 1998 with the opening of the market for large electricity consumers and ended in 2004 with the opening of the market for small consumers. This brought about the 'unbundling' of the formerly integrated electricity companies into a competitive production division, a competitive supplier division, and a monopolistic grid division, thereby creating competition between parties active in the same part of the electricity supply chain.

The European Directive 2003/54/EG has been institutionalized in the Netherlands with the creation of the Dutch Electricity Act 1998. Article 31 of this Act requires that the grid operators together make a proposal to the board of management of the regulating authority for the conditions they will wield with respect to a number of technical and procedural issues (Ministry of Economic Affairs 2007). In response, the Grid Code, System Code, the Metering Code and the Information Code have been formulated. The first two are the most important ones: the Grid Code describes the way in which grid operators should operate nets, and the System Code describes how they should deliver system services. Further, the Metering Code describes the conditions for the metering of electricity supply and demand, while the Information Code describes the determination and exchange of information between market parties. Finally, a Tariff Code is made in response to article 36 of the Electricity Act. In the Tariff Code is determined how the costs of the Dutch electricity grid are distributed among network users by means of tariff structures for connection, transport and system services. See Figure A2.

It must be noted that the Codes, although induced by the Electricity Act, has a different status. They are an indirect form of regulation. Although the existence of the Codes is required by law, the conditions in the Codes are not part of legislation. However, these conditions have been formulated with the general requirements of transparency, equity and fairness, and the rules of the Electricity Act in mind[30]. If market parties violate the Codes, they can still be judged on the basis of provisions of the Electricity Act itself.

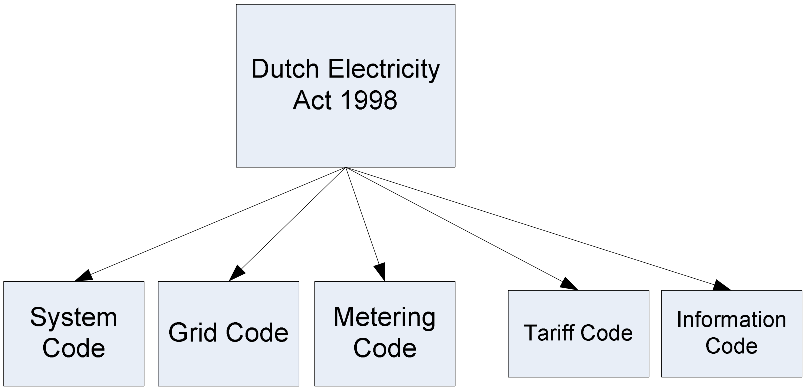

Figure A2: National regulation for the Dutch electricity system

Relevant actors in the Dutch electricity system

There are quite a number of actors that are part of the Dutch electricity system, or that influence this system to a large extent. At first sight, the type and role of the relevant actors appear quite logical. But if we look further, the multiplicity of roles and responsibilities of the actors reveal the actual complexity of the network of actors. The network of actors of the Dutch electricity system is briefly described here. It is visualized in Figure A3.

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[30] Actually, the grid operators have to wield conditions that are reasonable, objective and non-discriminating by article 26a of the Electricity Act.

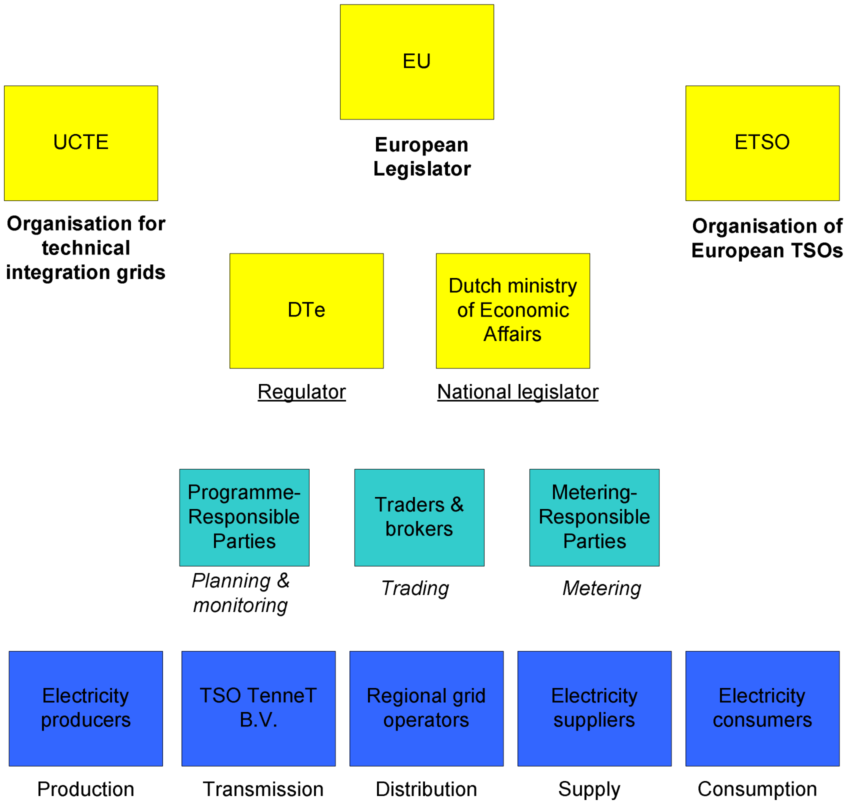

Figure A3: the network of actors for the Dutch electricity system

The network can be looked upon from different perspectives. The simplest is the perspective of the supply chain of the commodity electricity. The different subsequent functions in this chain are all exercised by a different actor. These functions are production, transmission, distribution, supply and consumption.

Production is carried out by electricity producers. In the Netherlands, most of the electricity is produced at large power plants by five different producers (Electrabel, E.ON Benelux, Nuon, Essent and EPZ). These large central power plants are coupled to the transmission grid. Also, electricity is being produced at smaller plants, which are coupled to the distribution grid: distributed generation. These are owned by a larger number of different producers.

The transmission network, which transports the electricity across the country from the central power plants to the different distribution networks, is owned and operated by the Dutch TSO, TenneT. It must resolve transmission restrictions and balance national electricity supply and demand.

The different distribution networks, which transport the electricity from the transmission network to the consumers, are owned by Distributed System Operators (DSOs). As of 2006, there were 13 DSOs, of which four large ones: Essent Netwerk, Continuon Netbeheer, ENECO Netbeheer, and Delta Netwerkbedrijf.

The function of supply is carried out by electricity suppliers. They are the administrative and commercial focal point for the customer: they deliver the electricity by buying it from producers (or traders) and selling it to the customers/consumers. There are 13 'traditional' suppliers in the Netherlands, and a growing number of newcomers. The largest (traditional) suppliers are: Nuon, Eneco, Essent and Delta (EnergieNed 2006). These and some other suppliers also deliver natural gas.

Electricity consumers are the customers of the electricity. One can differentiate between large consumers and small consumers. Large consumers are industries, commercial enterprises and business offices, of which many are directly coupled to higher voltage lines. Small consumers are generally households, which are coupled to the low voltage lines at the ends of the distribution network. The household consumers, of which there are over seven million in the Netherland, are the group of interest for this research.

From the names of the energy companies, it looks as if some actors are engaged in several functions. In fact, there are holdings which contain a production, network and supply division. This structure originates from the history of the system, and the 'unbundling' that has taken place. This is a first complication of the network of actors.

Unbundling of the electricity sector was carried out along with the liberalization in the Netherlands, meaning that the vertically integrated energy companies were disintegrated into a production part, a supply part, and a distribution part (and a metering part). Because of this separation, the specialized electricity producers and suppliers participate in the liberalized market as competing market parties, whereas the regional grid operators own and operate the grid as a monopolist, making sure that all market parties have equal access. The unbundling of the different market functions has not been complete, however: until now, only administrative and legal unbundling has been enforced. The production, grid and supply divisions of the formerly integrated energy companies are still part of the same holding. The last step in the unbundling process would be ownership unbundling, which is not required by the European Commission but strongly advocated by the Dutch government. In November 2006, the Law for Independent Grid operation (WON) was accepted with splitting only obligatory when certain conditions are present, but the new cabinet is planning to implement the law 1 August 2007 (RTV Noord 2007).

The functions of trading and metering can be seen as part of the supply chain as well, but they are discussed separately, because they have not so much to do with the actual delivery of electricity. Electricity traders buy and sell electricity, trying to make profits from the price difference in a competitive market. There are suppliers and producers with their own trading floor. There are also brokers, who do not have a position in the market, but are mediating between supply and demand in the name of market parties. Metering of electricity production, consumption is carried out by so-called Metering-Responsible Parties (MRPs), as defined in the Metering Code. MRPs are often separate entities from the mentioned energy holding companies.

Three other actors are directly related to the regulatory regime for the Dutch electricity system. First, there is a regulating authority directed to the Dutch electricity market: the Direction Supervision Energy, the DTe. The DTe controls and checks the execution and compliance of the Dutch Electricity Act 1998, among else by giving its approval to the Codes the grid operators together have to formulate. In essence, it is the supervisor for fair competition in the Dutch electricity market. Then there is the ministry of Economic

Affairs, which is responsible for the Dutch energy policy and has formulated the Electricity Act. Finally, the European Union has drawn up the European electricity directive 2003/54/EG, of which the (revised) Act is the national transposition.
There are two other relevant European actors, especially in consideration of important position of the Dutch transmission network in the research. The Union for the Co-ordination of Transmission of Electricity (UCTE) is the association of Transmission System Operators in continental Europe. It safeguards a reliable European electricity market by co-ordinating ' the international operation of high-voltage grids that all work with one "heart beat": the 50 Hz UCTE frequency related to the nominal balance between offer and demand' (UCTE 2005). The Netherlands is connected to the 'UCTE-grid'. European Transmission System Operators (ETSO) is, as the name indicates, a member organization of the European TSOs. The grid operators of all Member States of EU-15, and more, are part of it. ETSO is concerned with the commercial side of the European electricity market, such as cross-border tarification, interconnection capacity problems and market coupling (ETSO 2007).

The last actor group from Figure A3 that has not been named yet is the group of Programme Responsible Parties (PRPs). This is the most complicated actor, because this actor is artificially created by law for the purpose of safeguarding security of electricity supply in the Netherlands. The role and tasks of the PRPs are described extensively in the Electricity Act and the Codes, while the actual activities of PRPs in the real electricity market, and the interplay with other actors shows yet another picture.
In short, all parties connected to the Dutch electricity grid have Programme Responsibility. This encompasses that all connected parties draw up Programmes in which they indicate how much electricity they are planning to produce and/or consume on the next day, and which are the relevant grid supply points. And, more importantly, they should stick to those Programmes. These Programmes must be submitted to TenneT, who uses them to resolve transmission capacity problems and balance system supply and demand, and to settle imbalances with the PRPs who deviated from their Programme.

Because Programme Responsibility for a grid connection can be taken over by another party, in reality there are a countable number of PRPs, among which are producers and suppliers.

The importance of PRPs and their Programme Responsibility for the Dutch electricity system is that it effectuates a-priori system balancing, making the instantaneous system balancing task for TenneT a lot smaller in scale.

In conclusion of the above description of the network of actors for the Dutch electricity system, it can be seen that this network is indeed more complex than might be thought in first instance. This has to do with, among else, the non-transparent division of roles as understood by the electricity supply chain and the concept of Programme Responsibility. In addition, the different existing markets (the day-ahead market, the bilateral market, the import capacity auction, and the market for Regulating and Reserve Power that is part of the balancing market) make the actor interrelations and behaviour even more complex. Finally, the frequent changes in the regulatory regime (e.g. the ‘splitting law’ WON), changes in the actor field (mergers, take-overs), and technological changes (e.g. the connection to Norway under construction) will continue to change the position, structure, interests, roles and responsibilities of the actors in the Dutch electricity system.

System structure and performance figures

The purpose of this section is to give some main figures for the current Dutch electricity system and its performance. This will give an idea of the orders of magnitude the system is concerned with and of its current performance. More importantly, it will show the relative position of the Dutch balancing market in this system, and give a general indication of the current operational performance of the Dutch balancing market design.

According to the UCTE-website, about 450 million people are supplied with electric energy through the networks of the UCTE, with annual electricity consumption totalling approximately 2300 TWh. Compared to this, the electricity usage of the Netherlands is very small: there are over 16 million people in the Netherlands (3.6 % of the UCTE number), and annual national consumption is around 110 TWh (4.8% of the UCTE number).

The core figures for electricity in the Netherland for the year 2005 will now be given. They are assumed to be similar for 2007. There was 21,719 Megawatts (MW) of installed production capacity, but the highest load of the transmission network has been 15,224 MW, which is 70.1% of the installed capacity (EnergieNed 2006). This difference is related to the keeping of reserve capacity, and the fact that operational capacity is lower than the maximum reflected by the installed capacity number, but also to the existence of distributed generation. After all, DG is coupled to the distribution network: transported electricity can directly flow to consumers, avoiding the transmission lines. How large the share of DG in the Netherlands currently is, is difficult to find. It will be low compared to total production capacity, however, because only CHP has really broken through, economically. CHP in the Netherlands is 10,616 MW, which is 48.9 % of total production. The largest part of this is coupled to the transmission grid, however. All Dutch solar power units, wind turbines, hydropower units, and gas engines combined only constitute 3 GW of the national 21.7 GW capacity, according to 2005 figures (CBS 2005a). The DG technologies that the research will focus on are hardly present yet: only 51 MW of solar power is available, while the first micro-CHP units are just being placed and tested at the moment of writing.

The total national electricity production in 2005 was 101,764 million kWh (101.8 TWh), while electricity consumption was 110,186 million kWh (110.2 TWh). The surplus consumption was met by the net electricity import, which was 16.6% of consumption in 2005: 18,290 million kWh. Of the total national consumption, 37,661 million kWh (34%) was related to small consumers, and 72,525 million kWh (66%) to large consumers. From the 37,661 million kWh for small consumers, 22,522 million kWh was used by households. So, 20.4% of total consumption in the Netherlands is from household consumers, which shows the significance of a large-scale penetration of DG at Dutch households.

Because the number of Dutch private households on 1 January of 2006 was 7,146,088 (CBS 2005b), it can be calculated that the average yearly consumption of households is

3,152 kWh. EnergieNed gives a yearly household consumption of 3,397 kWh for 2005, which is a similar number.

Finally, the average electricity tariffs for household consumers are of interest here. The electricity price for household consumers, which includes Regulatory Energy Tax and VAT, was 0.21 euro/kWh. This results in a basic energy bill of 713 euro per year, assuming a yearly consumption of 3,397 kWh.

The core figures given above are also listed in Table A1 below.

Production	**2005**
Installed electric capacity [MW]	21,719
Highest load high-voltage network [MW]	15,224
Total electricity production [million kWh]	101,764
Consumption	
Total electricity consumption [million kWh]	110,186
Consumption large consumers [million kWh]	72,525
Consumption small consumers [million kWh]	37,661
Consumption households [million kWh]	22,522
Average yearly consumption households [kWh]	3,397
Average electricity tariffs (incl. REB en BTW)	
Small consumers [€/kWh]	0,23
Households [€/kWh]	0,21

Table A1: Core figures for the Dutch electricity system (adapted from EnergieNed 2006)

Before the attention is directed toward the Dutch balancing market, it is useful to give some insight in the electricity network of the Netherlands. For this purpose, first the definition of the transmission network and distribution network, as will be used in this research, will be given.

Looking at the short descriptions of the transmission network and distribution network given, it is not clear how these two network types are differentiated: at which point does the national transport from power plants stop and distribution to consumers start? Definitions are usually related to the voltage level of the network. The electricity is transported from high-voltage lines, via intermediate voltage lines, to low-voltage lines, which end up at the small consumer sites. Although voltage levels haven been ranked high, intermediate and low differently by different sources, intermediate and low voltage lines are generally found to be part of the distribution network. The definition of TenneT is used here: the transmission network comprises of all lines of 110 kilovolts (kV) or higher, and the distribution network comprises of all lines of 50 kV or lower (TenneT website).

Finally, it is useful to get a first impression of the relative importance of the balancing market within the Dutch electricity market. This is done by estimating the involvement of the market for Regulating and Reserve Power, including emergency power, in the Dutch electricity market for a number of Programme Time Units spread over the last two years[31]. Data used is retrieved from the TenneT website. See Table A2.

Date	PTU	Measured system load (MW)	Net volume deployed control power (MW)	Proportion control power/total power (%)
18-06-2007	54	11,540	226.52	2.0 %
18-03-2007	66	10,748	287.18	2.7 %
18-12-2006	32	14,928	253.29	1.7 %
18-09-2006	37	14,220	232.88	1.6 %
18-06-2006	72	10,380	162.42	1.6 %
18-03-2006	81	13,120	239.12	1.8 %
18-12-2005	70	13,024	217.89	1.7 %
18-09-2005	96	8,940	294.82	3.3 %
18-06-2005	90	9,956	177.29	1.8 %

Table A2: Estimation of the involvement of the balancing market for a number of different PTUs (website TenneT)

For different dates the national measured system load, as well as the absolute volume of settled Regulating, Reserve and Emergency Power (control power), are given for the PTU that had the largest absolute volume of settled control power[32]. The measured system load and the volume of settled control power presented are in MW, obtained by multiplying the MWh/PTU and kWh/PTU values given by the TenneT website with a factor 4, respectively a factor 0.004. From these numbers, the relative volume that the market for RRP (incl. emergency power) handled in the Dutch electricity market is estimated for the given PTUs by dividing the volume settled control power by the national measured load.

It follows from Table A2 that the Dutch balancing market (or actually the market for Regulating and Reserve Power (RRP) plus the dispatch of emergency power) has a relatively small role within the Dutch electricity market in the order of a few percentages. The average percentage from the sample is 2.0 %; the highest percentage found was 3.3 %. This outcome indicates that the Dutch balancing market is indeed operating satisfactorily: the relative amount of dispatched control power is only 1.5-3.5%, or in other words, the system imbalance is usually not larger than 3.5% of the total electricity volume transported. This means that Programme Responsible Parties generally hold on to the E Programmes they submit, and thus that electricity production and consumption is predictable and controllable.

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[31] For an extensive explanation of the market of Regulating and Reserve Power, see paragraphs 2.2 and 2.5.

[32] With 'absolute volume' is meant, the absolute value of the dispatched negative control power plus the absolute value of the positive control power (negative control power is indicated by a negative sign).

Appendix B: Detailed information profile methodology

Regulations for the profile methodology

The profile methodology is laid down in the Metering Code (in Dutch: the Meetcode), a form of secondary regulation: the Metering Code is made by DTe, following article 21 lid 1 sub b of the Electricity Act 1998, which requires that conditions are formulated concerning the measurement of electricity transport data and data exchange. Like the Grid Code and the System Code, the Metering Code therefore has a different status than the Act itself.

In article 2.1 of the Metering Code is laid down that the connection points between the grid and the connected parties should be provided with metering facilities, and that for grid connections of which the contracted transport capacity is 0.1 MW or larger, these facilities should be readable daily (every PTU) from distance. In addition, article 4.2.1 states that for connection with less than 0.1 MW transport capacity, which do not have a (voluntary) daily readable metering facility, Programme Responsibility should be carried out with the help of consumption profiles.

The profile methodology itself can be found in addendum 14. As has been mentioned earlier, there are nine consumption profiles (profile categories). These are specified in the Metering Code, and are presented in Table 1 of paragraph 2.4.

All but two profiles (E1A and E2A) have a double tariff, which requires two meter readings, one for peak hours and one for off-peak hours. A double tariff also complicates the calculation of the profiled consumption, as described above.

Another part of the profile methodology described in the Metering Code is the determination and change of the Standard Yearly Consumptions and the consumption profiles/profile categories. The Standard Yearly Consumption of a grid connection is determined by dividing the measured consumption for that grid connection over the smallest possible measured consumption period of minimally 120 days by the sum of the profile fractions in the consumption profile over the relevant period (DTe 2006, B.14.3.1). The SYC is renewed when a new and validated meter reading becomes known by the grid operator, by means of recalculation. Concerning the change of consumption profiles, not later than in the third week of January, April, July, and October, all grid operators combined submit a motivated proposal to the conference platform about the profiles that will be used in the next quarter of the year. This platform, in which reside all grid operators and PRPs that have Programme Responsibility for profile customers, decides about this proposal in less than one week (DTe 2006b).

Finally, it is also described in the Metering Code how the Assumed Profiled Consumption and the Corrected Profiled Consumption are calculated, as will be explained below. It is also described how the TCFs are calculated, which is not explained here but should be calculated for both peak hours and off-peak hours and per PRP, profile category, and tariff category.

Detailed calculation of the APC and the CPC

The calculation of the Assumed Profiled Consumption and the Corrected Profiled Consumption is a little more complicated then shown above, because of the inclusion of two other factors next to the MCF: the Climate Correction Factor (CCF), and especially the Tariff Correction Factor (TCF). The CCF is included to correct for climate differences and effects throughout time, but up to now it has been set to the value of 1. The TCF is included to adapt the consumption profile in such a way that the proportions between 'off-peak consumption' and 'peak consumption' of the profile corresponds with the proportions between 'off-peak consumption' and 'peak consumption' for the group of profile customers for which the profile is being used (PVE 2003). Off-peak consumption is consumption during cheaper 'off-peak hours'; peak consumption is consumption during full-price 'peak hours'. Most profiles have a double-tariff structure, stimulating consumers to shift consumption to the less-used and cheaper hours, thereby levelling electricity demand.

In short, the Corrected Profiled Consumption per PRP per profile category (consumption profile) is calculated in the following way. First the sum of the SYCs of the group of profile customers with the same PRP, profile category and tariff category is calculated[33]. Then, for this group, the TCFs are determined for every tariff period (off-peak hours and peak hours). After that the CCF is determined per profile category (which is 1 up to today). Next, the Assumed Profiled Consumption is determined for the group of profile customers with the same PRP, profile category and tariff category. This is done by multiplying the profile fraction with the TCF, the CCF and the sum of the SYCs of the group of profile customers, and consecutively by summing up the APCs for that group with the same PRP and profile category[34]. After that, the total consumption of profile customers is determined by subtracting the continuously metered customers, the calculated profiles and the calculated net losses from the total electricity amount fed into the grid. Then, the MCF is determined by dividing the total consumption of profile customers by the APC. Finally, the Corrected Profiled Consumption per PRP per profile category is calculated by multiplying the Assumed Profiled Consumption per group of profile customers with the same PRP and profile category with the MCF. In formula, the calculations are:

$APC = PF \times TCF \times CCF \times \Sigma\, SYC$

$CPC = APC \times MCF = PF \times TCF \times CCF \times \Sigma\, SYC \times MCF$ (PF = profile fraction)

A schematic overview of the above calculation is reproduced in Figure B1. This calculation takes place for every PTU, and is done by the regional grid operators. The results are briefed to TenneT for calculation and settlement of imbalances.

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[33] Although the methodology enables the use of different tariff categories, there currently is no more than one tariff category in any profile category.

[34] Again, this summing is only relevant for the situation in which there are more than one tariff categories in a profile category, something that has not yet been practiced.

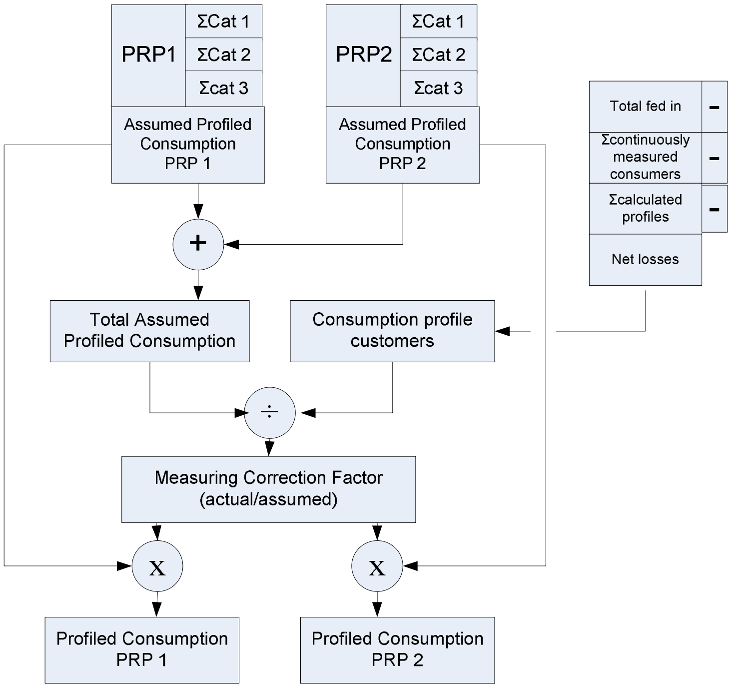

Figure B1: Schematic overview of the calculation of the profiled consumption per PRP[35]

Translation of key words profile methodology

English (translated word)	*Dutch (original word)*
profile methodology	profielenmethodiek
consumption profile	verbruiksprofiel
profile customers/consumers	profielklanten
Metering Code	MeetCode
reconciliation	reconciliatie
profiled consumption	geprofileerd verbruik
Assumed Profiled Consumption (APC)	Verondersteld Geprofileerd Verbruik (VGV)
Corrected Profiled Consumption (CPC)	Gecorrigeerd Geprofileerd Verbruik (GGV)
Actual Consumption	Actueel Verbruik
Standard Yearly Consumption (SYC)	StandaardJaarVerbruik (SJV)
Metering Correction Factor (MCF)	MeetCorrectieFactor (MCF)
Climate Correction Factor (CCF)	KlimaatCorrectieFactor (KCF)
Tariff Correction Factor (TCF)	TariefCorrectieFactor (TCF)
Programme Time Unit (PTU)	ProgrammaTijdsEenheid (PTE)
Programme Responsible Parties (PRPs)	Programmaverwantwoordelijken (PV's)
Allocation	Allocatie
telemetry facility	telemetrie-inrichting
connections	aansluitingen
meter reading	meterstand

Table B1: Translation of key words concerning the Dutch profile methodology

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[35] PVE, 2003. "Profielenmethodiek Elektriciteit – Versie 3.04" (*Dutch-only*), page 13, figure 3.

Appendix C: List of requirements for the Dutch balancing market.

Below, a list of requirements that should be met by the Dutch balancing market design to ensure a high operational performance is given.
The list includes both objectives and constraints (in contrast to the goal-tree, which only shows objectives). The requirements are derived from the descriptions of the nature and workings of the Dutch balancing market. When they follow literately from documents, this is indicated by a footnote.

1. Programme Responsibility

- Programme Responsible Parties should submit E Programmes to TenneT in correspondence with specifications in the Codes: E Programmes should be sent for each PTU, in the right format, and timely.
- Costs for PRPs to submit E Programmes and for TenneT to administer the E Programmes are minimal.
- The net volumes specified in the E Programmes should be as close as possible to the actual net volumes.
- The transport volumes specified in the T Prognoses should be as close as possible to the actual transport volumes.
- Electricity demand and supply are predicted as well as possible.
- Metering of production, transport and consumption is as accurate as possible.
- PRPs have ample possibility to minimize their imbalance before the PTU of execution (notably by internal balancing and via the intraday market)
- The balancing market rules are such that all PRPs together are stimulated to balance system and supply before the time of delivery by minimizing their own imbalance[36]

2. Single-buyer market for Regulating and Reserve Power

- Connected parties, not being grid operators, with a contracted and made available capacity of more than 60 MW, offer to TenneT all the capacity that they can consume less, respectively produce more or less, by means of bids[37]
- The RRP margin should be optimal
- The total amount of offered RRP should be sufficient for the resolution of system imbalances
- The costs of non-deployed but offered RRP should be minimal
- Enough regulating power, reserve power and emergency power should be contracted to safeguard the resolution of system imbalance that the single-buyer market for RRP can not cope with.
- The offered RRP meets the following specified requirements[38]:
    - Dispatch time smaller than 7 days
    - Regulating speed larger than 7 % per minute

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[36] TenneT, 2005. "De onbalansprijssystematiek per 01-01-2001, herzien per 26-10-2005"

[37] DTe, 1 April 2006. “Netcode – Voorwaarden als bedoeld in artikel 31, lid 1, sub a van de Elektriciteitswet 1998” (Dutch-only)

[38] TenneT, 2003. "Handleiding bieden regel- en reservevermogen"

    - Size of bid for regulating up between 5 and 100 MW, for regulating down between -100 and -5 MW (including boundary values)
    - Bid price between -100,000.00 and 100,000.00 €/MWh
    - The response time of regulating power may not exceed 30 seconds[39]
    - Regulating power can be deployed in parts; positive reserve power is dispatched in blocks, negative reserve power can be partially dispatched
- The number of bids is high enough (to ensure a high market liquidity)
- Bids should be sorted, called and settled correctly by means of the bid ladder mechanism
- The administration costs for TenneT should be minimal
- Emergency power is dispatched a minimum number of PTUs per year.
- The risks for market parties of bidding RRP should be smaller or equal to not bidding[40]
- The resulting dispatch prices should reflect the costs of deploying RRP but still stimulate the offering of RRP

3. <u>Imbalance settlement</u>

- The net volume difference for each PRP for each PTU should be correctly determined.
- The imbalance prices for positive and negative imbalance should be correctly determined
- The imbalances for each PRP for each PTU should be determined correctly.
- Settlement of the imbalances should be just and in time.
- The imbalance settlement process should be transparent, and therefore as simple as possible.
- Information exchange part of the imbalance settlement process should be conducted in time.
- The allocation should be predictable (so that PRPs can better minimize their imbalance)[41]
- The allocation process should be as accurate as possible
- The allocation process should be transparent[42]
- The allocation process should be efficient and workable[42]
- Disincentive for behaviour that upsets the balance; incentive for behaviour that restores the system balance; the risks of asked/specified behaviour are smaller for market parties than unasked/unspecified behaviour.[42]
- The imbalance prices form a sufficient financial incentive to minimize imbalances but conversely do not lead to excessively high imbalance costs.
- The prediction of consumption/production of profile consumers by means of profiles and Standard Yearly Consumption should be as accurate as possible.
- The allocation of actual consumption/production of profile consumers by means of profiles should be as accurate as possible.

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[39] TenneT, 2006. "Implementation Regulations for Grid Code and System Code"

[40] Wenting, F., 2002. "Program Responsibility" TenneT document

[41] B'con, 2007a. "OG08, Allocatie & Reconciliatie – Voortgangsdocument"

- The costs of making new profiles and allocating fitting profiles to the profile consumers should be minimal
- The time needed to allocate the total consumption of profile consumers should be smaller than the fifteen minutes

4a. Additional requirements concerning smart metering

- The metering data should be as accurate as possible
- Smart meters should give meter readings of the desired meters of electricity exchange, DG feed-in, and/or own production.
- Smart meter should send metering data in the intended specified time cycle
- The metering data should be transparent
- The costs of data collection and management are minimal
- The time needed for allocation with metering data should be smaller than fifteen minutes
- The time needed for data collection and management is minimal

4b. Additional requirements concerning technical integration DG

- Network voltage changes in the distribution network are minimized
- The voltage level must remain between specified limits
- Protection of the distribution network against faults is maximized
- Power quality in the distribution network is maximized
- Transient stability of the distribution network is high (when faults occur and DG units fall out, stability of the distribution network is maintained)
- The current level in the equipment (transformers, power lines, fuses, switches, etc.) must not exceed the thermal ratings
- The ability to balance demand and production on the distribution network level is maximized
- The ability to solve transport restrictions in the distribution network is maximized

5. Resulting system requirements

- The short-term costs of the balancing market should be minimal
- The short term reliability of the Dutch electricity system should be maximal.

The future decentralized situation is very different from the current situation of the Dutch electricity system in many different aspects. Compared to the current system, there will have occurred technical, institutional and economic changes. Two changes are taken inside the system boundaries and included in the analysis (see paragraph 3.4): the roll-out of smart meters at all Dutch households and the changed technological system caused by the domestic DG penetration. Below, implications of these changes for the balancing market requirements are taken into account. First, it is explained why these changes are incorporated, and second it is described which requirements result from them. These requirements are visible in the above list under 4.

Requirements for smart meters

In general, 'smart meters' are meters that transmit electricity data from a distance to data collectors, in contrast to the current 'dumb meters' that have to be read manually. There are however many different types of smart meters, depending on what type of data is sent, how often, if the communication is one-way or two-way, and if the smart meters can switch load. In essence, the smart meter provides the possibility to put through meter readings: not only of the current meter for electricity consumption (which can consider a peak and an off-peak reading), but also of meters measuring the own production of a domestic DG unit and/or the electricity fed back into the grid. However, also power quality could be metered, the meter could be remotely connected and disconnected, customers and suppliers could interact in different ways. (Jones 2007).

Recently, it is decided by the Dutch Ministry of Economic Affairs to provide all Dutch households with a smart meter, which could be completed by the year 2014. The conditions for these smart meters have just been determined in the NTA 8130. The aim is to make the smart meters readable from distance, to enable the grid operator to connect and disconnect a consumer from distance, and to enable suppliers/grid operators to decrease the transport capacity partially (which can be considered as partial disconnection), and to install both an external and an internal communication portal on the meter (Energie Nederland 2007).

It is assumed that all households will have a smart meter in the future decentralized situation, when the large-scale domestic DG penetration has arisen. After all, the roll-out of smart meters is aimed to be finished in 2014, while the large-scale DG penetration assumed in the scenarios will probably take many more years.

The roll-out of smart meters in combination with an accessible metering data register will make meter readings available more frequently. This offers opportunities to reconcile over shorter periods, and ultimately to have no reconciliation at all thanks to perfect allocation. (B'con 2007a). Perfect allocation by the metering, collection and use of meter reading every fifteen minutes can however be too demanding in effort, time and money, which is why the option to use the profile methodology for allocation is not discarded for the analysis.

The following ***requirements for the use of smart meters*** can be formulated. These requirements are straightforward, and formulated by the author:

- The metering data should be as accurate as possible
- Smart meters should give meter readings of the desired meters of electricity exchange, DG feed-in, and/or own production.
- Smart meter should send metering data in the intended specified time cycle
- The metering data should be transparent
- The costs of data collection and management are minimal
- The time needed for allocation with metering data should be smaller than fifteen minutes
- The time needed for data collection and management is minimal

Technical DG requirements

If distributed generation is to be integrated into the Dutch electricity system without endangering the technical integrity of the system, some requirements for the technical performance of DG should be met. These requirements should ensure that the technical operation of the distributed generation units do not lead to any technical malfunctions that hamper electricity production, electricity transport or electricity consumption. This would have negative consequences for the performance of the balancing market.

The requirements all apply to the distribution networks, because the distributed generation is directly connected to these networks, and electricity transport on these networks will increase and change as an effect. It is assumed that no technical requirements for the transmission system are needed, because the DG penetration tends to decrease electricity transmission flows. Furthermore, the requirements only represent general technical aims, of which quantification would not only be hard and imprecise, but also useless considering the conceptual status of the analysis.

The ***technical DG requirements*** are presented in the list below. The first four are derived from Jenkins, Allan, Crossley, Kirschen and Strbac (2000); the next to from Pehnt, Cames, Fischer, Praetorius, Schneider, Schumacher and Voβ (2006); the last two are formulated by the author.

- Network voltage changes in the distribution network are minimized
- The voltage level must remain between specified limits
- Protection of the distribution network against faults is maximized
- Power quality in the distribution network is maximized
- Transient stability of the distribution network is high (when faults occur and DG units fall out, stability of the distribution network is maintained)
- The current level in the equipment (transformers, power lines, fuses, switches, etc.) must not exceed the thermal ratings
- The ability to balance demand and production on the distribution network level is maximized
- The ability to solve transport restrictions in the distribution network is maximized

Although, in the decentralized situation to be analyzed, TenneT still is the only party actively involved in the system service of balancing system supply and demand, the requirement for balances on distribution network level is quite relevant. It would decrease transmission flows, decrease resulting technical problems on distribution network operation to which the other requirements refer, and increase the ability to balance national system demand and supply by operation of the balancing market.

Other additional requirements then the aforementioned ones concerning smart metering and technical conditions for DG integration are not relevant, because they either fall outside the system boundaries, or it is assumed that the relating factors remain constant. This is the case for the distribution of costs for the integration of DG (see paragraph 3.4). The mentioned additional requirements above are included in the list of requirements which should be met by the balancing market design in a decentralized situation, in order to have a high operational performance. These additional requirements were already presented in the list of requirements above.

Appendix D: Metering, profiling and allocation options

This appendix first describes possible metering options and profiling options, and then shows the resulting logical metering-profiling option. After that, two extreme allocation methods are described: allocation by profiling and allocation by metering. The metering-profiling options and allocation methods are used in the scenario analysis in Chapter 4, with the allocation methods taking a major part. The creation of metering and profiling options is heavily based on the report of Choudhury and Andrews (2002) called 'Payment mechanisms for micro-generation', although definitions and options are altered to correspond to the research scope.

Metering options

There are four different metering options discernable for a future Dutch electricity system with a large-scale DG penetration. For all four, it concerns the metering of both production and consumption of consumer-generators with smart meters[42]. An important starting remark is that we must now differentiate between consumption and import, because import will only be that part of demand that the DG unit is not able to generate. In the same fashion, export differs from (DG) production. The four metering options are:

1. Bi-directional metering
2. Import-export metering
3. Gross generation metering
4. Net generation metering

Bi-directional metering

In this metering option, one smart bi-directional meter is used for the metering of households with a DG unit installed. This bi-directional meter only meters the net exchange (net import/export volume) of electricity with the grid. The register runs forward if the instantaneous exchange is positive (i.e., electricity is imported), and it runs backward if the instantaneous exchange is negative[43] (i.e., electricity is exported).

Import-export metering

In this metering option, one smart import meter and one smart export meter are used for the metering of households with a DG unit installed. They are often combined in one metering facility, but the circuits are wired so that the import meter meters the electricity imported, and the export meter meters the electricity exported. It should be noted that actual household consumption and production are neither metered, nor can they be calculated from meter readings, in this metering option.

Gross generation metering

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[42] This means that the option of just one single-direction meter at a household with an installed DG unit is excluded, because such a meter is not capable of metering the electricity exported.

[43] The use of signs here is contrary to the general use: normally production is positive and consumption negative. But because the focus is here on former household consumers alone, and their consumption level indicated by meters and profiles is positive, the above use of signs is more convenient here.

In this metering option, one smart import meter, one smart export meter, and one generation meter are used for the metering of households with a DG unit installed. Because for the operation of the electricity system only the import and export volumes are important, generation does not have to metered, nor does it have to be a smart meter. The added value of the generation meter is that now both household production and consumption are known: production is metered directly, and consumption can be calculated by adding the production to the net exchange (*net exchange = consumption – production*).

Net generation metering
In this metering option, one smart bi-directional meter and one generation meter are used for the metering of households with a DG unit installed. The generation meter is not essential, but can have added value, just like for gross generation metering.

Bi-directional metering is obviously the simplest metering option, because it only involves one meter, and thus one meter reading (although perhaps spread on multiple registers, see below). The disadvantage of this metering option is, next to the fact that production and consumption are not revealed, that the net exchange does not reveal the exact import and export volumes either. If the meter is read every fifteen minutes, a net exchange of 0.1 kWh can mean that there was 0.1 kWh import and 0 kW export, or 0.2 kWh import in the first ten minutes and -0.1 kWh export in the last five. This is not desirable if the export tariff[44] gained for export is different from the retail price paid for import.

Import-export metering provides with a solution for the difficulty of bi-directional metering by metering import and export separately with two different meters. Although this option is more complex and more expensive (both in installation and in the collection and processing of metering data), knowing the exact import and export could earn back these extra costs.

With gross and net generation metering, consumption and production of consumer-generators become known, on top of the features of import-export metering and bi-directional metering, respectively. Knowing the exact generation and consumption of consumer-generators can be highly useful for the construction of better profiles for prediction, and for gaining insight in consumption and production behaviour in general. This includes insight in how consumer-generators respond to price signals, and how the installation of a DG unit influences the consumption pattern. In the end, this could lead to an optimization of rules and incentives, so as to maintain system reliability at lowest system balancing costs and stimulation of energy-efficient and sustainable DG technologies at the same time. Of course, the generation meter adds to the costs of installation, maintenance, and data processing, which makes gross generation metering the most expensive metering option.

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[44] This is more commonly referred to as 'feed-in tariff', but the author deemed this term to be confusing here

Profiling options

Next to different metering options, there exist different profiling options that can be used for consumer-generators (household consumers with a DG unit). The profiles can either be used for prediction, or for allocation instead of smart metering, or for both. There are four different profiling options:

1. Using the existing consumption profiles plus neglecting export
2. Using import profiles and export profiles
3. Using consumption profiles and production profiles
4. Using net profiles

The first profiling option is thoroughly considered by Choudhury and Andrews (2002), but that is because they look at the current situation in the UK electricity market, where few smart meters are placed yet. This research assumes however the existence of smart meters in all Dutch households in a decentralized future, where metering costs are much lower (due to experience and mass production). Furthermore, the use of current consumption profiles will lead to a significant profile error for most of the time, because it is the import that must be measured now. Finally, the neglecting of export is out of the question. Not only should export be accounted for by PRPs (which is not always the case in the UK), but its potentially huge technical and economical impact should be tackled, or utilized.

The second profiling option entails the composition of separate profiles for electricity import and electricity export, which are the electricity volumes of interest for both the operation of the electricity system and the electricity market. Each consumer-generator should be assigned one import profile and one export profile, which could be constructed directly from data generated with import-export metering. A disadvantage could be that the import and export profile of a consumer-generator are so closely related (you have export at times you do not have import), that the use of separate profiles has no added value.

Because information about import and export is a derivative of consumption and production patterns, it might be easier to construct consumption profiles and production profiles, and assign one of each to each consumer-generator. Also, the profiles would give more information (see above), and they would be assignable to groups of consumer-generators with the same production pattern and/or consumption pattern. However, generation meters should be installed, and the production profile and consumption profile must be combined to reveal the net exchange, which is of interest.

The use of one net profile for each consumer generator is simpler than the other two profiling options, but it will need the formation of much more profiles: assuming X different consumption patterns and Y different production patterns, there will be XY net profiles, in contrast to X + Y profiles for the other two profiling options. This will make profile development, i.e. improving profiles so that profile errors are smaller, much more difficult. Also, the net profile should include negative profile fractions to indicate the export.

Combining metering options and profiling options

As can be derived from the discussion of the different metering options and profiling options above, each metering option is logically accompanied by one or two profiling options. Bi-directional metering can be linked to the use of net profiles, because bi-directional meters measure the net exchange a net profile provides as well (in combination with the Standard Yearly Absolute Exchange[45]). In the same way, import-export metering corresponds with import and export profiles (in combination with the Standard Yearly Import/Export). Finally, both gross generation metering and net generation metering enable the formation and use of consumption profiles and production profiles, which has the advantage that current consumption profiles could be used. Besides, for gross metering import and export profiles could be formed just as well, and the same holds for net generation metering and net profiles. So, the gross and net metering options provide with two good profiling options, instead of one. See Table D1.

Metering option	**Corresponding profile(s) used**
Bi-directional metering	Net profile
Import-export metering	Import profile + export profile
Gross generation metering	consumption profile + production profile (import profile + export profile)
Net generation metering	consumption profile + production profile (net profile)

Table D1: Metering options and their corresponding profiling options for consumer-generators

Now we come to the relevance of the above metering options, profiling options, and their correspondence, for the analysis of the effects of domestic DG penetration on balancing market operational performance. Because it is believed that no metering option or profiling options is thought to have superior features and effects, the four metering-profiling options are all considered (instead of less metering-profiling options, or just metering options. The four different metering options above can all be implemented, and are therefore examined in the analysis. For simplification, the corresponding profiling options are assumed to be implemented alongside of them.

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[45] Since the net exchange is of interest, and metered as well, the determination of the Standard Yearly Absolute Exchange is much more suitable than the Standard Yearly Consumption. The absolute Exchange should be known, because negative fractions can than easily represent export volumes.

Allocation by profiling and allocation by metering

Within each of the four metering-profiling options to be considered, there are two process arrangements possible: either smart metering is used for allocation (allocation by metering), or profiles are used for allocation (allocation by profiling). Allocation by metering makes use of metering data remotely read by means of smart meters, while allocation by profiling makes use of profiles. The choice between these two allocation methods can have major implications, and will therefore be considered in the analysis as well.

In Figure D1, the process model for the current Dutch electricity market is shown. Different information streams are given, and it indicated if it belongs to the Programme Responsibility process, the allocation process, the imbalance settlement process, or the reconciliation process. Profiles are used for prediction of consumption, but also for allocation of consumption of consumers. Data is collected by a Metering Responsible Party.

Figure D2 shows the process model for the profiling allocation method in the system to be analyzed. In this case more (smart) meters and profiles are necessary, but the process structures remain essentially the same in comparison to the current ones. However, the introduction of smart meters makes possible the transfer of information, signals and orders between suppliers and consumer-generators, although to a lesser extent than with allocation by metering. This can also be done by an Energy Service Company (ESCO), hired by the supplier. Also, an Aggregator could bundle available DG capacity and offer it as RRP to TenneT, making sure that RRP requirements are met, and transferring RRP settlements between itself, TenneT, and the suppliers of the relevant consumer-generators. This aggregator could be the supplier, or a body belonging to the same energy holding. Profiles are used for allocation, and for production of both consumption and production. Data is collected by a Metering Data Company.

In Figure D3, the process model of the metering allocation method is depicted. Here, allocation is based on metering data from the smart meters, so that profiles are merely used for prediction. This results in the removal of the reconciliation process (if all connected parties are metered every PTU). Further, information transfer, signalling, and participation in the RRP market is facilitated by the increased data pool, more active consumers and market players, and shorter-term information.

Finally, the new roles and tasks of the different actors must be underlined. The Ministry of Economic Affairs wants a regulated roll-out of smart meters among Dutch households, because it does not want the possibilities of smart meters to be hampered by differences in metering technology, software or procedures. Suppliers should not use the smart meters in such a way that free market mechanisms are abused, and switching between suppliers is made difficult. Therefore, the DSOs will have the ownership of the smart meters, while the suppliers become responsible for the management of the data, although the Metering Data Companies will collect the data. The installation of the smart meters will be a public investment, possibly financed by network tariff or energy tax raises (Jones 2007; meeting B'con OG08, July 2007).

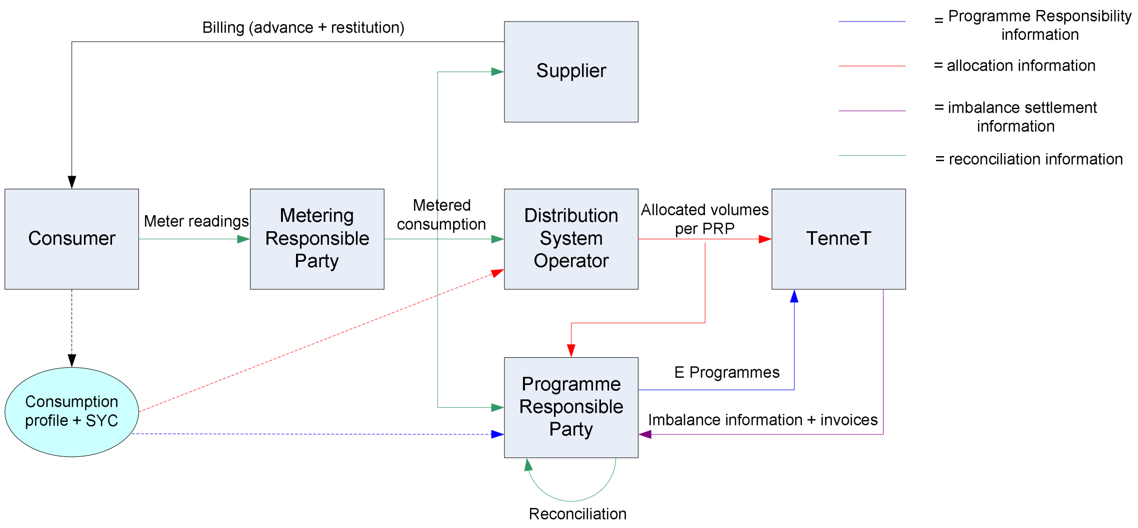

Figure D1: Allocation, imbalance settlement and reconciliation in centralized system

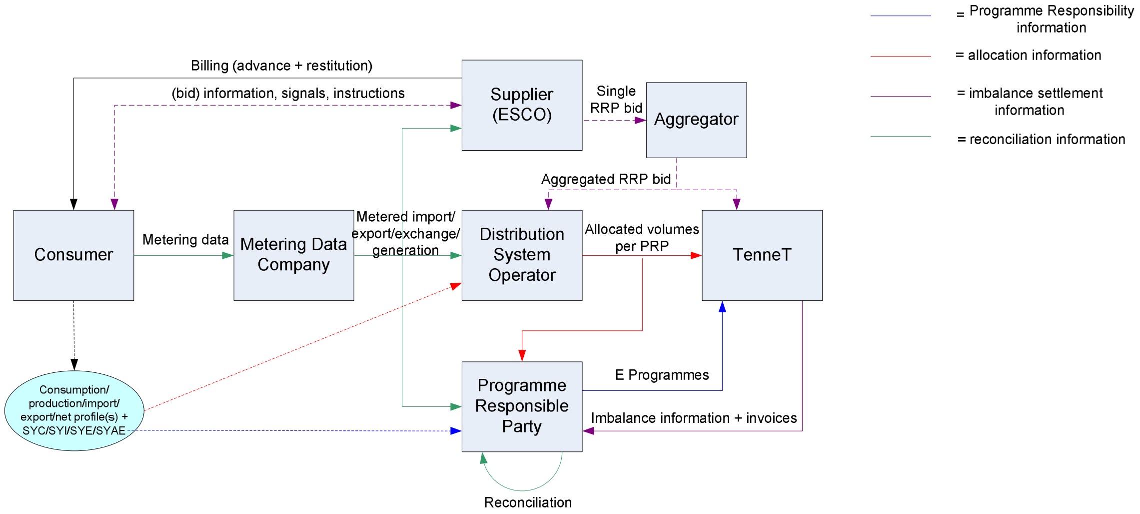

Figure D2: Allocation by profiling in decentralized system

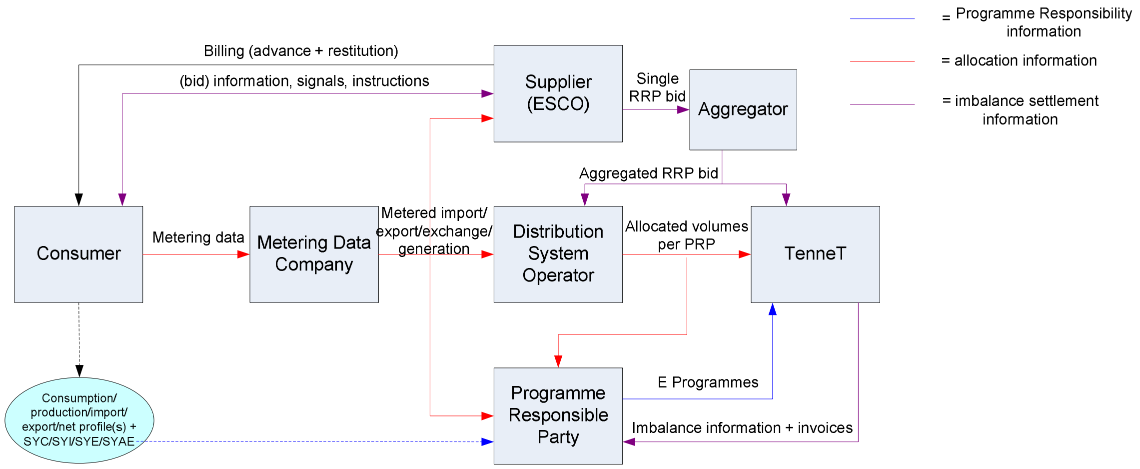

Figure D3: Allocation by metering in decentralized system

Appendix E: Characteristics of distributed generation

There is much to be said about distributed generation, because it has many definitions, there are many DG technologies with all different features, and the consequence of large-scale penetration can both be positive and negative depending on many factors. The research makes use of the definition of Ten Donkelaar: distributed generation consists of "small-scale power generation plants, connected to the distribution network or at the customer side of the network". The different DG technologies in existence are:
PV cells, micro-CHP (micro turbines, fuel cells, reciprocating engines, Stirling engines), wind turbines, hydropower, geothermal power, and small-scale steam turbines.

This research focuses on large-scale DG penetration at households. Therefore, the characteristics PV cells and micro-CHP will be considered in detail in this appendix. Before that, some general characteristics of DG penetration at households will be given. Both parts will provide information for the analysis of the effects of domestic DG penetration on the operational performance of the Dutch balancing market design.

SWOT analysis of distributed generation at households

For many technical factors that are influenced by DG penetration, even the direction of the effects is uncertain. System reliability is argued to be reduced, because the networks will have to cope with bi-directional power flows, and electricity from very different technologies that do not have the frequency stabilizing effect of central power plants (Reza 2006). On the other hand, some think that DG will increase reliability, because the fall-out of single units has a much smaller impact on the system (see e.g. Alanne and Saari 2004). Further, the probability of network failures will likely be lower.

Jenkins, Allan, Crossley, Kirschen and Strbac (2000) discuss the technical effects distributed generation units can have on the operability of the electricity system. These include the negative effects of the change of electricity flows in the distribution circuits and hence the voltage profile, the higher probability of faults in the distribution network, and the difficulty of installing suitable protection equipment and mechanisms when faults occur. However, effects on power quality are stated to be unsure: "Depending on the particular circumstance, embedded generation plant can either decrease or increase the quality of the voltage receive by other users of the distribution network" (Jenkins et al. 2000, p. 14).

Also, network stability effects of DG penetration can be either positive or negative, according to literature. According to Jenkins et al. (2002): "as the inertia of embedded generation plant is often low and the tripping time of distribution protection long, it may not be possible to ensure stability for all faults on the distribution network" (p. 17). On the other hand, the electricity volumes produced and consumed within the households do not have to flow through the grids, which frees a considerable amount of transport capacity. This decrease stresses on equipment and increases manageability of power flows, which increases the grid stability.

Finally, whether or not more or less distribution network capacity is used as a consequence of large-scale domestic DG penetration depends on the location of the distributed generation with respect to the load and the electricity export rate of the DG units, among other things (Choudhury and Andrews 2002).

In short, it is not possible to conclude on the nature of the technical effects of DG penetration. Literature mentions both positive and negative effects of DG for the same technical aspects (power quality, grid stability, voltage stability), and usually adds that exact effects depend on the circumstances. The SWOT analysis below shows strengths, weaknesses, opportunities and threats of large-scale DG penetration at households.

Strengths
- Can operate at part load
- Avoidance of line losses
- Load-following capability
- Scalability (to the size of consumption by household)
- Less capacity needed of both transmission grid and distribution grid
- Increasing redundancy

Weaknesses
- Lower electric efficiency
- High investment costs
- Limited lifetime
- Noise pollution
- Increasing unpredictability net production/consumption pattern

Opportunities
- Less transmission network capacity used
- Less distribution network capacity used
- Heat utilization
- Peak shaving
- Network stability increase
- Power quality increase
- Usage by suppliers to balance supply and demand
- Extra opportunity for DSM

Threats
- More distribution network capacity used
- Power quality decrease
- Current level in the equipment increases above the thermal ratings
- Network voltage changes
- Protection problems
- Load transfer problems
- Connection/disconnection problems
- Network stability decrease
- Bad reflection of costs and benefits in tariffs for DG users
- Effects of bi-directional flows on distribution grid stability
- Safety threats

Some factors deserve to be mentioned, apart from what is already said above.

To start, the introduction of a large share of DG reduces line losses, because electricity flows across much smaller distances. This is related to the lower electricity transport volumes the transmission network will have to cope with, thanks to the DG units, which produce the electricity where the consumption is. Moreover, the electricity generated and consumed in the same household ('behind' the grid connection of the generator-consumer) does not have to enter the distribution network either. On the other hand, electricity production volumes in excess of the instantaneous production volumes will be exported through the distribution infrastructure. This can become a problem when every household generates a high export volume at the same time, e.g. for PV cells when the sun is shining but demand is low. In such situations, export electricity might flow back to the transmission network, possibly even increasing line losses and capacity problems, compared to centralized production.

Further, an important aspect for maintaining grid stability is reactive power control. Reactive power (Q) is no real power (P), but is still necessary for electricity transport in AC networks. Apparent power (S) is the product of root mean square voltage and current, and the three factors are related according to the formula $S = P + jQ$, which is a complex number. The power factor, which indicates the ratio between real power and apparent power in a circuit (P/S), should remain between certain limits, and DG penetration could have an impact on this as well. Also, this impact differs among DG technologies. Some may “even be able to act as sources/sinks of reactive power when not generating” (Peças Lopes et al. 2006, p. 1192).

Next, many opportunities large-scale DG penetration offers in increasing network stability and power quality could be offered by active management (AM) of distribution networks. According to Peças Lopes et al. (2006), “AM techniques enable the distribution network operator to maximise the use of the existing circuits by taking full advantage of generator dispatch, control of transformer taps, voltage regulators, reactive power management and system reconfiguration in an integrated manner” (page 1192). There are different implementation levels of AM, and it remains the question how much is really needed to enable DG integration for different penetration levels. Active management by DSOs is related to the design option of decentralized balancing control (see Chapter 5).

Finally, the opportunity to provide ancillary services, notably providing Regulating and Reserve Power, is an important issue when considering DG integration, as Peças Lopes et al. (2006) clearly express: “As DG penetration increases it will become an economic imperative that DG participates in the provision of ancillary services needed for secure and reliable operation of the power system. This is important for the simple reason that if DG only displaces the energy produced by central generation but not the associated flexibility and capacity, the overall cost of operating the entire system will rise” (Peças Lopes et al. 2006, page 1193).

Description of PV cells and micro-CHP at households

First, a short list of the main advantages and disadvantages of PV cells and micro-CHP is given. Then, PV-cells and micro-CHP units are examined in detail separately. The advantage as disadvantages mentioned are derived from Borbely and Kreider (2001), Chamber et al. (2001), and Jenkins et al. (2000).

List of advantages and disadvantages

PV cells

Advantages:
- Do not have CO2 emissions
- Utilize a renewable energy source
- Modularity
- Easy maintainability
- Low weight

Disadvantages:
- Are limitedly predictable and controllable: intermittency
- Depend on sunshine or wind
- Significant area required
- High investment costs
- Modest efficiency

Micro-CHP

Advantages:
- Are rather predictable and controllable
- large load range for top efficiency
- High energy-efficiency, especially when product heat is utilized.

Disadvantages:
- Do have CO2 emissions
- Depend on natural gas supply, a finite fossil fuel
- Restrictions by heat-led/electricity-led

Detailed description

PV cells:

Photovoltaic cells are an electrochemical energy conversion technology that is used to convert the energy of solar beams into electricity. Semiconductor material facilitates the creation of electron-hole pairs by the photons falling on the PV cell. The electrons and holes are then separated and driven around an external circuit by an electric field established at the junction of a diode (Jenkins et al. 2000, p. 41).

Cells are arranged in series or parallel strings to obtain higher voltages and currents, and then packaged into modules. A PV module must be complemented with an inverter, which typically consists of a Maximum Power Point Tracker, a DC/DC converter, a DC/AC inverter, an isolation transformer, and an output filter.

Although all photovoltaic cells operate on the same general principles, there are a number of different materials used. Among the different PV cells are mono-crystalline silicon cells, poly-crystalline silicon cells, and thin film cells. (Jenkins et al. 2000, pp. 44-46)

Because one photon can only free up one electron, the PV electrical efficiency is limited. Cell efficiencies lie in the range of 20% and lower. An important remark is that the voltage, and thus the power output, decreases linearly with increasing temperature. "Therefore, PV cells operate best when the cells are cool and the solar irradiance is high" (Borbely et al. 2001, pp. 100-105).

Micro-CHP:

Micro-CHP units are small Combined Heat and Power production units. They are often fuelled by natural gas, but other fuels are possible as well (e.g. fuel cells often run on hydrogen, and microturbines can run on propane and landfill gas). The option to co-generate heat for utilization is optional, but the advantages of this option (higher energy-efficiency, lower operational costs) are generally conceived higher than the disadvantages (reduced flexibility, higher capital costs), even though many types are not yet cost competitive. The technological features and performances of different micro-CHP technologies can vary a lot (Pehnt et al. 2006; Chambers et al. 2001).

Different micro-CHP technologies

For each of the technologies considered in the research (reciprocating engines, Stirling engines, fuel cells and ORC-based units), a short description and a list with characteristics are given. These characteristics are derived from Pehnt et al. (2006), Onovwiona and Ugursal (2004), and Hawkes and Leach (2005), and apply all to 1 kW_{el} units, which are considered in the scenario analysis of this research.

Micro gas turbines

Pehnt et al. (2006) state that micro gas turbines "have only been developed with capacities above 25 kW_{el} and are thus not categorized as micro cogeneration technologies according to our definition" (p. 3). Because in the micro-CHP scenarios of this research 1 kW_{el} units are assumed this technology is not relevant here.

Reciprocating engines

Reciprocating engines are also called Internal Combustion Engines (ICEs).

"Reciprocating engines are based on conventional piston-driven internal combustion engines. For micro cogeneration applications, typically spark ignition (Otto-cycle) engines are used, comparable to those used in automobiles" (Pehnt et al. 2006, page 4).

"In an Otto engine, a fuel, for instance natural gas, is mixed with air and compressed in a cylinder. This mixture is than ignited by an externally supplied spark. The now hot, expanding gas moves a piston, thereby causing the crankshaft to rotate. The mechanical energy produced by this combustion is then used to drive a generator." The exhaust heat is recovered from the engine parts are then supplied to the heating system (Pehnt et al. 2006, page 4)

Characteristics:

- High operation temperature
- NO_x production / higher exhaust emissions
- Electric efficiency for 1 kW: 20-25 %
- Total efficiency 80-90%.
- Subject to economies of scale
- Heat-electricity production ratio: 2.5:1 (Senertec), 1.4:1 (Vector CoGen)
- Relatively noisy
- Bad part-load performance
- High regulating speed
- Heat supply disrupted when engine fails

Stirling engines

Stirling engines are a type of external combustion engines.

"Unlike spark-ignition engines, for which combustion takes place inside the engine, Stirling engines generate heat externally, in a separate combustion chamber. In the Stirling engine developed in 1816 by Robert Stirling, a working gas (for instance helium or nitrogen) is, by means of a displacer piston, moved between a chamber with high temperature and a cooling chamber with very low temperature. On the way from the hot to the cold chamber, the gas moves through a regenerator, consisting of wire, ceramic mesh or porous metal, which captures the heat of the hot gas and returns it to the gas as the cold gas moves back to the hot chamber. …The mechanical energy of the Stirling engine is used to drive a generator" (Pehnt et al. 2006, page 7).

Characteristics:

- High fuel flexibility
- Low emissions
- 20% electrical efficiency (24% for large future models)
- Total efficiency: >85%
- Heat-electricity ratio: 7:1 (WhisperTech)
- Relatively low noise level
- Good part-load performance
- Opportunity for continuous heat supply when engine fails

Fuel cells

"A fuel cell converts the chemical energy of a fuel and oxygen continuously into electrical energy. Typically, the fuel is hydrogen. … Basically, the fuel cell consists of a sandwich of layers that are placed around a central electrolyte: an anode at which the fuel is oxidized; a cathode, at which the oxygen is reduced; and bipolar plates, which feed the gases, collect the electrons, and conduct the reaction heat." (Pehnt et al. 2006, p. 9)

Typically, natural gas is the available fuel for micro cogeneration applications. Generally, fuel cells can reach the highest electrical efficiencies of all micro-CHP technologies. However, "it is so far unclear whether fuel cell systems can achieve the same thermal efficiencies as promised by the competing technologies. This is due to the fact that the heat cannot be extracted at well-defined points in the system, but rather at many dispersed heat sources, leading to greater measures being required for insulation and heat exchange" (Pehnt et al. 2006, pp. 9-10)

High temperature fuel cells, such as the solid oxide fuel cell (SOFC) and the molten carbonate fuel cells (MCFC), with a operating temperature of 600-1000 degrees Celsius, have a higher electrical efficiency, and probably also a higher thermal efficiency, because of lower thermal losses. Their regulating speed and part-load behaviour rather bad, however, because they require a constant operating temperature to function properly. Low temperature fuel cells do not have this operational restriction: "a 200 kW PEM fuel cell may operate at 45% electrical efficiency *regardless of its load*". (Chambers et al. 2001, p. 99). In the research, low-temperature fuel cells are therefore considered.

According to the analysis results presented in the thesis of Van Kreijl (2007), the (high-temperature) fuel cell is expected to deliver the highest performance of all micro-CHP technologies for energy provision in a house. This includes both the environmental and the economic performance.

Characteristics:

- electrical efficiency PEMFC (proton exchange membrane fuel cell): 28-33%
- Total efficiency: 80-85%
- Heat-electricity ratio: 1.5:1 (Vaillant)
- Modularity
- Silent operation
- Almost zero local emissions
- Good part-load behaviour (for low-temperature cells)
- Complex thermal management

<u>ORC-based unit</u>

In the United Kingdom, Energetix microPower Limited has developed a new micro-CHP system (called the Genlec^{TM}) based on a process known as the Organic Rankine Cycle. According to their website, "this is effectively the same process as used in fridges, freezers and air conditioning systems, but operating in reverse" (website Energetix 2007).

Characteristics[46]:

- 2.5 kW, in the future 1 kW (Energetix)
- Heat-electricity ratio: 13.2 : 1, future 9:1.
- Overall efficiency: 90% or more
- Easy grid connection
- Heat-led
- Minimal export of power

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[46] http://www.eere.energy.gov/de/pdfs/conf-03_microchp_wkshp/butcher.pdf, Viewed on August 3rd, 2007

Appendix F: General technical effects of high DG penetration levels

In this appendix, the general effects of a large-scale penetration of DG are examined. This serves as background for the analysis of the effects of PV/micro-CHP integration on the operational performance of the market for Regulating and Reserve Power (RRP). In specific, the implications the technical effects might have on the need for and use of RRP are the reason for examining those effects.

First, the current levels arising from the export volumes should not exceed the thermal ratings of equipment in the distribution networks. In specific, distribution transformers might not be able to cope with the export, according to literature. As export volumes are argued not too be too large, equipment should be able to manage the reverse flows. For the remaining difficulties bi-directional flows might pose, possible future large-scale integration of DG at households should be taken into consideration when old transformers and other equipment are replaced.

Subsequently, protection schemes should secure the safety and stability of both the DG units and the distribution networks. "Apart from own protection schemes that each generator should possess, DG plants are often required to install a set of protection systems for interconnection with the local grid, to ensure that the production plant will be disconnected from the network once a fault is detected in the grid" (Peças Lopes et al. 2006, page 1198). However, this is probably more relevant to DG connected to the medium voltage network. Besides, the smart meters will be able to effectively connect and disconnect the consumer-generator, or just the DG unit if a generation meter is installed.

Next, the transient stability, or the N-1 safety of the system is another aspect of the technical effects of DG penetration. According to Peças Lopes et al. (2006), "this issue may become the limiting factor to the increase of DG production in areas with low consumption levels" (page 1198). This is not the case in the scenarios, because the Dutch households have a consumption level that is in proportion to the DG capacity: the average household SYC being 3,397 kWh, a 0.38 kW unit operating continuously could supply all the demanded electricity. The consumption is not spread uniformly, however: based on the consumption profile fractions (Ecofys 2001) and the average household consumption, needed power rate can go up to 800 W. Viewing this, a 1kW unit is well suited.

The N-1 safety depends on angle, frequency and voltage stability when one element of the system fails (a big generator, a transmission line, a transformer). According to Thong et al. (2003), "DG units connected via electronic power converters do not have large capabilities to control active and reactive power" (page 1), and therefore often operate at unity power factor. This appears to be the case for both photovoltaics and micro-CHP. Besides, DG units "hardly take part in controlling system voltage and frequency" (page 2). The results of a simulation study for the Belgium system, which is similar to the Dutch one, show that DG penetration levels as large as assumed in the scenarios have a significant impact on the transient stability of the system. "In both N-1 studies, with an assumed generation and line outage, the transient stability becomes worse in DG connection cases compared to the base case…In most cases, the induction generator has a larger influence compared to the synchronous." (page 4).

As relaxation, the following can be said. First, the long-term stability of systems with high DG penetration levels is rather similar to the system without DG; long-term being around 100 seconds. Second, the limited transient stability arises from the fact the remaining central generators have to control reactive power, voltage and frequency to the same extent, because the DG units do not contribute. However, according to Jenkins et al. (2000), CHP units can contribute to reactive power. Furthermore, more static devices could be introduced in the grid, which can generate reactive power, as noted by Thong et al. (2003). Third, the effects may be significant, but appear still to be rather similar to those of a system without DG, and N-1 security is warranted.

Finally, the effects of DG units on the dynamic behaviour of the whole electricity system must be considered. Peças Lopes et al. (2006) conclude that "the dynamic behaviour of the system can be strongly affected by the presence of DG units, not only because of their protection devices or due to the intrinsic nature of the electronic interfaces of the units that use this technology" (page 1200), based on modelling results for the Portuguese transmission system with either 500 MW or 1500 MW connected to it. Although both the absolute and the relative size of DG assumed in the scenarios are larger, the differences between the countries, between now and the future and between the model and reality make it hard to be certain about negative dynamic behaviour as a result of large-scale DG penetration in the Netherlands.

Appendix G: Information for scenario analysis

Scenario A

Predictability production & consumption

The predictability of generation for an individual PV cell is a different issue than the predictability of generation for a group of consumer-generators with a PV cell. First, the predictability of generation of a single PV cell depends on the predictability of the solar irradiance[47], in W/m^2, in the Netherlands. After all, the other factors that determine PV output are all constants: the electric efficiency of the cell, the surface area of the cell, the location, and the orientation (assuming that cell can not be rotated). In general, the PV cell will obviously generate more electricity when the momentary solar irradiance is higher. However, the cell voltage, and thereby the conversion efficiency, tends to drop when the cell temperature increases. "Therefore, PV cells operate best when the cells are cool and the solar irradiance is high" (Borbely and Kreider 2001, p. 105).

The solar irradiance is dependent on the weather type. Basically, the solar irradiance will increase and drop during the day following the orbit of the sun through the sky during the day, which results in a parabolic development of the momentary power output of a PV cell on clear days. This can be seen in Figure G1, which shows some daily curves of the power output of a 93 W_p PV cell in the Netherlands, on cloudless days.

The unit '(k)W_p' is often used in relation to PV cell capacity. It points to the fact that the given capacity is only reached when weather conditions are optimal: the solar irradiance is high, while the cell temperature is not. According to the website of Segaar/Polder PV (2007), the highest power output are mostly in the spring, when the sun is blazing between white clouds, the air temperature is low, and the wind blows with high speed[48]. This explains why the power output in Figure G1 does not reach the rated power of 93 W_p. Furthermore, the figure shows that the change of seasons on PV power output have effect on the maximum power output and the time period of PV generation: on summer days the power output is higher and generation time is longer than on winter days. This means that the daily energy output is much higher on summer days than on winter days. Assuming the same relation between rated power and actual power for the 1 kW_p PV cells in the scenario as in the figure, one such PV cell will have a peak output of 750 W (75% of rated power) on the best cloudless summer days, down to 450 W (45% of rated power) on the worst cloudless winter days.

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[47] The solar irradiance can be regarded as the power density of solar beams falling on the surface of the earth. Other terms used are irradiation, solar radiation intensity, and insolation.

[48] http://www.polderpv.nl/seizoenseffecten1.htm#LOVS93Wp, Dutch website of Segaar/Polder PV, viewed on July 23rd 2007.

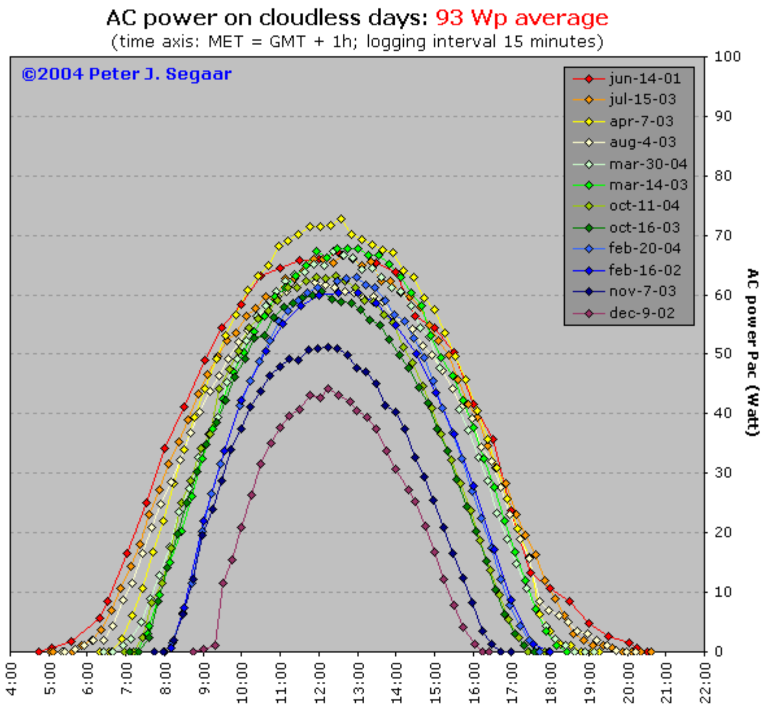

Figure G1: Seasonal differences in momentary PV power output on cloudless days (© Peter J. Segaar/Polder PV, Leiden (NL))

The seasonal differences for momentary power output of PV cells leads to a specific energy output pattern over the year. The energy output of PV cells rises from January up to June, after which it drops again. November, December, January and February are the months with the lowest energy output in the Netherlands, with roughly only 20-40% of the output in the summer months, according to measuring data of PV cells in the Netherlands[49].

Network stability

The PV production peaks, which tend to fall at off-peak hours, can be flattened by fine-tuning the PV panel orientation, as indicated above. Paatero and Lund (2006) find that "the power generation peak during the PV operation is smoother when the PV panels are orientated to east and west than to the south only, or 10% smoother in Lisbon and 30% in Helsinki, respectively" (page 227). Since the climate of the Netherlands is more similar to that of Finland than to that of Portugal, a percentage of 25% could hold for the Netherlands. According to Paatero and Lund, this would result in about 20% lower total yield, but network over-voltage would also reduce 40% (page 227-228, values adapted for the Netherlands). The flattening of the PV generation peak might be needed to prevent undesirable technical effects of the high generation peaks, but that would decrease total output as well. Probably a good trade-off is to orientate PV panels differently at different households, in such a way that the production peak at summer mid-hours is as large as the total residential consumption connected to the distribution network.

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[49] See the website of Ton Peters, http://www.pv-solar24.info, viewed on July 26th, 2007.

Furthermore, Paatero and Lund (2006) also studied the voltage rise effects and network losses arising from PV penetration. For a penetration level of 50% (which was modelled by 0.5 kW in every household in a distribution system) only minor current flow occurred, leading to small voltage rises no larger than 0.7 % of nominal voltage. The total network losses were reduced up to 1 kW_p/household (page 229). Since the study assumed a yearly consumption that was at least 25% lower than the average in the Netherlands, all above results can be expected to hold for the Netherlands as well.

RRP offered

See Figure G2, which illustrates average household consumption based on the consumption profile from Ecofys (2001) and PV production on a cloudless summer day, based on solar irradiation metering data from Sunergy (2007) [50]. Figure G3 illustrates the average household consumption and PV production on a cloudy summer day (one day later!).

The first thing that can be derived from these figures is that the fit between household consumption and PV production is rather poor. This is confirmed by a study from Coppye et al. (2002) for Belgium, who state that "although the overall correlation is weak, PV power output matches rather well with the bump in the averaged consumption profile at midday" (page 4). A 'midday bump' is not visible in the Dutch consumption profile, but even if it would be there, overall correlation remains low.

Furthermore, the figures show that daily differences can be huge: on the cloudless day the household exports large amounts of electricity for twelve hours, while on the cloudy day there is only one hour of export. Note that PV production on the clear day steeply decreases and increases between 12.00h and 15.00h, as a result of passing clouds. So the fluctuations caused by passing clouds can result in sharp increases/decrease of electricity import/export rates on the distribution network level, and are limitedly predictable.

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[50] Sunergy website, 2007. Data from http://sunergy.nu/cms/?On_line_metingen, viewed on July 26th, 2007.

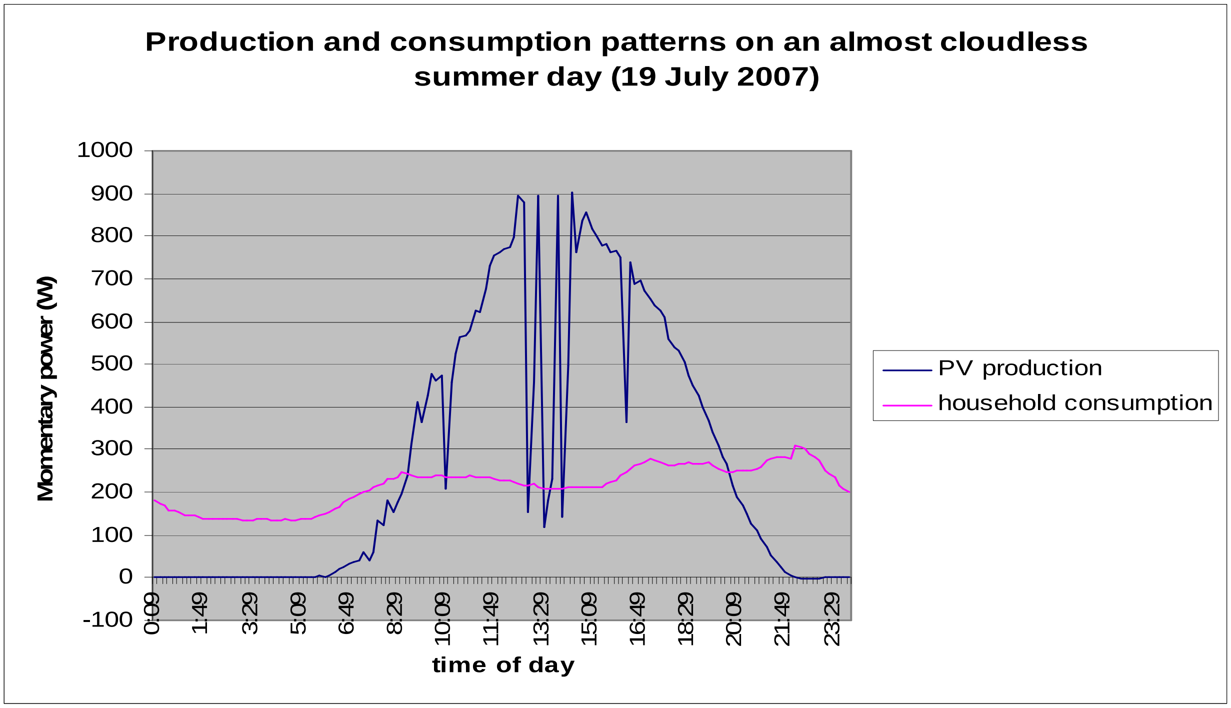

Figure G2: Consumption and production pattern for a consumer-generator on a clear day (Sunergy 2007; Ecofys 2001)

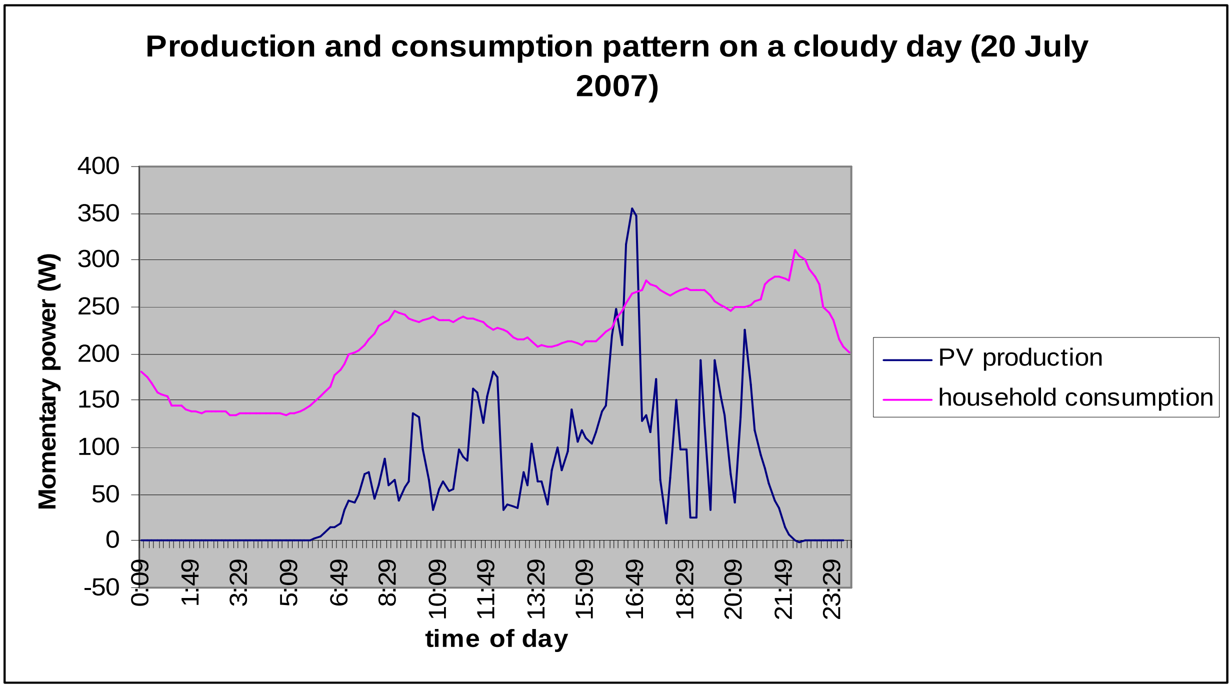

Figure G3: Consumption and production pattern for a consumer-generator on a cloudy day (Sunergy 2007; Ecofys 2001)

Figure 20 is based on data from PV panels with 900 kWh/kW$_p$ per year output, and the profile fractions of profile E1A (Ecofys 2001) in combination with a yearly household consumption of 3,397 kWh (the 2005 average). The 900 kWh/kW is in accordance with Yogi Goswami (2003; p. 240), so is assumed to hold.

With yearly PV production of 900 kWh and a yearly consumption of 3397 kWh, 26 % of total consumption could in theory be delivered by own production. However, because of the export volumes at times of overproduction, actual contribution of the PV to own consumption will be much lower.

What the picture shows is that the yearly PV production curve and the yearly consumption curve are oppositely shaped: when PV production is at its highest, household consumption is at its lowest, and vice versa. It appears that in summer, the PV contribution to household consumption can become 50%, while in winter it can be less than 10%.

Although the weather cannot be influenced, the position and orientation of the PV panels can, which affects the generation pattern of the PV cells. Paatero and Lund (2006) have analyzed the effects of different panel orientations, and found that "the "East-West"-case has the most flat mean power, but the total energy production is reduced. On the other hand, the "All South"-case gives the highest total energy output as expected, but the shape of the PV curve is steepest of all cases" (p.227). Because the production peak does not coincide with the morning and evening demand peaks (which is shown by Paatero and Lund as well), it could pay to flatten the production curve at the expense of total PV production to increase system balancing possibilities. The impact of panel orientation is high: in Helsinki, the production peak could be lowered by 30% (p. 227).

Scenario B

This scenario assumes the large-scale domestic penetration of heat-led micro-CHP, which is the main type investigated, because heat is generally seen as the primary product of micro-CHP systems. For example, COGEN Europe (2004) states that micro-CHP is “a replacement for conventional gas boilers in domestic dwellings, with the micro-CHP unit operating in a ‘heat-led’ mode” (Hawkes and Leach 2005, p.712). There are however more operating strategies, which will be discussed in scenario C and D.

There are different possibilities for domestic heat supply in micro-CHP scenarios: a supplementary boiler or a heat storage tank could be added. The combination of the micro-CHP unit, and a possible heat storage tank and/or a conventional boiler can be called the **micro-CHP system**. So there are mainly four micro-CHP systems (see Figure G4):

1. A stand-alone micro-CHP unit
2. A micro-CHP unit with a supplementary boiler
3. A micro-CHP unit with a heat storage tank
4. A micro-CHP unit with a boiler and a heat storage tank

In system 1 and 3, the micro-CHP unit is the only heat production device, while in the other two systems the supplementary boiler can used to generate heat as well. A heat storage tank can store heat generated by the micro-CHP unit that is demanded at the time of production, up to a certain level. According to Haeseldonckx et al. (2005) “cogeneration units are mostly considered as stand-alone facilities, although, in reality, they will be part of a system that may also contain a back-up boiler and a thermal-storage tank.” (p. 1229). The choice for a micro-CHP system has consequences for the regulating speed of heat production capacity, the amount of electricity produced, and the flexibility of the micro-CHP system.

How likely and desirable the integration of boilers and storage tanks are, depends on costs and design developments, on the heat and electricity demand patterns of the households, but also on the technological features of micro-CHP. Different **micro-CHP technologies** can favour different micro-CHP systems. Table G1 below shows the electrical efficiency, total efficiency and heat-electricity ratio of the four micro-CHP technologies that are considered in this analysis. These four technologies include three of the four most important mini/micro-CHP technologies considered by developers and researchers: reciprocating engines, Stirling engines and fuel cells. Microturbines are not included, because they cannot be sized down to 1 kW_{el}, at least not at the moment. ORC-based units are a new, small, and simple technology with properties very different from the others. They are currently produced by Energetix, in the UK[51]. For a description of the technologies, see appendix D.

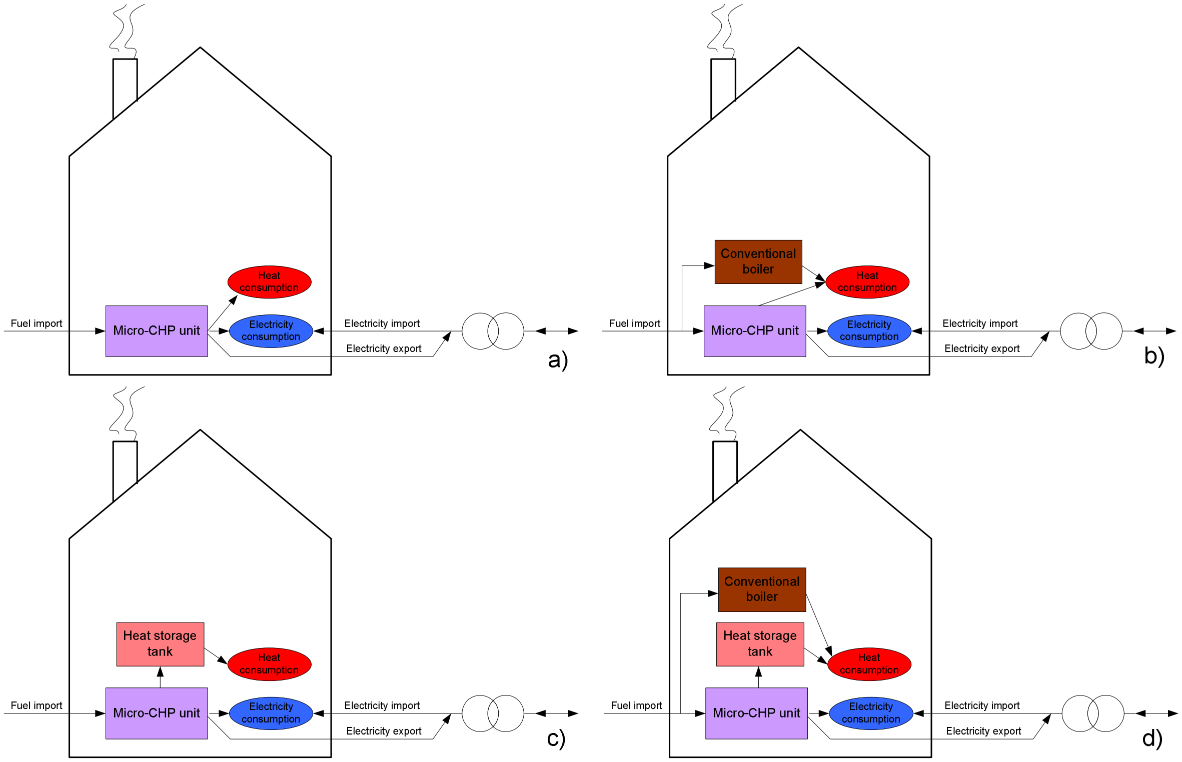

Figure G4: Different micro-CHP systems for electricity and heat supply to households: a) stand-alone, b) with a supplementary boiler, c) with a heat storage tank, and d) with both a boiler and a tank

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[51] http://www.energetixgroup.com. Viewed on August 1st, 2007.

Values from Table G1 are adapted from numbers given by Pehnt et al. (2006), and show efficiencies and heat-electricity ratios that can already be achieved. It can be seen that the efficiencies make large-scale penetration of these micro-CHP technologies attractive from an environmental perspective.

Micro-CHP technology (all 1 kW_{el})	Electrical efficiency	Total efficiency	Heat-electricity ratio
Reciprocating engine	25%	85%	2:1
Stirling engine	20%	90%	3.5:1
Fuel cell	30%	80%	1.5:1
ORC-based unit	10%	90%	8:1

Table G1: Efficiencies and heat-electricity ratios of the four micro-CHP technologies

For comparison of the above micro-CHP heat-electricity production ratios, it is useful to know the average household consumption heat-electricity ratio in the Netherlands.
In 2004, an average Dutch household used 1,736 m^3 natural gas, of which 96% was used for domestic heating (of water and space)[52]. Assuming the delivery of Dutch natural gas from Groningen, which has a caloric value of 31.7 MJ/m^3, on average 14,675 kWh was used for heating in 2004. Taking this value as the annual heat consumption, and 3,397 kWh as the annual electricity consumption (see appendix A), the heat-electricity consumption ratio for the average Dutch household is 4.3:1.

It must be noted, however, that it has been assumed that the system environment stays the same, which includes the electricity demand and heat demand of households. However, it is generally predicted that residential electricity demand will rise, while heat demand will drop. If both are true, the heat-electricity consumption ratio will be lower than the current 4.3:1. According to De Jong et al. (2006), the average electricity demand could have grown to 4960 kWh per Dutch household by 2030, a rise of 46%. Furthermore, the heat demand of German households could have dropped with 30% 2030 (Pehnt et al., p. 60), meaning for Holland that the average heat demand would have dropped from 14,675 kWh to 10,273 kWh. If both predictions are true, the average heat-electricity consumption ratio will become 2.1:1, a decrease of 50%. This changes the relative suitability of the different micro-CHP technologies for Dutch households.

Furthermore, an important insight is that the 1 kW_{el} micro-CHP units assumed are able to provide the households their entire electricity demand, having derived from the profiles from Ecofys (2001) and the average electricity consumption of 3,397 kWh that the peak heat electricity demand of the average household is around the 800 W (Ecofys 2001). In contrast, the heat demand will never be able to provide the entire heat demand. This can be shown by the heat demand patterns for the similar UK households in Hawkes and Leach (2005), where the maximum heat demand is higher than 12 kW_{th} (see Figure G6), while the highest thermal power output possible for a 1 kW_{el} micro-CHP unit is 8 kW_{th} (from the ORC-based unit, see Table G1). This implies that a supplementary boiler is a necessary part of the micro-CHP system.

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[52] www.energielabel.nl, Viewed on June 23rd, 2007.

Predictability production & consumption

Considering daily patterns of heat and electricity consumption, Figure G5 shows the electricity consumption throughout the day according to the consumption profile of Ecofys (2001). Not only can the seasonal differences be seen again, but also the consistency in the daily pattern. Of course, for the individual household there will be many sharp fluctuations (caused by the switching of appliances) which are diminished for the aggregate consumption of large groups of households.

In Figure G6, typical residential heat demand patterns (the black lines) are shown for the individual household. The difference between heat, winter and summer is confirmed, as are the higher energy amounts demanded, compared to electricity: the heat demand can be higher than 12 kW_{th}. This figure is adapted from Hawkes and Leach (2005), and also shows the heat delivery of a 2 kW_{el} Stirling engine that is heat-driven (in red).

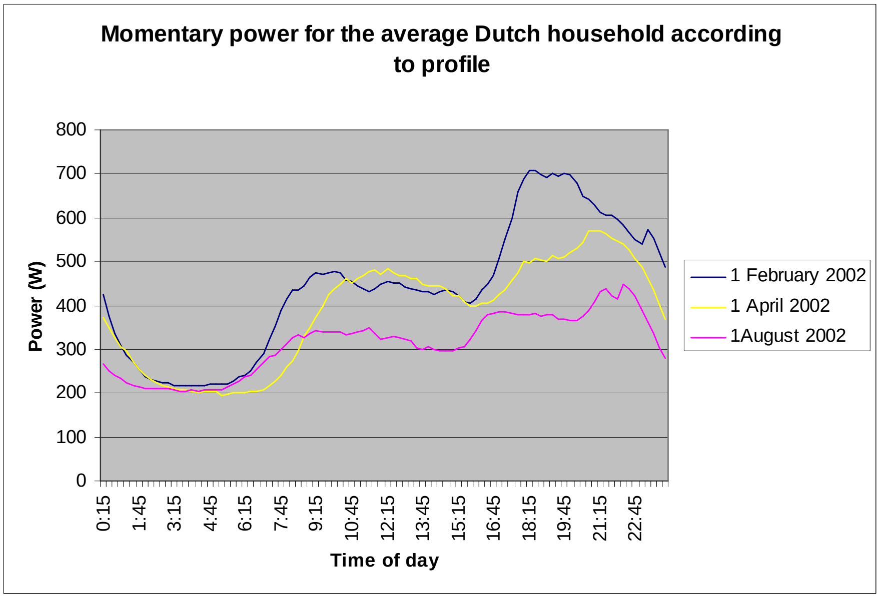

Figure G5: Power output for the average Dutch Household according to profile (Ecofys 2001)

Here, it is also confirmed that a supplementary boiler is needed: the Stirling engine cannot provide all the heat, even though it is twice as big as assumed in this analysis. Besides, the heat demand profile shows very sharp fluctuations. The only consistency visible is perhaps the bulk heat consumption in the morning between 7.00h and 9.00 and in the evening between 18.00h and 23.00h.

In short, what can be at least understood from the figures is that heat consumption is at a higher level than the electricity consumption, that both individual patterns show sharp fluctuations, and that, very roughly, both show a morning peak and an evening peak.

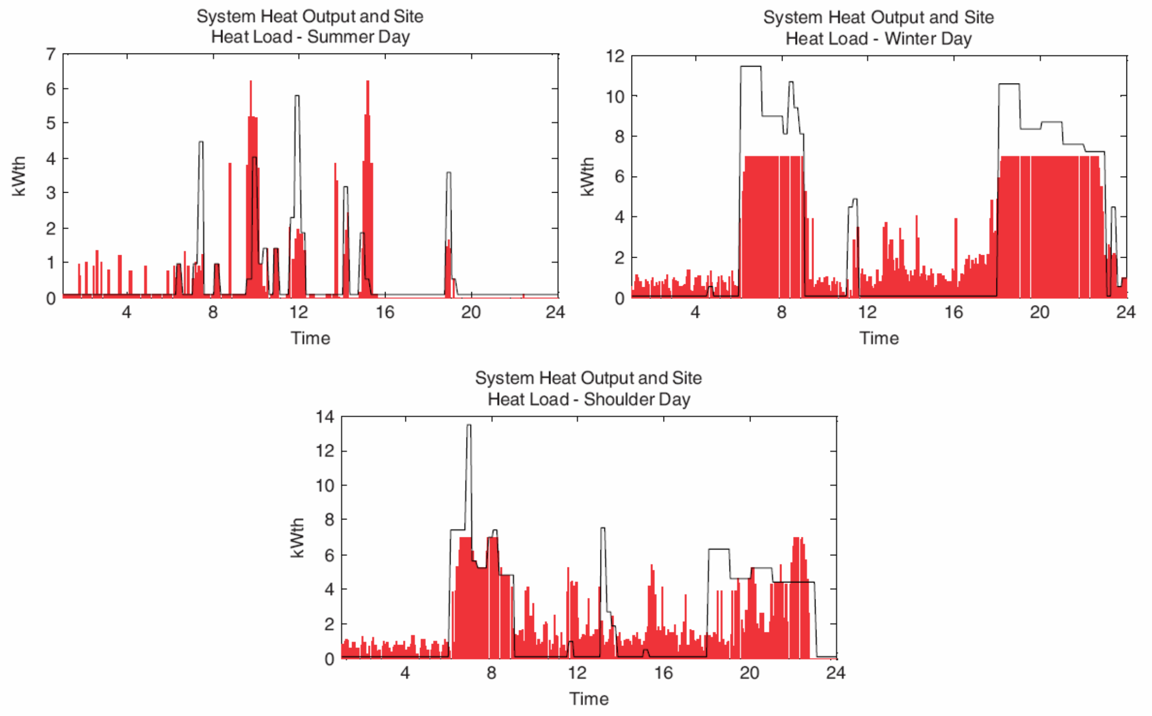

Figure G6: Residential heat demand and heat output of a 2 kW$_{el}$ Stirling engine on three days in different seasons (Hawkes and Leach 2005, from fig. 3)

Network stability

Peças Lopes et al. (2006) have examined the technical effects of DG integration in general. First and foremost, they indicate that DG is capable of providing ancillary services like reserve power, especially technologies like micro-CHP: "Non-renewable distributed generation already provides standing reserve services to the TSO" (p. 1194). This confirms the above, and implies that the technical implications are at least manageable.

The opportunities for provision of other ancillary services by DG are stated to be better for micro-CHP than for PV, although still limited: "Because of the relatively low availability of DG compared to network components and … voltage standards, opportunities will be limited for DG to provide voltage support or overload reduction. Only non-intermittent DG would be suitable for such applications." (Peças Lopes et al. 2006, page 1194).

RRP offered

The match between residential consumption and production by consumer-generators was found to be reasonable under 'predictability production & consumption'. On the distribution and transmission system level, this should therefore lead in an overall reduction of the system load, and limited export volumes. Figure G7, presented in Peacock and Newborough (2006), confirms this statement. Shown is the aggregate electrical load of a distribution network with 50 households, where the micro-CHP penetration is 76%, and the individual capacity 1.5 kW_{el}. What can be seen is that the general system load is indeed decreased, although for the night the decrease is minimal. Furthermore, the largest decreases indeed occur at the times just before peak electricity demand times, when the heat demand peaks. In this case, the large penetration results in net electricity export for the entire distribution network during the peak heat demand periods. This export is however much smaller than the former peak load in the network.

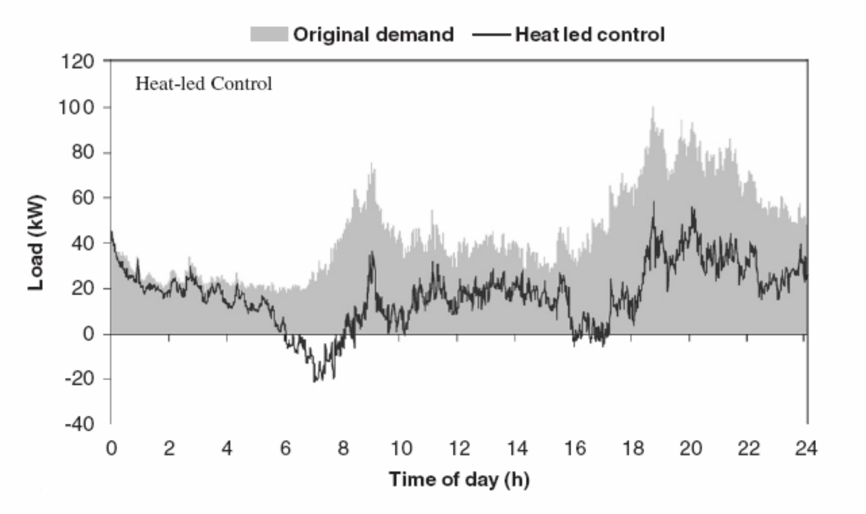

Figure G7: Effect of heat-led micro-CHP control on electrical load in a distribution network with 50 dwellings on a January day (Peacock and Newborough 2006, fig. 3a)