Design of a flexible tariff for electricity transport

Master thesis report

Remco Vroegop

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Universiteit Utrecht

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Preface

With this thesis project my master program Energy Science comes to an end. I chose this study after finishing the bachelor study electrical engineering. An important reason for choosing this master program was the multidisciplinary subjects that are treated during this master. Also the subject of this thesis project “Designing a flexible tariff for electricity transport” is related to different disciplines: economical, regulatory and technical. This made it an interesting research for me. I have learned a lot during this period. On the one hand of course about the subject itself but also about structuring an extensive individual assignment.

I would like to thank the company DELTA Netwerkbedrijf for offering me the assignment and giving me the opportunity to do my final project for my master program. During the project I have had several meetings with different employees of the company, which were very helpful. They cleared up some problems I had, gave ideas to come to solutions and provided input data for the calculations. A special thanks goes to my direct supervisors within DNWB Arjen Jongepier and Eric Verbrugge who delivered the assignment. In addition, they were also supporting in giving feedback and new ideas for the design of a flexible tariff.
The meetings and the contact by e-mail and telephone I had with my supervisor of Utrecht University, Wilfried van Sark, guided me through my project. Moreover, discussing now and then the progress of the project and the ideas I had was very helpful, thanks for that as well!

Remco Vroegop
February 2013

Summary

Network operators are looking for ways how to introduce a flexible tariff for electricity transport and how such a tariff would look like. This has several reasons. An important one is that the planned wide introduction of smart meters will give the opportunity to introduce such a tariff on a large scale. Also the expected future developments like an increase of distributed generation and an increase of consumers' peak capacity because of a rise in the use of electric vehicles and heat pumps make this subject an important issue for network operators.

DELTA Netwerkbedrijf (DNWB), the network operator in the Dutch province Zeeland, is interested in how such a tariff could be designed. A flexible tariff would replace the current capacity tariff, which is nothing more than a fixed amount per year. This project is executed for DNWB to find the possible characteristics of a flexible tariff and to show how such a tariff could look like. Literature studies, expert interviews and analysis of practical data form the base for the results found during this project.

The current capacity tariff can be divided into four components: costs for grid investments, costs to cover grid losses, costs to purchase capacity on the TenneT grid and remaining operational costs. It is recognized that the level of the first three components may change in time because of external factors and individual consumption patterns. The different cost components have different factors that sets the level of the costs. For one cost component the costs depend on the level of individual energy consumption and for another on the capacity demand of the whole grid. The tariff for each cost component should therefore be designed in such a way that the level of the tariff depends on the level of the corresponding factor.

When a grid is dimensioned one takes into account the maximum load demand that is expected for that particular grid. New grid investments are done when the limits of a grid are reached, such as because of an increase in load demand or because of new entrants on that grid. Maximum load in a residential area (usually) occurs between 15:00 and 21:00, this will therefore also be the period in which a grid will reach its limits first. The proposed flexible tariff for this cost component therefore depends on the peak demand of an individual consumer in that period.

Network operators need to buy energy to cover the losses in their grid. The square of the current (I) is an important factor in the calculation of grid losses in a grid. This factor is therefore chosen to distribute the costs to cover grid losses over the hours of a day in a flexible tariff. However, several problems will occur when such a system is implemented in practice. For example, the unknown load factor of assets and the unknown distance between production and consumption of electricity also have a substantial influence on the level of grid losses.

The grid of DNWB is connected with the national grid of TenneT, for this a tariff must be paid to TenneT. This tariff consists of two parts; one is based on the peak demand from the TenneT grid in each month and the other on the peak of the whole year. The factor at which the tariff to consumers for this cost component is based will therefore be the load demand of the total DNWB grid from the TenneT grid. Different methods are possible to calculate this tariff but all have the same goal, that is to lower peak demand from the TenneT grid and thereby lowering costs for both network operator and consumers.

Together the tariffs of the cost components form the flexible electricity transport tariff for consumers. When possible this should be done with a Time-of-use system, in which the tariffs for each hour are communicated a day in advance to consumers. This gives the consumers or their Home Energy Management System the possibility to schedule their energy use and minimize costs.

The designed tariff gives options for how a flexible tariff can be set. Before they can be implemented more research will be needed, especially looking at the practical consequences of the implementation of the tariff. The table below shows for each cost component the result for one of the suggested options.

Cost component	Tariff	Unit
Grid investment costs	19.38	€/kW_{peak}
Grid losses - winter weekday (average costs method)	0.0032 – 0.0135	€/kWh
Costs of purchasing capacity on Tennet grid - winter weekday (Peak Pricing method)	≈ 0.07	€/kWh (during peak demand from TenneT grid)
Remaining operational costs	29.10	€/year

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1 Introduction

1.1 Background

Our energy system is changing; it is developing from a system based on conventional fuels into a system based on renewables. This energy transition has several reasons: awareness of climate issues, depletion of fossil fuels, rising fossil fuel prices and renewables are becoming cheaper. In a lot of countries this had led already to a substantial amount of solar- and wind energy capacity. One of the characteristics of solar- and wind energy is their unpredictable and unstable production pattern. The increase of the production capacity of these power sources will lead to a less constant and potentially less controllable supply of energy, while power supply needs to follow power demand to ensure balance between them on the grid.

Unsteady energy flows at the electricity grid over the day result in a varying load of grid components. A fluctuating load on the electricity grid is not only caused by distributed generation but also by the natural differences in demand of energy during the day. Peaks in energy demand will possibly rise even more when the amount of electric vehicles and heat pumps increases. For network operators this is an unfavourable situation. To operate as efficient as possible network operators want a demand for energy, which is evenly spread during the day.

The current tariffs for electricity and electricity transport are based on an average of the total costs which results in a tariff that is independent of the time someone uses the energy (except the day-night/weekend tariff system that is sometimes in place). A graphical example of the difference between real costs and the charged retail tariff is given in Figure 1. The upper graph presents real marginal costs of electricity over a period of some hours, including short-term costs of networks. The area surrounded by the dashed line illustrates additional costs of electricity transmission over a smaller time period, e.g. due to congestion. In a theoretically ideal tariff structure, the whole structure should be signalled to the end user, provided that he is supposed to adjust his behaviour in an economically efficient manner (e.g. through demand response technologies). In the case of a flat retail and transmission rate, the short-term marginal costs of transmission and generation are averaged over time or location in transmission tariffs. In that case there are no incentives to shift loads for consumers, as seen in the lower part of Figure 1. The time of electricity use is economically indifferent from the end user's point of view and no incentives to shift usage according to real costs exist. (Similä, Koreneff and Kekkonen, 2011)

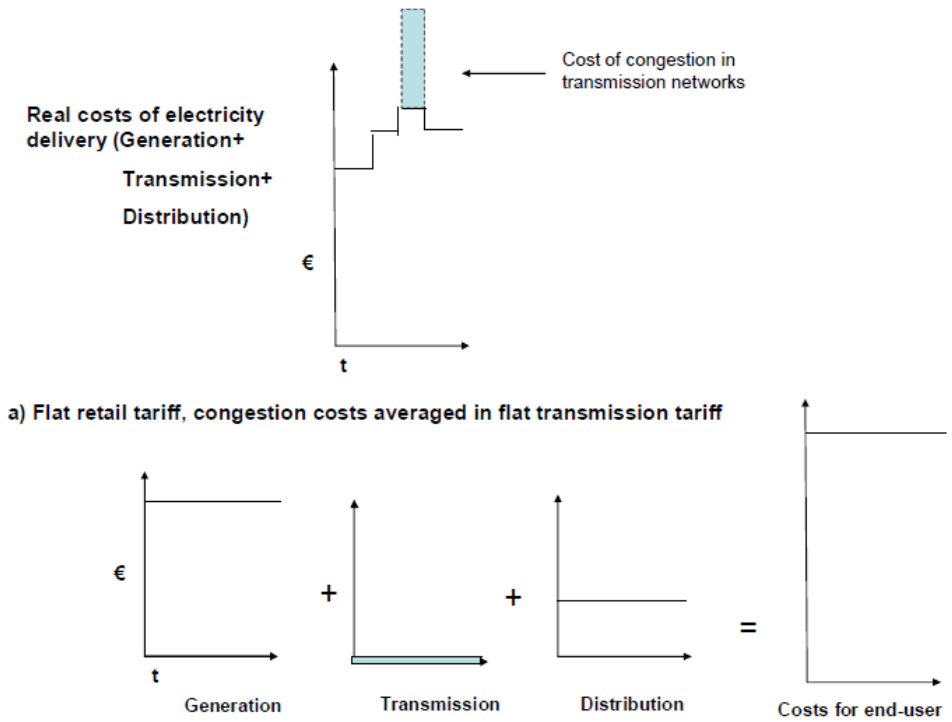

Figure 1 The effect of generation and network costs on pricing and tariffs (Similä, Koreneff and Kekkonen, 2011)

1.2 Project description

Netbeheer Nederland (2012) states in their roadmap "The road to a sustainable and efficient energy supply": "Smart grids are essential to facilitate the transition to renewable energy sources". The growing contribution of renewable energy, rising demand of electricity and the increase of consumer-produced electricity is changing the role of the electricity and gas grid. The central point in this is that the grids need to become more intelligent. The addition of ICT systems for users and in the grid itself makes the grid able to facilitate the much more dynamic transmission demand in the coming years.

The example in Figure 1 shows the inefficient way the current tariffs are designed. With the introduction of smart meters and a smart infrastructure there are possibilities to influence the load levels of customers. So, the technical prerequisites are in place to implement a flexible tariff system for electricity transport. Nevertheless the implementation of such a system is not straightforward and needs to be done thoroughly. DELTA Netwerkbedrijf (DNWB) is very interested in the way a tariff system could be designed such that it helps to shift energy use of consumers in order to lower costs for both the network operator as well as the consumer. The primary goal for DNWB is not to lower overall energy consumption by consumers but to shift the use of energy from peak moments to periods with a lower energy demand.

Textbox 1.1 DELTA Netwerkbedrijf

DELTA Netwerkbedrijf is the Distribution Network Operator in the province Zeeland. They are responsible for the construction, maintenance and development of the electricity- and gas grid. In short, for gas and electricity for everybody in Zeeland, always and everywhere.

Together with all other network operators in the Netherlands they are also operating in the branch organization Netbeheer Nederland. (DNWB, 2012a)

1.3 Research questions

This project is executed to find a solution for the issues raised in the previous subsections. The following main question is set for this research:

What are the characteristics of an efficient and future-proof tariff system for electricity transport to consumers?

The sub questions below are drawn up to find an answer to the main research question.

Current situation

1. In what way is the energy sector organized in terms of tasks and responsibilities regarding the transmission and balancing of electricity?
2. In what way is the tariff for customers currently determined?

Design

3. What tariff systems can possibly be implemented?
4. To what extent are consumers willing to change their electricity consumption behaviour?
5. What are possibilities for consumers to shift energy use? And what is its potential?
6. What are the savings potentials in the infrastructure?
7. a. How much tariff intervals are desired from the point of view of the network operator?
   b. How much tariff intervals are acceptable from the point of view of the customer?
   c. What is the desired forecast horizon of the tariffs? (real time vs. day/week/month/year ahead)

Consequences

8. a. What are the consequences of a new tariff system for DNWB?
   b. What are the consequences of a new tariff system for energy supplier?
9. How is the income of the network operator secured?

To structure the sub questions, they are divided in three groups. The first two sub questions will help to get to know the current situation and which problems occur in this situation. The sub questions in the design phase will help to construct a proper tariff system for the transport of electricity to consumers. Answers to the last two sub questions will show the consequences of the designed tariff system.

1.4 Methodology

To find answers to the sub questions, several methods have been applied.

A. **Literature research**
   Literature and reports from DNWB and other sources have been studied.

B. **Expert interviews**
   1. DNWB: Experts within DNWB have been contacted to gather information about the way the tariffs are currently set, to see on which costs the tariffs are based and to find options and ideas which could be incorporated in the new tariff.
   2. Externs: External experts have been asked for information about their views on this topic. They were also asked about their experiences done with pilot projects.

C. Tariff design

Although energy consumption data of individual houses situated in a few small blocks was available, the new tariffs have been mainly designed with the use of general average energy data. This had the advantage of designing a tariff that would be more useful for general use because it is not based on a small amount of single energy users.

Special attention was given to the design of the tariff in that new methods and ideas have been used, to avoid tariff design that would be merely an extension of earlier designed tariffs.

2 Theoretical base

2.1 Energy sector

The structure of the supply of energy in the Netherlands has fundamentally changed in the last 10 years. The energy market is liberalized and no longer national. Foreign parties play a prominent role in the Dutch energy supply. This has led to an efficient and reliable energy supply. Citizens and companies gain from a competitive energy price and a high security of supply. (Min. EZ, L&I, 2011)

The syllabus "Electricity: market design and policy choices" (de Vries, Correljé and Knops, 2011) clearly describes the way the Dutch energy sector is organized and this is used here for the description of the Dutch energy sector.

Liberalization has separated the value chain of electricity, which used to be largely integrated. Different actors now control different parts of the electricity system. This has caused a significant increase in the complexity of the sector. Figure 2 shows an overview of the Dutch energy sector. There is a distinction between the physical chain through which the electricity flows and the institutional layer; this layer contains the different actors and parties that are involved.

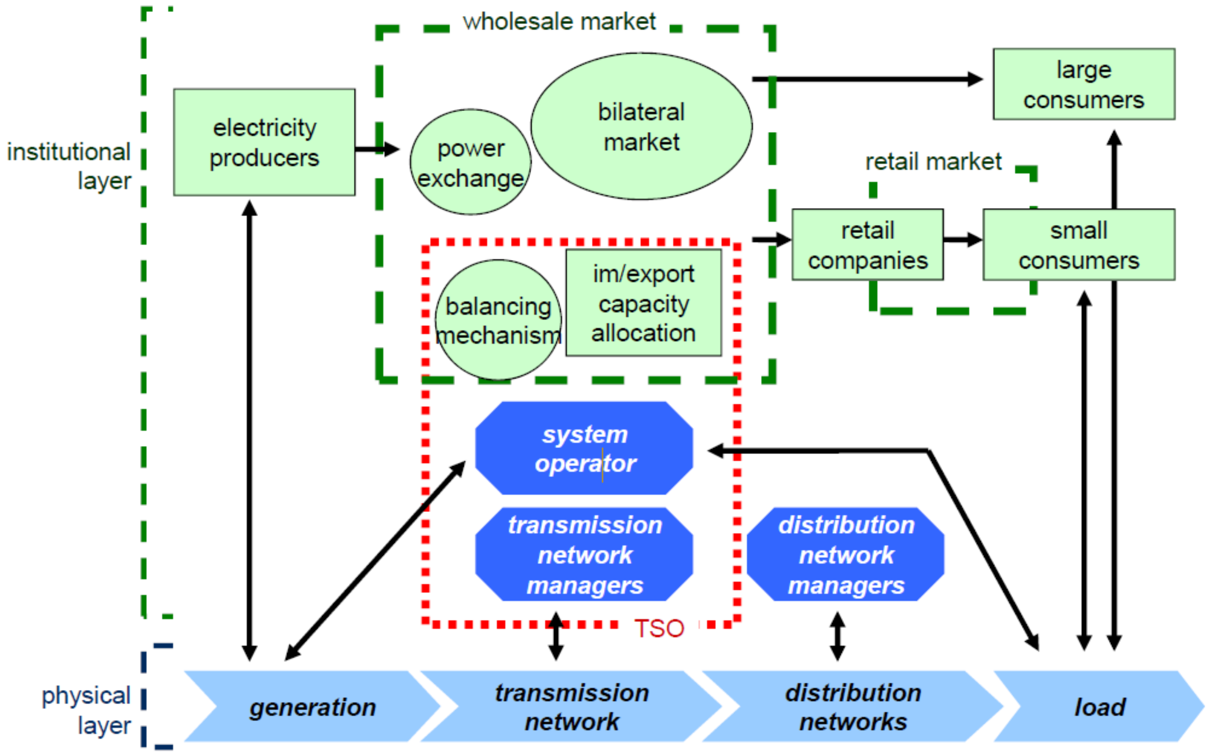

Figure 2 Overview of the Dutch energy sector (de Vries, Correljé and Knops, 2011)

The most important items from Figure 2 will be discussed here. The supply side of the electricity market consists of electricity producers. Based upon the prices that the producers offer, the market decides upon the quantity of electricity that each electricity producer may sell at each moment in time, but the electricity producers themselves decide which of their power plants they run. Thus electricity producers and consumers together determine the load flow in the electricity network.

Producers and consumers meet in the market, which actually consists of multiple related markets. The largest volume of electricity, about 85% in the Netherlands, is sold in the bilateral market. This means that the electricity is sold directly by the generating companies to their customers. These are either large consumers, traders or supply companies who deliver it to small and medium size consumers. Bilateral contracts are confidential; as a result of this there are no good data available regarding their price and duration.

The APX is the only Dutch power exchange. Its most important activity is the spot market, where electricity is traded for the next day on an hourly basis. The need for short-term trade is created by unforeseen changes in demand and supply and the inability to store electricity in a commercially viable way. As a result the value of electricity is much higher during the peak than during the night.

The Dutch Transmission System Operator (TSO) is TenneT. TenneT has three tasks: balance the production and consumption of electrical power in the transmission network (including cross-border transactions), manage the Dutch electricity transmission network and manage the import capacity usage. Society and economy rely heavily on a secure supply of electricity. As an independent TSO, TenneT has a responsibility towards people, environment and society and focuses on innovation. (TenneT, 2012)

2.1.1 Distribution System Operator

The distribution of electricity takes place through regional distribution grids. Each regional distribution grid is managed by a Distribution System Operator (DSO). The DSO is responsible for transport of electricity, maintaining the grid and solving disturbances. DSOs have a monopoly position, the Netherlands Competition authority (NMa) regulates the operation of DSOs to make sure that the quality of transport is decent and consumers pay a reasonable price for that. This is done based on the Electricity Act of 1998. (NMa, 2012)

Generally speaking, there are three relevant aspects with respect to the regulation of DSOs:

I. The technical conditions for users of the networks

Generation facilities, network components and also the equipment of consumers need to meet all sorts of technical requirements. In addition, there is a need for clear rules about the way the different actors (producers, network managers and consumers) interact. The technical conditions for the use of the electricity system are established at different levels. The Dutch Electricity Act of 1998 contains certain basic rules and the technical conditions are contained in different technical codes (Network-, System and Metering Code). Everything that is not regulated by law or technical codes may be arranged through agreements between the network manager and the individual user of the system.

II. The price of the services

There are three goals for the economic regulation of the network managers. Network managers need to be able to collect sufficient revenues to be able to perform their functions properly. Individual consumers need to be protected against excessive tariffs. Third, the tariff system should stimulate the efficient use of the networks and the network services.

III. The quality of the delivered services

To prevent the quality of the networks from deteriorating to a socially undesired level, a system of quality regulation was proposed by DTe (Dienst uitvoering en Toezicht Energie, Dutch Office of Energy Regulation, now called Energiekamer, or Energy Office of the Dutch Competition Authority). In this system, the focus is on the reliability of supply as the main quality parameter. With quality regulation an increase in quality is rewarded with higher revenues for the network manager and a reduction of quality is punished with a reduction of revenues. The underlying idea is that quality has a certain price: society is assumed to be willing to pay a certain price for quality improvements; conversely, a lower level of quality would cost society a certain amount.

(de Vries, Correljé and Knops, 2011)

2.1.2 The Electricity Grid

The technical principles of the electricity grid did not change that much over the years. Large power plants feed the generated energy in the high voltage grid. Several transformers lower the high voltage level to a level that is suitable to use in homes. An overview of this is given in Figure 3.

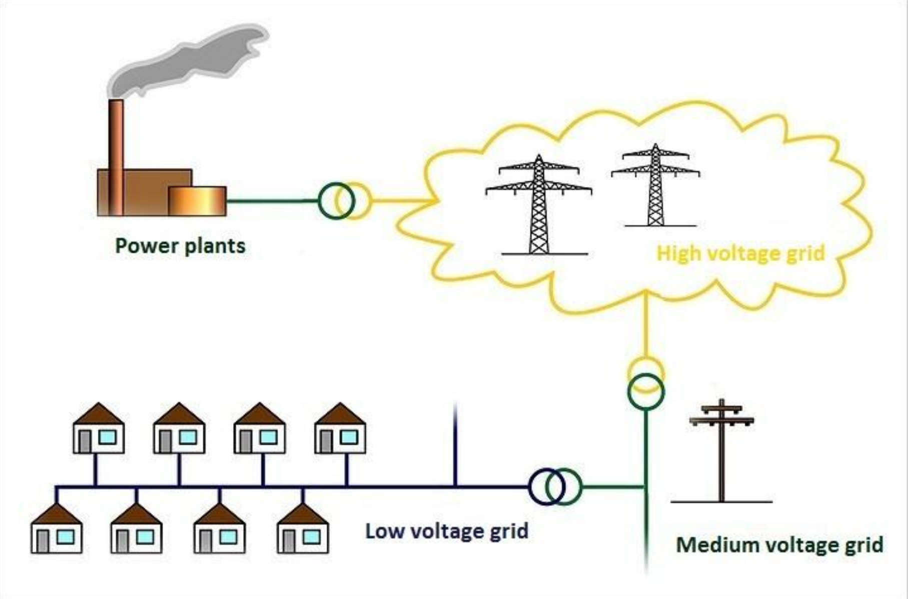

Figure 3 Simplified overview of a power grid (Kennislink, 2010)

> **Textbox 2.1 Smart Grid**
> A smart grid is an umbrella term that covers modernization of both the transmission and distribution grids. The concept of a smart grid is that of a "digital upgrade" of distribution and long distance transmission grids to both optimize current operations by reducing the losses, as well as open up new markets for alternative energy production.
> (Vijayapriya and Kothari, 2011)

Based on 20th century design requirements and having matured in an era when expanding the grid was the only option and visibility within the system was limited, the grid has historically had a single mission; keeping the lights on. The electricity industry is poised to make the transformation from a centralized, producer-controlled network to one that is less centralized and more consumer-interactive. (Litos S.C., n.d.) A smart(er) grid makes this transformation possible by bringing the philosophies, concepts and technologies that enabled the internet to the utility and the electric grid. A smart grid will change the industry's entire business model and its relationship with all stakeholders, involving and affecting utilities, regulators, energy service providers, technology and automation vendors and all consumers of electric power. An automated, widely distributed energy delivery network will be characterized by a two-way flow of electricity and information and will be capable of monitoring everything from power plants to customer preferences to individual appliances. It incorporates into the grid the benefits of distributed computing and communications to deliver real-time information and enable the near-instantaneous balance of supply and demand at the device level. (Litos S.C., n.d.) A possible design of a future smart grid is given in Figure 4.

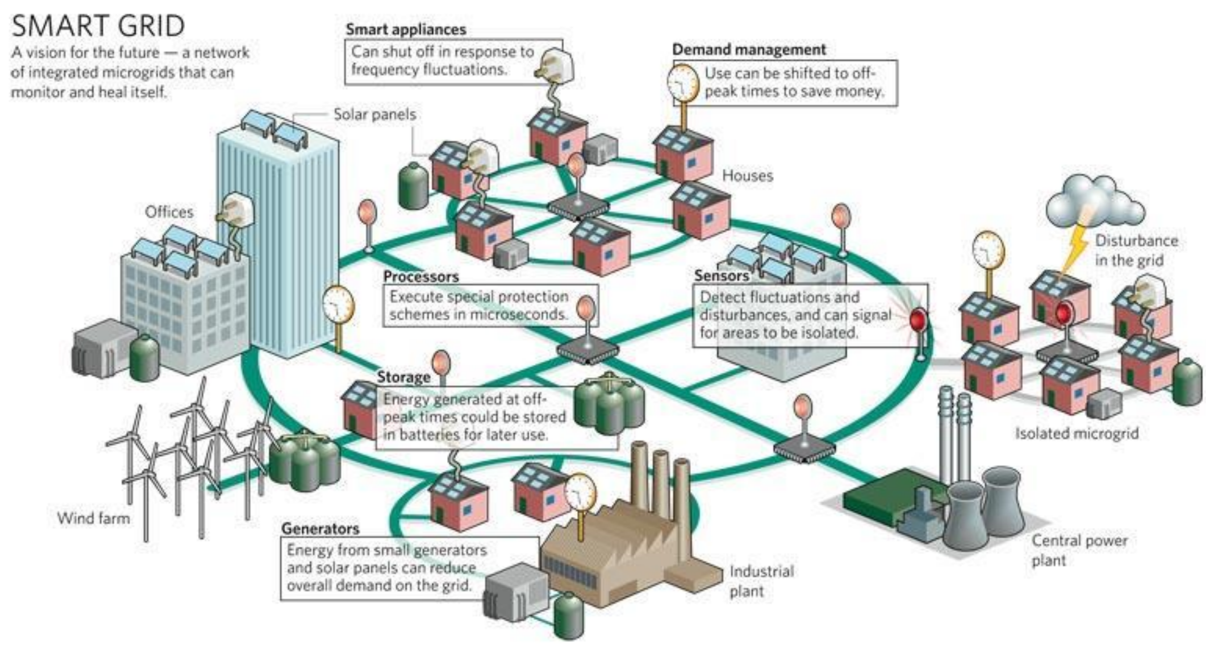

Figure 4 Overview of how the design of a smart grid can look like. (infowars, 2011)

2.2 Economics behind the electricity grid

Network operators are working under special circumstances, namely in a monopoly market. In general, a market shows monopoly characteristics if there is only one supplier. From an overall welfare perspective, monopolies are undesirable. A monopolist faces a downward sloping demand curve, indicating it can restrict output to gain higher prices. However, for DSOs economic efficiency dictates that demand is supplied by a single entity due to its network character. The high costs of constructing a competing distribution network are blocking entrants from joining the market. Such a situation is called a natural monopoly. (Missfeldt, 2012)

Textbox 2.2 Natural monopoly

In a natural monopoly situation the costs of supply exhibit characteristics such that single-firm production is always more efficient than multi-firm production. In a single-product case such a situation is caused by substantial economies of scale induced by a high fixed cost component.
(George, Joll and Lynk, 1992)

A natural monopoly is characterized by a sub-additive cost function. To simplify, a sub-additive cost function is characterized by falling average costs per produced unit. This was concluded from a research of Econ Pöyry AS (2008) to optimal tariffs and allocation of costs in Norway. They found that in the distribution grid, the capital costs given by depreciation and return on capital make up roughly a little less than half of the total grid costs. The variable costs consist mainly of transmission and distribution losses, which normally constitute 10-15 per cent of the total costs (depending on the power price; the price of the energy that is needed to cover the losses). Operation and maintenance costs are generally independent of the consumption level in the short run. In the long run, these costs will also vary with the level of consumption, but the relation between consumption and costs to operation and maintenance is not linear.

They also looked at a specific example of how the cost structure in the grid may be at the level of one single installation, using an investment in a 132 kV line as a starting point. There are five different alternatives for the cross-section of the line with different thermal transmission capacities. In Figure 5 the incremental unit cost (or marginal cost) of increasing the cross-section and thus the capacity are illustrated. The first part of the curve shows the average cost in €/MW (for one km of line length) of building the line with the lowest transmission capacity. The next part shows the average cost per MW capacity of building a cross-section with extra capacity. It is interesting to see the relationship between the marginal costs and the average cost in the different capacities. Similar economies of scale will also apply to other kinds of grid installations apart from lines such as cables and transformers. (Econ Pöyry AS, 2008)

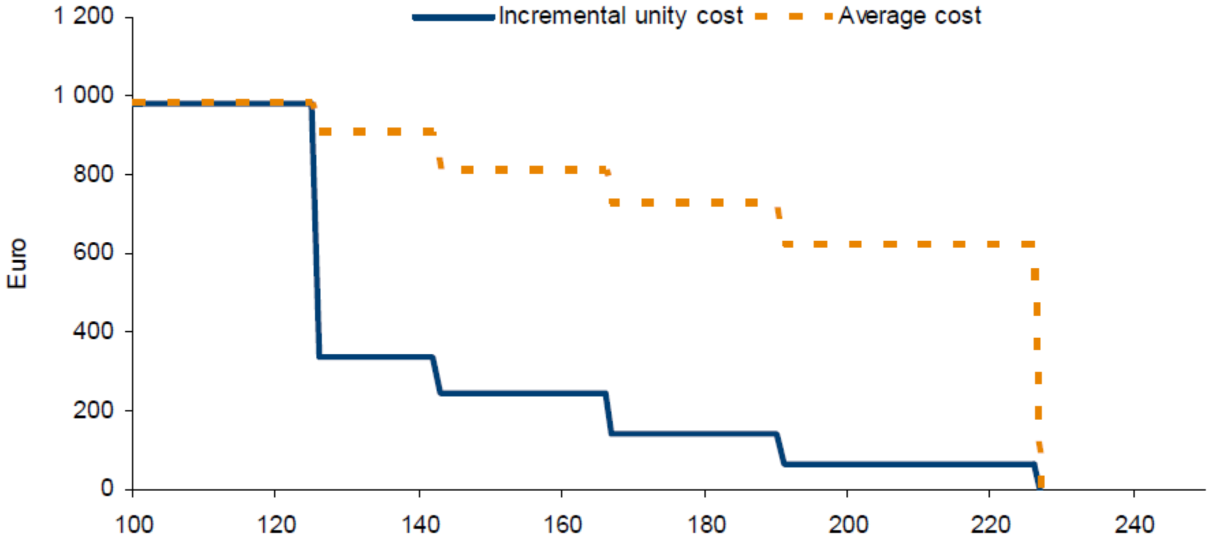

Figure 5 Incremental unity cost vs. average cost of building a transmission line (€/MW) (Econ Pöyry, 2008)

2.3 Tariff of Dutch DSOs

Activities like production of electricity were no longer regulated by the 1998 Electricity Act since it became a "free" economic activity. The act limited itself to activities that remained a monopoly such as network management. Network management would need to be regulated by the newly created DTe. (de Vries, Correljé and Knops, 2011)

The 1998 Electricity Act has been changed several times in the past years. The *TarievenCode Elektriciteit 2009* (Tariff code electricity) is also a result of 1998 Electricity Act and describes the way the tariff of the DSO is determined. The different tariffs that are charged to consumers are described below. (NMa, 2011)

I. Tariff: Connection

Each producer or consumer who has a connection or asks for a connection on the grid is offered connection service by the DSO. The connection tariff must be paid for this service; this tariff consists of two components.

a. Initial investment costs (once)
b. Costs for maintaining the connection (yearly)

II. Tariff: Transport

Another service that is offered by the DSO is the transport service. Transport service is described in the *TarievenCode Elektriciteit* as the transport of electricity from producers to consumers with the use of the grid, which includes:

I. Solving transport constraints
II. Compensation of losses during electricity transport
III. Maintaining the voltage and reactive power levels

The costs are divided in two categories:

a. Transport dependent costs:

- Depreciation of grid infrastructure
- A reasonable return on investments in grid infrastructure
- Costs of construction and maintenance of the grid infrastructure
- Costs of purchasing energy to cover grid losses
- Costs of solving transport constraints
- Costs of maintaining the voltage and reactive power levels
- The cascade costs of grids on a higher voltage level
- Operational costs

b. Transport independent costs:
Costs of:
- Processing measurement data
- Management of the connection register
- Allocation, reconciliation and validation
- Billing, customer support, money collection and customer- and contract administration
- Fulfilling data requests of Netherlands Competition Authority (NMA)
- Administering data of switching and moving customers

III. Tariff: System services

TenneT, as system operator of the national high voltage grid, performs the system services. For these services a tariff is charged to the electricity consumers. This tariff covers the costs that are made for:

- Control and reserve power
- Black-start facilities[1]
- Several other (internal) activities of TenneT

2.3.1 Tariffs of DNWB

The tariffs for the network operator are usually one of the items on the energy bill of a consumer. So they are charged together with the costs of energy consumption. The difference with these costs is that the tariff for network operators is independent of the amount of energy used and therefore charged as a fixed amount. The tariffs for the customers of DNWB for 2012 can be found in Table 1.

Table 1 DNWB's tariff that consumers need to pay in 2012 (DNWB, 2012)

Tariff category	Capacity (kW)	Capacity tariff	Fixed transport charge	Periodical connection tariff	System services	Metering tariff	Total (Excl. VAT)	Total (Incl. VAT)
1x6 A t/m 3x25 A	4	€ 147.60	€ 18.00	€ 23.04	€ 4.163	€ 26.38	€ 219.18	€ 265.21

With the use of an internal DNWB document (kostentoerekening, 2012) an estimation is made to divide the capacity tariff in different cost components: this resulted in the values given in Table 2. This data will be the input for the calculations in chapter 3 of this report. The data comes from a draft document and still need to be verified, which gives uncertainty about the accuracy of the numbers. In this research however the focus is on the methods to calculate the tariffs, the exact numbers are less important.

[1] A facility needed to start the own electricity supply of an electricity generator when the grid is dead, after that the production of electricity can be restarted.

Table 2 The capacity tariff divided in different cost components

Capacity tariff	€ 147.60	
Investment costs	€ 77.50	52.5%
Grid losses	€ 25.00	16.9%
Costs of purchasing capacity on TenneT grid	€ 16.00	10.8%
Remaining operational costs	€ 29.10	19.7%

2.4 Demand Response

For the past century, electricity pricing has not reflected the time-variation in costs that characterizes the industry. This has had the unfortunate effect of encouraging excessive consumption of electricity during the expensive peak-period hours and discouraging consumption during the inexpensive off-peak period hours. There is a consensus among economists that such a shift in the pricing paradigm toward time-varying rates would raise welfare. For many years, the problem was the high costs of installing the appropriate metering infrastructure. With digitalization, costs have fallen and the economics of upgrading the infrastructure are examined by many States of the United States of America. However, in most cases, the operational savings in distribution automation only cover roughly half of the total investment. The remainder has to be covered through demand response. (Faruqui and Sergici, 2010)

In a Demand Response (DR) program (or time based pricing system), the price you have to pay for a service or commodity depends on the time it is provided or delivered. The background of time based pricing can be found in the fact that the balance of supply and demand of some services or commodities changes over time. This type of pricing is standard in for example the tourist industry. Higher (room) prices are charged during the peak seasons or during special events, in off-peak seasons only the operating costs are charged.

Time-based pricing is also more and more introduced in the electricity sector. Several different structures are in place to be implemented. An important remark here is that literature on this topic usually focusses on time-based electricity prices and not on prices for electricity transport.

Several types of benefits of DR can be identified. First the reduction in the need to install peak generation capacity. This is a long run benefit and consists of the sum of avoided capacity costs. These can be readily estimated based on the capacity costs of a combustion turbine. The second benefit is the avoided energy costs that are associated with the reduced peak load. Third, and matching with this project, is the reduction in transmission and distribution capacity. This is also a long run benefit, but is however harder to quantify and is heavily dependent on system configurations that vary regionally. (Faruqui, Harris and Hledik, 2009)

Textbox 2.3 Demand Response

Demand Response (DR) can be defined as the changes in electricity usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time. Further, DR can also be defined as the incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. DR includes all intentional electricity consumption pattern modifications by end-use customers that are intended to alter the timing, level of instantaneous demand, or total electricity consumption.
(Albadi and El-Saadany, 2008)

While regulators cannot set retail tariffs, they do have control over Transmission and Distribution tariffs. These tariffs make up a substantial amount of a consumers' energy bill. The total electricity bill is on average €700 (DELTA, 2013). So the total DNWB tariff (€265.21, see Table 1) is about 37.9% of the total electricity bill. However, this tariff is not totally suitable for demand response.

A dynamic tariff, where transmission and distribution charges vary with customer use at times of peak demand, could encourage further demand management. The tariffs could also be increased when there is congestion on the grid. (Faruqui and Harris, 2009)

Time-of-use (TOU)
In a TOU pricing structure different blocks of time are made in which one electricity price is charged. A higher price during peak periods and lower prices during off-peak periods. The goal is to flatten the load curve by reducing peak demand and increasing off-peak demand. (Jongejan et al, 2010) A simplified TOU scheme is used sometimes in the Netherlands with different prices during peak (day) and off-peak (night and weekend) demands.

Critical Peak Pricing (CPP)
In some rare occasions the maximum production capacity must be used because peak demand is extremely high. The high costs resulting from this are normally discounted in averaged tariffs but can be lowered by the introduction of CPP. (Blom et al, 2012)
CPP tariffs are, in essence, a form of TOU programs except that CPP is even more targeted. Instead of daily on-peak times as in TOU rate structures, the on-peak times are limited to just a few days per year when demand is expected to be the highest, such as during heat waves when a lot of air conditioners are switched on. The primary goal of this tariff is to shift load from on-peak to off-peak hours on these peak demand days.
Participants in this rate program are offered lower power prices during off-peak hours in return for being charged much higher rates during critical hours. On-peak rates can typically range between 400-700% of off-peak rates. CPP rate plans typically designate a specific time window for the CPP tariff, such as between 2pm and 7pm, and limit the number of event days, typically 6 to 15 per year. (Jongejan et al, 2010)
A variation of this pricing scheme is the so-called variable peak pricing (VPP/CPP-V). This system is similar to the "normal" CPP rate, with the exception that the window of critical peak hours is not fixed. The specific hours of the event are provided to participants at the same time that they are notified of the upcoming critical event (on a day ahead basis). This provides utilities and system operators with the flexibility to respond to emergencies and high-priced periods of varying lengths occurring at different times of the day. (Faruqui, Hledik and Palmer, 2012)

CPP/TOU
Some utilities have implemented pilots that combine the elements of both TOU and CPP with very promising results. One central argument for combining CPP and TOU is that TOU plans do not create sufficient incentives to conserve energy on CPP event days, while CPP days only address demand during a very small number of days. A combined CPP/TOU system addresses peak demand throughout the year as well as during critical peak periods. (Jongejan et al, 2010)

Peak Pricing (PP)
In a PP tariff structure, a peak price is in place during the daily peak-hours and not just on the critical peak-hours occurring only a few times per year. The PP scheme is charged when load demand is for example above 80% of the daily peak load. An advantage of this tariff scheme, compared to a CPP system, is the fact that the PP scheme gives a consistent incentive during the year. (Kohlmann, 2011)

Real-time pricing (RTP)
RTP models enable utilities to charge customers the actual real-time costs of electricity production based on supply and demand. Technological advances in metering infrastructure and wireless communication technology have created the ability for utilities to communicate real time electricity price information to its customers. (Jongejan et al, 2010)
The main advantage of RTP rates is that they provide the most granularity in conveying accurate hourly price signals to customers. These rates also provide a dynamic price signal that responds to changing market conditions. They have a long history of full-scale deployment among large commercial and industrial customers. (Faruqui, Hledik and Palmer, 2012)

Peak-Time Rebate (PTR)

These programs offer a rebate to customers who reduce their electricity demand on critical peak days when compared to a reference level on a non-CPP day. The perception of a PTR program (receiving money) may be a useful characteristic of this program and help to make it successful. (Jongejan, 2010) The PTR scheme provides a level of bill protection. Because it provides a rebate during critical events but does not increase the rate during other hours, a customer's bill can only decrease under the PTR in the short run.

A disadvantage of this system is the fact that it requires the calculation of each customer's baseline usage, which is necessary for determining individual rebate payments. This process is inherently inaccurate. Furthermore the system does not convey the true time-varying cost of providing electricity and does not provide the price signal necessary to encourage adoption of plug-in electric vehicles or rooftop solar systems. For these reasons, the PTR scheme is considered by some to be an option for a transition to time-varying rates and encouraging participation, rather than an ideal long-term solution. (Faruqui, Hledik and Palmer, 2012)

2.5 Consumer acceptance

Consumers will not always be in favour of a new tariff system. They would rather response negatively and different barriers will show up. A study identified 24 potential barriers to demand response, which were grouped into four categories: (Faruqui, Harris and Hledik, 2009)

- *Regulatory:* Regulatory barriers are caused by a particular regulatory regime, market design, market rule or the DR programs themselves.
- *Technical:* Potential technological barriers to implementation of DR include the need for new types of metering equipment, metering standards or communications technology.
- *Economic:* Economic barriers refer to situations where the financial incentive for utilities or aggregators to offer DR programs, and for customers to pursue these programs, is limited.
- *Other:* These are generally related to customer perceptions of DR programs and a willingness to enroll.

Arguably, several EU Member States are making excellent progress in tackling the regulatory and technical barriers. The potential stumbling blocks that may require greater focus in the future are the economic barriers and persuading customers to switch to more dynamic tariffs. For some customers, DR programs may not provide a sufficient financial incentive to participate, and customers may find it hard to estimate the benefits of switching to a dynamic tariff. Customers have had similar difficulties in estimating the benefits of energy efficiency measures. Customers may be risk-averse, worrying that their bills will increase if they switch to a dynamic tariff, rather than focusing on the potential savings. Customers may feel that they do not know how to shift demand to make the most of dynamic pricing, and there may also be inertia that contributes to low participation rates in voluntary programs.

Quantifying and stressing the environmental benefits of dynamic tariffs can be appealing to some customers groups. Evidence in the United States shows that some customers are willing to adopt dynamic tariffs based on environmental benefits. (Faruqui, Harris and Hledik, 2009)

Overcome economic barriers

A challenge facing utilities trying to enrol customers in demand-response pricing programs is the concerns consumers have that their rates will go up. In response to this concern, many utilities offer bill protection for their customers who enrol. A typical bill protection program will refund any customers whose electricity bills rise under a demand response tariff (e.g. over a 12-month commitment period). After an initial period, the customer typically is no longer eligible for bill protection refunds. Bill protection could be an important lever to use because it provides risk-averse customers with an insurance against higher bills. (Jongejan et al, 2010)

Education
One message that is consistent throughout several tariff pilots is the importance of educating customers about the programs and about the steps that each customer can take to reduce consumption. Customers may be inclined to think that they cannot curtail demand, which means that education about strategies for demand reduction is essential to reach success. This issue relates in part to the fact that customers typically cannot decipher what leads to increases or decreases in consumption simply by reading a typical electric bill. (Jongejan et al, 2010)

Ensuring transparent and adequate financial rewards can help to overcome customer inertia. Where technology allows, suppliers can simplify the choice for customers by offering to take over their demand response for them. An example of this is the earlier mentioned CPP scheme. The advantage of this is that the gains for the customer are predictable and easy to understand. (Faruqui, Harris and Hledik, 2009)

2.6 Possibilities of shifting energy consumption

When consumers are encouraged to shift their energy use to other timeslots, it is good to look at the possibilities that are in place to do so. The use of several household appliances is hard or unpopular to advance or postpone, think of cooking on an electrical stove or watching a program on television. Kester en Zondag (2006) conclude from data of Basisonderzoek Elektriciteitsverbruik Kleinverbruikers 2000 that 47% of electricity use from consumers is used by appliances which use can be shifted over time (within certain margins). Important appliances that contribute to that are the dishwasher, washing machine, dryer, fridge, freezer and electrical boiler. (Kester and Zondag, 2006) But also rechargeable appliances like mobile phones, tablets, laptops are appliances for which the moment of charging can be shifted in time and besides are becoming more and more popular. Moreover, the expected growth of the use of electrical vehicles will give an enormous increase of the potential of controllable energy use. Table 3 shows the energy use of the before mentioned household appliances. The total yearly average energy use of these appliances is 814.5 kWh, which is 24.6% of the total average energy use of Dutch households of 3,312 kWh. (Nibud, 2012)

Table 3 “Best-of-class” data for energy use of household appliances which use can be shifted in time (greenem, 2012)

Appliance	Energy use in 2010 (kWh)	Frequency of use	Yearly energy use (kWh)
Dryer	1.60	112x per year	179.2
Washing machine	0.78	187x per year	145.9
Fridge	140	per year	140
Dishwasher	0.90	206x per year	185.4
Freezer	164	per year	164

3 Tariff design

3.1 Description of cost categories

The aim of the new tariff system for electricity transport to consumers is to shift energy use in time in order to lower costs. With the tariff system consumers will be triggered to change the way they use the electricity grid. The new tariff will replace the current capacity tariff, which is nothing more than a fixed amount of money per year. Three cost components can be distinguished from the current capacity tariff for which consumers can expect savings because of a shift in energy use:

I. Grid investment costs
II. Costs of purchasing energy to cover grid losses
III. Costs of purchasing capacity on TenneT grid

This section covers the description of these cost categories and looks at the possibilities of savings that can possibly be achieved.

3.1.1 Grid investment costs

Software programs like Gaia and Vision are used by the asset managers of DNWB to dimension and design a new grid. (A meeting with the asset managers on this subject is reported in appendix 1) Concerning peak demand, an important formula that is used is the Strand-Axelsson (also known as Velander) formula. (Oirsouw, 2011) With this formula it is possible to calculate the maximum load of a connection or part of the grid. The maximum load is an important indicator when a grid is dimensioned. The formula is given by:

$$P_{max,n} = \alpha \times V + \beta \times \sqrt{V} \qquad [3.1]$$

With:

$P_{max,n}$ Maximum load of n connections (kW)
V Yearly energy use of n connections (kWh/year)
α, β parameters determined by measurements

The parameters V, α and β depend on:

- Type of the region
- Type of the connections
- Amount of connections (Oirsouw, 2011)

The asset managers of DNWB do not measure the parameters by themselves but standardized Dutch values are used. A shift in energy use by consumers will imply a change in the input parameters. The parameters that are currently used are the optimized results of a range of practical measurements of yearly energy use and maximum load. When this way of grid dimensioning is continued, no downsizing of new grid infrastructure can be expected because empirical results of a changed consumption pattern are needed first.
Furthermore, the optional savings of installing cables with a smaller diameter are expected to be small because there is not much price difference between the cables plus digging and street work needs to be done anyway. Investments in transformers on the other hand, may be lower when the maximum load is lowered.
Another possible financial advantage of a lower maximum load can be that investments in an existing grid can be postponed. Grid investments are usually not done because the assets are used up but because its limits are reached due to higher energy consumption and new entrants to the grid. A

lower maximum load will ensure that the grid reaches its limits later, and investments can be postponed.

3.1.2 Grid losses

Grid losses occur in cables and transformers when electricity is transported and distributed over the grid. The losses are as high as the difference between the generated and imported energy that is injected in the grid and the consumed energy (load) from the grid:

$$P_{Loss} = P_{generated} + P_{imported} - P_{load} \qquad [3.2]$$

Losses in cables consist of two different components. The biggest share is caused by the current transport and is directly proportional to the resistance of the cable:

$$P_{Loss} = I^2 \times R_{cable} \qquad [3.3]$$

The second component of losses in cables is the di-electrical losses, which are caused by a changing electrical field in the isolation. The di-electrical losses are usually neglected in grid calculations. (Oirsouw, 2011)

Also for transformers there are two different loss components. The calculation of the copper losses in a transformer is comparable with the first component of the cable losses. It can be calculated at both the primary and secondary side of the transformer:

$$P_{copper\ losses} = I_{prim}^2 \times R_{prim} = I_{sec}^2 \times R_{sec} \qquad [3.4]$$

The other component are the zero load losses, these are dependent on the voltage level (U_{sec}). The formula of these losses is:

$$P_{Zero\ load} = \frac{U_{sec}^2}{R_f} \qquad [3.5]$$

R_f = Main field resistance (Oirsouw, 2011)

DNWB is obliged to compensate for the energy losses in their grid. This is done by buying energy on the Endex power NL market for prices around €0.065 (peak) and €0.055 (off peak) per kWh. (see also appendix 2). The yearly grid losses are about 100 million kWh, which resulted for 2011 in € 6.1 million of energy costs in 2011. (DNWB, 2012b)

The grid losses in the national grid are about 4-5% of the total electricity production. These are the losses at all different voltage levels and the corresponding transformers. The lower the voltage level that is used for energy consumption, the more voltage levels are used for the electricity transport. Because of that, the total percentage of losses is on average 7-8% for electricity consumed at LV level. (Oirsouw, 2011)

3.1.3 Costs of purchasing capacity on TenneT grid

This type of cost needs to be paid to TenneT, and the tariff consists of two different parts:

1. Contracted capacity tariff, this is based on the projected capacity in a certain year and will be adapted when actual peak load exceeds this. The tariff is currently €12.80/kW/year.
2. Maximum load per month, € 1.29/kW/month. (appendix 2)

The capacity used by DNWB is measured for each quarter of an hour. The quarter of an hour in a year in with the highest capacity is demanded will be used to charge the contracted capacity tariff. The same principle holds for the second part of the tariff, but now the quarter of an hour with the maximum load in each month is the base for the calculations.

The demand of DNWB for capacity on the TenneT grid is not directly linked with the demand for energy by the customers of DNWB. Electricity generated by wind and cogeneration etc., can be injected directly in the grid of DNWB, which influences the capacity that is needed from TenneT. Thus, the demand for capacity on the TenneT grid is the demanded capacity by customers minus the injected capacity in the DNWB grid. This makes that injections in the DNWB grid have a big influence on the height and timing of the maximum load demand from the TenneT grid. This has led in some occasions to a situation that DNWB became a “net producer” to the TenneT grid because more energy was injected by distributed generation than consumed at these moments.

The dominant influence of distributed generation on the load pattern of the grid asks for a tariff scheme that focuses not on peak shaving of consumer demand but focuses on the load pattern of the whole DNWB grid in order to lower the costs of purchasing capacity. Furthermore the tariff is based on just one quarter of an hour in each month that is not known beforehand. Specific measures to find this quarter and lower maximum load at that time may be more effective to save costs for purchasing capacity than when the regular daily consumption peak is shaved.

3.2 Converting cost categories to tariff components

The cost categories that will be influenced when a demand response system is introduced are described in the previous paragraph. In this paragraph these descriptions will be elaborated and it will be described how these can be converted into the different components for the new tariff.

3.2.1 Grid investment costs

As it was also indicated in paragraph 3.1.1, postponing of investments is the most relevant aspect when one thinks of savings on the cost component grid investment costs. Postponing of grid investments will happen when it takes longer before the grid reaches it limits. The limits are reached when peak load is as high as the maximum load the grid can handle. This situation will not occur during the summer period when energy use is lower but this will happen during the more energy intensive winter period. The trigger for consumers to lower their peak load must therefore focus on yearly peak load and not on the daily peaks.

If a new investment can be postponed, the depreciation period can be lengthened. This lowers the level of the yearly depreciation costs for DNWB and thereby the level of the cost component grid investment costs of the tariff.

The amount of years with which the investments can be postponed is hard to determine upfront. Of course this depends on the level of peak shaving that can be achieved. But it depends also on the number of future entrants on the grid and the policy that is applied for grid extensions. Because it is not known beforehand if and to what extent consumers' peak load will decline it is not possible to set a rebate on grid investment costs in advance.

An option therefore is to determine afterwards what the peak load of an individual consumer was. But also the timing of that peak over a day is important. The peak in a residential area occurs (on average) between 15:00 and 21:00. So that is also the moment at which a grid in that area will first reach its limits. Consumers should therefore be charged for their maximum load during this period. A tariff in €/kW_{peak} can be determined to calculate the costs for an individual consumer. This tariff should be communicated to consumers in advance, which gives them the possibility to schedule their energy consumption and thereby lower their peak load during the before mentioned period.

3.2.2 Grid losses - average losses

The current (I) and the resistance (R) are prominent factors in the calculations of the different grid loss factors. The resistance is expected to be constant over time so the current remains the dominant variable in the calculations. The square of the current is used both for the calculation of grid losses in cables as in transformers. That is why this factor is chosen as leading factor for the calculation of the costs of grid losses. Note that the expected increase of distributed generation in the future will influence the distance between energy production and consumption. This has its influence on the resistance and thereby also on the grid losses.

Average numbers and consumption patterns can be used to find a way to calculate the grid losses cost component. The average energy consumption pattern of consumers is used to find the energy flows during the day, from that the current can be defined. Combined with the 7-8% (Oirsouw, 2011) of average grid losses for energy consumed on the LV level it is possible to calculate the average grid losses in a year. The square number of the current sets the distribution of the grid losses over the hours of a day. Depending on the period of the day (peak or off-peak), the costs will be calculated with the energy price of 6.5 eurocents or 5.5 eurocents (see paragraph 3.1.2). This results in a Time-of-use scheme with €/kWh prices on an hourly basis.

$$Tariff_{Grid\ Losses,t} = E_{cons} \times x\% \times \frac{I_t^2}{\sum_{t=1}^{365\times24} I_t^2} \times C_{energy}/E_t \qquad [3.6]$$

With: $Tariff_{Grid\ Losses,t}$ = Tariff component for the costs of covering grid losses at hour t (€/kWh)
E_{cons} = Average amount of energy consumed per household per year (kWh)
$x\%$ = percentage for average grid losses on the LV level
I_t = Average load current at hour t (A)
E_t = Energy consumption in hour t in a previous year(kWh)
C_{energy} = Costs of purchasing energy to cover grid losses (€/kWh)

3.2.3 Grid losses - average costs

Another way of calculating the tariff for grid losses is based on the idea that the costs for grid losses that are currently incorporated in the capacity can be spread over the hours of a day. Again the squared number of the current is used to distribute the costs over the hours. But this time there are no average grid losses calculated but just the costs are spread out over the day. This is done following the formula:

$$Tariff_{grid\ losses,t} = CapTar_{grid\ loss} \times \frac{I_t^2}{\sum_{t=1}^{365\times24} I_t^2} /E_t \qquad [3.7]$$

With: $CapTar_{grid\ loss}$ = Cost for grid losses which are currently incorporated in the capacity tariff (€)

This method makes sure that the costs for the customer stay the same when his energy consumption pattern follows the profile of the profile of an average consumer. A disadvantage of this method is that the difference in purchase costs (€0.065 and €0.055) between peak and off peak periods is not taken into account.

3.2.4 Cost of purchasing capacity on TenneT grid - peak pricing

The pattern of electricity demand from the TenneT grid over a day does not fit with the pattern of electricity demand by consumers. It is therefore not useful to use the consumers demand pattern to define the height of this type of costs over the day. Furthermore the costs that must be paid to TenneT are based on the peak demand in a month and a year and not on the daily peak.

A Peak Pricing tariff scheme can be introduced to charge this tariff component. In this scheme the TenneT costs will only be charged to the consumers during the monthly peak hours. Data from the previous year can be used to find the maximum peak in a certain month in that year. In the hours in which the demand from the TenneT grid approaches the peak of that month in the year before the tariff is charged. The number of hours in which this situation will occur needs to be estimated beforehand in order to calculate the costs per kWh. The calculations of the $Price_{peak}$ can be calculated per year or per month.

$$Tariff_{TenneT,t} = Price_{peak} \text{ } if \text{ } Load \text{ } t > x\% \times P_{max}, \quad else \text{ } Tariff_{TenneT} = 0 \qquad [3.8]$$

$$Price_{peak} = \frac{C_{TenneT}}{Hours_{peak}} / E_t \qquad [3.9]$$

With: $Tariff_{TenneT}$,t = Tariff component for the costs of purchasing capacity on TenneT grid at hour t (€/kWh)

Load t = Load which is demanded from the TenneT grid at hour t

P_{max} = Maximum peak load in that month in the previous years (MW)

C_{TenneT} =Costs for purchasing TenneT grid capacity which are passed through to consumers (€)

E_t = Energy consumption in hour t in a previous year(kWh)

$Hours_{peak}$ = Number of hours in which a load is expected of $x\% \times P_{max}$

Textbox 3.1 Home Energy Management System

Home Energy Management Systems offer monitoring and control of selected devices for residential buildings, and like energy-efficient, are gaining a toehold in new and retrofit markets as more homeowners adopt solutions to reduce overall energy bills. (Smartgridlibrary, 2011)

There are two options for the timing at which the energy flows are determined, real-time or a day in advance on the basis of predictions. When the tariff is based on predictions beforehand, the consumers know the peak moments in advance. Consumers or their Home Energy Management System (HEMS) can plan their energy use for that day which helps to use energy as efficient as possible. This is harder to do when the real-time option is chosen, then the consumers are notified at the same time as the peak occurs. However, real time measuring will result in more realistic load values because actual data is used.

Within DNWB load predictions are made a day in advance, these are handed over to TenneT who will use them for balancing the electricity flows in the grid. So the process of making load predictions is already a part of the company’s daily activities. Cogeneration and wind power are by far the most important sources of distributed generation in the grid of DNWB. A capacity of 162 MW of cogeneration is installed and already 230 MW of wind power. For 2013 another 80 MW wind power is scheduled to become operational.

The main inputs for the load predictions are the load pattern of the same day in the week before and the forecasted wind. The shape of the realised load graphs is most of time similar to the predicted one but is often shifted in time because the wind started to blow somewhat earlier or later. This shift can lead to quite some errors in the predicted load values when you look at the load in a certain hour.

For the calculation of this part of the tariff, it is important to find the moments in which a peak in load from the TenneT grid occurs. In practice this will be when the situation is such that demand is high, there is no wind and thus no injection of wind power and no or little injections of energy from cogeneration. The absence of wind can usually be well predicted a day in advance, this makes that also the predictions of peaks in demand can be forecasted well. Moreover, it is planned for 2013 to take also the scheduled injections of electricity from cogeneration into account when the load predictions are made. This all makes that the predictions are expected to be accurate enough and useable for the calculations of the tariff.

This tariff component is based on the expected number of hours in which the peak load is expected to be approached. It is likely that the actual number of peaking hours will not exactly match with the expected number. This will result in too much or too less revenues to cover the tariff that must be paid to TenneT. Nevertheless, this will not result in substantial difficulties. A shortage of revenue in one month can be compensated by a surplus in the next month and vice versa. Furthermore tariffs can be adapted for the next day, month or year to cover unexpected income flows.

Other options for covering the costs of purchasing capacity on the TenneT grid are described in the next two sections.

3.2.5 Costs of purchasing capacity on TenneT grid - discount for granting access

A totally different approach is this method called “discount for granting access”. The network operator can settle an agreement with a consumer that gives the network operator the opportunity to switch off some distribution circuits of the meter cupboard during peak hours. This can for example be the groups of the washing machine, dryer or dishwasher. As reward the consumer gets a discount on his energy transport bill. The consumer will be given the opportunity to break the agreement and use his washing machine even though it was switched off by the network operator. But his discount will be lowered to compensate for that.

This method can be an interesting option from a marketing point of view. Offering a discount usually sounds attractive to consumers, which helps to get a high participation rate. Such a method can be seen as a variation a Peak-Time Rebate scheme (see paragraph 2.4).

3.2.6 Costs of purchasing capacity on TenneT grid – afterwards calculation

A third method for charging the costs of purchasing capacity on the TenneT grid is with the use of an afterwards calculation. After each month the peak of that month can be determined. When the timing of that peak is known, the load demand of each individual customer during that peak can be defined. The costs that must be paid to TenneT can directly be passed through to the customers. This way of calculating can also be applied for the costs of the yearly contracted capacity tariff. After each year the peak is known and customers can be charged for their contribution to that peak.

This way of calculating does really reflect the costs that are made by DNWB, this gives a fair tariff for customers. But customers do not know when peaks occur so some kind of signalling system needs to be designed which warns customers for upcoming peaks.

3.3 Calculation of tariff components

In this paragraph the proposed methods from paragraph 3.2 will be calculated. When possible practical data will be used for that.

3.3.1 Grid investment costs

The current capacity tariff is a flat-rate tariff based on a load capacity per consumer of 4 kW. Some consumers will exceed this value and the peak load of others will be lower. The average of 4 kW will also be used in this calculation.

The value of the cost component "Grid investment costs" in the current capacity tariff is €77.50 (kostentoerekening, 2012). In the new tariff the level of this cost component will be different per consumer depending on the level of their individual peak load. This can be done in this way: $Tariff_{grid\ investments} = 77.50/4 = 19.38$ €/kW_{peak}. As described in paragraph 3.2.1 this tariff will be charged over the maximum load between 15:00 and 21:00.

In practice the average maximum capacity of a consumer can be somewhat higher or lower. Table 4 shows the consequences of that for the tariff.

Table 4 $Tariff_{grid\ investments}$ for different values of the average maximum capacity

Average maximum capacity (kW)	$Tariff_{grid\ investments}$ (€/kW_{peak})
3.0	25.83
3.5	22.14
4	19.38
4.5	17.22
5.0	15.50

Implementing the tariff in this way makes the whole cost component flexible. It can also be decided to make a part of it a fixed tariff and make the flexible component somewhat lower. This can help to secure the income of the network operator but will decrease the incentive to lower peak demand of consumers.

3.3.2 Grid losses - average losses

With the use of a consumer energy use profile (obtained from DNWB) and the average yearly energy consumption of 3,312 kWh (Nibud, 2012) it is possible to calculate the average energy consumption. In appendix 3 the average energy consumption is given for two weekdays (January 13 and July 5) on the basis of the energy use profile of 2011. For these two days the tariffs for grid losses are calculated. This is not only done with the average grid loss percentage of 7-8% given by Oirsouw (2011) but for different grid loss percentages to see if this has a substantial effect on the results. The tariff was calculated for each hour of the two weekdays. For four different grid loss percentages the minimum, maximum and average tariff was determined, see Table 5. Figure 6 shows the tariff over the two days for each hour with a grid loss percentage of 7%.

Table 5 Minimum, maximum and average grid loss tariff for two weekdays and four different grid loss percentages based on the average losses method

$Tariff_{grid\ losses}$ (€/kWh)	13-jan 5%	6%	7%	8%	5-jul 5%	6%	7%	8%
Minimum	0.0012	0.0014	0.0016	0.0019	0.0011	0.0013	0.0015	0.0018
Maximum	0.0058	0.0070	0.0081	0.0093	0.0028	0.0034	0.0040	0.0045
Average	0.0031	0.0037	0.0044	0.0050	0.0020	0.0024	0.0028	0.0032

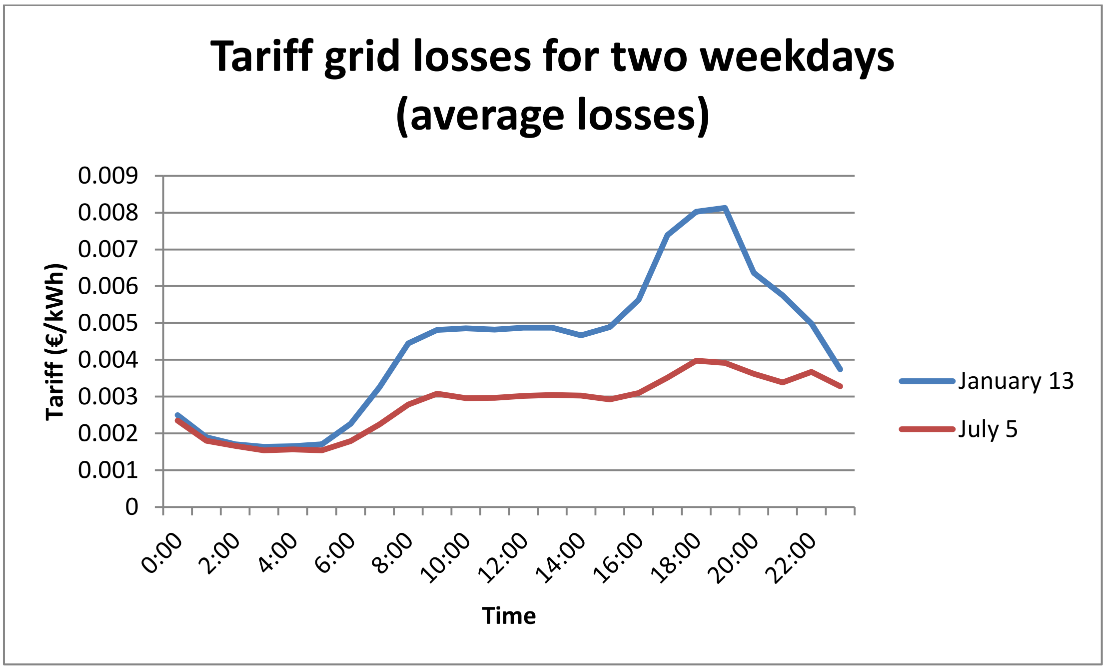

Figure 6 Tariff$_{grid\ losses}$ for two weekdays with a grid loss percentage of 7%, calculated with the average losses method

3.3.3 Grid losses - average costs

The same data is used as in the calculations in paragraph 3.3.2. This resulted in the tariffs that are shown in Figure 7. The shape of graphs in Figure 6 and Figure 7 is quite similar but the level of the tariffs is about 1.5 times higher in Figure 7.

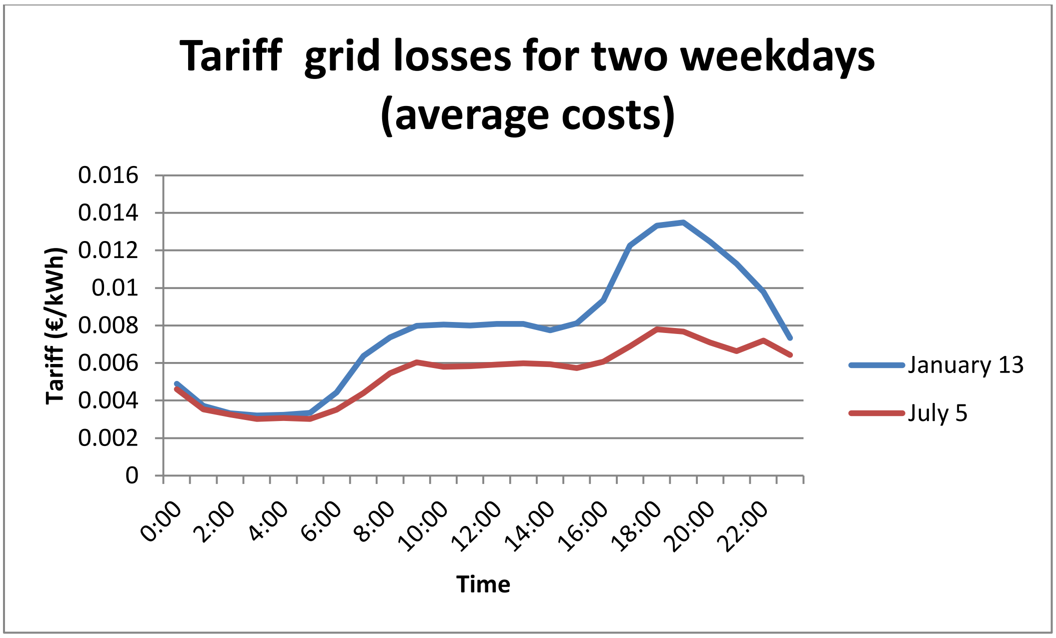

Figure 7 Tariff$_{grid\ losses}$ for two weekdays calculated with the average costs method

3.3.4 Costs of purchasing capacity on TenneT grid - Peak Pricing

The grid of DNWB is connected to the TenneT grid at different points. The connection points together form a virtual connection point for which the load data is received for the years 2010 and 2011. This data set exists of a range of kWh numbers, each number represents the amount of energy transported through the connection points in each quarter of an hour of the two years. Load peaks and the moments that this peak was approached are analysed using this data. These can be important inputs for a new tariff. Although the costs that must be paid to TenneT are based on the quarter of an hour with the highest load, the analyses below are based on the hours with the highest loads. This is done because the load predictions made by DNWB are also made per hour of the day.

First the four kWh values for each hour are added up which results in kWh/hour values or the average load (kW) in that hour. For each month the maximum average load value is determined. In addition there is also a calculation made to find how often this maximum value is approached. This is done by counting the amount of hours in which load is >x% of the maximum load in that month. In Figure 8 both results can be found, the blue line shows the value of the maximum load in each month and the bar charts show the number of hours in which load exceeds x% of the maximum load. The monthly load peaks follow the same pattern in the two years; this can also be seen in appendix 4. The total number of peak hours in a year can be found in Table 6 this is the average number of 2010 and 2011.

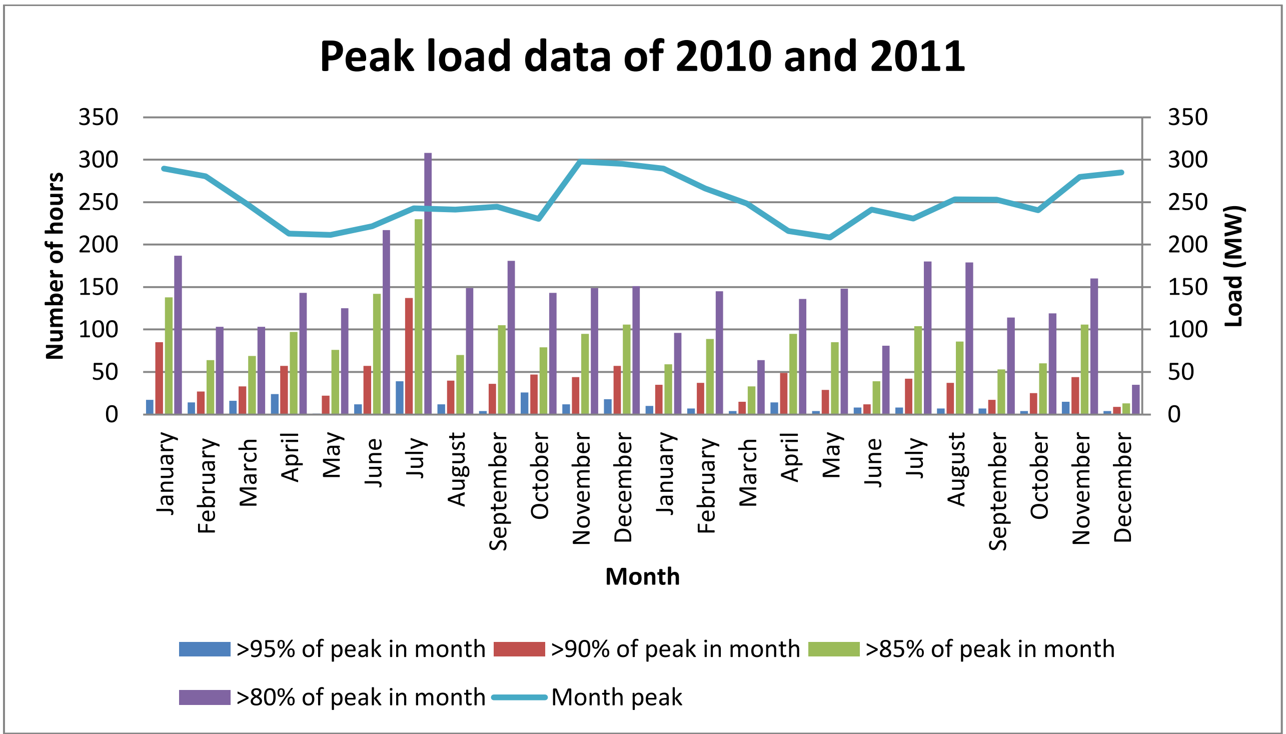

Figure 8 Peak load data of the years 2010 and 2011

Table 6 Number of hours in which the peak load is approached (average of 2010 and 2011)

	Average number of peak hours in a year
>95% P_{max}	143.5
>90% P_{max}	496.5
>85% P_{max}	1046.5
>80% P_{max}	1708

Now that the number of peak hours is known, it is possible to calculate a tariff per hour. To get a tariff in €/kWh, this tariff must be divided by the energy consumption by consumers in the hours that a peak load is approached. This is done with the earlier described data, which can be found in appendix 3.

For these two days the tariff is calculated. It is assumed that on both days a peak in load is expected from 10:00 to 13:00. This is a realistic assumption because load peaks often occur at that time. The costs for purchasing TenneT grid capacity which are passed through to consumers (C_{TenneT}) are € 16,- per year (kostentoerekening, 2012). Under these assumptions the tariffs in Table 7 are calculated.

Table 7 Tariff component $Tariff_{TenneT}$ in €/kWh for two days and different values for $x\%P_{max}$

	13-jan				5-jul			
Time	$>95\%P_{max}$	$>90\%P_{max}$	$>85\%P_{max}$	$>80\%P_{max}$	$>95\%P_{max}$	$>90\%P_{max}$	$>85\%P_{max}$	$>80\%P_{max}$
0:00 -	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10:00	0.239	0.069	0.033	0.020	0.331	0.096	0.045	0.028
11:00	0.241	0.070	0.033	0.020	0.330	0.095	0.045	0.028
12:00	0.238	0.069	0.033	0.020	0.325	0.094	0.045	0.027
13:00 -	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

3.3.5 Costs of purchasing capacity on TenneT grid - discount for granting access

Insight in the potential for peak shaving because of this measure is needed to calculate the discount that can be offered to consumers. Essential for this is the height of the load that is demanded by the wet household appliances during the monthly peaks. There is currently no data for this available and it is also hard to determine. Differences will probably also show up when you look at the type of household (e.g. elderly people or double-income households). Pilot projects can be of good help to find an appropriate level of the discount for customers and the potential for peak shaving.

3.3.6 Costs of purchasing capacity on TenneT grid - afterwards calculation

The calculation of the tariff in this way is quite obvious; the peak load is defined afterwards and consumers are charged for their contribution to that peak. Their load demand during the monthly peak can be multiplied with €1.29/kW and during the yearly peak with €12.80/kW. However, an option can be to raise the price during the monthly peak and lower the price during the yearly peak. This makes sure that consumers are not confronted with extremely high prices for an accidental high-energy demand during the yearly peak. Furthermore it increases the incentive for consumers to lower their energy use during the monthly peak. To ensure that consumers can adapt their energy use during the monthly peaks they need to know in advance when the peaks might occur. In paragraph 3.2.3 is described that load predictions are made a day in advance by DNWB. This prediction could also be used here to warn consumers in advance that a peak is expected. It will be communicated at which hours peak load is foreseen and consumers can adapt their energy use according to that.

For 2010 and 2011 calculations are made to find what the tariff for consumers would have been if this afterwards calculation method was used. First the quarter of an hour in which the monthly and yearly load peak from the TenneT grid occurs is determined. Next, the load of an average consumer during these quarters of an hour has been found. The load values are multiplied with the tariffs that must be paid to TenneT. This results for 2010 and 2011 in the tariffs shown in Table 8. The data separated per month can be found in appendix 5.

Table 8 $Tariff_{TenneT}$ calculated for 2010 and 2011 based on the afterwards calculation method

Year	Tariff monthly peaks	Tariff yearly peak	Total $Tariff_{Tennet}$
2010	€ 6.93	€ 5.77	€ 12.70
2011	€ 7.14	€ 5.93	€ 13.08

3.4 Combining cost components into one tariff

The described cost components and the possible methods to incorporate them in a flexible tariff will be combined in one tariff in this paragraph. It will be shown how the total transport tariff will look like on a winter and a summer weekday with the use of some of these methods. Several combinations are possible but in this example the method "average costs" is chosen for the grid losses and the "Peak Pricing" method for the costs of purchasing capacity on the TenneT grid. As in paragraph 3.3.4, a peak in load from the TenneT grid is assumed between 10:00 and 13:00 and x in $x\%P_{max} = 90$.

The introduced method to calculate the cost component grid investment costs results in a tariff per year independent of the amount of energy consumed. To show how much these costs are compared to the other cost components, the tariff is also calculated per kWh based on the average energy consumption of 3,312 kWh. The same holds for the not earlier described cost component Remaining operational costs, which price is set at €29.10 per year (see also paragraph 2.3.1). So note that both cost components are incorporate in this example as an indication and will not be charged per kWh.

The results for this combined tariff can be found in Figure 9 and Figure 10.

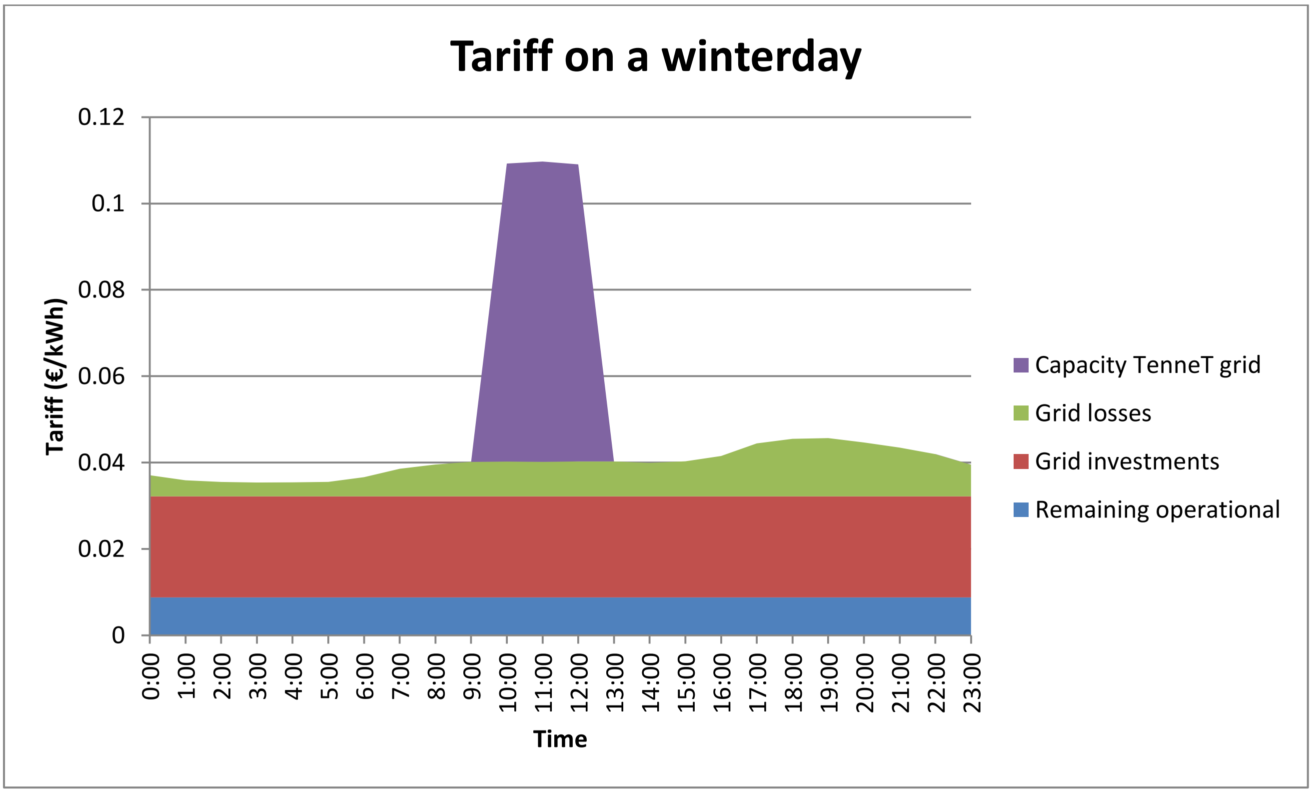

Figure 9 Example of a possible flexible electricity transport tariff on a winter day (January 13)

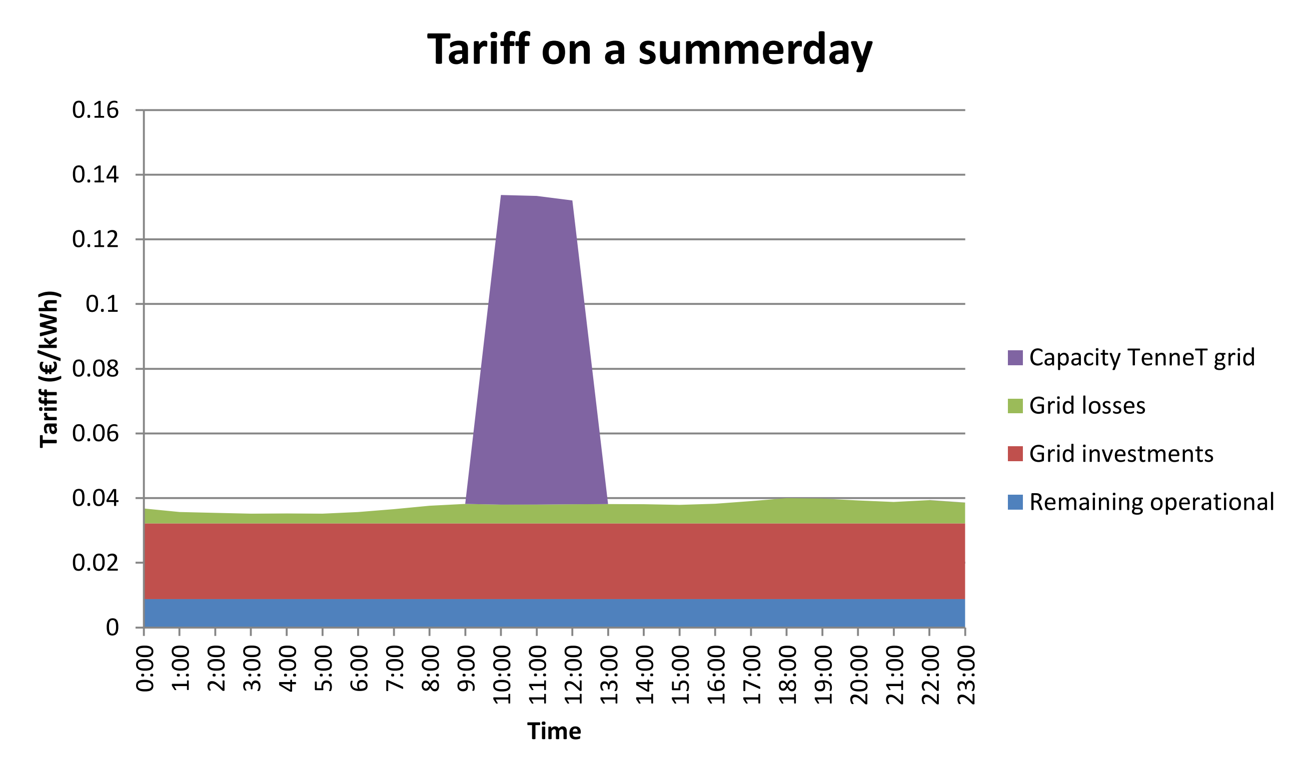

Figure 10 Example of a possible flexible electricity transport tariff on a summer day (July 5)

The tariff makes use of a Time-of-Use structure; the tariff is calculated for each hour a day in advance. This gives consumers or an HEMS the possibility to schedule their energy use for a day and thereby minimizing their electricity transport costs. When an HEMS is used to schedule energy use the number of tariff intervals is less important because it can always calculate the cheapest option. The load predictions per hour are made by DNWB a day in advance, so for them that required input data is already in place, which makes it easier to calculate the tariff.

The tariffs for the different cost components are calculated with the use of an unverified division of the costs of the current capacity tariff. When these data are verified the costs might be shifted somewhat between the cost components. When this is the case it will basically only lead to a somewhat higher tariff for one cost component and a somewhat lower tariff for another cost component.

Implementing a flexible tariff like the one introduced here will bring about some substantial changes for DNWB. The transport tariff changes from one single yearly tariff into a tariff that is divided into different cost components of which the level depends on the timing and level of energy use. The tariff for the average consumer will not change a lot when the tariff of Figure 9 and Figure 10 is introduced. €147.60 is paid in the current situation, dividing by the average energy consumption of 3,312 kWh results in 0.045 €/kWh. However, individual consumers will get the possibility to influence the level of their transport tariff because they can shift or lower their energy consumption.

A whole new (digital) framework needs to be designed to make sure that data collection, tariff calculations and collecting of the tariff are done in an efficient way. Currently the transport tariff is usually incorporated in the energy bill that the consumer gets from the energy supplier. It must be considered if this is also desirable when a flexible tariff is introduced. On the other hand it can also be interesting to merge the tariff into a flexible tariff of the energy supplier. This can be a transparent system for consumers and help them to minimize their overall electricity costs.

The current capacity tariff and average energy consumption patterns form an important base of the designed tariff. This makes that the income for DNWB will not change that much when consumers' energy consumption patterns stays the same. Incomes and expenses will shift when consumers start to change their energy use behaviour. Also an external factor like the amount of hours at which demand from the TenneT grid peaks because of the absence of wind influences incomes and expenses. The fact that the tariffs are forwarded just a day in advance to the consumers makes that there are always possibilities to adjust tariffs on short term. This can help to secure the income level of DNWB.

4 Discussion

Because this study takes place in a new research area, not much practical experiences and data was available. Furthermore it was intended to design a new method for the calculations of a tariff and not to follow directly a method that was already designed by others. This made that this research started from scratch. The tariff ultimately was designed in a way that it is divided in different cost components and each component can be calculated in a different way. Different assumptions have been made during the design of the tariff and execution of the calculations. These are described below together with some other remarks that can be made about the designed tariff and the design of tariffs in general.

Tariff - Grid investment

The level of this part of the tariff is dependent on the level of the demanded load capacity between 15:00 and 21:00 of an individual consumer. So no longer an average of 4 kW for everyone is used as it is now in the current capacity tariff. The value of 4 kW is assumed to be the average load capacity of consumers and therefore still used in the calculation of the new tariff. The question is how solid this assumption is. If the average in practice is for example in the range of 3.5 kW, DNWB will lose lots of income. It will therefore be important to define the actual average load capacity before such a tariff is implemented.

Tariff - grid losses

Future pattern of energy consumption and energy production by consumers has a big influence on the level of the grid losses. Is decentralised generated electricity consumed in the neighbourhood? Or will it be transported to higher grid levels? These are important questions because the distance over which the electricity is transported directly affects the height of the grid losses.

Furthermore when a lower peak demand can be realized and the load level is more even divided over the day, it will take longer for assets to reach their limits and new assets can be dimensioned lower. This will result in a higher average load factor of the assets and corresponding higher grid losses.

The square of the current is taken as leading factor to distribute the costs over the hours of a day. Although this factor is a dominant factor in grid loss calculations it leaves out the contribution of the di-electrical losses and zero load losses (see paragraph 3.1.2). This makes the calculations somewhat incomplete. However, these factors are small and the zero load losses are even often neglected when a grid is dimensioned. (Oirsouw, 2011)

There is a difference in the energy costs for covering the grid losses between peak and off peak periods. So even when it is not possible to calculate the level of grid losses accurate enough, it can be an option to incorporate this difference in energy costs somehow in a tariff to consumers.

Tariff - costs of purchasing capacity on TenneT grid

Three different methods are proposed for this cost component. The Peak Pricing method is primarily based on load data of the previous years and makes use of load predictions a day in advance. A high level of accuracy of these predictions will be essential for a successful tariff. The occurrence of an unpredicted peak leads to costs for DNWB while no money is generated. On the other hand when peak load is predicted but does not occur consumers will be confronted with needless costs. Nevertheless it is possible to compensate for a lack or abundance of money in the following days, months or years although this will not lead to a transparent way of tariff calculating.

Making use of load data of previous years assumes that the load pattern will be similar in the current year. The presence or absence of wind has a big influence on the level of the load demand from the TenneT grid. Load demand will therefore be influenced by the erratic pattern of the wind. Using load data based on a longer range of years will probably end up with the most reliable results.

The before mentioned statement about the importance of accurate predictions also holds for the afterwards calculation method. When consumers are not warned for a load peak they must pay significantly more, which they could not prevent because they were not aware that a peak could occur.

Voluntary versus mandatory tariffs

When a tariff is introduced it can be chosen if it is made mandatory or that a participant can voluntary participate in the tariff. Some tariff schemes however are more suitable to make voluntary and others mandatory. For example voluntary participation seems to be most suitable for the introduced method “discount for granting access” to calculate the cost component cost “purchasing capacity on the TenneT grid”. Especially such a voluntary tariff will be sensitive for participating “free-riders”. This free-rider effect can definitely lower the cost-effectiveness of an introduced tariff. Participating in this tariff seems to be interesting for people who work during the day. That is also the moment that most peaks occur and the network operator will switch off some distribution circuits of the customers. These people will receive a discount but no peak capacity will be saved because these people would also otherwise not have used these distribution circuits. From the point of view of the network operator, costs are made but no (or minimum) savings are realized.

5 Conclusions

The broad introduction of smart meters that is planned gives the opportunity to influence consumers' energy consumption with the use of a flexible tariff for electricity transport. This is desirable, especially because network operators will have to deal with several huge changes in energy consumption and production in the future. These changes will lead to an increase in costs for network operators. A flexible tariff will make sure that the costs for both the network operator as the consumer can be minimized.

In this project the possibilities for the implementation of a flexible tariff for electricity transport instead of the current capacity tariff are investigated. The tariff is divided into 4 different cost components:

I. Grid investment costs
II. Costs of purchasing energy to cover grid losses
III. Costs of purchasing capacity on TenneT grid
IV. Remaining operational costs

The component remaining operational costs is assumed to be independent of electricity use and load demand and is therefore not incorporated in a flexible tariff. The other components depend, at least to some extent, on the level of electricity use and/or load demand. But the cost driver and timing is not the same for each cost component. This means that it is essential to find for each component the timing of the moments at which costs are made or when they are at its highest. When this is succeeded it is possible to give consumers a financial incentive to adjust their energy use at these moments.

I. Grid investment costs

It is found that the level of grid investment costs depend on the maximum load demand in a grid or a part of the grid. Maximum load in a residential area will (usually) occur during the winter period between 15:00 and 21:00. The maximum load of an individual consumer during this period will be the value at which the level of this cost component must be determined. This maximum load (in kW) will be multiplied with a price in €/kW to get the yearly costs for this component. This price can be set by dividing the costs for investments that are involved in the current capacity tariff by the average maximum peak load of consumers during the before mentioned period.

II. Costs of purchasing energy to cover grid losses

The squared number of the current (I) is an important factor in the calculation of grid losses in the grid. This is therefore taken as leading factor to determine the tariff in the two methods that are introduced to calculate this cost component. One method makes use of an estimation of the percentage grid losses in a low voltage grid. The other method divides the costs for grid losses that are currently incorporated in the capacity tariff over the hours of a day.
Although these possible methods are introduced, it is also described that it will be hard to design an accurate system in practice. The distance between energy production and consumption has a substantial influence on the level of grid losses. Because this distance is (usually) unknown it is not possible to incorporate this factor in a tariff.

III. Costs of purchasing capacity on TenneT grid

Three possible methods are introduced to calculate a tariff to consumers for the costs of purchasing capacity on the TenneT grid. These costs must be paid to TenneT and depend on the demanded peak capacity from the TenneT grid. The tariff is based on the peak of each month and the peak per year. The incentive to consumers must focus on lowering these peaks to save costs.

A Peak Pricing system is the first introduced method; the purchase costs that are incorporated in the current capacity tariff will be divided over the moments at which a peak or an approach of the peak is expected. The second option is that a consumer gives the network operator the possibility to shut of some distribution circuits of the consumer when a load peak is approached. As a reward the consumer gets a discount on its energy transport bill. The third option is to calculate afterwards what the contribution of an individual consumer was to the peak demand of each month and per year. The consumer can be charged with the same price as the network operator must pay to TenneT.

The tariff

It is important that people or their Home Energy Management System (HEMS) can schedule their energy use in advance. When possible, it is therefore proposed to make use of a time-of-use system and communicate the tariffs to the consumers a day in advance. The tariffs can be set for each hour; this is also a suitable time interval for DNWB because the load predictions they make are also per hour.

Several options are proposed for how a flexible tariff can be designed. These kinds of methods can be used when a flexible tariff is implemented. However, more analysis and research will be needed on the accuracy of the calculations and used data. Especially concerning the practical consequences of such a tariff.

5.1 Recommendations for further research

While this project ends here, other researches to flexible electricity transport tariffs will be started up or continued. Therefore some remarks and recommendations are given here which can be taken into account when other projects in this field are executed.

Behaviour of consumers

The intension of a flexible electricity transport tariff is often to change consumers' behaviour or to let them behave in a way that is desired by the network operator. The question is when people start to react on a certain financial incentive? How big must this incentive be? When are they willing to adapt their daily routine? Answers to these kinds of questions are important to know when the success of the implementation of a flexible tariff is to be determined.

Verification of used data

It can be questioned for several of the used input data how accurate they are. For example, a division of the costs of the current capacity tariff is used for the design of the flexible tariff. This division comes from a draft document and is unverified. When this kind of numbers will be used when a tariff is implemented, it is important to analyse this data and to make sure that the values match with the costs that are made in practice.

A similar remark can be made for the used average capacity of 4 kW for the calculations of the cost component grid investments. It is important to find out what the exact value for the average maximum capacity in practice is because it is an essential factor in the calculations.

Technical consequences for the grid

The technical status of the grid and the consequences for the grid were out of the scope of this research. But several important issues can be addressed to this subject, think of: How are load levels divided over the grid? And how will they change when the share of distributed generation increases in the future? Which components in the grid can be identified as critical? And what is the effect of a flexible tariff on imbalance and the costs of imbalance?

Costs of purchasing capacity on the TenneT grid - Peak Pricing

In this method the yearly costs are divided over the number of (expected) peak hours in a year. It can be interesting to do similar calculations for each month separate. Furthermore, the costs in the designed method are the costs for both the monthly peaks as the yearly peak. An option can be to split this and make two tariffs, one for the monthly peaks and one for the yearly peak. Or for example not divide the costs for the yearly peak over the whole year but just over the winter months.

Informing/educating consumers

It does not matter what kind of tariff will be introduced, well informed consumers are vital for a successful introduction. Most of the consumers are unfamiliar with the costs that are made by a network operator or with the terminology used by network operators. Investigating what way of information provision will give the best results will be useful.

Quantifying consequences of a flexible tariff

Before a flexible tariff is implemented it is important to analyse the (financial) consequences of that introduction. On the one hand because the level and timing of the income for the network operator will change drastically. But also because the costs for metering and billing probably will rise due to the introduction of the new system.

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Appendix 1

Meeting 12-11-2012 at the DNWB office with Piet Oosterlee and Jaap Moerland (asset management)

Short report of the meeting:

The meeting was arranged to discuss the possibilities of lower expenditures in grid investment and grid losses due to a lower peak demand.

Grids are dimensioned with the use of software programs like Gaia and Vision. These programs make use of the Strand-Axelsson formula to calculate the peak demand. The inputs for this formula are standard numbers and coefficients. The coefficients can be measured in practice, but DNWB uses standardized values for this. Schemes that lead to a lower peak demand because of a shift in energy will change the input coefficients of the formula.

Savings in investments of cables with a smaller diameter because of peak shaving are expected to be very low (negligible). A reason for this is the fact that a substantial part of the costs of building a new cable are because of digging and street work, which needs to be done anyway. Furthermore the difference in price of a cable with a slightly smaller diameter is very small.
DNWB installs just a few different transformers, looking at the capacity size (100, 160, 250, 400 kVA). Peak shaving may ensure that a smaller transformer is needed for a certain case. When for example 260 kVA is needed for an investment, a transformer of 400 kVA should be purchased. A lower peak demand can bring the needed capacity below 250 kVA, which makes a 250 kVA transformer sufficient and save money on the investment. However, these kinds of savings are case specific and hard to quantify in general.

Grids are usually installed for a period of 40 years. After this period the grid is often not used up but reaches the maximum capacity of the grid because of a growth in energy use and thereby a higher peak demand (also because of new houses/companies enter the grid). Energy use which is evenly spread over the day will lower the peak demand and it will take more time to reach the limits of a grid. New grid investments can therefore be postponed. It is not clear yet how to quantify the financial advantages of this.

Grid losses can be calculated by using the before mentioned software. Hans de Groot will be contacted for the financial consequences of the grid losses.

Appendix 2

Meeting 13-11-2012 at the DNWB office with Hans de Groot

Short report of the meeting:

Goal of the meeting was to learn about the way the capacity purchase costs for TenneT are calculated and to get to know the costs that are involved with grid losses.

The yearly grid losses in the grid of DNWB are about 100,000 MWh/year. The energy is bought on the ENDEX power NL market, this is done up to 2.5 year in advance. Current prices on this market are around: (prices at www.apxendex.com)
Peak price (weekdays 8:00-20:00): €0.065/kWh
Off-peak price (weekdays 20:00-8:00 and weekend days): €0.055/kWh

The capacity purchase costs to TenneT consist of two parts:

1. Contracted capacity tariff, this is based on the projected capacity in a certain year, this is currently €12.80/kW/year
2. Maximum load per month, € 1.29/kW/month

Tariff is measured on the quarter of an hour which has the highest load. Electricity generated by wind and Cogeneration has a big influence on the amount of energy that is demanded from the grid of TenneT. This is because electricity of wind and Cogeneration is injected directly in the DNWB grid. This lowers the energy demand of the TenneT grid at some moments which makes the timing of peak demand unpredictable. Injections even become at such a high level at some moments that more energy was injected in the grid than consumed.

The unpredictability of the moments that peaks will occur makes it hard to incorporate the costs for purchasing capacity on the TenneT grid into a flexible tariff in advance. A possibility can be to adapt (raise) the tariff on a real time base at moments when electricity demand approaches a certain monthly peak. (for example the peak demand of that month in the previous year)

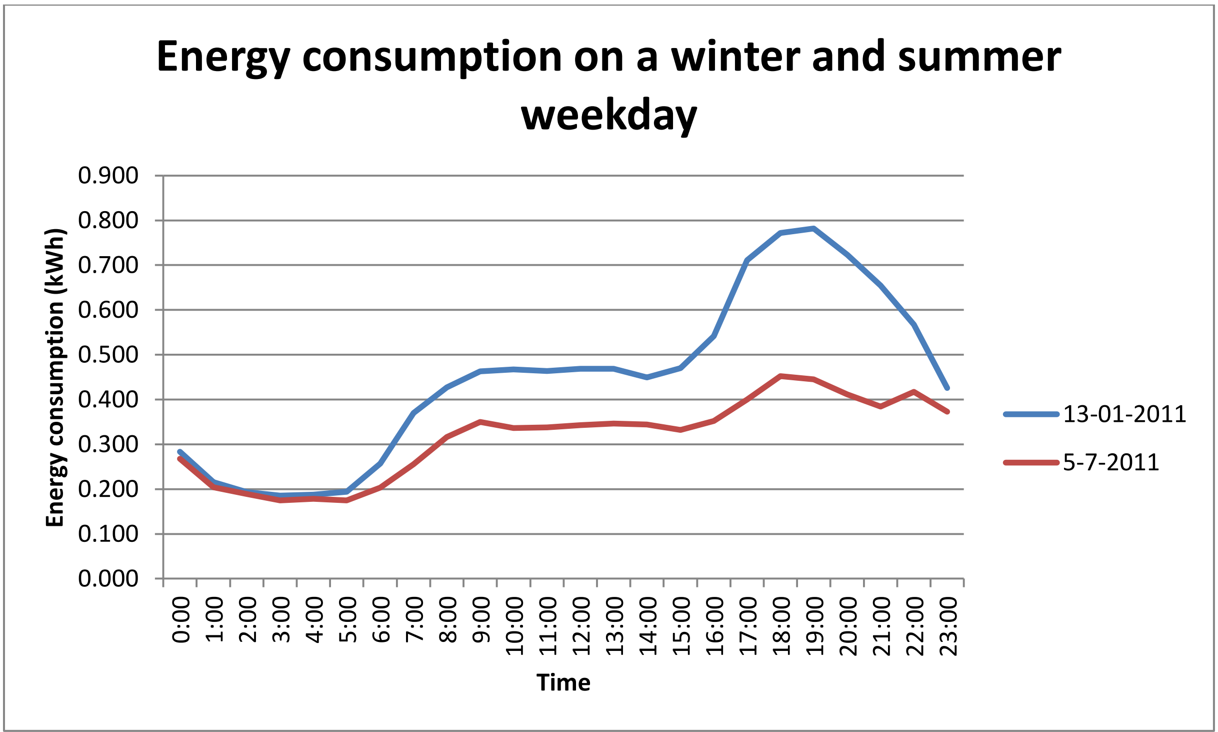
Appendix 3

Energy consumption data of consumers based on an energy use profile of 2011 and an average yearly energy use of 3,312 kWh (Nibud, 2012)

Energy consumption by consumers on a winter and a summer weekday based on an energy use profile of 2011

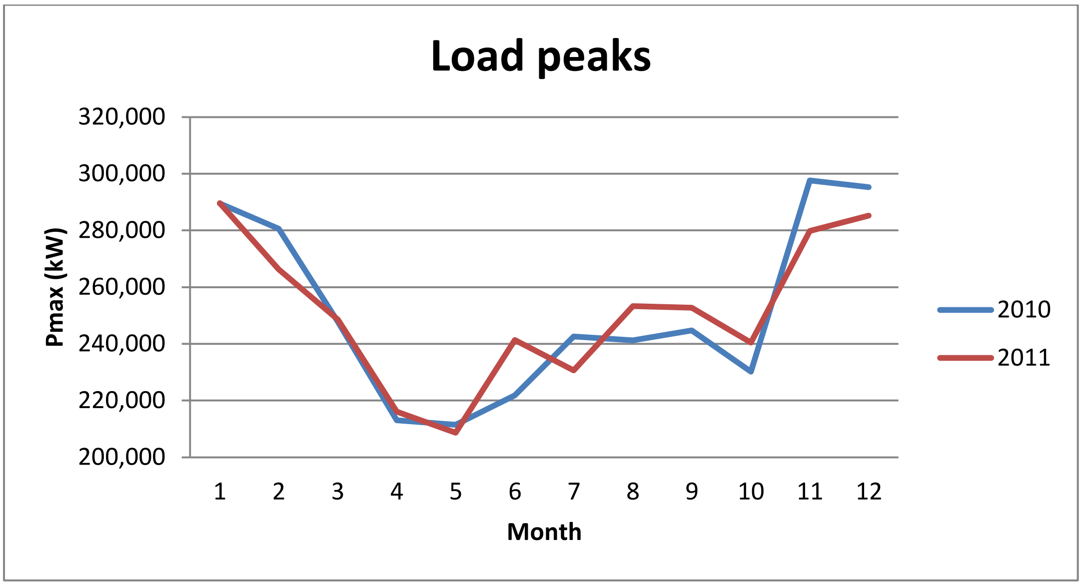
Time	Energy consumption on 13-1-2011 (kWh)	Energy consumption on 5-7-2011 (kWh)	Time	Energy consumption on 13-1-2011 (kWh)	Energy consumption on 5-7-2011 (kWh)
0:00	0.284	0.267	**12:00**	0.469	0.343
1:00	0.215	0.204	**13:00**	0.468	0.347
2:00	0.193	0.189	**14:00**	0.449	0.344
3:00	0.186	0.175	**15:00**	0.470	0.332
4:00	0.188	0.178	**16:00**	0.542	0.352
5:00	0.194	0.175	**17:00**	0.711	0.400
6:00	0.257	0.204	**18:00**	0.772	0.452
7:00	0.370	0.256	**19:00**	0.782	0.445
8:00	0.427	0.317	**20:00**	0.723	0.412
9:00	0.463	0.350	**21:00**	0.654	0.384
10:00	0.467	0.337	**22:00**	0.567	0.417
11:00	0.463	0.338	**23:00**	0.426	0.373

Energy consumption by consumers on a winter and a summer weekday



Appendix 4

Maximum loads in each month which are demanded by the DNWB grid from the TenneT grid in 2010 and 2011



Appendix 5

Timing of monthly peaks	25-01-10 12:00	15-02-10 11:00	16-03-10 10:15	29-04-10 21:00	23-05-10 22:30	30-06-10 23:15	20-07-10 13:30	25-08-10 21:00	23-09-10 21:00	9-07-10 22:45	29-11-10 11:15	7-12-10 11:30
Consumers load demand during peak (kW)	0.475	0.494	0.390	0.456	0.479	0.412	0.356	0.479	0.532	0.435	0.451	0.416
$Tariff_{TenneT}$ (€)	0.612	0.637	0.503	0.588	0.618	0.531	0.459	0.617	0.686	0.561	0.582	0.537

Load data of an average consumer during the monthly and yearly peak demand of DNWB from the TenneT grid and the tariff that results from that.

Timing of month peaks	31-01-11 11:30	28-02-11 11:45	18-03-11 11:45	21-04-11 21:15	30-05-11 20:45	28-06-11 14:30	24-01-11 11:30	25-08-11 21:00	30-09-11 21:15	1-10-11 21:00	22-11-11 14:30	21-12-11 14:00
Consumers load demand during peak (kW)	0.464	0.475	0.399	0.490	0.414	0.350	0.444	0.471	0.573	0.591	0.399	0.468
$Tariff_{TenneT}$ (€)	0.598	0.613	0.515	0.632	0.534	0.452	0.572	0.608	0.739	0.762	0.515	0.603

Timing of yearly peaks	29-11-10 11:15	31-01-11 11:30
Consumers load demand during peak (kW)	0.451	0.464
$Tariff_{TenneT}$ (€)	5.772	5.935