Integrating Renewable Energy Resources

A microgrid case study of a Dutch drink water treatment plant

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Executive Summary

In the Netherlands 1.2 billion cubic meters of drinking water are produced each year, which uses about 480 GWh of electricity per year as an energy intensive industrial process. While there are some examples of renewable based microgrids around the world that illustrate the benefits of producing and consuming renewable electricity onsite, there has been little research on the potential of a renewable-based hybrid system at a much larger scale and in a Dutch context where wind speeds are higher, solar irradiation more moderate, and where subsidy schemes for renewable energy investment exist.

Objective. Thus, this research aimed to identify the technical and economic potentials of integrating solar photovoltaic (PV) and wind power with demand response into a grid-connected versus stand-alone microgrid at a Dutch drink water treatment plant. It also aimed to investigate the economic implications for flexible demand in the water pumping process with demand response (DR) and the extent of reliance on grid-imports, storage, and back up generation. Lastly, it aimed to evaluate the economic potential of the microgrid system in 5 years if investment costs would further decrease.

Method. Waternet's drink water treatment plant in Nieuwegein (DWP-NWG) was used as a case study to model a microgrid integrating solar PV and wind power with demand response by researching its electricity demand, the production potential for renewable electricity (RE) supply, and the flexible demand potential in the pumping process. These were then used as inputs to model a variety of grid-connected and stand-alone microgrid cases using HOMER modelling software under the current financial support scheme and in 2018. The main technical potentials were evaluated based on renewable electricity production potential, fraction of onsite electricity demand supply for renewable electricity, reliance on grid imports, back up diesel production, and storage throughput. Economic potentials were evaluated based on the system's levelized cost of electricity (COE), net present value (NPV), and discounted payback period (PBP).

Results. The DWP-NWG has the potential to supply 70-96% of its annual electricity demand with 17.8-25.6 GWh/year of locally produced solar PV and wind power combined with demand response. The most profitable system configuration is a 5.6MWp Solar PV – 8MW wind (4 turbines) combined with demand response, yet without storage. This microgrid system can be 88% self-sufficient on renewable electricity, with a COE of 0.020 €/kWh versus 0.082 €/kWh for the current situation without renewables, an NPV of €12.7 million, and a payback period of 7.3 years. The least cost stand-alone system is a 5.6MWp solar PV – 8MW wind – 1.3MW diesel generation – 2MW cell stack/45MWh electrolyte flow battery storage with demand response, which has a COE of 0.094 €/kWh and an NPV of €-7 million. If electricity prices rise, grid-connected potentials increase by 16-55%.

- **Demand response**: Comparing a 4 wind turbine system with demand response to one without demand response, the former has an NPV of €11.8 million and the latter €11.2 million. This shows that demand response adds about €600,000 of value over a 25 year project lifetime. Annually, shifting 29% of normal annual demand to be supplied during renewable electricity production earns an additional €59,000 per year in avoided transport and energy taxes. Larger capacity microgrid systems, which can pump slightly more water above normal demand from the excess RE produced, earn up to €71,000 per year. The maximum capacity RE system with DR and without batteries can utilize 12% of the additional flexibility provided by the water storage buffer at the Dunes; however, in order to utilize the maximum 15% flexibility from the buffer at the Dunes, adding battery storage is required in order to defer the use of excess electricity when the

strongest pumps are not being used. This is due to the limitations of the current pump installations and transport network which prevent significantly more water to be pumped in one time step.

- **Grid imports, back up generation, storage**: Even at these high potentials, both grid-connected and stand-alone cases still rely on 1-4.5 GWh of electricity per year imported from the grid in grid-connected cases or supplied by back-up diesel generators in stand-alone microgrid cases. This is due to the intermittency of solar PV and wind power production. Grid-connected microgrids don't necessarily need storage, yet stand-alone microgrid cases require 2.2-3.2 GWh of annual storage throughput.

- **2018 Potentials**: If investment costs further decrease and no tax incentives of subsidies exist for RE, the most profitable microgrid case configurations remains the 5.6 MWP solar PV – 8 MW wind (4 turbines) – DR without battery storage configuration with a COE of 0.030 €/kWh, an NPV of €10.7 million, and a discounted PBP of 11 years. The least cost stand-alone microgrid has a COE of 0.118 €/kWh, and an NPV of €-11 million. If the EIA & SDE+ financial support is still available in 5 years, NPV potentials are 40% higher.

Conclusion/Discussion: The technical results show that a significant portion of electricity demand of an industrial sized water treatment plant can be met with a few wind turbines and large PV capacity. They also confirm that a solar-wind combination is optimal over a wind-only configuration. The economic results indicate that stand alone microgrids are not cost-effective, while grid-connected microgrids are very profitable. This is because directly consuming renewable electricity onsite avoids the majority of electricity costs, sell-back of excess electricity is possible, and because the impact of investment costs has decreased since the SDE+ subsidy decreases wind investment costs by at least 50% and solar PV investment costs have drastically dropped by over 40% over the last year. Moreover, based on the sensitivity analysis of electricity prices, the profitability of these systems is even underestimated if electricity prices rise in the future.

The results also indicate that while the technical potential to shift electricity demand with demand response is significant, the economic advantages are relatively small since the margin between buy-in and sell-back electricity prices is marginal for wholesale electricity consumers. Nonetheless, the investment for demand response could be paid back in less than 2 years and will become more profitable as electricity prices rise and sell-back rates decrease.

Moreover, a 100% renewable system would require extremely large battery storage, which is not currently cost effective. Ultimately, even at the low wholesale electricity and sell-back price for large industrial electricity consumers, grid-connection and the ability to trade excess electricity is extremely important for the cost-effectiveness of microgrid system. Lastly, although PV costs have already dropped significantly making the current economic potentials from grid-connected solar-wind microgrid configurations very high, waiting to invest within 5 years can be even more profitable as long as the EIA and SDE+ support remain.

Keywords: Dutch microgrid, industrial water treatment flexible load (demand response), renewable electricity, wind power potential, solar PV power potential, microgrid economic potential

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List of Abbreviations

CORUS	Tata Steel
CvG	Crown van Gelder
DER	Distributed Energy Resources
DG	Distributed Generation
DS	Distributed Storage
DR	Demand Response (Deferrable/Flexible Load)
DSO	Distribution System Operator
DWP-NWG	Drink Water Plant at Nieuwegein
EIA	Energy Investment Allowance
GC	Grid-connected
NPV	Net Present Value
PBP	Payback Period
PV	Photovoltaic
PWN	Puur Water & Natuur
RE	Renewable Energy/Electricity
SDE+	Subsidie Duurzame Energie
SA	Stand-alone
WHG	Westelijk Havengebied

1. Introduction

In the Netherlands, 10 water companies make about 1.2 billion cubic meters of drinking water a year, 3 times that of 1952 (Starre, 2012). Satisfying these water needs requires significant amounts of energy for supply, purification, distribution, and treatment of water and wastewater. As an energy-intensive industrial process, this amount of water production equates to about 480 GWh of power consumption per year, which is equivalent to the power use of about 137,000 Dutch households[1].

Water treatment is an industrial-scale process to make water more acceptable by de-contaminating the water so it is fit for a desired end use for drinking water, industry, medical applications and other uses. The multi-step process involves solids separation using physical processes such as settling, filtration, and aeration, and chemical processes such as disinfection and coagulation (refer to Appendix A). However, the main energy intensive process of water treatment is the pumping of water from sources like canals and polders, between stages of chemical and physical filtration, and ultimately transporting and distributing to households, industrial parks, and other users (EPA, 2012). Electricity represents approximately 75% of the fuel cost of municipal water processing and distribution (Powicki, 2002). With continuously rising demand for clean water, industrial water treatment plants require more and more power, which puts a strain on these water treatment utilities as electricity prices are always rising and also increases their carbon footprint due to their dependence on grey electricity.

Options to optimize energy use in order to decrease the carbon footprint and mitigate the exposure to rising electricity prices are energy efficiency measures and renewable energy implementation. Energy efficiency improvements decrease the total demand for power, thereby decreasing carbon emissions and minimizing costs. Moreover, utilizing renewable energy, like wind and solar technologies, on site provides a clean source of energy which significantly lowers emissions. However, considerable techno-economic limitations hinder the implementation of renewables: high investment costs and their intermittent nature.

The high costs associated with renewable energy implementation have a negative impact on short term costs, particularly if unsupported by regulatory schemes, even though they help minimize costs in the long term by decreasing the dependency on the main grid. Moreover, the *intermittent* nature of renewable power production creates a significant technical challenge since they cannot always be dispatched as needed. This is due to the fact that renewable energy is dependent on external variables, like the weather, which cause problems in balancing supply with demand. This is particularly problematic in the context of water treatment and distribution, which needs to maintain a relatively stable level of production, and thus a stable level of power to support the process.

A potential solution to optimize electricity consumption and alleviate the intermittent nature of renewables is to integrate distributed generation (DG) and energy consuming loads into a decentralized microgrid using storage and demand response (Dohn, 2011); however, each of these solutions also face significant techno-economic and societal limitations (Eyer, 2010).

Due to the energy intensity of the industrial water treatment process and the high electricity costs associated with it, it is interesting to investigate whether water treatment plants can become decentralized microgrids to decrease

[1] Assuming about a power demand of 0.4 kWh/m3 of water produced and an average annual power demand of about 3,500 kWh per Dutch household (Waternet, 2012a; Enipedia, 2010)

dependence on grey power and rising electricity prices, yet still maintain water production using clean energy sources.

1.1 Problem Definition

This section introduces some common nomenclature in the field of smart grids and microgrids, and reviews their application in general, from the microgrid perspective, and applied to the water treatment and distribution process.

Smart Grid, VPP, Microgrid, Hybrid Energy Systems

A variety of terms are used to describe advanced power networks that incorporate traditional and renewable energy: smart grid, VPP, microgrid, and hybrid energy systems. A smart grid constitutes a vision of an electricity grid that is improved through two-way digital communication between consumers and suppliers to increase its efficiency. Most authors supplement this definition with Demand Response (DR) (Claessen, 2011). Demand response refers to a variety of actions which can be taken at the customer side of the electricity meter in response to particular conditions within the electricity system. These depend on the goals of the electricity user and grid owner, and can include peak shaving (if electricity price is higher during the day), load adjustment, and improved power reliability and flexibility (S&C Electric Company, 2013).

An extension on this smart grid vision is to break it down into sections, which can be Virtual Power Plants (VPP) or microgrids. A VPP is usually defined as a collection of Distributed Energy Resources (DER), also known as Distributed Generation (DG), which are centrally controlled, and discussions generally focus on the role of the VPP within the main grid. A microgrid, on the other hand, focuses on the internal structure of the energy system from the consumer-perspective to be autonomous from the main grid by matching supply and demand internally. In simple terms, a microgrid is a discrete energy system consisting of electrical loads interconnected with DER. These are sometimes referred to as hybrid energy systems if multiple DG are combined to supply the energy demand. A microgrid may also contain additional options to help match supply and demand, such as energy storage and DR. Some authors specifically include storage capability in the definition, as well as the ability to operate a microgrid independently from the main grid for some period of time, referred to as “islanding” (Claessen, 2011; O’Connell, 2012). Microgrids and hybrid systems are the focus of this research.

The opportunities and benefits of integrating DG into a microgrid exist for both end-users and the main electrical grid. For these end users, onsite microgrid implementation can provide improved electric service reliability, better power quality, and lower electricity costs by meeting some or all of its electricity needs locally. Moreover, enabling a higher level of self-consumption through local power production, storage, and demand response also reduces system congestion for the main grid and helps balance the intermittent nature of DG like wind and PV (EPIA, 2012).

Novelty of Smart grid applications in the Netherlands

While European utilities have used various forms of load shedding mechanisms with large industrial customers to reduce demand during peak over the past 20 years, the US is significantly ahead of Europe when it comes to demand response (Whitehouse, 2011). Europe’s load management mechanisms have been based on discrete timing and pricing of interruption, which have been contract based rather than automated. There are several countries, like Spain and Italy, with long standing arrangements to harness the largest and most energy intensive

industrial customers through Direct Load Control & Interruptible Programmes using interruptible tariffs or time of day pricing; although mechanisms for compensating industries varies significantly. This means that the economic and technological potential of demand response varies from country to country depending on the incentives structures in place and the amount of industrial manageable power (Torriti et al., 2010).

No such programs have been implemented in the Netherlands, but smart grid research and applications have started blossoming within the last decade. The first smart grid pilot projects recorded began in 2006 by ECN (Energy research Centre of the Netherlands) to create a Smart Power System (Smart Grids Projects, 2012). Since then a variety of local organizations and industrial consortia are initiating large scale Smart Grid projects (refer to Appendix B. for a list of 8 Dutch initiatives). Recent examples of residential smart grid projects include those in Grongingen & Zaanstad (Shahan, 2011; iNSnet, 2013). For the most part, these pilot programs are meant to test new technologies, market models and consumer behaviour, as well as regulatory and financial aspects. However, since these pilots have only been initiated in recent years, the results and benefits are still not completely clear. Moreover, the focus of these projects is more from the perspective of grid-automation rather than from the consumer-perspective and few are applied to industrial users.

Microgrids internationally and in the Netherlands

Decentralized microgrids take a more internal consumer perspective, and there are numerous examples and pilots done on grid-connected and islanded microgrids around the world. Self-sufficient energy systems already have been set up in a number of developing countries in order to help with the implementation of rural off-grid electrification in countries such as China, Mexico, Kenya and Bangladesh. The energy systems often consist of PV with battery packs or even backup diesel generators and are located in tropical regions (Urmee et al., 2009). However, these focus on a small rural energy demand, and therefore cannot be compared to the energy intensive power demand of an industrial process in a developed country. Multiple load microgrid examples also exist internationally, which meet the demand from residential and commercial buildings. For example, the Sendai microgrid in Japan has been able to supply 5 university buildings, an aged care facility, and a high school. The majority of this microgrid is comprised of reciprocating engines and supplemented with PV, a fuel cell, and battery storage. It is normally grid-connected to help deal with the intermittency of its renewable energy generation, although it is not allowed to feed power back to the grid, which is a common barrier for grid-connected microgrids (Irie, 2012; Soshinskaya, 2013). While this shows that larger load microgrid implementation is feasible, is does not indicate the feasibility of a predominantly RE-based microgrid at such a scale since most of these examples rely on conventional generators. In the context of the Netherlands, one such RE-based microgrid was tested in the village of Bronsbergen. The PV-battery microgrid with grid-connected and islanding capability was a test pilot, but was ultimately not economically viable due to the amount of storage required and the significant capital costs associated with the storage capacity (Cobben, 2008). No other Dutch microgrid examples have been documented.

These cases illustrate that there is currently no standard method for becoming a self-sufficient energy user by integrating DG into a microgrid because of differing environmental conditions and energy demands. They also indicate the importance of aggregating multiple energy producing devices in order to stabilize power production, and minimize storage in order to have more cost-effective energy mixes. While these cases prove that microgrid implementation is feasible, they also prove that high capital costs of renewables and storage can prevent their commercial implementation. Therefore, there is a knowledge gap on whether RE-based microgrids can be cost-effective, particularly in the Dutch context.

Hybrid Energy Systems Applied to Water Treatment Process

There are also limited pilot cases and literature about the application of a microgrid to an industrial scale water treatment plant. However, some literature does discuss the feasibility of renewable energy powered water desalination plants and hybrid systems to show the sustainable application of renewable sources in water pumping systems (Lindemann, 2004; Mahmoudi et al., 2008; Ramos & Ramos, 2009). In the former, a seawater desalination plant in the Arabian Gulf is supplied by a stand-alone 750kW wind energy plant and a reverse osmosis (RO) plant was supplied by a stand-alone 4.8kWp PV system with additional battery storage of 60kWh[2]. However, these are small scale systems that do not incorporate the energy-intensive pumping of water to distribute it. Ramos & Ramos (2009), on the other hand, modelled stand alone and grid-connected hybrid energy systems of wind/PV/battery combinations on a water pumping system in Portugal and showed that wind and PV energy can compliment each other to enhance system reliability; although systems with a greater proportion of PV were less cost-effective.

These studies are still smaller scale than an industrial sized water treatment plant and are targeted for areas with greater solar primary energy and lower wind speeds compared to the Netherlands. Additionally, these hybrid systems were simulated four or more years ago, when the capital costs, particularly for PV, were significantly higher than today. Therefore, there is a knowledge gap on the compatibility of such RE-based hybrid systems at a much larger scale and in a Dutch context where wind speeds are higher, solar irradiation more moderate, and subsidy schemes for renewable energy investment exist. Additionally it is unknown whether the significant drop in capital costs over the past few years can make PV implementation as part of the optimal energy mix more cost-effective.

In conclusion, an extensive literature review of both scientific articles and web-based searches, reveals that there is a knowledge gap when it comes to the technical and economic feasibility of a predominantly RE-based microgrid for a Dutch drink water treatment plant due to the novelty of smart grid technology, variety of microgrid structures, and incomparable internal, environmental, and regulatory conditions from other microgrid cases.

1.2 Aim of Research Project

This research aims to fill the knowledge gap of the application of a smart microgrid to a large scale industrial water treatment plant in the Dutch context. By taking a scenario approach of different combinations of DG, storage, DR, and grid-connection, it aims to identify the technical and economic feasibility of integrating DG at a drink water treatment plant into a microgrid to directly meet its demand with local supply. This leads to the following research question:

1.3 Research Question and sub-questions

"To what extent can an industrial drink water treatment plant become self-sufficient from a stable supply of renewable electricity integrated into a microgrid, and what are the techno-economic potentials of being grid-connected versus stand-alone?"

[2] Although desalination and reverse osmosis are different water treatment processes than ground water treatment, they are comparable in energy usage; with the latter potentially needing more energy in the future as new drinking water regulations will increase the use of higher energy consuming processes, such as ozone and membrane filtration (WateReuse, 2011)

Sub questions:

1) What margin of flexibility is there in the water pumping process for demand response and what are the financial implications?
2) To what extent are grid imports, back-up generation and back up storage required, and what are the economic implications?
3) How do the economic potentials change if investment takes place 5 years from today if no subsidies exist, investment costs decrease, and electricity prices increase?

1.4 Methodology

In order to answer the main research question and related sub questions, a Dutch drink water plant (DWP) was used as a case study to research the different components, particularly electricity demand and associated costs costs, supply, and demand response individually. The results were then used to model the proposed microgrid cases using HOMER modelling software to determine the fraction of onsite electricity demand that could be supplied by locally produced renewable electricity and whether that would create value for the system compared to the current base case of purchasing all electricity from the grid. In this section the case and scope are presented, the choice for the HOMER model is explained, and an overview of the research methodology is discussed.

Case & Scope

Waternet is the water cycle management and administration municipality of the Amsterdam area, and supplies more than 90 million cubic metres of drinking water annually to households and business facilities in and around Amsterdam (Waternet, 2012b). In 2009 it consumed 108 GWh of electricity, 40% of which was at its 3 drink water treatment plants (DWP): Nieuwegein (NWG), Leduin, and Weesperkarspel (Knibbe, 2011). In order to minimize its carbon footprint and cut the costs associated with this large power usage, Waternet is continuously looking to implement renewable energy and optimize its power use in a financially attractive way. Due to the large amount of space required for the water treatment process and the distance from many residential homes, the DWP in Nieuwegein is a good candidate for wind and solar energy, located along the Lek Canal with 10,300m^2 of roof surface area and about 70,000m^2 of land on Parceel Zuid (Meer, 2012; Velden, 2011). Therefore, it will be used as a case study for this research. Heat demand at the site is relatively negligible, and in turn will not be included. The lack of methane-producing biomass from the groundwater treatment process would require the plant to be dependent on purchasing large amounts of wood supply for biomass electricity generation to be a viable option. The sustainability of this option is questionable as this would require large amounts of land use elsewhere. Therefore, only wind and solar electricity potential are explored.

HOMER Model

There are a large number of different models available to investigate the integration of renewables. Based on the review of a number of articles and web-based searches, in combination with the requirements the model needs to have (particularly modelling various renewable energy sources, power demand, energy storage, demand response, and financial parameters), is was concluded that the HOMER (Hybrid Optimization Model for Electric Renewables) energy model, developed in 1992 by the National Renewable Energy Laboratory in the USA, would be the most useful model for this research (Connelly et al., 2010; COMMEND, 2012; HOMER Energy, 2013). Other model options

include EnergyPlan or H2RES, but are not as useful in simulating microgrid energy systems because EnergyPlan is a deterministic model and does not optimize investment costs, and H2RES does not simulate grid-connection.

HOMER is a very accessible and user-friendly model that allows for the simulation and optimization of stand-alone (SA) and grid-connected (GC) power systems with any combination of energy supply including: wind turbines, PV arrays, run-of-river hydro power, biomass power, internal combustion engine generators, microturbines, fuel cells, batteries, and hydrogen storage, serving both electrical and thermal loads. The input parameters are therefore extensive and very specific depending on the selected system components and control which are modelled and whether the system is grid-connected or stand-alone. However, for this research the focus will be modelling the electrical load since the thermal load of a drink water treatment plant is relatively negligible, and focuses on solar PV and wind power production combined with demand response, back up storage and diesel generation, so not all model functionalities are used. However, all technology, grid-connection, infrastructure, fuel, and finance costs are included for each system component. General input components are illustrated in Figure 1 below and chapters 2 through 4 discuss the specific input parameters and units needed to model each component in this research.

Once all chosen technical and economic parameters are input, HOMER simulates 1 year of system production for all combinations of input technology sizes to supply the input electricity demand based on the indicated control/dispatch strategy and by cost optimization using a minimum time-step of 1 minute. This means that at each time step, HOMER chooses to use the cheapest power supply option within the system dispatch and control constraints based on the input fuel costs (€/kWh) to supply the electricity demand. The annual costs for the 1 year simulation of each feasible system are then extrapolated over the project lifetime and discounted, based on the input discount rate, in order to calculate the net present costs for each system for the project lifetime. The resulting feasible microgrid configurations are then listed based on the lowest net present cost for the project lifetime. The main optimization output results list the size and combination of components simulated (kW or number of wind turbines), grid-connection capacity (kW), initial capital (€), operating cost (€/yr), total net present cost (€), COE (€/kWh), renewable fraction of load (%), capacity shortage (%), diesel fuel used (L), and generator hours. However, more in depth technical production and economic are also produced and analysed. Refer to Appendix D for the full list of output parameters and units from the components modelled in this research. The listed system designs and techno-economic outputs provide the opportunity to evaluate and compare each system to other systems and to the current base case which relies purely on grid imports. However, the latter is only possible in grid-connected models. The cost cash flows and comparisons are used to calculate net present value (€), return on investment (%), internal rate of return (%), simple payback period (year), and discounted payback period (years).

Method & Data Collection

The first step of this research was defining the electricity load for an industrial water treatment plant, which was done using the DWP-NWG's measured electricity use from 2012. Grid-supply was defined based on Waternet's contracted supply and electricity prices. The potential for locally produced solar PV and wind power was then modelled based on the local geography and climate using studies already done for the DWP-NWG, a few site visits, and KNMI (Royal Dutch Meteorology Institute) measured wind speeds, solar irradiance, and temperatures from Cabauw (which is less than 15km away from the DWP-NWG), and publically available information about the chosen solar and wind technologies. Sell-back rates for renewable electricity was based on the contracted agreement between Waternet and the energy supplier, which is common for large scale electricity consumers, and regulatory

policy and financial support was calculated based on publically available information, input from John Wright, Waternet's Subsidy Coordinator, and publically available ECN advise.

The amount of renewable energy supply also has implications on the amount of storage, back up generation, storage, and/or demand response that will be necessary to balance the intermittency of the renewable and ensure a stable power supply. Storage was modelled based on literature research and publically available information about the chosen batteries, back-up diesel generators were modelled based on publically available information and the technical characteristics of the diesel generators already located at the DWP-NWG. Lastly, flexible demand was modelled using a bottom's up approach based on the DWP-NWG's customer demands, onsite technical pump installations, and storage capacity.

All of these microgrid components were then used as inputs in the HOMER model. Since microgrids can have different configurations based on the RE potential, technology sizing, and need to back up generation, and/or storage, a variety of scenarios with different electricity mixes and component capacities were run to optimize to see which one is the most cost-effective. Since grid-connection is also a way to regulate intermittency, all scenarios were run in grid-connected mode. Additionally, in order to gauge whether the drink water plant can be completely self-sufficient without depending on the grid, stand alone scenarios were also run to test the technical and economic feasibility of this option. Figure 1 below illustrates the overview of the research methodology used and the input parameters that were investigated and modelled.

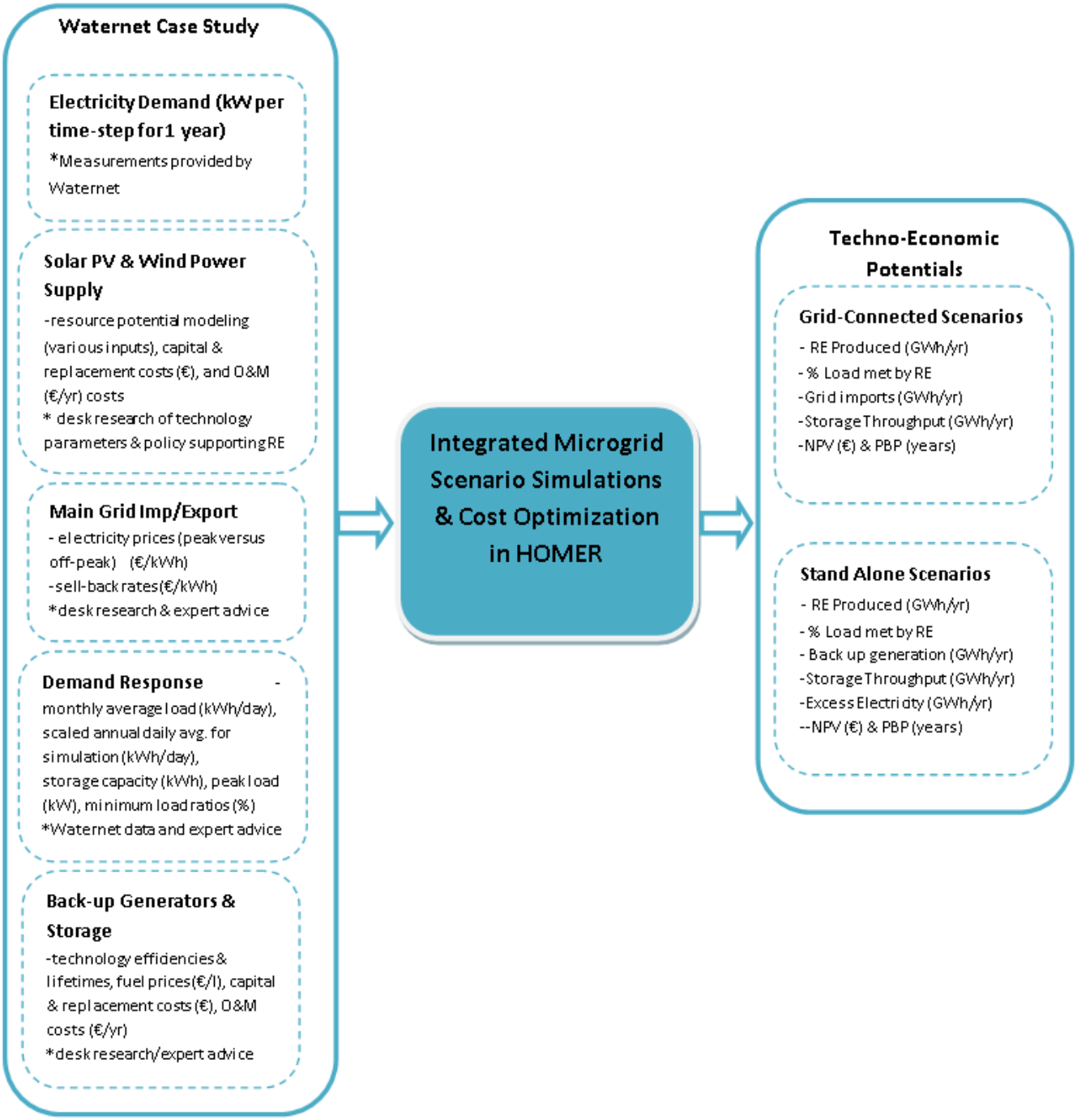


Figure 1. Flow diagram of general input parameters and research methodology

The technology potential integration simulation for 1 year of production, in conjunction with the optimization model of different energy mix scenarios determined the most cost-effective scenarios and the associated technical potentials for a microgrid at the drink water treatment plant. These results indicated the extent to which the plant can become a self-sufficient and stable microgrid and the financial implications of doing so.

1.5 Reading Guide

In Chapters 2, 3, and 4 the methodology and assumptions used to model the various microgrid cases will be presented. Chapter 2 discusses the electricity consumption of the industrial water treatment plant. Chapter 3 explains the electricity supply for the grid, wind and solar PV power production, and the incentives currently available for renewable energy implementation. Chapter 4 discusses the microgrid components which regulate the intermittencies including flexible demand (demand response), storage, back-up generation, and the dispatch strategy for these components. Chapter 5 then summarizes the scenarios modelled and the general assumptions for the model inputs. The technical and economic potentials of the modelled scenarios, along with a sensitivity analysis of the major uncertain parameters, are then presented in chapter 6. The model inputs and constraints are then discussed in chapter 7. Finally, a conclusion is given in chapter 8 and recommendations for further research are offered in chapter 9.

2. Electricity Demand

In order to derive the load profile of the drink water treatment plant, two key questions need to be addressed: 1) What is the total electricity demand over the course of the year, and 2) How is the demand distributed over a year, week, day, and on an hourly level. In the context of this research, a bottom-up approach is used to model the energy use of a drink water treatment plant using the measured data from the DWP Nieuwegein (DWP-NWG) plant.

2.1 Total Electricity Demand

In 2012, the DWP-NWG required 16.85 GWh of electricity to produce about 98 billion cubic meters of water, which is slightly higher than the 16 GWh average annual electricity demand over the past 5 years. From 2005 to 2009 it decreased from its highest usage of nearly 20 GWh to its lowest annual usage of about 15 GWh (see Figure 1). This significant decrease is predominantly due to decreasing the use of the largest pumps and automating the pumping system. Once automation was complete, electricity demand stabilized around 15-16 GWh per year between 2009 and 2011. Since 2011, annual power demand increased by about 13 % due to increased maintenance and a 10% increase in water production demand from this specific site[3] (Braam, 2013). Going forward, an annual electricity demand of 16.5-17 GWh is expected at this higher level so the 2012 annual electricity consumption will be used in the model.

[3] This increase in demand is caused by a redistribution of water production from the Andijk WRKIII treatment plant to the Nieuwegein plant for efficiency reasons, rather than an overall increase in demand for drinking water (Braam, 2013)

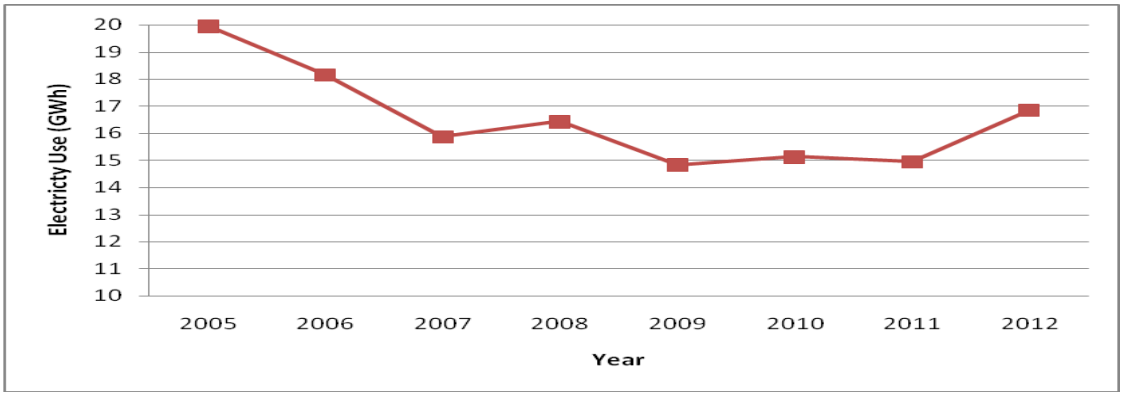


Figure 1. Annual Electricity Demand 2005-2012 (Waternet, 2013)

When comparing electricity demand on a monthly basis, there is a slight inverted U-shaped trend indicating that more electricity is used in the summer months versus the winter months. This is due to the higher evaporation levels in the Leiduin dunes, which take in almost 50% of the water produced at DWP-NWG (refer to Appendix C for DWP-NWG customers), during the summer months. This results in the need for greater production of water to compensate for this evaporation, and in turn more electricity demand (Kors, 2013). This seasonal variation is important for modelling the demand profile for this specific site, but may not apply to other locations since this water filtration step is specific to the Netherlands (Lenntech, 2012).

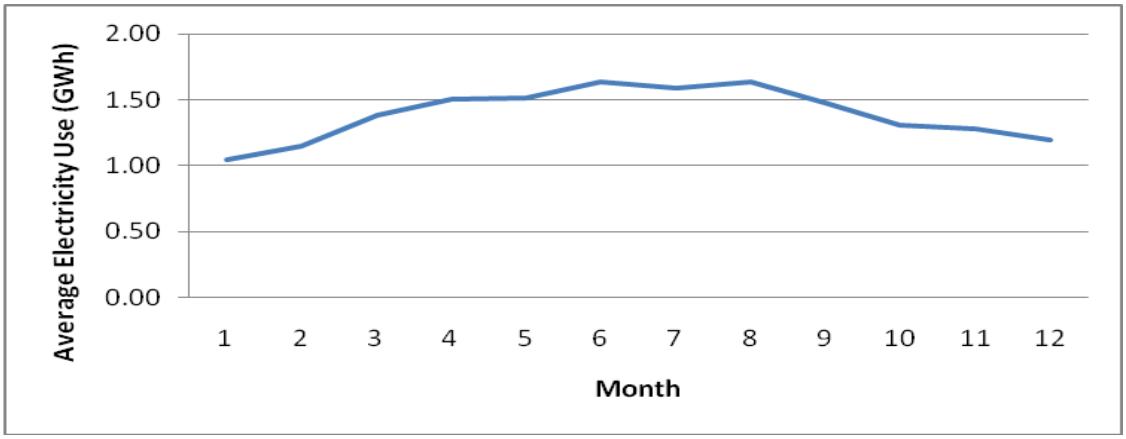


Figure 2. Monthly Electricity Demand Comparing 2005-2012 (Waternet, 2013)

2.2 Distribution of Electricity Consumption

Unlike residential electricity demand, which follows an oscillating electricity distribution between the day and night, with more power used during the day and less at night, the distribution of power consumption for industrial drink water treatment over a day and a week is relatively flat and stable, as seen in Figure 3 and 4 below, with an average load of 1900 kW in 2012. *Peak electricity* was 3222kW in July, a summer month when evaporation is significant in the dunes and requires extra production, leading to a load factor of 59% since it is defined as the average electricity load divided by the peak load at a moment in time. This high load factor indicates a more constant electricity use through the day, which is common for industrial scale consumers (Pabla, 2008). The maximum contracted feed-in value is 3450 kW (Waternet, 2006).

The use of electricity is automated to keep the treatment process stable and determined by customer demand for water. The flat electricity distribution curve is due to the fact that an industrial DWP is a bulk supplier so it has set points of production that are automated and programmed for the day or the week. In the DWP-NWG case, these points are set between 250,000 to 380,000 m^3/day. The DWP-NWG pumps about 46% of its water to the Leiduin dunes for the last stage of filtration, which takes about 3 months, 25% to Tata Steel (aka Corus) where it uses what it needs and the rest is stored in large reservoirs, 25% to PWN for final drink water production, 2% to Crown van Gelder for paper production, and a marginal amount to Westelijk Havengebied (WHG) (refer to Appendix C from an overview diagram) (Braam, 2013). Deviations from the set point only occur due to a change in demand from a particular customer or if the water level in the reservoirs is either too high or too low, depending on the amount of water the steel plant uses. Changing a water production setting for a change by 600 m^3/hour, for example, could result in a change of 200-300 kWh of use. As seen in Figures 3 & 4, which illustrate the power distribution of a week in the winter and a week in summer, there is no daytime/night time pattern, nor weekday/weekend pattern since the DWP production is programmed to maintain constant production, which is optimal for stable water treatment, and so customer demand does not drastically fluctuate (Braam, 2013).

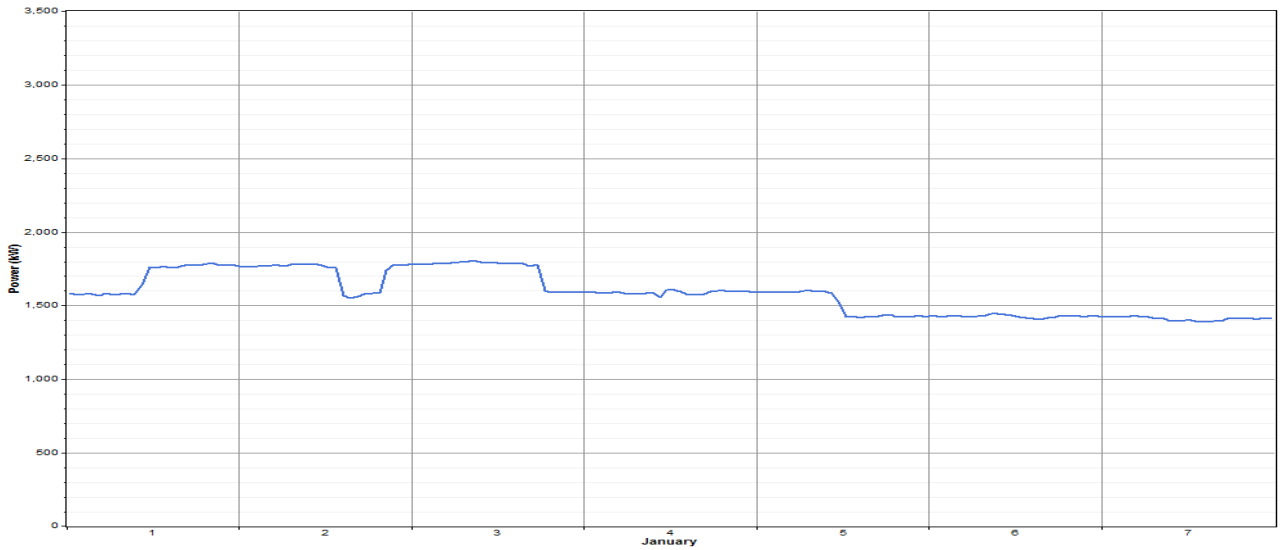


Figure 3. Electricity demand distribution over 1 week in January 2012 from Sunday to Saturday

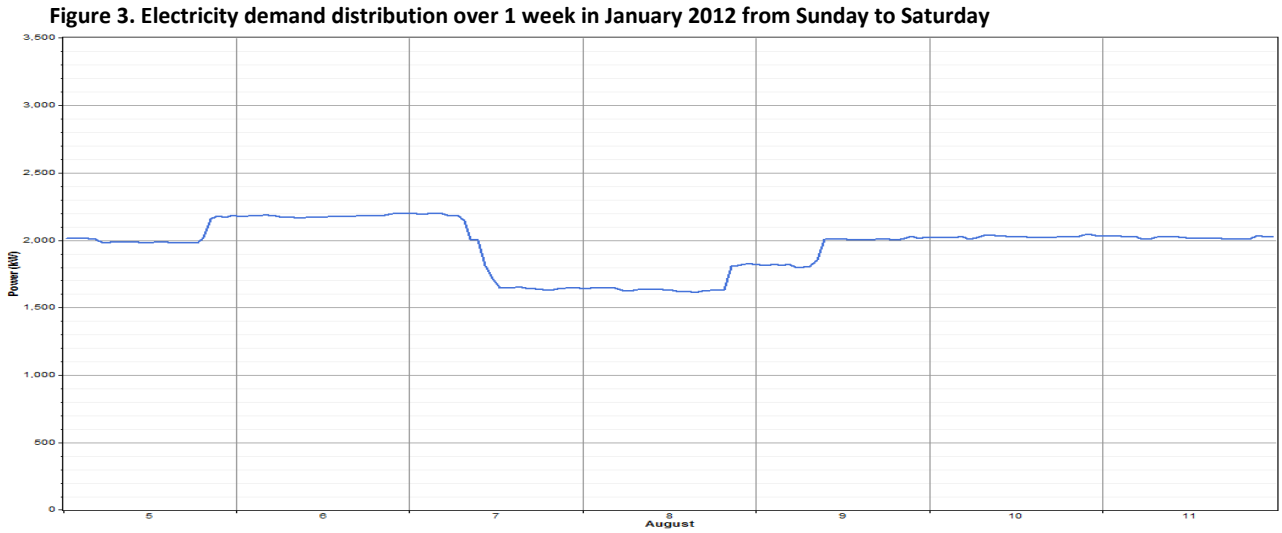


Figure 4. Electricity demand distribution over 1 week in August 2012 from Sunday to Saturday

In the base case scenarios modelled in HOMER, the 2012 electricity consumption data from the DWP-NWG will be used to model the primary load, which has a random variability of 16.6% day-to-day and 8.21% from time-step to time-step. Also, the peak load is assumed to be 3222 kW, average load is 1912 kW, and the average daily electricity consumption is 45,881 kWh/day for an annual load of 16.75 GWh.

In the scenarios modelled with flexible demand, the primary electricity load is downscaled to 32,220 kWh/day resulting in an annual minimum primary load of 11.76 GWh and average load of 1342kW, in order to meet the DWP-NWG minimum customer demands. The deferrable (flexible) load on top of this minimum primary load is modelled to have a peak load of 2064 kW and an average daily possible consumption of 27,095 kWh/day. These underlying assumptions for the deferrable (flexible) load are further discussed in chapter 4.1.

3. Electricity Supply

Electricity supply can be based on electricity from purchased from the main grid, which is predominantly grey electricity, or green electricity produced on site. This chapter will first discuss the current grey electricity grid-connection and costs. Then is will discuss the potential for green electricity from wind and solar PV production at the DWP-NWG site, the associated costs, feed-in tariffs, and the relevant Dutch renewable policy and support for this case.

3.1 Grid Electricity: Grid connection and costs

In order to meet its current electricity demand, the DWP depends on mostly grey electricity from the main grid, which it receives at one central location. The site has a connected load of two times 3 x 300 A, and electricity is fed in at high voltage levels and then transformed at various internal substations to medium- and low-voltage levels depending on the type of consumption (Meer, 2012). For example, the transport pumps require medium-voltage electricity since they are the major power users on site, while the office and other buildings require low-voltage electricity.

Since the DWP site has a load connection of 3 x 300A, this allows it to pay wholesale electricity prices, rather than retail prices, as a bulk consumer (Braam, 2013). Therefore, large industrial users like the DWP can hedge against the volatility of daily changes in electricity price by buying electricity in bulk in advance for a fixed amount of time (ie. 3-4 month blocks) and a fixed price. Nonetheless, all electricity prices are made up of several components:

- Delivery rate,
- Transportation tariff,
- Energy tax,
- VAT

Delivery costs are charged for delivering a kWh of electricity from a distribution operation, which is Nuon in this case. Table 1 summarizes the 2013 and 2014 contracted delivery prices.

Table 1. Summary of contracted delivery costs for 2013 and 2014 (Knibbe, 2013).

Year	Off-peak (11pm-7am)	Peak (7am-11pm)
2013	0.04639 €/kWh	0.07400 €/kWh
2014	0.04554 €/kWh	0.06426 €/kWh

A *transportation tariff* is charged by the grid owner, which is Stedin in the case, for using the main grid to transport a kWh of electricity. This depends on the kW transported and includes a fixed system service fee, as seen in Table 2. DWP-NWG falls in the third category, paying 0.0114 €/kWh for peak and off-peak transport.

Table 2. Transport costs for electricity in the Netherlands for 2013 (Knibbe, 2013)

Classification based on kW contribution	Off peak rate/ kWh	Peak rate € / kWh
<50 kW	€ 0.0210	€ 0.0420
50 – 136 kW	€ 0.0114	€ 0.0114
136 – 2000 kW	€ 0.0114	€ 0.0114
>2000 kW	N/A	N/A
System Service Fee	€ 0.0111	€ 0.0111

An *energy tax* is also levied on electricity. This price component depends on the total consumption over a year as seen in Table 3, and is paid per category with a decreasing tax in the greater consumption categories. With an average annual electricity consumption of 16-17 GWh imported from the grid, this DWP pays the majority of its energy tax in the 0.0117 €/kWh; however, if it were to produce and consume electricity onsite, any electricity demand greater than 10 GWh would cost 0.00052€/kWh.

Table 3. Energy tax for electricity in the Netherlands for 2013 (Knibbe, 2013)

Annual Electricity Consumption	Tariff per kWh
0 – 10,000 kWh	€ 0.11760
10,000 – 50,000 kWh	€ 0.04380
50,000 – 10,000,000 kWh	€ 0.01170
>10,000,000 kWh (don't consume onsite)	€ 0.01170
>10,000,000 kWh (consume onsite)	€ 0.00052

Value Added Tax (VAT) is normally 21% of total costs; however, since the drinkwater sector also charges VAT for delivering water to households and companies, these costs are offset and therefore not included in the electricity price at the DWP-NWG (Meer, 2012; Knibbe, 2013).

Combining all of these separate components, the DWP-NWG pays 0.06975 €/kWh off-peak and 0.08847 €/kWh during peak hours if it doesn't produce and consume electricity on-site. For an expected electricity consumption of 16.8 GWh in 2013, DWP-NWG will pay about €1.4 million, with a fixed interconnection cost of about €110k included (Knibbe, 2013). However, if DWP-NWG produces and consumes electricity on site as a microgrid, the respective off-peak and peak electricity prices would decrease since the energy tax is dependent on the amount of electricity purchased from the grid. Therefore, presuming production begins in 2014, the electricity prices used in this research are 0.06661€/kWh and 0.08533 €/kWh, assuming that the energy tax is about 0.00856 €/kWh which is the calculated average for grid-purchases less than 10 GWh and greater than 10 GWh.

For future electricity costs, it is assumed that electricity prices will increase by about 4.5% per year, adjusted by 2% for inflation, based on the historical average at Waternet from 2001-2011. Thus, 2018 off-peak and peak prices are assumed to be 0.07536 €/kWh and 0.09654 €/kWh, respectively.

3.2 Green Electricity

If Waternet produces green electricity onsite and consumes it directly, it can avoid paying these high electricity costs. In this case, solar and wind technologies are chosen due to the aforementioned reasons in the case description. These two options will be discussed and modelled in this chapter.

3.2.1 Wind Power

In 2012, Ritzen & Gastel completed a quick scan study for wind energy production potential of multiple Waternet locations, one of which was the DWP-NWG. Utilizing the WindPro model, they deduced that the DWP-NWG has the potential for 3 Vesta V90 wind turbines producing about 15GWh of electricity using weighted average wind speed data sets from Schipol and Herwijnen (23% and 77%, respectively), and taking into account shadow effect, noise disturbance, and potential negative environmental factors on the surrounding residential and natural area. Refer to Appendix E for the potential placement of these 3 wind turbines. This research will use some similar assumptions for the placement, shadow/noise/environmental effects, yet use a slightly different methodology to model the wind energy potential at the DWP-NWG. In order to model the electricity production from wind power in the HOMER model, the wind energy distribution and total possible installed capacity are the necessary input parameters. These are mainly dependent on the hour-to-hour wind speed and the type of wind turbine, which will be discussed here. This chapter will also end with the cost assumptions for wind turbines.

Location Wind Speeds

The site-specific potential for wind energy depends on the wind speeds at the location. Figure 5 illustrates the measured average wind speeds in the Netherlands at 10m (left) and computed average wind speeds at 100m (right). Locations with average annual wind speeds of more than 5.6 m/s are suited for wind production (Manwell et al., 2009). At 52.029559 latitude, 5.112426 longitude, the DWP-NWG is located Northwest of Cabauw and Southwest of De Bilt, putting it in the 4-4.5 m/s wind speed category at a height of 10 m and 6.0-7.0 m/s wind speed category at 100m, according to Figure 5. Due to its close proximity to Cabauw (15km) and similar wind speed category, 2012 measured wind speed data from the Cabauw wind station is used to simulate the wind climate at the DWP-NWG. Average monthly wind speed at 10m height measured in 2012 can be seen in Figure 6 below, with an average annual wind speed of 4.47 m/s. Analyzing measured KNMI data from 2002-2011, average wind speeds ranged from 4.16 m/s to 4.69 m/s, with the 10 year average at 4.49 m/s. Therefore, 2012 measured data from Cabauw is a good representative data set to model from.

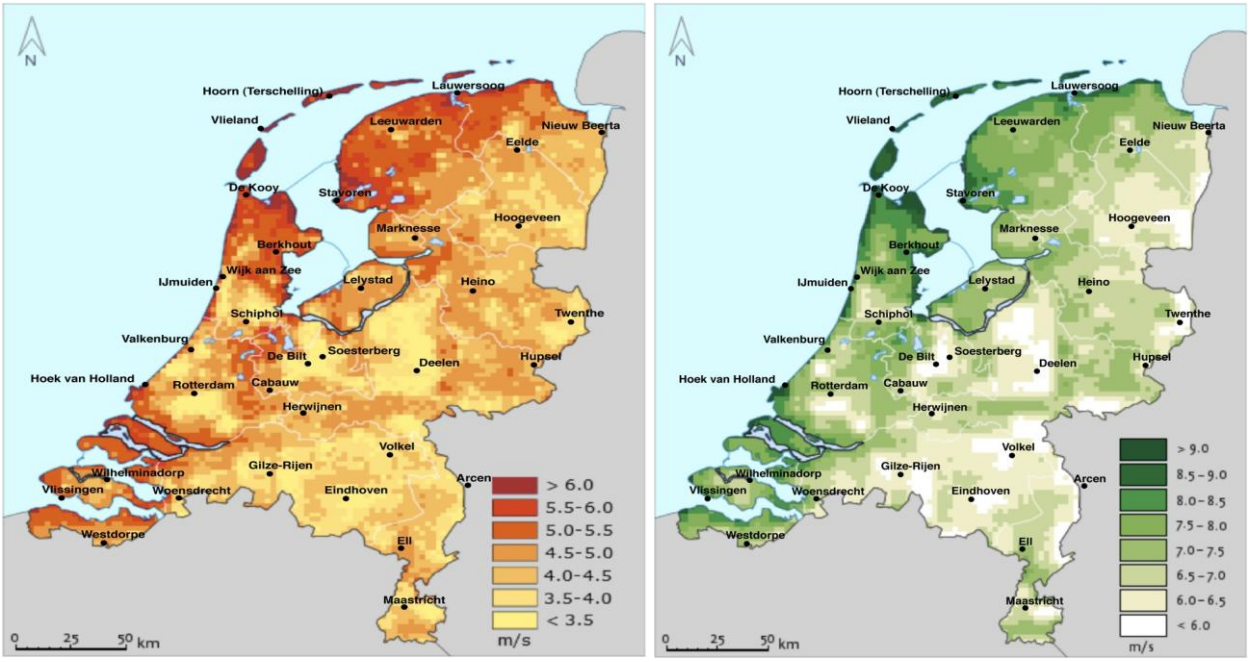


Figure 5. Average annual wind speeds in the Netherlands, (left at 10m; right at 100m) (KNMI, 2012)

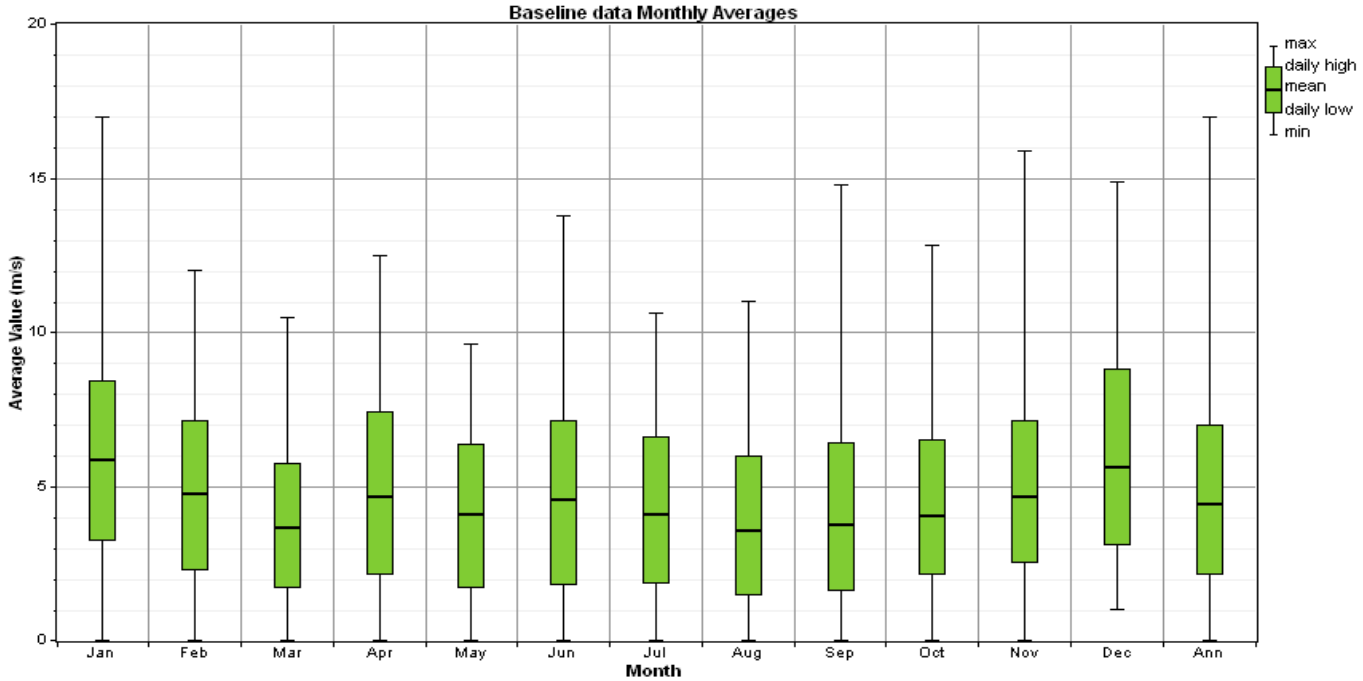


Figure 6. 2012 wind speed monthly averages in Cabauw at a height of 10m (KNMI, 2012)

Wind Turbine Selection

The most commonly used type of wind turbine is a horizontal axis turbine with a three blade rotor spinning in a vertical plane attached to a nacelle. The Vestas V90 – 2.0 MW wind turbine is an example and is specially designed for low to medium wind speeds, such as those found at the DWP-NWG. This wind turbine was also selected in the wind energy potential study at the DWP-NWG by Ritzen & Gastel (2012). Therefore, it will be used in this research. Table 4 summarizes the characteristics of the chosen wind turbine.

Table 4. Characteristics of Vesta V90 - 2 MW wind turbine modelled in HOMER (Vestas, 2012)

Vestas V90 – 2.0MW	
Installed Capacity	2,000 kW
Hub height	105 m
Rotor Diameter	90 m
Swept Area	6,362 m^2
Cut-in wind speed	4 m/s
Cut-out wind speed	25 m/s

Adjusting the Wind Speeds

Since the KNMI data is measured at a height of 10m, the following formula is used to adjust the wind speed at 105m, the hub height of the selected turbine, and a 0.03 surface roughness length at the 10m:

$$\frac{U_{hub}}{U_{anem}} = \frac{\ln(z_{hub} / z_0)}{\ln(z_{anem} / z_0)}$$

Where:

U_{hub} = the wind speed at the hub height of the wind turbine [m/s]

U_{anem} = the wind speed at anemometer height [m/s]

z_{hub} = the hub height of the wind turbine [105m]

z_{anem} = the anemometer height [10m]

z_0 = the surface roughness length [0.03m]

ln*(..)* = the natural logarithm

Adjusting the wind speeds at 105m leads to an average wind speed of 6.25 m/s. This is in line with the 6.5 m/s (+/- 0.7) wind speed estimated in the wind potential study done by Ritzen & Gastel (2012), which used a weighted average of wind speed data sets from Schipol and Herwijnen, based on the distance from the DWP-NWG to the measuring stations.

Power output is calculated at standard temperature and pressure based on the turbine production curve in Figure 7 and the computed wind speeds from step 1. Additionally, an air density correction is applied since air is denser at sea level than it is at a higher altitude and will therefore carry and transfer more energy to the blades of a wind turbine than air moving at the same speed at a higher altitude. The DWP-NWG is 1m above sea level, and therefore has relatively dense air, which improves power production. The following air density correction formula is used:

$$P_{WTG} = (\rho / \rho_0) \times P_{WTG,STP}$$

Where:

P_{WTG} = the wind turbine power output [kW]

$P_{WTG,STP}$ = the wind turbine power output at standard temperature and pressure [kW]

ρ = the actual air density calculated based on altitude of site (1m at DWP) [kg/m3]

ρ_0 = the air density at standard temperature and pressure (1.225 kg/m3)

Source: Lambert, 2007

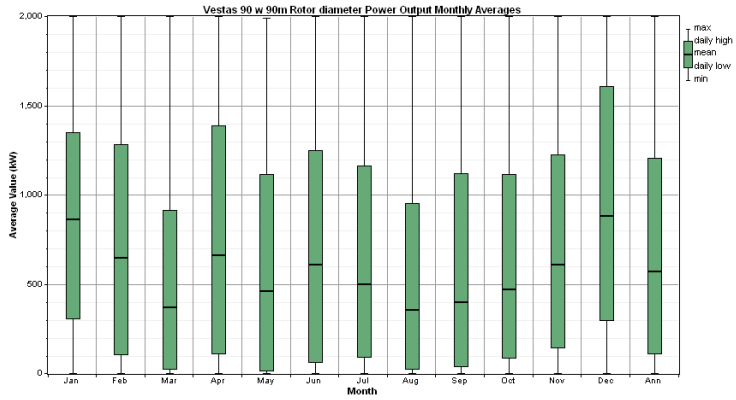


Figure 7. (Left) Reconstructed power curve for Vesta V90 2MW wind turbine (Vestas, 2012)
Figure 8. (Right) Simulated annual power output (kW) of 1 Vesta V90 turbine

This results in 5 GWh of annual electricity produced per turbine and a capacity factor of 28.6%, which is in line with the production results from Ritzen & Gastel (2012). Figure 8 illustrates that the higher wind speeds during the winter months lead to greater production compared to summer months. This is emphasized in Figure 9 below, which indicates that the average hourly winter output of 1 Vesta V90 wind turbine is 726 kW, 40.3% greater the average summer power output of 433 kW per hour. There is also a stark difference in output from the daytime (here defined as 7am-7pm) versus night-time (7pm-7am). The largest difference between night and daytime power output is 64.7% during the summer months and the lowest day/night difference is 23% in the fall and winter. On a full year basis, the average output during the day is 39.4% higher than during the night.

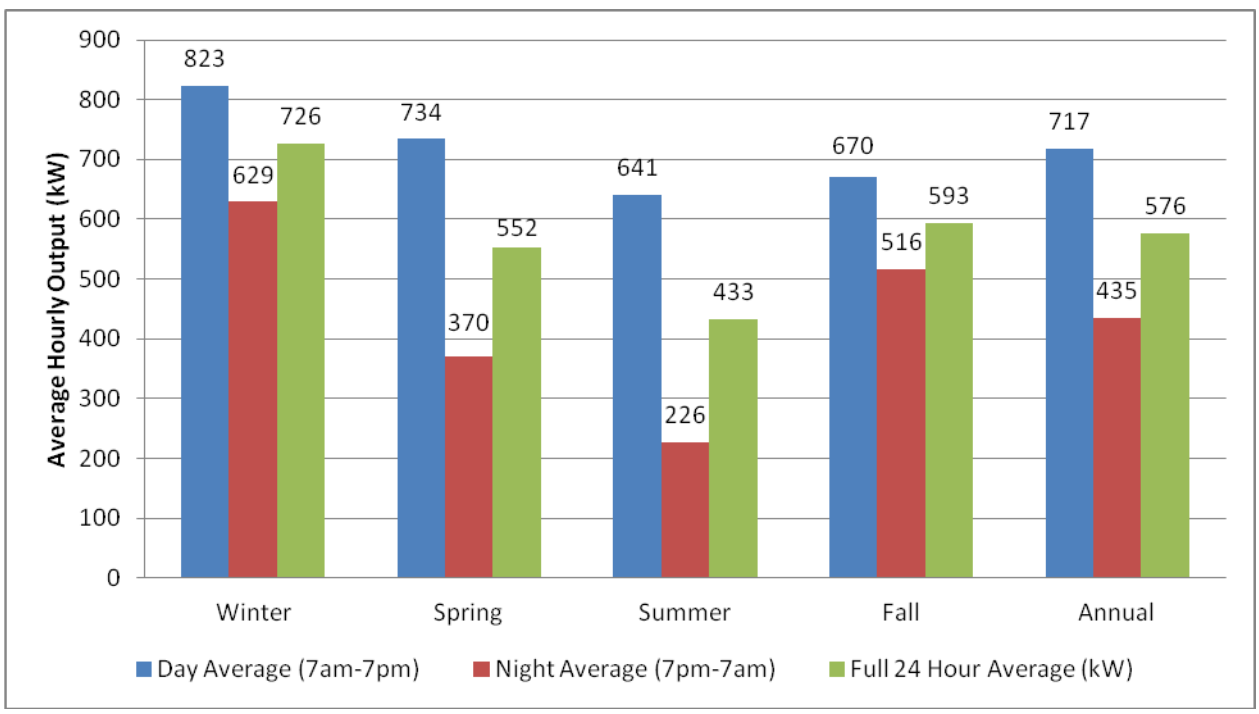


Figure 9. Average hourly output (kW) of 1 Vesta V90 on a seasonal, daily, and nightly basis

The total onsite potential for wind depends on the space requirement per turbine and space available onsite. The amount of space required for a wind turbine depends primarily on the height and diameter of the turbine both in relation to other turbines and the built environment. Normally a spacing of about 5 to 10 rotor diameters between turbines is necessary in order to maintain optimal wind speeds and production for each turbine (Andrews & Jelley, 2007). Taking into account the distance to nearby houses, shadow cast by the turbines, and noise effects on the surrounding environment Ritzen & Gastel (2012) suggest placing 3 turbines along the Lek Canal (Refer to Appendix E) however, assuming a 4 or 5 diameter spacing between turbines there is the potential for a fourth wind turbine to be placed about 400-500m south of the three shown along the Lek Canal near Parceel Zuid and KWR Labs. This would extend the shadow cast over Parceel Zuid, which could negatively affect the solar electricity potential if PV cells are placed there (discussed in the next chapter). Placing four V90 wind turbines at the DWP site along the Lek Canal results in a maximum potential of about 20 GWh of wind electricity production per year. Thus, 0 to 4 turbines will be considered in the microgrid system configurations modelled in HOMER.

Wind Turbine Costs

The initial capital costs of wind energy projects are dominated by the cost of the wind turbine itself, yet also includes development costs such as grid connection, permits, consulting fees, etc. Average investment costs in Europe for a 2MW turbine in 2006 in Europe were about €1.2 million per MW (Wind Energy, 2009). Since this is a very developed technology, costs have not drastically changed since then. The study done by Ritzen & Gastel (2012) for this specific site actually estimated total capital expense of about €1.4 million per MW, which is slightly higher than the EU average, but includes €218k in site-specific development costs.

From 1980-2003 the costs of wind turbines drastically decreased by 55-60% worldwide due to technological innovations and economies of scale. From 2003-2008, however, the costs of wind turbines increased by 10-15% per year, with the exception of China, due to a variety of factors including raw material commodity prices (ie. steel) and energy prices, which increased substantially up until the 2008 financial crisis. From 2008-2010 prices dropped by about 8% in the whole of Europe and are expected to drop by 1%-6% per year in the near term (Lantz et al, 2012). Table 5 below summarizes the cost assumptions used in modelling the wind turbine economics.

Table 5. Summary of cost figures used in economic simulation of chosen wind turbines

Lifetime	20 years
Initial Investment Costs	€ 2,855,000 per turbine
Replacement Costs (at end of lifetime)[a]	€ 2,135,540 per turbine
Annual O&M (2% of initial investment)[b]	€ 57,000
Future Scenario (in 5 years) [c]	
2018 Initial Investment Costs	€ 2,647,203
Replacement Costs [a]	€ 1,980,108
Annual O&M [b]	€ 53,000

[a] Based on a forecasted and conservative 20% capital cost reduction by 2030 and excluding the costs for replacing the foundation, which are about 6.5% of initial investment costs (Lantz et al., 2012; Wind Energy, 2009; WWI, 2012)

[b] For modern wind turbines the estimated annual operation and maintenance (O&M) costs are in the range of 1.5% to 2% of the original investment per annum (excluding development costs) (WWI, 2012).

[c] Based on average cost reduction of 3.5% per year in the near term since wind capital costs are expected to decrease 1-6% per year (Lantz et al., 2012)

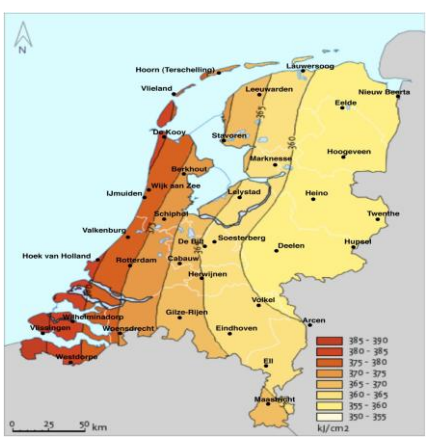
3.2.2 Photovoltaic (PV) Power

Solar photovoltaic (PV) technology converts the sun's radiating energy into electricity. However, the sun's energy that reaches the earth varies over time. Since the Earth has an elliptical orbit and changes its axis relative to the sun, the amount of radiating energy that reaches a specific latitude varies within a year and from year to year. The solar irradiance is also affected by the "clearness index" which is based on the cloud cover and atmospheric haze since these scatter, absorb, and reflect the sun's radiation. These factors result in varying solar irradiance at a specific latitude, which is one of the main factors in electricity production from the sun.

Besides the solar irradiance, the total amount of electricity produced by solar PV also heavily depends on the specific characteristics of the PV cells, like the conversion efficiency, the placement of the PV panels in relation to the sun, and de-rating factors which cause the PV cells to perform below the rated efficiency. Haberlin (2012) also indicates that ambient temperature affects power output; however, since HOMER does not explicitly model this effect, it is built into the de-rating factor (Lamberts, 2007). These will be discussed here as inputs into the model in order to ultimately calculate the total electricity potential for solar PV at the DWP-NWG. This chapter will also end with the selection of inverters for the PV modules and the cost assumptions used for both technologies.

Solar Irradiance

Compared to more southern countries, the solar irradiance in the Netherlands is relatively low due to its higher latitude. The Netherlands receives about 1000 kWh/m2/year, while Mediterranean countries can receive twice as much (Haberlin, 2012). Moreover, figure 10 (left below) illustrates that more western regions of the Netherlands receive a higher solar irradiance than those Northeast. The DWP-NWG site is located in the center region, receiving about 365-370 kJ/cm2, which is the same as Cabauw. Therefore, KNMI measured data for Cabauw is used again. However, since solar irradiance data is only measured as a daily average instead of on an hour to hour basis, this full year data is incompatible with the HOMER model since it can model either hourly (or less) time steps, or interpolate monthly averages. Therefore, monthly averages of solar irradiance of the past decade (2003-2012) were calculated from measured data for Cabauw and converted from J/cm^2 per day to kWh/m^2 per day[4] to be used as the baseline data for HOMER to interpolate into hourly data. Figure 11 (right below) illustrates the average solar radiation and clearness index at DWP-NWG based on 2003-2012 measured average daily solar irradiance in Cabauw , at 52° 1' N latitude and 5° 6'E longitude.



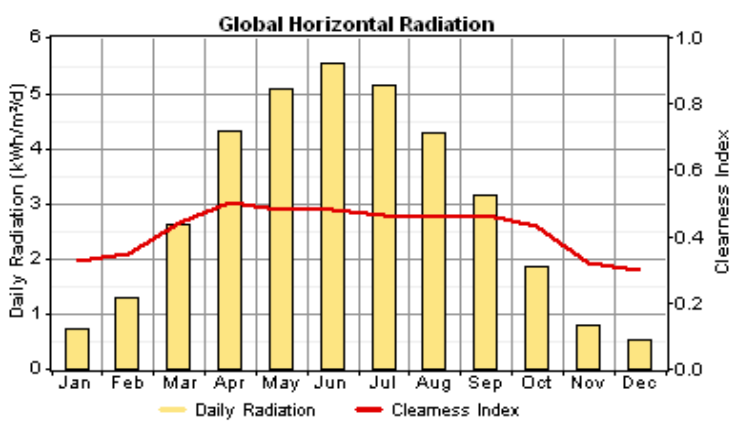


Figure 10. (Left) Solar irradiance in the Netherlands (KNMI, 2012)

Figure 11. (Right) Average solar radiation and clearness index at DWP Nieuwegein based on 2003-2012 measured average daily solar irradiance in Cabauw , at 52° 1' N latitude and 5° 6'E longitude.

[4] (J/cm^2)*(10,000 cm^2/m^2) = (J/m^2) / 1000 = (kJ/m^2) / 3600 = kWh/m^2

PV Panel Characteristics

At current levels, PV technology used for commercial purposes ranges from 12-16% in conversion efficiency, which differs depending on cell type and manufacturer. The PV model chosen for this research is the monocrystalline silicon cell CSUN255-60M model from ChinaSunergy, which has a proven cost-effective technology[5]. The efficiency of a module is 15.71% at standard testing conditions (STC) [T = 25° C, 1000 W/m2] and yields about 157 Wp / m^2 (refer to Table 5 below for a summary of characteristics of the modeled PV cells). However, this efficiency is slightly less at nominal operating cell temperature (NOCT) [T= 20° C, 800 W/m2], which is modeled by taking into account the NOCT cell temperature, the temperature coefficient of power in its calculations of power output, and a de-rating factor, which is explained in the forthcoming PV placement section. The temperature coefficient of power, which is -0.43%/°C for the chosen PV module, indicates how strongly the PV array power output depends on the cell temperature, meaning the surface temperature of the PV array which is influenced by the ambient temperature. Since power output decreases with increasing cell temperature (Lambert, 2007), KNMI average monthly ambient temperature data from 2001-2012 is used in the model to calculate the cell temperature at each step using the following equation, in accordance with Duffie and Beckman (1991):

$$T_c = \frac{T_a + \left(T_{c,NOCT} - T_{a,NOCT}\right)\left(\frac{G_T}{G_{T,NOCT}}\right)\left[1 - \frac{\eta_{mp,STC}\left(1 - \alpha_P T_{c,STC}\right)}{\tau\alpha}\right]}{1 + \left(T_{c,NOCT} - T_{a,NOCT}\right)\left(\frac{G_T}{G_{T,NOCT}}\right)\left(\frac{\alpha_P \eta_{mp,STC}}{\tau\alpha}\right)}$$

Where:

T_c = the PV cell temperature [°C]
T_a = the ambient temperature [°C]
$T_{c,NOCT}$ = the nominal operating cell temperature [°C]
$T_{a,NOCT}$ = the ambient temperature at which the NOCT is defined [20°C]
$G_{T,NOCT}$ = the solar radiation at which the NOCT is defined [0.8 kW/m^2]
G_T = the solar radiation striking the PV array [kW/m^2]
α_p = the temperature coefficient of power [0.43%/°C]
$\eta_{mp,STC}$ = the electrical conversion efficiency of the PV array at maximum power [%]
$T_{c,STC}$ = is the cell temperature under standard test conditions [25°C]
$\tau\alpha$ = the solar transmittance of any cover over the PV array *the solar absorptance of the PV array [0.9]

[5] This is based on the PV pilot project that Waternet has already installed in Leiduin in 2012 (Lambrechts, 2012)

Table 6. Summary of characteristics of modelled PV modules (Lambrechts, 2012; CSUN, 2012)

CSUN255-60M	Dimensions
Length	1640 mm
Width	990 mm
Height	40 mm
Surface area of 1 module	1.62 m^2
	STC 1000W/m2
Maximum power (P_{max})	255 Wp
Open circuit voltage (U_{oc})	38.0 V
Short circuit current (I_{sc})	8.82 A
Optimum operating voltage (U_{mpp})	30.7 V
Optimum operating current (I_{mpp})	8.3 A
Module Efficiency (η_{module})	15.71%
Max production per m2	157 Wp
Lifetime	25 years
Nominal cell temperature	45°
Temperature coefficient of power	-0.43% / °C

PV Placement

Power output of the PV panels is also highly dependent on how and where the PV modules are placed, since the following variables influence electricity yield:

- Tilt angle of the array (slope depending on the location latitude)
- Azimuth (the direction towards which the panels face)
- Ground Reflectance (aka albedo, which is the fraction of solar radiation incident on the ground that is reflected)
- De-rating factors (internal & external) that hinder maximum power production

Tilt angle of the PV array (slope). The slope of the PV module is the key to optimum energy yield since they are most efficient when they are perpendicular to the sun's rays. In order to maximize electricity production, the default tilted angle is equal to the location's latitude plus 15 degree in winter, or minus 15 degrees in summer. At 52° latitude at the DWP-NWG site, this would be 77° in the winter and 37° in the summer. However, the sun's path and solar altitude vary throughout the year and from year to year. Thus a tilt angle of 28° – 30° is recommended to optimize the capture of solar radiation; however, tilt angles between 20° – 60° are possible without significant losses in yield (Renewable Energy Concepts, 2012). This research will model with a slope of 29° to be conservative. Tracking systems are available on the market to rotate the PV panels in accordance with the changes in the sun's orientation to maintain maximum optimum angles over time; however, these systems are less resistant to climatic conditions and require more maintenance (Lambrechts, 2012). Therefore, these are not considered for this research.

The *azimuth* is the direction towards which the PV panels face. With fixed-azimuth systems, the panels are almost always oriented towards the equator, which is 0° azimuth in Europe because this ensures the highest yield. Therefore, the PV modules modeled in this research are geographically oriented south with a 0° azimuth. However, PV panels can face up to 45° E or W without significantly decreasing their performance (Renewable Energy Concepts, 2012).

The *ground reflectance* (also called albedo) is the fraction of solar radiation incident on the ground that is reflected back onto the PV array. Ground reflectance positively influences power output, with higher values having a more

significant impact (ie. Snow-covered areas may have a reflectance as high as 70%). The DWP-NWG is a grass-covered area, which has a normal ground reflectance of 20% (Budikova, 2012). This value is used in calculating the radiation incident on the tilted PV panels, but it has only a modest effect (Lambert, 2007).

De-rating factors negatively influence the power performance of PV modules. Their performance is very sensitive to factors that may prevent the cells from capturing the sun's rays like dirt, snow cover, or shading from surrounding trees, buildings, etc. These factors can also be internal like wiring losses and aging PV cells. For example, the CSUN255-60M modules used have a power warranty of 90% at 10 years and 80% after 25 years (Lambrechts, 2012). Since HOMER does not separately include these in the model, a de-rating scaling factor is applied to the PV array power output to account for reduced output in real-world operating conditions compared to operating conditions at which the array was rated. Lambert (2007) suggests a normal de-rating factor between 80-90%. However, the PV pilot in Leiduin that used these PV modules had a simulated performance ratio of 82.7%, which includes the negative effects of linear shading on the module and the positive effects of ambient temperature on PV array performance, since the average temperatures in Nieuwegein are comparable to Leiduin (Lambrechts, 2012). In order to account for the 90% power warranty after 10 years and any un-cleaned dirt or snow covering the panels over time, this simulated performance ratio is corrected by 90% to a comprehensive de-rating factor of about 75%.

The following equation is used in HOMER to calculate the real-world output of the PV array:

$$P_{PV} = Y_{PV} f_{PV} (G_T / G_{T,STC}) \, [1 + \alpha_p (T_c - T_{c,STC})]$$

Where:

Y_{PV}	= the rated capacity of the PV array, meaning its power output under standard test conditions [kW]
f_{PV}	= the PV derating factor [%]
G_T	= the solar radiation incident on the PV array in the current time step, which depends on the tilted angle (slope) of the PV panel and the ground reflectance (albedo) [kW/m^2]
$G_{T,STC}$	= the incident radiation at standard test conditions [1 kW/m^2]
α_p	= the temperature coefficient of power [0.43 %/°C]
T_c	= the PV cell temperature in the current time step [°C]
$T_{c,STC}$	= the PV cell temperature under standard test conditions [25 °C]

Source: Lambert, 2007

Inverters

Since PV technology produces AC electricity, inverters are required to convert the AC power to DC power in order to be used by the system and injected into the grid. Since it has proven compatibility with the chosen PV modules based on the Leiduin PV pilot, the modeled inverter is the Sungrow SG30KTL inverter[6]. The maximum AC power output is 98.8% and inverter efficiency is 97.8% at full load, which is well above the required 95%. It has a wide DC input range with a maximum of 1,000 V, and offers a 20 year replacement and repair warranty on these inverters (Sungrow, 2013). However, normal inverter lifetimes are 15 years, so this will be assumed in this research. It should

[6] Sungrow is the first and largest Chinese PV inverter manufacturer, founded in 1997, and as of today they have more than 400 MW of inverters installed in Europe, and the world leader in inverter technology and size (Sungrow, 2013)

be noted that HOMER uses the term “converter” to refer to an “inverter” so these terms are used interchangeably in the report.

Total solar PV potential

Although at general measurement there seems to be about 7 hectares of ground space available on Parceel Zuid and about 1 hectar of roof space, these are not all suitable for placement of solar PV panels (Velden, 2011, Meer, 2012). Taking into consideration that PV cells perform better when more of them are contiguously connected, a surface area that allows for one large PV system is optimal. Therefore, only Parceel Zuid is considered. Not including the space rented to the nearby KWR research lab and for dogwalkers/horse grazing, the total area available for PV modules is about 3.6 hectares, or 36,000 m^2 (Velden, 2011).

At 157 Wp/m^2 this PV technology requires about 6.37 m^2, or about 4 PV modules, to produce 1 kWp so the maximum solar PV potential is 5,652 kWp. Depending on how many panels there are and how they are arranged, the space requirement is often adjusted by a factor of 2 to 6 depending on the location order to avoid panels from casting shade on each other (Haberlin, 2012). No literature states which factor to use specifically for the Netherlands, and PV system placement is very case specific. However, a factor of 2 was used for the Dutch pilot system in Leiduin so this will also be taken into account in this research (Meer, 2013). If adjusted by a factor of 2 the PV production potential is about 2,826 kWp, and if adjusted by a factor of 4 the PV capacity is 1,413 kWp. In order to see the effects of larger and smaller PV systems, the solar PV system sizes considered are: 0, 1.4 MWp, 2.8 MWp, and 5.6 MWp. The common PV array-inverter ratio is 1.5, and the Leduin pilot project used a ratio of 1.13. This research will assume the latter and consider the following inverter sizes in the models: 0, 1.3 MW, 2.5 MW, and 5.2 MW.

Cost assumptions

Large systems (>=15 kWp) are cheaper than smaller systems per kW. Since the potential for solar PV production is large at the DWP-NWG, Table 7 summarizes the cost figures used for the PV system, which are modified from actual costs incurred for the 136 kWp solar project in Leiduin completed in the end of 2012, which cost about €1.29/Wp for the entire system. The price of inverters has significantly dropped since that project completion, so this system component is adjusted down to €150/kW to represent current costs. This results in an assumed PV system cost of €0.95/Wp. PV system investment costs are expected to decrease even further, partly due to decreasing prices of inverters, which are a major component of a PV system, reduced installation costs, and production costs (Meer, 2012; EnergyTrend, 2013).

For example, an analysis conducted by McKinsey suggests that the cost of a commercial-scale systems, which include inverters, could be reduced by 40 percent by 2015, to $1.70 per Wp from roughly $2.90 per Wp in 2011, and by approximately another 30 percent by 2020 (Aanesen et al., 2012). Prices in 2012 have already reached the 2015 reduced price, and the price of inverters has already decreased by about 70% since 2012. However, there are current discussions about Europe implementing a tariff on PV imports from China, which would impact the decreasing price trend of PV systems (EnergyTrend, 2013). Therefore, a more conservative 20% reduction is assumed within 5 years, to about €0.76 per Wp by 2018. Since the development of solar PV costs is very rapid and uncertain in the future, this is further explored in a sensitivity analysis in chapter 6.

Table 7. Summary of cost assumptions for PV modules and inverter technology

PV System Cost Assumptions	PV modules	Inverter	Total PV System
Lifetime	25 years	15 years	
Initial Investment Costs	€ 820 / kW	€ 150 / kW	€ 952/ kW*
Replacement Costs	€ 400 / kW	€ 100 / kW	
Annual O&M	€ 4 / kW	Included in PV module	
Future Investment Costs	€ 656 / kW	€ 120 / kW	€ 762 / kW

*PV array to inverter ratios is assumed to be 1.13

3.2.3 Green Electricity Grid Connection: Sell-back rates

Selling green electricity back to the grid can be a significant source of revenue and is thus an incentive to implement large scale renewable electricity production, which has been successful in countries like Germany and Denmark with comprehensive feed-in tariff schemes. In the Netherlands small consumers are treated differently than large consumers, where the former receives standard sell back rates from their energy supplier and the latter has case by case contracts. Since DWP-NWG is a large consumer, it has an agreement with the energy supplier that the sell back rate for any renewable energy production is equal to the commodity price, which is €0.04649/kWh off-peak and €0.07400/kWh during peak hours, and there is currently no limit (Knibbe, 2013). Therefore, selling back to the grid has no advantage over using the electricity directly onsite.

3.2.4 Dutch Renewable Policy and Support

In order to reach the 16% goal of renewable energy supply by 2020, a number of subsidy schemes are available including the Energy Investment Allowance (EIA) and Subsidies Duurzame Energie (SDE+) in the Netherlands (Agentschap NL, 2012). Table 8 summarizes some additional EU level support schemes that this case can be eligible for; however, since the application deadlines are either already closed or have not begun yet, they will not be included in this research.

Table 8. Summary of support schemes that are available to Waternet DWP-NWG for solar/wind/innovative projects, the time period available, and their current status (Gemeente URK, 2013; Wright, 2013)

Program Name	Amount	Year(s) Available	Status
SDE+ [NL]	€ 3 billion for 2013	2012-2013	Open
Energy Investment Allowance (EIA) [NL]	41.5% of total investment costs are tax deductible (€48.84 million maximum)	2013 - unspecified	Open (tax incentive)
Innovation Climate Neutral Cities (IKS) [EU]	€ 5 billion for pilot projects	12.11.2009 - unspecified	Already closed for applications
NER300 – Investment in CCS & RE [EU]	€ 4.5 billion	09.11.2010 - 31.12.2013	Already closed for applications (Wright, 2013)
Seventh Framework Programme - Thematic area	€ 2.35 billion (for entire period)	01.01.2007 - 31.12.2013	Tender ended 28/2/2013

5: Energy [EU]			
Seventh Framework Programme - Thematic area 6: Environment [EU]	€ 1.89 billion (for entire period)	01.01.2007 - 31.12.2013	Tender ended 4/4/2013
Horizon 2020	€ 80 billion for entire period	01.01.2014 - 31.12.2020	Not open for applications yet in 2013

SDE+

The SDE+ is an operating subsidy for the amount of electricity actually produced, rather than an investment subsidy. Since the cost of renewable electricity is still higher than that of grey electricity from fossil resources, this subsidy can make renewable electricity more competitive and ideally more profitable. The subsidy compensates the difference between the cost price of grey electricity and renewable electricity for 5, 12, or 15 years depending on the technology. It is ultimately a feed-in premium regulation in addition to the revenues received from the local energy supplier. It also applies for producers who consume the electricity produced onsite[7](Agenstschap, 2012; Agentschap NL, 2013).

The SDE+ has one integral budget ceiling where a variety of technologies for the production of renewable electricity, renewable (bio)gas fed into the Dutch natural gas network, and renewable heat or CHP are applicable. The following renewable electricity technologies (excluding CHP) are eligible for the SDE+ subsidy:

- solar PV > 15 kWp & connected to a large scale energy connection (over 3 x 80A)
- wind (on- & off-shore),
- hydropower,
- waste water and sewage treatment plants with thermal pressure hydrolysis,
- osmosis

The budget is distributed in multiple phases on a "first come first served" basis with the most economic subsidies (for the government) distributed first. In 2012, €1.7 billion were distributed; however, the entire budget was allocated on the first day due to the volume of applications. In 2013, there is a €3 billion budget to be administered in 6 phases. Table 9 below summarizes the phases and subsidies available for onshore wind and solar in 2013.

[7]This excludes the electricity used by the installation itself.

Table 9. Summary of phasing and tariff rates for solar-PV and wind for 2013 (adapted from Agentschap NL, 2013)

Renewable Electricity	Phase 1 from 4 April	Phase 2 from 13 Mei	Phase 3 from 17 June	Phase 4 from 2 Sept.	Phase 5 from from 30 Sept.	Phase 6 from 4 Nov.	Base energy price	Prelim. Correction amt. 2013	Max. load hours per yr.	Max. Subsidy duration (yrs)	Times can change start date
Units	Base amount per phase (€/kWh)						(€/kWh)		hours	years	unit
Solar PV (>= 15 kWp)	0.070	0.080	0.090	0.110	0.130	0.148	0.055	0.055	1000	15	3
Wind on land <6 MW (max. load hrs)	0.0875 (2640)	0.1000 (2240)	0.1125 (1920)	0.119 (1760)	0.119 (1760)	0.119 (1760)	0.054	0.055	Phase dep.	15	4
Wind on land >= 6MW (max. load hrs)	0.0875 (2880)	0.1000 (2880)	0.1125 (2504)	0.119 (2400)	0.119 (2400)	0.119 (2400)	0.054	0.055	Phase dep.	15	4

The SDE+ compensates the difference between the cost price of grey electricity (*correction amount*; a.k.a. current electricity commodity price) and that of green electricity (*base amount*) based on the following formula:

SDE contribution = base amount – correction amount

Thus, the correction amount has a minimum of 2/3 of the long term electricity price expectation: *the base energy price. S*ee Figure 12 for visual representation.

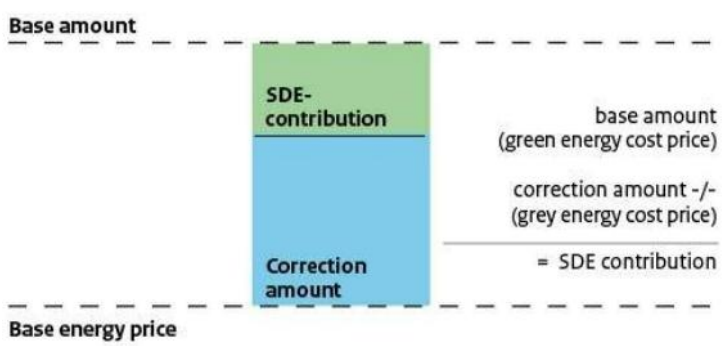


Figure 12. Visual representation of SDE contribution (Agentschap NL, 2012)

The budget claim is determined based on:

(base amount – base energy price) x subsidy period x nominal capacity x max. full load hours per year

Assuming that the SDE+ subsidy is granted in the first phase, since there is a high chance that the budget will be fully distributed again before reaching the second phase, the SDE+ contribution is €0.015/kWh leading to a subsidy

of about €600k for a 2,826 kW solar PV producing about 2.7 GWh per year at 955[8] loads hours for the full 15 years. For wind production, the maximum SDE+ contribution distributed is 80% of €0.0325/kWh in order to balance for years when wind production is significantly low production, and thus a smaller annual subsidy, and excess production in other years when producers would not be able to get the additional proceeds. The maximum SDE+ subsidy for wind is therefore, €7.9 million for an 8MW system producing 20.2 GWh at 2523 load hours or €5.9 million for a 6 MW wind potential producing about 15 GWh. It should be noted that if the SDE+ makes it to the second phase, these subsidies can increase substantially[9].

Since HOMER does not have subsidy input parameters, these amounts are discounted separately using a 3.6 % real discount rate (5.6% nominal interest rate adjusted by 2% for inflation) over the 15 years that the SDE+ is distributed, resulting in present values of €1.5 million per wind turbine and €162 per kWp solar. These present values are deducted from the investment costs in the scenarios which include financial support.

The Energy Investment Allowance (EIA)

EIA is a tax scheme that falls under the responsibility of the Ministers of Finance and Economic Affairs (EZ), where 41.5% of total investment costs can be deducted from corporate income taxes (25 % in the Netherlands), leading to a tax benefit which indirectly reduces the total investment costs. Ultimately, if the full investment per kW is eligible for the EIA tax deduction, this results in a net EIA advantage of about 10%[10] of the investment (Agentschap NL, 2013c).

As a water authority, Waternet would normally not be eligible for such a scheme since it is legally registered as a Foundation, so it does not pay corporate income taxes; however, with plans to create a joint venture (registered as a corporation) with another company in order to make large scale investments, this would qualify the wind turbines and solar PV electricity production in this case situation for the EIA tax benefits since this new entity will pay the 25% corporate income tax (Meer J., 2013).

For wind production the maximum energy investment that is eligible for the EIA is €600/kW, which is less than the €1,428/kW costs for the wind turbines in this research. Therefore, the net EIA advantage for wind is about 4% of total investment costs, or about €117.5k per 2MW turbine. If a maximum of 8MW wind capacity is implemented without solar PV, this would save a total of €470k of the total €11.4 million of investment costs.

For solar PV, the maximum amount eligible for the EIA is €3000/kW, so 100% of the solar PV investment costs are eligible, leading to an EIA of about 10% of total investment costs. On a solar PV installation of 2.8 MWp, the EIA would save €280k out of the €2.85 million in total installation costs, or about €98.5/kW (Agenstschap NL, 2013c).

[8] Maximum load hours for solar are 1000 and 2640 hours for wind in the first phase of the SDE+; however, since the subsidy is adjusted annually based on actual production, the actual simulated hourly loads for solar and wind are used in the calculation.

[9] As of June 2013, the SDE+ has made it to the 2nd phase where 220MW of wind projects have been granted at 0.10€/kWh. This could be a positive indicator for future incentives for wind production.

[10] Net EIA advantage % = NPV EIA / total investment costs;

Table 10. Summary of EIA investment eligibility and actual investment reductions after tax deductions applied

	Maximum investment eligible for EIA	Portion of Investment eligible for EIA	EIA % of investment tax benefit	EIA tax benefit (aka indirect investment reduction amount)[11]
Wind >=6MW (€1428/kW)	€600/kW	42%	4%	€352k (6MW) or €470k (8MW)
Solar PV system[12] (€952/kW)	€3000/kW	100%	10%	€280k (2.8MW) or 560k (5.6MW)

4. Controlling Intermittencies & Back up Generation

Integrating solar and wind electricity to meet the power demands of the DWP-NWG can potentially reduce the need for electricity purchased from the grid. However, due to the intermittent nature of these two renewable energy sources, methods to deal with these irregularities can have an impact on the best configuration of the microgrid. These methods include demand response, storage, and backup generation, which will be discussed in this chapter.

4.1 Flexible Demand with Demand Response (DR)

Demand response has been used in industrial processes for decades via top down approaches from the electricity suppliers by changing demand during peak hours for peak shaving, or bottom up through dynamic pricing. At the DWP-NWG itself, peak shaving was even manually implemented years ago using the backup diesel generators when the difference between peak and off-peak prices was significant. However, now the difference between peak and off peak power is not as great so the gains are not significant enough to continue this peak shaving practice. In this research, demand response can be useful in altering the level of the electricity consumption in response to the availability of wind and/or solar power for a period of time due to the large potential for integrating these renewable electricity sources onsite.

In order to model this in HOMER, the electricity consumption load needs to be broken out into a primary load that must be met at all times and takes priority, and a flexible deferrable load, which needs to be met within some time period, but the exact time period is not important—for example, when there is excess electricity production from renewable sources. In order to model this inflexible and flexible demand, a bottom up approach is taken based on the 2012 measured electricity consumption data of the plant itself, its direct customer demands, storage capacity, and pump/system constraints.

Potential for Flexible Demand at the DWP-NWG site

Table 11 below illustrates that pumping makes up 94% of the electricity demand at DWP-NWG, 13% of which is for the run-water pumps bringing water into the treatment process from the Lek Canal and 81% for the distribution pumps transporting pre-treated water to its direct customers and storage reservoirs.

[11] where NPV EIA = [(Energy Investment * 41.5%) * 25% Corporate Tax] / 1 + Project Rate; where
Project Rate = [(1-25% Corp Tax)*5.6% Rate Loan*80% Debt of Invest.] + (20% Equity of Invest.)*(12% Req. return on Equity)
[12] Includes inverter investment costs

Table 11. Breakdown of Electricity Consumption at the DWP-NWG plant in 2012 (Waternet, 2013a)

Category	Electricity Usage (kWh/year)	% of Total Consumption
WRK I distribution pumps	8,098,495*	48.1 %
WRK II distribution pumps	5,638,061	33.5 %
Runwater pumps (from Lek Canal)**	2,153,664	12.8 %
WRK I&II besides pumps (company/office building, labs, rapid filters)	711,920	4.2 %
Test Building & Backup pumps	183,860	1.1 %
Chemical Building (lights & power)	29,080	0.2%
NSA Energy Buildings (lights & power)	25,077	0.1%
Aeration Building (lights & power)	5,248	0.0%
TOTAL 2012 Electricity Demand	16,845,405	100%

* Since WRKI meters are not functioning correctly, this figure is calculated based on 2010 hours usage of WRKI pumps multiplied by their rated power (~6.6 GWh) plus about 1.4 GWh unaccounted for compared to grid feed-in meters; **includes small amount for lights & power for coagulation process (Waternet 2012a;Waternet, 2013b)

In order to keep the treatment process stable, the electricity consumption of run-water pumps and the electricity demands of the internal buildings and processes are assumed to be inflexible. However, this still leaves a maximum flexible demand of 81% from the distribution pumps since they do not have to be turned on during specific times of the day—they pump water more or less continuously throughout the day. However, this flexibility is also affected and limited by:

- customer demand,
- storage capacity (Leiduin Dunes),
- and pump and transport network characteristics

Customer Demand

Table 12 below breaks down the average hourly and annual required customer demand for the DWP-NWG, along with the annual power usage needed to distribute the annual water demand. These operating demands are more or less constant 24 hours in the day and every day of the week, with some ranging hourly demands from Corus and PWN, and WHG taking in about 1000 m^3 per day less on the weekends (Braam, 2013). Thus, there is never a point in the day or week when immediate customers are not demanding water.

Table 12. Summary of average hourly and annual customer demand

	Production		kWh Required*
CUSTOMERS/RECEIVERS	**Avg. Hourly Demand (m3/hr)**	**Avg. Annual Demand (million m3/yr)**	**Avg. Annual Electricity Required (million kWh/yr)**
Corus (TaTa Steel)	4000	23**	3.21
Crown van Gelder	400	0.146	0.020
PWN	2900	20	2.80
Westelijk Havengebied (WHG)	168	0.061	0.008
Leiduin Dunes	6300	55	7.69
➔ Dunes Min. (at lowest pump capacity of 9600m3/hr)	2133	18.68	2.61
Total excl Dunes	**7468**	**43.21**	**6.04**
Total incl Dunes	**13,768**	**98.21**	**13.73**
Total incl Min Dunes	**9600**	**61.89**	**8.65**

*based on 0.14 kWh/m^3 power consumption of distribution pumps for total water production in 2012

**35 million m^3/year required capacity of Corus (Tata Steel), 12 million of which comes from WRKIII (Andijk). In practice, if WRKIII needs to shut down for an emergency, WRK I & II can increase production to compensate for WRK III, and vice-a-versa; however, to simplify the situation, it is assumed that emergency shut downs to do not happen often and the established normal proportion of distribution between WRK III versus WRK I & II is maintained (Stouten & Pinksteren, 2010).

On average, Corus (Tata Steel) and PWN are the largest immediate customers requiring about 44% of the total average annual DWP-NWG production, while Crown van Gelder and Westelijk Havengebied are the smallest immediate customers requiring only about 2% of total average annual production. The Leiduin Dunes take in the remaining 50-55% of average water production (Stouten & Pinksteren, 2010). Unlike the first four customers, which use the water immediately for their operations, the Leiduin Dunes are more of an intermediary receiver since they are used to naturally filter the pre-treated water from the DWP-NWG for about 3 months before the water treatment plant in Leiduin[13] finalizes the process (Heck, 2013).

In order to consistently meet the required customer demands, the electricity usage required to meet those demands is considered inflexible and thus included in the inflexible primary load. The Dunes, on the other hand, have the flexibility of accepting anywhere between 0 – 10,000 m3/hour (Braam, 2013). However, in order to maintain a certain level of pressure and consistency in water flow to the dunes, it is assumed that about 2000 m^3/hour is fixed since this is the amount produced by the 4 lowest rated pumps which will be running anyway to meet the other customer demands. Running at the lowest pumps is not uncommon, particularly in the winter months when customer demand is low. Thus, in order to meet this required water production, transport pumps alone have a total annual consumption of 8.65 GWh (summarized in Table 12). Adding the 2012 power consumption of the run-water pumps and internal operations (Table 11), results in a 11.76 GWh annual primary load or an annual average of 32,220 kWh per day that must be met.

[13] The power consumption for this final treatment process is not included in this research since the Leiduin water treatment plant is not a direct neighbour of the DWP-NWG and therefore cannot be directly connected to the onsite microgrid.

Storage Capacity and Buffer

The main water storage reservoirs are located at Corus, and the Dunes themselves can be considered as water storage since they are extremely vast and hold water for about 3 months. However, the storage reservoirs at Corus are only built in order to handle the daily fluctuations in use from Corus and PWN. Therefore, these reservoirs are not considered as a potential storage buffer for extra water pumped above the normal contracted capacity. Table 13 below summarizes the maximum hourly intake and annual capacities for extra pumping for the Leiduin Dunes only. These maximum production capacities are converted to kWh required to pump these amounts based on 0.14 kWh/m^3 power consumption of distribution pumps in 2012 for total water production.

Table 13. Summary of Maximum water intake per hour and per year of DWP-NWG

	Production (million m3/yr)		GWh Required		Buffer (Max – Avg. required)	
	Avg. Annual	Max Annual	Avg. Annual	Max Annual	Annual flexible water volume (million m3)	Annual flexible GWh
Dunes (at 6300m3/hr avg)	55	73*	7.7	10.2	18	2.5
Dunes (at 2000m3/hr	18.7	73	2.6	10.2	54.3	7.6

*up to 10,000 m^3/hour is technically possible; however, in practice a maximum intake of 200,000 m^3/day is possible, or about 8,333m^3/hour (Stouten & Pinksteren, 2010).

If normal average hourly water demand is pumped to the Dunes (6300 m^3/hour) this results in a 2.5 GWh buffer which is an additional 15% of flexibility on top of 2012 normal electricity usage. However, if a minimum of 2000 m^3/hour is definitely pumped to the Dunes on a continuous basis instead of 6300 m^3/hour, an additional annual 7.6 GWh can be pumped at different times within the year, or an annual average of 20,803 kWh per day. Therefore, 40% of the total maximum electricity demand can be flexible (19.4 GWh).

Pump Characteristics

While the large storage buffers in the Dunes offer a maximum of 40% flexibility for the whole year, this is limited by the pump characteristics and transport system constraints on an hourly and daily basis. Table 14 below summarizes the transport pump characteristics and production efficiencies with which the DWP-NWG was designed. Since 2 pumps can only work at the same time to maintain optimal efficiency within each WRK pipeline, the plant is designed for a maximum production capacity of 20,000 m^3/hour. In practice, however, the 2 most powerful pumps in WRK I and the 4 most powerful in WRK II are not used due to the deteriorating conditions of the transport network which cannot handle the higher pressures from the strongest pumps. Thus in practice, the maximum water production capacity is 15,600 m^3/hour provided by two 920 kW pumps in WRKI and two 534 kW pumps in WRKII, which does not include down time for maintenance which takes place every 10 years for each pump[14] (Braam, 2013). Since this maintenance occurs so infrequently, it is not included in this model since HOMER only simulates one year. However, these pump limitations are used to limit the peak load of the flexible deferrable load.

[14] Each pump is unavailable for 8-10 weeks every 10 year interval, usually during periods of low demand (not in the summer). The removal and replacement of a pump takes 1 workday each , during which that pumping station is shut down. Only maintenance on WRK I pumps 4 and 9 , WRK II pumps 3 and 7 has any impact on the 15600 m3/h capacity, maintenance on the other pumps only limits the flexibility of the operation (Braam, 2013).

Table 14. Overview of rated power and production efficiency of the distribution pumps at DWP-NWG (Waternet, 2013c)

WRK I (10 pumps) – 1 pipe (1.5 diam)	Rated Power (kW)	Efficiency (m3/hour)
1 (1)	192	2400
1A (6)	192	2400
2 (2)	330	3000
2A (7)	330	3000
3 (3)	534	3600
3A (8)	534	3600
4 (4)	920	4200
4A (9)	920	4200
5 (5) (not used)	1287	4800
5A [10] (not used)	1287	4800
WRKII (8 pumps) – 2 pipes of 1.2 diam.		
1 (1) (not used)	1400	5200
1A (5) (not used)	1400	5200
2 (2) (not used)	920	4200
2A (6) (not used)	920	4200
3 (3)	534	3600
3A (7)	534	3600
4 (4)	230/450	2400/3000
4A (8)	230/450	2400/3000

Summary of steps to construct the minimum inflexible Primary Load:

1) 2012 real electricity use data is used to maintain the original seasonal curve, day-to-day variability of 16.6%, and time-step-to-time-step variability of 8.21%, which is based on HOMER's statistical analysis of the imported 2012 real electricity data.
2) Then a scaled annual average of 32,220 kWh/day is used to scale the baseline data in order to definitely meet the average daily immediate customer demands and the steady minimum pumping of 2000 m3/hour to the Dunes. This results in a minimum load of 100 kW, average load of 1342 kW, a peak load of about 1900 kW, and total minimum annual load of 11.76 GWh. Figure 13 below illustrates the daily and seasonal profile of this inflexible primary load.

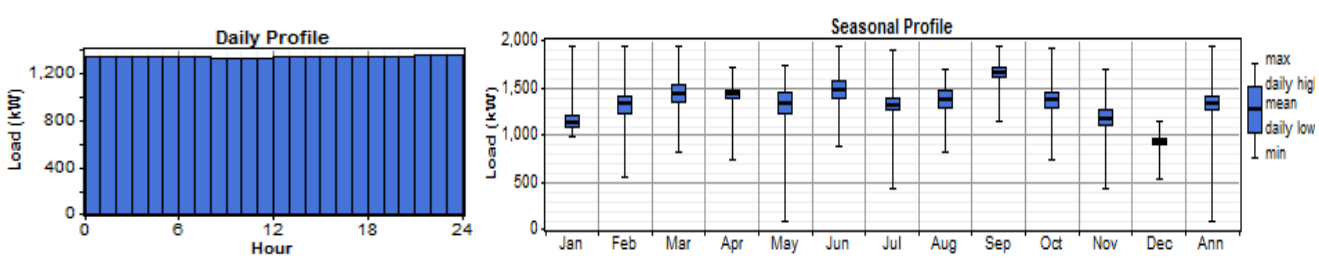


Figure 13. Daily (Left) and seasonal (Right) profiles of minimum fixed primary loads

Summary of HOMER inputs to construct the Deferrable (flexible) Load:

1) **Baseline Average kWh/day load per month** and scaling– During the winter months it is possible to pump a little extra since the overall customer demand is lower so the average deferrable load is set at 26,000 kWh/day for November-February and 22,000 kWh/day in March-May and October. However, in the summer months (June-September) there is less flexibility when demand is higher (greater primary load

means that stronger pumps are used), so the baseline data for these months is 18,000 kWh/day. This results in an annual average of about 22,000 kWh/day, which is then scaled down for the simulation to the established annual average of 20,803 kWh/day based on the maximum annual storage buffer.

2) **Storage Capacity (in kWh as HOMER input)** is assumed to be the about 10.2 GWh for the year since the Dunes can take up a maximum of 73 million m^3/yr (based on a 200,000 m3/day maximum in practice). Since the primary load includes a minimum pumping of 2000 m^3/hour to the Dunes, this storage capacity should never be depleted to zero. In HOMER, this means that the deferrable load will not become a critical load, so it will only be met by excess renewable electricity production rather than grid imports.
3) **Peak Deferrable Load (kW)** is the rated power of pumps; however in this case, only 2 pumps can work at the same time so if there is extra wind power production and pumping will ramp up to automatically utilize this clean energy, the weakest pumps (ie 384 kW for WRK I) will turn off and the more powerful pair of pumps will turn on (ie. 1840 kW for both pumps in WRK I). Therefore, the peak deferrable load is calculated as:

   Peak Deferrable Load = Sum of Maximum Rated Pumps – Sum of rated pumps to meet primary load

   The sum of the maximum rated power pumps available for use is 2908 kW and the sum of the rated power of pumps used to meet the primary load is 844 kW in order to meet the 9600m3/hour minimum demand for water. This results in a maximum deferrable peak load of 2064 kW for WRK I & II together.

4) **Minimum Load Ratio** is the minimum amount of power that can serve the deferrable load, expressed as a percentage of the peak load. In this case, there are a few stronger pumps that can first ramp up before the strongest pumps are needed so the minimum load ratio in this case is the sum of the rated power of the next strongest pumps divided by the calculated deferrable peak load (2064 kW). This leads to a 75% minimum load ratio.

Most flexibility is possible on an hourly and daily basis at a maximum of 49,536 kWh/day if the strongest pumps were used the whole day versus the weakest pumps. However, since this flexibility is tied to renewable energy production in excess of primary load demand, which does not occur for the full 24 hour day, the actual daily flexibility will be less than this. Based on the maximum annual water storage buffer, the annual average flexibility per day is 20,803 kWh/day.

In order to meet average annual water production levels (98-100 million cubic meters), the total annual electric load needs to be at least 16.5 – 17 GWh for the full year. Therefore, at least 4.8 GWh of the deferrable (flex) load needs to be met in addition to the minimum primary load, which is 29% of the normal annual load (16.7GWh/year). Only systems with significant electricity production in excess of the primary load will be able to do this. Systems meeting less than 4.8 GWh of the deferrable load are considered infeasible.

Costs for Demand Response

In order to integrate loads and DG with demand response and load management in a microgrid, specific microgrid hardware and Information Technology (IT) controls are necessary to facilitate communication and control between electricity demand and supply. There is a lot of research and development on different forms of hardware and controls for microgrids, with demonstration and pilot cases popping up around the world, as mentioned in the

problem definition. However, this hardware and IT systems have not yet reached full commercialization so their costs are case specific and difficult to estimate. This research assumes microgrid hardware/IT fixed capital costs of about €96,000 ($129k at 0.748 average 2011 exchange rate) based on a Canadian case study done by Morris et al. (2011) to create a framework for the cost benefit analysis of microgrids. This includes all controllers, communications devices, and disconnect switches and assumes that the microgrid infrastructure distribution feeders already exist. These costs are assumed not to change drastically in the next 5 years.

4.2 Storage

Electricity storage can be used in a variety of applications to provide significant benefits within both fuel based, renewable and mixed electricity systems. These can be generally divided into power applications and energy applications. Power applications require high power output in relatively short period of time (seconds to minutes), in order to fulfill power quality and bridging power functions like ancillary services, voltage support, spinning reserves, and assuring continuity of service when switching between generation sources. In grid-connected microgrid systems, these applications are less imperative since the grid power generally fulfills these functions from the end-user point of view. Energy applications, on the other hand, require storage of relatively large amounts of electricity for discharge durations of many minutes to hours, to fulfill energy management functions which decouple the timing of electricity generation and consumption by shifting energy use to a different point in the day when there is either more demand or grid prices are higher. In this application category, storage can significantly aid the integration of renewable energy by providing renewable capacity firming so that these intermittent resources can be a nearly constant electricity supply, and storing low-value energy from the renewable energy generation and then dispatching it at a later time to offset other purchases or sell it when it is more valuable. This energy management application would also enable consumers to be electrically independent from the grid for many hours (ESA, 2011; Eyer & Corey, 2010). Since this research focuses on integrating wind and solar energy at a load, the energy application is the most important; however, the capability to be used in power applications is also relevant in this case if grid-independence is ever necessary in the future. Ultimately, storage technology that can fulfill both applications provides the greatest system flexibility and increases the percentage of renewable energy potential in the system.

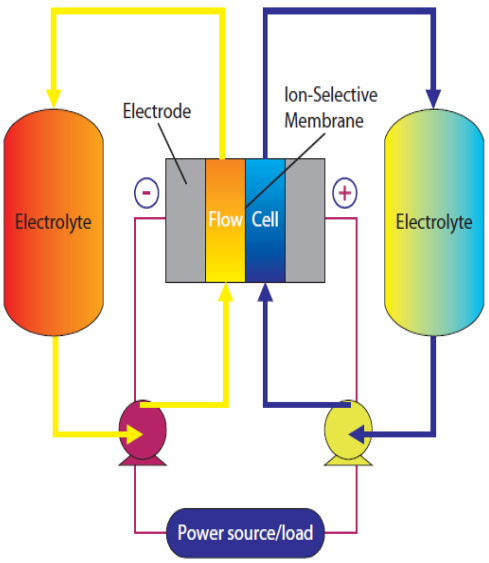
Storage Technologies	Main Advantages (relative)	Disadvantages (Relative)	Power Application	Energy Application
Pumped Storage	High Capacity, Low Cost	Special Site Requirement		●
CAES	High Capacity, Low Cost	Special Site Requirement, Need Gas Fuel		●
Flow Batteries: PSB VRB ZnBr	High Capacity, Independent Power and Energy Ratings	Low Energy Density	◑	●
Metal-Air	Very High Energy Density	Electric Charging is Difficult		●
NaS	High Power & Energy Densities, High Efficiency	Production Cost, Safety Concerns (addressed in design)	●	●
Li-ion	High Power & Energy Densities, High Efficiency	High Production Cost, Requires Special Charging Circuit	●	○
Ni-Cd	High Power & Energy Densities, Efficiency		●	◑
Other Advanced Batteries	High Power & Energy Densities, High Efficiency	High Production Cost	●	○
Lead-Acid	Low Capital Cost	Limited Cycle Life when Deeply Discharged	●	○
Flywheels	High Power	Low Energy density	●	○
SMES, DSMES	High Power	Low Energy Density, High Production Cost	●	
E.C. Capacitors	Long Cycle Life, High Efficiency	Low Energy Density	●	◑

Figure 14. Comparison of storage technologies advantages, disadvantages, and best suitable applications; full circle indicates the technology is fully capable and reasonable for the application; half circle indicates the technology is reasonable for the application; empty circle indicates the technology is feasible but not quite practical or economical; no circle indicates the technology is not feasible or economical for that application (ESA, 2011)

There are a variety of storage technologies from the oldest form of pumped hydro to more modern chemical batteries or mechanical types. Each technology has some inherent limitations or disadvantages, whether practical or economical, causing some to be better suited for power applications and others better suited for energy

applications. This is summarized in Figure 14. Since a microgrid case optimally requires both power and energy applications, the practically and economically suitable technology options for this research are flow batteries, NaS (Sodium Sulfur) batteries, Ni-Cd (Nickel-Cadmium), and Electrochemical Capacitors. Flow batteries and NaS batteries are the only ones with much longer discharge times, which is important when intermittent renewable generation is not meeting demand. However, NaS batteries have high production costs and safety risks due to their extremely high operating temperature requirement, so flow batteries are the best option for this case. Moreover, flow batteries have a wider range of possible system rated capacities, which is important in this case research in order to properly size the storage system to the optimal energy generation mix (ESA, 2011).

Flow Batteries



Similar to conventional batteries, flow batteries charge and discharge electricity via a [reversible] redox (reduction-oxidation) chemical reaction between two liquid electrolytes. However, unlike conventional batteries where power conversion and electrolyte storage are combined in the battery making the power and energy rating fixed, flow batteries store the necessary electrolytes outside of the battery stack in large storage tanks (refer to Figure 15 for an overview). By decoupling the battery cell stack, which can be modified for the specific power rating, from the electrolyte storage tanks, which modify the energy content transferred a flow battery can be designed for high power applications as well as high-capacity electricity storage. This decoupling means that a 100 kW-rated system can store 500kWh, 1000kWh, or just 5kWh, depending on the system requirements. Flow batteries are also not site dependent like pumped hydro and CAES, and can also be attractive in situations in which the system is not cycled frequently since there is no self-discharge (Boer and Raadschelders, 2007).

Figure 15. Schematic overview of a redox flow cell energy storage system (Boer and Raadschelders, 2007)

Flow Battery Selection: ZnBr vs. VRB vs. PSB Flow Batteries

The most promising redox couplings which have reached commercialization are Polysulphide Bromide Batteries (PSB), Zinc Bromide (ZnBr), and Vanadium Redox Batteries (VRB), and each type has its own specifications and is developed for a certain application. PSB focuses on large-scale applications (>5MWe) and a still in the development phase so these are not further discussed for this research. VRB development focuses on applications in wind farms, and ZnBr are mainly developed for small-scale applications. In a ZnBr flow battery, the electrodes (Zn- and Br+) act as substrates for the reaction so if the battery is not completely and regularly discharged, their performance capacity can be degraded. Moreover, ZnBr efficiency is relatively low (60-75%) compared to VRB efficiency of 70-85% (Boer and Raadschelders, 2007). Therefore, VRB flow battery storage will be modeled for this research.

The VRB ESS Flow Battery by Prudent Energy is an all-Vanadium battery and already developed and used in a variety of commercial applications. It is unlike other systems at industrial scale because its performance is independent of its State of Charge (SOC), which is the available capacity at a point in time. Since the electrolytes in VRB systems do not degrade over the system lifetime, it can produce over 10,000 full-depth charge/discharge cycles (or over

100,000 partial cycles) without affecting its storage performance. It also contains a Power Conversion System (PCS), which provides the control of the system and communication between itself, generators, and loads. Because it is a stationary storage system, it requires very little maintenance—only scheduled cleaning and inspection (Prudent Energy, 2012). HOMER models a battery based on its round-trip efficiency (energy discharged versus energy in), and lifetime (based on number of discharge/charge cycles the battery can withstand at a given DOD). Table 15 below summarizes the input specific parameters for the VRB ESS Flow Battery.

Table 15. Summary of VRB ESS Flow Battery Characteristics (Prudent Energy, 2012)

Roundtrip Efficiency	**80 %**
Cell stack lifetime	**15 years**
Electrolyte lifetime	**125 years**

Storage Costs

Although flow battery technology is not yet a completely mature technology, its costs are still relatively lower than other technologies; however costs range significantly based on the size and design of the system. Based on 2007 estimates, initial investment costs can range from €750-2,750/kW for the cell stack and €200/kWh for the electrolyte energy storage, depending on the scale of the system and the amount of required electrolyte. These prices are expected to decrease to a lower level of approximately €500/kW and €100/kW as soon these systems are mass-produced on the market (Boer and Raadschelders, 2007).

Over the last two decades, R&D has been driving commercialization of VRB flow batteries, which has significantly improved efficiencies, lowered the capital and operational costs and improved material durability. However, there are still quite a few technological and political barriers that can hinder this technology from reaching mass production, which would significantly lower capital costs. These barriers include high costs associated with sourcing the electrolyte and manufacturing the battery stack. Policy barriers include lack of awareness/instruments supporting energy storage, and research funding policies that focus on flagship technologies like fuel cells and lithium-ion batteries. Therefore, capital costs are expected to decrease moderately in 5 years (Kear et al., 2011). Table 16 below summarizes the cost assumptions used in HOMER according to the Prudent Energy website and converted from USD to Euro using a 1.3 Euro/USD conversion.

Table 16. Summary of storage cost assumptions[15] for VRB ESS Storage Systems (Prudent Energy, 2012)

	Cell Stack & Electrolyte Storage
Initial Investment	€577 / kW & €154 / kWh
Replacement	€385/kW
Variable O&M	€0.006/kWh
2018 Investment Costs	€500 / kW & €150 / kWh

4. 3 Back-up Generators

By integrating solar PV and wind power into the DWP-NWG microgrid system, the amount of power required from the grid can be significantly reduced. However, since solar and wind resources are both inherently intermittent in nature, the system design requires some form of backup generation, particularly if grid connection is interrupted for

[15] Based on low range estimates from www.pdenergy.com and converted to euros from dollars using a €1.3 Euro per USD conversion as of April 22, 2013.

any reason, and especially if it needs to be in island (stand-alone) mode for a longer period of time. During grid-connection, back-up generators serve the purpose of meeting minimum demand if there is a short interruption in the grid since the grid normally provides the balance between generation and local demand onsite. However, in stand-alone systems, back-up generators can play a more significant role to help balance demand and supply locally.

Generator Selection

In this case, the DWP-NWG already has two 660 kW diesel generator sets for back-up power production in order to maintain the water treatment and pumping process. Already having backup generators is not exceptional in this case since constant water demand is imperative, so most industrial water treatment plants have backup generators already onsite for emergencies. Therefore, these onsite diesel generators will also be used in this research. Each set consists of a Cummins KTA 38-G3 engine and an AVK 0SG74M-4 Generator. These diesel generators are known for their reliability, and have been proven to be suitable for utility peaking plants, distributed generation facilities, peak shaving, and power management at commercial and industrial sites. Since these generators do not run all the time, their lifetime is expressed in hours. In this case, these generators have a lifetime of about 15,000 hours and 30% minimum load ratio, which is the minimum allowable load on the generator, as a percentage of it rated capacity (Cummins, 2012). Moreover, diesel generators are superior to gasoline generators since they are more fuel efficient, require less maintenance since there are no carburettors or spark plugs, and have fewer emissions. The one down-side is that diesel generators have significantly higher initial investment costs, however, due to their durability and low relative maintenance, diesel is actually less expensive over the relative lifetime compared to gasoline engines.

Table 17 summarizes the fuel consumption assumptions used for the modelled diesel generators and Figure 16 illustrates the fuel efficiency based on these fuel consumption assumptions. This fuel consumption pattern leads to a 0.01614 L/hr/kW rated Intercept coefficient, which indicates the no-load fuel consumption of the generator divided by its rated capacity.

Table 17. Fuel consumption assumptions for 600kW diesel generator (Diesel Service & Supply, 2013)

kW	Fuel Consumption (l/hr)*
150	50.0
300	83.3
450	119.2
600	162.0

*converted from gal/hr at 3.78541 liters/gallon

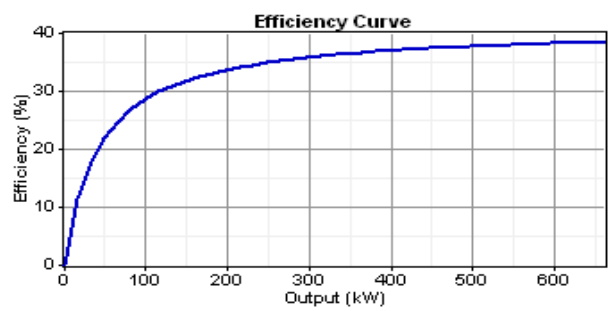


Figure 16. (Right) reproduced fuel efficiency curve based on fuel consumption data from Table 17

Cost Assumptions

The initial investment for a 600 kW diesel generator runs at about $85,000, or about €65,000 euro using a 1.3 conversion (GeneratorJoe, 2013). However, since diesel generators already exist at the DWP-NWG site, these investment costs have already been incurred and are not relevant. However, at the end of their lifetime, which depends on how often they are used, they will need to be replaced. Assuming the diesel generators are a mature

technology, prices will not decrease significantly over their lifetime so replacement costs are assumed to be 90% of the today's investment costs, although their lifetime in years depends on how often they are used. Table 18 below summarizes the cost and fuel price assumptions used to model these back up diesel generators. Based on the historical average trend of a 12% increase in diesel fuel prices every two years in the Netherlands from 2004-2012, the price of diesel in 2018 is assumed to be 1.777 €/liter (adjusted for 2% inflation).

Table 18. Diesel generator cost & fuel price assumptions for each generator

Category	Amount
Initial Investment	€0
Replacement (90% of current prices)	€ 58,500
O&M	€ 8.58 /hr[a]
Diesel Fuel Price	€1.478/liter[16]
2018 Future Diesel Prices (12% increase every 2 years)	€1.777/liter

[a]O&M based on €0.013/kW cost for a generator running about 200 hours or less per year in study done in 2003 comparing costs of utility distributed generators in 24 case studies (EPRI, 2003). Although these are privately owned diesel generators, they are still quite large and more comparable to utility scale DG versus small scale DG.

4.4 Dispatch Strategy – Load Following

When there is a primary load and a flexible load, or deferrable load, the latter is second in priority behind the primary. However, the flexible load takes priority over charging the batteries. In order to consume any excess produced electricity, a load following strategy is employed so that the deferrable load is served only under these circumstances (or when the storage capacity reaches its limit).

Storage and generators can be dispatched using two different strategies in HOMER: Cycle charging or load following. The optimal strategy depends on the grid-connection, amount of renewable electricity generation, and prices since HOMER operates the dispatch-able power sources—generators & batteries—in such a way as to minimize costs. Cycle charging describes the strategy where the generator charges the battery, and is therefore optimal in systems with low renewable generation potential. Load following, on the other hand, just dispatches the generator to meet the load demand but does not charge the battery. This tends to be the optimal strategy in systems with a lot of renewable electricity potential which produces significant excess power beyond the load demand.

Generators can be also dispatched based on a specified schedule, or optimized based on the electrical demand and economics of the generator versus the grid and availability of other power generators, like renewable electricity and storage. Since the generators are mainly for backup, their scheduling is optimized based on the cost of using them for power in the specific time step versus the cost of other power sources in this research.

Since this system has a high potential for wind and solar power, the load following dispatch strategy is used so that the deferrable load is only met when there is excess renewable electricity production. Moreover, grid-sell back from the battery is prohibited to peak hours and battery charging from the grid is prohibited. In this case (and for most industrial users), the electric load and generators are connected to the grid, which is generally less expensive to balance the intermittencies than using battery storage. Since VRB battery storage has not reached full market

[16] Diesel price as of April 16, 2013 (http://www.fuel-prices-europe.info/)

maturity, and remains relatively expensive, it is expected that minimal storage will be needed in a grid-connected microgrid since HOMER will discharge the battery to serve the load whenever there is power available in the battery, but only when the battery power is cheaper than grid power. However, in island mode when the microgrid is disconnected from the grid, battery storage will become more important in order to balance supply with demand.

5. Integrated System: Scenarios & Summary of Assumptions

Once the system components are modelled, HOMER runs 1 year cost-optimization simulations of the different combinations of system design and then ranks them based on net present cost. The following table summarizes the component system inputs based on the feasibility and needs of the DWP-NWG. HOMER filters out any infeasible combinations from the list of optimized systems.

Table 19. Summary of component sizing inputs

Wind Production (2 MW turbines)	**0; 1; 2; 3; 4**
Solar Production (kW)	0; 1413; 2826; 5652
Converter (kW)	0; 1260; 2490; 5160
Flow Battery Cell Stack (kW)	0; 1000; 2000; 3000
Flow Battery Electrolyte Storage Tank (kWh)	0; 20000; 45000; 60000
Diesel Generators	0; 2x660kW

Separate models are created to simulate systems including demand response via a deferrable load, future scenarios, and stand-alone microgrids without grid connection (summarized in Table 20). Future scenarios are based on 5 years from today, or 2018. This is chosen because there are plans for major renovations at the DWP-NWG by 2018 (Braam, 2013), so it would be a prime opportunity to include the necessary components for a microgrid into the overall changes made to the DWP. Due to the multiple sizing options explored for each system component, there are thousands of possible system designs. Therefore, the realizable and relevant system designs are chosen based on maximum renewable production possibilities, cost optimization, and for the sake of comparison.

Table 20. Summary of model scenarios run in HOMER

Time	Grid-Connection	Deferrable (Flex) Load [DR]
Today (2013)	Y	No
Today (2013)	Y	Yes*
Today (2013)	N	Yes*
Future (2018)	Y	Yes*
Future (2018)	N	Yes*

*Scenarios in models with a deferrable load are extracted based on significant renewable energy production in order to meet sufficient deferrable load (>4.9GWh) and in turn meet average annual water production requirements

Table 21 below summarizes the 2018 future cost assumptions for the technological components and fuels prices of the microgrids already discussed in their previous respective chapters.

Table 21. Summary of future cost assumptions and 2018 investment costs

Technology	Reduction Assumption	2018 Investment Costs
2 MW V90 Wind Turbine	3.5% per year	€2,647,203 per turbine
CSUN/Sungrow PV system	20% by 2018	€763 per kW
VRB Flow Batteries	13% by 2018	€500/ kW & €150/kWh
Electricity (peak/off-peak)	4.5% per year	€0.09654 / €0.07536 per kWh
Diesel	12% every 2 years	€1.777 per liter

These scenarios are evaluated and compared based on technical and economic indicators, which are summarized below in Table 22. Economic potentials are based on a 25 year project lifetime.

Table 22. Summary of technical and economic indicators used to evaluate and compare scenarios

Technical	Economic
Annual RE Production (GWh/year)	Levelized Cost of Electricity (COE) [a] (€/kWh)
Annual Generator Supply (GWh/year)	NPV[b] (€ million)
RE Fraction of Load (%)	Discounted PBP (years)
Annual Grid Purchases (GWh/year)	
Annual Storage Throughput (GWh/year)	

[a] Levelized Cost of Electricity (COE) = $C_{ann,tot}$ / E_{served}; where $C_{ann,tot}$ = total annualized cost of the system [€/yr] (based on the total net present cost of the system discounted at a 3.6% real interest rate, adjusted for 2% inflation, and 25 year lifetime) and E_{served} = total electrical load served (including grid sales) [kWh/yr]

[b] Calculated as NPC of Grid-only system (to meet same load as RE microgrid system) minus NPC of RE microgrid system; NPC = Sum of (Costs – Revenues) $*(1/(1+r)^n)$ where r = real interest rate (3.6%)[17] and n = year of cash flow (out of 25 year project lifetime).

Since the amount of annually met deferrable load ranges from 4.9 GWh to 7 GWh depending the amount of renewable electricity production, the deferrable load met by the system with a total load closest to 16.7 GWh is fixed as the total base load in order to make the economic calculations comparable to the current base case without RE production, onsite consumption, or flexible demand. For stand-alone microgrids, the NPV is calculated using the current base case as the grid-only alternative case.

6. Results: Microgrid Techno-Economic Potentials

Having run the HOMER software for current grid-connected, current stand alone, future grid-connected, and future stand-alone models, this chapter will explain the technical and economic potentials of various optimal system designs. It should be noted that abbreviations are used for the capacities of the system components, particularly in the graphs. For example, "GC_5.6MWpPV+4W+3MW/60MWhVRB+DR" refers to a grid-connected, 5.6MWp solar PV, 4 wind turbine (2MW each), 3MW cell stack – 60MWh electrolyte VRB flow battery storage combined with demand response. Similarly, "SA_2.8MWpPV+3W+1.3D+2MW/45MWhVRB+DR" refers to a stand-alone (not

[17] Cost of capital is 5.6% for the Drink Water sector to borrow from the municipality, which is then adjusted by 2% for inflation, which is the average inflation rate from 1984-2013 (http://www.tradingeconomics.com/netherlands/inflation-cpi)

connected to grid), 2.8MWp solar PV, 3 wind turbine, 1.3MW diesel generator capacity (2x660kW), 2MW cell stack-45MWh electrolyte VRB flow batter storage with demand response system.

6.1 Technical Potentials

Figure 17 below compares the annual solar PV production, wind power production, grid purchases, storage throughput and grid sales relative to normal onsite electricity demand (16.7 GWh/year) and how much total electricity demand can be served per year by excess RE production with flexible demand for grid-connected scenarios versus the current base case. Figure 18 provides a similar comparison between stand-alone microgrid configurations. Storage throughput and grid sales are graphically depicted as negatives since they are not consumed immediately but stored either onsite or in the main grid for later use.

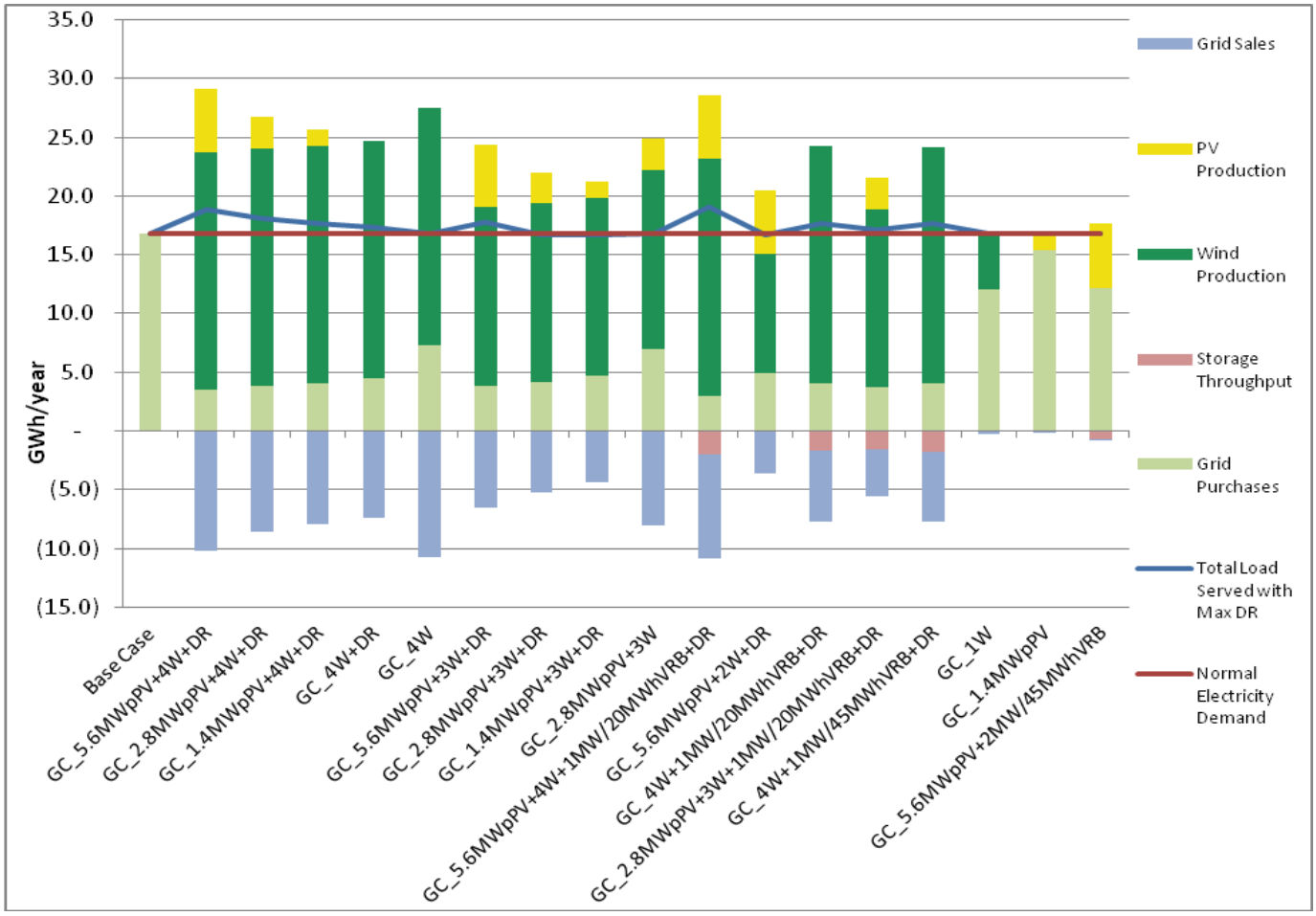


Figure 17. Annual PV production, wind power production, storage throughput, and grid purchases relative to normal onsite electricity demand (16.7 GWh/year) and how much total electricity demand can be served per year by excess RE production with flexible demand for grid-connected scenarios versus the current base case. Microgrid cases are ordered by NPV from highest to lowest starting from the left after the base case.

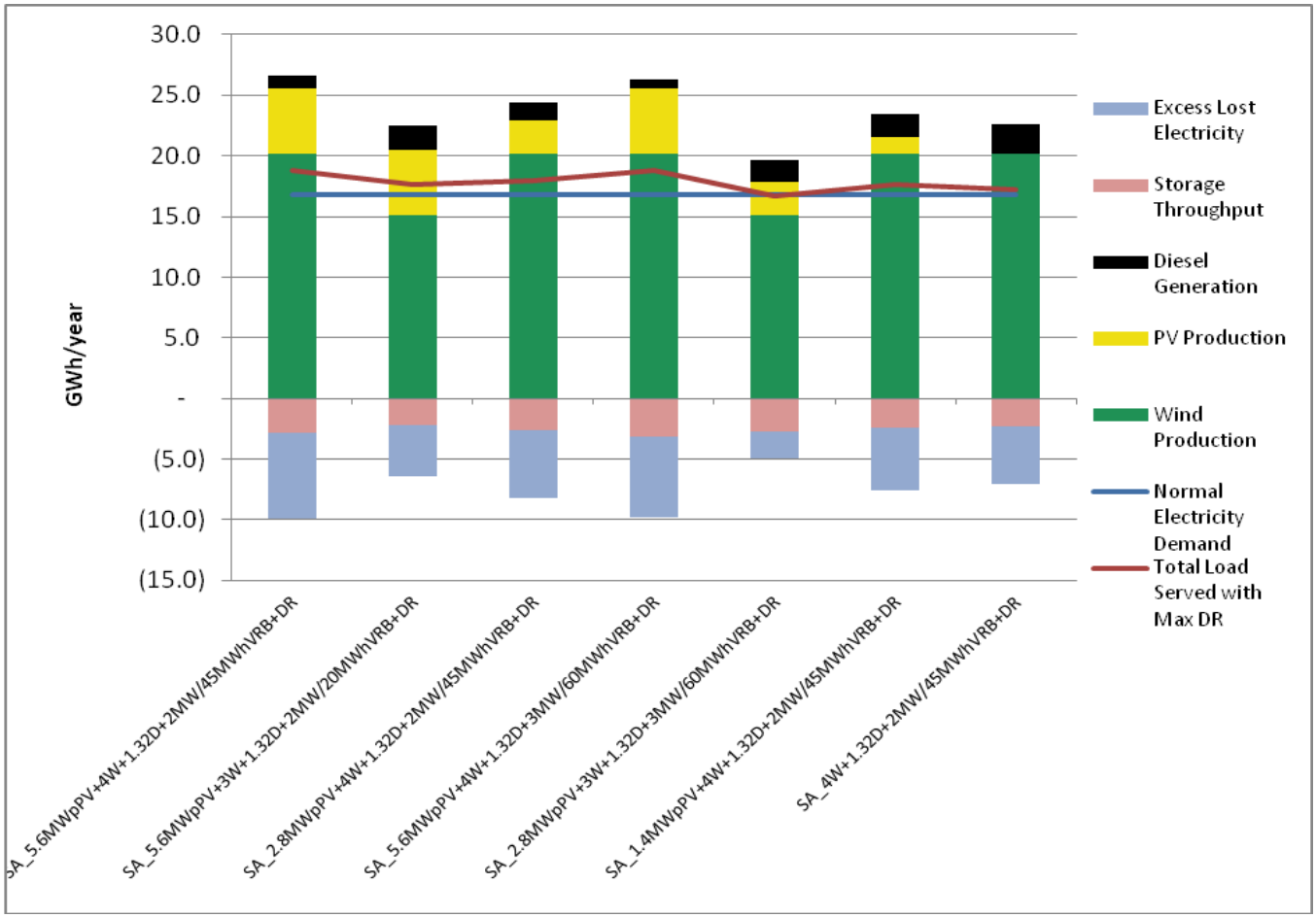


Figure 18. Annual PV power production, wind power production, diesel power generation, storage throughput, and excess lost electricity versus normal annual electricity demand and total demand served with maximum DR per year for stand-alone (SA) microgrid system configurations

In this following sections the main technical potentials from the cases compared in Figures 17 and 18 above are discussed: annual renewable electricity (RE) production and in turn fraction of load (demand) met by RE, along with a deeper explanation of annual grid purchases, diesel generator supply, and storage throughput for both grid-connected and stand-alone microgrid system configurations. The effect of onsite consumption and demand response is covered in the grid purchases section.

Annual RE Production & Fraction of Onsite Load Met by Renewable Electricity

A system configuration of maximum RE production capacity (5.6MWp solar PV[18] and 4 wind turbines of 8MW) combined with very large battery storage (3MW power/60MWh electrolyte VRB storage) and flexible demand (DR) can supply 96% of onsite electricity demand (stand-alone microgrid)[19]. In grid-connected scenarios, 90% of onsite

[18] Requires 36,000 m^2 of space if arrays can be arranged so that no additional space is needed between arrays to prevent them from casting shade on each other. If arrays need to be arranged with extra space in between them, this maximum solar PV capacity would require about twice as much space, and would therefore not entirely fit on Parcel Zuid.

[19] Even if storage capacity is doubled, the intermittency of wind and solar power does not permit 100% of load to be supplied by renewable electricity

power demand supplied by renewable electricity is possible with the same RE production capacity, yet a third of the storage capacity (1MW/20MWh VRB storage). This is just 2 percentage points higher than a system with the same RE capacity yet without the storage, which is still able to meet 88% of the onsite electricity demand.

These very high RE fractions are possible because the annual renewable electricity production potential is 25.6 GWh per year from 4 wind turbines (8MW) and 5.6 MWp Solar PV, which represent 79% and 21% of total renewable production, respectively. The maximum 25.6 GWh produced per year is 53% more electricity produced onsite than the normal 16.7 GWh annual power demand. Adding storage allows some of this excess renewable electricity to be used at another point in time to meet the demand when production in low, causing the RE fraction of onsite demand to be 2-8% higher than systems without battery storage.

In grid-connected cases, the excess electricity that is not stored is exported back to the grid, which also increases the amount of renewable electricity on the main power grid network. Figure 17 above illustrates that there are many grid-connected microgrid case configurations that produce significant amounts of excess electricity beyond onsite demand, which they sell back to the main grid, making the imported grid electricity more "green" in absolute terms. However, if there is no grid-connection, this excess renewable electricity is lost. In all stand-alone cases, the amount of excess electricity that is lost ranges from 2.2 GWh to 7.1 GWh, which can be even higher if maximum solar PV and wind capacities are implemented without battery storage. This is a problem in stand-alone microgrid scenarios since oversizing RE production makes them more cost-effective by minimizing the need for expensive diesel generation and storage, yet results in large losses of clean electricity.

In terms of monthly distribution power production, Figure 19 illustrates the monthly average electricity production in a grid-connected 5.6 MWp Solar PV - 4 wind turbine with flexible demand (DR). Due to the large amount of electricity produced and consumed on site, the reliance on the grid imports is minimized. It should be noted again that these potentials are only realistic in this case if the solar PV array is not drastically affected by the shade cast by the 4th wind turbine and if the solar PV arrays can be situated on the 36,000m^2 of available space on Parcel Zuid without casting shade on each other.

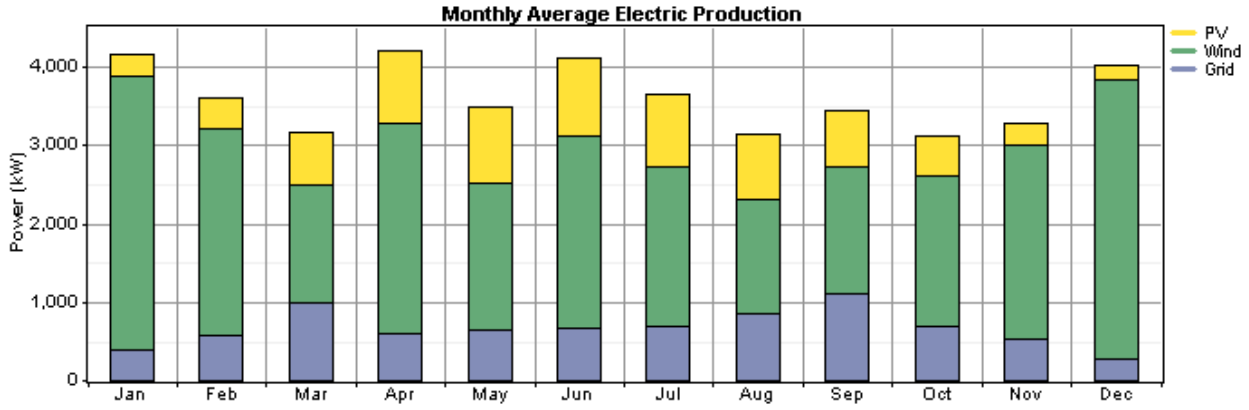


Figure 19. Monthly average electric production in a 4 wind turbine-5.6 MWp solar PV system

Even if a 4 wind turbine-solar PV combination is not possible, a pure 4 wind turbine configuration results in an annual RE production of 20.2 GWh, which is 21% more than the 16.7 GWh/year required onsite. Figure 20 below illustrates the monthly average electricity production of a 4 wind turbine system with flexible demand (DR) versus

the average monthly power imported from the grid to meet the demand that the wind production does not meet. In the winter months, when wind speeds are higher and there is greater wind production, less power needs to be imported from the grid. In the summer months, when customer demand is greater and there is less wind production twice as much electricity needs to be purchased from the grid.

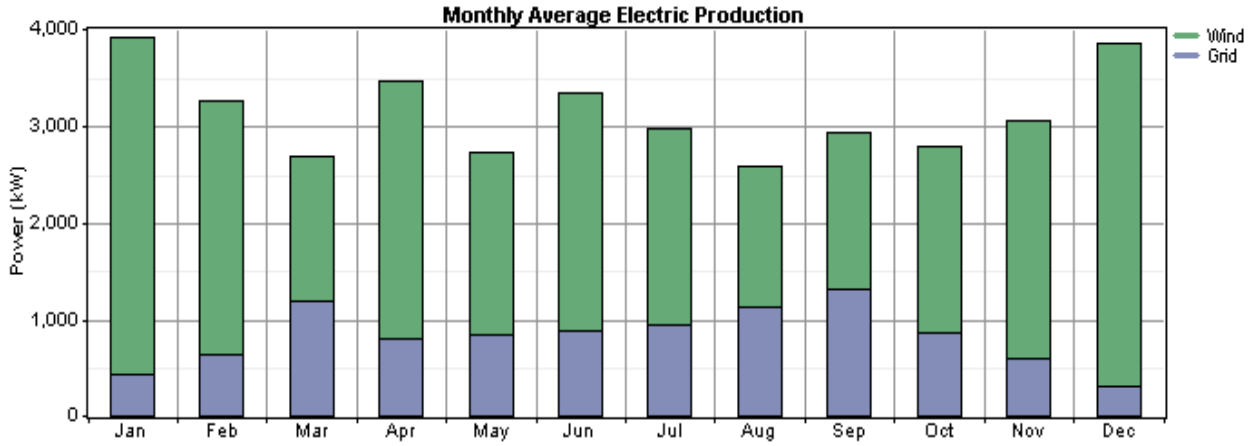


Figure 20. Monthly average electric production in a 4 wind turbine system

A wind-solar configuration of 2.8MWp solar PV[20] and 3 wind turbines produces 17.8 GWh/year of renewable electricity per year, which is 12% less than a 4 wind turbine only configuration. Compared to a maximum RE production system (5.6MWp Solar PV+4 wind turbines), this system produces 30% less renewable electricity, yet still 6% more than the normal electricity demand per year. Since it produces less than the maximum system, it relies on 20% more grid-purchases per year. Figure 20 illustrates the monthly average electricity production for this system, which also demonstrates how the added solar PV production capacity, in place of a 4th wind turbine, supplements production in the summer months and mitigates the volatility of wind production. This creates a more stable renewable energy supply, especially since solar PV production is more predictable than wind production.

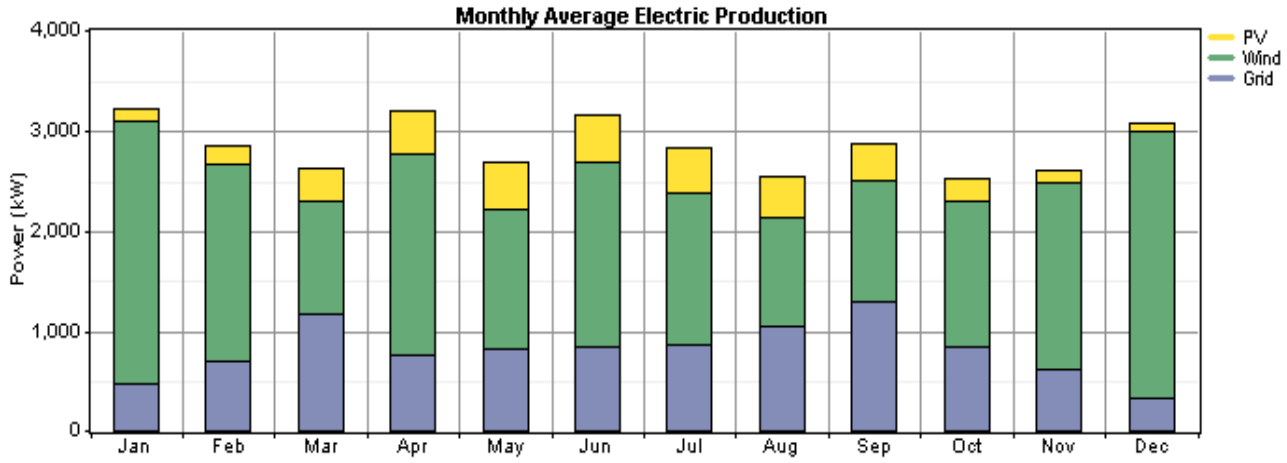


Figure 21. Monthly average electric production in a 3 wind turbine and 2.8 MW solar system

[20] If PV arrays need to twice as much space than the PV array surface area, this PV system capacity requires 36,000 m2, which is precisely the space available on Parcel Zuid.

Smaller RE systems of only 1 wind turbine without flexible demand produce 5 GWh of renewable electricity per year, which meets 30% of onsite demand and a system of only 1.4MWp solar PV without flexible demand produces 1.3 GWh per year, which meets 16% of onsite demand, as seen above in Figure 17. Figure 21 below illustrates the monthly average electric production, with the left graph representing the 1 wind turbine system and the right graph representing the 1.4 MWp solar PV system.

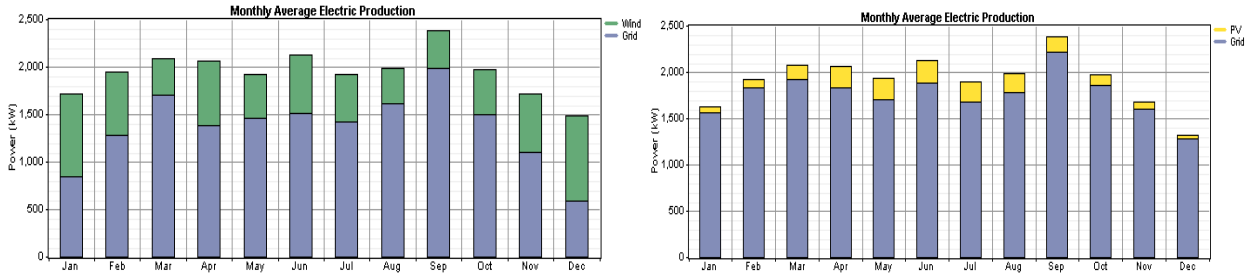


Figure 22. Monthly average electric production of a 1 wind turbine system (Left) and a 1.4 MWp solar PV system (Right)

Grid Purchases – Effect of onsite consumption & flexible demand (Demand Response]

In grid-connected scenarios, adding RE generation to the system to be consumed directly onsite significantly decreases the amount of grid imports compared to the current base case, which requires 16.7 GWh to be purchased from the grid on an annual basis. For example, 74% of onsite demand can be met by consuming the electricity from 4 wind turbines, without flexible demand, which decreases the amount of grid imports by 57% to 7.3 GWh per year. This is seen in Figure 23 below, which compares the current base case to a grid-connected 4 wind turbine system with and without flexible demand (DR).

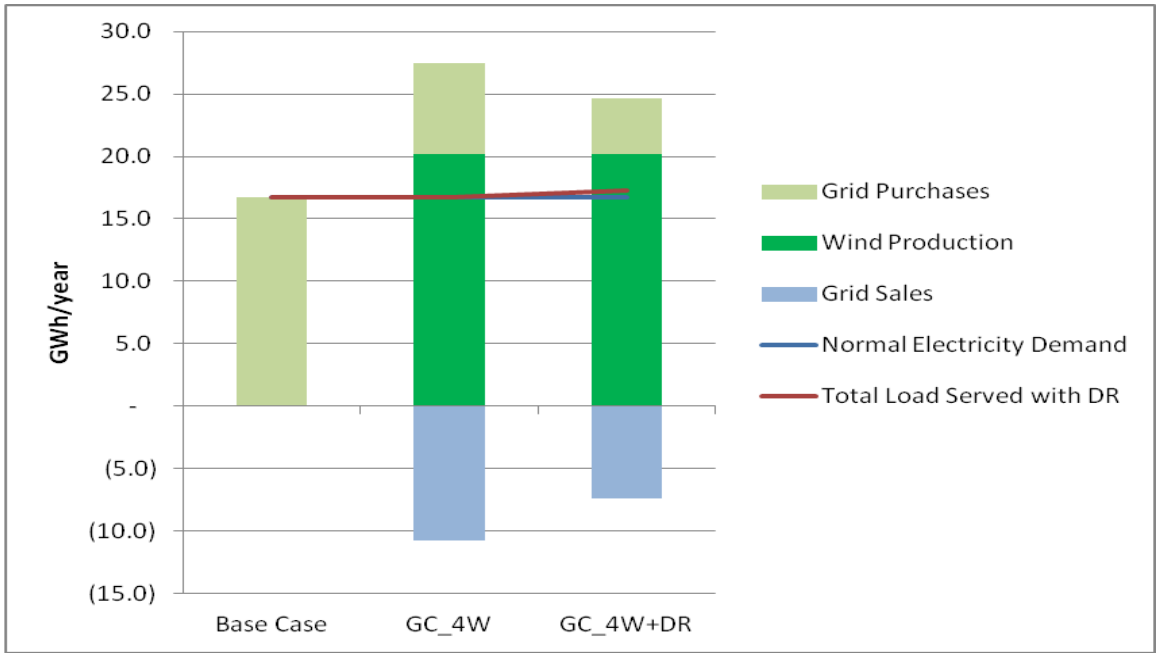


Figure 23. Comparison of grid purchases and sales per year between the current base case, a GC 4 wind turbine system without flexible demand (DR) and a GC 4 wind turbine system with flexible demand (DR)

Figure 24 below of daily profiles of grid electricity purchases in a 4 turbine system illustrates that utilizing renewable energy production immediately onsite significantly decreases the amount of electricity purchased from the grid, particularly between 6am and 7pm, which are predominantly peak hours. This earns about €154,000 per year in avoided transport and energy taxes by consuming onsite instead of purchasing all the electricity from the grid and selling the same renewable electricity produced back to the grid. These modest earnings are explained by the fact that the load profile of water treatment is relatively high and stable throughout the day and it pays wholesale electricity prices unlike a residential area, which has significantly greater electricity demand during peak hours versus off-peak and much higher electricity prices, so the benefit of consuming onsite would be greater.

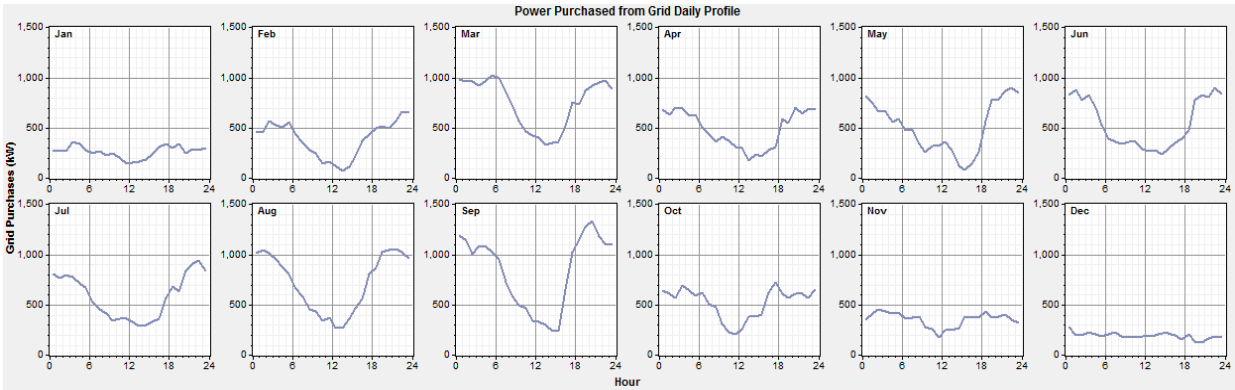


Figure 24. Monthly electricity purchases from grid daily profile of a 4 turbine system

Implementing a flexible demand strategy, in addition to just consuming onsite, increases the fraction of onsite demand supplied by RE to 82%, and in turn decreases the amount of grid-purchases by an additional 38% from 7.3 GWh/year to 4.5 GWh/year in a 4 wind turbine configuration with flexible demand (DR). Figures 28 and 29 illustrate the difference between a system with flexible demand (top) and without flexible demand (bottom) on a daily basis. In the system with flexible demand (Figure 28), as renewable electricity production increases (green line), the larger pumps are activated to pump more water, which increases the onsite electricity demand and consumption (blue line).

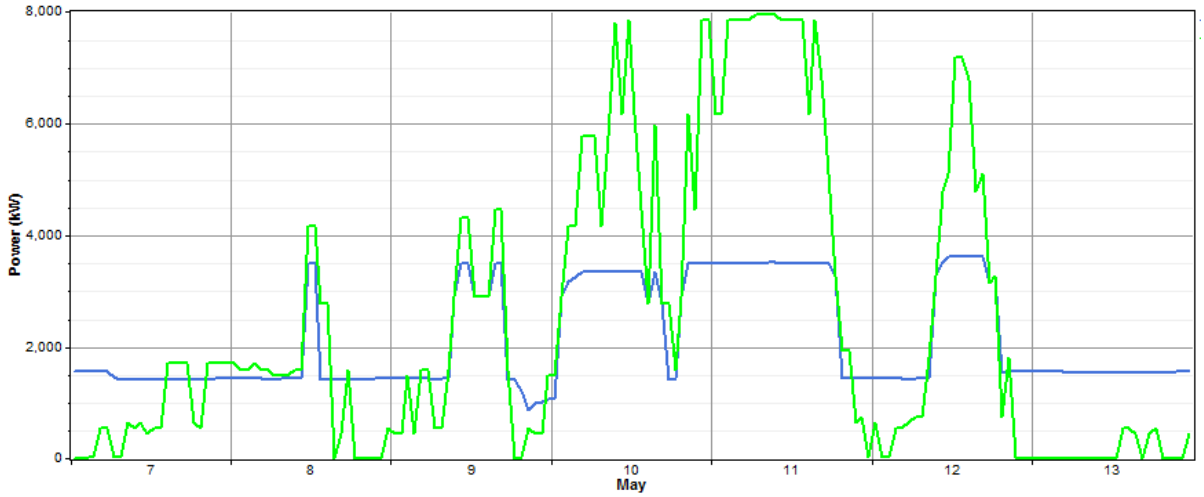


Figure 25. Example of 1 week in May of electrical demand (blue line) increasing in response to increased renewable production (green line) from 4 wind turbines

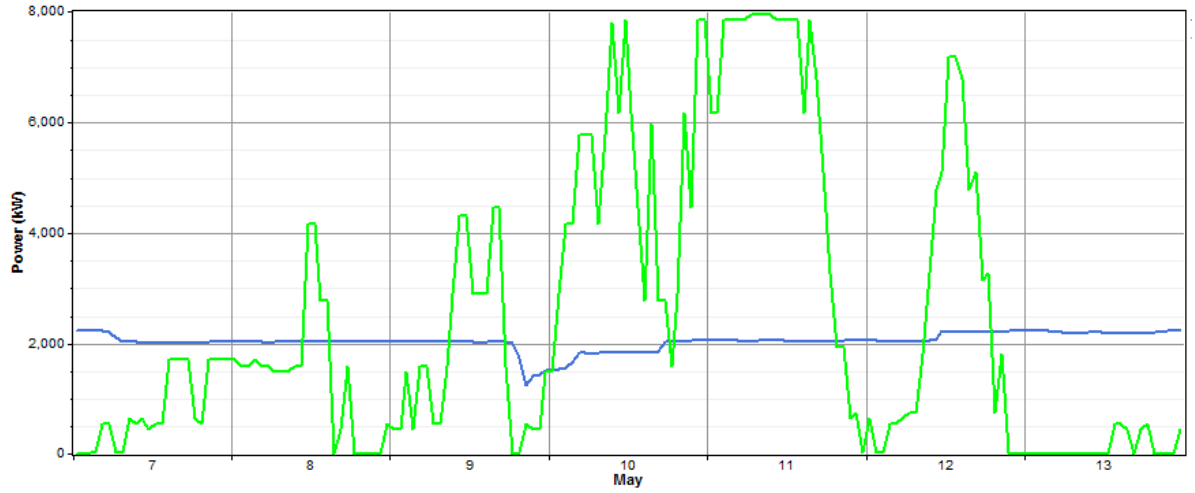


Figure 26. Example of 1 week in May of 2012 electrical demand (blue line) versus renewable production (green line) from 4 wind turbines

Under the modelled flexible demand strategy to pump more water when there is excess renewable electricity, this 4 wind turbine system with flexible demand (DR) can pump an additional 0.5 GWh worth of water per year above the normal 16.7 GWh annual demand. This additional pumping combined with the 29% shift of normal annual demand to be consumed during RE production causes grid-sales to decrease by 31% from 10.7 GWh to 7.4 GWh per year. Even though grid sales decrease, the net benefit of avoiding transport and energy taxes on these 3.3 GWh equates to an additional gain of €71,000 per year. If maximum solar PV capacity (5.6MWp) and/or battery storage is added to this 4 wind turbine system with flexible demand, the demand response strategy allows up to about 2 GWh worth of additional water to be pumped to the Dunes per year, which is 12% more than the base case (seen in Figures 17). This results in a maximum additional benefit of about €102,000 per year from implementing this flexible demand strategy. This increase in pumping is possible because the additional solar PV production and/or storage discharge occurs at different parts of the day when wind production is less significant, causing the larger pumps to be used. However, this increase in pumping is still marginal relative to the amount of excess RE production. This is explained by the limitations of the current pump installations and transport network which prevent significant amounts of additional water to be pumped in one time-step when there is exceptional RE production (ie. minute or hour). This limit is clearly seen above in Figure 25 where the electricity use (blue line) is capped at 3450 kW in each hour of the day even though RE production can be twice as much in that time step. Moreover, while this additional pumping is possible over 1 year of a few in the short term, its sustainability over the long term is uncertain since storage capacity at the Dunes is limited and would require the overall customer water use to increase in order to maintain the extra buffer space for additional pumping for multiple years.

A grid-connected system design of 2.8MWp solar PV-3 wind turbines with demand response is the smallest system that produces enough renewable electricity in each hourly time-step to maximize flexible demand at 29% and still meet normal annual demand. This decreases the grid purchases by 41% from 7 GWh/year to 4.2 GWh/year. However, this system does not produce enough excess electricity to pump extra water above the normal annual demand. Systems with smaller RE capacity and production will not be able to achieve the 29% minimum flexible demand, and will therefore need to rely more on grid-imports in order to sufficiently meet the normal 16.7 GWh annual demand.

Overall, even at the high aforementioned renewable energy potentials and high RE fractions of load with flexible demand, all grid-connected systems still rely on about 3.0-4.5 GWh of electricity imports from the grid, due to the intermittency of wind and solar production.

Since stand-alone systems do not connect to the grid, they will not import electricity from the grid. Nonetheless, these scenarios prove that it is feasible for an industrial-sized drink water treatment plant to operate independently from the grid as long as there is very high potential for solar and wind energy, large battery storage, and dispatchable diesel generation to supplement RE production.

Annual Generator Supply

In grid-connected microgrid scenarios, diesel generators do not need to provide any power to meet the electrical demand onsite during normal operations. This is due the fact that electricity purchased from the grid is less expensive than the cost of diesel fuel. Therefore, diesel generators are only necessary in cases of emergency for grid-connected microgrid scenarios.

In stand-alone microgrid cases, however, diesel generators are necessary in order to meet the required demand for normal water production when RE production and stored RE is insufficient. This is particularly the case for a microgrid system without solar PV, which needs more power supply from the diesel generators in order to supplement production when there is less wind power production. This is seen in Figure 18 when looking at a stand-alone 4 wind turbine-2MW/45MWh VRB system design with flexible demand that requires 2.4 GWh of power supply from diesel generators, which is 36% more than the 1.5 GWh/year needed by a stand-alone wind-solar-battery-DR microgrid design with 2.8MWp solar PV. This is seen in Figure 24 below which illustrates the increasing need for diesel power supply (black line) on an hourly/daily basis when renewable electricity production (green line) and battery power output (yellow line) are not high enough to meet onsite electricity demand (blue line).

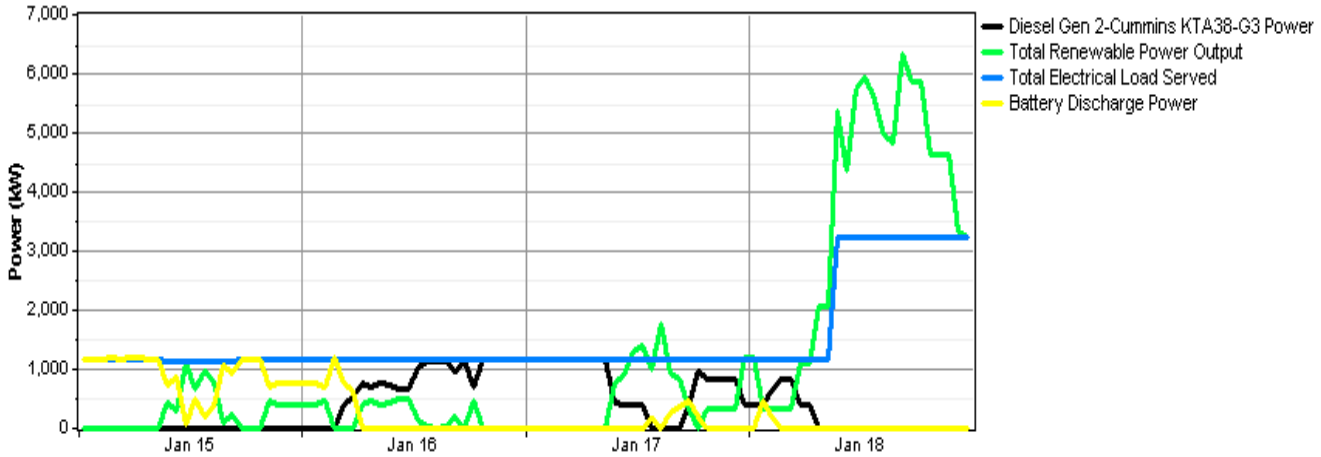


Figure 27. Renewable electricity, battery output, and diesel generator supply during four days in January

Storage Used

In grid-connected scenarios, storage is not absolutely necessary due to the very high RE production potential and the ability to export power back to the grid. However, adding storage has the advantage of decreasing electricity imports from the grid. For example, adding 1MW/20MWh VRB storage to a 4 wind turbine system provides an annual storage throughput of 1.7 GWh, and decreases annual grid purchases by 11% from 4.5 GWh to 4.0 GWh.

This earns an additional €10,500 per year in avoided transport and energy taxes, which is not very significant relative to the high investment costs of battery storage. Similarly, adding the same amount of storage to a 2.8MWp solar PV-3Wind system decreases grid purchases by 12%.

In stand-alone microgrid scenarios, storage is imperative to meet electricity demand when there is not enough renewable electricity production. This was already seen in Figure 27 above, which demonstrated the need for storage output and diesel generation during times of low renewable electricity production throughout the day. The largest modelled system design of 5.6MWp solar-4 wind turbines-3MW/60MWh VRB storage with flexible demand has the largest storage throughput of 3.2 GWh. However, this is still not enough to meet 100% of demand without requiring 0.8GWh of diesel generation. Even with this large storage capacity, this system loses 6.6 GWh/year of excess electricity, which is 3 times more lost electricity than a downsized RE capacity of 2.8MWp Solar PV and 3 wind turbines (combined with diesel generation) combined with 3MW/60MWh VRB storage for 2.7 GWh of annual storage throughput which helps minimize excess lost electricity. Figure 28 below also shows the daily and monthly distribution of stored electricity for this system, which illustrates that stored RE is predominantly used during evening hours when there is very low renewable electricity production.

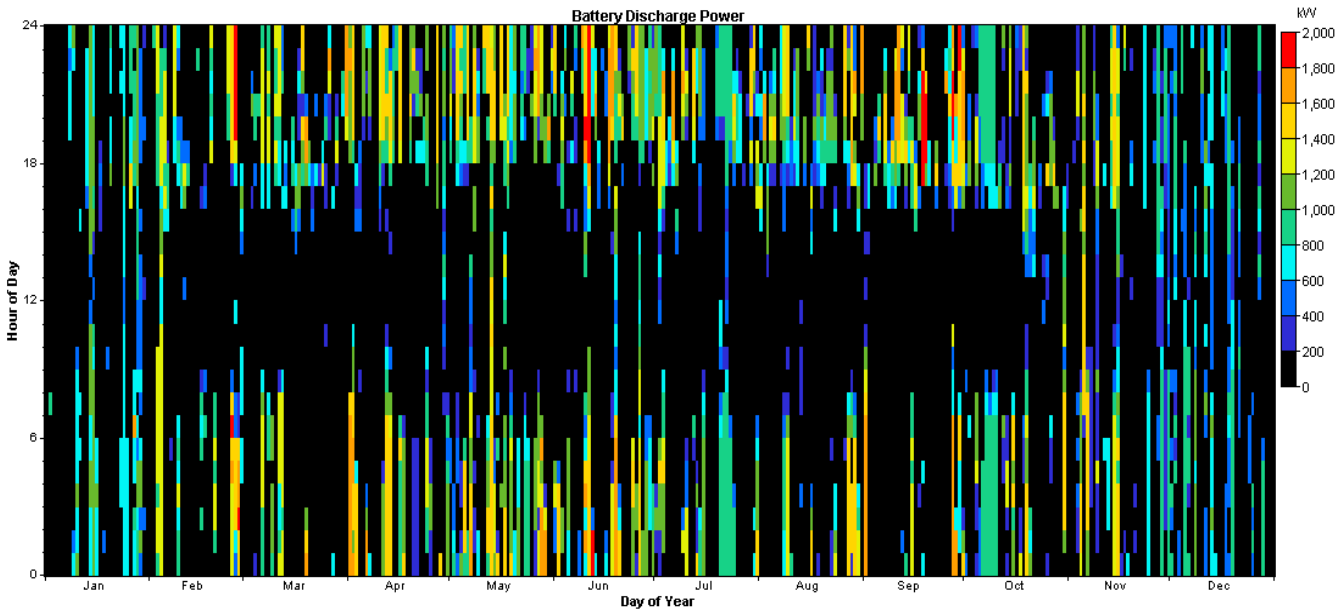


Figure 28. Battery Discharge Power distribution throughout the day over the entire year for a stand-alone microgrid system that produces the lowest excess lost electricity (2.8 MWp Solar PV+3Wind tubine+1.32 MW diesel generator+3MW/60MWh VRB storage system)

Ultimately, adding storage to grid-connected cases adds a marginal benefit since the main grid acts as a sort of storage at a cheaper price; however, in stand-alone cases large storage is necessary to mitigate the amount of diesel generation needed and to mitigate the amount of lost electricity. Optimally downscaling RE capacity is the most effective way of minimizing lost electricity though.

6.2 Current 2013 Economic Potentials

The current economic potentials, which include the EIA tax incentive and the SDE+ subsidy are discussed in this section, beginning with the levelized cost of electricity (COE) per kWh for the grid-connected and stand-alone systems. Then the cost-effectiveness of the systems is discussed based on their Net Present Value (NPV) and discounted payback periods (PBP).

COE

Figure 29 below illustrates the difference in COE between the base case (red column) and the chosen grid-connected (GC) and stand-alone (SA) microgrid systems (blue columns).

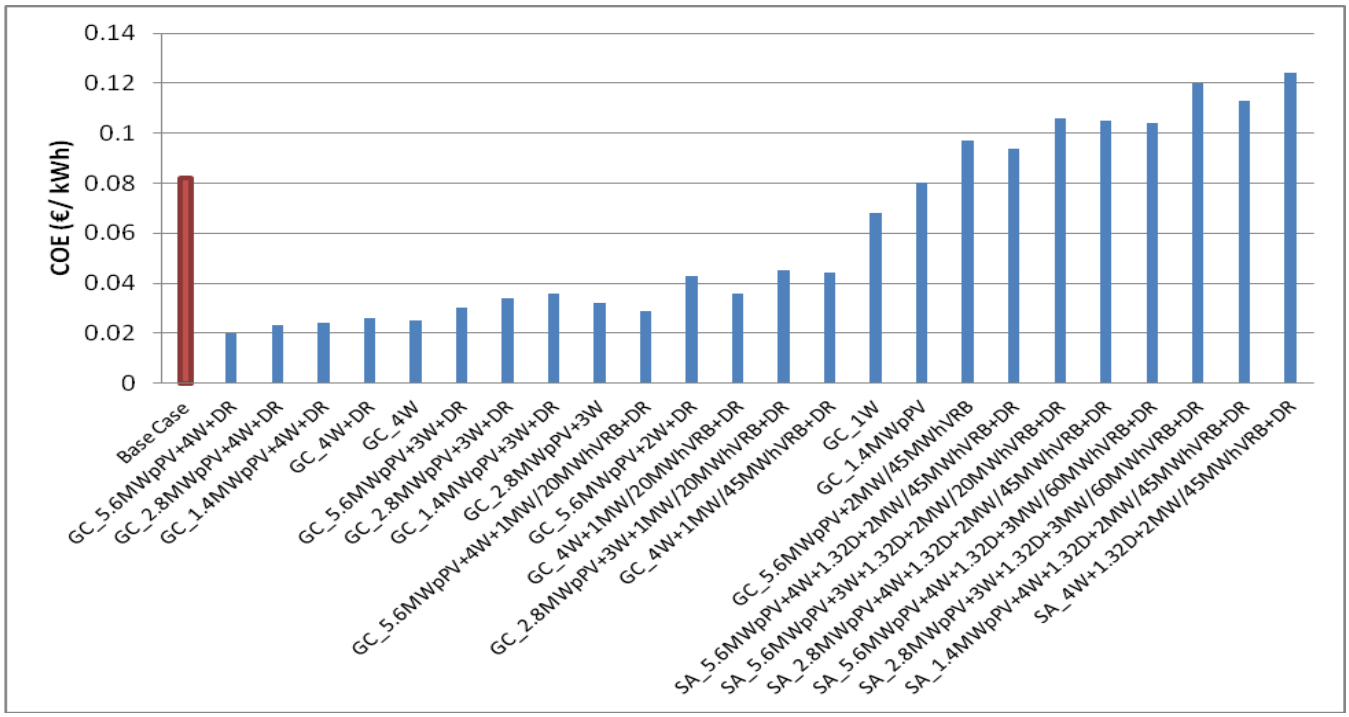


Figure 29. Summary comparing base case COE (red) to the chosen grid-connected and stand-alone system configurations

Grid-connected system configurations containing 4 wind turbines (with or without solar PV) and without battery storage have the lowest cost of electricity (COE) between 0.020-0.026 €/kWh. This is 68% less than the current base case COE of 0.082 €/kWh since there is a significant drop in grid-imports due to onsite consumption and flexible demand. Figure 30 below shows a breakdown of the annualized costs for the system with the lowest COE (5.6MWp solar PV + 4 wind turbines + DR). The positive grid costs are due to the significant 10.2 GWh/year grid sell-back that outweighs the 3.5 GWh/year grid purchases.

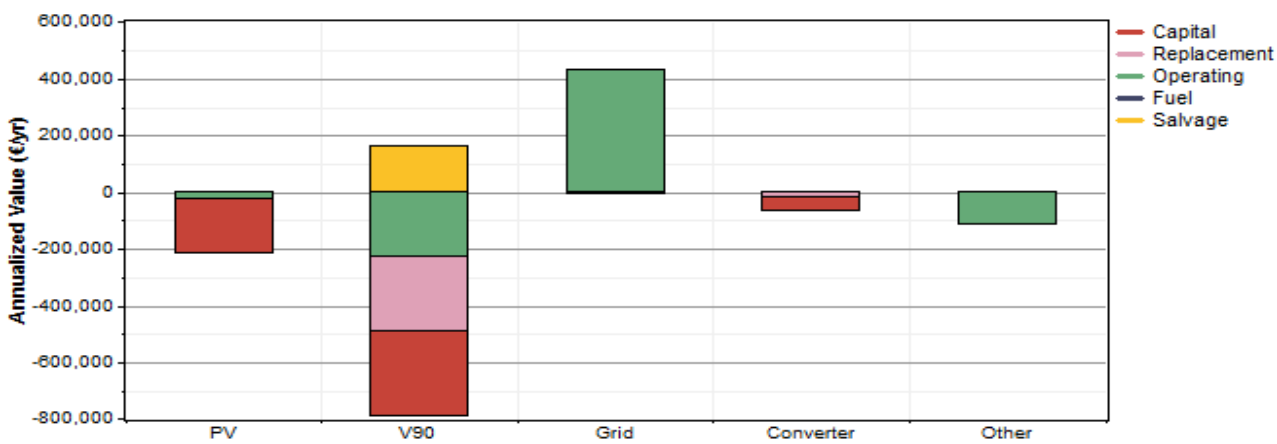


Figure 30. Annualized costs by system component and category for the system with the lowest COE (5.6MWp + 4 wind turbines + flexible demand); Note: "Other" relates to the annual grid-connection fee of €110,000 per year; the costs for the PV panels & converter are also split here.

System designs with 3 wind turbines combined with 2.8MWp or 5.6MWp Solar PV (without battery storage) have a COE between 0.030-0.036 €/kWh, which is 60% less than the current base case COE. This is also due to the onsite consumption and 5.2-6.5 GWh/year of grid sell-back. System configurations that do have VRB battery storage have a COE ranging from 0.036 – 0.097 €/kWh depending on the size of storage. Larger battery storage combined with fewer wind turbines results in a higher COE since there is less excess low cost renewable electricity production that can be stored and used at a later time instead of importing from the grid. Refer to Appendix F for a breakdown of the cost cash flows for the chosen scenarios.

Stand-alone system configurations have a minimum COE of 0.094 €/kWh for a 94% renewable design with maximum renewable production (5.6MWp Solar PV + 4 wind turbines) and the mid-sized battery storage option (2MW/45MWh VRB) with demand response. If storage is increased to the largest option (3MW/60MWh), the COE increases by 10 cents to 0.104 €/kWh since the high investment costs for the additional storage are still greater than the fuel cost saved by decreasing diesel generation by 27%. System designs without solar PV and only wind turbines have the highest COE, starting at 0.124 €/kWh or higher if the number of wind turbines in the system decreases causing the amount of diesel power generation to increase. Therefore, a solar-wind system combination is also optimal from a COE perspective since adding solar PV production minimizes the need for diesel generation. Figure 31 shows the cost breakdown for the least cost system design. Wind turbines and VRB storage represent nearly 80% of capital and replacement costs; however diesel costs represent 63% of fuel and O&M costs. Ultimately, the least cost system is the one that minimizes diesel generation, yet has storage that is not too large.

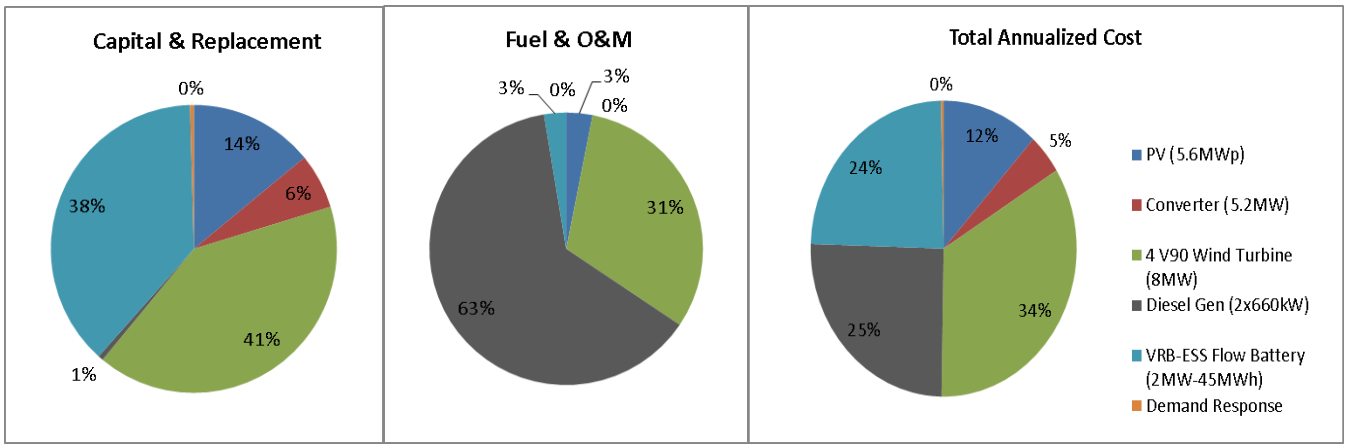


Figure 31. Cost Summary for the least cost stand-alone system design (5.6 MWp + 4 wind turbine + 1.32 MW Generator + 2MW/45MWh VRB storage+DR)

NPV & PBP

The most profitable system is the configuration with maximum RE production and flexible demand (5.6MWp Solar PV – 4 wind turbines-DR) with an NPV of €12.7 million and a discounted PBP of 7.2 years, as seen in Figure 32 below, which compares all NPV's and PBP's for the modelled grid-connected (GC) and stand-alone (SA) microgrid cases.

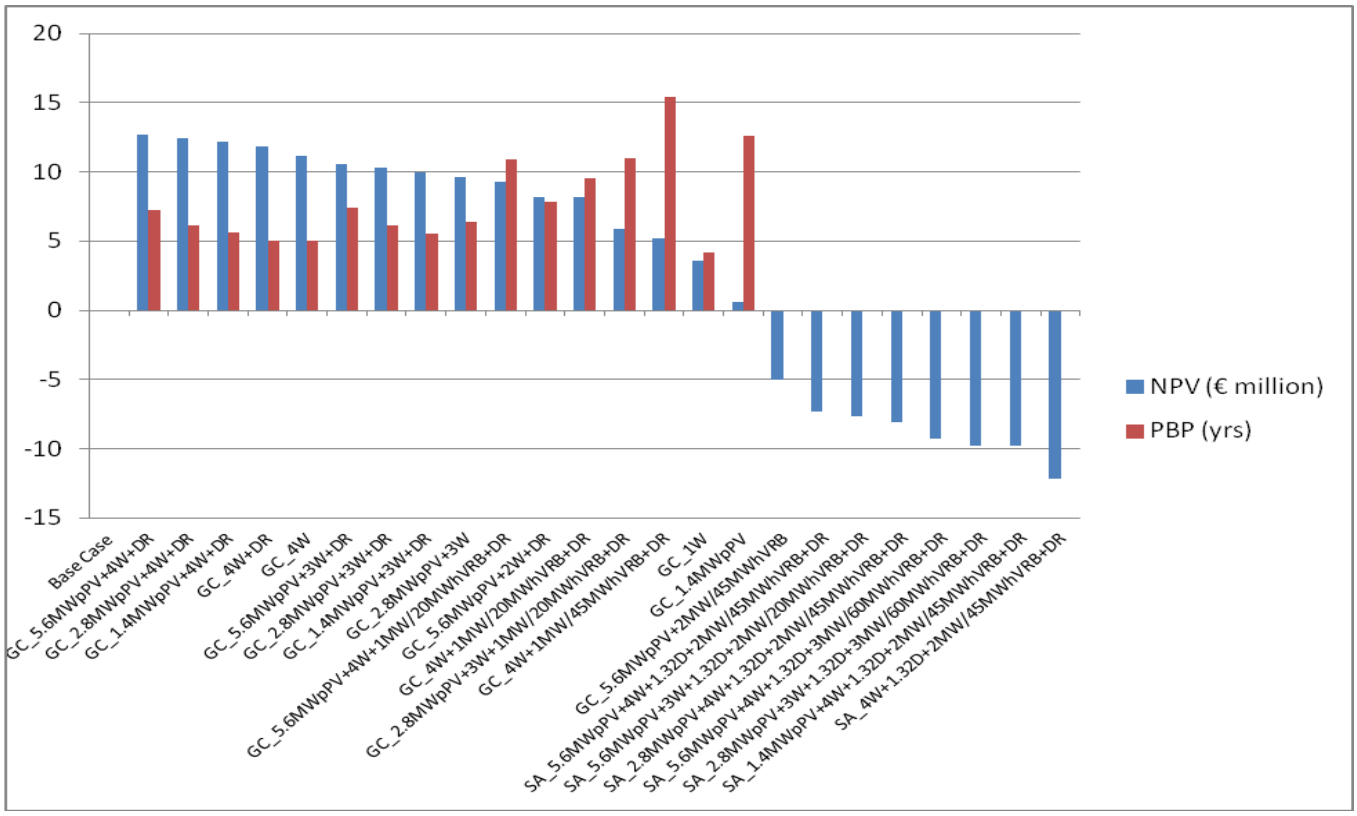


Figure 32. Summary of NPV's and PBP's for grid-connected and stand-alone microgrid configurations. Stand-alone PBP are not applicable because NPV's are negative so they will never be paid back

With every 50% decrease in solar PV capacity, NPV decreases by about 2%. A 4 wind turbine (8MW) only system has an NPV of €11.8 million, which is 7% lower than the maximum RE system containing 5.6MWp Solar PV. However, this wind only system has a slightly shorter discounted PBP of 5 years. Compared to a wind only configuration without flexible demand, the system with flexible demand has a 5% higher NPV (€11.8 versus €11.2 million). This is because a 4 wind turbine system with flexible demand can meet 82% of the electricity demand versus 74% met by a 4 wind turbine system without flexible demand wind turbine system by shifting 29% of normal annual demand to times of RE production and pumping 0.5 GWh extra per year with excess RE production. By meeting 82% of the demand immediately onsite instead of selling back to the grid, this system gains about €300,000 per year by avoiding transport and energy taxes. At an estimated €96,000 capital investment for communication and control software to make onsite consumption and flexible demand possible, this would be paid back within 1 year.

The most profitable grid-connected system design containing battery storage is a configuration of 4 wind turbines combined with 1MW/20MWh VRB battery storage. This system has an NPV of €8.2 million and a PBP of 9.5 years. Doubling the storage to 1MW/45MWh decreases the NPV by €3 million and increases the PBP by nearly 6 years to 15.4 years. Combining maximum solar PV capacity (5.6 MWp) with the same large storage capacity (without wind turbines) is the least profitable system that actually loses money. This is due to the fact that solar PV alone does not produce enough excess electricity to pay off that additional investment costs for such a large battery storage unit.

For stand-alone scenarios, there are no cases which are profitable. This is due to the large amount of storage required and use of diesel fuel, which are both more expensive than importing electricity from the grid. The least

cost system that meets sufficient load has an NPV of €-7.3 million and would require the maximum solar PV (5.6MWp) and wind turbine (4) combination, combined with 2MW/45MWh VRB storage in order to be technically feasible and to minimize the diesel fuel consumption. The system configuration that loses the least amount of renewable electricity (2.8MWp + 3 wind turbines + 1.32 MW diesel generation + 3MW/60MWh VRB) has an NPV of €-9.8 million, yet loses 4.4 GWh less of renewable electricity than the least cost stand-alone system with oversized RE capacity. Therefore, the trade-off for losing less excess electricity is significantly higher costs from diesel generation in order to supplement smaller RE supply.

6.3 Future 2018 Economic Potentials

This chapter discusses the 2018 economic potentials, which include investment cost decreases and increased electricity and fuel costs, yet exclude any regulatory support. Figure 33 below compares the 2018 base case COE to the COE of the chosen grid-connected and stand-alone microgrid cases while Figure 34 compares the NPV's and PBP's for them.

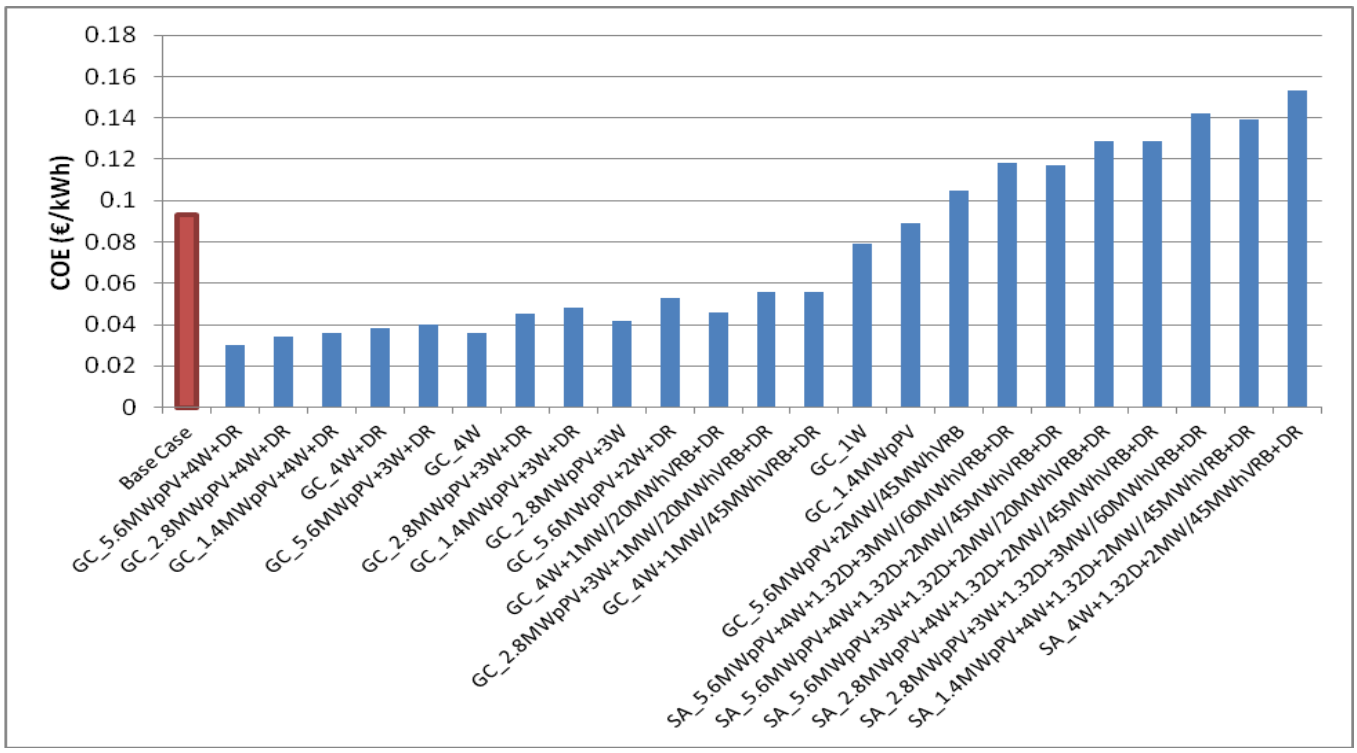


Figure 33. Summary comparing 2018 base case COE (red) to the COE of modelled microgrid cases

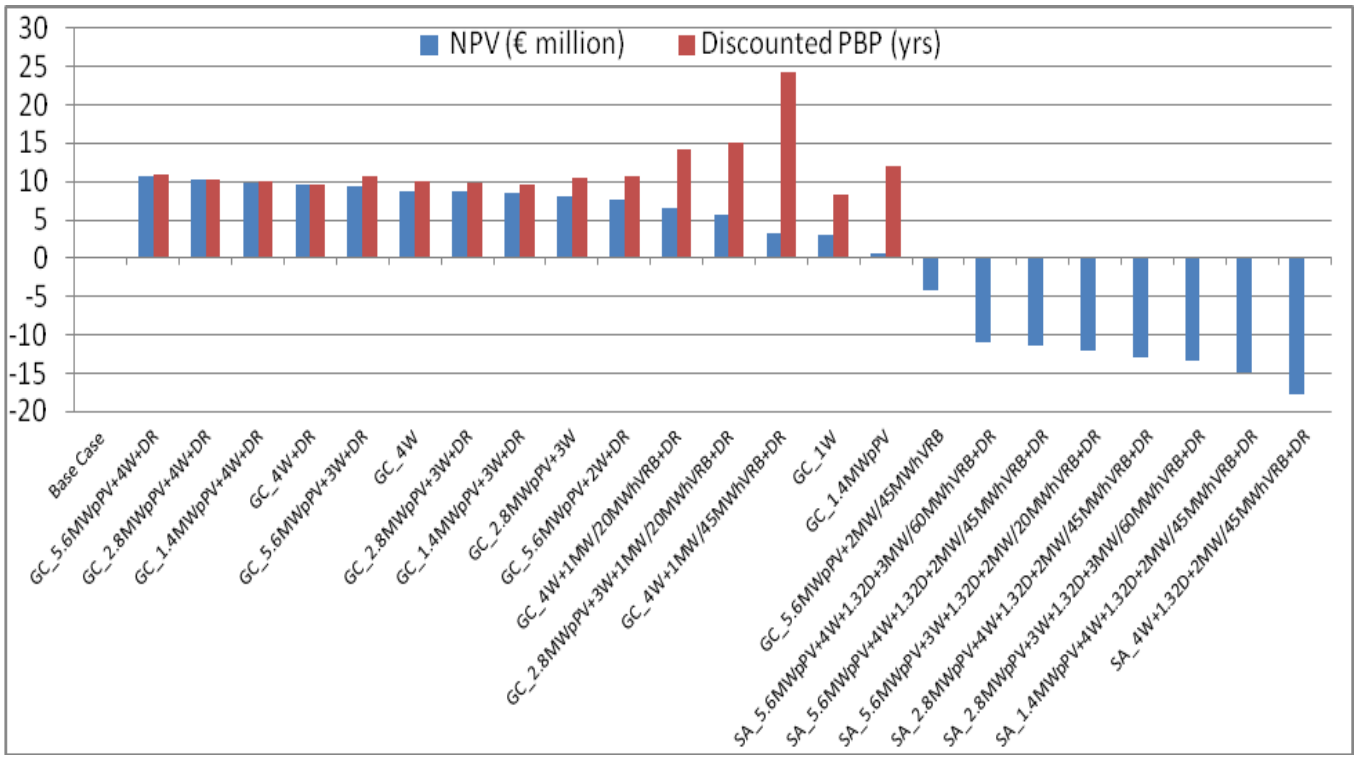


Figure 34. Summary comparing 2018 NPV's and PBP's of chosen grid-connected and stand-alone microgrid cases.

COE

At a 4.5% annual increase in electricity prices, the COE of the base case grid-only system is 0.093 €/kWh. System configurations containing 4 wind turbines without battery storage have a COE ranging from 0.030-0.038 €/kWh. This is 59-68% cheaper than the base case, which is similar to the current 2013 advantage in COE compared to the current base case. Adding 1MW/20MWh storage to a 4 wind turbine system increases the COE to 0.046 €/kWh, and doubling storage capacity to 1MW/45MWh increases the COE to 0.056 €/kWh. This is still 40-50% less expensive than purchasing all power demand from the main grid. Systems with 3 turbines combined with solar and/or battery storage have a similar range in COE. This significant advantage is due to the high percentage of load that is met by renewable electricity.

Stand-alone systems are still more expensive than the grid-connected base case, with COE beginning at 0.118 – 0.153 €/kWh. This is due the fact that diesel fuel prices are expected to increase faster than electricity prices so well-designed grid-connected systems will normally be more profitable than stand-alone systems.

NPV & PBP

The most profitable system configuration is still the 5.6MWp Solar PV – 4 turbine configuration, which has an NPV of €10.7 million, which is €2 million less than 2013, and a discounted PBP of 11 years, which is nearly 4 years longer than 2013 economic potentials. This is because the decrease in investment costs by 2018 are not as significant as the EIA & SDE+ benefits received today in 2013. This causes the economic potential of all scenarios (NPV) to decrease by about €1-2 million and discounted PBP's to increase by 3-5 years.

In stand-alone systems, all systems still have negative NPV's if initial investment is in 2018. Since the drop in investment costs is not enough to outweigh the increase in diesel fuel prices, stand-alone systems are not profitable. However, the least cost microgrid becomes the system with maximum RE production (5.6MWp solar PV-4 wind turbines) combined with diesel generation, flexible demand (DR), and the largest storage capacity (3MW/60MWh VRB) since battery storage becomes slightly cheaper.

6.4 Summary of Current and Future Techno-Economic Potentials

Table 23 & 24 list the summarized details from Figures 17 and 18, which are extracted system configurations from the long list of overall complete realizable configurations. These system designs were chosen based on lowest cost and contribution of renewable sources to meet the load in the realizable set-ups. Models without a deferrable (flex) load are also listed for comparison purposes (highlighted in yellow). Grid-connected systems with flexible demand are highlighted in green, and stand-alone systems with flexible demand are highlighted in orange. Table 25 lists the 2018 economic potentials for the chosen grid-connect and standalone microgrid cases.

Table 23. Extracted system designs from overall optimization results for the current grid-connected models ordered by NPV (€million) (yellow = no flexible demand + onsite consumption; green = flexible demand + onsite consumption)

Microgrid System Design							Technical Potentials						2013 Economic Potentials		
Grid	PV	V90	Gen (2)	Converter	VRB-ESS Battery Power	VRB-ESS Battery Storage	Total Annual RE Prod.	Total Ann. Load Served	Annual Grid Purch.	RE % of onsite load	Annual Grid Sales	Annual Battery Thruput	COE	NPV	Discounted PBP
Y/N	MWp	#	MW	MW	MW	MWh	GWh/yr	GWh/yr	GWh/yr	%	GWh/yr	GWh/yr	€/kWh	€ million	years
Y	Base Case						-	16,7	16.7	0%	-	-	€0.082	-	0
Y	5.6	4	-	5.2	-	-	25.6	18.8	3.5	88%	10.2	-	€0.020	€12.7	7.2
Y	2.8	4	-	2.5	-	-	22.9	18.1	3.8	86%	8.6	-	€0.023	€12.4	6.1
Y	1.4	4	-	1.3	-	-	21.5	17.7	4.1	84%	7.9	-	€0.024	€12.2	5.6
Y	-	4	-	-	-	-	20.2	17.3	4.5	82%	7.4	-	€ 0.026	€11.8	5
Y	-	4	-	-	-	-	20.2	16.7	7.3	74%	10.7	-	€0.025	€11.2	5.05
Y	5.6	3	-	5.2	-	-	20.5	17.7	3.9	84%	6.6	-	€0.030	€10.6	7.4
Y	2.8	3	-	2.5	-	-	17.8	16.7	4.2	81%	5.2	-	€0.034	€10.3	6.1
Y	1.4	3	-	1.3	-	-	16.5	16.7	4.7	78%	4.4	-	€ 0.036	€10.0	5.5
Y	2.8	3	-	2.5	-	-	17.8	16.7	7.0	72%	8.0	-	€0.032	€9.6	6.4
	5.6	4	-	5.2	1	20	25.6	19.0	2.9	90%	8.8	2.4	€0.029	€9.3	10.9
Y	5.6	2	-	5.2	-	-	15.5	16.7	5.0	76%	3.6	-	€0.043	€8.2	7.8
Y	-	4	-	1.3	1	20	20.2	17.7	4.0	83%	6.1	1.7	€0.036	€8.2	9.5
Y	2.8	3	-	2.5	1	20	17.8	17.1	3.7	82%	4.0	1.6	€0.045	€6.9	11
Y	-	4	-	1.3	1	45	20.2	17.7	4.0	83%	6.0	1.8	€0.044	€5.2	15.4
Y	-	1	-	-	-	-	5.0	16.7	12.0	30%	0.3	-	€ 0.068	€3.6	4.2
Y	1.4	-	-	1.3	-	-	1.3	16.7	15.4	8%	0	-	€ 0.080	€0.6	12.6
Y	5.6	-	-	5.2	2	45	5.6	16.7	12.1	31%	0.1	0.7	€0.097	€-5.0	n/a

Table 24. Extracted system designs from overall optimization results for the current stand-alone models ordered by NPV (€million)

Microgrid System Design							Technical Potentials						2013 Economic Potentials		
Grid	PV	Converter	V90	Gen (2)	VRB-ESS Battery Power	VRB-ESS Battery Storage	Total Annual RE Prod.	Annual Generator Prod.	Total Ann. Load Served	RE % of Load	Ann. Excess Electricity	Annual Battery Throughput	COE	NPV	Discounted PBP
Y/N	MWp	MW	#	MW	MW	MWh	GWh/yr	GWh/yr	GWh/yr	%	GWh/yr	GWh/yr	€/kWh	€ million	years
N	5.6	5.2	4	1.32	2	45	25.6	1.1	18.8	94%	7.1	2.8	€0.094	€ -7.3	n/a
N	5.6	5.2	3	1.32	2	20	20.5	1.9	17.6	89%	4.2	2.2	€0.106	€ -7.7	n/a
N	2.8	2.5	4	1.32	2	45	22.9	1.5	17.6	91%	5.7	2.6	€0.105	€ -8.1	n/a
N	5.6	5.2	4	1.32	3	60	25.6	0.8	18.9	96%	6.6	3.2	€0.104	€ -9.3	n/a
N	2.8	2.5	3	1.32	3	60	17.8	1.8	16.7	89%	2.2	2.7	€0.120	€ -9.8	n/a
N	1.4	2.5	4	1.32	2	45	21.5	1.9	17.6	89%	5.1	2.5	€0.113	€ -9.8	n/a
N	-	2.5	4	1.32	2	45	20.2	2.4	17.2	86%	4.7	2.3	€0.124	€ -12.2	n/a

Table 25. Summary of 2018 COE, NPV, and discounted PBP for chosen scenarios ordered by NPV from largest to smallest

Microgrid System Configuration							2018 Economic Potentials		
Grid	PV	V90	Gen (2)	Converter	VRB-ESS Battery Power	VRB-ESS Battery Storage	COE	NPV	Discounted PBP
	MWp	#	MW	MW	MW	MWh	€/kWh	€ million	years
2018 Base Case		-	-	-	-	-	0.093		-
Y	5.6	4	-	5.2	-	-	0.030	10.7	11
Y	2.8	4	-	2.5	-	-	0.034	10.2	10.3
Y	1.4	4	-	1.3	-	-	0.036	9.9	10
Y	-	4	-	-	-	-	0.038	9.5	9.7
Y	5.6	3	-	5.2	-	-	0.04	9.3	10.7
Y	-	4	-	-	-	-	0.036	8.8	10
Y	2.8	3	-	2.5	-	-	0.045	8.8	9.9
Y	1.4	3	-	1.3	-	-	0.048	8.4	9.6
Y	2.8	3	-	2.5	-	-	0.042	8.0	10.4
Y	5.6	2	-	5.2	-	-	0.053	7.6	10.6
Y	-	4	-	1.3	1	20	0.046	6.6	14.1
Y	2.8	3	-	2.5	1	20	0.056	5.6	15
Y	-	4	-	1.3	1	45	0.056	3.2	24.3
Y	-	1	-	-	-	-	0.079	3.1	8.25
Y	1.4	-	-	1.3	-	-	0.089	0.7	11.9
Y	5.6	-	-	5.2	2	45	0.105	-4.2	n/a
N	5.6	4	1.32	5.2	3	60	0.118	-11.0	n/a
N	5.6	4	1.32	5.2	2	45	0.119	-11.3	n/a
N	5.6	3	1.32	5.2	2	20	0.129	-12.1	n/a
N	2.8	4	1.32	2.5	2	45	0.129	-12.9	n/a
N	2.8	3	1.32	2.5	3	60	0.142	-13.4	n/a
N	1.4	4	1.32	2.5	2	45	0.139	-15.0	n/a
N	-	4	1.32	2.5	2	45	0.153	-17.8	n/a

The results confirm that there is a high production potential for wind power and a relatively moderate production potential for solar PV power at this location in the middle of the Netherlands. With these significant combined potentials for renewable electricity production onsite, there are a multitude of system designs that can make the DWP-NWG greater than 70% self-sufficient from renewable electricity. Assuming that the space needed for the solar PV arrays has to be increased by a factor of 2 to prevent them for casting shade on each other and assuming the shadow cast by adding a 4th turbine would significantly influence the solar PV power production, the maximum fraction of onsite demand that can be met by renewable electricity ranges from 72-83% depending on the combined solar PV, wind, and battery capacity. In grid-connected microgrid cases, there are multiple microgrid configurations and sizes that can achieve this, which are cost-effective and even quite profitable both with current financial support from the EIA & SDE+, and even in 5 years if no financial support is available. However, if the sizing assumptions and negative interactions can be avoided, up to 96% of the onsite power demand can be met by

renewable electricity with maximum solar PV capacity (5.6MWp), maximum wind capacity (4 wind turbines of 8 MW), and large VRB flow battery storage of 3MW-60MWh combined with flexible demand (DR).

The results indicate even with these high RE production potentials, a 100% renewable system without grid imports or diesel generation would require significantly larger storage, which is already cost-***ineffective***, as seen in the non-profitable stand-alone cases. However, as long as there is grid-connection to sell back excess renewable electricity, microgrid configurations with moderately sized battery storage can still be cost-effective and profitable, although not necessary. The significantly higher wind potential for this area indicates that wind turbines should definitely be part of the energy mix. The solar PV potential is also substantial and creates a more balanced power supply onsite when combined with wind power. Therefore, a solar PV- wind turbine power production combination is optimal in this area and is the most cost-effective as long as there is grid-connection and sell-back to the grid.

2013 vs. 2018. The results show that in both current and future investment scenarios, there are many profitable grid-connected cases, yet stand-alone cases remain unprofitable since excess electricity is lost rather than traded with the main grid. However, if investment is postponed to 2018 and the financial support from the EIA and SDE+ are not available as they are in 2013, the value of all cases decreases since the anticipated decrease in investment costs does not outweigh the substantial SDE+ support currently available, particularly for wind. Nonetheless, grid-connected cases are still profitable in both current and future cases due to the significant net benefit from avoiding transport and energy taxes from the main grid by consuming upwards of 70% of renewable electricity onsite and selling the excess electricity back to the grid.

6.5 Sensitivity Analysis

By modelling a variety of scenarios with different mixes of renewable component sizes, storage, diesel generation, and flexible demand (DR), the uncertainties around the technical potentials of meeting onsite demand with renewable electricity have been explored. However, due to the complexity of a microgrid and the multitude of integrated components, there are a number of major variables which are still uncertain and can influence the main economic potentials of this research (NPV & PBP). Therefore, a sensitivity analysis is performed and discussed in this chapter for the following parameters: electricity prices, discount rate, sell-back rate, technology lifetimes, 2018 investment costs and fuel prices, and EIA/SDE+ support in 2018.

Electricity prices. In normal project evaluation for renewable technology investments, electricity prices are typically assumed to increase over the project lifetime. However, since HOMER simulates only one year, it uses a fixed electricity price over the project lifetime. Moreover, the change in future electricity prices is uncertain. Therefore, a sensitivity analysis is done of increasing electricity prices on the NPV and PBP of a 3 wind turbine-2.8MWp solar PV microgrid system.

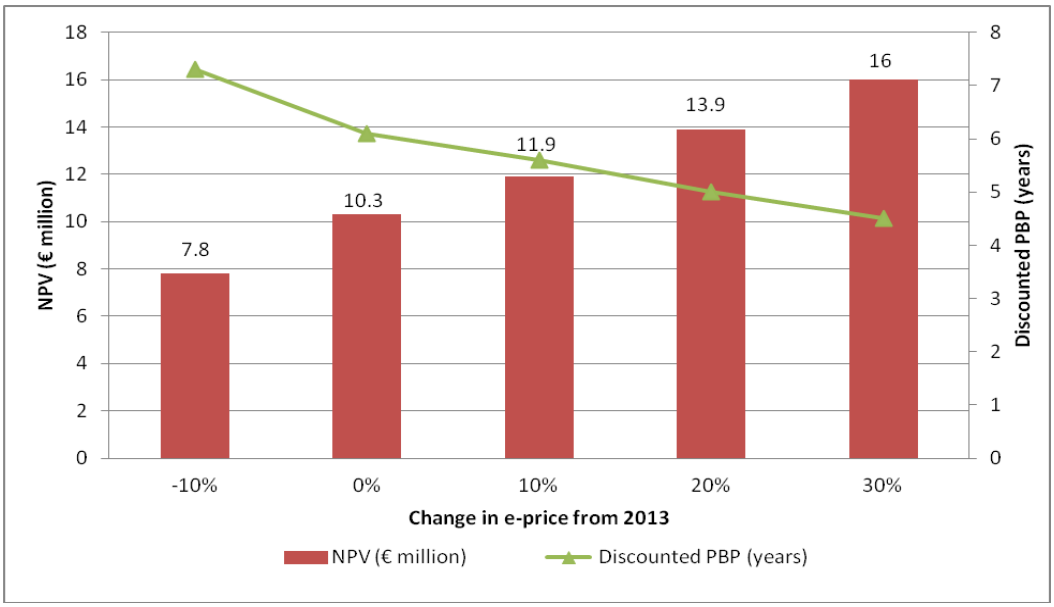


Figure 35. Example of effect of increasing electricity price on the NPV and PBP of a 3 turbine/2.8MW solar PV system

Figure 35 illustrates that if the average electricity prices over the 25 year project period increase by 10% from current prices, NPV's increase by 16% and discounted PBP decreases by 8%. If the average electricity prices over the project lifetime increases by 20%, NPV's increase by 35% and discounted PBP's decrease by 10%. If average electricity prices increase by 30% from current prices, NPV's increase by 55% and discounted PBP decreases 26%. This shows that the economic potentials are moderately to highly sensitive to changes in electricity prices and confirms that as electricity prices increase, investment in renewable energy technologies is more profitable and cost-effective since the avoided costs of using electricity from the grid are greater. Therefore, this should be kept in mind when reviewing and analysing the economic potentials in this research. Ultimately, this sensitivity does not negatively influence the cost-effectiveness of the modelled systems, and only underscores the profitability of a microgrid at the DWP-NWG.

Discount Rate. The discount rate is assumed to be the cost of capital, which is currently 5.6%. However, the method of financing, and in turn the cost of capital, is uncertain for such large projects at a public organization where renewable energy investments are not part of the core business. Therefore a sensitivity analysis is done on the discount rate. Figure 36 below indicates that for every 2% change in discount rate, NPV changes by about 29% and discounted PBP changes by about 9%.

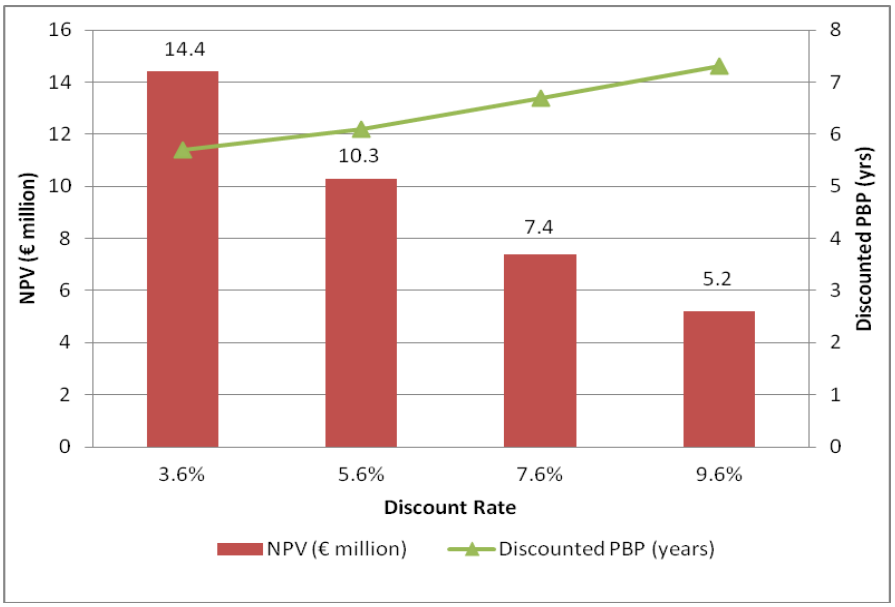


Figure 36. The effect of a increasing discount rate on NPV and discounted PBP for a 2.8MWp-3 wind turbine system configuration

This shows that economic potentials are highly sensitive to small changes in discount rate, so this should be kept in mind. However, even if discount rates are much higher than expected, there are multiple system configurations which are still cost-effective and profitable.

Sell-back electricity prices. Currently, the contracted sell-back price for renewable electricity is equal to the respective peak and off-peak electricity delivery price, which is about 70% of the full electricity price. However, as more renewable electricity is implemented and produced in the Netherlands in order to meet the 2020 Climate Goals, there is less certainty that electricity companies will be willing to pay the same price as delivery for the extra power supply. This means that as electricity prices rise in the future, there is no guarantee that sell-back rates will also rise, or even stay the same. Therefore, a sensitivity analysis is done on the change in margin between buy-in and sell-back rates by assuming 10% changes in buy-in electricity price and corresponding 20% changes in sell-back prices, which makes buying electricity more expensive, yet selling excess renewable electricity less attractive (summarized in Table 26).

Table 26. Summary of simulated electricity price changes for buying electricity versus selling back to the grid to see what the effect is of decreasing sell-back rates while buy-in rates increase. The current situation is bolded: 70% sell-back price of full buy-in electricity price

Change in Buy-in electricity price	-10%	**0%**	10%	20%	30%	40%
Change in Sell-back electricity price	20%	**0%**	-20%	-40%	-60%	-80%
Respective Peak Sell-back Rate (€/kWh)	0.07583	**0.06426**	0.05012	0.03727	0.02442	0.01157
% Sell-back price of full Buy-in electricity price	100%	**70%**	54%	37%	22%	10%

Table 27 summarizes the effect of an increasing margin between buy-in and sell-back electricity prices on NPV and discounted PBP for a 2.8MWp solar PV – 3 wind turbine – DR system (5.2 GWh grid sell-back per year), and Figure

32 illustrates the increasing trend in NPV and the additional annual benefit from implementing a flexible demand if the sell-back rate decreases relative to the full electricity prices.

Table 27. Summary of NPV, discounted PBP, and additional annual benefit from flexible demand (DR) for a 2.8MWp solar PV – 3 wind turbine with flexible demand system

Sell-back price relative to buy-in	NPV (€ million)	Discounted PBP (years)	Annual Benefit from DR
100%	9.3	6.6	5,800
70%	10.3	6.1	58,996
54%	10.5	6	109,832
37%	11.1	5.8	161,847
22%	11.6	5.7	213,863
10%	12.3	5.4	265,878

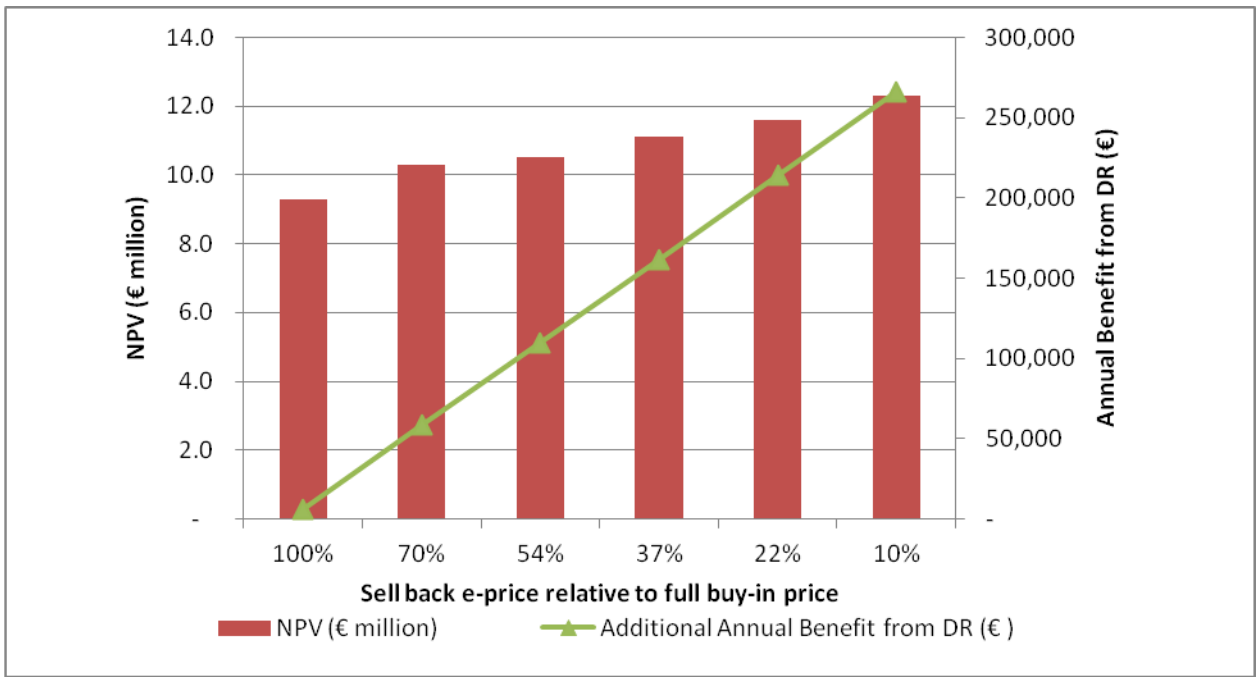


Figure 37.The effect of a changing margin between buy-in and sell-back electricity prices on NPV and discounted PBP for a 2.8MWp-3 wind turbine with flexible demand system configuration

For every 10% increase in electricity price combined with a 20% decrease in sell-back price, the NPV increases by about 6% and discounted PBP decreases by 3%. This increase in NPV is due to the significant increase in benefits (€'s saved) of consuming the renewable energy onsite, which outweighs the decrease in benefits from selling excess electricity back to the grid. This is also seen via the additional benefits of flexible demand, which increase if buy-in electricity prices increase and sell-back rates decrease. This indicates the economic results are only slightly sensitive to changes in sell-back rates relative to inverse changes in electricity prices so the effect on overall cost-effectiveness of a microgrid system is insignificant. However, it should be noted that for the largest capacity microgrid cases with significantly more grid-sales (greater than 5.2 GWh/year), the additional financial advantage from onsite consumption barely balances out the disadvantage of selling back to the grid at very low sell-back rates.

Component Lifetimes. Although lifetime assumptions were made based on manufacturer technical information, there is no guarantee that technologies will last as long as the manufacturer lifetimes. Due to this uncertainty, a sensitivity analysis is done on the lifetimes of the microgrid technology components in scenarios by adding and subtracting 5 years from the intended lifetime. In HOMER, the lifetimes of VRB flow batteries are fixed since they are quite certain and electrolyte storage has a lifetime greater than 100 years so these are excluded from the scenarios.

Running the case models under these lifetime scenarios still resulted in an optimal least cost configuration of a grid-connected PV/Wind/DR system without battery storage. Figure 38 below illustrates the effect of shorter and longer component lifetimes on the NPV and discounted PBP. If all variable component lifetimes are 5 years shorter, NPV's decrease by 20%. If variable component lifetimes are 5 years longer, then NPV's increase by 13%. Since all lifetime scenarios are very profitable and the discounted PBP is shorter than 10 years, the discounted PBP does not change if lifetimes are shorter or longer by 5 years.

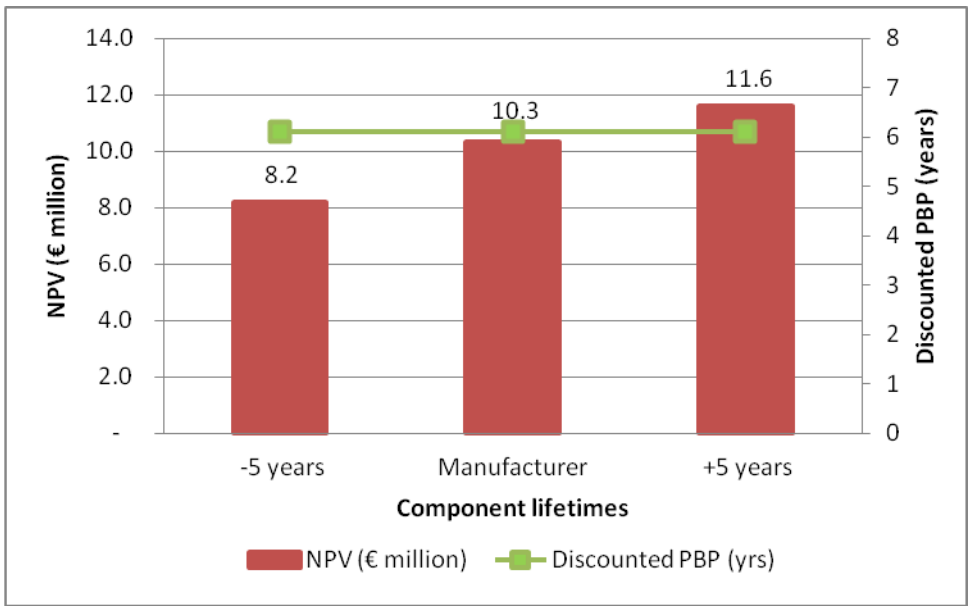


Figure 38. Effect of changing component lifetimes by +/- 5 years from manufacturer intended lifetimes on NPV and PBP of a 2.8MWp solar PV + 3 wind turbine + DR grid-connected microgrid configuration

This slight sensitivity to different component lifetimes indicates that their effect on the economic potentials is insignificant. Overall, the all grid-connected case scenarios remain cost-effective and stand-alone scenarios are not cost-effective.

EIA & SDE+ Support in 2018. Although it is not certain that the EIA tax incentive and SDE+ subsidy will be available in 2018, there is a high chance that regulatory support will exist in order to achieve the Dutch 2020 goals of achieving 16% renewable energy. Moreover, while the EIA tax incentive is guaranteed, the chance of getting the SDE+ subsidy is not so certain since the annual budget is limited and there is significant competition from many other renewable energy projects, including those for heat like CHP, which are currently much more cost effective. Since there is a chance that no SDE+ subsidy is received for solar and/or wind production, a sensitivity analysis is done to see the implications on costs and optimal system design in 2018, using the same EIA and SDE+ support assumptions from today (2013).

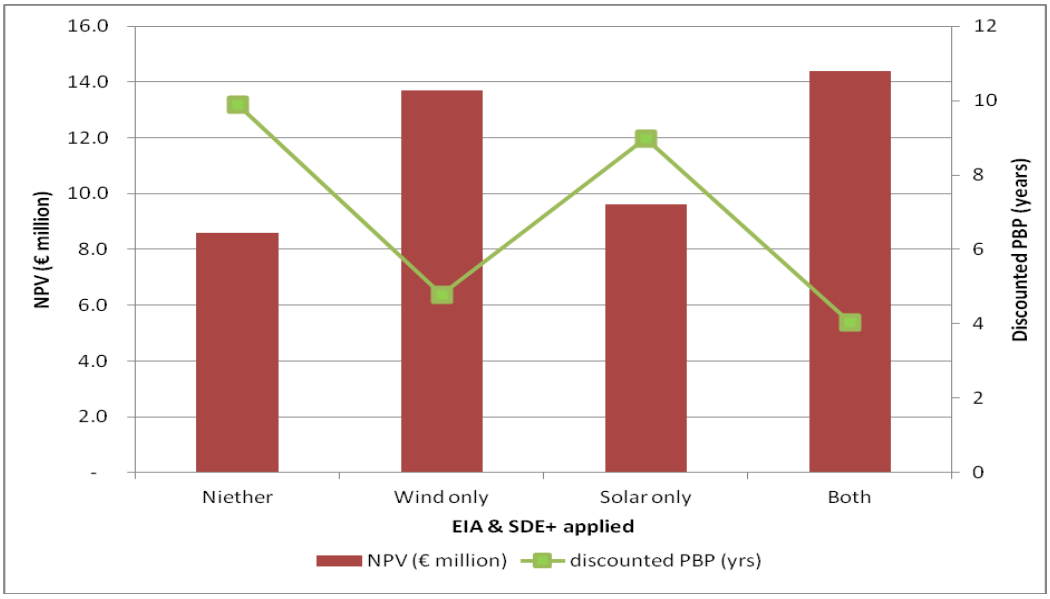


Figure 39. Example of effect of regulatory support on NPV and discounted PBP on a 2.8MWp + 3 wind turbine system configuration

The results of running the future scenarios again with different combinations of support for solar and/or wind (neither, wind only, solar only, & both) results indicate that the optimal least cost system combination will always be a grid connected PV/Wind/DR configuration without battery storage whether or not there is regulatory support. Figure 39 above and table 28 below summarize the effect on NPV and discounted PBP for a 2.8 MWp solar PV – 3 wind turbine system configuration under different financial support scenarios.

Table 28. Example of effect of regulatory support on NPV and discounted PBP on a 2.8MWp + 3 wind turbine + DR system configuration

Financial Support Applied	NPV (million)	Discounted PBP (yrs)
Neither	€ 8.6	9.9
Wind only	€ 13.7	4.8
Solar only	€ 9.6	9.0
Both	€ 14.4	4.0

If financial support remains the same as today (with the lowest SDE+ subsidy phase assumed for both wind and solar), the 2018 NPV of the system nearly doubles to €14.4 million and the discounted PBP decreases by over 50% to 4 years. It should be kept in mind that if the SDE+ subsidy increases by 2018 for the first phase and/or is granted in later phases, these economic potentials can be substantially higher. Although the 2018 economic results are relatively sensitive to adding financial support for solar and/or wind production, the results show that even without financial support applied, a grid-connected PV/Wind/DR system combination is profitable in 2018 with an acceptable payback period.

Future Investment Costs

Grid-Connected & Change in Electricity Prices. Assumptions were made for the development of investment costs for the major microgrid components and fuel prices by 2018. Since future developments are naturally uncertain, a sensitivity analysis is necessary. In addition to the anticipated scenarios discussed in the results chapter, 4 more scenarios are tested: worst case, pessimistic, optimistic, and best case. In the worst case, wind investment costs could potentially increase and the other technology investment costs will barely decrease relative to 2013 costs. In the best case scenario, wind costs will decrease by a maximum of 6% per year, PV system costs will decrease by 40% by 2018, VRB battery cell stack will decrease by 23% by 2018, and VRB electrolyte storage will decrease by 6% by 2018. These cost assumptions are discussed in the previous cost chapters for each technology. Table 29 below summarizes the cost decrease assumptions and capital multipliers used in HOMER (in [brackets]) relative to the anticipated case for the worst case, pessimistic, anticipated, optimistic, and best case scenarios.

Table 29. Summary of future 2018 investment cost assumptions and respective capital multipliers used in HOMER (in [brackets]) relative to anticipated costs for the worst case, pessimistic, anticipated, optimistic, and best case scenarios

	Worst Case	Pessimistic	Anticipated	Optimistic	Best Case
		% decrease [capital multiplier used in HOMER]			
Wind invest./replace./O&M (per year)	+3.5% [1.41]	-2.5% [1.05]	-3.5% [1.0]	-4.5% [0.95]	-6.0% [0.88]
PV System incl. converter (by 2018)	-5% [1.19]	-10% [1.13]	-20% [1.0]	-30% [0.88]	-40% [0.75]
VRB cell stack (by 2018)	-2% [1.13]	-7% [1.07]	-13% [1.0]	-18% [0.94]	-23% [0.89]
VRB electrolyte storage	-2% [1.02]	-3% [1.01]	-4% [1.0]	-5% [0.99]	-6% [0.98]

These future scenarios are each run at a 3%, 4.5% (historical average), 6%, and 7.5% annual increase in electricity prices since the development of electricity prices is also uncertain over the next 5 years. In all future case scenarios, the lowest cost microgrid combination remains a grid-connected PV/Wind/DR system without battery storage. Table 30 below summarizes the results of the sensitivity analysis for a 2.8MWp + 3 wind turbine + DR system configuration.

Table 30. Summary of future cost scenarios on NPV and discounted PBP for a 2.8 MWp + 3 wind turbine microgrid + DR system configuration

	Percent increase in annual e-price by 2018							
	3%		**4.50%**		6%		7.50%	
	NPV	PBP	**NPV**	**PBP**	NPV	PBP	NPV	PBP
	(€ million)	(years)	**(€ million)**	**(years)**	(€ million)	(years)	(€ million)	(years)
Best Case	9.2	8.9	**10.8**	**8.1**	12.5	7.4	14.4	6.7
Optimum	8	10	**9.7**	**9.1**	11.4	8.3	13.2	7.5
Anticipated	7.2	11	**8.8**	**9.9**	10.5	9	12.4	8.2
Pessimistic	6.4	12	**8**	**10.8**	9.6	9.8	11.6	8.9
Worst Case	2	17.9	**3.6**	**15.8**	5.3	14	7.2	12.5

Relative to the anticipated case at an average 4.5% annual increase in electricity prices, the best case NPV is 23% higher (€10.8 versus €8.8 million), and worst case NPV is 72% lower (€2 versus €7.2 million). Conversely, the best case PBP is 18% shorter (8.1 versus 9.9), and the worse case PBP is 58% longer (15.8 versus 9.9 years).

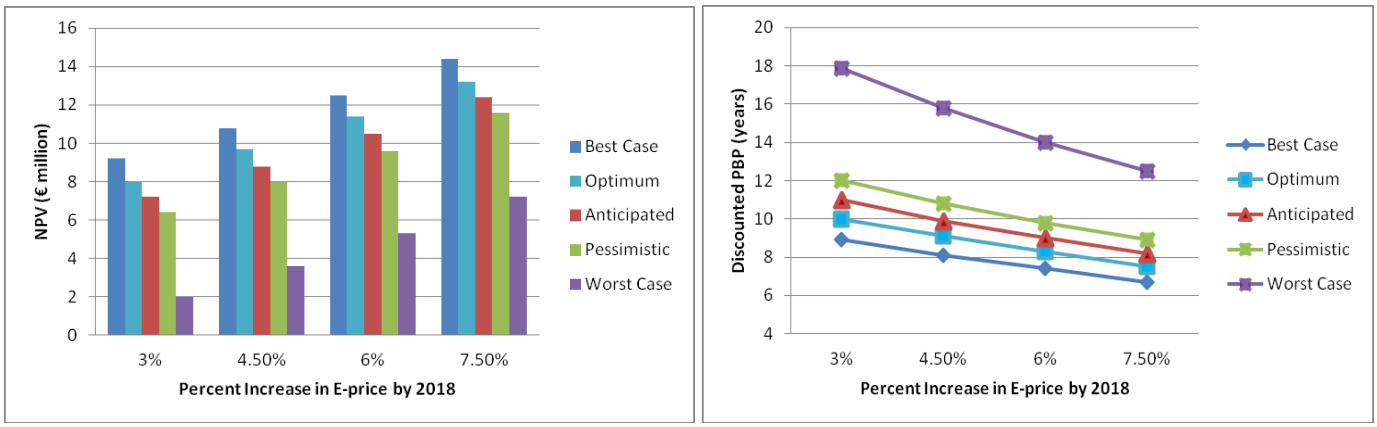


Figure 40. NPV (Left) and discounted PBP (Right) in all future scenarios for a 2.8MWp + 3 wind turbine microgrid

In the pessimistic, optimistic, and best case scenarios, for every 1.5% increase in electricity price, discounted PBP decreases by about 9%, and NPV increases by 16%, 18%, 22% for the best, optimistic, and pessimistic case scenarios, respectively. In the worst case scenario, for every 1.5% increase in electricity price, NPV increases by an average 54% and PBP decreases by an average 11%. This is illustrated in Figure 40 above. These results indicate that the economic potentials are moderately to highly sensitive to changes in investment costs and electricity prices by 2018. However, even in the worst case (and least probable) scenario if wind costs increase and solar PV costs only decrease by 10%, a microgrid system configuration with a large wind and solar PV capacity is still cost-effective with a payback period still within the project lifetime, although it's quite long.

Stand Alone and change in diesel fuel prices. The same future investment cost scenarios are run for stand-alone microgrid cases at an 4%, 8%, 12% (anticipated), and 16% diesel fuel price increase every two years to test the effect of the profitably of a stand-alone system if diesel prices increase at a slower or faster rate than expected. Table 31 summarizes the NPV results of the least cost stand-alone system (5.6MWp solar PV + 4 wind turbines + 1.32 MW diesel generators + 3MW/60MWh VRB storage + DR).

Table 31. Summary of NPV in the future 2018 scenarios of investment cost development at a 4%, 8%, 12%, and 16% increase in diesel fuel prices every two years from 2013 for the least cost stand-alone system configuration (5.6MWp solar PV + 4 wind turbines + 1.32 MW diesel generators + MW/60MWh VRB storage + DR)

Increase in diesel fuel price vs. 2013	Best Case	Optimum	Anticipated	Pessimistic	Worst Case
(every two years)	NPV (€ million)				
4%	-6.6	-8.5	-10.0	-11.6	-17.6
8%	-7.1	-9.0	-10.5	-12.1	-18.1
12%	-7.6	-9.5	-11.0	-12.6	-18.6
16%	-8.3	-10.1	-11.6	-13.2	-19.2

In the worst case scenario if diesel prices rise by 16% every two years instead of 12%, the profitability of this least cost stand alone microgrid decreases by about 66% to € -19.2 million. In the best case scenario if diesel fuel prices only rose by 4% every two years, the NPV would increase by nearly €5 million; however, it would result in a negative NPV so this system would still not be profitable. Therefore, significant changes in future investment costs and diesel fuel prices would not change the ultimate cost-effectiveness of stand-alone microgrid configurations. In order to be

potentially cost effective, they would need significant regulatory financial support in order to mitigate investment costs enough to offset even a small increase in diesel fuel prices.

This sensitivity analysis shows that the economic potentials are barely sensitive to changes in component lifetimes and slightly sensitive to changes in sell-back rates. Economic potentials are moderately sensitive to electricity price changes and regulatory support in 2018, and moderately to highly sensitive to changes in future investment costs and electricity prices, and highly sensitive to changes in discount rates. However, overall in the worst or most extreme cases, the economic potentials remain acceptably cost-effective for grid-connected scenarios and not cost-effective for stand-alone scenarios.

7. Discussion

Due to the inherently uncertain nature of modelling and the number of assumptions that need to be made, the validity and reliability of the model need to be discussed. Therefore, this chapter will discuss the input data used to model the microgrid scenarios and limitations of the HOMER modelling software. Ultimately, recommendations for improvement are suggested.

7.1 Model Input Data

Wind speeds, solar irradiation, & temperature. Measured data wind speed, solar irradiation, and temperature for the exact location of the DWP-NWG was not available, which could cause discrepancies in the wind and solar power potential. However, measured data was used from a very nearby location (less than 15km away) with similar wind and solar characteristics to the DWP-NWG, which minimizes these discrepancies. Additionally, solar potential could be more accurate by using hourly measured solar irradiance rather than interpolating from monthly averages. It should also be kept in mind that these inputs and resulting potentials are case specific. If this research would have been done on a case at a more western location with high solar irradiance and high wind speeds, the results would indicate higher RE production potentials with the same amount of space, or less space for similar RE production potential. The opposite would apply for more eastern locations with lower solar irradiance and wind speeds. Various case scenarios with a range of solar PV and wind turbine capacities were discussed in the results to explore these differences. Since potentials can vary by up to 30%, this should be kept in mind. However, this variability does not have a significant impact on the profitability of grid-connected systems since the results indicate the even systems with less wind and solar capacity are profitable.

Technologies. This research modelled specific component technologies using manufacturer data and efficiency/de-rating assumptions based on literature research and case studies. However, if different specific technologies are used (ie. smaller wind turbines or less efficient solar PV panels), the renewable energy potentials could be less. Moreover, the CSUN solar PV manufacturer claims that its PV panel technology has integrated bypass diodes to protect the solar cell circuit from hot spots during partial shading(CSUN, 2012); however, the magnitude of the negative effect of partial shading of the power output of the array is unknown. If the negative effect of partial shading is significant, this can decrease the potentials of cases combining 4 wind turbines with solar PV since the

4th turbine located near Parcel Zuid will cast a moving shadow over the area throughout the day. However, the cases discussed in the results with only 4 wind turbines or with 3 wind turbines combined with solar PV still have a high RE production potential that can supply more than 70% of onsite demand with renewable electricity. Lastly, the sensitivity analysis for changes in assumed technology lifetimes prove even if they are all shorter, the economic results are not significantly affected.

Demand Response (Deferrable Flex Load). Due to time constraints, simplified assumptions were made about the flexibility of energy consumption based on the minimum pumping power and maximum pumping power of the pumps currently located at the DWP-NWG. These limits are within the maximum pressure and flow limits of the transport network because the strongest pumps are not used at the maximum pumping power since it was discovered that it was inefficient to use them and the transport system cannot handle their power. In reality it takes more energy to pump more water in the same hour since there is more resistance in the transport network (Stouten, 2013). Therefore, the implications of pumping at a higher power rating for an extended period should be investigated on the pump efficiency, transport network, water storage, and stability of the environment at the Dunes. This could potentially be done by simulating the transport pumping system and network in Matlab converting the increases in power to increases in water production on an hourly basis, and testing their effects on the water levels and pressure of the system.

Maintenance of pumps was not included in the maximum production estimates since it takes place once every 10 years rather than annually, so this cannot be modelled directly in HOMER which simulates only one year. Moreover, only maintenance on WRK I pumps 4 and 9 , and WRK II pumps 3 and 7 has any impact on the 15600 m^3/h capacity, while maintenance on the other pumps only limits the flexibility of the operation (Braam, 2013). However, over a 25 year project lifetime, this maintenance would need to occur about twice per pump, which would slightly reduce the 15,600 m^3/hour maximum pumping potential and alter the flexibility in power consumption. Since maintenance of pumps needs to occur so infrequently, this is not expected to have a significant impact on results.

There can be potential ecological concerns at the dunes during breeding season (Feb-mid July) over the stability of the nesting ecosystem if water levels change too drastically (Braam, 2013). However, there is currently no agreement about the range of acceptable variability and its effects on the ecosystem so this is not taken into account here. If the water levels in the Dunes do indeed need to be kept stable during nesting season, this makes the pumping system less flexible for 5-6 months out of the year. During this time, the fixed primary load would be greater and the deferrable load would decrease or be close to zero, depending on the stability requirements. This would make the system rely more on grid-purchases during low wind/solar electricity production, which would increase annual operational costs. However, since wind/solar electricity would still be used directly to meet this higher stable load during these 5-6 months, the effect on the results is not expected to be drastic. This is seen in the modelled cases without flexible demand, which can still meet more than 70% of onsite demand with renewable electricity.

During rainy periods, the Dunes naturally take in more water and thus logically require less pumping from DWP-NWG. However, since the pump characteristics limit the deferrable load significantly within the annual storage capacity of the Dunes, the model inherently incorporates the storage capacity available for increased precipitation

levels during rainy season. Therefore, the results would not be significantly affected if the rainy periods were taken into account.

Although this method is quite site specific based on the operating characteristics of the pumps on site, a minimum of 29% flexibility that is established can be safely assumed to be applicable in other industrial water treatment sites that distribute was since these also require either multiple pumps of increasing power ratings or large multi-frequency pumps that can function at different rating. However, this flexibility will also be dependent on specific consumer demands, network constraints, and storage capacities. For example, if the water transport network was more expansive so that the larger pumps could be used at this site, this would increase the flexibility of electricity consumption significantly since this would add another level of pumping.

Technology Costs. The costs assumptions used for wind turbine, solar PV systems, and diesel generators were based on commercially available data as of the writing of this report. However, due to the novelty of VRB Flow batteries there is a wide range of costs since sizing and installation is site dependent so accurate cost data is not readily available. In order to mitigate this, the lower end of average costs were assumed in the range, which should be kept in mind when reviewing the techno-economic potentials of microgrid configurations that include battery storage. Similarly, the costs for demand response communication and control technology are not commercially available and are very case dependent depending on the needs of the site. Although costs assumed for demand response are based on a study in the industry, they can be understated. However, relative to wind and PV costs, DR costs are not as significant and probably would not have a significant impact on the overall results. Lastly, although future cost assumptions were based on literature research and expert advice, the scenario sensitivity analysis of future cost developments indicate that economic potentials are significantly affected by the magnitude of investment cost changes, particularly if investment costs for wind turbines increase in the worst case scenario. This should be kept in mind when evaluating the cost-effectiveness of the modelled system configurations.

7.2 Model Constraints

Electricity Costs, Diesel Fuel Costs, and Sell-Back Rates. One of the main modelling constraints of the HOMER model software is the inability to simulate changing electricity prices, fuel costs, and sell-back rates over the project lifetime, which significantly influences the economic potentials of the different microgrid cases. Although actual contracted electricity prices were used, it would be expected that if electricity prices and sell-back rates rise, the economic potentials would also be greater. This was confirmed by the sensitivity analysis of electricity prices, future diesel costs, and sell-back rates, which showed that the economic potentials are significantly understated in grid-connected cases if prices change and over-estimated for stand-alone cases if diesel fuel costs rise into the future. Therefore, this is very important to keep this in mind when reviewing the results.

Increasing Electricity Demand. Similarly to cost changes, HOMER software does not have the capability to simulate an annual change in electricity demand over the project lifetime since it only simulates one year of supply and demand. Although electricity demand is expected to stay relatively the same around 16.5-17 GWh per year, there is always a chance that the demand for water will increase in the future. This is explored in the model scenarios with deferrable (flex) load which serve a total load greater than 16.7 GWh per year due to the excess electricity production—these models simulate scenarios with greater water production. Since there is such a high potential

for RE to produce so much excess electricity, a small increase in electricity load (<15%) does not have a significant impact on the results.

Regulatory/Financial Support (EIA & SDE+). The modelling software does not have regulatory/financial support input parameters. Since the EIA and SDE+ are available today, this model constraint was resolved by modelling and calculating the NPV of maximum benefits for the EIA and SDE+ over the subsidy's 15 year lifetime, and the subtracting the NPV of financial support from the initial investment costs. Since the SDE+ calculation is dependent on the evolution of the electricity prices and on the actual RE production of the year, the overall SDE+ benefits could potentially be less than the simplified NPV calculation. Nonetheless, this would not have a significant impact on the results because the future grid-connected scenarios discussed in the results, which do not include any tax incentives or subsidies, are still very profitable.

NPV for Scenarios with Deferrable Load (DR). The way that HOMER models deferrable flex load with a load following strategy depends on the capacity size inputs for the renewable electricity production components, which cause the total load served to vary if there is not a lot of RE production versus excess RE production. Since the larger combined solar PV-wind capacities can serve a greater total electricity demand than the normal base case demand, the resulting individual NPV's are not entirely comparable since the demand served is not the same. In order to deal with this, the deferrable load simulated for the grid-connected microgrid case that met a 16.7GWh total demand was exported and then imported as a fixed primary load so that the electricity demand would be comparable. This makes the NPV calculations for larger loads slightly understated since the benefit of consuming the extra load onsite instead of selling back to the grid is not taken into account. However, since the effect is only 1-2% of the total NPV due to the pump limitations and the marginal difference between buying and selling electricity, this has a negligible effect on the overall results.

7.3 Recommendations for Improvement

Based on this model inputs and constraints discussion, the following improvements could make this research better:

- Onsite solar irradiation, wind speed, and temperature data can be measured for 1 year at maximum hourly time steps in order to make the solar and wind potential calculations more accurate for this case.
- This model should be replicated for other Dutch industrial water treatment sites where electricity demand, location wind speeds, solar irradiance, temperatures, and space available are different from the DWP-NWG case, which has average wind speeds, slightly below average solar irradiance for the Netherlands, and a significant amount of space available for RE technologies. A case comparison of the results would allow for better conclusions to be made about the overall Dutch potential for microgrids serving industrial-sized loads.
- Modelling the deferrable load could be more accurate by modelling the water pumping process of the transport pumps in Matlab to see what effect pumping various degrees of water volume over a daily, monthly, and annual timeframe has on the pump efficiency, transport network, and storage buffer at the Dunes. The resulting electricity consumption for acceptable pumping fluctuations would provide more accurate inputs for simulating the deferrable flexible load over a monthly and yearly time frame. The

change in water levels in the Dunes during rainy season could also be measured in order to make the seasonal flexibility in demand response more accurate.

- The next version of HOMER modelling software should implement annual change parameters for electricity prices, sell-back rates, fuel costs, and electricity load variables in order to more accurately account for the development of these parameters over the project lifetime. Until that happens, electricity price, fuel cost, and electricity load development of the project lifetime can be modelled outside of HOMER and then the averages over the lifetime could be used in the HOMER simulation. However, this method comes with its own inaccuracies, which should be accounted for.

8. Conclusions

The main aim of this research was to explore the techno-economic potential for a predominantly renewable electricity-based microgrid serving an industrial-sized drink water plant in the Netherlands since there have been no documented cases or research done for a microgrid serving this type of electricity demand in the Dutch context. Therefore, grid-connected and stand-alone microgrid scenarios were modelled using Waternet's drink water treatment plant in Nieuwegein as a case study in order to answer the main research question:

"To what extent can an industrial drink water treatment plant become self-sufficient from a stable supply of renewable electricity integrated into a microgrid, and what are the techno-economic potentials of being grid-connected versus stand-alone?"

Utilizing measured wind speed and solar irradiation data from a nearby town, real time manufacturer data for technology components, and a bottom-up approach to model a flexible demand from demand response, the modelled results prove that **t**here is a very high potential for renewable electricity at the DWP-NWG, which can make this drink water treatment plant's electricity consumption between 70-96% self-sufficient with renewable electricity from solar PV and wind power production. The results show that wind production potential is very high onsite and can meet 82% of onsite demand without adding solar PV. However, the results indicate that PV production potential is also substantial and provides a more balanced supply which can supply electricity at times when wind production is insufficient. Due to the supplemental supply over different parts of the day, adding solar PV also increases the benefits gained from the demand response strategy. Therefore, a solar-wind system combination is recommended over a wind only system.

If maximum solar PV (5.6MWp) and wind capacity (4 turbines for 8MW) are implemented together and combined with large storage and demand response, the 25.6 GWh/year of locally produced renewable electricity can supply up to 96% of the onsite electricity demand. However, due to the large storage capacity which is still very expensive, this system configuration is not one of the top cost-effective grid-connected systems, and even has a negative NPV in stand-alone systems since the 6.6 GWh/year of excess electricity is lost instead of sold-back to the grid and diesel fuel costs are high. The least cost stand-alone system can meet 94% of onsite demand with maximum RE capacities with slightly smaller but still large battery storage, yet it has a COE of 0.94 €/kWh, which is 12 cents more expensive

than currently buying all electricity from the grid. Since excess electricity is lost instead of traded, diesel fuel is more expensive than grid electricity, and battery storage is still very expensive, the least cost stand-alone microgrid has a negative NPV of €-7.3 million. Although these stand-alone cases prove that an industrial-sized water treatment plant can continue operating without grid-connection, it is not profitable for an industrial electricity load that to be completely independent from the grid in the Netherlands when it can receive very low wholesale electricity prices. Therefore in the case of the DWP-NWG, disconnecting from the main grid should only be done in emergency situations.

With these high RE potentials onsite, grid-connected microgrid systems which can sell excess electricity beyond the demand, are very profitable. The most profitable system configuration is a 5.6MWp Solar PV – 8MW wind (4 turbines) combined with demand response, yet without storage. Provided that the PV panels are not significantly affected by the shadows cast by the 4th wind turbine onsite and don't need extra space between arrays, the microgrid system can be 88% self-sufficient on renewable electricity, with a COE of 0.020 €/kWh, an NPV of €12.7 million, and a payback period of 7.3 years. However, even if the space required for PV array placement needs to be doubled in order to prevent them from casting shade on each other, and the 4th turbine is not built in order to avoid any negative effects on partial shading on the nearby PV arrays, the resulting 2.8 MWp solar PV – 6 MW wind (3 turbine) system with demand response can still supply 81% of the load with its 17.8 GWh of locally produced renewable electricity. Moreover, even though it does not produce as much excess electricity as the largest system configuration, this system is also very cost-effective with a COE of 0.034 €/kWh, an NPV of €10.3 million, and payback period of 6.1 years. Since solar PV investment costs have drastically dropped by over 40% over the last year, the SDE+ subsidy decreases wind investment costs by at least 50%, directly consuming RE onsite avoids the majority of electricity costs, and sell-back of excess electricity is possible, grid-connected cases are very profitable. Moreover, based on the sensitivity analysis of electricity prices, the profitability of these systems are even underestimated if electricity prices rise in the future, which is highly likely considering historical increases. Ultimately, even at the low wholesale electricity and sell-back price for large industrial electricity consumers, grid-connection and the ability to trade excess electricity is extremely important for the cost-effectiveness of microgrid system.

Three sub-questions were also explored to support this main research question in regards to the potential for flexible demand and the financial implications, the economic implications of grid-imports, back-up diesel, and battery storage, and the economic potentials of postponing investment until 2018 when technology investment costs further decrease.

8.1 Load Flexibility with Demand Response

Using a bottoms up approach by taking into consideration the customer water demands and the water storage buffer capacity at the Dunes and onsite pump installations, 29% of normal 16.7 GWh annual demand is calculated and modelled to be flexible with an additional 15% of flexibility to pump more water to the Leiduin Dunes, which have an approximate 18 million cubic meters water storage buffer above normal water demand (55 million m^3).

The results show that shifting 29% of normal annual demand to be supplied during renewable electricity production earns an additional €59,000 per year in avoided transport and energy taxes. Larger capacity microgrid systems, which can pump slightly more water above normal demand from the excess RE produced, earn up to €71,000 per

year. The maximum capacity RE system with DR and without batteries can utilize 12% of the additional flexibility provided by the water storage buffer at the Dunes; however, in order to utilize the maximum 15% flexibility from the buffer at the Dunes, adding battery storage is required in order to defer the use of excess electricity when the strongest pumps are not being used. This is due to the limitations of the current pump installations and transport network which prevent significantly more water to be pumped in one time step.

The annual benefits are relatively insignificant due to the low wholesale electricity prices for large industrial electricity users and the marginal difference between electricity prices and sell-back rates. Therefore, adding battery storage in order to maximize the flexibility of the load does not make sense with the current investment costs and electricity buy-in and sell back prices. However, the sensitivity analysis of potential future changes in sell-back incentives indicates that employing flexible demand will become more attractive and profitable if sell-back rates drop to be 54% of the buy-in electricity price (versus 70% of the buy-in price today), or lower, since the margin earned between the electricity buy-in and sell back rates increases. This larger difference in electricity buying and selling price creates a greater incentive (via costs avoided per kWh) to consume more electricity onsite rather than selling it back to the grid. Since electricity costs are expected to rise in the future, and sell-back prices are likely to decrease as more renewables are implemented nationally in order to reach 2020 Climate Change Goals, implementing load flexibility with demand response is an important part of the microgrid system and will become more and more profitable.

8.2 Grid imports & back-up generators & back-up storage

Due to the intermittency of wind and solar production, the results show that even at the high aforementioned renewable energy potentials in this case study and high fractions of load with flexible demand supplied by renewable electricity, all systems still rely on about 1-4.5 GWh of electricity purchased from the grid or supplied by diesel generators in order to meet 100% of the onsite electricity demand. This depends on the amount of storage in the system configuration since storage defers the consumption of renewable electricity to another time, thereby decreasing the need for grid or diesel reinforcements. In grid-connected cases, this small amount of grid-imports only marginally decreases the value of the system since the price of electricity is so low for industrial electricity consumers. However, the value of stand-alone configurations decreases more significantly if more diesel generation is required in order to meet 100% of onsite demand due to higher fuel costs.

In this case study, where there is such a high RE production potential onsite, battery storage is not necessary since adding storage decreases economic potentials by 27% or more if larger storage is added since VRB flow batteries are still expensive. The grid-connected cost optimization results indicate that while systems with moderately large battery storage are cost-effective and profitable, adding storage does not add value and also takes up a lot of space. Therefore, solar-wind-DR system configurations are currently optimal from a cost perspective.

In stand-alone cases, the results confirm that moderately large battery storage is absolutely necessary in order to supply electricity when RE production is insufficient. Moreover, in order to minimize the amount of lost excess electricity and the need for diesel generation, very large storage is necessary. However this decreases the value of the microgrid by 28%, especially since a substantial amount of RE is lost instead of fed-back to the grid. Thus, optimally sizing battery storage to RE production and electricity demand is imperative to maximize the value of the system.

Ultimately, due to need for back-up electricity supply and/or back-up storage to balance the intermittencies of renewable electricity production, the investment costs of storage will have to drastically drop before a 100% renewable system will be economically feasible.

8.3 Postponing Investment: Economic Implications of investing in 2018 stead of 2013

The results show that if no subsidies are available 5 years into the future, stand-alone microgrids are even less cost-effective due the rise in diesel fuel costs, and grid-connected microgrid cases are still very profitable, although slightly less profitable than investing today with financial support. This is because benefits of consuming electricity onsite and selling back the excess electricity, combined with the expected decreases in investment costs, are still very significant even without financial support from the EIA and SDE+. Moreover, the sensitivity analysis of future support from the EIA and SDE+ indicate that grid-connected systems will be about 40% more profitable if the EIA and SDE+ are both available. If SDE+ subsidies increase in the first phase or are granted in later phases, future economic potentials can be even greater. However, the sensitivity analysis of future investment cost scenarios shows that the extent of profitability is highly dependent on how the investment costs of wind turbine and PV costs evolve. Nonetheless, even in the worst case scenario, which is highly unlikely in this economy and at the rate that PV costs are dropping, a mid-sized solar –wind microgrid configuration combined with DR without battery storage still has a positive NPV without financial support and a payback period well within the 25 year project life. Therefore, although PV costs have already dropped significantly making the current economic potential from grid-connected solar-wind microgrid configurations very high, waiting to invest within 5 years can be even more profitable as long as the EIA and SDE+ support remain.

The applicability of these results for a renewable electricity-based microgrid to all Dutch industrial drink water treatment plants is inevitably dependent on the annual electricity use, potential for renewable energy production, and whether the infrastructure for a separate electrical grid already exists. Relative to two other drink water treatment plants in Leiduin and Weesperkarspel, which used 12.7 GWh/yer and 7.7 GWh/year in 2012, this case study has a 24-54% larger annual electricity use (Waternet, 2012a). In this respect, this case study is special because it pumps so much water to the Leiduin Dunes for the next filtration step. Without this extra intermediary water "consumer/storage", the DWP-NWG would have comparable annual electricity consumption between 10-12 GWh/year. Consequently, drink water treatment plants with lower electricity demand would require less renewable electricity capacity in their microgrid system in order to serve the same fraction of annual load with renewable electricity. Due to the nature of the water treatment process, which requires a significant amount of land, it is very common to have a significant amount of open land and roof space for solar PV arrays and/or wind turbines. This means, the potential for RE can be high at many drink water treatment plants, yet will naturally vary depending on the location, space available, and proximity to residential areas. While it is common for drink water plants to be in remote areas near industrial areas, it can be possible for them to be too close to residential areas, which could hinder the wind potential due to residential proximity and noise regulations. Lastly, this case study already has the established infrastructure for a microgrid, so no additional costs were included for this aspect of a microgrid system. Due to the high power requirements of transport pumps it is common for drink water plants to have their own substations connecting to the main grid in order to supply high voltage electricity to the transport pumps and transform high voltage power to low voltage power to supply smaller electricity consumption like the labs, offices, chemical processing, and aeration buildings spread around the plant's grounds. These substations can serve as the

Point of Central Control (PCC) for connection and power quality control between the microgrid and the main grid. Ultimately, since other drink water treatment sites have smaller annual demand which would require less renewable electricity capacity, yet still have the infrastructure and space for potential RE production, the relevance and applicability of a microgrid system for drink water treatment plants is substantial and should be further explored.

Relative to other energy intensive industries like steel, chemical, and cement production, which require significantly more heat for the production process, the drink water treatment industry is special in that it has a relatively low thermal demand. Therefore, the resulting predominantly RE based microgrid from this research is particularly suitable for the drink water industry and not necessarily applicable to other industrial process sites which have a different mix of energy demand. Nonetheless, onsite self-sufficiency with a microgrid system could still be an option for other types of industrial sites, but would require different components like cogeneration (CHP) technology as part of the microgrid energy mix in order to more efficiently meet heat demand. Depending on the land and resources available, this could still be renewable if fuelled with biomass. Ultimately, becoming self-sufficient via a microgrid system is relevant to many industries, but the energy mix and system configuration is very much case dependent.

9. Recommendations for further research

This research takes a first look at the feasibility of a renewables-based microgrid serving an industrial-sized load with solar and wind energy in terms of optimal design and cost-effectiveness. The results indicate that a significant portion of electricity demand of an industrial sized water treatment plant can be met with a few wind turbines and large PV capacity, which can be very profitable if grid-connection and trading of excess electricity is possible. This leads to a number of questions that still need to be answered, particularly in terms of technical feasibility. Therefore, the following points are recommended for further research.

- **Effect of shadows on PV array output.** In light of the significant amount of space available not only on Parcel Zuid, but also on the remainder of the DWP-NWG campus and rooftops which could offer even more renewable electricity production from solar PV, more research needs to be done on how much the moving shadows cast by the nearby wind turbines affect electricity production. In connection to this, it would be interesting to investigate whether there are innovative technologies that are more tolerant to partial shading, and what the cost implications are.

- **PV array placement.** Since the maximum onsite capacity for solar PV produces twice as much power as a PV array that requires twice as much space to prevent the arrays from casting shade on each other, it would be interesting to research whether there are new developments in PV array placement or panel technology in order to maximize the potential of available space.

- **Adding heat demand**. The scope of this research was limited to the electricity consumption of the site since the heat demand is relatively low. However, in light of the large RE potential which can produce

significantly more electricity than needed, it would be interesting to investigate whether the excess electricity could cover the heat demand and whether is it financially attractive.

- **Sharing excess electricity with neighbours instead of feeding back to grid –** The results indicate that the benefits of consuming onsite by avoiding transport and energy taxes is substantial yet relatively marginal compared to grid-sell back of excess electricity, which is still an important cash flow and incentive to implement renewable. Moreover, as national implementation of renewables increases and sell back rates potentially decrease, the benefit of consuming RE onsite increases. It is therefore interesting to further investigate the techno-economic potential of adding a neighbouring electricity load to the microgrid.

- **Interconnection & grid sell back.** This research assumes that for grid-connected microgrid cases, interconnection with the main grid has no limitations and importing/exporting electricity can be done freely without restrictions. However, if renewable electricity will be first consumed onsite and then excess electricity injected into the grid, the microgrid must meet applicable interconnection rules and requirements (Eyer, 2010). Additionally, microgrid pilots documented around the world, as mentioned in the introduction, have shown that grid-operators have restricted excess electricity feed-back to the main grid, which is one of the main barriers to a more rapid implementation of microgrids around the world. Since the high RE potentials at this location produces significant excess electricity, it is an important next step to research the extent of restriction set by the Dutch regulatory framework for interconnection and selling excess electricity back to the grid, since these restrictions can affect the optimal system configuration and profitability of the system.

- **Power quality & reliability.** Although this research provides a first look into the feasibility of a microgrid for the specific site in terms of renewable energy potentials and optimal system design based on costs, the model is limited in simulating the technical feasibility of the microgrid cases in terms of power quality and reliability of the system. Therefore, another important research step is to investigate the real-time technical feasibility of the optimal system design chosen from the HOMER model simulation**.**

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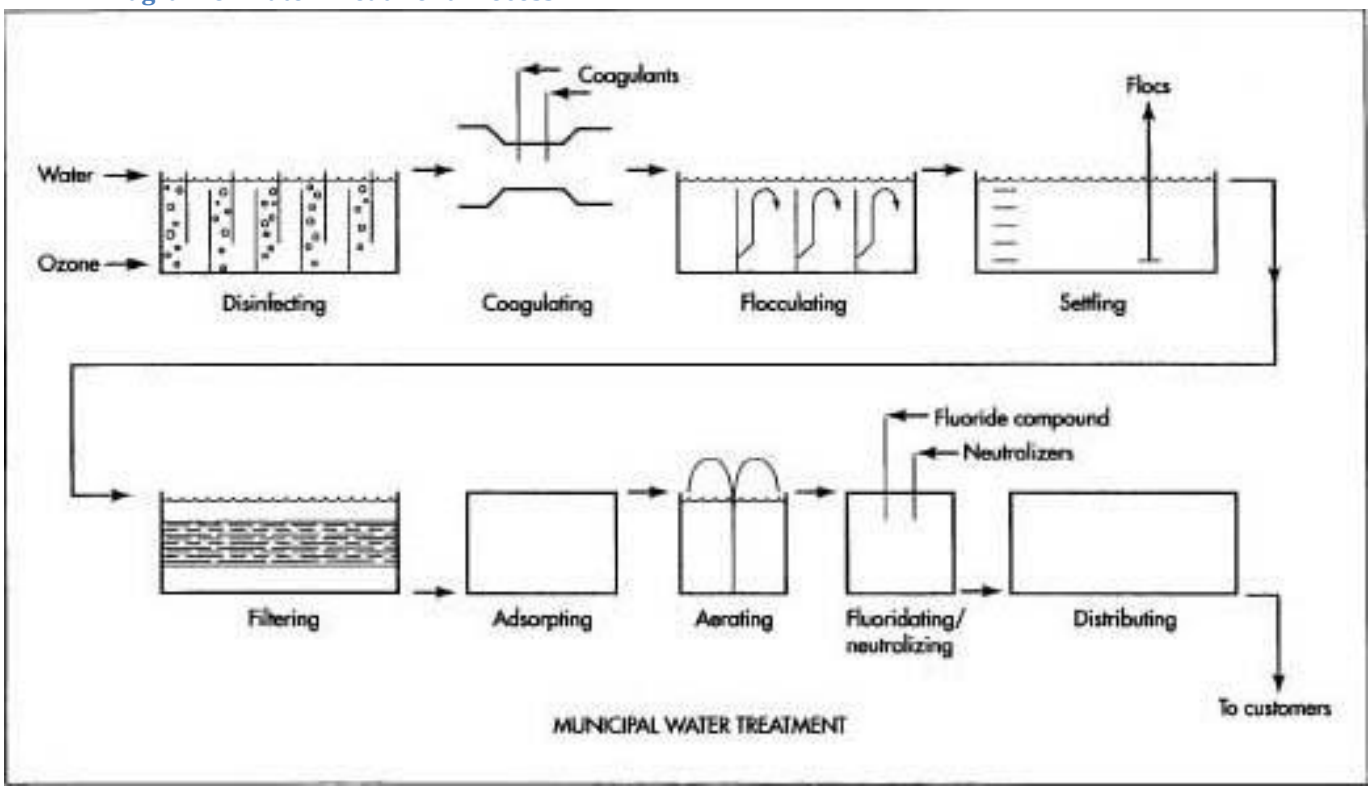
Appendix

A. Diagram of Water Treatment Process



Source: (Made How, 2013)

B. Smart Grid Projects in the Netherlands

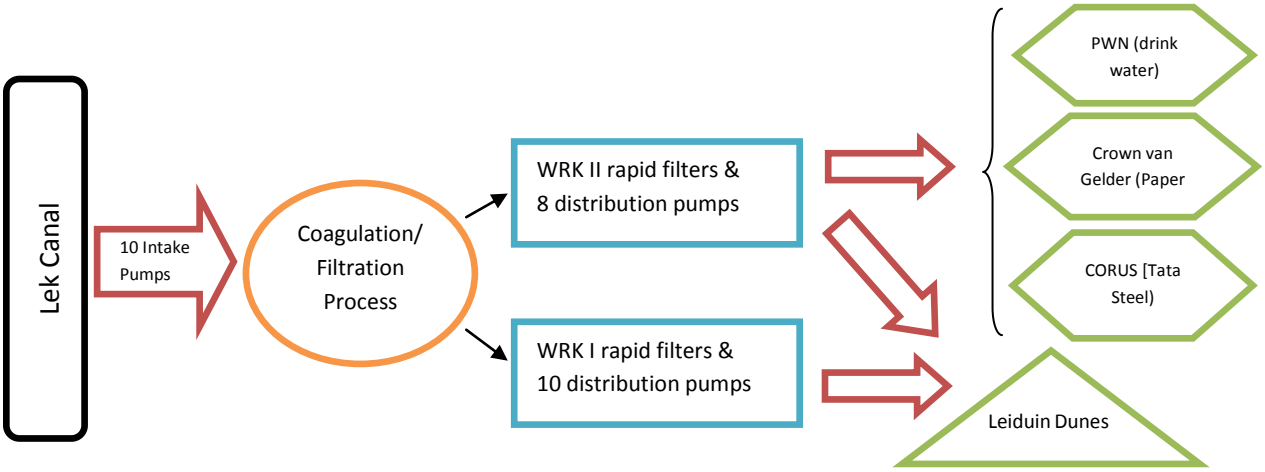
Name	*Organization*	*Period*	*Category*	*Description*
DA (Distribution Automation)	*Enexis BV (NL)*	*2007-2010*	*Grid Automation Distribution*	*Building an integrated architecture (i.c.: interaction between business-processes, information-architecture and primary network layout) to maximize Enexis' MV-grid performance (10-20 kV).*
Demonstration project Smart Charging	*Enexis (NL)*	*Sept 2010-Dec 2011*	*Grid Automation Distribution*	*Test and demonstrate an environment in which commercial market parties are enabled to provide charge services to EV customers in cooperation with EV infrastructure parties and grid operators.*
Easy Street	*Enexis (NL)*	*Jan 2011-Jun 2014*	*Integrated System*	*Insight into the workings of technology, incentives and interaction in order to mobilize flexibility from customer's electricity usage.*
Fieldtrail Mobile Smart Grid	*Enexis (NL)*	*Apr 2010-Apr 2011*	*Grid Automation Distribution*	*Demonstrate an earlier tested proof-of-concept (PoC) for demand response with one EV on multiple EVs and charge spots in one location based on individual driver demands.*
Pilot Smart Metering	*Enexis (NL)*	*2007-2010*	*Smart Meter and AMI*	*Research has been focused on alternative data-com infrastructures, AMI-system performances, standardization of meter requirements, possibilities of firmware upgrades, security & privacy guidelines and measures, mass roll out processes and customer satisfaction.*

Smart Energy Collective	*KEMA (NL)*	*2010-2013*	*Grid Automation Distribution*	*The Smart Energy Collective is an industry-wide collective that is setting up 5 to 10 large-scale smart grids demonstration projects across the Netherlands with a total of around 5,000 private and small business end-users. This industry initiative is dedicated to the practical development of smart energy services and networks, integrating interoperable services, technologies, and infrastructures, i.e. electricity, gas, heat, and ICT.*
Smart Metering NTA Roll Out	*Enexis (NL)*	*Jul 2010-Dec 2011*	*Smart Meter and AMI*	*To introduce the NTA-smart meter as the default meter in all processes and to be ready for the obligations introduced by the new law. Involving the contracting of installation capacity and training of people.*
Smart Power System - First trial	*ECN, Energy research Centre of the Netherlands (NL)*	*2006-2007*	*Integrated System*	*The main goal of the field test was to demonstrate the ability of such a VPP to reduce the local peak load on the single low-voltage grid segment.*

Source: Smart Grid Projects, 2012

C. Operation Overview of DWP Nieuwegein

(WHG is excluded from graphic since its demand is relatively small)



D. HOMER Output Variables

Output	Unit	Output	Unit
Grid Capacity	kW	AC Primary Load Served	kWh/yr
PV array	kW	Deferrable Load Served	kWh/yr
V90 Wind Turbines	#	Ren. Fraction	
Diesel Generator Size	kW	Cap. Shortage	kWh/yr
VRB-ESS Flow Battery Power	kW	Cap. Shortage Frac.	
VRB-ESS Flow Battery Storage	kWh	Unmet Load	kWh/yr
Converter	kW	Unmet Load Frac.	
Total Capital Cost	€	Excess Electricity	kWh/yr
Total NPC	€	Diesel	L/yr
Tot. Ann. Cap. Cost	€/yr	CO2 Emissions	kg/yr
Tot. Ann. Repl. Cost	€/yr	CO Emissions	kg/yr
Total O&M Cost	€/yr	UHC Emissions	kg/yr
Total Fuel Cost	€/yr	PM Emissions	kg/yr
Total Ann. Cost	€/yr	SO2 Emissions	kg/yr
Operating Cost	€/yr	NOx Emissions	kg/yr
COE	€/kWh	Gen 1 Fuel	L/yr
PV Production	kWh/yr	Gen 1 Hours	hr/yr
Wind Production	kWh/yr	Gen 1 Starts	starts/yr
Gen 1 Production	kWh/yr	Gen 1 Life	yr
Grid Purchases	kWh/yr	Battery Autonomy	hr
Grid Sales	kWh/yr	Battery Throughput	kWh/yr
Grid Net Purchases	kWh/yr	Battery Life	yr
Tot. Electrical Production	kWh/yr		

E. Potential placement of 3 wind turbines at DWP Nieuwegein

Source: Ritzen & Gastel, 2012

F. Breakdown of current 2013 costs for all chosen grid-connected and stand-alone scenarios

[starting with the 2013 base case and then ordered by COE from lowest to highest (yellow = grid=connected/onsite consumption/NO flexible demand; green = grid-connected/onsite consumption/flexible demand; orange = stand-alone/onsite consumption/flexible demand); *Total O&M costs/year includes grid purchases and grid sales]

Grid	PV	V90	Gen (2)	Converter	VRB-ESS Power	VRB-ESS Storage	Total Initial Capital Cost	Operating Cost (excl Cap. Costs)	Total NPC (over 25 years)	Tot. Ann. Cap. Cost	Tot. Ann. Repl. Cost	Total O&M Cost*	Total Fuel Cost	Total Ann. Cost	COE
	MW	#	MW	MW	MW	MWh	€ million	€ million/yr	€ million	€ million/yr	€ million/yr	€ million/yr	€ million/yr	€ million/yr	€/kWh
Y	Base						€ -	€1.49	€ 22.66	€ -	€ -	€ 1.49	€ -	€ 1.49	€ 0.082
Y	5.6	4	0	5.2	0	0	€8.98	€0.04	€9.61	€ 0.55	€ 0.11	€-0.07	€ -	€ 0.59	€ 0.020
Y	2.8	4	0	2.5	0	0	€7.00	€0.18	€9.94	€ 0.43	€ 0.10	€ 0.08	€ -	€ 0.61	€ 0.023
Y	1.4	4	0	1.3	0	0	€6,02	€0.25	€ 10.18	€ 0.37	€ 0.10	€ 0.16	€ -	€ 0.62	€ 0.024
Y	0	4	0	0	0	0	€4.95	€0.38	€ 11.16	€ 0.30	€ 0.10	€ 0.28	€ -	€ 0.68	€ 0.025
Y	0	4	0	0	0	0	€5.05	€0.33	€ 10.49	€ 0.31	€ 0.10	€ 0.24	€ -	€ 0.64	€ 0.026
Y	5.6	4	0	5.2	1	20	€12.6	€0.03	€ 13.1	€ 0.78	€ 0.08	€-0.05	€ -	€ 0.80	€ 0.029
Y	5.6	3	0	5.2	0	0	€7.74	€0.24	€ 11.72	€ 0.47	€ 0.09	€ 0.16	€ -	€ 0.72	€ 0.030
Y	2.8	3	0	2.5	0	0	€5.69	€0.44	€ 12.83	€ 0.35	€ 0.08	€ 0.36	€ -	€ 0.79	€ 0.032
Y	2.8	3	0	2.5	0	0	€5.76	€0.39	€ 12.06	€ 0.35	€ 0.08	€ 0.31	€ -	€ 0.74	€ 0.034
Y	1.4	3	0	1.3	0	0	€4.79	€0.46	€ 12.37	€ 0.29	€ 0.08	€ 0.39	€ -	€ 0.76	€ 0.036
Y	0	4	0	1.3	1	20	€8.89	€0.32	€ 14.15	€ 0.55	€ 0.07	€ 0.25	€ -	€ 0.87	€ 0.036
Y	5.6	2	0	5.2	0	0	€6.50	€0.47	€ 14.09	€ 0.40	€ 0.06	€ 0.40	€ -	€ 0.86	€ 0.043
Y	0	4	0	1.3	1	45	€12.74	€0.27	€ 17.15	€ 0.78	€ 0.02	€ 0.25	€ -	€ 1.05	€ 0.044
Y	2.8	3	0	2.5	1	20	€9.42	€0.37	€ 15.44	€ 0.58	€ 0.05	€ 0.32	€ -	€ 0.95	€ 0.045
Y	0	1	0	0	0	0	€1.24	€1.08	€ 18.78	€ 0.08	€ 0.02	€ 1.05	€ -	€ 1.15	€ 0.068
Y	1.4	0	0	1.3	0	0	€0.99	€1.28	€ 21.85	€ 0.06	€ 0.00	€ 1.28	€ -	€ 1.34	€ 0.080
N	5.6	4	1.32	5.2	2	45	€17.32	€0.89	€ 29.99	€ 1.06	€ 0.05	€ 0.40	€ 0.44	€ 1.94	€ 0.094
Y	5.6	0	0	5.2	2	45	€12.18	€0.94	€ 27.47	€ 0.75	€ 0.05	€ 0.99	€ -	€ 1.68	€ 0.097
N	5.6	4	1.32	5.2	3	60	€20.11	€0.73	€ 31.97	€ 1.23	€ 0.02	€ 0.38	€ 0.30	€ 1.96	€ 0.104
N	2.8	4	1.32	2.5	2	45	€15.21	€1.06	€ 30.72	€ 0.93	€ 0.04	€ 0.40	€ 0.62	€ 1.99	€ 0.105
N	5.6	3	1.32	5.2	2	20	€12.23	€1.22	€ 30.33	€ 0.74	€ 0.08	€ 0.36	€ 0.78	€ 1.96	€ 0.106
N	1.4	4	1.32	2.5	2	45	€14.42	€1.22	€ 32.46	€ 0.88	€ 0.05	€ 0.40	€ 0.77	€ 2.09	€ 0.113
N	2.8	3	1.32	2.5	3	60	€16.86	€1.06	€ 32.42	€ 1.03	€ 0.00	€ 0.34	€ 0.72	€ 2.09	€ 0.120
N	0	4	1.32	2.5	2	45	€13.63	€1.41	€ 34.82	€ 0.83	€ 0.05	€ 0.40	€ 0.96	€ 2.24	€ 0.124