The Impact of Renewable Energy on Natural Gas Consumption for Power Generation

Why Natural Gas is Essential for Accommodating Renewable Energy[1]

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Background

Over the past years the share of electricity generated from renewable sources has increased significantly and, supported by EU legislation, is expected to increase further in the coming years. When setting the 20/20/20 target of having 20% reduction in carbon emissions, 20% of energy from renewable sources and 20% reduction in energy usage, the EU made clear it takes combating carbon emissions seriously (European Comission 2011). On top of that, in the G8 meeting in L'Aquila in July 2009 Europe agreed to a target of 50% emission reduction in 2050 (compared to 1990 levels) if global action would be taken (United Nations Environment Programme 2011).

In order for the EU to reach these targets, an increase in electricity from renewable sources will be essential. This will lead to a reduction of electricity demand from conventional thermal power plants (e.g. coal fired, natural gas fired power plants or nuclear power plants). The power sector is an important natural gas consumer. On a global level the power sector is by far the largest gas consumer with about 39% of total gas consumption in 2008 and rising to 40% in 2035. Over the period 2000 to 2010 90% of the new build electricity output in OECD countries was gas-fired (International Energy Agency 2011, 23; 101).

The majority of electricity from renewable sources is by nature variable in production - wind turbines depend on the availability of wind, and solar PV on sunlight. Therefore, an increase in renewable electricity production will also increase the fluctuations in demand from thermal power plants. Thermal power plants will need to act as a back-up for renewable energy by producing the electricity not delivered by renewable energy. It can be expected that with increasing levels of renewable energy, the production profile of thermal plants will become more volatile. Natural gas fired power plants are considered to be the most flexible type of power plants, and therefore an increase in renewable electricity production could lead to an increase in demand for gas fired power plant.

Based on a simulation model, this paper investigates what the impact of an increase in renewable energy will be on the conventional thermal power generation mix, with a focus on the natural gas demand from the power sector. This is done by simulating the future electricity market for a five year period (period 2026 - 2030) for six Northwest European countries[2] with varying levels of electricity from renewable sources. The model determines by which types of power plants the fluctuating demand can be generated and calculates and minimises overall cost for the conventional electricity generation such that all electricity demand is fulfilled.

[1] This paper is a revised and short version of the thesis The optimal power mix: cost efficiently accommodating renewable energy. For a more elaborate information the authors would like to refer to this document.
[2] Belgium, Denmark, France, Germany, The Netherlands and United Kingdom.

Aims

This paper investigates the impact of an increased penetration of electricity from renewable sources on the investment and usage of thermal power plants with a focus on natural gas consumption. This is answered by a model simulating part of the European electricity market for a five year timeframe in the future. The model optimises the number and types of power plants to be built, such that electricity demand is fulfilled effectively and reliable and costs of the thermal power plants are minimised with minimal curtailment of renewable electricity as possible.

Methods

The core of this paper is the model simulating the future electricity market. In order to build this model, a large number of inputs were gathered and decisions had to be made, which will be discussed in this section. For readability the gathering of the inputs is in most cases placed in a separate appendix.

The model assumes a Greenfield approach, implying that the current mix of electricity generation in place is not of relevance. And thus, the model answers the question, “what if you are allowed to rebuild all power plants, which power plants would you build”. It is assumed that the chosen power plants can only be built at the start of the five-year period and are directly available.

The construction of the model is structured in seven steps, shown in figure 1. The first three steps determine the residual demand, which is the electricity demand not being produced by renewable electricity production, and therefore having to be produced by thermal power plants. In step four the operations of the electricity grid are looked at, explaining how the balance is maintained in the power grid. Step five covers the technical aspects of the thermal power plants used in the model in order to deliver the residual demand, step six is the twin of step five looking at the financial characteristics of the power plants. Finally, in step seven the model is build.

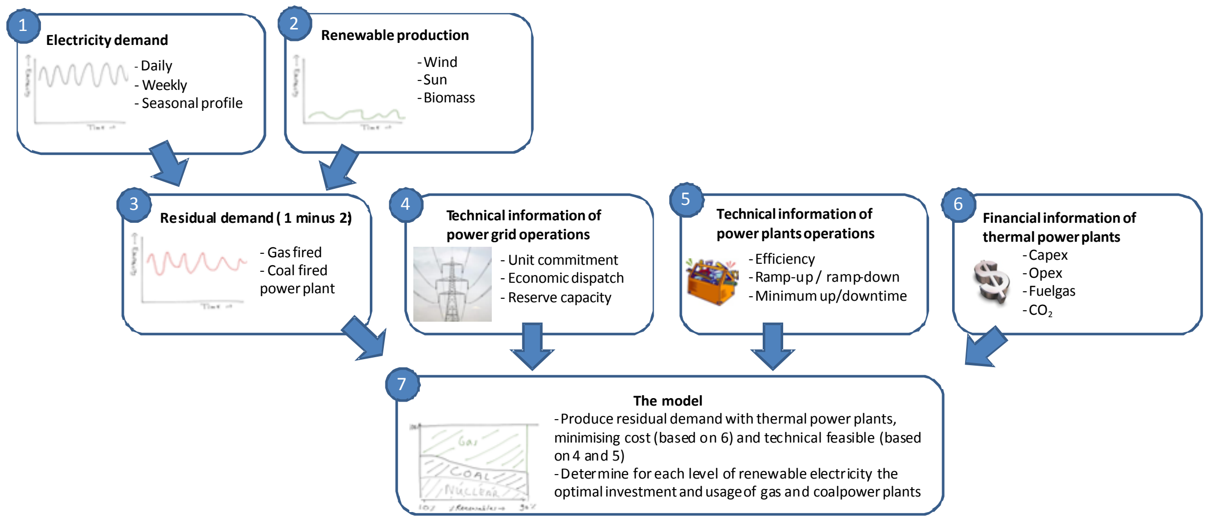

Figure 1:
Structure for building the model

Future Electricity Demand

The studied market area consists of the following six Northwest European countries: Belgium, Denmark, France, Germany, the Netherlands and the United Kingdom. These countries are already relatively well integrated and are expected to be further integrated in the future. It is assumed that these countries form an isolated market area within which electricity can move freely, resembling a copper plate.

The electricity demand for the future five year period (2026 – 2030) is determined by extrapolating on historical electricity consumption in the years 2006 to 2010. The historical data is multiplied with the expected growth of electricity demand of 1.2% per year which applies for OECD Europe according to (International Energy Agency 2011, 176). Hourly consumption data has been used.

For Belgium, France, Germany and the Netherlands the electricity consumption data from the ENTSO-E statistical database (ENTSO-E 2011) has been used. The Danish electricity consumption has been taken from the website Energinet.dk (Energinet.dk 2011), where the gross electricity demand for Western and Eastern Denmark is summed. For the United Kingdom half hour data on electricity consumption has been gathered and then averaged[3] from the website of Nationalgrid (NationalGrid 2011).

Renewable Electricity Production

The following three types of renewable energy are included: wind, solar and biomass. These are the major renewable sources according to the baseline scenario of (International Energy Agency 2010, 314), apart from Hydro. Hydro has not been included as it is not always a variable source of electricity but often dispatchable and also not widely available in studied market area.

The future renewable electricity production from wind and sun is based on the theoretically possible hourly renewable electricity production based on the period 2006 through 2010. Theoretically possible wind electricity production has been predicted from realised wind speeds, and solar predicted from realised sunshine hours in the given time period. Biomass electricity production is taken from a simulation from a binominal statistical distribution.

Different levels of renewable electricity are used as input into the model varying from 0% to 50% of the total electricity demand. This is done by multiplying the hourly renewable electricity (the sum of wind, solar and biomass renewable electricity production) by a factor. Within each scenario, Wind has been set to generate 50% of renewable electricity production and biomass and solar for 25% each (based on the 2050 expectation of the baseline scenario of (International Energy Agency 2010, 314)).

Wind and solar electricity production both are dependent on the weather. Wind speed in essence is driven by temperature differences, while solar electricity production depends the amount of sunlight. Therefore there is a correlation between wind electricity production and solar electricity production. To make use of these correlations both sunshine hours and wind speed data were gathered from the same seven weather stations spread out over the market area.

Biomass plants are similar to coal fired power plants, except that they burn plant matter and other biological material as fuel (European Climate Foundation 2010, 35). Biomass plants are dependent on the availability of the biomass system and the availability of sufficient feedstock. Within the model, biomass plants are expected either to be producing fully, or not producing at all, if no feedstock is available. Therefore the biomass production has been based on several binominal distributions.

[3] Furthermore a correction has been performed for the hour time difference between the United Kingdom and the other countries in the market area.

Residual demand

The future residual demand is defined as the total future electricity demand minus the renewable electricity production and represents the electricity that needs to be produced by thermal power plants. As renewable production has the lowest marginal cost, it will be curtailed the latest. In the model it is assumed that renewable electricity production will only be curtailed if it is larger than electricity demand.

Operations of the electricity grid

In a power system the balance between generation and consumption needs to be maintained closely, as a small imbalance could directly result in to a failure of the grid. The transmission system operator (TSO) has an important role in balancing the grid. In this section two methods will be explained how the balance in the grid.

First of all, there is a distinction between the unit commitment phase and an economic dispatch phase. The unit commitment phase involves determining which power plants to operate. This involves the calculation of the optimal selection of units for power generation for a certain period of time (hours to days) (Van den Bosch 1983). The economic dispatch performs the actual distribution of the load between committed units, which is optimised for each operation state while taking into account all economic and technical aspects of the units (Ummels 2008). The model includes a separation between the unit commitment phase and the economic dispatch phase.

Secondly, the TSO assures the security in the grid by the availability of reserve capacity. Reserve capacity is electricity production that is able to fluctuate in order to bring the grid into balance in case supply does not matched demand. There are different types of reserve capacity, depending on how quickly it can be operated (Holtinnen, et al. 2009, 29). The required level of reserve capacity is set by the system operator and increases as the level of renewable energy increases. Once a system operator sets the level of required reserve capacity, market participants can subscribe to deliver reserve capacity.

The delivery of the reserve capacity is not included in the model. It is assumed that other sources, that are able to respond more quickly, will deliver that. Examples are pumped hydro or gas fired power plants that are quickly operatable (open cycle gas turbines). In reality, thermal power plants that are not operating at minimum or maximum could be used as reserve capacity; the effects of including a reserve capacity requirement on the outcome of the model should further be explored.

Technical characteristics of thermal power plants

A thermal power plant converts heat via mechanical energy into electrical energy (Roth 2005). Two types of thermal power plants are included in the model: a gas fired and a coal fired power plant. Besides nuclear power plants, these are the most common types of thermal power plants (International Energy Agency 2010, 314).

Coal fired and nuclear power plants are both considered baseload power plants. It makes sense to include only one type of baseload power plant, as both have a cost structure with lower variable cost and higher fixed cost compared to the gas fired power plant. Considering the uncertainty in investment in nuclear power plants following Fukushima, it is decided to include only coal fired power plants. The gas fired power plant included is a combined cycle gas turbine (CCGT), which are the most used gas fired power plants. Within the model both the coal and gas fired power plants are assumed not to have Carbon Capture Storage (CCS).

The model contains one type of gas fired and one type of coal fired power plant, which can be build a multiple times. These power plants are based on the technical and financial characteristics expected to be available in the future and are more flexible than the current power plants. The technical and financial characteristics are further elaborated on in appendix B and C respectively.

Operational stages of a power plant

A power plant has a number of operating stages. The stages in the model are shown in Figure 1. The times required to go from one stage to another are discussed in the Results section.

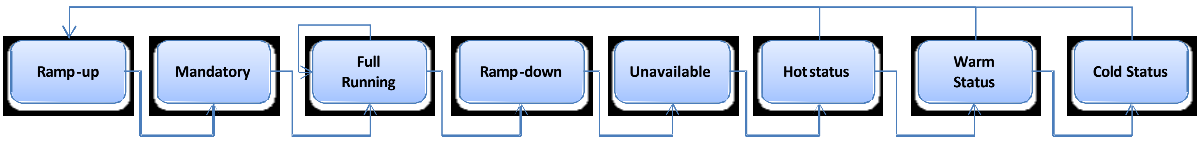

Figure 1:
Operational stages of a power plant in the model

A power plant can be brought into operation from either a hot, warm or cold status. A hot start means a unit starting up within a few hours after shutting down, and the metals in the unit are still hot. A warm start would be when the unit has been off for slightly longer, and the metals have begun to cool but are not yet cold. It would be a cold start if the unit had been off for a long period and the metals were completely cooled. A cold start is the most damaging of all cycling activities (Lefton and Besuner, Power plants operations and unbundling their effect on plant heat rate 2001).

When a power plant is brought into operation, it will go into a ramp-up period, where it will increase its production. After the ramp-up period the power plant can produce everything between minimum and maximum output; however, the power plants requires to be in operation for a number of hours, which is reflected by the mandatory phase.

When it is decided to turn a power plant off in the full-running stage, the plant first goes into ramp down and then into a period of unavailability. The unavailable period represents the minimum number of hours required to be not producing. After the unavailable period the power plant continues into the hot status, and, if not called upon for a number of hours, the power plant would cool down and go into the warm status and after a number of hours into the cold status. As will be discussed in the financial characteristics of power plants, the cost for starting up a power plant from the hot status is lower than from the warm status which in turn is less expensive than starting-up from the cold status.

Efficiencies

The efficiency of a power plant is the ratio between the energy input - in the form of coal or natural gas - and the electricity output. The efficiency is dependent on the usage of the power plant. If the plants are operated on a low usage factor than this will negatively influence the performance and vice versa. In de appendix B this relation is elaborated on. It is unclear what the impact is on the efficiency if power plants are not producing on a constant level but instead are fluctuating their production. For the model it is assumed that this has no impact on the efficiency.

Cycling cost

When a generating unit is subject to varying loads, the components in the unit are subject to wear and tear, due to the thermal and mechanical stresses the system undergoes as a result of the load variations. This is known as cycling and includes ramping up and down and switching on and off. These damage s accumulate over time and eventually lead to accelerated component failures and forced outages (Lefton, Besuner and Grimsrud, Understand what it really costs to cycle fossil-fired units. 1997). The cost associated with cycling are discussed in following part "financial characteristics of thermal power plants" and in appendix C.

Financial characteristics of thermal power plants

A division can be made between variable costs and fixed costs. Contrary to fixed costs, variable costs are dependent on the amount of electricity produced.

Fixed cost

The fixed costs consist of capital cost and annual fixed overhead cost. The capital cost reflect the cost involved for building the power plant, including the licencing, technical design, and connecting the power plant to the electricity grid. Fixed operating cost comprise of operating labour, planned and unplanned maintenance, through life capital maintenance, taxes, insurance and network use of system charges (Mott MacDonald 2010).

In accordance with (Mott MacDonald 2010), only cost associated with production and transportation of the electricity to the grid are included. Additional investments, such as interconnection within the market area, are not included.

Variable Cost

The variable cost comprise of fuel cost, carbon cost, variable operational cost and cycling cost.

Fuel prices and carbon prices fluctuate continually. To include these fluctuations, the historical prices over the period 2006 to 2010 have are extrapolated to an estimated future price level by multiplying the realised prices with a factor. The average future price level is based on (International Energy Agency 2011, 89) which makes an estimation of the prices for 2015 to 2035[4].

The gas prices are based on daily prices on the National Balancing Point (NBP), reported by (ICIS Heren 2006-2010). The coal prices are based on monthly prices for delivery in Western Europe (area Amsterdam, Rotterdam and Antwerp) reported by (Argus/McCloskey's 2006-2010). The CO_2 prices are based on monthly CO_2 prices giving the right to emit CO_2 in the year 2012 from the EEX (European Energy Exchange 2011).

Cycling cost

The true cost of cycling is difficult to estimate and differs from plant to plant (Grimsrud and Lefton 1995). The costs associated depend on a number of things, amongst other the age and previous operating patterns of the generators. Most conventional units are designed for continuous rather than variable operations (Lefton, Besuner and Grimsrud, Understand what it really costs to cycle fossil-fired units. 1997).

[4] Natural gas prices are on average 24.7 EUR/MWh, coal prices 9.5 EUR/MWh and CO_2 prices 37.0 EUR/ton. The prices were reported in 2009 dollars, therefore a recalculation has been performed using an exchange rate of 1 EUR = 1.39 USD, which is the average applicable exchange rate based on ECB (European Central Bank, 2011) and an inflation correction for 2009 and 2010 (Eurostat, 2011). The original price estimations given by (International Energy Agency 2011, 89): gas price is 9.8 $/MBtu, coal price is 105 $/ton and CO_2 price is 50 $/ton.

An overview of all the associated cycling can be found in (Denny 2007, 67) including a range between the maximum and minimum cost for cycling. The model assumes each cycling has a fixed amount of cycling costs associated with it depending on whether the power plant is in hot, warm or cold status. These costs are incurred upon start-up of a plant. Also it is assumed that the power plant operator is aware of these costs. The cycling costs used in the model are based on the middle of the range given by (Denny 2007, 67) and is given in appendix C.

The model

The model has been build using Matlab. Input to the model are the different scenarios for the residual demand, with a contribution of renewable energy varying from 0 to 50% in steps of 10%. This residual demand has to be fulfilled by using a given number of thermal power plants. The model contains two types of thermal power plants: a gas fired and a coal fired power plant. The approach chosen is a multi-case analysis. For each given scenario of residual demand, several configurations of power plants are calculated. The resulting cost for each case and the generated power are outputs. The variables were the six scenarios for the residual demand, nine different energy mixes (varying from 10% coal fired plants and 90% gas fired plants to 90% coal fired plants and 10% gas fired plants in steps of 10%), and six different scenarios for the maximum capacity of all plants combined (varying from 97.5% to 200% of maximum demand at any given hour). Multiplying these parameters gives a total of 324 cases that are calculated on an hourly basis.

Within each case, the model calculates the optimal strategy for the given set of power plants for the entire five year period. This will mean that in some cases, the demand cannot be fulfilled by the given set of power plants, because the total capacity is limited or the power plants face technical constraints. In other cases, there will be an overcapacity so that demand can be fulfilled, but fixed costs are very high. The analysis of the results of all cases will give more insight in a balance between security of supply and minimizing cost, and on the optimal power mix for the different scenarios of residual demand.

During each hour the model decides which power plants to operate for the coming hours, based on the marginal cost of each type of power plant for the current hour, including cycling cost. As a result of the cycling cost, it is cheaper to use a power plant already in operation, than a power plant which needs to start up.

The model takes into account technical constraints described in appendix B, such as ramp-up times, unavailability after ramp-down, and a minimal time needed in full running mode. This means that in case the fluctuations in residual demand are larger than the operating range of the power plant, the peaks are not delivered by gas fired or coal fired power plants. In those situation a short term type of electricity source should be used (pumped storage or open cycle gas turbine). At the moment, these are not included in the model, resulting in possible underdelivery.

During the start of the hour the model performs a economic dispatch for that hour, determining the usage of each types of power plant. The type of power plant with the lowest marginal cost will be used first, as long as each power plant is able to deliver their minimum stable load. Cycling cost are no longer relevant during the economic dispatch as the decision which power plants to operate have already been made.

Results

Future Electricity Demand

As a reference, the total estimated future electricity demand for the six countries in the market area is shown in Figure 2 and Figure 3 for a week in January and July in the year 2030. A daily, weekly and seasonal pattern can be identified. Electricity demand is higher during the day than during the night. In January the daily peak takes place between six and eight in the evening, while in summer the peak takes place around noon. Electricity demand during weekends is lower than during weekdays.

Over the five year period, demand in the winter period (October till March) is 20% higher than demand in the summer period (April till September). The maximum peak over the five year period took place in December 2030 and equalled 339 GWh per hour; the minimum was 128 GWh per hour and occurred in May 2029.

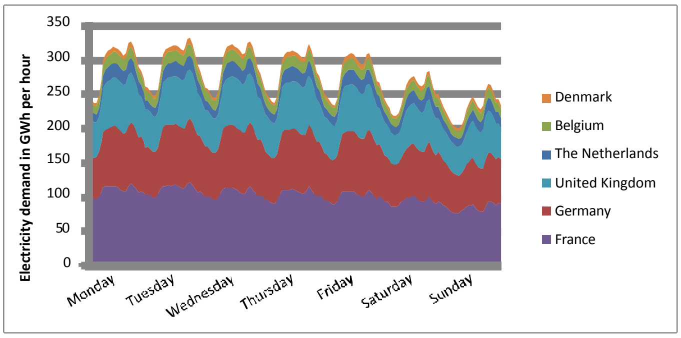

Figure 2:
Future electricity demand: a week in January 2030

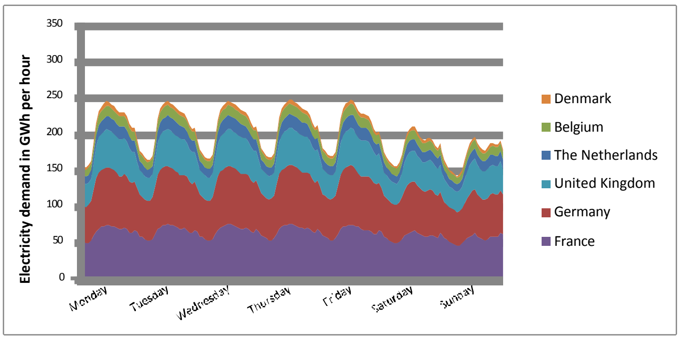

Figure 3:
Future electricity demand: a week in July 2030

Renewable Electricity Production

Renewable electricity production has a daily and seasonal profile. The daily profile is similar each day, as explained in appendix A.

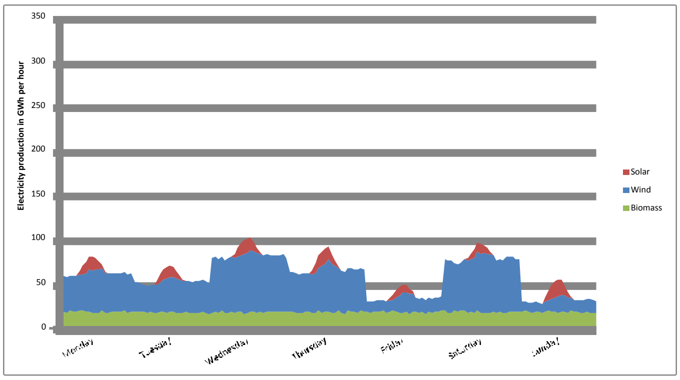

Figure 4:
Renewable electricity production: a week in January 2030
(renewable electricity equals 30% of electricity demand)

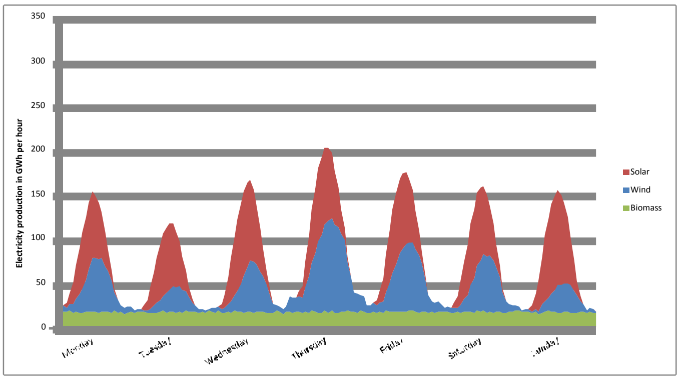

Figure 5:
Renewable electricity production: a week in July 2030
(renewable electricity equals 30% of electricity demand)

Solar production is minimal in the winter: only a few hours of production around noon. In summer solar production is observed during large parts of the day with its peak during midday.

Wind production hardly has a daily profile during the winter, while during summer there is a clear daily profile. As a result, electricity production from solar and wind in the summer coincides, resulting in large renewable production peaks.

Biomass is a relatively baseload delivery, independent from weather conditions and time.

Residual demand

In Figure 6 and Figure 7 the residual demand is shown (black line), which is the result of subtracting renewable electricity production from the electricity demand (dotted line). The subtraction of the renewable electricity production has the largest impact during the summer, especially during weekends around noon. If the share of renewable electricity production would be increased further, the renewable electricity production would surpass demand in the week shown in Figure 7 and renewable electricity needs to be curtailed.

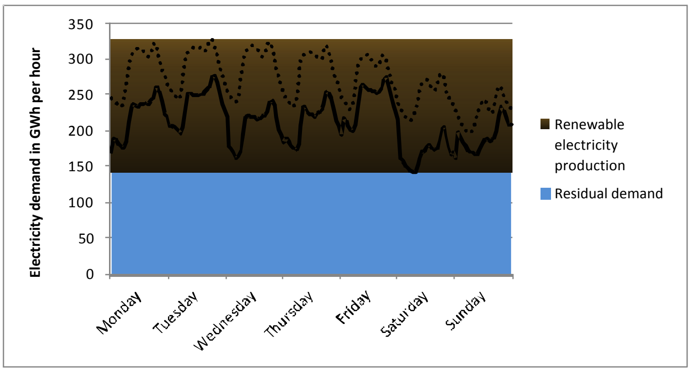

Figure 6:
Residual demand : a week in January 2030
(renewable electricity equals 30% of electricity demand)

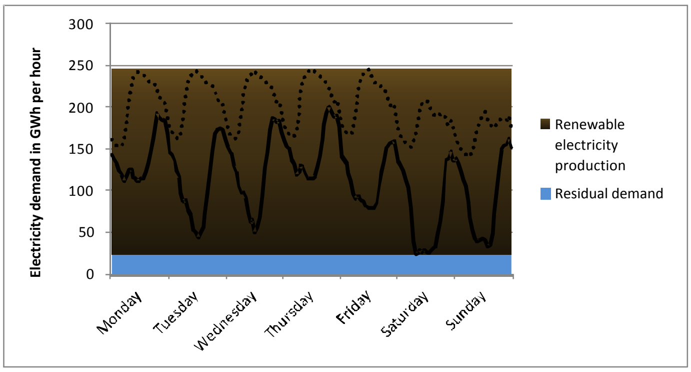

Figure 7:
Residual demand: a week in July 2030
(renewable electricity equals 30% of electricity demand)

Technical characteristics of thermal power plants

The technical characteristics determine how flexible the different power plants are in their production. These characteristics are based on future power plants, and are taken from (European Climate Foundation 2010). The operational stages of a power plant were described in the methods. In Figure 8 the hours required to go from one stages to another stage used in the model are shown. Because the model of this paper is based on hourly data the stages are translated in full hours (see appendix B).

On a large number of elements the coal fired power plants have similar characteristics as gas fired power plants: the ramp-up and ramp-down period, the period of unavailability after a shut-down, and the times to go from a hot status to a warm status and then to a cold status are similar. What differs is the period of mandatory production, these are for gas fired power plants longer than for coal fired power plants, making gas fired power plants less flexible. Gas fired power plants are slightly quicker able to ramp-up, with 25% of available capacity in the first hour and 75% the second hour, while coal fired power plants have a ramp-up rate of 20% of available capacity in the first hour and 60% the second hour. Also gas fired power plants have a lower minimum production (40% compared to 50% for coal). All on all, gas fired power plants are included in the model are not that more flexible than coal fired power plants.

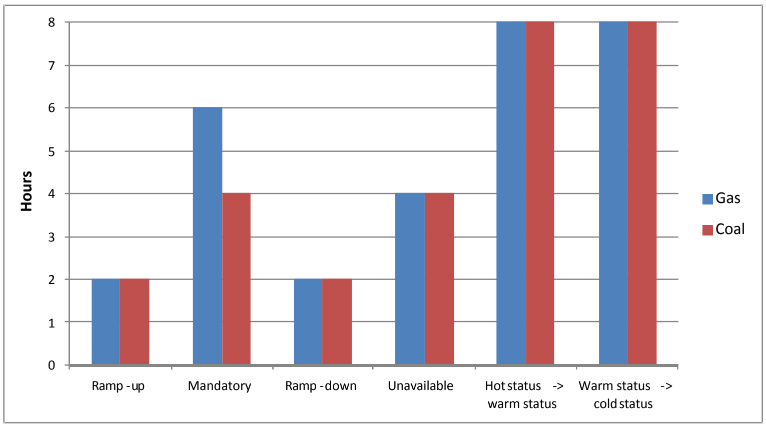

Figure 8:
Overview technical aspects thermal power plants

Current new build gas fired power plants are more flexible than coal fired power plants(Vos 2012)(Meray 2011). Gas fired power plants have lower start-up times and are able to quicker ramp up and down. According to the technical details of (European Climate Foundation 2010) in the future coal fired power plants will become as flexible as gas fired power plants. As is described in (International Energy Agency 2011) coal fired power plants are catching up with gas fired power plants on flexibility. However, it might be true that coal fired power plants are catching up, it is seems debatable whether coal fired power plants will become as flexible as gas fired power plants. The initial model has been based on the characteristics of (European Climate Foundation 2010), however, further research will need to be performed to see the impact if coal fired power plants will not fully become as flexible as gas fired power plants.

Financial characteristics of thermal power plants

Once a power plant has been build, the fixed cost should not matter anymore for deciding which power plant to operate. Instead the variable cost should determine which plants to operate. In Figure 9 the variable cost are shown, including fuel cost and CO_2 cost, but without cycling cost.

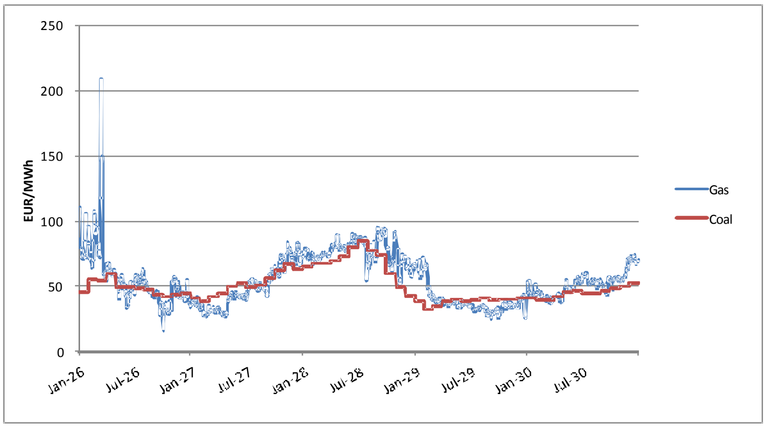

Figure 9:
Variable cost for thermal power plants[5]

[5] An efficiency is assumed of 61% for the gas fired power plants and 50% for the coal fired power plants, which is based on an average usage.

Marginal cost of gas fired power plants are in approximately 60% of the hours higher than those of coal fired power plants. Gas prices tend to have a more seasonal pattern. A seasonal pattern would give gas fired power plants an edge in summer and coal fired power plants a cost advantage in winter.

In Figure 10 the a verage cost including fixed cost and cycling cost are given for a gas and goal fired power plant. In appendix C an overview of the underlying assumptions is given. The fixed and CO_2 cost are higher for coal fired power plants, and the fuelcost are higher for gas fired power plants. The average price of coal fired power plants is only minimal lower than those of gas fired power plants.

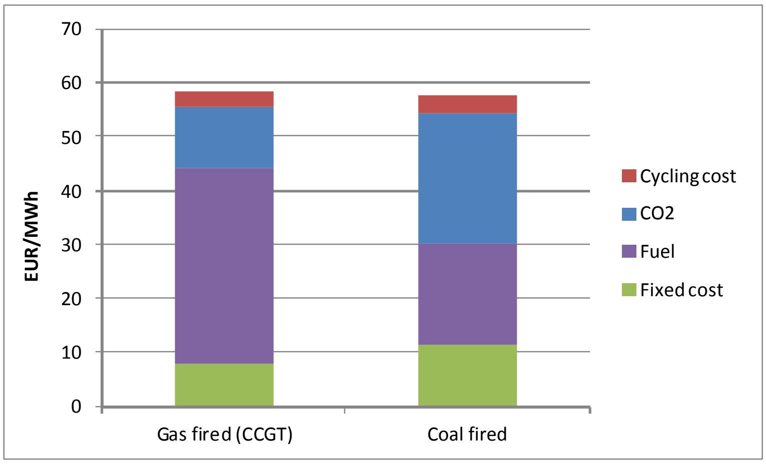

Figure 10:
Overview average cost of thermal power plants

Results from the model

At the time of writing this paper, the model was in development. In this section the first results of the model are shown. In the coming period, the model will be expanded further and sensitivity analysis will be performed.

The model has given various results. First is discussed which power plants are most cost efficient to build for varying levels of electricity from renewable energy. Then the usage of these power plants is looked at. And finally the impact in gas demand, both the absolute demand, as well as the needed flexibility.

The model has calculated several cases. The first variable is the contribution of renewable energy. This variable is varied from 0% renewable energy to 50% renewable energy in steps of 10%. The second variable is the ratio between gas fired power plants and coal fired power plants. This variable is varied between 10% gas fired power plants and 90% gas fired power plants in steps of 10%. The third variable is the total capacity of all power plants combined. This variable is varied from 97.5% (i.e. the demand cannot be fulfilled completely) to 200% through 100%, 105%, 110% and 125%. This leads to a total number of 324 cases. For all of these cases, the model has calculated the hour-to-hour supply generated by the available power plants, and the costs associated herewith.

In Figure 11, the relative contribution of gas and coal fired power plants is given as a function of the contribution of renewable energy. The total capacity of all power plants combined was 200% of the total demand, and the model had 50% gas fired power plants and 50% coal fired power plants, so that the demand could on each moment in time be supplied fully with either coal or gas fired power plants. In other words, there were no limitations on the amount of power plants available, and the model was on each moment in time free to choose the power plants with the lowest marginal costs.

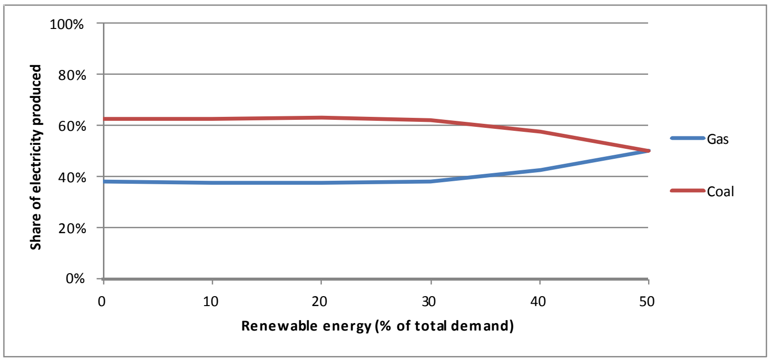

Figure 11:
Relative contribution of thermal power plants

Figure 11 shows that when the contribution of renewable energy is (relatively) low, the ratio between coal- and gas fired power plants is approximately 60% to 40%. This coincides with the ratio of coal versus gas prices: in 60% of time, coal has the lowest marginal cost. When the contribution of renewable energy increases however, the contribution of gas fired power plants increases. This cannot be explained by marginal costs, and is therefore related to the technical constraints of the coal fired power plants. The demand cannot be fulfilled any longer by coal fired power plants.

To verify this hypothesis, in Figure 12 the total supply and residual demand are plotted as a function of the contribution of renewable energy. The residual demand decreases as the contribution of renewable energy increases. The total capacity of all power plants combined is 100% of the total residual demand, in other words, there is no overcapacity. What can be concluded, is that as the contribution of renewable energy increases, the residual demand can be fulfilled if the majority of power plants are coal fired. However, as the contribution of coal fired power plants increases, the non-delivery increases significantly. In the 50-50 scenario, the residual cannot be fulfilled for any contribution of renewable energy. This has to do with the technical limitations related to stops and starts of power plants, and indicates that there will be a need for some overcapacity.

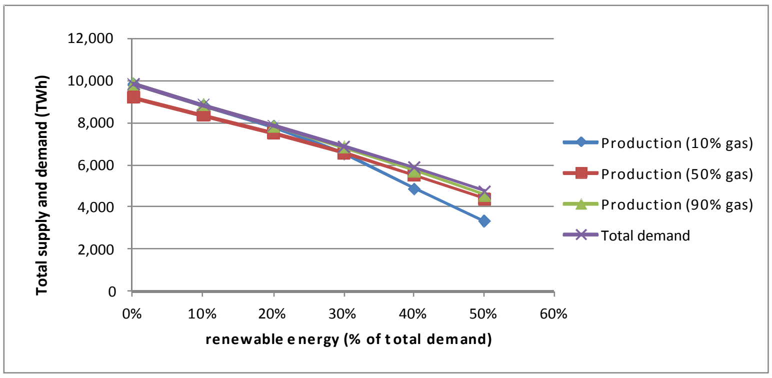

Figure 12:
Supply versus demand as a function of gas share

In the model, there is not yet a penalty on underdelivery. When looking at the total costs, and accepting underdelivery up to a given level, there are several scenario's in which the residual demand can be fulfilled when there is a 50% contribution of renewable energy. The least expensive scenario is the scenario in which there is a 90% contribution of gas fired power plants. However, more work is to be done to draw definitive conclusions. In a next step, a penalty for non-delivery will be added to the model, so cost can be more accurately compared.

Conclusions

In this paper, a model has been build that, based on assumptions of both technical characteristics, operational requirements and market conditions can calculate cost associated with a given mix of power plants for different market demand scenarios. Based on the model, conclusions are drawn on the most cost efficient power mix and the role of natural gas in case the share of renewable energy increases.

First results indicate that from a technical point of view, the flexibility of gas fired plants is still needed to fulfil the residual demand not filled by renewable energy. As the contribution of renewable energy increases, demand can no longer be fulfilled by a mix that contains a majority of coal fired power plants. Off course, much will depend on the assumptions that are used, and much work is needed to study sensitivities. Nevertheless, the current model seems fit to be used as the basis for these studies.

What can also be concluded, is that the usage of the natural gas for electricity production will change: the absolute level will decrease as a result of an increase in renewable electricity, but also the pattern of the natural gas consumption. Variable renewable electricity production from wind and sun is more volatile in summer than in the winter. This will also impact the natural gas demand, which will be more volatile especially in summer.

The current model seems an excellent starting point for these investigations, and first results indicate that gas is indeed the fuel of choice in combination with a larger share of renewable energy. Further sensitivities need to be performed in order to determine the aspects on which natural gas has to focus to make sure it is the “fuel of choice”.

Appendices

Appendix A: Estimated renewable electricity production

Three types of renewable energy are included: wind, sun and biomass. Biomass is assumed not to be dependent on the climate conditions, while wind and sun are. In order to be able to make use of the correlations between wind and sun, wind speed data and sun duration data for the same time period on the same location has been used. Wind speed and sun duration information is given on a daily basis by the European Climate Assessment & Dataset (Klein Tank 2002) for a large number of weather stations within Europe.

From the available whether stations, seven[6] locations have been used for the renewable energy production. The chosen stations are spread out over the market area including locations offshore, close to sea and inland, and should therefore give a proper representation of the wind and sun in the market area.

In the paragraphs below will be explained how wind speed and sunshine durations are transformed in an electricity profile. European Climate Assessment & Dataset (Klein Tank 2002) gives daily data, while the model uses hourly data. Therefore a profile within the day has been distilled for wind and sun data.

Wind

KNMI (KNMI 2011) publishes wind speed data on an hourly basis for various locations in the Netherlands. For four[7] locations spread-out over the Netherlands, for each month, an average hourly profile has been calculated based on the hourly data from 2006 to 2010.

The relation between wind speed and wind electricity production has been based on (University of Edinburgh 2006) and is shown in Figure 13. The minimum threshold before the wind turbine start producing electricity is 4 m/s, between 4 m/s and 15 m/s the electricity output increases as the wind speed increases, between 15 m/s and 25 m/s it is on plateau, and with wind speeds above 25.5 m/s the turbine is shut off and no electricity will be produced.

[6] Fuerteventura (Spain), Saarbrucken (Germany), Kassel (Germany), Helgoland (Germany), List (Germany), De Bilt (Netherlands) and Westerdorpe (Netherlands). Fuerteventura is not located in the market area itself, it is located closely to the market area. Because of a lack of data from weather stations in France, this weather station has been chosen.

[7] Off-shore location K13, Terschelling, De Bilt and Valkenburg

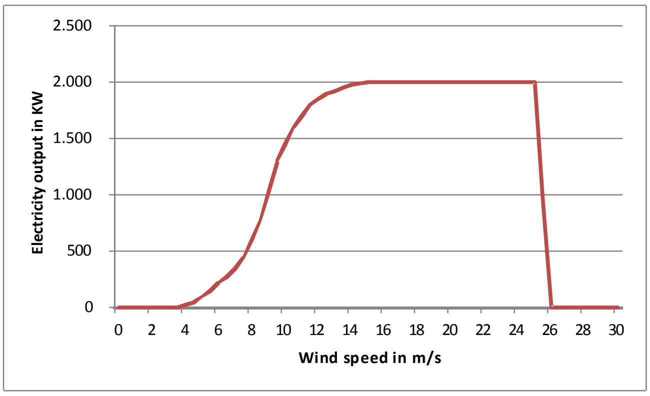

Figure 13:
Relationship between wind speed and wind electricity production

For each location the hourly wind electricity production is calculated, and summed together. Because of the non-linear relation between wind speed and electricity output it is important to first calculate the electricity output per location and add these up to the total electricity output.

Solar

There is a linear relation between electricity production from solar PV panels and global radiation. Global radiation is the amount of solar energy that passes through the atmosphere reaching Earth (mpoweruk.com 2011). Based on the relationship between the sunshine duration, the days length and the extra-terrestrial radiation as described in (Rietveld 1978), the global radiation for a specific point on a specific day could be calculated.

In order to calculate the global radiation the relative sunshine is needed, which is the percentage of sunshine from the maximum number of sunshine possible. (KNMI 2011) publishes the relative sunshine on a monthly basis (as the sunshine duration fraction). The daily relative sunshine for the seven locations is estimated by taking the daily sunshine hours and dividing it by the monthly average of maximum hours of sun. In Figure 14 the daily maximum hours of sunshine are shown for De Bilt: in the summer there are more than twice the amount of sunshine hours compared to winter.

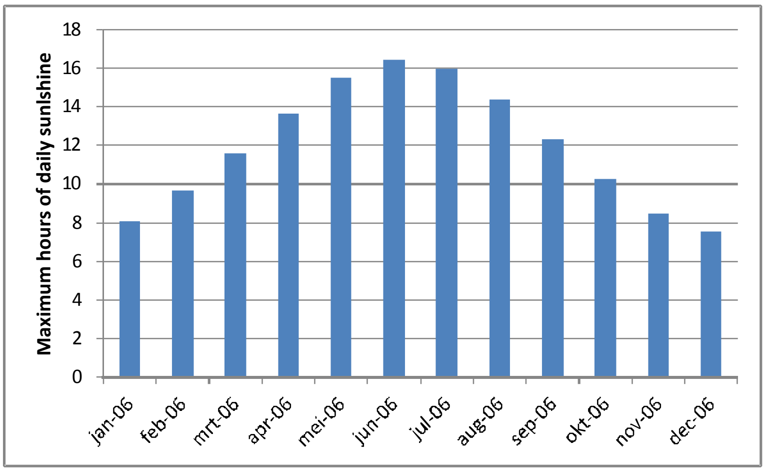

Figure 14:
Maximum hours of daily sunshine for De Bilt

Only part of the sun light is converted to electricity. It is assumed that the efficiency of the solar PV is constantly over time.

Biomass

Different from wind and solar, biomass production is not dependent on the climate conditions, instead it is dependent on whether the biomass-plant is available and whether there is sufficient feedstock accessible. According to (U. S. Environmental Protection Agency Combined Heat and Power Partnership 2011) an operating availability of between 92% and 98% for a well-designed biomass steam system should be achievable.

The biomass profile has been based on the summation of 50 binominal distribution, representing whether a biomass power system is working or not. Each biomass power system is of the same size, and each has a 90% probability of producing at full capacity and 10% of not producing at all for a certain hour.

Appendix B: Technical aspects of thermal power plants

The capacities given in Table 1 are the nameplate capacities. Once a power plant has been in operation for some time, it will not be able to reach these nameplate capacities. For the model it is assumed that the nameplate capacities are applicable throughout the lifetime of the plant.

The availability of a power plant has been included into the model by assuming that the availability multiplied by the capacity is the capacity available at all times.

	Coal fired power plant	Gas fired power plant
Capacity (MW)	1600	830
Availability (%)	90.2%	91.2%
Ramp up / ramp down (% of max output)	40%	50%
Min. stable load (hours)	50%	40%
Life time of plant (years)	40	30

Table 1:
Technical information of conventional power plants based on (European Climate Foundation, 2010) (Mott MacDonald, 2010, pp. 77-79)

Power plants can be operated between minimum load and the available capacity. When plants are operated on a lower usage level, this will negatively influence the efficiency, and vice versa. (Vuorinen 2011) gives more details on the relationship between usage and efficiency, which has been used for determining Figure 15.

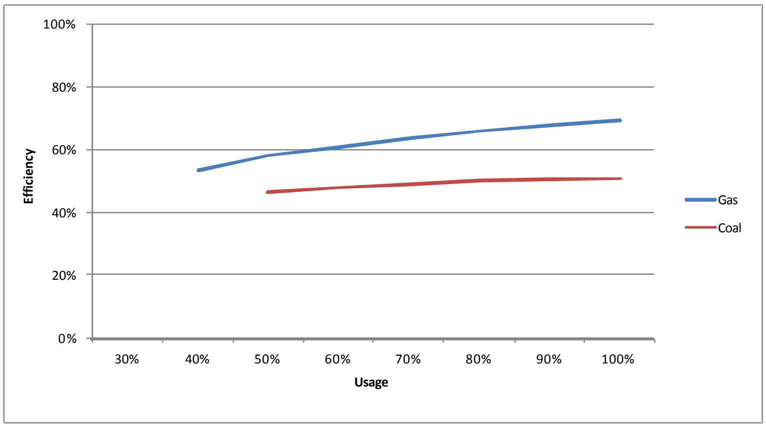

Figure 15:
Relationship between efficiency and usage (based on Vuorinen, 2011)

Figure 15 gives the efficiencies in case of a constant usage of the power plants. It is unclear what the impact is on the efficiency if power plants are not producing on a constant level but instead are fluctuating their production. For the model it is assumed that this has no impact on the efficiency.

The capacity, availability and life time of the various plants are based on (Mott MacDonald 2010, 77-79), the maximum ramp-up and ramp-down percentages, the minimum stable load and the minimum up and down times are based on (European Climate Foundation 2010).

Starting or shutting down production from a conventional power plant happens with a ramp-up or ramp-down period. During this period the power plant increases or decreases its production to the requested capacity. According to (European Climate Foundation 2010) a coal fired power plant can increase or decrease its production in one hour by 40% of the maximum capacity and a gas fired power plant with 50%. This would mean that a coal fired power plant could reach its maximum capacity in 2.5 hours and a gas fired power plant in 2 hours. For the model it is assumed that the ramp-up will be linear from 0% to 100% and that the average capacity over an hour is produced.

A gas fired power plant will during the first hour produce 25% of the maximum capacity and during the second hour 75% of the maximum capacity. For a coal fired power plant the first hour 20% of maximum capacity, the second hour 60% of maximum capacity and the third hour 95% of maximum capacity. Because the coal fired power plant can during the third hour practically produce the full capacity, it is assumed that the coal fired power plant has a ramp-up period of only two hours. For the ramp-down capacity the reverse percentage of the ramp-up are assumed: for a gas fired power plant the first hour 75% and second hour 25%, for a coal fired power plant 60% the first hour and 20% the second hour.

Appendix C: Financial information thermal power plants

There are multiple sources which give information about the estimation of costs for building and operating a power plant (see for instance (International Energy Agency 2011), (International Energy Agency 2010), (European Climate Foundation 2010). The input for this section on the long term cost is based on the medium cost estimation for a "next of a kind" power plant reported in ((Mott MacDonald 2010)). Similar to ((Mott MacDonald 2010)) a discount rate of 8% has been used. The fixed cost are presented in Table 2 and the variable and maintenance cost in Table 3.

	Gas fired power plant (Combined Cycle Gas Turbine)		Coal fired power plant[8]	
	Cost (mln EUR)	Time (years)	Cost (mln EUR)	Time (years)
Pre-development period	45.8	2	140.8	3
Construction period	610.2	2.5	3008.5	4
Fixed operating cost (yearly)	26.6	n/a	98.6	n/a

Table 2:
Long term cost of power plants (source (Mott MacDonald, 2010))

	CCGT	Coal
EUR/MWh	2.0	1.8

Table 3:
Variable operational and maintenance cost (source (Mott MacDonald, 2010))

An overview of all the associated cycling can be found in (Denny 2007, 67) including a range between the minimum and maximum cost for cycling. The model assumes each cycling has a fixed amount of cycling costs associated with it depending on whether the power plant is in hot, warm or cold status and are incurred at start-up. The power plant operator is aware of these costs. These cycling are based on the middle of the range given by (Denny 2007, 67) and are given in Table 4[9].

EUR/MWh	CCGT	Coal
Cold start	1,3	1,5
Warm start	2,4	2,5
Hot start	3,0	3,3

Table 4:
Cycling cost in the variable cost in EUR/MWh

CO_2 emissions are dependent on the efficiency of a power plant, which in turn is a function of the usage of a plant. The amount of CO_2 emitted per produced MWh of electricity are based on (International Energy Agency, 2011, p. 94), where the average has been taken for an efficient plant and less efficient plant has been taken for the year 2020.

[8] Based on a pulverised fuel coal plant
[9] Assuming that a gas fired power plant uses Heat Recovery Steam Generator (HRSG) boilers and the coal plant a subcritical drum boiler.

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