Karlsruher Institut für Technologie

Interdisciplinary Project - Assignment

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Evaluation and modeling of a Virtual Power Plant – Karlsruhe case study

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Abstract (Dhruv)

A Virtual Power Plant (VPP) was constructed to meet the electricity demand for the city of Karlsruhe for every hour in the span of one year. It involved a detailed consideration of all technologies where the energy could be generated and stored. Various potential sources of energy were evaluated on the basis of economic, environmental and technological viability. Rooftop solar PV for peak load and gas turbine for base load were found to be most suitable and were finalized for use in VPP. Lithium ion batteries were chosen as the appropriate storage technology, while import and export from gird was used to balance the load curve on remaining hours. The calculation for the cost and capacity of different technologies to be installed was done with the help of the VPP Optimizer model. Under a set of assumptions, the total cost of the VPP and share of each technology was calculated using the model for two scenarios- the present 2017 and the future 2030 to satisfy the load demand. It was observed that marginal costs would be responsible for the greatest contribution to total VPP cost in the future. Solar energy was concluded to be the only currently viable source of renewable energy in Karlsruhe.

1. Introduction (Dhruv)

A virtual power plant acts like a control center for the energy generation and distribution across the whole city. It aims to manage the energy coming from different sources like wind, solar, grid, storage, thermal power plant and distribute its load at each moment of time in the most economical way to match the energy demand of the consumers in the city. Our virtual power plant will consider the city of Karlsruhe and control the electricity demand of the whole city.

Cost can be analyzed in different ways with varying levels of detail. For a primary investigation, the Levelized cost of electricity generation (LCOE) were used. The reason for choosing this simplified approach was the wide range of energy sources and their technologies which would be considered because LCOE is already a widely used method used in different renewable energy technologies. [27]. For the secondary calculations, annualized cost was used as described in chapter 4.3.5.

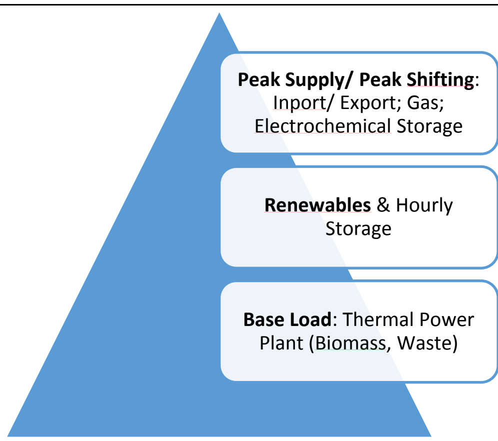
2. Aim / Concept of the VPP (Imke Hebbeln)

Two main points can summarize the aim of the project:

1. To identify the available and feasible primary energy resources for Karlsruhe and to evaluate the technical, environmental, and economic feasibility of the different technologies as well as their capability of contributing to the load demand curve.

2. To develop an electricity mix, which matches with different load development scenarios and sets of pre-defined targets based on research and trends.

The concept of VPP was set up based on the concept in Figure 2.1



1) achieving a share of 15% renewables

2)establish a maximal economical feasible electricity mix

3) evaluating the feasibility of storage integration in the VPP

4) fulfilling the demand curve of Karlsruhe to decrease the necessary import to below 1%

Figure 2.1: Concept and main targets and concept of the virtual power plant for Karlsruhe.

For fulfilling the demand of a city, it is crucial to provide a base load power plant, which can fulfill a stable base demand and has high reliability. Thermal power plants are especially suitable, due to their reliable power output that exclusively depends on the fuel fed and their low electricity costs.

Besides the base load plants multiple generation units or imports can contribute to fulfill the daily or hourly demand peaks. Suitable are either gas turbines, which provide a great generation flexibility or renewables. The implementation of fluctuating renewables can add up, combined with storage, to decrease the necessary installed base load power plant or to fulfill the peak demand. Due to their dependency on weather and daytime, they can just be a reliable generation unit if combined with a grid connection back-up connection or a storage device. If contributing to the base load supply, a daily storage must be added. If supporting peak supply, an hourly storage is sufficient. With an increase share in the targeted renewable fraction in the final electricity mix for a VPP combined with the limitation of import below 1%, the urge of increasing storage capacity rises to ensure the matching of the demand.

3. Load Data (Bruno)

The first point of reference to be taken into account for the design of the VPP is the load of the area which it is going to be overseen. The electricity demand for the area of study consisted in 105120 intervals of 15 minutes which covered the years of 2013 to 2015. In all the different years a typical week load profile was identified (Figure 3.1). This pattern in crucial for the proper functioning of the VPP since it is necessary to anticipate during which hour(s) of the day the peaks in the load appear. The importance of the peaks in the load profile is mainly related to the installed capacity necessary for the available technologies in order to meet the demand at any given time. In the area of study, the highest peaks in the load appear during the winter and there are typically two distinct peaks during the day. The typical summer day has a lower average consumption and only displays a load peak during noontime. The lowest load values during the day are as well higher during an average winter day than a summer day. Therefore to establish an annual base load for the VPP, the minimum load values during the summer are the most relevant. To establish the peak technologies and their respective generation, the maximum load values during winter are the most relevant.

Since the number of year for which the data is available is relatively low, no clear patterns can be assumed. The percentage at which the annual demand evolves (table3.1) is considerable different and without further year for comparison it is not possible to determine if the annual demand from 2013 is abnormally high or if is the result of a colder year. Since the annual demand of 2014 and 2015 have a lower difference between them they are assumed to be within the average range.

Table 3.2. Comparison between annual demands between 2013 and 2015

Year	Annual Demand $[GWh]$	Evolution $[GWh/yr]$	Evolution $[\%/yr]$
2013	689,5958	-	-
2014	669,2499	-20.3459	-2.95
2015	664,1485	-5.1014	-0.76

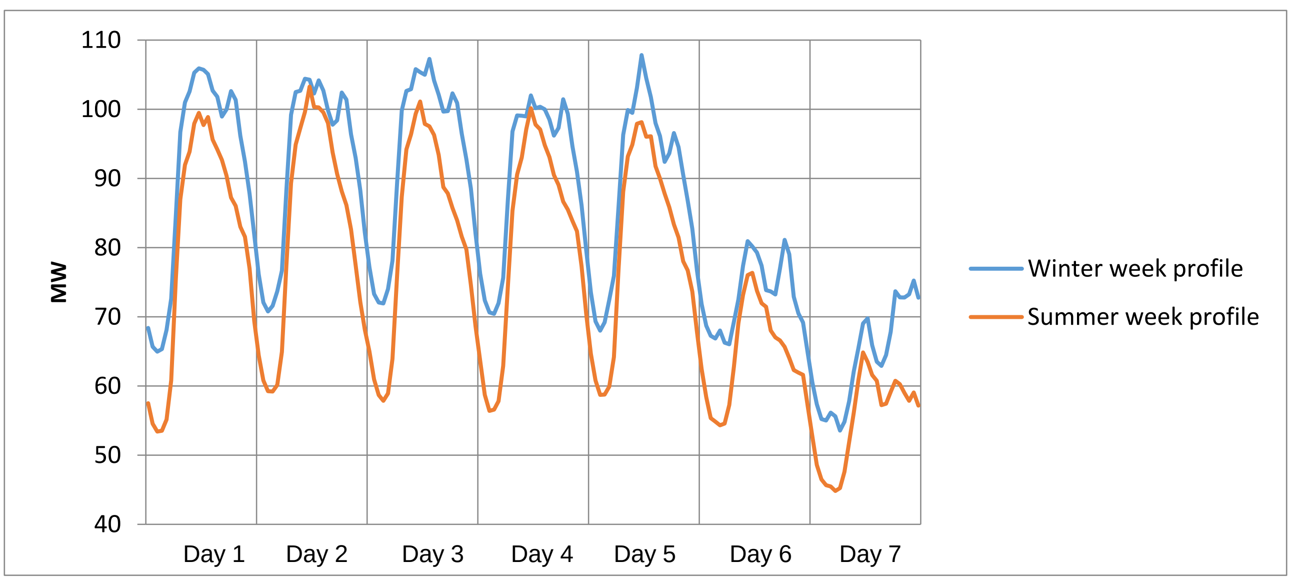


Figure 3.1. Load profile of a typical week in summer and winter

3.1. Load Data development (Imke Hebbeln)

For the implementation of future scenarios as well as an implementation of a VPP that meets also future the demand, it is crucial to analyze the possible development of the demand curve.

Research in the future demand of e-mobility as well as the development of the city Karlsruhe, resulted in two scenarios:

1) Constant Demand:

For the first scenario the development of the population in Karlsruhe has been compared to the electricity consumption in private households per habitants. The results in figure XY show, that an increased demand counteracts the increased efficiency for domestic costumers. The scenario is based study from the city of Karlsruhe, which implies that an increased electricity demand due to automatization will be encountered by an increase in efficiency [41].

1) Increase in demand due to an increased amount of EV

In this scenario EVs are expected to be responsible for 0,1-0,2% by 2020 and 1,3-1,6% by 2030 of total electricity consumption [51] The DIW released a paper in 2015, that the impact of EV's on the demand curve in the future will depend on incentives regarding the charging behaviour of the customers. If the charging is cost driven, the charge occurs during off-peak hours or high generation hours, when the electricity prices are low. This way, EVs can support the flattening of the demand curve. If the price is user-driven, the EV will increase the already existing demand peaks, since the will always be charged directly after usage.

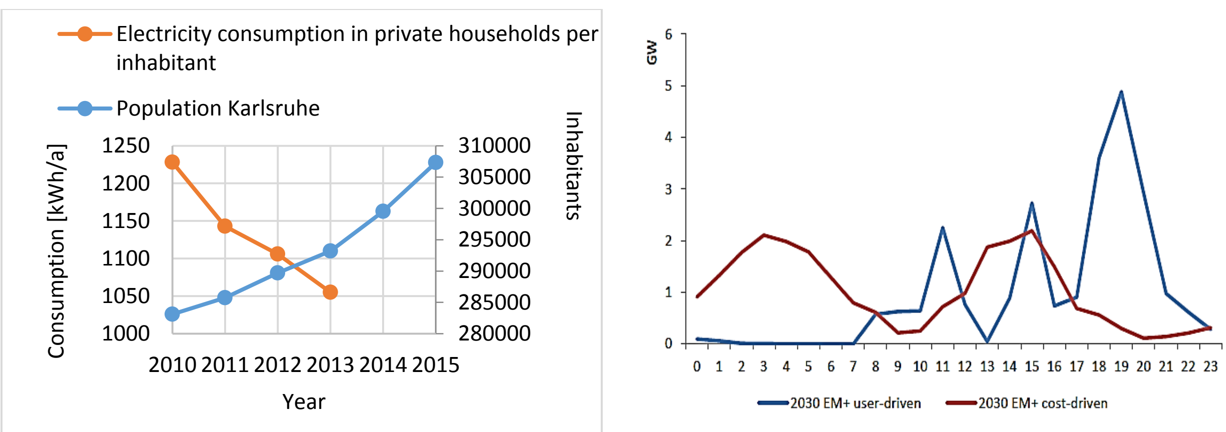


Figure 3.2: Development of the population and electricity consumption for private household in Karlsruhe (left). User and cost driven models for the impact of EVs on the daily demand curve [51].

4. Potential Energy Technologies

In this chapter different potential energy sources and technologies are analyzed for the area of Karlsruhe. The assessment of the different technologies is done taking into account their economic viability, environmental impact and risk analysis regarding the implementation of the technology.

4.1 Wind (Dhruv)

Energy from wind is generated through the kinetic energy in the wind flow and converted to electrical energy using Wind turbines. It is one of the most used forms of renewable energy because of comparatively high efficiency, mature technology, minimal operational cost and negligible pollution. Generation of energy from wind draws three main types of criticisms-

The noise generated from wind turbines have been known to be a matter of annoyance for some people, especially at 40 decibels of higher. But a study observed that annoyance is more of a result from attitude and visual cues of the wind turbines than the noise itself. Till date, no direct causal link between physiological health effects in people living in proximity to wind turbines and the noise from them has been found in any peer-reviewed research [3]. Regardless, the noise level can be kept under check by remaining under the standard 45 dBA noise limit in Germany [4], by keeping a recommended minimum setback distance of 300-600 meters between wind turbines and residential areas [5]

Wind turbines are also popularly known to cause harm to birds and bats around the area where they are set up. However, a 2012 study only found the adverse affects on bats nearby and no significant affect on birds, so it was recommended to build small scale wind turbines at least 20m away from potentially valuable bat habitats [6]. It is also worthy to note that other types of power plant, buildings and power lines also pose more or similar harm to birds and bat population in the region. Hence this criticism is unfounded when compared to other energy technologies.

The third and the biggest criticism of wind is that it generates highly irregular and variable energy, which depends a lot on the region's flow of wind over the year. The following chapter shows the potential for generating wind power in Karlsruhe.

4.1.1 Potential in Karlsruhe

The power generated from a wind turbine depends on the factors described in the following equation. [7]

$$P = 0.5 * A * v^3 * Cp * \rho \qquad (1)$$

where the generated power (P) is given in Watts, the swept area (A) in square metres by the wind turbine blades, the air density (ρ) in kilograms per cubic metre and the velocity (v) in metres per seconds of the wind coming on the blade. Cp is the maximum power coefficient ranging from 0.25 to 0.45 (max

Betz limit = 0.59) [7]. The value of Air Density changes with respect to temperature,. at a temperate of 20 degrees, it's value is 1.20 kg meter cube [8].

The measurements for wind speed are typically given at a height of 10 meters [7]. For varying height of turbines, the speed of wind at different altitudes can be calculated using the Hellman exponent law.

$$V_2 = V_1 (\frac{H_2}{H_1})^{\alpha} \qquad (2)$$

where V_1 and V_2 are the wind speeds at height H_1 and H_2 respectively. α is the shear wind coefficient which depends on the friction in the air.

As seen in equation 1, The most sensitive variable for wind power generation is wind speed. Karlsruhe has an annual average wind speed of 3 m/s at 10 meters [9]. For a successful wind project, an average annual speed of 6.1 m/s at a height of 50 meters is required [10]. Using the Hellman exponent law, with shear wind coefficient for small town as 0.30, Karlsruhe's annual average wind speed at 50 meters is 4.9 m/s. This is significantly less than the required speed for an economically successful project. It is important to note that this is a simplified calculation for wind potential in Karlsruhe, actual data may vary depending upon a variety of other parameters of a site like landscape, topography, local roughness coefficients etc. [11].

To comprehend how low the wind speeds actually are in Karlsruhe, Figure 1 gives a good estimation of the number of days a certain wind speed is reached in Karlsruhe. It can be observed that, the speed barely manages to cross the threshold of 5 m/s in 15-20 days a month on average. Moreover, it never really reaches the maximum power generation output speed of 14m/s, except for around 15-20 days in the whole year [12].

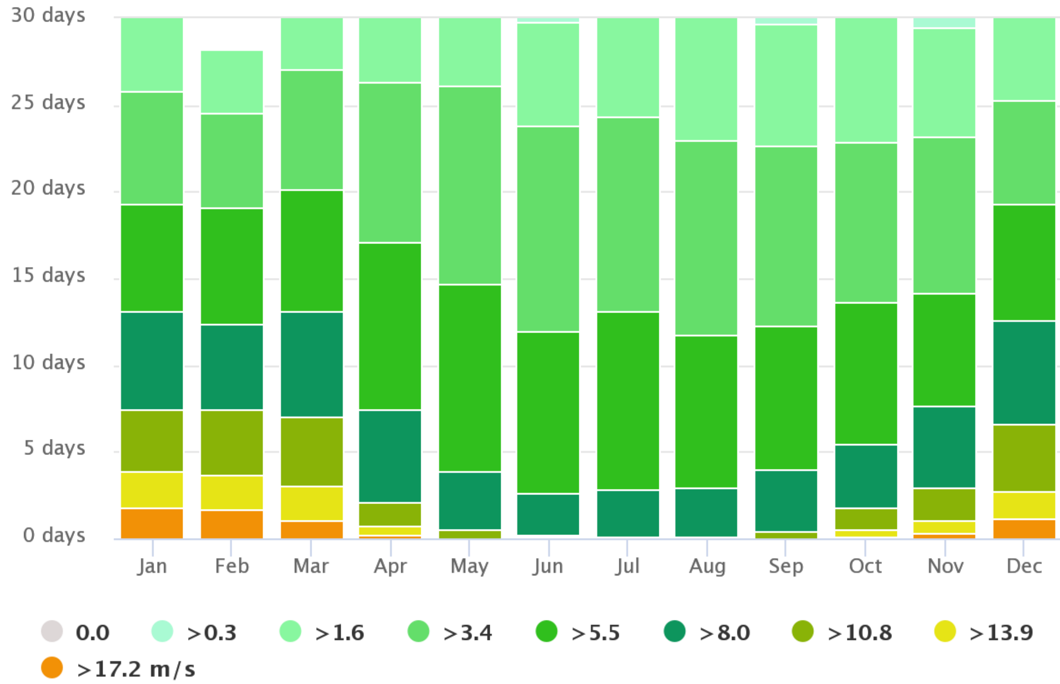


Figure 4.3.1 Wind speed in Karlsruhe in different months of year [12]

4.1.2 Cost evaluation

Wind energy is known to be the most cost effective source of energy. The estimated levelized cost of wind power generation is from 30-71€ Per MW/hr [16]. which is a cheaper than almost all other sources of power generation. Costs of electricity generated from wind turbine from Karlsruhe is estimated to be between 6.7 and 12.6 €ct/kWh [13].

The actual precise costs are dependent on situation and the company offering the wind turbine. But it is estimated that the total installation cost of a wind turbine in Germany is 1300€ per KW which includes price for turbine, cost for foundation and grid connection. Around, 80% of this cost is the price of the turbine [14]. Approximately 22,000 million € will be saved per TWh of energy generated using wind compared with oil over the lifetime [14].

4.1.3 Conclusion

Wind power was rejected as a source of energy for VPP solely because of lack of wind speed and potential in Karlsruhe . It would be economically inefficient to invest in wind power plants when they would never work at their full potential.

Nearby areas around Karlsruhe hold a better potential of wind generation. The feasible potential for wind power in the state of Baden Württemberg was estimated between 11.8 TWh and 29.1 TWh at costs between 6.7 and 12.6 €ct/kWh [13]. Most of the areas with potential for wind power generation lie in the north east part of Baden Württemberg [15].

4.2 Geothermal (Dhruv)

Geothermal energy is the energy stored below the surface of earth in form of heat. Conventionally, it has been popularly used for heating purposes and electricity generation in areas near tectonic plate boundaries (volcanic plains or hot springs), but has been historically limited to those areas. Recent developments have explored the concept of extracting heat from hot dry rock beneath the ground. This is known as deep geothermal energy, which is typically defined for depths below 1km and temperatures exceeding 60°C [17]. Enhanced geothermal system (EGS) refers to a series of engineering methods to artificially create underground steam and hot water resources which could be used to generate electricity. These processes involve fracturing of hot rocks 3-5 km below surface, injecting fluid in those newly created porous rocks and then extracting the heated fluid to run a turbine and generate electricity. Due to unavailability of any volcanic reservoir or hot water springs in Karlsruhe, the potential for geothermal power production through EGS plants using heat 3-5 km below the surface was the only geothermal source, that was evaluated.

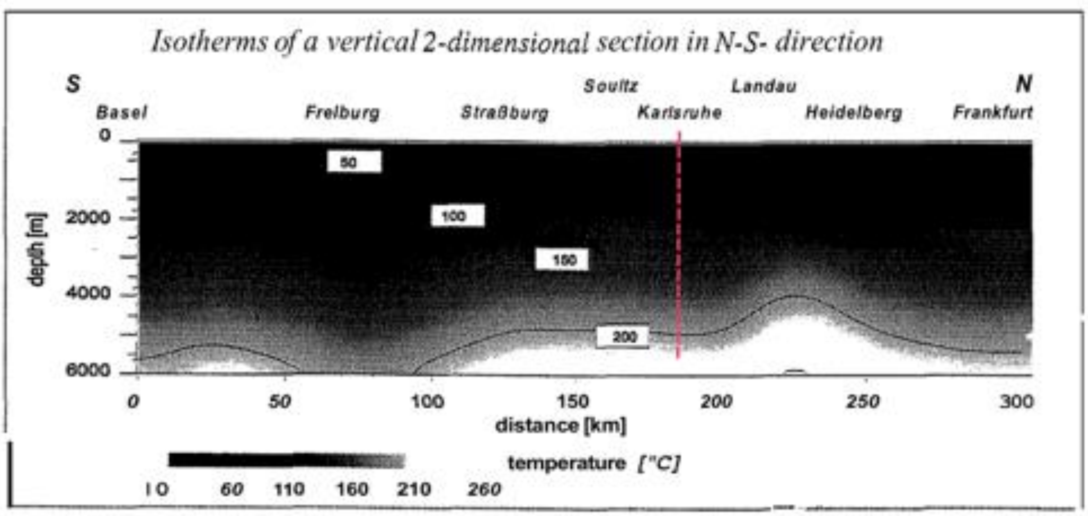


Figure 4.2.1 Temperature at various depths in and around Karlsruhe [19]

4.2.1 Potential in Germany & Karlsruhe

According to one research from 2003, the total technical potential for geothermal power generation in Germany is 300,000 TWh without including the potential for heat generation in it. This corresponds to about 600 times the annual electricity demand of all of Germany. About 95% of this potential is calculated to come from crystalline rocks below the surface [18].

Another report from 1999 which analyzed 300kms of surface of upper Rhine area from Frankfurt to Basel, (including Karlsruhe), estimates the technically usable terrestrial heat, suitable for production of electricity in that area to be 1000 times the yearly energy consumption of Germany [19]. It is important to note that the estimated values of potential should be regarded as the upper limit because the exploitation technology is not fully developed and the resources necessary for its development are not known in a comprehensive manner. Figure 4.2.1 shows the temperature of rocks beneath the ground in Karlsruhe according to that study. The higher the temperature level below ground, the better the efficiency of power generation. Karlsruhe has estimated 200°C of rock temperature at 5km depth [25]. Compared to rest of the cities in Europe as seen in figure 4.2.2, it has a huge potential for geothermal.

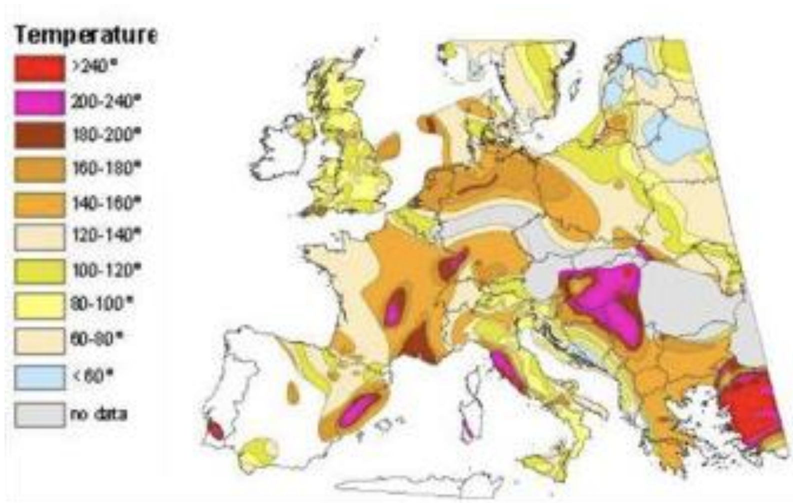


Figure 4.2.2 Temperature at 5km depth in across Europe [25]

4.2.2 Evaluation

The biggest advantage of using geothermal energy is the consistent all year round supply of base load electricity, uninterrupted by weather conditions and fuel costs. It provides an appropriate renewable alternative to base load thermal power plants running on conventional fuel like coal and gas. Although, it does release some trapped greenhouse gases from rocks, during the drilling phase of EGS plant, production of electricity from it can essentially be called as generating zero net greenhouse gas emissions [20]. However, the technology has some serious limitations. The following points made the EGS technology unviable for use in our Virtual Power Plant-

1. Immaturity of technology

Currently, very few EGS plants exist, those which do are still in research and pilot stage. Many pilot projects are being tested out across the world. Soultz-Sous-Forêts is France and Germany's leading research EDS power plant (1.7MW) which lies on the upper Rhine region. It makes use of 200°C hot rock at 5km depth through 4 boreholes [21].

2. Very high capital and levelized costs

The costs of a commercial EGS power plant are difficult to calculate accurately because the existing power plants are designed for research and not power production, but it is estimated that capital costs of EGS plant would be roughly twice as much as a traditional geothermal plant, which makes it a very expensive choice [22].

A study by Setis GmBH [23] estimated the start up costs of a small EGS plant extracting from a 5 km depth to be 13,000€ / kWh today with drilling costs typically being 30-50% of total cost of the plant. For reference, just drilling two boreholes to a depth of 3 km will cost around 14 million euros. The piping costs would vary between 200€ - 6000€ / meter in urban areas [23]. While the LCOE for conventional high temperature geothermal plants are cheap, ranging from 50€ - 90€ / MWh, the levelized costs for EGS power plants are very high, between 200€ - 300€ / MWh as of 2012 [23].

3. High failure rate

There is a high exploration risk of drilling a geothermal well and not finding the reservoir of adequate quantity of quality required at this stage [17]. In fact, The success ratios for it is estimated to be as low as 20% and no higher than 60% [23].

Other negative impacts of this technology include potential to induce seismic disturbances and earthquakes. Visual and odor related negative effects on surrounding areas are also a downside.

4.2.3 Conclusion

Electricity generation from geothermal energy is a serious option as a renewable energy source in the long term future (25+ years) in Karlsruhe and Germany even if only a fraction of the estimated potential can be used. This would require a strong push from the government with regard to policies, legal framework, research funding and support schemes. Further estimates of geothermal power potential on a regional and local scale need to be provided in detail with a thorough understanding of seismic, visual and odor related negative effects on the regions [24]. The advances in drilling technology would determine the adoption of the technology in future.

For now and the near future, EGS geothermal energy to produce electricity in Karlsruhe can be best described as an idea in nascent stage. Hence, it was rejected as a possible technology in our virtual power plant for all the mentioned reasons in previous sub-chapter.

4.3 Solar and Photovoltaic (Imke)

Over the last years, the implementation of photovoltaic increased strongly. In 2015 PV covered about 7% of Germany's electricity demand [4.5]. The advantage of using PV is the usage of local resource and the independency of the market fuel price. Disadvantages are the fluctuating availability of sun as a primary resource and therefore the small reliability and high back-up costs.

In this chapter two PV potential simulation software were applied:

1) PVGIS stands for "Photovoltaic Geographical Information System" which is being provided as a freeware from the Joint Research Center of the European Union. It provides the option to simulate an approximate PV electricity output per installed capacity for different system implementations as well as irradiation and further weather data. The database for Europe is based on an interpolation of long-term ground station measurements from 19981 to 1990 [39].
2) PVSYS is PV integration simulation software, which provides hourly data based on inputs regarding location and technology used [40]. The advantage of achieving the hourly available electricity for a system for an entire year, is the availability of considering the impact of PV as a fluctuating generation unit, which is crucial for the VPP optimizer in this report.

4.3.1 Potential in Karlsruhe

Major factors to be considered for the electrical design of a solar array are the sun intensity, the sun angle, the load matching for maximum power and the operating temperature.

The location of Karlsruhe is set on a latitude of 49°, an altitude of 8,4° at about 318m above sea level and results in the average daily global irradiation per square meter in Karlsruhe displayed in figure 4.3.1.

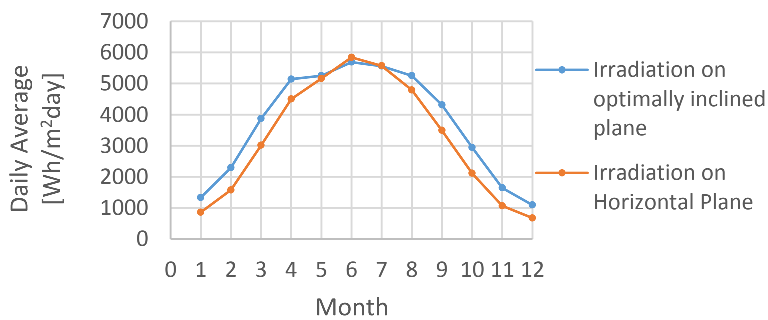


Figure 4.3.1: Global monthly irradiation based on PVGIS calculations [24].

Over the last years, the amount of installed PV capacity increased in Karlsruhe. The amount of energy received by PV in Karlsruhe in 2013 was to 24000 MWh, what results in an increase by 57% compared to 2011 [41]. Table 4.3.1 gives an overview of the installed capacity as well as the available potential for further installations in Karlsruhe for rooftops in 2013 [42].

Table 4.3.1:PV Installations and potential for Karlsruhe in 2013 [4.3]

		Existing in 2013	Further potential in 2013
Capacity available	[MW]	22.558	760.646

A research on already installed PV panels in Karlsruhe, resulted in an average hourly output per installed capacity of 0,1149 [43] in the years 2012 to 2016. The data neither give any information about the used technology, orientation and pitch of the panel or nor further information about eventual shading objects, thus can just be considered as reference values for state of art in Karlsruhe (Appendix 4.1).

4.3.2 Technologies available

For photovoltaic electricity generation, several technology options are available. Differences occur regarding module types as well as structural set-up and orientation. PV systems contain the module and the auxiliary components, such as inverters, structures and controls.

4.3.2.1 Module types

Crystalline Silicon Wafers represent the first-generation of modules. They use the wafer-based crystalline silicon (c-Si) technology, which can be separate in single (sc-Si) or multi-crystalline (mc-Si) and have decreasing performance with higher temperatures. In 2015 about 93% of the total production in Europe were Si-wafer based PV [44], with 68% mc-Si of total production. Mc-Si provide lower cell efficiency but are also less expensive.

Thin film PV technologies belong to the second-generation system and consist out of thin semiconductors which are deposit directly on large, inexpensive substrate such as glass. Therefore, they require up to 99% less material than crystalline solar cells. The lower capacity costs though have to compete with low module efficiencies and low c-Si module costs (figure). Examples for thin films are amorphous and micromorph silicon, Cadmium-Telluride and Copper-Indium-Selenide. In 2015, the market share of all thin film technologies amounted to about 8 % of the total annual production [44].

Due to the abundant space on rooftops in Karlsruhe, the high amount of already installed mc-Si in this area combined with the present high market share of mc-Si on the German market, polycrystalline modules will be implemented, which are expected to provide a reasonable cell cost-efficiency ratio (figure 4.3.2). The nominal efficiency of commercial mc-Si for STC conditions is around 16% [45] .

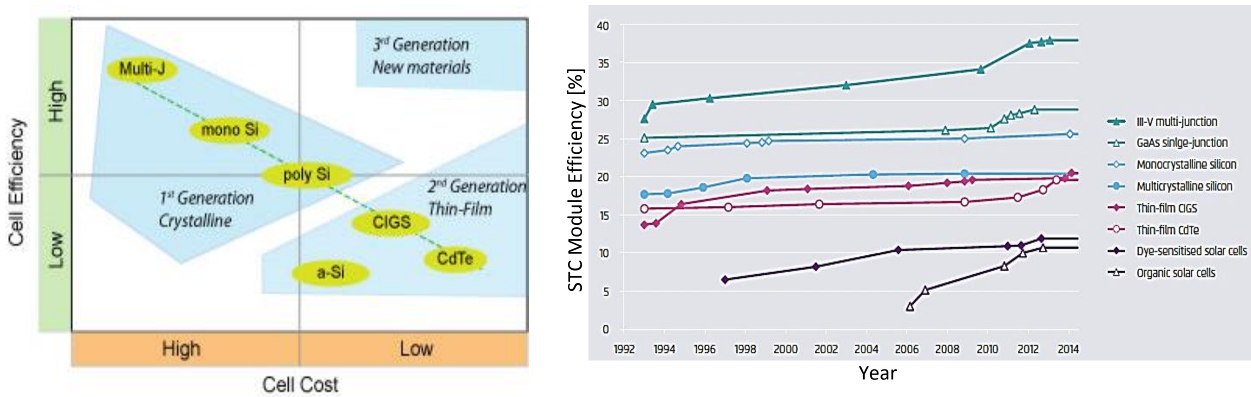


Figure 4.3.2 Overview of Cell efficiency-cost relationship of different modules (left) [31] and the development of module efficiencies over the last years (right) [30].

4.3.2.2 Structure

When analyzing the feasible structuring for PV in Karlsruhe, it will first be distinguished between different generation unit scales:

- Concentrating Photovoltaics (CPV)
- Rooftop (domestic scale <10 kWp, industrial roof scale 10-100 kWp)
- Ground mounted utility scale (>1 MW)

CPV collect the incident light by parabolic mirrors and focused on a small area. By focussing the light less semiconductor material is necessary which can be chosen as high-performing semiconductors. For being economical feasible, parabolic systems must be used in areas with GHI around 2000-2500 kWh/m^{2}a and with a high amount of direct light, since diffuse light can not be concentrated [47]. Since for Karlsruhe the GHI is below 1200 kWh/m^{2}a [39] this technology will be neglected for further electricity production.

Ground mounted installations provide the advantage, that they have no weight limitation and therefore can be sized on a larger scale, if an adequate area for the installation is available. This results in comparable lower PV generation costs. The range of the LCOE for ground mounted system in Germany in 2013 was 0,078-0,105 €/kWh [47].

Installing the modules with a tracking structure leads to greater efficiencies but with the trade-off of an increase in O&M costs as well as the necessary self-consumption of the tracking motor. It is to differentiate between 1-axis tracker, which follow the sun from east to west during the day and two-axis tracker, which additionally adjust to the optimal panel angle automatically throughout the year [48]. Advantages are an increase in the energy yield over the year, when compared to the fixed-array, as well as an achievement of high output performance during more hours during a day, since the azimuth tracker is adjusting to the daily sun path. Due to a lack of information regarding the total investment and O&M costs over the years as well as the actual benefits in Germany, table 4.3.2 provides the upper limit for the annual costs of different tracking technologies. The PVGIS software has been used to investigate under which conditions, a future application of tracked systems would be economically feasible. Therefore, the hourly capacity factor for PV has been defined by equation (3). The feasible annualized costs show the maximum costs for a utility scale power plant compared to the increasing efficiency towards fixed tilted planes. This is achieved by equation (4) [53]. No further benefits such as a more efficient space usage were considered.

$$CF_{PV} = \frac{\int_{t1}^{t2} E_{injected,AC}}{P_{p,installed} * \Delta t} \tag{3}$$

$$Cost_{annualized,max} = Cost_{average,fixed} * CF_{tracking,i} * 8760 \tag{4}$$

Where,

$E_{injected,AC}$	[kWh]	AC electricity injected to the grid within t
$P_{p,installed}$	[kWp]	Peak capacity installed
Δt	[h]	Time of the integral between t_1 and t_2; Δt =1 for the hourly provided values.

Table 4.3.2 PVGIS generation output for different tracking devices for the location of Karlsruhe (data appendix).

Tracking System:	Daily Production	Annual average Cf	Max annualized costs	Compared to fixed system
	[kWh/kWp]	[-]	[€/kWp]	[%]
Fixed	2,89	0,120	83,54	100,00
Vertical	3,69	0,154	106,67	127,68
2 axis	3,75	0,156	108,40	129,76
inclined axis	3,67	0,153	106,09	126,99

For Rooftop panels have a limited size and weight based on the available rooftop area and its stability. Based on a study provided by the Fraunhofer ISE, the scale of rooftop systems will be divided into small scale systems (<10kWp) and medium scale (10-100 kWp). The LCOE for small rooftop systems in Germany was between 0,098 and0,142 €/kWh in 2013 [47]. The higher LCOE compared to ground mounted systems, is potentially counterbalanced by a higher availability of unused rooftop space.

Due to the weight and size constrains, tracking will not be further investigated for rooftop systems. An alternative to tracking devices is the installation of manually adjustable structures, which can be optimize throughout the year. The structure and O&M costs are lower than for the tracking option and a higher energy output than for a fixed panel can be achieved. Figure shows the output for a different summer (20°), winter (55°) and all year fixed (35°) for the location of Karlsruhe. Due to a lack of sun hours in winter, it can also be feasible in Karlsruhe to fix the panel with a summer angle.

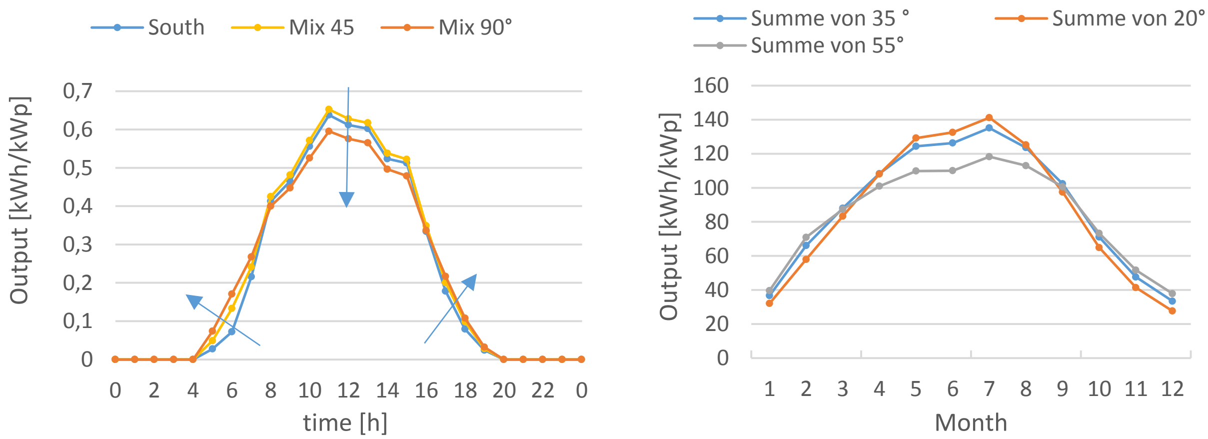


Figure 4.3.3 Impact of combination of different orientated panels (left) and the change due to different tilts when facing South (right).

With respect to the location of Karlsruhe and based on the simulated energy yields, it can be stated that the highest energy output per installed capacity is achieved, when adjusting the panels to the south. The Fraunhofer Institute ISE discussed the contribution of a distributed fixed panel orientation to the aim of meeting the daily load curve [49]. Even though the fixing of panels toward East and West leads to a decrease in the average energy yield per installed capacity, it widens the production curve, thus the time that PV contributes to the generation without being stored in batteries. For low module prices this option becomes more attractive compared to tracking system costs. Figure shows the DC output for capacity just directed to the south as well as a combination of 30% to the East and West and 40% installed to the South at 45° and 90°.

4.3.2.3 Inverter

The inverter converts the DC electricity produced from the PV modules into the AC electricity that is injected to the grid. The size and numbers depend on the installed PV capacity and the system design. They typically account for 5% of total installed system costs and their conversion efficiency for STC varies around 2% [50].

4.3.3 PV system for the VPP

Depending on the manufacturer and environmental conditions, 20-30 years lifetime for a PV panel can be expected and an average decrease of 0,1% per year in efficiency for the entire PV system[49]. For the calculations in this report, the simulated solar system will be assumed at constant module efficiency.

When looking at the space of rooftops available and the difference in average electricity costs, we will implement 20% big scale on rooftops (10-100 kWp) and distribute the other 80% by small scale rooftop systems (<10 kWp) within the city of Karlsruhe.

The electricity output per rated power is defined by equation (6).

$$\frac{E}{P_{peak,installed}} = \frac{h}{H_0} * \eta_{pre}\eta_{sys}\eta_{rel} \tag{6}$$

Where η_{pre} reflects the pre-conversion losses that occur before the beam hits the module surface (shading, snow, reflection), η_{sys} represents the losses of the system due to wiring, inverter and transformer, η_{nom} is the module efficiency for STC (G=1000 W/m^2; T=25°C) and η_{rel} the relative module efficiency which occurs due to a module efficiency decrease for an increase in temperature above STC.

For the simulated hourly PV generation values, equation (7) results in the hourly CF of the PV plant. Thus, it indicates the amount of installed capacity usable during $\Delta t = 1hour$.

Losses depend on site, technology used and the size of the system. The performance ratio measures the performance of a system throughout the operation period and is defined by equation XY. The average performance ratio for the simulated rooftop system is 76,7%, what is slightly below today's average, which lies between 80-90% [44].

$$PR = \frac{Actual\ Yield\ AC}{Target\ Yield\ DC} = \eta_{pre}\eta_{sys}\eta_{rel} \tag{7}$$

4.3.4 Concepts & Electricity output

Space in cities is limited. Due to the trend of further growing population and the comparable low competition of the rooftop space with other usage, the exclusive implementation of rooftop panels will be assumed. Combined with the outcome of the technology discussion, this results in two final model options, which will be further analyzed:

a) Fixed panels with (<10kWp): suitable for average domestic home rooftops [49]
b) Fixed panel large scale rooftops (10-100 kWp): suitable for larger walkable rooftops [52]

The different potential PV application scenarios were analyzed in the VPP optimizer, by using the resulting CF for the different options. It turned out, that for the given system the trade-off of installing the PV panels with different orientation did not lead to a decrease in battery usage or export that would be high enough to justify the decrease in production during peak hours. When comparing the different angles (35°, 20°, 55°) in the VPP optimizer, the 35° angle was selected to be the best option, since the higher electricity prodcution for the 20° that occurs from May to August currently does not match with the higher loads that occur from September to April. If the demand for cooling in summer will increase in the future or better storage possibilities will be available, the option of installing the summer angle migh be worth to consider. The ratio of the capacity installed and the electricity injected to the grid is given by equation.

Therefore, the final PV system will be a sum of modules (<10 kWp) and (10-100 kWp) on rooftops that are orientated to the south and adjusted with the optimum all year tilt of 35°. The monthly potential of this system is displayed in figure 4.3.4, and results in an average electricity output per installed capacity of 1042,7 kWh/kWp per year. The average hourly output for a day for the different seasons of the years is displayed in figure. The VPP optimizer resulted in a necessary installation of a PV capacity of 100 MW, which is possible due to the PV potential study from chapter 4.3.1.

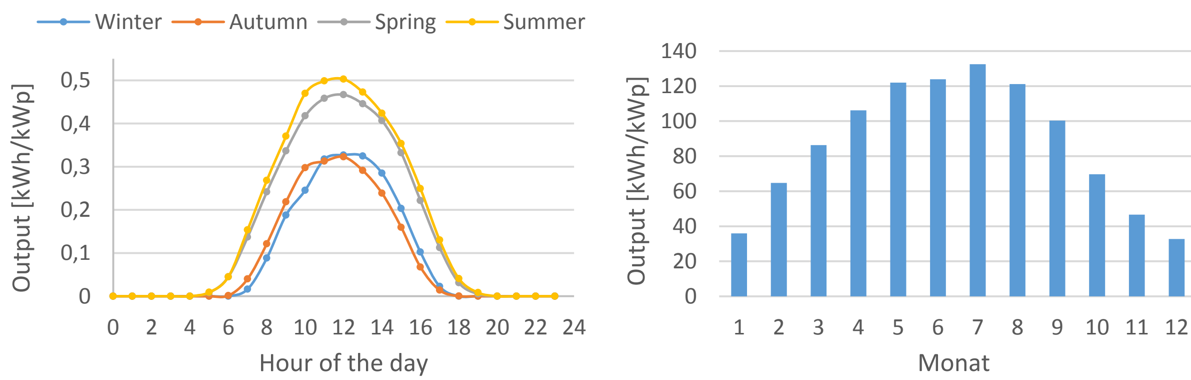


Figure 4.3.4. Average hourly output for different seasons (left) and average monthly electricity output (right).

4.3.5 Costs

The annualized costs for electricity produced by PV are the investment costs at time t_0 and the annual O&M costs. The O&M costs are assumed to be constant over the years. Since solar as a resource is free, no marginal costs occur per kWh consumed.

For PV an interest rate of 4% will be considered [47]. Table 4.3.3 represents the assumptions used for calculating the annual PV costs for the model in this paper and the resulting average electricity costs for the integrated system. The lifetime is set to 25 years [47]. CRF is the Capital return factor which is calculated with the equation (8). The annualized costs result via equation (9) and the average electricity costs are based on equation (10) [51].

$$CRF = \frac{Interest\ Rate}{1 - (1 + Interest\ Rate)^{-Life}} \tag{8}$$

$$Annualized\ Cost = CRF * CapitalCosts + O\&M\ Costs \tag{9}$$

$$Average\ Electricity\ Costs = \frac{Annualized\ Costs}{8760 * CF_{annual\ average}} \tag{10}$$

It has been chosen, to also represent the utility scale PV costs, to give an impression of the cost advantages in case of sufficient free space available. For the future this might be the case in the surrounding area if it does not compete too much with alternative land usage such as for agriculture or homes. It should be pointed out, that an increased share of PV capacity leads to a rise in the integration costs. Balance of System costs (BOS) include the costs for mounting systems, installation, cable (DC), infrastructure, transformer, grid back-up connection as well as planning and documentation. Figure shows how the PV system LCOE behaves due to a rise share of PV in the generation mix. Additional costs occur due to overproduction during peak sun hours, the full load hour reduction of conventional plants plays a big role and backup costs due to control energy, storage and grid connections. These extra costs occur due to the vulnerability of PV generation. For a share of 25% PV the study achieved a system LCOE that was nearly double to the PV generation costs [50].

Table 4.3.3 Annualized costs and average energy costs for the displayed PV rooftop systems.

		ISE (10-100 kWp system) [34]	WEO 2016: PV Roof [37]
O&M	€/kWp*a	19,05	16
Capital Costs	€/kWp	1270	1440
Interest Rate	-	0,04	0,04
Lifetime	Years	25	25
Average CF (incl. efficiency)	-	0,117	0,117
CRF	-	0.064	0.064
Annualized Costs	€/kWp*a	100.35	108.18
Average Energy Costs	Cents/kWh*a	9,44	10,18

4.3.6 Trends

Due to the WEO the cost learning rate for PV installations is about 20% for the next years [52]. Such a learning rate implies that costs decrease by a fifth with every doubling of capacity installed. The average electricity costs for the considered rooftop system's when installed in the future at a point t_i. The values for the large rooftop system (10-100 kWp) have been adjusted to the WEO learning rate.

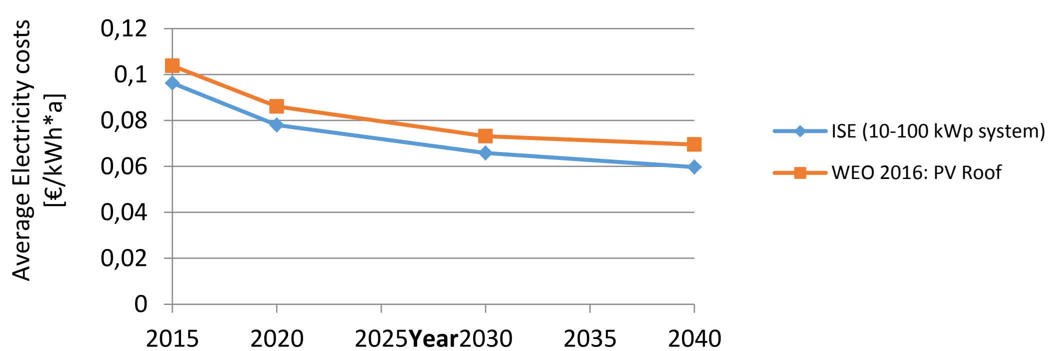


Figure 4.3.5 Average electricity costs development based on WEO learning rate assumptions [52].

4.4 Biomass Energy (Dhruv)

Biomass energy involves generating energy from living or recently living plants, trees, grasses or other agricultural crops as fuel source. It is a pollutant free, carbon neutral way of generating energy in the sense that all of carbon dioxide released in burning the fuel was taken in by that plant fuel source when it was living. A huge variety of biomass material can be used to generate energy which gives the added advantage that this technology can be used in most places from locally derived fuel.

The downsides of the technology include high costs when compared with gas, competition for land from food and animal feed, environment damage, indirect biodiversity loss caused due to fluctuation of local and global prices for biomass feedstock.

4.4.1 Potential

In 2014, renewables contributed to generating 25.8% of overall electricity production. Biomass accounted for 8% gross share in the total electricity generation [26].

The following are the basic category of feedstock materials which can potentially be used for energy generation-

1. Energy crops grown specifically for energy applications

2. Wood from forestry, wood processing or from urban waste. (Chipped, scrapes, pellets, sawdust etc.)

3. Agricultural residues from agriculture harvesting and processing (rice husks, shavings, straw etc.)

4. Food waste from residents in the city

5. Municipal and industrial solid waste (MSW)

High value material of good quality, for which there is an alternative market cannot be used as fuel for Biomass generation because of competition. One example of this is Timber which has many other uses in the consumer industry, would be unavailable to be used as energy source.

The high variation in chemical composition of the different types of biomass is a problem in combustion and power generation technologies. Although some technologies can accept high variation in type of feed, most cannot. Table 4.4.1 describes the various technologies that could be used for biomass plants, their average capacity for power generation and possible fuel types [27]. The decision to choose a biomass power plant and the a feedstock source would be taken after evaluation in chapter 4.4.2.

Table 4.4.1 Various possible technolgies for biomass power plants and their characteristics [27].

Biomass conversion technology	Commonly used fuel types	Particle size requirements	Moisture content requirments (wet basis)	Average capacity range
Stroker grate boilers	Sawdust, non-stringy bark, shavings, end cuts, chips, rice husks and other agricultural residues	6-50 mm	10-50%	4 to 300 MW, many in 20-50 MW range
Fluidized Bed Combustor	Bagasse, low alkali content fuels, mostly wood residues with high moisture content.	< 50 mm	< 60%	Up to 300 MW (many at 20 to 25 MW)
Co-firing: pulverized coal boiler	Sawdust, non-stringy bark, shavings, flour, sander dust	< 6 mm	< 25%	Up to 1500 MW
Co-firing stokers. Fluidized bed	Sawdust, non-stringy bark, shavings, flour, hog fuel, bagasse	< 72 mm	10- 50%	Up to 300 MW
Fixed bed (updraft) gasifier	Chipped wood or hog fuel, rice hulls, dried sewage waste sludge	6- 100 mm	< 20%	5 to 90 MW
Downdraft moving bed gasifier	Wood chips, pellets, wood scrapes, nut shells	< 50 mm	< 15%	25 to 100 kW
Anaerobic digesters	Animal manures, food processing residues, MSW, other industry organic residues	N/A	65- 99.9%	

4.4.2 Evaluation

About 20% of Germany's arable land is already used for producing primary raw material like straw , maize for bioenergy production. This shows how limited the potential is, in Germany, for using more arable land to grow biomass feedstock [28]. Hence, the following looks into possibilities of importing the feedstock for biomass energy production. Table 1 below the approximate prices of different feedstock per ton in Germany [32].

Table 4.4.2 Prices of different biomass feedstocks in Germany (€/tonne) [32].

Straw	160
Forestry residues	30 to 80
Organic municipal waste	-50 to -60
Waste wood	-60 to -25
Food processing residues	0 to 180
Energy crops	80 to 160

The unsubsidised levelized cost of generating electricity through biomass is 76 euros - 110 euros / MWh. This cost is a comparably higher than the cost of generating electricity through gas turbine which is around 42 euros - 70 euros [16]. The total capital cost of a biomass plant will be between 2800 euros - 3800 euros / kWh. This is at least three times as high as a gas turbine power plant [16].

After the Renewable energy act came into force in 2009, the government of Germany offered basic payments, discounts and bonuses for setting up a biogas plant upto 11 cents/ kWh depending on different type of fuel used, capacity, integration of heat and pollution limitation. This included Basic Payment: 7-11 cents/kWh depending upon the power production, Renewable Resources bonus: 2.5-6 cents/kWh depending upon feedstock source, CHP Bonus: 3 cents/ kWh for extra use in space heating among many other bonuses [29].

But on August 2014, with the amendment of the Renewable Energy Sources Act, the German government dropped the allowance for provision of renewable raw materials with significant recovery and pre-treatment costs. This included most biomass raw materials like straw, forest residues etc. with the exception of organic waste. This change in policy put up another economic limitation to making electricity from biomass a suitable energy technology for use in our VPP [30].

Owing to the already high capital and levelized cost of putting up a biomass power plant, all the different feedstock materials with positive cost in €/Tonne were rejected. Of the negative feedstock costs, the waste is discussed in chapter 5.5. Wood is predominantly used for heating rather than electricity production. In fact, 58.2% of all biomass plants in germany are used for heating only, 41.1% for combined heating and power (CHP) and only 0.01% for electricity production solely [31]. Hence, it is evident that wood biomass CHP plants would produce more heat than electricity. As this report only concerns with electricity demand of Karlsruhe, this would not be discussed in more detail.

4.4.3 Conclusion

It was decided to not use any kind of biomass generated electricity in our VPP because of the high costs associated with a biomass power plant. A gas turbine power plant was found to be more profitable and hence was chosen over biomass power plant as described in chapter 4.7.

Any possibilities for future electricity production from biomass must take into account the heating factor for biomass CHP plants. Biomass has better efficiency and use in heating rather than electricity generation. Hence, it is recommended to use combined heat and power plants for Karlsruhe [31].

It is also strongly recommended that any future planning / development of a biomass power plant in Karlsruhe take into consideration the global agricultural and fossil fuel price trends. Profitability of growing biomass on arable land can lead to conflict of interest, causing an adverse food crises in developing countries [28].

4.5 Waste to Energy (Dhruv)

In Karlsruhe, waste is gathered and distributed in three main types, the segregation is done by residents through different bins kept in front of their houses. Table 1 describes the types of waste bins, some examples of waste and quantities of each type of waste produced per day in Karlsruhe on average for the year 2013 [33]. In the whole year, a total of 150,000 tons of waste was generated in Karlsruhe [38].

Table 4.5.1 Type of waste segregation in Karlsruhe [33][38].

Type of waste	**Example**	**Quantity produced per day on average (2013)**	**Contribution to total**
Residual	Rubber, wax, old clothes	123 tons	30%
Recyclable	Paper, Aluminium, packages	250 tons	61%
Biowaste	Food residues, other biodegradable wastes	37 tons	9%
Total	All	410	100%

From 2015 onwards, a fourth segregation type of waste for paper related wastes like books, cartons, newspapers was added in addition to the original three main types [34]. According to the department of waste management of Karlsruhe, each resident generated on average 500 kgs (0.5 tons) of total waste in the

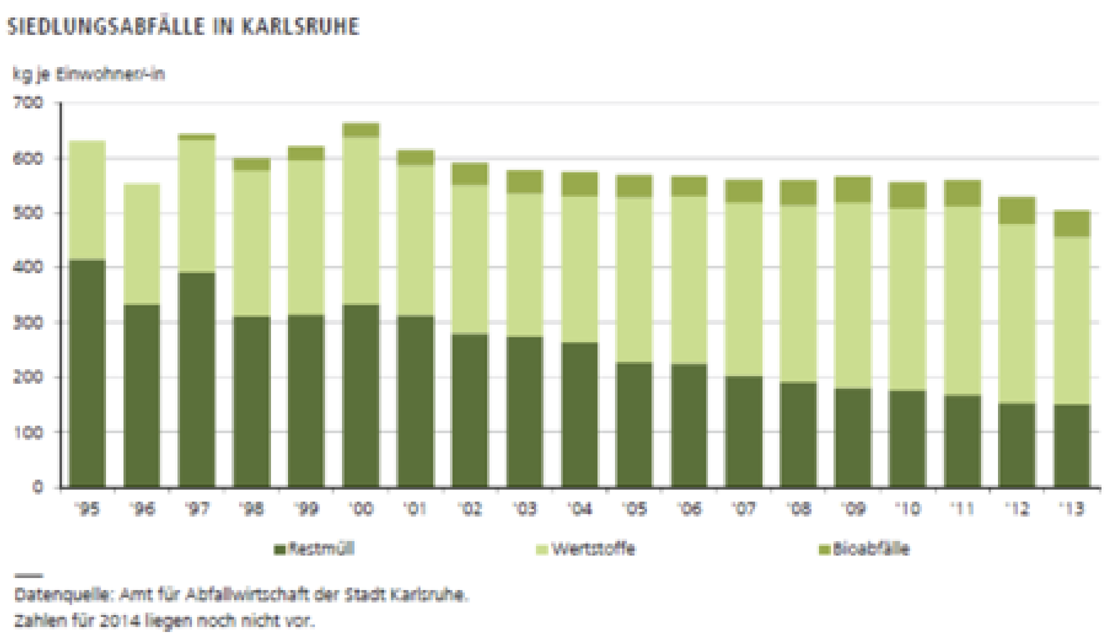


Figure 4.5.1 Amount of waste produced by each resident on average in Karlsruhe from 1995 to 2013 [38]

year 2013, as shown in the figure 4.5.1 [38].

With a population of approximately 300,000 people in the city, the total waste generation is at 410 tons per day. Meanwhile, a municipal solid waste to energy plant would on average generate a net energy of 500 kWh per ton of solid waste being put inside it. If it is a combined heat and power plant, it would generate 500 kWh electricity and 1000 kWh of heat for district heating from the same ton of solid waste [35]. Assuming that all of the total waste would be used in a Waste to energy plant, 150,000 tons of waste would generate estimated 75,000 MWh of electricity per year. This gives a peak power of only 8.55 MW. In reality, it does not make environmental and economical sense to use all types of waste in a WTE plant. According to the waste hierarchy pyramid, if possible, it is always better to reuse and recycle the waste than use it to harness energy [36]. Therefore, all the recyclable waste in Karlsruhe is not considered as feed source, hence, only 39% of our total waste (Residual and Biowaste) has potential for energy generation, giving peak power of only 3.3 MW.

It was also observed that Germany faces severe waste shortage and often has to import waste from other countries for its other existing waste to energy plants [37]. Therefore, it is recommended to export the waste in Karlsruhe to existing WTE plants in Germany rather than making a new WTE plant in the city itself. For these two reasons above, energy from waste was rejected as possible energy source in our VPP.

4.6 Energy Storage (Dhruv / Imke)

The increasing role of variable renewable sources like solar make an appropriate energy storage choice of paramount importance. Studies show that integration of up to 20% renewables in the grid do not require a need for energy storage, but would need changes in operational practices from the consumer side [76]. However, we want stabilization from the VPP to be prioritized and hence different energy storage technologies in the following would be analyzed to balance the variable power from PV panels.

4.6.1 Potential sources (Dhruv)

Figure 4.6.1 describes the various possible technologies for energy storage based on their discharge time, power and energy storage capabilities [77]. There is no requirement of an energy storage of high power and low energy capacity (the left portion of the figure) in our VPP because grid requires medium to high energy capacity. Therefore, flywheels and super-capacitors are neglected as possible technologies.

Moreover, conditions for PHES and CAES are not feasible in the local Karlsruhe area, even though some PHS potential is available around 50 km further South in the Schwarzwald region, e.g. Forbach [78]. Due to the high initial investment costs, environmental constrains and a lack of local potential, these two options will also be neglected for the VPP scenarios.

The remaining possible technologies are electrochemical storage devices- Lithium ion batteries (LIB), vanadium flow batteries, lead-acid batteries, sodium sulphur batteries and hydrogen fuel cells. These devices provide the advantage of having no on sight environmental constraints. They can be sized due to the required power output and energy storage capacity. Lead-Acid Batteries are equipped with a lower energy density than LIB but are less expensive and the more mature technology. With the increased usage of LIBs over the last years for home storage and VIB the prices have been decreasing and are expected to fall further. Due to the higher energy density and an expected increase of the economical feasibility of LIBs, latter will be preferred. The comparision of the remaining four different types of electrochemical batteries is given in Appendix 4.6.

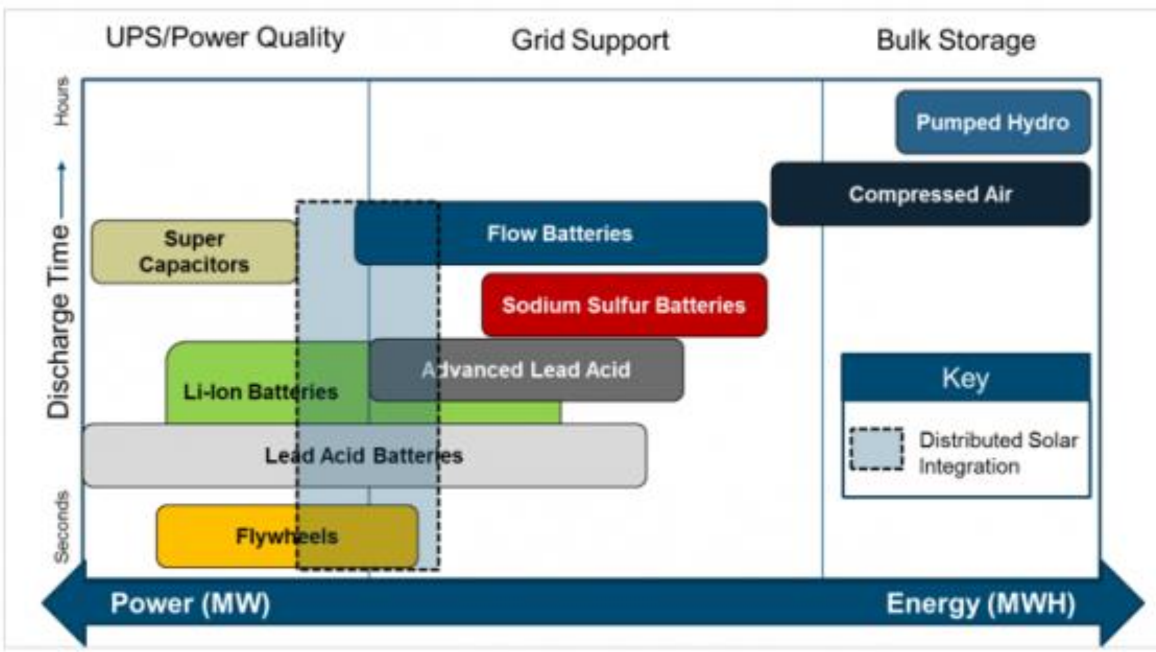


Figure 4.6.1 Possible storage technologies shown graphically accordng to their discharge time, power and energy storage capability [77]

4.6.2 Hourly fluctuation stabilization (Imke)

The hourly fluctuation stabilization refers to the energy storage needed to balance the PV power generation over different hours of the day i.e. storing the overproduction of electricity generated from PV panels so it can be used to meet the demand at a later time in the day when there is a peak in load curve as described in chapter 3.

Lithium ion batteries were found to be the most appropriate for hourly fluctuation stabilization because they have a comparable high energy density (250-676 Wh/L), a very small memory effect and a low self-discharge rate (8% at 21°C). The specific energy varies, depending on the used chemistry, between 100 and 265 Wh/kg [79].

The model of the battery finalized was a Tesla Powerwall. The chosen configurations are given in Figure 4.6.2. [80].

The values for LIB are based on the Lazard report [16] and the costs provided by the manufacturer Tesla. Annual O&M costs are assumed to be 1% of the capital costs. The storage system is assumed to run 350 days per year. Each cycle is assumed to be fully used. The Capital costs include the reinvestment costs after 8,57 years after 3000 cycles, when the remaining capacity reached 80%. An interest rate of 4% was assumed.

Table 4.6.2.1 Various costs of lithium ion battery [16]

	Unit	LIB (Tesla, 7 kW 2 hours)
O&M	[€/kWp*a]	10,07
DoD	[%]	80
Capital Costs at t_0	€/kWp	3945,43
Annualized Costs	[€/kWp*a]	262,63

Table 4.6.2.2 Specifications of Tesla Powerwall [2]

Peak power	7 kW
Energy storage	14 kWh
Continuous charge	2 hrs

Figure 4.6.2 Tesla powerwall

4.6.3 Daily Fluctuation stabilization (Dhruv)

The daily fluctuation stabilization becomes important when the VPP has a greater share of renewables in electricity generation. It is not required in scenario described in chapter 7. In case the share of renewables has to go above 15% in future scenarios, the need for a daily fluctuation arises in the VPP.

Vanadium flow batteries were chosen to be the most appropriate energy storage technology for this case. They offer themselves as excellent candidates because of their cost and simplicity [81]. Following are some more advantages of the vanadium flow redox batteries -

- They are completely non-flammable because they use water-based electrolyte, unlike lithium ions batteries which are at potential risk of producing fires or explosions

-There is negligible degradation of capacity of the Flow cell per year (~0.1% per year)
- Flow batteries have a extraordinarily higher lifetime compared to any other solid batteries like Lithium ion.

Vanadium flow batteries were not analyzed further because of their exclusion from scenarios of VPP due to no requirement for a daily storage. There data available for its cost was also unreliable. Regardless, these batteries offer significant potential of use in the near future and are already being regarded as a breakthrough in energy storage. [82].

4.6.4 Future Projection (Dhruv)

The costs of batteries are projected to decrease in the future due to an increased commercial adoption [83]. To what degree will the prices of batteries fall, remains a question of discussion. Different reports and agencies have presented differing estimates regarding the same. Figure given below describes the general battery price projections from four different reports for years 2012- 2048. The projections are blended for different types of battery storage and drawn as one general estimate for all battery types. [83]

The maximum projected drop in price estimated by Navigant, proposed a 65% fall in battery prices by 2030, while the minimum projected drop estimated by US Energy information administration (EIA) proposed a 30% fall. Considering these estimates, a conservative estimate of 35% price drop for lithium ion batteries was chosen for the future 2030 scenario of our VPP. The greater inclination towards the estimate of EIA was due to the fact that predictions of government agencies have more reliability and neutrality in them than a third party.

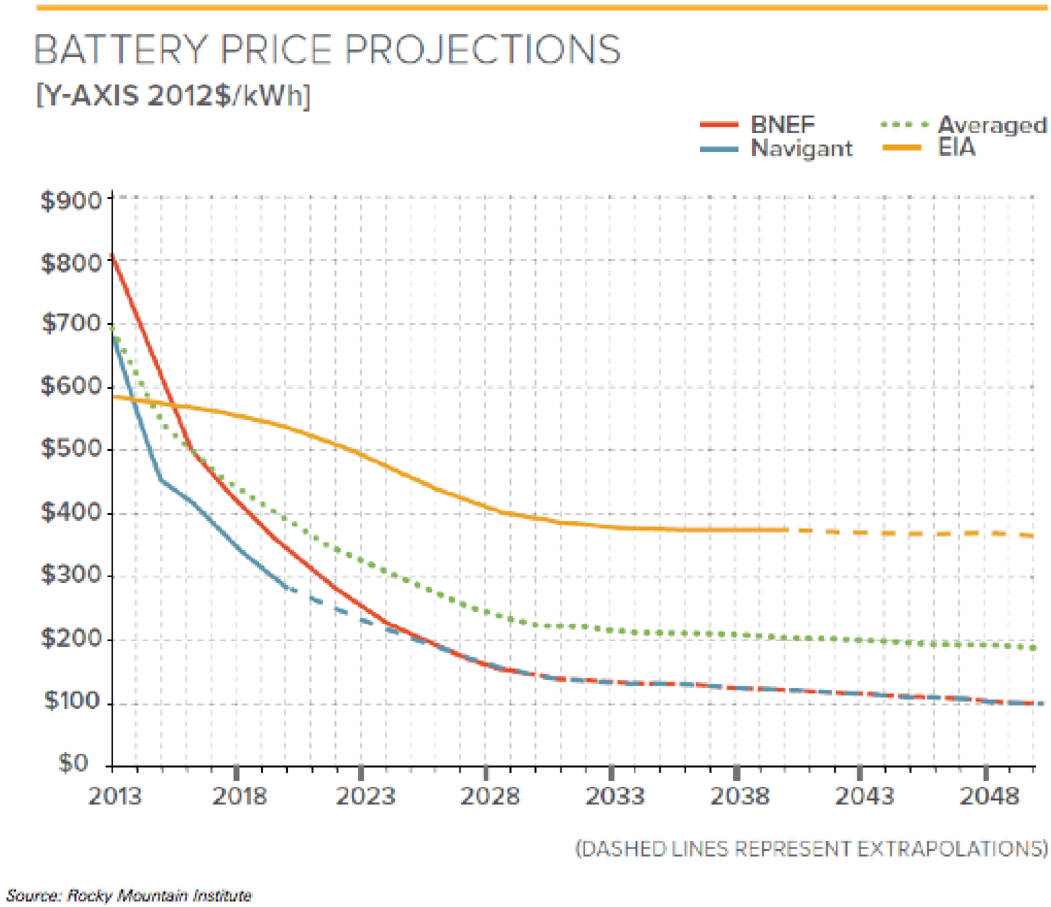


Figure 4.6.3 Battery price projections according to different estimates

4.7 Thermal Power Plant (Amir)

4.7.1 Preliminary study of different technologies for thermal power plant

In the first step, the electricity demand of Karlsruhe is analyzed by the given data. The base load and the peak load were calculated. It has been driven from our analyses that the maximum average base load and peak load are 40MW and 65 MW respectively. It is considered that the thermal power plant will supply at least the base load demand, and compensate the intermittent generation of renewables, those remained amount that cannot be met by the storage. Therefore, to achieve this goal, the most flexible technology is desirable.

There are different kinds of technologies that can be used as a thermal power plant including; coal, lignite, biomass, integrated gasification combined cycle (IGCC), combined cycle gas turbine (CCGT) and Open cycle gas turbine (OCGT) [61].

There are different ways of assessing the economy of power plant. The simplest way and widely used is the levelized cost of electricity (LCOE) in which the unit price of electricity for power plant is calculated (€/kWh) [64]. Chapter 1 presents how to calculate the LCOE. The LCOE considers costs and electricity generation over whole lifetime of power plant, and it is a function of investment cost, O&M, carbon price, plant lifetime, full-load hour, discount factor and electrical efficiency [64]. In this study, we calculate LCOE maximum (the maximum value of all cost components are considered except electrical efficiency in which minimum value is considered) and LCOE minimum (the minimum value of all cost components are considered except electrical efficiency in which maximum value is considered), for both cases carbon factor and power plant life time do not change [64]. As it is shown in the table 4.7.1, the minimum LCOE belongs to lignite power plant and then, coal power plant, CCGT, and OCGT respectively. Although, the lignite and coal technologies have the lowest LCOE, their investment costs are considerably high. Additionally, they have higher time from planning to completion in comparison to OCGT and CCGT [61]. Accordingly, the return on an investment starts earlier for OCGT and CCGT than other prime movers [61].

Meanwhile, the lignite and coal power plant emit more carbon dioxide per unit rather than natural gas power plant [61]. Mostly, they are used as based load and they need to operate whole time since the start-up costs are relatively high and their ramp up time is considerably higher than that of OCGT [62]. Additionally, as we move into a more carbon-constrained World, there is increasing pressure to switch from coal and liquid fuels to natural gas as the primary fuel for power generation, bringing increasing opportunities for gas turbines [65].

To sum up, due to reasons mentioned above, the lignite, coal and IGCC technologies are rejected for this project.The biomass potential is discussed in chapter 4.4.

Table 4.7.1 Levelised Cost of Electricity (LCOE) [64].

	Coal supercritical	Lignite supercritical	Gas CCGT	Gas OCGT
Min Investment Cost (€/kW)	1,200	1350	550	400
Max Investment Cost (€/kW)	1,700	1800	800	720
Min discount rate (%)	4	4	4	4
Max discount rate (%)	7	7	7	7
Life time (y)	40	40	30	30
Min O&M (€/kW/a)	32	35	19	14

Max O&M (€/kW/a)	39	43	23	17
Min Fuel Costs (€/MWh)	7	4	19	19
Max Fuel Costs (€/MWh)	11	6	28	28
Min Carbon price (€/tCO2)	5	5	5	5
Max Carbon price (€/tCO2)	10	10	10	10
Min Electrical Efficiency (%)	44	42	59	39
Max Electrical Efficiency (%)	46	43	61	44
Carbon Factor (tCO2/MWhth)	0.339	0.404	0.202	0.202
Min Full-Load Hours (h)	2000	3000	750	500
Max Full-Load Hours (h)	4500	7000	2500	750
Min LCOE (ct/kWh)	4	2.9	5.3	9.5
Max LCOE (ct/kWh)	11.6	8.4	16.8	22.7

4.7.2. The fuel price and carbon dioxide allowance

The fuel cost that has been used in economic evaluation is shown in table 4.7.1. Figure 4.7.1 shows the natural gas import price by pipeline. It can be observed that the gas import price decreased from 2013 to 2015 by an average of 27.2% for European Union Member States.

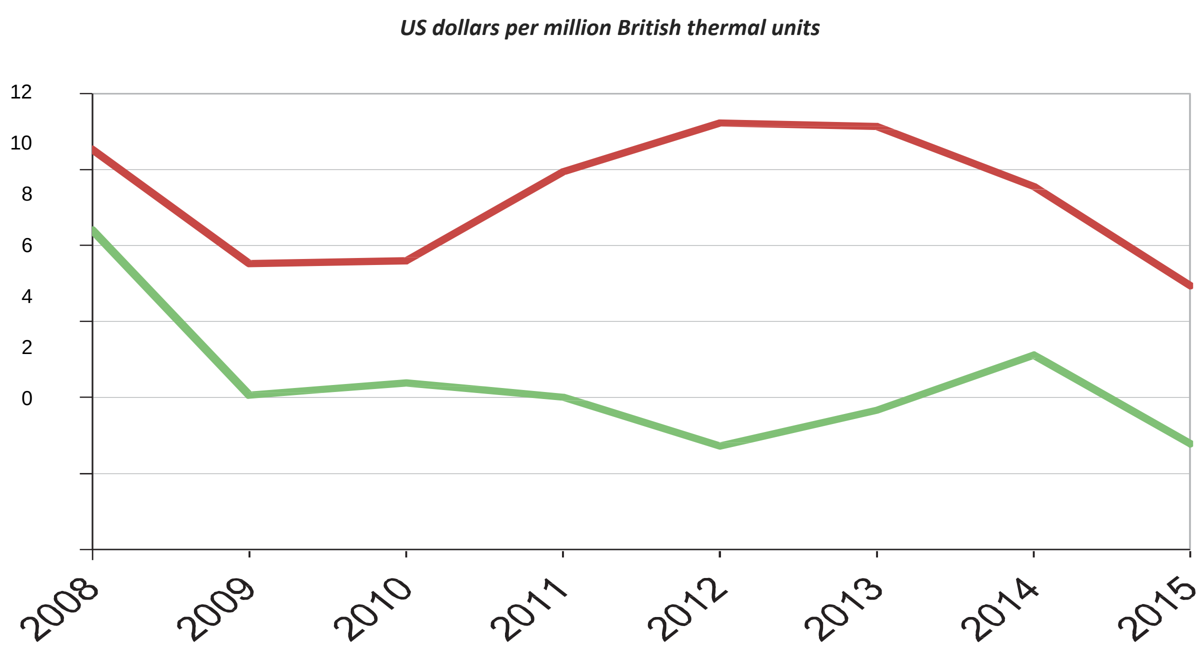


Figure 4.7.1 Natural gas import prices by pipeline [74].

European Union Member States United States

Table 4.7.2 shows fuel price forecast under certain assumption for years 2020, 2030, 2040 and 2050. Although the lignite price remains constant, the gas price and coal price increase.

*Table **4.7.2**: Fuel Price Forecast. Assumptions about fuel prices (BMWi (2013), NEP (2013), BMU (2012), Prognosis (2013)) [75].*

Fuel price [$Euro_{2013}$/kWh]	2013	2020		2030		2040	2050
		lower	upper	lower	upper		
Brown coal	0.001	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016
Hard coal	0.011	0.0103	0.0114	0.0112	0.0175	0.0188	0.0200
Natural gas	0.028	0.0276	0.0320	0.0287	0.0363	0.0398	0.0470

Table 4.7.3 shows the CO2 allowance price forecast. It will be increased dramatically by the year 2050.It can be concluded that since the price for gas, coal and CO2 allowance will be increasing, the gas based technologies are able to reduce their marginal costs, and therefore increase their profitability.

*Table **4.7.3**: CO_2 allowanceprice(NEP(2013),Prognosis(2013)) [75].*

CO_2 allowance price [$Euro_{2013}/tCO_2$]	2013	2020	2030	2040	2050
upper value (Prognos)	5.3	21.7	42	50.7	55
medium value	5.3	19.3	35	42.9	47.5

4.7.2.1 Carbon taxes (Imke Hebbeln)

Due to the high impact of CO2-emissions on the climate change, several pricing systems for carbon dioxide emissions have been developed and party implemented.

The European Union introduced the Emission Trading Scheme (EU ETS) in 2005 for all member states to target the goals of the Kyoto Protocol. Carbon dioxide take the biggest share in this scheme. Within the energy sector, it caps all power stations and other combustion plants that excess 20 MW thermal rated input (expect hazardous or municipal waste installations) [75] The “cap and trade” system sets the total amount of carbon dioxide that can be emitted by a system. Within this cap, companies receive or buy an allowance which they can choose to keep or trade. If too many allowances are being granted, the price for certificates drop due to an oversupply. Prices for CO2 emission papers in 2016 are displayed in Figure. Due to the FÖS actual environmental costs of Co2-emission reach up to 80€/tonne. Additionally, some countries apply a CO2-tax on every tonne emitted to the atmosphere. Already 15 countries worldwide introduced such a tax, including Great Britain. In a study from 2014, the FÖS recommends a minimal CO2-price of 35€/ton for fossil fuel for the future in Germany, based on prices that already exist in Great Britain and that are still feasible [75].

Figure 4.7.2 Auction price for CO2-emission-certificates on the primary spot market in Germany for 2016 [75] (EEX, 2017).

4.7.3. Gas turbine

4.7.3.1. Gas turbine introduction

As long as the capital cost, time from planning to completion, maintenance cost and environmental factors maters, the gas turbine is the best choice compared to other thermal power plants. It has the lowest maintenance and capital cost of any other prime movers [61]. The lowest completion time to full operation is also another advantages of it over other prime movers [61]. It has the disadvantage of having high heat rate, however, this exhausted heat can be used in other cycles and processes, which increase the overall efficiency of systems. There are different factors that need to be considered for designing gas turbine power plant, the most important of which are high efficiency, high reliability and thus high availability, ease of installation and commission ,conformance with environmental standard and flexibility to meet the various service and fuel needs [61].

4.7.3.2. Typical categories of Gas Turbine

Typical categories of Gas Turbine [61]:

- Frame type heavy-duty gas turbine (power output ranging from 3 MW to 480 MW, efficiency from 30-46%).
- Aero-Derivative gas turbine (power output ranging from 2.5 MW to 50MW, efficiency from 35-45%).
- Industrial type gas turbine (power output ranging from 2.5 MW to 15MW).
- Small Gas Turbine (power output ranging from 0.5 MW to 2.5 MW, efficiency from 15-29%).
- Micro-Turbine (power output ranging from 20 KW to 350 KW)

4.7.3.3. Major gas turbine component

Major gas turbine component includes compressor (Axial flow compressor & Centrifugal flow compressor), regenerators (optional, increase the efficiency for industrial gas turbine rage 1MW-50MW), combustor, and turbines (Axial-Flow Turbine & Radial-Inflow Turbine) [61].

4.7.3.4. The thermodynamic cycle of Gas Turbine

The thermodynamic cycle that gas turbine works is based on it is Bryton Cycle and its various modifications. The Bryton cycle consists of two isentropic processes and two isobaric processes [63]. The two isentropic processes include the compression stage and the expansion stage. The combustor system and HRSG are represented by the two isobaric processes [63].

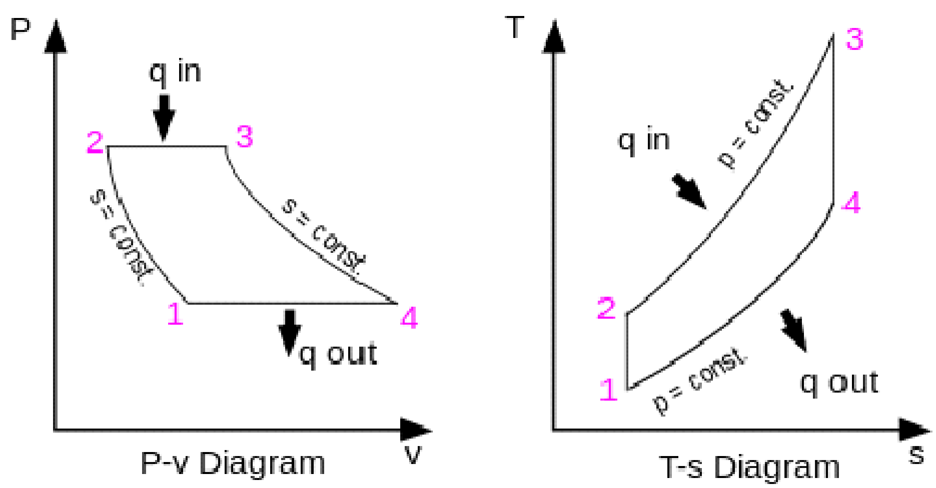


Figure 4.7.3 Typical Brayton cycle in pressure-volume and temperature-entropy frames [66].

The overall cycle efficiency:

$$Wcyc = Wt - Wc \quad (11) \qquad\qquad \eta = \frac{Wcyc}{Q2,3} \quad (12)$$

There are two approaches to increase the efficiency of Brayton cycle, increasing the pressure ratio and increasing the turbine firing temperature [62]. Although increasing the pressure ratio increases the overall efficiency at a given temperature, it should be taken into account that increasing it beyond a certain value at any given temperature results in lowering overall cycle efficiency, and may cause damage to compressor blade [61].

4.7.3.5. Fuel

One of the significant advantages of gas turbine is that they can burn various type of fuels. However, natural gas is the ideal fuel for gas turbine since it is clean it increase the plant's lifetime. Due to this fact and good availability of natural gas in Karlsruhe, natural gas is used as GT fuel in this project [68].

4.7.4. Selecting the Gas Turbine model

As mentioned above, one of the most important challenges that the VPP is aimed to address is minimizing the effect of intermittent renewable energy. To achieve this objective, the most flexible technology is needed. Of those types of gas turbines mentioned above, the suitable ones include heavy duty gas turbine and aero-derivative gas turbine, for their power range match the required capacity for the VVP. Meanwhile, configuration of several small gas turbines can meet that demand as well, which in turn increase the flexibility of the whole system considerably. As discussed earlier, using them in a combined cycle will increase the efficiency of system, however, CCGT configuration is not an appropriate case for this project because of their having high capital, and maintenance cost [64]. Additionally, they have higher time from planning to completion, and start-up time in comparison to OCGT ([61], [65]). Meanwhile, the CCGTs are relatively slow responses to support intermittent generation resources in comparison to OCGT [65].

Of those appropriate technologies, modern industrial and heavy duty gas turbines were designed to provide high efficiency base load combined cycle operation with high exhaust and steam cycle temperatures [65]. Furthermore, they are not the most suitable ones for this project.

Significantly, aero-derivative gas turbines, in particular the Industrial Trent, have potential of being fast starts, high load ramp rates, full load rejection, and fast shutdowns, making the Industrial Trent a highly appropriate technology that meets and exceeds the challenges facing power generators and grid operators today [65].

In power generation application, the Industrial Trend types are designed for generating power ranged from 43 to 66 MW [65]. The initial product development industrialized three core areas: the lift fan was replaced with an aerodynamically matched 2 stage axial Low Pressure Compressor configuration that delivered the same pressure rise as the standard aero core; the Low Pressure Turbine was adapted, converting thrust output to rotational energy, by increasing the length of the last 2 blade rows of the 5 stage power turbine, and the combustion system was adapted to provide dry low emissions (DLE) and wet low emissions (WLE) alternatives for the control of exhaust emissions [65].

The modular package design is optimized for Operation and Maintenance and minimal installation time. With the core exchange principle allowing offsite maintenance of the core turbine, overhaul outages are reduced to less than 2 days downtime [65].

Various available configurations of gas turbine is shown in table 4.7.4.

*Table **4.7.4:** ISO performance data for 50Hz Industrial Trent configurations .[65].*

Configuration	Power Output (MW)	Efficiency (%)
DLE	53.1	42.4
DLE + ISI	63.5	43.2
WLE	66	40.4
WLE + ISI	66	41.5

4.7.5. Business model for peak load operation

In operation mode where frequent start-up and shut-down is required or in peak load operation mode, the economic assessment of power plant does not depend only on generation costs, but the Internal Rate of Return [65]. Although, an open cycle aero-derivative gas turbines are less efficient than a CCGT utilizing heavy duty gas turbines, the lower capital expenditure and reduced O&M compared to a CCGT costs outweigh the higher fuel consumption because of the limited number of operating hours [65]. This property makes OCGT the best technology for selling electricity in intraday market, future market and ancillary service. Figure 4.7.4 shows that although peaking plants operate less than base load technologies, their generated electricity have higher selling price comparing to that of base load technologies.

The industrial trend provides the fastest power response time on the market (only 10 minutes is required to be with full load available for dispatch from cold start) [65]. The Industrial Trent has a 25000-hour overhaul regime and is capable of 7500 cold starts between overhauls [65]. The typical Industrial Trent has a load ramp of 21MW/minute, but the ramp rate can be increased – up to 75MW/minute under certain circumstances [65]. It is can be understood from the table 4.7.5 that the Industrial Trend has a less start-up time and shut-down time in open cycle comparing to that of in CCGT configuration.

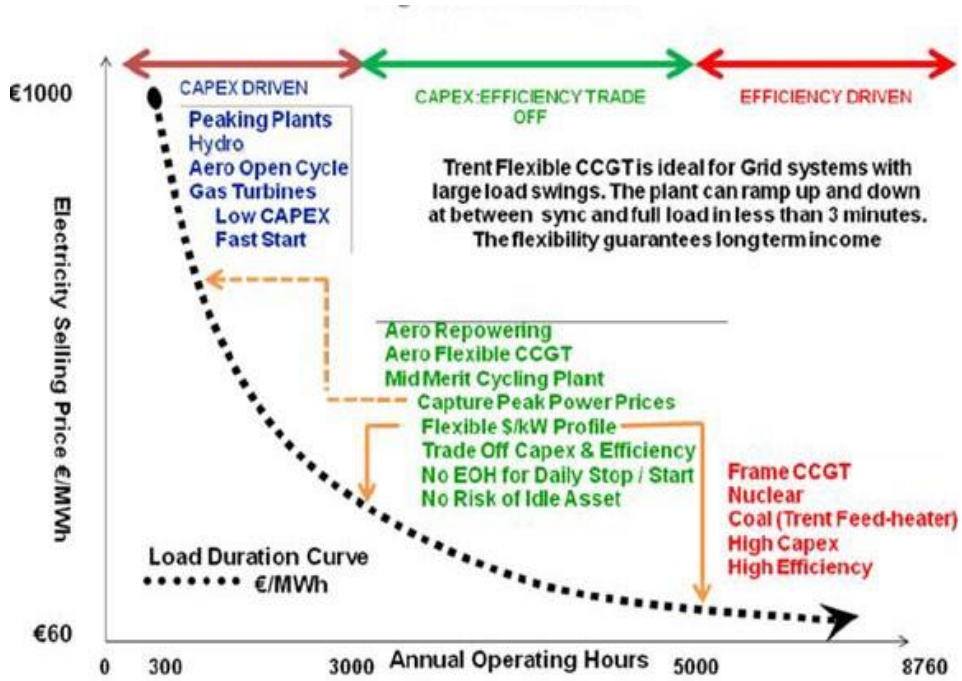


Figure 4.7.4 Typical Power Generation Economics Chart *[65].*

*Table **4.7.5:** Assumptions for Pulse Load Calculations for 100MW case [65].*

		Trent DLE OC	Trent DLE CCGT
Full Load Net Efficiency	%	41.87	53
Start-up time	Minutes	10	40
Shut-down time	Minutes	5	20
O&M costs	EUR/MWh	3.50	4

*Table **4.7.6.** Industrial trend 60 characteristics [69].*

Power generation range	53.1–66.0 MW(e)
Gross efficiency	41.1–43.4%
Heat rate	8,300–8,760 kJ/kWh
Turbine speed	3,000–3,600 rpm
Pressure ratio	33.3:1–39.0:1
Exhaust mass flow	155.0–180.0 kg/s
Exhaust temperature	416–433°C

4.7.6. Increasing Gas Turbine efficiency

Two main categories of the practical methods for power augmentation are inlet cooling and injection of compressed air, steam, or water. Inlet cooling technique includes evaporative method, refrigerated inlet cooling systems, combination of evaporative and refrigerated inlet systems, and thermal energy system storage [61]. Injection of compressed air, steam, or water technique includes, injection of humidified and heated compressed air, steam injection, and water injection [61].

Among above techniques for power augmentation, inlet cooling, in particular ISI, has been successfully implemented in Industrial Trent type. This technique reduces the ambient inlet temperature and decreases the energy required for compression by introducing water into the gas turbine air inlet. This would lead to increase in both power and efficiency [65]. Intercooling decreases the compressor work and reheating increase the turbine work, which finally leads to increase in overall efficiency increase in both cases [65].

As it is shown in table 4.7.4, ISI increases the efficiency from 42.4 % to 43.2 % for DLE type. However, as it can be seen from figure 4.7.5, the ISI has significant impact on GT's efficiency when the ambient temperature is more than 12°C. Since Karlsruhe is not located in warm region, it is neglected to implement ISI technique. Meanwhile, some exhausted heat will be used in CHP configuration which back the idea of using GT without ISI.

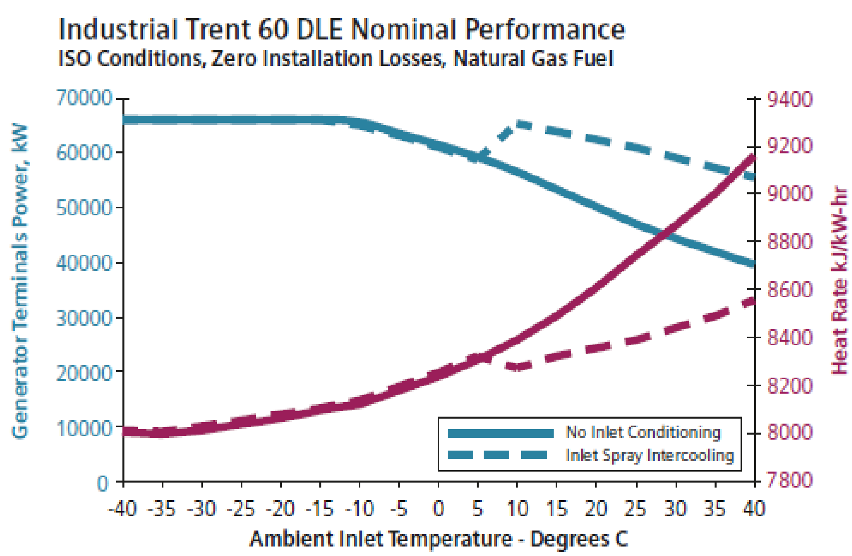


Figure 4.7.5 Industrial Trent 60 nominal performance [65]

Of two typical techniques of using exhausted heat in order to increase efficiency, CHP and CCGT, as it is discussed above, the CCGT is not appropriate for this project since it has high investment cost and lower flexibility in comparison to OCGT. The Industrial Trent was designed for optimum simple cycle efficiency and so has a relatively low exhaust gas temperature of around 450°C at full load comparing to over 600°C for a heavy duty gas turbine [65]. This exhausted gas is sufficient for producing process heat, which can be used in industries or buildings. In ideal case, the CHP configuration can increase the power plant overall efficiency up to 80 % [65].

In this project, one of the GTs will be set in CHP configuration due to the project requirement which is the highest flexibility so other one can operate in higher flexibility status. Furthermore, the base load GT does not need to have a flexibility as much as the peak load technology.

It is worthy to mention, since it is decided to locate the thermal power plant in industrial center near Karlsruhe, the Rheinhafen where there is demand for heat, the probability of selling heat is somehow guaranteed. Furthermore, it increases the efficiency of the system and the probability of the project. Although the CHP potential has been studied, the revenue from selling heat is not taken into account for economic evaluation of the VVP.

4.7.7. Generator and grid synchronization

In principle, there are two kinds of generators: asynchronous machine (induction machine), and synchronous machine. Mainly, in power plant application, the synchronous machine is used due to their appropriate power factors. The two main parts of synchronous motors are stator and rotor. Excitation, rotor winding, stator winding, bearing, shaft, control box, and welded frame are other important parts to be considered in design [71].

There are four types of generators categorized by their cooling system which are typically used in thermal power plants. They include Air-cooled generators, Pressurized air-cooled generators, Hydrogen-cooled generators, and Water-cooled generators [71].

Among the types of generators mentioned above, the air-cooled generators, in particular Generator SGen-1200A series from Siemens, are the most suitable ones for this project, for their being cheaper because of using air as coolant, and their being an appropriate technology for gas power plant. Table 4.7.7 shows some technical data of this kinds of generator.

The synchronization is an essential task for connecting the generator with the grid. Phase angle, frequency, voltage sequence and amplitude of the voltages have to be the same for the generator and the grid in the three phase system [72].

*Table **4.7.7.** Technical data of SGen5-1200A [70].*

Number of poles	Frequency	Power factor	Apparent power	Efficiency	Terminal voltage
2	50 Hz	0.80	Up to 370 MVA	Up to 98.8 %	20 kV

In power plants synchronization, three essential variables that have to be specified before grid synchronization are briefly explained below [72].

A. The relationship between the between electrical frequency and rotational speed can be explained by:

$$F_{elec} = \frac{w_{rot} . p}{120} \qquad (13)$$

Where F_{elec} is frequency of electrical system, p is the number of poles in synchronous machine and w_{rot} is the speed of rotation [72].

The electrical frequency of generator is proportional to turbine power. Furthermore, the frequency of voltage can be controlled by the input power, which is done by governor through adjusting the input power [72].

B. Variation of the phase between synchronous machine and the grid can be calculated from:

$$\varphi = (f_{grid} - f_{gen}). t \quad (14)$$

Where t is the time period, f_{grid} is frequency of grid, and f_{gen} is frequency of generator [72].

Furthermore, in order to match the phase of generator into grid side, the frequency of generator needs to be adjusted in the specific period of time.

C. Amplitude of output voltage in synchronous generators is proportional to the excitation field, which can be provided through power electronic devices or coupled DC generators [72].The synchronous speed of synchronous machine can be driven from formula:

$$N_s = 60 \frac{f}{p} \quad (15)$$

In which f is the frequency of the AC supply current in Hz, and p is the number of poles per phase [72].

4.7.8. Location of plant

There are various factors that should be taken into account for determining the location of power plant. The most important ones are distance from transmission lines, location from pipe lines, fuel ports, and the type of fuel availability. Site configuration is not constraint. The plant type is significantly an important factor [61]. Generally, the aero-derivative is used for off-shore location and on most on-shore cases, where the sizes of plant exceeds 100MW, the frame type is best choice [61]. And for the sizes between 20-100 MW, both types can be used. For small sizes 2-20 MW, the industrial type best suits for the plant [61].

According to the Stadtwerke Karlsruhe GmbH, the vicinity of Mineralölraffinerie Oberrhein has a great potential for consuming heat [68]. In other world, the constant demand for heat with the lowest pipeline length can be guaranteed. Moreover, it is located in the vicinity of Rein, which is an advantage for supplying water to power plant. Therefore, this region is more suitable for constructing power plant.

4.7.8. Gas turbines configuration

As it is mentioned earlier, the thermal power plant capacity is determined to be 105 MW and the Industrial Trent 60 gas turbine is chosen as an appropriate technology to operate in the site. The configuration of gas turbines is specified according to achieving high efficiency, high flexibility, and security of supply during maintenance time. It is driven from load data analysis that the base load is 40 MW. So, it is advantageous to use one separate gas turbine to operate most of time with full capacity for covering this amount because of so called efficiency change due to partial load. Figure 4.7.7 shows how the efficiency changes as the GT output is changing. It is clear from it that operating with higher load is beneficial since the efficiency reduction is lower. Meanwhile, the efficiency change due to load change is more sensitive for GT in simple cycle comparing to combine cycle. However, as mentioned in previous paragraphs, simple cycle is preferred because of its higher flexibility to that of combine cycle.

The power output for Industrial Trent 60 is ranged between 53.1–66.0 MW(e) [69]. Furthermore, the GT from this type with minimum capacity is preferred. The base load gas turbine can operate in CHP configuration since it operates most of the hours per year, and therefore the additional heat can be sold. This increases the total efficiency of base load GT up to 80 % [65]. The storage potential is discussed in chapter 5.6, it is clear that it cannot completely compensate the intermittent of renewables. Furthermore, another gas turbine with super flexibility for covering the remained load is necessary. The same model is chosen for this part as well, Industrial Trent 60 with 53.1 MW(e) capacity. This GT is preferred because of its high flexibility, high efficiency and its ease of maintenance.

Additionally, the configuration of two gas turbines has the advantage of having high security of supply even during overhaul and maintenance period. Therefore, the overhaul and maintenance periods for GTs can be managed to be done in different time slots. Figure 4.7.6 shows the thermal power plant configuration.

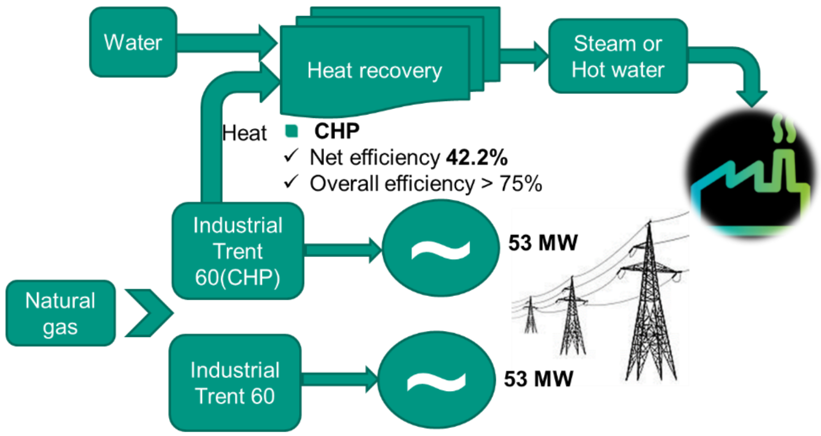


Figure 4.7.6 power plant configuration Plant operation mode.

The figure 4.7.7 shows that it is more efficient to run gas turbines with higher capacity. The base load GT will operate most of the hours per year with power output as high as possible. However, the peak load GT output power is depended on the amount load left as a result renewables fluctuation. Therefore, its power output fluctuates considerably. However, as the GT is considered as a competence technology for intraday market, future market, and capacity market, the power output can be adjusted to be as high as possible when the export of electricity is profitable. Furthermore, during the times that peak load GT needs to be operating, the power output can be kept as high as possible and excessive amount of electricity can be exported.

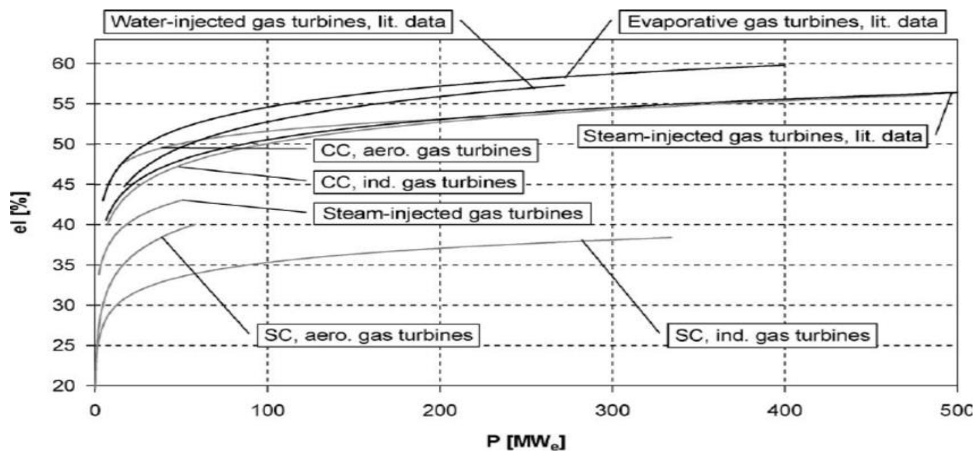


Figure 4.7.7 Efficiency changes due to partial load [73].

5. Import & Export (Imke)

The German wholesale electricity market can generally be divided in three parts: a forward market, a day-ahead-market and an intra-day-market. Most trading occurs on the European Exchange (EEX) in Leipzig, the EPEX Spot [58] and the Energy Exchange in Austria (EXAA). The forward market is based on negotiations about supply up to seven years in advanced but is often also used for three or one year ahead trading due to liquidity reasons.

5.1 Set-up of cost

The electricity costs in Germany are set together out of three components: generation costs, network charges and government wedges. An overview of the average prices for a standard residential customer on low voltage level in 2016 is given in Figure 5.1. It shows, that 15,51 Cents/kWh, what makes 54% of the final price, is due to government wedges. The figure points out, that the price development over the years did not increase due to production costs but due to higher government wedges and network costs. Especially the latter is expected to increase even further over the next years, due to high network investment costs, based on a high amount of distributed renewable generation units.

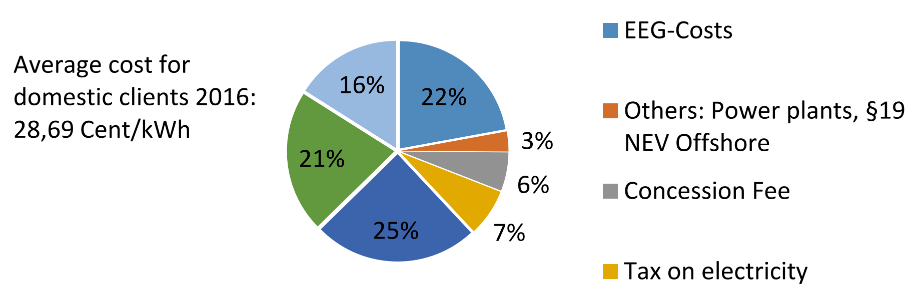


Figure 5.1 Average electricity price for a domestic client in Germany (consuming 3500 kWh/year) [57]

The distributed grid operators (DSO) in Germany are responsible for the low, medium and high voltage network. They connect the power plants levels to their grids, reimburse the plant operators for the feed-in power, use the power to satisfy the load in their own system and pass on the surcharges to the transport system operators (TSO), who again reimburses them in turn [56]. In Germany, the transport system on is managed by four TSO. The responsible TSO for Karlsruhe is Transnet BW. All costs for the transmission are allocated to the end users. Large and small end user costumers are differentiated due to their hours of usage per year. In Germany, every consumer will be charged for the maximum amount of power that has been consumed during the highest peak hour of the year. The network charges for 2017 by the Transnet BW are shown in Table.

Table 5.1: Network costs claimed by Transnet BW in 2017, when connecting directly to the transformer substation. [55]

Costs	Working Price (marginal)	Fixed Price (based on P_{max})
Hours of usage	[Cents/kWh]	[€/kWa]
$\geq 2500\,h/a$	0.03	63.49
$< 2500\,h/a$	2.04	13.22

5.2 Import & Export system for the VPP

The generation costs for the imports will be assumed to be equal to the average hourly EXX spot market in 2014. The spot market was chosen due to the necessary flexibility of the imports in the system. Import is just the final solution for peak demand, when storage and an increase in the gas power plant production are not sufficient to meet the systems demand.

Regarding network charges for import to the VPP in the Karlsruhe area, just the costs for the connection to the TSO substation (380 kV/220 kV) from 2017 were considered. This is justified by the general assumption that within the VPP-system different voltage levels will be neglected. The final system import costs for electricity are reflected by equation (16).

For export no taxes or network costs occur within the present system (equation 17). Since it is assumed, that just a short-term noticed overproduction will be fed up to the transport grid, the gain from the sold electricity will be based on the available price on the EEX Spot-Market during the hour of exceeding production.

$$Price_{import}[€] = P_{max,a}[kW] * C_{Fixed}\left[\frac{€}{kW}\right] + \int_{i=0}^{8760} E_i[kWh] * C_{working,i}\left[\frac{€}{kWh}\right] \qquad (16)$$

$$Price_{export}[€] = \int_{i=0}^{8760} E_i, surplus[kWh] * C_{EEX-Spot,,i}\left[\frac{€}{kWh}\right] \qquad (17)$$

Where,

$P_{max,a}$	Maximum consumed power during one hour in the year
C_{Fixed}	Fixed connection costs, based on hour of usage
E_i	Electricity imported during hour i
$C_{working,i}$	Working price during hour i

$E_i, surplus$	Overproduction during hour i
$C_{EEX-Spot,,i}$	EEX Spot Market Price during hour I in 2014

5.3 Trends

Due to AGORA, over the last years, wholesale market prices have been decreasing in Germany, due to an oversupply of low-marginal cost generation units, a flat demand due to the recession and an increase in energy efficiency [4.8].

The increase of distributed generation and the resulting grid expansion and regulation costs result in an expectation of growing network costs over the year. Depending on the necessary investments and the amount of costumer development in the region, the development of final network prices varies between the system operators. Due to the rather stable conditions regarding the consumption in the small area of Transnet BW and the rather small amount of expected new distributed generation units on HV level, the increase in price for the Karlsruhe area can be expected comparable moderate [56].

Government wedges are expected to increase further over the next years, due to the increasing complexity of the political incentives and a higher share of renewables in the electricity mix [56].

6. Modelling "VPP Optimizer" (Bruno P.)

In order to try to obtain the most cost-efficient virtual power plant with the available technologies, a set of assumptions to contextualize them in the area of Karlsruhe and a model ("VPP Optimizer") were developed. This model is meant to be an iterative tool in developing the complex system that is a virtual power plant and not a final answer for its final form. The model is meant to run with a set of data corresponding to 8760 hours (1 year) in order to generate an output. This output is a matrix which contains the usage of every technology and the installed capacity necessary to generate that amount of electricity for every hour of the sample year.

6.1. Assumptions

To model and reach optimization of the virtual power plant, economic performance, weather data and the purpose of use for each technology need to be taken into consideration. The optimization of the capacities and usage of the technologies accounts for the following assumptions:

1. The term "capacity factor" will be applied in this model as the possible output of a technology at a given time step t divided by its installed capacity.
2. *Thermal power plant acts as a single generation unit with steady state economic and technical parameters*. This proposition can be achieve by having a flexible technology such as two gas turbines working together to produce the amount of energy required at any time. The capacity factor for the thermal power plant is assumed to be '1' for the model.
3. *Breakdown and maintenance interruptions are not taken into account [53]*. Despite recognizing that in a real system power plants have breakdowns and require maintenance

time, this set of complications was not modelled due to being out of the scope of the study case.

4. *Full backup power connection to the grid*. It is important in any energy system to have the ability to back up the power required from it due to a complication. Even though the technologies in use are not modelled to take into account physical breakdowns, it is appropriate to have a connection to the grid that would allow a full back up of power in the absence of the virtual power plant.
5. *Exchanges of energy from the national grid (imports and exports) are done in very high voltage.* In case the technologies available are not able to generate enough electricity to meet the demand at any given time step, the virtual power plant has always the option to import electricity from the national grid. Additionally the electricity imported from the national grid is assumed to not contribute for the share of renewables in any percentage.
6. *Export of electricity to the national is always available.* It is assumed that at any given time, the VPP can export electricity without any restriction.
7. *Photovoltaic electricity generation is estimated from its hourly capacity factor (section)*.
8. *Photovoltaic generation has priority in consumption*. In order to increase the amount of renewables share in final energy mix, the virtual power plant prioritizes the consumption of electricity generated from photovoltaic. In case there is an excessive generation of electricity from the combination of all the technologies, electricity will be exported. The exported electricity will be from the thermal power plant and therefore will be in very high voltage.
9. *The load data is from the assumed standard year of 2014*. The model takes as inputs non-averaged weather data and spot market prices; it would be incorrect to match them with averaged load data of several years. 2014 is the sample year since it is the year with less fluctuation in annual values between the available years with load data (chapter 3.1).
10. *Load, weather data and spot market prices are considered constant during each $1h$ time step of the simulation.* The available data for all the parameters mentioned above has different time steps intervals and it is therefore necessary to adjust the data to the same time steps. Because spot market prices has the largest time steps $(1h)$ and due to convenience that is to have the output of a given technology (kW) multiplied by $1h$ interval to obtain kWh , $1h$ time steps are adopted in this model.
11. *Batteries are implemented with the purpose of storing excessive photovoltaic generation and to smooth the fluctuations of the thermal power generation without resorting to import of energy from the national grid.* On top of these two main purposes for storage units, others can be added for specific scenarios in order to widen the scope and increase the potential viability of this technology.

The capacity factor for batteries is 0.8. In order to increase the number of cycles for the lifetime of the batteries, only 80% of the installed capacity is allowed to be used. This assumption will also allow for the model to disregard the batteries degradation over the year since the accumulated annual degradation and capacity factor chosen do not reach the same value within the technology’s expected lifetime

6.2. List of symbols (Bruno P.)

Table 6.1. List of symbols

Symbol	Unit	Definition
$i = \begin{bmatrix} tp \\ pv \\ bc \\ bd \\ imp \\ exp \end{bmatrix}$	$[-]$	• Thermal power plant • Photovoltaic • Battery charging • Battery discharging • Import of electricity • Export of electricity
t	$[hour]$	Time step for the model, $t \in [1, 8760]$
t_s	$[hour]$	Time step interval, always as the value of 1
$\mathrm{C}_{i,t}$	$[kW]$	Capacity of technology i at time segment t
$x_{i,t}$	$[kW]$	Usage of technology i at time segment t
cc_i	$[€/kW]$	Annualized specific first cost of technology i
mc_i	$[€/kW]$	Specific maintenance cost of technology i
η_{tp}	$[-]$	Efficiency of Thermal power plant
η_{bc}	$[-]$	Efficiency of charging electricity with storage technology chosen
η_{dc}	$[-]$	Efficiency of discharging electricity with storage technology chosen
$\mathrm{P}_{sm,t}$	$[€/kWh]$	Price of spot market at time segment t
P_g	$[€/kWh]$	Price of fuel for the thermal power plant
$\mathrm{cf}_{i,t}$	$[-]$	Capacity factor for technology i at time segment t
$\mathrm{T}_{c,t}$	$[€]$	Total cost at time segment t
ld_t	$[kWh]$	Load at time segment t
cg_{kWh}	$[€/kWh]$	Additional cost per kWh imported from the grid
cg_{kW}	$[€/kW]$	Annual cost per kW connected to the grid = cc_{imp}
tax_{imp}	$[€/kWh]$	Government vetches
$b_{s,t}$	$[kWh]$	Battery status at time segment t
$b_{s,t+1}$	$[kWh]$	Battery status at time segment $t+1$
$\mathrm{CO}_{2,f}$	$[kg\mathrm{CO}_2/kWh]$	Carbon factor for thermal power plant CO_2 emissions
$\mathrm{P}_{\mathrm{CO}_2}$	$[€/kg\mathrm{CO}_2]$	Price of CO_2 emissions
T_{AC}	$[€]$	Annual total cost for the virtual power plant
TS_{renew}	$[kWh]$	Annual total share of renewables sources
$TS_{n-renew}$	$[kWh]$	Annual total share of non-renewables sources

In the table of symbols above (table 6.1) all of the inputs and outputs for the virtual power plant model are represented. For further detail, it is worth mentioning that the symbols that do not need to be provided are: $\mathrm{T}_{c,t}$,$\mathrm{C}_{i,t}$, $x_{i,t}$ and $b_{s,t+1}$. These variables do however behave within boundary conditions. The value for all the other symbols need to be provided and are either constant throughout the entire simulation or are constant within each time step t of the simulation depending on which assumption they follow.

6.3. Model formulae (Bruno P.)

The formulae for this VPP are presented summarized in this section and complemented in appendix 2. In equation (18), it is presented the objective function which sums the specific annualized costs, the specific operation and maintenance costs, the specific marginal costs and the efficiency of the thermal power plant, import and export of electricity. The model determines, for every hour of the year, the most cost efficient combination of installed capacity and usage of the available technologies while fulfilling the electricity demand and respecting boundary conditions.

$$\mathrm{T}_{c,t} = \sum_{i} \frac{(\mathrm{cc}_i + \mathrm{mc}_i)}{8760} \cdot \mathrm{C}_{i,t} + t_s \cdot [(\frac{\mathrm{P}_g}{\eta_{tp,t}} + \mathrm{CO}_{2,f} \cdot \mathrm{P}_{\mathrm{CO}_2}) \cdot x_{tp,t} + x_{imp,t} \cdot (\mathrm{P}_{sm,t} + \mathrm{cg}_{kWh} + tax_{imp}) - x_{exp,t} \cdot \mathrm{P}_{sm,t}] \quad (18)$$

Addition sets of linear equalities, inequalities and boundary conditions need to be designed in order to properly model the behavior of all the technologies. A particular important inequality for this model is the inequality (19). It assures that at any given time step t the electricity being generated is higher or equal to the electricity demand. The electricity in the system corresponds to sum of the generated electricity from every technology.

$$\mathrm{ld}_t \leq t_s \cdot (x_{tp,t} + x_{pv,t} + x_{bd,t} \cdot \eta_{dc} - x_{bc,t} + x_{imp,t}) \quad (19)$$

To safeguard the local grid, there is also a need to guaranty that all of the electricity generated is either consumed, stored in batteries or exported. There cannot be a surplus of electricity in system without any purpose. The equality below (20) assures that sum of all the electricity generation and consumption is a zero sum. In this study-case export of electricity to the national grid is assumed to be always possible. Therefore whatever amount of energy the virtual power plant cannot consume will be exported to the national grid.

$$t_s \cdot (x_{tp,t} + x_{pv,t} + x_{bd,t} \cdot \eta_{dc} - x_{bc,t} + x_{imp,t} - x_{exp,t}) - \mathrm{ld}_t = 0 \quad (20)$$

In order to obtain meaningful result from the model, appropriate boundary condition need to be in place. An unrestricted model is not able to represent a real scenario and therefore the boundary conditions are based in the limitations of the technologies available and the general assumptions for the study-case. The values given are not permanent and need to be re-adjusted if specific scenarios are to be tested. A particular use that the boundary conditions can have is the convergence of the value between lower and upper boundaries. If a specific installed capacity for one or more of the technologies available are to be tested, the value for lower and upper boundary condition for their installed capacity must be the same ($lb(\mathrm{C}_{i,t}) = ub(\mathrm{C}_{i,t})$) for all time step t. Due to this convergence it is possible to transform a variable of the model into a constant.

In appendix 2 it is detailed the complete set of equalities, inequalities and boundary conditions for this model. It is further shown the methodology for post-simulation analysis necessary to properly extract results from the “VPP Optimizer”.

6.4. Post-simulation analysis (Bruno P.)

Since the model is only a tool to help reaching a specific set of objectives for the virtual power plant, it is necessary to dissect the data generated in each simulation to identify if it is adequate to represent a desired scenario. After each simulation, it is possible to see the entire range of values of the usage $(x_{i,t})$ and the capacities installed $(C_{i,t})$ for every technology, as well as the battery state during the all steps t of the simulation. The two most influential values to validate a simulation are the annual total cost for the virtual power plant and the annual energy mix generated.

The annual energy mix from the virtual power plant is composed by sum of the usage from the technologies that discharge into the system. Therefore some adjustments to the total usage provided by the simulation are necessary. The total share of renewables (21) is the total amount photovoltaic generation minus the energy losses in efficiency between charging and discharging. The total share of non-renewable generation (22) is the total amount of electricity generated from the thermal power plant minus the total amount of electricity exported to the national grid, plus the total amount of electricity imported from the national grid.

$$TS_{renew} = \sum_{t=1}^{8760} (x_{pv,t} - x_{bc,t} + x_{bd,t} \cdot \eta_{dc}) \ (21), \qquad TS_{n-renew} = \sum_{t=1}^{8760} (x_{tp,t} - x_{exp,t} + x_{imp,t}) \ (22)$$

In initial simulations it is useful to unconstraint installed capacities$(C_{i,t})$. Since the simulation takes a set of inputs (ld_t , $\mathrm{P}_{sm,t}$, $\mathrm{cf}_{pv,t}$) that change according to the time step t in which the simulation is in, there is a great likelihood that the installed capacities vary for each time step. This variation will allow observing under which conditions a specific technology will be preferable over the others. Once a pattern is establish for data provided to the model, it is possible to begin adjusting lower and upper boundary conditions or add new constraints according to the specifications of the desired the virtual power plant.

A crucial component to address in the post-simulation analysis is the calculation of the annual total cost for the virtual power plant. Theoretically, by summing the optimized total cost (18) for all time steps of the simulation, the annual total cost should be obtained. However this only happens if the installed capacities for every technology are fixed ($lb(\mathrm{C}_{i,t}) = ub(\mathrm{C}_{i,t})$) before running the simulation. In case the installed capacities are allowed to vary during the simulation, an alternative method (23) is used to calculate the annual total cost. Since there is no fixed installed capacity, the maximum value registered for every technology during the simulation is taken ($max(\mathrm{C}_{i,t}), \forall t$) and used to calculate the annual total cost as if it was fixed before the simulation. Due to the nature of marginal costs, there is discrepancy between their values in either method used.

$$\mathrm{T}_{AC} = \sum_{i} (\mathrm{cc}_i + \mathrm{mc}_i) \cdot \max(\mathrm{C}_{i,t}) + \sum_{t=1}^{8760} (t_S \cdot x_{tp,t} \cdot (\frac{\mathrm{P}_g}{\eta_{tp,t}} + \mathrm{CO}_{2,f} \cdot \mathrm{P}_{\mathrm{CO}_2}) + t_S \cdot x_{imp,t} \cdot (\mathrm{P}_{sm,t} + \mathrm{cg}_{kWh} + tax_{imp}) - t_S \cdot x_{exp,t} \cdot \mathrm{P}_{sm,t}) \ (23)$$

7. Scenario 15REN 2017 (Bruno P.)

The scenario "15REN 2017" is a set of constraints that are used to validate or discard the results of the simulations generated by the virtual power plant's model. In this scenario, the annual energy mix must contain at least 15% of the generated energy from renewable sources (24). It is also necessary to have at least 99% of the total amount of electricity supplied to the local grid to be generated from local units(25). The batteries being used in this scenario are Lithium-Ion (chapter 4.6.2) since they were deemed the most appropriate. Batteries were also compulsory for this scenario. A scenario with the inclusion of batteries provides a more comprehensive analysis of what a VPP can look like.

$$\frac{TS_{renew}}{TS_{renew}+TS_{n-renew}} \geq 0.15 \quad (24), \qquad \frac{\sum_{t=1}^{8760} x_{imp,t}}{TS_{renew}+TS_{n-renew}} < 0.01 \quad (25)$$

After the iterative process necessary to reach appropriate results, the simulation which validated all the necessary criteria presented the following approximately installed capacities and annual capacity factors:

Table 7.1. Installed capacities for the considered technologies and their respective annual capacity factor

Technology $[i]$	Installed capacity $[MW]$	Annual capacity factor $[-]$
Thermal power plant	106	0.626
Photovoltaic units	100	0.117
Batteries	20	0.679

The annual energy mix and the corresponding annual cost share obtained are the following:

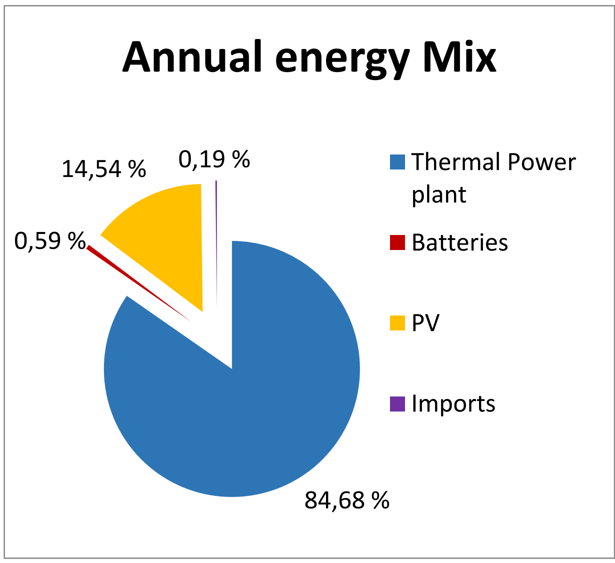


Figure 7.2.Annual energy mix of Scenario "15REN 2017"

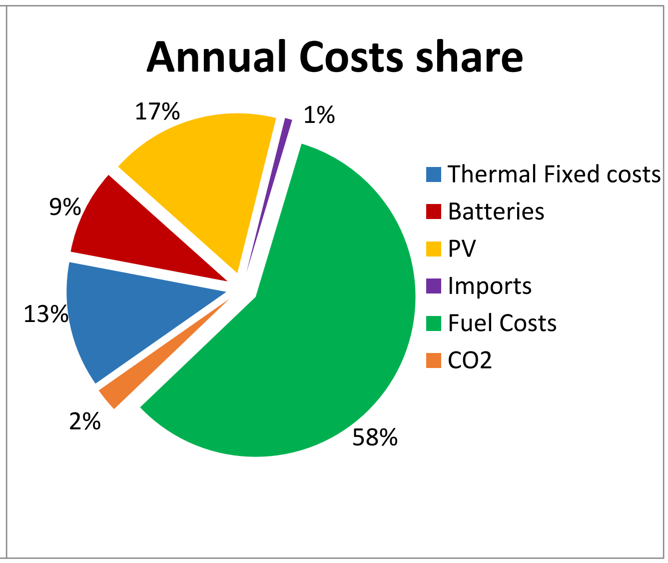


Figure 7.4.Annual Costs share of Scenario "15REN 2017"

Table 7.2. Detail of specific costs, total costs and shares ratios in scenario "15REN 2017"

Technology $[i]$	Annualized Fix Costs $[€/kW]$	Marginal costs $[€/kWh]$	Annual total cost $[M€]$	Share ratio $[-]$
Thermal	72.96	-	7.733	1.16
Fuel	-	0.025	35.453	-
CO_2 taxes	-	0.005	1.468	-
Photovoltaic	105.334	-	10.533	0.855
Batteries	262.62	-	5.252	0.066
Imports	13.22	0.1704 + $P_{sm,t}$	0.405	-
Exports	-	-$P_{sm,t}$	-0.287	-
	Annual fix costs $[M€]$	Annual marginal costs $[M€]$	Annual total costs $[M€]$	
VPP	23.656	36.901	60.557	

Figure 7.1 shows only 14.45 % of photovoltaic electricity generation; however the energy stored and later discharged from the batteries is exclusively from photovoltaic generation. Adding now both of their shares will result in a percentage of renewables slightly above the 15 % margin. It is also possible to observe that the import of electricity is substantially below the 1% margin pre-set which reveals that the VPP is able to properly supply the area for the vast majority of the year. The thermal power plant revealed itself to be, as expected, the cornerstone of the VPP. Having an energy share of nearly 85% is overwhelmingly relevant for both an economic and a sustainability analysis. In one hand, having such a large share offers the opportunity to have presently optimized costs, but on the other hand, it also leaves the VPP vulnerable to future unfavorable changes for electricity generation with gas turbines.

The costs for the VPP are separated in fix and marginal costs. From both figure 7.2 and table 7.2, is possible to observe that by having high dependency in the thermal power plant, the marginal costs of the VPP outweigh by a significant amount (22% or 13.243 $M€$). The largest share of all the different costs is naturally the fuel costs for the thermal power plant since it amount for nearly 85% of the energy generated, however the respective CO_2 emission taxes for such a considerable electricity generation are actually staggeringly low. Although CO_2 emission taxes are expected to rise (chapter 4.7.2), currently they represent a small price to pay for such a convenient electricity generation unit. The import and export of electricity play a relatively small role in the total costs of the VPP and the marginal costs of importing (0.267 $M€$) are nearly identical to the profits from exporting (0.287 $M€$). The amount of electricity that is necessary to export to match the marginal import cost is however nearly ten times higher than the imported electricity (appendix 3).

Regarding the fixed costs, it is worth noting that photovoltaic generation has a competitive ratio between share in annual energy mix and share in annual costs (table 7.2). This share ratio can be translated into a "viability index" which indicates the overall performance of a technology. In contrast, the batteries simulated in this scenario have unimpressive low share ration. Part of the reason why their ratio is so low is due to only 80% of the capacity being allowed to be utilized and due to their usage being limited to photovoltaic over-generation. However, the main reason lies in their cost. They are simply too expensive to be able to be economically feasible at present conditions.

The design of the VPP consisted in linear optimization; therefore it is naturally expected for the total cost to vary linearly with all of its parameters as it can be observed in figure7.3. Since fuel costs represented a 58% share of the total costs and it is responsible for the generation of nearly 85% of the total annual electricity, any fluctuation in its cost will represent a considerable increase of marginal costs for the VPP. Even though the installed capacity of photovoltaic generation units is relatively high, fluctuations in their annualized specific costs do not represent a significant increase/decrease for the VPP since their costs is currently low. CO_2 emission taxes have the lowest impact per percentage of all the costs but unlike all the other parameters these costs are expected to have an increase in the hundreds of percent.

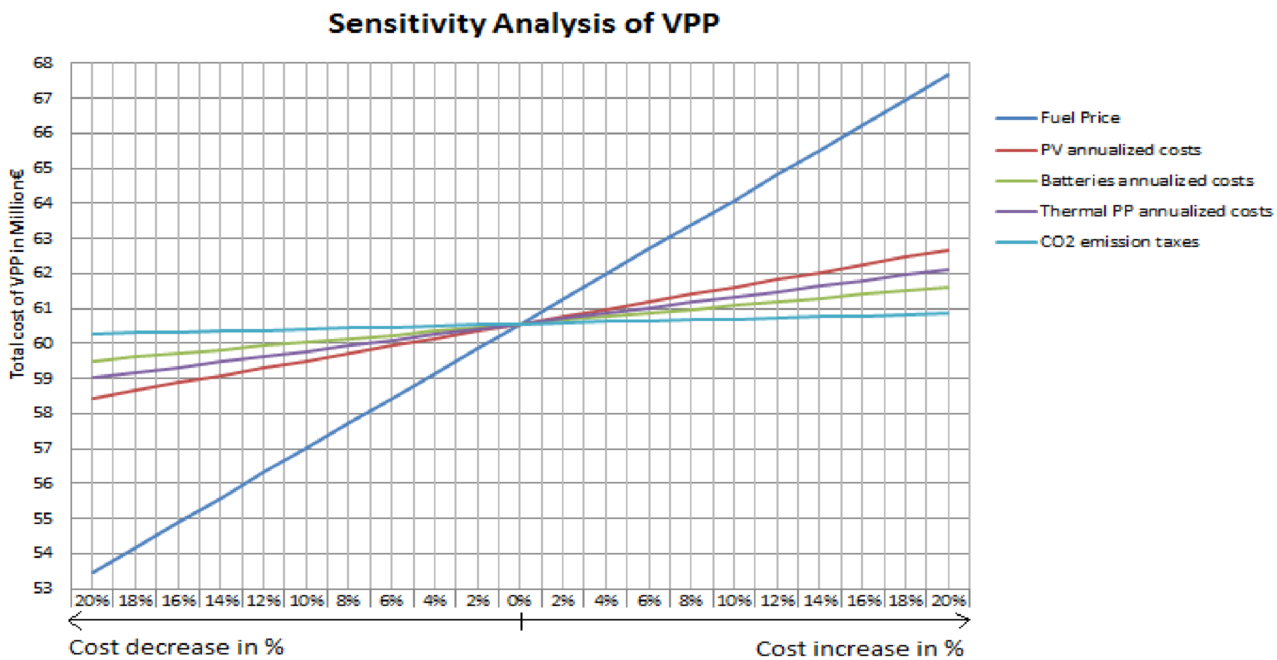


Figure 7.3. Sensitivity analysis of the virtual power plant in scenario "15REN 2017"

7.1. Comparison to other possible base scenarios (Bruno P.)

In this section 3 different possible base scenarios are compared. Scenario c) corresponds to "15REN 2017" analyzed previously. Scenario a) corresponds to a VPP that is entirely dependent in thermal electricity generation. Scenario b) corresponds to a VPP which needs to have an energy mix with near 15% renewables without batteries systems. Since scenario b) is meant to function without batteries for energy management, instead of assuming that photovoltaic panels are pointing south for maximization of their output (chapter 4.3), these panels are distributed in a way where there are a percentage of them pointing east, another south and another west in order to smooth the solar output throughout the day.

Table 7.3. Detail of main parameters for the different possible base scenarios

Scenario	a)	b)	c)
Installed capacities:	-	-	-
Thermal PP $[MW]$	110	106	106
Photovoltaic $[MW]$	0	100	100
Batteries $[MW]$	0	0	20
Annualized Costs:	-	-	-
Fix Costs $[M€]$	8.026	18.365	23.658
Marginal Costs $[M€]$	42.498	36.685	36.901
Total Costs $[M€]$	50.5234	55.051	60.559

The 3 scenarios provide a reasonable base for what the VPP could look like depending on what is expected from it. If no environmental factors are to be taken into account, currently the most cost effective solution is to rely entirely in a thermal power plant for electricity generation. However environmental awareness, sustainability and emissions penalties are factor that are continuously growing in relevance. Scenario “N15REN WB 2017” can be interpreted as a sub-analysis of scenario “15REN 2017” if batteries were not considered. Despite the annualized total costs gradually increase with the inclusion of renewable technologies, the marginal costs fall. This characteristic from renewables, and in particular photovoltaic generation, can be considered a benefit since photovoltaics units are not affected by fluctuation in fuel prices. The difference in total costs from scenario “N15REN WB 2017” to scenario “15REN 2017” can be almost entirely be attributed to the installation of batteries. Since the VPP in scenario “N15REN WB 2017” is able to supply the demand of Karlsruhe and even decrease the amount of imported electricity with the adjustment of the solar panels to have a more homogenous output throughout the day, batteries reveal themselves to be a luxury for energy management.

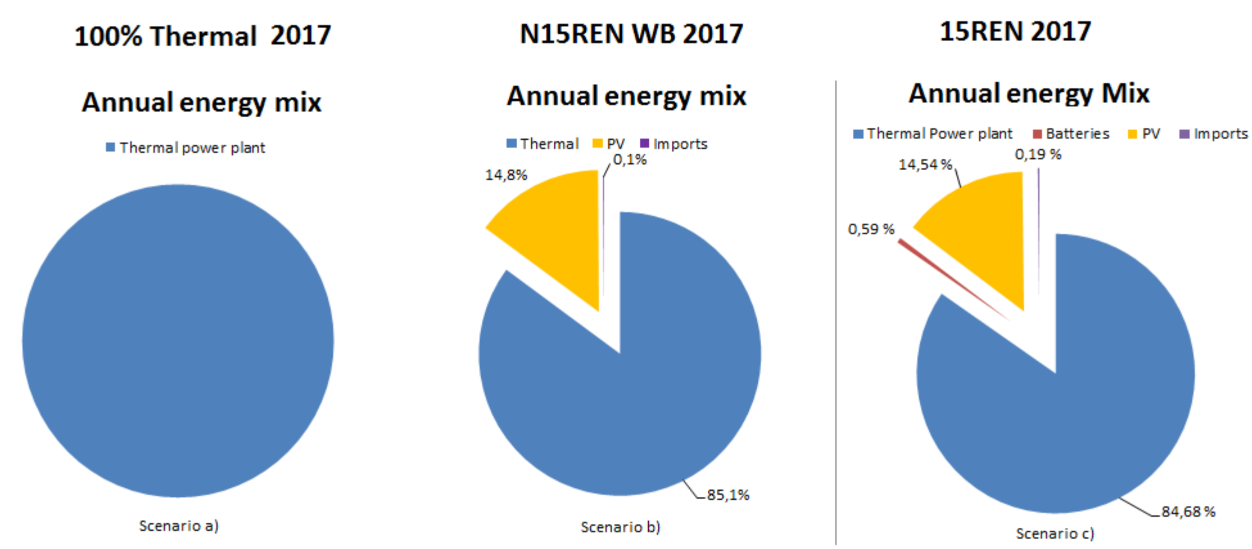


Figure 7.4 Comparison of annual energy mix for 3 possible base scenarios.

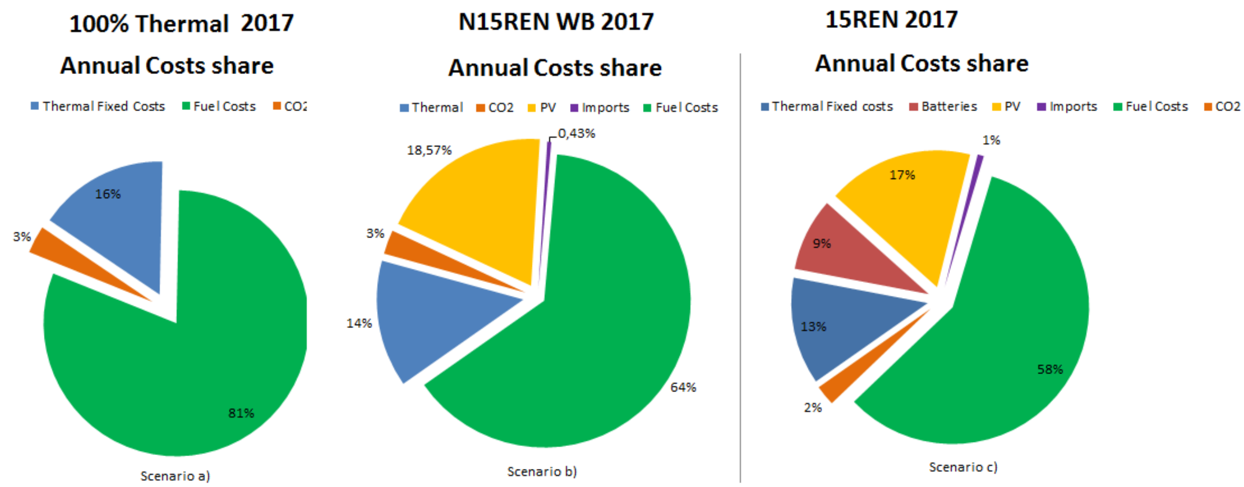


Figure 7.5 Comparison of annual costs share for 3 possible base scenarios.

8. Future Scenario – 15REN 2030 (Bruno P.)

The future scenario “15REN 2030” is the adaptation of scenario “15REN 2017” to expected future conditions. This scenario has different input values regarding annualized costs for the technologies, annual demand, fuel prices for the thermal power plant and CO2 emission taxes. The installed capacities are forced to remain the same as determined in scenario “15REN 2017” since the desired results from this scenario are the observance of how will the virtual power plant respond to future changes and whether it could be economically beneficial to not invest in the present but rather wait for future thresholds to be met.

The annualized costs for the thermal power plant are assumed to remain constant since it is a mature technology with small improvement ranges. The fuel prices are assumed to increase to a value of 0.03125 $€/kWh$, which in within boundaries mentioned in table 4.7.2. This path is assumed since the virtual power plant is highly reliable in the thermal power plant and therefore the evaluation of a worst case scenario has a higher importance than best case scenario. CO_2emission taxes follow a similar path, in which they are expected to rise up to 35 $€/MWh$ (chapter 4.7.2). The annualized costs for photovoltaic installation are assumed to lower their value by 25% (chapter 4.3.6) to approximately 79 €/kW. Lithium-Ion batteries are assumed to have a steeper drop in annualized costs of 35% (chapter 4.5) to approximately 170.7 €/kW. The total annual demand is assumed to have an increase of 1.25 % compared to 2017 (chapter 3.1), which is equivalent to 8.3GWh. Since the impact of EV’s in Karlsruhe is assumed to have a cost driven charging policy, the load curve does not exhibit any increase in peak demand. The thermal power plant is therefore able to provide for the entirety of load increase.

The annual energy mix and annual cost share are the following:

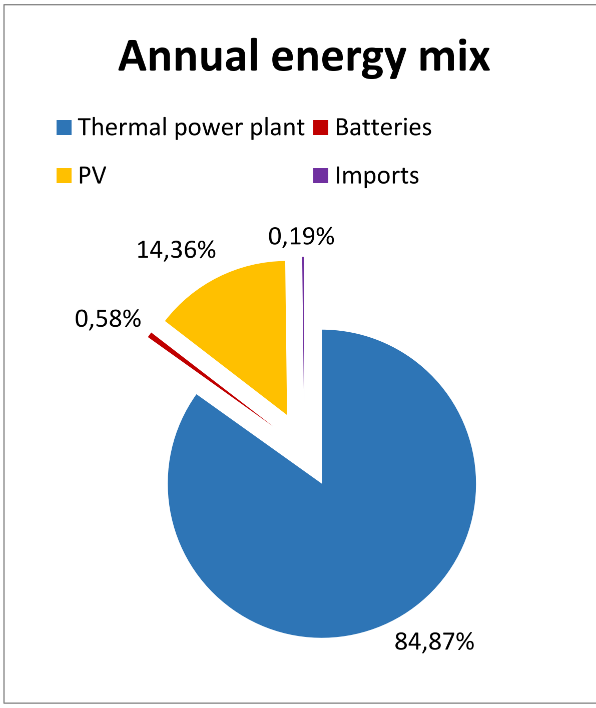


Figure 8.1. Annual energy mix of Scenario "15REN 2030"

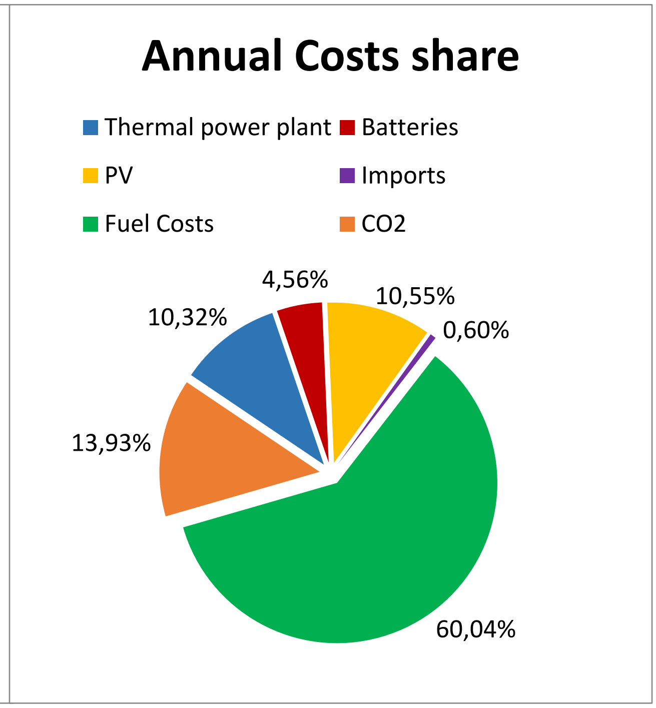


Figure 8.2. Annual Costs share of Scenario "15REN 2030"

Table 8.1. Detail of specific costs, total costs and shares ratios in scenario "15REN 2030"

Technology $[i]$	Annualized Fix Costs $[€/kW]$	Annual Marginal costs $[€/kWh]$	Annual total cost $[M€]$	Share ratio
Thermal PP	72.96	-	7.733	1.01
Fuel	-	0.03125	44.949	-
CO_2 taxes	-	0.035	10.424	-
Photovoltaic	79	-	7.900	1.36
Batteries	170.703	-	3.414	0.13
Imports	13.22	0.1704 + $P_{sm,t}$	0.405	-
Exports	-	-$P_{sm,t}$	-0.287	-
Annualized costs	Total fix costs $[M€]$	Total marginal costs $[M€]$	Annual total costs $[M€]$	-
VPP	19.185	55.353	74.538	-

The small increase in load due to EV's has as expected a negligible impact in the annual energy mix and the 15% of renewables is still achieved. The most evident impact of the expected future changes is the widening of the gap between the annual fixed costs and annual marginal costs for the VPP. Under these future conditions it is less expensive to invest in the different technologies of the VPP however it is considerable more expensive meeting the load of Karlsruhe. This increase in costs is the result of unfavorable changes for electricity generation with the thermal power plant. Even though the expected changes penalize the VPP for relying so extensively in the thermal power plant, it still holds a positive share ratio which indicates that it does not lose its economic competitiveness.

Despite batteries having the steepest drop in costs, their share ratio remains significantly lower than all other technologies. This behavior indicates that batteries require a more extensive range of applications for the VPP than the ones currently in place and either a further reduction in installation costs or substantially increase in life time. Alternatively, a different storage technology from lithium Ion batteries can fulfill these requirements. Photovoltaic generation is the technology which has largest increase in its economic competitiveness with the expected changes. This increase is however counteracted by system limitation. The installation of additional capacity represents a problem since the majority of photovoltaic generation is seasonal. If the installed capacity were to increase substantial overproduction would occur and without a storage system that allows the economical feasible long term storage of this overproduction, the VPP would still need to heavily rely in thermal electricity generation in both winter and autumn.

8.1. Net present value (Imke Hebbeln)

Other instruments to evaluate the feasibility of a produced are the Net Present Value (NPV), the payback time and the internal rate of return (IRR). The equations are given by --- The results are plotted in figure… Both NPV are positive, which indicates the feasibility of the project. The IRR indicates the maximum interest rate for which an investment in the project would be feasible. Interest rates represent the risk of investment in a project. Due to studies by Fraunhofer ISE [51] an average interest rate of 9% for electricity generation projects is feasible. Thus, the higher the IRR the better the project, since it can compete with higher interest rates. Table 8.2 represent the outcome of the benefit analysis. It can be seen, that the results add up to the outcome of the VPP costs analysis, where the 15REN2017 is more profitable, when being installed today. Due to the high dependence on the marginal costs for the thermal power plant, the profitability decreases due to the assumption of an increase in fuel prices as well as CO2 taxes in the 15REN2030 scenario. Due to expected lifetime of the implemented technologies (thermal, PV, batteries) it has been simplifying assumed, that no rest values will exist. Primary investment in thermal, PV and batteries will be assumed as installed overnight at t_0. For batteries a reinvestment will occur after 9 years due to the limited amount of cycles available. Grid connection costs will be assumed as an annual investment. Marginal costs are the fuel cost for the thermal as well as the imports. The used data, which are based on the outcome of the VPP optimizer and the investigations in the different technologies, are given in Appendix.

$$NPV = \sum_{j=1}^{n} \frac{R_{Lj}}{(1+a)^j} - \sum_{j=0}^{n-1} \frac{I_j}{(1+a)^j} + \frac{V_r}{(1+a)^n}$$

$$R_{Lj} = R_j - O\&M_j - Costs_{marginal}$$

Where,

Table 8.2 list of symbols

R_{Lj}	[€]	is the net income per year	Avoided imports + exports
a	[%]	Interest rate	9
V_r	[€]	Rest value after project lifetime	0
n	Years	Project lifetime	25
$O\&M_j$	[€]	Annual O&M costs	Some of O&M for all technologies
$Costs_{marginal}$	[€]	Marginal Costs	Fuel costs for the technologies; import costs
I_j	[€]	Investment costs	Investment costs for technologies in year j

Table 8.3 Benefit analysis for a project life time of 25 years, an average project interest rate of 9%

Scenario	NPV	IRR	Payback time
	[10^8€]	[%]	Years
15REN2017	6,68	40,89	3
15REN2030	3,46	30,54	4

8.2 Comparison to other possible future scenarios (Bruno P.)

In this section, 3 possible future scenarios with the same expected future variables changes mentioned in scenario “15REN 2030” are compared. Scenario c) corresponds to “15REN 2030” analyzed previously. Scenario a) corresponds to the evolution of scenario “100% thermal 2017” and scenario b) corresponds to the evolution of scenario “N15REN WB 2017”. These two new future scenarios have as a constraint the same installed capacities determined in their respective 2017 scenario. As observed in the previous chapter, the increase in electricity demand has negligible effects in the annual energy mix and therefore they are disregarded in this section. The annual costs however show a substantially change with expected future conditions and are shown in the following figure 8.4 and table 8.4.

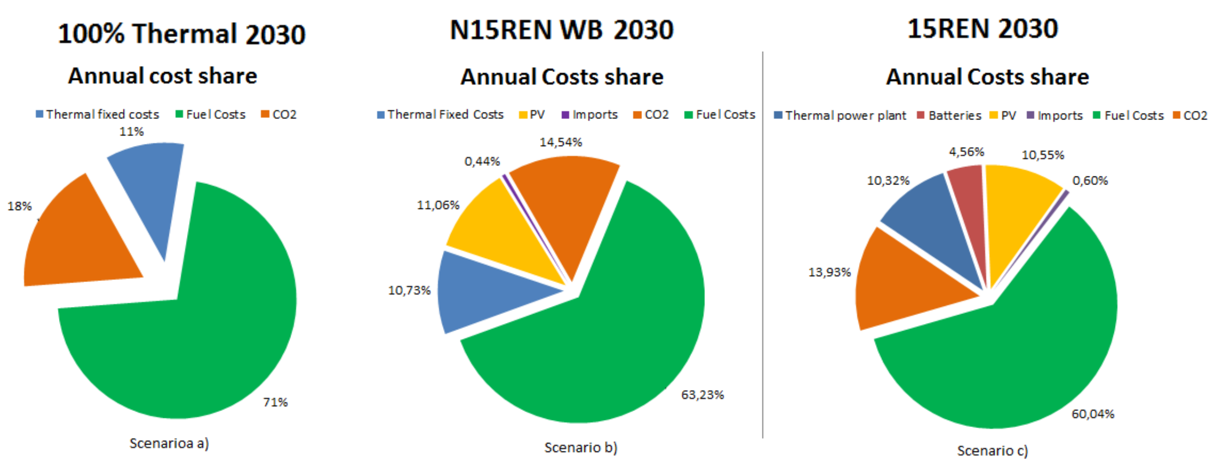


Figure 8.4 Comparison of the costs for the evolution of the 3 different possible base scenarios

Table 8.4 Detail of main parameters for the evolution of the different possible base scenarios

Scenario	a)	b)	c)
Annual Costs:	-	-	-
Fix Costs $[M€]$	8.026	15.672	19.185
Overall increase $[\%]$	0	-14.66	-18.90
Marginal Costs $[M€]$	67.401	55.447	55.353
Overall increase $[\%]$	58.59	45.46	50.00
Total Costs $[M€]$	75.427	71.119	74.538

The thermal power plant has the largest factor for costs increase. From both table 8.4 and figure 8.4 it possible to observe that despite current scenarios having thermal electrical generation as the most cost-effective of all technologies considered, it can over the lifetime of the VPP actually increase the overall costs. This increase in costs is particular apparent when scenario a) and b) are compared. From their previous scenario comparison in table 7.3, in scenario a), the VPP is annually 4.5 $M€$ less expensive to implement and run. Under these new conditions, in scenario a), the VPP is annually 4.2$M€$ more expensive to implement and run. Scenario b) and scenario c) keep approximately the same gap in total annual from the previous comparison in table 7.3 which is caused by the implementation of batteries. The addition of battery systems to the VPP in scenario c) is therefore still not economically competitive, under these favorable conditions, when compared to the very similar VPP in scenario b).

9. Conclusion

In the first part of this study, the concept of a virtual power plant was explored and the area of Karlsruhe was assessed for its load demand and its potential resources to generate electricity. The load pattern showed stability throughout the years with relatively small fluctuations in total annual values. It was researched a wide variety of technologies to supply Karlsruhe for electricity, of which only gas turbines, photovoltaics, batteries and grid connection were deemed worth of further examination and testing.

In the second part of this study, the viable technologies were mathematically modelled and joined into the “VPP Optimized”. This model was used as an additional tool for optimization of the VPP. With different constraints, different scenarios were generated in order to be compared and evaluate which is the configuration for the VPP that allows the most economically feasibility for current and future conditions.

In present conditions, the VVP relying only in gas turbines to supply the load demand is the best option from a purely economic point of view. However, this configuration arises sustainability and reliability issues. A configuration with the inclusion of photovoltaics, imports and exports is 8.97% more expensive but includes nearly 15% annual renewable energy in its final share. Despite renewables being a prime resource to be paired up with batteries systems, they revealed themselves to be far too economically unfeasible under current conditions to be considered a good investment.

For any sizable investment, it is necessary not only to look at current conditions but also assess future developments. The three scenarios generated were tested under expected future conditions in order to determine how they would react. With the increase in fuel costs and CO_2emission taxes, along with decreasing annualized costs for renewables, the most cost efficient configuration for the VPP appeared under scenario “N15REN WB 2030”. If the VPP is entirely reliant in the thermal power plant, any small fluctuation is fuel prices will result in drastic increases in costs. By reducing around 15% the dependency in the thermal power plant with photovoltaics and imports, the VPP becomes more resilient to future unfavorable conditions.

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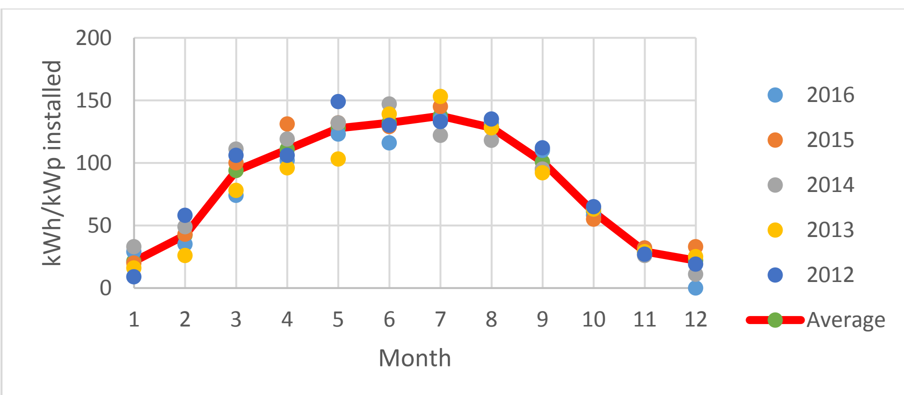
Appendix

1. Solar

1.1 Average monthly output per installed kWp from2012 to 2016 based on data from the Solarenergie-Foerderverein [43].



2. Model formulae

In this appendix the entire set of equalities, inequalities and boundary conditions necessary to comprehend the model “VPP Optimizer” are presented.

Linear Inequalities in this model are the following:

Table 3. Equalities and respective description present in the model

Inequality	Description	Nº
$x_{tp,t} \leq \mathrm{C}_{tp,t} \cdot \mathrm{cf}_{tp,t}$	Usage of thermal power plant must be less or equal to the total thermal installed capacity times the capacity factor of the thermal power plant for all time steps t.	(24)
$t_s \cdot x_{bc,t} \leq \dfrac{t_s \cdot \mathrm{C}_{bc,t} \cdot \mathrm{cf}_{bd,t} - \mathrm{bs}_{s,t}}{\eta_{bc}}$	The energy charged in the batteries must be less or equal to the total installed capacity of the batteries times the capacity factor minus the energy stored in the batteries divided by the efficiency of storing energy with the storage technology chosen, at time step t.	(25)
$x_{bc,t} \leq \dfrac{\mathrm{C}_{bc,t} \cdot \mathrm{cf}_{bd,t}}{\eta_{bc}} \cdot 0.5$	The energy charged must be less or equal to half of the maximum available charging capacity. The batteries need at least two hours at full load to fully charge the batteries.	(26)
$t_s \cdot x_{bd,t} \leq \mathrm{bs}_{s,t} \cdot \mathrm{cf}_{bd,t}$	The amount of energy discharged from the batteries must less or equal to the amount of energy stored in the batteries times the capacity factor of discharge assumed to the storage technology, at time step t.	(27)

Linear equalities in this model are the following:

Table 4. Inequalities and respective description present in the model

Equality	Description	Nº
$\mathrm{C}_{bc,t} = \mathrm{C}_{bd,t}$	The installed capacity for the batteries is same for both indexes $i = [bc \;\; bd]$. This distinction in indexes is necessary for the usage of the batteries ($x_{i,t}$, $i = [bc \;\; bd]$).	(28)
$x_{pv,t} = \mathrm{C}_{pv,t} \cdot \mathrm{cf}_{pv,t}$	Photovoltaic generation is equal to the capacity installed times the photovoltaic capacity factor at time step t. This equality forces the usage of photovoltaic generation into the local grid as a form of renewable source prioritization.	(29)
$b_{s,t+1} =$ $b_{s,t} + t_s \cdot x_{bc,t} \cdot \eta_{bc} - t_s \cdot x_{bd,t}$	The battery status at the time step t+1 is equal to the battery status plus the amount of energy charged, minus the amount of energy discharged at time step t.	(30)
Conditional Equality	Description	Nº
if $\mathrm{C}_{pv,t} > 0.11$, then $x_{bd,t} = 0$	If the capacity factor for photovoltaic generation is higher than 0.11 (average value for yearly capacity factor) then the amount of electricity discharged from the batteries must be zero.	(31)

The default lower (lb) and upper (ub) boundary conditions are the following:

$$lb(\mathrm{C}_{i,t}) = 0, \quad i = [tp, \quad pv, \quad bc, \quad bd, \quad imp, \quad exp] \qquad (32), \dots, (38)$$

$$lb(x_{i,t}) = 0 \quad i = [tp, \quad pv, \quad bc, \quad bd, \quad imp, \quad exp] \qquad (39), \dots, (45)$$

$$lb(b_{s,t+1}) = 0 \qquad (46)$$

$$ub(\mathrm{C}_{i,t}) = inf \ , i = [tp, \quad pv, \quad bc, \quad bd \ , \quad imp, \quad exp] \qquad (47), \dots, (48)$$

$$ub(x_{i,t}) = inf \ , i = [tp, \quad pv, \quad bc, \quad bd, \quad imp, \quad exp] \qquad (49), \dots, (55)$$

As mentioned in chapter 6.3 the boundary conditions are the most prompt to be changed between simulations and very unlikely to remain constant. They need to be adapted to specific technologies in order to improve the approximation to real behavior.

3. Appendix of chapter 7

In this appendix a detailed description of the technologies and their costs is presented. Costs which need to be covered in the VPP have a positive sign, as well as electricity going into the system. Profits generated and electricity exiting the system have a negative sign.

Table A7.1. Overview of all the considered technologies in scenario "15REN 2017"

Technology $[i]$	Installed capacity MWh	Annual output GWh	Energy share [%]	Annual Costs $M€$	Costs share [%]
Thermal	106	581.4355	84.6	44.655	73.3
PV	100	102.4915	14.6	10.533	17.3
Batteries	20	-	-	5.252	8.6
Charging	-	-4.4121	-	-	-
Discharging	-	3.9709	0.59	-	-
	Maximum connection at 1 single hour MW	Annual output GWh	Energy share [%]	Annual Costs $M€$	Costs share [%]
Import	10.4464	1.3052		0.404	0.8
Export	26.9827	-15.5411	-	-0.287	-

Table A7.2. Overview of all the considered technologies in scenario "N15REN WB 2017"

Technology $[i]$	Installed capacity MWh	Annual output GWh	Energy share [%]	Annual Costs $M€$	Costs share [%]
Thermal	106	579.2944	85.1	44.51	81.0
PV	100	98.991	14.8	10.533	18.57
	Maximum connection at 1 single hour MW	Annual output GWh	Energy share [%]	Annual Costs $M€$	Costs share [%]
Import	7.4464	0.7076	0.1	0.247	0.43
Export	25.6489	-9.7431	-	-0.248	-

Table A7.3. Overview of all the considered technologies in scenario “100% Thermal”

Technology $[i]$	Installed capacity MWh	Annual output GWh	Energy share [%]	Annual Costs $M€$	Costs share [%]
Thermal	110	669.2499	100	50.523	100

Since it is initially assumed that there are no generation units in the area of Karlsruhe, all of the load demand would need to be covered from imports from the national grid. The price of importing the total annual demand from the national grid with respective spot market prices is presented in the table A7.4 and follows equation (16) and the values from table 5.1.

Table A7.4 Detail of calculations for 100% imports from the national grid.

	Total	Specific cost	Annual cost $[M€]$
Grid connection	109.3295 $[MW]$	63.4 $[€/kW]$	6.9413
Electricity imported	669,2499 $[GWh]$	0.03 $[cent/kWh]$	0.2008
Spot market	669,2499 $[GWh]$	Variable $[€/kWh]$	23.2303
Government vetches	669,2499 $[GWh]$	0.15$[€/kWh]$	100.3875
Total annual cost	-	-	130.7599

4. Appendix Chapter 4.6

The following table gives a comparision of the different types of electrochemical storage.

Table A4.6: Analysis Different types of electrochemical storage.

Storage technology	**Advanced and developing batteries**		**Flow batteries**	**Fuel cells/ hydrogen**
	Li-Ion	NaS	Vanadium redox	
Power rating [MW]	0,001-40	0,5-50	0,03-7	0,001-50
Energy rating [time]	Min-hours	Sec-hours	Sec-10 hours	s-24h+
Response time	Sec	X	ms	Min
Specific Energy [Wh/kg]	75-250	150-240	75	X
Round-trip effiency	85-100	85-90	85	30-50
Calendar Life [years]	5-20	10-15	5-20	5-15
Power cost [€/kW]	700-3000	700-2000	2500	2000-6000
Energy cost [€/kWh]	200-1800	200-900	100-1000	X
Maturity stage	Demo	Commercial	Demo	Demo/ R&D