elyntegration

Grid Integrated Multi Megawatt High Pressure Alkaline Electrolysers for Energy Applications

Specific national business cases

DELIVERABLE 6.8

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Content

Tables

Figures

1 EXECUTIVE SUMMARY

The research and innovation project “Grid Integrated Multi Megawatt High Pressure Alkaline Electrolysers for Energy Applications“ (ELYntegration) focuses on the design and engineering of a robust, flexible, efficient and cost-competitive single stack multi megawatt high pressure alkaline water electrolyser.

The main purpose of the present study consists to analyse different scenarios involving the exploitation of large scale alkaline high-pressure electrolysers for the centralized production of H_2 wherein said electrolysers are integrated in the electric grids and powered using at least partly renewable electricity.

The business case presented and analyzed by this study deals with the operation of a centralized hydrogen production plant based on a multimegawatt alkaline electrolyze directly connected and powered on-grid. The exploitation of the electrolysis plant leads to two different types of revenues:

- those derived from the sale of electrolytic H_2 (preferably decarbonated) as feedstock for the chemical sector and as fuel for mobility applications
- those related to the fees (flat and variable) paid by the grid operator for the services provided to the secondary regulatory market when using the electrolyzer as a balancing device.

The sensitivity analysis carried out in section 4 on the basis of the operational and economic parameters and the assumptions described in section 3 leads to conclude that the 10 MW business case scenario is in principle more competitive, due to the possibility to negotiate lower electricity tariffs and the economies of scale which are more likely achievable in terms of capex and fixed costs.

Some countries may be more interesting than other for the implementation of the business cases described in the present study and this is essentially related to the possibility to access relatively lower wholesale electricity tariffs in the case of large industrial consumers (consuming between 50 and 100 GWh per year as in the case of the 10 MW plant).

Having said that, it still appears that some countries are seemingly more attractive than others, namely Netherlands, some Scandinavian countries, Germany, Austria and possibly France.

Of course, other criteria must be considered to identify those countries (or regions within a country) where market conditions are the most favorable. Among such criteria we must mention the presence of P2M customers, the decarbonated character electricity and possibly a regulatory market interested to profit of the balancing services which can be provided by the electroyzer

2 OBJECTIVES

According to Elyntegration DoA, in order to help exploiting the project results in Europe, several business cases (case studies) will be developed to support the further implementation of electrolysers integrated in grids with renewable generation.

In these case studies, the actual data with respect to (capital and operational) costs, renewable sources, location, permits and financial plan will be determined.

To determine the financial feasibility, DCF (Discounted Cash Flow) models will be developed, and strategies will be developed to solve possible bottlenecks, for example relating to capital, permitting, etc.

Beside carrying out under more general terms a comparative description of different possible operational scenarios and the corresponding business cases, we will endeavour to provide some complementary information on the specificities expected in some countries such as Austrian, Belgium, UK, etc. taking notably into account factors such as revenues paid for balancing grid services and electricity prices.

The main purpose of the present study consists to analyse different scenarios involving the exploitation of large scale alkaline high-pressure electrolysers for the centralized production of H_2 wherein said electrolysers are integrated in the electric grids and powered using at least partly renewable electricity.

According to the foreseen scenarios (case studies), the analysis take into account a series of data related notably to capex, installation costs, grid connecting costs, opex , electricity price, revenues generated from grid services and sales of produced H_2 (either to the mobility and the chemical market).

The feasibility of the different scenarios from an economic point of view is evaluated using standard financial indicators such as NPV, TV, IRR and DCF analysis. The way how such financial parameters are modified by the modification of different operational factors and boundary conditions is also assessed (sensitivity analysis) in order to understand under which conditions business case performance can be optimized and which are the main bottlenecks (i.e. cost and or operational factors).

From the infrastructure standpoint, two alternative types of centralized H_2 generation plants are considered: one based on a 5 MW single stack high pressure alkaline electrolyser and a second one based on a 10 MW version. The installation sizes proposed are in the range with the MWs size analysed in the project and with the information available related to auxiliary units (compressor, storage) that has been able to gather for the analysis.

The most appropriate geographical localization for the plants is also suggested considering existing regulatory frameworks, electricity prices, grid services and H_2 valorization opportunities in different possible ecosystems.

Different types of grid services can be envisioned. The principle consisting to operate an electrolyser as grid services tool for generating additional revenues is discussed in greater detail in the following sections.

3 BUSINESS CASE SCOPE, PARAMETERS, ASSUMPTIONS AND MODEL LIMITATIONS

3.1 Balancing Power Needs and Demand Site Management

Driven by the long-term goal of global decarbonization, more renewable energy technologies are expected to be developed/installed and to come on line. In the case of solar (photovoltaic) and wind power generation processes, it is important to remember that such processes are primarily dependent on meteorological conditions and hence they are not always generating electricity at constant rate like power generators which use other feedstock such as natural gas, oil, coal, hydro or geothermal.

This implies that more balancing power will be necessary to account for intermittent electricity output associated to such processes and stabilize the grid. The increased PV and wind power capacity in the energy mix can be dealt with either by implementing larger electrical grids or by increasing energy storage capacities.

The first solution would consist to build additional transmission and network infrastructure, that resulting in more electric lines, transformers, sub stations etc. This may encounter public resistance and can be quite expensive. The relation between cost and capacity (MW) is not linear. A NREL source [1] gives cost data per MW-km: 746$ -3318$ for long distance and 1491-6636 for lower voltage transmission lines. Substation costs vary between 10,700–24,000 $/MW and investment in transmission systems are higher in scenarios with higher renewable shares. Another source [2] indicates that for a transmission electric line of 380 kV investment can be of 1 million €/km.

The second solution may encompass the utilization of a flexible technology like water electrolysis since an electrolyser can be used as a variable load to stabilize the grid (i.e. to compensate either positive or negative frequency deviations) and at the same time to convert excess electricity into a valuable and storable energy vector such as molecular hydrogen.

This technology thanks to its flexibility can find application to implement on the customer side a series of grid stabilization strategies and energy storage solutions which are more generally known under the term of Demand Site Management (DSM). DSM is of growing interest across the world and more specifically in those areas of the world where the share of renewable intermittent energy sources is relatively high since it can help to manage variable electricity supply efficiently.

The idea of DSM is known since 50 years but it is now more important than ever due to the expected growing share of renewables and the evolution of smart grid technology. Electricity consumers, in particular electrolyzer operators, can follow their own energy consumption and use information from the grid to decide predictively how to use energy supply. The idea of being able to control electricity end usage is a fundamental concept in DSM.

Under more general terms, DSM deals with two major activities which enable end users to manage their energy consumption by shifting demand during peak periods and/or decrease overall consumption.

These two activities are 'load shifting' or energy efficiency/conservation programs[1]. However, the most pertinent activity in the case of an electrolyzer is the first one. Load shifting is a response technique where the consumer, in our case the operator of an electrolyzer, can offer up his electrical load during high (or low) demand periods. This is at the basis of a variety of business models based on grid services which can be provided to DSO/TSO.

This shift can occur on a daily basis or occasionally during high (or low) demand periods throughout the year and will depend essentially on the willingness of the consumer to curtail (or increment) his own demand, i.e. the load of the electrolyzer.

Load shifting therefore may contribute to level off and flatten the overall load profile. Load shifting can be done in primarily three ways by reducing, increasing or shifting consumption and these three types of load shifting strategies provide alternatives to traditional processes for storing electricity.

As previously stated, DSM in the form of load shifting has the potential to be used in grid balancing, frequency stabilization in order to maintain grid balance.

Of course the services provided by the electrolyzer operator to the DSO/TSO are rewarded through a relatively complex system of flat fees and additional financial compensations which take into account the type of addressed regulating power market, the quality and the volume of grid services provided over a predefined lapse of time (expressed for instance in MWh ultimately activated) as well as the reserved capacity (expressed in MW per bid).

Although a detailed description of the different types of actions which can be undertaken to keep an electric grid well balanced is not the main purpose of this document, it may be useful for sake of completeness to briefly review here the main types of grid services generally required by a DSO/TSO or the regulating authority and those which are more pertinent for an electrolyzer, in particular a large scale multimegawatt unit. This will be the object of the following section.

3.1.1 Power Balancing Markets and electrolyzer as Grid Balancing Tool

Playing on supply and demand, the operators of electrical grids constantly balance power consumption and power generation throughout a given distribution and transmission network.

This strategy is implemented by trying to forecast any possible short-term energy unbalance, using predictive mathematical models, historical data and operator experience and ultimately by anticipating and overcoming short- and long-term variations in the power demand susceptible to negatively affect frequency stability.

Despite such efforts, electricity demand and production can be nevertheless influenced by aleatory factors, and therefore unexpected changes in electricity demand (from the customers) and supply (from the power producers) may cause deviations from the 50 Hz frequency that must be maintained in the European electrical net-work. Whenever a change in frequency occurs then the grid operator activates simultaneously a number of coordinated electrical exchanges with the purpose to mitigate and correct the imbalance.

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1 Energy efficiency/conservation programs aim to reduce customer's electricity consumption. These programs generally target appliances like air-conditioning units or refrigerators to reduced yearly consumption usually coupling the appliances with signals coming from the grid (smart grid approach)

Frequency deviations can occur in both negative and positive directions. A positive frequency deviation may occur when at a certain point of time power generation exceeds demand. Conversely, a negative frequency deviation occurs when electricity consumption exceeds the electric power produced and supplied via the grid.

For instance, failures in the power supply such as power plant going offline cause a negative frequency deviation. When an event like this occurs, the grid operator (TSO) must quickly deploy a reserve power in order to restore the nominal 50 Hz grid frequency. Another way to face and possibly contribute to solve the imbalance situation could consist to temporarily decrease the load (e.g. for instance of an electrolyzer) connected to the grid.

Four different categories of reserve power exist. Such reserves must be triggered in due time to minimize the negative consequences of a frequency deviation.

The four categories are briefly described here below as well as the main utilization requirements/criteria according to the European regulatory framework referring to reserve power.

Instantaneous Reserves (IR)

Instantaneous Reserves are supposed to enter immediately into service to restore the target frequency of 50 Hz as soon as a deviation is detected. The deployment of such reserves is automatically triggered by a series of monitoring and metering devices which can quickly generate and send the necessary alert signals. The power associated to this type of reserves comes from the kinetic energy of large spinning masses (i.e. turbines, generators). Within a given system, all "large spinning masses" rotate synchronously hence the available power in this type of reserve is limited by the size of the system itself.

Primary Reserves (PR)

Primary reserves are also known as **frequency containment reserves** (FCR) and are usually provided by large power generators. The most typical case of FCR is supposed to be available in few seconds from the moment when TSOs require their deployment. Besides such reserves they must be able to ensure either positive or negative grid balancing depending on TSOs request. These reserves not only must be activated within few seconds, as previously stated, but must also provide normally back-up power generation during up to 15 minutes. The ultimate goal of FCR consists to compensate the frequency deviation and eliminate any possible gap thus reestablishing the nominal grid operating conditions as quickly as possible. This goal is achieved not only by connecting large generators in case of frequency drop, but also by dispatching the reserves in equal proportion to all generators to ensure a synchronous restoration of the whole system.

Secondary Reserves (SR)

Secondary reserves are also known as **frequency restoration reserves (FRR)** and represent the **fall back** solution in case the frequency imbalance is not eliminated within 15 minutes. FRR usually need between 3-5 minutes up to 15 minutes in some countries to be fully active from standby and therefore they are started and ramped up during FCR to ensure a smooth transition. FRR technologies include hydropower infrastructures and are expected to provide the required power during at least 60 minutes. FRR are activated by TSOs in a selective manner depending on the location where the frequency imbalance is firstly detected.

Tertiary Reserves (TR)

Tertiary reserves are also known as **Replacement Reserve (RR**) and are generally activated only if a frequency deviation still persists more than 60 minutes after that the original problem has been detected and secondary offline or idle power plants have had the time to enter into full service. RR are supposed to ensure balancing power for up to 4 hours unless the problem is solved before.

Although the previous examples essentially refer to cases where a negative frequency imbalance occurs and an additional power input is needed to restore the frequency at the 50 Hz nominal operating set point, it is important to point out that the opposite situation can also occur. A positive frequency deviation implies that a demand lower than expected causes a surplus of electric power on the grid. In this case the DSO/TSO must be able to increase the consumption in order to restore grid equilibrium. In other words, to overcome the imbalance situation the load of an electrolyzer should be increased.

Generally speaking, a large scale multimegawatt electrolyzer is expected to be able to play a grid stabilization role essentially on the secondary and possibly on the tertiary reserve markets since other devices (e.g. electrochemical devices such as batteries) should be more appropriate for the primary market.

From a technical point of view it is worth to recall that according to a recent study a **pressurized** alkaline electrolyzer could respond sufficiently to regulate the electrical grid through load shifting, even without a spinning reserve as a backup in the system. The same study [3] also suggests that pressurized alkaline electrolysis when used as a dynamic demand response technology could help in reducing the spinning reserves required to ensure the stability of a grid.

Of course, the implementation and development of electrolysis as grid balancing technology will strongly depend on the regulatory framework put in place by the energy authorities and the availability of appropriate spot market opportunities

Expected challenges will be notably the development of advanced metering devices and improved control and communication algorithms. It will also be necessary to overcome underlying concerns about the fact that DSM electrolysis technologies will add a certain degree of complexity to traditional grid management procedures.

Power Regulating Markets and National Specificities - Examples

For sake of example, an economic analysis of electrolysis DSM in Germany suggest that electrolysis would be competitive in tertiary reserve markets [4].

In case of Spain and its underutilized electrical grid, another study indicates that by using electrolysis as a grid balancing technique, it would be possible to increase considerably balancing capabilities without adding power generation capacities [5].

All of the long-term scenarios suggest that if UK decided to reduce his heavy dependence on imported fossil fuels, then large volumes of hydrogen should be generated by electrolysis using excess energy from RES and DSM techniques involving electrolysis could be common practice by 2030 [6].

3.2 Valorization of Product Hydrogen

The participation to reserve markets is only one of the sources of revenue accessible through the operation of an electrolyzer. The most important financial contributions are expected to arise from the sales of H_2 whereas O_2 is usually not valorized.

The best-known hydrogen valorization routes are:

- Power-to-Power (P2P): hydrogen is used to produce electricity in a fuel cell or in a more conventional gas turbine;
- Power-to-Gas (P2G): hydrogen, preferably green hydrogen, is injected into the natural gas grid. Under certain circumstances it may also be appropriate to use such hydrogen to convert carbon dioxide (CO_2) into methane before injection;
- Power-to-Mobility (P2M): hydrogen can be valorized in the mobility market to fuel FCEVs and other types of hydrogen vehicles. Green hydrogen can also be used for the production of methanol (that can be blended with traditional fuels), methane (replacing CNG generally used for cars) and for the production of low carbon footprint fuels in the frame of traditional refinery process (e.g. desulfurization processes);
- Power-to-Chemicals (P2C): of course, last but not least hydrogen is an important industrial gas which can be used by the chemical industry for a variety of reduction processes such as the production of ammonia, in the petrochemical industry and/or the food industry. Moreover, green hydrogen can find application in decarbonizing certain important feedstocks used by the chemical sector thus optimizing the potential of the renewable energies.

As it will be described in greater detail in the following sections, two main ways of valorization have been selected for the purpose of this study, i.e. P2M and P2C. The revenues generated by selling variable proportions of hydrogen produced in the frame of the case studies have been calculated and their impact on the global profitability of the different business scenarios has been simulated.

3.3 Cases studies: 5 and 10 MW

In the frame of the present report, two distinct case-studies are taken into account, a first one based on the deployment and exploitation of a 5 MW high pressure single alkaline electrolyzer and a second one based on the utilization of a single stack electrolyzer of 10 MW , two times more powerful, having nevertheless analogous technical and behavioral performances (efficiency, service life time, dynamics, operating pressure, accessible load-span, etc).

The operational and business schemes chosen for the two cases are basically the same and consist to produce large volumes of hydrogen at intermediate pressure, further compress the gas inside tubular trailers (up to 500 bar to facilitate the delivery) and sell it (ex-works) to a range of different P2M and P2C customers which are located in a defined area around the plant. Oxygen by-product is not valorized and just vented.

The electrolyzers are connected on-grid and over the year they run in the average at only a fraction of their nominal power (load).

This is because the electrolyzers depending on circumstances may be operated in a load-shifting mode to provide grid services, thus generating an additional source of revenues and taking advantage of available cheap electricity. According to the foreseen scenarios, the electrolyzers are supposed either to serve:

- the secondary FRR positive market periodically effacing a fraction of their nominal power demand (depending on DSO needs) down to a minimum load of 50% or
- the secondary FRR negative market periodically incrementing their load from the same “rock bottom” load value of 50% up to 100%

For the purpose of our simulation, the number of hours during which the electrolyzer is operated either at full or 50% load and is supposed to efface or increment its electricity demand is an independent variable and can be modified depending on the selected scenarios.

Both electrolysis plants (i.e. 5 and 10 MW) comprise a series of ancillary infrastructures, namely a battery of tanks which can be used as buffer to temporarily store part of the hydrogen coming directly from the electrolyzers and, as previously mentioned, large compressors capable to further pressurize the gas up to 500 bar. This pressure is slightly higher than the level at which generally operate static buffers of HRS delivering H_2 fuel at 350 bar (i.e. 440 bar). This is also the pressure level at which can be charged last generation composite tube trailers[2] [1] whose utilization could be foreseen for the delivery of the gas to the end-users network (e.g. by truck), thus improving the efficiency of the whole logistic chain.

The major difference between the two case studies consists in the fact that they deal with multimegawatt single stack electrolyzers whose maximum power and nominal H_2 output differ by a factor two.

The purpose here consists to better understand the impact that economies of scale achievable when doubling the size of the hydrogen generation plant can have on the profitability of the corresponding business cases.

To avoid getting off the main subject (i.e. electrolysis) and adding too much complexity to our simulations, the case studies do not cover the complete hydrogen delivery logistic chain.

As previously mentioned, the operational and business case scope only extend up to the compression of the hydrogen gas at 500 bar (to make possible the refilling of the light composite tube trailers used for the transportation of the gas to the end-users).

The rest of the logistic costs (such as e.g. the procurement and amortization or the leasing of the pressurized trailers, the transportation costs per km etc .) are not taken into account. The customers themselves (or a third party, such as a logistic company) are supposed to organize the distribution logistics and cover the related costs. This implies that according to the foreseen scenarios the generated H_2 is sold at ex-factory price.

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2 As of September 2013, The Linde Group *has introduced a tube trailer operating at 500 bar (50.0 MPa; 7,250 psi) utilizing new, lighter storage materials to more than double the amount of compressed gaseous hydrogen to 1,100 kilograms (2,425 lb), or a normal 13,000 cubic metres (17,000 cu yd) of hydrogen gas. The new trailers can be filled and emptied in less than 60 minutes.*

The valorization achievable for the hydrogen sold to P2M and P2C clients is different and tendentially higher for the mobility application. However, in a realistic medium-term scenario it is difficult to assume that mobility market demand will be large enough to absorb the totality of hydrogen produced by large scale centralized electrolysis plants like those object of the preset study.

A secondary commercial outlet is therefore foreseen, and it is specifically directed to P2C market although leading to relatively lower contribution margins. Of course, the first step in the elaboration of our model consisted to identify the major technical-economical, commercial and operational parameters susceptible to impact the behavior of the electrolyzers and the profitability of the business cases.

Some of these parameters (e.g. electricity prices, capex, H_2 selling prices, etc) have been arbitrarily modified (independent variables) and those depending on the former ones (dependent variables) have been simply calculated and injected in the model.

By varying the numerical values of all these variables (independent and dependent) different operational and business scenarios have been characterized and for each scenario the relevant financial indicators have been determined (e.g. EBIT, EBITDA, DCF, NPV, Terminal Value, Pay-back period) with the purpose to assess profitability level and identify the major bottlenecks (sensitivity analysis). The parameters taken into account will be described in greater detail in the following sections.

3.4 Centralized vs Decentralized Models – Advantages of Centralized Model and High-Pressure Large Scale Alkaline Electrolyzers

The centralized models, contrary to those based on the utilization of several smaller on-site electrolyzers integrated to a network of HRS scattered on a vast territory (decentralized), imply the development of a logistic chain ensuring the shipment of the hydrogen to the end-users.

However, thanks to the evolution of the technologies used for the transportation of the gas (i.e. utilization of composite light tube trailers working at nominal pressures significantly higher than the conventional stainless tubular tanks) and the concentration of H_2 vehicles in a perimeter relatively close to the electrolyzer (according to the captive fleet approach), it is possible to simplify the operations necessary to deliver the gas and decrease the related costs.

On the other hand, the centralization of H_2 production may lead to significant economies of scale (EL capex, amortizations, maintenance costs, electricity costs etc.) due to the utilization of large multi megawatt units (compared to a multiplicity of smaller on-site electrolyzers), the localization at an industrial site facilitates the follow up of the operations (by well-trained technical staff) and basically limits possible footprint issues.

Besides, the usage of high-pressure electrolyzers rather than atmospheric ones (which need the installation of larger and more expensive compressors) contributes to improve operations profitability and is particularly well adapted to a centralized hydrogen production model.

Moreover, as previously mentioned, the electrolyzers are supposed to provide grid services and generate some upside revenues. Once again, high pressure electrolyzers present an advantage versus the atmospheric versions since they are characterized by faster response and more favorable dynamics.

Finally, it's worth to mention that the supply of balancing services to the reserve market is relatively easier by load shifting one single large electrolyzer connected to the grid (centralized production model) rather than a multiplicity of smaller devices connected at different points of the grid (e.g. HRS comprising onsite electrolyzers) and supposed to operate independently one from another [3].

3.5 Parameters Overview - Assumptions and Model Limitations

An Excel model has been developed to calculate over a period of 20 years the profitability of the two plants, the one comprising a 5MW electrolyzer and its larger version based on a 10 MW electrolyzer as well as a series of ancillary facilities (intermediate pressure buffer tanks and down-stream compressors) necessary to temporarily store part of the generated hydrogen and inject the gas into the tube trailers used for shipment.

As mentioned above, several numerical parameters are involved in the models, all together impacting the profitability of the business cases.

3.5.1 Operational parameters

The way how the electrolyzers are supposed to operate in order to produce the required amount of merchant hydrogen and at the same time provide grid services is matter of choice. We have mentioned in the previous section that according to the selected model the electrolyzers are supposed to operate on the secondary FRR positive or negative market. Therefore, they are supposed either to periodically reduce their power demand depending on DSO needs (positive market) or conversely, they can periodically increment their power demand (to supply the negative market).

Fixing the operating window between at least 50% and at most 100% of the nominal load, the *average load* on a yearly basis will be of course somewhere between 50% and 100%.

For the avoidance of doubt we assume that electrolyzer will never run below 50% of its nominal load in order to supply sufficient volumes of electrolytic hydrogen to P2M and P2C sectors.

For sake of simplicity, in order to easily simulate different *average load scenarios* with a reasonable degree of accuracy without complexifying too much our mathematical model, three discrete load levels are taken into account by the Excel routine i.e. 100%, 75% and 50%.

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3 An electrical grid comprises transmission and distribution networks. As previously mentioned the final goal is to maintain grid frequency as close as possible to 50 Hz both on the transmission and distribution networks in order to maintain complete system balance. In Europe transmission lines are usually operated at 400 kV and cover extended territories encompassing more than one country and regions. The boundaries of the transmission network correspond to the transmission lines and a multiplicity of power substations where transformers are used to step the voltage down to the voltage level of the distribution lines. The distribution system is then supposed to transfer the lower voltage power coming from the transmission lines and carrying it on to the end consumers. The entire infrastructure necessary to transport and distribute the electricity from the power production sites to the end-users include low, medium and high voltage lines. Depending on the configuration of the different interconnected networks, the location of the power feeding points and the substations, the distribution and density of the customers, the risk of voltage and frequency imbalance may vary from one geographical location to another.

The Excel routine allows to enter the number of hours during which the electrolyzer is operated under each one of the predefined load regimes. This arbitrarily defined numerical values result in variable (and easily tunable) *average yearly load* somewhere comprised between 100% and 50%.

On the basis of this *average load* value (annual basis), the model allows to assess the profitability of the corresponding business cases (taking into account the incomes linked to the sales of hydrogen and the balancing services provided to the regulating power market).

For purpose of illustration, according to the scenario detailed in Table 1, an electrolyzer of 5 MW supposed to serve the positive secondary market could operate at full load (100% of its nominal rate power) during at least six months whereas during the rest of the year its load could be modulated in compliance with the bids applied by the BSP and the incoming DSO requests without however dropping below 50% . Always according to this example, the average load over the year will be finally equivalent to that of an electrolyzer preferably running a 100% of its nominal rate power during six months, 75% during three months and 50% during the rest of the time. However, it is important to point out here that from a formal point of view these operating values can also be interpreted as referring to an electrolyzer supposed to run at minimum 50% of its nominal power rate under let's say ordinary conditions and occasionally increasing the load in order to serve the negative secondary market. All in all, the final average load on annual basis could be the same but the quality of the balancing services provided to the regulating authority will be different.

In the Table 1, independent and dependent parameters (operational, technical-economical and commercial) susceptible to impact the profitability of the business cases are shwon. The numerical values shown in Table 1 are provided for sake of example. Red digits (assumptions) are numerical values arbitrarily assigned to the independent parameters. Black digits are calculated on the basis of the red ones and correspond to the numerical values of the dependent parameters. All these values are used to simulate specific operational scenarios and assess business case profitability.

Electricity price (EUR/MWh$_{el}$) 1500 h/year	**20**
Electricity price (EUR/MWh$_{el}$) 2000 h/year	**30**
Electricity price (EUR/MWh$_{el}$) 5260 h/year	**70**
Avg Electricity Price (EUR/MWh$_{el}$)	**52,3**
Fraction of Total amount of H_2 produced per year sold to H2 Mobility Market	**75%**
Fraction of Total amount of H_2 produced per year sold to Chemical Industry	**25%**
Electrolyser Approvals & Certifications	**50000**
Cost of Civil Constructions hosting H2 Storage Tanks (EUR)	**50000**
Linear Depreciation of Civil Constructions hosting H_2 Storage Tanks over 20 years at 5% per year (EUR/year)	**2500**
Land Lease 20 years (EUR/year)	**10000**
Interconnecting pipe lines between EL-Compressor-Storage Areas (EUR)	**35000**
H_2 Selling Price - Mobility (EUR/kg)	**4,25**

H_2 Selling Price - Chemical (EUR/kg)	3,2
EL Utilization factor @100% Load (% of 8760 h)	50,0%
EL Utilization factor @ 75% Load (% of 8760 h)	25,0%
EL Utilization factor @ 50% Load (% of 8760 h)	25,0%
Hours operated @100% Load (h)	4380
Hours operated @75% Load (h)	2190
Hours operated @50% Load (h)	2190
EL Efficiency System , LHV (MWh$_{H2}$/MWh$_{el}$)	70,0%
EL Nominal Power @ 100% Load (MW$_{el}$)	5
EL H_2 OUTPUT @ 100 % Load (MWh$_{H2}$/hour) LHV	3,5
EL H_2 OUTPUT @ 75 % Load (MWh$_{H2}$/hour) LHV	2,625
EL H_2 OUTPUT @ 50 %load (MWh$_{H2}$/hour) LHV	1,75
Average Load % on annual basis (%)	81,3%
EL Average Operating Power on annual basis (MWel)	4,0625
Electricity consumed on annual basis (MWhel)	35587,5
Average H_2 output per hour (MWhH2/hour)	2,84375
Average H_2 output per hour (kgH2/hour)	85,3978
Average H_2 output per hour (Nm3H2 /hour)	939,376
Total amount of H_2 produced per year (MWhH2/year)	24911,3
Total amount of H_2 produced per year (kgH2/year)	748085
Total amount of H_2 produced per year (Nm3H2/year)	8228933
EL Grid Connecting costs paid to DSO one shot for engineering (EUR)	100000
EL Grid Connecting Costs Paid to DSO (EUR/MWel)	70000
Electrolyser Capex per MW (EUR/MW)	625000
Electrolyser Total Capex (EUR)	3125000
Electrolyser maintenance costs on annual basis (% of Capex)	1%
Electrolyser maintenance costs on annual basis (EUR)	31250
Electrolyser Overhauling costs (% of total capex)	25%
Electrolyser Overhauling costs (EUR)	781250
Electrolyser fixed costs on annual basis Labour & Utilities (% Capex)	2,5%
Electrolyser fixed costs on annual basis Labour & Utilities (EUR)	78125
Electrolyser Depreciation over 20 years (EUR/year) stack non incl.	156250
Total Costs for Connecting the Electrolyser to the Grid (EUR)	450000
Grid services fees for effacing 1,25 MW during max 2190 h (EUR/year)	100000
Grid services fees for effacing 2,5 MW during max 2190 h (EUR/year)	125000

Capex for 500 bar H_2 Compressor (min suction pressure 15 bar) diaphragm or pistons (EUR/100 kgH_2/hour)	900000
Capex for H_2 Compressor (from 15 to 500 bara) ionic liquid technology - 100 kgH_2/hour or 1100 Nm3/h (EUR)	768580
Compressor Depreciation over 20 years (% of Capex /year)	5%
Compressor Depreciation over 20 years (EUR/year)	38429
Compressor Maintenance Costs (% of Capex/year)	1%
Compressor Maintenance Costs (EUR/year)	7686
Energy Consumption for H_2 Compression from 15 to 500 bara (% of LHV)	15%
Electricity Cost for Compression (EUR/MWh)	52,3
OPEX for H_2 Compression from 15 to 500 bara (for fleets and chemical market, 500 bar trailers) (EUR/year)	195451
Total Geometrical Volume of H2 Storage Tanks @ 15 bara - 24 hours production @ 100% load (m3)	1890
Capex H_2 Storage Tanks (EUR/m3)	900
Total Capex of the H_2 Storage Tanks (EUR)	1700575
Maintenance of H_2 Storage Tanks equivalent to 0,5% of Tanks Capex (EUR/year)	8503
H_2 Storage Tanks Depreciation on annual basis (% of Capex)	5%
H_2 Storage Tanks Depreciation on annual basis during 20 years (EUR/year)	85029

Table 1 Independent and dependent parameters impacting business case profitability

Regardless the way how load shifts events (number, amplitude, duration) are really distributed over the year and the type of regulating market they are intended to serve, an average load regime can be ultimately calculated. According to Table 1 scenario the average load regime is 81,3%. This value looks plausible since it allows to achieve a good trade-off between the need to assure a significant hydrogen output to support sales and the intention provide balancing services. This value will be taken as reference for the following simulations, including those related to the 10 MW electrolyzer.

It is important to point out that the electrolyzer will reach a similar annual average load if instead of supplying the positive secondary market starting from a steady 100% load regime, will supply the negative secondary market starting from a steady 50% load regime. The total amount of off-taken or incremented energy in our simulation will be the same as long as the duration of each formal intermediate load step is assumed to be the same. However, when comparing the time spent by the electrolyzer to supply the balancing market it will be longer in the latter case (9 months rather than 6). Of course, from a strategic point of view, the decision to bid on the positive secondary market and just down shift from time to time the load from 100% provides more guaranties about plant's capacity to produce all the volume of hydrogen necessary to supply the P2M and P2C customers. This is not the case when bidding on the negative secondary market and starting from a minimum load of 50% since the accepted bids and the positive load shifts at the end of the year could be not enough to cover all the hydrogen demand. Another issue is the regularity of the supply for the P2M and P2C customers.

Other conditions being the same, the simulations will help to better understand if and to which extent a 2X increase of the size of the plant can favorably influence the profitability of the business case.

3.5.2 Technical-economic parameters

Beside the operational parameters described in the previous paragraph, several technical-economic parameters pertaining to the electrolyzer and its ancillary infrastructures have been taken into account:

- High pressure electrolyzer: capex, expected overhauling costs at mid-life service, BOL efficiency and efficiency evolution over the years, maintenance costs, fixed costs /labour and utilities, depreciation rate
- Ancillary storage/compression infrastructure: compressors capex /efficiency-opex (energy consumption for compression)/maintenance costs, buffer tanks capex and maintenance costs, depreciation rate

The numerical values assigned to each one of such parameters have been defined depending on the characteristics of each type of plant (5 and 10 MW)

3.5.3 Commercial parameters

Of course, a series of additional assumptions have been made regarding:

- average electricity prices
- hydrogen selling prices (depending on the final application e.g. P2C or P2M)
- percentage of produced H_2 sold to P2M and P2C clients
- grid services revenues (flat[4]and variable fees)
- electrolyzer grid connecting costs.

Finally, investment and fixed costs such as civil works and land lease costs have also been taken into account essentially on the basis of plant foot-print.

3.5.4 Relevant financial indicators

Entering the numerical values corresponding to each one of the parameters previously described into an appropriate Excel model, it has been possible to simulate different operational and business scenarios.

In particular the model has allowed to calculate, on annual basis and during a period of 20 years, hydrogen output and total operating expenditures, taking into account notably, electricity costs, efficiency degradation during service life time, average utilization factor resulting from periodic load shifts, ordinary and extraordinary maintenance costs, fixed costs (utilities, labor, permits etc) , storage and additional compression costs, equipment and infrastructures costs, grid connecting costs, depreciation and amortization. Besides, the revenues related to the sales of hydrogen to P2M and P2C clients, total EBITDA and total EBIT have been calculated. Such parameters are shown in Table 2 for the business case related to 5 MW (analogous sheet is developed for the 10 MW scenario).

4 Revenue is generated from simply agreeing to be a regulating power entity

Business Case Electrolyser 5 MW
Electrolyser Total Capex (EUR)
Electrolyser maintenance costs (EUR/year)
Electrolyser Overhauling costs (EUR)
Electrolyser fixed costs (Labour & Utilities) (EUR/year)
Electrolyser depreciation over 20 years (EUR/year) stack non inclusive
Electrolyser Grid Connecting costs paid to DSO (EUR)
Electrolyser GRID Connecting costs amortisation (EUR/year)
Cost of Electrolyser Civil Constructions (EUR)
Depreciation of Electrolyser Civil Constructions costs over 20 years (EUR/year)
Land Lease over 20 years (EUR/year)
Costs for Approvals & Certifications (EUR)
Amortization of Approvals & Certification costs (EUR/year)
Capex for Interconnecting Pipe lines (EUR)
Depreciation of Interconnecting pipe lines (EUR/year)
Capex of H_2 Storage Tanks - 15 bar/1 day production @ full load (EUR)
Depreciation of H_2 Storage Tanks over 20 years (EUR/year)
Maintenance costs for H_2 Storage System (EUR/year)
Cost of Civil Constructions to host H_2 Storage Systems (EUR)
Depreciation of Civil Constructions hosting H_2 Storage Systems over 20 years (EUR/year)
Capex of H_2 Compressor (from 15 to 500 bara) - 100 kgH_2/hour or 1100 Nm3/h (EUR)
Depreciation of Compressor over 20 years (EUR/year)
Compressor maintenance costs (EUR/year)
Electricity consumed on annual basis (MWh_{el}/year)
Cost of electricity for the electrolyser (EUR/year)
Grid services fees for effacing 1,25 MW during max 2125 h and 2,5 MW during max 2125 h (EUR/year)
OPEX for H_2 Compression from 15 to 500 bara (for fleets and chemical market , delivery via 500 bar trailers) (EUR/year)
EL Efficiency System , LHV (MWh_{H2}/MWh_{el})
Volume of Produced H_2 (MWh_{H2}/year) *(Despite Efficiency Losses volume is kept constant increasing electricity consumption (see D31))*
Volume of Produced H_2 (kg_{H2}/year)

Total Cost of Produced H_2 @ 15 bara (EUR/year) *excl. Compression Opex-Maintenance-Amortisations*
Cost of Produced H_2 @ 15 bara (EUR/MWh_{H2}) *excl. Compression Opex-Maintenance-Depreciations*
Cost of Produced H_2 @ 15 bara (EUR/kg_{H2}) *excl. Compression Opex-Maintenance-Depreciations*
Total Cost of Produced H_2 @ 500 bara (EUR/year)
Cost of Produced H_2 @ 500 bara (EUR/MWh_{H2})
Cost of Produced H_2 @ 500 bara (EUR/kg_{H2})
Revenues generated by sales of pressurized H_2 for Fleets @ 4,5 EUR/kg (EUR/year Total income)
Revenues generated by sales of pressurized H_2 for Chemical Application @ 3,5 EUR/kg (EUR/year Total income)
Total Revenues (EUR/year Total income) inclusive Fees Grid Services
Cumulated Revenues (EUR)
Depreciation & Amortization (EUR/year)
Operating Expenditures (EUR/year)
EBITDA related to sales of pressurized H_2 and grid services (EUR/year)
Cumulated EBITDA (EUR)
EBIT generated by sales of pressurized H_2 and grid services (EUR/year)
Cumulated EBIT (EUR)
Acquisition Tangible Assets Capex (EUR)
Total Initial Expenditures (EUR)

Table 2 Inputs and outputs of Excel simulation

The initial expenditures for the acquisition of the plant infrastructures (acquisition tangible assets capex) and the total initial expenditures have also been calculated at Y0. Capital assets including notably buildings and equipment have been depreciated linearly over 20 years.

According to the model, possible stack overhauling interventions are scheduled at Y6 and Y12. This is a very conservative assumption since the stack usually needs to be overhauled not earlier than 10-15 years after the commissioning according to the experience developed in the industrial chemical sector essentially under base load conditions. Overhauling costs are estimated at only 25% of the initial capex thanks to the recyclability of many subcomponents. The model also considers a contraction of the revenues on Y6 and Y12 due to the temporary drop of the average production capacity on those years. Of course, a way to limit the period during which operations are interrupted could consist to dispose of redundant solutions (for instance spare brand new stack, ready to replace the old one; but this alternative scenario has not been integrated in the model nor analyzed in any detail).

The earning and expenditure indicators generated by the Excel model have been further elaborated in order to understand the viability of the business cases over the predefined period of 20 years. To this purpose different analytical methods have been used (explanation in ANNEX 1):

- Discounted Cash Flow Analysis (DCF) calculating the Terminal Value (TV) of the project based on the perpetuity growth methodology
- Unlevered DCF FCF Build up
- Net Present Value (NPV)
- Pay Back Period
- Internal Rate of Return (IRR)

Business case viability has been assessed by combining the information provided by the different financial indicators as a function of specific hypothetical scenarios. This analysis has also led to the identification of most favorable assumptions (scenario boundary conditions) and critical bottlenecks (Figure 1)

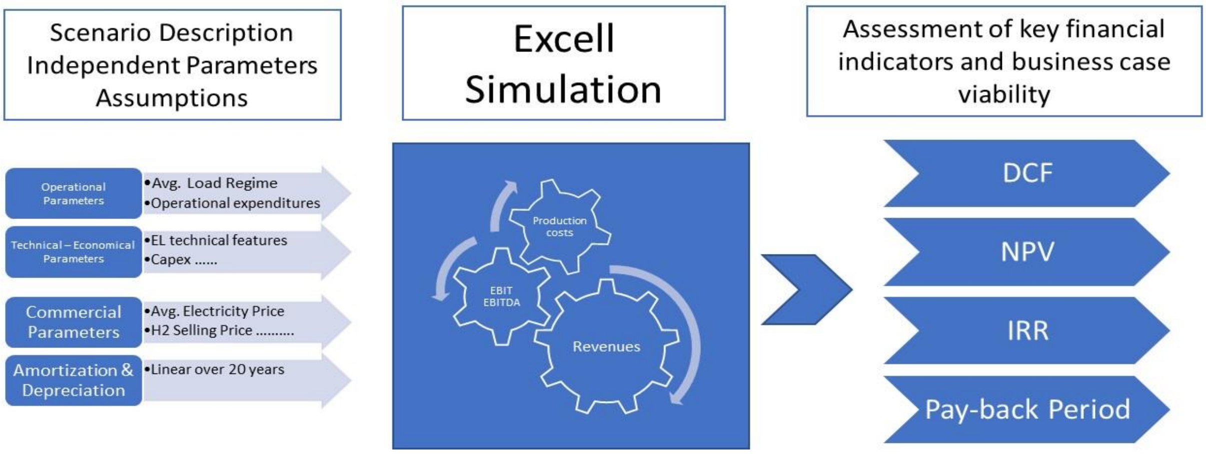

Figure 1 Methodology for the assessment of business case viability

3.5.5 Plausible Scenarios and Sensitivity Analysis

The number of independent parameters necessary to describe a given business scenario is very large. For sake of simplification the sensitivity study focuses on those parameters which are expected to have the most significant impact on the financial viability of the business case.

For each one of such parameters, a plausible range of different numerical values have been entered while keeping the others constant at the central values of their own plausible variation range.

3.5.6 Type of Electrolyzer

The electrolyzer is the heart of the hydrogen generation plants whose performances are analyzed by the present case studies. Hence it is appropriate to briefly recall here its major technical characteristics.

The high pressure multi megawatt single stack electrolyzers based on IHT technology and more particularly their most recent and advanced versions are particularly well adapted for the centralized hydrogen production plants described in point 3.4.

The basic design of these types of electrolyzers results from more than sixty years of continuous optimizations at the industrial scale and provide the possibility to operate very large bipolar stacks producing huge volumes of pressurized hydrogen. Such electrolyzers, thanks to the way how anolyte and catholyte streams are handled inside the stack, utilize a simple and very flexible BoP. The whole systems achieve exceptionally long service life time as well as outstanding reliability/robustness and high efficiency. Finally, the maintenance of these stacks entails low overhauling costs.

The total cost of ownership (purchase price plus the costs of operation) of these electrolyzers is particularly competitive and lower than what is achievable by ordinary atmospheric versions.

As a matter of fact, the capex of a high pressure electrolyzer is not necessarily higher than that of an equivalent atmospheric unit while its unique capability to generate highly pressurized gas allows to limit post compression costs.

In the case of the IHT electrolyzers, H_2 may be generated in the stack at a pressure as high as 33 bar without any significant penalty in terms of efficiency[5].

If required, this allows to efficiently store larger amounts of gas in a buffer without being obliged to use a mechanical compressor to limit the volume of the storage tank. Of course, in case it was nevertheless necessary to further compress the gas (for e.g. injection in a pipeline or in the buffer of an HRS (up to 440 or 890 bar) or, as in the case of our study, inside a rack of tubular trailers (up to 500 bar)) the availability of hydrogen already pressurized at 33 bar allows to simplify the design of a downstream compressor.

The reduction of the number of compression stages limits significantly capital investment and operational expenditures, especially for the big compressors which are needed to handle the large volumetric gas flows which characterize the hydrogen generation plants object of the present study.

Moreover the electrolyzers of IHT, thanks to their thermal inertia and low internal resistance exhibit better dynamics than the atmospheric versions and are perfectly capable to modulate their load (production rate) in compliance with the reaction times required by the FRR market (Figure 2, Figure 3)

Finally, alkaline electrolyzers are more mature, robust and much cheaper (lower capex/MW, maintenance and overhauling costs) than PEM.

For the purpose of the present study two high pressure single stack units respectively of 5 MW and 10 MW have been considered.

5 When operating an electrolyzer at 30 bar instead of 1 bar, a theoretical overvoltage of 65 mV (@ 25°C) can be calculated on the basis of purely thermodynamic considerations (ANNEX 2). However this slightly negative effect on efficiency is largely compensated by a better dispersion of the gas in the liquid electrolyte (bubble size reduction) and consequently a higher cell conductivity; besides it is well known that a gas compression process is much more efficient if carried out electrochemically rather than mechanically due to the absence of frictional losses

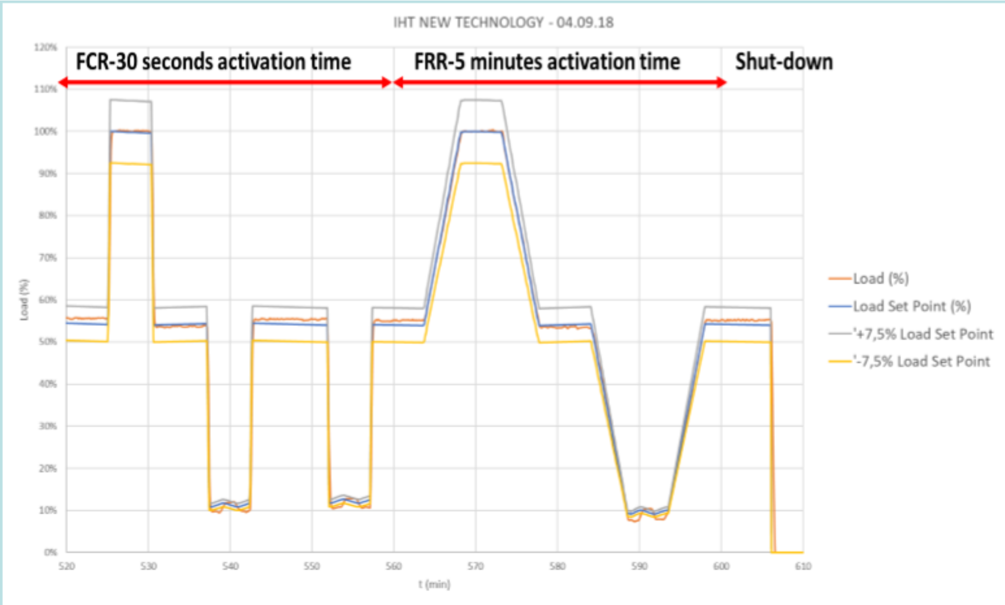

Figure 2 Dynamic response of IHT high pressure alkaline electrolyser

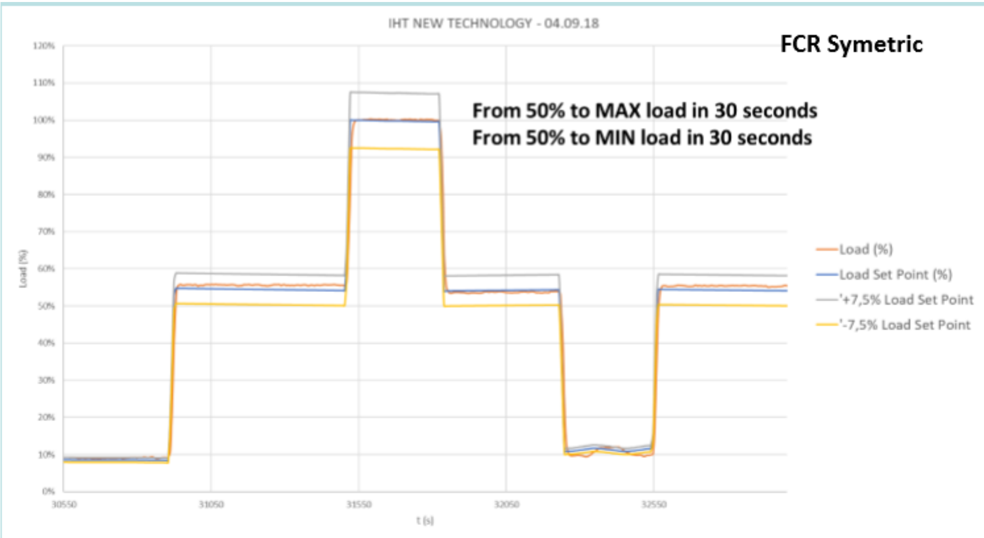

Figure 3 Dynamic response of IHT high pressure alkaline electrolyser (detail)

In this connection it's worth to mention that while single stack electrolyzers of up to 6 MW have already been manufactured using standard IHT technology and exploited at industrial scale, 10 MW single stack units (expected to be even more competitive in terms of capex/MW and TCOs compared to smaller versions) have not been commercialized so far and their design is one of the strategic objectives of the Project[6].

Therefore we deem it appropriate to analyze a series of operational scenarios based on the exploitation of this type of very large scale 10 MW unit and understand the possible benefits arising for the corresponding business cases (notably in comparison to those scenarios based on the exploitation of a smaller 5MW single stack version).

6 DoA: O1 Design of a Multi Megawatt High Pressure Alkaline Water Electrolysis (MW HP AWE) of 4.5 t H2/day for energy applications.

3.5.7 Hydrogen markets

It has already been mentioned in previous paragraphs that the electrolytic hydrogen is further compressed to facilitate its delivery to a range of different P2M and P2C customers which are in a defined area around the plant (whereas oxygen is simply vented).

These sales constitute the major source of revenue although not the only one.

The plant operator is also supposed to provide grid services by bidding fraction of the electrolyzer nominal load on the positive FRR market. Of course, this limits hydrogen production and consequently also the revenues expected from P2M and P2C clients.

It is therefore important that the fees generated by grid services at least compensate the corresponding decline in hydrogen sale revenues.

Importance of Decarbonated Hydrogen Supply

It is not purpose of this study to analyze in any detail the business cases related to the downstream utilization of H_2 (neither as fuel nor as feedstock for the chemical sector). However, it is important to recall that the demand of decarbonized or low carbon hydrogen is expected to grow in the years to come, notably for the decarbonization of certain chemical feedstocks and the needs of the ZE mobility/transportation markets.

Therefore, the hydrogen generation plant should be preferably powered by renewable or decarbonized electricity (e.g. solar, wind, hydro or nuclear). Of course, in order to make possible the utilization of the electrolyzer as power regulating device it should be connected on-grid.

Nevertheless, ways should be identified to guarantee the green nature of the electricity supplied by the DSO/TSO (via appropriate guarantees of origin (GO). The capacity to supply decarbonated hydrogen could help to gain market shares to the detriment of fossil H_2 (produced by e.g. SMR) and hopefully justify a premium price

Plausible market prices (ex-factory) for pressurized hydrogen sold to P2M and P2C clients are respectively in the range of 4.3 EUR/kg and 3.2 EUR/kg independently from the size of the plant (5 or 10 MW).

Importance of the Mobility Application and Need to Diversify Commercial Outlets

The hydrogen valorization potential expected for the mobility market is higher than for the chemical sector, but mobility market is still in an early development phase and it may be difficult to dispose of enough P2M customers to use up all hydrogen inventories (at least during the first years of the business plan).

Therefore, it looks wise to identify complementary commercial outlets although *a priori* less profitable. The diversification of the commercial outlets is also supposed to improve business case resilience to the vagaries of the economic situation and market demand.

This approach is intended to diversify hydrogen commercial outlets and mitigate the risks related to fluctuation of the demand, avoiding occasional overcapacity problems which may occur when the turnover is generated by selling the gas to a limited number of clients.

In this perspective supplying the **chemical sector** with decarbonized hydrogen looks more promising than injecting surplus hydrogen in a NG grid since in the last case hydrogen could hardly exceed its thermal valorization (i.e. roughly 3 times NG price[7]).

Consequently, part of the gas should be supplied to IGS or directly to P2C customers as merchant commodity feedstock for the chemical sector. Lower valorization potential and contribution margins are expected from this type of market (especially if the gas is sold to IGS rather than to the P2C end-users).

In particular, for the larger plant versions described in the study (10 MW), this commercial strategy is supposed to contribute maintaining an elevated stream factor (high average loads an annual basis) and to facilitate the access to competitive electricity tariffs.

P2M Customers Addressed by the Centralized Hydrogen Production Models

As previously mentioned it is generally recognized that mobility market is particularly attractive due to:

- good hydrogen valorization perspectives, in the range of 180 EUR/MWh (when considering fossil fuel equivalent pricing), much better than for currently foreseen for P2G models (usually 30 EUR/MWh, when no feed-in tariff premium is taken into account due to the decarbonated nature of the gas)
- large demand potential, enough to justify massive production of electrolytic hydrogen at the multimegawatt scale.

According to the proposed scenarios most of the electrolytic hydrogen should be sold to P2M customers (indicatively 75%). However, the profile of such P2M customers may play an important role for the success of the related business cases.

The presence of multimodal logistic hubs, bus depots and/or other types of professional captive fleets comprising a significant number of hydrogen driven vehicles at proximity of the centralized hydrogen generation plant allows to simplify the distribution logistic.

Such captive fleets may be composed by e.g. busses, taxis, urban and/or regional goods delivery trucks, refuse trucks used to collect and dispose domestic wastes, vans and LCVs used for regional/urban postal and parcels delivery services, other types of LDV & HDV, possibly material handling vehicles and special maintenance vehicles.

In this case, large volumes of hydrogen need to be delivered only to a limited number of high capacity dispensers (350 bar) rather than to a capillary network of smaller hydrogen refueling stations (usually 700 bar) supplying a park of private passenger cars across an entire region or country.

The reminder of this section is intended to describe the typical profile of the P2M clients to which most of the hydrogen produced by the centralized plant foreseen in this study should be supplied.

7 Of course P2G business models viability is related to a drastic reduction of the electricity prices (indicatively 10-15 EUR/MWh) compared to NG. In this perspective RES shares should be much higher than today or the electrolyzer should be directly connected to a wind or photovoltaic plant in a pure off-grid configuration. The analysis of business scenarios based on off-grid configurations is not within the scope of the present report.

Generally speaking, we have to point out that altough there is scope for continuing efficiency improvements in diesel trucks or the use of alternative fuels such as biofuels and natural gas, a truly zero emissions solution (coupled with low carbon upstream energy production) will be soon required to meet ambitious long term CO_2 goals.

Hydrogen fuel cell trucks are a promising solution for meeting these dual challenges of *climate change and air pollution.* For urban trucks in particular, there is an increasing need for zero emission solutions to comply with upcoming access restrictions imposed by cities as part of air pollution reduction strategies.

Hydrogen fuel cell busses are also very promising and are currently moving to large scale joint procurement following successful demonstration in numerous European and world cities.

Besides heavy-duty vehicles and buses mentioned before, also light commercial RE FCEVs (minivans) are today an interesting commercially available solution addressing professional end-users willing to comply with increasingly tough antipollution regulations and overcome cities access restrictions

Among the urban trucks, refuse trucks are particularly attractive application for the commercialisation of heavy-duty fuel cell based trucks for a number of reasons, namely:

- most refuse trucks operate from a single depot, allowing them to be incorporated into captive fleets. This improves the utilisation of local hydrogen refuelling infrastructure, and thus the infrastructure's economics.
- refuse trucks operate in urban areas where air quality is a particularly important issue. Due to the heavy-duty cycles required the hydrogen fuelled option is one of very few zero emission options that can provide the equivalent flexibility of diesel fuelled vehicles, as battery vehicles struggle to meet the range requirements. In addition, today's standard refuse trucks use a conventional truck chassis.
- the deployment of this type of vehicles will have a significant impact on the utilisation of urban refuelling stations: numerous analyses, such as in the various national H_2Mobility initiatives, have highlighted the challenging economics of hydrogen refuelling stations when the demand at the station is low
- these vehicles also tend to be operated either by municipal authorities, or large subcontractors, who are sensitive to environmental issues and hence prepared to assign a considerable economic value to the zero emissions which are available from a hydrogen refuse vehicle.

Similar arguments and drivers can be put forward for the hydrogen buses.

To date, there have been some steps to accelerate the commercialisation of several heavy-duty fuel cell transport applications, most notably in the bus sector where approx. 60 buses have been deployed in Europe and approximately 500 additional vehicles are expected by 2020 through FCH JU-funded initiatives such as the JIVE project and the joint procurement process running in parallel.

An option to address the low load factor at early stations is the *captive fleet model.* For all the types of vehicles previously mentioned (refuse trucks, busses, LCVs, taxis etc.), fleets of multiple vehicle types operating in local areas can create a stable baseline demand for hydrogen at a station, improving its economics.

The specifications of the vehicles to be used here suggest that when operated in their intended environment, each truck will create a demand of about 15-20 kgH_2 at 350 bar per day, equivalent to c. 20-25 private passenger cars.

As refuse vehicles, as well as busses and LCVs fleets, operate in localised areas, such vehicles are ideal to be operated in a captive fleet model. In case of buses (standard 12 meters models accomplishing a daily mission of ca 250 km before returning to the depot) H_2 consumption can be estimated at ca 20 kg H_2 at 350 bar/day.

In case of RE FCEV (minivans) H_2 consumption can be estimated at 1.5 kg H_2 at 350 bar/day.

3.5.8 Model Limitations and Assumptions

One of the problems encountered when simulating hybrid business cases based at the same time on the production and supply of merchant electrolytic hydrogen and on balancing services lies in the extreme difficulty to reliably predict not only the electricity prices but also the revenues generated by supplying regulatory power market, in our case, more specially the FRR secondary market. It is of course inappropriate to assume that the regulatory authority will systematically accept all the bids submitted by the balancing services provider, in this case the electrolysis plant operator.

The randomness of the load-shift events (whose frequency and amplitude is essentially controlled by the grid operator during the activation phases) complicates all attempts to estimate the total GS turnover since not only the occurrence of load-shifts as well as their amplitude escapes from the control of the plant operator but also because the volume of the hydrogen produced is no more under his full control and hence cannot be exactly planed (due to the correlation between load and gas output)

It is therefore necessary to factor some real-world scenarios into this economic evaluation. One way to simplify the predictive models (without necessarily improving the accuracy of the underlying hypotheses) consists to assume that, in the average, only a predefined percentage of bids will be accepted that leading to an average utilization factor of the electrolyzer somewhere between e.g. 100% and 50% on annual basis.

In order to easily simulate the final average load, it is possible to enter in the Excel model three different load levels, (100%, 75% and 50%) and arbitrarily modify their respective duration. This approach consisting to replace an erratic load profile fluctuating between 50 and 100% with a simple three steps function characterized by steps of different duration (arbitrarily defined) enables to easily match any average load numerical value without however accurately fit the real shape of the load curve. In other words, it is always possible to define a fictive stepwise load evolution function depending on time whose integral (over the year) corresponds to the energy consumed to power the electrolyzer and equals the area underlying the real load curve.

EL Utilization factor @100% Load (% of 8760 h)	50,0%
EL Utilization factor @ 75% Load (% of 8760 h)	25,0%
EL Utilization factor @ 50% Load (% of 8760 h)	25,0%

Table 3 Example of electrolyser capacity factor

As previously mentioned the annual average load is not expected to drop below 50% (by an appropriate definition of the bids and the reserved capacities) to avoid the risk that the volume of hydrogen produced drops at levels which could be insufficient to address P2M and P2C demand. According to the Excel model, in the course of a year, the DSO is expected to curtail in the average during the activation phases a total amount of electric energy equivalent to 25% of the electrolyzer nominal load for 2190 hours/year and 50% of the nominal load during the same lapse of time. Such "not-consumed energy" (i.e. saved) can thus contribute to compensate negative frequency deviations. Fees are supposed to be paid (as shown here below for sake of example) since in this case the electrolyzer may be viewed as a regulating device supplying the negative secondary regulatory market

Grid services fees for effacing 1,25 MW during max 2190 h (EUR/year)	**50000**
Grid services fees for effacing 2,55 MW during max 2190 h (EUR/year)	**75000**

Table 4 Example of grid services fees

We note however that from a formal point of view the same amount of electric energy could also be viewed as "consumed extra energy" (rather than saved) in case the electrolyzer was normally run at a load equal to 50% of its nominal rate power and occasionally ramped up during the activation phases up to a maximum of 100% of its nominal rate power. Such "consumed extra energy" could contribute to compensate positive frequency deviations. In this case the electrolyzer would be viewed as a regulating device supplying the negative secondary regulatory market. Of course, fees could also be generated as previously mentioned. Besides, the total amounts of "consumed extra energy" and "saved energy" would be the same as far as in the average the periods of time during which the electrolyzer run at 50%, 75% and 100% of its nominal rate power were the same.

This approach, albeit its simplicity, allows to simulate the revenues earned when using the electrolyzer as grid regulating device as long as the assumptions on the fees and the load shifts are correct. Once defined the amount of energy (off-taken or injected) it is also possible to calculate on the basis of the assumed fees the remuneration of the grid services in EUR/MWh.

A similar approach has been adopted for modelling different electricity prices (see example below).

Electricity price (EUR/MWh$_{el}$) 1500 h/year	**20**
Electricity price (EUR/MWh$_{el}$) 2000 h/year	**30**
Electricity price (EUR/MWh$_{el}$) 5260 h/year	**70**
Avg Electricity Price (EUR/MWh$_{el}$)	**52,3**

Table 5 Example of electricity price

Once again it is reasonable to expect that electricity tariffs will change during the year and from one year to another. It is therefore necessary to define, for the needs of the simulation, an average tariff value on annual basis.

Basically, the Excel model provides the possibility to change the all-in price at which the electricity can be procured during three different periods of the year, having each period a predefined duration (1500 h, 2000 h and 5260h). By entering different electricity prices for each one of the aforementioned periods the model calculates a weighted average all-in electricity price. Electricity price is by far the variable, between those related to OPEX parameters (i.e. nitrogen, KOH, water, etc), which has biggest impact in the business case profitability, and therefore it will be one of the key parameters to analyzed.

3.5.9 Electricity Prices and National Specificities

Tariffs can change from one country to another. Electricity price can also vary within a same country depending on the supplier and the consumer profile.

Of course, to add more realism to our analysis, it is preferable to focus on electricity prices as plausible as possible, i.e. referring to tariffs recently charged in different EU countries to industrial clients whose profile matches as closely as possible that of the 5 and 10 MW plants operators.

Real tariffs are the result of several factors. They are usually built up on the basis of three main components: the commodity price, the network cost, and all other costs (taxes, levies and certificate schemes).

The detailed analysis of such price components and the way how they change from one country to another depending on the customer profiles goes beyond the purpose of our task.

However the analysis of the main characteristics of different national electricity markets with a special focus on tariffs applied for ***large industrial consumers*** can help to understand which EU countries could be a priori good candidates for the implementation of the centralized H_2 generation plants object of the present study.

In this connection, we note that 2016-2017 tariffs applied for ***industrial customers*** in countries such as Germany, France, UK, Belgium and Nederland are available from some open access surveys.

Besides, the so called industrial customers may be differentiated into different subgroups depending on the average amounts of electric energy they consume on annual basis.

In case of the 5 MW plant the annual consumption should be in the range of 35 GWh (average load 81%) and around 70 GWh for the 10 MW (similar average load). One should add the consumption due to the ancillary infrastructures in particular the compressor.

If we assume that the total volume of hydrogen produced on annual basis by an electrolyzer of 5 MW running in the average at 81% of its nominal rate power is 24911 MWh (see Table 6) then the electricity consumed for its further compression should be in the range of 3,7 GWh and indicatively 7,4 GWh for the 10 MW plan. All in all, the two pants should consume around 40 GWh and 80 GWH per year.

Electricity consumed on annual basis (MWh_{el}/year)	35588
Cost of electricity for the electrolyzer (EUR/year)	-1861438
OPEX for H_2 Compression from 15 to 500 bara (for fleets and chemical market , delivery via 500 bar trailers) (EUR/year)	-195451
EL Efficiency System , LHV (MWh_{H2}/MWh_{el})	70,0%
Volume of Produced H_2 (MWh_{H2}/year) *(Despite Efficiency Losses volume is kept constant increasing electricity consumption (see D31))*	24911
Volume of Produced H_2 (kg_{H2}/year)	748085

Table 6 Example of electricity consumption and H_2 produced for 5 MW case study

Both plants are expected to be powered on the medium-high voltage network (DSO) using a connection voltage in the range of 50 -100 kV.

For purpose of illustration, it appears from Figure 4 to Figure 7 that average tariffs charged to E2 profile industrial customers (average annual consumption 25 GWh) in Belgium (different regions and suppliers) are in the range of 50-80 EUR/MWh and slightly lower i.e. typically 60 EUR/MWh for E3 profile customers (100 GWh)[8].

Besides, 2016 power prices are tendentially lower than those of 2017. Tariffs look definitely cheaper in Netherland (ca.50 EUR/MWh) but more expensive in Germany and particularly in UK.

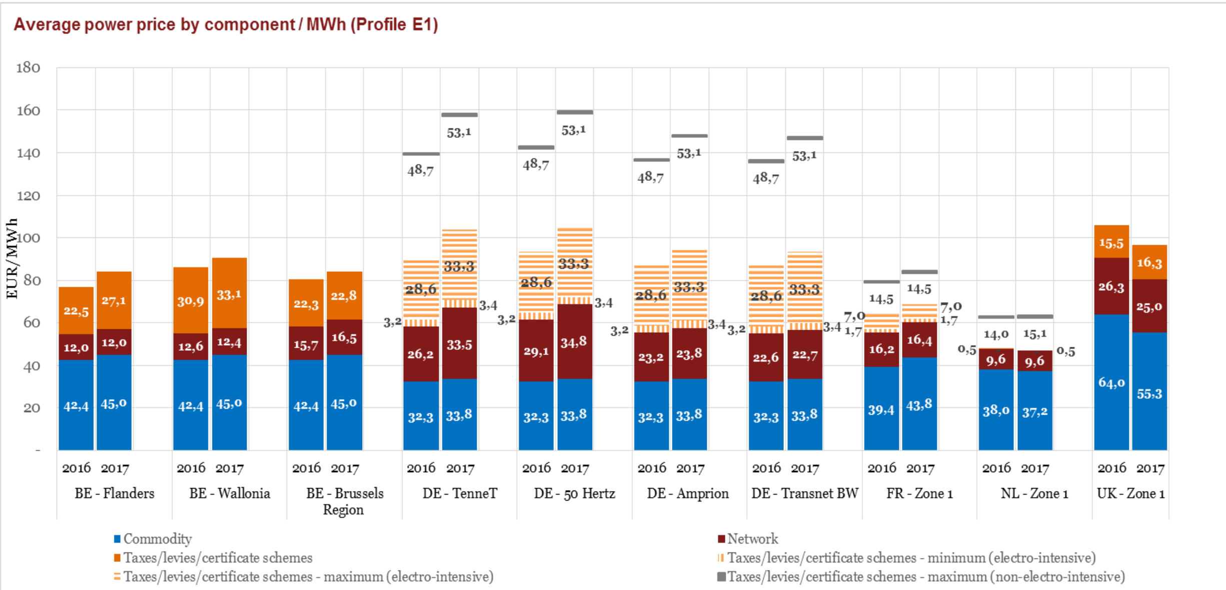

Figure 4 Average power prices in Belgium, Germany, France, Netherland and UK (2016-2017, E1 Industrial profile)

8 Consumer profiles E1 and E2 represent industrial electricity consumers with an annual consumption of respectively 10 and 25 GWh. Consumer profiles E3 and E4 represent very large industrial electricity consumers, amounting to an annual consumption of respectively 100 GWh and 500 GWh.

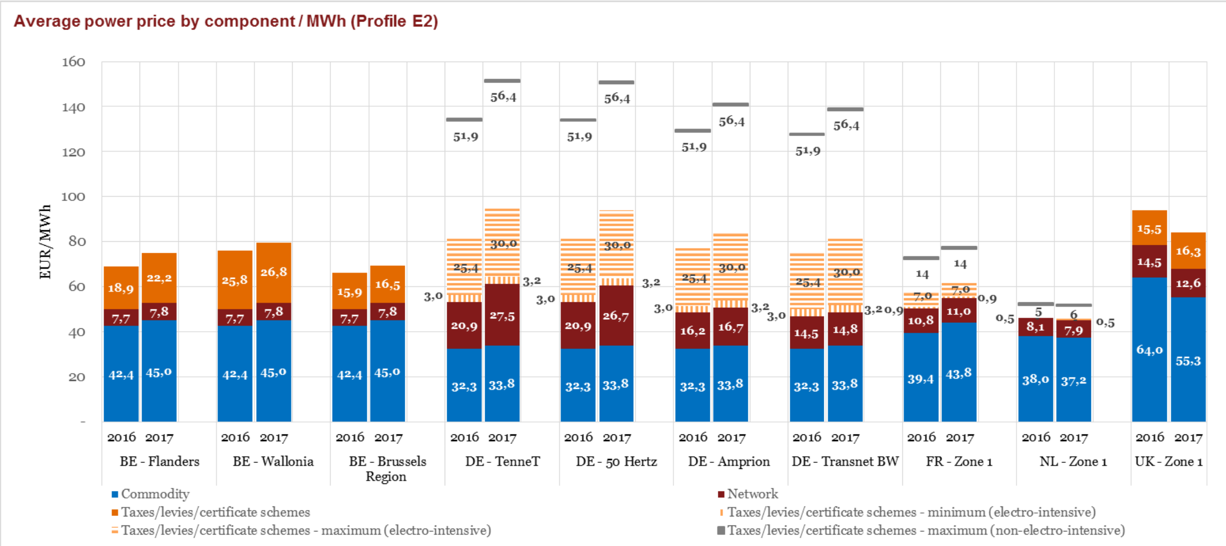

Figure 5 Average power prices in Belgium, Germany, France, Netherland and UK (2016-2017, E2 Industrial profile)

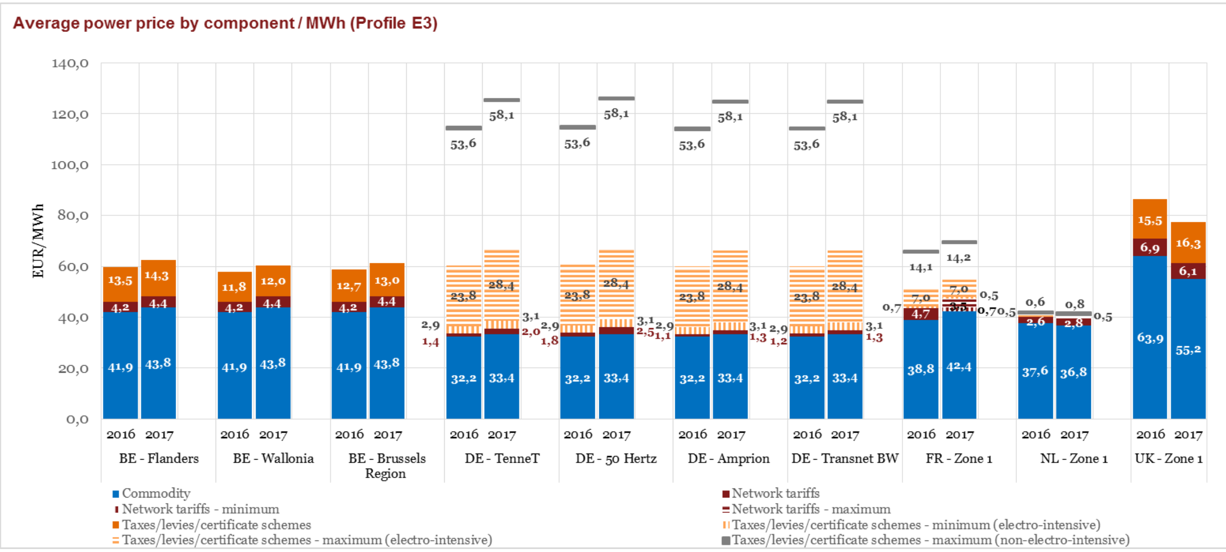

Figure 6 Average power prices in Belgium, Germany, France, Netherland and UK (2016-2017, E3 Industrial profile)

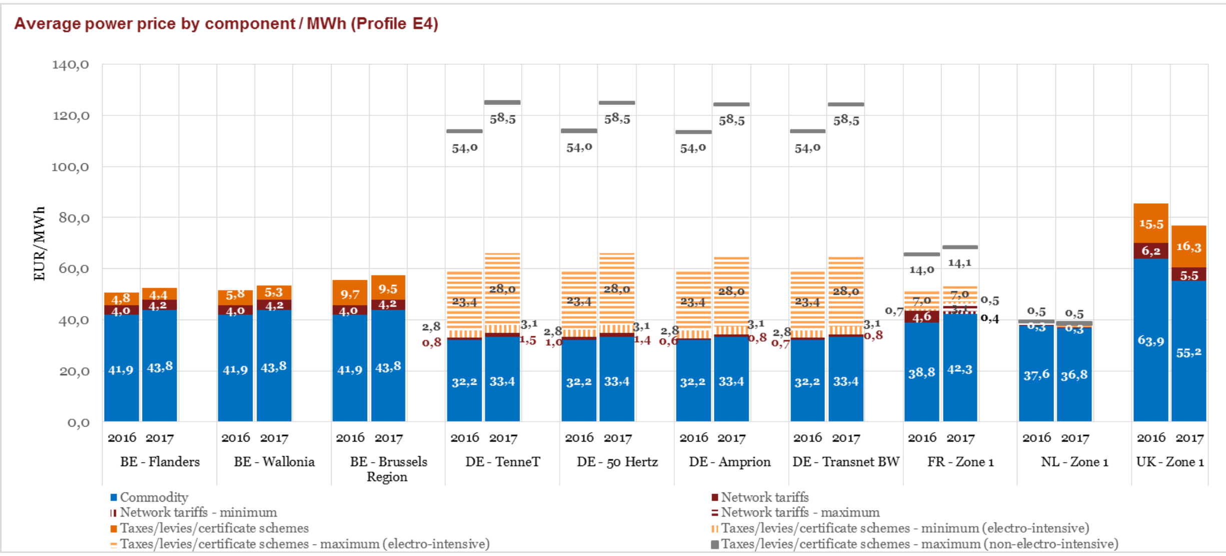

Figure 7 Average power prices in Belgium, Germany, France, Netherland and UK (2016-2017, E4 Industrial profile)

Of course, electricity prices may be significantly higher for **house-hold and non-house hold consumers**. For **large industrial consumers** (100 GWh per year, base load or peak) some additional statistics are available and are worth to be mentioned in the frame of our study.

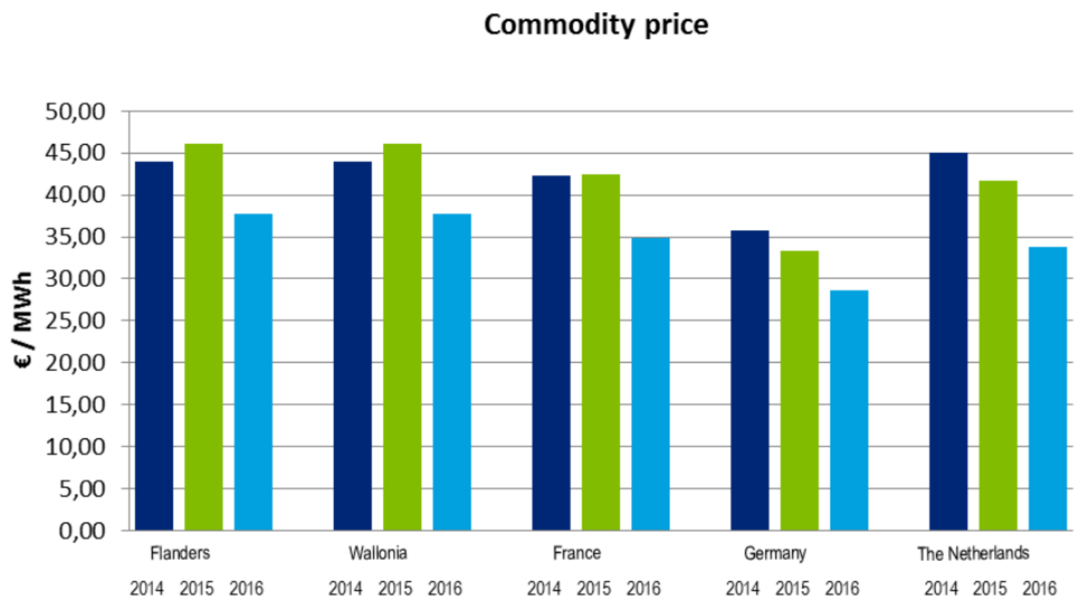

Figure 8 Commodity prices for very large consumers (100 GWh) base load profile (source Deloite)

As already mentioned before, the all-in prices described here after are the result of three price components: i.e. commodity or wholesale price[9], transmission/ distribution price and additional taxes and levies.

The Figure 8 indicates that 2015-2017 **wholesale electricity** prices in Germany remain substantially below the market prices in the other countries and are comprised between 30 and 35 EUR/MWh. For 2017, Belgian market prices are nearly in line with **wholesale market prices** in France ca 42 EUR/MWh but remain 13% more expensive than in the Netherlands (37 EUR/MWh) and 21% more expensive than in Germany (35 EUR/MWh).

When considering average **all-in prices**, we observe that in Belgium large **industrial baseload consumers** are facing higher tariffs than in the neighboring countries.

In 2017, average all-in electricity prices for 100GWh baseload consumers were close to 60 EUR/MWh in Flanders, 70 EUR/MWh in Wallonia and 45 EUR/MWh in France (Figure 9, source Deloite).

9 Wholesale energy is a term referring to the bulk purchase and sale of energy products – primarily electricity, but also steam and natural gas – in the wholesale market by energy producers and energy retailers. Other participants in the wholesale energy market include financial intermediaries, energy traders and large consumers The concept of wholesale trading relates to the business of selling of goods in large quantities and at low prices, typically to be sold on by retailers at a profit. In general, it is the sale of goods to anyone other than a standard consumer. In the wholesale energy market, the term generally relates to purchasing and selling large quantities of electricity between utility companies, but other smaller independent renewable energy producers are also entering the wholesale energy market.

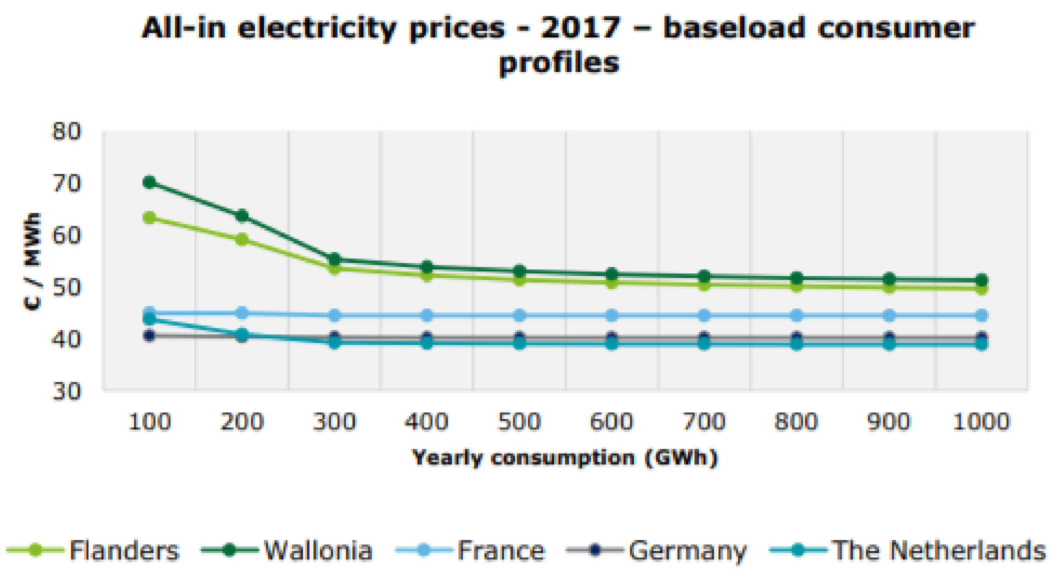

Figure 9 All-in electricity prices for base load consumer profiles in the range 100-1000 GWh

Figure 10 All-in electricity prices for 100 and 1000GWh consumers base load profile in different countries (source Deloite)

In Germany and the Netherlands significant discounts are applied not only on the commodity price but also on the network costs and taxes. That explains the fact that 2017 electricity prices are particularly competitive in these two countries, close to 40 EUR/MWh in Germany and less than 45 EUR/MWh in the Netherlands.

All-in electricity prices are even lower when considering larger industrial consumers. For instance, they can drop below 40 EUR/MWh in these two countries for 1000 GWh baseload profiles (Figure 10). However, according to Figure 9 it is not necessary to reach such extremely high consumption levels in order to benefit of such tariffs. It appears that electricity prices in Germany and the Netherlands basically drop slightly below the 40 EUR/MWh already starting from consumptions of circa 300 GWh/year.

This trend is more particularly caused by a sharp drop of network costs and taxes in the range 100-300 GWh (Figure 11, Figure 12). Network tariffs in Belgium increased (+4% to +5%) in 2017 and remain higher than those in the neighboring countries. In France, Germany and the Netherlands, a maximum 90% discount on network costs is applicable for certain consumption profiles. This discount does not exist in Belgium, which explains the large differences between Belgium and its neighboring countries.

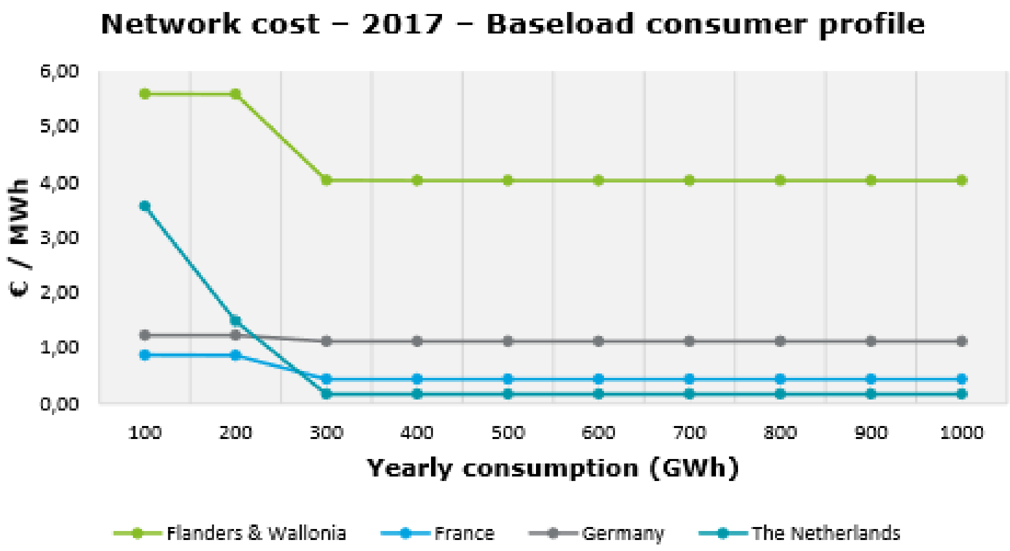

Figure 11 Evolution of network costs depending on yearly consumption – Base load consumers (source Deloite)

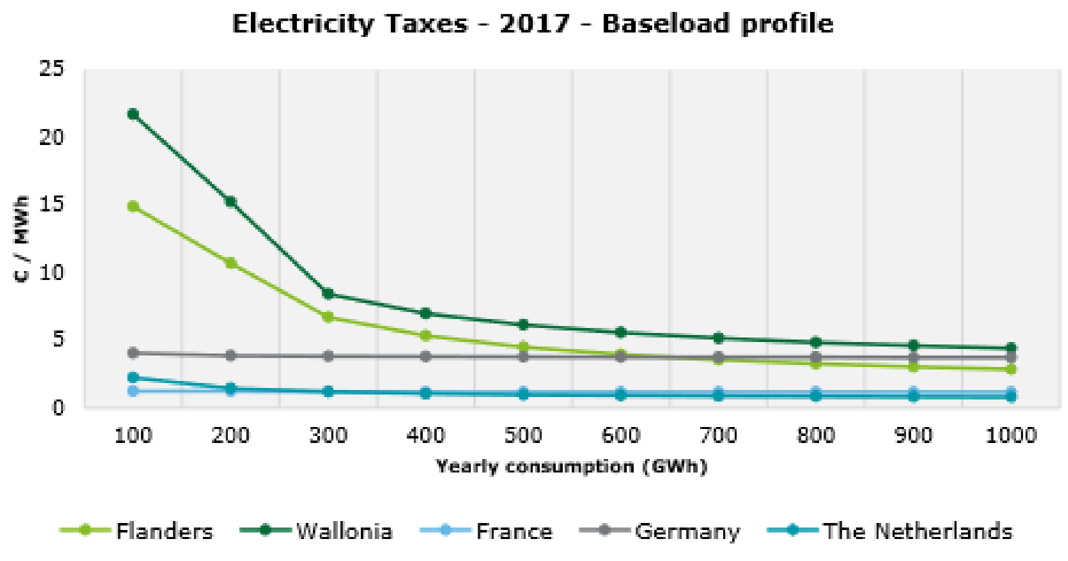

Figure 12 Evolution of electricity taxes depending on yearly consumptions – base load consumers (source Deloite)

Recent statistics are also available for large industrial peak load consumer profiles in the same countries. All-in electricity prices are generally higher. The most competitive tariffs are observed in the Netherlands and range between 60 and less than 50 EUR/MWh for yearly consumptions between 100 and 300 GWh (Figure 13)

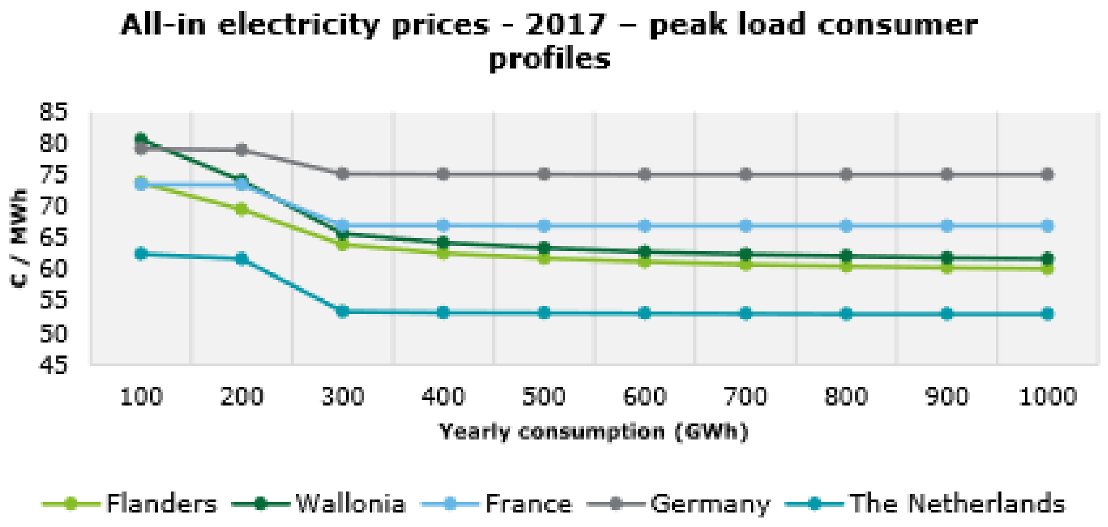

Figure 13 All-in electricity prices for peak load consumer profiles in the range of 100-1000 GWh (source Deloite)

In France, Germany and the Netherlands industrial consumers with a peak load profile do not benefit from discounted network costs. Discounts for baseload consumers are justified by the fact that baseload consumer contribute positively to the stability of the network.

Additional statistics covering a broader range of different EU countries and specifically related to industrial consumers are shown from Figure 14 to Figure 17.

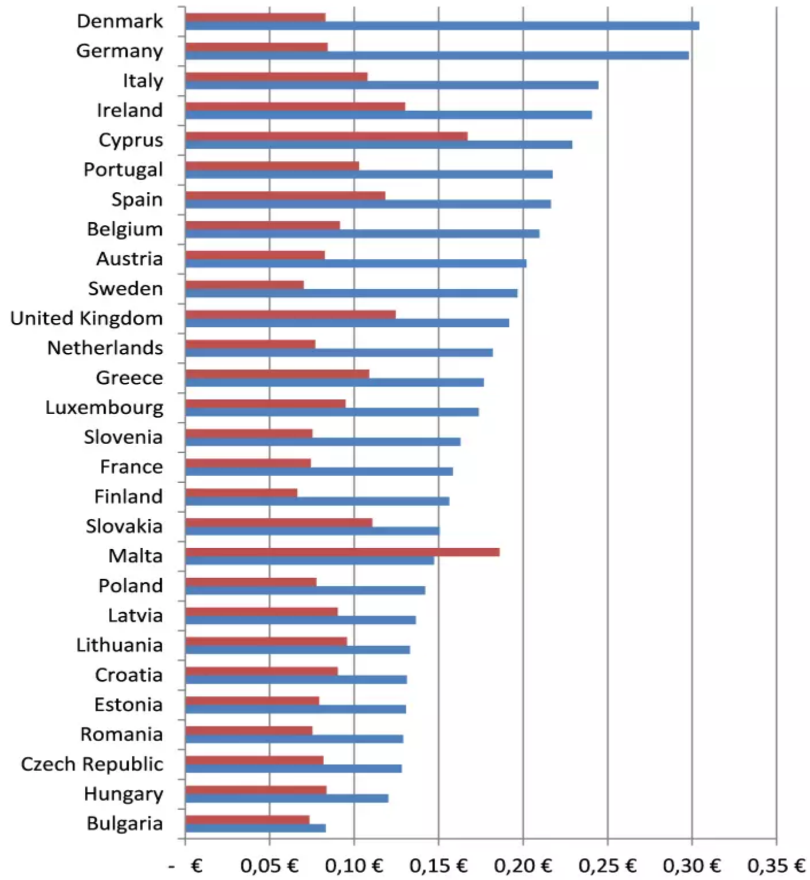

Figure 14 Electricity prices charged to final consumers (blue) and for industry (red) (source [7])

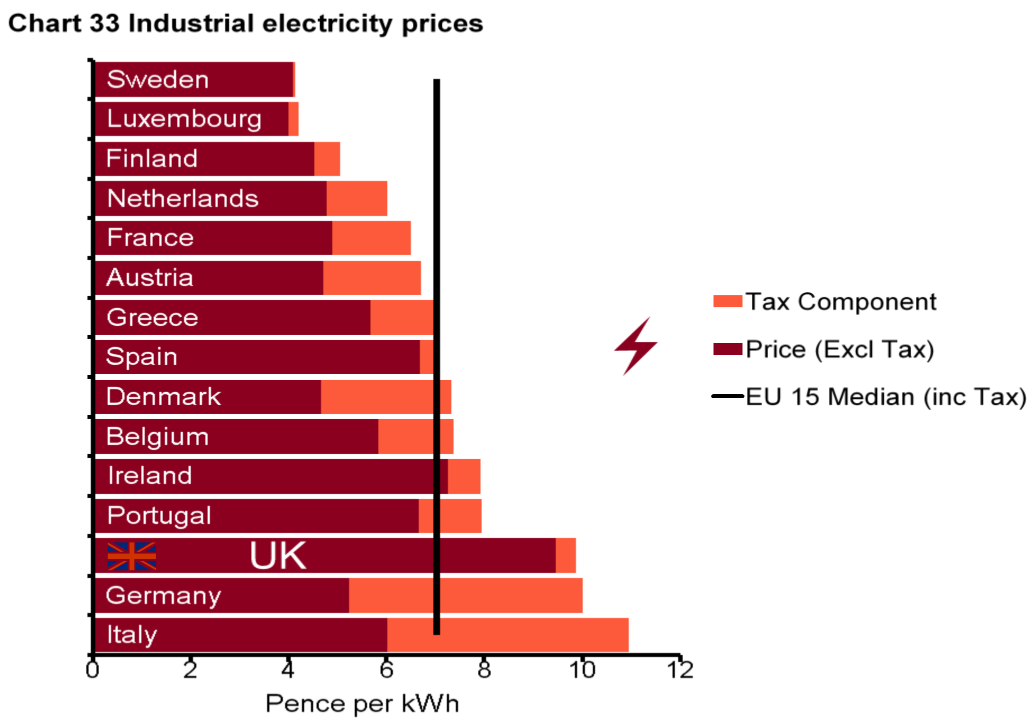

Figure 15 Prices for medium consumers (2-20 GWh) in the EU. January-June 2016 (source [8])

Figure 16 Electricity prices (inclusive of taxes) – Households – Estimated for the second quarter of 2018 (source [9])

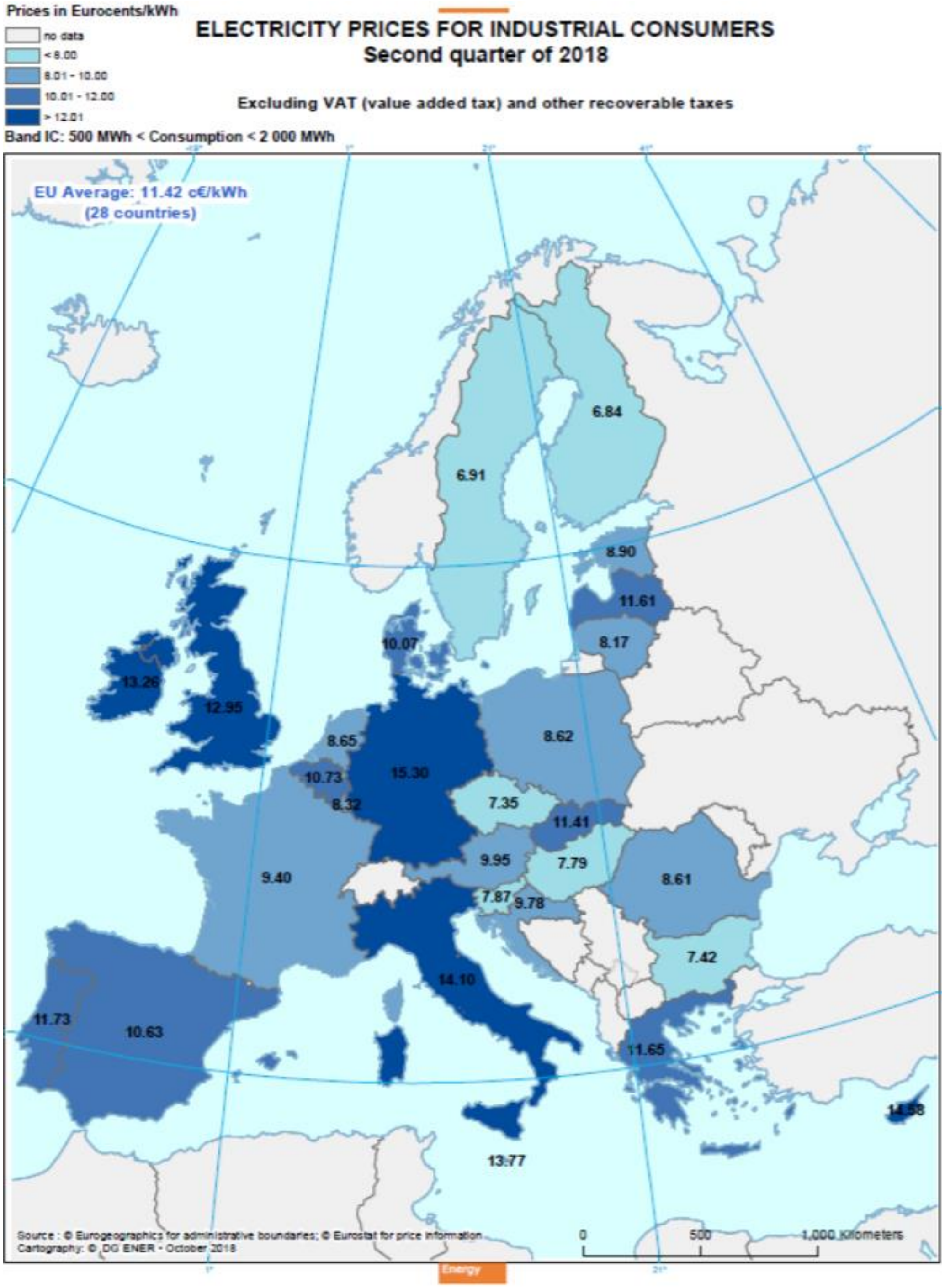

Figure 17 Electricity prices (no VAT and no recoverable taxes). Industrial consumers. Estimated second quarter 2018 (source [10])

In light of these data it seems plausible to assume that under the most favorable conditions all-in electricity prices in some countries could be close of 50 EUR/MWh for large and in particular very large consumers.

Such values look realistic in light of the situations observed in some EU member states, such as the Scandinavian countries, Netherlands, Germany and possibly France, in particular when considering base load large scale industrial consumer profiles close to 100 GWh (cf. 10 MW plant). In other countries such as UK, Italy, Ireland, Spain, Portugal, Greece and Belgium, electricity is definitely more expensive.

Of course the future increase of RES share in the energy mix as well as a wise localization of the hydrogen generation plant on sites characterized by appropriate boundary conditions (e.g. proximity to specific delivery points such as nuclear plants, hydropower plants, waste-to-electricity generation plants to reduce network costs etc) and the evolution of the tax regulatory framework suggest that future tariffs could be even more favorable and possibly lower than 40 EUR/MWh for large industrial consumers.

As previously discussed, electricity prices may drop significantly for industrial and in particular for very large industrial consumers (e.g more than 100 GWh/year). This situation advocates for the centralized production model object of our case studies. A very large centralized electrolyzer (supplying e.g. several refueling stations surrounding the hydrogen generation plant) is more likely to benefit of favorable electricity tariffs than several smaller on-site electrolyzers scattered within the same area.

Accordingly, plants larger than 10 MW should be even more competitive. Besides, the scale-up of a 10+ MW electrolyzer could positively impact other factors such as the Capex/MW ratio at system level, fixed and maintenance costs. However, as previously mentioned, this would require the availability of appropriate commercial outlets for the produced hydrogen.

An electrolyzer used as balancing device should be sized taking into account the actual needs of the regulating power market that it is expected to serve.

3.5.10 Pricing and Scoring of Reserve Bids

The revenues generated by supplying grid balancing services (BS, notably to the secondary regulatory market) and their impact on the selected business cases are not easily predictable. This is due to several factors including the lack of transparency characterizing the price structure of the electric regulatory markets across Europe, the different scoring mechanisms used by the regulatory authorities to accept the bids, the unpredictability of the random processes leading to the selection of the bidders and the contracting/dispatching phase (energy actually off taken or supplied to the grid), the specificities of the different production/transmission systems in terms of resilience/robustness (capacity to cope with demand volatility) and last but not least the way how all these elements are expected to evolve on the short-medium-long term.

The situation is further complicated by the fact that the idea to utilize an electrolyzer as balancing device is relatively new and there are basically no records to which future possible scenarios could be inspired. In other words, balancing revenues are volatile and hardly predictable.

An effort has nevertheless been done to figure out their possible impact on the BC taking into account historical records provided by some EU regulatory authorities (ANNEX 3).

To better understand why BS revenues forecast may be so difficult, it is useful to recall which are the main mechanisms regulating the BS procurement processes. Of course, each country and each regulatory authority may adopt different BS procurement processes.

Generally said mechanisms define the way how the bidders are requested to offer their services to the TSO and the scoring rules applied to establish the final merit order for the selection of the bids.

There are several options for pricing and scoring. Of course, such options may influence the behavior of the bidders (potential BSPs) and their chances to be selected by the TSO during the dispatch (or activation) phase.

In general, it is important to distinguish the contracting and dispatch phases of the procurement process:

• Contracting phase – on the basis of the submitted bids, the TSO selects the parties to contract with. Contracted parties reserve the capacity the TSO may subsequently decide to call at short notice. This phase is usually renewed periodically e.g. every few months. The offers comprise a series of parameters, part of which are relevant for the selection of the bidders (contractually binding)[10].(*)

• Dispatching phase – TSO decides which devices to dispatch for short term balancing. This is a short term, e.g. daily, decision that is usually made only on the basis of energy price criteria. During the actual dispatching phase, non-contracted parties may or may not participate. In the former case the TSO has the option to call energy from contracted and non-contracted parties.

The TSO can take into account energy, capacity or energy and capacity criteria when selecting the contracted parties – the selection is based on the parameters specified by the bidder in his offer.

Different pricing and scoring options are possible. For instance, in the Netherlands, on the secondary reserve market, the bids of the contracted parties are scored on the basis of energy and capacity criteria with selection at the contract phase based exclusively on capacity criteria. Non-contracted parties may also participate to the bidding phase on the basis of pricing criteria.

The TSO ranks the bids price-wise. The BSPs may communicate the costs (and possibly his cost structure) to supply balancing services. Usually, there are three methods to price a bid:

• **Energy price only** – The bidder specifies a price (EUR/MWh) for each MWh of energy he expects to deliver (positive reserve) or consume (negative reserve). This remuneration is paid by the TSO only if the energy is actually called.

• **Capacity price only** – The bidder offers a capacity price (EUR/MW). This price is paid regardless of whether the BSP is requested to activate the energy delivery process during the dispatch phase. Usually, an additional down-payment is due for the actual call of energy. Such additional fee is either flat or calculated on the basis of a predefined formula (identical for all BSPs).

[10] *Another phase exists before the start of the procurement process – the so called “pre-qualification phase”. In the pre-qualification phase the potential bidders are supposed to prove that they comply with the technical and formal requirements needed to enter the bidding process. Of course, strict prequalification criteria can be a market entry barrier for those parties which are willing to become BSPs.*

• **Capacity and energy price** – The bidder offer a capacity price (EUR/MW) and an energy price (EUR/MWh). The capacity price is due and paid by the TSO for the reservation of the device, when available. The energy price is only paid if the option is actually called.

It is worth to mention that not all price components are relevant through the different phases of the procurement process previously described (contracting and dispatching phase).

In Germany, for instance, the TSO receives both capacity and energy bids during the contract phase. However, during the contract phase the TSO only takes into account the capacity bid. Conversely during the dispatching phase only energy bids are taken into account to establish the merit order for the activation of the reserve capacities.

It is important to stress that the operator of the electrolyzer in such regime will take into account his expected returns on possible energy delivery before submitting a capacity bid during the contract phase.

In other EU countries the existing pricing rules for reserve procurement may be different. For instance in the Netherlands, pricing rules differ depending on the type of services provided. For sake of example, in the Netherlands, secondary reserve procurement consists of two procurement paths which are linked:

- <u>Annual contracts with a capacity and an energy price</u> – TSO enters into annual contracts with selected bidders. The contracted party is remunerated with a contractual fee (kind of capacity-based remuneration) and on the top of that with an energy fee for the energy called. The energy price is formed via the bid price ladder (i.e. a tool showing the order book i.e. bid prices along with the last traded price, on a vertical interface, and their real-time evolution). Hence, contracts may be classified as having two price components. Generally, the energy criteria which contracted party has to comply with are not fully transparent. Usually, contracted parties only have the obligation to bid into the energy price ladder at a price calculated according to a formula that takes into account the day ahead price. However, this price is not necessarily binding because non-contracted parties usually put pressure on the price. Contracted parties could in theory bid a very high energy price to avoid being called for reserves and then use their balancing device on the wholesale market.

- <u>Energy bids into the bid ladder</u> – Non-contracted parties can bid into the bid ladder and are remunerated only if energy is called. Therefore, their bid can be seen as an energy bid only.

The fact that both contracted and non-contracted parties can bid into the same bid ladder induces some distortions into the energy bid prices:

- **contracted parties** - the contract established between BSP and TSO forces the BSP to bid a reserve energy price and to keep an available reserve capacity; contracted parties can bid for reserve energy based on their energy costs and price expectations (as they already get a compensation for capacity costs on a contractual basis)
- **non-contracted parties** – such parties include their energy costs and price expectations for reserve energy but also attempt to recover their capacity costs. They also need to take into account the fact that they may support capacity costs without receiving any compensation at all as they get paid only if they are actually called off.

The following example shows the challenges that non-contracted parties have to face when the procurement process is designed according to the mechanisms previously described. For sake of example, let’s imagine a non-contracted party with energy costs of 40 EUR/MWh, capacity costs (opportunity costs on the wholesale market) of 10 EUR/MW per hour and a probability of being called of only 10 %.

In this situation, the non-contracted party should include a mark-up on its energy bid of 10 EUR/MW per hour divided by 10% i.e. 100 EUR/MW per hour. This amount should be added to the energy generation costs that leading to an energy bid into the price ladder of 140 EUR/MWh.

This example shows that, under certain conditions, non-contracted parties may not be able to compete with contracted parties. This is particularly true in those countries where contracted parties are relatively free to bid their choice of energy price.

Only non-contracted parties supporting capacity costs (opportunity costs[11] for not being able to sell their electricity output on the wholesale market) close to zero may be able to compete with contracted parties.

Contracted parties have the possibility to uplift their energy price bid above their energy dispatch costs if the contracted capacity is small compared to the required amount of reserve; and the non-contracted parties cannot bid competitive energy prices (if they need to include capacity costs into their bid).

This example shows that a contract ensuring a reserve capacity (important from the TSOs perspective) and allowing that energy is bid into the price ladder at any price (without any restriction) can create some competition distortions between contracted and non-contracted parties during the dispatch phase.

Generally speaking, the stricter the rules for the energy bids in the dispatching phase are, the higher will be the contract price asked by the bidder. On the other hand, if the provider expects to have higher “upward chances” from the energy price ladder he must be ready to contract for a lower capacity price.

Today, most balancing markets are national (or limited to a specific control area within a country). This leads to a great variety of market designs, namely rules for balance responsible parties, for products and procurement processes and finally for imbalance prices.

From what previously said, it appears that BS revenues generated by an electrolyzer are hardly predictable and highly volatile even if all the rules of the balancing services (BS) procurement process are known.

3.5.11 Ancillary Infrastructure and Related Costs

The term “ancillary infrastructures” is used here to designate those infrastructures which are part of the plant but not elements of the electrolysis system, i.e. essentially the buffer tanks used to store temporarily part of the gas collected at the outlet of the gas purification system

[11] *Opportunity costs represent the benefits an individual bidder misses out when choosing one alternative over another (in this case when he chooses to offer his capacity to the reserve market rather than using such capacity to produce electricity to be sold on the wholesale market*

(generally comprising a dryer and à deoxo unit necessary to comply with O_2 content specifications of the P2M customers) and the compressor used to pressurize the gas inside the delivery tubular trailers.

Although the design and the technical characteristics of the ancillary infrastructures as well as their capex and operating costs (in particular in the case of the compressor) are susceptible to affect business case profitability, yet such factors are not the main object of our study (essentially focused on the electrolytic part of the plant, the related procurement and operating costs as well as the foreseeable turnovers generated throughout the supply of green hydrogen and balancing services). Having said that, it is still useful to briefly mention the main features of such facilities (Table 7). All numerical values are provided for sake of example.

H_2 Storage Tanks	
Total Geometrical Volume of the H_2 Storage Tanks @ 15 bara - 24 hours production @ 100% load (m^3)	**1890**
H_2 density at 30 bar (kg/m3)	**2,67**
H_2 density at 20 bar (kg/m3)	**1,78**
H_2 density at 15 bar (kg/m3)	**1,335**
H_2 density at 1 bar (kg/m3)	**0,089**
H2 Storage Tanks (Costs)	
Capex H_2 Storage Tanks (EUR/m3)	**900**
Total Capex of the H2 Storage Tanks (EUR)	**1700575**
H_2 Storage Tanks Depreciation on annual basis (% of Capex)	**5%**
H_2 Storage Tanks Depreciation on annual basis during 20 years (EUR/year)	**85029**
Maintenance of H_2 Storage Tanks equivalent to 0,5% of Tanks Capex (EUR/year)	**8503**
Civil Constructions hosting H_2 Storage Tanks (EUR)	**50000**
Linear Depreciation of Civil Constructions hosting H_2 Storage Tanks over 20 years at 5% per year (EUR/year)	**2500**
H_2 Compressor 15 -> 500 bar @ 200 kgH_2/hour	
Capex for 500 bar H_2 Compressor (min suction pressure 15 bar) diaphragm or pistons (EUR/100 kgH2/hour)	**900000**
Capex for H_2 Compressor (EUR)	**768580**
Compressor Depreciation over 20 years (% of Capex /year)	**5%**
Compressor Depreciation per year over 20 years (EUR)	**38429**
Compressor Maintenance Costs (% of Capex/year)	**1%**
Compressor Maintenance Costs (EUR/year)	**7686**
Energy Consumption for H_2 Compression from 15 to 500 bara (% of LHV)	**15%**
Electricity Cost for Compression (EUR/MWh)	**52,3**
OPEX for H_2 Compression from 15 to 500 bara (for fleets and chemical market , 500 bar trailers) (EUR/year)	**195451**

Table 7 Technical-economical parameters describing the ancillary infrastructure (5 MW case)

As in the case of the electrolyzer, the parameters in red can be arbitrarily modified, whereas those in black are dependent variables (directly derived from the former ones). The buffer tanks are supposed to be able to store an amount of hydrogen equivalent to 24 hours of production (@ 100% load) up to a pressure of 15 bar (1,335 kg/m3).

Tanks capex is estimated at 900 EUR/m3. Maintenance costs forecast corresponds to 0.5% of the capex (still pretty conservative). Additional costs are those related to tanks depreciation (linear over 20 years) and erection of the building and other civil constructions expected to host the plant. Another important equipment is the compressor. Of course, different technical solutions are foreseeable.

As a general rule of thumb, we assume a minimum suction pressure of 15 bar (in case of part load operations) and a capex of 900 kEUR/100 kgH_2/hour (diaphragm or pistons multistage intercooled technology). As previously said the compressor is supposed to reach a discharge pressure of 500 bar. Compressor procurement costs represent a significant part of the initial total investment. Such costs may be arbitrarily modified in the Excel model (red figure) in order to better to understand their impact on the business case.

Business case performance is sharply depending on compression opex. This type of costs is of course related to electricity price and the energy needed to raise the pressure of the gas from 15 bar (storage pressure) up to 500 bar.

According to literature data, energy needed to carry out this mechanical compression work is estimated at ca 15% of the LHV (Figure 18).

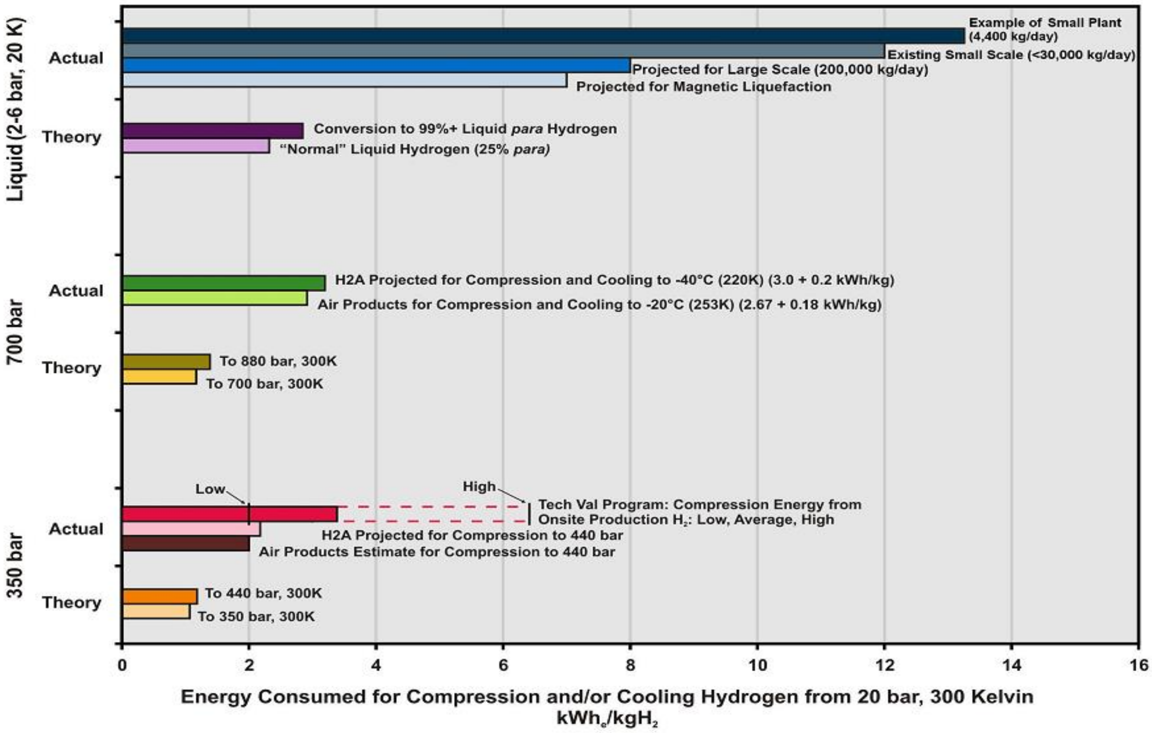

Figure 18 Relation of energy consumption in hydrogen compression from 20 bar (source [11])

This value is of course significantly lower than what would be required if the first stage suction pressure was only 1 bar.

The availability of high-pressure hydrogen at the electrolyzer outlet allows to achieve significant cost savings in terms of compressor capex and opex (at a given electricity price).

The compressor is depreciated linearly over 20 years and its maintenance costs are estimated at 1% of the capex.

4 RESULTS

4.1 Effect of Electricity Prices

The Excel model has been used to simulate the impact that electricity prices have on the financial indicators described in point , i.e. Project Value, NPV, IRR and Pay-Back Period.

In the case of the 5MW plant several scenarios have been analyzed each of them characterized by a different average electricity price. Average electricity prices range between about 65 and 25 EUR/MWh. All other parameters describing the 5MW cases are kept constant and correspond to those detailed in Table 1. In particular, the electrolyzer capex is fixed at 625 kEUR/MW and the revenues generated by operating the electrolyzer as a power regulating device on the negative FRR market (periodically effacing between 25% and 50% of the nominal rate power) are estimated in the average at 125 kEUR/year.

NPV becomes positive starting from an average electricity price of about 50 EUR/MWh, whereas reasonable IRR (indicatively 15%) are expected only at an average electricity price of around 35 EUR/MWh with pay-back periods of ca 6,5 years (over a project duration of 20 years). Between 25 and 30 EUR/MWh pay back is estimated at ca 5,5 years and IRR comprised between 16,5% and 19% (Table 8, Figure 19 and Figure 20).

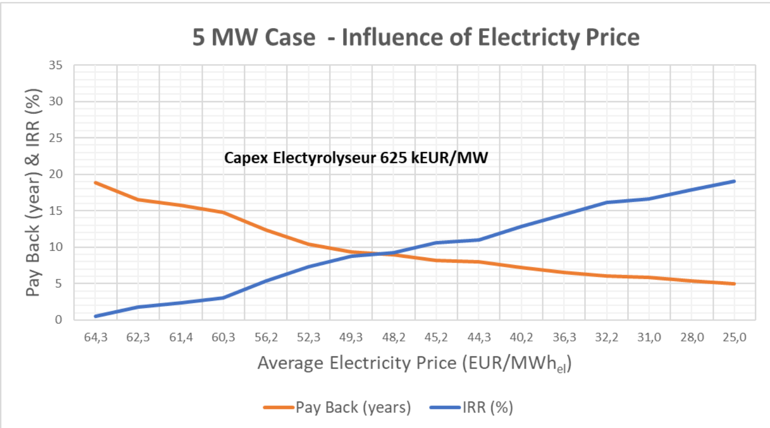

Figure 19 ***The 5 MW Case – Dependency of Pay-back Period and Internal Rate of Return (IRR) on electricity prices***

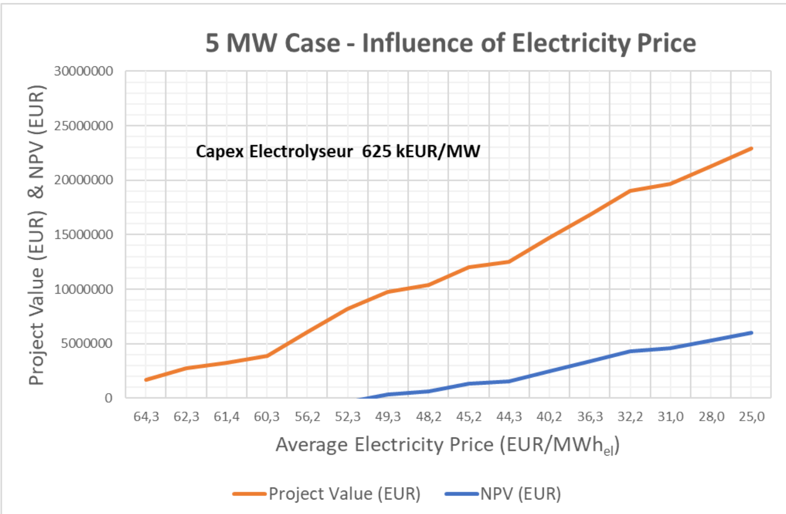

Figure 20 ***The 5 MW Case – Dependency of Project Value (PV) and Net Present Value (NPV) on electricity price***

Electricity Price Spot (EUR/MWh_{el}) 1500 h/year	Electricity Price Spot (EUR/MWh_{el}) 2000 h/yr	Electricity Price Spot (EUR/MWh_{el}) 5260 h/yr	Average Electricity Price Annual Basis (EUR/MWh_{el})	Capex of the Electrolyser (EUR/MW)	Total Capex of the Electrolyser (EUR)	Total Initial Investment (EUR)	Project Value (EUR)	NPV (EUR)	IRR (%)	Pay Back (yr)
35	*45*	*80*	64,3	625000	3125000	6489156	1692527	-3118418	0,5	18,82
30	*40*	*80*	62,3	625000	3125000	6489156	2769866	-2655878	1,8	16,50
25	*40*	*80*	61,4	625000	3125000	6489156	3231582	-2457647	2,3	15,72
25	35	80	60,3	625000	3125000	6489156	3847204	-2193339	3,0	14,81
25	30	75	56,2	625000	3125000	6489156	6081911	-1233899	5,3	12,33
20	30	70	52,3	625000	3125000	6489156	8162713	-340537	7,3	10,39
20	30	65	49,3	625000	3125000	6489156	9781799	354594	8,7	9,32
20	25	65	48,2	625000	3125000	6489156	10397421	618903	9,3	8,98
20	25	60	45,2	625000	3125000	6489156	12016506	1314034	10,6	8,20
15	25	60	44,3	625000	3125000	6489156	12478223	1512265	11,0	8,00
15	20	55	40,2	625000	3125000	6489156	14712930	2471704	12,8	7,18
10	20	50	36,3	625000	3125000	6489156	16793732	3365067	14,5	6,56
10	15	45	32,2	625000	3125000	6489156	19028440	4324506	16,2	6,01
10	10	45	31,0	625000	3125000	6489156	19644062	4588815	16,6	5,83
10	10	40	28,0	625000	3125000	6489156	21263147	5283946	17,8	5,39
10	10	35	25,0	625000	3125000	6489156	22882233	5979077	19,0	5,01

Table 8 The 5 MW case – Influence of electricity price

Entering in the 10 MW Excel model the same numerical values for electricity price previously considered for the 5MW case (assuming that grid services revenues are doubled i.e. of 250 kEUR/year and the nominal capex of the electrolyzer is the same i.e. 625 kEUR/MW), it is possible to calculate the same financial indicators. For the 10 MW plant, NPV becomes positive starting from a higher electricity price i.e. 55 rather than 50 EUR/MWh. Similarly, IRR and pay-back are slightly more favorable at the same electricity price. We also note that between 30 and 25 EUR/MWh, estimated pay-back period is pretty much close to 5 years (Figure 21*,* Figure 22 *and* Table 9).

These performances could be further improved due to the fact that in the 10 MW scenario it is possible to achieve lower electricity prices (see consumer profile) and capex (EUR/MWh) (scale economies).

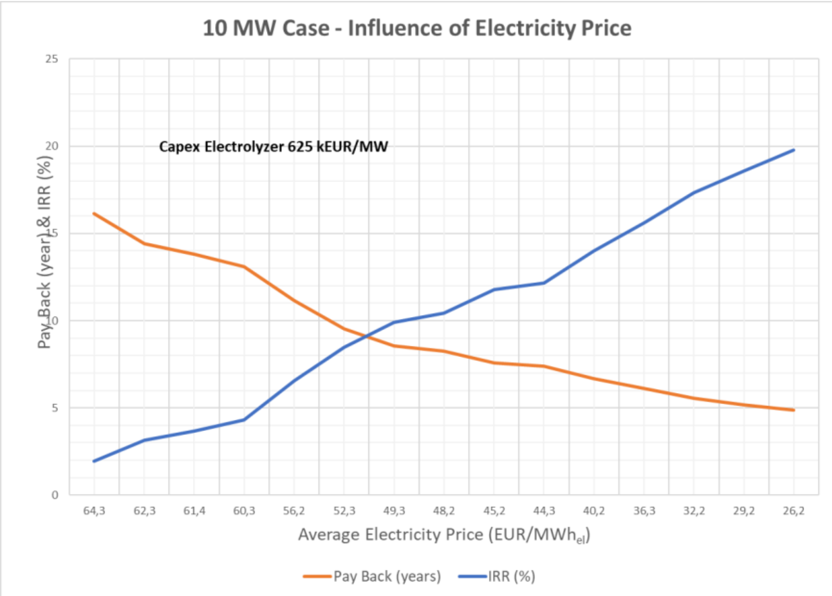

Figure 21 ***The 10 MW Case – Dependency of Pay-back Period and Internal Rate of Return (IRR) on electricity prices***

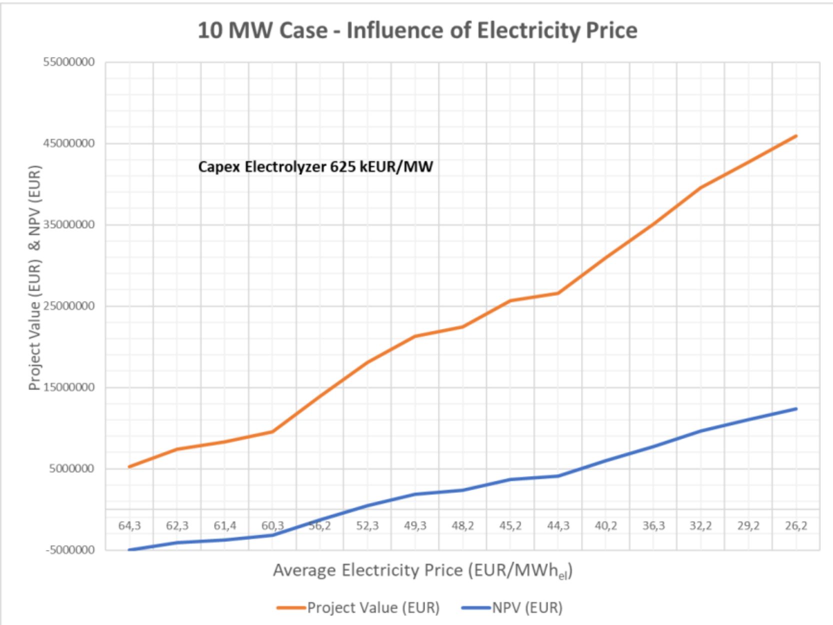

Figure 22 ***The 10 MW Case – Dependency of Project Value (PV) and Net Present Value (NPV) on electricity price***

Electricity Price Spot (EUR/MWh_{el}) 1500 h/year	Electricity Price Spot (EUR/MWh_{el}) 2000 h/yr	Electricity Price Spot (EUR/MWh_{el}) 5260 h/yr	Average Electricity Price Annual Basis (EUR/MWh_{el})	Capex of the Electrolyser (EUR/MW)	Total Capex of the Electrolyser (EUR)	Total Initial Investment (EUR)	Project Value (EUR)	NPV (EUR)	IRR (%)	Pay Back (yr)
35	45	80	64,3	625000	6250000	12503311	5252923	-5027872	1,9	16,12
30	40	80	62,3	625000	6250000	12503311	7382304	-4115863	3,2	14,41
25	40	80	61,4	625000	6250000	12503311	8294896	-3725002	3,7	13,80
25	35	80	60,3	625000	6250000	12503311	9511685	-3203854	4,3	13,08
25	30	75	56,2	625000	6250000	12503311	13928630	-1312087	6,6	11,14
20	30	70	52,3	625000	6250000	12503311	18041378	449393	8,5	9,52
20	30	65	49,3	625000	6250000	12503311	21241533	1820012	9,9	8,57
20	25	65	48,2	625000	6250000	12503311	22458323	2341160	10,4	8,27
20	25	60	45,2	625000	6250000	12503311	25658478	3711780	11,8	7,57
15	25	60	44,3	625000	6250000	12503311	26571070	4102641	12,2	7,40
15	20	55	40,2	625000	6250000	12503311	30988015	5994408	14,0	6,66
10	20	50	36,3	625000	6250000	12503311	35100763	7755888	15,6	6,11
10	15	45	32,2	625000	6250000	12503311	39517708	9647655	17,3	5,55
10	10	45	31,0	625000	6250000	12503311	40734497	10168803	17,8	5,41
10	10	40	28,0	625000	6250000	12503311	43934653	11539422	19,0	5,05
10	10	35	25,0	625000	6250000	12503311	47134809	12910041	20,2	4,76

Table 9 The 10 MW Case – Influence of electricity price

A closer comparison of the 5 and 10 MW scenarios at different electricity prices is shown in Figure 23 and Figure 24.

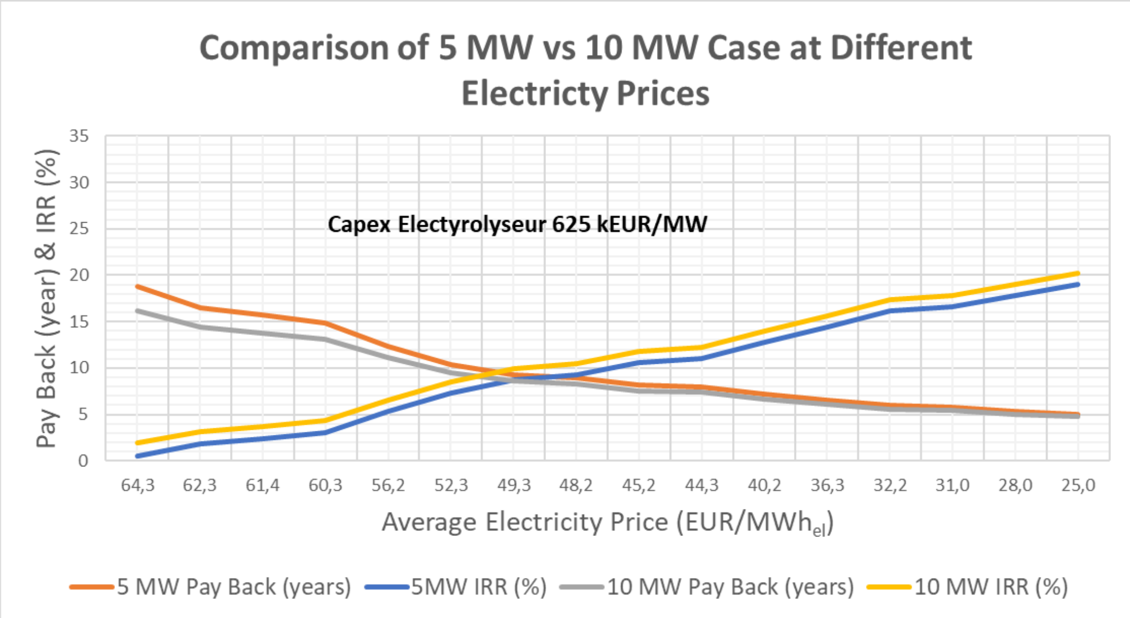

Figure 23 Comparison of 5MW vs 10 MW Case at different electricity prices - Pay-back period and IRR

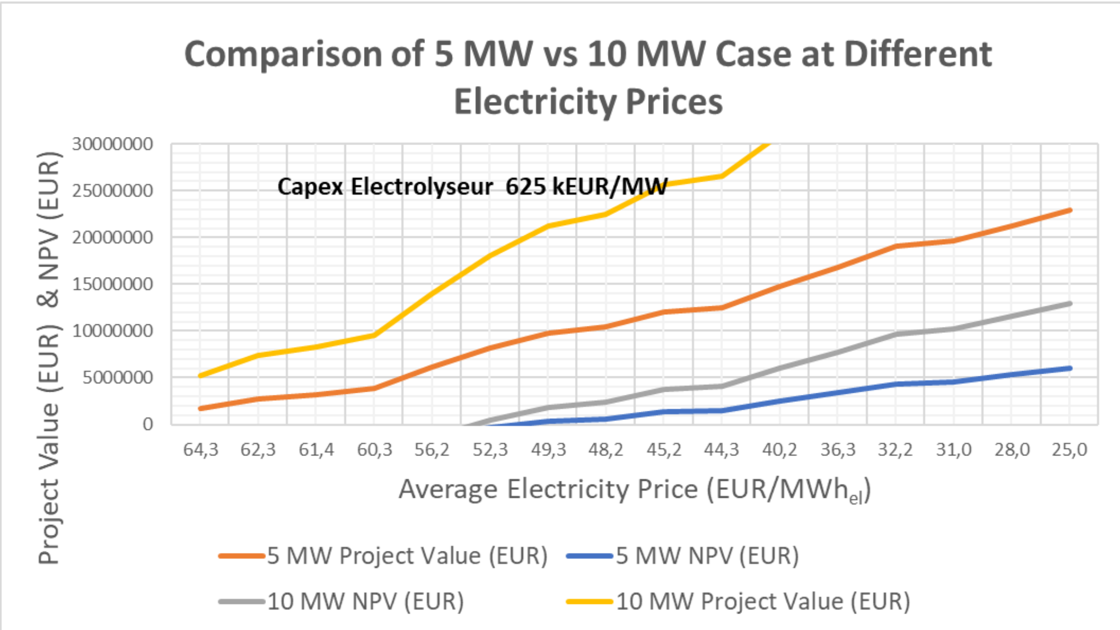

Figure 24 Comparison of 5MW vs 10 MW Case at different electricity prices -Project value and NPV

4.2 Effect of Electrolyzer Capex

Several 5 MW scenarios have been analyzed each one characterized by different values of the electrolyzer capex (ranging between 625 and 400 kEUR/MW), all other parameters being the same. In light of the conclusions drawn in point 4.1, the average electricity price has been arbitrarily fixed at 49,3 EUR/MWh. This is the value around which NPV becomes positive when the capex is 625 kEUR/MW. The revenues generated by supplying the negative FRR market (periodically effacing between 25% and 50% of the nominal rate power) are always estimated at 125 kEUR/year.

Electricity Price Spot (EUR/MWh_{el}) 1500 h/yr	Electricity Price Spot (EUR/MWh_{el}) 2000 h/yr	Electricity Price Spot (EUR/MWh_{el}) 5260 h/yr	Average Electricity Price Annual Basis (EUR/MWh_{el})	Capex EL (EUR/MW)	Capex EL (EUR)	Total Initial Investment (EUR)	Project Value (EUR)	NPV (EUR)	IRR (%)	Pay Back (yr)
20	30	65	49,3	625000	3125000	6489156	9781799	354594	8,7	9,32
20	30	65	49,3	600000	3000000	6364156	9909634	480821	9,0	9,14
20	30	65	49,3	575000	2875000	6239156	10037469	607049	9,3	8,96
20	30	65	49,3	550000	2750000	6114156	10165305	733276	9,6	8,78
20	30	65	49,3	525000	2625000	5989156	10293140	859503	9,9	8,61
20	30	65	49,3	500000	2500000	5864156	10420975	985730	10,2	8,43
20	30	65	49,3	475000	2375000	5739156	10548810	1111958	10,5	8,25
20	30	65	49,3	450000	2250000	5614156	10676646	1238185	10,9	8,08
20	30	65	49,3	425000	2125000	5489156	10804481	1364412	11,2	7,90
20	30	65	49,3	400000	2000000	5364156	10932316	1490640	11,6	7,73

Table 10 The 5 MW Case – Influence of electrolyzer capex (average electricity price 49,3 EUR/Mh, average Grid Services Fees 125 kEUR/y)

From the results shown in Table 10, Figure 25 and Figure 26, it appears that, at a fix average electricity price of circa 49 EUR/MWh, a reduction of capex from 625 kEUR/MW to 500 kEUR/MW leads to an increase of IRR (from 8,7% up to 10,2%), of NPV (from 354 kEUR up to 985 kEUR) and of the Project Value (from ca 9,8 MEUR up to 10,4 MEUR). In parallel the Pay-back Period decreases from 9,3 to 8,4 years.

The effect is however less pronounced than that caused by a drop of the electricity price. For instance, a 37,5% decrease of the capex (from 625 to 400 kEUR/MW) leads to an increase of IRR of only 32 % (from 8,7 % to 11,6 %). On the contrary, a relatively similar decrease of the electricity price (from 49,3 to 31 EUR/MWh) makes IRR to increase of almost 80 % (from 9,9 % up to 17,8 %). Similar trends can be observed for the other financial indicators such as NPV, Pay-back Period and Project Value.

Within the same range of capex and electricity price variations, the NPV increases 4,4 times (due to capex) rather than 17 times (due to electricity price), the pay-back period decreases by 17% (due to capex) rather than 50% (due to electricity price) and the project value increases by 11,7% (due to capex) rather than by 212% (due to electricity price).

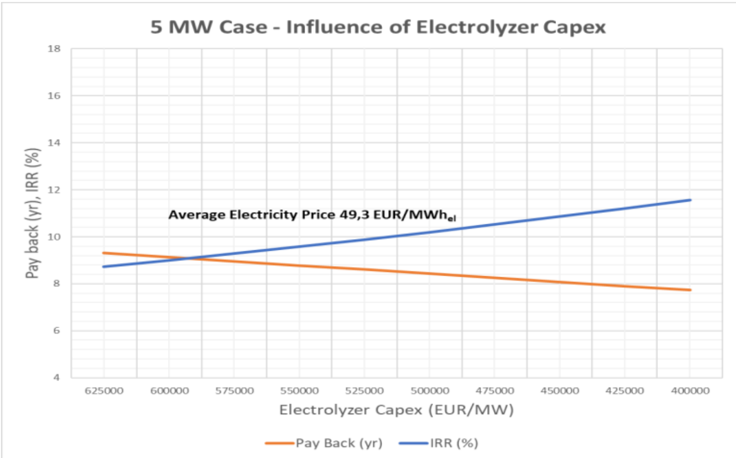

Figure 25 ***The 5 MW Case – Dependency of Pay-back Period and Internal Rate of Return (IRR) on electrolyzer capex***

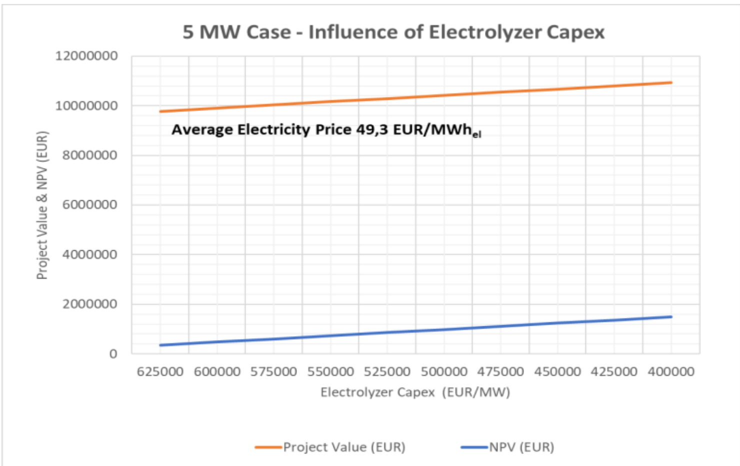

Figure 26 ***The 5 MW Case – Dependency of Project Value (PV) and Net Present Value (NPV) on electrolyzer capex***

A similar analysis has been carried out for the 10 MW Case (Figure 27, Figure 28 and Table 11). Using the Excel model, several 10 MW scenarios have been simulated by systematically changing the electrolyzer capex (in the 625 - 400 kEUR/MW range) and keeping all of other parameters constant. Based on the conclusions of point 4.1, the average electricity price has been arbitrarily set at 49,3 EUR/MWh. This is the value around which the NPV of the 5 MW business case becomes positive if the electrolyzer capex is 625 kEUR/MW.

The revenues generated by supplying the negative FRR market (periodically effacing between 25% and 50% of the electrolyzer nominal rate power, according to case assumptions) are estimated at 250 kEUR/year.

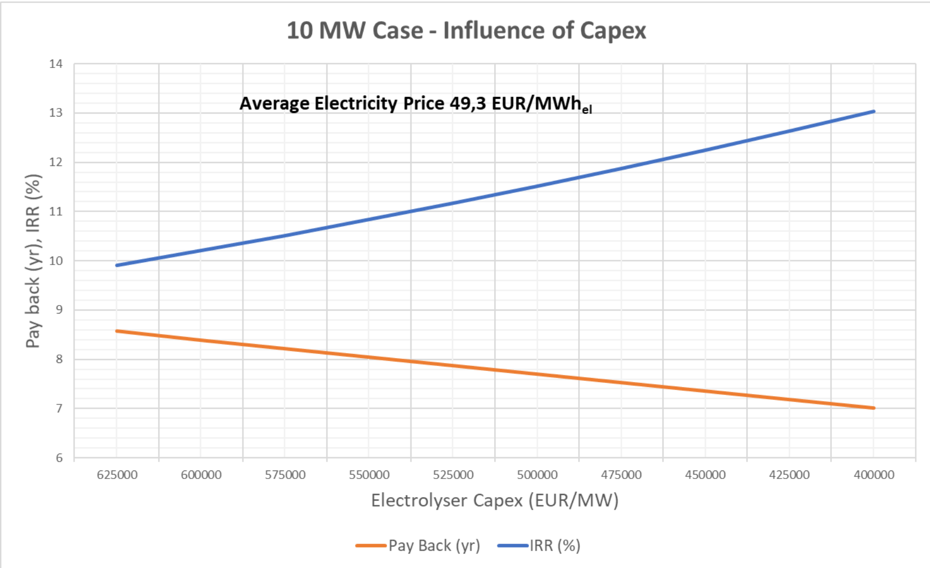

Figure 27 ***The 10 MW Case – Dependency of Pay-back Period and Internal Rate of Return (IRR) on capex***

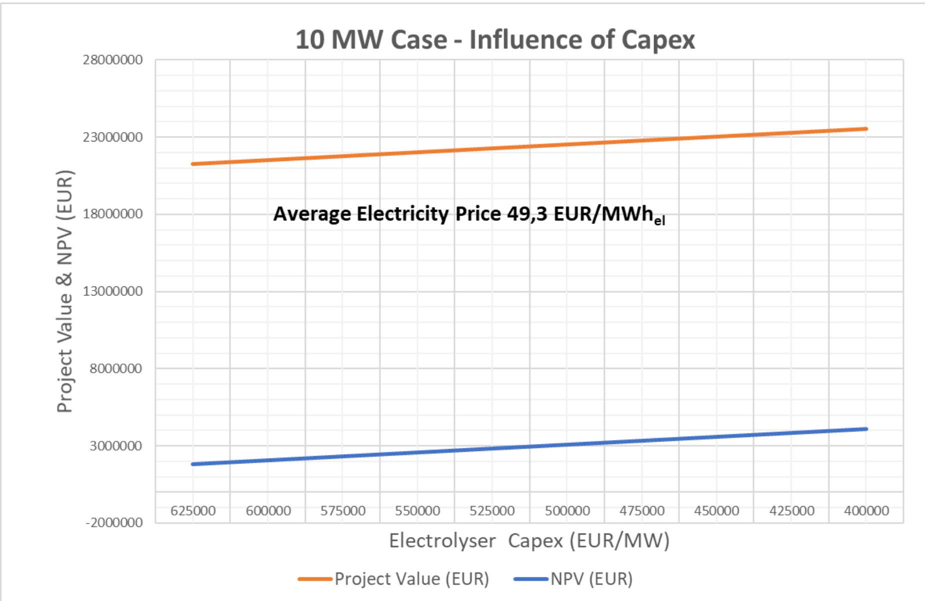

Figure 28 ***The 10 MW Case – Dependency of Project Value (PV) and Net Present Value (NPV) on capex***

Electricity Price Spot (EUR/MWh_{el}) 1500 h/yr	Electricity Price Spot (EUR/MWh_{el}) 2000 h/yr	Electricity Price Spot (EUR/MWh_{el}) 5260 h/yr	Average Electricity Price Annual Basis (EUR/MWh_{el})	Capex EL (EUR/MW)	Capex EL (EUR)	Total Initial Investment (EUR)	Project Value (EUR)	NPV (EUR)	IRR (%)	Pay Back (yr)
20	30	65	49,3	625000	6250000	12503311,19	21241533	1820012	9,9	8,57
20	30	65	49,3	600000	6000000	12253311,19	21497204	2072467	10,2	8,40
20	30	65	49,3	575000	5750000	12003311,19	21752874	2324922	10,5	8,22
20	30	65	49,3	550000	5500000	11753311,19	22008545	2577376	10,8	8,04
20	30	65	49,3	525000	5250000	11503311,19	22264215	2829831	11,2	7,87
20	30	65	49,3	500000	5000000	11253311,19	22519886	3082285	11,5	7,70
20	30	65	49,3	475000	4750000	11003311,19	22775556	3334740	11,9	7,52
20	30	65	49,3	450000	4500000	10753311,19	23031227	3587194	12,2	7,35
20	30	65	49,3	425000	4250000	10503311,19	23286897	3839649	12,6	7,18
20	30	65	49,3	400000	4000000	10253311,19	23542568	4092103	13,0	7,01

Table 11 The 10 MW Case – Influence of capex

As already observed in the previous section, all financial indicators of the 10 MW case are slightly better than those of the 5 MW within the investigated capex range. A closer comparison of the 5 and 10 MW scenarios at different capex is shown in Figure 29 and Figure 30.

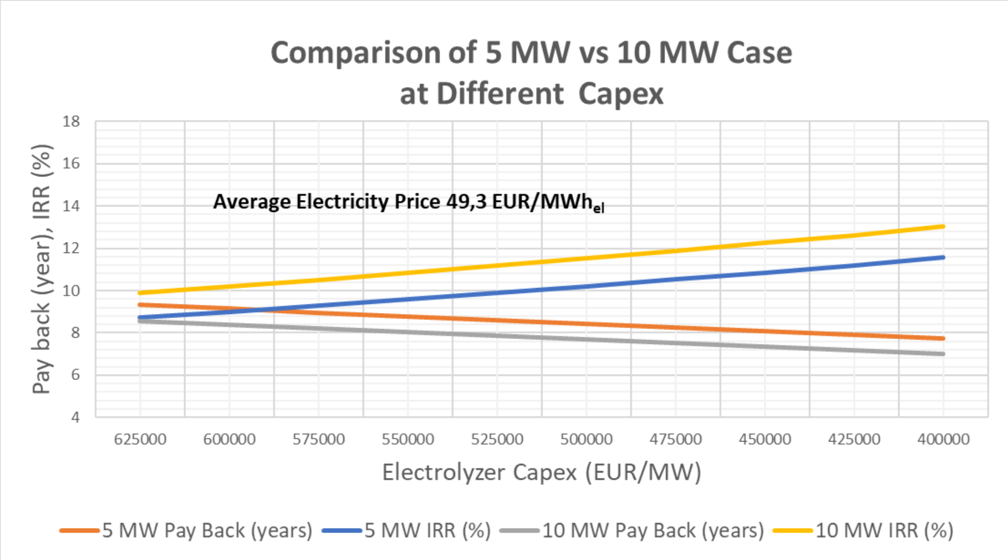

Figure 29 ***Comparison of 5 and 10 MW Case – Dependency of Pay-back and IRR on capex***

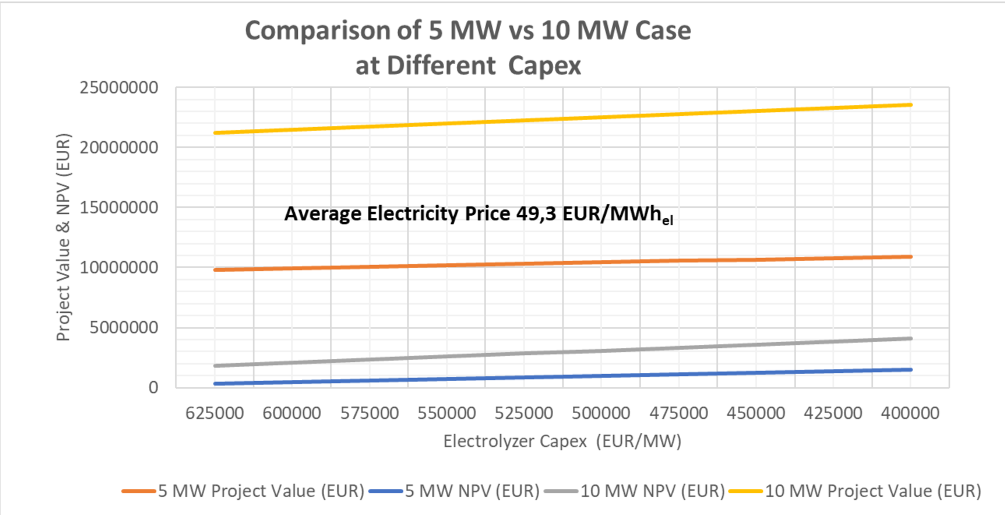

Figure 30 ***Comparison of 5 and 10 MW Case Dependency of Project Value (PV) and Net Present Value (NPV) on capex***

4.3 Effect of Grid Balancing Services (GS) Revenues

Electrolyzer readiness to undergo random load shifts in compliance with TSO requests is as such a balancing service provided to the grid operator and it generates a financial compensation which is usually broken down into two price components i.e. GS flat (contractual) and variable (marginal) fees paid by the Authority responsible for grid balancing to the BSP (Balancing Services Provider). For a more detailed description of the different balancing markets see 3.4.

It is hard to estimate with any good degree of approximation the volumes and prices of offered balancing services (bids applied by the BSP) as well as the volumes and prices of actually procured balancing services (as paid by the SO to the BSP).

In particular it is difficult to make reliable assumptions on the revenues that the BSP can generated when using an electrolyzer as power regulating device and more particularly when supplying the negative or positive secondary FRR balancing market.

This is due to the mechanisms which leads to volumes and prices definition, more specifically to the fact that the power regulating market is based on an auction system. The “Authority” responsible for keeping frequency and voltage in the grid in its predefined technical band-with is for instance purchasing offtake-capacity in advance in case of bids dealing with the positive secondary market. Therefore, the first price component is paid, no matter if this capacity will be used or not later on. The second price component is paid au prorata of the capacity actually used. Once the tender for incoming time slots is formalized, the BSP disposing of enough capacity decides whether to file a bid specifying his price offer for a certain capacity reservation and for actual electricity intake. All bids are collected and automatically uploaded into the so called “Merit-Order-list”.

When the time comes, if the algorithm in the central control room of the “Authority” recognizes the need to activate negative secondary balancing capacity, then said Authority starts by calling to tenders which have applied the most competitive bids (lowest price request) and if needed it progressively includes additional capacity along the merit-order-list until the imbalance situation is solved. In conclusion there is no predefined price for every MWh “removed from the grid” and access to reliable market data history is extremely difficult.

TSO/DSO shall not necessarily accept all the bids of the electrolyzer operator (in this case acting as Balance Service Provider, BSP[12]).

Not only the marginal fees (power volume effectively balanced, e.g. in our case, energy off taken when supplying the positive FRR market or additional energy consumed when supplying the negative secondary market) but also the flat fees (defined contractually and negotiated on e.g. annual basis with the TSO) may vary depending on the country, grid specificities/needs, power regulating market features, electrolyzer location as well as TSO/DSO procurement strategy, methods for scoring the balancing services (order of selection of balancing bids), principles and regulatory frameworks. Moreover, it is reasonable to suppose that balancing market needs will evolve over the years during the service life time of the hydrogen generation plant.

An additional factor adding complexity to our analysis lies in the fact that the utilization of an electrolyzer as power regulating device, beside generating hardly predictable flat & variable fees, also indirectly affects the hydrogen volume out-put and the corresponding turnover (i.e. incomes generated by supplying merchant hydrogen to P2C and P2M clients).

In an effort to integrate GS revenues to our Excel model, without nevertheless attaining an unjustified level of complexity, it seems appropriate to adopt a pragmatic approach consisting to assume that the total number of load shifts operated to supply the balancing market

[12] *As previously mentioned the main methods used to procure balancing services. Balancing services are often provided by BSPs to the SO through bidding in balancing service markets. Different balancing service markets may be installed for different service classes and types. Alternatively, balancing services could be acquired by SOs through bilateral contracting, through an obligation for BSPs to provide balancing services, or the SOs may own balancing resources themselves.*

correspond to a volume of off taken or additional consumed energy equivalent to what could be achieved if the electrolyzer was operated permanently below its nominal load at a defined load rate during a given period of time.

According to a possible 5 MW scenario, the electrolyzer is supposed to run continuously at 100% of its nominal load (according to Table 1 scenario, during 50% of the year) except if, in compliance with specific grid operator signal, the load is decreased down to a minimum 50% load (-2,5 MW) to mitigate imbalance situations associated to a negative frequency deviation.

Conversely the electrolyzer is supposed to run at minimum 50% of its nominal load (according to Table 1 scenario, during 25% of the year) except if, further to a grid operator signal, the load is increased up to maximum 100% load (+ 2,5 MW) to mitigate an imbalance situation associated to a positive frequency deviation.

Of course, this stepwise operating profile is just a way to simulate a final average load regime comprised between 50 and 100%. As a matter of fact, the actual load can almost permanently fluctuate over the time depending on bids acceptance between 100% and 50% (the exact load slot is predefined by the tenderer, BSP).

With the aim to assess the sensitivity of the 5 MW business case to the variation of the earnings generated by supplying grid balancing services, two sets of five different GS revenue values (worst, unfavorable, central, favorable and best) have been purposely entered in the Excel model, each set corresponding to the specific range through which the elecyrolyzer load is supposed to fluctuate depending on TSO needs:

- 0 kEUR/year (worst), 25 kEUR/year (unfavourable), 50 kEUR/year (central), 75 kEUR/year (favourable) and 100 kEUR/year (best); when load shifts amplitude spans between 5 MW down to not less than 3.75 MW (at most a 25% drop of the nominal power rate) or
- 25 kEUR/year (worst), 50 kEUR/year (unfavourable), 75 kEUR/year (central), 100 kEUR/year (favourable) and 125 kEUR/year (best); when load shifts amplitude spans between 5 MW down to not less than 2.5 MW (at most a 50% drop of the nominal power rate).

In conclusion, with the aim to supply the positive FRR market, the 5 MW electrolyzer is supposed to operate at 100% of its nominal load randomly[13] effacing max 2,5 MW in the course of the year.

Conversely, for the purpose to supply the negative FRR market, the 5 MW electrolyzer is supposed to operate at 50% of its nominal load randomly incrementing its load up to a max of 2,5 MW in the course of the year.

That leads to an average operating load that is comprised between 100% and 50% as simulated by the model.

[13] *The term “randomly” here refers to the fact that the bids acceptance process and the subsequent decision to activate or not the balancing service escapes to the control of the BSP (i.e. the plant operator) but are based solely upon merit-order criteria and DSO’s need to correct unpredictable frequency deviations*

Taking into account the target revenues previously mentioned we can break-down the 5 MW GS Case into five scenarios:

- 0+25 kEUR/year (worst)
- 25+50 kEUR/year (unfavourable)
- 50+75 kEUR/year (central)
- 75+100 kEUR/year (favourable)
- 100+125 kEUR/year (best).

The 10 MW scenario is described similarly, except that all power slots and corresponding fees are multiplied by a factor two.

Analogously to what already done for the 5 MW case, two sets of five possible GS revenue levels are foreseen for the 10 MW case:

- 0 kEUR/year (worst), 50 kEUR/year (unfavourable), 100 kEUR/year (central), 150 kEUR/year (favourable) and 200 kEUR/year (best); when load shifts amplitude spans between 10 MW down to not less than 7.5 MW (at most a 25% drop of the nominal power rate)
- 50 kEUR/year (worst), 100 kEUR/year (unfavourable), 150 kEUR/year (central), 200 kEUR/year (favourable) and 250 kEUR/year (best); when load shifts amplitude spans between 10 MW down to not less than 5 MW (at most a 50% drop of the nominal power rate).

Based thereupon, we can break-down the 10 MW GS Case into five scenarios:

- 0+50 kEUR/year (worst)
- 50+100 kEUR/year (unfavourable)
- 100+150 kEUR/year (central)
- 150+200 kEUR/year (favourable)
- 200+250 kEUR/year (best).

The two sets of five numerical values have been entered in the Excel model to calculate the corresponding financial indicators as already done for electricity prices and capex.

For comparative purpose the average electricity price is kept constant at 49,3 EUR/MWh and capex at 625 kEUR/MW for both 5 and 10 MW Cases.

The results of the simulation for the 5 MW case are shown in Table 12, Figure 31 and Figure 32.

The financial upside due to GS revenues is relatively limited. For instance, an almost ten-fold increase of the revenues generated by providing balancing services leads to a reduction of the PBP of only 15% (i.e. from 10,2 down to 8,6 years) and a parallel increase of IRR of around 30% (i.e. from 7,5% up to 9,8% on 20 years).

When GS revenues are low (worst and unfavorable scenarios), NPV is negative or only slightly positive and PBP very long (around 10 years). This happens because poorly remunerated GS negatively affects H_2 output and turnover (when operating on the negative FRR market) without bringing enough incomes to compensate the losses of productivity.

Grid Services Fee for the curtailment of 1,25 MW during 25% of 8760 h (EUR/yr)	Grid Services Fee for the curtailment of 1,25 MW during 25% of 8760 h (EUR/yr)	Total Grid Services Fees (EUR/yr)	Electricity Cost Average (EUR)	Capex EL (EUR/MW)	Capex EL (kEUR)	Total Initial Investment (EUR)	Project Value (EUR)	NPV (EUR)	IRR (%)	Pay Back (yr)
0	25000	25000	49,3	625000	3125000	6489156	8450888	-219085	7,5	10,18
25000	50000	75000	49,3	625000	3125000	6489156	9116343	67754	8,1	9,73
50000	75000	125000	49,3	625000	3125000	6489156	9781799	354594	8,7	9,32
75000	100000	175000	49,3	625000	3125000	6489156	10447254	641434	9,3	8,95
100000	125000	225000	49,3	625000	3125000	6489156	11112710	928274	9,9	8,61

Table 12 The 5 MW Case – Influence of Grid Services fees

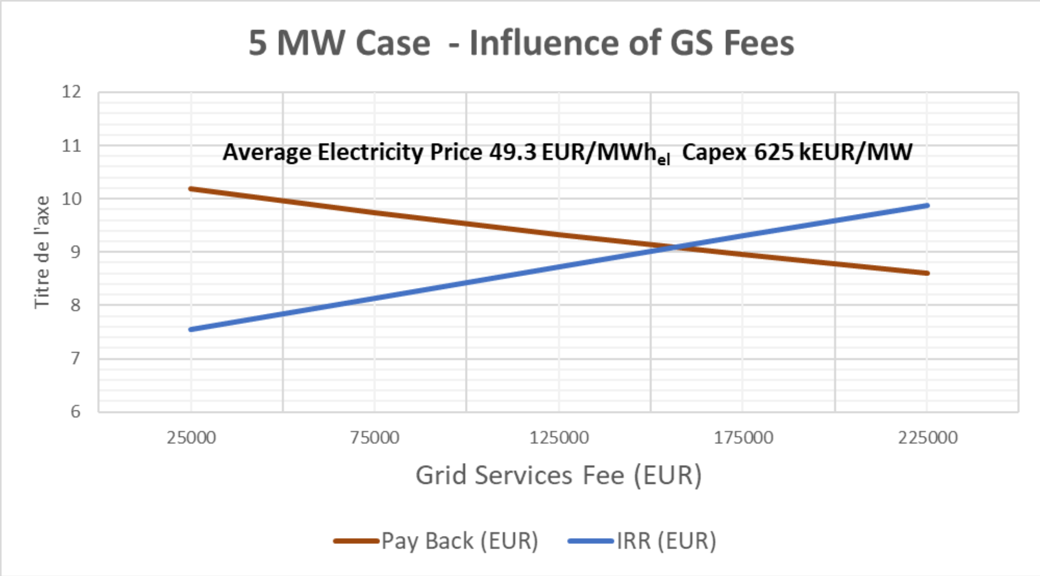

Figure 31 ***The 5 MW Case – Dependency of Pay-back Period and Internal Rate of Return (IRR) on GS Fees***

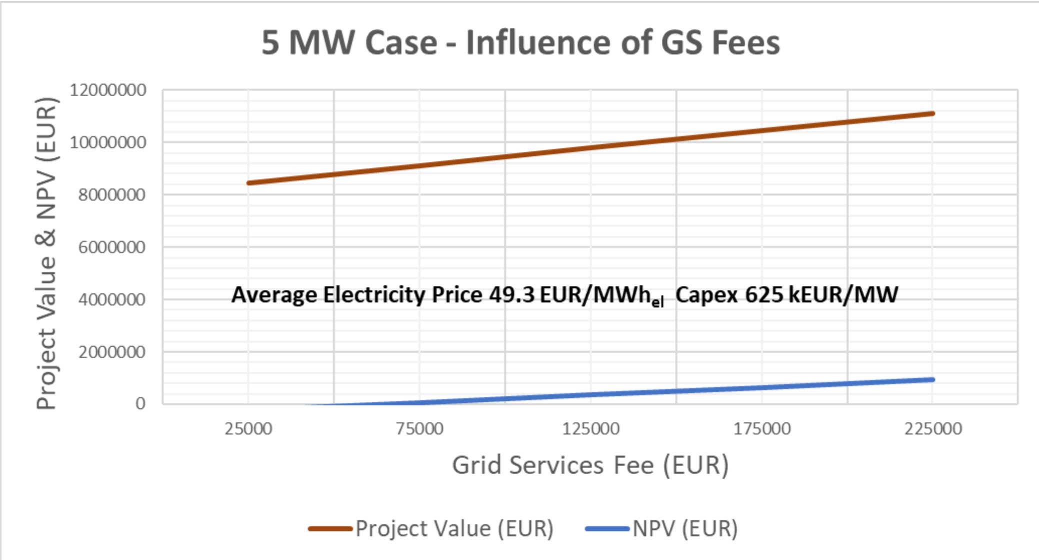

Figure 32 ***The 5 MW Case – Dependency of Project Value (PV) and Net Present Value (NPV) on GS Fees***

The results of the simulation for the 10 MW case are shown in Table 13, Figure 33 and Figure 34.

The sensitivity analysis indicates that the impact of GS revenues on the attractiveness of the 10 MW business case is quite limited and proportionally comparable to what observed in the case of the 5MW scenario. Also in this case, an almost ten-fold increase of the revenues generated by balancing services leads to a reduction of the PBP of 15% (i.e. from 9,3 down to 7,9 years) and a parallel increase of IRR of around 27 % (i.e. from 8,7 up to 11,1%).

The advantage of the 10 MW case is that even when GS revenues are very low (worst and unfavorable scenarios), NPV remains positive and IRR is slightly better than for the 5MW business case.

Grid Services Fee for the curtailment of 1,25 MW during 25% of 8760 h (EUR/yr)	Grid Services Fee for the curtailment of 1,25 MW during 25% of 8760 h (EUR/yr)	Total Grid Services Fees (EUR/yr)	Electricity Cost Average (EUR)	Capex EL (EUR/MW)	Capex EL (kEUR)	Total Initial Investment (EUR)	Project Value (EUR)	NPV (EUR)	IRR (%)	Pay Back (yr)
0	50000	50000	49,3	625000	6250000	12503311,19	18579711	672653	8,7	9,35
50000	100000	150000	49,3	625000	6250000	12503311,19	19910622	1246333	9,3	8,94
100000	150000	250000	49,3	625000	6250000	12503311,19	21241533	1820012	9,9	8,57
150000	200000	350000	49,3	625000	6250000	12503311,19	22572445	2393692	10,5	8,24
200000	250000	450000	49,3	625000	6250000	12503311,19	23903356	2967372	11,1	7,93

Table 13 The 10 MW Case – Influence of Grid Services fees

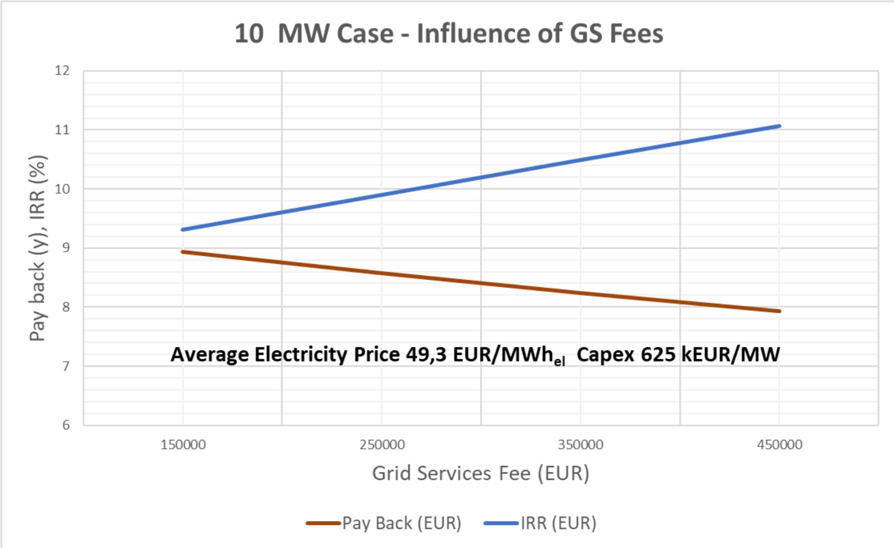

Figure 33 ***The 10 MW Case – Dependency of Pay-back Period and Internal Rate of Return (IRR) on GS Fees***

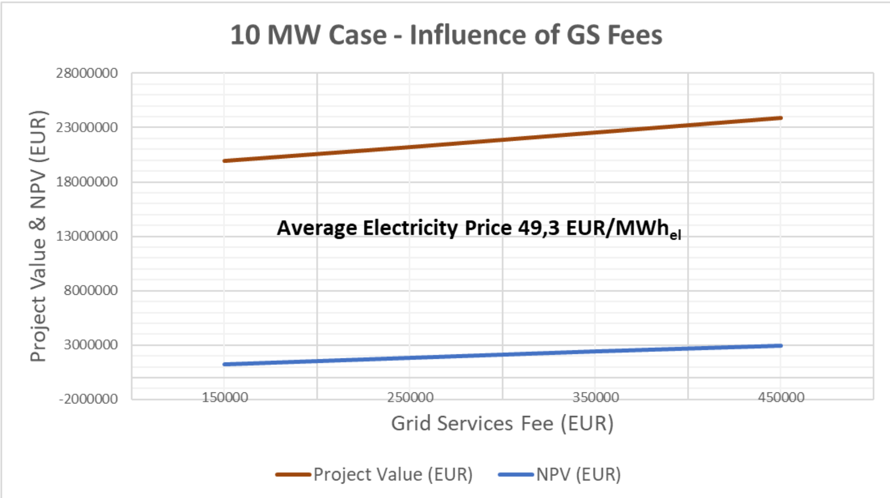

Figure 34 ***The 10 MW Case – Dependency of Project Value (PV) and Net Present Value (NPV) on GS Fees***

GS revenues taken into account for the previous sensitivity analysis are probably much higher than those which can be expected when supplying most of the power regulating markets and the reliability of the assumptions is debatable. According to a more conservative approach it seems realistic to assume that GS revenues (flat + marginal fees) should rather be in the ranges of 25-75 kEUR/year and 50-150 kEUR/year respectively for the 5 and 10 MW cases. For the 5MW case, that corresponds to an expected average price paid by the TSO for the withdrawal of 8,2 GWh/year comprised between 3 and 9 EUR/MWh.

4.4 Comparison of 5 and 10 MW Cases – National Electricity Markets and Business Cases Viability

The results presented in sections 4.1 to 4.3 allow to better understand how the 5 and 10 MW plant profitability evolves under different operating and economic conditions, more specifically for different average electricity prices, electrolyzer capex and GS revenues.

Certain assumptions may be further refined, avoiding bottle-necks while remaining credible in terms of market potential and. perspectives.

In this section, 5 and 10 MW business cases are parametrized taking into account the assumptions previously made with the aim to optimize financial viability without losing sight of markets and technology constraints (central case scenarios).

The **central scenario** parameters of the 5 MW case are detailed in Fig. 23. We note an average electricity price of 48,2 EUR/MWh, an electrolyzer capex of 600 kEUR/MW and total GS revenues of 75 kEUR/year (in the average 9 EUR/MWh[14]). The other parameters are those already reported in Table 1.

5 MW Case - Central Scenario	
EL Nominal Power @ 100% Load (MW_{el})	5
Electrolyser Capex per MW (EUR/MW)	600000
Electricity price (EUR/MWh_{el}) 1500 h/year	20
Electricity price (EUR/MWh_{el}) 2000 h/year	25
Electricity price (EUR/MWh_{el}) 5260 h/year	65
Avg Electricity Price (EUR/MWh_{el})	48,2
H2 Selling Price - Mobility (EUR/kg)	4,3
H2 Selling Price - Chemical (EUR/kg)	3,2
Fraction of Total amount of H2 produced per year sold to H2 Mobility Market	0,752
Fraction of Total amount of H2 produced per year sold to Chemical Industry	0,248
EL Efficiency System , LHV (MWh_{H2}/MWh_{el})	0,70
Average Load % on annual basis (%)	0,81
EL Average Operating Power on annual basis (MW_{el})	4,06
Electricity consumed on annual basis (MWh_{el})	35588
Average H2 output per hour (MWh_{H2}/hour)	2,84
Average H2 output per hour (kg_{H2}/hour)	939
Total amount of H2 produced per year (MWh_{H2}/year)	24911
Total amount of H2 produced per year (kg_{H2}/year)	748085
Grid services fees for effacing 1,25 MW during max 2190 h (EUR/year)	25000
Grid services fees for effacing 2,5 MW during max 2190 h (EUR/year)	50000

Table 14 The 5 MW Case – Central scenario

[14] *Assuming almost all bids are accepted. Reminder, the total off-taken (or consumed) energy, consequence of these load shifts, is supposed to be ca. 8,2 GWh which can formally result from a load shift of max 1,25 MW during 2190 hours and 2,5 MW during the same time duration. Differently said the 8,2 GWh can be broken down into 2,73 GWh {corresponding to load curtailment (or increment) of max 1,25 MW [i.e. 25% of the nominal load] during a time slot of max 2190 h [25% of the year]} and 5.46 GWh { corresponding to a load curtailment (of increment) of max 2,5 MW [i.e. 50% of the nominal load] during a second time slot of the same duration}*

For the 5 MW case, two alternative scenarios are taken into account, namely:

- an **unfavorable** scenario (Table 15) characterized by higher capex (625 kEUR/MW), higher average electricity price (52,3 EUR/MWh) and lower GS revenues (50 kEUR/year, in the average 6 EUR/MWh)
- a **favorabl**e scenario (Table 16) characterized by lower capex (575 kEUR/MW), lower average electricity price (45,2 EUR/MWh) but GS revenues equivalent to those foreseen for the central scenario (75 kEUR/year 9,1 EUR/MWh)

5 MW Case - Unfavorable Scenario	
EL Nominal Power @ 100% Load (MW_{el})	5
Electrolyser Capex per MW (EUR/MW)	625000
Electricity price (EUR/MWh_{el}) 1500 h/year	20
Electricity price (EUR/MWh_{el}) 2000 h/year	30
Electricity price (EUR/MWh_{el}) 5260 h/year	70
Avg Electricity Price (EUR/MWh_{el})	52,3
H2 Selling Price - Mobility (EUR/kg)	4,3
H2 Selling Price - Chemical (EUR/kg)	3,2
Fraction of Total amount of H2 produced per year sold to H2 Mobility	0,752
Fraction of Total amount of H2 produced per year sold to Chemical Ir	0,248
EL Efficiency System , LHV (MWh_{H2}/MWh_{el})	0,70
Average Load % on annual basis (%)	0,81
EL Average Operating Power on annual basis (MW_{el})	4,06
Electricity consumed on annual basis (MWh_{el})	35588
Average H2 output per hour (MWh_{H2}/hour)	2,84
Average H2 output per hour (kg_{H2}/hour)	939
Total amount of H2 produced per year (MWh_{H2}/year)	24911
Total amount of H2 produced per year (kg_{H2}/year)	748085
Grid services fees for effacing 1,25 MW during max 2190 h (EUR/year	25000
Grid services fees for effacing 2,5 MW during max 2190 h (EUR/year)	25000

Table 15 The 5 MW Case – Unfavorable Scenario

5 MW Case - Favorable Scenario	
EL Nominal Power @ 100% Load (MW_{el})	5
Electrolyser Capex per MW (EUR/MW)	625000
Electricity price (EUR/MWh_{el}) 1500 h/year	20
Electricity price (EUR/MWh_{el}) 2000 h/year	25
Electricity price (EUR/MWh_{el}) 5260 h/year	60
Avg Electricity Price (EUR/MWh_{el})	45,2
H2 Selling Price - Mobility (EUR/kg)	4,3
H2 Selling Price - Chemical (EUR/kg)	3,2
Fraction of Total amount of H2 produced per year sold to H2 Mobility	0,752
Fraction of Total amount of H2 produced per year sold to Chemical Ir	0,248
EL Efficiency System , LHV (MWh_{H2}/MWh_{el})	0,70
Average Load % on annual basis (%)	0,81
EL Average Operating Power on annual basis (MW_{el})	4,06
Electricity consumed on annual basis (MWh_{el})	35588
Average H2 output per hour (MWh_{H2}/hour)	2,84
Average H2 output per hour (kg_{H2}/hour)	939
Total amount of H2 produced per year (MWh_{H2}/year)	24911
Total amount of H2 produced per year (kg_{H2}/year)	748085
Grid services fees for effacing 1,25 MW during max 2190 h (EUR/year	25000
Grid services fees for effacing 2,5 MW during max 2190 h (EUR/year)	50000

Table 16 The 5 MW Case –Favorable Scenario

Analogously, the 10 MW case has been broken down into three possible scenarios:

- a central **scenario** whose distinctive parameters are detailed in Table 17. Average electricity price is 48,2 EUR/MWh (as for the 5 MW case), electrolyzer capex 550 kEUR/MW and GS revenues of 150 kEUR/year (in the average 9,1 EUR/MWh).
- an **unfavorable scenario** (Table 18) corresponding to an average electricity price of 49,3 EUR/MWh, electrolyzer capex of 575 kEUR/MW and lower GS revenues of 50 kEUR/year (in the average 6 EUR/MWh).
- a **favorable scenario** (Table 19) corresponding to lower average electricity price of 44,3 EUR/MWh, lower electrolyzer capex of 525 kEUR/MW and GS revenues substantially equal to those of the central case i.e. 150 kEUR kEUR/year (9,1 EUR/MWh).

10 MW Case - Central Scenario	
EL Nominal Power @ 100% Load (MW_{el})	10
Electrolyser Capex per MW (EUR/MW)	550000
Electricity price (EUR/MWh_{el}) 1500 h/year	20
Electricity price (EUR/MWh_{el}) 2000 h/year	25
Electricity price (EUR/MWh_{el}) 5260 h/year	65
Avg Electricity Price (EUR/MWh_{el})	48,2
H2 Selling Price - Mobility (EUR/kg)	4,3
H2 Selling Price - Chemical (EUR/kg)	3,2
Fraction of Total amount of H2 produced per year sold to H2 Mobility Market	0,752
Fraction of Total amount of H2 produced per year sold to Chemical Industry	0,248
EL Efficiency System , LHV (MWh_{H2}/MWh_{el})	0,7
Average Load % on annual basis (%)	0,81
EL Average Operating Power on annual basis (MW_{el})	8,13
Electricity consumed on annual basis (MWh_{el})	71175
Average H2 output per hour (MWh_{H2}/hour)	5,69
Average H2 output per hour (kg_{H2}/hour)	939
Total amount of H2 produced per year (MWh_{H2}/year)	49823
Total amount of H2 produced per year (kg_{H2}/year)	1496170
Grid services fees for effacing 2,5 MW during max 2190 h (EUR/year)	50000
Grid services fees for effacing 5 MW during max 2190 h (EUR/year)	75000

Table 17 The 10 MW Case – Central Scenario

10 MW Case - Unfavourable Scenario	
EL Nominal Power @ 100% Load (MW_{el})	10
Electrolyser Capex per MW (EUR/MW)	575000
Electricity price (EUR/MWh_{el}) 1500 h/year	20
Electricity price (EUR/MWh_{el}) 2000 h/year	30
Electricity price (EUR/MWh_{el}) 5260 h/year	65
Avg Electricity Price (EUR/MWh_{el})	49,3
H2 Selling Price - Mobility (EUR/kg)	4,3
H2 Selling Price - Chemical (EUR/kg)	3,2
Fraction of Total amount of H2 produced per year sold to H2 Mobility Market	0,752
Fraction of Total amount of H2 produced per year sold to Chemical Industry	0,248
EL Efficiency System , LHV (MWh_{H2}/MWh_{el})	0,7
Average Load % on annual basis (%)	0,81
EL Average Operating Power on annual basis (MW_{el})	8,13
Electricity consumed on annual basis (MWh_{el})	71175
Average H2 output per hour (MWh_{H2}/hour)	5,69
Average H2 output per hour (kg_{H2}/hour)	939
Total amount of H2 produced per year (MWh_{H2}/year)	49823
Total amount of H2 produced per year (kg_{H2}/year)	1496170
Grid services fees for effacing 2,5 MW during max 2190 h (EUR/year)	25000
Grid services fees for effacing 5 MW during max 2190 h (EUR/year)	50000

Table 18 The 10 MW Case –Unfavorable Scenario

10 MW Case - Favorable Scenario	
EL Nominal Power @ 100% Load (MW_{el})	10
Electrolyser Capex per MW (EUR/MW)	525000
Electricity price (EUR/MWh_{el}) 1500 h/year	15
Electricity price (EUR/MWh_{el}) 2000 h/year	25
Electricity price (EUR/MWh_{el}) 5260 h/year	60
Avg Electricity Price (EUR/MWh_{el})	44,3
H2 Selling Price - Mobility (EUR/kg)	4,3
H2 Selling Price - Chemical (EUR/kg)	3,2
Fraction of Total amount of H2 produced per year sold to H2 Mobility Market	0,752
Fraction of Total amount of H2 produced per year sold to Chemical Industry	0,248
EL Efficiency System , LHV (MWh_{H2}/MWh_{el})	0,7
Average Load % on annual basis (%)	0,81
EL Average Operating Power on annual basis (MW_{el})	8,13
Electricity consumed on annual basis (MWh_{el})	71175
Average H2 output per hour (MWh_{H2}/hour)	5,69
Average H2 output per hour (kg_{H2}/hour)	939
Total amount of H2 produced per year (MWh_{H2}/year)	49823
Total amount of H2 produced per year (kg_{H2}/year)	1496170
Grid services fees for effacing 2,5 MW during max 2190 h (EUR/year)	50000
Grid services fees for effacing 5 MW during max 2190 h (EUR/year)	100000

Table 19 The 10 MW Case –Favorable Scenario

As previously mentioned, the relevant financial indicators have been calculated and they are compared in Figure 35 and Table 20.

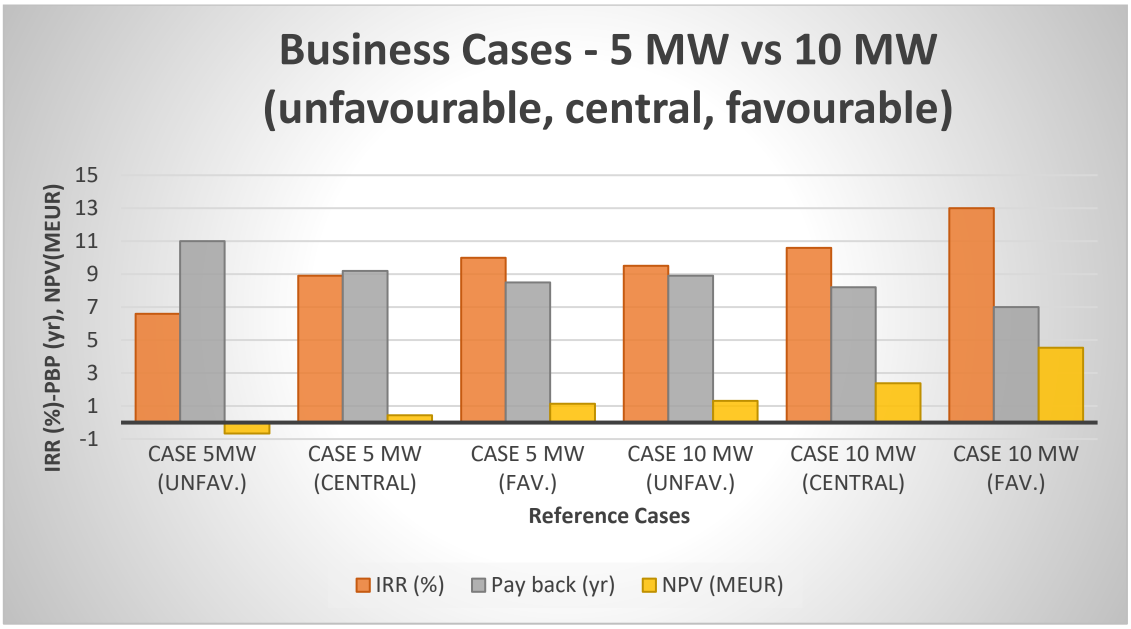

Figure 35 *Comparison of selected 5 MW and 10 MW scenarios (unfavorable, central , favorable essentially depending on different electricity price, electrolyzer capex and GS turnover assumptions)*

	Case 5MW (unfav.)	Case 5 MW (central)	Case 5 MW (fav.)	Case 10 MW (unfav.)	Case 10 MW (central)	Case 10 MW (fav.)
IRR (%)	6,6	8,9	10,0	9,500	10,600	13,000
Pay back (yr)	11,0	9,2	8,5	8,9	8,2	7,0
NPV (MEUR)	-0,66466	0,43820	1,13333	1,3210	2,3814	4,5388

Table 20 Comparison of selected 5 MW and 10 MW scenarios (unfavorable, central , favorable essentially depending on different electricity price, electrolyzer capex and GS turnover assumptions)

The data shown above suggest that, as far as market demand allows to absorb all the generated hydrogen and balancing services theoretically offered by the electrolyzer are in line with the size of the regulatory market, the 10 MW case is more attractive than the 5 MW one.

4.5 10 MW Case – Revised Scenarios

Two revised scenarios for the 10 MW case merit to be considered and analyzed in further detail. As previously said, the electricity demand of the 10 MW plant approaches that of a large industrial consumer (100 GWh/year) and therefore the plant operator should be able to negotiate particularly favorable electricity tariffs.

The electricity tariffs taken into account so far for the 10 MW case (see Table 17 to Table 19) might range between 49 EUR/MWh (unfav.scenario) and 44 EUR/MWh (fav.scenario). This assumption is based upon the statistics presented in point 3.5.9 and is particularly realistic in some EU countries such as Netherlands, Germany or France.

However, in the coming years, the access to cheaper electricity should be facilitated also by the growing share of renewables in the energy mix of different EU countries. Green electricity tariffs ranging between 35 and 40 EUR/MWh look a realistic assumption, in particular when considering, as previously explained, large scale multimegawatt electrolysis units.

Besides, capital expenditures and overhauling costs could be even lower than what foreseen in Table 17 to Table 19 (namely 550 kEUR/MW (central case) or 525 kEUR/MW (favorable case)) due to the expected development and consolidation of the electrolysis supply chain as a whole.

For a 10 MW unit, it is reasonable to expect that standard capex be as low as 500 kEUR/MW whereas for an electrolysis plant of several tens of MW it could drop even below the 500 kEUR/MW threshold.

Revised versions of the 10 MW case scenarios described in point 4.4 (central and favorable) have been developed by entering electricity prices and capex mentioned before (all other conditions being the same).

Of course, such revised scenarios look more realistic in those EU countries where electricity prices for large industrial consumers (close to 100 GWh/year) are particularly low and where renewables share is expected to grow at relatively higher pace. Generally speaking, it sounds reasonable to assume that on the longer term the growth of the share of variable renewable electricity in the energy mix could not only contribute to reduce the average wholesale electricity price but also to increase the need for balancing services on the frequency regulatory market (although all previsions regarding the evolution of the reserve market remain particularly difficult).

Among the countries mentioned in section 3.5.9, those which seem to better comply with these conditions are the Netherlands, Germany and possibly France due to the difficulty that its nuclear power plants might encounter in compensating any further increase in demand volatility.

According to the *revised central* 10 MW scenario (Table 21) the average all-in electricity price is close to 40 EUR/MWh and the standard capex 525 kEUR/MW. The turnover generated by balancing services is that assumed for the central scenario (Table 17).

10 MW Case - Revised Central Scenario	
EL Nominal Power @ 100% Load (MW_{el})	10
Electrolyser Capex per MW (EUR/MW)	525000
Electricity price (EUR/MWh_{el}) 1500 h/year	20
Electricity price (EUR/MWh_{el}) 2000 h/year	30
Electricity price (EUR/MWh_{el}) 5260 h/year	50
Avg Electricity Price (EUR/MWh_{el})	40,3
H2 Selling Price - Mobility (EUR/kg)	4,3
H2 Selling Price - Chemical (EUR/kg)	3,2
Fraction of Total amount of H2 produced per year sold to H2 Mobility Market	0,752
Fraction of Total amount of H2 produced per year sold to Chemical Industry	0,248
EL Efficiency System , LHV (MWh_{H2}/MWh_{el})	0,7
Average Load % on annual basis (%)	0,81
EL Average Operating Power on annual basis (MW_{el})	8,13
Electricity consumed on annual basis (MWh_{el})	71175
Average H2 output per hour (MWh_{H2}/hour)	5,69
Average H2 output per hour (kg_{H2}/hour)	939
Total amount of H2 produced per year (MWh_{H2}/year)	49823
Total amount of H2 produced per year (kg_{H2}/year)	1496170
Grid services fees for effacing 2,5 MW during max 2190 h (EUR/year)	50000
Grid services fees for effacing 5 MW during max 2190 h (EUR/year)	75000

Table 21 10 MW Case – Revised Central Scenario

According to the *revised favorable* 10 MW scenario (Table 22) the average all-in electricity price is close to 35 EUR/MWh and the standard capex 500 kEUR/MW. The turnover generated by balancing services is that assumed for the favorable scenario (Table 19).

10 MW Case - Revised Favorable Scenario	
EL Nominal Power @ 100% Load (MW_{el})	10
Electrolyser Capex per MW (EUR/MW)	500000
Electricity price (EUR/MWh_{el}) 1500 h/year	15
Electricity price (EUR/MWh_{el}) 2000 h/year	25
Electricity price (EUR/MWh_{el}) 5260 h/year	45
Avg Electricity Price (EUR/MWh_{el})	35,3
H2 Selling Price - Mobility (EUR/kg)	4,3
H2 Selling Price - Chemical (EUR/kg)	3,2
Fraction of Total amount of H2 produced per year sold to H2 Mobility Market	0,752
Fraction of Total amount of H2 produced per year sold to Chemical Industry	0,248
EL Efficiency System , LHV (MWh_{H2}/MWh_{el})	0,7
Average Load % on annual basis (%)	0,81
EL Average Operating Power on annual basis (MW_{el})	8,13
Electricity consumed on annual basis (MWh_{el})	71175
Average H2 output per hour (MWh_{H2}/hour)	5,69
Average H2 output per hour (kg_{H2}/hour)	939
Total amount of H2 produced per year (MWh_{H2}/year)	49823
Total amount of H2 produced per year (kg_{H2}/year)	1496170
Grid services fees for effacing 2,5 MW during max 2190 h (EUR/year)	50000
Grid services fees for effacing 5 MW during max 2190 h (EUR/year)	100000

Table 22 10 MW Case – Revised Favorable Scenario

The main financial indicators (IRR, PBP and NPV) calculated for the revised 10MW scenarios are shown in Figure 36 and Table 23.

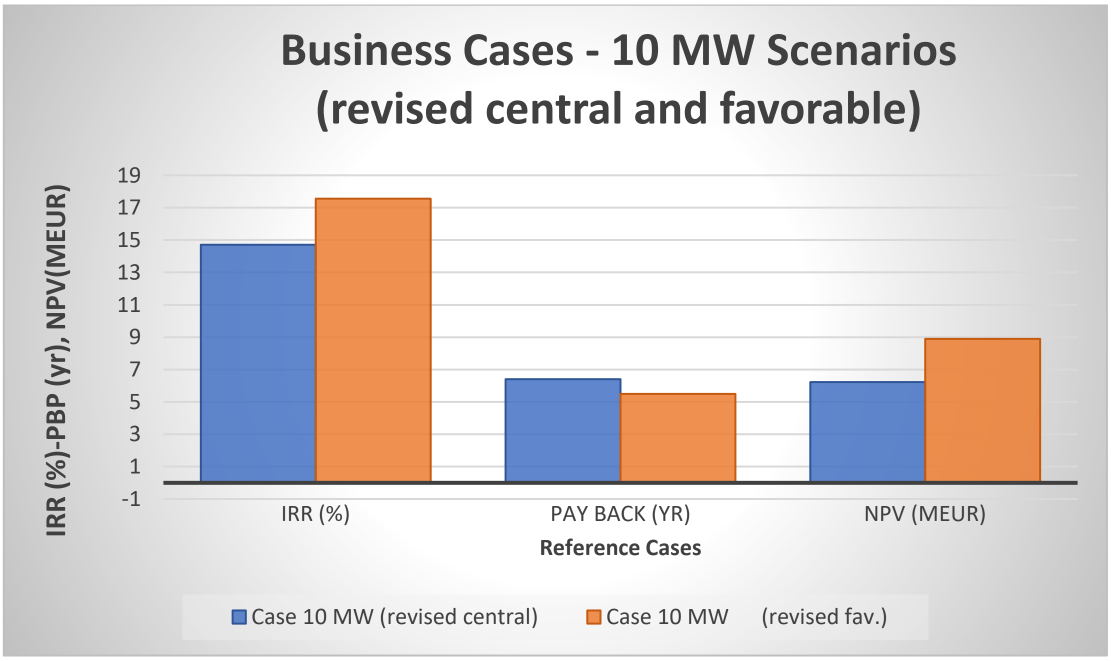

Figure 36 *Comparison of revised 10 MW scenarios - Revised Central vs Revised Favorable*

	Case 10 MW (revised central)	Case 10 MW (revised fav.)
IRR (%)	14,7	17,6
Pay back (yr)	6,4	5,5
NPV (MEUR)	6,22	8,90

Table 23 Comparison of revised 10 MW scenarios - Revised Central vs Revised Favorable

5 DISCUSSION AND CONCLUSION

The business case presented and analyzed by this study deals with the operation of a centralized hydrogen production plant based on a multimegawatt alkaline electrolyze directly connected and powered on-grid. The exploitation of the electrolysis plant leads to two different types of revenues:

- those derived from the sale of electrolytic H_2 (preferably decarbonated) as feedstock for the chemical sector and as fuel for mobility applications
- those related to the fees (flat and variable) paid by the grid operator for the services provided to the secondary regulatory market when using the electrolyzer as a balancing device.

IHT multimegawatt high pressure technology is particularly adapted for the implementation of centralized production models wherein scale economies achievable via the reduction of the specific capex (EUR/MW), fixed and maintenance costs as well as electricity costs are expected to offset expenditures associated to gas delivery logistics.

This is particularly true when it is possible to supply the produced hydrogen to a limited number of large consumers located not far from the hydrogen generation plant. The proposed business case scenarios assume that most of the electrolytic hydrogen is sold to the mobility market (indicatively 75%).

It is generally recognized that mobility market is particularly attractive due to:

- good hydrogen valorization perspectives, in the range of 180 EUR/MWh (when considering fossil fuel equivalent pricing), better than what currently foreseen for P2G models (usually 30 EUR/MWh, when no feed-in premium tariffs are taken into account due to the decarbonated nature of the gas)
- potential demand, large enough to justify massive production of electrolytic hydrogen at the multimegawatt scale.

The presence of multimodal hubs, bus depots and/or other types of professional captive fleets comprising several hydrogen driven vehicles including taxis, LCV, and /or trucks (LDV and/or HDV) close to the electrolysis plant allows to simplify the hydrogen delivery logistics.

In this case, the gas needed to fuel the fleets can be delivered to a limited number of high capacity dispensers (350 bar or dual) rather than to a dense network of smaller stations (usually 700 bar) spread across an entire region/country and supposed to refuel a large park of private passenger cars.

However, according to the proposed business case, part of the hydrogen should also be valorized as commodity feedstock for the chemical sector and sold ex-factory either to Integrated Gas Suppliers (IGS) or directly to P2C end-users. It is reasonable to expect a lower valorization potential for the merchant hydrogen supplied to the chemical sector (especially when the gas buyers are IGS rather than P2C end-users). Nonetheless this approach may be commercially justified in order to diversify and increase the total number of clients, mitigate the risks arising from demand volatility and economic negative cycles.

In particular, for the largest electrolysis plant described in the study (10 MW), this multi sectorial sales strategy is supposed to help maintaining elevated stream factors (high average load an annual basis) and facilitating the access to competitive electricity tariffs (generally reserved to large and very large industrial consumers).

In this perspective, the participation to the regulatory market can provide a complementary business upside. However, our analysis suggests that the contribution of balancing services to total revenues is relatively modest and hardly predictable. The volatility of such revenues is a consequence of the mechanisms which regulate the reserve market procurement process (bids) and, of course, the variability/randomness of the phenomena at the origin of imbalance situations requiring DSO/TSO corrective interventions.

Moreover, the participation to the regulatory reserve market may interfere with normal hydrogen production operations. In particular, depending on the frequency with which the electrolyzer is used to provide balancing services, the occurrence of successive and frequent load shifts totally independent from plant operator's control may perturb the planification of hydrogen manufacturing campaigns and complicate the regular supply of the P2M and P2C customers. For instance, in case of significant and prolonged down turns of the electrolyzer (to serve the positive secondary reserve market), the volumes of hydrogen generated by the plant might drop below a critical threshold and be insufficient to address the needs of the gas end-users.

It is therefore important for the plant operator to assess, under all circumstances, whether and to which extent the participation to the reserve market is justified in terms of global business profitability (in other words, to understand if the gains possibly generated by the supply of balancing services may offset the opportunity costs linked to the participation to the regulatory market) and of course to be sure being able to honor orders backlog.

The sensitivity analysis carried out in section 4 on the basis of the operational and economic parameters and the assumptions described in section 3 leads to conclude that the 10 MW business case scenario is in principle more competitive, due to the possibility to negotiate lower electricity tariffs and the economies of scale which are more likely achievable in terms of capex and fixed costs.

The results presented in section 4 indicate that the profitability of the different scenarios is only marginally impacted by the grid services revenues being all other conditions the same.

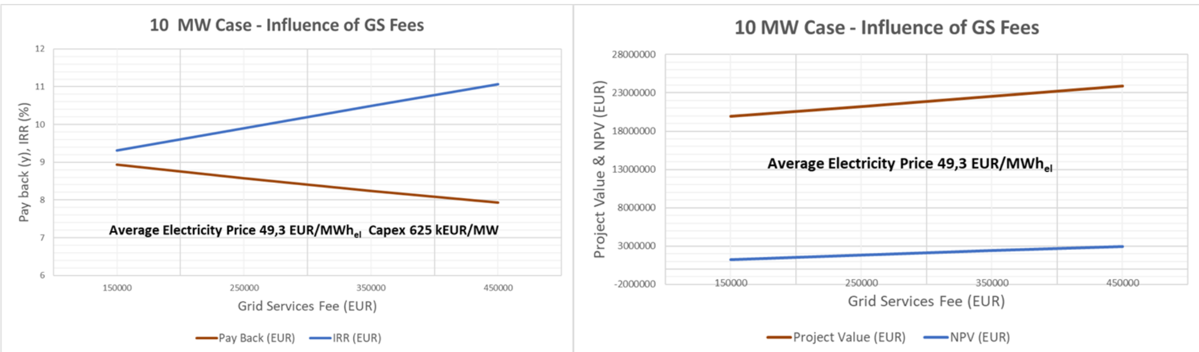

Figure 37 ***Sensitivity Analysis – 10 MW Scenario: Influence of GS Fees***

As a matter of fact, the average electricity price is by far the parameter having the strongest influence on financial indicators such as IRR, Pay-Back period, NPV.

Figure 38 ***Sensitivity Analysis – 10 MW Scenario: Influence of Average Electricity Price***

The electrolyzer capex also plays a role on business case viability, but relatively less critical than electricity price, at least within the investigated range 400-625 kEUR/MW.

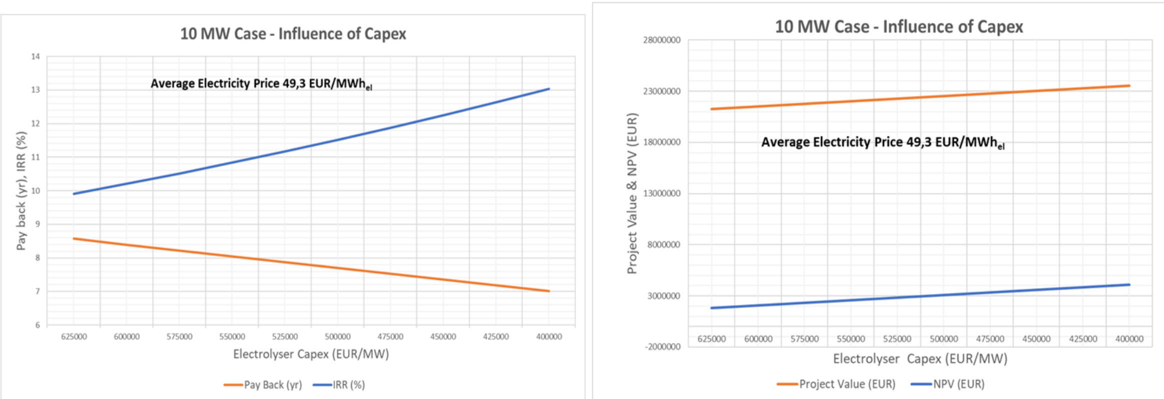

Figure 39 ***Sensitivity Analysis – 10 MW Scenario: Influence of Electrolyzer Capex***

The revised 10 MW central scenario (Table 21) is characterized by an IRR of almost 15% and an NPV of more than 6 MEUR with a payback period close to 6 years. These financial indicators have been calculated assuming total initial expenditures of 11,5 MEUR wherein the electrolyzer capex represents 5,250 MEUR and average electricity prices is of 40,3 EUR/MWh. The exploitation of the electrolyzer takes place over 20 years as well as all amortizations.

Two overhauling interventions (respectively at YR 6 and Yr12) are foreseen during this lapse of time. It’s worth to mention that this assumption is very conservative since industrial experience for IHT alkaline high pressure electrolyzers shows that such interventions generally take place much less frequently (every 10 years and in some cases not earlier than 15-20 years after commissioning depending on utilization conditions).

With regard to grid services, the revised 10 MW central scenario assumes that the participation to the regulatory market generates an average turnover of 150 kEUR/year that corresponding to a global (flat + marginal) fee of 9 EUR/MWh (assuming ca. 16,4 GWh/year supplied to the secondary positive or negative reserve market).

Even better profitability can be expected in the case of the revised 10 MW favorable scenario (Table 22 and Table 23). In this case the IRR is comprised between 17 and 18%, NPV is close to 9 MEUR with a payback period of 5,5 years.

This particular scenario is derived when assuming an electricity prices of 35,3 EUR/MWh and lower capital expenditures for the procurement of the electrolyzer i.e. 5 MEUR, all other conditions being basically the same.

The results of the discounted and unlevered discounted cash flow analyses carried out for the 10 MW business case scenarios described in section 4 are summarized in Table 24, Figure 40 and Figure 41.

FORESEEN SCENARIO	PARAMETERS				DISCOUNTED CASH FLOW ANALYSIS				UNLEVERED DISCOUNTED CASH FLOW ANALYSIS		
10 MW Case	Capex EL (€/kW)	Avg. Electricity Price (€/MWh)	Grid Services Fees (kEUR/year)	Total Initial Expenditures (M€)	Terminal Value -TV (M€)	Present Value of Cash Flow (M€)	Present Value of TV (M€)	Project Value (M€)	Present Value of Cash Flow (M€)	Present Value of TV (M€)	Project Value (M€)
Unfavorable	575	49,3	25/50	12,003	21.949	18.372	4.709	23.081	15.971	3.452	19.423
Central	550	48,2	50/75	11,753	23.870	19.805	5.121	24.926	17.875	3.686	21.561
Favorable	525	44,3	50/100	11,503	28.298	23.065	6.071	29.137	22.019	4.242	26.262
Revised Central	525	40,3	50/75	11,503	32.146	25.875	6.896	32.772	25.462	4.738	30.201
Revised Favorable	500	35,3	50/100	11,253	37.760	30.004	8.101	38.106	30.671	5.447	36.119

Table 24 Discounted Cash Flow (DCF) Analysis and Unlevered Discounted Cash Flow (UDCF) Analysis Results for different 10MW Business Case Scenarios: Unfavorable, Central, Favorable, Revised Central, Revised Favorable

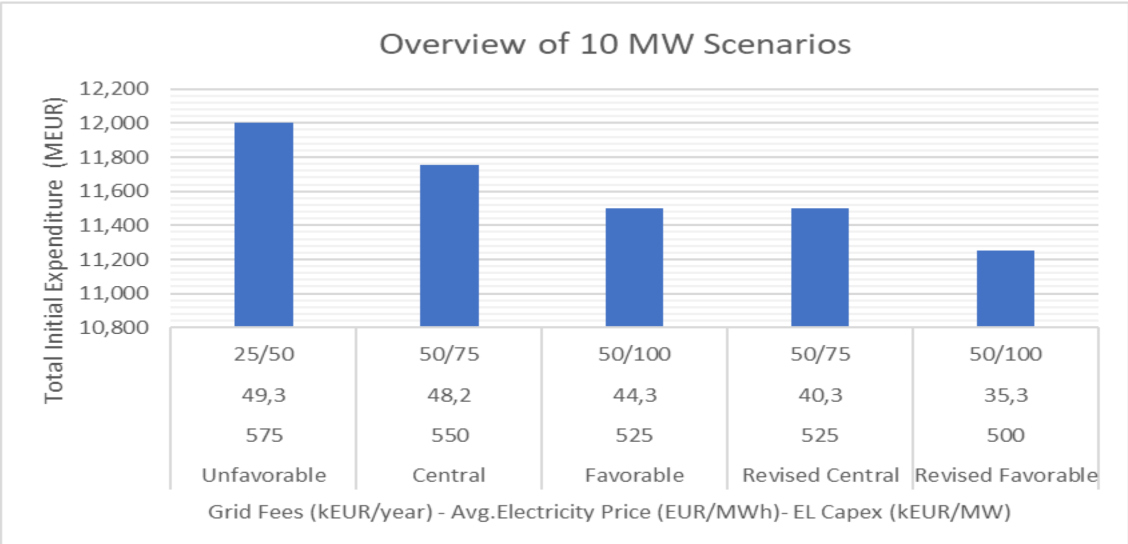

Figure 40 ***Discounted Cash Flow (DCF) Analysis and Unlevered Discounted Cash Flow (UDCF) Analysis Results for different 10MW Business Case Scenarios: Unfavorable, Central, Favorable, Revised Central, Revised Favorable***

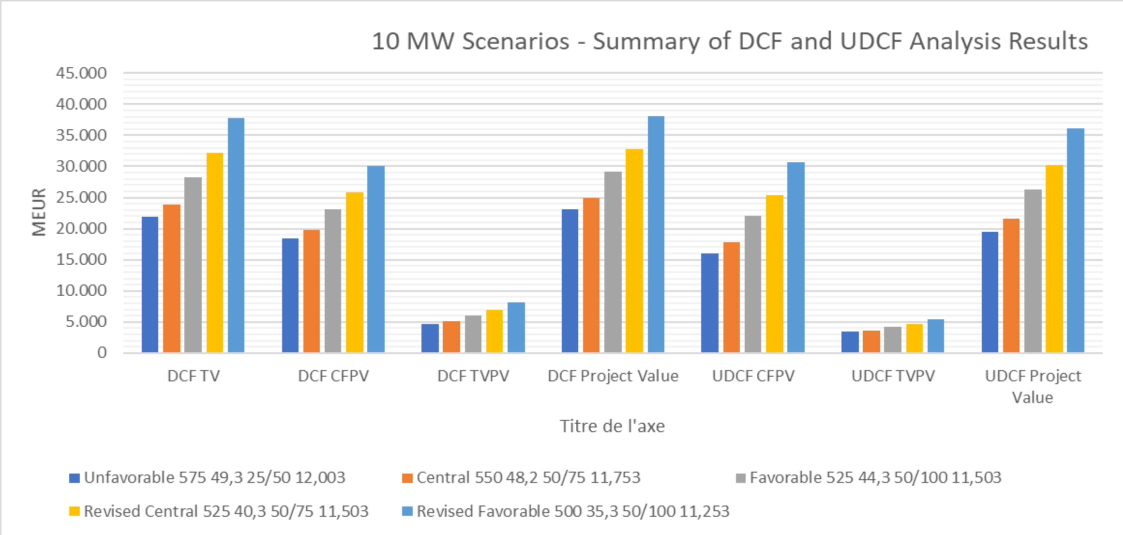

Figure 41 ***Discounted Cash Flow (DCF) Analysis and Unlevered Discounted Cash Flow (UDCF) Analysis Results for different 10MW Business Case Scenarios: Unfavorable, Central, Favorable, Revised Central, Revised Favorable***

Some countries may be more interesting than other for the implementation of the business cases described in the present study and this is essentially related to the possibility to access relatively lower wholesale electricity tariffs in the case of large industrial consumers (consuming between 50 and 100 GWh per year as in the case of the 10 MW plant). However, when referring to large and very large industrial consumers, available market statistics are not always pertinent. Some data inconsistencies have also been noted from one source to another.

Having said that, it still appears that some countries are seemingly more attractive than others, namely Netherlands, some Scandinavian countries, Germany, Austria and possibly France. Whereas other EU countries such as UK, Italy and Spain have higher charge electricity prices even for large industrial consumers according to literature sources analyzed.

Of course, other criteria that must be considered is to identify those countries (or regions within a country) where market conditions are the most favorable. Among such criteria we have to mention the presence of P2M customers, the decarbonated character electricity and possibly a regulatory market interested to profit of the balancing services which can be provided by the electroyzer.

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7 ANNEX

7.1 ANNEX 1

Different analytical methods have been used to assess business case viability.

Discounted Cash Flow Analysis (DCF) calculating the Terminal Value (TV) of the project based on the perpetuity growth methodology.

TV defined as all future cash flows in perpetuity when one can expect stable growth rate forever. In other words, the perpetuity growth approach assumes that free cash flow will continue to grow at a constant rate into perpetuity. The terminal value can be estimated using this formula: TV =(FCFn x (1 + g)) / (WACC – g) where TV = terminal value, FCF = free cash flow, g = perpetual growth of FCF, WACC= weight average cost of capital (in our model g has been set to zero for a more conservative estimate of TV) - NB the Project could be financed by Debt and Equities. WACC is the average cost of that money. For the purpose of the present DCF analysis, and for sake of simplicity, we neglect emission of equities and the WACC is assumed to be equal to the Cost of Capital linked to the debt

Unlevered DCF FCF Build up

When calculating the operations of the Project using a Discounted Cash Flow Model , the OPERATING CASH FLOW (OCF) is needed. The OCF is also called the Unlevered Free Cash Flow (UFCF). The term "Unlevered" refers to the fact that the cash is calculated before payment of interests and debts. The term "Free" refers to the fact that the cash is free to be paid back to the suppliers of capital.

Calculating Unlevered FCF for a particular year, we have calculated the UFCF as follow

- i. We have started with the annual sales (revenues or turnover) and subtracted cash costs (e.g. maintenance, fixed costs, loan leasing, labour costs, utilities, etc) as well as depreciation & amortization to calculate the earnings before interests and taxes (EBIT). Incidentally the EBIT is also referred to as the "Operating Income" and represent the pre-tax earnings without regard to how the Project is financed
- ii. We have then multiplied the EBIT by 1 minus the tax rate to calculate the earnings before interest and after taxes (EBIAT). Incidentally the EBIAT represents the after-tax earnings of the Project as if it were financed entirely with equity capital.
- iii. We have added the Depreciation & Amortization expenses back to the EBIAT and subtracted the capital expenses (Capex) that were not charged against earnings to calculate the UCFC

Net Present Value (NPV)

NPV is calculated by subtracting the initial outlay expenditures (initial expenses for the construction of the plant) to the sum from Y0 to Y20 of the actualized CFAT (Cash Flow After Taxes)

Pay Back Period

For the avoidance of doubt by “Pay Back Period” we intend the time required for the initial outlay (amount invested in the Project to start operations at Yr0) to be repaid by the net cash flow generated during the Project. The payback period of course ignores the time value of money, unlike other methods of capital budgeting, such as net present value, internal rate of return or discounted cash flow. According to the present analysis the net cash flows are assumed to be equal to CFAT.

Internal Rate of Return (IRR)

The IRR is the discount rate at which the net present value of future cash flows is equal to the initial investment, and it is also the discount rate at which the total present value of costs (negative cash flows) equals the total present value of the benefits (positive cash flows). To maximize returns, the higher a project's IRR, the more desirable it is to undertake the project. If all projects require the same amount of up-front investment, the project with the highest IRR would be considered the best and undertaken first. The appropriate minimum rate to maximize the value added to the firm is the cost of capital, i.e. the internal rate of return of a new capital project needs to be higher than the company's cost of capital. This is because an investment with an internal rate of return which exceeds the cost of capital has a positive net present value.

7.2 ANNEX 2

Thermodynamics of high pressure electrolysis

Thermodynamics of High Pressure Electrolysis

$$E_N = E^0 - \frac{RT}{2F} \cdot \ln \prod_i a_i^{\nu_i}$$

$$E^0 = -\frac{\Delta G^0}{2 \cdot F}$$

$$E_N = E^0 - \frac{RT}{2F} \ln \frac{\left[a_{H_2O}\right]^2}{\left[\frac{p_{H_2}}{p_0}\right] \cdot \left[\frac{p_{O_2}}{p_0}\right]^{1/2}}$$

p/bar	Electrolysis voltage / V		
	ΔV/mV	at 25°C	at 80°C
1	0	1.229	1.165
10	44	1.273	1.209
30	65	1.294	1.230
100	88	1.317	1.253

⇒ High-pressure electrolysis requires just little additional energy

7.3 ANNEX 3

Austrian Situation https://www.apg.at/en/markt/netzregelung

Local Control Area Manager in Austria is APG (a Verbund subsidiary). APG is responsible for the procurement and activation of the required power plant capacity in his own control area.

A balance between generation and consumption is essential at all times to guarantee a stable grid frequency. Deviations from this balance, which could for example be caused by power plant failures or unexpected changes, must permanently be compensated through the activation of power plant capacity. Activation must be possible in both directions (increased/reduced generation). In its role as control area manager, APG is responsible for the procurement and activation of the required power plant capacity in the APG control area. (A control area is a grid area in which the balance between generation and consumption is coordinated.)

Control energy market

Since 2012, the control power required in the APG control area will be procured uniformly by APG by way of regular tenders. Each market participant, who meets specific technical and contractual conditions, can participate in these tenders. For technical and economic reasons, a distinction is made between three types of control energy.

1. Primary control: it is needed to automatically compensate an imbalance between generation and consumption within a few seconds through corresponding activation (control) thus leading to the stabilisation of the frequency. Primary control power in the amount of +/-3000 MW is continuously available in the Continental European Grid. All control areas make a contribution on the basis of their annual generation. The volume of primary control power that must be provided by the APG control area lies at approximately +/-65 MW. The primary control energy is registered as unintentional deviation between the control areas and compensated.
2. Secondary control: it is automatically activated to relieve primary control so that it can resume its function of balancing the system. Secondary control is activated when the system is affected for longer than 30 seconds or it is assumed that the system will be affected for a period longer than 30 seconds. Prior to this, a surplus or deficit in the grid is only balanced using primary control. The required volume of secondary control depends on the size of the control area and the availability of power plants in the control area. Secondary control must be capable of compensating for the failure of the largest power plant block in the control area. In the APG control area, the largest power plant block is covered by secondary control in combination with tertiary control. The costs of secondary control (capacity provision and energy) are allocated in the following manner in compliance with §69 of the Electricity and Organisation Act, ElWOG 2010: 78% are charged to the electricity producers with an installed bottleneck capacity of over 5 MW in accordance with the system utilization tariff. This tariff component is referred to as a system service. The remaining 22% are forwarded to the balancing groups as a partial component for the entire balancing energy.
3. Tertiary control (minutes reserve): it is activated in cases where the deviation in the control area lasts more than 15 minutes. (This is also referred to as "minutes reserve".)

Tertiary control is used to relieve secondary control so that this is once again free to support or restore the availability of primary control should this be necessary. Tertiary control can be activated automatically or manually. In the APG control area, tertiary control is activated manually. In the APG control area, tertiary control is also used to support secondary control to ensure that the largest power plant block can be compensated in the event of a failure without endangering grid stability. Hence, positive tertiary control is also referred to as "failure reserve" and the charges, similarly to secondary control (78-22 division) passed on.

Activation fees of positive tertiary control are only allocated to secondary control in the case of a power plant failure. Normally, 100% of the activation fees are taken care of via balancing energy. Negative tertiary control is always allocated to the area "balancing energy". The price for balancing energy is calculated from the costs and volume of minute reserve.

List of prequalified Control energy participants per control energy type in Austria

https://www.apg.at/en/markt/netzregelung

Participants	PCP	SCP	TCP
A1 Telekom Austria AG		X	X
Energie AG Oberösterreich Kraftwerke GmbH	X	X	
EVN AG	X	X	X
GEN-I Vienna GmbH			X
Innsbrucker Kommunalbetriebe AG	X		
KELAG-Kärntner Elektrizitäts-Aktiengesellschaft	X	X	X
Lechwerke AG			X
Linz Strom GmbH			X
Next Kraftwerke GmbH		X	X

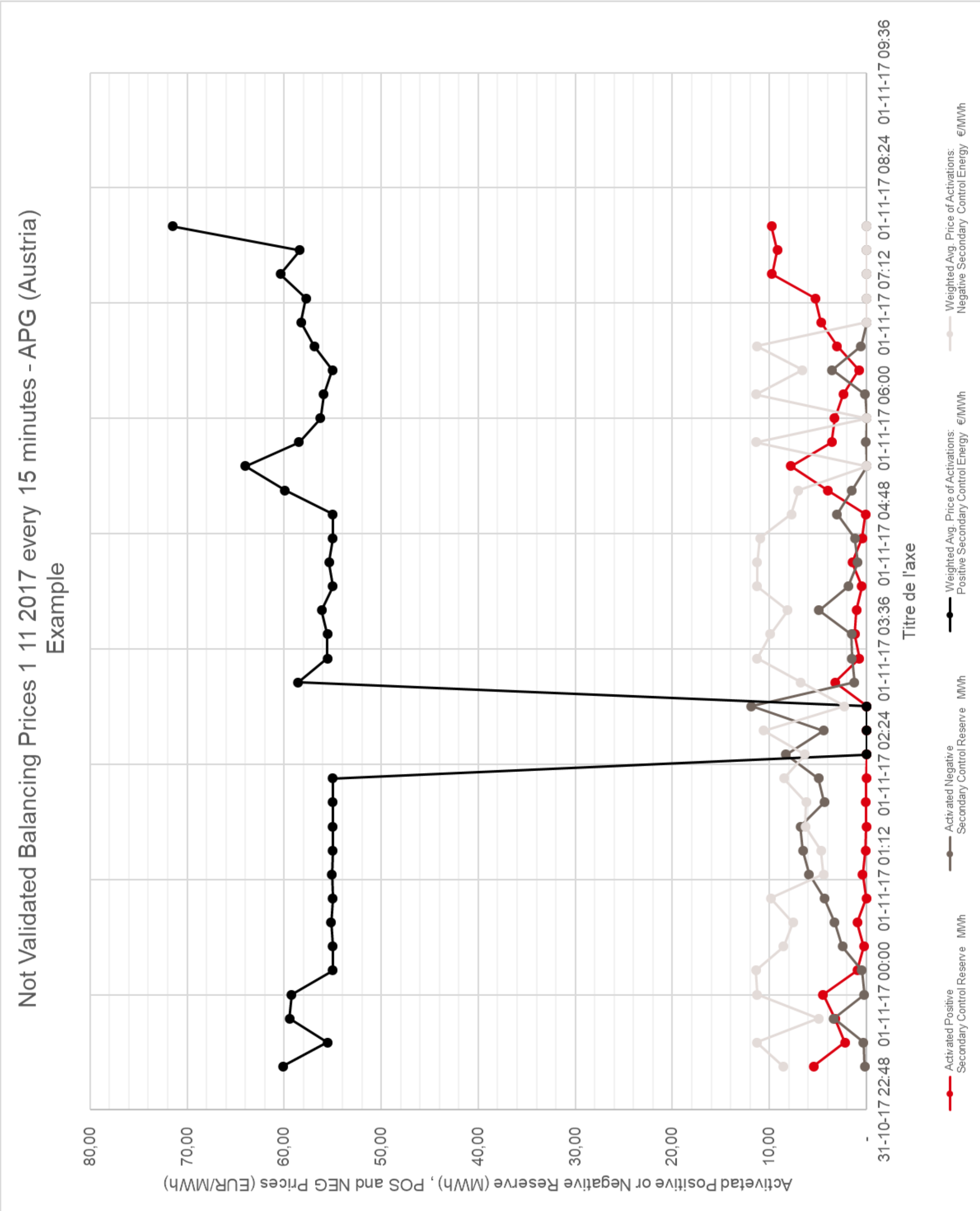
Norske Skog Bruck G.m.b.H.*			
ÖBB-Infrastruktur AG		X	X
TIWAG-Tiroler Wasserkraft AG	X	X	
Salzburg AG für Energie, Verkehr und Telekommunikation	X	X	X
VERBUND Solutions GmbH		X	X
VERBUND Trading AG	X	X	X
Vorarlberger Kraftwerke AG			X
Wien Energy GmbH		X	X

*) prefers no publication in regard to control energy type

APG Austria – Example of Weighted Avg. Prices of Activation (Secondary POS and NEG reserve market in EUR/MWh)

Date Local Time	End Time Local Time	End Time (UTC)	Activated Positive Secondary Control Reserve	Activated Negative Secondary Control Reserve	Weighted Avg. Price of Activations: Positive Secondary Control Energy	Weighted Avg. Price of Activations: Negative Secondary Control Energy
dd.mm.yyyy	hh:mm:ss	dd.mm.yyyy hh:mm	MWh	MWh	€/MWh	€/MWh
01-11-17	00:15:00	31-10-17 23:15	5,48	0,20	60,14	8,59
01-11-17	00:30:00	31-10-17 23:30	2,23	0,33	55,55	11,33
01-11-17	00:45:00	31-10-17 23:45	3,24	3,39	59,45	4,95
01-11-17	01:00:00	01-11-17 00:00	4,49	0,22	59,26	11,29
01-11-17	01:15:00	01-11-17 00:15	0,98	0,48	55,00	11,40
01-11-17	01:30:00	01-11-17 00:30	0,28	2,50	55,00	8,54
01-11-17	01:45:00	01-11-17 00:45	0,98	3,28	55,16	7,59
01-11-17	02:00:00	01-11-17 01:00	0,01	4,34	55,00	9,87
01-11-17	02:15:00	01-11-17 01:15	0,39	5,93	55,10	4,44
01-11-17	02:30:00	01-11-17 01:30	0,12	6,58	55,00	4,71
01-11-17	02:45:00	01-11-17 01:45	0,01	6,80	55,00	6,29
01-11-17	03:00:00	01-11-17 02:00	0,05	4,36	55,00	6,22
01-11-17	03:15:00	01-11-17 02:15	0,04	4,96	55,00	8,51
01-11-17	03:30:00	01-11-17 02:30	-	8,29	-	6,36
01-11-17	03:45:00	01-11-17 02:45	-	4,46	-	10,61
01-11-17	04:00:00	01-11-17 03:00	-	11,87	-	2,29
01-11-17	04:15:00	01-11-17 03:15	3,24	1,25	58,55	6,79
01-11-17	04:30:00	01-11-17 03:30	0,75	1,49	55,54	11,29
01-11-17	04:45:00	01-11-17 03:45	1,22	1,56	55,53	9,94
01-11-17	05:00:00	01-11-17 04:00	1,03	4,90	56,14	8,15
01-11-17	05:15:00	01-11-17 04:15	0,51	1,88	55,00	11,29
01-11-17	05:30:00	01-11-17 04:30	1,48	0,91	55,37	11,29
01-11-17	05:45:00	01-11-17 04:45	0,44	1,21	55,00	10,97
01-11-17	06:00:00	01-11-17 05:00	0,12	3,02	55,00	7,77
01-11-17	06:15:00	01-11-17 05:15	4,03	1,49	59,91	7,03
01-11-17	06:30:00	01-11-17 05:30	7,80	-	64,01	-
01-11-17	06:45:00	01-11-17 05:45	3,59	0,05	58,47	11,40
01-11-17	07:00:00	01-11-17 06:00	3,29	-	56,27	-
01-11-17	07:15:00	01-11-17 06:15	2,40	0,17	55,95	11,40
01-11-17	07:30:00	01-11-17 06:30	0,80	3,53	55,05	6,59
01-11-17	07:45:00	01-11-17 06:45	3,05	0,58	56,92	11,31
01-11-17	08:00:00	01-11-17 07:00	4,69	-	58,26	-
01-11-17	08:15:00	01-11-17 07:15	5,31	-	57,75	-
01-11-17	08:30:00	01-11-17 07:30	9,73	-	60,37	-
01-11-17	08:45:00	01-11-17 07:45	9,21	-	58,41	-
01-11-17	09:00:00	01-11-17 08:00	9,81	-	71,46	-

<u>APG Austria – Example of Weighted Avg. Prices of Activation (Secondary POS and NEG reserve market in EUR/MWh)</u>

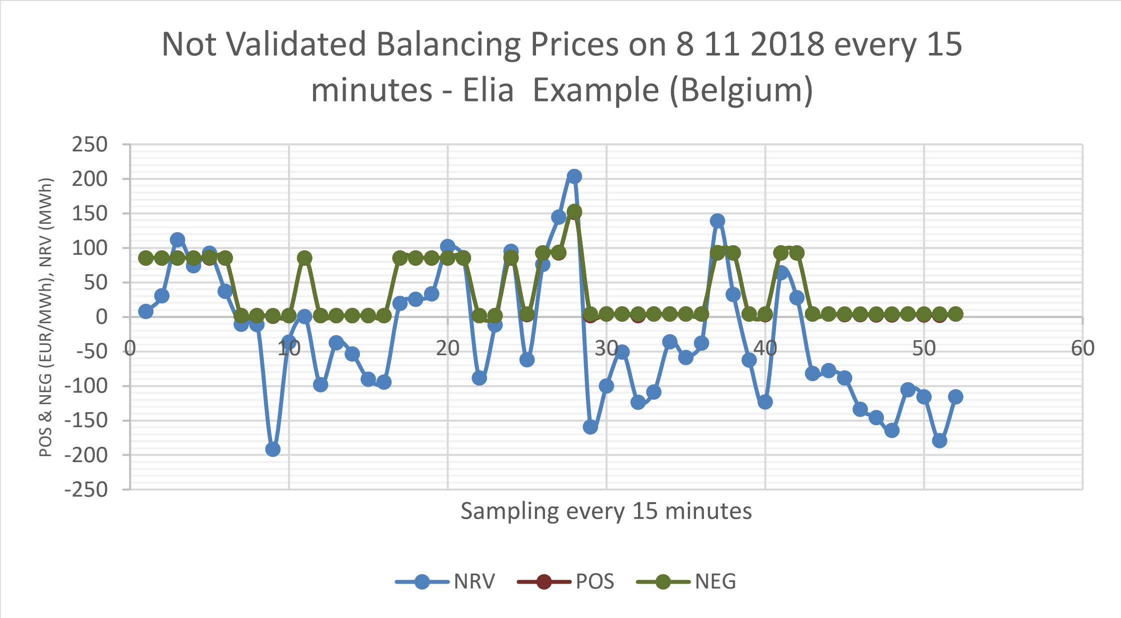


ELIA (Belgium)

http://www.elia.be/en/grid-data/balancing/imbalance-prices

Abbreviations

NRV (Net Regulation Volume)	the net regulation volume is calculated for each quarter-hour using the difference between the sum of the volumes of all upward regulations and the sum of the volumes of all downward regulations requested by Elia
SI (System Imbalance)	the system imbalance is calculated for each quarter-hour using the difference between the Area Control Error (ACE) and the NRV
α	additional incentive applied on top of the regulation costs in cases of major system imbalances.
MIP	the highest price paid by Elia for upward regulation during the quarter-hour in question
MDP	the lowest price received by Elia for downward regulation during the quarter-hour in question
POS	tariff applicable for a positive imbalance
NEG	tariff applicable for a negative imbalance
SR	Strategic Reserve price when there is an volume of Strategic Reserve activated in the system >= 0MW



Example of Not Validated Balancing Prices on 8 11 2018 every 15 minutes - Elia (Belgium)

execdate	strQuarter	NRV (MWh)	POS (EUR/MWh)	NEG (EUR/MWh)
09-11-18	00:00 -> 00:15	69,683	86,12	86,83
09-11-18	00:15 -> 00:30	58,347	86,12	86,12
09-11-18	00:30 -> 00:45	-23,014	2,11	2,11
09-11-18	00:45 -> 01:00	-20,384	2,11	2,11
09-11-18	01:00 -> 01:15	47,196	86,12	86,83
09-11-18	01:15 -> 01:30	66,177	86,12	86,12
09-11-18	01:30 -> 01:45	52,215	86,12	86,12
09-11-18	01:45 -> 02:00	-19,914	2,11	2,11
09-11-18	02:00 -> 02:15	127,035	86,12	86,12
09-11-18	02:15 -> 02:30	41,704	86,12	86,12
09-11-18	02:30 -> 02:45	201,85	86,12	86,96
09-11-18	02:45 -> 03:00	42,945	86,12	86,12
09-11-18	03:00 -> 03:15	-67,163	2,11	2,11

09-11-18	03:15 -> 03:30	59,597	86,12	86,12
09-11-18	03:30 -> 03:45	39,107	86,12	86,12
09-11-18	03:45 -> 04:00	115,81	86,12	86,12
09-11-18	04:00 -> 04:15	-61,833	2,11	2,11
09-11-18	04:15 -> 04:30	-22,799	2,11	2,11
09-11-18	04:30 -> 04:45	-6,462	2,11	2,11
09-11-18	04:45 -> 05:00	84,449	86,12	86,12
09-11-18	05:00 -> 05:15	180,622	86,12	86,72
09-11-18	05:15 -> 05:30	27,879	86,12	86,12
09-11-18	05:30 -> 05:45	37,612	86,12	86,12
09-11-18	05:45 -> 06:00	-3,049	2,11	2,11
09-11-18	06:00 -> 06:15	-225,501	3,17	4,4
09-11-18	06:15 -> 06:30	-109,052	4,4	4,4
09-11-18	06:30 -> 06:45	11,536	92,93	92,93
09-11-18	06:45 -> 07:00	80,434	92,93	92,93
09-11-18	07:00 -> 07:15	69,597	92,93	92,93
09-11-18	07:15 -> 07:30	64,253	92,93	92,93
09-11-18	07:30 -> 07:45	19,241	92,93	92,93
09-11-18	07:45 -> 08:00	-3,915	4,4	4,4
09-11-18	08:00 -> 08:15	57,513	92,93	92,93

http://www.elia.be/en/grid-data/balancing/imbalance-prices