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Cost-Benefit Analysis (CBA) Modelling - Business Case and Operational Scheme of the P2G Project

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EXECUTIVE SUMMARY

The Dutch Transmission System Operator, TenneT TSO B.V., with the support of the Technical University of Delft, cooperates with the Dutch TSO for Gas, the N.V. Nederlandse Gasunie, to monitor a **power to gas (P2G) pilot installation** on the premises of Gasunie in Zuidwending. This project is part of the Synergy Action within the TSO2020 project (Electric 'Transmission and Storage Options' along the TEN-E and TEN T corridors for 2020 - http://tso2020.eu/) and is facilitated by the Dutch Ministry of Infrastructure and Water Management.

The aim of the TSO2020 project is to facilitate flexibility in the power system in the Eemshaven area to allow for the integration of variable renewable energy in the Northern Netherlands region and the landing of the COBRAcable HVDC interconnector. There is a large volume of generation capacity (coal/ wind/ landing of interconnection) situated in an area combined with relatively low demand. Within this project, 6 Activities have been defined, of which cost-benefit analysis modelling is investigated in Activity 3.

This report concerns the work done within and the results of Activity 3, Task 3. Task 3 has the goal to analyse the **business case and operational scheme** of the P2G project from the point of view of investors. It concerns the preparation of the business model and the operational scheme to determine the costs and benefits for the owner/operator of the P2G installation. For the perspective of a market party, an optimisation model has been developed to optimise the costs and benefits on market-based products (e.g. market-based balancing products). This builds further on the work done in Activity 3, Task 1, which investigated the societal cost-benefit analysis of the electrolyser and the impact of its operation to facilitate flexibility in the Eemshaven area to allow the integration of renewable energy into the Northern Netherlands region.

To analyse the business case of the electrolyser, first an investigation was conducted into the various markets where the electrolyser could operate in. The most interesting markets for the electrolyser are the hydrogen market, the day-ahead electricity market (DAM), the intra-day market (IDM) and the automatic Frequency Restoration Reserve (aFRR) market.

Operation in these markets was translated into six potential operational strategies for the electrolyser:

1. **Maximising day-ahead value**: bidding at 300 MW with a step function at the activation price (the marginal cost of producing hydrogen)
2. **Day-ahead bidding (1) with utilisation of residual capacity on a single market**
   a) Residual capacity used on ID market
   b) Residual capacity used for aFRR
3. **Day-ahead bidding (1) with hybrid utilisation of residual capacity on two markets**
   a) Residual capacity split between ID and aFRR: 50-50%
   b) Residual capacity split between ID and aFRR: 75-25%
   c) Residual capacity split between ID and aFRR: 25-75%

Each operational strategy was analysed through a dispatch optimiser to maximise yearly revenues of the electrolyser under various scenarios of market developments (Reference, Conservative, Progressive and Progressive+). The revenue side was then combined with the CAPEX (capital expenditure) and OPEX (operational expenditure) of the system to obtain a net present value (NPV) for each operational strategy and scenario. This led to the following conclusions:

- The base analysis shows a positive NPV for the Conservative and Progressive+ scenario after 20 years for most of the operational strategies;
- For the Reference and Progressive scenarios, the NPV after 20 years is negative regardless of the operational strategy;
- The Progressive+ scenario leads to the best result in NPV across operational strategies; and
- The operational strategy 3b (day-ahead bidding with utilisation of residual capacity: 75% on IDM and 25% for aFRR) is most promising across the scenarios.

Next to the basic analysis of the business case under different operational strategies and scenarios of market development, also the impact the business case from the adopted assumptions regarding market developments and cost parameters was analysed through a thorough sensitivity analysis, resulting in the following conclusions:

- The business case of a large-scale electrolyser mainly depends on the operation on the day-ahead market. This market can supply the bulk of the required electricity as the other markets are relatively small.
- Doubling the market volume of the intraday, aFRR and the hydrogen market leads in all cases to better results and, except for the Reference cases, to a positive NPV. A positive NPV after 20 years does, however, not directly mean that investing in an electrolyser in the northern Netherlands is attractive for a market party. This depends on the intentions of this party. Industrial parties often go for much shorter payback times.
- Doubling the hydrogen market has the largest positive influence on the business case results.
- The improvement of the NPV by doubling the ID market volume is about twice as high as the improvement of doubling the volume of the aFRR market in all four scenarios except for the Reference scenario. For this scenario the improvement is slightly less.
- The price of hydrogen has by far the highest impact on the NPV in all scenarios. A 50% higher hydrogen price leads to a positive NPV after 20 years in the Reference scenario with a payback time of 12 years.
- The next largest influence on the results comes from the CAPEX of the equipment and the efficiency of the electrolyser.
- The influence of both components of the transmission tariff and the weighted average capital costs (WACC) is comparable, and considerably less than the influence of CAPEX and efficiency. The WACC has more influence for the scenarios with higher NPVs after 20 years.
- Reducing both electricity transport tariff and contracted capacity tariff by 50%, leads to 3-5 years shorter pay-back times. Rationale for this reduction may be the potential revenues for grid support services that the electrolyser could provide, as this may have positive societal value.
- Storage cost and OPEX of equipment have the lowest impact on the NPV in all scenarios.

The NPV and pay-back time found in Task 3 differ from the results of the societal cost benefit analysis performed in Task 1. The main reason for this is the inclusion of a number of additional costs that an investor would incur but are not considered in Task 1 as societal cost, such as network tariffs and the cost of paying back loans. Based on the positive societal benefit of the electrolyser, an argument could be made for bridging the cost gap in the electrolyser business case. As the sensitivity analysis has shown, multiple approaches could be utilised for bridging this gap – from a direct investment subsidy to a reduction of network tariffs.

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1 INTRODUCTION

The Dutch Transmission System Operator, TenneT TSO B.V., with the support of the Technical University of Delft, cooperates with the Dutch TSO for Gas, the N.V. Nederlandse Gasunie to monitor a **power to gas (P2G) pilot installation** on the premises of Gasunie in Zuidwending. This project is part of the Synergy Action within the TSO2020 project (Electric 'Transmission and Storage Options' along the TEN-E and TEN T corridors for 2020 - http://tso2020.eu/) and is facilitated by the Dutch Ministry of Infrastructure and Water Management.

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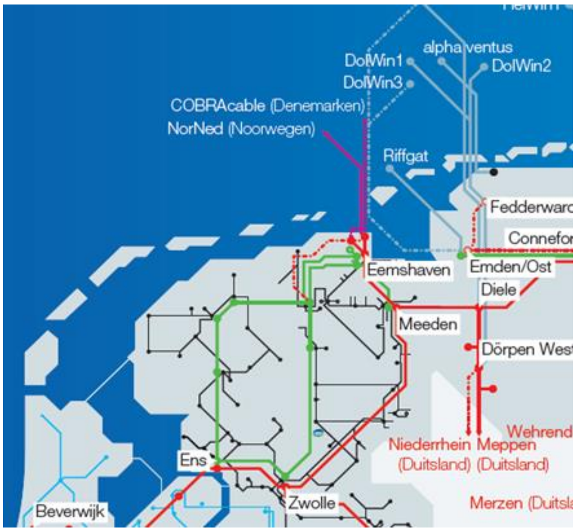


Figure 1-1: Grid lay-out northeast Netherlands. (source: TenneT TSO B.V.)

Activity 3: cost benefit analysis (CBA) modelling of an electrolyser in the Eemshaven region involves the following tasks:

- Task 1: Assessing the value of the electrolyser to society[1];
- Task 2: Assessing the contribution of the electrolyser to local grid stability[2];
- Task 3: Assessing the business model and operational scheme of the P2G installation, or electrolyser.

This report concerns the work done within and the results of Task 3. Task 3 has goal to analyse the **business case and operational scheme** of the P2G project from the point of view of investors. It concerns the preparation of the business model and the operational scheme to determine the costs and benefits for the owner/operator of the P2G installation. For the perspective of a market party, an optimisation model has been developed to optimise the costs and benefits on market-based products (e.g. market-based balancing products). This builds further on the work done in Task 1, which investigated the societal cost-benefit analysis of the electrolyser and the impact of its operation to

[1] See report Activity 3, Task 1
[2] See report Activity 3, Task 2

facilitate flexibility in the Eemshaven area to allow the integration of renewable energy into the Northern Netherlands region.

The results of this deliverable provide input to the analysis to scale-up to mass application within the TSO2020 project (Activity 5).

The remainder of this report consists of four chapters. Chapter 2 includes the project under investigation and provides more detail regarding hydrogen production of the electrolyser, possible market strategies and an overview of the different markets that the electrolyser could operate in. Chapter 3 provides an overview of the methodology used to optimise the operational scheme of the electrolyser. This includes an overview of the model used, a description of possible operational strategies, an overview of the dispatch strategy and details regarding the employed cost and benefit assumptions. Next, chapter 4 discusses the obtained results from the analysis of multiple dispatch strategies and provides insights into the key uncertainties of the business case through a thorough sensitivity analysis. Conclusions are provided in chapter 5.

2 ELECTROLYSER SETUP

Task 3 looks into the business case and operational scheme of a 300 MW electrolyser located in the Eemshaven region in the Northern Netherlands. The electrolyser is envisioned to primarily be used to produce hydrogen from (excess) low-cost electricity purchased on the day-ahead market to serve the mobility or industry sectors in the area (see Report Activity 3, Task 1[3]). However, this revenue stream could be complemented by operating in other markets to potentially strengthen the business case through stacked revenues. This chapter describes the electrolyser technologies and the various markets, both for hydrogen and electricity, where the electrolyser could operate in.

2.1 Hydrogen technology

Power-to-gas technology converts electrical energy into chemical energy, performed in the process of water electrolysis. This core element is executed by an electrolyser consisting of two electrodes, an electrolyte, which conducts ions, and a membrane or separator, which keeps the produced gas stream separate. Different principle set-ups of electrolysis exist, varying in the electrolyte they utilise.

Most well-known are the alkaline water electrolysis using a liquid alkaline electrolyte, the acidic proton exchange membrane (PEM) electrolysis characterised by a proton-conducting polymeric element, and the solid-oxygen electrolysis (see Figure 2-1). Although the three technologies are not inferior to one another, the focus of this report will be on the PEM technology, because of its future potential[4].

By running electricity through the electrodes of an electrolyser cell, water molecules split at the anode in hydrogen ions, oxygen, and two electrons. The hydrogen ions diffuse through the membrane or separator and are collected at the cathode. Here the hydrogen ions collide with electrons and form hydrogen molecules. Oxygen is produced as a by-product.

An electrolyser consists of multiple stacks, which in turn consist of multiple cells. The stacks are linked with an oxygen/water separator and a hydrogen/water separator (see Figure 2-2). The oxygen is mostly released to the atmosphere while the hydrogen is collected, dried and stored.

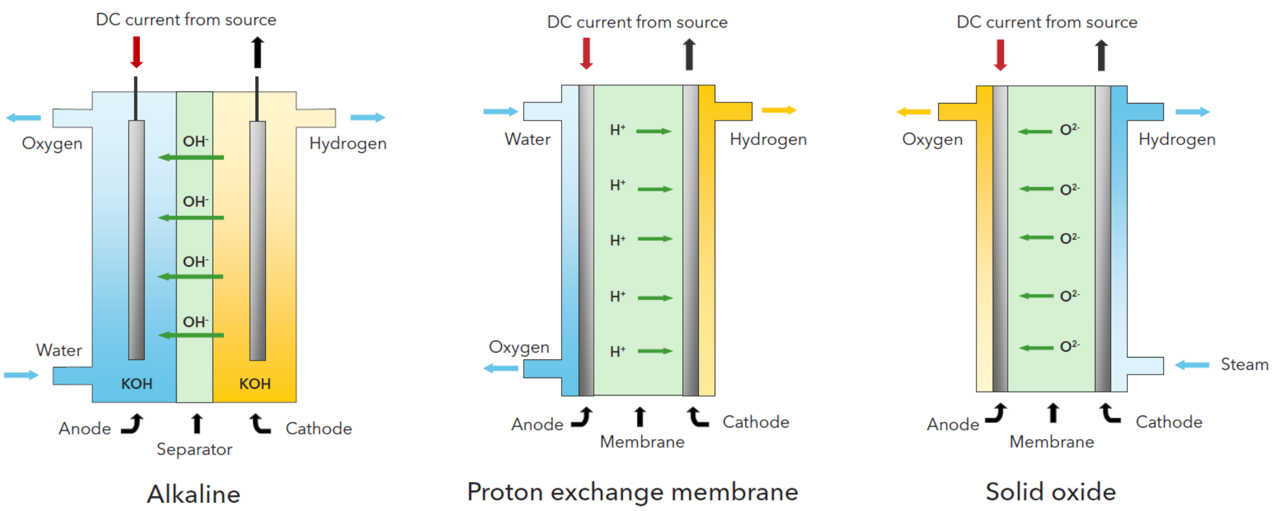


Figure 2-1: Principle set-up of electrolysis. (source: DNV GL)

[3] Report Activity 3, Task 1

[4] TKI, Countouren van een routekaart waterstof (n.d.)

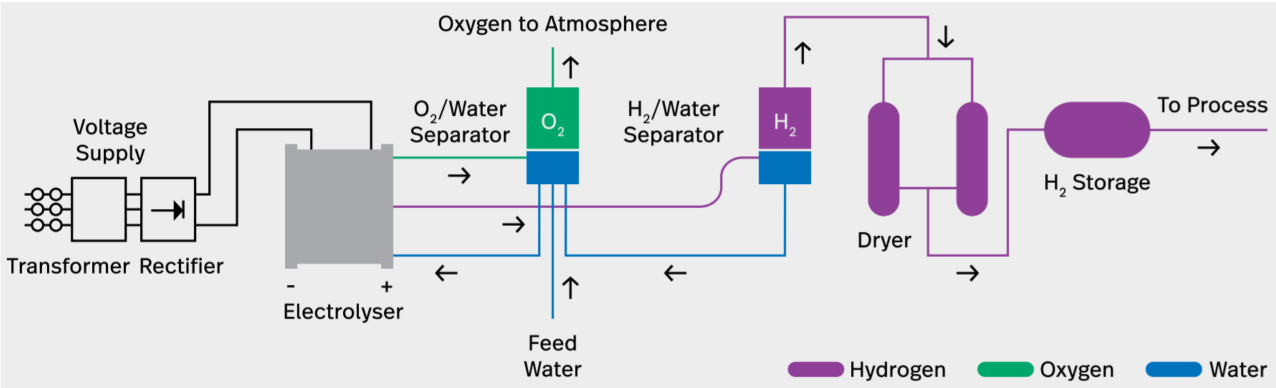


Figure 2-2: PEM electrolyser installation principle. (source: Nelhydrogen[5])

2.2 Market strategy

The goal of the electrolyser operation is to optimise costs and revenues to create the best business case and lowest pay-back time possible. Due to its size and inherent flexibility, the electrolyser has multiple possible operational strategies, each with their own associated costs and benefits. Simultaneously, the control strategies used to dispatch the electrolyser range from simple to complex. For example, the electrolyser can adopt a very simple strategy of using all its capacity on a single market. This makes the revenue potential predictable but is unlikely to be optimal. Conversely, the electrolyser can adopt more complex strategies, where it combines different markets and uses different bidding strategies. These strategies increase the revenue potential, but their complexity makes it difficult to predict future revenues. In addition, there is no certainty that a strategy that was optimised based on historical data will also remain optimal in the future.

In order to cover the necessary bases, this chapter outlines the different potential markets and indicates the markets that were selected for the revenue optimisation study (as well as the reasoning behind this), before diving into the different dispatch strategies that were tested for the optimisation process. The markets will be revisited in a later chapter, where potential or expected market developments are highlighted. These will be used as input for a sensitivity analysis on the results of the optimisation study.

2.3 Hydrogen market

Produced hydrogen will be sold in the hydrogen market in the Northern Netherlands. Activity 3, Task 1 of the TSO2020 project described this market based on a thorough investigation[6]. The chemical industrial and mobility sectors have been identified as the two main potential market segments in this region. The potential hydrogen consumption and the connected market prices of hydrogen have been estimated for both segments and are detailed in the following sections.

2.3.1 Market volume

In the chemical industry sector, both a methanol plant and a hydrogen peroxide plant are currently present in the Northern Netherlands, more specifically in the industrial zone 'Delfzijl'. The industrial processes of these plants require hydrogen, which is currently supplied by an on-site Steam Methane Reforming (SMR) plant. In the future, an ammonia plant is envisaged that runs on green hydrogen. This

5 https://nelhydrogen.com/assets/uploads/2016/05/Nel-Electrolysers-Brochure-2018-PD-0600-0125-Web.pdf

6 See report Activity 3, Task 1

is in line with the current ambitions of companies and authorities in the Netherlands that wish to invest over 2 billion euros in hydrogen in the North of the Netherlands.[7]

For the mobility segment, buses, trains and trucks (both light duty trucks and garbage trucks) have been identified as vehicles with a high potential for the transition from conventional fuel to hydrogen. The passenger vehicle segment is expected to undergo transition towards electric vehicles. Only a small fraction of the fleet is expected to run on green hydrogen in the future.

Figure 2-3 shows the potential hydrogen market in the Northern Netherlands in 2030 and 2040 determined by Activity 3, Task 1, compared with the annual production of a 300 MW electrolyser.

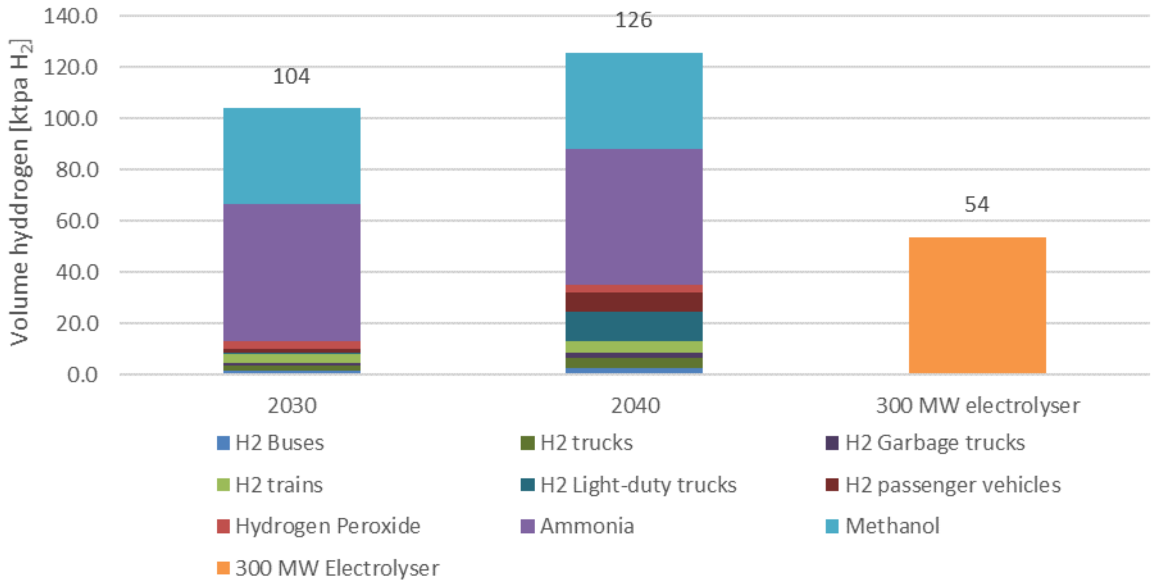


Figure 2-3: The identified potential hydrogen market in the Northern Netherlands in 2030 and 2040 compared with the annual production of a 300 MW electrolyser. (source: Tractebel)

2.3.2 Market price

The market price of hydrogen is the competitive price threshold that off-takers are willing to pay. The envisaged industries are conventionally using Steam Methane Reforming (SMR)-based hydrogen. For these off-takers, it is therefore assumed that if green hydrogen could be produced with the electrolyser at the same cost as SMR-based hydrogen, industrial players would be willing to shift to green hydrogen.

The competitive price thresholds vehicle users will be ready to pay for hydrogen have been assessed by looking at the price and efficiency of conventional fuel vehicles in comparison to fuel-cell vehicles, which is assumed to be diesel for all vehicles. For passenger vehicles, this is a conservative estimate since a part of these vehicles run on gasoline, which is more expensive than diesel. From a technology readiness and market maturity perspective, the produced hydrogen will be allocated sequentially to trucks and buses, to trains, and then light-duty truck and finally passenger cars.

The conclusion from Task 1 is that the highest competitiveness is reached in the mobility segment and the lowest competitiveness for the chemical industry. The market value of hydrogen for the different end-users are displayed in Table 2-1 for the involved scenarios for 2030 and 2040.

[7] https://energeia.nl/fd-artikel/40078827/noorden-wil-2-8-mrd-investeren-in-waterstof

Table 2-1: The competitive cost of hydrogen in €/kg H_2 for the different segments[8].

	Conservative		Reference		Progressive(+)	
Market segment	**2030**	**2040**	**2030**	**2040**	**2030**	**2040**
H_2 buses / trucks	3.8	4.3	4.0	3.3	4.0	4.4
H_2 trains	3.8	4.3	4.0	3.3	4.0	4.4
H_2 light-duty trucks	4.6	5.2	4.8	3.9	4.8	5.3
H_2 passenger vehicles	4.7	5.3	5.0	4.0	5.0	5.5
Hydrogen Peroxide	1.8	2.1	2.6	1.7	2.3	2.8
Ammonia	1.8	2.1	2.6	1.7	2.3	2.8
Methanol	1.5	1.8	2.4	1.5	2.0	2.5

2.4 Electricity markets

Two types of electricity markets can be recognised: the wholesale market and the balancing market. The wholesale market is the commodity market where electricity is traded based on expected demand and available supply, before consumption and production take place. The balancing market is set up to keep the grid stable in case actual consumption and production in real-time do not meet the prior expectations. Both of these markets present potential value streams for the electrolyser, and will therefore both be discussed in more detail in the subsequent sections.

2.4.1 Wholesale market

Wholesale trading happens bilaterally, over-the-counter (using a broker) or through an exchange (e.g. APX). For the purpose of this study, only the exchanges are considered as the average electricity price in fixed price contracts is currently too high, and the electrolyser will require price volatility to purchase electricity below its marginal costs.

When trading on an exchange, every portfolio owner (demand or supply) is responsible for balancing demand and supply in its own portfolio and is classified as a 'Balance Responsible Party' (BRP). In order to supply its consumers, the BRP makes a prediction of the amount of energy its consumers will use per hour the next day. This is combined with the price the BRP is willing to pay for its energy into a demand curve per hour. Similarly, the BRPs with supply in their portfolio create a supply curve based on how much they are able to produce and the price they want to receive per MWh of energy in each hourly period. This becomes a supply curve. These demand and supply curves are then sent to the exchange and aggregated to create a single demand and supply curve per hour for the next day, see Figure 2-4. Hourly supply and demand curves are automatically matched at the intersection by the exchange, leading to a single market price and volume sold per hour, see Figure 2-5.

Both the demand and the availability of supply have an effect on these curves and therefore on the wholesale market price. If demand increases, the demand curve shifts to the right and the price increases. In case of a surplus in production (for example resulting from high amounts of wind production), the supply curve shifts to the right and the price decreases. Similarly, a lack of wind production will shift the curve to the left and increase prices. An increase in volatile production will therefore lead to increasingly volatile market prices.

Two types of exchanges can be distinguished, each with its own time-scale: the *day-ahead market (DAM)* and the *intraday market (IDM)*.

[8] Source: Tractebel, Activity 3, Task 1 report

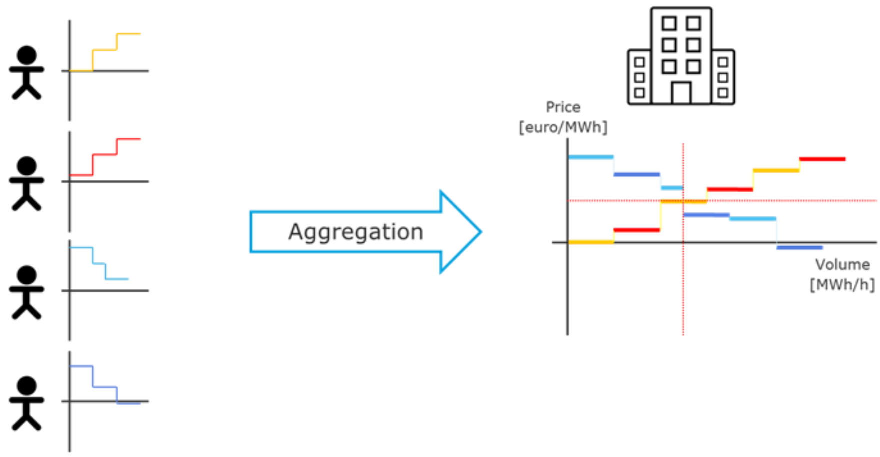


Figure 2-4: Aggregation of supply and demand curves in an exchange. (source: DNV GL[9])

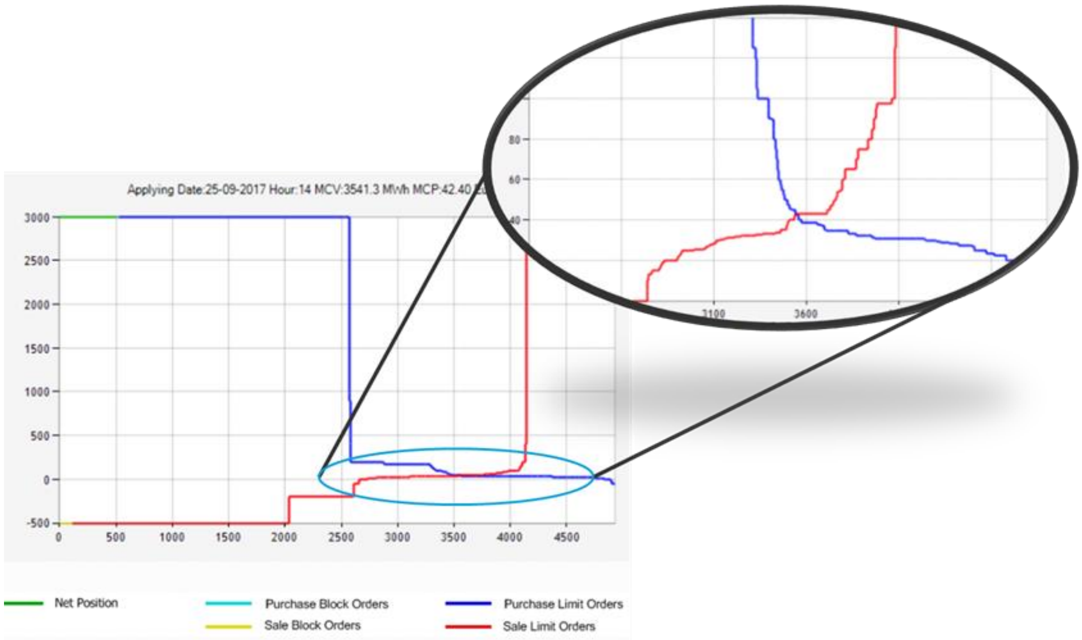


Figure 2-5: Example of EPEX NL(APX) aggregated curves. (source: DNV GL based on[10])

2.4.1.1 Day-ahead market (DAM)

Initial trading takes place on the day-ahead market, which closes at 12.00 CET on the day before delivery is set to take place. The electrolyser will typically use the day-ahead market as its primary source to purchase electricity to produce hydrogen. The electrolyser will opt to purchase electricity for the production of hydrogen in case the day-ahead market price is lower than the marginal cost of producing hydrogen as to not generate at a loss.

[9] Source figures:
person by Brian Dys Sahagun from the Noun Project
Office by Mary Kosyakova from the Noun Project
[10] http://www.apxgroup.com/market-results/apx-power-nl/aggregated-curves/, 2017

2.4.1.2 Intraday market (IDM)

The intraday market is primarily used by BRPs to correct errors in their submitted E-programs (complete prediction of supply and demand per PTU (programme time unit) per BRP) after the day-ahead market has closed but before actual delivery, in order to prevent imbalance costs. These errors could, for example, arise through an incorrect prediction of customer load, or through forecast errors on the amount of available renewable production. Purchasing and selling on the intraday market can take place up to 5 minutes before delivery time.

The electrolyser can make use of the intraday market to purchase (ID+) or sell (ID-) electricity. The electrolyser can consider additional purchases if the price on the day-ahead market was too high, or if the available volume for an acceptable price was too low. In case of an underestimation of the amount of renewable production, or an overestimation of the customer load, intraday prices can drop to a level that is attractive to the electrolyser. Furthermore, the electrolyser can choose to sell electricity that was purchased on the day-ahead market, if the intraday price increases and the margin on sales of electricity exceeds that of the sale of hydrogen. This can happen in case of underestimations of renewable production or overestimations of customer load.

2.4.2 Imbalance market

The imbalance market is a market aimed at mitigating any mismatch between supply and demand in real-time, either by absorbing a surplus or by increasing supply in case of a shortage. As trading on wholesale markets happens on an hourly or quarterly basis, using averages, differences will occur in real-time. This may be the result of a number of factors, such as:

- Forecast errors,
- Demand and supply are not (and don't have to be) constant throughout each programme time unit (PTU).

A combination of passive and active mechanisms can be used to restore balance between demand and supply in real-time:

- Passive balancing; or
- Ancillary services (active balancing).

Passive balancing is meant to provide market parties an incentive to retain balance within their own portfolio, by matching actual demand and supply to the expectation that was used for trading on the wholesale markets. While often referred to as a 'market', this is not an actual market as there is no trading between market parties, but rather an incentive scheme. In case the incentive proves insufficient, and real-time imbalances occur, these will be resolved using ancillary services. Due to the unique nature of the balancing market in the Netherlands, passive balancing and ancillary services will be looked at separately in the subsequent sections.

2.4.2.1 Passive balancing

While most countries utilise a penalty system for portfolio imbalance to incentivise BRPs to match their submitted E-programs, TenneT has opted for a transparent market system. In the Netherlands, the imbalance volume and associated imbalance price per minute are published with a three-minute delay. This not only incentivises parties to balance their own portfolio, but also invites those with flexibility in their portfolio to contribute to system balance. Rather than being punished for deviating from their initial forecast, parties are rewarded if the imbalance in their portfolio contributes to the balancing of the system. In this context, getting paid does not necessarily mean that the BRP will receive money, but could also refer to a reduction in cost (e.g. when consuming more electricity than predicted in the E-program). A schematic overview of this mechanism is depicted in Figure 2-6.

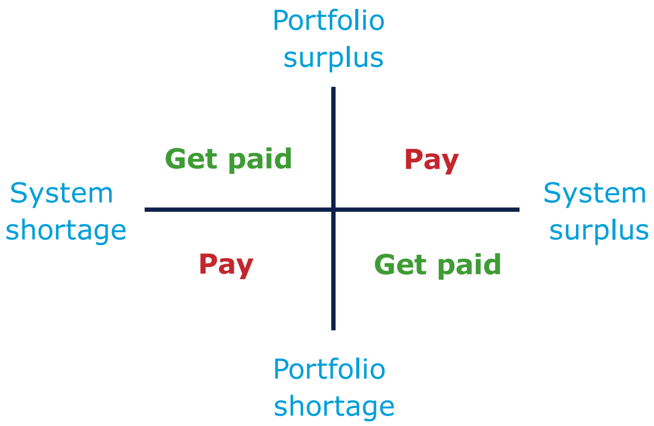


Figure 2-6: Schematic overview of position of BRP. (source: DNV GL)

The price on the imbalance market is the so-called *imbalance price*, which is calculated based on the merit order for Frequency Restoration Reserve (FRR) (see section 2.4.2.2). The electrolyser can make use of the imbalance market by consuming more electricity than forecasted or reducing its consumption based on the market price. However, trading on the passive balancing market was not considered for this report for the following reasons:

- The passive balancing market is risky and highly volatile. Due to the three-minute delay, there is no certainty that the electrolyser will contribute to resolving system imbalance. If the system imbalance was resolved in the three-minute delay period, the electrolyser will cause system imbalance and will be forced to pay the imbalance price;
- This is exacerbated by the fact that the electrolyser capacity (300 MW) is very large in comparison to the total imbalance size in the Netherlands (1.1 TWh, equal to an average of 126 MW)[11]. As a result, dispatch of the electrolyser will have a significant (and often unwanted) effect on the imbalance price;
- There is no certainty about the continuation of the passive balancing market. Due to European Union (EU) harmonisation efforts, the passive balancing market may be phased out in the near future.

2.4.2.2 Ancillary services

Imbalances that are not solved in the passive balancing market will lead to frequency deviations, which will need to be corrected. This is done using ancillary services. Three types of ancillary service products are used[12], see Figure 2-7:

- Frequency containment reserves (FCR – also known as primary reserves)
- Frequency restoration reserves (FRR – also known as secondary reserves)
- Replacement reserves (RR – also known as tertiary reserves)

[11] TenneT. Market Review (2017). https://www.ensoc.nl/files/20180405-market-review-2017-bron-tennet.pdf
[12] TenneT. Market Review (2017). https://www.ensoc.nl/files/20180405-market-review-2017-bron-tennet.pdf

These products all work on different timescales, have different requirements and different settlement schemes. These differences, and the impact on the electrolyser, are outlined in the following sections.

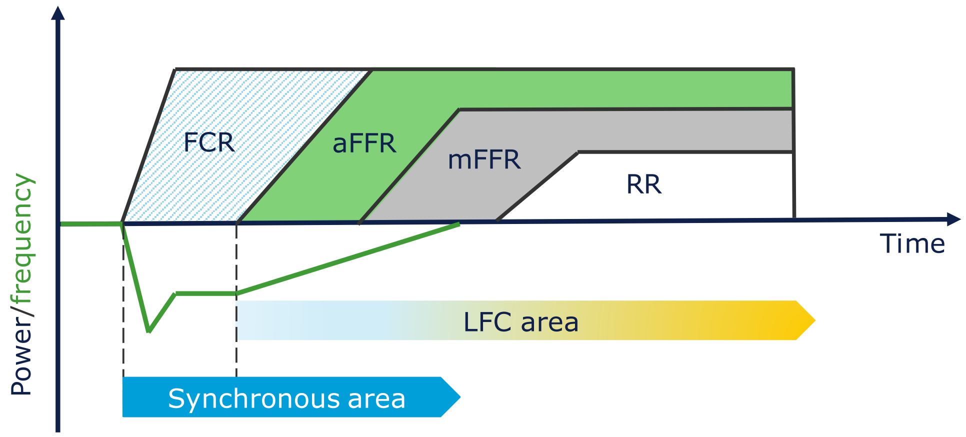


Figure 2-7: Ancillary service products. LFC = Load Frequency Control. (Source: DNV GL based on ENTSO-E)

FCR

FCR consists of fast acting reserves that are not meant to reduce the surplus or deficit in power, but rather to stabilise the frequency deviation caused by the imbalance. Ramping requirements for FCR are therefore the strictest, with a requirement being able to dispatch 50% within the first 15 seconds and 100% within 30 seconds[13]. It is also the shortest acting reserve product, having to deliver for a maximum of 15 minutes after a frequency event. The goal is to replace FCR as soon as possible, in order to free up the capacity for future events.

FCR is automatically activated based on frequency deviations. This is done using *droop control* (also known as proportional control), where the maximum allowed frequency deviation is +/- 200 mHz. At a deviation of 200 mHz, 100% of the available FCR capacity will have to be activated[13]. Due to the proportionality, this means that at 100 mHz deviation, only 50% of available will have to be dispatched. This also goes for 25% at 50 mHz, etcetera.

Parties willing to participate in FCR enter their capacities into auctions. Currently, these auctions are once per week, but this will be replaced by daily auctions in the near future[14]. Eventually, the expectation is that all FCR auctions will be for 4-hour periods. At this auction, the lowest bids are typically accepted, though limitations exist for the amount of power that can be offered to ensure a diversity of sources for FCR capacity. The selected parties will receive a fee for keeping their capacity available for the sole purpose of delivering FCR during the contracted period.

Although Activity 2 of the TSO2020 project has shown that the fast ramping abilities of the electrolyser make it a good technical fit for the FCR product, and FCR is typically seen as the market with the highest earning potential, it has not been incorporated in the business case for the electrolyser for the following reasons:

- The FCR market size in the Netherlands (~110 MW) is very small in comparison to the size of the electrolyser (300 MW), which is a competitive market that is likely to be saturated in 2030. This market size is not expected to increase in the future due to its independence from the supply mix.

[13] TenneT, FCR Product Specification (2017)
[14] https://www.tennet.eu/fileadmin/user_upload/SO_NL/Developments_and_discussions_regarding_FCR_market_framework_nov_2018_ENG.pdf

- FCR is currently a symmetrical product (providing both upward and downward regulating power), which the electrolyser cannot easily provide.
- The FCR auction currently closes on Tuesday, where capacity is contracted for the following week starting Monday (6 days in advance). This is too early for the determination of the electrolyser dispatch strategy, which will be decided on day-ahead.

FRR

FRR consists of reserves that are necessary to fully mitigate the imbalance in terms of power but require a bit more time to come online than FCR. FRR is required to come online as fast as possible but has to be 100% available within 15 minutes and deliver power for up to 2 hours continuously[15]. While FRR ramps up, the frequency deviation will reduce and FCR can ramp down. As FRR replaces the cause of the imbalance 1-on-1, the amount of FRR dispatched is equal in power to the size of the imbalance. The amount of available FRR is therefore determined based on the biggest generation or load outage possible in the Netherlands (currently, Claus-C power plant for generation after it comes online in late 2020, and the BritNed interconnector for load).

FRR consists of two different types: automatic FRR (aFRR) and manual FRR (mFRR). These types refer to the method of dispatch. As the name implies, aFRR is dispatched automatically and mFRR is dispatched manually. mFRR is therefore kept as a backup to aFRR, and is also sometimes referred to as *emergency power*. FRR also consists of two types of bids: contracted and free bids. Parties interested in contracted FRR will participate in an auction, similar to that of FCR. These auctions take place on a weekly and monthly basis. The parties that are selected based on these auctions are required to keep the offered capacity in reserve, and to submit bids into the merit order for their capacity. They are compensated for both the capacity they keep in reserve, as well as for the energy delivered when dispatched.

Whereas FCR currently requires symmetrical bidding (offering the same capacity upward and downward), FRR can be provided asymmetrically using the aFRR+ and aFRR- products. The plus and minus refer to the direction in which power needs to be provided to solve the imbalance. aFRR+, or *upward aFRR*, indicates that there is a shortage of power in the system. This can be solved by generators providing additional power, or by consumers such as the electrolyser reducing their demand. aFRR-, or *downward aFRR*, is activated in case of a surplus of electricity. This will require generators to ramp down, or consumers such as the electrolyser to ramp up. Both products work with their own merit order, and will have different imbalance prices, see Figure 2-8. As these both concern real-time products, it is possible that both aFRR+ and aFRR- are dispatched during the same 15-minute period.

The alternative bidding type is the so-called *free bid*. These can be entered at any point in time for the next PTU, by any party, without restrictions on minimum capacity. Parties participating in free bids do not have to keep capacity in reserve. As a downside, free bidders only receive payment for the energy delivered. All parties providing a bid for FRR are entered into a merit order, where the cheapest bid is called off first and the most expensive bid is called off last. TenneT uses a marginal clearing price system for determining the imbalance price, which means that the most expensive bid called off determines the imbalance price.

While the electrolyser cannot easily participate in the FRR auction, similarly to the way it cannot participate in the FCR auction, it is definitely able to participate using free bids. It can theoretically offer any electricity it has purchased day-ahead, or offer the capacity it was unable to purchase electricity for.

[15] TenneT. Productinformation aFRR (2018)

In case it was able to acquire electricity for part of its capacity, it can offer FRR in both directions.

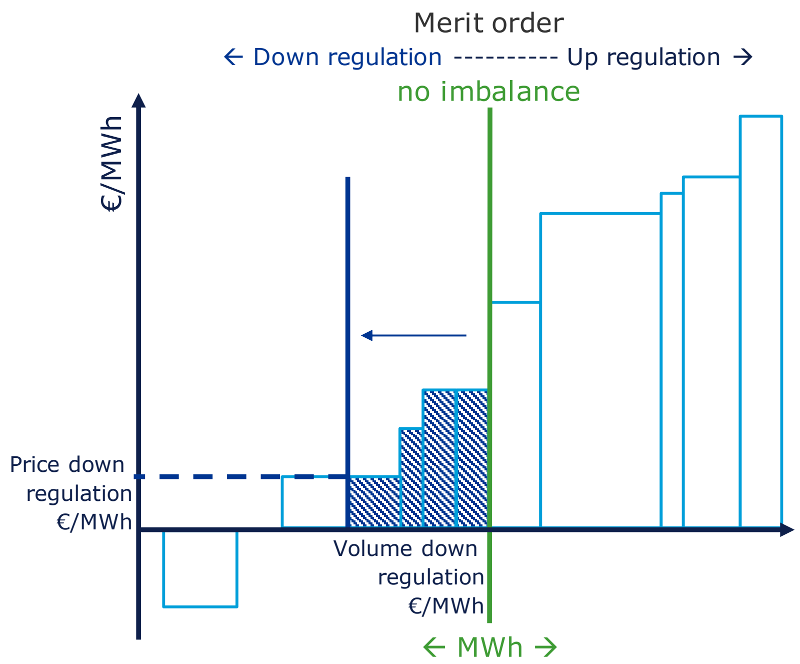


Figure 2-8: Merit order of aFRR bids. If no imbalance, no volume is traded. For example, when downward regulation is required, all bids are dispatched for the required volume, leading to a market price set by the last activated bid in the merit order. Similarly, up regulation will lead to dispatch of bids at the opposite side of the equilibrium. (source: DNV GL)

RR

Replacement reserves (RR) are slow-ramping units (typically 30-60 minutes) that are used to free up FRR resources in case of imbalances that take a long time to resolve (typically >2 hours). As RR is currently not implemented in the Netherlands, RR participation was not considered.

2.4.2.3 Other potential costs or benefits

The electrolyser could potentially also obtain revenues from other streams, such as payments received for providing grid support services. The report of Activity 3, Task 1 includes the analysis of the effect of the electrolyser on various key performance indicators (KPIs) on the grid-side that were identified and analysed for the purpose of the societal cost-benefit analysis:

- Flexibility
- Technical resilience (obtained from Activity 2)
- Security of supply
- RES integration (avoided curtailment)
- Variation in losses in the electricity network
- Avoided transmission upgrades (congestion support)
- Voltage support (following an analysis performed on contribution to local grid stability, Task 2)

- Reactive power support (following an analysis performed on contribution to local grid stability, Task 2)

The Activity 3, Task 1 report showed that for most of these KPIs the electrolyser has a positive impact compared to the system without electrolyser. However, these services are not unambiguously translatable into monetary terms and are therefore only included in a qualitative discussion on the obtained results from the business case analysis with only market-based revenues (day-ahead, H_2, aFRR and intraday) included.

Revenue streams from grid support are highly uncertain but could lead to a reduction in costs incurred by the electrolyser (e.g. a reduction of connection charges).

2.4.2.4 Overview of electrolyser markets

In summary, the following markets are considered for the business case of the electrolyser in the following chapters:

- the hydrogen market;
- the day-ahead market (DAM);
- the intra-day market (buy/sell) (ID+, ID-); and,
- the aFRR market (up/down).

Several operational algorithms are defined that reflect the operation of the electrolyser under various combinations of the above markets. A dispatch algorithm is formulated to optimise the electrolyser operation in the different markets based on the chosen algorithm. The following chapter details the full extent of the business case analysis methodology developed for the electrolyser.

3 BUSINESS CASE ANALYSIS METHODOLOGY

After introducing the various markets where the electrolyser could operate in, this chapter focusses on the methodology developed to analyse the business case of the electrolyser. First, an overview of the model is given to then provide more detail regarding:

- the selected operational strategies,
- the market data required for the analysis,
- the dispatch schedule optimiser and assumptions,
- the benefits and costs considered for the business case, and lastly,
- the various scenarios and cases that were analysed.

3.1 Model setup (input, output, components)

The goal of this section is to provide an overview of the modelling approach developed to quantify the business case of the electrolyser under various defined scenarios and operational strategies. This methodology will be employed to analyse the economic and strategic operation of the electrolyser. Figure 3-1 provides an overview of the different steps in the business case analysis of the electrolyser.

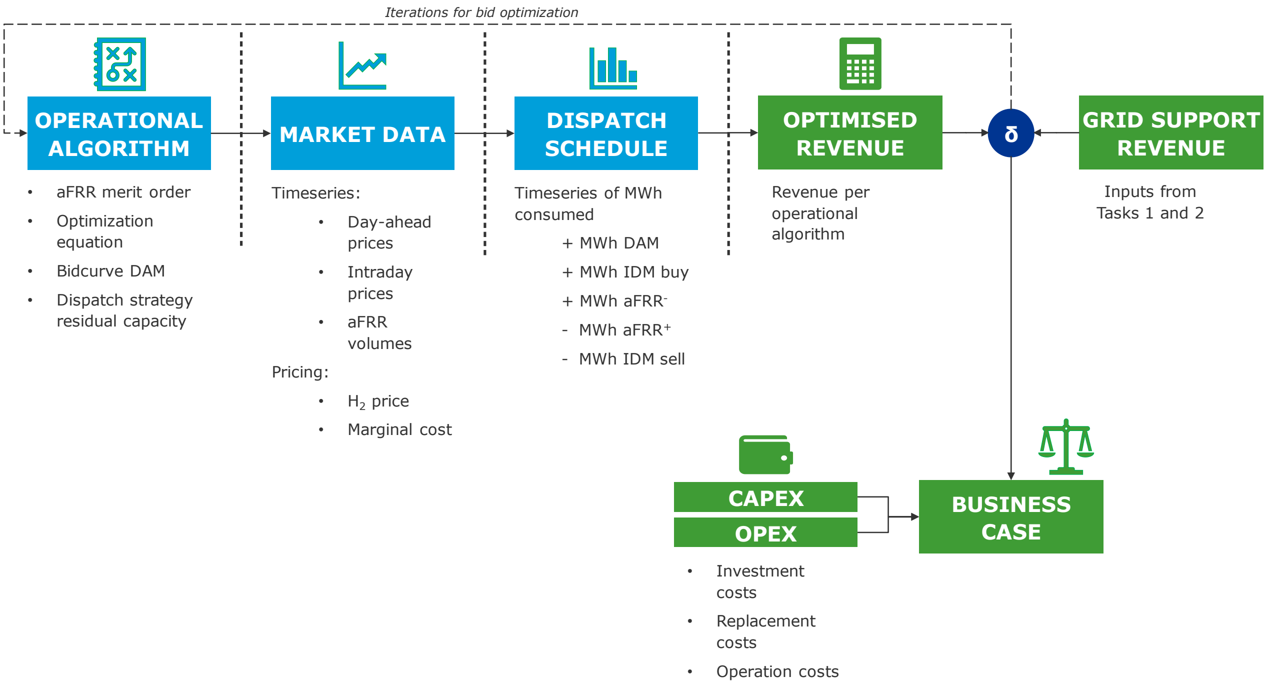


Figure 3-1: Optimisation and economic modelling scheme for the electrolyser. (source: DNV GL)

The electrolyser can operate under various operational algorithms. The selected **operational algorithm** determines the volume constraints for operating the electrolyser in the selected markets. To optimise the economic dispatch of the electrolyser, input data needs to be obtained regarding the volume and price time series for the selected **markets**. Next, the **dispatch schedule** of the electrolyser is optimised to maximise revenues following the selected operational algorithm.

The dispatch strategy results in a time series of energy purchased or sold by the electrolyser in the different markets, as well as produced hydrogen. This results in a yearly **revenue** of the electrolyser for each selected operational algorithm. The obtained revenue could be complemented through potential remuneration through contributions of the electrolyser to **grid support**.

Next to the revenue side, both **capital (CAPEX) and operational (OPEX) expenditures** related to the investment, construction, connection and operation of the electrolyser are required to perform the **cost benefit analysis**. The next sections provide more detail regarding each of these steps.

3.2 Operational strategies

Due to its flexibility in operation, the electrolyser can trade on multiple different markets and various combinations of markets. This is determined by the chosen operational algorithm. In order to determine the maximum optimised revenue that can be obtained, and to account for different circumstances, a number of potential operational strategies was investigated.

For each of these strategies, the day-ahead market is the starting point of the dispatch optimiser. The operational algorithm determines the different markets considered in the optimisation process as well as any volume constraints for operating in these markets. Algorithm 1 starts with baseload operation, focussing on the day-ahead electricity and hydrogen markets only. Further strategies add trading on additional markets, which may increase revenues but also operational complexity. All bidding curves are step functions set to the activation price (the equivalent electricity price below which hydrogen production becomes economically viable, in line with the marginal cost of the electrolyser).

1. **Maximising day-ahead value**: bidding at 300 MW based on on-off operation (step function) at the activation price
2. **Day-ahead bidding (1) with utilisation of residual capacity on a single market**
   a) Residual capacity used on ID market
   b) Residual capacity used for aFRR
3. **Day-ahead bidding (1) with hybrid utilisation of residual capacity on two markets**
   a) Residual capacity split between ID and aFRR: 50-50%
   b) Residual capacity split between ID and aFRR: 75-25%
   c) Residual capacity split between ID and aFRR: 25-75%

For each operational algorithm, the hourly operation of the electrolyser is subsequently optimised. The model developed to optimise the dispatch schedule of the electrolyser (see section 3.4), designed in Excel (217 kB), uses price and volume data from the different markets (see section 3.3).

3.3 Market data

For the optimisation of the economic dispatch of the electrolyser, input data is required from the day-ahead market, the intraday market and the aFRR market. The next three sections describe how the volume and price time series for the selected markets have been obtained.

3.3.1 Day-ahead

Day-ahead price forecasts have been developed for the years 2030 and 2040 under various energy market development scenarios. Four scenarios of market development have been defined under Activity 3, Task 1[16]: conservative, reference, progressive and progressive+. The basic assumptions of the four scenarios are largely based on the ENTSO-E TYNDP 2018 scenarios[17] and complemented with considerations of the latest national political decisions and plans, including coal phase-outs, which are expected to have a substantial impact on the energy mix in the Netherlands and the two neighbouring countries affecting the Eemshaven area, i.e. Denmark and Germany. Full details of the scenario assumptions and parameters are included in the report from Activity 3, Task 1 "*Cost-Benefit Analysis (CBA) Modelling – P2G project's value to society*".

The day-ahead power price forecast has been performed with a European power **market model** built by DNV GL in the PLEXOS®[18] tool. The market model includes:

- DNV GL's European power market model is a fundamental market model that simulates the day-ahead spot price by optimising unit commitment and economic dispatch of the electricity generation in various interconnected European countries. The optimisation is based on the minimisation of the total generation costs of the system: the cheapest generation is used first. A perfect competition situation is simulated for the European power system within an energy-only market. An overview of the (main) inputs required for this optimisation is shown in Appendix I: Market model (Figure 2). The optimisation is performed with an hourly time resolution for several focus years.
- The model contains detailed representations of the electricity generation, transmission and demand for most European countries, divided in core and non-core countries, see Appendix I: Market model (Figure 1). Power plants (> 50 MW) in the core countries are modelled on an individual basis with detailed techno-economic characteristics. For example: flexibility parameters, such as ramp rates and minimum stable level, heat rate curves, maintenance availability parameters, variable operation & maintenance and start costs are included. For the Nordics and South-East Europe (non-core countries), the generation capacities are aggregated by technology-fuel categories. Each country (bidding zone) is modelled as a single node with power plants and a demand profile, without any internal grid constraints ("copper plate"). Market exchanges between countries (bidding zones) are limited based on net-transfer-capacities (NTC).
- The modelling covers the central-western Europe region and the different bidding zones, with focus on the Central Western European (CWE) system: the Netherlands and neighbouring countries (Germany, Belgium, France, Great Britain and Denmark). More specifically, this model is a regional model that looks at each market as a whole (no internal network).

More detailed information on the market model can be found in Appendix I: Market model and in the report of Activity 3, Task 1. The results of the market model simulations are **hourly time series of day-ahead prices for 2030 and 2040 for the four different scenarios**. Table 3.1 summarises the yearly time-weighted average price in the day-ahead market for 2030 and 2040 under the different scenarios obtained through the European power market model.

[16] See Report Activity 3, Task 1

[17] https://tyndp.entsoe.eu/tyndp2018/

[18] Energy Exemplar, PLEXOS® Integrated Energy Model, 2017. (PLEXOS, 2017).

Table 3.1: Yearly time-weighted average day-ahead electricity prices [€/MWh] for 2030 and 2040 for the analysed scenarios. (source: DNV GL European power market model)

	Conservative	Reference	Progressive	Progressive+
2030	54.3	81.2	62.5	58.7
2040	58.2	46.2	69.4	61.5

3.3.2 Intraday

Intraday hourly price and volume time series have been established based on historical data. As no historical intraday data is available for the Netherlands, both intraday and day-ahead data from Germany from 2017 was used from EPEX Spot[19]. The price profile was created using the following steps:

1. The 2017 intraday data from Germany was converted from quarterly to hourly by taking the price of the first PTU of each hour, in order to match with the day-ahead timescale while preserving volatility;
2. An hourly price difference profile was created by taking the difference between the 2017 day-ahead and intraday prices from Germany;
3. The normalised difference profile was applied to the forecasted day-ahead price profiles by the market model (see section 3.3.1) to create intraday hourly profiles for 2030 and 2040 for the four different market scenarios for the Netherlands.

Based on the above methodology, the yearly average intraday prices are similar to the day-ahead prices. As volume profile, the 2017 volume data obtained from Germany were used (preserving the correlation between volume and price). This volume series was then scaled based on the volume ratio between the Dutch and German markets in 2017. It was possible to combine data from different countries, as no correlation could be found between day-ahead and intraday volumes.

Due to the high uncertainty regarding the development of intraday volumes in the future, no growth in the intraday market volume was assumed at this point for 2030 and 2040. The effect of potential growth of this market is addressed in the sensitivity analysis (see section 4.2).

3.3.3 aFRR

aFRR prices and volumes were determined by making use of a randomised stochastic profile, based on historical aFRR data from the Netherlands[20]. The probability of a certain aFRR volume occurring for either upward or downward regulation, equation (3.1), is determined per 15 minutes, $\boldsymbol{t_i}$, for each month, k, using historical quarter-hourly data from January 2015 until 13 July 2018.

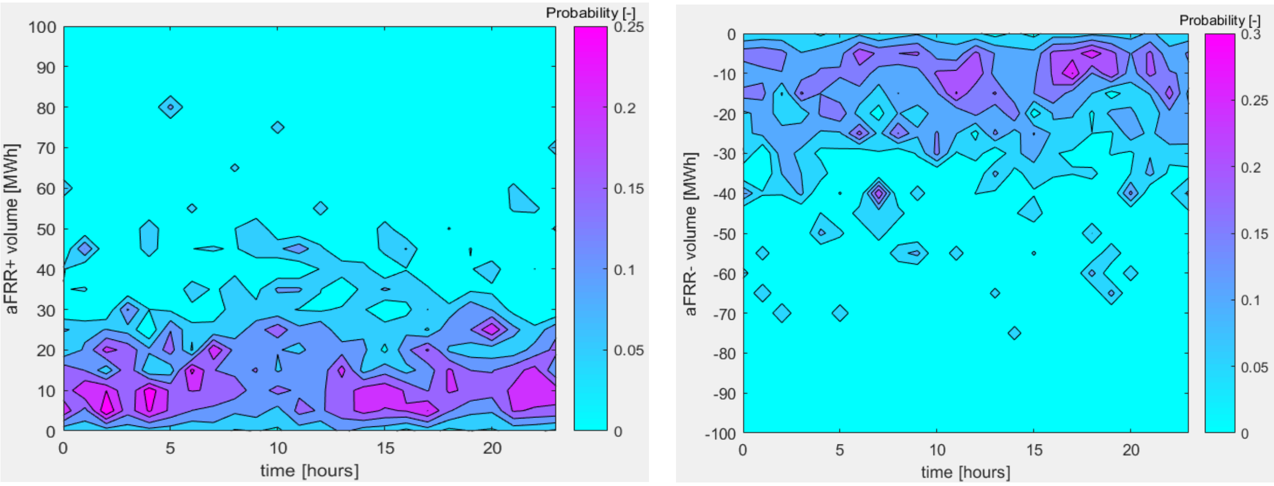
$$\boldsymbol{Prob_k(E_{FRR,j};\, t_i) = \frac{N_{E_{FRR,n}}(t_i)}{\sum_{n=0}^{21} N_{E_{FRR,n}}(t_i)}} \qquad (3.1)$$

Where E_{FRR}, is the required energy dispatched in the aFRR market per PTU, n the specific volume range, from 0 until 100 divided into (n) 21 blocks of 5 MWh. aFRR volumes are counted (N) if occurring in a certain price block for a certain time (hour and month). Then, this sum of counted values in this price

[19] EPEX SPOT (https://www.epexspot.com/en/)

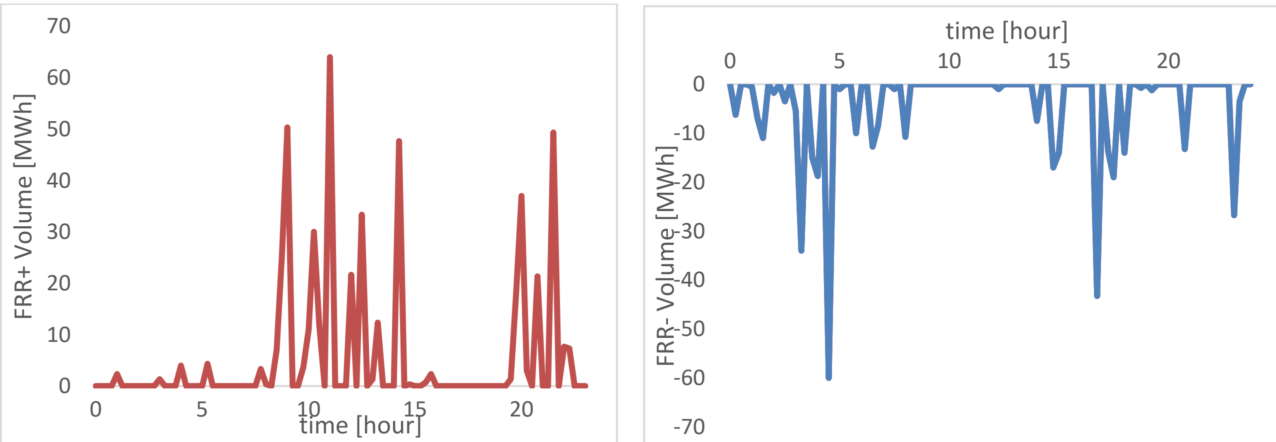
[20] https://transparency.entsoe.eu/balancing/r2/activationAndActivatedBalancingReserves/show?name=&defaultValue=false&viewType=TABLE&areaType=MBA&atch=false&dateTime.dateTime=01.01.2017+00:00|CET|DAYTIMERANGE&dateTime.endDateTime=01.01.2017+00:00|CET|DAYTIMERANGE&reserveType.values=A96&marketArea.values=CTY|10YNL----------L!MBA|10YNL----------L&dateTime.timezone=CET_CEST&dateTime.timezone_input=CET+(UTC+1)+/+CEST+(UTC+2)

block is divided by the counted sum of all aFRR volume values for all the blocks in that specific time, to determine the probability for a certain FRR volume to occur in a certain hour. An example of this stochastic profile is given in Figure 3-2. From this probability map, a profile can be extracted for a day, an example is presented in Figure 3-3. Then, for example for the month April, 30 daily profiles are extracted, representing each a day in the month. In a similar way, other profiles are extracted for the remaining months and their corresponding days. Resulting in a quarter-hourly dataset for 365 days, functioning as a basis for the aFRR volume curve in the model.



(a) *(b)*

Figure 3-2: Probability heat map of FRR upward (a) and downward (b) regulation in the Netherlands for an average day in April based on historical quarter-hourly data from January 2015 until 13 July 2018[20].



(a) *(b)*

Figure 3-3: Example of an extracted daily profile of FRR upward (a) and downward (b) regulation in the Netherlands for an average day in April. (source: DNV GL based on historical data from ENTSO-E[20])

A cross-check has been performed to ensure that the extracted time series corresponds with “average” values without extremes. These historical values and model average values are shown in Table 3.2.

Table 3.2: aFRR price and volume cross-check.

Market	Unit	Historical average	Reference model average
aFRR+ volume	MWh	6.67	6.78
aFRR+ price (zero values excluded)	€/MWh	70.46	71.41
aFRR- volume	MWh	7.32	6.78
aFRR- price (zero values excluded)	€/MWh	14.21	14.84

After designing the aFRR volume series, accompanied aFRR prices curves are constructed through an economic dispatch (ED) model developed for this purpose specifically. This report assumes that aFRR market participants bid at their short run marginal cost (SRMC) as bidding price. For each market development scenario, the market participants and their characteristics change in line with the scenario assumptions. The outcomes of the ED were calibrated until realistic average prices were obtained, without the electrolyser considered. The yearly average from the obtained price time series was then additionally validated with historical data of the aFRR average prices between 2015 and 2018.

Besides the bid price validation, the total required imbalance volume was calibrated and validated based on the need for balancing in 2018, which is 1000 and 1020 MWh[21], for the aFRR+ and aFRR-, respectively. More information on the SRMC of the different participants and the electrolyser can be found in Appendix II: SRMC of the electrolyser in the aFRR market.

Due to the high uncertainty regarding the development of aFRR volumes and prices in the future, no growth or increase was assumed for the reference scenario for 2030 and 2040. The effect of potential growth of this market is addressed in the sensitivity analysis (see section 4.2).

3.4 Dispatch schedule optimiser

The cost-benefit analysis in this report focusses on the optimisation model to maximise profit for the electrolyser operator across the selected markets. Market operating costs include purchases of electricity in the DAM, IDM and for ancillary services provision (aFRR). However, by selling produced hydrogen, or selling previously purchased DAM electricity on the ID and aFRR markets, revenues can be gained. Therefore, all potential market operating revenues are described as benefits, despite the correction for electricity purchasing costs, and used in the optimisation model described through equation (3.2).

$$\begin{aligned}\max \sum_{t=1}^{n} & \overbrace{\mathbf{E_{DAM,t}} * \left(\eta_{ELY} * \lambda_{H_2} - \lambda_{F,DAM,t}\right)}^{\text{DAM- CCT}} + \overbrace{\mathbf{E^{down}_{aFRR,t}} * \left(\eta_{ELY} * \lambda_{H_2} - \lambda^{down}_{F,aFRR,t}\right)}^{\text{aFRR-AS+CCT}} \\ & + \overbrace{\mathbf{E^{buy}_{IDM,t}} * \left(\eta_{ELY} * \lambda_{H_2} - \lambda^{buy}_{F,IDM,t}\right)}^{\text{IDM-CCT}} + \overbrace{\mathbf{E^{up}_{aFRR,t}} * \lambda^{up}_{aFRR,t}}^{\text{aFRR-AS \& ARB}} + \overbrace{\mathbf{E^{sell}_{IDM,t}} * \lambda^{sell}_{IDM,t}}^{\text{IDM-ARB}}\end{aligned} \quad (3.2)$$

Where E_t [MWh] stands for the dispatched energy volume in real-time in PTU t, η_{ELY} [kg/MWh] the efficiency of the electrolyser system including compressor efficiency, $\lambda_{F,t}$ [€/MWh] the market fuel price including taxes (electricity tax, tax for renewable energy use ("opslag duurzame energie" or ODE) and grid tariff) in PTU t, and λ_{H_2}[€/kg] the hydrogen price in the market.

[21] https://www.tennet.eu/fileadmin/user_upload/Company/News/Dutch/2017/Notitie_FRR_2018_V1.0.pdf

The term ‘fuel price’ refers to the commodity consumed (electricity) and its accompanied taxes, ODE tariff 3.1 €/MWh and electricity taxes 0.58 €/MWh[22]. The optimisation of equation (3.2) is executed quarter-hourly (t) and summed over a year (n=35,040).

The volume agreed on the DAM allocated after DAM clearing, 24 hours before real-time ($V_{DAM,t}^{GTC}$) can differ from the energy dispatched in real-time ($\mathrm{E}_{\mathrm{DAM}}, t$), since trading can occur both intraday and leading up to real-time. The energy dispatched in real-time, bought on the DAM, therefore needs to be corrected for any sold volumes on the ID and aFRR markets, as described through equation (3.3):

$$\mathrm{E}_{\mathrm{DAM,t}} = V_{DAM,t}^{GTC} - \mathrm{E}_{\mathrm{aFRR,t}}^{\mathrm{up}} - \mathrm{E}_{\mathrm{IDM,t}}^{\mathrm{sell}} \quad (3.3)$$

3.4.1 Market operation

The red parts above equation (3.2) define the market and the type of optimised revenue, respectively. Each part is explained in their respective sections below.

3.4.1.1 Day-ahead market (DAM) – Cross commodity trading (CCT)

Revenue can be gained by purchasing electricity in the day-ahead market ($\mathrm{E}_{\mathrm{DAM}}, t$) at the electricity market price ($\lambda_{\mathrm{F,DAM,t}}$) and selling producing hydrogen at the corresponding hydrogen price in the market ($\eta_{\mathrm{ELY}} * \lambda_{\mathrm{H_2}}$). This is also referred to as *cross commodity trading* (CCT) by purchasing electricity and selling produced hydrogen. The revenue is then created through purchasing electricity at a price ($\lambda_{\mathrm{F,DAM,t}}$) including taxes, below the ‘activation price’. The latter reflects the marginal cost of producing hydrogen at a hydrogen price in the market ($\eta_{\mathrm{ELY}} * \lambda_{\mathrm{H_2}}$). The activation price is described in more detail in section 3.4.2. However, this DAM purchased volume can still be sold in the intraday or aFRR markets ($\mathrm{E}_{\mathrm{aFRR,t}}^{\mathrm{up}}, \mathrm{E}_{\mathrm{IDM,t}}^{\mathrm{sell}}$) between the closure of the day-ahead market and real-time. Corrections on the potential DAM-CCT revenue have therefore been included, see equation (3.3).

3.4.1.2 aFRR – Ancillary service (AS) and Cross commodity trading (CCT)

For downward regulation ($\mathrm{E}_{\mathrm{aFRR,t}}^{\mathrm{down}}$), the electrolyser consumes electricity in order to balance a system with surplus of electricity, see section 3.3.3. This extra electricity consumption at the aFRR down price ($\lambda_{\mathrm{F,aFRR,t}}^{\mathrm{down}}$) can be used to produce additional hydrogen supplementary to the day-ahead market production. This leads to similar benefits as for the DAM cross commodity trading, because the electrolyser converts the electricity into hydrogen that can be sold in the hydrogen market.

3.4.1.3 Intraday market (IDM) – Cross commodity trading (CCT)

The last option for the electrolyser to purchase electricity in order to gain revenue from the produced hydrogen is in the intraday market ($\mathrm{E}_{\mathrm{IDM,t}}^{\mathrm{buy}}$). If, closer to real-time, prices in this market ($\lambda_{\mathrm{F,IDM,t}}^{\mathrm{buy}}$) are sufficiently low, purchases of electricity is beneficial. The plant operator can then gain revenue due to cross commodity trading.

3.4.1.4 aFRR – Ancillary services (AS) and arbitrage (ARB)

Besides hydrogen production to gain revenues, the electrolyser can also consume less energy than allocated after DA market clearing, to balance the system in case of an electricity shortage. This is purchasing electricity to sell electricity again on a different market closer to or during real-time. For this revenue stream, DAM purchases are required ($V_{DAM,t}^{GTC}$) in order to offer reduction in electricity consumption ($\mathrm{E}_{\mathrm{aFRR,t}}^{\mathrm{up}}$), because without DAM purchases the electrolyser cannot offer to reduce its consumption. This strategy only generates revenue if the price for the purchased electricity on the DAM price is lower than what it can be sold for on the aFRR market. The difference between these two, times

[22] https://www.rijksoverheid.nl/onderwerpen/milieubelastingen/energiebelasting

the sold volume, reflects the revenue gained. The DAM revenue has therefore also been corrected for this reduction in volume in equation (3.3).

3.4.1.5 IDM – Arbitrage (ARB)

The last benefit for electricity market participation, considered in this report, is arbitrage by purchasing electricity day-ahead to sell this electricity again in the IDM ($\mathrm{E}_{\mathrm{IDM},t}^{\mathrm{sell}}$) at the price in the IDM ($\lambda_{\mathrm{IDM},t}^{\mathrm{sell}}$). Again, similar requirements for arbitrage in the aFRR apply for IDM arbitrage. Previously purchased electricity on the DAM can be sold in the IDM. This strategy only generates revenue if the price for the purchased electricity on the DAM price is lower than what it can be sold for on the IDM. The difference between these two, times the sold volume is the revenue gained. The DAM revenue has therefore also been corrected for this reduction in volume in equation (3.3).

3.4.2 Bidding strategy

The bidding strategy of the electrolyser will determine what available revenue streams, as expressed in equation (3.2), will be 'activated' in assessment case. A bidding strategy of the electrolyser regarding the purchased volumes, bold symbols in equation (3.2), determines its energy profile and its hydrogen production, while taking into account the time constraints of the gate time closure of different markets. First, the gate time closure of the DAM approaches at 24 hours before real time (RT), $V_{DAM,t}^{GTC}$. At this point, the electrolyser plant operator can decide to optimise the bidding volumes in the four markets (DAM, IDM, FRR+ and FRR-) for the next day. However, the uncertainty to predict expected revenue on the IDM and FRR market at 24 hours before real-time, makes it difficult to optimise the bidding strategy, see Figure 3-4.

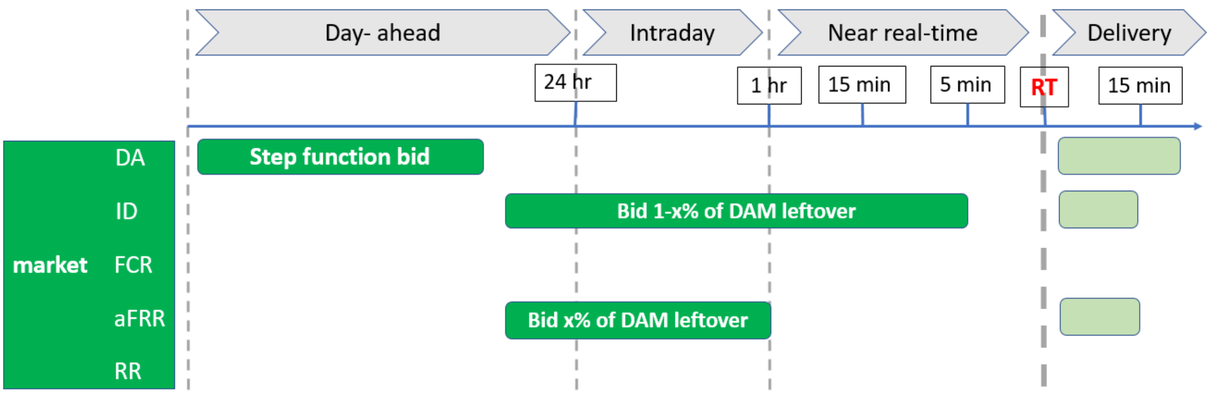


Figure 3-4: Schematic overview of the electrolyser bidding strategy time horizon. (source: DNV GL)

Therefore, the electrolyser plant operator first bids on the **DAM** ($V_{DAM,t}^{GTC}$), because of the gate time closure and the large electrolyser volume available to be dispatched. Price and volume bidding in the DAM follow a step-function curve, as visualised in the blue line in Figure 3-5. By means of this step function bid curve in the DAM, the electrolyser bids its maximum volume for prices below the activation price, $\lambda_{\mathrm{activation}}$, indicated through the red dot in Figure 3-5. This is the price for which the revenue from hydrogen production reaches break-even compared to its electricity fuel cost. From this price onward, the bid volume will be zero.

The revenue, B_{CCT} , of producing hydrogen per electricity activation price and hydrogen price, i.e. cross commodity trading (CCT), can be calculated according:

$$B_{CCT} = \eta_{ELY} * \lambda_{H_2} - \lambda_{electricity} - \text{taxes} \tag{3.4}$$

$\lambda_{electricity}$ [€/MWh] refers to the price of electricity in either the DAM, IDM or aFRR market. Solving for the break-even electricity price results in the following activation price:

$$\lambda_{activation} = \eta_{ELY} * \lambda_{H_2} - \text{taxes} \tag{3.5}$$

After the DAM Gate-time-closure (GTC), the market clearing price and volumes are determined. Until the next GTCs of the other markets, the electrolyser can, per PTU, buy additional power, expressed as an orange arrow in Figure 3-5, or sell this previously bought DAM power, expressed as a green arrow in Figure 3-5. Any capacity which will not be activated day-ahead can then still be used on the IDM and aFRR market. The division between aFRR (x%) and IDM (1-x%) in percentage for the leftover (non-cleared) volume after DA market clearing, is part of the operational strategy, as discussed in section 3.2. The electrolyser time horizon bidding strategy is shown in Figure 3-4.

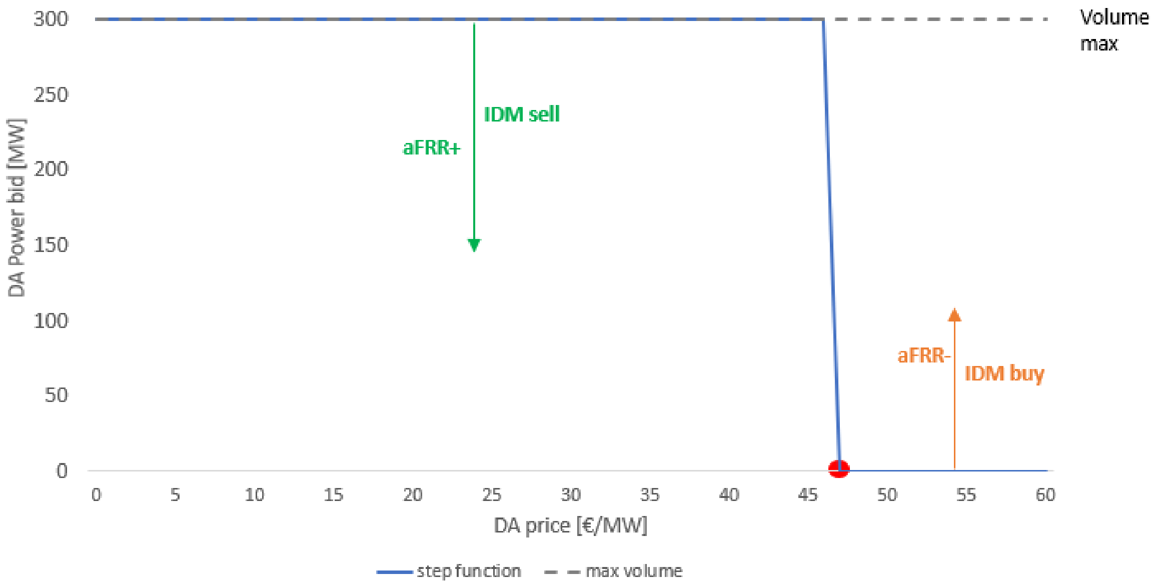


Figure 3-5: Step function day-ahead bid curve for price (x-axis) and volume (y-axis) and potential to also engage in the ID and aFRR markets. (Source: DNV GL)

The 1-x% leftover volume reserved for the IDM can be bid until 5 minutes before real-time. Total aFRR reserved volume, which is x% of the DAM leftover volume, is bid all at once before its GTC. Preferably, the plant owner should in practice be more flexible to anticipate more accurate analysis closer to real-time and bid accordingly. However, this possible improvement is not investigated in this report.

3.4.2.1 Decision tree

The decision tree in Figure 3-6 visualises a stepwise bidding decision strategy in the different electricity markets and combines both the time constraints and bidding strategy.

In the upper part of Figure 3-6, above the blue horizontal line, the step function decision is made (diamond shaped block) purely based on DAM prices. Two hours after GTC of the DAM the other markets are open for bidding, as indicated by the rest of the figure under the striped blue horizontal line that reflects the buying and selling 'leftover' options.

Buying options are positioned on the left-hand side under the horizontal striped grey line and are applicable when the maximum power of the electrolyser is not fully dispatched on the DAM. Selling previously bought DAM power options, located on the lower right-hand side, are suited when the dispatched volume on the DAM is greater than zero. The columns at the bottom of Figure 3-6 are an illustration of the indicative amount of power available for different markets after different decisions made and actions taken (green oval blocks).

The bids to sell electricity purchased on the DAM on the IDM and aFRR market depend on the price in those markets. Revenues to sell the leftover power should be greater than the revenue for the same amount of energy bought on the DAM. In these cases, it is beneficial to sell the already purchased electricity. Various electricity markets result in different bid and volume prices. **Table 3.3** summarises these bidding approaches per electricity market.

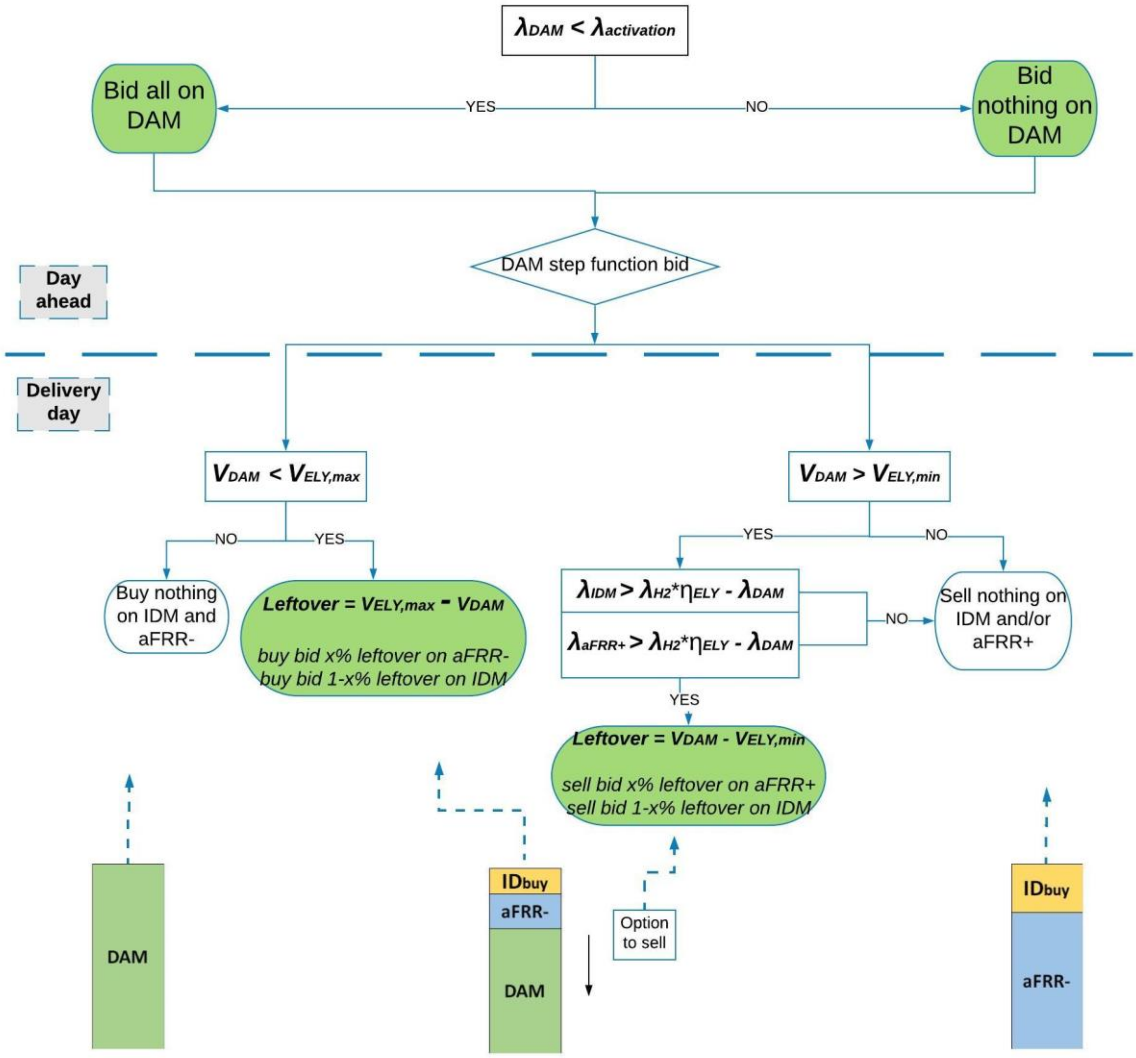


Figure 3-6: A stepwise volume bidding strategy decision tree for the electrolyser, acting in the different electricity markets[23]

[23] Note that the dispatched volumes are represented by the symbol E, while the GTC bid volumes in the decision tree are given by the symbol V. λ = price; η_{ELY} = electrolyser efficiency

Table 3.3: Overview of electrolyser price and volume bid approach per market

Market	Bid price	Bid price equation	Bid volume
DA	Activation price	$\lambda_{\text{activation}}$	Maximum or zero
ID buy	Activation price	$\lambda_{\text{activation}}$	1-x% of DAM leftover to buy
aFRR-	SRMC[24] buy	$\eta_{\text{ELY}} * \lambda_{H_2,t}$	x% of DAM leftover to buy
ID sell	SRMC[23] sell	$\eta_{\text{ELY}} * \lambda_{H_2,t} - \lambda_{\text{F,DAM}}$	1-x% of DAM leftover to sell
aFRR+	SRMC[23] sell	$\eta_{\text{ELY}} * \lambda_{H_2,t} - \lambda_{\text{F,DAM}}$	x% of DAM leftover to sell

3.4.2.2 Assumptions

The following assumptions are considered regarding electricity market modelling, the future energy system and electrolyser operation in this report. An overview of these assumptions is given in Table 3.5.

Table 3.4: Assumptions used in this report.

Category	Assumptions
Market	Electrolyser has no price impact on DAM and IDM
Energy system	Perfect competition is modelled
Market	aFRR participants similar bids aFRR- and aFRR+
Energy system	No idle time of dispatch other energy generators in aFRR market
Energy system	Similar future electricity system structure as 2030 status
Market	Similar imbalance settlement aFRR market as current
Energy system	Hydrogen market size cap that increases over time
Energy system	Power flows no limiting factor
Operation	Hydrogen from electrolyser meets required quality
Energy system	Zuidwending storage location
Operation	PEM efficiency development occurs towards 68% in 2030
Operation	Input water freely accessed from North Sea
Market	Only DAM, IDM and aFRR markets considered
Market	IDM prices follow marginal price scheme
Market	The electrolyser can at most provide 10% of the IDM volume per PTU (i.e. trade limitation up to 300MW)
Market	No DAM volume limitations for the electrolyser (up to 300 MW)
Market	Within one PTU electrolyser can provide upward and downward aFRR bids
Operation	Years in between 2030 and 2040 similar electricity market prices and volumes curves as 2030
Energy system	Sufficient hydrogen distribution infrastructure is available
Energy system	Interpolated both hydrogen price and demand between 2030 - 2040

$V_{\text{ELY,max}}$ = maximal volume of the electrolyser, i.e. 300 MW
$V_{\text{ELY,min}}$ = minimum volume of electrolyser, i.e. 0 MW

[24] SRMC refer to the short run marginal cost of the electrolyser, which differ per market since it is a large consumer of electricity.

Energy market operation

Although the 300 MW installation is relatively large, it is assumed that the electrolyser has no impact on the price in the DAM and IDM. Thereby, the electrolyser only behaves strategically in the aFRR market while assuming other energy entities to bid according to their marginal cost, i.e. perfect competition. Furthermore, these participating entities bid similar volumes in both upward and downward regulation during each quarter-hour of the year. Thus, for the economic dispatch in the aFRR market in this report it is assumed that generators have no idle time periods.

The organisational structure of the electricity system is considered to be similar to the current situation, thereby, the imbalance settlement of the aFRR market, regulated by the TSO, does not change either. ENTSO-E is currently examining possible collaboration between European countries[25]. Such an initiative could impact the imbalance settlement and procurement. However, this international cooperation is currently not considered in this report.

Hydrogen and electrolysis

Produced hydrogen is assumed to meet the required quality for end-use applications, both from the salt cavern as from the compressor. Although plans for building salt caverns are already made, it is assumed in this report that the Zuidwending location only allocates hydrogen from the analysed electrolyser.

The operation of the electrolyser is capped by the hydrogen demand in the market in the respective years, see section 2.3.1. This means that the electrolyser will produce hydrogen throughout the year as long as it can sell this hydrogen in the market (i.e. as long as there is demand for hydrogen and the maximum volume cap is not reached). Over the years, the hydrogen market size will increase, which will allow the electrolyser to produce more hydrogen as long as this can be done at electricity prices below the activation price. Table 3.5 summarises the employed hydrogen market volume caps employed in the dispatch model for 2030 and 2040 based on the analysis performed in Activity 3, Task 1. In between 2030 and 2040, this demand and also the hydrogen price are assumed to linearly increase.

The water used as input for the electrolyser can be freely accessed from the North Sea[26]. Anticipated development of the PEM electrolyser by various reports are assumed to occur, e.g. increasing efficiency towards 68%.

Table 3.5: Assumed hydrogen market sizes that put a cap on hydrogen production (and hence revenues) by the electrolyser.[27]

	2030	2040
Maximal hydrogen demand that can be supplied by the electrolyser [kton]	10.0	32.2[28]

Energy trading

Regarding electricity trading possibilities, this analysis only considers electricity trade in market exchanges, i.e. the DA, ID and aFRR markets. Difficulties to model the relatively recently established IDM result in the assumption that, despite the marginal price scheme, the electrolyser can pick up volumes during the day conform the market clearing price. In reality, prices picked up may differ from

25 https://www.entsoe.eu/network_codes/eb/

26 See report Activity 3, Task 1

27 Based on analysis in Activity 3, Task 1

28 In between 2030 and 2040, this demand is assumed to linearly increase

the average final price at GTC. Furthermore, unlimited volume trading in this market is unrealistic and therefore, it is assumed that the electrolyser can trade 10% of the IDM volume per PTU, up to its maximum volume of 300MW.

Next, the DAM historical liquidity shows large volumes. In this report, it is assumed that the DAM has no volume limitations for the electrolyser with a capacity of 300 MW. Regarding the aFRR market, the electrolyser can place bids for both upward and downward regulation within one PTU and even deliver in both directions if required. Finally, the hydrogen supply structure is assumed to be sufficiently established by 2030, in order to easily sell hydrogen to different end consumers.

Data time series

Price and volume curves for two years are modelled, i.e. 2030 and 2040, as detailed in section 3.3. The years in between 2030 and 2040 have the same electricity market price and volume curves as the modelled year 2030.

The years in between 2040 and 2050 have the same electricity market price and volume curves as the modelled year 2040. The hydrogen demand in these years is similar to the demand in 2040.

3.5 Benefits

The electrolyser can benefit from a variety of revenue streams as highlighted in section 3.4 and equation (3.2). This chapter summarises the benefits considered for the business case. The total operating revenue of the electrolyser is given in equation (3.6).

$$\text{Operational revenue} = \mathrm{B_{DA}} + \mathrm{B_{aFRR}^{down}} + \mathrm{B_{ID}^{buy}} + \mathrm{B_{aFRR}^{up}} + \mathrm{B_{ID}^{sell}} \quad [€] \tag{3.6}$$

In general, selling either electricity or hydrogen generates benefits for the plant operator. Figure 3-7 visualises the five different benefits as described in equation (3.6) for the three markets (top row). The blocks in the middle indicate the type of commodity that is bought (red) and sold (green), this latter generates revenue. Then at the bottom the type of benefit, described in section 3.4, is given in blue circles[29].

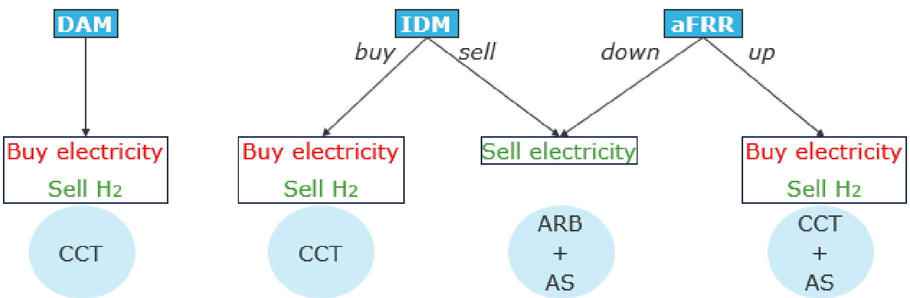


Figure 3-7: Benefit types for corresponding electricity markets. (Source: DNV GL)

3.5.1 Cross commodity trading

The first revenue stream ($\mathrm{B_{DA}}$, $\mathrm{B_{aFRR}^{up}}$, $\mathrm{B_{ID}^{buy}}$) is based on buying electricity, using this in the electrolyser to produce hydrogen and selling this in the hydrogen market. This form of CCT can be done in all three electricity markets. In both the DAM and IDM, the plant operator can bid volume and price with a chance to be dispatched. In the aFRR market, the plant operator can reserve a certain amount of capacity for

[29] Ancillary services (AS) in third circle of Figure 3-7 only refer to the aFRR market and not the IDM.

downward regulation. For the electrolyser this means that, if dispatched, it consumes energy and thus produces hydrogen which can be sold.

3.5.2 Arbitrage

Besides selling the produced hydrogen from the DAM cleared volume, another option exists to gain revenue. The purchased electricity DAM can be sold directly on the IDM. This is referred to as arbitrage. This case purely focusses on financial revenue, instead of producing hydrogen. Arbitrage occurs by purchasing electricity on the DAM and selling on either the IDM or the aFRR market. For participating in this aFRR market, the electrolyser provides capacity when the system is long, to consume less than planned after the DAM clearing, and thus offer electricity to the TSO for balancing purposes.

3.5.3 Ancillary services

The electrolyser can provide ancillary services by reserving capacity for both upward and downward regulation. Downward regulation benefits are described at 3.5.1, while upward regulation benefits are discussed in 3.5.2. Besides gaining revenue from either selling hydrogen or offering electricity, aFRR participation enhances the power system stability. Therefore, the plant operator receives more beneficial prices compared to the prices on the DAM.

3.5.4 Other revenues

Besides revenues from the hydrogen sales and trade on the electricity markets, other revenues might be collected by the electrolyser based on benefits for the power system. The societal cost-benefit analysis (SCBA) executed in Task 1 of the TSO2020 project revealed that the electrolyser is expected to reduce renewable energy source (RES) curtailment, grid losses and the congestion level in the electricity network in most of the investigated scenarios (Conservative, Reference, Progressive and Progressive+). Whether these benefits can contribute to the business case depends on whether these benefits will lead to extra revenues. The question to be answered is: could the owner of the electrolyser make money out of the mentioned benefits? The following sections will look at each potential benefit in more detail.

3.5.4.1 RES curtailment and congestion

There are two reasons for RES curtailment: network constraints and market constraints. It is the task of a network company to avoid network constraints. If operation of an electrolyser reduces network constraints, the network company might want to reward the owner of the electrolyser. If there is proof that the operation of the electrolyser leads to avoided investment in the network, a reduction of the network tariff may be considered (see also section 3.6). The results of Task 1 only show avoided investment in one of the scenarios in 2030 (15 million Euro in the Reference scenario). For 2040, higher benefits are expected for all scenarios, but no calculations were made due to the focus on 2030 for the grid modelling activities. The reduction of the network tariff is considered in one of the sensitivity cases in this report (see section 4.3).

Only network constraints are expected to provide potential benefits to the electrolyser operator. Market curtailment happens during a surplus of renewable production when prices are zero or low enough for the electrolyser to already run at full capacity.

3.5.4.2 Network losses

Reduction of network losses is a direct benefit for the transmission and/or distribution company. These companies buy electricity, to compensate for these losses, on the market at wholesale prices. There is no mechanism yet to remunerate flexibility providers for this benefit. Nevertheless, since Task 2 of

Activity 3 shows that the operation of the electrolyser could lead to reduced losses in the network[30] for which the electrolyser could be rewarded.

3.6 Costs

After determining the benefits, the various costs related to the investment and operation of the electrolyser are examined that are to be included in the techno-economic analysis. Three cost components are investigated:

- CAPEX: Capital Expenditures; the initial investment costs
- OPEX: Operational Expenditures; recurring costs
- Marginal costs of producing hydrogen

Whereas the CAPEX and OPEX determine the total system costs that will need to be recovered by the revenues of the electrolyser, the marginal costs will determine the break-even price level for the production of hydrogen and therefore the amount that can be earned in the sales per kg of hydrogen. For CAPEX and OPEX the different components and assumptions will be outlined in the subsequent sections. The marginal cost was included in the dispatch optimisation and detailed in section 3.4.

3.6.1 CAPEX

In literature, four cost components are usually distinguished that make up the electrolyser CAPEX (see also **Figure 3-8**):

- The electrolyser stacks;
- Balance of plant: Auxiliary equipment necessary for operations (e.g. MV/LV transformers, rectifiers, heating & cooling);
- EPC: Engineering, procurement & construction. Everything that is related to construction of the plant, including the design, rental of machinery and payment of the construction workers; and
- Site costs: Land lease and electrical infrastructure (from MV/LV transformers to the connection to the high voltage grid).

[30] Source: Circe, report Activity 3, Task 2.

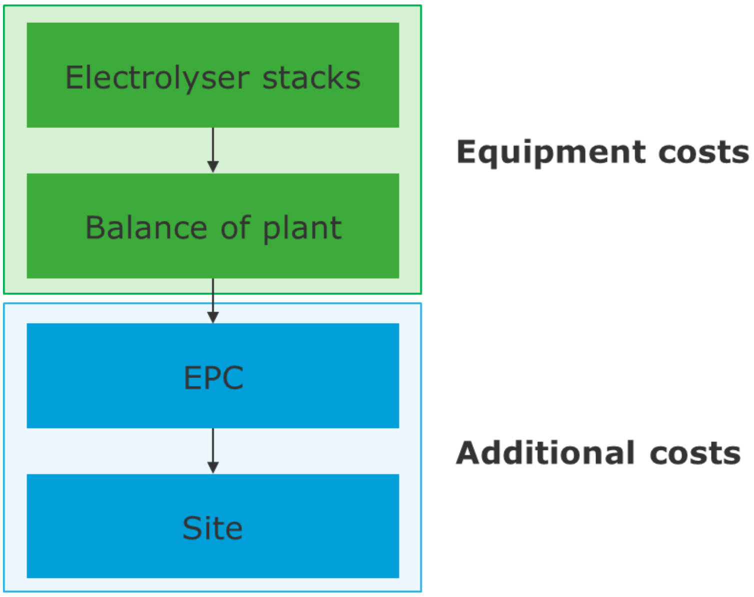


Figure 3-8: Main cost components of the electrolyser installation. (source: DNV GL)

In the societal CBA performed in Task 1 of Activity 3 of this project, the first two of these components were investigated under the banner *equipment costs*. For a 300 MW electrolyser, the equipment costs were estimated at 400 €/kW in 2030. As the societal cost-benefit analysis does not include EPC or site costs, a 20% mark-up was estimated, bringing the assumed equipment costs to 480 €/kW. However, there is still a large degree of uncertainty with regard to the final cost in 2030. Some sources estimate that learning curves could lead to equipment costs as low as 200 €/kW (50% lower)[31]. Similarly, it is also possible that a price drop to 400 €/kW will not be achievable either, and that future costs will be significantly higher. As such, a CAPEX range +/- 50% will be utilised as part of the sensitivity analysis (see sections 3.7 and 4.3). Table 3.6 summarises the different CAPEX parameters considered for the business case of the electrolyser system.

Table 3.6: CAPEX parameters electrolyser system[32]

Cost component	Value	Unit
Equipment costs	400	€/kW
Other costs (20%)	80	€/kW
Desalinator costs	52,000	€/m^3/h
Storage costs	8.4	€/kg
Compressor (65 bar)	490	€/kg/h
Compressor (180 bar)	600	€/kg/h

[31] Asset (2018). *Technology pathways in decarbonization scenarios*.
URL: https://ec.europa.eu/energy/sites/ener/files/documents/2018_06_27_technology_pathways_-_finalreportmain2.pdf
[32] See report Activity 3, Task 1

Figure 3-9 gives an example of the CAPEX division of the different components described above. As can be seen, equipment cost is the main component of the CAPEX. Furthermore, other costs and storage costs account together for approximately one-third of the CAPEX.

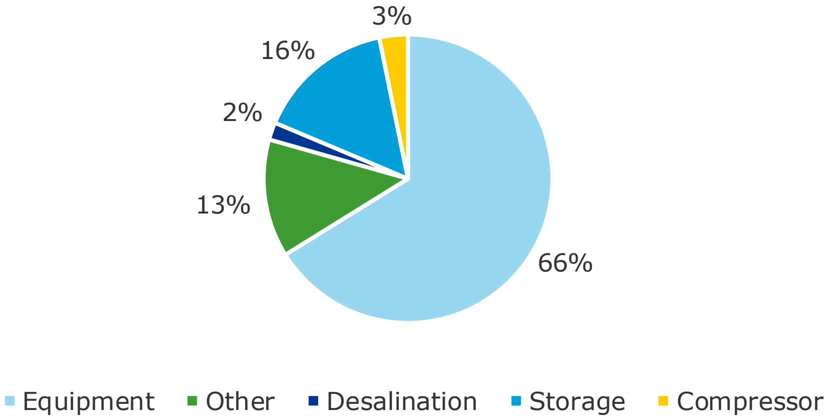


Figure 3-9: CAPEX division among different components. (source: DNV GL)

3.6.2 OPEX

OPEX costs are necessary for operating and maintaining the different technical components of the system, as well as the site as a whole. Some of these costs are fixed, while others are variable and dependent on either throughput or operational hours. Due to the large investments required, money can be borrowed from both investors and financial institutions in the form of a loan. section 3.7 discuss the loan repayment in more detail. OPEX were assumed for:

- Electrolyser operations & maintenance of the electrolyser (fixed)
- Desalinator operations (fixed and variable)
- Hydrogen storage costs (variable)
- Other costs (staff, site maintenance)

Whereas operation and maintenance (O&M) costs for the electrolyser are independent of operation, the desalinator maintenance costs will be dependent on the throughput. Similarly, costs per kg of hydrogen are assumed to determine the O&M costs of the storage to account for losses.

The OPEX parameters of the electrolyser system used in the cost-benefit analysis are shown in Table 3.7. Figure 3-10 gives an example of the OPEX division of the different components described above. Interestingly, the electricity tariffs account for 76% of the total OPEX each year. Next to this, the compressor cost has some impact on the yearly payments, while the other OPEX components are relatively insignificant compared to the electricity tariff.

Table 3.7: OPEX parameters electrolyser system[32]

Cost component	Value	Unit
Electrolyser O&M	2% of CAPEX	€/kW/y
Other costs	2% of CAPEX	€/kW/y
Desalinator maintenance	3% of CAPEX	€/m³/h/y

Hydrogen storage costs	3% of CAPEX	€/kg/y
Gas tariff[33] [entry, exit]	2.19 / 0.57	€/kWh/h/y
Electricity transport tariff	27,120	€/MW/y
Electricity capacity tariff	21,720	€/MW/yr
Electricity connection tariff	2,000	€/MW/yr

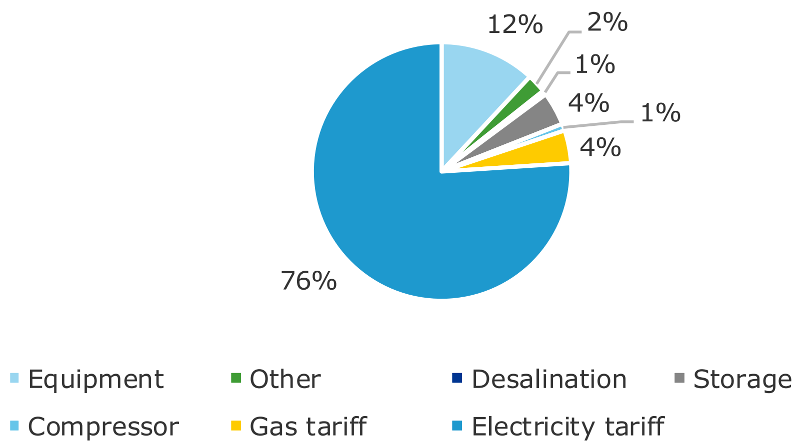


Figure 3-10: OPEX division among different components. (source: DNV GL)

3.7 Assumptions financial analysis

This report analyses an electrolyser system for 20 years, starting from 2030. Another important cost component is the stack replacement cost. It is assumed that after 60,000 operation hours, the efficiency of the stack is too low for beneficial operation and replacement is required with a cost of 200 €/kW[32].

Project financing related assumptions are the weighted average capital cost (WACC) and the loan repayment. For this analysis, it is assumed that the WACC is 4%[32] and the amount of money borrowed from institutions is 30% of the CAPEX with a loan interest rate of 8% over a 10-year period.

Tax payments for purchasing electricity in different electricity markets are described in section 3.4. The values for these financial assumptions are summarised in Table 3.8. Using these parameters together with the CAPEX, OPEX and optimised revenue values, the annual NPV is calculated.

Table 3.8: Overview of the assumed values for the financial parameters.

Financial assumptions	Values
Time scope [years]	20
Degradation rate electrolyser stack [%/1,000 operating hours]	-0.2
Stack replacement [operating hours]	60,000
Stack replacement costs [€/kW]	200

[33] https://www.gasunietransportservices.nl/en/shippers/terms-and-conditions/tsc

WACC [%]	4
Loan repayment period [years]	10
Loan repayment [% CAPEX]	30
Loan interest rate [%]	8
Electricity operation tax[22] [€/MWh]	0.58
ODE[22] [€/MWh]	3.1

3.8 Scenarios / cases

The business case of the electrolyser will be investigated for both a basic analysis and a sensitivity analysis as detailed in the following sections.

3.8.1 Basic analysis

The business case of the electrolyser is analysed with the dispatch optimiser for various scenarios and cases. Each identified bidding strategy (i.e. the operational strategies as described in section 3.2) is analysed for each scenario of energy system development (i.e. Conservative, Reference, Progressive and Progressive+) to evaluate the robustness of the business case for each selected operational strategy under uncertain developments of the energy system for 2030 and 2040. Each "case" represents the analysis of one operational strategy under one energy system development scenario. With six analysed operational strategies (1, 2a, 2b, 3a, 3b, 3c) and four scenarios (i.e. Conservative, Reference, Progressive and Progressive+), this results in the analysis of 24 cases in the base analysis. The parameter assumptions are the "reference" values in Table 3.9. This base analysis allows to identify the most promising operational strategy for the electrolyser under the adopted assumptions and analysed scenarios. The results of this base analysis are described in section 4.1.

3.8.2 Sensitivity analysis

Next to the basic analysis of the business case under different operational strategies and scenarios of market development, it is important to see what the impact is on the business case from the adopted assumptions regarding market developments and cost parameters. This has been analysed through a thorough sensitivity analysis. The results of the sensitivity analysis are described in sections 4.2 and 4.3 respectively.

3.8.2.1 Market variations

The market variations that have been investigated for the different energy system scenarios (conservative, reference, progressive, progressive+) for the most promising operational strategy are:

- doubling of the required volume on the intra-day market (ID double volume),
- doubling of the required volume on the aFRR market (aFRR double volume) and
- doubling of the required volumes on both the intraday and aFRR markets (ID & aFRR double volume).

In addition, the impact on the business case under the most promising operational algorithm has been investigated for a doubling of the hydrogen market size in 2030 and 2040. This reduces the risk of overproduction of hydrogen compared to the hydrogen demand in the market.

3.8.2.2 Parameter variations

Variations in the assumptions of cost parameters have also been performed to identify their impact on the business case of the electrolyser. The reference and minimum and maximum values for the analysed parameters are summarised in Table 3.9. Note that the electricity market prices are not included in the sensitivity analysis as these are varied as part of the energy market scenarios (Conservative, Reference, Progressive and Progressive+).

Table 3.9: Input values for parameter sensitivity analysis

Parameter	Unit	Reference[34] value	Value min[35]	Value max[36]
CAPEX equipment	€/kW	400	600	200
OPEX equipment	% CAPEX	2	3	1
Transport tariff	€/MWh	27,120	40,680	13,560
ELY system efficiency	kWh/kg	49.0	53.9	44.1
WACC	%	4	6	2
Contract capacity tariff	€/MW/y	21,720	32,580	10,860
Storage cost	€/kg	8.0	12.6	4.2
H_2 price	€/kg	3.3 – 4.4[37]	1.90	6.45

4 RESULTS & SENSITIVITY

The results of the basic analysis (analysis with basic assumptions as highlighted in section 3.8.1) are discussed in section 4.1. Sensitivity calculations have been performed for market circumstances (see section 4.2) and for technology parameters (see section 4.3), as described in section 3.8.2.

4.1 Results basic analysis

Calculations of the business case of the electrolyser have been made using the dispatch optimiser with the basic assumptions for the six bidding strategies described in section 3.2, each under all four scenarios. The scenarios are not based on the performance of the electrolyser but based on assumptions of the development of generation mix and demand in the European energy system, where the progressive scenario has more electrification and renewable generation than the conservative scenario. The Net Present Values (NPVs) for each of these twenty-four combinations are shown in Table 4.1.

Table 4.1: NPV of basic analysis for six operational strategies and four scenarios in million €. (source: DNV GL)

Bid strategy \ Scenario	Conservative	Reference	Progressive	Progressive+
1 Maximise DAM	-14.9	-224.9	-72.7	6.0
2a Residual for ID	30.7	-187.2	-32.2	42.4
2b Residual for aFRR	-62.5	-247.2	-113.6	-40.4
3a Residual for ID&FRR 50%-50%	26.4	-177.0	-26.9	41.9
3b Residual for ID&FRR 75%-25%	53.1	-155.5	-6.9	62.7
3c Residual for ID&FRR 25%-75%	1.0	-200.5	-50.6	17.0

34 Report Activity 3, Task 1
35 DNV GL, generally -50% from reference values
36 DNV GL, generally +50% from reference values
37 Depending on scenario and modelling year.

The NPV after 20 years is negative for 15 of the 24 combinations. The darkest green values are the most positive and the darkest red values are the most negative. The best results are reached for the Conservative and Progressive+ scenarios regardless of bid strategy. This is due to the interaction between the average day-ahead prices and hydrogen market sizes and their evolution from 2030 to 2040.

In 2030, the hydrogen demand in the market is relatively low, limiting the dispatch of the electrolyser. However, for the Conservative and Progressive+ scenario the average electricity prices drop, and hydrogen demand is relatively large in 2040. This combination results in high optimised revenues for both scenarios. The Conservative scenario average DA price is the lowest (with st dev=18.9 €/MWh), however the hourly prices are less volatile compared to the Progressive+ scenario (st dev=32 €/MWh). More volatile prices result in more PTUs with lower electricity prices and thus higher optimised revenues.

From Table 4.1 it can be seen that for all scenarios, operational strategy 3b (day-ahead bidding with hybrid utilisation of the residual capacity split between ID and aFRR market based on 75%-25%) gives the best results. More detail on the results for strategy 3b is given in the following paragraphs. The volume dispatched by the electrolyser per electricity market for different scenarios and modelling years for strategy 3b is displayed in Figure 4-1.

First of all, the electrolyser trades more volumes in 2040 compared to 2030 for each scenario, due to the increased hydrogen demand. Most volume trading differences occur because of the obtained DAM price curves and the activation price resulting from the hydrogen price, see equation (3.5), since the electrolyser trades most volume in the DAM to sell hydrogen. The lower the DAM price and the higher the hydrogen price, the more trading occurs. Figure 4-2 shows the optimised revenue generated by the electrolyser per electricity market type for all four scenarios for 2030 and 2040 for bidding strategy 3b.

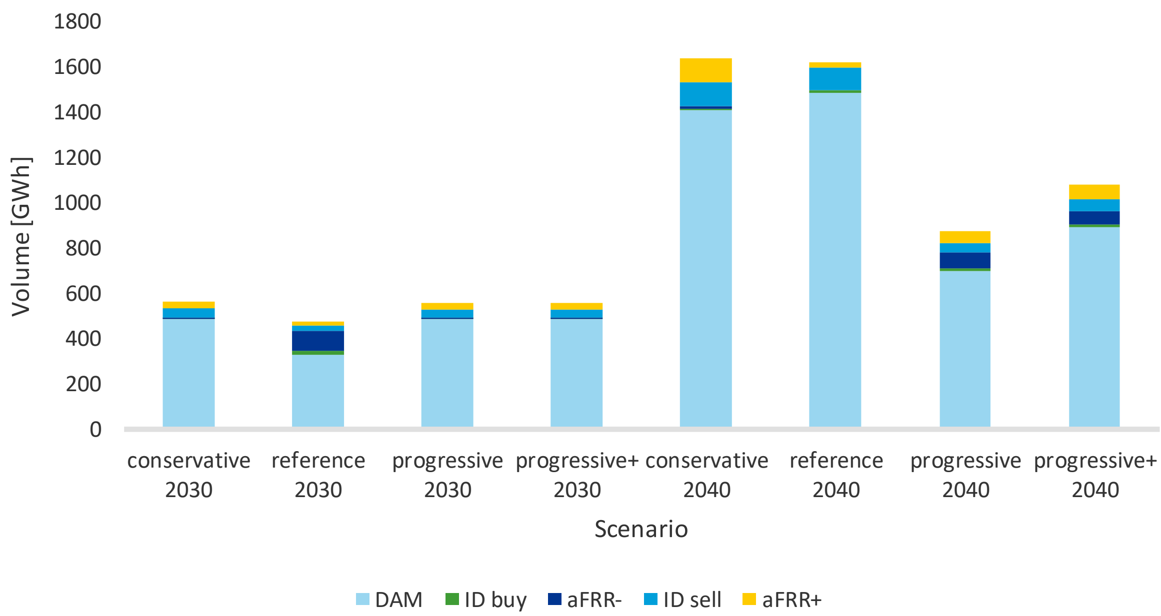


Figure 4-1: Volume dispatched by the electrolyser per electricity market for different scenarios and modelling years for operational strategy 3b. (source: DNV GL)

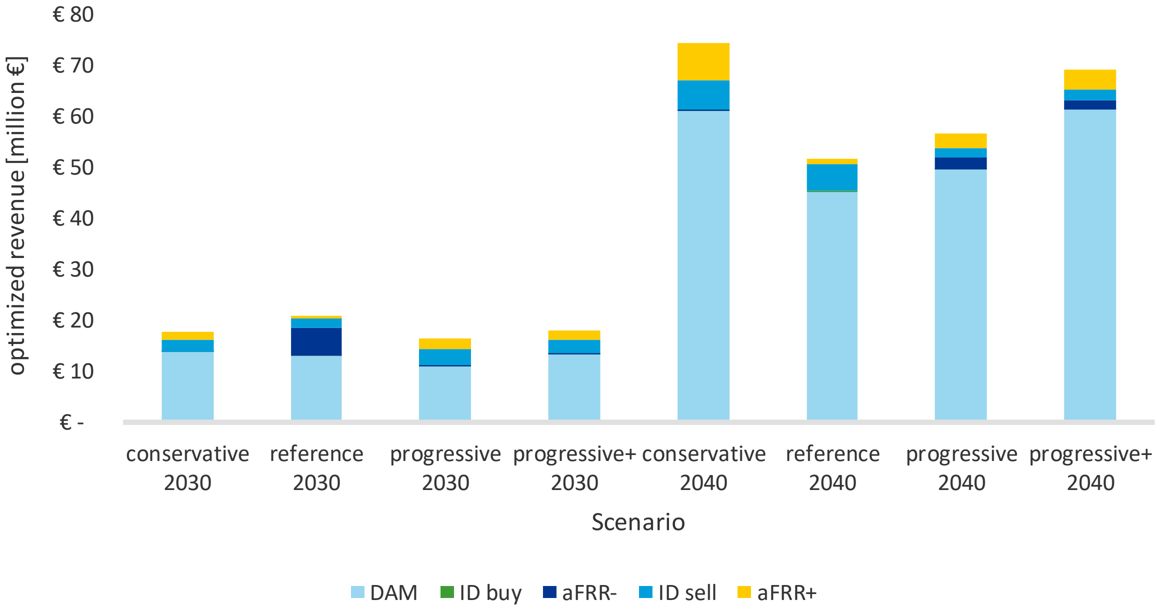


Figure 4-2: Optimised revenue generated by the electrolyser per electricity market type for different scenarios and modelling year for operational strategy 3b. (source: DNV GL)

Observations:

- In 2030, of all scenarios, the Reference scenario shows the lowest volume but also the highest revenues. This is mainly caused by a larger aFRR- revenue for reference compared to the other scenarios. In the Reference scenario, less DAM volume is bought due to relatively high prices in the day-ahead market, which leads to more opportunities to purchase electricity on the aFRR market. The bidding strategy used in this report requires to decide 24 hours before real-time to either purchase full capacity (300MW) or zero volume (step function) on the DAM. The results of the Reference scenario indicate that purchasing lower volumes on the DAM can be beneficial. The drawback of this method is that estimating aFRR volumes 24-hours upfront is challenging and difficult. Situations could occur that the plant operator decides not to purchase electricity in the DAM for a certain PTU (even below the activation price) in order to participate in the aFRR- market, but no aFRR volumes are required within this PTU. Therefore, using the step function in the DAM can be seen as a safer strategy.

- In 2040, the Progressive and Progressive+ scenarios show lower trading volumes than the other two scenarios in 2040. The optimised revenues, however, are higher because prices are more volatile (st dev = 35 and 32 €/MWh, compared to 18.7 (Reference) and 18.9 (Conservative) €/MWh). This in general gives more moments with low electricity prices that in turn lead to higher optimised revenues.

- The Reference scenario shows the lowest optimised revenue in 2040, despite of a high volumes. The relatively high volume is caused by the relatively low activation price, due to lower volatility and hydrogen price. Therefore, the revenues per volume are relatively low. The balance is an overall lower revenue.

The costs and optimised revenue with the accompanied net present values (NPV) for the best strategy (3b) and the four scenarios are visualised in Figure 4-3 until Figure 4-7. The costs and benefits are positioned along the zero axis to indicate a positive or negative value. The NPV (green line) is the obtained sum, discounted over the respectively years.

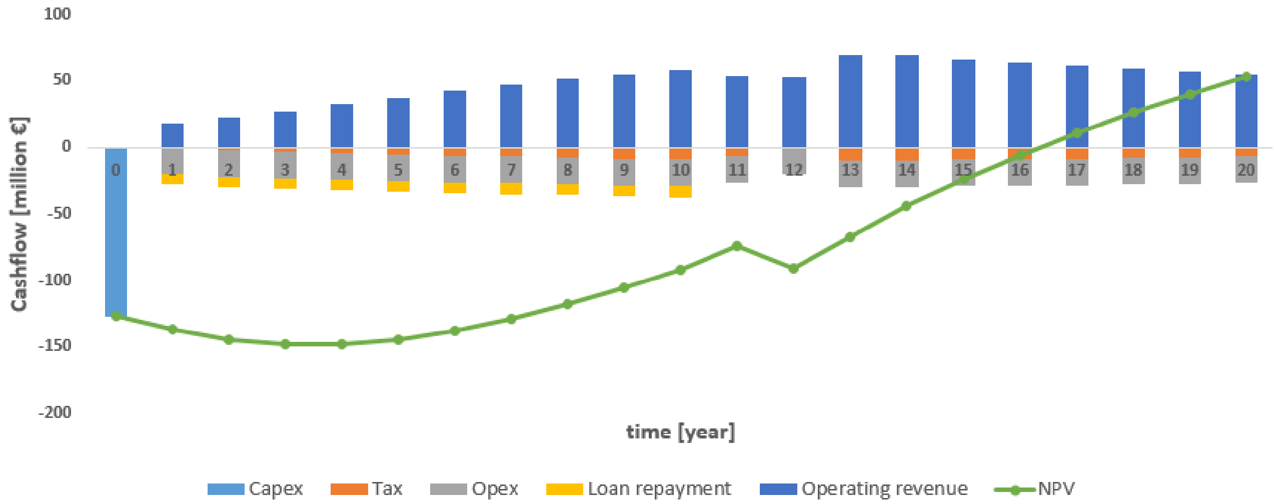


Figure 4-3: Yearly discounted cashflow for electrolyser operation – Conservative scenario, 3b. (source: DNV GL)

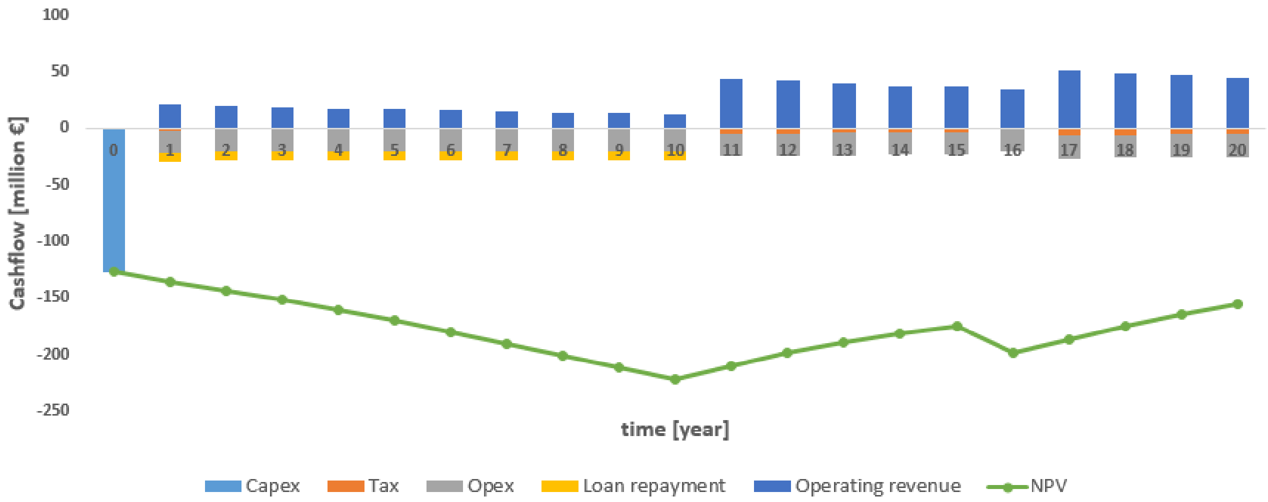


Figure 4-4: Yearly discounted cashflow for electrolyser operation – Reference scenario, 3b. (source: DNV GL)

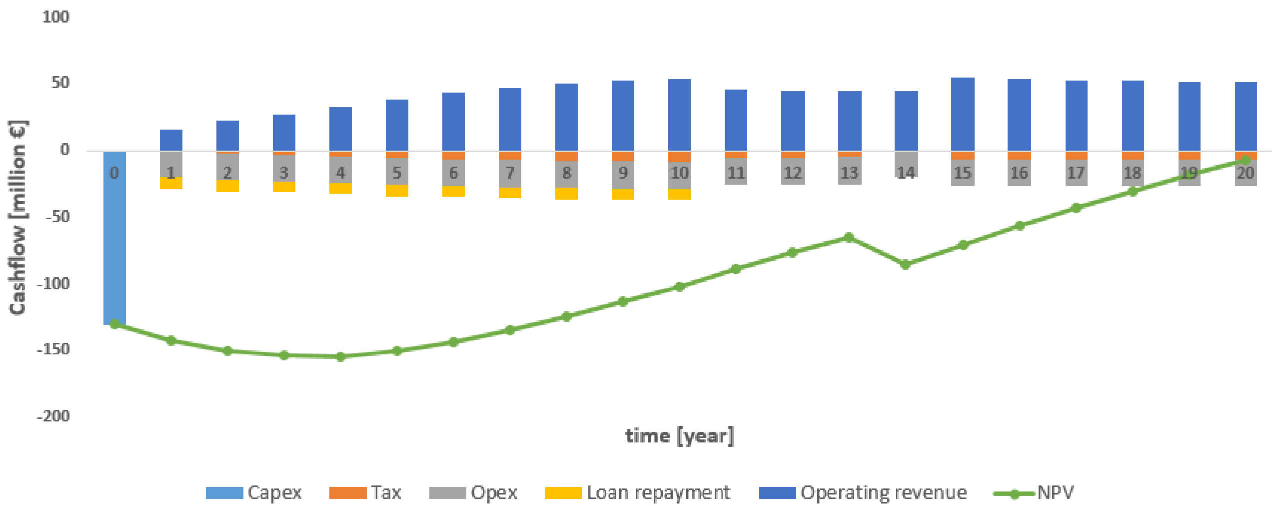


Figure 4-5: Yearly discounted cashflow for electrolyser operation – Progressive scenario, 3b. (source: DNV GL)

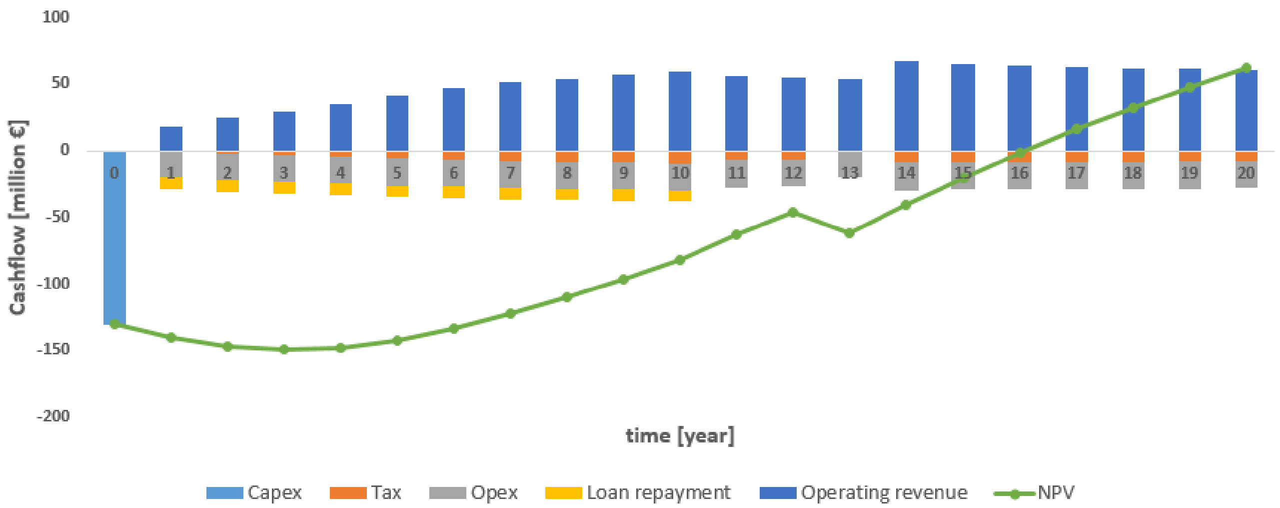


Figure 4-6: Yearly discounted cashflow for electrolyser operation – Progressive+ scenario, 3b. (source: DNV GL)

Figure 4-7 summarises the yearly NPV trend for all scenarios for strategy 3b.

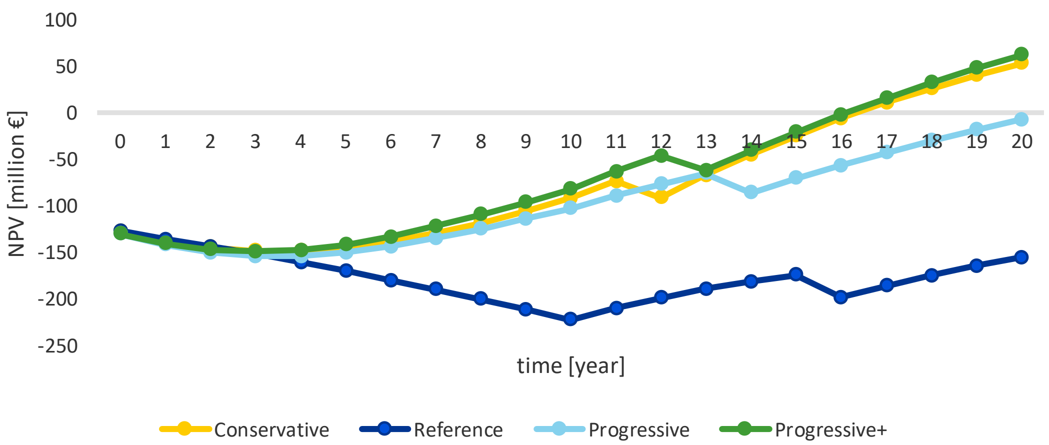


Figure 4-7: Overview of the annual NPV for the four scenarios, 3b. (Source: DNV GL)

Observations:

- For the optimum bidding strategy, the business case of the electrolyser is positive in the Conservative and the Progressive+ scenarios and negative in the other two scenarios, within the time frame of twenty years, in particular in the Reference scenario.
- The Reference scenario is the only scenario that has a negative cash flow in the first decade which leads to a lower NPV in year 10 than at the start of the project. In the Reference scenario there is no benefit from increasing hydrogen demand, since the electrolyser operates at its maximum DAM participation in 2030 already (given the high electricity prices), with equal costs and optimised revenue (both approximately 20 million €/year in 2030). Thereby, stack degradation and decreasing hydrogen prices lessens optimised revenues until year 2040 and therefore the NPV decreases. In the other scenarios, optimised revenues increase due to both the larger hydrogen demand and increasing price throughout year 2030 until 2040, due to increasing DAM participation for greater hydrogen demand as the electricity prices are lower and DAM participation can be increased with increasing hydrogen demand. The hydrogen demand and price increase namely linearly for all scenarios between 2030 and 2040 as discussed in section 3.4.2.2. This results in an increasing NPV since optimised revenues start outperforming the costs.
- Due to the low hydrogen price, in the second decade the annual cash flows in the Reference scenario are lower than the cash flows in the other scenarios, despite the favourable electricity price. Together with the previous observation, this leads to the most negative NPV for the Reference scenario.
- In all scenarios, the NPV curve has a dip for one year, because of the investment in stack replacement. For example, in the Progressive+ scenario this occurs in year 12.
- After the replacement of the stack, the optimised revenues increase compared to the year before, due to higher electrolyser efficiency.
- The Conservative and Progressive+ scenarios show steeper NPV curves (higher annual cash flows) after ten years compared to the Reference and Progressive scenarios. This is caused by relatively low DAM prices (due to more volatility), which lead to higher benefits (see also observations below Figure 4-2). Low DAM prices also occur in the Reference scenario, although low hydrogen prices decrease benefits compared to the Conservative and Progressive scenarios.
- The results of the Progressive and Progressive+ scenarios show the importance of the electricity purchase price on the DAM. The costs and aFRR composition in both scenarios are similar but in DA the price curves are different. In both 2030 and 2040, the Progressive+ scenario gives lower average DAM prices and therefore more revenue is generated by hydrogen production based on electricity purchase on the DAM resulting in better result.

4.2 Sensitivity: Market

As mentioned in section 3.7, the impact of four different market variations has been investigated and compared to the basic analysis. This analysis has been done for all four energy system scenarios for the most promising operational strategy from the basic analysis, namely bidding 75% of the DAM residual on the IDM and 25% on the aFRR market (bidding strategy 3b). The first three market variations concern doubling the required volume on the ID market, on the aFRR market and on both the ID and aFRR markets. In addition, the impact on the business case has been investigated for a doubling of the hydrogen market size. The results of this sensitivity analysis are shown in Table 4.2 for bidding strategy

3b for the four scenarios. Appendix III summarises the sensitivity results for all bidding strategies.

Table 4.2: Net present value in million € for market sensitivities for the most promising operational strategy (3b). (source: DNV GL)

Scenario \ Sensitivity market	Basic analysis	ID double volume	aFRR double volume	ID & aFRR double volume	Hydrogen double volume
Conservative	53.1	104.4	77.9	130.4	139.3
Reference	-155.5	-118.9	-130.2	-99.2	-155.5
Progressive	-6.9	52.6	23.4	71.2	80.0
Progressive+	62.7	118.5	91.5	137.3	167.5

Table 4.3: Payback time in years for market sensitivities for the most promising operational strategy (3b). (source: DNV GL)

Scenario \ Sensitivity market	Basic analysis	ID double volume	aFRR double volume	ID & aFRR double volume	Hydrogen double volume
Conservative	16	13	15	12	10
Reference	>20	>20	>20	>20	>20
Progressive	>20	17	18	15	13
Progressive+	16	13	14	11	10

Observations:

- Doubling the market volume of the intraday, aFRR and the hydrogen market leads in all cases to better results and, except for the Reference cases, to a positive NPV. A positive NPV after 20 years does, however, not directly mean that investing in an electrolyser in the northern Netherlands is attractive for a market party. This depends on the intentions of this party. Industrial parties often go for much shorter payback times.
- Doubling the hydrogen market has the largest positive influence on the business case results.
- The improvement of the NPV by doubling the ID market volume is about twice as high as the improvement of doubling the volume of the aFRR market in all four scenarios except for the Reference scenario. For this scenario the improvement is slightly less.

4.3 Sensitivity: Parameters

Uncertainty in the results occurs due to the difficulty to predict future values for the input parameters like the expected efficiency of the electrolyser in 2030. Assumptions regarding values assigned to parameters impact the outcomes. This section analyses the sensitivity for selected cost and benefit parameters on the NPVs obtained for strategy 3b for the four scenarios. The sensitivity ranges for the different varied parameters go from 50% lower to 50% higher values compared to the basic assumptions, except for the electrolyser efficiency (see also section 3.8.2.2). For the latter, a 10% lower and higher efficiency has been assumed. Table 4-4 summarises the reference values of the selected parameters together with their minimum and maximum values used for the sensitivity analysis.

Table 4-4: Assumptions for sensitivity cases with minimum and maximum values.

Parameter	Unit	Reference value	Minimum value	Maximum value
CAPEX equipment	€/kW	400	200	600
OPEX equipment	% CAPEX	2	1	3
ELY system efficiency	kWh/kg	49.0	44.1	53.9
WACC	%	4	2	6
Transport tariff	€/MW/y	27,120	13,560	40,680
Contract capacity tariff	€/MW/y	21,720	10,860	32,580
Storage cost	€/kg	8.00	4.20	12.60
H_2 price	€/kg	3.3 – 4.4	1.9	5.7

For each parameter value (reference, max, min) the NPV is calculated. This results in a Tornado diagram that provides insight into the impact on the NPV for variations per parameter. The parameters are then sorted from highest to lowest impact on the NPV. Note that for some of the parameters, a minimum value leads to a better NPV result and for the other parameters to worse NPV results. This also applies to the maximum values of the parameters. To show consistency and avoid confusion, in the Tornado diagrams the sensitivity values, as presented in Table 4-4, have been divided into values that have a positive and values that have a negative impact on the NPV results as indicated in Table 4-5. The NPV results of the sensitivity calculations are shown in Figure 4-8, Figure 4-9, Figure 4-10 and Figure 4-11 for the four scenarios for parameter variations in bid strategy 3b.

Table 4-5: Assumptions for sensitivity cases presented according to impact on NPV.

Parameter	Unit	Reference value	Value with negative impact	Value with positive impact
CAPEX equipment	€/kW	400	**600**	**200**
OPEX equipment	% CAPEX	2	**3**	**1**
ELY system efficiency	kWh/kg	49.0	44.1	53.9
WACC	%	4	**6**	**2**
Transport tariff	€/MW/y	27,120	**40,680**	**13,560**
Contract capacity tariff	€/MW/y	21,720	**32,580**	**10,860**
Storage cost	€/kg	8.00	**12.60**	**4.20**
H_2 price	€/kg	3.3 – 4.4	1.7	6.6

Observations:

- The price of hydrogen has by far the highest impact on the NPV in all scenarios. Payback time ranges from greater than 20 (Reference) years until 5 years (Progressive+). A 50% higher hydrogen price leads to a positive NPV after 20 years in the Reference scenario with a payback time of 12 years.
- The next largest influence on the results comes from the CAPEX of the equipment and the efficiency of the electrolyser. The influence is about equal in all scenarios. The first 10 operating years in the Reference scenario (see Figure 4-4) visualise the impact of the efficiency on the decreasing NPV.

- The influence of both components of the transmission tariff and the WACC is comparable, and considerably less than the influence of CAPEX and efficiency. The WACC has more influence for the scenarios with higher NPVs after 20 years.
- Reducing both electricity transport tariff and contracted capacity tariff by 50%, leads to 3-5 years shorter pay-back times. Rationale for this reduction may be the potential revenues for grid support services that the electrolyser could provide, as this may have positive societal value (see also section 3.5.4.).
- Storage cost and OPEX of equipment have the lowest impact on the NPV in all scenarios.

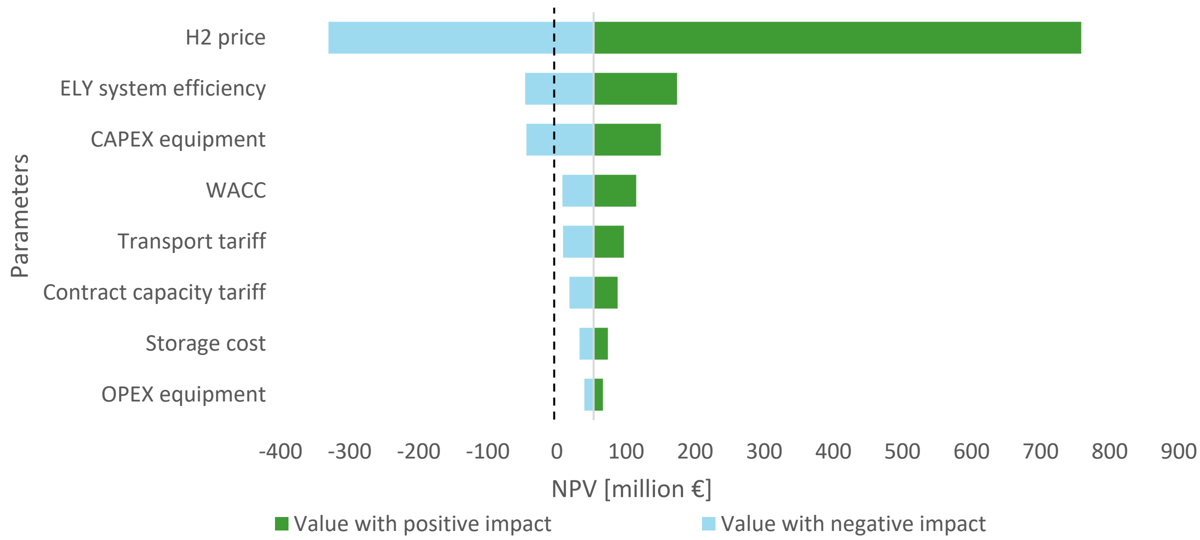


Figure 4-8: Sensitivity tornado - Conservative scenario, 3b. (source: DNV GL).

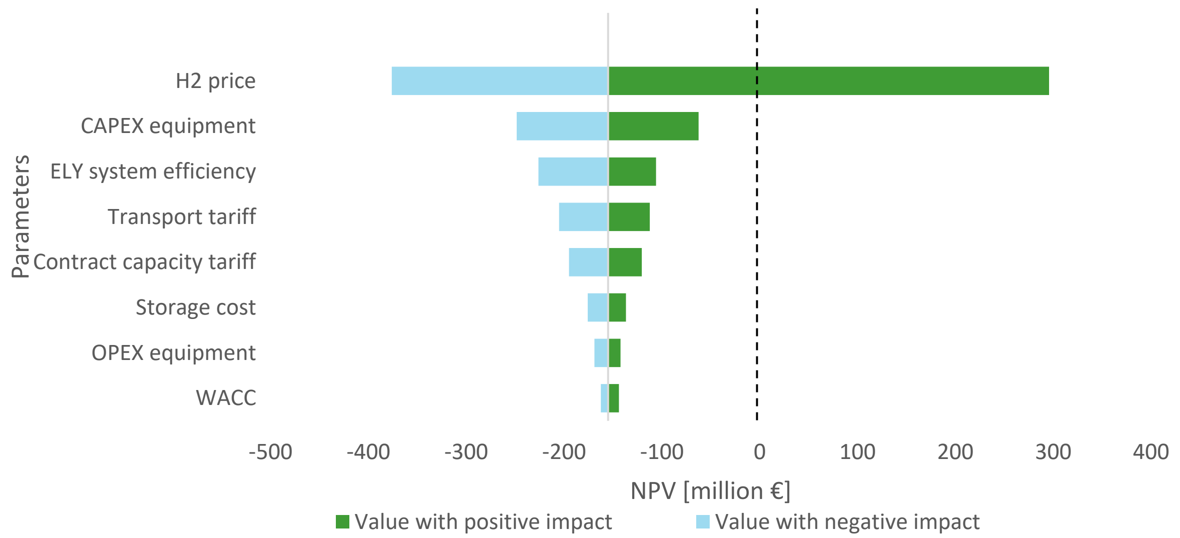


Figure 4-9: Sensitivity tornado - Reference scenario, 3b. (source: DNV GL).

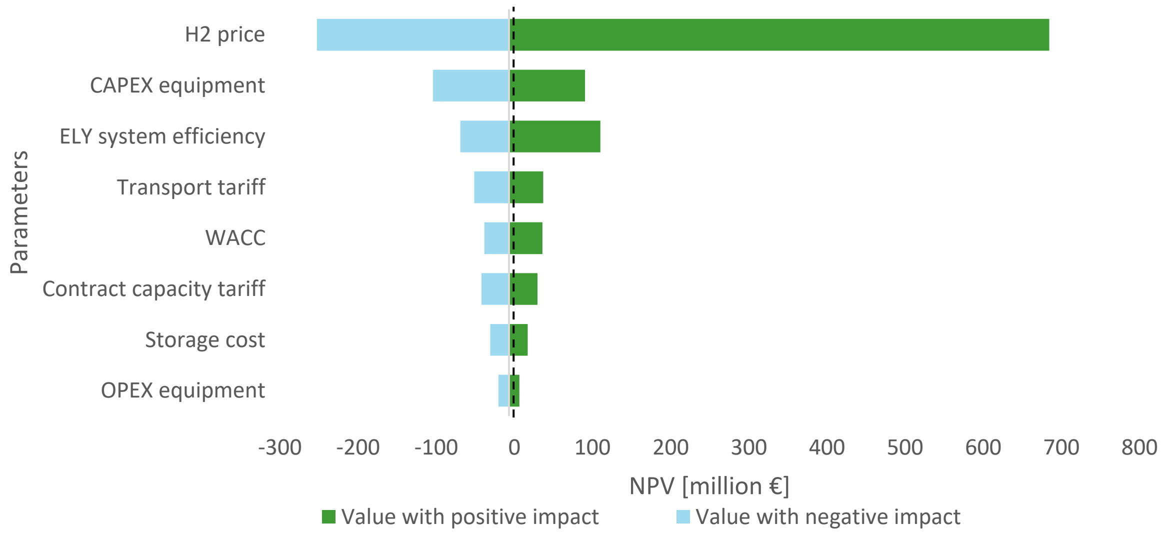


Figure 4-10: Sensitivity tornado - Progressive scenario, 3b. (source: DNV GL).

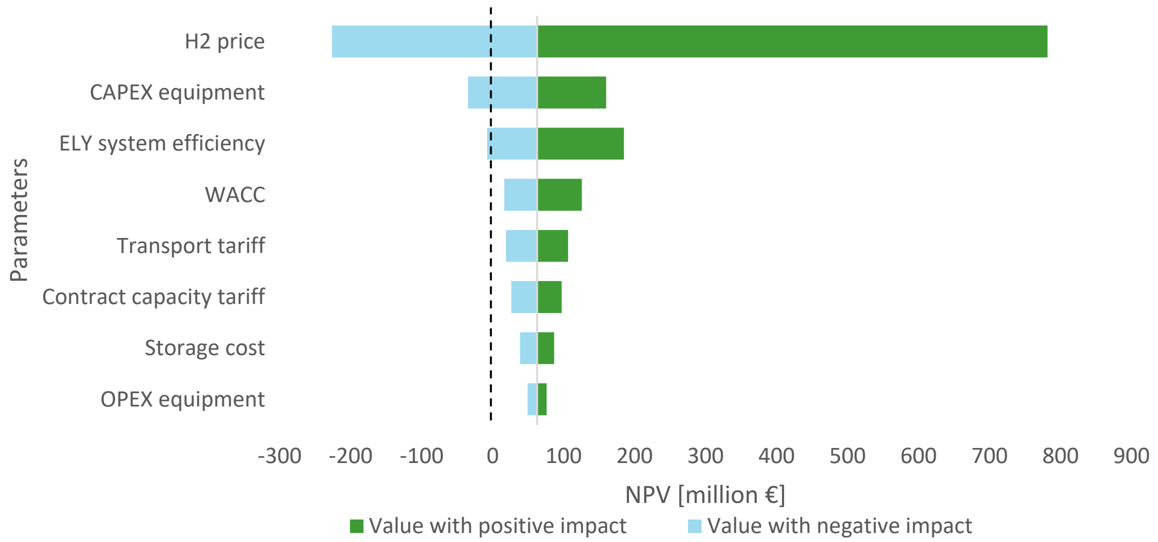


Figure 4-11: Sensitivity tornado - Progressive+ scenario, 3b. (source: DNV GL).

5 CONCLUSIONS

To analyse the business case of the electrolyser, first an investigation was conducted into the various markets where the electrolyser could operate in. The most interesting markets for the electrolyser are the hydrogen market, the day-ahead electricity market, the intra-day market and the aFRR market.

Operation in these markets was translated into six potential operational strategies for the electrolyser. Each operational strategy was analysed through a dispatch optimiser to maximise yearly revenues of the electrolyser under various scenarios of market developments (Reference, Conservative, Progressive and Progressive+). The revenue side was then combined with the CAPEX and OPEX of the system to obtain net present values for each operational strategy and scenario. This led to the following conclusions:

- The base analysis shows a positive NPV for the Conservative and Progressive+ scenario after 20 years for most of the operational strategies;
- For the Reference and Progressive scenarios, the NPV after 20 years is negative regardless of operational strategy;

- The Progressive+ scenario leads to the best result in NPV across operational strategies; and
- The operational strategy 3b (day-ahead bidding with utilisation of residual capacity: 75% on IDM and 25% for aFRR) is most promising across the scenarios.

Next to the basic analysis of the business case under different operational strategies and scenarios of market development, also the impact on the business case from the adopted assumptions regarding market developments and cost parameters was analysed through a thorough sensitivity analysis, resulting in the following conclusions:

- The business case of a large-scale electrolyser mainly depends on the operation on the DAM. This market can supply the bulk of the required electricity as the other markets are relatively small.
- Doubling the market volume of the intraday, aFRR and the hydrogen market leads in all cases to better results and, except for the Reference cases, to a positive NPV. A positive NPV after 20 years does, however, not directly mean that investing in an electrolyser in the northern Netherlands is attractive for a market party. This depends on the intentions of this party. Industrial parties often go for much shorter payback times.
- Doubling the hydrogen market has the largest positive influence on the business case results.
- The improvement of the NPV by doubling the ID market volume is about twice as high as the improvement of doubling the volume of the aFRR market in all four scenarios except for the Reference scenario. For this scenario the improvement is slightly less.
- The price of hydrogen has by far the highest impact on the NPV in all scenarios. A 50% higher hydrogen price leads to a positive NPV after 20 years in the Reference scenario with a payback time of 12 years.
- The next largest influence on the results comes from the CAPEX of the equipment and the efficiency of the electrolyser.
- The influence of both components of the transmission tariff and the WACC is comparable, and considerably less than the influence of CAPEX and efficiency. The WACC has more influence for the scenarios with higher NPVs after 20 years.
- Reducing both electricity transport tariff and contracted capacity tariff by 50%, leads to 3-5 years shorter pay-back times. Rationale for this reduction may be the potential revenues for grid support services that the electrolyser could provide, as this may have positive societal value.
- Storage cost and OPEX of equipment have the lowest impact on the NPV in all scenarios.

The NPV and pay-back time found in Task 3 differ from the results of the societal cost-benefit analysis performed in Task 1. The main reason for this is the inclusion of a number of additional costs that an investor would incur but are not considered in Task 1 as societal cost, such as network tariffs and the cost of paying back loans. Based on the positive societal benefit of the electrolyser, an argument can be made for bridging the cost gap in the electrolyser business case. As the sensitivity analysis has shown, multiple approaches can be utilised for bridging this gap – from a direct investment subsidy to a reduction of network tariffs.

NOMENCLATURE

aFRR	automatic Frequency Restoration Reserve
ARB	Arbitrage
AS	Ancillary services
BRP	Balance Responsible Party
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
CCT	Cross-commodity trading
CET	Central European Time
CO_2	Carbon dioxide
COP	Coefficient Of Performance
DA / DAM	Day-ahead (market)
ED	Economic dispatch
ELY	Electrolyser
ENS	Energy Not Served
ENTSO-E	European Network of Transmission System Operators of Electricity
EOS	Eemshaven-Oudschip (name of substation in GDO network)
EPC	Engineering, Procurement and Construction
EU	European Union
EUCO	External Scenario developed by the European Commission
EV	Electric Vehicles
FCR	Frequency Containment Reserve
FRR	Frequency Restauration Reserve
GDOF	Groningen-Drenthe-Overijssel-Friesland
GTC	Gate Time Closure
H_2	Hydrogen
HT	High Temperature
HVDC	High Voltage Direct Current
ID / IDM	Intra-day (market)
KPI	Key Performance Indicator
ktpa	Kilo-tonnes per annum
LCOH	Levelised Cost of Hydrogen
LFC	Load Frequency Control
LT	Low Temperature
LV	Low Voltage
mFRR	Manual Frequency Restoration Reserve
mHz	Milli Hertz
MV	Medium Voltage
MW	MegaWatt
MWh	MegaWatt hour
NL	Netherlands
NOx	Nitrogen Oxide
NPV	Net Present Value
ODE	Opslag duurzame energie
O&M	Operation & Maintenance

OPEX	Operation Expenditure
P2G	Power-to-gas (electrolyser)
PEM	Polymer Electrolyte Membrane
PTU	Program time unit
RES	Renewable Energy Sources
RR	Replacement Reserves
RT	Real-time
SMR	Steam Methane Reforming
SOx	Sulphur Oxide
SRMC	Short run marginal cost
ST	Sustainable Transition scenario
st dev	Standard deviation
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
V2G	Vehicle-to-Grid
WACC	Weighted Average Cost of Capital

APPENDIX I: MARKET MODEL

General description of the model

The developed scenarios of the European power system have been implemented in DNV GL's European power market model. This model contains detailed representations of the electricity generation, transmission and demand for most European countries, divided into core and non-core countries, see Figure 1.

Power plants (> 50MW) in the core countries are modelled on an individual basis with detailed techno-economic characteristics. For example: flexibility parameters, such as ramp rates and minimum stable level, heat rate curves, maintenance availability parameters, variable operation & maintenance and start costs are included. For the Nordics and South-East Europe (non-core countries), the generation capacities are aggregated by technology-fuel categories. Each country (bidding zone) is modelled as one zone with power plants and a demand profile, without any internal grid constraints ("copper plate"). Market exchanges between countries (bidding zones) are limited based on net-transfer-capacities (NTC).

Figure 1: Modelled countries. (source: DNV GL)

Different types of combined heat and power plants (CHP) are distinguished in the model: district heating, industrial CHP and horticultural CHP (especially in the Netherlands). These power plants have must-run obligations due to the heat delivery, but they have different levels of flexibility provided by heat-only boilers and/or heat storage for district heating.

For the purpose of the analysis of the market-based KPIs, DNV GL has built a model of the European day-ahead electricity market in the PLEXOS®[38] Integrated Energy Model software. DNV GL's European power market model is a fundamental market model that simulates the day-ahead spot price by optimising unit commitment and economic dispatch of the electricity generation. The optimisation is based on the minimisation of the total generation costs of the system: the cheapest generation is used first. A perfect competition situation is simulated for the European power system within an energy-only market. An overview of the (main) inputs required for this optimisation is shown in Figure 2. The optimisation is performed with an hourly time resolution per modelled year.

[38] Energy Exemplar, PLEXOS® Integrated Energy Model, 2017. https://energyexemplar.com/ (PLEXOS, 2017).

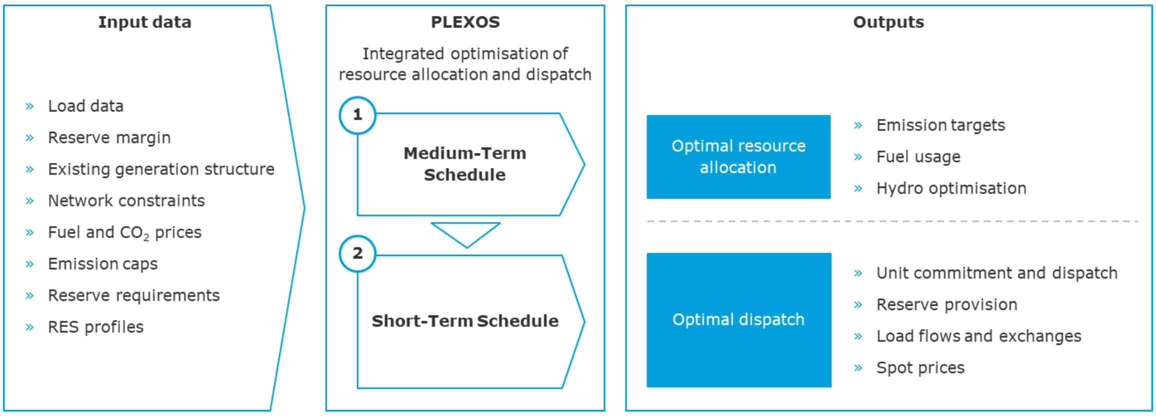


Figure 2: Schematic overview of the features of the employed market model. (source: DNV GL)

Different scenarios have been developed and implemented of the European system. Scenarios entail different developments of installed capacity mix in each country, demand and interconnections. For simulated years, an average climatic year is used as input for renewable- and demand time series. This time series is scaled with the developing annual demand and respective installed capacity mix in each country. An average climatic year is used to obtain insight in the behaviour of the system. A full adequacy study is beyond the scope of the project.

It is assumed that generators price their generation based on their short-run marginal costs, i.e. the power price is set by the cheapest (marginal) power plant that does not run at its maximum capacity. These assumptions simulate a perfect competition situation within an energy-only market. Capacity markets and balancing markets are not explicitly modelled. Based on the dispatch of the generation assets, the (hourly) power price is calculated for each bidding zone. In addition to the power price, the power market model also provides insights in the electricity generation per type of asset and also import/exports of a bidding zone.

The modelling approach used for this study is illustrated Figure 2. Both a medium- and short-term schedule are optimised with the developed market model.

The medium-term schedule is a model which includes a full representation of the generation and transmission system and major constraints, but without the complexity of unit commitment and with a reduced time resolution. It can simulate over long horizons and large systems in a short time and is run ahead of the short-term schedule. Its primary focus is on managing fuel supply (like water resources) or electricity offtake and emission constraints that need to be addressed over timescales longer than a day or week as analysed in the short-term schedule.

The short-term schedule is a fully-featured chronological unit commitment and dispatch model. The electricity generation and reserve capacity requirements are jointly optimised in one optimisation calculation. PLEXOS simulates the commitment and dispatch of individual generation units on an hourly and chronological basis while considering all technical and commercial details like ramp rates, minimum up and down times, minimum stable levels, etc.

The market model of the European power system has been developed for the selected scenarios (based on the ENTSO-E TYNDP 2018 scenarios) to model the behaviour of various cases (incl. with electrolyser or battery) in the Netherlands. The results of the optimisation are postprocessed to obtain selected market-based KPIs for the societal cost-benefit analysis as well as the operational behaviour of the cases with electrolyser and battery.

Implementations of selected asset types

Renewable generation

Renewable generation assets are modelled based on an installed capacity (MW) combined with a renewable energy generation time series. Renewable generation takes volatility into account through the use of historical or re-analysed time-series of e.g. wind-speeds and solar-irradiation data for different locations. Profiles are based on an average climatic year and take geographical correlation into account.

Demand

The demand consists of an hourly fixed demand profile ("traditional demand") and a flexible "demand side management" component due to flexibility of demand response, electric mobility and heat storage. There is an increase of flexibility in demand resulting from time shifting possibilities of demand shedding, electric vehicle (EV) charging, electric heating and industrial demand response. Depending on the scenario, certain types of flexible demand are included.

APPENDIX II: SRMC OF THE ELECTROLYSER IN THE aFRR MARKET

Concerning downward regulation, the electrolyser purchases electricity from the TSO if it is required to balance the system and the electrolyser's bid price is lower than the imbalance price. The SRMC to bid a price in this market is the price at which running the ELY is break-even, just like for buying in the DAM. The revenue from the sold hydrogen should at least cover the expenses of buying electricity in the aFRR- market.

$$\boldsymbol{p_{aFRR}^{down}} = \boldsymbol{\eta_{ELY}} * \boldsymbol{\lambda_{H_2,t}} = \boldsymbol{activation\ price} \quad [€/\mathrm{MWh}]$$

The SRMC for the aFRR- market is different than for the aFRR+. Participating in this market is only possible after buying in DAM volumes first before selling it. The price of selling the volume that is available according to the bid strategy used in this report should gain more revenue than using this already bought volume in the DAM, i.e. the benefits of selling in the aFRR market should be greater than the benefit of buying in the DAM:

$B_{aFRR}^{up} > B_{DAM}$

This is similar to:

$E_{aFRR}^{up} * \lambda_{aFRR}^{up} E_{DAM} > (\eta_{ELY} * \lambda_{H_2} - \lambda_{F,DAM})$

In case of selling this DAM volume in the aFRR market, the DAM volume equals the aFRR up volume, $E_{aFRR}^{up}= E_{DAM}$ and can be omitted from the equation. Then, solving the equation for the aFRR up price (λ_{aFRR}^{up}) in the aFRR+ market, the minimum bid price (λ_{aFRR}^{up} becomes p_{aFRR}^{up}) can be calculated in the equation below:

$$\boldsymbol{p_{aFRR}^{up}} = \boldsymbol{\eta_{ELY}} * \boldsymbol{\lambda_{H_2,t}} - \boldsymbol{\lambda_{F,DAM}} \quad [€/\mathrm{MWh}]$$

p_{aFRR}^{up} , p_{aFRR}^{down} : Bid prices for both upward and downward imbalance regulation

APPENDIX III: ADDITIONAL RESULTS MARKET SENSITIVITIES

The following tables provide the NPV results for the market sensitivities for the four scenarios and all six bidding strategies.

Conservative

	Constant	ID+	aFRR+	ID+ & aFRR+	Hydrogen
Bid strategy	NPV [M€]	NPV [M€]	NPV [M€]	NPV [M€]	NPV [M€]
1	-14.90	-14.90	-14.90	-14.90	78.57
2a	30.72	81.20	30.72	81.15	122.51
2b	-62.46	-59.18	-26.36	-26.36	-4.25
3a	26.44	76.30	77.42	128.28	103.29
3b	53.15	104.42	77.88	130.44	139.33
3c	0.98	47.69	53.84	102.82	69.11

Reference

	Constant	ID+	aFRR+	ID+ & aFRR+	Hydrogen
Bid strategy	NPV [M€]	NPV [M€]	NPV [M€]	NPV [M€]	NPV [M€]
1	-224.94	-224.94	-224.94	-224.94	-224.94
2a	-187.15	-150.38	-187.15	-153.80	-187.15
2b	-247.16	-239.26	-203.03	-203.03	-247.16
3a	-176.98	-137.00	-130.85	-100.81	-176.98
3b	-155.53	-118.87	-130.21	-99.15	-155.53
3c	-200.50	-164.04	-147.75	-118.71	-200.50

Progressive

	Constant	ID+	aFRR+	ID+ & aFRR+	Hydrogen
Bid strategy	NPV [M€]	NPV [M€]	NPV [M€]	NPV [M€]	NPV [M€]
1	-72.70	-72.70	-72.70	-72.70	4.44
2a	-32.20	22.33	-32.20	11.83	54.10
2b	-113.55	-93.37	-64.13	-64.13	-55.78
3a	-26.89	34.45	22.13	70.53	52.75
3b	-6.94	52.58	23.37	71.24	80.01
3c	-50.60	4.07	-5.05	41.29	18.52

Progressive plus

	Constant	ID+	aFRR+	ID+ & aFRR+	Hydrogen
Bid strategy	NPV [M€]	NPV [M€]	NPV [M€]	NPV [M€]	
1	6.04	6.04	6.04	6.04	95.27
2a	42.42	92.32	42.42	84.03	143.32
2b	-40.36	-24.24	0.09	0.09	26.60
3a	41.88	98.50	84.20	131.87	138.31
3b	62.65	118.53	91.51	137.28	167.47
3c	17.00	68.29	55.95	98.21	102.49