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TSO2020 Report – Activity 3

Cost-Benefit Analysis (CBA) Modelling – P2G project's value to society

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EXECUTIVE SUMMARY

Objectives

This report is the first deliverable of Activity 3 of the TSO 2020 project. The objective of Activity 3 is to analyse the total value to the society and the project's business case in the market environment. This deliverable focuses on the former. It assesses the value of a 300 MW electrolyser considered for the Eemshaven region in the Northern Netherlands to the region and the society as a whole.

The Cost-Benefit Analysis (CBA) approach that is considered for this Task studies the impact of the electrolyser on integration of locally generated renewable energy (mainly offshore wind) and integration of the COBRA HVDC interconnector with Denmark. It also analyses synergies between energy and transport, CO_2 emissions reduction and network congestion reduction. It is important to evaluate and compare how different technology options (e.g. Power-to-Gas, battery storage) can play a role to stabilise the power system and how these can be operated effectively with a viable and attractive business case compared to today's conventional technology.

Methodology

The CBA consists of: (1) defining the key assumptions (e.g. cases, scenarios, key performance indicators - KPIs), (2) Market and Grid modelling and (3) KPI assessment based on the modelling results.

The first key assumption is that the performance of the hydrogen electrolyser considered for the Eemshaven area is compared with a corresponding battery investment. The selected power of both facilities is 300 MW, assuming this investment would come into operation in 2030.

Concretely, the modelling horizon of two snapshots, for years 2030 and 2040, is selected for this study. Three scenarios are defined for both 2030 and 2040 scenarios, largely based on the ENTSO-E 2018 scenarios: 'Conservative', 'Reference' & 'Progressive'. A fourth scenario, called 'Progressive+' is added to reflect the specific national plans in the region.

A set of 12 KPIs is selected to allow for full-fledged assessment of the impact of both assets, comprising economic aspects such as socio-economic welfare and financial attractiveness, environmental aspects like air quality and CO_2 reductions, and grid-related aspects like RES (renewable energy sources) curtailment reduction and grid losses reduction.

Secondly, a Market model is built by implementing the different scenarios (and other relevant) assumptions in the PLEXOS tool. The Grid model is built in DIgSILENT Power Factory using grid data from the Dutch transmission system operator TenneT TSO B.V. and other sources.

The modelling results directly feed the KPI assessment in the third phase.

Last but not least, defining assumptions for the hydrogen market and electrolyser operation in particular is an important and innovative part of this exercise. It has been defined at the beginning of this Task and continuously adjusted to achieve an optimal electrolyser operation strategy, namely the 'electrolyser activation price' (i.e. electricity price below which an electrolyser starts operating) as the modelling results and learnings advanced.

A trade-off between two extreme points has to be found: On the one hand, with too many running hours, the electrolyser would also produce during moments of too high electricity prices and, therefore, at higher prices becomes unattractive for potential hydrogen off-takers. On the other hand, running the electrolyser too few hours per year would lead to a low hydrogen volume and challenges the return on investment of the associated hydrogen production infrastructure. The key variables include: (1) which sectors and actors are the potential hydrogen off-takers, (2) what are the competitive price thresholds for green hydrogen, and (3) the energy mix of each of the scenario (the electrolyser operation strategy had to be optimised separately for each scenario and year).

Key results

The key finding of the analysis is that **the electrolyser outperforms the battery** for the considered KPIs for any given year of a specific scenario.

The cross-sectorial integration made possible by the electrolyser (i.e. coupling between the electricity and mobility markets), enables the electrolyser to achieve much higher financial attractiveness (i.e. shorter payback time and higher NPV, net present value). By selling hydrogen outside the electricity market, the electrolyser can maximise its revenues and demonstrate the economic viability of the complete implemented hydrogen value chain, namely from production to distribution together with the required infrastructure (i.e. hydrogen pipeline from the electrolyser located in Eemshaven to salt cavern facilities in Zuidwending, followed by a tube trailer distribution to final refuelling stations). Additionally, through the greenification of the transport sector, the electrolyser contributes to significantly reduced CO_2, NO_x, SO_x and particles emissions. In contrast, the battery is not financially viable when only looking at energy trading in the day-ahead market: revenue stream stacking from other market segments (out of the scope of this study) could help improve the attractiveness.

The electrolyser also contributes to stronger reduction of RES curtailment (i.e. up to twice the amount compared to the battery), grid losses (i.e. reduction up to 6.5% for the electrolyser, while no improvement is noticeable for the battery) and congestion compared to a battery of similar size. These behaviours can be explained as follows: an electrolyser has no strong limitation[1] to the energy it can absorb, being able to draw a power up to 300 MW, while the energy a battery can absorb is limited by its state of charge.

Additionally, both investment cases tend to achieve higher performances in 2040 than in 2030. In more progressive scenarios, the tendency towards lower green hydrogen production costs, combined with higher competitive thresholds for the selling price of hydrogen to mobility consumers (i.e. fuel expected to be more expensive by 2040 in the more progressive scenarios than in the reference and conservative scenarios[2]), strengthen the business case of the electrolyser.

Recommendations

The results presented in this study are valid for the considered scenarios and system boundaries, assuming that the 300 MW electrolyser is a 'first mover' in the Eemshaven region, assuming a price setting behaviour.

The financial attractiveness of the electrolyser has been assessed by capturing the main building blocks of the hydrogen value chain, from production to end-users. However, simplifications are made for the purpose of the total value to society assessment. The third deliverable of Activity 3 studies the business case of the electrolyser in more detail.

Additionally, expanding the scope of the analysis to a market setting where one or more electrolysers already operate could provide additional insights. The authors believe that the outcomes of Activity 3 will be relevant inputs for Activity 5: 'Analysis to scale-up to mass application (business plan)'.

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[1] Theoretically, the electrolyser is limited by the time-synchronous demand and/or the storage volume and capacity for hydrogen and/or available transport capacities. Admittedly, these barriers are wider than the one from the battery.

[2] Consequences of 1) Higher carbon prices adjusted in progressive scenarios to create an investment signal that enables developments in distributed generation technologies 2) 'Low oil price' scenario generated from WEO2016 New policies for Reference scenario, see https://www.entsoe.eu/Documents/TYNDP%20documents/entsos_tyndp_2018_Scenario_Report_ANNEX_II_Methodology.pdf

The cross-sectorial integration made possible by the electrolyser (i.e. coupling between the electricity and mobility markets), demonstrates the great potential to decarbonise the transport sector in the Northern Netherlands region. An in-depth distribution infrastructure and Total Cost of Ownership assessments could be made to validate the findings of this study.

Finally, even though the mobility sector was selected as the most promising market to address with this 300 MW electrolyser, supplying green hydrogen to industrial off-takers should still be considered in the future. Stricter environmental regulations, strong innovation ambition and willingness to inject sustainability requirement into its development are all reasons for which the industrial sector will most probably undergo a major transformation, going from a conventional fuel-based supply (natural gas, coal, etc.) to a green-based supply such as hydrogen. Moreover, hydrogen competitiveness could be specific to regional conditions.

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1 INTRODUCTION

The aim of the TSO 2020 project is to facilitate flexibility in the power system in the Eemshaven area (see Figure 1-1) to allow the integration of variable renewable energy in the Northern Netherlands region, also further referred to in this report as Groningen-Drenthe-Friesland region (GDF), and the landing of the COBRAcable HVDC interconnector. The project specifically addresses the consequences of (possible) congestion in the local power grid. There is a large volume of generation capacity (coal/wind/ submarine interconnections) situated in the area combined with a relatively low demand.

Various technology options, such as Power-to-Gas (P2G), battery or conventional grid reinforcement, can be envisaged in order to address these challenges, to provide the required flexibility and to support the Renewable Energy Sources (RES) integration. The value to society of the first two options will be assessed in this deliverable.

The different technology options (i.e. Power-to-Gas and battery) deployed in the project have indeed the potential to relieve congestion stress on the available grid in the region and can be remunerated for these services by the TSO (who will be able to postpone/refrain from further grid expansion). This can have a positive effect on socio-economic welfare, as it possibly is a cheaper solution than grid expansion. Furthermore, the Power-to-Gas (P2G) unit can provide additional benefits to the society, such as decarbonisation of the local or even regional industry and mobility sectors.

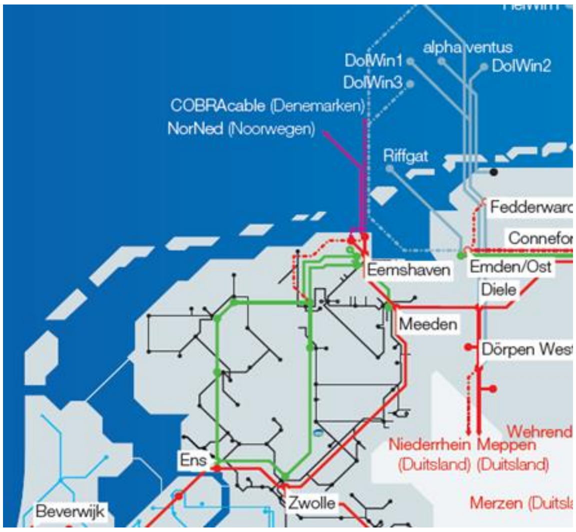

Figure 1-1: Grid lay-out northeast Netherlands. (source: TenneT TSO B.V.)

Activity 3 has goal to analyse the **total value to the society** and the **project's business case** in the market environment. *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;
- Task 2: Assessing the contribution of the electrolyser to local grid stability;
- Task 3: Assessing the business model and operational scheme of the electrolyser.

This document is the deliverable of Task 1, which focusses on the techno-economic, societal and environmental aspects.

This report is organised as follows. The CBA consists of: (1) defining the key assumptions (e.g. cases, scenarios, key performance indicators - KPIs), (2) Market and Grid modelling and (3) KPI assessment based on the modelling results.

The modelling horizon of two snapshots, for years 2030 and 2040, is selected for this study. Three scenarios are defined for both 2030 and 2040 scenarios, largely based on the ENTSO-E 2018 scenarios: ‘Conservative’, ‘Reference’ & ‘Progressive’. A fourth scenario, called ‘Progressive+’ is added to reflect the specific national plans in the region.

A set of 12 KPIs is selected to allow for full-fledged assessment of the impact of both assets, comprising economic aspects such as socio-economic welfare and financial attractiveness, environmental aspects like air quality and CO_2 reductions, and grid-related aspects like RES (renewable energy sources) curtailment reduction and grid losses reduction.

Secondly, a Market model is built by implementing the different scenarios (and other relevant) assumptions in the PLEXOS tool. The Grid model is built in DIgSILENT Power Factory using grid data from the Dutch transmission system operator TenneT TSO B.V. and other sources.

The modelling results directly feed the KPI assessment in the third phase.

2 CBA METHODOLOGY AND MODELLING INPUTS

2.1 CBA methodology overview

The **value to society** will be assessed starting with the Cost Benefit Analysis (CBA) Model of ENTSO-E[3]. This CBA-model looks at characterising the impact of the project regarding both the added value to society and costs. This is a full assessment with various societal and cost related indicators (KPIs), as indicated in Figure 2-1 below, which are quantified either in monetary or physical units.

Figure 2-1: Scope of the CBA-analysis. (source: THINK project[4])

Key Performance Indicators (KPIs) in several benefit categories are included (e.g. RES integration, variation in CO_2 emissions, etc.) as well as in various cost categories (e.g. financial attractiveness, etc.) and residual impact categories (environmental impact and others). They are described in more detail in section 2.3. The total value of the project is then determined through a multi-criteria approach (see section 2.1.1), providing a total project case to decision-makers.

The total value to society will be assessed through the methodology presented in Figure 2-2.

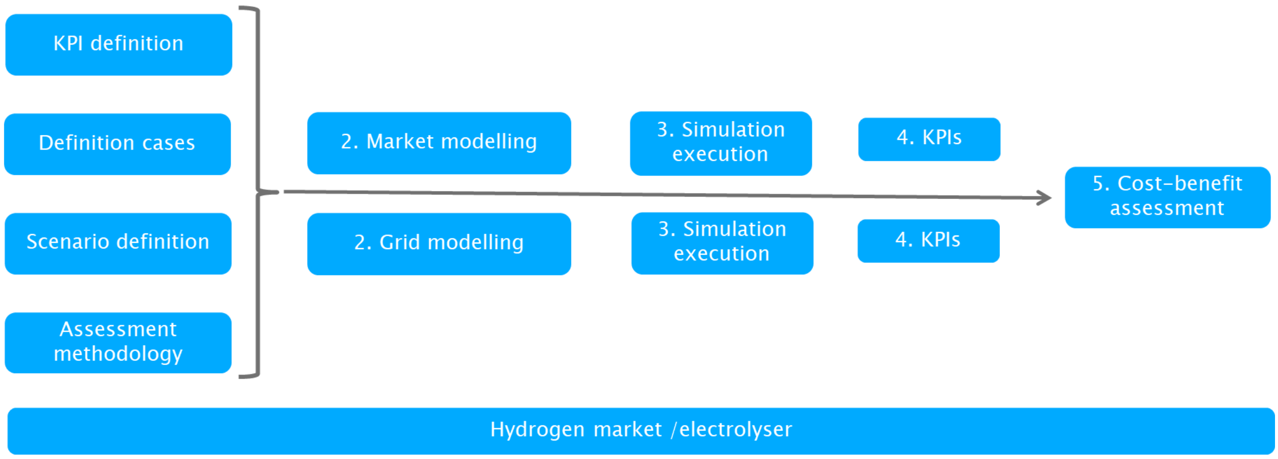

Figure 2-2: CBA methodology overview. (source: Tractebel).

[3] ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, FINAL- Approved by the European Commission, February 2015.
[4] ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, FINAL- Approved by the European Commission, February 2015.

The **first stage** of the CBA includes the following steps:

- **Cases definition**: Different **technologies** are compared and assessed. The benefits of a P2G facility and a battery storage solution are compared with a situation without any reinforcement.
- **Assessment methodology**: A **multi-criteria approach** (see section 2.1.1) is constructed to capture the potential benefits of these different technologies according to different aspects, covering economic, societal and environmental aspects.
- **Scenario definition**: Scenarios are defined (see section 2.2) to assess the evolution of the costs/benefits over the years and possible future trends in fuel and CO_2 prices, RES penetration, national energy policies, etc.
- **KPI definition**: Multiple **Key Performance Indicators** are defined (see section 2.3) to assess these potential benefits.

In the second and third stages, models are constructed, and simulations performed. Two simulation models are constructed to incorporate all input data:

- **Market model** built by DNV GL in the PLEXOS tool (section 4.1). It includes:
  - The tool optimises the dispatch of the different generation plants from an economic perspective: In a purely *market-based optimisation*, forecasted hourly electricity prices determine if, and when the P2G facility will produce, i.e. at times when electricity prices are low. This market-based optimisation looks at day-ahead prices and the cost of production of H_2 to optimise revenue and make the business case for the P2G project. Similarly, for the battery case, forecasted hourly electricity prices determine if and when the battery will be charged/discharged.
  - The modelling covers the central-western Europe region and the different bidding zones, with focus on the Central Western European system: the Netherlands and neighbouring countries (DE, BE, FR, GB and DK). More specifically, this model is a regional model that looks at each market as a whole (no internal network).
  - Simulations are performed on an hourly basis for each year.
- **Grid model** built by CIRCE in DIgSILENT PowerFactory using grid data from TenneT TSO B.V. (section 5.1). It includes:
  - Optimal Power Flow based assessment. The Optimal Power Flow (OPF) optimises a certain objective function in a network whilst fulfilling equality constraints (the load flow equations) and inequality constraints (e.g. generator active and reactive power limits). One of the objective functions for the OPF is the minimisation of costs function in which the goal is to supply the system under optimal operating costs. More specifically, the aim is to minimise the cost of power dispatch based on non-linear operating cost functions for each generator and on tariff systems for each external grid.
  - Covers the GDOF area (i.e. Groningen-Drenthe-Overijssel-Friesland).
  - Simulations are performed on an hourly basis.

In the fourth and fifth stages, KPIs will be assessed and the Cost-Benefit-Analysis will be carried out (sections 4.2, 5.2, 6, 7).

The Hydrogen market and electrolyser operation will be characterised transversally for the whole CBA assessment. The P2G[5] operation strategy is iteratively optimised[6] with the Market model, taking into account the assessed hydrogen market (i.e. possible revenue streams). The defined strategy is then used to construct the Market and Grid models, which directly impact the simulations and the KPIs

[5] In the rest of the report, P2G and electrolyser will be used to describe the same technology.
[6] In view of maximising the revenues of the electrolyser.

assessment. The hydrogen market in the Northern Netherlands is described in section 3.1, while the electrolyser operation strategy is described in section 3.2.

2.1.1 Multi-criteria approach

The cost benefit assessment is based on a multi-criteria approach covering several aspects, including economic, environmental and societal ones. Figure 2-3 provides an overview of the multi-criteria analysis.

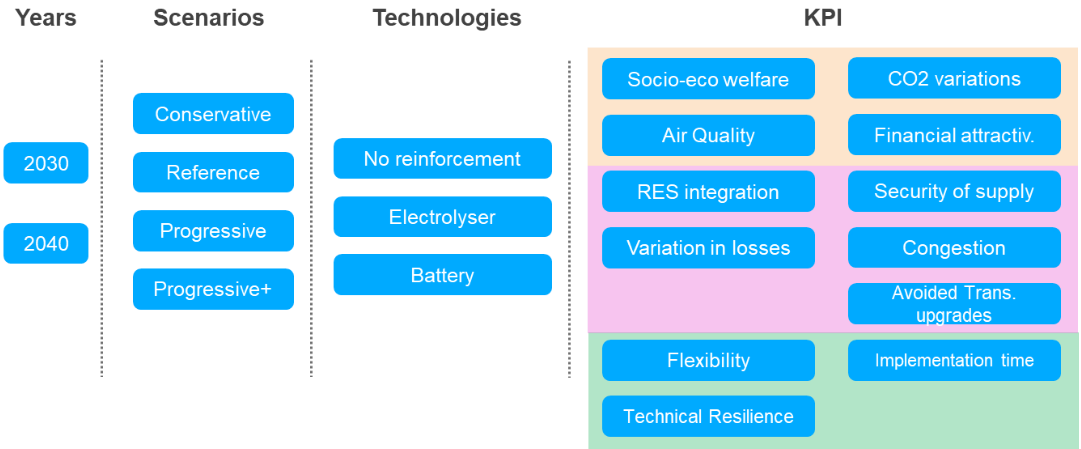

Figure 2-3: Multi-criteria analysis (Market model, Grid model, Other). (source: Tractebel)

The following KPIs are assessed with the Market model: socio-economic welfare, CO_2 variations, air quality and financial attractiveness. Security of supply, congestion, RES integration and variation in losses are analysed via the Grid model. Other KPIs, such as flexibility and implementation time, are investigated either through technical review or engineering expertise. Finally, technical resilience is studied in collaboration with Activity 2.

These KPIs are compared between three main cases: a P2G facility (i.e. electrolyser), a battery storage solution and a configuration without any reinforcement, to demonstrate the potential benefits of new types of reinforcement. The results for the P2G facility are then compared with the other proposed reinforcements, as well as with the situation without any reinforcement. An example of how this comparative assessment is performed is illustrated in Figure 2-4.

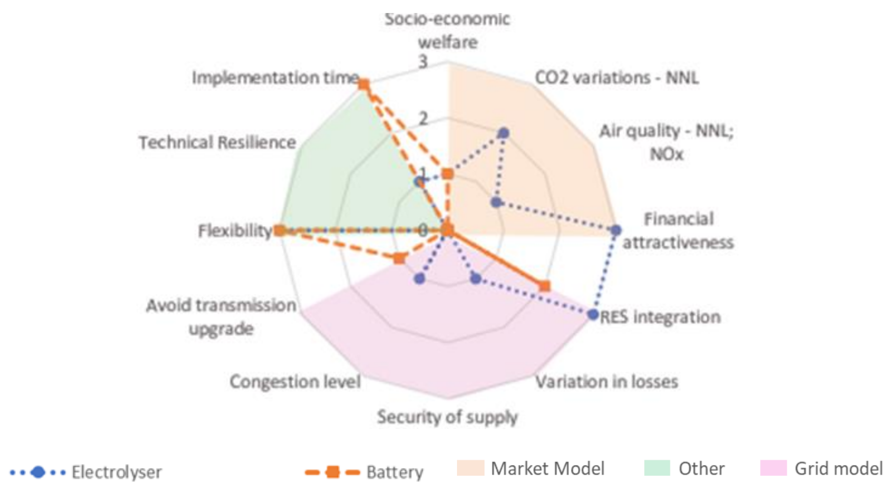

Figure 2-4: Illustration of an overall assessment for a given year and scenario. (source: Tractebel)

The cost-benefit analysis (CBA) is conducted for the two snapshots of the modelling, respectively for years 2030 and 2040[7]. The analysis is performed for four scenarios of market development (Conservative, Reference, Progressive and Progressive+), based on the ENTSO-E Ten Year Network Development Plan (TYNDP) 2018 scenarios (see section 2.2). Such an assessment will capture the evolution of the different KPIs along two dimensions as illustrated in Figure 2-5: time horizon (i.e. 2030 vs. 2040) and scenarios (i.e. different trends in energy policies, fuel and CO_2 prices, RES penetration, etc.).

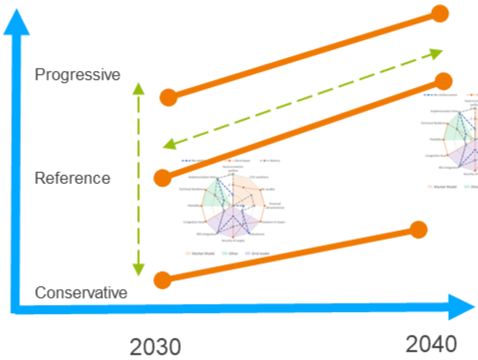

Figure 2-5: Cost-benefit assessment - sensitivity analysis: KPIs evolution over years and scenarios. (source: Tractebel)

From these diagrams, trends and sensitivity analyses are performed, and the following conclusions are presented:

- Results of the simulations are the inputs for a **total value to society**:
    - A score from 0 to 3 is assigned to all KPIs;
    - The different technologies (i.e. cases) are assessed;
    - Comparisons between the P2G facility and the other technologies are carried out for the two snapshots (i.e. 2030 and 2040) and for the different scenarios, which highlights how the potential benefits evolve:
        - Along the time-horizon for a given scenario;
        - From one scenario to another, for a given time snapshot.
- Conclusions on the total value to society are then drawn.

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[7] Considering a lifetime of 20 years for an electrolyser (see Table 2-8), the CBA should ideally be conducted for 2030 and 2050. Nevertheless, the assessment performed in the CBA is based on several assumptions, such as fuel and CO_2 prices evolutions, generation capacities / demand profiles / net transfer capacities profiles / etc. for the Netherlands and neighbouring countries. Data needs to be collected thoroughly and in a consistent way for the four identified scenarios. These scenarios have been largely built on ENTSO-E Ten Year Network Development Plan (TYNDP) 2018 scenarios (see section 2.2), which unfortunately do not provide data for 2050, but only until 2040, reason for which the two snapshots 2030 and 2040 were considered.

2.2 Scenarios

The modelling horizon of two snapshots, for years 2030 and 2040, was selected for this study. Three scenarios were defined both for 2030 and 2040 scenarios based on the ENTSO-E 2018 scenarios[8]: 'Conservative', 'Reference' & 'Progressive'. A fourth scenario, called 'Progressive+' was added to reflect the specific national plans in the region.

2.2.1 Key parameters

The key assumptions that characterise the four scenarios are summarised in Figure 4-1. The key relevant parameters of the scenarios are explained in this section. The basic assumptions, based on ENTSO-E, have been 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. Lastly, this section also explains how demand side management (DSM) is considered in the different scenarios and in the Market modelling.

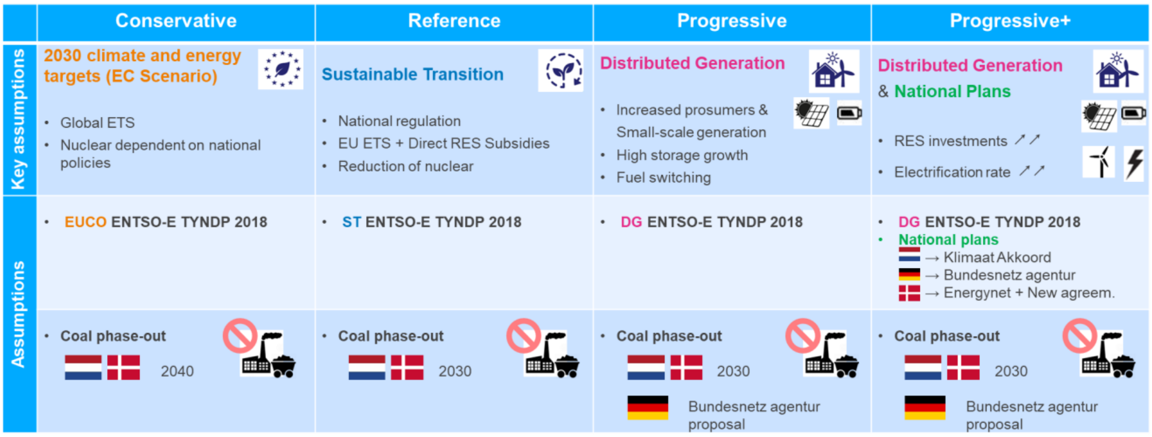

Figure 2-6: Adapted ENTSO-E scenarios taking into account foreseen coal phase-outs and RES ambition in the core countries. (source: Tractebel)

2.2.1.1 Coal phase-out

The Netherlands:

The Dutch Klimaatakkoord[9] envisages the coal phase-out in the Netherlands by 2040. This includes shut-down of the two oldest coal-fired power plants, Hemweg 8 (600 MW) in Amsterdam & Amer 9 (600 MW) in Geertruidenberg (with no capacity replacement) and conversion of all remaining coal capacities into biomass plants, likely with the continuation of already introduced subsidies (for biomass co-firing).

The Reference, Progressive and Progressive+ scenarios assume that the policy will be put in place by 2030. The Conservative scenario considers that its implementation will be delayed until 2040.

Denmark:

The Danish Ministry of Energy, Utilities and Climate also unveiled proposals to phase out coal for electricity production by 2030.[10] But as the new political agreement on energy was just settled in mid-2018, the surrounding scenarios were not yet updated at the time of conducting this study. The yearly

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[8] For details see https://www.entsoe.eu/Documents/TYNDP%20documents/14475_ENTSO_ScenarioReport_Main.pdf
https://www.entsoe.eu/Documents/TYNDP%20documents/entsos_tyndp_2018_Scenario_Report_ANNEX_II_Methodology.pdf
https://www.entsoe.eu/Documents/TYNDP%20documents/entsos_tyndp_2018_Scenario_Report_ANNEX_I_Country_Level_Results.pdf

[9] Bijdrage van de Sectortafel Elektriciteit aan het Voorstel voor hoofdlijnen van het Klimaatakkoord, 10th July 2018; https://www.klimaatakkoord.nl/documenten/publicaties/2018/07/10/bijdrage-elektriciteit

[10] Denmark Eyes 2030 for Complete Coal Phaseout, 3rd May 2018; http://ieefa.org/denmark-eyes-2030-for-complete-coal-phaseout/

analysis assumptions published by the national TSO Energinet from 2017 were thus considered (also for the national plans in the Progressive+ scenario, see section 2.2.2.4).

The Reference, Progressive and Progressive+ scenarios assume that the coal phase-out policy will be put in place by 2030. The Conservative scenario considers that its implementation will be delayed until 2040.

Germany:

In Germany, a committee established by the Government and made up of coal sector stakeholders was tasked to explore the terms for a fair and feasible German coal exit. It came to a landmark compromise agreement on a full exit from coal by 2035-2038. In the resulting compromise, 12.5GW of coal power capacity will close by 2022 and another 25.6GW by 2030.[11] These concrete terms were not yet known when modelling for this study was conducted. Instead, the scenarios published by the Bundesnetzagentur were taken as a basis for the analysis.[12]

Progressive and Progressive+ scenarios assume that the coal phase-out policy will be put in place by 2030. To accommodate for this policy, the values of coal and lignite in these scenarios (building upon DG2030 and DG2040) were adjusted to correspond to Scenario B of Bundesnetzagentur, assuming that the capacities will remain the same between 2035 and 2040. To avoid distortion of the ENTSO-E scenarios and to stay aligned with realistic assumptions on the potential of the different resources like biomass, the difference of the lignite and hard coal capacity taken out of the system was shifted to gas.

The Conservative and Reference scenarios consider that the implementation of the coal phase-out is delayed until after 2040.

2.2.1.2 Demand Side Management

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. The different types are described in the following paragraphs.

Demand response

In some of the ENTSO-E scenarios there is an additional DSR (demand side response) category included. This electrification has been implemented as downward only demand response (load shedding). For the Netherlands and neighbouring countries, this capacity has been divided into three intervals, with each 1/3 of the total capacity from the ENTSO-E scenario and different (high) wholesale power price levels at which each shedding interval is triggered (300, 650, 1000 EUR/MWh). These price levels and approach are based on a simplification of the model implementations of load shedding in Belgium from the Belgian TSO Elia.[13]

For the other countries, this load shedding is activated in one capacity step of which the activation threshold is a high wholesale power price level of 650 EUR/MWh (average of price interval). All capacity steps have a maximal consecutive activation time of 3 hours. The latter means that they can be activated at most three hours consecutively, but without limitations on the daily activation.

[11] Germany to quit coal by 2038, under Commission proposal, 26th January 2019; https://www.climatechangenews.com/2019/01/26/german-quit-coal-2038-commission-proposal/

[12] Genehmingung des Szenariorahmens 2019-2030, 15th June 2018; https://www.netzausbau.de/SharedDocs/Downloads/DE/2030_V19/SR/Szenariorahmen_2019-2030_Genehmigung.pdf?__blob=publicationFile

[13] Thresholds demand response Elia study: Elia, ELECTRICITY SCENARIOS FOR BELGIUM TOWARDS 2050 - ELIA'S QUANTIFIED STUDY ON THE ENERGY TRANSITION IN 2030 AND 2040, November 2017, p37. http://www.elia.be/~/media/files/Elia/About-Elia/Studies/20171114_ELIA_4584_AdequacyScenario.pdf

Electric vehicles

Batteries in electric vehicles (EV) can supply flexibility to the system. Electric vehicles can shift (part of) their demand in time, as well as deliver power back to the grid. The batteries of electric cars can be used to supply flexibility services to the system through smart charging. With the significant deployment of electric vehicles, also vehicle-to-grid (V2G) services will be made available: the batteries of the cars can be used to supply power to the grid. The number of electric vehicles per bidding zone per scenario as provided by the ENTSO-E scenarios determine the annual demand from electric vehicles per bidding zone.

The available power for charging and V2G services varies across the day: almost the full capacity of the electric car fleet is available during the night, very limited capacity is available during the morning and evening mobility peaks as cars are used for travelling, and around 50% of the full capacity is available during the day. However, regardless of flexible charging and V2G services, the EV battery is required to be fully charged in the morning, limiting the availability for flexible charging.

Electrification of heating

Electric heating can also be shifted in time. Electrification of heating consists of two major components: space heating and industrial process heating.

Space heating

Space heating is electrified using air-source heat pumps or hybrid heat pumps (air-source combined with gas boiler) with inherent flexibility. Electricity consumption for space heating can be flexibly shifted across the day. This is because buildings with heat pumps or ground-based heat storage are well insulated and there is enough thermal inertia in the buildings to shift the heat demand a few hours without loss of comfort.

Electricity demand for space heating depends on the ambient air temperature: high demand in the winter period and low demand during the summer period. The number of hybrid and electric heat pumps per bidding zone per scenario as provided by the ENTSO-E scenarios determine the annual electricity demand from heat pumps, which can flexibly be shifted in time.

Electrification of industry

Electricity demand for industrial process heat is implicitly included in the Progressive+ scenario as the difference in annual demand between the ENTSO-E based Progressive scenario and the country-specific scenarios (e.g. Klimaatakkoord for the Netherlands). It is assumed that this increase of annual electricity consumption, compared to the ENTSO-E Progressive scenario, is related to the additional demand coming from the electrification of industry. This increase is translated to an additional baseload demand to be added on top of the traditional demand. However, electrified industrial processes are not expected to be flat in demand but rather have various mechanisms that can introduce flexibility in this demand depending on the industrial applications, for example, load shedding, load shifting of low temperature heat or load shifting of high temperature heat processes.

From Dutch studies on industrial heating[14], about ¾ of electrified industrial demand will come from high temperature processes (> 250 degrees Celsius) and the remaining ¼ from low temperature processes (< 250 degrees Celsius). High temperature processes are largely continuous processes without shifting possibilities and require an electric boiler to reach desired temperatures. Low temperature processes, in

[14] AgentschapNL, Warmte en koude in Nederland, 2013,
https://www.rvo.nl/sites/default/files/Warmte%20en%20Koude%20NL%202NECW1202%20jan13.pdf
https://www.rvo.nl/sites/default/files/Warmte%20en%20Koude%20NL%202NECW1202%20jan13.pdf

contrast, could have some time shifting capabilities and heat pumps for heat generation. Based on this, in the Netherlands, industrial electrification has been implemented as follows:

- ¾ of the annual industrial demand comes from high temperature processes (HT) that can have fuel switching capabilities between an electric and gas boiler, allowing for load shedding at times with high wholesale electricity prices. The switching price is here the equivalent price of the operation of gas boiler operation (based on the gas and CO_2 prices in the respective year and scenario).
- ¼ of the annual industrial demand comes from low temperature processes (LT) that can have shifting and shedding behaviour, depending on the source of heat generation:
    - A share of this (50%) ¼ will use switching between a heat pump and gas boiler. This leads to load shedding in the electricity market as this load is now met by gas, similarly to the high temperature processes. The switching price is here the equivalent price of gas boiler operation (based on the gas and CO_2 price in the respective year/scenario) times the COP (coefficient of performance) of 3[15] for the heat pump.
    - The remainder of this (50%) ¼ will be able to time shift their load throughout the day.

Based on this assumption for the Netherlands, for the other focus countries Denmark and Germany, the following was assumed. For Denmark, no increase in annual demand was observed comparing the Energienet and progressive scenarios. Hence no specific implementation of industrial demand as in the Netherlands was adopted.

For Germany, the Bundeznetzagentur scenario defines an extra demand category which is implemented similarly to the Dutch implementation. From literature, the share of high and low temperature heating processes in Germany is 65% and 35%, respectively.[16,17,18]

2.2.2 Scenarios overview

Table 2-1 complements the global overview of the four scenarios in Figure 2-6 with overview of evolution of fuel and CO_2 prices.

	Conservative		Reference		Progressive(+)	
	2030	**2040**	**2030**	**2040**	**2030**	**2040**
Hard coal (€/GJ)	4.30	4.70	2.70	2.50	2.70	2.80
Gas (€/GJ)	6.90	8.10	8.80	5.50	8.80	9.80
Lignite (€/GJ)	2.30	2.3	1.10	1.10	1.10	1.10
Nuclear (€/GJ)	0.47	0.47	0.47	0.47	0.47	0.47
CO_2 (€/ton)	27.00	36.00	84.30	45.00	50.00	80.00

Table 2-1: Fuel and CO_2 prices for the different scenarios in 2030 and 2040 (source: ENTSO-E[19]).

15 http://www.ispt.eu/media/Electrification-in-the-Dutch-process-industry-final-report-DEF_LR.pdf

16 Industrial heat pumps in Germany: Potentials, technological development and market barriers, Wolf S., Institute for Energy Economics and the Rational Use of Energy (IER), 2016.

17 Heat and cooling demand and market perspective, Pardo N., Vatopoulas K., Krook-Riekkola A., Moya J.A., Perez A., JRC scientific and policy reports, European Commission, 2012

18 IEA WEO 2017 https://www.iea.org/newsroom/news/2018/january/commentary-clean-and-efficient-heat-for-industry.html.

19 Based on ENTSO-E TYNDP 2018 scenarios: EUCO30 as Conservative-2030, ST2030 as Reference-2030, DG2030 as Progressive(+)-2030; ST2040 as Reference-2040, DG2040 as Progressive(+)-2040. Values for Conservative-2040 are extrapolated from EUCO30 and trends observed in IEA World Energy Outlook 2016-Current Policies scenario. For details see:
https://www.entsoe.eu/Documents/TYNDP%20documents/14475_ENTSO_ScenarioReport_Main.pdf
https://www.entsoe.eu/Documents/TYNDP%20documents/entsos_tyndp_2018_Scenario_Report_ANNEX_II_Methodology.pdf
https://www.entsoe.eu/Documents/TYNDP%20documents/entsos_tyndp_2018_Scenario_Report_ANNEX_I_Country_Level_Results.pdf

2.2.2.1 Conservative

Conservative scenario corresponds to an *External Scenario developed by the European Commission (EUCO30)*: The scenario models the achievement of the 2030 climate and energy targets as agreed by the European Council in 2014 but including an energy efficiency target of 30%. Even though ENTSO-E does not extend this external scenario until 2040, it is extended in the model in the purpose of the analysis to be carried out in this project, with consistent assumptions.

The evolution of the installed capacities between 2030 and 2040 follows the same trends as between 2030 and 2040 of the reference scenarios.

In addition, it considers the coal phase-outs in Denmark and the Netherlands as described above.

2.2.2.2 Reference

Reference scenario corresponds to *Sustainable transition scenario (ST2030 and ST2040)*: Targets reached through national regulation, emission trading schemes and subsidies, maximising the use of the existing infrastructure.

In addition, it considers the coal phase-outs in Denmark and the Netherlands as described above.

2.2.2.3 Progressive

Progressive scenario corresponds to *Distributed generation (DG2030 and DG2040) scenarios*: Prosumers at the centre – small-scale generation, batteries and fuel switching society engaged and empowered.

In addition, it considers the coal phase-outs in Denmark, Germany and the Netherlands as described above.

2.2.2.4 Progressive +

The **Progressive+ scenario** builds on the *Distributed generation (DG2030 and DG2040) scenarios* and also considers coal phase-outs in all the three countries, like the Progressive scenario. It aims at assessing the impacts of the National plans in the three countries as far as development of **renewable energy sources investments** and **electrification** (namely penetration of EVs and heat pumps, as well as electrification of heating demand for industrial processes) are concerned, largely beyond the ambition of the ENTSO-E DG scenarios. The installed capacity mix of the ENTSO-E DG scenarios is thus replaced with those from the respective national plans for all assets, and in some cases also for the energy demand forecasts. For example, the electricity demand for industrial process heat is included as the difference in annual demand between the ENTSO-E based Progressive scenario and the country-specific scenarios (see 4.1.2.2 for more detail). This ensures the adequacy between the installed capacities and the demand, and consequently prevents disturbing the power flows in the Market model.

The key changes based on the national plans of the three countries are:

- For **Denmark** (based on Energinet[20]): Off-shore wind installed capacity has been increased corresponding to the Energinet scenario. This capacity is reached by transferring some of the solar PV capacity, which is much higher in ENTSO-E DG than forecasted by Energinet. All other capacities remain as in DG2030 and DG2040. Energy demand, the number of EVs and the number of heat pumps remain as in DG2030 and DG2040 (i.e. higher electricity demand than projected by Energinet). By doing this, change of the flows in the model is avoided while taking into account a higher penetration of off-shore wind as planned with the Danish New Energy agreement.

[20] Energinet's analysis assumptions 2017. https://en.energinet.dk/Analysis-and-Research/Analysis-assumptions/Analysis-assumptions-2017

- For **Germany** (based on Bundesnetzagentur (scenario B)): The 2030 values for installed generation capacities (i.e. RES and conventional) and electrification are based directly on the national scenario. As no data was available for 2040, the same trend as between DG2030 and DG2040 was applied for DE national scenario 2040. Demand from EVs and electric heat pumps from Bundesnetzagentur has also been considered in the update. Electricity demand for industrial process heat is explicitly included as previously explained.
- For the **Netherlands** (based on the Klimaatakkoord): The 2030 values for installed generation capacities (i.e. RES and conventional) and electrification are based on values directly available from national plans. As no data was available for 2040 for the Netherlands, the same trend as between DG2030 and DG2040 was applied (coherent with the approaches applied for DK and DE). Demand from EVs and electric heat pumps from the Klimaatakkoord has been also considered in the update. As the Klimaatakkoord does not include data for battery storage and additional DSR, values from ENTSO-E DG scenarios were kept. Electricity demand for industrial process heat is explicitly included as previously explained.

2.3 KPIs

The cost-benefit assessment is conducted for several technology options (P2G, battery storage) and for the four scenarios as previously defined. For each scenario, the results for the P2G facility are compared with the other proposed technology option, as well as with the situation without any reinforcement.

For each of the benefit categories, KPIs need to be evaluated in a methodological manner through scoring criteria: a score between 0 and 3 is assigned for each KPI. The scoring methodology is detailed later in sections 4.2, 5.2 and 6.

The following sub-sections describe the selected KPIs and how they are calculated. These KPIs have been established following ENTSO-E[21] methodology. Additional KPIs are also suggested to extend the scope of the analysis. Table 2-2 provides the mapping between the different KPIs and the model/methodology to be used for their assessment.

No.	KPIs	Input for assessment from
1	Socio-economic welfare	Market model
2	CO_2 variations	Market model
3	Air quality	Market model
4	Financial attractiveness	Market model
5	Flexibility	Literature review / Expert judgment
6	Technical Resilience	Activity 2
7	Implementation time	Literature review / Expert judgment
8	Security of supply	Grid model
9	RES integration	Grid model
10	Congestion level	Grid model
11	Variation in losses	Grid model
12	Avoided transmission upgrades	Grid model

Table 2-2: KPIs – Mapping with model used for assessment.

[21] ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, FINAL- Approved by the European Commission, February 2015.

2.3.1 Market-based KPIs

The following sections describe the KPIs assessed with the Market Model built by DNV GL in the PLEXOS tool.

2.3.1.1 Socio-economic welfare

The socio-economic welfare benefit is calculated from the reduction in total generation costs[22]. The socio-economic welfare KPI is calculated as follows:

$$Socio\ economic\ welfare = \frac{Total\ electricity\ generation\ costs_{Flexibility} - Total\ electricity\ generation\ costs_{No\ Flexibility}}{Total\ electricity\ generation\ costs_{No\ Flexibility}}$$

Equation 1: The formula to calculate the socio-economic welfare KPI.

The numerator displays the benefit or loss every year the system can obtain by introducing a decentralised energy asset as flexible grid solution, such as a 300 MW electrolyser. This benefit or loss is calculated by measuring the difference for all the scenarios between the total electricity generation costs of the Netherlands over a year with this additional flexibility in the form of an electrolyser or battery and the total electricity generation costs of the Netherlands over the same year without additional flexibility.

Two different evolutions are possible. The first is a reduction in generation costs thanks to the introduced flexibility technologies. The second evolution is an increase in generation costs, due, for instance, to the additional load in the form of an electrolyser connected to the grid.

The denominator is equal to the total electricity costs of the Netherlands without any flexibility.

2.3.1.2 CO_2 variations

A second KPI is the impact on the CO_2 emissions in the Northern Netherlands related to the production of electricity, the mobility sector and industry sector potential switch to hydrogen.

For the scenarios including electrolyser, the potential decrease in CO_2 emissions that the electrolyser can introduce by greenifying the consumption of other sectors is accounted for. More specifically, the electrolyser will produce hydrogen that will be sold to external off-takers (i.e. mobility, industry, etc.) who will substitute their conventional consumptions (i.e. gasoline, diesel, gas, etc.) with green hydrogen. Such a greenification will contribute to lowering down the CO_2 emissions. The hydrogen possible off-takers are explained in chapter 3 in detail.

The CO_2 emissions associated with electricity production are calculated from the Market model for the entire Netherlands[23]. To convert this value to the CO_2 emissions for the Northern Netherlands, the following formula is used:

$$CO_2(N\_NL)(N\_NL) = \frac{Electricity\ demand_{N-NL}}{Electricity\ demand_{NL}}.CO_2(NL) + CO_2(mobility, industry)$$

Equation 2: The formula used to approach the CO_2 emissions of the Northern Netherlands (N-NL).

The ratio $\frac{Electricity\ demand_{N-NL}}{Electricity\ demand_{NL}}$ is obtained with energy consumption data from the Dutch ministry and Rijkswaterstaat, and is equal to 11%[24]. In other words, the CO_2 emissions related to the electricity production for the Northern Netherlands are assumed to be 11% of the CO_2 emissions related to the electricity production in the Netherlands.

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[22] The demand is assumed to be price inelastic. The 'Total generation costs' approach of ENTSO-E is therefore selected.
ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, FINAL- Approved by the European Commission, February 2015.

[23] The Market model represents the Netherlands as a single node with interconnections to its neighbouring countries.

[24] https://klimaatmonitor.databank.nl/dashboard/Dashboard/Energiegebruik/

For the scenarios where electrolyser flexibility is included in the grid, these CO_2 emissions are also calculated for the demand sectors that are converted to hydrogen, being possibly the mobility and industry segment.

For example, the CO_2 emissions of the mobility sector fuelled by Diesel is equal to 0.267 kg CO_2/kWh[25].

2.3.1.3 Air quality

Another KPI that is compared between the different scenarios, is the air quality. The air quality is related to the SO_x, NO_x and dust particles. These emissions are harmful to human health and the environment. The amount of SO_x, NO_x and dust particles associated to each scenario are calculated through two main contributors. First, SO_x, NO_x and dust particles can be associated with the production of electricity and depend on the energy mix and the dispatch of the different generators. This contribution is calculated through the Market model. Secondly, SO_x, NO_x and dust particles emissions are also assessed for the hydrogen off-takers: the hydrogen produced by the electrolyser substitutes conventional fuels in industry/mobility segments (see chapter 3) and therefore reduces their amount compared to a situation without any reinforcement or with the battery, where the greenification of industry/mobility is not directly enabled.

For the emissions related to electricity production, obtained through the Market model, the SO_x, NO_x and dust particles are calculated for all the different generation units optimised by the model in 2030 and 2040, such as biomass and gas units. The emissions limits from the European Directive 2010/75/EU[26] were used to calculate them. However, in some cases these limits appear to be obsolete (i.e. today's environmental performance of typical large combustion plants in the EU-28 is better). In such cases, stricter limits by the European Environment Agency are considered[27].

Pollutant	Units	Biomass	Liquid fuels	Natural gas	Coal	Lignite
SO_2	t/TWh_prim	28.8	156.6	0.0	205.2	399.6
NO_x	t/TWh_prim	244.8	104.4	104.4	205.2	363.6
Dust	t/TWh_prim	14.4	10.4	0.0	13.7	18.0
Efficiency	-	25.0%	35.5%	44.0%	41.5%	41.5%
SO_2	t/TWh_elec	115	441	0	494	963
NO_x	t/TWh_elec	979	294	237	494	876
Dust	t/TWh_elec	58	29	0	33	43

Table 2-3: Considered emission limits of large combustion plants in Europe, used to calculate the SO_x, NO_x and dust particles emissions of the electricity production in the Netherlands.

These emissions related to the electricity production of the Northern Netherlands are calculated for every scenario, with or without reinforcement, with the same method as for the CO_2 emissions, see Equation 2.

For the scenarios where electrolyser flexibility is included in the grid, these emissions are also calculated for the demand sectors that are converted to hydrogen, being potentially the mobility and industry segment. The reason why only the mobility segment is considered, is explained in section 3.2. For example, the number of vehicles that will possibly be shifted from Diesel to hydrogen in 2030 and 2040 in the Northern Netherlands, will result in a reduction of these type of emissions. To illustrate this, the avoided emissions of the mobility segment are calculated using Table 2-4, Table 2-5 and Table 2-6.

[25] https://www.engineeringtoolbox.com/co2-emission-fuels-d_1085.html

[26] DIRECTIVE 2010/75/EU OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 24 November 2010 on industrial emissions (integrated pollution prevention and control); 2010; Accessible on: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32010L0075&from=en

[27] https://www.eea.europa.eu/data-and-maps/indicators/emissions-of-air-pollutants-from/assessment-1

Pollutant	Units	Diesel	Gasoline
NO_x	mg/km	80	60
Dust	mg/km	5	5

Table 2-4: European directive for Euro 6 passenger vehicles.[28]

Pollutant	Units	Diesel	Gasoline
NO_x	mg/km	125	82
Dust	mg/km	5	5

Table 2-5: European directive for Euro 6 light duty vehicles.[28]

Pollutant	Units	Diesel	Gasoline
NO_x	mg/kWh	400	400
Dust	mg/kWh	10	10

Table 2-6: European directive for Euro 6 heavy-duty vehicles.[29]

2.3.1.4 Financial attractiveness

This KPI assesses the financial attractiveness of the proposed technology options in terms of payback time. The purpose is to evaluate the financial attractiveness of the proposed reinforcement. The **Discounted[30] payback period** of the specific investment is calculated. One should note that the aim of this Task 1 is to perform a societal CBA. The full business case analysis from the point of view of the investors is performed in Task 3 with a more in-depth analysis.

The calculation of the payback time inherently implies the revenue streams assessment on top of the investments (i.e. CAPEX) and maintenance related costs (i.e. OPEX), both for the P2G and the battery reinforcement. Details regarding the implemented value chains are provided in paragraphs *P2G value chain* and *Battery value chain* hereunder.

The financial attractiveness is evaluated by assessing the discounted payback time (i.e. time when the Net Present Value of the project will reach the breakeven point in the cumulated discounted cashflow). The cumulated discounted cashflow is based on the following assumptions[31]:

- For years corresponding to the investigated time horizon (i.e. 2030 and 2040), exact values obtained from the Market model are used (e.g. electricity average electricity price, produced hydrogen volumes, running hours of the electrolyser, etc.)
- For years between the two-time horizons, benefits and expenditures are linearly interpolated.
- For years beyond the furthest time horizon (after 2040): benefits and expenditures of this farthest time horizon are maintained.
- Only the hydrogen market and the Cross-Commodity Trading[32] have been considered for this analysis. Additional revenues streams are considered in Task 3.

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28 Regulation (EC) No 715/2007 of the European Parliament and of the Council of 20 June 2007 on type approval of motor vehicles with respect to emissions from light passenger and commercial vehicles (Euro 5 and Euro 6) and on access to vehicle repair and maintenance information (Text with EEA relevance); 2007; Accessible on: https://eur-lex.europa.eu/legal-content/en/ALL/?uri=CELEX%3A32007R0715

29 REGULATION (EC) No 595/2009 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 18 June 2009 on type-approval of motor vehicles and engines with respect to emissions from heavy duty vehicles (Euro VI) and on access to vehicle repair and maintenance information and amending Regulation (EC) No 715/2007 and Directive 2007/46/EC and repealing Directives 80/1269/EEC, 2005/55/EC and 2005/78/EC; 2009; Accessible on: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009R0595&from=EN

30 A uniform discount rate of 4% will be considered (i.e. real Weighted Average Cost of Capital), following ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, FINAL- Approved by the European Commission, February 2015.

31 *2nd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, ENTSO-E, FINAL, Approved by the European Commission, 27 September 2018*

32 Buy/Sell electricity, sell hydrogen.

P2G value chain

For the calculation of the business model and the payback time associated to the P2G reinforcement, it is best to define parties in the value chain (producer, storage party, distribution party, end users). Expenditures can be associated to each of these parties. They have been grouped in three main categories (i.e. upstream, midstream and downstream). The following items have been implemented in the hydrogen value chain as illustrated in Figure 2-7.

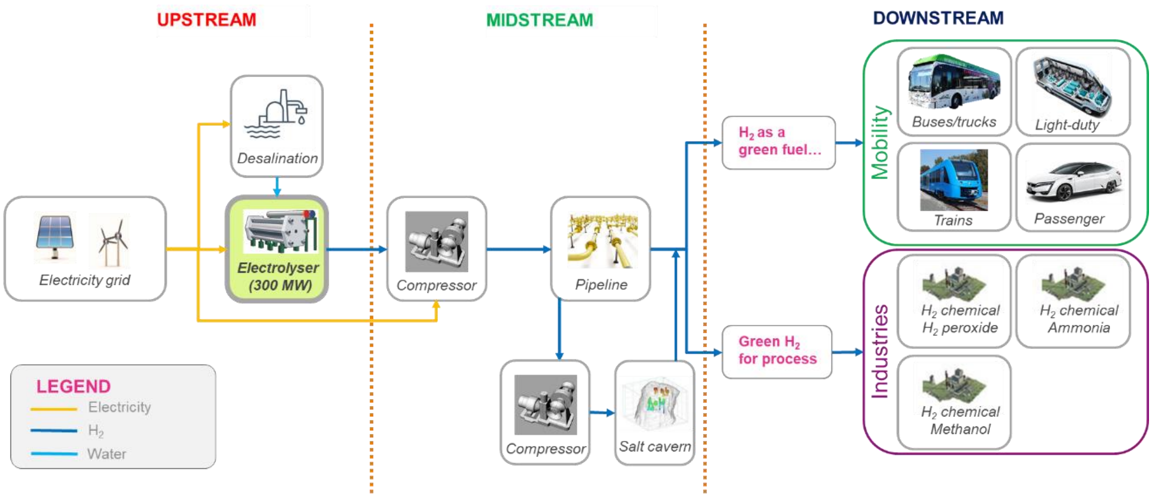

Figure 2-7: Hydrogen value chain. (source: Tractebel)

On the cost side:

- **Upstream expenditures**: costs related to hydrogen production.
    - Electrolyser investment and stack replacement;
    - Electrolyser fixed Operation & Maintenance cost (O&M);
    - Desalination unit investment[33];
    - Desalination fixed Operation & Maintenance cost (O&M);
    - Electricity cost for operating the electrolyser and the desalination unit.
- **Midstream expenditures**: costs related to the storage of the hydrogen. From the simulations, the seasonality of hydrogen production will clearly appear, leading to the need for hydrogen storage.
    - Compressor unit (30-65 bar) for pressurisation of the hydrogen to be circulated in the distribution pipeline;
    - Pipeline for hydrogen distribution from hydrogen production site (i.e. Eemshaven) to hydrogen storage location (i.e. Zuidwending);
    - Compressor unit (60-180 bar) for pressurisation of the hydrogen for storage;
    - Salt cavern for storage of the hydrogen.
- **Downstream expenditures**: distribution and dispensing costs. For instance, for mobility application, this includes distribution and dispensing costs (e.g. tube trailers) from the storage facility to the fuel stations end-users will come and buy hydrogen.

[33] Considering the location of the electrolyser (i.e. seaside), catering to the water requirements of the electrolyser through a desalination unit (rather than using clean available water), provides a global system approach englobing the major steps of hydrogen production. Furthermore, such an approach is resilient to water scarcity issues that may arise in the future. Finally, it should be mentioned that considering clean available water instead of a desalination unit will not change the conclusions of this study: contribution of water supply to the final Levelised Cost of Hydrogen is marginal (Tractebel).

On the revenue side:

The revenue stream considered in the scope of the study is related to the selling of the produced hydrogen to hydrogen off-takers, taking into account both the potential size of the different markets, as well as the price end-users will be ready to pay for green hydrogen. As it is explained in more detail in section 3.1, the following hydrogen markets have been envisaged:

- Mobility: buses, trucks, trains, light-duty trucks and passenger vehicles;
- Industry: hydrogen peroxide, ammonia production, methanol production.

Each player of this value chain will likely require returns in every step. Nevertheless, within the Cost Benefit Assessment, only the total margin of the full value chain is assessed, answering the questions 'Is it interesting from a societal perspective to consider hydrogen? Is there an interesting business case to invest in the hydrogen value chain?'. The split of the margin between production, distribution, storage and sales is out of the scope of the CBA[34].

Out of scope:

This KPI assessment does not take into account the following items:

- Purification section with drying unit and pressure swing absorption: it is assumed that the quality of the hydrogen out of the salt cavern is sufficient to meet hydrogen-oriented mobility requirements.
- The implemented Market model is day-ahead oriented. Intraday market will be analysed in Task 3[35].
- Additional revenues streams, inherent to hydrogen production, are not accounted for[36] (i.e. they could further increase P2G financial attractiveness).
    - Monetisation of services provided to the grid (i.e. balancing, congestion management, etc.). This is included in Task 3 of Activity 3[37].
    - Monetisation of oxygen production in the electrolysis process (i.e. to be used in industries such as steel, glass semi-conductor, hospital, etc.): from Tractebel experience, this contributes to a small decrease in the total Levelised Cost of Hydrogen (LCOH)[38].
- Additional costs related to the connection to the electricity grid[39].

In the scope of this value to society assessment, certain costs have not been taken into account for the business case analysis of the electrolyser since the aim is to capture an overview of the benefits the electrolyser can bring on several aspects. The reader is invited to read the report of Task 3 of this Activity 3 for deeper insights on the business case of the electrolyser.

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[34] The overall margin is captured through the total discounted payback time analysis and the Net Present Value curve (see section 4.2.4.1). A project resulting in an NPV above zero at the end of the project can be translated as a project generating economic value, meaning that there is a margin to be shared among the different players.

[35] Uncertainty related to the evolution of intraday/imbalance markets' volumes, etc. are considered in Task 3 through sensitivity analysis.

[36] Long-term uncertainty of these value streams, thus should not be a determining factor in the business case assessment

[37] *Assessing the business model and operational scheme of the electrolyser*

[38] i.e. 0.2 €/kgH_2, *Prefeasibility study for a 100 MW electrolyser in Northern Netherlands.*

[39] As it is touched upon in Task 3, for the hydrogen market to materialize in the Northern Netherlands, incentives and/or amendments to current regulatory frameworks will most probably be required (e.g. electricity transport/capacity/connection tariffs). Uncertainty related to these tariffs are considered in Task 3 through sensitivity analysis.

Battery value chain

The value chain of the battery reinforcement is composed of the following expenditures:

On the cost side:

Battery power (i.e. MW) investments and fixed O&M, including the inverter and the balance of plant.

- Battery capacity (i.e. MWh) investments and fixed O&M.
- For a large-scale battery system, a capacity maintenance plan is taken into account: Every year, 2% of the capacity (MWh) is assumed to be lost (20% over 10 years). It is assumed that this capacity will be replaced every year, so that the capacity remains the same every year.

On the revenue side:

The revenue stream considered in the scope of the study is related to energy trading in the spot (i.e. day ahead) market also referred to as “arbitrage”. The battery operator will generate revenues by charging the battery at low electricity prices and discharging it (i.e. sell electricity back to the grid) at high electricity prices. Considering that the implemented Market model is day-ahead oriented and consistent with the approach considered for the electrolyser, additional revenues such a grid balancing, frequency control or capacity remuneration mechanisms are not accounted for, even though such revenue stacking could represent a relevant revenue stream and further shorten the payback time.

2.3.2 Grid-based KPIs

The following sections describe the KPIs assessed with the Grid model built by CIRCE in DIgSILENT PowerFactory using grid data from TenneT TSO B.V..

The Optimal Power Flow (OPF) optimises a certain objective function in a network whilst fulfilling equality constraints (the load flow equations) and inequality constraints (e.g. generator power limits). One of the objective functions of the OPF is the minimisation of costs function, in which the goal is to supply the system under optimal operating costs. More specifically, the aim is to minimise the cost of power dispatch based on non-linear operating cost functions for each generator and on tariff systems for each external grid.

The methodologies developed for the assessment of the Grid-based KPIs are mainly based on the Optimal Power Flow analysis. For each scenario, an OPF simulation is run taking into account the specificities, constraints and the generation mix of that specific scenario. From the results of the OPF simulation, several KPIs can be assessed.

2.3.2.1 RES integration

Due to network technical problems such as overvoltage, over-frequency, local congestion, RES production can be curtailed partially or totally. Since renewable energy curtailment represents wasting very low cost and low carbon emitting energy, a key benefit of a strengthened grid is that such curtailment is reduced while still maintaining system security and reliability. The RES integration can be evaluated through the “energy curtailment of RES” which can be assessed as the difference between available RES energy ($E^{RES,available}$), given by the nodal generation profile $\xi_{n,t}$, and deployed RES energy ($E^{RES,deployed}$):

$$E_{CurtailmentSCENARIO,n} = E_n^{RES,available} - E_n^{RES,deployed} = \int_T \left(\xi_{n,t}\overline{P_n^{RES,CAP}} - P_{n,t}^{RES}\right) dt$$

$$E_{CurtailmentSCENARIO} = \sum_{n \in N} E_{CurtailmentSCENARIO,n}$$

Equation 3: Formula to calculate the RES integration KPI.

This index is a direct result from an Optimal Power Flow simulation. Renewable generation will produce as much as possible unless curtailment is necessary due to grid bottlenecks or low consumption (no other curtailment situations are taken into account).

Notations used in the Grid Model KPIs definitions can be found in Table 2-7.

Notation	
$P_{n,t}^{RES}$	Scheduled/deployed power output of RES generator at node *n* for time *t* [MW].
$\xi_{n,t}$	Expected generation profile of RES generation at node *n* for time *t* [-].
N	Set of all nodes.
$P_{n,t}^{shed}$	Load shed at node *n* during time *t* [MW].
T	Considered time horizon (i.e., 1 year).
$\overline{P_{n}^{RES,CAP}}$	Installed RES capacity at node n [MW] (parameter).

Table 2-7: Notations used in the Grid Model KPIs definition.

2.3.2.2 Security of supply

Energy not served (ENS) is a proxy to assess the security of supply, which is the ability of a power system to provide an adequate and secure supply of electricity in ordinary conditions, in a specific area. To evaluate this KPI, we consider all the load shedding taking place in the different network nodes during the whole simulated year:

$$ENS_{SCENARIO} = \sum_{n \in N} \int_T P_{n,t}^{shed} \, dt$$

Equation 4: Formula to calculate the security of supply KPI.

Both indexes should be a direct result from an Optimal Power Flow simulation.

Renewable generation will produce as much as possible unless curtailment is necessary due to grid bottlenecks or low consumption (no other curtailment situations are be taken into account). This index is also a direct result from an Optimal Power Flow simulation. Loads should always be fully met unless there is not enough energy to serve them.

2.3.2.3 Variation in losses

The evaluation of **losses** in the lines is, like the previous two KPIs, a direct output of the OPF. The energy efficiency benefit of a project is measured through the reduction of thermal losses in the system. At constant transit levels, network development generally decreases losses, thus increasing energy efficiency. Specific projects may also lead to a better load flow pattern when they decrease the distance between production and consumption[40].

2.3.2.4 Congestion

Regarding **congestion**, this KPI can also be directly derived from the results of the OPF.

Under the availability of sufficient transmission capacity, the merit order of the generators when dispatched to supply the demand can be respected. In this case, there is only one marginal generator, which is the last one in the merit order to be dispatched to satisfy the demand, i.e., the most expensive one, which sets the price and is only dispatched as much as needed (usually below its capacity limit) to cover the remaining demand.

A single congestion, however, might prevent a cheaper generator with sufficient capacity to supply the remaining demand to be dispatched to the required levels. This issue is caused by the grid not being able to absorb higher power injection levels at the generator's connection point. Given that the congestion prevents a cheap generator in the merit order curve (often a renewable energy generator with very low marginal cost) to produce as much power as required to satisfy the demand, another, more expensive

[40] ENTSO-E Guideline for Cost Benefit analysis of Grid Development Projects

'out-of-merit-order' generator is additionally required to be dispatched. This increases the total generation cost and thus, reduces social welfare as well as renewable energy penetration[41].

For each hour, the merit order of the dispatched generators will be compared with the ideal situation, with no congestions at all, as illustrated in Figure 2-8. For all the congested generators, the difference between the real and the ideal dispatch will be calculated. The sum of all these values provides an indicator of the total congestion for a specific hour of the year. The congestion can be expressed then as the total year congestion, adding all the hourly values, or as an average hourly value.

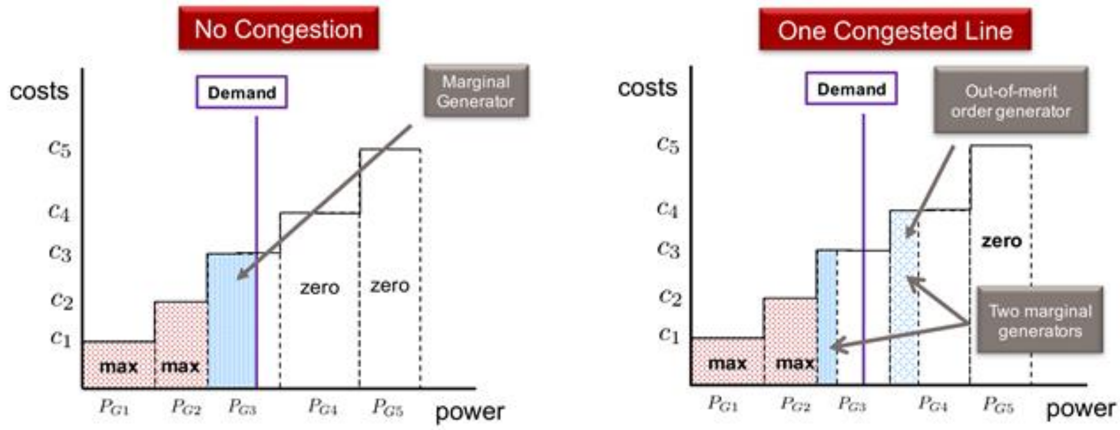

Figure 2-8: Comparison of merit order without and with congestion. (source: Best Paths Project[42])

2.3.2.5 Avoided transmission upgrades

An additional KPI will be calculated, called 'Avoided transmission upgrades'. In order to compute this KPI, the overloaded lines will be determined in each scenario. Following discussions with one of the partners in the TSO2020 consortium (i.e. TenneT TSO B.V.), only lines with a loading higher than 100% for a number of hours greater than 100 are considered as overloaded lines that would require an upgrade. Comparing the number of overloaded lines in the electrolyser/battery scenario with the base scenario, the avoided length of overloaded lines can be obtained.

The cost associated to the investment in an electrolyser and a desalination unit can be translated into a given annualised cost, taking into account the lifetime of the assets. A traditional grid reinforcement being characterised by a longer lifetime, a higher investment can be spent for the same annualised costs. The corresponding grid investment will be named hereafter 'Grid reinforcement threshold'.

If the cost of the avoided transmission grid reinforcements (i.e. enabled through the use of an electrolyser or a battery) is lower than this 'Grid reinforcement threshold', the KPI will score low.

[41] L. Halilbasic, F. Thams, R. Zanetti, G. Tsoumpa, P. Pinson and S. Chatzivasileiadis, "D13.1 "Technical and economical scaling rules for the implementation of demo results"," BEST PATHS project, 2018.

[42] L. Halilbasic, F. Thams, R. Zanetti, G. Tsoumpa, P. Pinson and S. Chatzivasileiadis, "D13.1 "Technical and economical scaling rules for the implementation of demo results"," BEST PATHS project, 2018.

2.3.3 Additional KPIs

2.3.3.1 Flexibility

The flexibility KPI is defined as '*The ability of the proposed reinforcement to facilitate trading/sharing of balancing services on wider geographical areas*'[43]. Focus is currently put on the impact in terms of capability of the system to provide FCR (i.e. Frequency Containment Reserve), aFRR (i.e. Automatic Frequency Restoration Reserve) or mFRR (i.e. Manual Frequency Restoration Reserve).

- The **Frequency Containment Reserve (FCR)**, commonly known as the primary frequency control, can be defined as follows[44]: it serves as the first barrier against active power imbalances. This service is designed to limit frequency excursions within the first 30 seconds after a disturbance, and it is based on the regulation of electricity generation or consumption in response to the change of frequency. Technically, FCR requests the activation of the full bid within 30 seconds in case of a ±200 mHz frequency deviation.
- **Automatic Frequency Restoration Reserve** (aFRR), commonly known as secondary frequency control, can be defined as follows[44]: aFRR acts right after FCR (after 30 seconds), in order to restore the active power balance in every control area within 15 minutes after a disturbance. The procurement of aFRR is handled by TenneT TSO B.V. in a centralised manner with Load Frequency Control (LFC). Power setpoints are realised in steps of 1 MW, a minimum ramp rate of 7 % of the bid per minute must be provided, and full activation of the bid must be completed within 15 minutes[45].
- **Manual Frequency Restoration Reserve** (mFRR), commonly known as tertiary frequency control, follows aFRR and constitutes an (economic) rescheduling of generation capacity in order to relieve aFRR for the longer term. In practice, mFRR is only activated when a severe outage occurs.

As suggested in the ENTSO-E methodology, accurately calculating the flexibility is quite complex. A literature review is therefore suggested rather than algorithmic calculation. Results from Activity 2 are also used to further characterise the ability of an electrolyser to participate in ancillary services.

2.3.3.2 Technical resilience

The technical resilience KPI is defined as '*The ability of the system to withstand increasingly extreme system conditions (exceptional contingencies)*'[46].

TenneT TSO B.V. and Energinet requested to consider disturbances close to Eemshaven substation due to the number of controllable devices connected to this substation and nearby substations.

More specifically, this KPI characterises the ability of the system to cope with disturbances (i.e. technical performance in terms of stability) such as N-1 (loss of one component) or even N-2 events (loss of 2 components) around the substations Eemshaven and Eemshaven-Oudeschip (located in GDO). Events such as line faults, generators disconnection, line tripping or 3-phase short circuits are considered. Contrary to the other KPIs, this stability analysis requires a dynamic electrical power system analysis, which cannot be directly provided neither by the Market model nor by the Grid model (i.e. static

[43] ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, FINAL- Approved by the European Commission, February 2015.

[44] *Integration of Power-to-Gas Conversion into Dutch Electrical Ancillary Services Markets*, Víctor García Suárez, José L. Rueda Torres, Bart W. Tuinema, Arcadio Perilla Guerra and M.A.M.M van der Meijden, Enerday 2018, 12th Conference on Energy Economics and Technology, April 2018.

[45] TenneT TSO B.V., *Productinformation aFRR (Regulating power)*, Jan. 2018. [Online]. Available: https://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/Dutch/Product_information_aFRR_-regulating_power-_16-01-2018.pdf

[46] ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, FINAL- Approved by the European Commission, February 2015.

models). The Dynamic model developed within Activity 2 can, on the other hand, characterise time varying response of the frequency, voltage magnitude and voltage angle to N-1 or N-2 events.

In that perspective, insights on the technical resilience KPI is provided by Activity 2. In the stability study of Activity 2, only the effect of the electrolyser on the electrical transmission system is considered and compared with a situation without any electrolyser. Consequently, this KPI is not assessed for the battery reinforcement. Finally, scenarios have already been defined for 2030 in Activity 2 based on TenneT TSO B.V.'s 2017 KCD[47][48]. After analysis, these scenarios are judged to be in line with the conservative scenario defined in the CBA analysis. Activity 2 has then extended its analysis to 2040 for the technical resilience KPI.

In conclusion, the technical resilience KPI is assessed based on Activity 2 results, but for a limited number of scenarios and cases:

- For 2030 and 2040 conservative scenarios only.
- Only the effect of the electrolyser is assessed.

2.3.3.3 Implementation time

This KPI assesses the required implementation time of the proposed decentralised energy solutions for providing flexibility to the transmission grid, meaning the electrolyser and the battery. This implementation time includes manufacturing and installation on-site. The implementation time of these solutions are compared with each other.

2.3.3.4 Public acceptance

No KPI related to *public acceptance* is considered in the scope of this CBA analysis. It is indeed reasonable to assume that the installation of an electrolyser or a battery in an industrial area is much less controversial than other energy transition projects such as on-shore wind farms in a greenfield or overhead power lines (e.g. visual impact).

47 Kwaliteits- en Capaciteitsdocument 2017 Deel I: Kwaliteitsbeheersingssysteem, TenneT, Accessible on: https://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/Dutch/TenneT_KCD2017_Deel_I_web.pdf

48 Kwaliteits- en Capaciteitsdocument 2017 Deel II: Investeringen Net op Land 2018 – 2027, TenneT, Accessible on: https://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/Dutch/TenneT_KCD2017_Deel_II.pdf

2.4 Grid reinforcement cases: technical and economic parameters

This section aims at summarising the key technical and economic parameters considered for the two considered reinforcement technologies, namely P2G (i.e. electrolyser) and battery storage. Moreover, this chapter also details the assumptions required for the electrolyser and battery value chains modelling (see pages 20 and 22), which are of direct use for the *financial attractiveness* KPI previously defined.

2.4.1 Power-to-Gas (electrolyser)

The primary equipment for hydrogen production is the **electrolyser**, which converts water and electricity into hydrogen. In the scope of the study, a 300 MW Polymer Electrolyte Membrane (PEM) electrolyser[49] is considered. Parameters are summarised in Table 2-8.

Parameter	Value	Unit	Source / Comment
Investment cost (CAPEX)	400	EUR/kW_{el}	Gasunie: Only Electrolyser, no costs included for project development and compression[50]
O&M	2 % of CAPEX	$EUR/kW_{el}/year$	Gasunie: excluding preventive maintenance /check by operator
Efficiency	49	kWh_{el}/kgH_2	Gasunie
Stack lifetime	60,000	hours	Gasunie
Degradation	0.2%	%/1000hrs	Gasunie
Stack CAPEX	200	EUR/kW_{el}	Tractebel
System lifetime	20	Years	Tractebel

Table 2-8: Technical and Economic parameters - Electrolyser.

Considering the location (i.e. Eemshaven), it is assumed that the electrolyser operator has a free access to sea water. A **sea water reverse osmosis** type of **desalination** unit is therefore included in the hydrogen production chain. Parameters for the desalination unit are summarised in Table 2-9.

Parameter	Value	Unit	Source / Comment
Investment cost	51,768	$EUR/(m^3\_H_2O/h)$	Tractebel internal studies
Fixed O&M	3% of CAPEX	$EUR/(m^3\_H_2O/h)/year$	Tractebel
Energy efficiency	3	$kWh/m3\_H_2O$	Tractebel
Lifetime	30	Years	Tractebel

Table 2-9: Technical and Economic parameters – Desalination unit.

From the performed simulations, the seasonality of hydrogen production and the inherent need for seasonal hydrogen storage can be observed. Considering the favourable context of the Northern Netherlands and its long experience with natural gas, storing hydrogen in a salt cavern is selected as the most suitable solution. It offers competitive cost compared to other solutions, such as a pressurised tank or dedicated hydrogen pipeline, especially for the scale at stake. More specifically, Zuidwending, with its direct connection to a gas storage facility, is ideal because of the available storage capacity. Zuidwending has salt caverns located 1000 meters underground. This location is also ideal because it is well connected to existing infrastructure[51]. Retrofitting of the cavern currently dedicated to natural gas

[49] PEM electrolyser, contrary to Alkaline electrolysers which are not eligible for grid service, demonstrate great dynamic response and flexible operation.

[50] Considering the high industrial activity of the Eemshaven region, we can assume that a sub-station is already available and that network connection costs will be neglectable compared to the other costs. For construction costs, the effect of a lang factor of 20% on the achieved payback time will be assessed for the different scenarios.

[51] https://www.gasunie.de/en/the-company/gasunie-corporate/future-projects

storage to a new type of cavern dedicated to hydrogen storage has already been studied for several years by different players, such as Gasunie and EnergyStock in the HyStock pilot project[52].

To transfer the produced hydrogen from Eemshaven to Zuidwending, hydrogen should be conveyed through a pipeline. In that perspective, compression related costs to supply the produced H_2 to a pipeline are additional costs to be considered. A typical output pressure of a PEM electrolyser is 30 bar. The H_2 pipeline to be used to transfer the hydrogen will be operated around 60 bar[53] (i.e. 60 bar is needed at the outlet of the pipeline, resulting in a required inlet pressure of the pipeline around 65 bars). Parameters of such a **compressor** (30 bar to 65 bar) are summarised in Table 2-10.

Parameter	Value	Unit	Source / Comment
Pressure IN	30	Bar	Tractebel: large scale PEM electrolyser
Pressure OUT	65	Bar	Gasunie: Pressure required at inlet of pipeline
Investment cost	490	EUR/(kg_H_2/h)	Tractebel
Fixed O&M	3% of CAPEX	EUR/(kg_H_2/h)/y	Tractebel
Efficiency	0.45	kWh_el/kg_H_2	Tractebel
Lifetime	20	Years	Tractebel

Table 2-10: Technical and Economic parameters – Compressor (30-65 bar).

To access the **pipeline**, an access fee is charged on a capacity basis (i.e. the user of the pipeline will not directly invest in it, the costs related to the hydrogen pipeline are viewed as an operational expenditure). A party such as Gasunie could convert an existing natural gas pipeline into a hydrogen pipeline. Additionally, it is assumed that such a party would want to obtain the same revenue regardless of whether the pipeline is operated with natural gas or with hydrogen. Reference values for today's entry[54] and exit[55] capacity tariffs for natural gas pipelines are considered. This tariff is then translated from natural gas to hydrogen[56].

Parameter	Value	Unit	Source / Comment
Entry capacity tariff	2.19	EUR/kwh/h/y (H_2)	Calculated based on Gasunie Transmission Services Conditions[57].
Exit capacity tariff	0.57	EUR/kwh/h/y (H_2)	Calculated based on Gasunie Transmission Services Conditions[57].
Pressure IN	65	bar	Gasunie
Pressure OUT	60	Bar	Gasunie

Table 2-11: Technical and Economic parameters – Hydrogen pipeline

52 https://www.energystock.com/about-energystock/the-hydrogen-project-hystock

53 Discussion with Gasunie experts

54 Assumed entry capacity tariff for natural gas: 0.97 €/kWh/h/year (i.e. it corresponds to Eemshaven average entry tariff, Appendix 1a, https://www.gasunietransportservices.nl/en/shippers/terms-and-conditions/tsc

55 Assumed exit capacity tariff: 0.252 €/kWh/h/year (i.e. it corresponds to Zuidwending storage exit tariff, Appendix 1b, https://www.gasunietransportservices.nl/en/shippers/terms-and-conditions/tsc

56 The energy content (i.e. in MJ/m3) of hydrogen is approximately three times smaller than of Groningen gas. To meet the same energy requirement, the volume of material to be transported must therefore be three times as large as for natural gas.

- Approach 1: It is known from research that the flow resistance of hydrogen is lower than natural gas, enabling to possibly circulate hydrogen with factor 3 faster than natural gas, while maintaining the same pressure drop. This would lead to applying the same capacity tariff for the two fluids.
- Approach 2: However, research also highlights the risks inherent to circulating hydrogen at high speed: erosion, corrosion, etc. This would imply to limit hydrogen speed, in the extreme case to the same speed as natural gas. Smaller amount of energy per hour would therefore be circulated with hydrogen than with natural gas, resulting in an increased capacity tariff to be applied on hydrogen (i.e. approximately a factor 3).

Assessing to which extent hydrogen speed can be increased is out of scope of the current CBA. An average factor of 2.25 is suggested (i.e. multiplication factor between gas and hydrogen tariffs).
Source: Verkenning waterstof infrastructuur, Ministerie van Economische Zaken, DNV-GL, available at https://www.topsectorenergie.nl/sites/default/files/uploads/TKI%20Gas/publicaties/DNVGL%20rapport%20verkenning%20waterstofinfrastructuur_rev2.pdf, November 2017

57 https://www.gasunietransportservices.nl/en/shippers/terms-and-conditions/tsc

Both the pipeline and the compressor for pressurisation of hydrogen from the electrolyser outlet pressure (30 bar) to the pipeline inlet pressure (65 bar) should be able to handle the maximum hydrogen production of the 300 MW electrolyser, namely 6122 kg/H_2/h.

Once conveyed until the storage facility, the pressure level is to be increased from 60 bar to 180 bar. Parameters of such a **compressor** (60 bar to 180 bar) are summarised in Table 2-12.

Parameter	Value	Unit	Source / Comment
Pressure IN	60	Bar	Tractebel: Pressure required at outlet of pipeline
Pressure OUT	180	Bar	Gasunie: Operating pressure of hydrogen salt cavern storage
Investment cost	600	EUR/(kg_H_2/h)	Tractebel
Fixed O&M	3% of CAPEX	EUR/(kg_H_2/h)/y	Tractebel
Efficiency	0.65	kWh_el/kg_H_2	Tractebel
Lifetime	20	Years	Tractebel

Table 2-12: Technical and Economic parameters – Compressor (60-180 bar).

Parameters related to the **salt cavern** (hydrogen storage facility) are summarised in Table 2-13.

Parameter	Value	Unit	Source / Comment
Investment cost	8.4	EUR/kg_H_2	HyUnder study[58]
Fixed O&M	3% of CAPEX	EUR/kg_H_2/year	Tractebel
Operating press	84-180	bar	Gasunie
Lifetime	50	years	Tractebel

Table 2-13: Technical and Economic parameters – Hydrogen salt cavern

2.4.2 Battery

As explained in Chapter 2, it is important to evaluate and compare how different technology options (e.g. P2G, battery storage) can play a role to stabilise the power grid and can be operated effectively with a viable and attractive business case compared to today's conventional technology. In that perspective, the total value to society of a Lithium-ion[59] battery system is investigated in parallel to the electrolyser. For comparison purpose, the battery power is matched to the analysed electrolyser, namely 300 MW. For such large-scale application and with energy trading purpose, 4 hours of storage is commonly selected[60,61], resulting in a power-to-energy ratio of 0.25 kW/kWh.

58 'Assessment of the Potential, the Actors and Relevant Business Cases for Large Scale and Long-Term Storage of Renewable Electricity by Hydrogen Underground Storage in Europe', Executive summary, June 2014

59 The Lithium-ion battery is suitable for power and energy applications. Furthermore it demonstrates several advantages: high round-trip efficiency, high energy and power density, low self-discharge, low maintenance, long cycle and calendar life, commercial availability, lots of research on this technology, price continuously decreasing, etc. ENGIE, Battery workshop, March 2018, Laborelec.

60 Charging Ahead on U.S. Storage Markets & Policy, Jason Burwen, Energy Storage Association (USA), Energy Storage Global Conference, October 2018.

61 The Economics of Energy Storage Projects, David J.A. Post, Enel, Energy Storage Association (USA), Energy Storage Global Conference, October 2018.

Parameters for the battery are summarised in Table 2-14.

Parameter	Value (2030 / 2040)	Unit	Source / Comment
Power CAPEX - Inverter	200 / 200	EUR/kW	Tractebel (no cost reduction expected)
Power CAPEX - BoP	100 / 100	EUR/kW	Tractebel (no cost reduction expected)
Energy CAPEX	175 / 125	EUR/kWh	Tractebel
Power fixed OPEX	2.5% of CAPEX	EUR/(kW*year)	Tractebel
Energy fixed OPEX	2.5% of CAPEX	EUR/(kWh*year)	Tractebel
Energy variable OPEX	1 / 1	EUR/kWh	DNV-GL
Charging/discharging efficiency	85 / 85	%	Tractebel
Max depth of discharge	80 / 80	%	Tractebel
Power-to-Energy ratio	0.25 / 0.25	kW/kWh	Tractebel
Self-discharge	0.004 / 0.004	[%/hr]	Tractebel
Lifetime	10 / 10	Years	Tractebel
Yearly capacity degradation	2 / 2	%/year	Tractebel

Table 2-14: Technical and Economic parameters - Battery.

3 HYDROGEN MARKET ANALYSIS

This chapter aims at characterising the hydrogen market in the Northern Netherlands and the electrolyser operation strategy.

The P2G unit, which is at the core of this project, can be operated to relieve congestion on the grid. It therefore adds load to the system, which needs to be accounted for in the simulations to be performed.

One should therefore address the following question: **How should the electrolyser be operated**? On the one hand, running the electrolyser too many hours of the year will lead to hydrogen production during moments of too high electricity prices and, therefore, to hydrogen that is non-competitive. Such hydrogen will as a consequence not be purchased by potential hydrogen off-takers. On the other hand, running the electrolyser too few hours per year will lead to a low hydrogen volume and a challenging return on investment of the associated hydrogen production infrastructure. A **trade-off must be found taking into account the potential off-takers** (i.e. which volume of hydrogen and for which sector(s)?), the **competitive price thresholds** they are willing to pay for the green hydrogen, as well as the **energy context** of each specific scenario.

The hydrogen market in the Northern Netherlands is described in section 3.1, while the electrolyser operation strategy is described in section 3.2.

3.1 Hydrogen market in the Northern Netherlands

The identification of a potential hydrogen market in the Northern Netherlands in 2030 and 2040 has been performed for this study. Two main potential markets have been identified in this region, being the industrial segment and the mobility segment. The assessed potential hydrogen markets of the Northern Netherlands in 2030 and 2040 are summarized in Figure 3-1. Moreover, they are put in perspective with the annual production of the 300 MW electrolyser considered in the scope of this study.

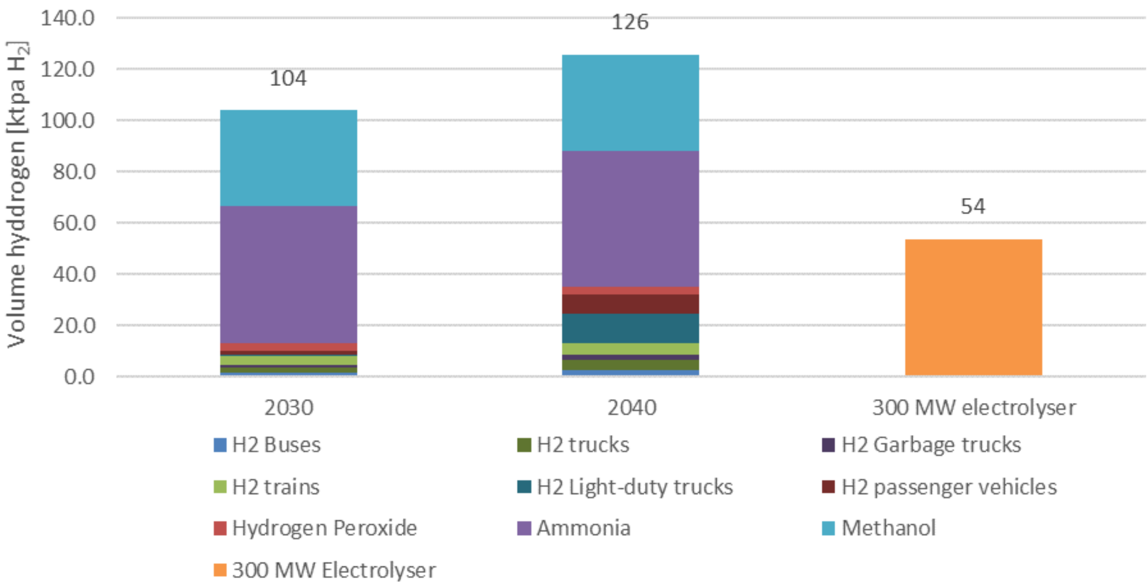

Figure 3-1: The identified potential hydrogen market of the Northern Netherlands in 2030 and 2040 compared with the annual production of a 300 MW electrolyser. (source: Tractebel)

3.1.1 Chemical industry segment in the Northern Netherlands

A methanol plant and hydrogen peroxide plant are currently present in the Northern Netherlands, in the industrial zone Delfzijl. Both of these industrial processes require hydrogen. Today, they are supplied by an on-site Steam Methane Reforming (SMR) plant.

Additionally, it can be imagined that an ammonia plant that runs on green hydrogen will be constructed in the Northern Netherlands. This 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.[62]

By 2030, it is feasible that a 300 ktpa methanol plant and a 300 ktpa ammonia plant run on hydrogen, as assumed by a study by Ad van Wijk[63]. Furthermore, a 50 ktpa hydrogen peroxide plant could be converted to a green hydrogen peroxide plant. This results in the following green hydrogen demands in the chemical industry segment in the Northern Netherlands in 2030:

- 53 ktpa hydrogen demand for the 300 ktpa ammonia plant;
- 38 ktpa hydrogen demand for the 300 ktpa methanol plant;
- 3 ktpa hydrogen demand for the 50 ktpa hydrogen peroxide plant.

It is assumed that this hydrogen demand for the industry remains the same in 2040, since no forecast was available regarding the potential increase of production for those industries. The annual green hydrogen demand for the chemical industry segment in 2030 and 2040 can be found in Figure 3-2.

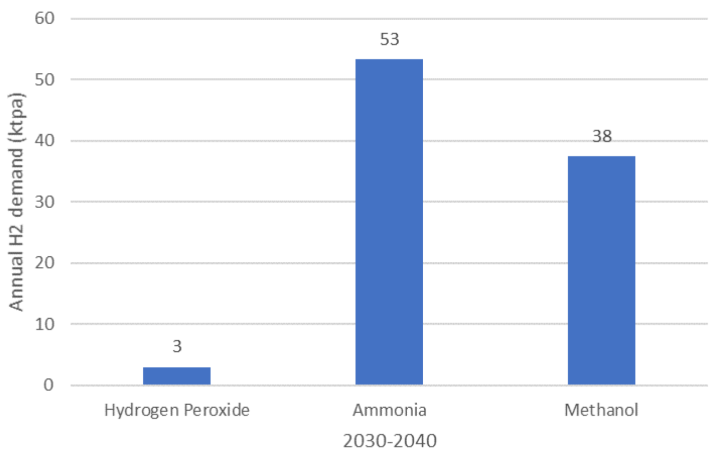

Figure 3-2: Annual green hydrogen demand for the chemical industry segment in 2030 and 2040. (source: Tractebel)

3.1.1.1 Competitive analysis – Chemical industry

The competitive price thresholds that industrial off-takers will be ready to pay for hydrogen is assessed by looking at the price they would pay by keeping on using conventional fuels. More specifically, the envisaged industries are conventionally using Steam Methane Reforming (SMR)-based hydrogen. 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.

[62] https://energeia.nl/fd-artikel/40078827/noorden-wil-2-8-mrd-investeren-in-waterstof Accessed on: 29/03/2019.

[63] The Green Hydrogen Economy in the Northern Netherlands, Noordelijke InnovationBoard, Ad van Wijk, 2018

Depending on the scenario, the competitive cost of non-green hydrogen produced with a SMR including a CO_2 tax (i.e. CO_2 emissions related to gas usage in SMR process), is between 1.46 and 2.76 €/kg H_2 (see Table 3-1). The natural gas price and CO_2 tax price are based upon ENTSO-E TYNDP 2018 scenarios[64].

Since the methanol plant already has a SMR on-site, we assume that the competitive cost of green hydrogen needs to be compared to the competitive cost of an amortised SMR. For both the ammonia plant and the hydrogen peroxide plant, a non-amortised SMR is considered for the comparison of the competitive cost. The reason is that the ammonia plant today is not yet built in the Northern Netherlands and that the SMR plant on the site of the hydrogen peroxide plant is relatively new and assumed not yet amortised.

	Conservative		Reference		Progressive(+)	
	2030	**2040**	**2030**	**2040**	**2030**	**2040**
Natural gas price (€/GJ)[65]	6.90	8.08	8.80	5.50	8.80	9.80
CO_2 price (€/ton CO_2)	27	36	84	45	50	80
SMR non-amortised (€/kg H_2)[66]	1.57	1.76	1.88	1.34	1.88	2.04
SMR amortised (€/kg H_2)	1.29	1.48	1.60	1.06	1.60	1.76
Total cost non-amortised SMR + CO_2 tax (€/kg H_2)	1.81	2.08	2.63	1.74	2.33	2.76
Total cost amortised SMR + CO_2 tax (€/kg H_2)	1.53	1.80	2.35	1.46	2.04	2.48

Table 3-1: Cost of producing hydrogen for the different scenarios in 2030 and 2040 with an amortised and non-amortised SMR, including future CO_2 taxes.

3.1.2 Mobility segment in the Northern Netherlands

For the mobility segment, the main assumptions for this study have been collected from Gasunie, New Energy Coalition, a study by Ad van Wijk[67] and Tractebel. The following vehicles with a high potential for the transition from conventional fuel to hydrogen have been identified as:

- Buses
- Trains
- Trucks
- Light duty trucks
- Garbage trucks

The passenger vehicle segment is expected to undergo transition towards electric vehicles. Only a small fraction of the fleet will run on green hydrogen. In 2030, it is assumed that 1% of the passenger vehicles in the Northern Netherlands will run on hydrogen and 5% in 2040. To identify the number of passenger vehicles in 2030 and 2040, the linear increase of passenger vehicles from 2000 to 2018 is assumed to be continued to 2030 and 2040[68]. The assumptions regarding the number of vehicles and their respective hydrogen consumption are summarized in Table 3-2.

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[64] ENTSO-E TYNDP 2018 Scenario Report, Annex 2, Methodology, available at https://docstore.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/Scenario_Report_ANNEX_II_Methodology.pdf

[65] Based on ENTSO-E TYNDP 2018 scenarios: EUCO30 as Conservative-2030, ST2030 as Reference-2030, DG2030 as Progressive(+)-2030; ST2040 as Reference-2040, DG2040 as Progressive(+)-2040. Values for Conservative-2040 are extrapolated from EUCO30 and trends observed in IEA World Energy Outlook 2016-Current Policies scenario.

[66] Based on Tractebel expertise

[67] The Green Hydrogen Economy in the Northern Netherlands, Noordelijke Innovation BoardInnovationBoard, Ad van Wijk, 2018

[68] http://statline.cbs.nl/Statweb/publication/?DM=SLNL&PA=7374hvv&D1=2-11&D2=0-1&D3=a&HDR=T&STB=G2,G1&VW=T

	# H_2 Vehicles 2030	# H_2 Vehicles 2040	Avg. dist. (km/day)	H2 consumption		H2 demand (ktpa H2)	
				(kg/100 km)	**(kg/day)**	**2030**	**2040**
H_2 Buses	164	300	300	9	-	1.3	2.4
H_2 trains	50	72	-	-	200	3.3	4.8
H_2 trucks	300	550	235	10	-	2.3	4.3
H_2 Light duty vehicles	600	10,000	-	1.7	3.5	0.7	11.6
H_2 Garbage trucks	164	250	-	-	20	1.1	1.7
H_2 passenger vehicles	10,004	55,744	13,200 km/year	1	-	1.3	7.4

Table 3-2: The assumptions regarding the number of vehicles and their respective hydrogen consumption.

The annual green hydrogen demand for the mobility segment in 2030 and 2040 is summarised in Figure 3-3.

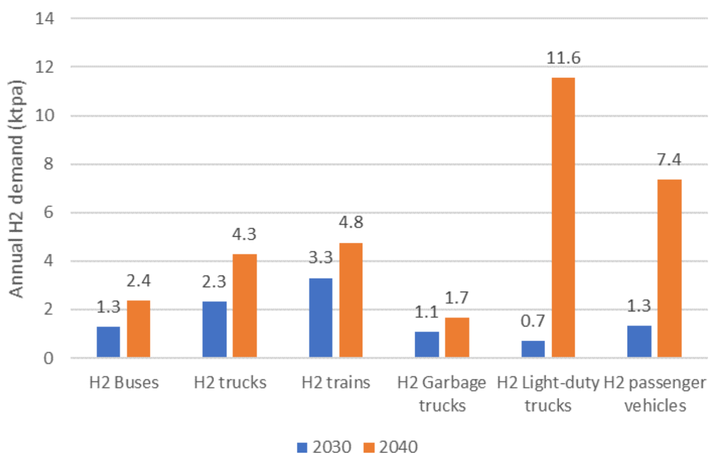

Figure 3-3: Annual green hydrogen demand for the mobility segment in 2030 and 2040. (source: Tractebel)

3.1.2.1 Competitive analysis – Mobility

For the competitiveness analysis of the mobility segment, buses, trucks and trains are combined. The comparison with diesel is performed for the B2B (i.e. Business to Business) vehicles and passenger vehicles. The reason that the comparison is made with diesel is related to the fact that B2B vehicles are generally fuelled more by diesel than gasoline. The comparison to diesel was also done for passenger vehicles to be conservative. Indeed, gasoline is typically more expensive than diesel (e.g. for instance due to higher excise duty[69,72]) and gasoline cars are less fuel efficient than diesel ones. Owners of gasoline passenger cars would therefore be willing to be pay more for green hydrogen than owners of diesel passenger cars. Targeting gasoline passenger cars might then lead to over-estimating the competitive hydrogen threshold, as well as the electrolyser business case. Diesel fuel price for the different scenarios in 2030 and 2040 including excise duty and taxes are summarized in Table 3-3.

From a technology readiness and market maturity perspective, the produced hydrogen will be allocated sequentially to trucks and buses, to trains, then to light-duty truck and finally to passenger cars.

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[69] http://statline.cbs.nl/Statweb/publication/?DM=SLNL&PA=7374hvv&D1=2-11&D2=0-1&D3=a&HDR=T&STB=G2,G1&VW=T

Hydrogen mobility demonstrates indeed a real advantage over battery electric vehicles for long distance type of vehicles (e.g. truck and inter-city buses) or vehicles aimed at transporting heavy goods[70] (e.g. commercial light duty trucks).[80]

	Conservative		Reference		Progressive(+)	
	2030	**2040**	**2030**	**2040**	**2030**	**2040**
Diesel price[71] (€/GJ)	20.5	23.57	21.8	17.1	21.8	24.4
Excise duty[72] (€/l)	0.49	0.49	0.49	0.49	0.49	0.49
Tax	21%	21%	21%	21%	21%	21%
Total fuel price (€/l)	1.49	1.62	1.55	1.34	1.55	1.66

Table 3-3: Diesel fuel price for the different scenarios in 2030 and 2040 including excise duty and taxes.

B2B Mobility – Buses, trucks and trains

The fuel efficiency of hydrogen buses that run on a fuel cell are compared with traditional diesel buses. A typical diesel bus has an efficiency of 32 litres of diesel per 100 km, compared to a hydrogen fuel cell bus that has an efficiency of 9 kg H_2 per 100 km[73]. Multiplying the diesel bus efficiency and the diesel price (Table 3-4), the OPEX competitiveness price in €/100 km is obtained. Dividing this number by the fuel cell bus efficiency, the OPEX competitiveness in €/kg H_2 is calculated. Adding the distribution and dispensing costs, this final number corresponds to the price end-users will be willing to pay at the pump station to fill their hydrogen tank. In other words, it corresponds to the price at which hydrogen could be sold at the end of the downstream step of the hydrogen value chain presented in Figure 2-7. The price at which hydrogen should be produced (i.e. the cost at the end of the midstream step (see Figure 2-7)) can consecutively be obtained by subtracting the distribution and dispensing costs[74]. H_2 competitive prices are summarised in Table 3-4.

	Conservative		Reference		Progressive(+)	
	2030	**2040**	**2030**	**2040**	**2030**	**2040**
OPEX competitiveness Diesel (€/100 km)	47.6	51.9	49.4	42.9	49.4	53.1
OPEX competitiveness Diesel (€/kg H_2)	5.3	5.8	5.5	4.8	5.5	5.9
Distribution and dispensing (€/kg H_2)[75]	1.5	1.5	1.5	1.5	1.5	1.5
Final OPEX competiv. Diesel (€/kg H_2)	3.8	4.3	4.0	3.3	4.0	4.4

Table 3-4: OPEX Competitive hydrogen price considering the efficiency of hydrogen fuel cell buses and diesel buses.

Only the OPEX regarding fuel consumption is considered and not the investment costs of fuel cell buses and diesel buses, since it is assumed that both will be at the same investment costs by 2030.[76] Depending on the scenario, the competitive price of hydrogen (at the end of the midstream step) in 2030 is between 3.8 and 4.0 €/kg H_2 and for 2040 between 3.3 and 4.4 €/kg H_2, see Table 3-4.

70 Fuel-cell vehicle saves significant weight compared to battery electric vehicle, resulting in higher effective weight they can transport.

71 Based on ENTSOE 2018 scenarios: 2020 Expected Progress, EUCO30 as conservative, ST2030 as reference, DG2040 as progressive; EUCO40 as conservative, ST2040 as reference, DG2040 as progressive

72 Excises 2018: https://www.unitedconsumers.com/tanken/informatie/opbouw-brandstofprijzen.asp

73 Sectoral integration- long-term perspective in the EU Energy System, Asset study for the European Commission, 2018. Available at: https://ec.europa.eu/energy/sites/ener/files/documents/final_draft_asset_study_12.05.pdf

74 Distribution and dispensing costs of 1.5 €/kg H_2 are considered for B2B mobility (i.e. typical delivery pressure: 300 bar).

75 Based upon Tractebel expertise and confirmed with California Energy Commission & NREL report, available at https://www.energy.ca.gov/2015publications/CEC-600-2015-016/CEC-600-2015-016.pdf.

76 Fuel Cell Electric Buses – Potential for Sustainable Public Transport in Europe, A Study for Fuel Cells and Hydrogen Joint Undertaking, Roland Berger, 2015. Available at: https://www.fch.europa.eu/sites/default/files/150909_FINAL_Bus_Study_Report_OUT_0.PDF

B2B Mobility – Light duty vehicles

Hydrogen light duty vehicles have pressurised tanks at 700 bar, thus resulting in higher distribution and dispensing costs. The competitiveness analysis is performed comparing the efficiency of hydrogen light duty vehicles and diesel light duty vehicles. The efficiencies are as follows:

- Efficiency H_2 light duty vehicle: 1.7 kg H_2/100 km[77]
- Efficiency diesel light duty vehicle: 7.4 l/100 km[78]

Depending on the scenario, the competitive price of hydrogen (at the end of the midstream step) in 2030 is between 4.6 and 4.8 €/kg H_2 and for 2040 between 3.9 and 5.3 €/kg H_2, see Table 3-5.

	Conservative		Reference		Progressive(+)	
	2030	**2040**	**2030**	**2040**	**2030**	**2040**
OPEX competitiveness diesel (€/100 km)	11.0	12.0	11.4	9.9	11.4	12.3
OPEX competitiveness diesel (€/kg H_2	6.6	7.2	6.8	5.9	6.8	7.3
Distribution and dispensing (€/kg H_2)[79]	2.0	2.0	2.0	2.0	2.0	2.0
Final OPEX competiv. diesel (€/kg H_2)	4.6	5.2	4.8	3.9	4.8	5.3

Table 3-5: OPEX Competitive hydrogen price considering the efficiency of hydrogen light duty vehicles and diesel light duty vehicles.

Passenger vehicles

The same method as the previous two competitive analysis is performed for the passenger vehicles, taking into account the differences in efficiencies[80]:

- Efficiency H_2 passenger vehicle: 1.0 kg H_2/100 km
- Efficiency diesel passenger vehicle: 4.5 l/100 km

	Conservative		Reference		Progressive(+)	
	2030	**2040**	**2030**	**2040**	**2030**	**2040**
OPEX competitiveness diesel (€/100 km)	6.7	7.3	7.0	6.0	7.0	7.5
OPEX competitiveness diesel (€/kg H_2	6.7	7.3	7.0	6.0	7.0	7.5
Distribution and dispensing (€/kg H_2)[79]	2.0	2.0	2.0	2.0	2.0	2.0
Final OPEX competiv. diesel (€/kg H_2)	4.7	5.3	5.0	4.0	5.0	5.5

Table 3-6: OPEX Competitive hydrogen price considering the efficiency of hydrogen passenger vehicles and diesel passenger vehicles.

The competitive price for hydrogen (at the end of the midstream step) is between 4.7 and 5.0 €/kg H_2 for 2030 and between 4.0 and 5.5 €/kg H_2 in 2040, compared to diesel passenger vehicles.

It needs to be stated that comparing hydrogen and electric passenger vehicles clearly shows that electric passenger vehicles remain more competitive when looking at the efficiencies (20 kWh/100 km for electric passenger vehicles). In that perspective, it is expected that the greenification of the passenger vehicle segment will undergo a transition towards electric vehicles. Consequently, the penetration rate of hydrogen-based passenger vehicles has been limited to 1% in 2030 and 5% in 2040.

[77] https://www.hyundai.news/eu/model-news/hyundai-motor-to-unveil-h350-fuel-cell-concept-at-the-2016-iaa-hanover/

[78] https://www.hyundai.be/fr/model/h350.html

[79] Based upon Tractebel expertise and confirmed with California Energy Commission & NREL report, available at https://www.energy.ca.gov/2015publications/CEC-600-2015-016/CEC-600-2015-016.pdf.

[80] Sectoral integration- long-term perspective in the EU Energy System, Asset study for the European Commission, 2018

3.1.3 Conclusions of the competitiveness analysis

By looking at the competitive thresholds[81] green hydrogen produced by the electrolyser should reach, the highest competitiveness is reached in the mobility segment and the lowest competitiveness for the chemical industry (see Table 3-7). The competitive thresholds related to the mobility segment are such that it can be expected that they can be reached with the 300 MW electrolyser with no additional support both in 2030 and 2040. For the chemical industry segment however, support would be needed for all the scenarios, except potentially the reference scenario in 2030 and progressive scenario in 2040.

€/kg H_2	Conservative		Reference		Progressive(+)	
	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

Table 3-7: The competitive cost of hydrogen for the different segments.

It rapidly appeared from the Market model simulations that the low competitive thresholds of the industry segment could not be reached and that trying to address the industry segment in the envisaged context would lead to financial losses (i.e. hydrogen is produced with the electrolyser at a higher cost than the price industry off-takers are willing to pay). The targeted market is therefore the mobility segment in the remainder of the study[82]. This is confirmed in section 3.2.2.

It is assumed that the distribution party that will come and buy the hydrogen at the storage facility will pay the same price for the hydrogen, whatever it is later on dedicated to B2B or B2C (Business-to-Consumer) mobility. Hydrogen competitive thresholds to be reached at the storage facility (i.e. at the end of the midstream step) must consequently be aligned between all mobility sub-segments. To ensure the competitiveness of the final products sold to end-users (at the end of the downstream step), prices are aligned on the lowest competitive thresholds of the different mobility sub-segments for all scenarios. The homogenised selling prices of hydrogen at the end of the midstream step for the Mobility segment are shown in Table 3-8.

	Conservative		Reference		Progressive(+)	
	2030	**2040**	**2030**	**2040**	**2030**	**2040**
Mobility (€/kg H_2)	3.8	4.3	4.0	3.3	4.0	4.4
Industry[83] (€/kg H_2)	1.5	1.6	2.4	1.5	2.0	2.5

Table 3-8: Homogenised selling prices of hydrogen at the end of the midstream step for the Mobility segment.

Revenues for the complete H_2 value chain (i.e. financial attractiveness KPI) are based on these selling prices, on top of which distribution and dispensing costs are added. This is a conservative approach: the

[81] Competitive thresholds give indication on the price both industry and mobility off-takers are willing to pay to substitute their conventional fuels to green hydrogen.

[82] In Activity 3, it is assumed that the 300 MW electrolyser will be the first in its kind in Eemshaven and hence could, with high probability, target in priority the most profitable markets accessible in this region. This is the way of reasoning for both Task 1 (Assessing the value of the electrolyser to society) and Task 3 (Assessing the business model and operational scheme of the electrolyser) within Activity 3.

[83] A similar homogenization process should also be applied to the Industry segment as for the Mobility segment.

business case of the electrolyser could be improved further if the full competitive thresholds could be captured for all mobility sub-segments.

3.2 Electrolyser operational strategy (activation prices)

3.2.1 Electrolyser activation price – Methodology

Once the hydrogen market has been defined both in terms of volumes and prices, the question on how to operate the electrolyser should be addressed.

In a purely day ahead market-based optimisation, forecasted electricity prices will determine if, and when the P2G facility will produce, i.e. at times when electricity prices are low. More specifically, an electricity price threshold under which the electrolyser starts operating needs to be defined to characterise the electrolyser's operational strategy, this price threshold will be named 'Electrolyser Activation Price'.

The electrolyser operational strategy needs to be optimised separately for each scenario and year to take into account the impact of the context (e.g. CO_2 and fuel prices evolution, RES penetration, national policies, etc.).

Figure 3-4 illustrates the iterative process for the electrolyser activation price, in order to maximise the revenues. For a given year and scenario, the following steps are part of this process:

1. Starting from the Market model, taking into account the year and the scenario, the electricity price duration curve is obtained.
2. Combining that with the electrolyser activation price[84], the volume of produced hydrogen can be assessed.
3. The *Levelised Cost Of Hydrogen* (i.e. LCOH) can then be evaluated by integrating the relevant investments and maintenance expenditures related to hydrogen production (i.e. section 2.4.1).
4. Taking into account the results of the hydrogen market analysis in the Northern Netherlands (i.e. section 3.1.3), one can assess the generated revenues.
5. These revenues then need to be optimised through an iterative process on the electrolyser activation price.

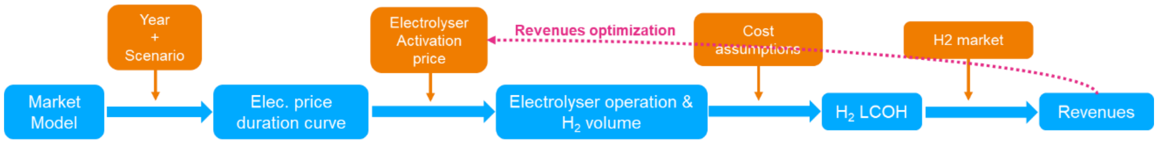

Figure 3-4: Electrolyser operational strategy. (source: Tractebel)

One can therefore understand the need to optimise the electrolyser activation price for each scenario and year in order to produce hydrogen at a price capturing the highest revenues.

By iterating on the electrolyser activation price, the following relevant curves can be generated:

- Levelised cost of hydrogen as a function of the electrolyser activation price;
- Yearly hydrogen volume produced by the 300 MW electrolyser as a function of the electrolyser activation price.

[84] Considering the size of the Netherlands electricity market and the relatively small size of the electrolyser, the electricity price duration curve demonstrates to be inelastic to the electrolyser operation.

From these curves, an optimal electrolyser activation price can be selected:

- Increasing the activation price will enable to capture a bigger share of the hydrogen market. From the competitiveness analysis performed in section 3.1.3, the mobility segment demonstrates the highest competitiveness. In order to maximise the revenues of the P2G, it is therefore assumed that the electrolyser owner will start by targeting this market.
- However, the effect of a higher activation price on the reached LCOH can be twofold. The average electricity price at which hydrogen is produced will inherently increase. However, the higher hydrogen production volume will help recovering the hydrogen production investment and maintenance expenditures (i.e. more running hours of the electrolyser). In some cases, the second effect will compensate the higher electricity price, resulting in a decrease of the LCOH with the electrolyser activation price. In other cases, the LCOH will increase with the electrolyser activation price.

A compromise has therefore to be found to maximise the total revenues.

3.2.2 Electrolyser activation price – Optimal solutions

Figure 3-5 illustrates how the LCOH evolves with the electrolyser activation price[85] in the case of the Reference scenario, respectively for 2030 and 2040. The modelled competitiveness thresholds (i.e. Table 3-8) of the mobility and industry segments are also displayed. The optimal electrolyser activation prices are 76.4 and 51.0 €/MWh, respectively for 2030 and 2040. These activation prices enable, in both years, the maximisation of the electrolyser revenues by capturing the full mobility segment potential, namely 10 kton/year in 2030 and 32 kton/year in 2040.

For instance, in 2040, a lower activation price would result in lower LCOH, but also in a lower hydrogen market share captured, i.e. a total lower revenue. A higher activation price would potentially enable to capture additional market share, but the remaining market to be addressed (i.e. industry related market) would not buy hydrogen at the achieved production costs. Going to a higher activation price would therefore lead to economic losses and therefore to a lower revenue.

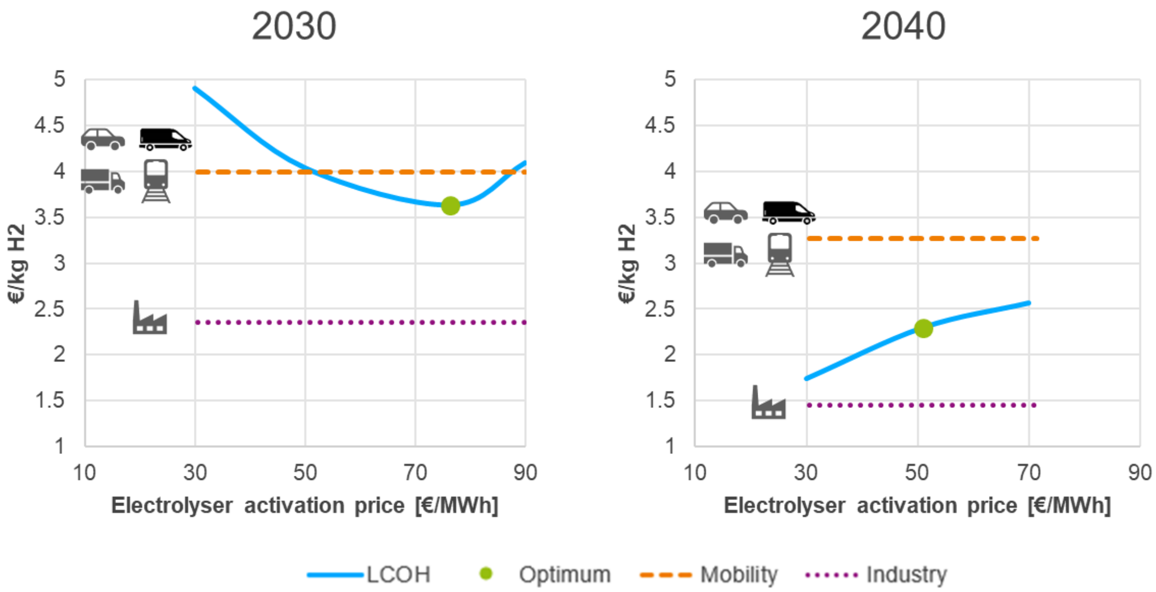

Figure 3-5: Electrolyser activation price optimisation for Reference scenario. (source: Tractebel)

[85] The electrolyser activation price is the electricity price threshold below which the electrolyser starts producing hydrogen.

Optimal activation prices for all years and scenarios can be found in Table 3-9. In all scenarios, the hydrogen volume associated to the optimal activation price fully captures the mobility market demand, while the low competitive cost thresholds of the industry potential off-takers cannot be achieved.

Electrolyser optimal activation price [€/MWh]							
2030				2040			
Cons.	**Ref.**	**Prog.**	**Prog.+**	**Cons.**	**Ref.**	**Prog.**	**Prog.+**
50.1	76.4	52.2	47.5	60.9	51.0	85.4	82.5

Table 3-9: Optimal activation prices for all years and scenarios.

In 2030, successively from the Reference to Progressive and Progressive+ scenario, it can be observed that the electrolyser optimal activation price decreases. This reflects the higher renewable penetration in the more progressive scenario[86]. Indeed, capturing the full mobility potential (i.e. 10 kton H_2/y in 2030) implies the same number of hours (i.e. approximately 1600 hours[87]) of operation of the electrolyser in all three scenarios. Fuel prices are similar through these scenarios (see Table 2-1), which means that in the more progressive scenario, there are more hours with cheaper generation units setting the unit commitment, namely renewable assets. This behaviour is further exemplified in Figure 3-6. To cover the mobility segment demand (i.e. 10 kton H_2/y, 1600 hours of operation), one can notice that the electrolyser is operated much more frequently at low electricity prices for the Progressive(+) scenario(s) than in the Reference one.

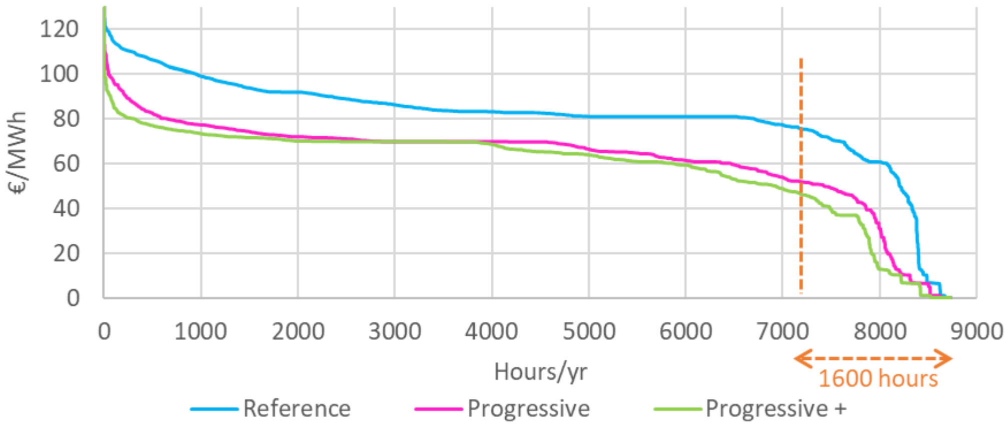

Figure 3-6: 2030 Electricity prices duration curve for Reference, Progressive and Progressive+ scenarios. (source: Tractebel)

86 Another important driver for the price in each year/scenario are the assumptions on CO_2 and fuel prices. For the Reference scenario in 2030 these are higher than the Progressive(+) scenario.

87 The optimal operation of the electrolyser heavily depends on the system boundaries, including the considered scenarios, identified hydrogen markets and competitive thresholds (see section 3.1). Furthermore it also depends on the electrolyser capacity, namely 300 MW, which has been imposed at the start of the project. A lower capacity at the beginning of the project could reduce CAPEX needs and lead to higher full load hours. However, one should be aware that that a trade-off needs to be found between high full load equivalent hours and cheap electricity for hydrogen production. The situation is different from a conventional power plant. In this case, operating the electrolyser at higher full load hours in 2030 by reducing the invested CAPEX (i.e. lower capacity than 300 MW) will result in higher electricity price for hydrogen production (i.e. electricity price duration curve). Such an increase should not be underestimated in the overall LCOH, considering its significant contribution to the LCOH up to midstream level (see section 4.2.4.1).

4 MARKET-BASED KPIS ASSESSMENT

4.1 Market model

4.1.1 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 4-1.

Figure 4-1: Modelled countries. (source: DNV GL)

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 levels, heat rate curves, maintenance availability parameters, variable operation & maintenance and start-up 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 copper plate with power plants and a demand profile, i.e. without any internal grid constraints. Market exchanges between countries (bidding zones) are limited based on net-transfer-capacities (NTC).

Different types of combined heat and power (CHP) plants are distinguished in the model: district heating, industrial CHP and horticultural CHP (especially in the Netherlands). These power plants have must-run requirements due to 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®[88] 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

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

market. An overview of the (main) inputs required for this optimisation is shown in Figure 4-2. The optimisation is performed with an hourly time resolution for several focus years.

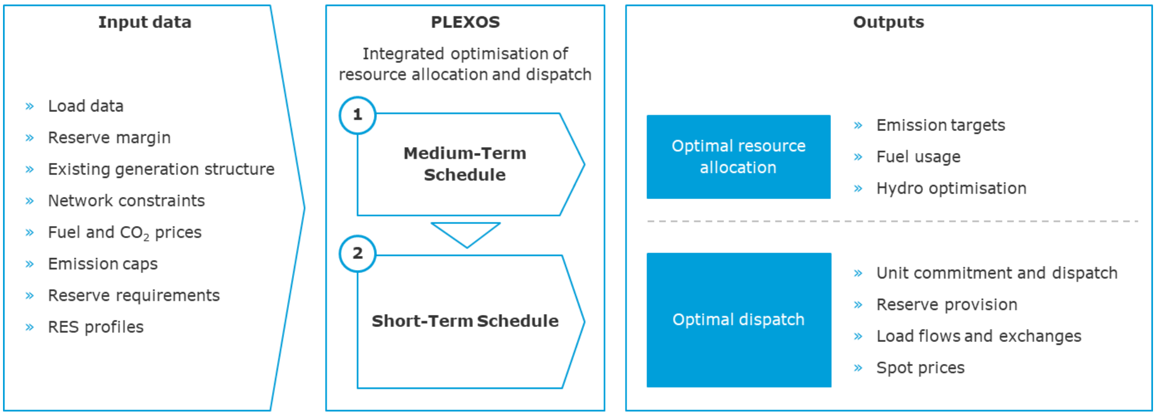

Figure 4-2: Schematic overview of the features of the employed Market model. (Source: DNV GL)

Different scenarios have been developed and implemented for the European system. Scenarios entail different developments of the 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 demand time profile 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 4-2. 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 post-processed 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.

4.1.2 Implementations of selected asset types

4.1.2.1 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.

4.1.2.2 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. The different types were described in section 2.2.1.2.

4.2 Market-based KPIs results

This section aims at analysing the market-based KPIs[89], namely socio-economic welfare, CO_2 emissions variations, air quality and financial attractiveness, whose definitions were discussed in section 2.3.1.

4.2.1 Socio-economic welfare

The socio-economic welfare scoring system is shown in Figure 4-3. If the generation costs with flexibility (electrolyser or battery cases) is status quo compared to the generation costs without flexibility, the socio-economic welfare score is equal to 1. This means that it is maximum 1% higher or lower. An increase in generation costs due to the introduction of flexibility in the electricity system results in a score of 0/3. A reduction in generation costs gives a score of 2/3 or 3/3, depending on the level of reduction in generation costs.

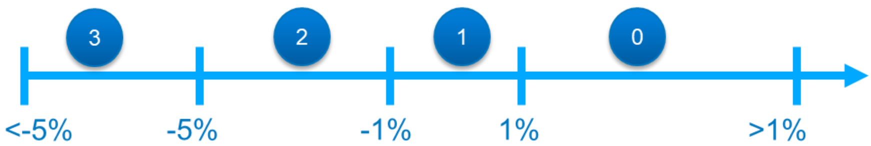

Figure 4-3: Scoring system for the KPI '*Socio-Economic Welfare*'. (source: Tractebel)

As it can be seen in Figure 4-4, the socio-economic benefits of a 300 MW electrolyser related only to national generation electricity costs is too small to be noticeable and is for all scenarios below 1%. Indeed, for the electrolyser scenarios, the improvements expected from the higher renewable penetration (i.e. reduction of total generation costs) is compensated by the additional electricity load associated to the hydrogen production (i.e. additional generation costs).

There is a very slight improvement noticeable (of less than 0.5%) in the case of the battery scenarios. The battery results in almost no additional electricity load (i.e. due to the battery roundtrip efficiency smaller than 100%, a very little increase of the load will theoretically happen). However, it enables to absorb excess electricity during periods of low electricity costs (i.e. renewable generation), which would

[89] The conclusions exposed in this report are only valid for the considered scenarios and system boundaries.

have to be curtailed otherwise. Moreover, the battery enables to reinject this energy into the grid during periods of high costs, thereby substituting expensive generation units (i.e. positive impact on the unit commitment and economic dispatch of the electricity generation units). The battery therefore reduces the generation costs very slightly. However, the differences in the KPI socio-economic welfare between the electrolyser and the battery are judged to be too small to differentiate their impact.

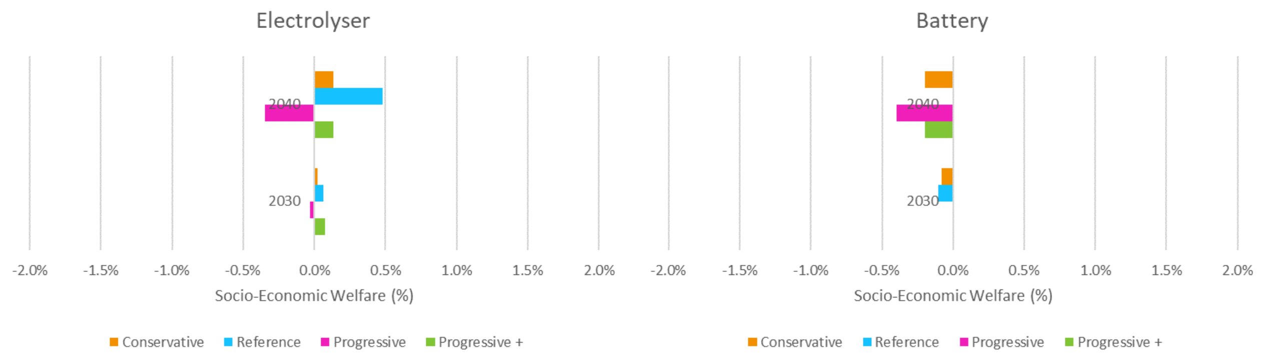

Figure 4-4: KPI '*Socio-Economic Welfare'.* (source: Tractebel based on results of the Market model analysis)

	Electrolyser							
	2030				2040			
	Cons.	Ref.	Prog.	Prog.+	Cons.	Ref.	Prog.	Prog.+
Socio-economic welfare (%)	0.0%	0.1%	0.0%	0.1%	0.1%	0.5%	-0.3%	0.1%
Score	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**

	Battery							
	2030				2040			
	Cons.	Ref.	Prog.	Prog.+	Cons.	Ref.	Prog.	Prog.+
Socio-economic welfare (%)	-0.1%	-0.1%	0.0%	0.0%	-0.2%	0.0%	-0.4%	-0.2%
Score	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**

Table 4-1: Resulting scores for the KPI '*Socio-Economic Welfare*'. (source: Tractebel based on results of the Market model analysis)

- **There is no significant impact of the electrolyser or battery on the electricity generation costs (impact below 0.5%).**
- **The battery has a slightly better performance since, in contrary to the electrolyser, it results in almost no additional electricity load.**
- **The differences in KPI socio-economic welfare between the different scenarios and years (2030 and 2040) are very small.**

4.2.2 CO_2 Emissions Variations

This KPI is calculated by comparing CO_2 emissions of the case without flexibility (i.e. electrolyser and battery) and of the cases with flexibility, being the electrolyser or battery, in the Northern Netherlands. More specifically, this KPI englobes the different markets impacted by the electrolyser (and the battery), namely the power sector and the mobility sector through greenification of the mobility. The base for the calculation is the situation without any reinforcement (no electrolyser and no battery) and for which the mobility is not greenified. It therefore includes the CO_2 emissions inherent to the power sector, taking into account the energy mix, and the CO_2 emissions related to diesel mobility.

The scoring system is shown in Figure 4-5. In case the CO_2 emissions decrease by 1 to 4% compared to the no-flexibility scenarios, a score for the CO_2 variations KPI is equal to 1. A higher decrease in CO_2 emissions leads to a higher score, as is visible in Figure 4-5. A decrease in CO_2 emissions of lower than 1%, or even an increase in CO_2 emissions, will lead to a score of 0/3.

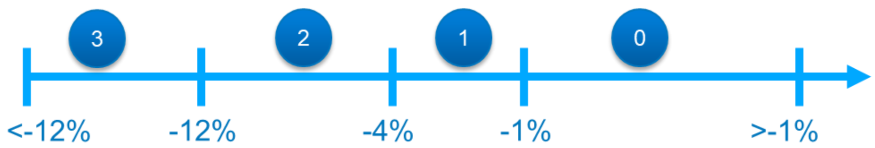

Figure 4-5: Scoring system for the KPI '*CO_2 variations*'. (source: Tractebel)

As is visible in Figure 4-6 and in Table 4-2, there exists big difference in decrease in CO_2 between the electrolyser and battery cases. The benefits of the electrolyser are higher, since it is used beyond the power sector, in contrary to the battery, see section 3.2. There is no significant impact of the flexibility assets, being the electrolyser and battery, on the CO_2 emissions related to the power production.

The differences between the different scenarios of the electrolyser are related to the relative impact of the CO_2 emission reduction impact from the mobility segment on the power sector. For example, comparing the Progressive scenario and Reference scenario, the CO_2 emissions related to the power sector are lower for the Progressive scenario than for the Reference scenario, due to the higher renewable penetration in the Progressive scenario. Therefore, the electrolyser's positive impact on reduction of CO_2 emissions is more emphasised in the Progressive scenario.

Additionally, the electrolyser contributes to a higher CO_2 emissions reduction in 2040 than 2030 thanks to the expected increase in hydrogen penetration in the transport sector in 2040.

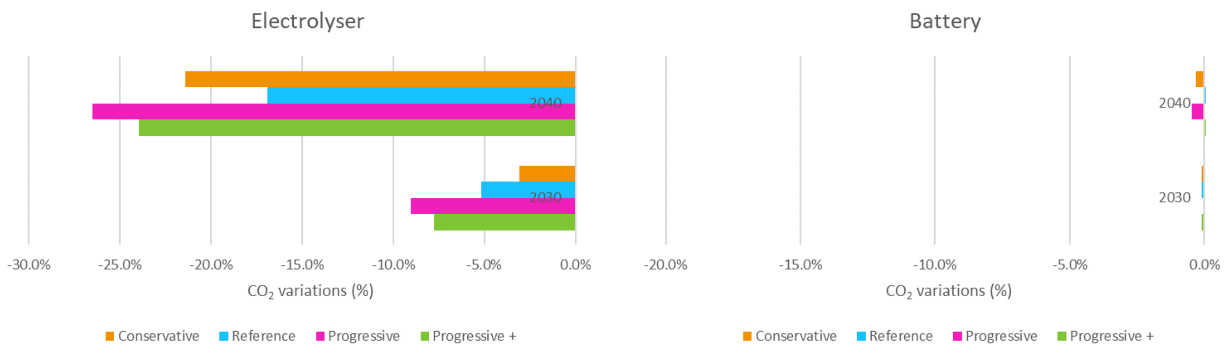

Figure 4-6: KPI '*CO_2 variations*'. (source: Tractebel based on results of the Market model analysis)

Electrolyser								
	2030				2040			
	Cons.	Ref.	Prog.	Prog.+	Cons.	Ref.	Prog.	Prog.+
CO_2 variations (%)	-3.1%	-5.2%	-9.0%	-7.8%	-21.4%	-16.9%	-26.5%	-24.0%
Score	**1**	**2**	**2**	**2**	**2**	**3**	**3**	**3**

Battery								
	2030				2040			
	Cons.	Ref.	Prog.	Prog.+	Cons.	Ref.	Prog.	Prog.+
CO_2 variations (%)	-0.1%	-0.1%	0.0%	-0.1%	-0.3%	0.1%	-0.5%	0.0%
Score	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Table 4-2: Resulting scores for the KPI '*CO_2 variations*'. (source: Tractebel based on results of the Market model analysis)

- **The electrolyser contributes to a reduction of CO_2 emissions mainly through a greenification of the transport sector. The relative impact is further emphasised in more progressive scenarios.**
- **The electrolyser contributes to a higher CO_2 emissions reduction in 2040 thanks to the expected higher hydrogen penetration in the mobility segment in 2040.**
- **Neither the electrolyser, nor the battery, brings significant impact on the CO_2 emissions related to the power sector.**

4.2.3 Air Quality

This KPI is calculated by comparing NO_x emissions of the different scenarios with or without flexibility in the Northern Netherlands[90]. Both SO_x and dust particles were also calculated but showed comparable results. The scoring system is shown in Figure 4-7. If the NO_x emissions have decreased by more than 12% for the reinforced cases (i.e. electrolyser and battery cases) compared to the transmission grid without any reinforcement, a score of 3/3 is obtained. If lower NO_x emission reduction is obtained for the reinforced cases, lower scores are given. A score of 0 is given if the NO_x emissions have increased or remained status quo compared to the case without any reinforcement.

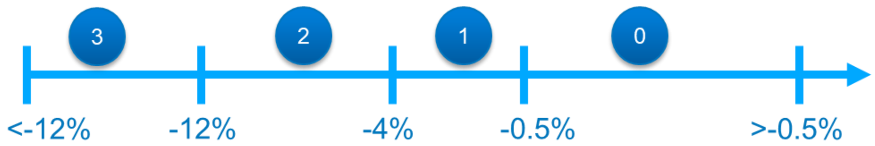

Figure 4-7: Scoring system for the KPI '*Air Quality' - NO_x*. (source: Tractebel)

As for the KPI CO_2 variations, no significant impact of the introduction of a battery in the power system is observed for the air quality KPI for all scenarios, see Figure 4-8 and Table 4-3. This is however not the case for the electrolyser, thanks to the impact of hydrogen in the mobility segment, see also chapter 3.

Comparing the CO_2 variations and the air quality, it can be observed that the introduction of hydrogen in the mobility segment in the Northern Netherlands impacts more the decrease in CO_2 emissions than that it leads to an improvement of the air quality. The reason is that the conventional mobility, meaning

90 Similarly to the CO_2 emissions variation KPI, this KPI englobes the different markets impacted by the electrolyser (and the battery), namely the power sector and the mobility sector through greenification of the mobility.

diesel-based vehicles, has a higher relative impact on the total CO_2 emissions (meaning electricity generation and mobility) than on the total air pollutants emissions. This is justified due to the strict policies in place for the NO_x and dust emissions in the transport segment compared to the power sector.

Looking at the different scenarios, the Progressive and Progressive+ scenarios reach a higher improvement of air quality with the electrolyser than the Reference and Conservative scenarios. This can be clarified since the Progressive(+) scenarios reach an overall lower level of NO_x emissions thanks to the higher penetration of renewable electricity assets in the power system. Therefore, the relative importance of the reduction of NO_x emissions of the mobility segment increases for those scenarios and has a higher impact on the KPI. Finally, the impact on the air quality KPI increases in 2040 compared to 2030 thanks to the increase in penetration of hydrogen in the mobility segment.

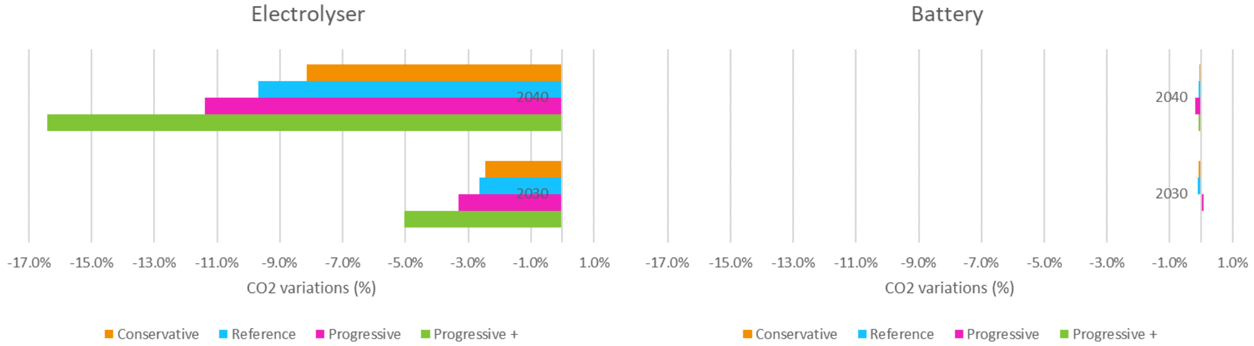

Figure 4-8: KPI '*Air Quality*'. (source: Tractebel based on results of the Market model analysis)

	Electrolyser							
	2030				2040			
	Cons.	Ref.	Prog.	Prog.+	Cons.	Ref.	Prog.	Prog.+
Air Quality (%)	-2.4%	-2.7%	-3.3%	-5.0%	-8.2%	-9.7%	-11.4%	-16.4%
Score	1	1	1	2	2	2	2	3

	Battery							
	2030				2040			
	Cons.	Ref.	Prog.	Prog.+	Cons.	Ref.	Prog.	Prog.+
Air Quality (%)	-0.1%	-0.1%	0.1%	0.0%	0.0%	-0.1%	-0.2%	-0.1%
Score	0	0	0	0	0	0	0	0

Table 4-3: Resulting scores for the KPI '*Air Quality'.* (source: Tractebel based on results of the Market model analysis)

- **The electrolyser contributes to a better air quality thanks to the introduction of hydrogen in the mobility segment, which is further emphasised in more progressive scenario.**
- **No significant impact of the battery on the air quality is observed.**
- **The achieved emission reduction of NO_x with the electrolyser is slightly below the CO_2 emission reduction.**
- **Similar conclusions can be drawn for SO_x and particles emissions.**

4.2.4 Financial attractiveness

The financial attractiveness KPI is calculated for each specific scenario taking into account the evolution of operational strategy (see section 3.2), market sizes and competitiveness thresholds over the years (i.e. for a specific scenario, results from the Market model for 2030 and 2040 are combined).

The financial attractiveness scoring system can be found in Figure 4-9. In case the considered reinforcement demonstrates a payback time lower or equal to 7 years, a score of 3 is assigned. A payback time between 7 and 10 years leads to a score equal to 2, while a score of 1 is assigned to a project achieving a return on investment between 10 and 15 years. Project with a higher payback time score 0.

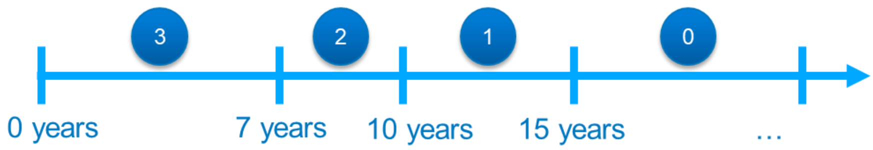

Figure 4-9: Scoring system for the KPI '*Financial Attractiveness*'. (source: Tractebel)

As can be observed in Figure 4-10 and Table 4-4, the 300 MW electrolyser demonstrates a discounted payback time lower than 10 years for all the envisaged scenarios and boundaries conditions defined in section 2.3.1.4[91]. In the Progressive and Progressive+ scenarios, payback times of respectively 6 and 7 years are reached, proving the financial attractiveness of investing in a 300 MW electrolyser in Eemshaven from a societal perspective.

More specifically, an NPV higher than 400 M€ is achieved in these two scenarios after 20 years of operation, compared to an initial investment around 160-170 M€[92]. Such a business case for the electrolyser is made possible thanks to the sectorial integration of mobility: buying electricity and selling the produced hydrogen outside of the electricity market enables to maximise the revenues of the electrolyser. The following trend can also be observed in Figure 4-10: the more progressive the scenario, the faster the payback time of the electrolyser. More details are provided in section 4.2.4.1.

On the other hand, it can be observed that the battery is not financially viable, in none of the scenarios, when only looking at energy trading in the day-ahead market: revenue stream stacking from other market segments (out of the scope of this study) could help improve the attractiveness. Indeed, only looking at energy trading results in negative NPV after 20 years of operation. More details are provided in section 4.2.4.2

More details regarding the implemented value chain for the electrolyser and the battery and the discounted payback time assessment are provided respectively in the following sections.

[91] Electrical integration costs are not included in this Task and might influence the results. Similarly ancillary services are not included in this Task. More insights will be provided in Task 3. Moreover, expected hydrogen prices will also be of high influence (see section 3.1).

[92] Initial investment includes investment in electrolyser, desalination unit, compressors and salt cavern.

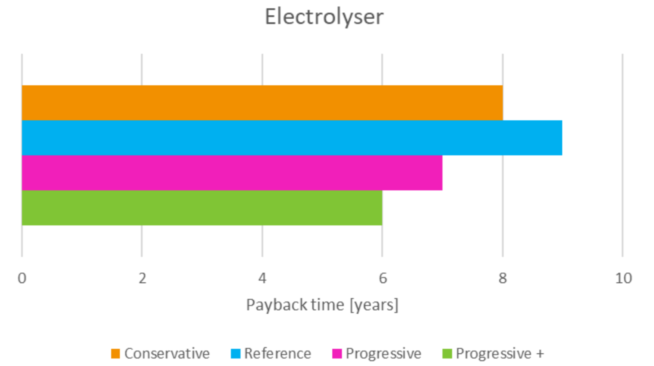

Figure 4-10: KPI '*Financial Attractiveness*. (source: Tractebel based on results of the Market model analysis)

	Electrolyser			
	Cons.	**Ref.**	**Prog.**	**Prog.+**
Payback time [Years]	8	9	7	6
Final NPV [M€]	348	239	411	543
Score	**2**	**2**	**3**	**3**

	Battery			
	Cons.	**Ref.**	**Prog.**	**Prog.+**
Payback time [Years]	-	-	-	-
Final NPV [M€]	-525	-499	-465	-473
Score	**0**	**0**	**0**	**0**

Table 4-4: Resulting scores for the KPI '*Financial Attractiveness'.* (source: Tractebel based on results of the Market model analysis)

- **The business case of the electrolyser is made possible because the hydrogen is sold outside the electricity market: sectorial integration of mobility enables to maximise the revenues of the electrolyser.**
- **The more progressive the scenario, the faster the payback time of the electrolyser.**
- **A battery is not financially viable when only looking at energy trading in the day-ahead market; revenue stream stacking from other market segments (out of the scope of this study) could help improve the attractiveness.**

4.2.4.1 Financial attractiveness of the 300 MW electrolyser in the Northern Netherlands

To assess the financial attractiveness of the 300 MW electrolyser, the associated hydrogen infrastructure (i.e. compressors, pipeline, storage) must be sized and their expenditures characterised. The sizes of these hydrogen assets are inherently dependent on the hydrogen production pattern as well as the hydrogen demand pattern, both of which are scenario and year dependent.

The targeted market for the produced hydrogen being the mobility, the **demand** profile is assumed to be **baseload**. We assume a steady consumption (i.e. the intra-day fluctuation of the hydrogen demand for mobility purpose is not accounted for) and no seasonality in the hydrogen demand.

However, the electrolyser production is inherently driven by the evolution of prices in the electricity market, namely production at electricity prices below the defined thresholds, and by the definition of the scenarios. The electrolyser is not connected 1-on-1 to renewable generation units, but it is reacting to the wholesale market prices in the Netherlands. This is impacted by the demand, renewables in the Netherlands, but also by the interconnections with the neighbouring countries (e.g. solar from Germany, hydro from Nordic countries through the NorNed cable, wind from Denmark through COBRAcable, etc.), all contributing to dynamics in the electricity prices over the year (i.e. **variability of hydrogen production**). As a result, the operation of the electrolyser fluctuates over the different seasons of the year.

As already described in section 2.4.1, a **need for seasonal hydrogen storage** and the associated infrastructure (i.e. compressors, pipeline, etc.) to convey the hydrogen from its production site (i.e. Eemshaven) to its storage location (i.e. salt cavern in Zuidwending) arises in all the scenarios. Figure 4-11, Figure 4-12, Figure 4-13 and Figure 4-14 illustrate the yearly dispatch of the hydrogen salt cavern for all scenarios and years.

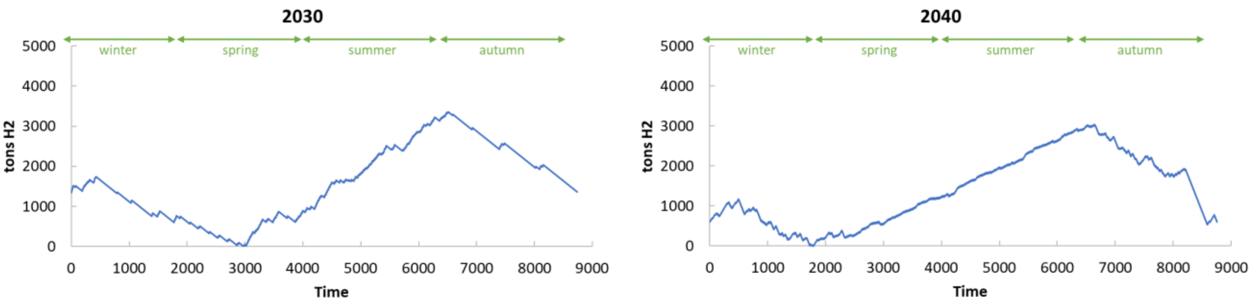

Figure 4-11: Hydrogen storage dispatch – Conservative. (source: Tractebel based on results of the Market model analysis)

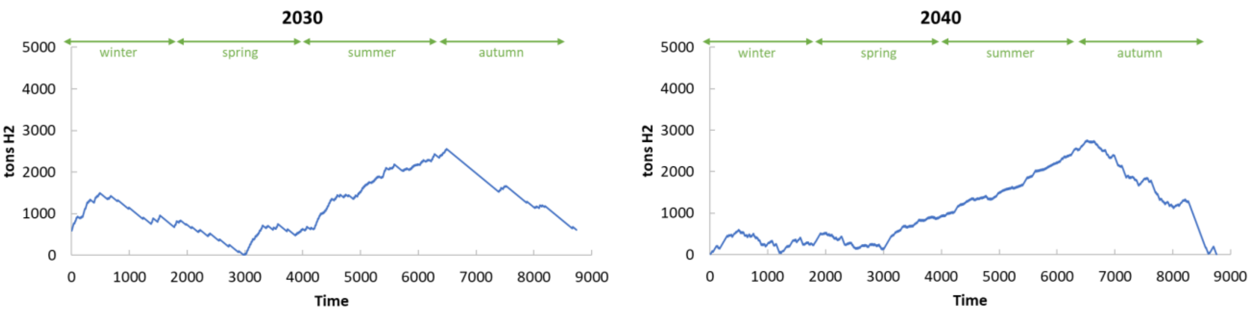

Figure 4-12: Hydrogen storage dispatch – Reference. (source: Tractebel based on results of the Market model analysis)

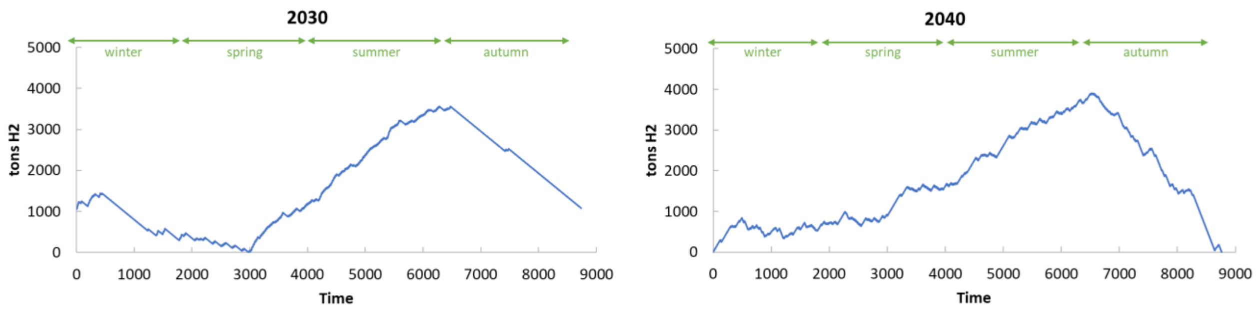

Figure 4-13: Hydrogen storage dispatch – Progressive. (source: Tractebel based on results of the Market model analysis)

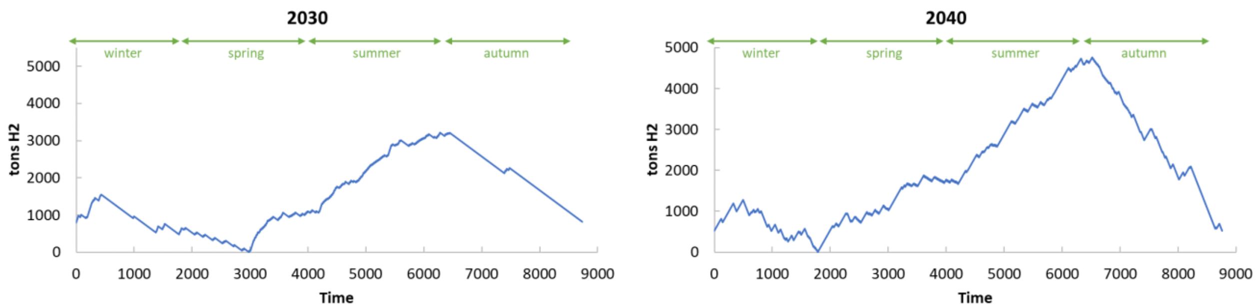

Figure 4-14: Hydrogen storage dispatch – Progressive+. (source: Tractebel based on results of the Market model analysis)

For a given scenario, hydrogen storage should be sized for the most constraining year, i.e. the year with the highest storage requirement (i.e. the highest cumulated surplus production of hydrogen). Similarly, the compressor for pressurisation of the hydrogen from the pipeline outlet pressure (60 bar) to the storage design pressure (180 bar) is sized for the most demanding year in terms of maximal injection capacity (i.e. max. send IN capacity). Hydrogen salt cavern requirements for the different scenarios and years are summarised in Table 4-5. These parameters directly drive the investments for the storage facility as well as the compressor to inject the hydrogen into the cavern.

	Hydrogen storage requirements							
	2030				2040			
	Cons.	Ref.	Prog.	Prog.+	Cons.	Ref.	Prog.	Prog.+
Size [ton H_2]	3,337	2,543	3,543	3,223	3,040	2,753	3,903	4,765
Max. send IN capacity [kg H_2/h]	4,980	4,980	4,980	4,980	1,145	1,145	1,145	1,145
Max. send OUT capacity [kg H_2/h]	2,475	2,475	2,475	2,475	3,650	3,650	3,650	3,650

Table 4-5: Hydrogen salt cavern requirements for the different scenarios and years. (source: Tractebel, based on results of the Market model analysis)

The discounted cumulated cash flow and the associated Net Present Value (NPV) curve, from which the discounted payback time can be assessed, can be found in Figure 4-15, Figure 4-16, Figure 4-17 and Figure 4-18 for the different scenarios. As it can be noticed, the discounted cumulated cash flow assesses the financial attractiveness of the total H_2 value chain, by covering all steps, from upstream to downstream (i.e. paragraph *P2G value chain*, page 20). In other words, steps from production to distribution to final end-users are included, together with the required infrastructure[93] (i.e. hydrogen pipeline from the electrolyser located in Eemshaven to salt cavern facilities in Zuidwending, followed by a

[93] As justified in section 3.2.2, the Industry segment was not selected (i.e. hydrogen will be produced to supply the mobility segment). In that perspective, the distribution infrastructure specific to the Industry segment is not studied in the scope of this analysis.

tube trailer distribution to final refuelling stations). It is indeed assumed that hydrogen will be delivered to all refuelling stations by tube trailers.

This is justified as follows:

- Yearly hydrogen demand of 10 and 32 kton have been identified for the mobility segments respectively for 2030 and 2040 (see Figure 3-3).
- The Northern Netherlands will need at least 100 hydrogen fuelling stations.[94,95,96]
- This results in a demand around 275 and 875 kg/day/station respectively for 2030 and 2040.

Typically, pipeline appears to be the most cost-effective solution for dense areas and for large hydrogen demand[97]. Considering the possible spread of all refuelling stations within the Northern Netherlands and the relatively low demand per station, the pipeline is not recommended when looking only at this project. However, the growth of the hydrogen demand in other sectors which might lead to small hydrogen hubs in the region, the introduction of other electrolysers in the region which might make use of Zuidwending facilities for hydrogen storage purposes, the hydrogen demand becoming more mature and the development of a denser hydrogen grid are all factors that might justify a different infrastructure to be shared among different players and reasons for which a supply through a dedicated pipeline infrastructure may be worth being considered.

These discounted cumulated cash flows are obtained by summing, for every year of the project, the expenses[98] (i.e. negative values, corresponding to investments or maintenance expenditures) and revenues[99] (i.e. positive values, corresponding to revenues obtained through the selling of the produced hydrogen to the mobility market).

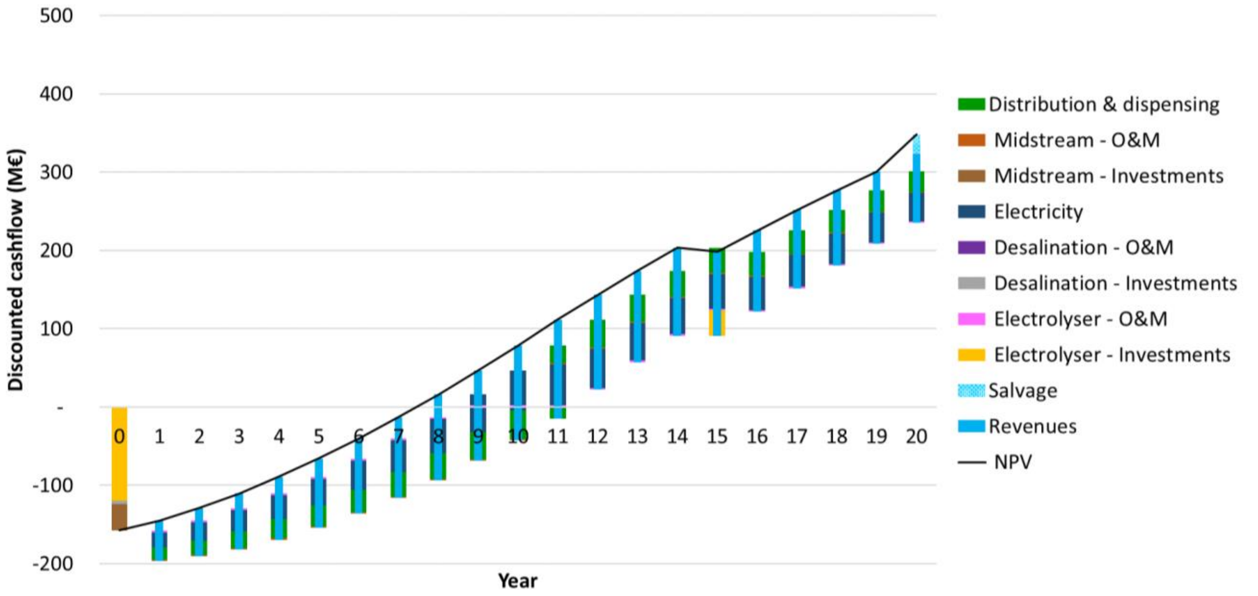

Figure 4-15: NPV curves for the 300 MW Electrolyser – Conservative. (source: Tractebel based on results of the Market model analysis)

94 The Green Hydrogen Economy in the Northern Netherlands, Noordelijke Innovation Board, Prof. Dr. Ad van Wijk, 2018, accessible on: http://profadvanwijk.com/wp-content/uploads/2017/04/NIB-BP-NL-DEF-webversie.pdf

95 http://www.tankpro.nl/specials/2014/09/17/aantal-tankstations-in-nederland-licht-gedaald/

96 https://www.ecn.nl/docs/library/report/2011/e11005.pdf

97 *Determining the lowest-cost hydrogen delivery mode*, Christopher Yang and Joan Ogden, Institute of Transportation Studies, Department of Environmental Science and Policy, University of California.

98 Outer parts in the stacked bar charts.

99 Inner parts in the stacked bar charts, represented in light blue. At the end of the project, a salvage takes place (i.e. residual value of assets not having reached the end of life).

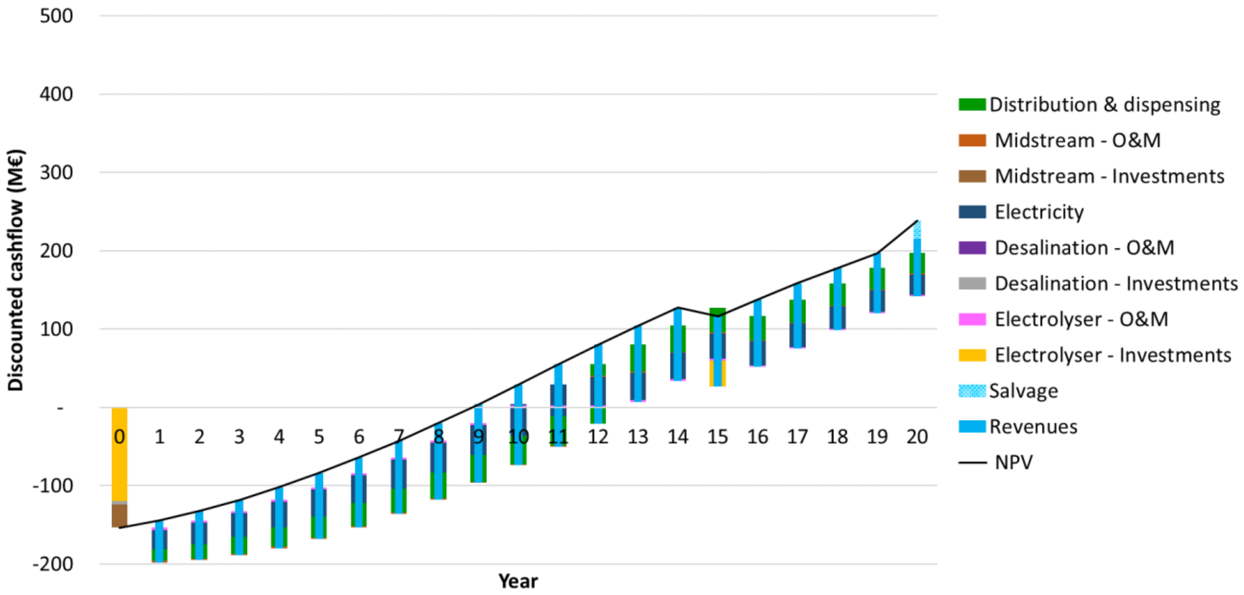

Figure 4-16: NPV curves for the 300 MW Electrolyser – Reference. (source: Tractebel based on results of the Market model analysis)

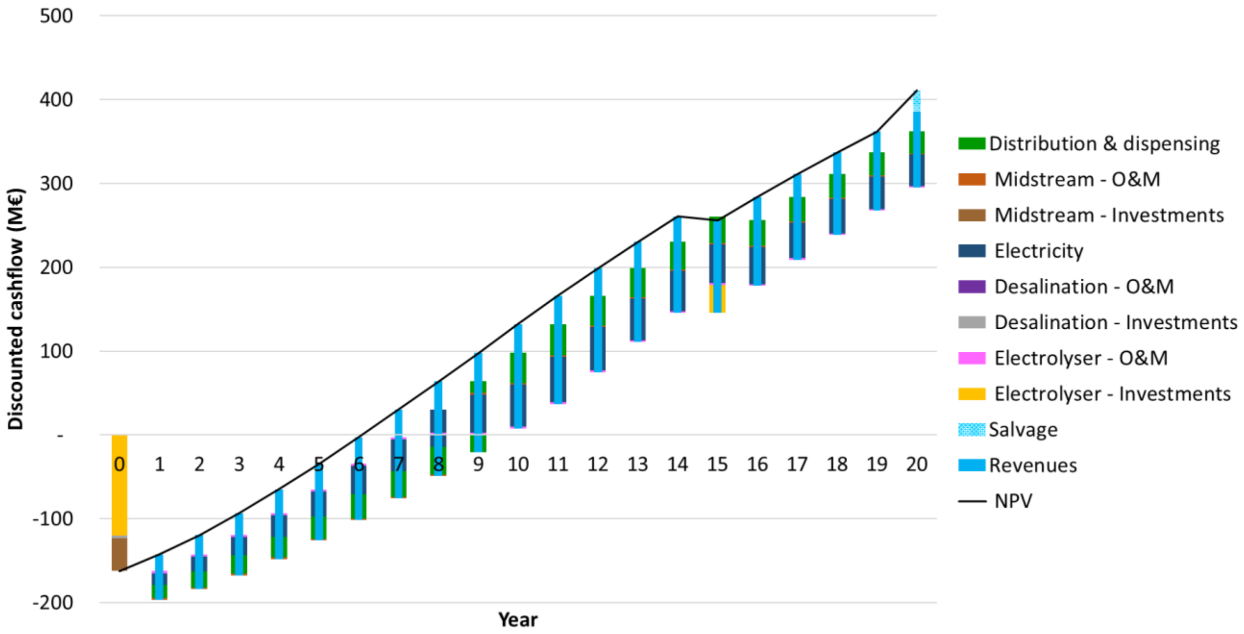

Figure 4-17: NPV curves for the 300 MW Electrolyser – Progressive. (source: Tractebel based on results of the Market model analysis)

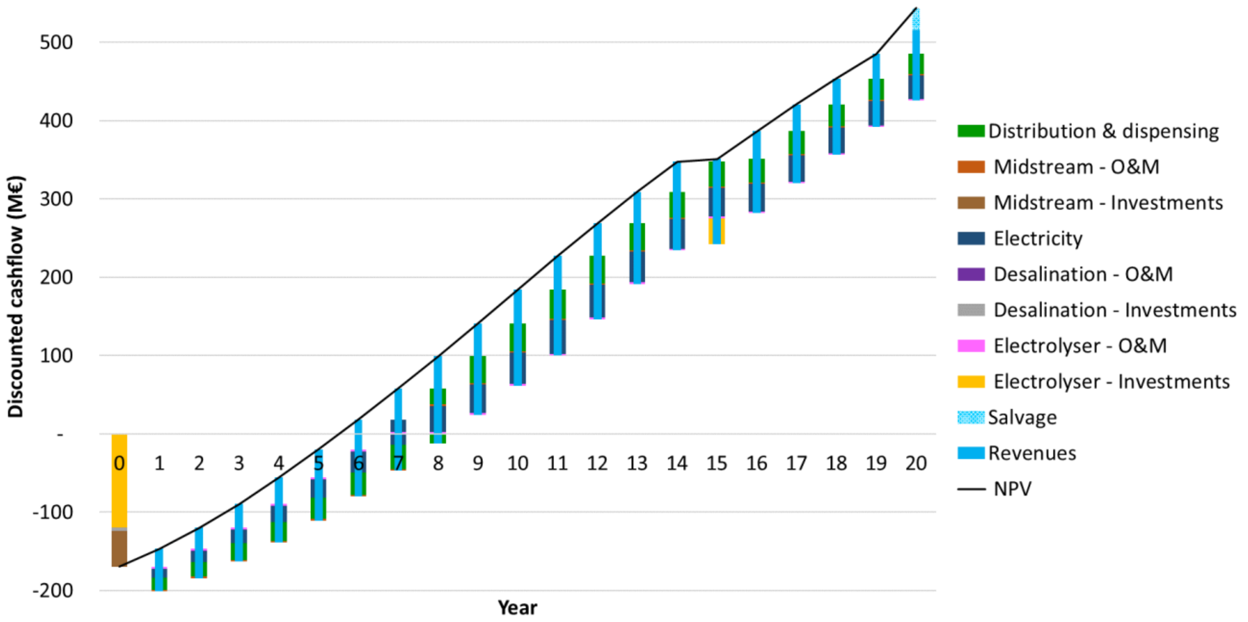

Figure 4-18: NPV curves for the 300 MW Electrolyser – Progressive+. (source: Tractebel based on results of the Market model analysis)

The electrolyser demonstrates a viable business case[100] and even reaches a payback time below 10 years for all scenarios. A general trend can be noticed: the more progressive the scenario, the shorter the payback time of the electrolyser.

When focussing on 2030, one can observe in Table 4-6 that, on the one hand, the average electricity price for hydrogen production decreases from 51.5 €/MWh to 29.9 €/MWh and 23.1 €/MWh, respectively from the Reference to the Progressive and Progressive+ scenarios. Higher RES penetration, lower fuel and CO_2 prices (see Table 2-1) in the more progressive scenarios result in more hours per year with low electricity prices. This results in lower green hydrogen production costs for the more progressive scenarios, as already demonstrated in Figure 3-6. However, the mobility hydrogen selling price thresholds for these scenarios are identical, which can result in similar revenues. This strengthens the business case of the electrolyser in the two progressive scenarios compared to the Reference one.

	Electrolyser usage characteristics							
	2030				2040			
	Cons.	Ref.	Prog.	Prog.+	Cons.	Ref.	Prog.	Prog.+
Avg. elec. price [€/MWh]	54.3	81.2	62.5	58.7	58.2	46.2	69.4	61.5
Activation price[€/MWh]	50.1	76.4	52.2	47.5	60.9	51.0	85.4	82.5
Avg. elec. price for H_2 prod. €/MWh]	40.2	51.5	29.9	23.1	50.3	37.1	52.2	42.5
Mobility H_2 selling price [€/kg H_2] (end midstream)	3.8	4.0	4.0	4.0	4.3	3.3	4.4	4.4

Table 4-6: Electrolyser usage characteristics or the different scenarios and years. (source: Tractebel, based on results of the Market model analysis)

100 In the scope of this value to society assessment, certain costs have not been taken into account for the business case analysis of the electrolyser since the aim is to capture an overview of the benefits the electrolyser can bring on several aspects. The reader is invited to read the report of Task 3 of this Activity 3 for deeper insights on the business case of the electrolyser.

Figure 4-19, Figure 4-20, Figure 4-21 and Figure 4-22 provide additional relevant insight into the contribution of upstream and midstream steps (see paragraph *P2G value chain*, section 2.4.1) to the Levelised Cost of Hydrogen (LCOH). The low electricity prices in 2040-Reference scenario result in a lower LCOH compared to the Progressive scenario. However, the competitive hydrogen selling price thresholds previously assessed (i.e. Table 3-8) offer significantly lower revenues in 2040 for the Reference scenario than for the Progressive one. For the Progressive+ scenario, low electricity prices both in 2030 and 2040 combined with high competitive hydrogen selling price thresholds further reinforce the business case of the electrolyser compared to the Progressive scenario.

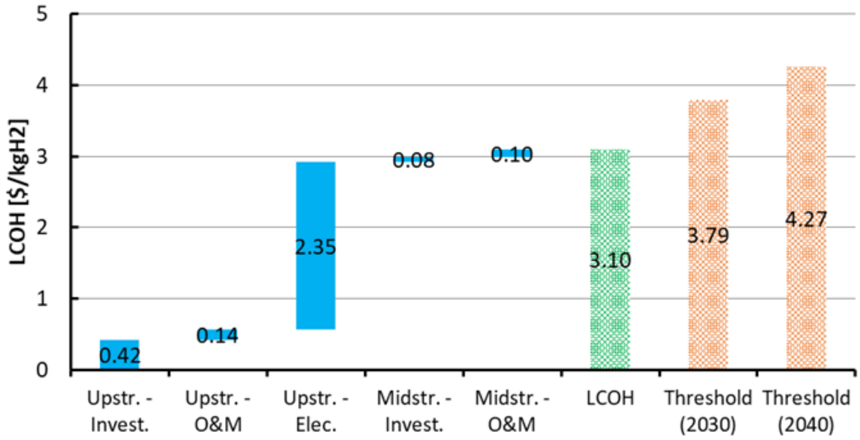

Figure 4-19: Contributions to LCOH up to midstream level – Conservative. (source: Tractebel based on results of the Market model analysis)

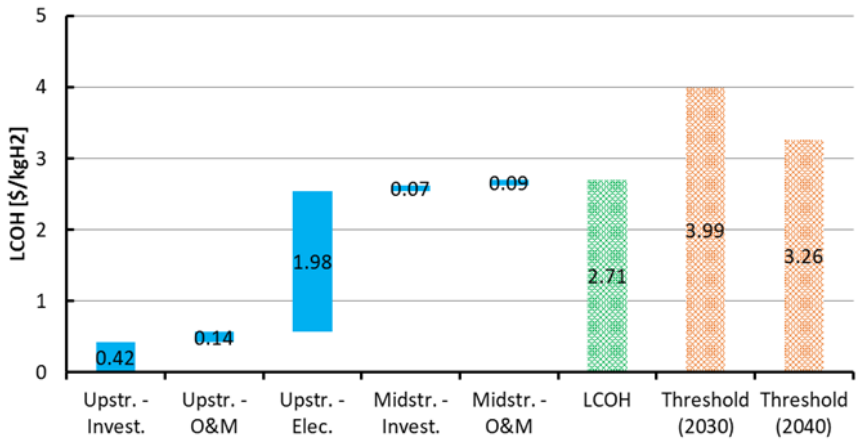

Figure 4-20: Contributions to LCOH up to midstream level – Reference. (source: Tractebel based on results of the Market model analysis)

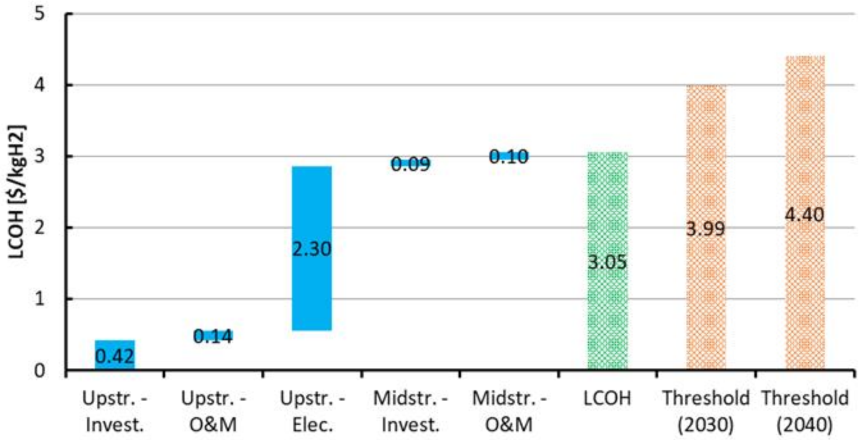

Figure 4-21: Contributions to LCOH up to midstream level – Progressive. (source: Tractebel based on results of the Market model analysis)

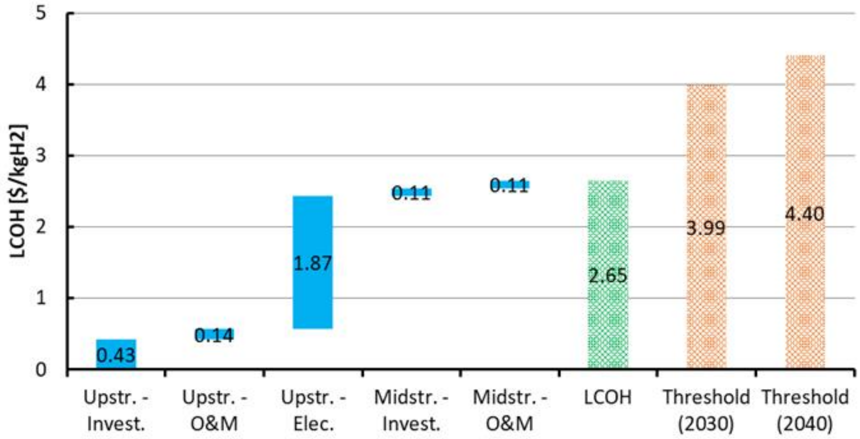

Figure 4-22: Contributions to LCOH up to midstream level – Progressive+. (source: Tractebel based on results of the Market model analysis)

A **sensitivity** on the **electrolyser investment cost** is performed to see the impact on the payback time for all scenarios[101]: an investment cost of 200 €/kW and 600 €/kW are considered[102], in addition to the initial considered assumption (i.e. 400 €/kW). Moreover, contribution of additional costs (i.e. construction costs, engineering costs, civils works, etc.) will be accounted for with a lang factor of 20%[103]. The obtained results are summarised in Table 4-7. The 20% lang factor increases for all scenarios, except for the Progressive scenario, the payback time by one year. The foreseen ultimate target of 200 €/kW would enable to reach a payback time in the range of 5 to 7 years, while the upper investment cost would lead to a payback time above 10 years, except for the Progressive+ scenario with 9 years.

[101] The sensitivity analysis is performed under the assumption of an unchanged operation strategy of the electrolyser compared to the base case with the investment cost of 400 €/kW. In other words, for a given scenario, the activation price of the electrolyser remains the same and the same markets are targeted. Even with the reduced investment cost (200 €/kW + 20% lang factor), the industry segment still appears to be difficult to target considering the assessed competitive thresholds. A more in depth analysis, taking into account the increase of the average electricity cost for hydrogen production related to this additional demand, the detailed infrastructure required to supply hydrogen to industry, etc. could be foreseen in a next study.

[102] A recent study from the European commission aiming to ensure robustness and representativeness of the technology assumptions by reaching out to relevant experts, industry representatives and stakeholders, who are in possession of the most recent data in the different sectors, stipulates a value of 340 €/kW for large scale electrolyser by 2030 with a ultimate target of 200 €/kW. https://ec.europa.eu/energy/sites/ener/files/documents/2018_06_27_technology_pathways_-_finalreportmain2.pdf

[103] The lang factor captures additional costs on top of major technical equipment. It is defined as the ratio of additional costs related to civil works, installation, engineering, etc. to the cost of major technical equipment (i.e. in this case electrolyser). From Tractebel expertise, lang factor around 20 to 30% can be considered for large scale electrolyser. https://www.gasunie.nl/nieuws/gasunie-en-engie-gaan-samenwerken-om-groene-waterstof-op-grote-sc

	Electrolyser			
	Cons.	**Ref.**	**Prog.**	**Prog.+**
400 €/kW	8	9	7	6
200 €/kW + 20%	6	7	5	5
400 €/kW + 20%	9	10	7	7
600 €/kW + 20%	12	14	10	9

Table 4-7: Electrolyser payback time – Sensitivity analysis. (source: Tractebel based on results of the Market model analysis)

4.2.4.2 Financial attractiveness of the 300 MW / 1200 MWh battery in the Northern Netherlands

In the scope of this analysis, the battery operator only generates revenues by buying electricity on the day-ahead market at moments of low electricity prices (i.e. corresponding mostly with high RES penetration) and selling it back during high electricity price periods. The operation of the battery within the Market model is optimised from an economic perspective in order to minimise the total generation cost of the system.

The discounted cumulated cash flow and the associated NPV curve can be found in Figure 4-23, Figure 4-24, Figure 4-25 and Figure 4-26 for the different scenarios.

Compared to the electrolyser, the battery business case appears to be much more challenging, because other sectors than the electricity market are not involved. As already stipulated, this conclusion is based on the consideration of energy trading on the spot market only.

Table 4-8 provides relevant insights to understand the observed behaviours. Despite an almost daily cycling of the battery, the delta between the SELL and BUY prices does not enable to recover the investments. Furthermore, in the Conservative and Reference scenario, the revenues do not compensate the buying of electricity and the yearly operational expenditures, resulting in an even lower NPV. In the Progressive and Progressive+ scenarios, as of 2030, the achieved deltas between SELL and BUY prices are such that the NPV increases over time. However, the observed increase will not compensate the required investments every 10 years (i.e. battery system lifetime), resulting overall in a decreasing NPV (see section 2.4.2). In none of the scenarios, the battery can demonstrate a viable business case.

In conclusion, energy trading in the spot market cannot be the only revenue stream of the battery: revenue stream stacking from other market segments (such as ancillary services and congestion management) could help improve the business case.

	Battery usage characteristics							
	2030				**2040**			
	Cons.	**Ref.**	**Prog.**	**Prog.+**	**Cons.**	**Ref.**	**Prog.**	**Prog.+**
Avg. elec. BUY price [€/MWh]	43.7	64.3	44.7	41.3	40.6	30.9	46.0	38.8
Avg. elec. SELL price [€/MWh]	66.4	100.3	78.6	77.3	75.2	62.3	88.8	84.5
SELL-BUY [€/MWh]	22.7	36.0	33.9	36.0	34.6	31.4	42.8	45.7
# cycles	189	250	269	231	210	256	279	232

Table 4-8: Battery usage characteristics or the different scenarios and years. (source: Tractebel, based on results of the Market model analysis)

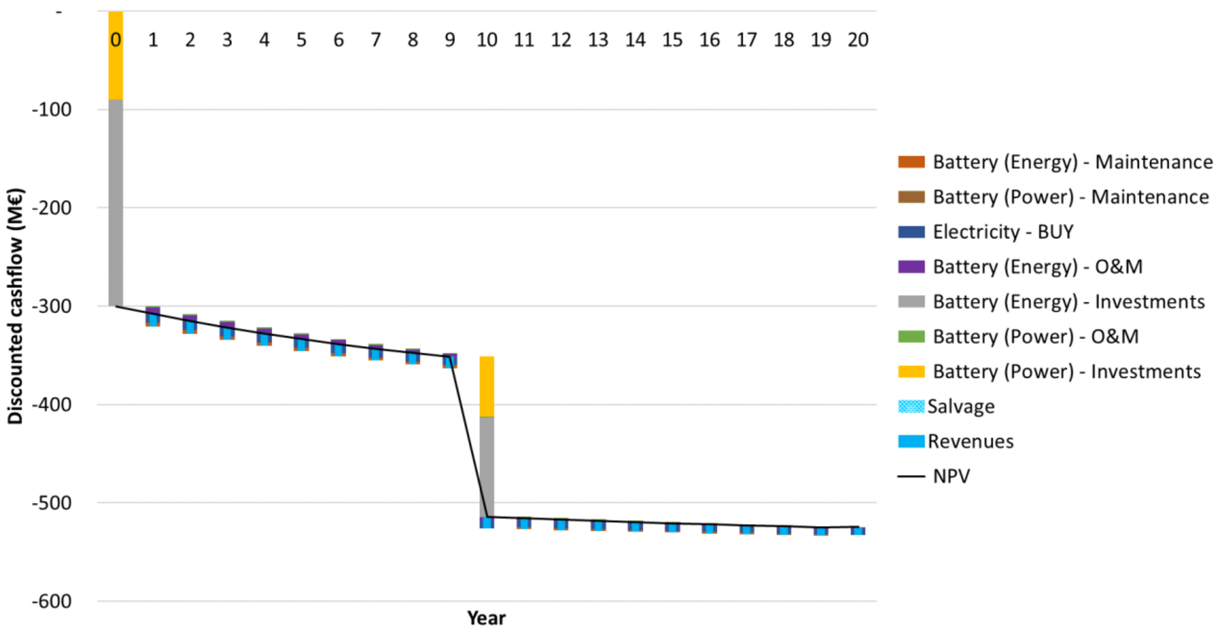

Figure 4-23: NPV curves for the 300MW / 1200 MWh Battery – Conservative. (source: Tractebel, based on results of the Market model analysis)

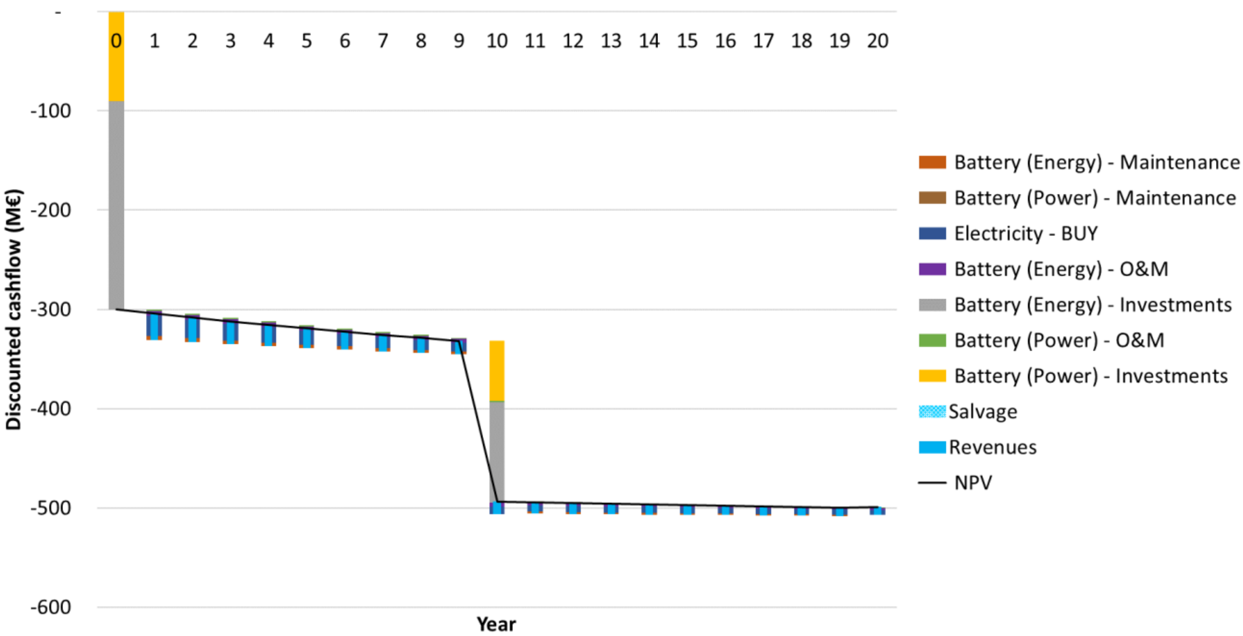

Figure 4-24: NPV curves for the 300MW / 1200 MWh Battery – Reference. (source: Tractebel, based on results of the Market model analysis)

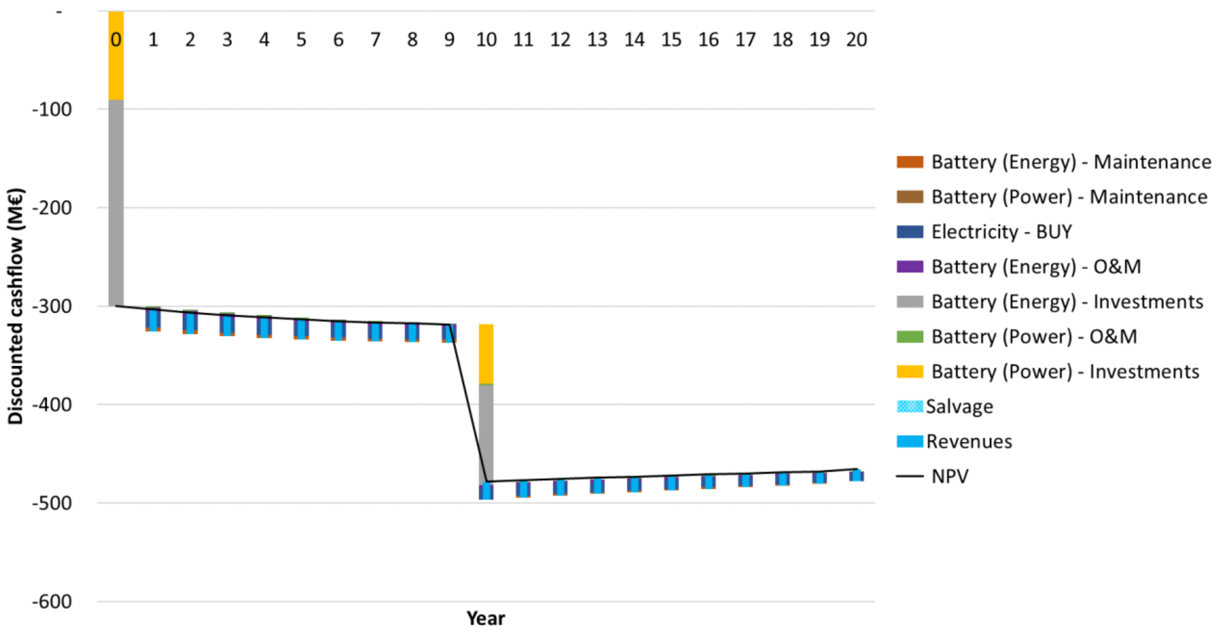

Figure 4-25: NPV curves for the 300MW / 1200 MWh Battery – Progressive. (source: Tractebel, based on results of the Market model analysis)

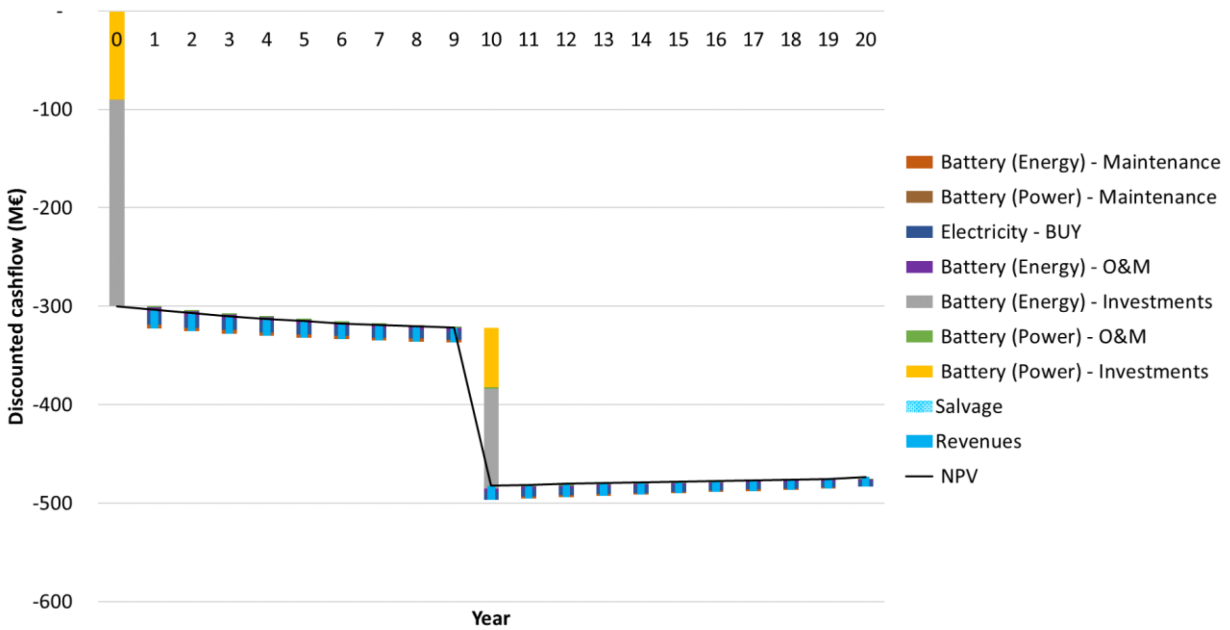

Figure 4-26: NPV curves for the 300MW / 1200 MWh Battery – Progressive+. (source: Tractebel, based on results of the Market model analysis)

5 GRID-BASED KPIS ASSESSMENT

5.1 Grid model

In order to perform an Optimal Power Flow (OPF) analysis, it is paramount to develop a network model of the analysed area. This network mode has to comprehensively include and characterise all the elements comprising the power system and describing all the electrical parameters. A non-exhaustive list of the elements to be included along with their electrical parameters is the following:

1. Electrical lines and grid topology:
    a. Length
    b. Capacity
    c. Reactance
    d. Resistance
    e. Capacitance
    f. Identification of the connection nodes of the line
2. Loads:
    a. Active and reactive power
    b. Hourly profile for the whole year
    c. Identification of the connection node
3. Generators:
    a. Active and reactive rated power
    b. Cost curve describing the operating cost for the generator
    c. Hourly power profile during the whole year for renewable energy sources (RES)
4. Interconnection with neighbouring countries:
    a. Capacity of the interconnection between countries
    b. Tariff system or exchange profile
    c. Net transfer capacity between countries/Areas

The network model that has been developed is based mainly on the following sources:

- Network dataset provided by TU Delft
- Open information available in TenneT TSO B.V. website[104]
- The information available in HoogspanningsNet[105]

In addition, some estimations have been carried out in order to include missing information on:

- Load estimation and allocation for a large part of the Dutch network
- Generator identification and allocation for a large part of the Dutch network
- Load profiles
- Network nodes geo-localisation
- Hourly renewable profiles

[104] Tennet, «Overzicht componenten 380kv en 220kv net» 2017. [Online]. Available: www.tennet.eu.
[105] «HoogspanningsNet» [Online]. Available: https://www.hoogspanningsnet.com/.

Additionally, the network model has been completed to properly represent the expected progress of the Dutch transmission power system for 2030 taking into account the following information:

1. TYNDP 2018 and PCI projects affecting the Dutch network: upgrading of the lines and corridors and interconnection with other countries
2. Expected planning for the wind energy deployment identifying the future onshore and offshore wind projects and potential sites.

The final display of the modelled Dutch network for 2030 can be found in Figure 5-1.

Due to the lack of available information regarding grid reinforcements up to 2040, a realistic network model for that term could not be built. The assessment and simulation performed for the whole set of scenarios leaded to unrealistic renewable curtailment values as the modelled grid is not able to allocate all the renewable power produced. Consequently, the obtained results have been disregarded. Results for Grid-based KPIs could therefore be only generated for 2030 scenarios.

Last but not least, all the scenarios developed for the market analysis have been translated into grid scenarios which, in essence, implied the development of a total of eight different network scenarios with three variants for each of them (base case, base case +electrolyser and base case +battery). Each scenario modifies the number and type of the generators in order to match the overall values stated in the market scenarios.

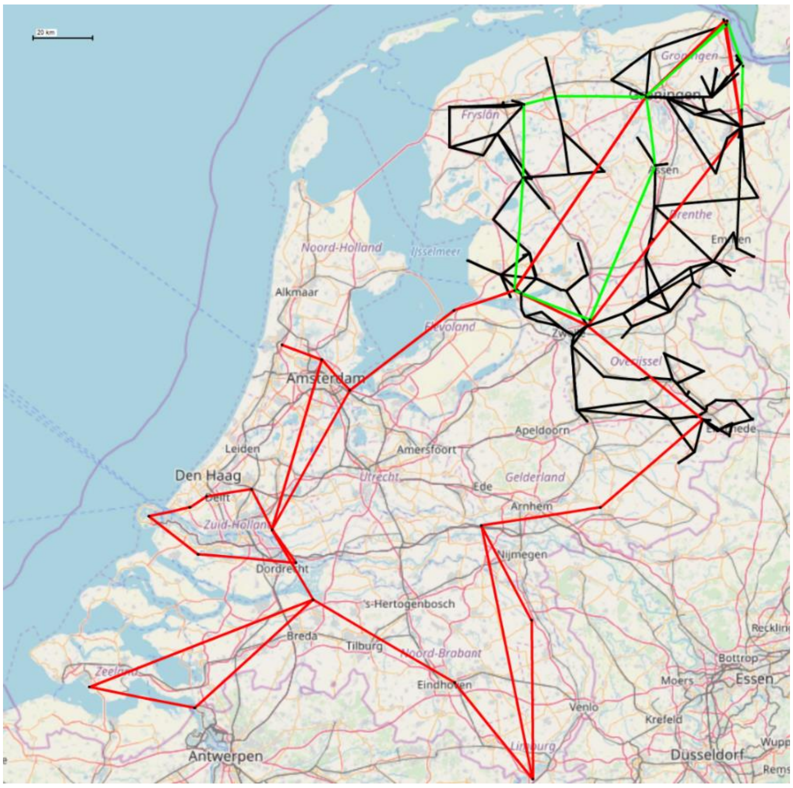

Figure 5-1: Final display of the modelled Dutch network. (source: Circe)

It should be mentioned that the results that are obtained after the analysis of the KPIs are highly affected by the developed network model. This model has been built based on different sources which have several weaknesses. Namely, regarding the model provided by TU Delft and TenneT TSO B.V.:

- Grid nodes are not geo-localised and an extra effort was devoted to identify the location of nodes (this is important to properly define generation, loads and renewable profiles)
- Only some part of GDOF network is provided and a great portion of the 110 kV network and some 220 kV lines as well as some substations linking the different voltage level network were missing.
- Some line lengths were not correct and were amended according to the estimated geographic coordinates.
- Model from HoogspanningsNet used to complete 110 kV network lacks electrical information for lines which was estimated using the TUD/ TenneT TSO B.V. model as reference.

Another source of error is the selection and allocation of generators in the future scenarios. Generators were chosen, allocated and modified to be powered by a different fuel to reach the installed capacities and generation mix stated by the scenarios in 2030 and 2040. It is an approximation and depending where the generators are allocated, and which fuel is powering them, results obtained for congestion level assessment may vary greatly.

These estimations imply that the accuracy of the results may be affected to an unknown extent, therefore the outcome of the grid KPI analysis should be taken carefully. Local congestions or grid issues may be due to defective input data used for the model.

Another limitation is imposed by the Optimal Power Flow tool used for the analysis which does not allow to optimise the schedule of the deployed energy storage systems, therefore if a time dependent optimisation was available for storage systems the results from the analysis of the battery cases could be more positive and slightly different.

5.2 Grid-based KPIs results

This section aims at analysing the grid-based KPIs[106], namely RES integration, security of supply, variation in losses, congestion and avoided transmission upgrades, whose definitions were discussed in section 2.3.2.

5.2.1 RES integration

This KPI is assessed through the analysis of the reduction in renewable energy curtailment. This KPI is affected by the use of the electrolyser or battery since it implies the absorption of renewable energy by these technologies, achieving a better exploitation of the variable renewable resources. Instead of curtailing surplus energy, it can be stored (battery) or transformed to other energy vectors using P2G technologies (electrolyser).

The scoring system for this KPI focuses on the reduction of RES curtailment. No reduction or a small reduction (lower than 1%) scores 0. The rest of the scoring is expressed in Figure 5-2.

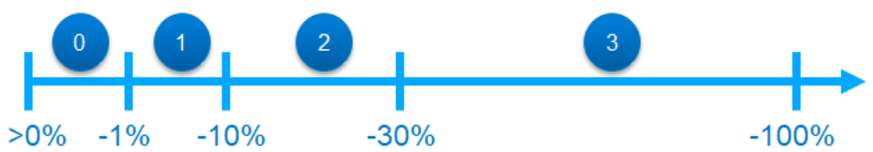

Figure 5-2: Scoring system for the KPI 'RES integration' (Reduction of RES curtailment). (source: Circe)

[106] The conclusions exposed in this report are only valid for the considered scenarios and system boundaries.

The addition of the electrolyser or the battery improves this KPI for almost every assessed scenario, except for the conservative ones. For every scenario and technology (battery and electrolyser), this KPI is expressed as the percentage of reduction of the Curtailment of the base case (without battery/electrolyser). Results can be found in Figure 5-3 and in Table 5-1.

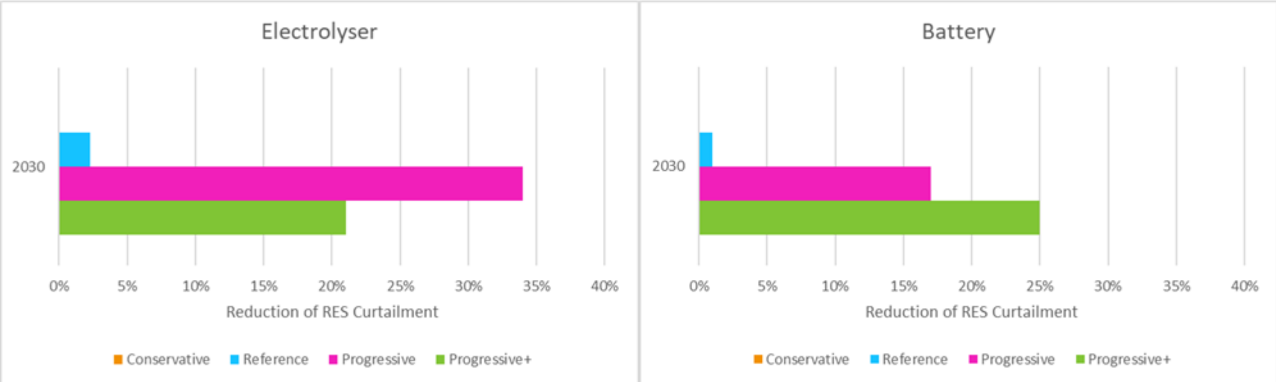

Figure 5-3: KPI *'RES Curtailment'.* (source: Circe based on Grid Model analysis)

	Electrolyser			
	2030			
	Cons.	**Ref.**	**Prog.**	**Prog.+**
RES Curtailment (%)	0%	-2%	-34%	-21%
Score	**0**	**1**	**3**	**2**

	Battery			
	2030			
	Cons.	**Ref.**	**Prog.**	**Prog.+**
RES Curtailment (%)	0%	-1%	-17%	-25%
Score	**0**	**0**	**2**	**2**

Table 5-1: Resulting scores for the KPI 'RES Integration' (Reduction in RES Curtailment). (source: Circe based on Grid Model analysis)

Additionally, Figure 5-4 provides insight into the absolute curtailment reduction. The significant contribution of the electrolyser, but also of the battery, in the Progressive and Progressive(+) scenario is clearly demonstrated.

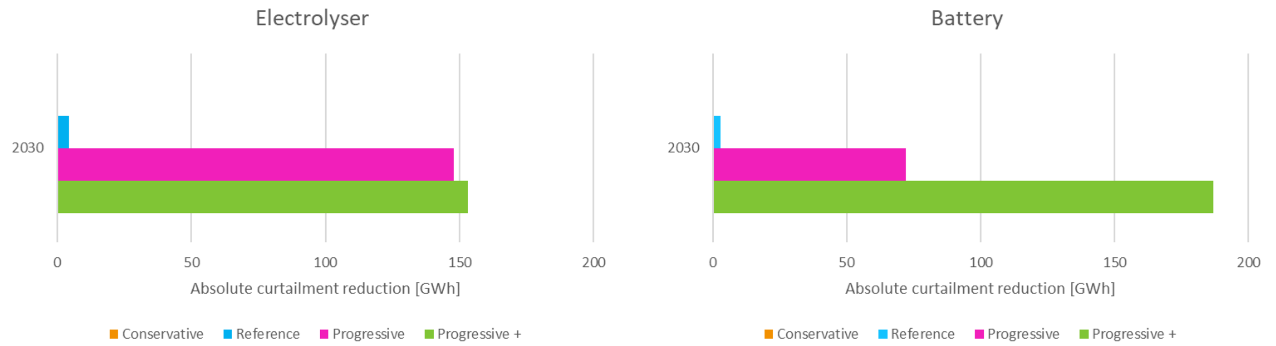

Figure 5-4: Absolute values (GWh) for Curtailment reduction. (source: Circe based on Grid model analysis)

- **The RES Curtailment substantially decreases both with an electrolyser or a battery, proving benefits of these technologies in RES integration.**
- **The electrolyser contributes, in most of the investigated scenarios, to a stronger reduction of RES curtailment than the battery. Battery's ability to absorb power is limited by its state of charge; there is no such limitation in the electrolyser.**
- **Benefits of the electrolyser and battery are generally further emphasised in more progressive scenarios characterised by higher RES penetration.**

5.2.2 Security of supply

The methodology and the scope of the analysis focus on the Energy Not Served (ENS) due to local congestions leading to load shedding.

Energy not served to loads could also be caused by faults in the transmission grid and other unpredictable issues. The developed methodology can neither capture nor take into account these effects and their impact on this KPI.

Moreover, adding an electrolyser, which is essentially a load, cannot decrease the energy not served to other loads in the power system.

It can be observed that neither the electrolyser nor the battery positively or negatively impacts the Security of Supply. This can be justified by the fact that data corresponding to an average climatic year (i.e. in terms of demand) has been used from ENTSO-E scenarios. These scenarios are set up to have no ENS under such climate[107]. Results are summarised in Table 5-2.

	Electrolyser			
	2030			
	Cons.	Ref.	Prog.	Prog.+
Security of supply (%)	0%	0%	0%	0%
Score	**0**	**0**	**0**	**0**

	Battery			
	2030			
	Cons.	Ref.	Prog.	Prog.+
Security of supply(%)	0%	0%	0%	0%
Score	**0**	**0**	**0**	**0**

Table 5-2: Resulting scores for the KPI 'Security of Supply'. (source: Circe based on Grid model analysis)

- **Security of supply is met in all the scenarios, both for the electrolyser and the battery case.**
- **No observable positive/negative impact: all the energy can be served (i.e. zero Energy Not Served).**

[107] E.g. extreme climate year, very cold or very hot, could have led to a different conclusion.

5.2.3 Variation in losses

The scoring system for variation in losses is shown in Figure 5-5. No reduction of losses is scored as 0, whereas reductions in losses are scored positively.

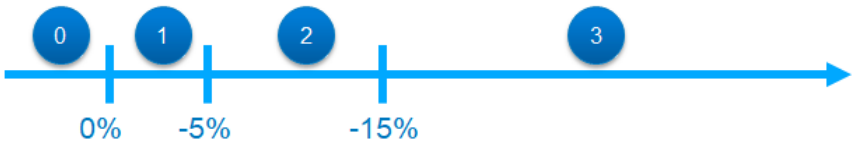

Figure 5-5: Scoring system for the KPI 'Variation in losses'. (source: Circe)

Locating the electrolyser/battery in a zone where the consumption is low and where there is a surplus of generation can theoretically reduce the power flow in the lines, since the available power is consumed more locally. As a consequence, for the electrolyser, there is a reduction in the line losses, since the power flowing through the lines is lower and the load is served by nearer generators. Otherwise, the produced power will flow to more distant loads incurring higher losses. This can be observed in Table 5-3 and Figure 5-6. For the battery however, no improvement is noticeable for the considered model and scenarios.

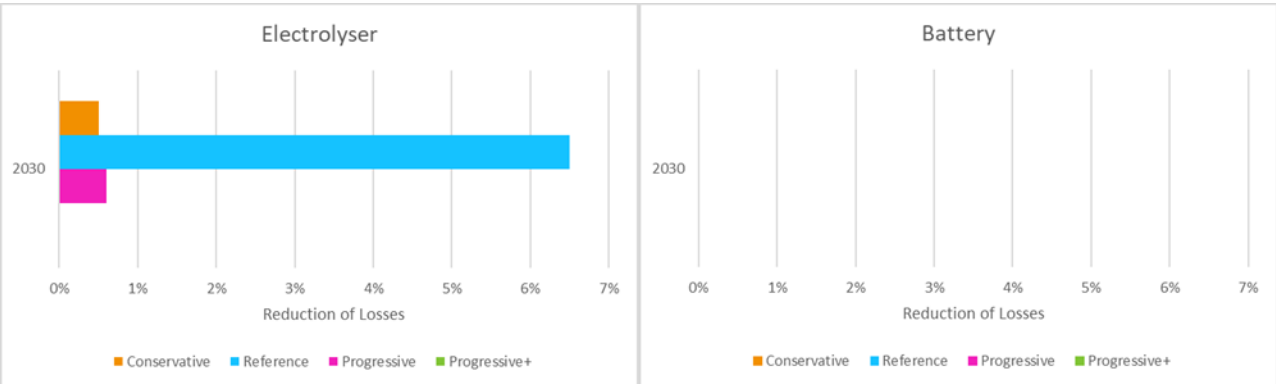

Figure 5-6: KPI '*Variation in Losses'.* (source: Circe based on Grid model analysis)

	Electrolyser			
	2030			
	Cons.	Ref.	Prog.	Prog.+
Variation in losses (%)	-0.5%	-6.5%	-0.6%	-0.0%
Score	**1**	**2**	**1**	**0**

	Battery			
	2030			
	Cons.	Ref.	Prog.	Prog.+
Variation in losses (%)	-0.0%	-0.0%	0.0%	0.0%
Score	**0**	**0**	**0**	**0**

Table 5-3: Resulting scores for the KPI 'Variation in losses'. (source: Circe based on Grid model analysis)

- **Using electrolyser leads to a reduction on the total yearly energy flowing through the lines when compared to the base case, resulting in lower losses on the electricity network.**
- **The electrolyser further reduces the losses compared to the battery.**

5.2.4 Congestion

The avoidance of congestion in the grid is mainly due to better exploitation of generators with lower marginal costs. Adding an electrolyser or battery in the GDOF area allows to absorb power that otherwise should be curtailed, in the case of RES, or limited in the case of dispatchable generators.

For every scenario and technology (battery and electrolyser), this KPI is expressed as the reduction of the congestion compared to the base case (without battery/electrolyser). The congestion is measured as the average congested power per hour and expressed in MW.

The scoring system for this KPI is summarised in Figure 5-7: a score 3 is assigned to congestion reduction above 250 MW, which is very close to the installed power of the different devices (electrolyser/battery). Lower scores are assigned to smaller reductions with minimal impact.

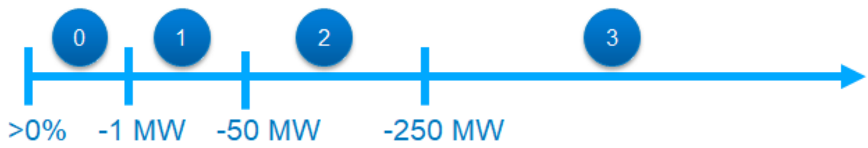

Figure 5-7: Scoring system for the KPI 'Congestion' (reduction). (source: Circe)

The assessed technologies have a positive impact on the level of congestion for the majority of the scenarios developed.

	Electrolyser			
	2030			
	Cons.	**Ref.**	**Prog.**	**Prog.+**
Congestion level (MW avg. per hour)	-204	-82	-3.2	-73
Score	**2**	**2**	**1**	**2**

	Battery			
	2030			
	Cons.	**Ref.**	**Prog.**	**Prog.+**
Congestion level (MW avg. per hour)	-326	0	0	-57
Score	**3**	**0**	**0**	**2**

Table 5-4: Resulting scores for the KPI 'Congestion'. (source: Circe based on Grid model analysis)

The following trend is observed: for almost every scenario, the impact of the electrolyser/battery in the reduction of the congestion decreases as the RES installed capacity increases, replacing generation with higher marginal cost. Nevertheless, congestion in the network model is closely linked to the generation mix of a specific scenario. The nodes selected as the connection point for the different generators is a best estimate for each scenario. This has an impact in the assessment of the congestion according to the devised methodology (see section 2.3.2.4). In the same vein, the selection of the fuel for a specific generator has been estimated to match the indications and the generation mixes established by the different scenarios. This estimate may also have an impact on congestion assessment.

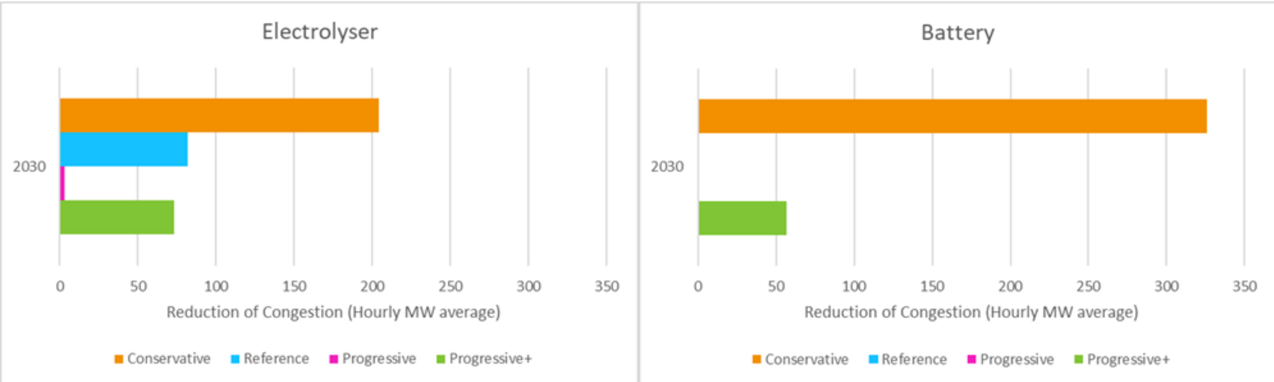

Figure 5-8: KPI *'Congestion'.* (source: Circe based on Grid model analysis)

- **The electrolyser contributes to a higher reduction of the congestion level compared to the battery, except for the conservative scenario.**
- **For the majority of the scenarios, as they have more RES installed capacity replacing generation with higher marginal cost, the impact of the electrolyser/battery in the reduction of the congestion decreases.**
- **This result is highly dependent on the placing of generators in the network. It is also impacted by the selection of the fuel for the generators to match generation mixes stated in the different scenarios.**

5.2.5 Avoided transmission upgrades

The basis of the assessment of this KPI is the 'Grid reinforcement threshold' as explained in section 2.3.2.5). The analysis is performed as follows (see Figure 5-9):

1) The annualised investments costs of the electrolyser and desalination unit are approximately 10 million € for a lifetime of 20 years (see section 2.4.1).
2) Translating this annualised investment costs of 10 million € of the electrolyser with the general lifetime of traditional grid investments being around 40 years, the maximal correlated investment for the traditional grid reinforcement is found, being approximately 200 million €.

TenneT TSO B.V. provided an approximate figure of 1 M€/km to estimate the cost of upgrading a line to calculate the avoided transmission upgrades in economic terms. TenneT TSO B.V. could therefore invest in about 200 km of reinforced cables.

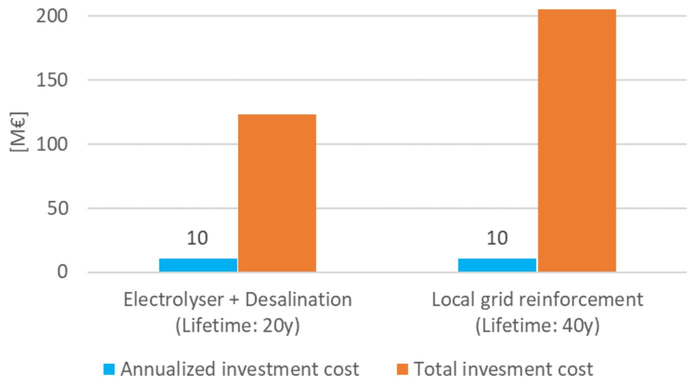

Figure 5-9: Correlation between Electrolyser and traditional grid reinforcement investments through annualisation. (source: Tractebel)

The addition of a 300 MW electrolyser has the same impact related to annualised costs as potential transmission grid reinforcements of 200 M€. Therefore, if the avoided transmission upgrade is higher than 200 M€, a score of 3/3 is given. Lower avoided costs for the transmission grid reinforcements ultimately means that the electrolyser or battery solution is not cost effective compared to traditional grid reinforcements. Of course, this KPI does not take into account the additional value streams related to the sales of hydrogen.

The scoring system for this KPI is expressed in Figure 5-10 and the results are shown in Table 5-5 and Figure 5-11.

Figure 5-10: Scoring system for KPI 'Avoided Transmission upgrade'. (source: Circe)

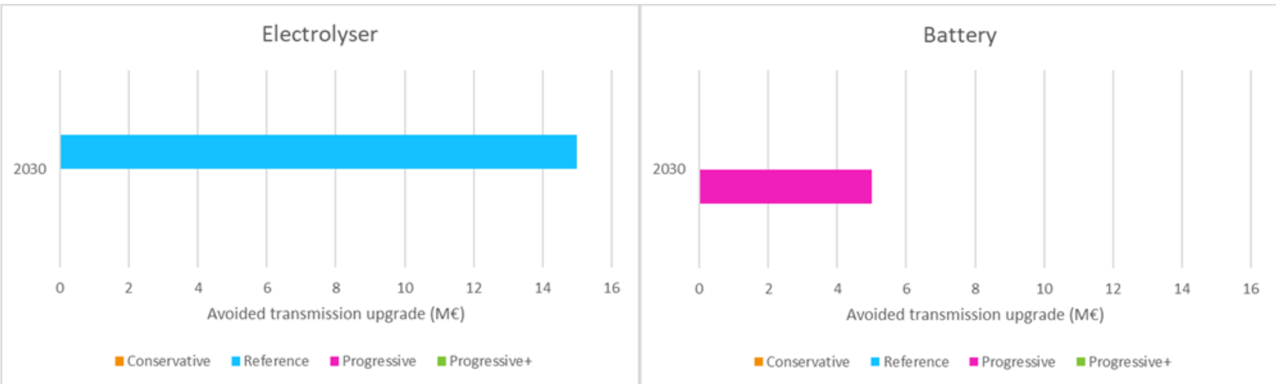

Figure 5-11: KPI 'Avoided Transmission Upgrade'. (source: Circe based on Grid model analysis)

	Electrolyser			
	2030			
	Cons.	Ref.	Prog.	Prog.+
Avoided Transmission Upgrade (M€)	0	15.0	0	0
Score	**0**	**1**	**0**	**0**

	Battery			
	2030			
	Cons.	Ref.	Prog.	Prog.+
Avoided Transmission Upgrade (M€)	0	0	5.0	0
Score	**0**	**0**	**1**	**0**

Table 5-5: Resulting scores for the KPI 'Avoided Transmission upgrade'. (source: Circe based on Grid model analysis)

- **For all scenarios, the avoided costs of the transmission grid reinforcements are below the 'Grid reinforcement threshold'.**
- **It needs to be stated that this KPI does not represent the additional value streams of the electrolyser in the other market segments (mobility).**

6 ADDITIONAL KPIS ASSESSMENT

6.1 Flexibility

The definition of the flexibility KPI can be found in section 2.3.3.1. The aim of this KPI is to characterize the capability of the electrolyser and of the battery to provide FCR (i.e. Frequency Containment Reserve), aFRR (i.e. Automatic Frequency Restoration Reserve) or mFRR (i.e. Manual Frequency Restoration Reserve).The flexibility scoring system can be found in Figure 6-1 and can be summarised as below:

- Score 3: The reinforcement facilitates FCR and aFRR/mFRR;
- Score 2: The reinforcement facilitates FCR;
- Score 1: The reinforcement facilitates aFRR or/and mFRR;
- Score 0: The reinforcement does not facilitate any frequency reserve.

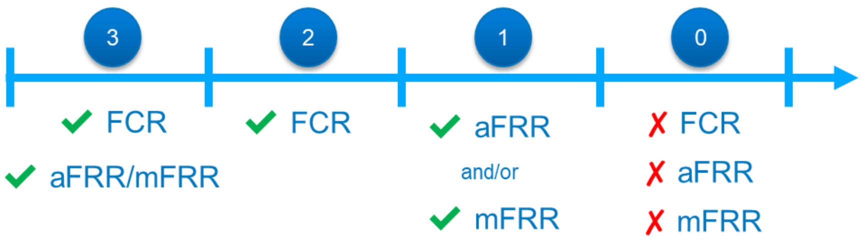

Figure 6-1: Scoring system for the KPI '*Flexibility*. (source: Tractebel)

As is visible in Figure 6-2 and Table 6-1, both the electrolyser and the battery can facilitate FCR and aFRR[108] and therefore, scores of 3 are reached for both technologies independently of the scenario or the year[109]. From the investigation performed in Activity 2, and more specifically related to the integration of Power-to-Gas conversion into Dutch electrical ancillary services markets[110] the following conclusions were drawn:

- The fast ramping performance of electrolysers indicates notable ability to participate in FCR, as any variation of demand can be achieved within just 1 second.
- The speed capabilities of electrolysers are well above the requirements of aFRR (i.e. minimum ramp rate of 7% of the bid per minute must be provided, and full activation of the bid must be completed within 15 minutes, see section 2.3.3.1), hence the provision of upward regulation aFRR by reducing consumption is a possibility.

[108] The capability of the electrolyser and the battery to deliver flexibility services at any moment will dependent on their loading (e.g. an electrolyser working at full capacity cannot increase further its load, while an electrolyser producing no hydrogen cannot further decrease its load). This arbitrage between operating the electrolyser at full/zero load or partial load (i.e. to reserve a part of the capacity to be able to answer a flexibility request) is out of scope of Task 1. Balancing services are however investigated in Task 3.

[109] It is however not claimed that no difference can be observed between the electrolyser and the battery. The focus of the KPI is only to assess the ability of the system to participate or not in FCR, aFRR, mFRR.

[110] *Integration of Power-to-Gas Conversion into Dutch Electrical Ancillary Services Markets*, Víctor García Suárez, José L. Rueda Torres, Bart W. Tuinema, Arcadio Perilla Guerra and M.A.M.M van der Meijden, Enerday 2018, 12th Conference on Energy Economics and Technology, April 2018.

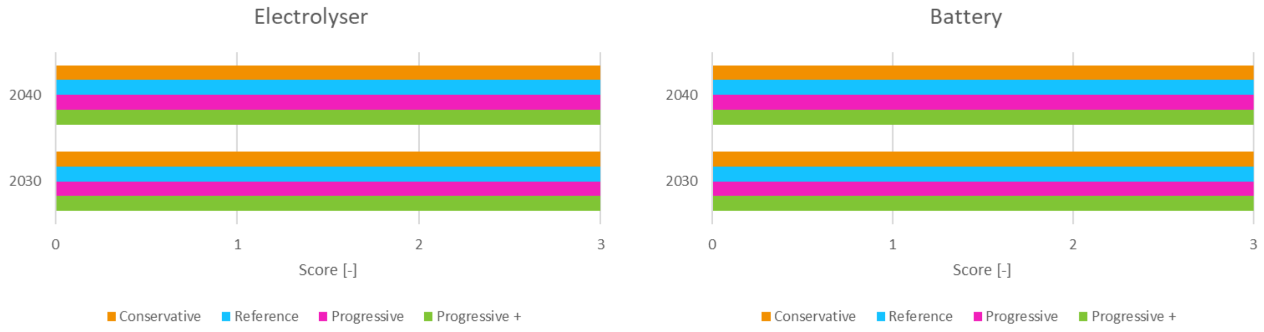

Figure 6-2: KPI '*Flexibility*. (source: Tractebel)

	Electrolyser							
	2030				2040			
	Cons.	Ref.	Prog.	Prog.+	Cons.	Ref.	Prog.	Prog.+
Score	3	3	3	3	3	3	3	3

	Battery							
	2030				2040			
	Cons.	Ref.	Prog.	Prog.+	Cons.	Ref.	Prog.	Prog.+
Score	3	3	3	3	3	3	3	3

Table 6-1: Resulting scores for the KPI '*Flexibility.*

- **The fast ramping performance of electrolysers indicates notable ability to participate in both in FCR and aFRR.**
- **Similarly, batteries can participate in both FCR and aFRR.**

6.2 Technical Resilience

As previously mentioned, the technical resilience KPI is investigated through a stability analysis which requires a dynamic electrical power system analysis. Such an analysis is out of the scope of the Market and Grid models used for the other KPIs. However, the Dynamic model developed within Activity 2 can characterise time varying response of the frequency, voltage magnitude and voltage angle to N-1 or N-2 events. This Dynamic model is therefore used. The following section summarises how this model was built.

6.2.1 Dynamic model

The Dynamic model developed in RSCAD[111] within Activity 2 focuses on the Northern Netherlands Network (i.e. N3) and more specifically on the GDOF area (Groningen-Drenthe, Overijssel and Friesland).

6.2.1.1 Network topology and operational scenarios

As illustrated in Figure 6-3, two different topologies of the N3 network are considered for the year 2030.

- First, in the intermediate situation, only two circuits between EOS-VVL are in service, while the 380 kV connection between VVL-ENS has not been installed yet and only one 430 MW generator linked to EOS is operative.
- For the final situation, the four 380 kV circuits between EOS-VVL and the 380 kV connection between VVL-ENS are in service, while all the generating capacity is operative.
- For the year 2040, the final network topology is used.

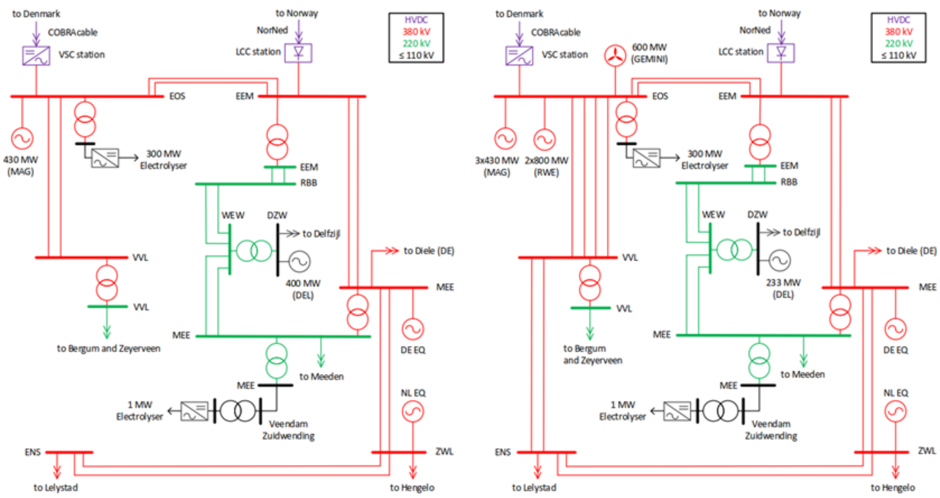

Figure 6-3: Considered network topologies in Dynamic model: intermediate (left) and final (right). (source: Activity 2)

The regional electricity demand in Groningen, Drenthe, Overijssel and Friesland for 2030 is projected in Activity 2 based on the demand of 2018, by considering the estimated proportion obtained from the KCD 2017 (Quality & Capacity Plan 2017) published by TenneT TSO B.V.[112]. The demand for 2040 is projected based on the demand projection considered in the Conservative scenario of the Cost Benefit Analysis performed in Activity 3.

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111 RSCAD is a RTDS Technologies' proprietary power system simulation software.

112 TenneT TSO B.V., "Kwaliteits- en Capaciteitsdocument 2017 (KCD2017)," Arnhem, the Netherlands, 2017. [Online]. Available: https://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/Dutch/TenneT_KCD2017_Deel_I_web.pdf

The generation scenarios for the years 2030 and 2040 were discussed with the experts from TenneT TSO B.V.. As described in Table 6-2, three generation scenarios are considered for 2030 and one scenario is considered for 2040. Scenario 1 is based on the intermediate network topology shown in Figure 6-3, in which generation and demand are reduced due to some of the circuits not being available. Nevertheless, scenarios 2 and 3 apply to the final network topology shown in Figure 6-3. For the 2040 case study, the generating capacity from scenario 2 in the 2030 model was modified and adjusted following the key assumptions considered in the Conservative scenario of the CBA analysis[113].

Generator / HVDC link	2030 Scenario 1	2030 Scenario 2	2030 Scenario 3	2040 Scenario 2
GEMINI wind farm (EOS)	0	600	450	2 x 600
MAG (EOS)	430	3 x 430	3 x 430	3 x 430
RWE (EOS)	0	2 x 800	2 x 800	2 x 500
DEL (DZW)	400	233	233	233
NorNed import (EEM)	700	700	700	700
COBRAcable import (EOS)	300	700	-700	700
Total	1830	4890	3490	4890

Table 6-2: Dispatch scenarios in the N3 area for the years 2030 and 2040 (in MW).

The N3 network topologies described in Figure 6-3 and the data gathered in Table 6-2 serve as an input for the power flow calculation.

6.2.1.2 List of simulated contingencies

The set of extreme contingencies summarised in Table 6-3 is defined to study the impact of electrolysers to support power system stability[114]. In total, 16 and 7 contingencies will be analysed respectively for 2030 and 2040, respectively. The impact of the battery is not analysed, as explained in section 2.3.3.2.

Contingency	2030 Scenario 1	2030 Scenario 2	2030 Scenario 3	2040 Scenario 2
Disconnecting COBRA	✓	✓	✓	✓
Disconnecting NorNed	✓	✓	✓	✓
Disconnecting GEMINI	✗	✓	✓	✓
Disconnecting 1 generator at EOS	✓	✓	✓	✓
Disconnecting 2 generators at EOS	✗	✗	✗	✓
Tripping 2 circuits between EOS-VVL	✗	✓	✓	✓
3-phase short circuit at VVL	✓	✓	✓	✓

Table 6-3: List of the contingencies considered for each scenario.

[113] The 800 MW coal-fired power plants (RWE) are assumed to be refurbished to biomass (i.e. Coal-phase out), respecting the same power rating, but dispatched at 500 MW. Also, a second offshore wind farm of 600 MW is installed at EOS substation, in similar fashion to GEMINI.

[114] Because of the network configurations and the generator dispatches, not all contingencies are simulated for the three scenarios. In particular, the disconnection of 2 generators at EOS is not included for the year 2030, since this disturbance would be too severe (given the model boundaries in RSCAD) in comparison with the total frequency support reserve assigned in the study, and therefore, the electrolyser influence cannot be determined for such contingency.

6.2.1.3 Dynamic modelling assumptions

The main assumptions of the Dynamic model are listed hereunder.

- In addition to the installed capacity in the N3 area, two more synchronous generators are included to represent the influence of the remainder of the Dutch network (NL EQ) and a section of the German network (DE EQ).
- The control structure and parameters of the generators in the N3 network are directly adapted from the PSS/E115 model of interconnected European countries. Also, the model and the parameters of the NL EQ and DE EQ generators follow the generic structure proposed in the PSS/E model for every German generator.
- In line with the definition of the Frequency Containment Reserve (FCR) product[116,117,] a capacity of ± 300 MW (i.e. ± 1500 MW/Hz) was assigned in the N3 network. In operational scenarios 2 and 3, the three power plants within the N3 network and the equivalent generator that represents the rest of the Netherlands have an approximate reserve of ± 25 MW each, while the equivalent generator that represents a section of the German grid has a reserve of ± 200 MW. In operational scenario 1, the values of the Dutch generators were increased to ± 35 MW to keep the total support constant while accounting for the disconnection of some of the generators.
- The electrolyser operates at rated capacity in all three scenarios (i.e. 300 MW). For such reason, the FCR reserve is not symmetric, as the electrolyser can only reduce its consumption in response to frequency drops. The reserve is set to -25 MW in scenarios 2 and 3, and to -35 MW in scenario 1.
- As the FCR reserves of the Dutch generators and the electrolyser are the same, the simulations can effectively compare the cases in which the support comes exclusively from synchronous generators with respect to the case in which the support of one of the generators in the Netherlands is substituted by the electrolyser.

6.2.2 Dynamic model-based results

The definition of the technical resilience KPI can be found in section 2.3.3.2. The technical resilience scoring system can be found in Figure 6-4. This KPI is evaluated in a scale of 0 to 3, depending on the percentage of contingencies in which the system performance improves when including the 300 MW electrolyser capacity, and can be summarised as below:

- Score 0: Improvements for less than 25% of the assessed contingencies;
- Score 1: Improvements for 25 to 50% of the assessed contingencies;
- Score 2: Improvements for 50 to 75% of the assessed contingencies;
- Score 3: Improvements for 75 to 100% of the assessed contingencies.

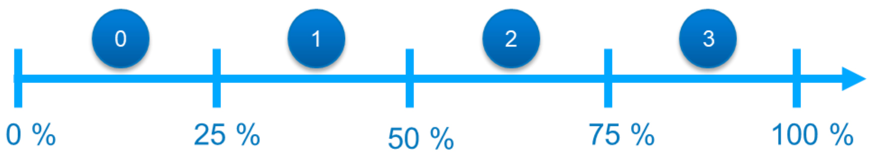

Figure 6-4: Scoring system for the KPI '*Technical Resilience*'. (source: Tractebel)

115 PSS/E, Power System Simulator for Engineering, is a high-performance transmission planning and analysis software developed by Siemens, https://new.siemens.com/global/en/products/energy/services/transmission-distribution-smart-grid/consulting-and-planning/pss-software/pss-e.html

116 TenneT TSO B.V., "Productspecificatie FCR," Nov. 2015. [Online]. Available: https://www.tennet.eu/fileadmin/user_upload/Bijlage_B__Productspecifications_FCR_ENG.pdf

117 regelleistung.net (2018). Internetplattform zur Vergabe von Relleistung [Online]. Available: https://www.regelleistung.net

More details regarding the achieved performance can be found in Appendix I, from which the following insights can be drawn.

- The participation of the electrolyser improves every situation in which generation or power import is lost. Since the electrolyser is operating at rated power, it cannot provide support in the case of a loss of energy export (i.e. COBRA in Scenario 3).
- The frequency performance for the short circuit and line tripping contingencies is not influenced in a significant manner with the inclusion of the electrolyser. The results are almost identical. For the short-circuit contingency, the voltage performance could be improved if the electrolyser was not operating at rated capacity (i.e. there is no extra power capability available in the electronic converter).
- The conclusions for the N3 2040 case are quite similar to those for the N3 2030 case.

As is visible in Figure 6-5 and Table 6-4, the participation of the electrolyser improves the assessed contingencies in more than half of the contingencies. More specifically, the electrolyser helps increasing the system performance in 10 out of the 16 investigated contingencies in 2030, while improving 5 out of the 7 contingencies investigated in 2040. The KPI has therefore a value of 2 for the electrolyser both in 2030 and 2040.

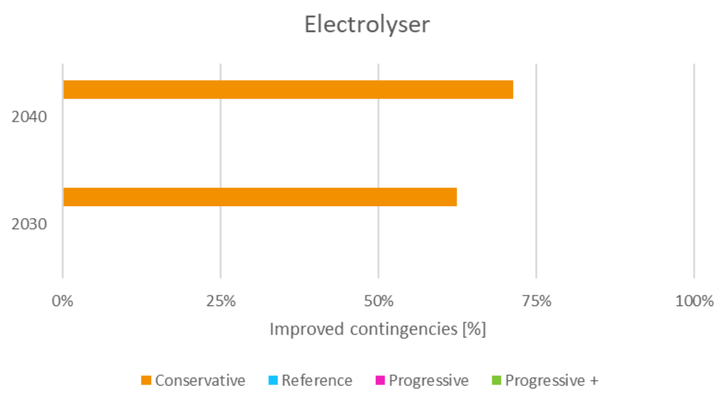

Figure 6-5: KPI '*Technical Resilience*' for the electrolyser case. (source: Tractebel)

	Electrolyser							
	2030				2040			
	Cons.	Ref.	Prog.	Prog.+	Cons.	Ref.	Prog.	Prog.+
Improved contingencies [%]	63	-	-	-	71	-	-	-
Score	**2**	**-**	**-**	**-**	**2**	**-**	**-**	**-**

Table 6-4: Resulting scores for the KPI '*Technical Resilience'*.

- **The participation of the electrolyser improves every situation in which generation or power import is lost.**
- **Since the electrolyser is operating at rated power, it cannot provide support in the case of a loss of energy export.**
- **The frequency performance for the short circuit and line tripping contingencies is not influenced in a significant manner with the inclusion of electrolyser.**

6.3 Implementation time

The KPI definition of implementation time is given in section 2.3.3.3. The scoring system is explained in Figure 6-6. If the implementation time (from study up to installation phase) of the electrolyser or the battery is below 4 months, a score of 3 is given. If it takes more than one year, a score of 0 is given.

Figure 6-6: Scoring system for the KPI '*Implementation time*'. (source: Tractebel)

For the electrolyser, it was confirmed by NEL (a hydrogen company delivering hydrogen solutions such as PEM electrolysers) that the manufacturing of a 300 MW electrolyser would take about a year. They are currently scaling up their electrolyser manufacturing capabilities in Norway, that should be able to produce 17 large-scale configurations per year[118].

Figure 6-7: 400 MW electrolyser configuration as designed by NEL[118].

[118] Simonsen B., NEL (2018). Multi MW electrolyser implementation time. [email]

For the batteries on the other hand, it has been proven by Tesla in Australia that in less than 4 months, it is possible to install a 100 MW battery[119].

There are no differences for these implementation times between the different scenarios and no assumption on difference was made for 2040 compared to 2030. A higher score is reached for the battery thanks to the lower implementation time, see Figure 6-8 and Table 6-5.

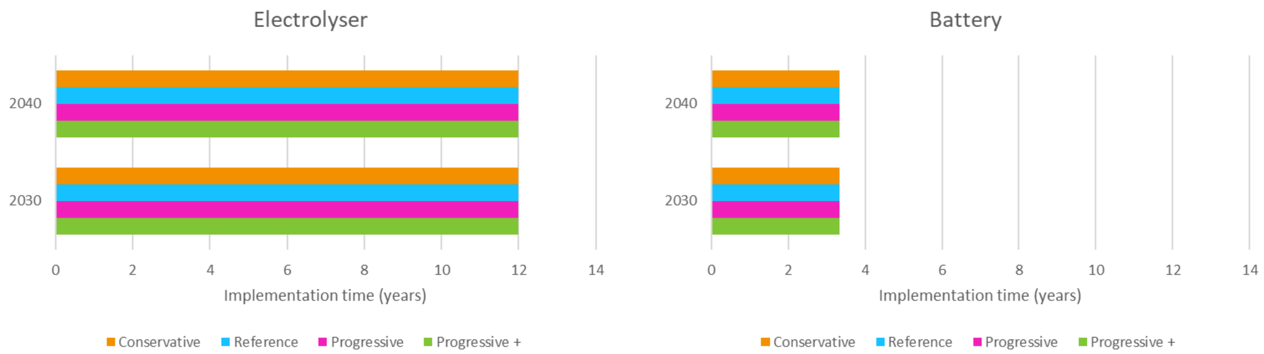

Figure 6-8: KPI '*Implementation Time.* (source: Tractebel)

Electrolyser								
	2030				2040			
	Cons.	Ref.	Prog.	Prog.+	Cons.	Ref.	Prog.	Prog.+
Implementation time [Months]	12	12	12	12	12	12	12	12
Score	1	1	1	1	1	1	1	1

Battery								
	2030				2040			
	Cons.	Ref.	Prog.	Prog.+	Cons.	Ref.	Prog.	Prog.+
Implementation time [Months]	3	3	3	3	3	3	3	3
Score	3	3	3	3	3	3	3	3

Table 6-5: Resulting scores for the KPI '*Implementation Time'.*

- **The battery reaches a lower implementation time, which is under 4 months.**
- **The electrolyser for a large-scale project however is one year.**

119 https://www.greentechmedia.com/articles/read/tesla-fulfills-australia-battery-bet-whats-that-mean-industry#gs.V4fjcAUy

7 TOTAL VALUE TO SOCIETY

7.1 Total value to society – Overview

Table 7-1 provides an overview of the achieved performances of the electrolyser and the battery in order to draw conclusions on the **total value to society** of these reinforcements. It clearly stands out from this table that the electrolyser outperforms the battery for the considered KPIs, and this for any given year of a specific scenario, for any scenario combining both 2030 and 2040 and for all scenarios combined. Evolution of the electrolyser and battery performances cannot directly be compared between 2030 and 2040 since some KPIs could only be assessed for 2030.

	Electrolyser			Battery		
	2030	2040	Total	2030	2040	Total
Conservative	14	13	27	10	7	17
Reference	16	12	28	7	7	14
Progressive	16	13	29	10	7	17
Progressive +	16	14	30	11	7	18
Total			**114**			**66**

Table 7-1: Sum of the KPIs scores for all scenarios.

However, for the KPIs assessed both in 2030 and 2040[120], Table 7-2 demonstrates that the electrolyser tends to achieve higher performances in 2040 than in 2030.

	Electrolyser	
	2030	2040
Conservative	11	13
Reference	10	12
Progressive	11	13
Progressive+	12	14

Table 7-2: Overview of scores obtained for KPIs assessed in both 2030 and 2040[120].

The key conclusions[121] and observations from the KPI analysis for all the studied scenarios and cases are the following:

- The cross-sectorial integration made possible with the electrolyser (i.e. coupling between the electricity and mobility markets), enables the electrolyser to score much better for the market-based KPIs than the battery. By selling hydrogen outside the electricity market, the electrolyser can maximise its revenues and demonstrate high economic viability. Additionally, through the decarbonisation of the transport sector, the electrolyser contributes to significantly reduced CO_2, NO_x, SO_x and particles emissions. Moreover, the *socio-economic welfare* KPI demonstrates that these benefits can be obtained at almost no additional electricity generation costs[122]. Therefore,

[120] Socio-economic welfare, CO_2 emissions variations, air quality, financial attractiveness, flexibility, technical resilience and implementation time.

[121] The conclusions are valid under the scope of the performed analysis, for the considered scenarios and system boundaries.

[122] This is valid under the scope of the performed analysis with a limited increase in demand from a 300 MW electrolyser. Higher penetration rate of electrolyser might impact this statement. The analysis is based on the assumption that this electrolyser is a first mover in the region. Investigation for generic electrolysers beyond the 300 MW electrolyser in Eemshaven is out of scope of the performed study.

the electrolyser is a clear example of the value driving that sector coupling entails[123], i.e. the needs to consider benefits from more than just one area.

- The battery on the other hand, always scores low (0 or 1 out of 3) for the market-based KPIs as it has no impact on CO_2, NO_x, SO_x and particles emissions, and as it is not financially viable when only looking at energy trading in the spot market.
- The electrolyser tends to contribute to higher RES integration than the battery through stronger reduction of the corresponding curtailment, with benefits further emphasised in scenarios with higher RES penetration. The electrolyser has no limitation to the power it can absorb, being able to draw up to 300 MW, the only limitation for its operation is the activation price. The battery, on the other hand, is limited by its state of charge. Nevertheless, depending on the generation and activations prices, this may change.
- The electrolyser further reduces the electrical losses compared to the battery. The availability of the electrolyser to consume locally produced energy is higher than the battery's one.
- The electrolyser contributes to a higher reduction of the congestion level compared to the battery. The electrolyser can absorb up to 300 MW from low marginal cost generators in its vicinity, leading to a better exploitation of those, whereas the battery has a limitation imposed by the state of charge. Consequently, in general terms, its impact is lower.
- The fast ramping performances of the electrolyser and the battery indicate notable ability to participate in both in FCR and aFRR (i.e. high flexibility).
- More progressive scenarios reach, on average, a higher global score for all their KPIs compared to the other scenarios:
    - For the CO_2 variations and air quality KPIs, this can be explained since the overall CO_2 emissions and air quality of the power sectors improve for the scenarios with more renewables included. This entails that the impact of CO_2 emissions reduction and air quality improvement related to the hydrogen impact on the mobility segment is more emphasised for these scenarios.
    - In more progressive scenarios, the tendency towards lower green hydrogen production costs, combined with higher competitive thresholds for the selling price of hydrogen to mobility consumers (i.e. fuel expected to be more expensive by 2040 in more progressive scenarios than in more conservative scenarios), strengthen the business case of the electrolyser.

Key messages and conclusions, for each KPI, can be found in the relevant KPI assessment sections: socio-economic welfare (4.2.1), CO_2 emissions variations (4.2.2), air quality (4.2.3), financial attractiveness (4.2.4), RES integration (5.2.1), security of supply (5.2.2), variation in losses (5.2.3), congestion (5.2.4), avoided transmission upgrades (5.2.5), flexibility (6.1), technical resilience (6.2.2) and implementation time (6.3).

[123] Conclusion valid under the current assumptions of scenarios and system boundaries.

7.2 Total value to society per scenario

In the following paragraphs, the KPIs will be analysed per scenario. As the additional KPIs (i.e. flexibility, technical resilience and implementation time) and financial attractiveness all score the same in 2030 and 2040 for a given scenario, they are not specifically mentioned in this overview.

For the **Conservative scenario**, some specific observations can be made (Figure 7-1):

- The market based KPIs reach a higher score in 2040 than 2030, with a maximum of 2/3, for the electrolyser. This can be explained for the CO_2 variations and air quality KPI, since the mobility market fed by hydrogen increases in 2040. Thus, improvements in CO_2 emissions and air quality are obtained.
- Battery and electrolyser reinforcements reach in general low score for the grid based KPIs in 2030. However, the congestion level for the battery reaches the highest score in 2030, and a score of 2/3 for the electrolyser. The minor effect of the electrolyser can be explained by the fact that it may be demanding energy in periods with a certain level of congestion on the lines and may aggravate the effect in those specific cases. Therefore, despite having a positive overall impact, this issue can reduce it when compared to the battery.

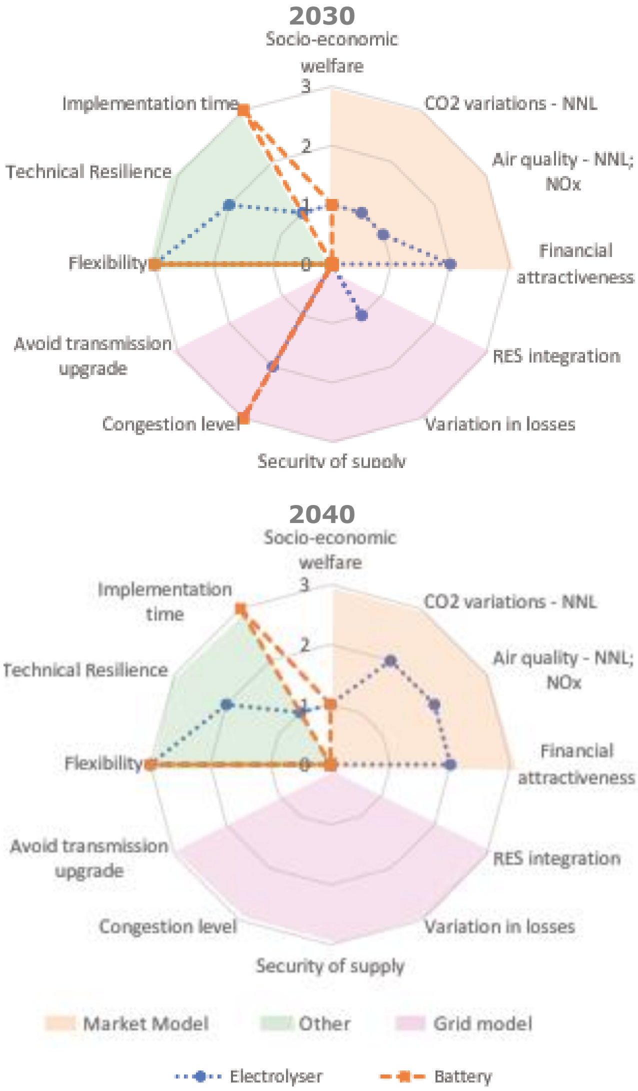

Figure 7-1: Evaluation of the performance of the electrolyser and battery cases for the Conservative scenario. (source: Tractebel)

For the **Reference scenario**, some specific observations can be made (Figure 7-2):

- The market based KPIs reach a higher score in 2040 than 2030, with a maximum of 3/3, for the electrolyser. This scoring is higher than for the Conservative scenario. The explanation is related to the higher RES share in the Reference scenario than in the Conservative scenario, resulting in lower CO_2 emissions and a better air quality related to the power sector. Therefore, the weight of the CO_2 emissions reductions and better air quality related to the hydrogen mobility segment is more pronounced in this scenario.
- The electrolyser reaches a higher score for the grid based KPIs in 2030 compared to the battery. The electrolyser has no strong limitation to the energy it can absorb, being able to draw up to 300 MW for long period of time[124], the only limitation for its operation is the activation price. The battery, on the other hand, is limited by its state of charge.

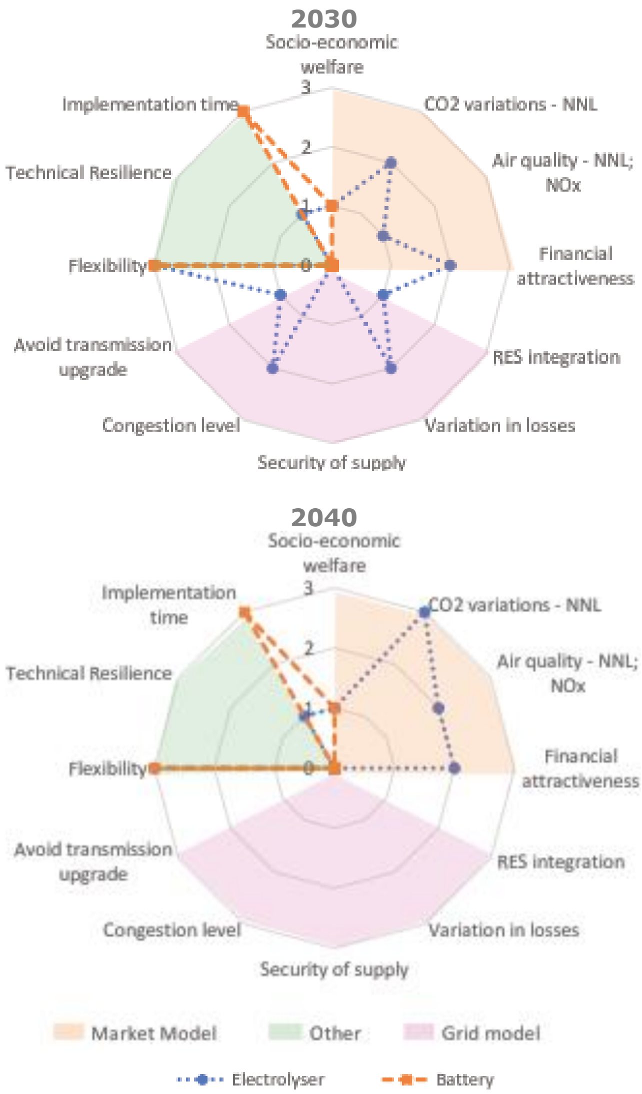

Figure 7-2: Evaluation of the performance of the Electrolyser and Battery cases for the Reference Scenario. (source: Tractebel)

124 Theoretically, the electrolyser is limited by the time-synchronous demand and/or the storage volume and capacity for hydrogen and/or available transport capacities. Admittedly, these barriers are wider than the one from the battery..

Observations can also be made for the **Progressive scenario** (Figure 7-3).

- Higher scores are reached for the electrolyser for the market based KPIs in this scenario. It can be clarified in the same manner as for previous scenario. Moreover, the financial attractiveness improves thanks to the tendency towards lower green hydrogen production costs, combined with higher competitive thresholds for the selling price of hydrogen to mobility consumers.
- The electrolyser demonstrates a higher RES curtailment reduction compared to the previous scenarios, while the battery reaches lower scores for the grid based KPIs. These effects are due to a higher share of renewable sources and a decrease in fossil sources. Thus, the electrolyser locally consumes renewable surplus and decreases curtailment (both in percentage and absolute value). From the Grid model analysis, it however appears that in more progressive scenarios, as there is more RES installed capacity replacing generation with higher marginal cost, the impact of the electrolyser/battery in the reduction of the congestion decreases. Due to higher availability of the electrolyser, it outperforms the battery.

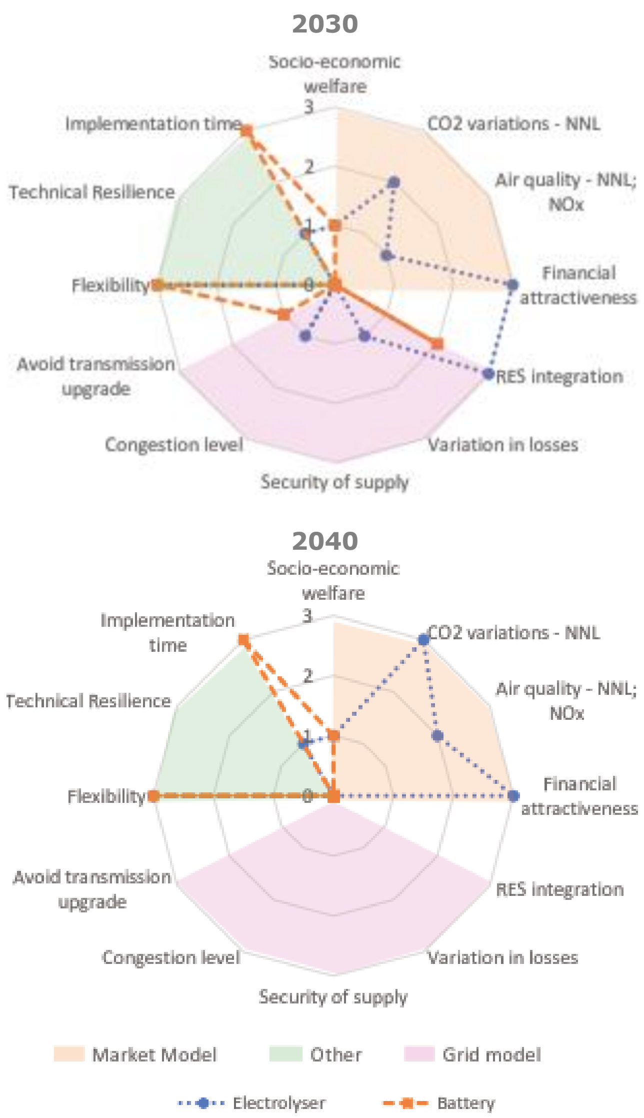

Figure 7-3: Evaluation of the performance of the electrolyser and battery cases Progressive scenario. (source: Tractebel)

The same continued trend is observed for the **Progressive + scenario** (Figure 7-4).

- Better scores are reached for the market based KPIs compared to previous scenarios. The same explanation as given earlier still applies.
- Compared to the Progressive scenario, the electrolyser reaches lower scores for the grid based KPIs, while the battery reaches higher scores. This results in the end in a battery better performing than the electrolyser on the grid point of view. Progressive+ scenario is different from the other scenarios, since fewer dispatchable sources are considered (only gas and biomass) and has a higher RES share. The outperforming of battery may be due to the different activation prices governing the operation of the battery and the electrolyser. The battery has a stronger impact on this KPI since its operation is better scheduled.

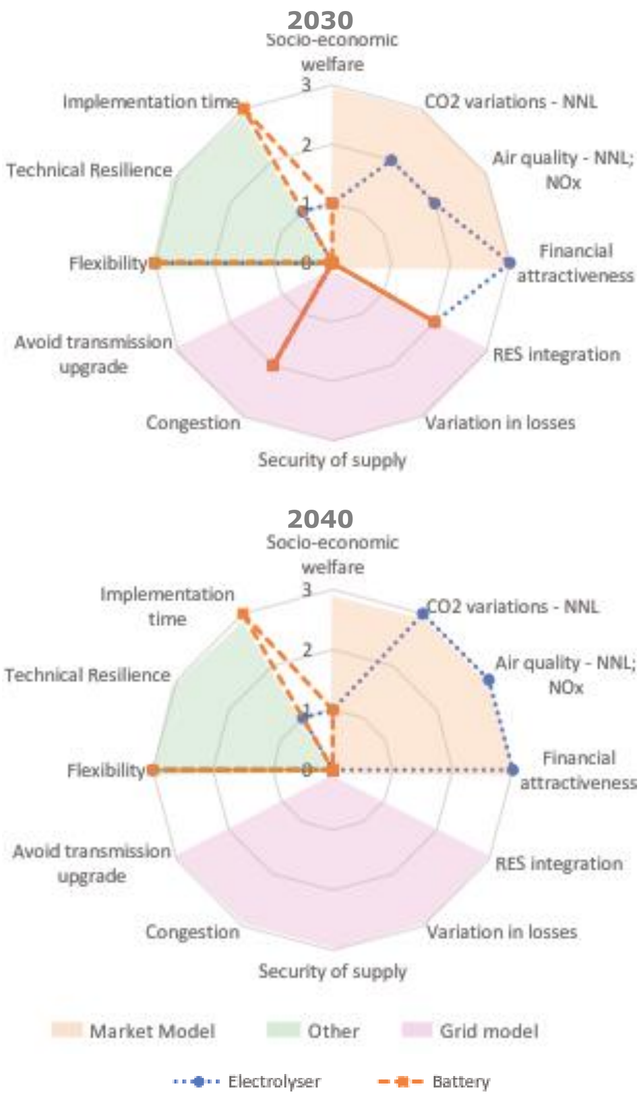

Figure 7-4: Evaluation of the performance of the electrolyser and battery cases for the Progressive+ scenario. (source: Tractebel)

8 CONCLUSIONS[125]

In the context of global warming, more and more variable renewable energy resources like wind and solar PV are being integrated into the electricity network. Nevertheless, variability and intermittency are the key challenges that need to be overcome in order to integrate these generation technologies into the power systems.

The Northern Netherlands region, with its significant development of onshore/offshore wind, the existing interconnection with Norway with the NorNed HVDC cable and the landing of the COBRAcable HVDC interconnector with Denmark, is at the core of this power sector transformation. The aim of the TSO 2020 project is to facilitate flexibility of the power system in the Eemshaven area to allow the integration of renewable energy into the Northern Netherlands region.

The aim of Task 1[126] of Activity 3 was to perform a **Cost-Benefit Analysis** (CBA) to demonstrate the total value to society of a 300 MW electrolyser in the Eemshaven area. More specifically, the CBA-model studies the impact of the electrolyser to allow the integration of locally generated renewable energy (mainly offshore wind) and the landing of the COBRAcable HVDC interconnector with Denmark.

In that perspective, **hydrogen markets** in the Northern Netherlands in 2030 and 2040 have been studied, looking at the potential hydrogen off-takers not only from the energy but also from the transport sector, i.e. covering from **mobility segment** to **industrial segment**, both in terms of volume of hydrogen and willingness to pay. Through a competitiveness analysis, the **mobility segment was identified as the most promising** one for the 300 MW electrolyser, to be installed in Eemshaven, in order to maximise its revenues. Hydrogen buses, trucks, trains, light-duty vehicles and passenger vehicles have been investigated.

The **operation** of the electrolyser has then been optimised through an **electrolyser activation price**, separately for 2030 and 2040 and for the 4 envisaged scenarios to capture the impact of the context (e.g. CO_2 and fuel prices evolution, RES penetration, national policies, etc.).

The performed simulations have demonstrated, amongst other things, the need for large-scale hydrogen storage (because of a variable production pattern of hydrogen throughout the year), and the capability of the electrolyser to reduce RES curtailment, electrical losses in the grid and the congestion level in the grid.

In addition, the **cross-sectorial integration**, enabled by the electrolyser (i.e. coupling between the electricity and mobility markets), **fosters** the **decarbonisation of the transport sector**, thereby significantly reducing CO_2, NO_x, SO_x and particles emissions in the Northern Netherlands **without increasing the cost for the society**. Indeed, it has been demonstrated that this green hydrogen can be produced at almost no extra electricity generation costs[127] through better usage of renewable resources and low marginal cost generation technologies. Moreover, the establishment of competitive hydrogen thresholds ensures that end users will have the possibility to shift from a carbon emitting supply to a green supply. More specifically, vehicle owners will be able to fuel their fuel cell-based vehicles at no extra costs compared to combustion engine vehicles, without considering the investment costs of the vehicles themselves. It is worth mentioning that a full Total Cost of Ownership analysis could be a relevant case to be studied in a next phase of the project.

125 The conclusions exposed in this report are only valid for the considered scenarios and system boundaries.

126 *'Assessing the value of the electrolyser to society'*

127 This is valid under the scope of the performed analysis with a limited increase in demand from a 300MW electrolyser. Higher penetration rate of electrolyser might impact this statement. The analysis is based on the assumption that this electrolyser is a first mover in the region. Investigation for generic electrolysers beyond the 300 MW electrolyser in Eemshaven is out of scope of the performed study.

Furthermore, this cross-sectorial integration also fosters the **economic viability** of the electrolyser throughout all scenarios, demonstrating the **value for society** (i.e. from production to storage, distribution and fuel station owners) to develop the hydrogen sector in the Northern Netherlands. A hydrogen value chain has been modelled from production to distribution to final end-users together with the required infrastructure (i.e. hydrogen pipeline from the electrolyser located in Eemshaven to salt cavern facilities in Zuidwending, followed by a tube trailer distribution to final refuelling stations). A payback time around 6 to 10 years can be achieved (with a possibility to decrease to 5 years in the most optimistic scenario and up to 14 years in the most pessimistic one). Furthermore, additional elements could potentially be taken into account to further strengthen the business case. First of all, **additional revenues streams** might improve the financial attractiveness of the Power-to-Gas facility: monetisation of oxygen production[128] in the electrolysis process and monetisation of services provided to the grid (i.e. ancillary services[129] such as aFRR or FCR), for which it is also technically suitable[130]. Secondly, hydrogen competitive selling prices (before the additional expenses related to distribution and dispensing) have been homogenised for all mobility off-takers while bi-lateral contracts (taking advantage of the full hydrogen competitiveness threshold) could be envisaged with a bus fleet operator, railway company, etc., to clear additional revenues. However, in the scope of this value to society assessment, certain costs have not been taken into account for the business case analysis of the electrolyser since the aim is to capture an overview of the benefits the electrolyser can bring on several aspects. The reader is invited to read the report of Task 3 of this Activity 3 for deeper insights into the business case of the electrolyser.

Even though focus has been put on mobility off-takers, industrial players should not be taken out of the picture. In the future, political decisions, people awareness, CO_2 regulations, etc., might be key drivers towards the decarbonisation of industries. More and more entities like regions, ports, groups of industries, show strong innovation ambition and are willing to inject sustainability requirement into their development as a potential competitive advantage. Moreover, stricter environmental regulations might come into place and will force the **industrial sector** to undergo a **major transformation**, going from a conventional fuel-based supply (natural gas, coal, etc.) to a green-based supply such as biogas or hydrogen. Hydrogen will indeed more easily compete against biogas than against natural gas. Finally, CO_2 prices evolution is difficult to predict, but a rise beyond the figures considered in the scope of this study would increase willingness of the industrial sector to move towards hydrogen. Electrolyser investment cost, electricity, fuel and CO_2 prices being key drivers of hydrogen competitiveness, the authors believe that future studies could fruitfully explore this issue by assessing the required thresholds for hydrogen to be competitive in the industry segment.

Besides the demonstrated environmental and economic benefits that the 300 MW Eemshaven electrolyser can bring to the Northern Netherlands, the power-to-gas facility will also bring **advantages to the local economy**. Such a project can be seen as a demonstration case bringing attention to the region, but it will also be an opportunity for the region to take advantage of its key experience and expertise in the gas process industry to modernise its activities.

Another grid reinforcement has been assessed and compared with the electrolyser and the normal situation without any grid reinforcement, namely a battery. However, the **electrolyser outperforms the battery** for the considered KPIs, and this for any given year of any specific scenario, for both 2030 and 2040. For instance, the battery is not financially viable when only looking at energy trading in the

128 To be used in hospitals, industries such as steel, glass semi-conductor, etc.

129 These services are analysed in Task 3 '*Assessing the business model and operational scheme of the electrolyser'* of this Activity 3.

130 See Activity 2 investigations: *Integration of Power-to-Gas Conversion into Dutch Electrical Ancillary Services Markets*, Víctor García Suárez, José L. Rueda Torres, Bart W. Tuinema, Arcadio Perilla Guerra and M.A.M.M van der Meijden, Enerday 2018, 12th Conference on Energy Economics and Technology, April 2018.

day-ahead market: revenue streams stacking from other market segments (out of the scope of this study) could help improve the attractiveness.

It should be mentioned that the scope of this study is to assess the business case of this specific 300 MW electrolyser, assuming all identified markets (i.e. mobility, industries, etc.) are reachable. In that perspective, the operation of the electrolyser and the markets it will target is based on the idea that this electrolyser is a first mover in the region. If case of competition amongst more electrolysers in the Northern Netherlands, the business case would be affected. Electrolysers would need to be operated differently to capture other market segments (e.g. industry) or the geographical scope of the hydrogen market investigation would need to be expanded outside of the Northern Netherlands (e.g. Netherlands, Germany), for which the distribution infrastructure should be studied in more detail. The authors believe that the outcomes of Activity 3 will be relevant inputs for Activity 5 *'Analysis to scale-up to mass application (business plan)'* to investigate generic electrolysers beyond the 300 MW electrolyser in Eemshaven.

9 NOMENCLATURE

aFRR	automatic Frequency Restoration Reserve
B2B	Business-to-Business
B2C	Business-to-Consumer
BE	Belgium
BoP	Balance of Plant
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
CHP	Combined Heat and Power
CO_2	Carbon dioxide
COP	Coefficient Of Performance
DE	Germany
DG	Distributed Generation scenario
DK	Denmark
EEGI	European Electricity Grid Initiative
ENS	Energy Not Served
ENTSO-E	European Network of Transmission System Operators of Electricity
EOS	Eemshaven-Oudschip (name of substation in GDO network)
EU	European Union
EUCO	External Scenario developed by the European Commission
EV	Electric Vehicles
FCR	Frequency Containment Reserve
FR	France
GB	Great Britain
GDOF	Groningen-Drenthe-Overijssel-Friesland
H_2	Hydrogen
HT	High Temperature
HVDC	High Voltage Direct Current
KPI	Key Performance Indicator
ktpa	Kilo-tonnes per annum
LCOH	Levelised Cost of Hydrogen
LT	Low Temperature
mFRR	Manual Frequency Restoration Reserve
NL	Netherlands
N-NL	Northern Netherlands
NO_x	Nitrogen Oxide
NPV	Net Present Value
O&M	Operation & Maintenance
OPEX	Operation Expenditure
OPF	Optimal Power Flow
P2G	Power-to-gas (electrolyser)
PEM	Polymer Electrolyte Membrane
RES	Renewable Energy Sources
RWE	Rheinisch-Westfälisches Elektrizitätswerk

SMR	Steam Methane Reforming
SO_x	Sulphur Oxide
ST	Sustainable Transition scenario
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
V2G	Vehicle-to-Grid
VVL	Vierverlaten (name of substation in GDO network)

10 APPENDIX I: TECHNICAL RESILIENCE DETAILED RESULTS

More details regarding the achieved performance can be found in Table 10-1, Table 10-2, Table 10-3, Table 10-4

Contingency	Freq. Nadir[131] [Hz] w/o electrolyser	Freq. Nadir [Hz] w/ electrolyser	Improvement
Disconnecting COBRA	49.70	49.72	Yes
Disconnecting NorNed	49.17	49.27	Yes
Disconnecting 1 generator at EOS	49.50	49.54	Yes
3-phase short circuit at VVL	Equal performance in both cases		No

Table 10-1: Summary of the Technical resilience KPI results obtained for the 2030 Scenario 1.

Contingency	Freq. Nadir [Hz] w/o electrolyser	Freq. Nadir [Hz] w/ electrolyser	Improvement
Disconnecting COBRA	49.21	49.26	Yes
Disconnecting NorNed	49.21	49.26	Yes
Disconnecting GEMINI	49.32	49.37	Yes
Disconnecting 1 generator at EOS	49.09	49.09	Yes
Tripping 2 circuits between EOS-VVL	Equal performance in both cases		No
3-phase short circuit at VVL	Equal performance in both cases		No

Table 10-2: Summary of the Technical resilience KPI results obtained for the 2030 Scenario 2.

Contingency	Freq. Nadir [Hz] w/o electrolyser	Freq. Nadir [Hz] w/ electrolyser	Improvement
Disconnecting COBRA	50.88	51.10	No
Disconnecting NorNed	49.22	49.27	Yes
Disconnecting GEMINI	49.55	49.57	Yes
Disconnecting 1 generator at EOS	49.03	49.09	Yes
Tripping 2 circuits between EOS-VVL	Equal performance in both cases		No
3-phase short circuit at VVL	Equal performance in both cases		No

Table 10-3: Summary of the Technical resilience KPI results obtained for the 2030 Scenario 3.

[131] The Frequency Nadir is an indicator of the maximum frequency deviation from the design frequency (50 Hz). For instance, following a sudden loss of generation or power import, the system frequency drops. The frequency Nadir is the point at which the frequency drop is arrested (i.e. maximum deviation) and as of which the frequency will move back towards its design value. The electrolyser will therefore improve the system stability performance if it reduces the frequency deviation compared to a configuration without it.

Contingency	Freq. Nadir [Hz] w/o electrolyser	Freq. Nadir [Hz] w/ electrolyser	Improvement
Disconnecting COBRA	49.20	49.25	Yes
Disconnecting NorNed	49.20	49.25	Yes
Disconnecting GEMINI	49.39	49.42	Yes
Disconnecting 1 generator at EOS	49.49	49.51	Yes
Disconnecting 2 generators at EOS	48.19	48.24	Yes
Tripping 2 circuits between EOS-VVL	Equal performance in both cases		No
3-phase short circuit at VVL	Equal performance in both cases		No

Table 10-4: Summary of the Technical resilience KPI results obtained for the 2040 Scenario 2.