North Sea Energy offshore system integration

D3.3

North Sea Energy 2023-2025

Business case assessment for the offshore value chain

Navigating the North Sea transition!

For centuries, the North Sea has been a source of economic strength, ecological richness, and international cooperation. Always subject to change, yet steadfast as a connector of nations, cultures, and economies. Today, it once again takes center stage—this time as a lighthouse region for the transition to a sustainable, affordable, and reliable energy system. The North Sea Energy program marks an important step in this development.

North Sea Energy is a dynamic research program centered around an integrated approach to the offshore energy system. Its aim is to identify and assess opportunities for synergies between multiple low-carbon energy developments at sea: offshore wind, marine energy, carbon capture and storage (CCS), natural gas, and hydrogen. At the same time, the program seeks to strengthen the carrying capacity of our economy, society, and nature.

The offshore energy transition is approached from various perspectives: technical, ecological, societal, legal, regulatory, and economic. Our publications provide an overview of the strategies, innovations, and collaborations shaping the energy future of the North Sea. They reflect the joint efforts of companies, researchers, and societal partners who believe in the unique potential of this region as a hub for renewable energy and innovation.

What makes this program truly distinctive is not only its scale or ambition, but above all the recognition that we are operating in a dynamic field of research. The energy transition is not a fixed path, but a continuous process of learning, adapting, and evolving. New technologies, a dynamic natural environment, shifting policy frameworks, and changing societal insights demand flexibility and vision. Within this program, we work together to ensure that science and practice reinforce one another.

This publication is one of the results of more than two years of intensive research, involving over forty (inter)national partners. This collaboration has led to valuable insights and concrete proposals for the future of the energy system in and around the North Sea. All publications and supporting data are available at: https://north-sea-energy.eu/en/results/

We are deeply grateful to all those who contributed to the realization of this program. In particular, we thank our consortium partners, the funding body TKI New Gas, the members of the sounding board, the stakeholders, and the engaged public who actively participated in webinars and workshops. Their input, questions, and insights have enriched and guided the program.

At a time when energy security, climate responsibility, and affordability are becoming increasingly urgent, this work offers valuable insights for a broad audience—from policymakers and professionals to interested citizens. The challenges are great, but the opportunities are even greater. The North Sea, a lasting source of energy, is now becoming a symbol of sustainable progress.

With these publications, we conclude an important phase and look ahead with confidence to the next phase of the North Sea Energy program. In this new phase, special attention will be given to spatial planning in the North Sea, European cooperation, and the growing importance of security in the energy system of the future.

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Executive summary

This study presents an integrated business case assessment of emerging offshore energy value chains in the Dutch North Sea region. It evaluates key components such as offshore wind, onshore and offshore electrolysis, offshore solar, hydrogen transport and storage, and electricity transport with the goal of quantifying cost drivers, identifying unprofitable gaps, and support decision-making for future infrastructure and investment strategies. It should be noted that this work is related to the qualitative business models (D3.2); a deep-dive on offshore electrolyser scaling and operation; and a system value assessment (D3.1), of which the key insights are harmonized in a whitepaper (D3.4). This report presents results from a project developer point of view.

Offshore Wind

Over the last decade, Dutch offshore wind has experienced rapid growth, with significant new capacity planned for 2030 and beyond. However, as the energy transition progresses, price cannibalization and market saturation threaten profitability. Dispatch modeling shows that in potential scenarios with ambitious renewable energy deployment (in this study explorative scenarios of grid operators are used) capture prices for offshore wind could drop as low as €10-25/MWh by 2050, undermining project viability (the base business case demonstrates levelized costs of 79 €/MWh and an unprofitable gap of 43 €/MWh). It should be acknowledged that future prices are inherently uncertain and unpredictable and forward electricity prices are higher than the prices we used based on marginal costs. However, it still indicates that the offshore wind business case may not remain profitable without support or changes in market design in the coming decades, and that the impact of price cannibalization could be significant if no additional measures, such as renewable energy demand stimulation and support fall back options, are implemented.

Onshore and Offshore Electrolysis

Electrolysis is a key enabler for green hydrogen production, but remains economically challenging. Projected levelized costs range between 235 and 693 €/MWh (or: 7.8-23.1 €/kg) and a baseline of 394 €/MWh (or: 13.1 €/kg) by 2030, driven primarily by high electrolyzer CAPEX, the costs of electricity, stack replacements and potential electricity grid connection costs. Onshore electrolysis is likely to outperform platform-based offshore electrolysis on a project level due to its lower costs.

While earlier research suggested that offshore electrolysis could become competitive with onshore electrolysis based on supply chain costs at large scales (4+ GW) and over long distances (>100 km offshore), this report finds that under current cost assumptions offshore electrolysis is under no conditions the cost optimal option on supply chain level by 2030. This is mainly because the impact of electrolysis costs on the total supply chain costs is so high, that the less expensive hydrogen transport costs do not outweigh the higher electrolysis costs of offshore electrolysis. If substantial electrolysis cost reductions (exceeding 75%) for both onshore and offshore take place, or if offshore electrolysis becomes less than 25% more expensive than onshore electrolysis, the costs of the offshore electrolysis supply chain could outcompete the costs of the onshore chain.

Offshore Solar Integration

The combination of offshore solar and wind can modestly enhance electrolyser utilization (adding ~200 operating hours annually for an offshore solar farm of 200 MW) and reduce storage requirements (~5%). However, with projected levelized costs around €160/MWh higher than offshore wind (namely 240 €/MWh), its integration remains economically unattractive through 2030. The benefits of offshore solar would begin to outweigh the costs if offshore solar costs could be reduced to no more than 50 €/MWh above those of offshore wind, according to our supply chain cost analysis.

Hydrogen offtake

Hydrogen competitiveness was assessed by comparing blue vs green hydrogen (i.e., grid hydrogen + certificates) options for an end-user that currently uses grey hydrogen. Users transitioning from grey hydrogen to green hydrogen face similar costs compared to blue hydrogen if an offtake mandate with HWIs (Hernieuwbare Waterstofeenheid Industrie) would be implemented. If a grey hydrogen offtaker would switch to 100% green hydrogen uptake (by purchasing HWIs for 100% of its hydrogen consumption) it would significantly rise its costs (leading to an additional cost gap of 61 €/MWh for the base case). Producing products with a significant green premium is likely to be required to close such a business case. Hydrogen competitiveness was also assessed by comparing it with natural gas. For end-users that currently use natural gas, the gap is significantly larger (an additional cost gap of 122 €/MWh to comply with REDIII and 206 €/MWh for 100% green hydrogen for the base case) and therefore an even higher green premium on its end-products would be required to switch towards green hydrogen.

Offshore Energy Transport

Offshore electricity and hydrogen transport costs are highly sensitive to network utilization. Therefore it is important to plan the offshore electricity network, offshore hydrogen network, interconnectors and offshore hydrogen locations and incentivize its operational strategies in alignment with each other. Under our basic assumptions, levelized costs of transport of respectively 22-57 €/MWh and 6-11 €/MWh for electricity and hydrogen could be achieved by 2050. Recent insights indicate that cost will be more on the higher side of these ranges for both electricity and hydrogen, which in our network cases led to rough estimations for total investments of 117 B€ and 5.4 B€ for the offshore electricity and hydrogen network respectively.

For the electricity network, smart solutions and optimized scaling are needed to avoid underutilization of cable connections for hybrid offshore wind and hydrogen projects. For the hydrogen network it is important that connection costs of first-of-its-kind projects can be spread over future users, and that the largest cost reduction impact can be gained in the compression regime and locations. Reuse of pipeline has potential to reduce costs as well, but since these are a minor share over the total offshore hydrogen supply chain costs with relative large volumes transported, it is likely that other factors than economic should be decisive in this matter.

Underground Hydrogen Storage (Onshore/Offshore)

Onshore salt cavern storage is the most cost-effective option for both short cycle and seasonal storage (base case results of €22-27/MWh, or: €0.7-0.9/kg). Offshore underground hydrogen storage is approximately 3-4 times more expensive and is unlikely to be pursued unless justified by policy goals such as energy security, public resistance to onshore storage, limited onshore capacity, or system-level benefits elsewhere in the energy network. These are political considerations that must be weighed carefully against added cost burdens, which – without any further measures – are likely to be felt by the other hydrogen value chain actors.

Final Note

The financial sustainability of offshore energy projects is increasingly uncertain. Realizing a viable offshore hydrogen economy will depend on strategic interventions, cost reductions, and collaboration among governments, industry, and research institutions to align technological development with system needs and market opportunities. Without structural policy support and cost reduction strategies, investment in offshore hydrogen and energy hubs will likely stall, despite their long-term strategic value to the North Sea energy system.

Recommendations

For Project Developers:

- Cost reductions, innovation, and proof-of-concept pilots are key for offshore electrolysis.
- Consider off-grid electrolysers to reduce electricity grid costs (but also consider that this is likely not societally optimal [1]), but only if an economically and technically feasible attractive alternative can be found on how to deal with the minimum load requirement of the electrolyser.
- Collaboration is needed to limit electricity and hydrogen grid connection costs.
- Identify end-users willing to pay green premiums, fostering vertical integration within supply chains.

For Governments:

- Stimulate flexible electricity demand to support offshore wind.
- Consider mechanisms like minimum price guarantees or Contracts for Difference (CfDs) for offshore wind. And harmonized supply-demand matchmaking for offshore wind and electrolysis.
- Differentiate support for onshore and offshore electrolysis to enable both technologies to develop.
- Collectively plan the (offshore) electricity grid, hydrogen grid, interconnection and electrolysis locations.
- Adjust grid reinforcement cost distribution to align system benefits with individual business cases.
- Develop a shared vision on offshore hydrogen storage needs and support models.

For Research Institutions:

- Detailed investigation in cost reduction pathways for offshore electrolysis and offshore solar.
- Assess long-term actor individual business feasibility under high-renewable energy scenarios.
- Recommend policy instruments that close the gap between business and system value.
- Research in the policy mix to harmonize supply-demand for offshore wind and electrolysis during future phases of the Dutch energy transition.

List of Abbreviations

Abbreviation	Meaning
OWF	Offshore Windfarm
HT	Hydrogen Transport
ET	Electricity Transport
OS	Offshore Solar
CAPEX	Capital Expenditure
OPEX	Operating Expenditure
ABEX	Abandonment Expenditure
WACC	Weighted Average Cost of Capital
TNVDW	Ten Noorden Van De Wadden (windfarm area)
TYNDP	Ten Year Network Development Plan
II3050	*Integrale Infrastructuurverkenning* 2030-2050
NAT	National Driver scenario as part of II3050
NT	National Trends scenario as part of TYNDP
GA	Global Ambitions scenario as part of TYNDP
FID	Final Investment Decision
EBIT	Earnings Before Interest, Tax
EBITDA	Earnings Before Interest, Tax, Depreciation, Amortization
CFADS	Cash Flow Available for Debt Service
NPV	Net Present Value
ROI	Return on Investments
IRR	Internal Rate of Return
PP	Payback Period
I-ELGAS	Integrated Electricity, Hydrogen and Gas markets model
TSO	Transmission System Operator
PPA	Power Purchase Agreement
SPV	Special Purpose Vehicle
HNO	Hydrogen Network Operator
RFNBO	Renewable Fuel of Non-Biological Origin
SMR	Steam Methane Reforming
ATR	Auto-Thermal Reforming
CCS	Carbon Capture and Storage
IO (scenarios)	Infrastructure Operator (scenarios), this involves the TYNDP and II3050 scenarios
GoO	Guarantees of Origin
HWI	*Hernieuwbare Waterstofeenheid Industrie*
LCOH	Levelized Cost of Hydrogen
DGF	Depleted Gas Field

1 Introduction

The ongoing energy transition demands robust collaborative models and innovative strategies to fully unlock the renewable energy potential of the North Sea region. This report presents a comprehensive business case assessment of emerging energy value chains ultimately aimed at developing offshore energy hubs through strategic partnerships across the North Sea countries. By examining essential value chain components—including offshore wind, offshore and onshore electrolysis, offshore solar, transport infrastructure, and hydrogen storage—this study quantifies economic viability and highlights critical factors influencing investment attractiveness and viability.

This research is motivated by the growing need to translate long-term system integration visions into tangible investment pathways and actionable strategies. As North Sea countries accelerate the build-out of offshore wind, green hydrogen, and its required energy infrastructure, key questions arise: Which collective and individual business cases can be defined to motivate stakeholder participation in the offshore energy hubs? Are there unprofitable gaps to realize certain projects within the value chain and what is needed to close them?

Given the substantial uncertainties tied to future market dynamics, technology costs, and policy developments, this research provides an essential step toward derisking and operationalizing offshore system integration. It does so by identifying the unprofitable gaps of individual project business cases within the offshore value chain, such as wind-to-hydrogen or offshore storage. Moreover, it is explored to what degree it can be economically viable under different scenarios and timelines. These insights are vital to inform upcoming decisions, including those related to the deployment of 100–500 MW offshore hydrogen pilots and the broader offshore infrastructure planning process across the Netherlands and neighboring countries.

To provide a thorough and integrated understanding, this report combines detailed evaluations of individual business cases with scenario-driven assessments, leveraging aligned energy and pricing projections established in earlier North Sea Energy (NSE) deliverables. Specifically, it builds upon foundational analyses from NSE WP1 Hub Designs (D1.1 [2]), the system-level scenario evaluations conducted in NSE WP3 (D3.1 [3]), and business model considerations detailed in D3.2 [4]. This integrated approach allows for evaluating individual business cases within a broader contextual framework, taking into account varying levels of technological maturity, evolving market dynamics, and anticipated infrastructure developments extending up to the year 2050.

Given the inherent uncertainties associated with future price and technological development assumptions this study utilizes sensitivity analyses to provide insights into how these uncertainties could affect economic outcomes. This facilitates a deeper understanding of potential investment risks, required support mechanisms, and the interplay between various technological and infrastructural developments within these complex value chains.

The findings from this report are intended to support informed decision-making for policymakers, industry leaders, and investors, promoting efficient, sustainable, and economically viable development strategies for offshore energy hubs. By outlining critical economic factors and identifying pathways toward successful implementation, the insights provided herein serve as a foundation for collaborative planning and investment in North Sea renewable energy infrastructure.

The report starts with its methodology and main assumptions in Chapter 2 (detailed numerical assumptions in Appendix A). The main insights per actor and per supply chain are presented in Chapter 3 (more specific results in Appendix B, C and D). The conclusions and recommendations are presented in Chapter 4.

2 Methodology and Assumptions

In order to quantify the business cases for the individual actors and the collective value chains, the North Sea Energy WP1 Hub Designs (D1.1 [2]); the energy and pricing scenarios of the System Analysis (D3.1 [3]) and the Business Model considerations (D3.2 [4]) were taken as starting point for the analysis. This chapter will highlight the general modelling assumptions (2.1, 2.2 and 2.3) and the specific assumptions per business case (2.5).

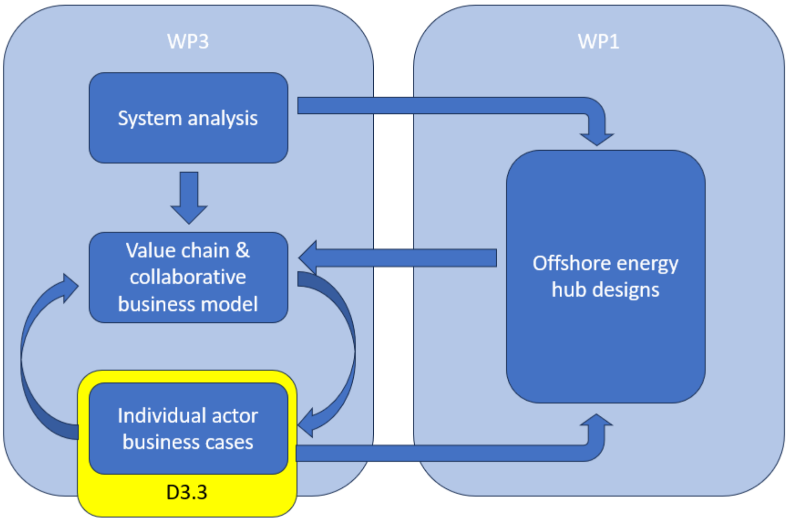

Figure 1: Overview relations between different NSE activities.

2.1 Conceptual value chain setup

In this report the same definitions are used as in D3.2 (see Box 1 for a recap). This report will mainly focus on the business case, which is *the financial justification of a project, business model or initiative*. The assumptions required to perform calculations on business cases have direct relations with the assumed value chain that these business models are performing in. Therefore, the chosen assumptions will be elaborated in this chapter and chapter 2.5.

Box 1: Recap of definitions as provided in [D3.2](#) [4]

As this report contains multiple typologies that should not be confused, we describe here the following definitions:

- Supply chain: A supply chain is a network of individuals and companies who are involved in creating a product and delivering it to the consumer. Links on the chain begin with the producers of the raw materials and end when the finished product is delivered to the end user [5].
- Value chain: A set of business models that describes the full range of activities needed to create a product or service [6].
- Business model: A company's plan for making a profit [7].
- Collaborative business model: A collaborative model is based on an alliance of two or more organisations that work together to achieve a common goal or outcome. It involves sharing resources, such as capital, assets, personnel, and technology [8]. This definition can be broadened under the aims of this deliverable where parties jointly formulate an objective based on a balanced interplay of financial, social and ecological values. All objectives, considerations, and timelines are then combined to form a collaborative business model where all stakeholders make agreements with each other [9].

The offshore supply chain will likely consist of assets to produce energy carriers. Those assets will be owned by actors and will be operated by them according to a business model to deliver value to other actors. The value relations assumed in this study are schematically represented on the left side of Figure 2, the physical connections on the right side.

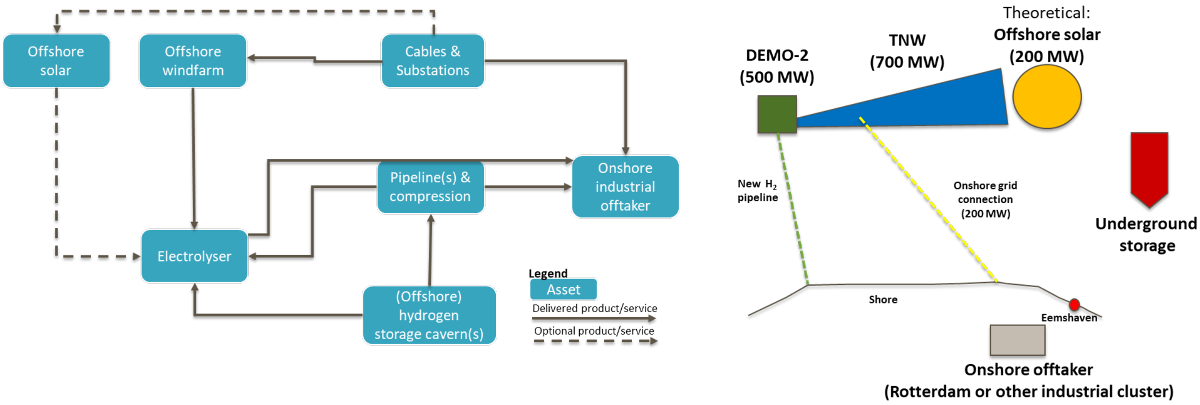

Figure 2: Schematic overview of the base case value chain network (left) and supply chain (right).

The physical connections and capacities assumed in the base case are directly based on the Hub Designs of WP1 [2]. Namely: a 700 MW offshore windfarm at TNVDW (*Ten Noorden van de Wadden*), a 500 MW offshore electrolyser installation as aimed for in DEMO-2, a connection to shore and onshore off-takers utilizing the generated energy. In consultation with the NSE partners, a large number of variations have been added in order to answer the research questions. These are variations in:

- Timing and maturity of the business cases starting in either 2030, 2040 or 2050 (in particular for offshore electrolysis);
- The hub location and size of the windfarm and electrolyser;
- The type of electrolysis: onshore, offshore on 100MW platforms or offshore on 500MW platforms;
- The type of electricity grid connection to shore: off-grid, 200MW or larger;
- Whether the electrolyser is operating on market prices or just following the wind generation profile;
- Whether or not offshore solar is added next to the offshore windfarm as energy source;
- Differences in type of off-takers for the hydrogen produced;
- Cost assessments for the different offshore pipeline and cable network scenarios;
- A separate cost assessment for multiple set-ups for offshore underground hydrogen storage.
- Next to the variations of the individual actor business cases, a supply chain cost comparison analysis is performed. Two cost comparisons have been made:
    - Onshore hydrogen versus the offshore hydrogen;
    - Offshore wind alone versus a combination of offshore wind and offshore solar.

The specific assumptions per actor and per analysis are discussed in Chapter 2.5.

2.2 Future energy scenarios and price assumptions

The described value chain does not operate in isolation. There is competition for commodities and energy prices will be determined by supply and demand in the market. The development of the market is highly uncertain and unpredictable, especially given that the energy transition is developing in an environment highly impacted by the political wind that is blowing.

Therefore, it is important to assess the potential impact of how future developments may unfold. To this end, the future energy scenarios developed in the NSE WP3 workstream on energy system analysis are considered [3]. This analysis primarily draws on the TYNDP and II3050 Infrastructure Operators' scenarios (see Table 1).

Table 1: Scenario input data selected from WP3 system analysis [3]. II3050: NAT = Nationaal Leiderschap, KA = Klimaatambitie scenario for the Dutch energy system. TYNDP: NT = National Trends and GA = Global Ambitions scenario for the North-West European energy system.

Case	2030	2040	2050
Lowest prices	II3050 – KA TYNDP – NT +10% onshore wind & solar	II3050 – NAT TYNDP – NT +10% onshore wind & solar	II3050 – NAT TYNDP – GA +10% onshore wind & solar
In-between	II3050 – KA TYNDP – NT	II3050 – NAT TYNDP – NT	II3050 – NAT TYNDP – GA
Highest prices	II3050 – KA TYNDP – NT -10% onshore wind & solar	II3050 – NAT TYNDP – NT -10% onshore wind & solar	II3050 – NAT TYNDP – GA -10% onshore wind & solar

The decision was made to use the energy price outputs from the I-ELGAS model based on the II3050 Klimaatambitie (KA) scenario for 2030, and the Nationaal Leiderschap (NAT) scenario for 2040 and 2050, for the Dutch Energy system. The North-West European energy system scenario sed was TYNDP2024 National Trends (NT) for 2030 and 2040, and Global Ambition (GA) for 2050. These scenarios were selected because they represent the lowest level of renewable energy deployment among the available options. Other scenarios featured such high renewable penetration that they could be considered unrealistic, leading to exceptionally low energy prices. While the scenarios used still include significant renewable capacity—assuming that all national targets of the North Sea countries are met—it results in comparatively moderate energy prices, though still lower than 2024 levels. For more details on the scenario assumptions and marginal cost curve analysis, refer to Deliverable D3.1 [3]. The price curves match the 'explorative scenarios' used in that analysis, with the addition that simulations were performed without modelling congestion, leading to national prices with more realistic marginal cost levels. Specific price assumptions used in each business case are outlined in Chapter 2.5.

2.3 Financial assumptions and formulas

All the business cases in this study include general financial assumptions and calculations.

The starting assumption taken is that *project finance* structures are used. These are perceived as more suitable for these kinds of investments, because it allows for projects to isolate risk in a Special Purpose Vehicle (SPV). Hereby, debt and equity can be based on the project's own merits and cash flows, rather than the creditworthiness of a parent company. It is assumed that 1) all agreements are made with the SPV (special purpose vehicle, the project company); 2) risks are assigned as much as possible to parties that understand them the best; and 3) certainty of cash flows are key for sponsors and lenders to provide finance.

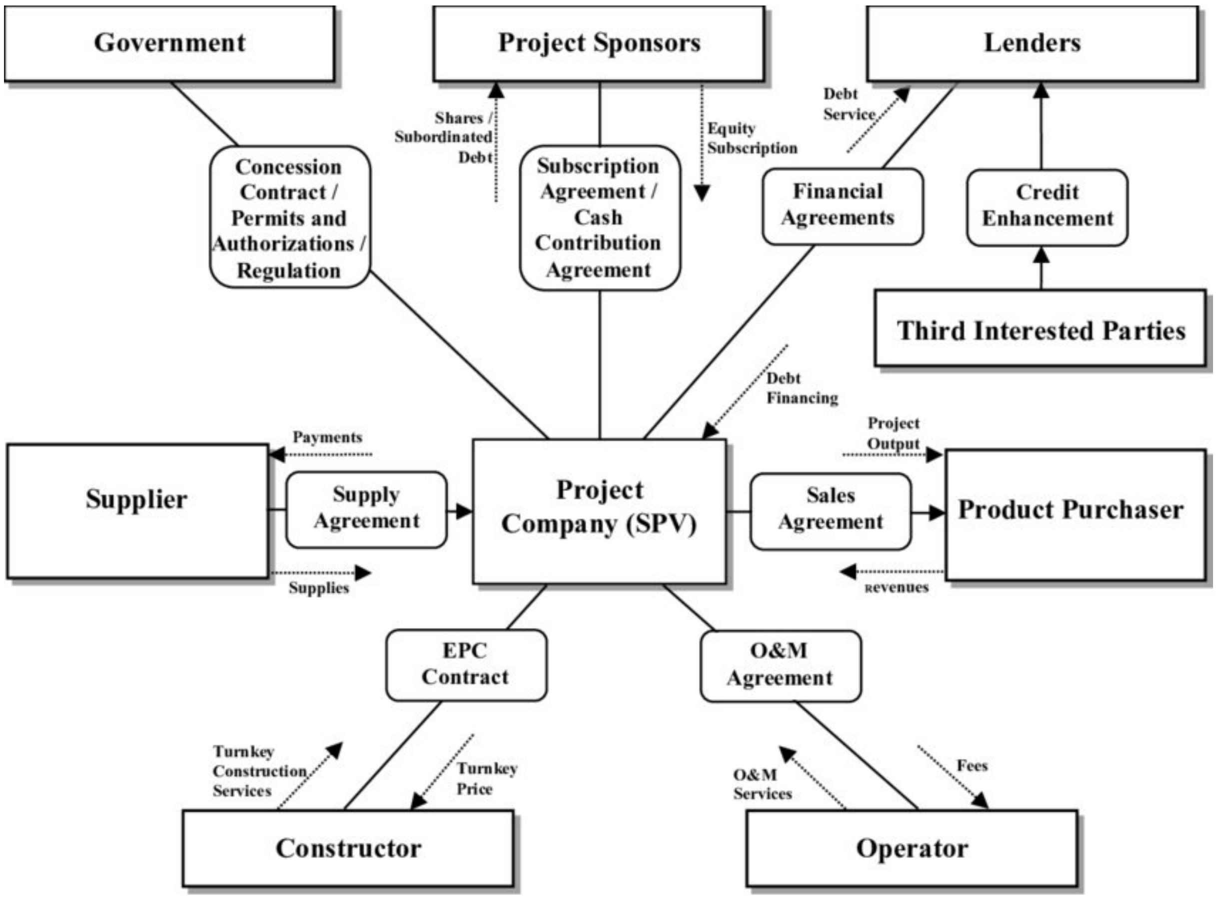

Figure 3: Schematic overview of project finance structure [40]

Key financial assumptions and criteria are outlined in Table 2. These have been discussed with NSE partners and financial parties outside the consortium. However, the conclusion of these discussions was that the numbers are highly dependent on individual project characteristics and changeable by market developments. Hence, these numbers are best estimates taken for this study and should be interpreted as such. Therefore, the impact is assessed in a detailed sensitivity analysis.

Table 2: Overview financial input assumptions. OWF = offshore windfarm, OS = offshore solar, HT = hydrogen transport, ET = electricity transport, UHS = Underground Hydrogen Storage.

Financial metric	Value pessimistic	Value medium	Value optimistic	Unit
Income tax rate	25.8	25.8	25.8	%
Inflation rate	2.0	2.0	2.0	%
Discount rate OWF & OS	9.25	8.5	7.75	%
Discount rate Electrolyser	9.5	9.5	7.0	%
Discount rate Offtaker	11.3	10.5	9.5	%
Discount rate HT, ET & UHS	4.5	4	3.5	%
Loan interest rate OWF & OS	7%	5%	4%	%
Loan interest rate electrolyser	13%	10%	7%	%
Loan interest rate offtaker	9%	7%	5%	%
Loan interest rate HT, ET & UHS	4%	3%	2%	%
Length of loan OWF & OS	15	15	15	years
Length of loan electrolyser	15	15	15	years
Length of loan offtaker	15	15	15	years
Length of loan HT & ET	30	30	30	years
Gearing OWF, OS, HT & ET	25%/75%	25%/75%	25%/75%	E/D %
Gearing electrolyser	50%/50%	50%/50%	50%/50%	E/D %

A series of standard financial calculations are done to calculate the business case results from the costs and revenues over the business case period. Three phases are distinguished in the business case period: the construction phase, the operational phase and the decommissioning phase. After FID is taken in the start year, the construction phase starts. A contingency reserve of 10% of the total investment value is injected during the first year of the business case, and withdrawn as dividends to the equity providers in the last year. It is assumed that the investment costs are equally distributed over the construction years. The investment costs are not corrected for inflation, because it is assumed that those are fixed during FID. According to the equity/debt ratio that is chosen, the annual investment costs during the construction years are covered by equity injection and debt drawdown.

During the operational and decommissioning phase, costs and revenues are corrected by inflation according the following formula:

$$OPEX_t = OPEX_0 \times (1+i)^t$$

Where:
$OPEX_t =$ Operational expenses in year t
$OPEX_0 =$ Initial operational expenses (base year)
$i =$ Annual inflation rate as decimal
$t =$ Number of years since the base year

In order to calculate the net profits and tax expenditures for every year (t), the following formulas are used:

$$EBITDA_t = Total\ annual\ revenues_t - Total\ annual\ operational\ expenses_t$$
$$Depreciation_t = \frac{Initial\ asset\ value}{Depreciation\ period}$$
$$EBIT_t = EBITDA_t - Depreciation_t - Amortization_t$$
$$EBT_t = EBIT_t - Interest\ costs_t$$
$$Tax\ expenses_t = EBT_t \times Income\ tax\ rate_t$$
$$Net\ profits_t = EBT_t - Tax\ expenses_t$$

The second priority on the payment ladder are the eventual debt payments according to annuity mortgage. Those are calculated for every year according to the following formula's:

$$Debt\ Repayment\ (interest)_t = Debt_{begin,t} \times i = Interest\ costs$$
$$Debt\ Service_t = \frac{D_0 \times i}{1-(1+i)^{-n}}$$

Where:
$D_0 =$ Initial loan amount
$i =$ Annual interest rate (decimal)
$n =$ Loan term in years

$$Debt\ Repayment\ (capital)_t = Debt\ Service_t - Debt\ Repayment\ (interest)_t$$
$$Debt_{end,t} = Debt_{begin,t} + Debt\ Drawdown_t - Debt\ Repayment\ (capital)_t$$

The Cash Flow After Debt Service are taken as the dividends that are returned to the equity providers. Typically, this should be positive for a favourable business case. A negative business case would result in negative dividends in the business case model (e.g. new cash from equity providers is needed to pay the bills). This is allowed for research purposes in order to identify the size of the unprofitable gap.

$$Cash\ Flow\ Available\ for\ Debt\ Service\ (CFADS)_t = EBITDA_t - Tax\ Expenses_t - Capital\ Expenditures_t$$
$$Cash\ Flow\ After\ Debt\ Service_t = CFADS_t - Debt\ Service_t$$

The calculated annual cashflows are used to evaluate the projected business case via several KPI's. The KPI's are divided into project KPIs and equity KPIs. The project KPIs are based on the direct costs and revenues of the project itself, which means that the taxes, amortization and debt financing do not impact these KPIs but solely the costs and revenues of the project. The equity KPIs are based on the equity injection and dividend cash flows, which means that the financing does impact the outcomes of these KPIs. For both cash flow types the Net Present Value (NPV), the Internal Rate on Return (IRR), the (discounted) Return on Investment (ROI) and the (discounted) Payback Period (PP) are calculated. The NPV measures the profitability of an investment by discounting future cash flows to their present value, indicating whether a project generates value over time. The IRR is the discount rate at which NPV equals zero, representing the project's expected annual return. ROI calculates the percentage gain or loss relative to the initial investment, helping assess overall profitability. Since IRR and ROI are percentages, these help to compare effectiveness of investments of different sizes, while NPV provides insight in the absolute value. The Payback Period determines how long it takes to recover the initial investment from cumulative cash flows. This is an indication of the risks and liability of investments. The Discounted ROI and PP accounts for the time value of money, offering a more realistic measure of profitability when long-term investments are involved. However, since discount rates are uncertain and party specific, both discounted and undiscounted values for these KPIs are calculated. Below the exact formulas for the KPIs are provided:

$$NPV = \sum_{t=0}^{n} \frac{C_t}{(1+r)^t}$$

$$0 = \sum_{t=0}^{n} \frac{C_t}{(1+IRR)^t}$$

$$ROI = \frac{\sum_{t=1}^{n} C_t - C_0}{C_0} \times 100\% \text{ and } Discounted\ ROI = \frac{\sum_{t=1}^{n} \frac{C_t}{(1+r)^t} - C_0}{C_0} \times 100\%$$

$$PP = \frac{Total\ investments}{Average\ annual\ returns} \text{ and } Discounted\ PP = \frac{Total\ discounted\ investments}{Average\ annual\ discounted\ returns}$$

Where:

C_t = (Project or equity) cash flow in year t

r = Discount rate (as a decimal)

n = Project lifetime (years)

C_0 = Initial investment (usually negative)

The total levelized costs, revenues and profits (or unprofitable gap) are calculated and its distribution over the different cost and revenue categories. These indicators can be used to obtain insights in the weight of different cost components and the cost gap per unit, which may indicate the required support per unit to close the business case. Below, the formulas to obtain the levelized costs and revenues are presented:

$$Levelized\ Cost\ of\ Energy\ (LCOE) = \frac{\sum_{t=0}^{n} \frac{K_t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{E_t}{(1+r)^t}}$$

$$Levelized\ Revenue\ of\ Energy\ (LROE) = \frac{\sum_{t=0}^{n} \frac{R_t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{E_t}{(1+r)^t}}$$

$$Levelized\ Profit\ of\ Energy\ (LPOE) = LROE - LCOE$$

Where:

R_t = Total revenues in year t

K_t = Total costs in year t

E_t = Total energy produced in year t (typically MWh in this study)

r = Discount rate (as a decimal)

n = Project lifetime (years)

2.4 Modelling tool

The calculations described in the previous section are performed in a customized business case tool written in Python. This tool is currently just partially able to communicate with ESDL in order to set up the scenario. However, it is developed with the end-goal in mind to retrieve the required techno-economic data from the Energy System Repository (EDR) of NSE5. Excel system analysis output files of I-ELGAS can be automatically read to update the price profile scenarios for the business cases. An overview of these dataflows is visualized in Figure 4. Within the business case tool, various business cases can be calculated individually, but also supply chain assessments can be performed.

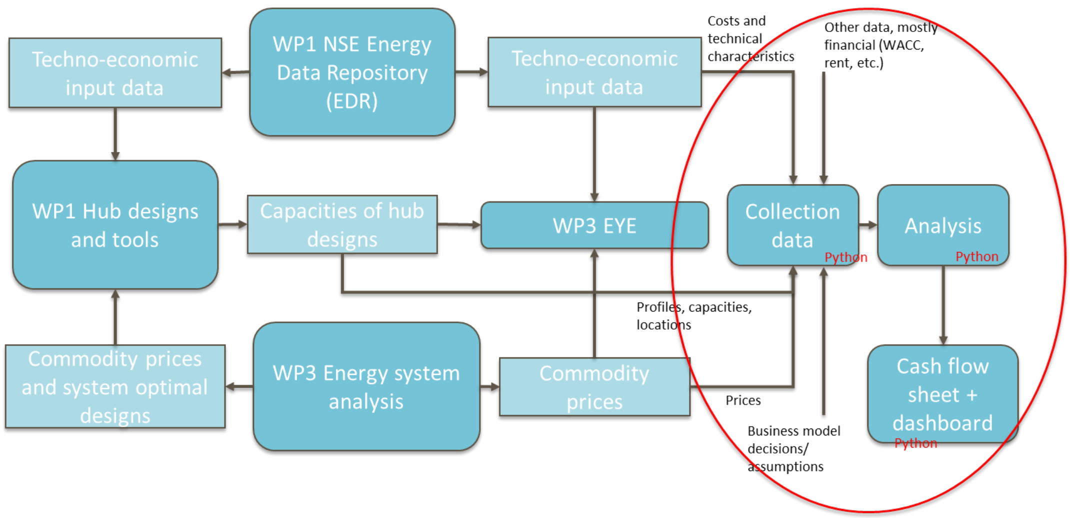

Figure 4: Overview of input data from other WPs into the Python business case model used for this study

2.5 Business case specific assumptions

In the next section the specific assumptions per actor will be discussed in greater detail.

2.5.1 Offshore windfarm

For the OWF business case, a windfarm with a capacity of 700 MW is assumed, as there are already plans to build a windfarm of this capacity in the Hub East area (Tender area 'Ten Noorden van de Wadden'). A centralised joint tender procedure is assumed for the OWF because this is the customary procedure in the Netherlands. The tender procedure for the windfarm is expected to start in 2027 and the windfarm is expected to be operational in 2031[1], which coincides with the planning for the offshore electrolysis (see below). For the base-case, it is assumed that the windfarm is connected to the electricity grid via a transmission system operator (TSO), as is customary in the Netherlands. A power purchase agreement (PPA) with the electrolyser operator is assumed in order to reduce the risk of the project. The pricing structure of the PPA is initially based on the capture prices of the OWF. We do not consider any green premiums or revenues from certificates, as these are highly uncertain in the future. It is prioritised that electricity generated by the windfarm is sold to the electrolyser (via the PPA). Any surplus electricity from the offshore wind farm (i.e. output exceeding the 500 MW electrolyser load) is fed into the electricity grid—up to a maximum of 200 MW, based on the assumed grid connection capacity—and sold on the general electricity market.

Table 3: Offshore windfarm business case assumptions

Offshore windfarm business case assumptions		
Category	**Assessed options**	**Unassessed options**
Tendering	• Coordinated tendering	• Integrated (combined) tendering • Joint tendering • Separated tendering
Electricity supply connection	• Electricity grid connection • Directly coupled to electrolysis	
Smoothening options	• Combining with offshore solar • Curtailment	• Combining with other renewables • Local electricity storage (e.g. batteries or CAES)

The cost and price assumptions are based on techno-economic assumptions of the NSE5 Factsheets (WP1) and the I-ELGAS system analysis results (WP3). The exact numerical

[1] At the time of the modelling activities the expectations were that the windfarm would be operational in 2031. Current expectations are that the windfarm will become operational in 2033 [41].

assumptions for offshore wind can be found in Appendix A.1 and the addition of offshore solar in Appendix A.2.

2.5.2 Offshore and onshore electrolysis

For the offshore electrolysis, an electrolyser with a capacity of 500 MW is assumed, as there are already plans to start a large pilot for an electrolyser of this capacity in the hub East area (DEMO-2). We assume that the electrolyser operator and the windfarm operator are two different parties, so a business case can be calculated for both individual operators. Thus, the electrolyser operator purchases electricity from the OWF and sells this to an onshore off-taker. We consider separate, but coordinated tendering of the OWF and the electrolyser. The electrolyser in the hub East area is expected to be operational in 2031[2], and the tender procedure will be at the latest in 2027. For the base case a 'wind-following' operational strategy is considered for the electrolysers. This means that the windfarm prioritises to sell its electricity to the electrolyser, and the remaining part is sold to the market via the electricity grid. The electrolyser shares the grid connection with the offshore windfarm in order to consume electricity from the grid only to meet the minimum load requirements. This implies that bidirectional cables are used, which are not applied for offshore electricity transport today. Therefore, it is assumed that technical and regulative hurdles are overcome when this project is started. It is assumed that the electrolyser pays a connection tariff for the electricity grid connection. For the base-case we assume that the electrolyser is connected to an offshore hydrogen grid operated by an offshore HNO. We consider that the electrolyser operator also needs to pay a grid fee in order to connect to this grid.

[2] In alignment with the expectations for the windfarm, current expectations are that DEMO-2 will also become operational in 2033.

Table 4: Electrolyser business case assumptions

Offshore windfarm business case assumptions		
Category	**Assessed options**	**Unassessed options**
Tendering	• Coordinated tendering	• Integrated (combined) tendering • Joint tendering • Separated tendering •
Ownership and operation	• Electrolyser developer	• Joint (consortium of) OWF and electrolysis developer • Conversion-as-a-service • Tolling
Electricity supply connection	• (Shared) electricity grid connection • Directly coupled windfarm	
Type of electricity grid connection to shore	• Bi-directional	• Single directional
Hydrogen connection to shore	• Offshore HNO grid	• Developer led pipeline • PPP • Blending regime in NG pipeline
Location structure	• Onshore • Platform (100MW, 500MW)	• In-turbine / near-turbine • Artificial Island
Operational modes	• Wind/renewable following • Market following	

The price assumptions are based on the I-ELGAS system analysis results (WP3). The cost and techno-economic assumptions of offshore hydrogen are based on the NSE5 factsheets (WP1). In order to compute onshore electrolysis costs – for the purpose of supply chain cost comparison analysis – data from the RHyCEET study has been used [10]. The exact numerical assumptions for onshore and offshore electrolysis can be found in Appendices A3-A5.

The majority of the time, when the electrolyser utilizes green electricity produced from the nearby windfarm, the hydrogen can be considered as an RFNBO (renewable fuel of non-biological origin). Following the Renewable Energy Directive III, a certain percentage of hydrogen used in industry should be renewable. This percentage is targeted as 42% by 2030 and 60% from 2035 onwards. In the Netherlands, a trading scheme 'Hernieuwbare Waterstofeenheden Industrie (HWI)' will be utilized to certify and promote the use of RFNBO hydrogen. The profits from trading HWI's are assumed to go fully the electrolyser operator. In Appendix A.6 a general explanation of the foreseen Dutch offtake mandate is provided.

2.5.3 Industrial off-taker

Two scenarios are considered for onshore industrial end-use of green hydrogen. One in which a large-scale industrial end-user replaces its existing grey hydrogen demand by green hydrogen, and a second in which an industrial end-user replaces its existing natural gas demand by green hydrogen.

In the first scenario, a large-scale industrial end-user currently has a large grey hydrogen demand that is fulfilled by its own SMR installation, that is now fully deprecated. The end-user also wants to decrease its environmental impact and comply with EU legislation, and therefore, will switch its hydrogen demand to hydrogen from the grid combined with HWI certificates. Since there are no revenues associated with this implementation, the business case is assessed with the 'avoided costs' of the alternative; blue hydrogen from an ATR + CCS plant which would be located at the end-user.

The ATR + CCS (autothermal reforming + carbon capture and storage) plant used for the 'avoided costs' of the business case is 450 MW which is based on the HyDelta factsheet [11] and the SMR (steam methane reforming) + CCS factsheet generated within North Sea Energy 5.

For the second scenario we look into a typical off-taker that represents an industrial company that currently uses natural gas for low temperature heating (100-180°C). In this scenario we assume that the off-taker completely switches from natural gas to hydrogen. We assume that the current annual natural gas demand is 28 million m^3, which is representative for such a plant, and that natural gas boilers utilized for a variety of processes such as steam production are in need of replacement. Again, as no revenues are associated with this implementation, the business case is assessed with the 'avoided costs' of the alternative: natural gas usage combined with associated EU ETS emission costs.

The price and scenarios are aligned with the I-ELGAS system analysis results (WP3) that are used in the other business case calculations as well. The ATR+CCS plant techno-economic data is retrieved from the HyDelta factsheet [11]. The techno-economic data for the low temperature heating customer is taken from a PBL study [12] and corrected for inflation. The exact numerical assumptions for the off-taker business cases can be found in Appendices A.6-A.7.

2.5.4 Hydrogen and electricity transport

For the transmission of electricity from the offshore windfarm, a cable distance of approximately 110km has been considered with a capacity of 200 MW. Electricity transport to shore (Eemshaven[3]) only occurs when the electrolyser is being utilized at maximum load, to deal with any overproduction of electricity from the offshore windfarm. Based on this arrangement, the usage of the cables is quite limited. The techno-economic assumptions (CAPEX, OPEX) for electricity transport are based on the North Sea Wind Power Hub (NSWPH) Databook and involves cost indications for a variety of offshore electricity transmission components (for both AC and DC configurations):

[3] Landfall of the electricity cables for windfarms Ten Noorden van de Waddeneilanden en Doordewind has long been uncertain, and was therefore assumed to be in the Eemshaven port area. Recent advice of the working group 'Programma Aansluiting Wind op Zee (PAWOZ) – Eemshaven' suggested the Schiermonnikoog Wantij route as the preferred option with landfall near Kloosterburen, approximately 30 km west of Eemshaven port area [42].

1. Platform costs
2. Substation costs (in AC and DC variations)
3. Cabling costs (in AC and DC variations)

For hydrogen transport via pipelines, costs have been calculated for a 110km pipeline[4] with a capacity of 7000MW. Under this circumstance the pipeline is over-dimensioned but assumes further connectivity to P2G facilities at Hub East (the Doordewind wind areas) and north-east areas of Hub North hence it is a fit-for-future scenario but has a price in terms of earlier than required investments. The techno-economic assumptions (CAPEX, OPEX) for hydrogen transport includes cost components for:

1. New offshore pipelines
2. Compression offshore

The techno-economic assumptions for pipelines are based on the NSWPH Databook [13] and compressor costs are based on the NSE5 compressor factsheet [14]. It is assumed that compression of hydrogen is the responsibility of the hydrogen transport operator, but since the NSE5 factsheet do not include potential structure costs to locate the offshore compressor, these are not included. For example, the compressor could be placed on the platform of the offshore electrolyser, or costs of a dedicated compressor platform should be considered. Any of these additional costs (e.g. for an increased electrolyser platform size) are considered outside the scope of this research.

2.5.5 Underground hydrogen storage

The techno-economic assumptions for Underground Hydrogen Storage (UHS) in this study are based on the report “Life Cycle Cost Assessment of an underground Storage Site” by the EU “Hystories” research project [15].

A hydrogen storage system is defined as the sum of components required for the implementation of underground hydrogen storage (on land or at sea) and is constituted of [16]:

1. The gas processing facilities, including compressor stations, drying and purification plants.
2. The pipelines between the gas processing facilities and one or more storage locations
3. The injection/production platforms
4. The injection/production wells
5. The subsurface space (i.e., depleted gas field or the salt cavern)
6. Landing point with connection to the hydrogen network.

These components can be arranged in various configurations. For instance, an onshore cavern in combination with onshore gas processing facilities is presented in Figure 5. While an offshore cavern system can be exemplified in Figure 6. Storage of hydrogen in depleted gas fields also follows a similar typology.

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4 The preferred options for landfall of the hydrogen pipeline are Ameland Wantij route and Zoutkamperlaag route. Landfall of the pipeline options is 50-60 km west of Eemshaven port area near Holwerd and Moddergat, respectively [42].

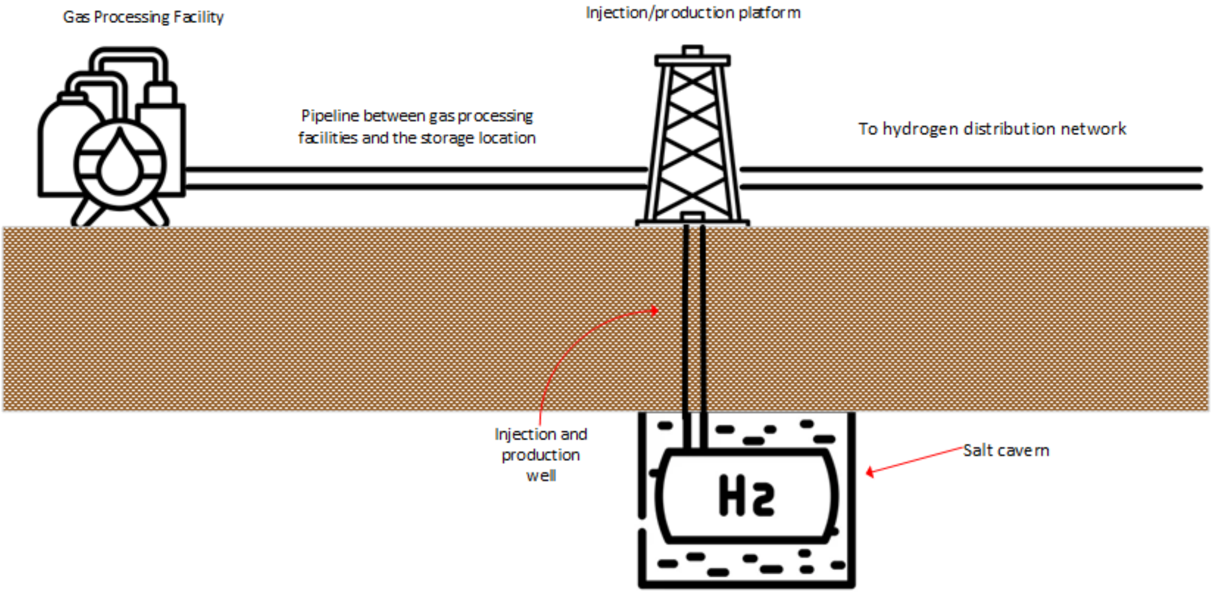

Figure 5: Overview of an onshore hydrogen storage system.

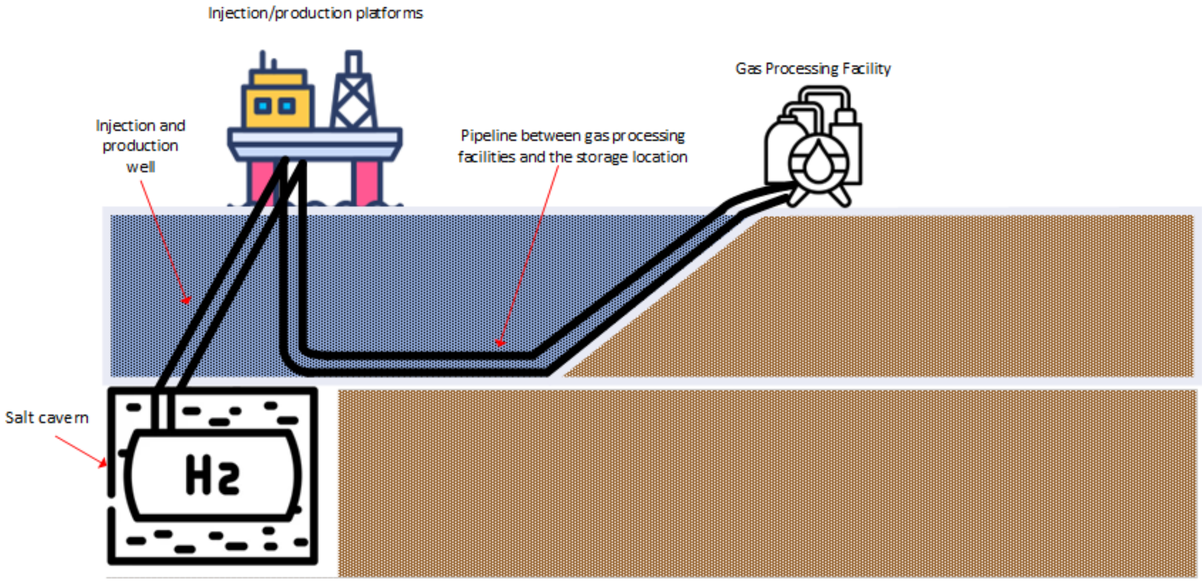

Figure 6: Overview of a potential offshore hydrogen storage system (for illustrative purposes).

Surface/Subsurface CAPEX components

From a cost perspective, the aforementioned components can be categorized into subsurface and surface CAPEX (Table 5). Subsurface CAPEX comprises of costs related to salt cavern development (solution mining) and consist of various engineering, procurements and construction (EPC) cost categories such as development drilling and leaching completion costs, leaching plant costs, leaching operation and maintenance costs and salt cavern conversion costs (de-brining & first gas fill). As part of salt cavern construction activities, it has been assumed that one well per cavern is drilled. For a detailed understanding of the techno-economic calculations behind each of these categories, please refer to [15]. For depleted gas fields, subsurface CAPEX cost categories only consist of development drilling costs and first gas fill costs. Contingencies for subsurface facilities is 20% of the total EPC costs.

Surface CAPEX components consist of hydrogen processing plant (composed of compressors, metering units, filtering and drying units, pressure reduction systems), wellpad and downstream equipment and piping costs, interconnection between wellheads and gas plant, hydrogen purification, balance of plant costs. Contingencies for surface facilities is 20% of the total EPC costs.

Table 5: Overview of surface and subsurface CAPEX components for salt-caverns and porous media.

	Subsurface CAPEX components	Surface CAPEX components
Salt-caverns	• Development drilling and leaching completion costs • Leaching plant costs • Leaching operation and maintenance costs • Salt cavern conversion costs (de-brining & first gas fill)	• Hydrogen processing plants • Wellpad & downstream equipment and piping • Interconnection between wellheads and gas plant (field lines) • Hydrogen purification • Balance of plant
Porous Media (Depleted Gas Fields)	• Development drilling costs • First gas fill costs	• Hydrogen processing plants • Wellpad & downstream equipment and piping • Interconnection between wellheads and gas plant (field lines) • Hydrogen purification • Balance of plant

A few important terms and assumptions are given more context below:

Cushion gas

Cushion gas is necessary to maintain the cavern pressure at or above the minimum level, thereby ensuring cavern integrity. The cushion gas can only be withdrawn at the time of decommissioning of the cavern (provided it has economic value). Cushion gas costs count as investment costs since caverns cannot work without initial gas costs. In depleted fields, the role of the cushion gas is played by the native gas of the reservoir. For hydrogen storage in depleted reservoirs, however, it may be necessary to inject hydrogen as a cushion gas in order to limit hydrogen blending with native gas [15].

First gas fill
First gas fill refers to the cushion gas costs plus the first cycle of working gas that will be used in operation (i.e., injected or withdrawn).

Subsurface Operation Costs (OPEX)
The fixed OPEX related to subsurface activities for both caverns and depleted gas fields is 3% of drilling and leaching completion costs.

Surface OPEX
Surface OPEX is based on fixed and variable OPEX categories and takes into consideration fixed costs related to hydrogen gas plant operation and maintenance and variable costs related to the purchase of electricity to operate the plant. For a detailed description of the techno-economic calculation behind these costs see [15].

Abandonment expenditures (ABEX)
The subsurface and surface ABEX for salt caverns and depleted gas fields is based on 20% of the sum of the EPCs for subsurface and surface CAPEX respectively.

Offshore cost factor
In order to account for costs within the context of an offshore underground storage system a cost factor of 3.5 has been considered. Note that this factor is used for indicative purposes, however in reality a linear cost factor increase of 3.5 isn't directly applicable to offshore environments as multiple scenarios may exist e.g. standalone offshore platform (floating or fixed installation), standalone subsea development without any platform, subsea tiebacks to existing offshore facilities, etc. [15].

Well Depth
For salt caverns, a well depth of 1,000 meters has been assumed, while for depleted gas fields, a depth of 3,000 meters is considered. It is important to note that increasing the well depth for salt caverns from 1,000 to 2,000 meters results in a 1.5-fold increase in subsurface CAPEX, regardless of whether the location is onshore or offshore.

2.5.6 Supply chain analysis
Unlike the individual actor business cases within the value chain, a separate analysis is conducted at the supply chain level to assess levelized costs. The aim of this approach is to provide a cross-stakeholder perspective on issues related to the overall supply chain design.

As opposed to the individual actor perspective, where each actor's decisions and its impact on the individual business cases in the value chain are analysed, the supply chain analysis compares the levelized costs of the whole supply chain from generation to landfall of energy. The difference with the system analysis perspective (see D3.1 [3]) is that the system analysis focusses on the whole energy system within a country or multiple countries geographical area, while this supply chain perspective only focusses on a single supply chain within the energy system.

Two supply chain design comparisons are chosen:

1. A supply chain with offshore electrolysis versus a supply chain with onshore electrolysis
2. A supply chain with solely offshore wind as electricity generator versus a supply chain combining offshore wind and solar

Figure 7 provides an overview of the supply chain setups that are required to make the comparisons. From left to right, the first supply chain represents offshore wind farms that transport electricity to shore where it is converted to hydrogen by onshore electrolysis. The second supply chain represents offshore windfarms that are directly coupled to offshore electrolysers on platforms. The hydrogen is transported to shore via a pipeline. The third chain represents combined offshore wind and solar farms with electricity landfall similar to the first chain, and the fourth chain represents combined offshore wind and solar farms with hydrogen landfall, similar to the second chain. The first two chains are used for the onshore vs offshore electrolysis comparison. All chains are used for the offshore wind scenario versus offshore solar and wind combination scenario, by comparing chain 1 and 2 (no offshore solar) with 3 and 4 (with offshore solar).

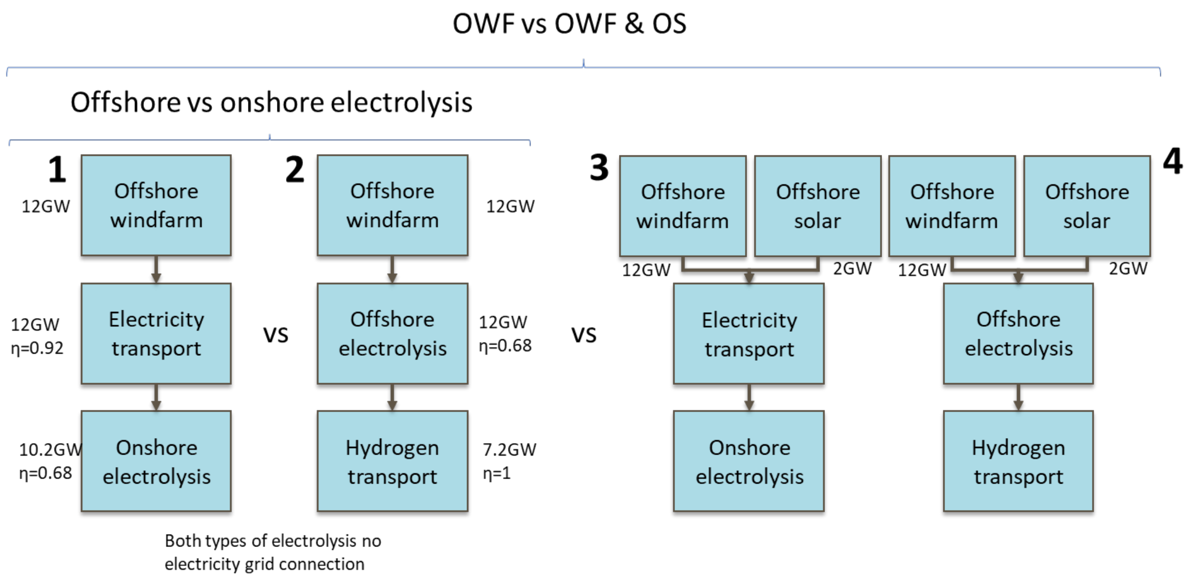

Figure 7: Overview of the conceptual supply chain designs for the supply chain analysis.[5]

In both supply chain comparisons, the offshore wind capacity is set at 12 GW, reflecting the scale of large offshore wind developments anticipated in Hub North. Due to the greater distance from shore, configurations that include offshore hydrogen production and offshore solar are expected to be more promising than the conventional electricity-based offshore wind supply chain. Additionally, such large volumes justify the use of a hydrogen pipeline, unlike smaller-scale offshore wind projects of, for example, 1–2 GW. The other components of the supply chain are scaled based on the assumed energy losses throughout the chain.

[5] For the electrolyser the efficiency of the NSE5 factsheets is taken. No hydrogen losses are assumed during pipeline transport, but costs of electricity consumption is incorporated. For HVDC electricity losses 8% is assumed [44].

Of course, real-world supply chains are likely to involve mixed configurations—such as combinations of onshore and offshore hydrogen production—and asset sizes can be optimized within the broader energy system. However, for the purpose of comparing supply chain costs, it is considered useful to keep the chains conceptually simple, in order to clearly highlight cost differences and implications between the various configurations. As such, only dedicated chain setups are considered.

The choice to add 2 GW of offshore solar was somewhat arbitrarily. However, varying the capacity did not affect the conclusions of this assessment.

3 Results and discussion

This chapter presents the results of the business case modelling. All business cases are connected within the assumed value chain and operating in the same energy scenarios. The results of the business cases will be presented in the following order:

- Offshore wind
- Offshore and onshore electrolysis
- The impact of adding offshore solar to the value chain
- The off-taker business case
- Electricity and hydrogen transport business cases
- Offshore hydrogen storage business case

Thereafter, in two subchapters the results of the supply chain analysis are presented:

- Onshore vs offshore hydrogen value chains
- Offshore wind vs combined offshore wind and solar hydrogen value chains

3.1 Offshore wind: emerging challenges after a successful period

Offshore wind capacities have been developed very successfully recently in the Netherlands. By 2018 and 2019, the first offshore wind farms have been permitted without subsidies. Since then, installed Dutch offshore wind capacities have more than quadrupled from just under 1 GW to 4.7 GW by the end of 2023 [17]. As of 2024, 1.5 GW are under construction and two new tenders have been awarded, representing an additional 4 GW of new installed capacity by 2028 and 2029 [18] [19]. However, each of these recent tenders attracted only two project bids, which is fewer than in previous tender rounds before.

In D3.2, new challenges for offshore wind such as the increase of investment costs and cannibalization of electricity prices have been discussed thoroughly [4]. As a result of these new challenges, the business case for offshore wind is currently not viable (see Figure 8). However, this reflects only a static snapshot of the business case; the following section explores the underlying dynamics of the key drivers in more detail.

The primary reason for the negative business case results are the low revenues. The low revenues are a result of the low capture prices of 28-36 €/MWh by 2030 and 10-25 €/MWh by 2050 as result of dispatch modelling according to the IO (Infrastructure Operator) scenarios. It should be noted that these scenarios involve relatively high expansion of renewable production compared to the rise of electricity demand. In February 2025, Dutch futures for power in 2030-2035 were sold for 60-70 €/MWh [20], which are higher than the average power prices that we used resulting from the IO scenarios (which were 47-60 €/MWh). Therefore, the exact values for future capture prices for offshore wind remains uncertain, but it is evident that cannibalization is a significant risk for future offshore wind development that could have severe effects on the business case.

The second major point of attention are the CAPEX and financing of offshore windfarms. CAPEX is the major cost component of offshore windfarms and an increase or decrease of the CAPEX will directly affect the contingency and interest costs[6]. In the base case the contingency and interest costs represent 12.5% of the total levelized costs. Next, higher WACCs negatively affect the offshore wind business case. In the base case, a WACC of 8.5% is applied; an increase of 0.75 percentage points would raise the levelized cost by approximately 6%, reaching 82 €/MWh.

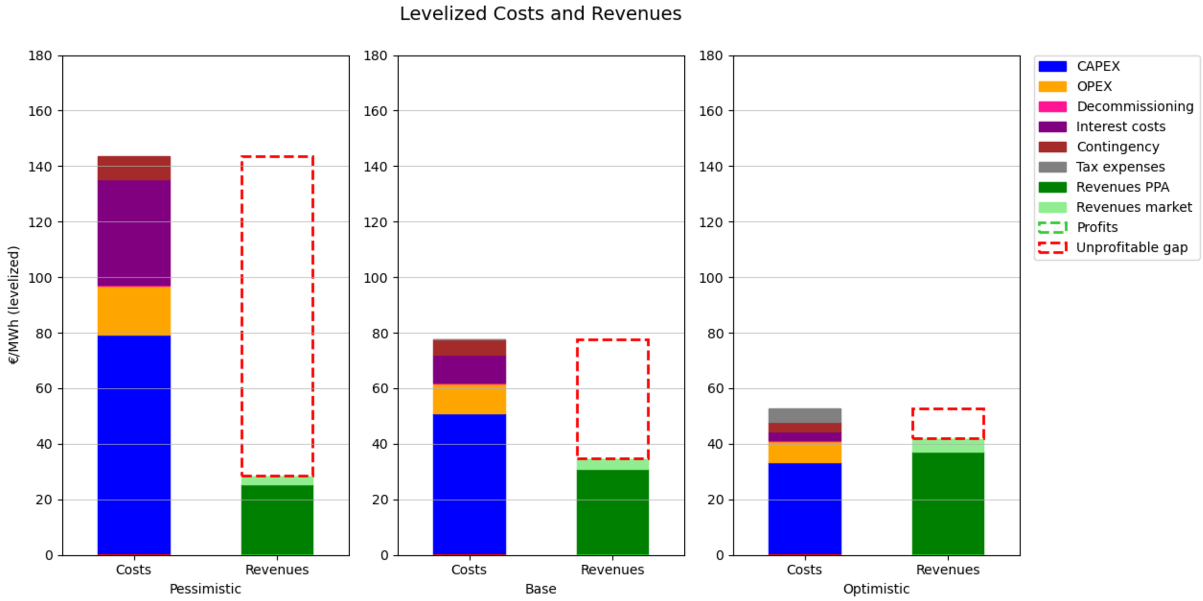

Figure 8: Levelized costs and revenues distribution for the offshore windfarm business case.

Offshore windfarms in the Netherlands do not pay for the electricity grid connection to shore (see also Figure 8). This means that no direct impact is felt whether the offshore windfarm is directly coupled to an electrolyser or to an electricity cable. However, it could impact scores on additional tendering criteria or indirectly impact revenues if the electrolyser would be willing to pay another price for the electricity.

Revenues for Guarantees of Origins (GoOs), revenues of potential ancillary services and balancing costs are not included in the business case.

In the NSE5 factsheets no scaling factor is assumed for offshore wind. Hence, no economies of scale cost advantages could be investigated when offshore windfarms would increase in size. In explorative work within WP1 it was indicated that larger offshore windfarms or windfarm areas could lead to higher wake effects and thereby reducing the relative output of the offshore windfarms. On the other hand, the system analysis indicated that revenues per MWh of generated wind electricity would be higher in lower full load hour scenarios for future offshore wind [3].

[6] Large companies that apply a corporate finance structure are less likely to take out a loan to finance assets which can make the business case more attractive. However, in this research we only consider the project finance structure, see section 2.3.

3.2 Electrolysis: essential but economically unattractive

From a system perspective, offshore electrolysis offers several potential advantages: it could lower the overall costs of offshore energy transport infrastructure, reduce energy losses associated with electricity transmission and conversion, and alleviate space constraints in ports. However, it remains a nascent technology, with the first megawatt-scale demonstrations only beginning around 2025. This chapter focuses on the business case from an individual project perspective. Specifically, it examines 100 MW and 500 MW offshore platform configurations and compares their results with a 100 MW onshore electrolyser business case.

3.2.1 Offshore electrolysis

Similar to onshore electrolysis [10], offshore electrolysis costs have increased significantly compared to projections of 2022 and earlier. Figure 9 shows that the levelized costs for offshore hydrogen via 5x100MW platforms starting operation in 2030 result in 235, 394 and 693 €/MWh (or: 7.8, 13.1 and 23.1 €/kg)[7] for the optimistic, base and pessimistic case, respectively.

The main cost drivers of the LCOH are the electricity costs, the electrolyser CAPEX, the stack replacement costs and the electricity grid connection tariff. The electricity costs and electrolyser CAPEX together already represent about 2/3rd of the total LCOH. Typically, the electricity costs result in studies as the largest cost component of the LCOH. However, in the IO scenarios the electrolyser runs in relatively favourable conditions capturing electricity at average prices of 18-22 €/MWh and 5900-6100 load hours under the base case scenario (including a minimum load of 10% of the full capacity). On the other hand, the electrolyser CAPEX of 2493, 4178 and 7299 €/kW, in the optimistic, base and pessimistic case respectively, are significantly higher than the 1270 €/kW that has been considered in the time that NSE4 has been executed [21]. The relatively low electricity costs and increased offshore electrolyser CAPEX result in that both components represent approximately the same share in the total LCOH. In the pessimistic case with a very high CAPEX, it is observed that the interest and contingency costs become very substantial (~100 €/MWh).

The hydrogen capture price of 60-66 €/MWh (or: about 2-2.2 €/kg) in the 2030's and 2040's, and just 42 €/MWh in the 2050's, resulting from dispatch modelling of the IO scenarios, are too low to cover high production costs of offshore hydrogen. If, potentially, for hydrogen produced by electricity from the offshore wind PPA, a HWI can be obtained and sold for 5 €/kg, it would mean a significant revenue for the business case. However, although this value has resulted from studies [22], it is highly uncertain what the HWI prices will be and if industry is willing or able to pay such a price (see Table 16 in appendix). Therefore, while the optimistic business case yields a positive outcome assuming a HWI of 5 €/kg, it is evident that offshore hydrogen still requires financial support to establish a robust and reliable business case.

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[7] Note that these costs are higher than the NSE5 'Scaling Offshore Wind-to-Hydrogen Systems' report [46]. The report uses similar cost input values as this report, however in this study more detailed cost components are used, which make the LCOH in this report higher. Think of: stack replacement costs, financing costs, decommissioning costs and storage costs.

Finally, two cost components that should be mentioned are the hydrogen storage tariffs and hydrogen network connection and transport tariffs. In Figure 9 the hydrogen storage costs represent a very small share of the business case. Due to lack of data, these costs were based on literature [23]. However, since hydrogen storage is not a mature technology yet, and storage tariffs are prone to supply and demand, these costs can be higher than presented in this figure. The same counts for hydrogen transport costs. We refer to chapters 3.5.2 and 3.6 for more information about these potential costs, which can potentially affect the offshore hydrogen business case if storage capacity is reserved and/or transport tariffs need to be paid by the electrolyser operator.

As described in the methodology section a wind-following operational strategy was assumed to generate these results. A what-if calculation has been perform to indicate if these results would differ if a market-following approach was taken, but it turned out that a relatively similar full load hours and cost and revenue distribution was seen. In both cases the electrolyser is mainly running when offshore wind is generating and the electricity prices are low.

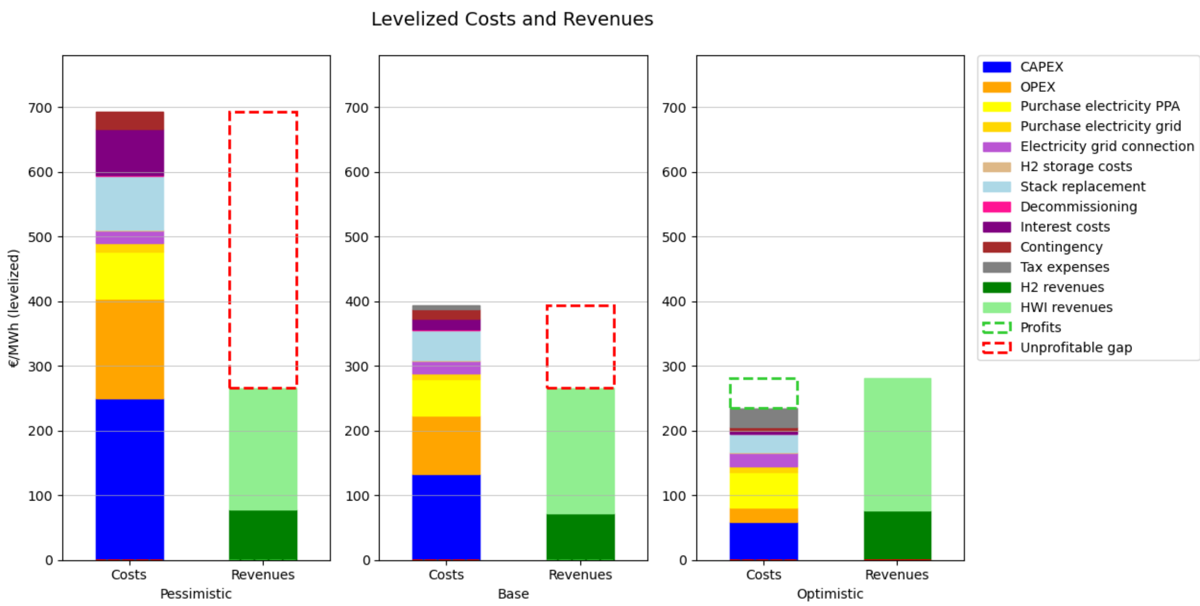

Figure 9: Levelized costs and revenues distribution for the 5x100 MW offshore electrolyser business case

For the 500 MW offshore electrolysis platforms a similar cost and revenue distribution is seen as for the 5x100 MW offshore electrolysis configuration (Figure 10). The main difference is that the LCOH of the 500 MW offshore electrolysis configuration is 10-20% lower, mainly because of the lower investment costs. This results in LCOH of 216, 338 and 578 €/MWh (or: 7.2, 11.3 and 19.3 €/kg) for the optimistic, base and pessimistic case, respectively.

However, due to the considerable size and technological advancements that are needed to build such a project, it is expected that this technology will become available from the late 2030s earliest. Therefore, this configuration might be a successful cost reduction strategy, while for the early developments smaller configurations would be required. Costs for other offshore electrolysis configurations, such as in-turbine, near-turbine and island based offshore electrolysis, are not calculated in this study because cost data for these technologies have not been collected successfully in the NSE5 factsheets.

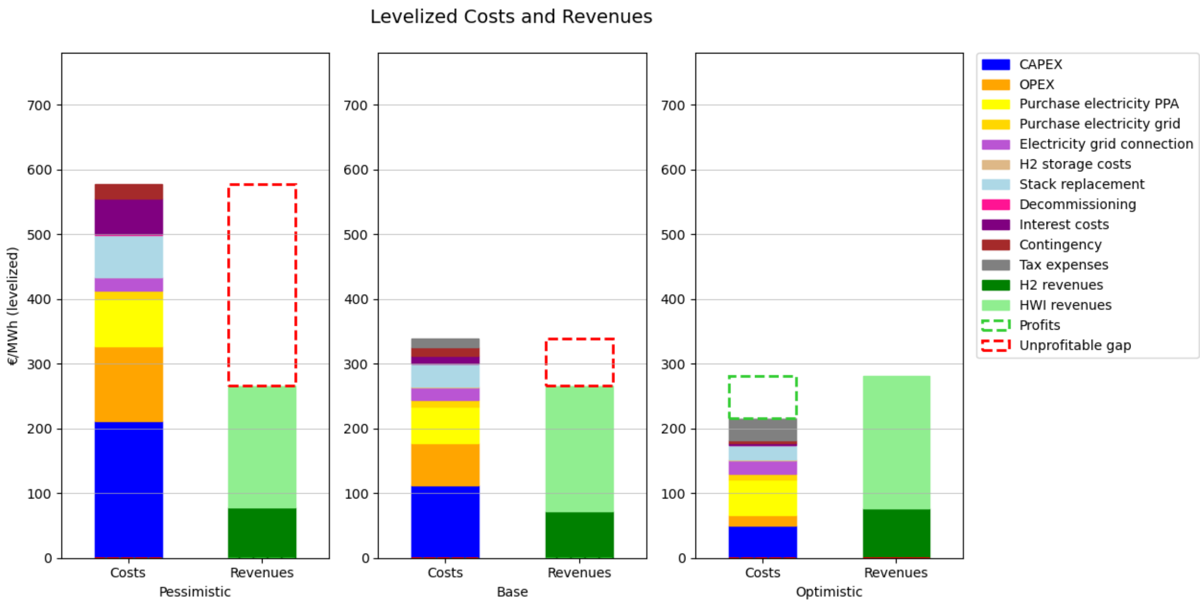

Figure 10: Levelized costs and revenues distribution for the 500 MW offshore electrolyser business case

3.2.2 Comparison with onshore electrolysis

Another relevant aspect is how, on a business case level, offshore electrolysis will compete with onshore electrolysis. The LCOH for a 100 MW onshore electrolyser in 2030 would be significantly lower than offshore electrolysis (Figure 11). The LCOH for the onshore electrolyser resulted in 231, 284 and 328 €/MWh (or: 7.7, 9.5 and 10.9 €/kg) for the optimistic, base and pessimistic cases, respectively.

The main difference between offshore and onshore electrolysis is the electrolyser CAPEX and OPEX, which do not involve platform costs and offshore construction and maintenance complexities for the onshore electrolyser. A lower CAPEX also results in lower interest and contingency costs for the onshore electrolyser.

While the business case gaps for onshore electrolysis may appear relatively small, it's important to note that these results are based on the relatively favourable market conditions assumed in the IO scenarios—namely low electricity prices, high full load hours, and a substantial hydrogen price supported by hydrogen wholesale incentives (HWIs) of 5 €/kg. Therefore, even onshore hydrogen production is unlikely to be financially viable without some form of subsidy or policy support.

The finding that both offshore and onshore electrolysis are likely to require substantial subsidies or support—combined with the fact that the onshore business case appears significantly more favourable over the coming decades—raises the question of whether differentiated subsidy schemes are necessary. If both technologies compete for the same pool of funding, onshore electrolysers are likely to secure the majority of grants, potentially leaving offshore electrolysis stranded in the so-called “valley of death.” This outcome could be undesirable from a system-wide perspective, particularly if offshore electrolysis ultimately proves to deliver lower overall societal costs, which is investigated in [3] and reflected on in [1].

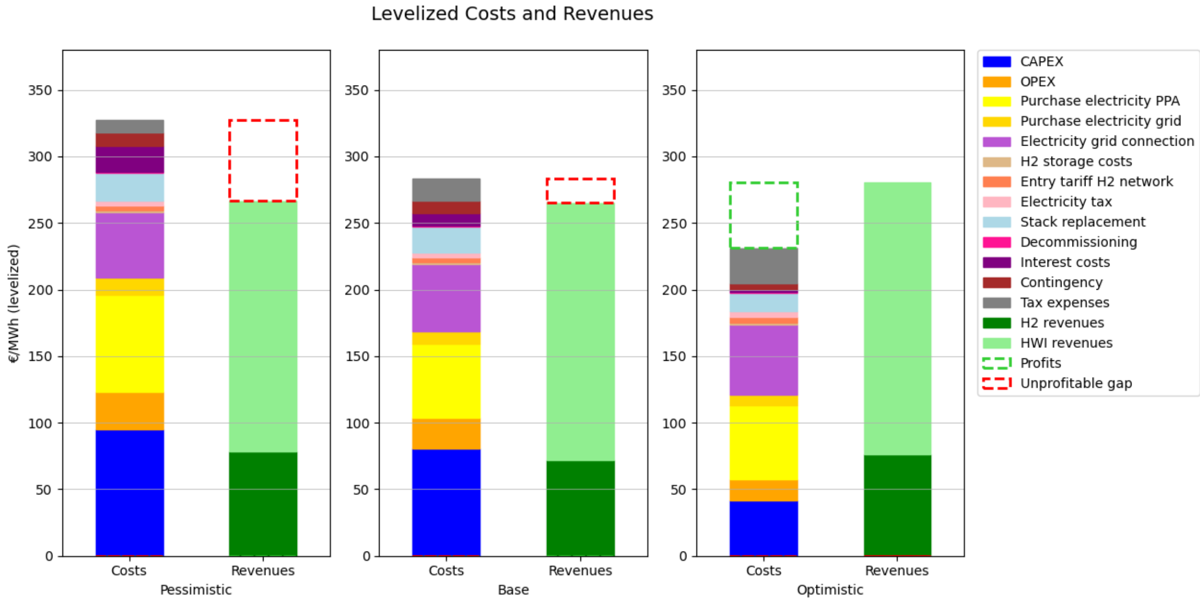

Figure 11: Levelized costs and revenues distribution for the 100 MW onshore electrolyser business case

3.2.3 Future business case outlook for offshore wind and electrolysis

The negative outcomes of the 2030 business cases for offshore wind and electrolysis raise the question on what the future outlook for the business case will be. Figure 12 shows the levelized profit gap outcome based on the starting year of the business case.

Based on the modelling assumptions used, the offshore wind business case deteriorates if project commissioning is delayed to 2040 or 2050 compared to a 2030 start. This is primarily due to declining modelled electricity capture prices, which drop from 28–36 €/MWh in 2030 to 21–35 €/MWh in 2040, and further to 10–24 €/MWh in 2050. Although some cost reductions for offshore wind technology are assumed over the decades, they are not substantial enough to offset the decline in capture prices.

Another factor considered is the location of future wind farms, which are expected to be situated farther offshore, potentially allowing for stronger wind resources. However, analysis of the 2015 wind profiles from WP1—adjusted for wake losses—shows that the average load factor of Ten Noorden van de Wadden (TNVDW) is 0.59. While this value is on the higher end of the spectrum, it is consistent with the modelling of smaller wind farm plots, which experience lower wake effects compared to larger configurations. This explains the increase relative to earlier profiles (e.g., Hub East), which were based on larger aggregated plots (e.g., 12 GW) that inherently suffer greater wake losses. Therefore, while the high-capacity factor may seem optimistic at first glance, it is justifiable given the smaller wind farm layout assumed in the current profiles. Nevertheless, even with stronger winds and modest efficiency gains, future wind areas are not expected to significantly improve the overall business case.

The offshore electrolyser business case is projected to improve gradually over the coming decades under our cost assumptions, but it continues to face a significant levelized profitability gap. While electricity capture prices slightly decline due to the IO scenario dispatch modelling, hydrogen capture prices also decrease, offering limited net benefit. Although cost reductions are assumed, they are applied conservatively and remain modest. For example, the offshore electrolyser CAPEX in 2050 is assumed to be only 6% lower than in 2030. This contrasts sharply with the variation across scenarios: the optimistic 100 MW CAPEX is 45% lower than the baseline, and the 500 MW baseline CAPEX is 28% lower than the 100 MW baseline. These disparities highlight the wide uncertainty in future cost trajectories, especially when comparing scale effects and scenario assumptions. While these cost scenarios are ultimately illustrative, they underscore the difficulty of predicting long-term reductions. Nevertheless, if scale-up to 500 MW is achieved and/or costs follow the optimistic pathway, a viable offshore electrolyser business case could emerge under favourable market conditions, offering substantial revenue potential for HWIs.

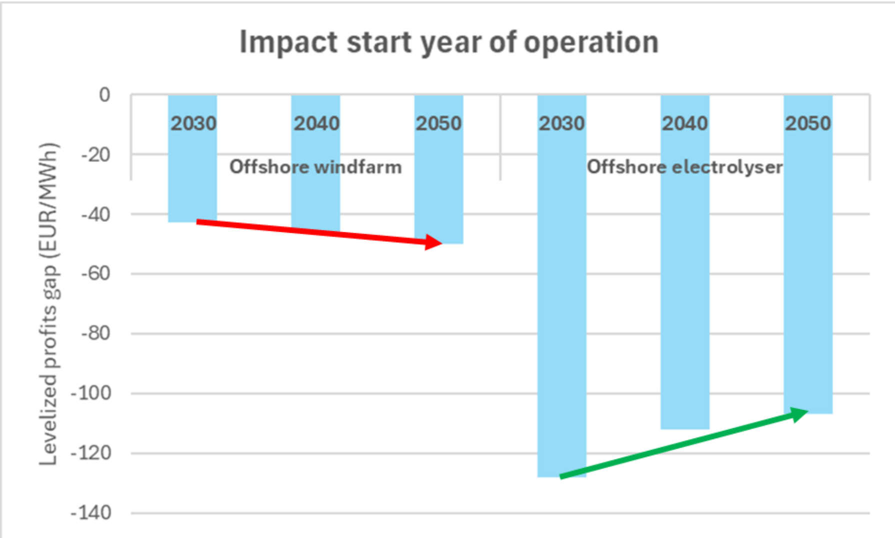

Figure 12: Impact of the start year of operation on the levelized profits gap for the offshore windfarm and offshore electrolyser.

3.2.4 Impact of the offshore electricity grid connection

Another issue of interest is the connection of the OWF and offshore electrolyser to shore. In the base case, a 200 MW electricity connection was chosen, as a result of the assumption that electricity supply was prioritized to the electrolyser. Additionally, the minimum load of the electrolyser was 50 MW, so a larger electricity grid capacity was not required for this setup.

The remaining question was what the impact of a smaller (or no) electricity grid connection would be on the business cases of offshore wind and offshore electrolysis. If there would be no electricity grid connection, this would mean that during the full load production hours of the offshore windfarm (700 MW), a significant part of the generated electricity (200 MW) could not be sold or valorised. This means lower revenues for the windfarm, and therefore, a negative impact on the business case (see Figure 13). For the offshore electrolyser no electricity grid connection leads to savings on electricity grid connection costs. However, if a minimum load of 50 MW is required for the offshore electrolyser, this is not met for 921 hours in the year. This is an important implication because without a grid connection another solution should be found for the minimum load requirement. A first option could be to add solar to offshore wind, but by adding 200 MW of solar still 679 hours of unmet load requirements are seen. A second option might be to use a battery for this, D1.1 evaluated that this might be a technical feasible solution, however the costs are not investigated yet [2]. A third option might be technical improvements to avoid or minimize the minimum load requirements. All in all, avoiding the electricity grid connection can save costs on the electrolyser business case, but only if an economically and technically feasible attractive alternative can be found on how to deal with the minimum load requirement of the electrolyser.

A consideration also mentioned (see D3.2 [4]) is that (offshore) electrolysers should be excluded from paying electricity grid tariffs. If this would be the case a similar cost reduction to the one shown in Figure 13 can be expected. Another option is that the connection tariff of the electrolyser would depend on the system value that it provides. Such considerations should be taken into account during the specification of offshore electrolyser electricity grid connection regulations.

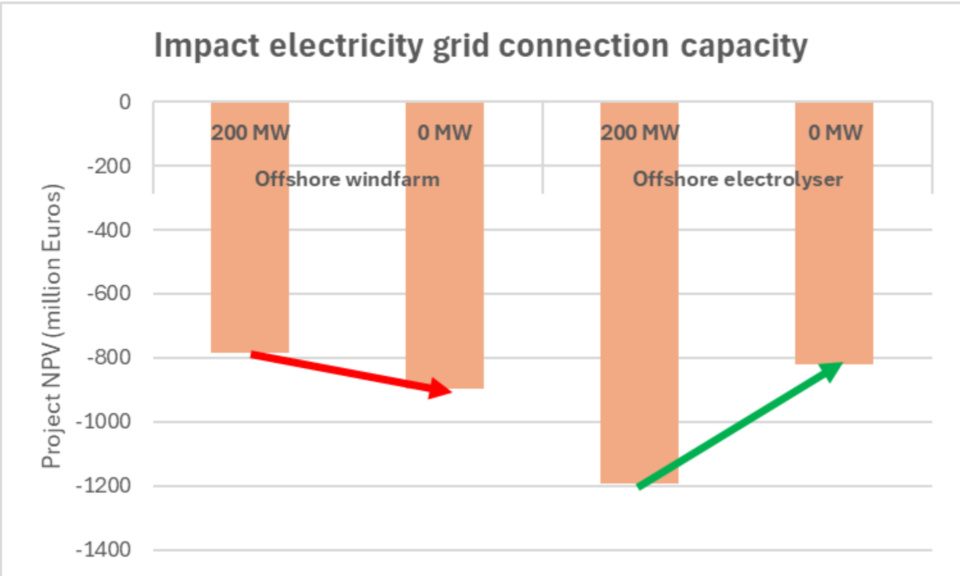

Figure 13: Impact of the grid connection capacity on the levelized profits gap for the offshore windfarm and offshore electrolyser.

3.3 Offshore Solar: only a beneficial addition if cost decrease sharply

Offshore solar could be a valuable addition to the offshore value chain, as it has the potential to increase the operating hours of offshore electrolysers and enhance the utilisation of offshore infrastructure. However, offshore solar remains a very novel technology and has so far only been implemented at a 5 MW scale off the Dutch west coast, as part of the Horizon project 'Nautical SUNRISE' [24].

To assess the business case of offshore solar in a future offshore value chain, a 200 MW solar farm is considered. Due to its novelty, the CAPEX of offshore solar is at the moment significantly too high to reach a positive business case (Figure 14). It is expected that the CAPEX will decrease if the technology matures. For example, the Nautical SUNRISE project expects to achieve an LCOE of <148 €/MWh [25], which is close to the optimistic business case calculated in this research (155 €/MWh). However, even if this cost reduction is realised, it is still significantly higher than the LCOE obtained from offshore wind (78 €/MWh) and far away from closing the business case due to the low expected revenues. Thus, to be a valuable asset to the offshore value chain a further significant decrease in offshore solar CAPEX is necessary.

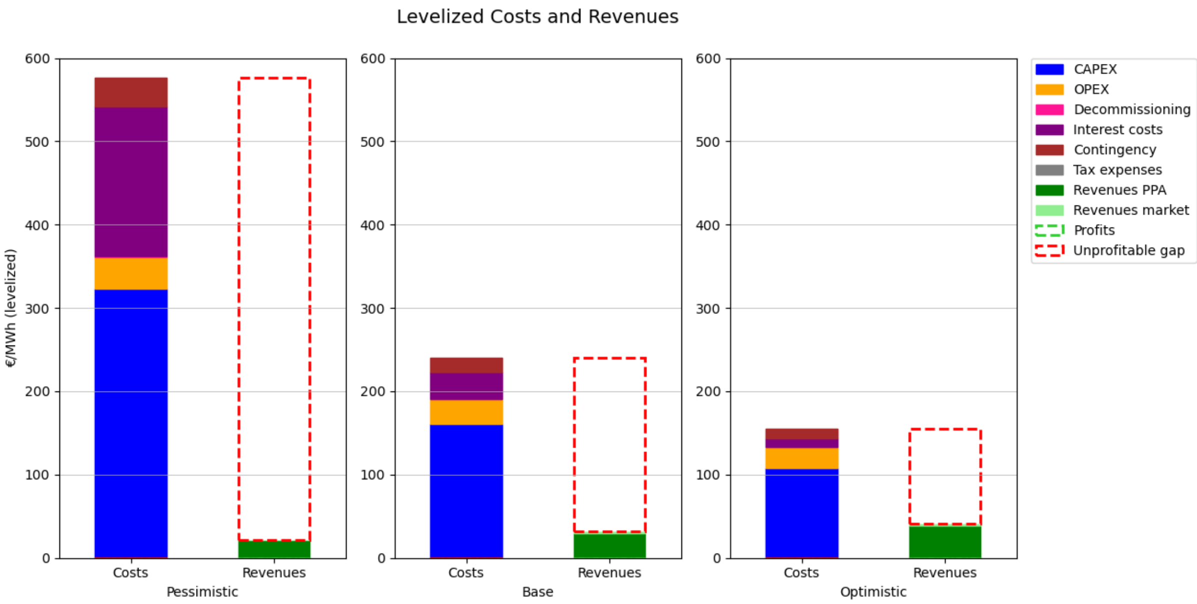

Figure 14: Levelized costs and revenues distribution for the offshore solar business case

3.3.1 Impact offshore solar on other business cases

The impact of offshore solar on other actors in the value chain was evaluated by re-calculating the individual business cases of the offshore windfarm, offshore electrolyser, and transport infrastructure. As expected, the addition of offshore solar to the offshore value chain has a positive impact on the offshore electrolyser due to its higher utilisation (Figure 15). In the base case, the offshore electrolyser had 6097 full load hours and in the offshore solar case 179 full load hours were added. Additionally, the presence of offshore solar had a positive impact on the offshore transport infrastructure business cases, though to a much smaller extent. This is explained by a small increase in utilisation of the offshore cables due to higher electricity supply, and a higher utilisation of the offshore pipelines due to the higher electrolyser utilisation. Offshore solar had a small negative impact on the business case of the offshore windfarm, as a part of the produced electricity could not be transported to shore by the limited grid capacity of 200 MW (in this investigation a 50/50 priority between the offshore windfarm and offshore solar installation was assumed).

It is clear that offshore solar has an overall positive impact on the other business cases in the offshore value chain. However, currently the offshore solar business case has a very significant unprofitable gap due to the high CAPEX of this novel technology. Therefore, even with the positive impact offshore solar has on the other business cases, from a value chain perspective, the addition of offshore solar is at this moment not beneficial. If a significant decrease in LCOE can be realised as this technology matures, it is valuable to reconsider the addition of offshore solar in the offshore value chain.

Also, it should be noted that the offshore windfarm profile of the TNVDW wind park had already a relatively high number of full load hours. It is expected that the positive benefits of offshore solar are larger at wind areas with a relatively low number of load hours. Another factor not included in Figure 15 is that energy storage capacity needs can be reduced by 4% if 200 MW of offshore solar capacity is added. However, unless offshore solar costs reduce significantly, the benefits of adding offshore solar in other wind areas, or taking into account lower storage needs, will also not outweigh the expected 2030 costs for realizing offshore solar capacities.

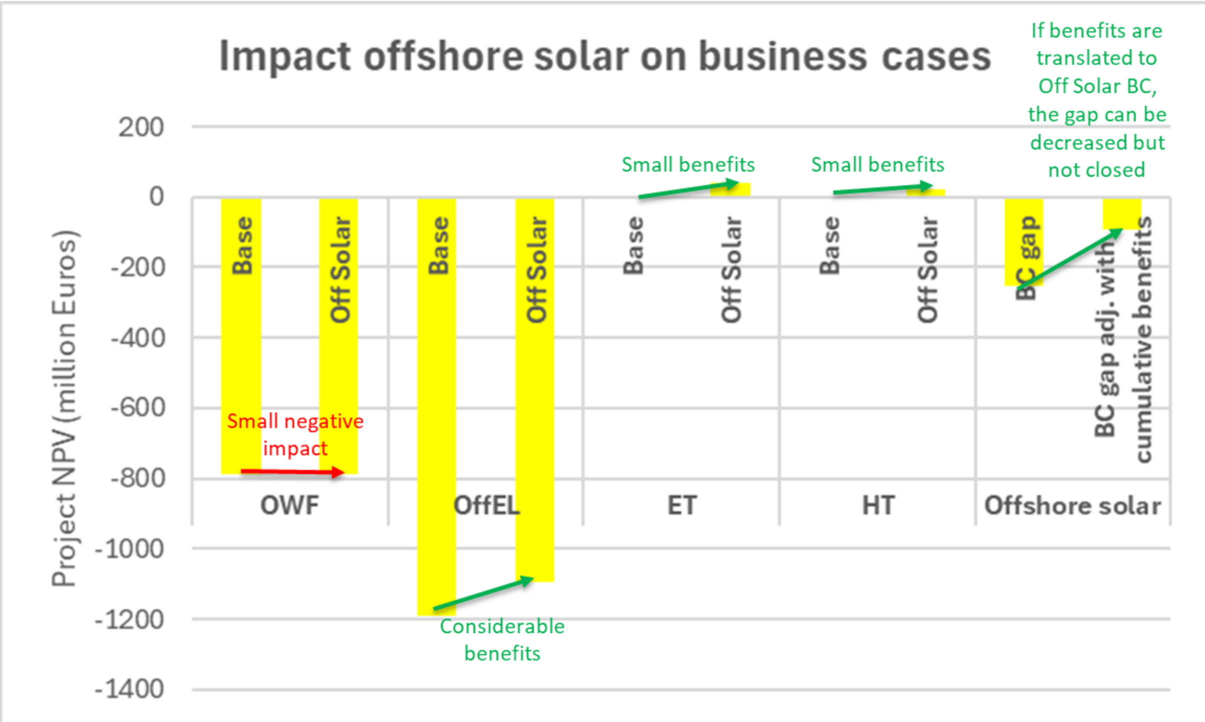

Figure 15: Impact of offshore solar on the other business cases in the offshore value chain. This figure compares the base results (0 MW offshore solar) with similar calculations if 200 MW of offshore solar would be added (off solar case) (OWF = offshore windfarm, OffEL = offshore electrolyser, ET = electricity transport, HT = hydrogen transport)

3.4 Off-taker: start in (niche) segments with high willingness-to-pay

The business case for two different off-taker scenarios is considered. The first scenario considers a large grey hydrogen off-taker, that has up till now produced its own grey hydrogen, that switches to hydrogen from the grid, in combination with HWI certificates. As this implementation is not associated with revenues (only cost implications are assessed), it is compared with an alternative option that also reduces its carbon footprint: blue hydrogen off-take from an ATR + CCS installation located at the end-user's site. The second scenario considers a natural gas off-taker that switches to hydrogen from the grid in combination with

HWI certificates, and is compared to the alternative, which is to continue using natural gas and pay for their CO_2 emissions, for instance under a carbon pricing mechanism.

Table 6: Summary of scenarios for the off-taker analysis

Scenario	Current State	Considered alternative option	Avoided alternative option	Revenues Considered?
Grey Hydrogen Off-taker	Producing and using grey hydrogen	Switch to grid hydrogen + HWI	Switch to blue hydrogen (ATR+CCS)	No
Natural Gas Off-taker	Using natural gas	Switch to grid hydrogen + HWI	Continue natural gas + CO_2 costs	No

Note that this method gives insights only into the costs associated with the energy carrier for the production process, and is intended to compare the relative effect of the switch to (partly) green hydrogen from the grid compared with the alternative. It is not taken into account whether the resulting product increases in value, for example if it can be sold with a green premium. Therefore, it is possible that the business case of the overall production plant is not affected to the same extent as the business case associated with the energy carrier.

3.4.1 Grey hydrogen off-taker

In the case of hydrogen off-take from the grid, the CAPEX investments are only a small contribution to the levelized cost, while the H_2 cost, HWI cost and H_2 network cost are the most significant contributors. It is not clear yet what the H_2 network cost will be and, therefore, the pessimistic case uses 2 times the current natural gas network costs. If the H_2 network costs will be similar compared to the current natural gas network costs (1 to 1.5 times the natural gas network costs calculated in the optimistic and base case, respectively), there is a potential for grid hydrogen to be a cheaper alternative than for ATR + CCS (Figure 16).

In the case of the alternative (ATR+CCS), the CAPEX has a slightly higher impact, but the operational expenses, in particular HWI cost and natural gas costs, are the most significant contributors to the levelized cost.

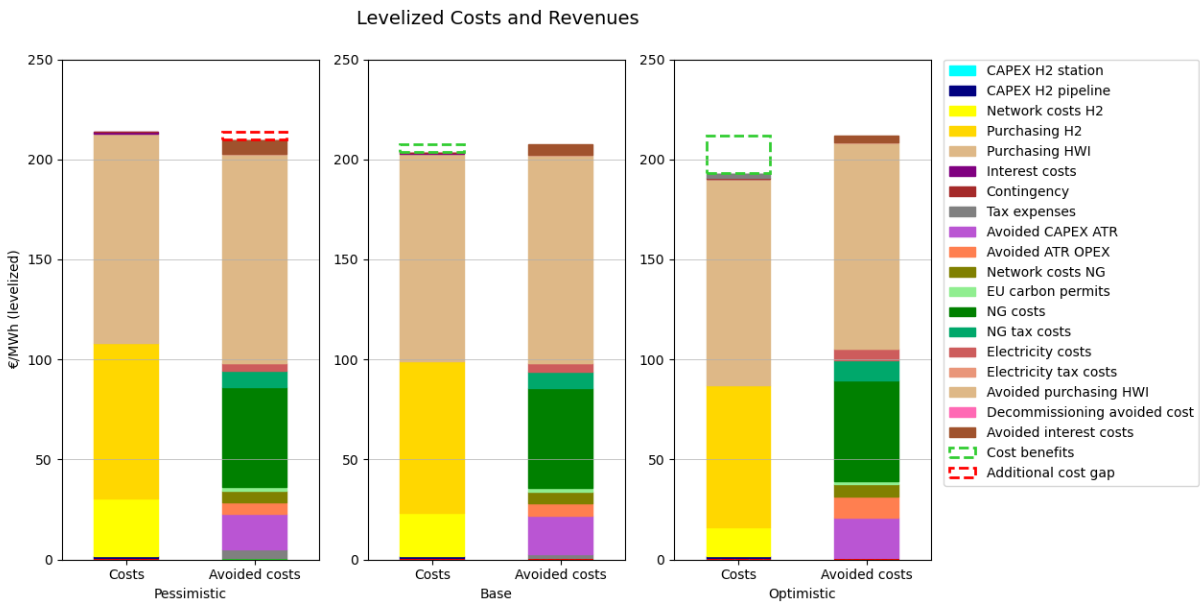

Figure 16: Levelized costs and avoided costs distribution for the onshore grey hydrogen off-taker. The costs represent hydrogen off-take from the grid with 42% HWI's from 2030 and 60% from 2035 onwards, the avoided costs represent the alternative, i.e., ATR + CCS.

The business case for a large-scale grey hydrogen end-user will be significantly impacted by the Renewable Energy Directive (RED) III, as from 2030 42% of hydrogen must be RFNBO hydrogen (i.e., green hydrogen, made from renewable energy), and this increases to 60% from 2035 onwards [26]. A HWI price of approximately 5 €/kg is used. This is a projection for 2030, and it is likely that the price will change over time. However, at this moment it is still unsure how this price will develop and, therefore, the price is kept around 5 €/kg during the business case.

The implementation of RED III has a large impact on the levelized cost of hydrogen (Figure 16), but since the required HWI's for hydrogen from the grid and blue hydrogen are the same, it does not affect the relative comparison between the two scenarios. If the off-taker decides to fully implement green hydrogen (and thus purchase 100% HWI's), the business case becomes significantly worse than that of the blue hydrogen alternative, as the HWI cost are the largest contributor to the levelized cost (Figure 17). Compared to hydrogen from the grid without HWI's (i.e., grey hydrogen), the cost is approximately doubled (if the off-taker complies with REDIII targets) or even tripled (if the off-taker fully switches to green hydrogen). Such a significant cost increase will be hard to accommodate for industrial end-users if no additional support in the form of subsidies will be provided.

Nevertheless, there are indications of (niche) customers with high willingness-to-pay in the market, based on the pilot auction of the European Hydrogen Bank (EHB) in 2024. The best scoring Dutch projects submitted bids for a subsidy contribution of only 1-2 €/kg, while the cost gap is much larger [10]. This suggests that these projects may be able to add a green premium to their product, which decreases the cost gap. However, it may also be possible that these project's strategy was: better to ask for a limited contribution to closing the cost gap than obtain no contribution at all.

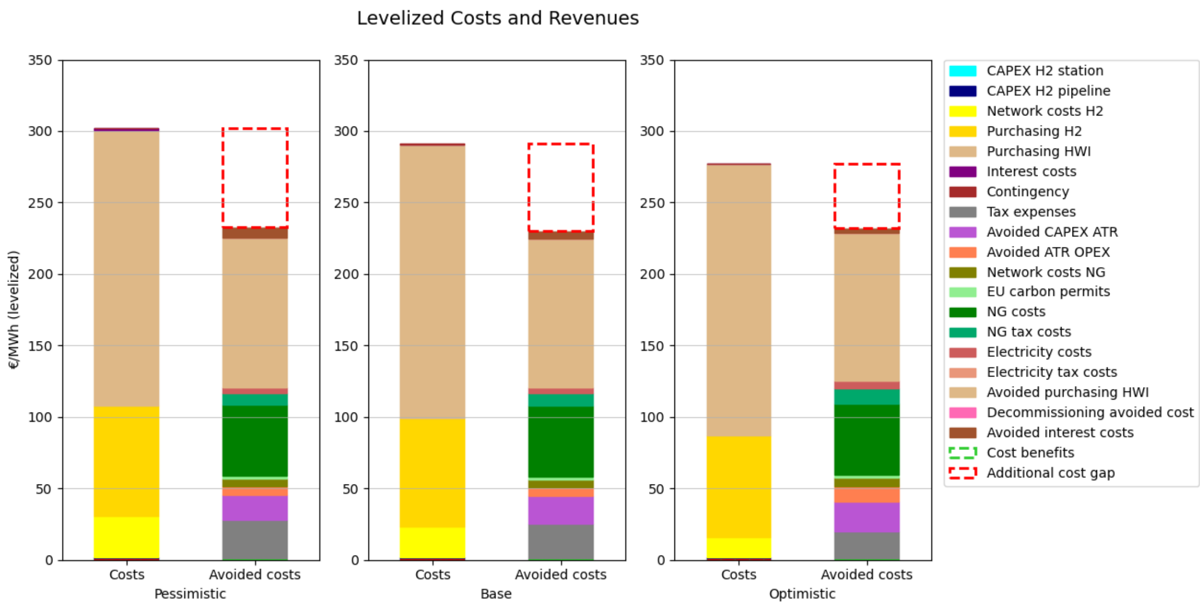

Figure 17: Levelized costs and avoided costs distribution for the onshore grey hydrogen off-taker with 100% green hydrogen (i.e., 100% HWI purchase). The costs represent green hydrogen off-take from the grid with 100% HWI's, the avoided costs represent the blue hydrogen offtaker that purchases the minimum number of HWIs needed for compliance.

3.4.2 Natural gas off-taker

For a natural gas off-taker that switches to hydrogen from the grid, the costs significantly increase for all scenario's (Figure 18). The most significant contributors to the LCOE are the H_2 costs, HWI costs, and H_2 network costs. The costs associated with purchasing hydrogen are about 1.5 – 1.7 times higher compared to those for natural gas, because the hydrogen price is expected to be almost double the natural gas price up till the early 2040s, after which the hydrogen prices are expected to decrease towards the natural gas price.

If the end-user buys enough HWI's to comply with the RED III targets (i.e., 42% from 2030 and 60% from 2035 onwards), the HWI's comprise about 39-47% of the LCOE. If the end-user would adapt to fully green hydrogen off-take with 100% HWI's this increases to 54-62% of the LCOE (Figure 19). In the hypothetical situation where HWI's would not be required or if their (expected) value would decrease drastically, the business case for hydrogen offtake compared to natural gas offtake would become more attractive. In Figure 18 this hypothetical case is not evaluated (in all cases a HWI price of 5 €/kg is considered). However, if the contribution of the HWI costs is extracted from the total levelized costs, the impact can be imagined. Still, even if the optimistic scenario would not include costs for HWI's, the LCOE would be roughly equal to that for the alternative with natural gas. This is partly due to the relatively low natural gas price, but also due to the relatively low carbon permit price. Overall, at this moment, the transition from natural gas to hydrogen is not an attractive pathway to decrease the carbon footprint of a company. This transition could become more attractive in the future if the H_2 and/or HWI price can decrease significantly or if the natural gas and/or the EU ETS[8] permit price would increase significantly.

[8] European Union Emission Trading Scheme.

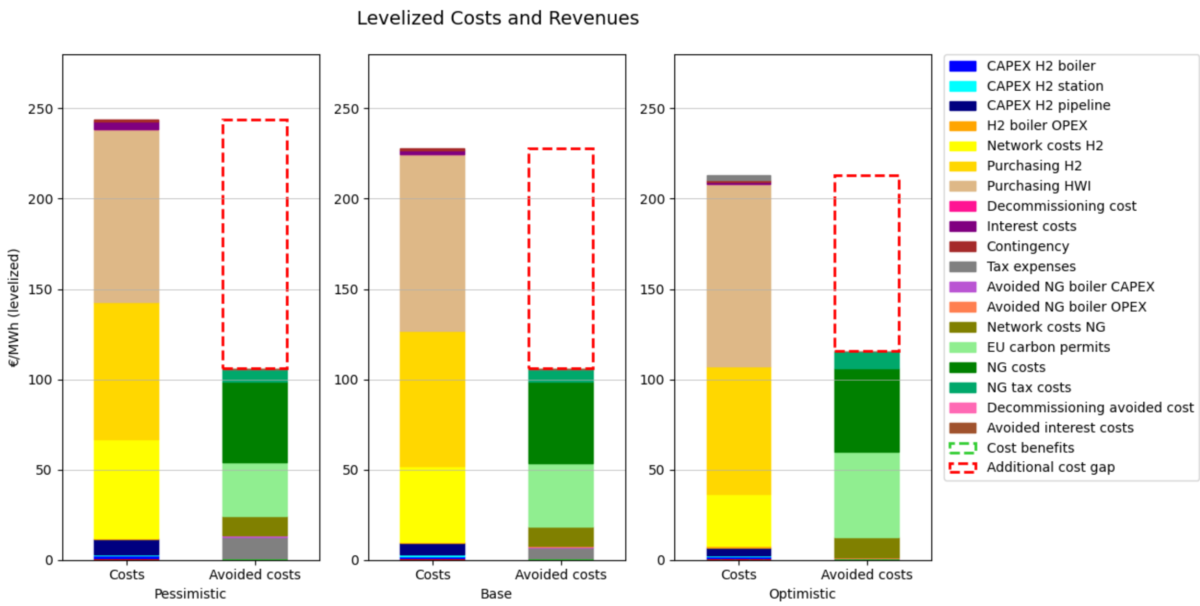

Figure 18: Levelized costs and revenues distribution for the onshore natural gas off-taker. The costs represent hydrogen off-take from the grid with 42% HWI's from 2030 and 60% from 2035 onwards, the avoided costs represent the alternative, i.e., natural gas from the grid.

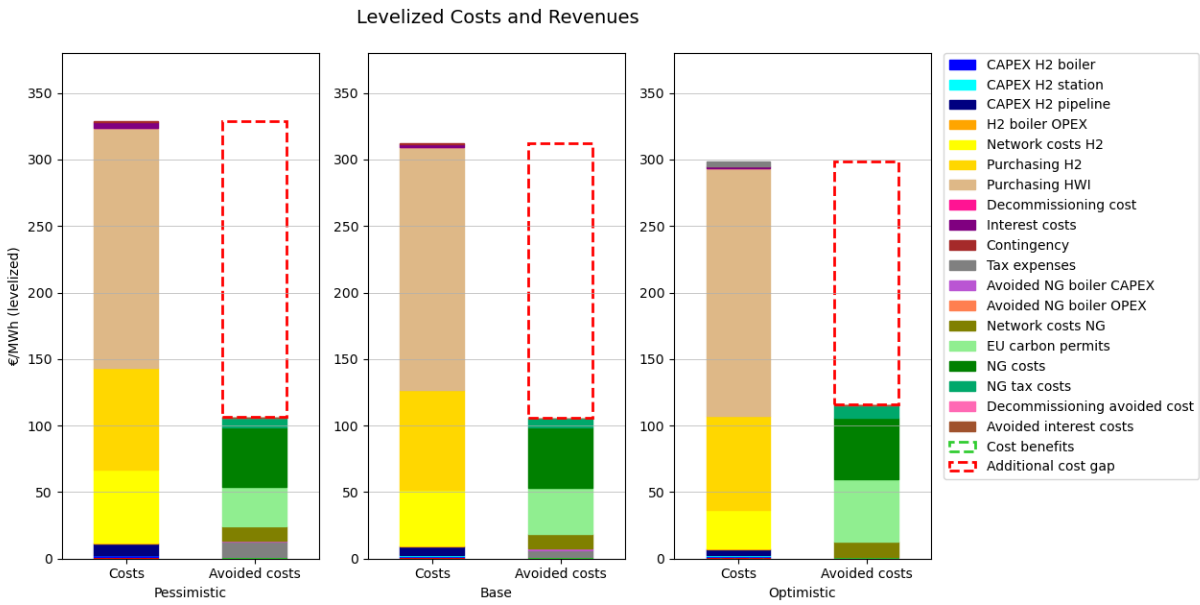

Figure 19: Levelized costs and revenues distribution for the onshore natural gas off-taker. The costs represent green hydrogen off-take from the grid with 100% HWI's, the avoided costs represent the alternative, i.e., natural gas from the grid.

3.5 Transport: coordination needed to minimize future tariffs

For the electricity and hydrogen transport scenarios the estimated revenues are at this moment not yet clear. It is expected that the tariffs resulting in the revenues will be based on the costs with a regulated margin, since the networks are likely to be operated by public entities. Therefore, the revenues of the business cases are not displayed in this chapter. The levelized transport costs provide an indication on the costs for other actors of the value chain, in order to economically deploy the assumed transport infrastructure.

For each electricity and hydrogen transport, for two types of cases the levelized costs have been calculated. The first are the landfall connection costs for the TNVDW and DEMO-II case. These results provide insights in the costs of connecting such a single project to shore. The second type of case are the levelized transport costs for the full electricity and hydrogen network in the NAT scenario developed by 2050 in the WP1 hub designs [2]. The results of this cases provide an indication of future transport costs in case a full network would be developed. Although it should be noted that this network cost calculation is a rough proximation since it is based on generic cost assumptions and no location specific costs, windfarm outputs and detailed pressure drop, power flow and other calculations have been performed. For both the partial reused and solely new hydrogen network cost factors for 7000 MW pipelines from the NWSPH Pathway Databook [13] have been taken into account, while in the WP1 design it turned out that different diameters for both options might be considered. Also, compression towards 100 bar has been assumed and no different pressure regimes have been taken into account. For more detailed technical considerations on hydrogen grid designs we refer to D1.1 [2] and D1.3 [27].

3.5.1 Electricity Transport

Figure 20 presents the levelized costs for electricity transport for connecting the TNVDW and DEMO-II project to shore. It should be noted that the main landfall of energy will be in the form of hydrogen, and just a 200 MW electricity connection for surplus generation of the windfarm and minimum load electricity consumption of the electrolyser was considered.

In all cases (base, pessimistic and optimistic), substation CAPEX stands out as the most significant cost driver, indicating that innovations or efficiency improvements in this area could yield substantial savings. OPEX costs (for both cables and platforms/substations) also contribute consistently across scenarios, underlining their long-term impact.

It is noteworthy to mention that the CAPEX numbers for the base case are based on the NSWPH Databook cost assumptions, but consultation with experts and recent publications [28] indicated that these numbers may be an underestimation compared to the latest cost information of grid operators. It was found that the CAPEX numbers for the pessimistic case, which are twice as high as the base case assumptions, may be closer to the realistic numbers. This would mean a significant increase in electricity landfall costs.

Overall, the analysis highlights that a cable used for the purpose of landing excess electricity and minimum load supply of the electrolyser (which is the case for the TNVDW+DEMO-II project as priority for electricity supply to the offshore electrolyser was assumed) would be relatively underutilized (load factor of 36%) and therefore has relatively high levelized costs of electricity transport. Therefore, such a connection might be needed to meet the minimum load requirements of the electrolyser, and might be beneficial for the offshore windfarm (since it is able to sell more electricity, while it does not have to pay for the underutilized electricity grid connection), but from a societal perspective it relatively increases the electricity grid costs.

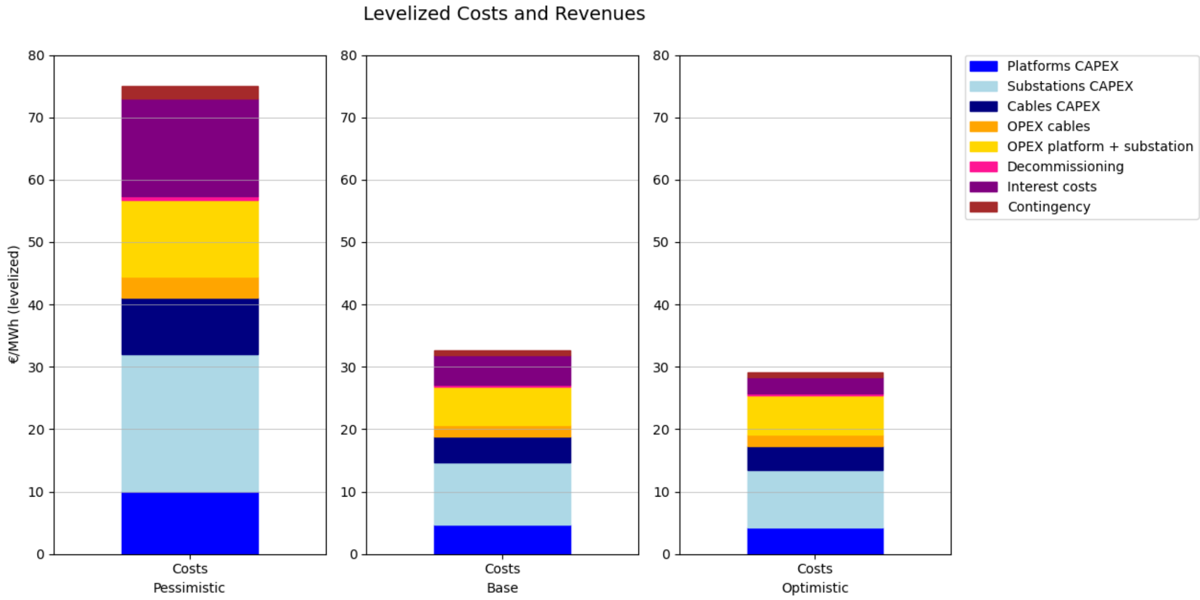

Figure 20: Levelized costs distribution for offshore electricity transport based on the connection of TNVDW to shore.

Figure 21 shows the levelized costs of the entire offshore electricity network, which extends approximately 2258 km and is based on the NAT 2050 hub scenario of WP1 [2]. In this design, landfall cable capacities are reduced if nearby electrolysers consume electricity locally (for instance, in Hub North). The total levelized costs are lower compared to the TNVDW-DEMO-II case (Figure 20), due to the higher utilization (50%) of the offshore electricity cables. In the large-scale electricity network (Figure 21), a similar distribution of cost components is observed compared to the case connecting to TNVDW (Figure 20).

The CAPEX of the full network in the base case is 59 billion Euros. In the pessimistic case, the costs would be twice as high, leading to an investment need of 117 B€. According to conversations with experts and recent insights form other studies, such as the projected needed 88 billion Euro investment for the offshore electricity grid between 2025 and 2040 by IBO [28], the pessimistic case seem closer to the current reality. This would mean a significant cost component that would be faced by future users of the electricity grid.

In this calculation only electricity output from the offshore windfarms was considered to be transported. If the same cables would be used as interconnections as well, the utilization of the network might increase and therefore the levelized costs could become lower than presented in the figure.

Overall, the utilization of the network is key for the economic viability of offshore electricity transport. The current network case led to an utilization of 50%, which was lower than the load factor of offshore wind (58%). The utilization in this case was lower because of the wind-following approach that assumed that offshore windfarms located next to offshore electrolysers would prioritize their electricity to the electrolysers. Obviously, many variants for operational strategies for offshore wind-electrolyser combinations are possible, and therefore those are highly important to consider in order to reduce future offshore energy infrastructure costs and tariffs.

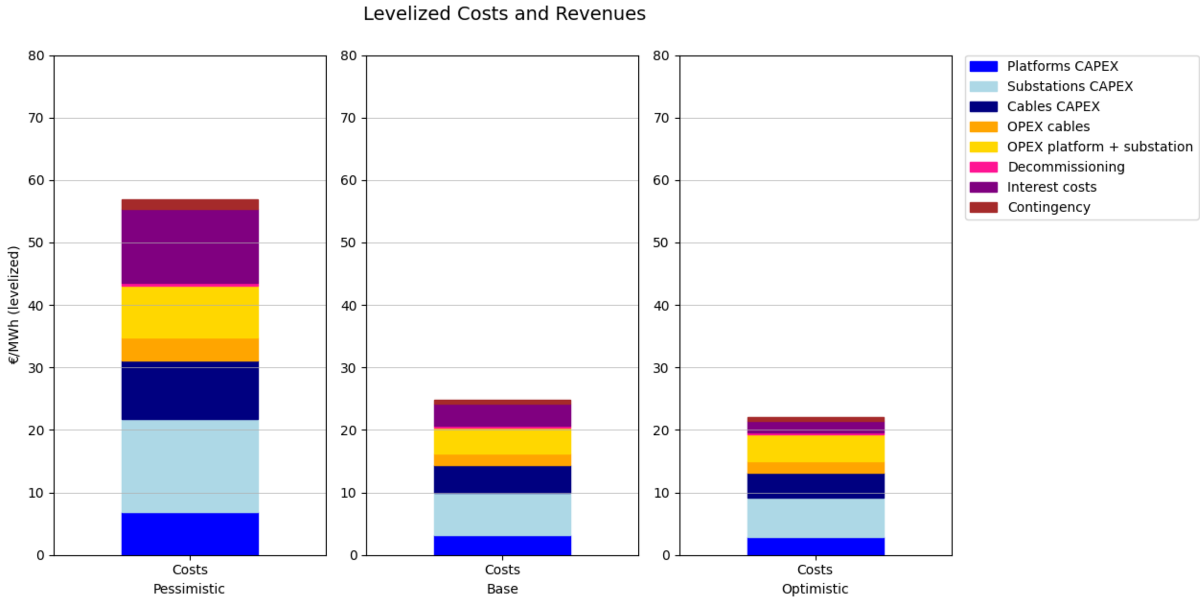

Figure 21: Levelized costs distribution for offshore electricity transport based on the total length of electricity cables within the network (2258km).

3.5.2 Hydrogen Transport

Figure 22 presents the levelized costs for hydrogen transport for connecting the TNVDW and DEMO-II project to shore. Noteworthy is that the assumptions taken imply that a large (7000 MW), futureproof, pipeline will be installed to connect DEMO-II. This means that the cost reflects a significant underutilization of the pipeline. Therefore, it is no surprise that the pipeline CAPEX is the largest cost component. The compressor is scaled according to the output of the DEMO-II project, and can be potentially expanded if a future network would develop.

Two things are noteworthy to mention to interpret these results rightfully:

- The CAPEX numbers for the base case are based on the NSWPH Databook, but consultation with experts indicated that these numbers may be an underestimation compared to the latest cost information of grid operators. It was found that the CAPEX numbers for the pessimistic case, which are twice as high as the base case assumptions, may be closer to the realistic numbers.
- No platform costs for the offshore compressor are included since we stuck to the numbers of the NSE5 factsheets. These costs can potentially be avoided/reduced if the platform can be shared with the electrolyser, otherwise additional platform costs should be included. The CAPEX of the compressor in this case was 30 million euros.

The levelized transport costs of such an underutilized pipeline are significant (26-50 €/MWh, or: 0.9-1.7 €/kg) if they would be charged to a first-of-its-kind offshore electrolysis project. However, if these costs (an investment of 350 million euros) can be spread over future users this issue can be solved. For example, via the inter-temporal cost allocation under the EU gas decarbonization package [29], as described in D3.2 [4]. A more relevant question with regards to this huge underutilisation is if such a large pipeline would be technically feasible to transport such small volumes. If not, (other) solutions would be needed.

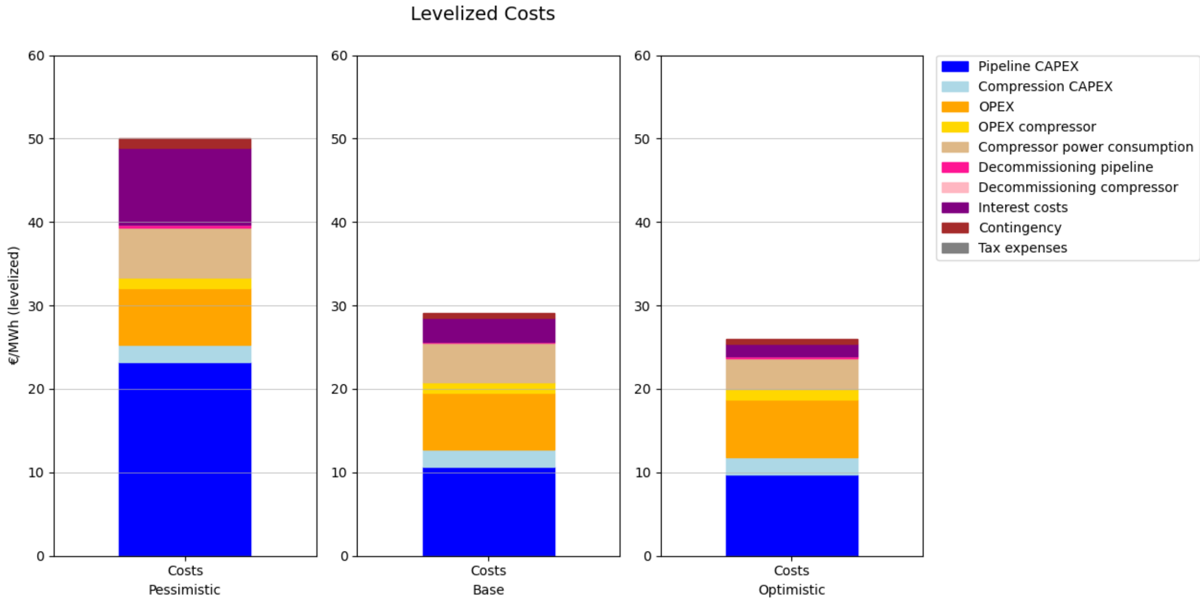

Figure 22: Levelized costs for hydrogen transport based on the TNVDW+DEMO 2 value chain in Hub East.

Similar to electricity, levelized costs for future large scale offshore hydrogen pipeline systems are calculated. Figure 23 presents the levelized cost for hydrogen transport for a hydrogen network utilizing 708 km of new pipelines. Figure 24 consists of the same for a hydrogen network of 413 km of new pipelines and 392 km of repurposed pipelines. Both cases are taken from the NAT 2050 hub design of WP1 [2]. As mentioned in the introduction of this chapter, the calculation is a simplified representation and should be considered as indicative. All pipelines are considered to be 7000 MW and no specific sizing, pressure calculations, location specific engineering and other detailed assessments have been performed. Also, the presented results are based on the assumption that the CAPEX of reused pipelines are 20% of the new ones based on [13]. However, this is a generic assumption. A detailed technical and cost assessment would be required on what the costs of reuse for these specific pipelines are. Moreover, given the limited pressure swings that reused pipelines may be able to handle, it should be assessed if offshore hydrogen storage is required for a network partially based on repurposed pipelines. This has not been assessed in this work, but based on chapter 3.6 it is indicated that this would add significant costs to the network.

Figure 23 shows that the levelized transport costs of a hydrogen network (7-11 €/MWh, or: 0.2-0.4 €/kg) are significantly lower than the underutilized pipeline to connect DEMO-II and the potential levelized cost of electricity infrastructure. Even, (similar to the electricity network) no cross border hydrogen volumes are included in the assumptions of this network, which could increase the utilization even further and thereby reduce the hydrogen transport costs more. It is also indicated that for this full network compression costs are a significant share of the total levelized transport costs, therefore attention on the pressure design and management in the network is needed to optimize the costs. The total investment in compressors resulted in 1.2 billion Euros without considering the potential platform costs. The pipeline CAPEX resulted in 2.1 B€ in the base case, and would double in the pessimistic case (which was indicated by experts based on recent cost projections). This would lead to an indicative total investment of 3.2-5.4 B€ for the total network.

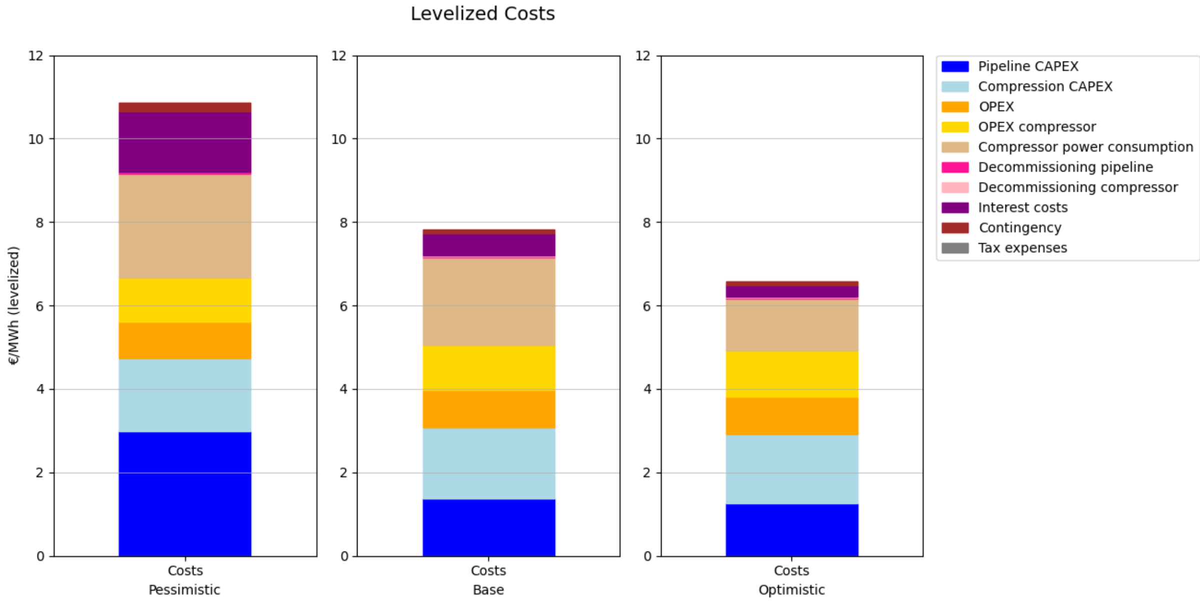

Figure 23: Levelized costs for a large-scale new hydrogen transport network.

Figure 24 presents the levelized cost for the full hydrogen network utilizing new and re-used pipelines (6-10 €/MWh, or: 0.2-0.3 €/kg). Pipeline CAPEX represents an even less significant share than in the results of utilizing new pipelines only, because of the significantly lower costs assumed for repurposed pipelines. The initial pipeline investment for this network is therefore 1.5 B€ instead of 2.1 B€ (or double if pessimistic cost assumptions are taken). The compressor costs are similar to the case utilizing new pipelines only, because it is assumed that new compressors are needed for this network and no differences in pressure regimes were considered, because this would involve more detailed assessment.

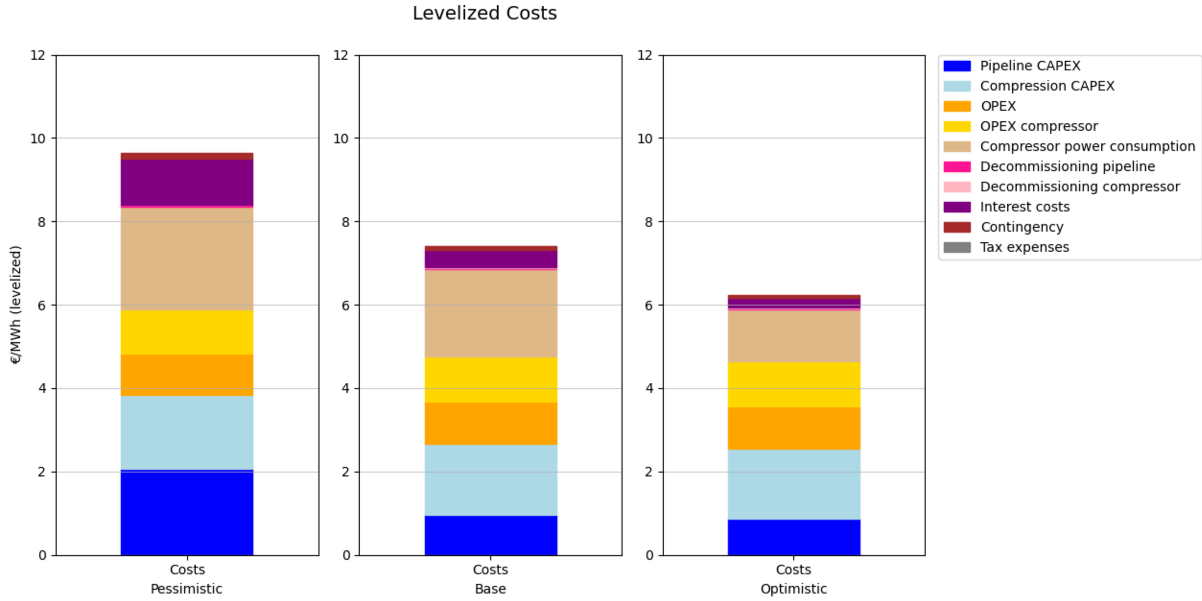

Figure 24: Levelized costs for a large-scale hybrid hydrogen transport network utilizing new and re-used pipelines.

Hence, this high-over evaluation is too limited to conclude on the potential cost benefits or disadvantages of new and partially reused hydrogen networks. However, the assessment made the following clear:

- The costs of the offshore hydrogen transport network are relatively limited compared to the costs of other activities in the offshore hydrogen value chain, such as offshore electrolysis and offshore storage (see chapter 3.6);
- It is likely that the relatively high connection costs of the first offshore hydrogen projects can be effectively distributed over future users. Also, because of the relatively low contribution of the transport costs compared to other parts of the value chain. The main issue for this first connection is the technical feasibility;
- The main hydrogen transport cost reduction impact can be made on the design and regime of compressors. Think of: structures to locate the compressors and the pressure regime and optimization in the network (see D1.1 [2] for different pressure regime options);
- Reuse of pipelines could reduce the pipeline CAPEX of the network. More detailed assessments are needed to get a better understanding of the exact cost reductions, and the implications for compression and potential hydrogen storage requirements within the network (for some of the technical implications see D1.1 [2]);
- If it turns out that the cost difference between a solely new and partial reused pipeline networks is relatively small compared to the total value chain costs, other factors than economics might become decisive. Such as: ecological impact, availability of the network and reliability of the network.

3.6 Offshore Underground Hydrogen Storage: a question of political willingness

Onshore underground hydrogen storage is an emerging application of a mature technology (e.g., underground natural gas storage in salt caverns, depleted gas fields, aquifers). Offshore underground hydrogen storage considers hydrogen storage beneath the seabed and is purely conceptual, its application to hydrogen storage remains entirely unproven. However, it is gaining interest as a potential large-scale storage solution in hydrogen economies located near offshore production hubs. We have calculated the levelized costs of onshore and offshore underground hydrogen storage based on input data from two studies [30] [15] but in consultation with experts it was determined to use the cost calculations and input data from the HyStories: “Lifecycle cost assessment of an underground storage site” [15] study and use an offshore multiplier factor of 200%-500% to account for costs in in an offshore context. While this simplified linear cost factor does not capture the full complexity or non-linear cost-behaviour of offshore infrastructure – such as increased engineering challenges, logistical constraints, and regulatory compliance – it serves to provide a preliminary indication of the possible cost range for offshore implementations. Hence, the costs reflected for offshore underground hydrogen storage should be viewed as an exploratory tool rather than a precise estimate.

Offshore underground hydrogen storage requires a significant development process that takes over a decade. During this time countless vessel movements will be required and the offshore conditions come with significantly more risks. Moreover, the compression and cleaning equipment will be so large that this should either be located onshore with dedicated pipeline connections, or offshore on an artificial island but the precise cost effect of placing these surface components onshore (e.g., Figure 6) or on an island is not reflected in the results and is simply represented under an offshore cost factor.

Levelized costs have been determined for hydrogen stored in both salt caverns and depleted gas fields operating under short-cycle and seasonal-storage cycles. Figure 25 presents the levelized costs per MWh of hydrogen stored for seasonal storage. The seasonal case is similar to the storage case presented in D1.1 [2] that was based on the output of a 8 GW offshore windfarm and electrolyser.[9] For both the seasonal salt cavern and depleted gas field, a storage facility of ≈3 TWh working gas volume (≈1000 mln Sm^3) with a maximum injection flowrate capacity of 18 mln sm^3/day and a maximum withdrawal flowrate of 24 mln sm^3/day is defined. The maximum number of full cycles per year is 3.6 for a depleted gas field and 3.8 for a salt cavern. The results are levelized costs of approximately 49 €/MWh (or: 1.6 €/kg) for onshore DGF and 27 €/MWh (or: 0.9 €/kg) for onshore salt caverns. In an offshore context, costs are in the range of 137 €/MWh (or: 4.6 €/kg) for offshore caverns and 254 €/MWh (or: 8.5 €/kg) for offshore depleted gas fields. Logically based on our assumptions, onshore storage costs are 3-4 times lower than the offshore costs.

[9] The only cost differences between this report and WP1 [2] are that this report uses electricity and hydrogen price inputs from I-ELGAS dispatch modelling and that this reports uses an offshore multiplication factor of 3.5 compared to WP1 that used 3 for its calculation.

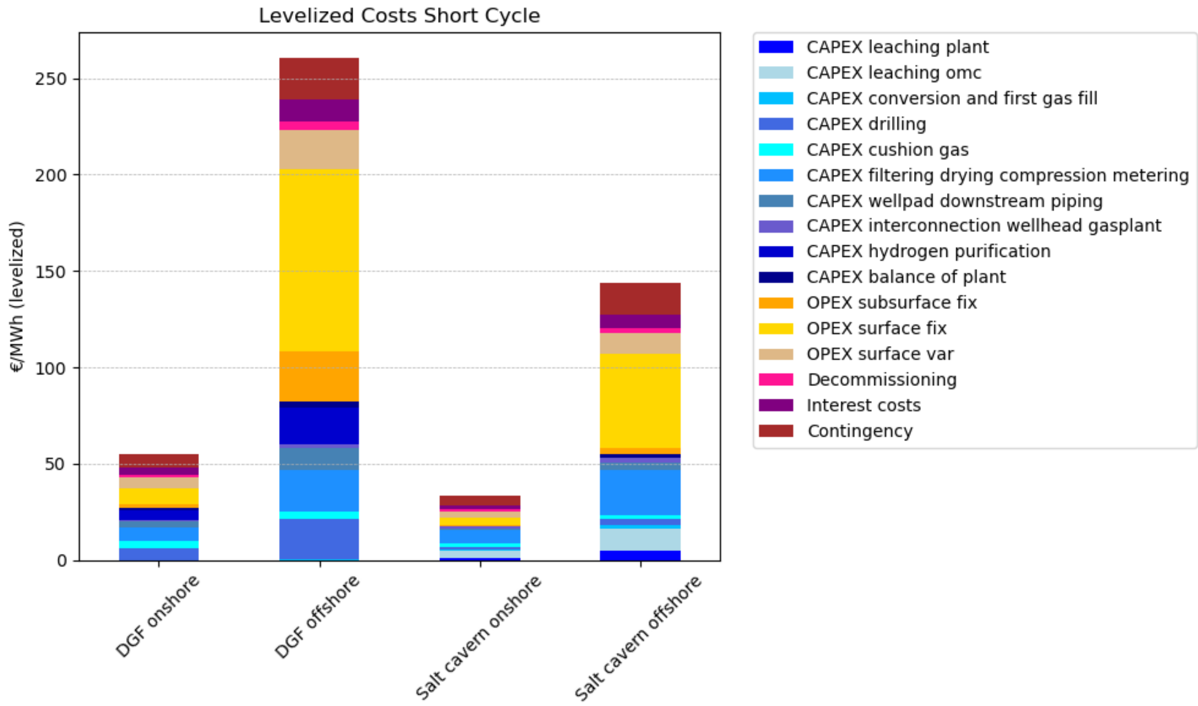

Figure 25: Levelized storage costs for seasonal hydrogen storage.

Some key observations emerge from the analysis. Significant cost drivers include fixed and variable OPEX related to surface processing infrastructure, such as compressors, purification units, and drying systems. Contingency allowances and financing (interest costs) also represent critical components, particularly in offshore scenarios where uncertainty and capital intensity are higher.

The type of storage plays a crucial role: salt caverns are generally more cost-effective to develop and operate than depleted gas fields, due to simpler construction requirements and lower operating complexity. Secondly. location is another decisive factor—offshore configurations significantly increase levelized costs due to added infrastructure, limited accessibility, and more complex operations. Moreover, the duration of construction for offshore storage in salt caverns takes at least 10 years, which makes private financing really a challenge and the availability of such a storage facility very late (at least after the 2040's). Also, 12 caverns need to be leached for its construction, which is a significant number. Therefore, for offshore storage combinations of salt cavern and depleted gas field storage could be considered as well, such as done in D1.1 [2].

Among the four configurations, onshore salt caverns stand out as the most economically attractive, with total levelized costs below 30 €/MWh (or: 1.0 €/kg). This is largely due to moderate CAPEX requirements for drilling, leaching, and compression, relatively low surface and subsurface OPEX, and limited financing and contingency costs. These findings confirm that onshore salt caverns currently represent the most cost-efficient option for seasonal underground hydrogen storage.

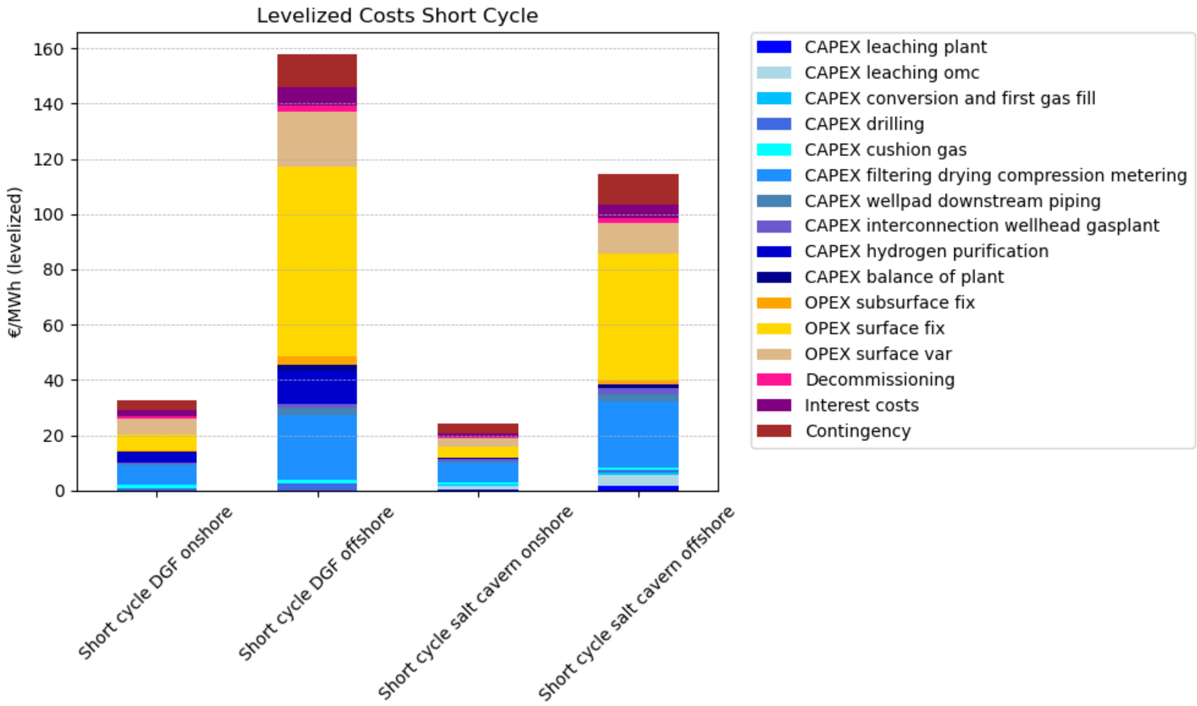

Figure 26: Levelized storage costs of short-cycle hydrogen storage.

Figure 26 indicates the levelized costs per MWh of hydrogen stored for short-cycle storage. For both the short-cycle cavern and depleted gas field assumptions, a storage facility of ≈1TWh working gas volume (≈335 mln sm^3) with a maximum injection and withdrawal flowrate capacity of 57.6 mln sm^3/day is defined, where the maximum number of cycles per year is 31.4.

The result are storage costs of 112 €/MWh (or: 3.7 €/kg) of hydrogen stored for offshore salt caverns and around 156 €/MWh (or: 5.2 €/kg) for offshore depleted gas fields. Onshore DGF has a levelized cost of 30 €/MWh (or: 1.0 €/kg) with surface OPEX and financing contributing significantly to the costs. Onshore salt caverns have a levelized cost of 22 €/MWh (or: 0.7 €/kg) which benefits from low drilling and leaching costs. Salt caverns consistently outperform DGF's due to lower CAPEX, higher operational flexibility, and better cycling efficiency. Onshore salt caverns remain the optimal solution for both long and short cycle hydrogen storage from an economic standpoint.

This study supports the findings of D3.2 [4], confirming that offshore underground hydrogen storage is significantly more expensive than onshore alternatives. As a result, implementing offshore storage would impose a substantial additional cost on stakeholders in the hydrogen value chain—such as electrolyser operators, consumers, or traders—who rely on storage reservations to ensure a stable supply of green hydrogen. Near shore underground storage reservoirs could be an in-between option, because significant cost savings can be expected if the surface equipment can be located onshore.

Nevertheless, offshore energy storage may still be justified for reasons beyond cost, including:

1. Limited public acceptance of onshore storage
2. insufficient onshore storage capacity to meet domestic demand, or
3. The potential for substantial cost savings elsewhere in the offshore and onshore hydrogen network.

These are inherently political considerations that must be carefully weighed against the higher costs associated with offshore underground hydrogen storage.

3.7 Supply chain results: change in perspective due to high electrolysis costs

As mentioned in chapter 2.5.6, the costs of whole supply chains were compared on two main characteristics:

- A supply chain with offshore electrolysis versus a supply chain with onshore electrolysis
- A supply chain with solely offshore wind versus a supply chain combining offshore wind and solar

The subchapters below discuss its main outcomes.

3.7.1 Onshore electrolysis versus offshore electrolysis supply chains

Due to the changed assumptions on onshore and offshore electrolysis CAPEX, the supply chain cost results of onshore and offshore electrolysis have changed significantly to what earlier research within NSE or other research programmes have found [31]. By 2020, the generally accepted projections for electrolyser systems CAPEX were within the range of 800-1300 €/kW by 2030 and 400-800 €/kW by 2040 [31. In the current research we use 1752-2792 €/kW for onshore electrolysis and 2493-7299 €/kW for offshore electrolysis by 2030, based on the technological assessment in WP1 [32]. It is evident that this difference in assumptions has significant implications for the results.

In NSE3, the 2030 result was that with significant scale (>4-6GW) and locations further from shore (>100km), the costs of offshore hydrogen would outcompete onshore hydrogen [31]. The 2030 results of the current study on the total levelized chain costs and the relation with the distance to shore are shown I, Figure 27. It can be seen that: 1) the offshore electrolysis supply chain costs are at any (considered) distance higher than the onshore electrolysis supply chain costs. 2) This is mainly due to the large share of the electrolyser costs in the total costs of the supply chain. 3) Due to the large impact of the electrolyser CAPEX, the cost impact of distance remains moderate (less than 15% of total costs). 4) Nevertheless, the costs of offshore hydrogen transport are always more than 3 times lower than offshore electricity transport, and the offshore electrolysis chain involves less energy (conversion) losses. 5) As was discussed in chapter 3.5.1, also estimations of electricity infrastructure costs have increased recently [28] and might be closer to our pessimistic scenario (twice as high) than the base cost assumptions that are used in

Figure 27. Still, in that case the electrolysis cost remain the main driver of the total supply chain costs.

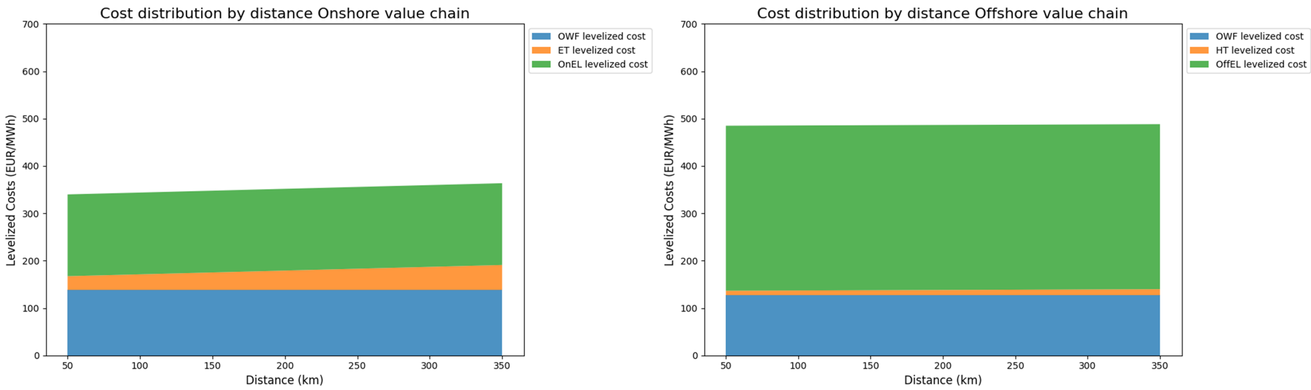

Figure 27: Total levelized chain costs for offshore (left) and onshore (right) supply chains.

Figure 28 shows the impact of the high offshore electrolyser CAPEX on the offshore versus onshore electrolysis supply chain comparison. The left graph shows the total levelized costs of the supply chain, i.e., a simplification of

Figure 27, for easier comparison with the new scenarios. These results show an offshore hydrogen LCOH (excl. electricity costs, because these are represented as OWF levelized costs) of 12.0 €/kg, which are doubled compared to the onshore LCOH of 5.9 €/kg.

The graph in the middle of Figure 28, shows that in order to make the offshore supply chain competitive with the onshore supply chain, a 75% cost reduction for the electrolyser (i.e., LCOH excl. electricity costs, for both onshore and offshore electrolysis) is required. In this case, the lower electrolyser costs are less pressing on the total supply chain costs, and therefore, the impact of the transport costs and chain efficiency increases, which is in favour of the offshore value chain. In order to achieve 75% cost reduction, the LCOH should decrease towards 1.5 and 3.0 €/kg for onshore and offshore respectively. Note that this LCOH excludes the electricity costs. In terms of total LCOH including electricity costs, these would be ~0.5-1 €/kg lower than the costs observed in the 2030 optimistic scenarios for onshore and offshore electrolysis (section 0). This indicates that this level of cost reduction is not unthinkable. Nevertheless, a significant cost reduction in electrolysis costs is needed for the offshore electrolysis supply chain to outcompete (for certain distances to shore) the onshore electrolysis supply chain in levelized costs. An even further reduction is required to outcompete the onshore electrolysis supply chain for all distances to shore.

The graph on the right shows an alternative scenario to reach cost competitiveness for the offshore value chain. Our current results suggest that the offshore hydrogen LCOH is twice as expensive as the onshore LCOH (see Figure 28, left graph). For the offshore hydrogen value chain to become competitive to the onshore value chain, the offshore LCOH (excl. electricity costs) is allowed to only be 25% more expensive than the onshore LCOH. This means that a very significant cost reduction for offshore electrolysis is required, while the onshore electrolysis stays the same. In this case, the lower transport and generation would weigh up against the higher electrolysis costs in the offshore electrolysis chain.

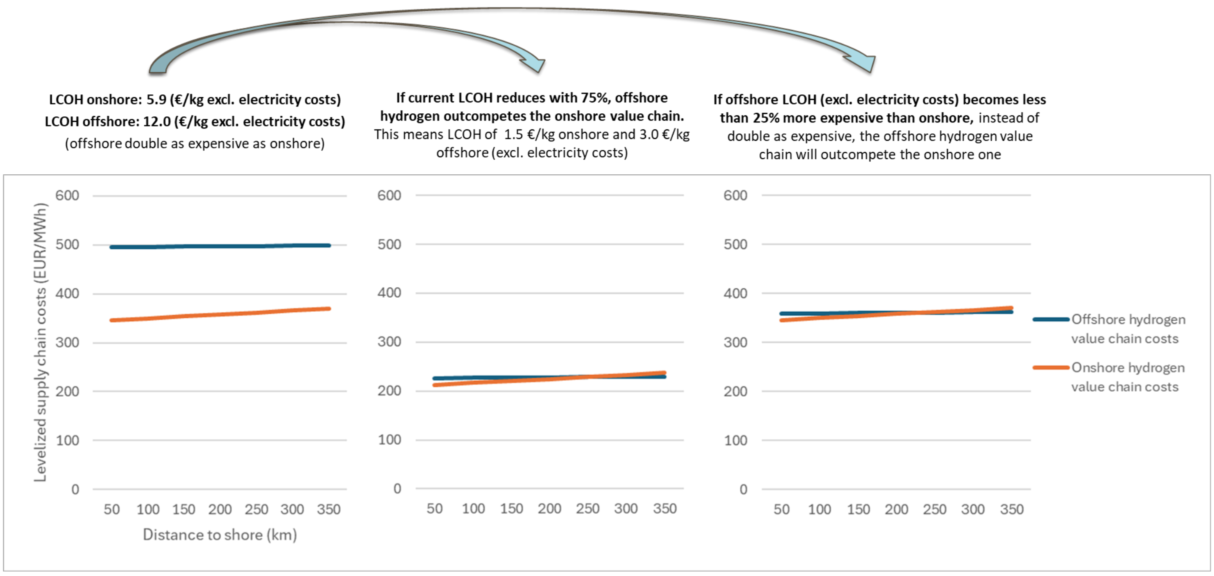

Figure 28: Cost reductions that are required to make the offshore hydrogen supply chain competitive.

In conclusion, while previous research indicated that the offshore supply chain can be cost-effective at certain scale and distance to shore, this research reaches a different conclusion: the onshore supply chain is favourable under all conditions evaluated. The significant increase in electrolyser CAPEX now dominates the total levelized costs of the supply chain while the transport costs have a relatively small impact on the levelized costs. If the electrolyser CAPEX were to decrease, the transport costs (which on itself are also recently projected higher than before [28]) are likely to become a more dominating factor again in the supply chain costs. These dynamics are important to realise and it is valuable to re-evaluate the onshore vs offshore value chain as it matures. However, it also should be noted that the supply chain cost perspective is just one. From a societal cost perspective it is still seen that partial offshore electrolysis makes sense despite its high costs [3], and other arguments might as well be considered assessing the offshore/onshore electrolysis location selection, such as scarcity of space, ecological considerations and supply chains for infrastructure development. In D3.4 a more holistic reflection is provided based on all the work done by WP in NSE 5 [1].

3.7.2 Offshore wind versus combined solar and wind supply chains

The comparison between offshore wind and combined offshore solar and wind supply chains resulted in lower levelized costs for the offshore wind value chain (Figure 29). Including offshore solar slightly increased the load factor of transport and electrolyser assets and therefore decreased their levelized costs. However, the levelized costs of offshore solar were 160 €/MWh higher than offshore wind, and therefore, significantly increased the costs of electricity generation. The benefits of the increased load factor do not outweigh the increased cost of offshore generation, and therefore, the chains relying solely on offshore wind results in lower costs. The supply chain can benefit from the addition of offshore solar if a significant reduction of the LCOE of offshore solar can be realised. If the levelized costs of offshore solar are less than 50 €/MWh higher than those of offshore wind, this would result in a decrease of the overall supply chain levelized costs.

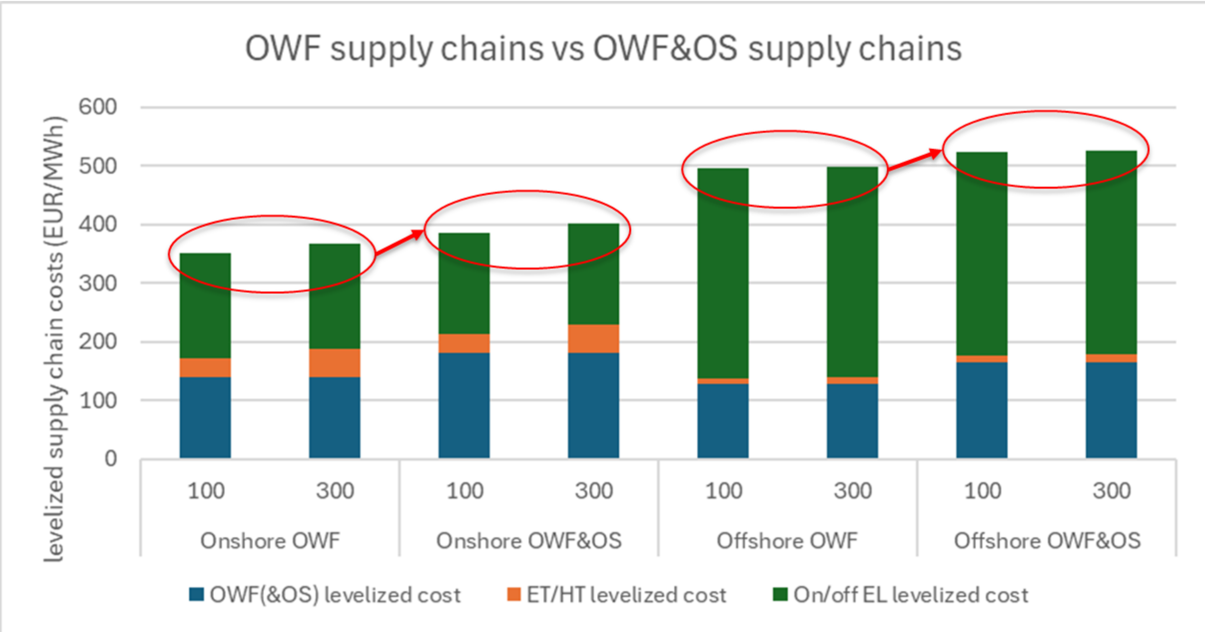

Figure 29: Supply chain levelized cost comparison for offshore wind and combined solar and wind supply chains (numbers on x-axis represent the distance to shore in km).

4 Conclusions

The aim of this report was to quantify business cases for the proposed business models in the offshore value chain in order to gain insights behind the causes of unprofitable gaps and the main cost drivers for every actor. Moreover, a supply chain cost comparison assessment has been performed to quantify (1) the difference in costs for onshore and offshore electrolysis supply chains (2) supply chains with offshore wind versus a combination of offshore solar and wind. The levelized costs, revenues and several business case KPIs have been calculated in order to obtain insights in the following aspects:

Offshore wind

The last 10 years of Dutch offshore wind developments can be seen as a great success. However, offshore wind and the Dutch electricity system are entering a new phase with an increasing risk of price cannibalization for longer periods in time. In this study, marginal cost based price results from dispatch modelling (D3.1) were used, based on the IO scenarios that reflect countries' ambitious renewable energy targets. These resulted in low capture prices (10-25 €/MWh by 2050) for offshore wind which significantly reduced the revenues, resulting in an unprofitable business case (LCOE of 79 €/MWh with unprofitable gap of 43 €/MWh). It should be acknowledged that future prices are inherently uncertain and unpredictable and forward electricity prices (which are inherently different from the marginal cost base price projections that we used) are higher than the price assumptions we used. However, it still indicates that there is a risk that offshore wind business case may not remain profitable without support in the coming decades, and that the impact of price cannibalization could be significant if no additional policy or market design measures will be implemented.

Onshore and offshore electrolysis

It is clear that both onshore and offshore electrolysis business cases have a large unprofitable gap to bridge (levelized cost range of 230-700 €/MWh by 2030, or: 7.8-23.1 €/kg. Base case of 394 €/MWh, or: 13.1 €/kg). Two third of the costs lie in the electrolyser CAPEX and electricity costs, but another significant share is compounded by the electrolyser stack replacement and electricity grid connection costs. On a business case level, the onshore electrolyser business case outcompetes the offshore alternative, because offshore electrolysers are more expensive and offer no significant cost advantages[10].

According to NSE3, offshore electrolysis can result in lower overall supply chain costs compared to onshore electrolysis when the production site is located more than 100 km offshore and operates at a large scale (over 4 GW), primarily due to reduced hydrogen transport costs [31]. However, in this study, the assumed CAPEX for offshore electrolysers is significantly higher. As a result, by the 2030 baseline scenario, the cost savings from cheaper transport via pipelines are not enough to offset the high offshore electrolyser costs. To make offshore hydrogen production more competitive, LCOH reductions of more than 75% for both onshore and offshore electrolysers are required.

[10] Note that this analysis only included offshore electrolysis on platforms. Other concepts such as in-turbine, near-turbine or island based offshore electrolysis have not been investigated.

While significant cost reductions are possible, they are not guaranteed. This study used the latest cost estimates from the WP1 technology assessment [32], which showed a wide range of projected levelized costs for offshore hydrogen production on platforms — from €250 to €700 per MWh — and relatively modest improvements over the coming decades (less than 10%). Additional savings of 12–15% could be achieved by using larger 500 MW platforms instead of 100 MW ones [33]. Avoiding a grid connection could reduce costs by another 10%, though this poses operational challenges related to maintaining the electrolyser's minimum load. Under optimistic assumptions and including high HWI[11] revenues of around €5 per kg, the offshore hydrogen business case could become profitable and even more cost-effective than the onshore alternative if the onshore alternative is deemed to pay tariffs for a larger electricity grid connection.

Combining offshore wind and offshore solar

Integrating offshore solar with offshore wind can increase the annual operating hours of electrolysers and electricity infrastructure by approximately 200 hours, and reduce the required energy storage volume by about 4%. While this offers some improvements to both the electrolyser and hydrogen transport business cases, the added value is limited when compared to the high additional costs of offshore solar. By 2030, the levelized cost of offshore solar (240 €/MWh) is projected to be €160/MWh higher than that of offshore wind. As a result, from both a project-level and supply chain perspective, the benefits of offshore solar for other actors in the chain do not justify the extra expense. However, if offshore solar costs could be reduced to within €50/MWh of offshore wind, the added benefits would begin to outweigh the costs. Whether such cost reductions are realistic was not assessed within the scope of this NSE program [34].

Hydrogen offtake

To assess the financial viability of hydrogen for industrial off-takers—without going into the specifics of their production processes—two types of users were considered: one using natural gas and the other using grey hydrogen, both planning to invest in new energy supply solutions. The green hydrogen option was compared against two alternatives: (1) natural gas combined with EU ETS permit certificate costs, and (2) blue hydrogen combined with HWI certificate costs, depending on the user type.

The analysis showed that HWI and fuel prices—particularly the price difference between natural gas and hydrogen—are the dominant factor influencing the business case. If the end-user that currently consumes grey hydrogen will purchase HWIs to cover 100% of their hydrogen consumption, energy supply costs would rise significantly (61 €/MWh). If they instead purchase only the amount of HWIs needed for regulatory compliance, the cost difference between self-producing blue hydrogen and purchasing hydrogen from the grid (based on IO scenario price projections) becomes small.

[11] In the Netherlands, a trading scheme 'Hernieuwbare Waterstofeenheden Industrie (HWI)' will be utilized to certify and promote the use of RFNBO hydrogen. The profits from trading HWI's are assumed to go fully the electrolyser operator.

For the end-user that currently consumes natural gas, but switches to hydrogen from the grid in combination with HWI certificates, the costs increase much more (122 €/MWh for compliance and 206 €/MWh for 100% HWI purchase) significantly because natural gas and EU ETS permits are much cheaper than the projected hydrogen and HWI certificate costs. Therefore, the switch from natural gas to (partly) green hydrogen is at this moment less attractive compared to the switch from grey hydrogen to (partly) green hydrogen.

It's important to note that the projected grid hydrogen price is much lower than the levelized cost of electrolysis. Therefore, to make green hydrogen financially viable, some form of compensation or value redistribution will be needed within the supply chain. Identifying end-users who are willing or able to pay higher green premiums is essential to supporting the business case.

Offshore energy transport

Levelized costs assessments for electricity and hydrogen transport have been performed for two types of cases: 1) connection of the 700 MW offshore windfarm (TNVDW) and the 500 MW electrolyser (DEMO-II) to shore and 2) the full 2050 network costs based on the NAT scenario hub design of WP1 [2]. For the future hydrogen network cost assessment, both a network option on solely new pipelines and a network option on partial reused pipelines have been taken into account. It should be noted that it was a high-over cost assessment based on generic parameters, and no location specific cost details or high level technical assessments, such as power-flow/pressure-drop calculations have been performed. Finally, it was mentioned by experts that due to recent cost increases the pessimistic cost assumptions might be closer to reality.

The utilization of transport infrastructure is key for the levelized transport costs, for both electricity and hydrogen. Therefore, utilizing cable connections only for peak generation moments and baseload requirements of the electrolyser results in relatively expensive electricity transport connections (29-75 €/MWh) compared to traditional connection costs. Moreover, of a future offshore electricity transport network significant investments of 57-117 B€ would be required and together with operational costs those lead to levelized costs of 22-57 €/MWh. It is important to align the electricity grid capacities with the locations of offshore electrolysers and stimulate its operational strategies in smart, innovative ways, to avoid underutilization of the network. Moreover, efficient routing of interconnectors can help to co-use certain cable sections. It is therefore important that the offshore electricity network, the offshore hydrogen network and offshore electrolyser locations are planned in alignment with each other. Only then electricity transport tariffs can be kept as modest as possible.

For the first-of-its-kind offshore hydrogen projects significant underutilization could be expected if the pipeline connection is scaled future proof, leading to levelized transport costs of 26-50 €/MWh (or: 0.9-1.7 €/kg). Due to the limited share of offshore hydrogen transport costs in a potential future network (6-11 €/MWh, or: 0.2-0.4 €/kg) compared with other costs in the hydrogen value chain (e.g. production being 150-600 €/MWh), it is likely that those relatively high connection costs of the first projects could be spread out over future users without hampering the future business cases. The main levelized cost reduction potential lies in the positioning (incl. structure) of compressors and their operational regime. Reuse of pipeline sections can reduce the capital costs, but the exact cost reductions and implications for compression and storage should be assessed in greater detail. It is likely that, if cost impact of new or reused pipelines turn out to be limited on the supply chain costs, that other factors, such as ecological impacts, availability and reliability of the network become more decisive reasons for choosing between solely new or partial reuse of pipelines in a potential Dutch offshore hydrogen network.

Offshore and onshore underground hydrogen storage

Levelized costs were assessed for hydrogen storage in salt caverns and depleted gas fields (DGF), under both seasonal and short-cycle operating regimes, and for both onshore and offshore configurations. The results show significant cost differences depending on the type of storage, location, and operational strategy.

For both seasonal and short-cycle storage applications, salt caverns consistently outperform depleted gas fields with 35-50% lower levelized costs thanks to simpler construction, better operational flexibility, and higher efficiency in cycling. In terms of levelized costs, short cycle storage can be performed at lower costs per unit than seasonal storage, because the throughput of hydrogen volumes can be significantly higher. Finally, location remains the most decisive cost factor, with offshore sites showing approximately 3-4 times higher costs than their onshore counterparts under the same technical conditions. Onshore seasonal and short cycle storage in salt caverns can be realized for 27 and 22 €/MWh respectively (or: 0.9 and 0.7 €/kg), while for offshore salt cavern storage levelized costs of 137 and 112 €/MWh were calculated (or: 4.6 and 3.7 €/kg).

Therefore, it is clear that offshore hydrogen storage will not be the most favorable from a business case perspective. It is likely that offshore hydrogen storage will only be performed if it is stimulated by political reasons, such as public acceptance, energy security and energy independence.

Overall conclusions

Business cases across offshore energy value chains are under increasing pressure. Without intervention, it is plausible that the traditional offshore wind sector may once again require financial support in the coming decade. For emerging offshore technologies—such as offshore hydrogen production and offshore solar—support was already anticipated. However, the projected business case outcomes for 2030 and beyond are now less optimistic than previously expected during the 2018–2022 period. This situation calls for deliberate action and thoughtful decision-making by relevant stakeholders. Accordingly, recommendations are outlined below.

Recommendations

Project developers:

- It is evident that the future offshore wind industry needs flexible electricity consumers. Electrolysers, despite its high costs, remain an essential part of the solution. The offshore and hydrogen industry should, more than ever, work together on realising cost reductions, proof-of-concept and innovations to scale up the required technologies. This involves:
    - Execution of collective research & development programs;
    - Preparation of mutual pilot projects, possibly in smaller ramping-up steps than projected before, but preferably not delayed in time;
    - Pilots should be carried out in collaboration with technology providers and finance institutions in order to guarantee proof-of-concept and reduce financing costs.
- If offshore electrolysers pay similar electricity grid tariffs as onshore electricity consumers, operating the offshore electrolyser off-grid can reduce costs12, but the minimum load factor of the electrolyser should be considered. Adding offshore solar remains too expensive for the near future.
- Collaboration between offshore wind, offshore electrolyser, electricity grid and hydrogen grid developers should take place to limit the connection costs to grids:
    - Offshore wind and electrolyser operators can share the offshore grid connection to limit their connection costs, however, issues on prioritization and regulation should be solved.
    - If offshore hydrogen compressors can be located on offshore electrolyser platforms or shared compression platforms, potentially costs can be reduced due to economies of scale in platform development.
- Electrolyser project developers should identify hydrogen off-takers with potentially high green premiums, even if this possibly means more vertical chain collaboration. Such as car manufacturers who can produce cars with green steel against slightly higher costs. Or airlines who can offer green flights to consumers who are willing to pay more for this.

Government:

- For the continuation of stable offshore wind development, a harmonized stimulation of (flexible) electricity demand is required. This can include, but is not limited to: demand response, batteries and electrolysers. It is required to harmonize the timelines of tenders and support schemes for those technologies and energy demand. Thereby, it should be noted that:
- Current government influence on electricity demand stimulation is limited;
- A fall-back support option, such as a minimum price guarantee or contract for difference, for offshore wind could be considered.
- Consider options for future supply-demand matchmaking in offshore wind and electrolysis tenders, such as a domestic H2Global-like mechanism in which (electricity

[12] However, it should be noted that this is probably not optimal from a societal value perspective, see D3.4 [1] for a more detailed explanation of these considerations.

and hydrogen) supply and demand side auctions are held next to each other and the price differences are minimized by an intermediary backed-up by the government.

- A differentiation in support for onshore and offshore electrolysis will be required to develop them both. Otherwise, offshore electrolysis technology development is likely to become stranded in the valley of death because onshore electrolysis is more cost-effective on a business case level.
- Reconsider the distribution of the electricity grid reinforcement costs, in a way in which system benefits are aligned with the individual business case optimal options, think of:
  - Electrolysers can be rewarded if they contribute to avoiding electricity grid reinforcements, taking into account system cost reductions if electrolysers are strategically located offshore (see results D3.1).
  - Offshore wind (and other renewables) are challenged to reduce their grid capacity needs (in contradiction to now, where the grid connection is offered for free), in order to avoid connections that are developed only utilized at peak generation moments.
- Offshore electricity grid, hydrogen grid, interconnection routes and electrolysis locations should be planned in alignment with each other to optimize the utilization of the infrastructure and thereby limit the transport costs.
- Governments around the North Sea can mutually provide clarity on future offshore electrolyser tendering capacities in order to provide long-term security for the development of an offshore electrolyser technology supply chain. Potentially, additional subsidies and support can be provided for EU-based manufacturing and technology development.
- Provide a vision on the desired future hydrogen (or: energy in general) storage requirements for the Netherlands, to what degree onshore underground storage is acceptable and as a result, in which degree offshore underground storage is needed despite its higher expected costs. If the conclusion is that offshore hydrogen storage is required:
  - Start developing a pilot program for offshore underground hydrogen storage;
  - Provide clarity in which reservoirs or salt structures hydrogen storage can be developed, and eventually consider compensation regimes if location decisions lead to stranded assets;
- Think about ownership and support models for offshore hydrogen storage (e.g., government investment in cushion gas as emergency buffer, and/or public involvement in the ownership and/or operation), taking into account the significant costs of offshore hydrogen storage that could hardly compete if sufficient onshore hydrogen storage capacity is available in neighbouring countries.

Research:

- Comparison of cost gaps for offshore electrolysis with the expected system value that it provides. This is done in NSE5 D3.4 [1].
- A detailed analysis is needed to investigate if there are future high renewable scenarios in which all the required individual business cases (e.g. offshore wind, electrolysers, energy storage, back-up generation) become economically feasible on the long term. And if this turns out to be not possible, provide suggestions on what structural measures should be taken in order to realise a renewable energy system with the lowest societal costs.

- Research in the policy mix and measures to harmonize supply-demand of offshore wind farms and electrolysers is needed.
- Detailed analysis in the potential cost reductions for offshore electrolysis and offshore solar. Including the impact of specific innovations and deployment speed. In order to make better projections of the (scenarios for) future technology cost developments.
- A thorough multi-criteria assessment of a solely new and partial repurposed Dutch offshore pipelines network is essential to make a well-grounded decision based on other factors than costs only. In order to get a better grasp on the cost advantages, a detailed assessment of conversion costs and compression and potential storage requirements might be desired as well.

5 References

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Appendix A: Cost Data

This section provides a detailed overview of the various cost data of assets used in the business case assessment. The associated cost data source for each asset is referenced under each section. Note that the costs are ordered in ‘high’, ‘medium’ and ‘low’. In order to calculate the business case results, the values are ordered in the right way in order to determine a ‘optimistic’, ‘base’ and ‘pessimistic’ case.

A.1 Offshore Windfarm

Table 7 indicates the cost data of offshore windfarm components utilized in the techno-economic analysis. Source of the data was based on the Offshore Windfarm factsheet provided by work package 1 (WP1) of the NSE5 research team [35].

Table 7: Offshore windfarm cost components.

Year	2030			2040			2050			
Case	High	Medium	Low	High	Medium	Low	High	Medium	Low	Unit
CAPEX - Rotor Nacelle assembly	16	12.3	9	16	13.8	9	16	13.8	9	M€/WT
Capex - Structure	10	8.3	6	13.19	10	6	13.19	10	6	M€/WT
CAPEX - electrical components[13]	1500	800	693	1500	800	693	1500	800	693	k€/MW
CAPEX - installation	245	200	100	211	200	100	211	200	100	k€/MW
CAPEX - project costs	313	200	100	314	200	100	314	200	100	k€/MW
OPEX	70	52	30	70	37	30	70	37	30	k€/MW /yr
ABEX/DECEX	211	160	80	196	160	80	196	160	80	k€/MW
Capacity Factor	58	58	58	58	58	58	58	58	58	%
Full Load Hours	5113	5113	5113	5113	5113	5113	5113	5113	5113	hours

[13] Refers to inter-array cabling costs not electricity transport cables to offshore.

Table 8 provides offshore windfarm electricity capture prices to the electricity market and via PPA. The ‘capture price sold via PPA’ is the price that is paid by the electrolyser to utilize the electricity. The remaining electricity is sold to the market via an electricity grid connection, which is represented by the ‘capture price electricity sold to market’. Revenues and volumes of electricity sold by the offshore windfarm and the volume of electricity purchased by the offshore electrolyser is also indicated.

Table 8: Key techno-economic performance indicators for 700 MW Offshore Windfarm (based on Ten-Noorden Van De Wadden Windfarm)

Year	2030			2040			2050			
Case	High	Medium	Low	High	Medium	Low	High	Medium	Low	Unit
Capture price electricity sold to market	26.6	23.6	20.9	20.9	16.6	13.9	21.1	15.8	7.8	€/MWh
Capture price sold via PPA	28.84	31.8	35.2	40.0	31.7	27.9	24.7	20.0	10.8	€/MWh
Revenues windfarm	121	109	98	132	105	92	86	69	37	M€/y
Electricity purchased by Offshore Electrolyser	3049	3049	3049	3049	3049	3049	3049	3049	3049	GWh
Total electricity sold by OWF	3579	3579	3579	3579	3579	3579	3579	3579	3579	GWh

A.2 Offshore Solar

Table 9 indicates the CAPEX and OPEX of offshore solar modules. Only cost data for 2030 is indicated since future values are too uncertain and no estimates could be made by WP1. Source of the data was based on the Offshore Solar factsheet provided by WP1 of the NSE5 research team [34].

Table 9: Offshore solar cost components.

Year		2030		
Case	High	Medium	Low	Unit
CAPEX	3	1.5	1	M€/MWp
OPEX	30000	22500	20000	€/MWp/yr
Module capacity	0.05	0.05	0.05	MW
Load Factor	11	11	11	%
Full Load Hours	1002.3	1002.3	1002.3	hours

A.3 Offshore electrolyser (100 MW)

Table 10 indicates the CAPEX and OPEX of a 100MW offshore electrolyser. The indicated CAPEX is significantly higher than in previous NSE studies due to the significant impact of inflation and risk premiums of technology providers, it turned out that these values were underestimated in literature from the previous years. Relatively modest decreases have been incorporated for future costs. There is also uncertainty behind the annual grid-connection costs for the future. Rising grid connection tariffs could be expected due to large electricity grid investments needed, but there has been chosen to stick to the existing grid tariffs seen in the *'SDE++ Basisbedragen'* study [36]. Table 11 indicates some important techno-economic characteristics while Table 12 indicates key techno-economic performance metrics such as the share of the electricity purchased by the electrolyser, electricity and hydrogen capture prices, energy content of hydrogen sold, volumes of electricity sold.

Source of the data was based on the offshore electrolyser factsheet provided by WP1 of the NSE5 research team [32].

Table 10: 100MW offshore PEM electrolyser cost components.

Year	2030			2040			2050			
Case	High	Medium	Low	High	Medium	Low	High	Medium	Low	Unit
CAPEX Total [14]	7299	4178	2493	6836	3910	2348	6836	3910	2348	€/MW
OPEX Total	484	311	86	436	233	52	436	233	52	€/MW /yr
Stack replacement costs	1500	810	450	1390	752	421	1390	752	421	€/MW
ABEX/DECEX[15]	2	2	2	2	2	2	2	2	2	%
Annual costs of electricity grid connections	144.3	144.3	144.3	144.3	144.3	144.3	144.3	144.3	144.3	€/kW
Loan percentage of Electrolyser	50	50	50	50	50	50	50	50	50	%

Table 11: Key techno-economic assumptions for a 100MW Offshore PEM Electrolyzer.

Techno-economic parameters	Value pessimistic	Value medium	Value optimistic	Unit
Electrolyser efficiency	68	68	68	%
Stack replacement	5	5	5	years
Full Load Hour of Electrolyser	6097	6097	6097	Hours

[14] Consists of electrolyser, balance of plant, compressor, indirect and owner costs.
[15] Refers to electrolyser decommissioning – 2% of CAPEX.

Table 12: Key techno-economic indicators for 100MW offshore PEM electrolyzer.

year	2030			2040			2050			
Case	High	Medium	Low	High	Medium	Low	High	Medium	Low	Unit
Share of electricity purchased by electrolyser	98	98	98	98	98	98	98	98	98	%
Capture price of total electricity purchased by offshore electrolyser	38.1	33.9	30.7	49.4	39.1	34.6	24.9	20.2	11.0	€/MWh
Hydrogen sold by Offshore Electrolyser	1824	1824	1824	1824	1824	1824	1824	1824	1824	GWh
Electricity purchased by Offshore Electrolyser	3049	3049	3049	3049	3049	3049	3049	3049	3049	GWh
Capture price H2 produced by Offshore Electrolyser	64.1	63.0	62.8	67.7	66.8	65.6	46.1	43.0	26.8	€/MWh
Margin electrolyser	22.1	12.8	2.1	14.4	3.2	-26.4	17.6	16.1	9.1	M€/y

A.4 Offshore electrolyser (500 MW)

Table 13 indicates the CAPEX and OPEX of a 500MW offshore electrolyser. Source of the data was based on the offshore electrolyser factsheet provided by WP1 of the NSE5 research team [33]. No 500 MW units are expected pre-2040, so the costs estimations provided by the factsheet started from 2040. For the sake of comparison with 100MW electrolysers in 2030, we assumed the costs in 2030 to be the same as for 2040.

Table 13: 500MW offshore PEM electrolyser cost components.

Year	2030			2040			2050			
Case	High	Medium	Low	High	Medium	Low	High	Medium	Low	Unit
CAPEX Total [16]	6200	3534	2119	6200	3534	2119	6200	3534	2119	€/MW
OPEX Total	339	187	43	339	187	43	339	187	43	€/MW/yr
Stack replacement costs	1092	585	333	1092	585	333	1092	585	333	€/MW
ABEX/DECEX[17]	2	2	2	2	2	2	2	2	2	%
Annual costs of electricity grid connections	144.3	144.3	144.3	144.3	144.3	144.3	144.3	144.3	144.3	€/kW
Loan percentage of Electrolyser	50	50	50	50	50	50	50	50	50	%

[16] Consists of electrolyser, balance of plant, compressor, indirect and owner costs.
[17] Refers to electrolyser decommissioning – 2% of CAPEX.

A.5 Onshore electrolyser (100 MW)

Table 14 indicates the CAPEX and OPEX of a 100MW onshore electrolyser. The source of the data is from the RHyCEET (Renewable Hydrogen Cost Element Evaluation Tool) study (Eblé & Weeda, 2024).

Table 14: 100MW onshore electrolyser cost components.

Year	2030			2040			2050			
Case	High	Medium	Low	High	Medium	Low	High	Medium	Low	Unit
CAPEX Total	2792.24	2531.5	1751.8	2233.8	2025.2	1401.4	2233.8	2025.2	1328	€/kW
OPEX Total	93.57	75.34	52.28	74.86	60.27	42.07	74.86	60.27	42.07	€/kW/yr
Stack replacement	418.8	379.7	262.8	335.1	303.8	210.2	335.1	303.8	199.2	€/kW
Decommissioning[18]	2	2	2	2	2	2	2	2	2	%
Annual costs of electricity grid connections	144.3	144.3	144.3	144.3	144.3	144.3	144.3	144.3	144.3	€/kW
Loan percentage of Electrolyser	50	50	50	50	50	50	50	50	50	%

[18] Refers to electrolyser decommissioning – 2% of CAPEX.

A.6 Onshore off-taker (Grey Hydrogen)

Table 15 indicates techno-economic parameters for the grey hydrogen off-taker, and Table 16 displays the relevant price input data. Source of the techno-economic data is from a HyDelta factsheet [11]. Source of the price input data is based on the outcomes of the system analysis, see also chapter 2.2 or D3.1 for more details. It should be noted that the electricity price trends for 2030, 2040, and 2050 are modelled based on different scenarios in which a fast and sharp deployment of renewables is considered, and therefore are merely an indication of what the prices could become if such progressive pathways would be followed, rather than precise expectations for each year. The HWI price is from the CE Delft report *'Toetsing beleidsontwikkelingen waterstof'* [37]. The EU ETS permit price is from Enerdata [38]. Figure 30 provides a general explanation of the foreseen Dutch hydrogen offtake mandate, which principles are followed in the business case in this research.

Table 15: Techno-economic parameters of a grey hydrogen off-taker with the option of switching to either hydrogen from the grid in combination with HWI certificates, or blue hydrogen from an ATR + CCS unit.

Techno-economic parameters	Pessimistic	Medium	Optimistic	Unit
CAPEX of ATR unit	1201	1300	1400	€/kW
Fixed OPEX	3	3	5	% of CAPEX
Specific natural gas consumption	1.18	1.202	1.202	MJ-NG/MJ-H2
Specific electricity consumption	0.011	0.014	0.014	kWh/MJ-H2
Electricity Tax	1.88	1.88	1.88	€/MWh

Table 16: Price input data for the onshore off-taker that currently used grey hydrogen.

Year	2030			2040			2050			
Case	Pes.	Base	Opt.	Pes.	Base	Opt.	Pes.	Base	Opt.	Unit
Average electricity price	47.14	51.70	61.09	96.80	108.25	141.76	14.04	24.15	28.55	€/MWh
Average Hydrogen price	64.83	63.71	63.44	68.04	67.02	65.64	46.59	43.43	27.23	€/MWh
Contracted price of natural gas	34.26	34.28	34.31	33.65	33.65	33.66	32.12	32.56	33.05	€/MWh
Hydrogen certificates (HWI)	5.20	5.16	5.12	5.20	5.16	5.12	5.20	5.16	5.12	€/kg
EU ETS permits	87	87	87	130	130	130	500	500	500	€/ton
Natural gas tax	0.05	0.05	0.06	0.05	0.05	0.06	0.05	0.05	0.06	€/m^3

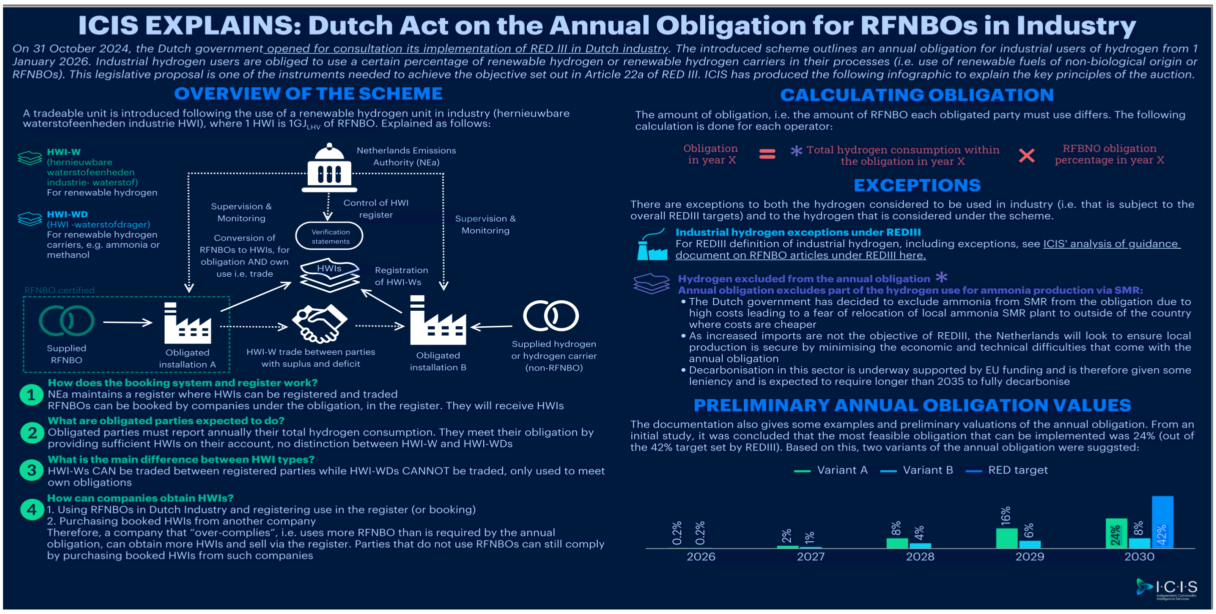


Figure 30: General explanation of the Dutch annual hydrogen offtake obligation for industry [39].

A.7 Onshore off-taker (Natural Gas)

Table 17 indicates the CAPEX and OPEX parameters for the natural gas off-taker utilizing a natural gas boiler with an option to switch to a hydrogen boiler running on (partly) green hydrogen from the grid. The off-taker has a nominal natural gas consumption capacity of 24.9MW. Source of the techno-economic data is based on data from the 'MIDDEN' study from PBL and is corrected for inflation [12]. The price input data used in this business case is equal to that of the grey hydrogen off-taker business case (Table 16).

Table 17: Techno-economic parameters of a natural gas off-taker with the option of switching to a hydrogen boiler.

Techno-economic parameters	Pessimistic	Base	Optimistic	Unit
CAPEX of NG boiler	0.069	0.069	0.069	M€/MWth
Fixed OPEX NG boiler	0.0021	0.0028	0.0035	M€/MWth
CAPEX of H_2 boiler	0.152	0.152	0.152	M€/MWth
OPEX of H_2 boiler	0.0048	0.0048	0.0048	M€/MWth/yr
Electricity Tax	1.88	1.88	1.88	€/MWh

A.8 Underground Hydrogen Storage (Salt Cavern-Short Cycle)

Table 18 - Table 22 provides cost details for underground hydrogen storage based on salt caverns. The values behind each cost component are based on formula's outlined in the Hystories study [15]. For more details with regards to the calculations refer to the report. Costs are highly dependent on the number of wells/caverns. The values below reflect costs for a 12-cavern system with a total working volume of ≈ 335mln Sm^3 / 1TWh (also see section 3.6). Cavern height is 100m and the cavern diameter is 65m with a working volume per cavern of 27.9 mln m^3 and a cushion volume per cavern of 18.6 mln m^3. The duration of one full-cycle operation is approximately 12 days which is equivalent to about 31.5 cycles per year.

Due to the long development times of offshore underground hydrogen storage facilities in salt caverns, it is expected that solely private financing is almost impossible. Even if public financing will be applied, higher contingency factors and/or interest rates might be applicable than the generic ones that this report uses.

Table 18: Subsurface CAPEX components for short cycle underground hydrogen storage in a salt cavern.

Subsurface CAPEX components	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Drilling and leaching completion	100,602	67,068	46947.6	k€
Leaching plant	160,500	107,000	74,900	k€
Leaching operation and maintenance costs	170,683.5	113,789	79,652.3	k€
Salt cavern conversion cost – Debrining & first gas fill	74,209.5	49,473	34,631.1	k€
Cushion gas	64,219.5	42,813	29,969.1	k€
Contingency	114,043.5	76,029	53,220.3	k€

Table 19: Surface CAPEX components for short cycle underground hydrogen storage in a salt cavern.

Surface CAPEX components	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Filtering, drying & compression, and metering units	2,337,912	1,558,608	1,091,025.6	k€
Wellpad & downstream equipment and piping	266,484	177,656	124,359.2	k€
Interconnection between Wellheads and Gas Plant	190348.5	126,899	88,829.3	k€
Hydrogen purification	0	0	0	k€
Balance of Plant	151,737	101,158	70,810.6	k€
Contingency	589,296	392,864	275,004.8	k€

Table 20: Subsurface OPEX costs for short cycle underground hydrogen storage in a salt cavern.

Subsurface OPEX	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Fixed costs related to subsurface activities	3018	2,012	1408.4	k€

Table 21: Surface OPEX costs for short cycle underground hydrogen storage in a salt cavern.

Surface OPEX	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Fixed costs related to H2 Gas Plant	121,009.5	80,673	56,471.1	k€
Variable surface facility cost	96,763.5	64,509	45,156.3	k€

Table 22: ABEX costs for short cycle underground hydrogen storage in a salt cavern.

ABEX	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Subsurface ABEX[19]	124,008	82,672	57,870.4	k€
Surface ABEX[20]	707,155.5	471,437	330,005.9	k€

[19] 20% of CAPEX
[20] 20% of CAPEX

A.9 Underground Hydrogen Storage (Salt Cavern-Seasonal Cycle)

Table 23 - Table 27 provides cost details for underground hydrogen storage based on salt caverns operating on a seasonal cycle. Cavern characteristics are exactly the same as the short-cycle version except that the duration of one full-cycle operation is approximately 100 days which is equivalent to about 3.5 full cycles per year.

Table 23: Subsurface CAPEX components for a seasonal cycle underground hydrogen storage in a salt cavern.

Subsurface CAPEX components	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Drilling and leaching completion	100,602	67,068	46947.6	k€
Leaching plant	160,500	107,000	74900	k€
Leaching operation and maintenance costs	427,596	285,064	199544.8	k€
Salt cavern conversion cost – Debrining & first gas fill	118,294.5	78,863	55,204.1	k€
Cushion gas	248,658	165,772	116,040.4	k€
Contingency	211,129.5	140,753	98,527.1	k€

Table 24: Surface CAPEX components for seasonal cycle underground hydrogen storage in a salt cavern.

Surface CAPEX components	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Filtering, drying & compression, and metering units	813,474	542,316	379,621.2	k€
Wellpad & downstream equipment and piping	135,909	90,606	63,424.2	k€
Interconnection between Wellheads and Gas Plant	81,007.5	54,005	37,803.5	k€
Hydrogen purification	0	0	0	k€
Balance of Plant	63,519	42,346	29642.2	k€
Contingency	218,782.5	145,855	102,098.5	k€

Table 25: Subsurface OPEX costs for seasonal cycle underground hydrogen storage in a salt cavern.

Subsurface OPEX	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Fixed costs related to subsurface activities	3,018	2,012	1408.4	k€

Table 26: Surface OPEX costs for seasonal cycle underground hydrogen storage in a salt cavern.

Surface OPEX	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Fixed costs related to H2 Gas Plant	46,906.5	31,271	21,889.7	k€
Variable surface facility cost	40,410	26,940	18,858	k€

Table 27: ABEX costs for seasonal cycle underground hydrogen storage in a depleted gas field.

ABEX	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Subsurface ABEX[21]	203,625	135,750	95,025	k€
Surface ABEX[22]	262537.5	175,025	122,517.5	k€

[21] 20% of CAPEX
[22] 20% of CAPEX

A.10 Underground Hydrogen Storage (Depleted Gas Field-Short Cycle)

Table 28 - Table 32 provides cost details for underground hydrogen storage based on depleted gas fields. The values behind each cost component are based on formula's outlined in the Hystories study [15]. For more details with regards to the calculations refer to the report. Based on the screening in D1.1 it was seen that the number of wells per DGF significantly differs per geological location (2-11 wells per DGF). The values below reflect costs for a depleted gas field with 5 development wells and 1 observation well and a working volume of ≈ 335mln Sm^3 / 1TWh. Cushion gas volume is 570 mln Sm^3. The duration of one full-cycle operation is 11.6 days which is 31.4 times per year.

Table 28: Subsurface CAPEX components for short cycle underground hydrogen storage in a depleted gas field.

Subsurface CAPEX components	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Development drilling costs	222,552	148,368	103,857.6	k€
First gas fill of porous media	3,477	2,318	1622.6	k€
Cushion gas	163,416	108,944	76,260.8	k€
Contingency	77,889	51,926	36,348.2	k€

Table 29: Surface CAPEX components for short cycle underground hydrogen storage in a depleted gas field.

Surface CAPEX components	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Filtering, drying & compression, and metering units	2,789,077.5	1,859,385	1,301,569.5	k€
Wellpad & downstream equipment and piping	238,149	158,766	111,136.2	k€
Interconnection between Wellheads and Gas Plant	166,621.5	111,081	77,756.7	k€
Hydrogen purification	1,333,048.5	888,699	622,089.3	k€
Balance of Plant	238,345.5	158,897	111,227.9	k€
Contingency	953,049	774,234	444,756.2	k€

Table 30: Subsurface OPEX costs for short cycle underground hydrogen storage in a depleted gas field.

Subsurface OPEX	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Fixed costs related to subsurface activities	6676.5	4,451	3115.7	k€

Table 31: Surface OPEX costs for short cycle underground hydrogen storage in a depleted gas field.

Surface OPEX	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Fixed costs related to H2 Gas Plant	193,759.5	129,173	90,421.1	k€
Variable surface facility cost	191,142	127,608	89,325.6	k€

Table 32: ABEX costs for short cycle underground hydrogen storage in a depleted gas field.

ABEX	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Subsurface ABEX[23]	60,873	40,522	28,365.4	k€
Surface ABEX	1,143,658.5	762,439	533,707.3	k€

[23] 20% of CAPEX

A.11 Underground Hydrogen Storage (Depleted Gas Field – Seasonal Cycle)

Table 33 - Table 37 provides cost details for underground hydrogen storage based on depleted gas fields operating on a seasonal cycle. Reservoir characteristics are exactly the same as the short-cycle version except that the duration of one full-cycle operation is approximately 100 days which is equivalent to about 3.5 full cycles per year.

Table 33: Subsurface CAPEX components for seasonal cycle underground hydrogen storage in a depleted gas field.

Subsurface CAPEX components	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Drilling and leaching completion	92,730	61,820	43,274	k€
Leaching plant	5410.5	3,607	2524.9	k€
Cushion gas	448,804.5	299,203	209,442.1	k€
Contingency	109,389	72,926	51,048.2	k€

Table 34: Surface CAPEX components for seasonal cycle underground hydrogen storage in a depleted gas field.

Surface CAPEX components	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Filtering, drying & compression, and metering units	954,570	636,380	445,466	k€
Wellpad & downstream equipment and piping	51,709.5	34,473	24131.1	k€
Interconnection between Wellheads and Gas Plant	71,121	47,414	33,189.8	k€
Hydrogen purification	754,585.5	503,057	352,139.9	k€
Balance of Plant	103,599	69,066	48,346.2	k€
Contingency	387,114	258,076	180,653.2	k€

Table 35: Subsurface OPEX costs for seasonal cycle underground hydrogen storage in a depleted gas field.

Subsurface OPEX	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Fixed costs related to subsurface activities	2782.5	1,855	1298.5	k€

Table 36: Surface OPEX costs for seasonal cycle underground hydrogen storage in a depleted gas field.

Surface OPEX	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Fixed costs related to H2 Gas Plant	80,574	53,716	37,601.2	k€
Variable surface facility cost	79,837.5	53,225	37,257.5	k€

Table 37: ABEX costs for seasonal cycle underground hydrogen storage in a depleted gas field.

ABEX	Value pessimistic (+50%)	Value medium	Value optimistic (-30%)	Unit
Subsurface ABEX[24]	41,505	27,670	19,369	k€
Surface ABEX[25]	464,541	309,694	216,785.8	k€

[24] 20% of CAPEX
[25] 20% of CAPEX

A.12 Electricity Transport (Offshore)

Table 38 provides cost details with regard to the infrastructural components of electricity transport based on direct current (DC) systems. DC platform costs represent the jacket or foundation, the topside (main deck and structural steel), accommodation, access, helidecks etc. DC substation refers to electrical equipment such as converters, switchgear, transformers, filters, cooling and protection systems. Topside DC adjustment is a cost correction adjustment for extra topside weight margin or reinforcement due to unexpected equipment needs, interface engineering costs between platform and substation vendor, late design changes, vendor-specific uplifts (e.g., if the supplier of the DC substation equipment requested more topside space or weight-bearing), contingency or risk buffer for DC system integration challenges. Essentially this cost category is needed to reflect since DC substations are custom built, with significant design variability depending on vendor and transmission specs. AC substations/platforms on the other hand are more standardized, hence less risk of mismatch or last-minute integration cost with no need for an “adjustment”.

The source of this data is based on the NSWPH Databook (North Sea Wind Power Hub Datasets, 2023). This source does not differentiate costs between unilateral cables and potential bidirectional cables.

Table 38: Cost components of electricity transport based on DC systems.

Year	2030			2040			2050			
Case	High	Medium	Low	High	Medium	Low	High	Medium	Low	Unit
CAPEX – DC Platform	0.528	0.264	0.264	0.512	0.256	0.256	0.498	0.249	0.249	M€/MW
CAPEX – DC Substation	0.528	0.264	0.264	0.512	0.256	0.256	0.498	0.249	0.249	M€/MW
CAPEX – DC Topside Adjustment	0.094	0.047	0.047	0.092	0.046	0.046	0.09	0.045	0.045	M€/MW
CAPEX – DC Cables	4.218	2.109	2.109	4.092	2.046	2.046	3.978	1.989	1.989	M€/MW
OPEX – Per component	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	% of CAPEX

A.13 Hydrogen Transport

Table 39 provides cost details with regard to hydrogen transport components which consist of new and re-used pipelines and compressors. The source of the pipeline data is based on the NSWPH Databook (North Sea Wind Power Hub Datasets, 2023) and the compressor data is based on the NSE5 compression factsheet of WP1.

Table 39: Cost components of hydrogen transport.

Year	2030			2040			2050			
Case	High	Medium	Low	High	Medium	Low	High	Medium	Low	Unit
CAPEX – New Pipeline	886	443	443	860	430	430	836	418	418	€/MWth LHV/km
CAPEX – New Compressor	1789	1789	1789	1789	1789	1789	1789	1789	1789	k€/MWe
CAPEX – Reused Pipeline	20	20	20	20	20	20	20	20	20	% of CAPEX
OPEX - transport	10.67	10.67	10.67	10.67	10.67	10.67	9.7	9.7	9.7	€/MWth LHV/km/year
OPEX – compression	5	5	5	5	5	5	5	5	5	% of CAPEX

Appendix B: Impact Trend-Reflective scenarios

The main difference between the explorative scenarios based on the IO scenarios (TYNDP and II3050) and the Trend-Reflective scenarios, is that the Trend-Reflective scenarios were adjusted based on an interaction between the OPERA and I-ELGAS model results (see D3.1 for more details). Therefore, the Trend-Reflective scenarios should be adjusted towards a more realistic roll out of renewable energy. Three Trend-Reflective scenarios are considered: ADAPT, TRANSFORM and LCI. For the details about scenarios we refer to D3.1. The main conclusion of this appendix is that, considering this scenarios rather than the IO scenarios, would not lead to significantly different outcomes and conclusions.

Figure 31 shows that the offshore windfarm business case results based on Trend-Reflective scenario prices do barely differ from the main results presented in this study (<5% difference in costs/revenues). The electricity capture prices are higher in 2030 (~60 €/MWh compared to ~30 €/MWh), but are lower in the next decades (~5-20 €/MWh compared to ~20-35 €/MWh). Overall, the revenues of the Trend-Reflective scenario are slightly lower than in the results based on the IO scenario prices.

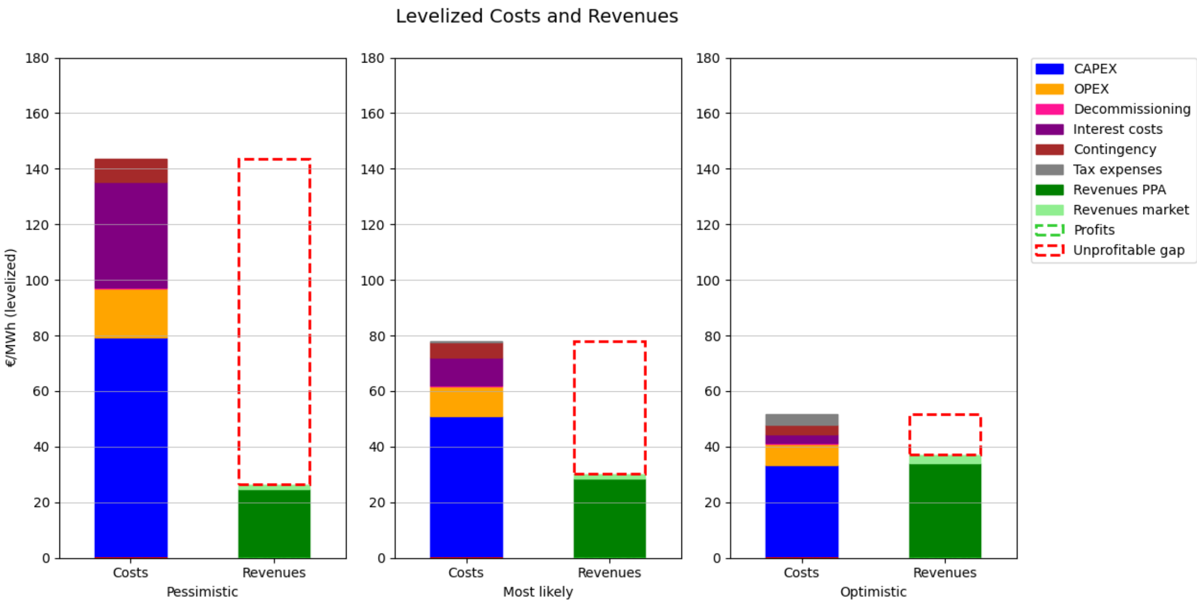


Figure 31: Levelized costs and revenues results for OWF based on Trend-Reflective price scenarios.

Figure 32 shows that the levelized cost results of the offshore electrolyser do not visually differ from the results based on the IO scenarios. The revenues of the Trend-Reflective scenarios are in 2030 30 €/MWh higher than in the IO scenarios, but do not differ significantly in the next decades.. However, the price for purchasing electricity is also higher at the start of the 2030s, than in the results based on the IO scenarios.

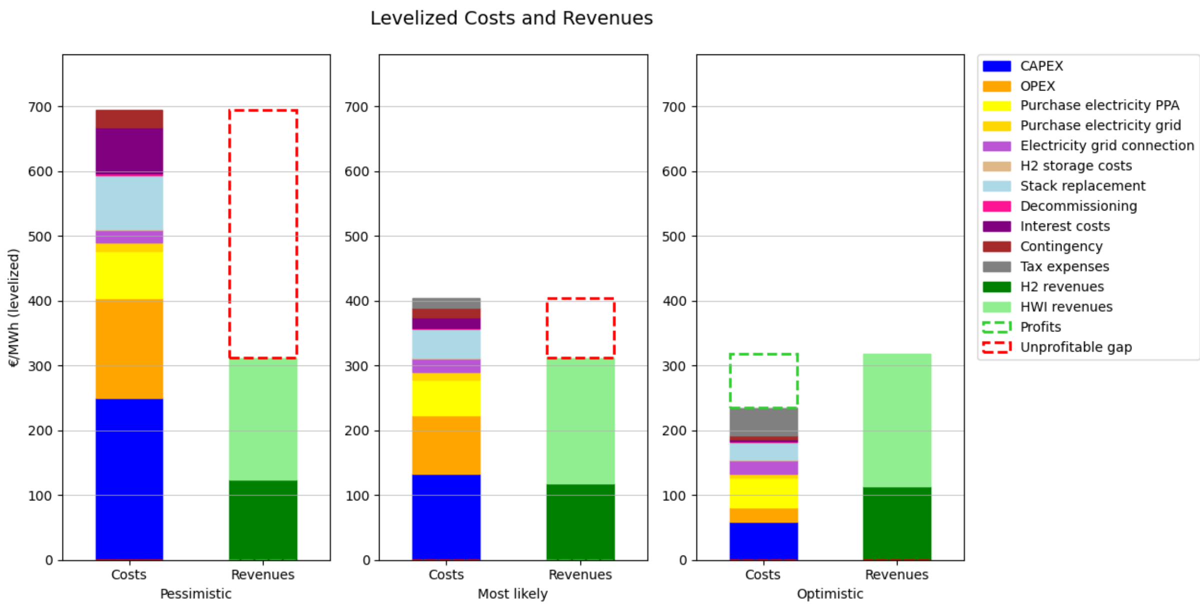


Figure 32: Levelized costs and revenues for offshore 5x100MW electrolyser wind-following.

If the electrolysers operational mode is determined by market prices (market-following) instead of the offshore wind production profile (wind-following), its operational output does not differ significantly compared to the wind-following approach. Under the market-following approach, the load factor and margins of the electrolyser are slightly higher in the early 2030's, compared to the wind-following approach. For the remaining decades, slightly lower values are observed. Therefore, overall the revenues are slightly lower compared to the wind-following approach, but remain within a 5-10% difference (see Figure 33).

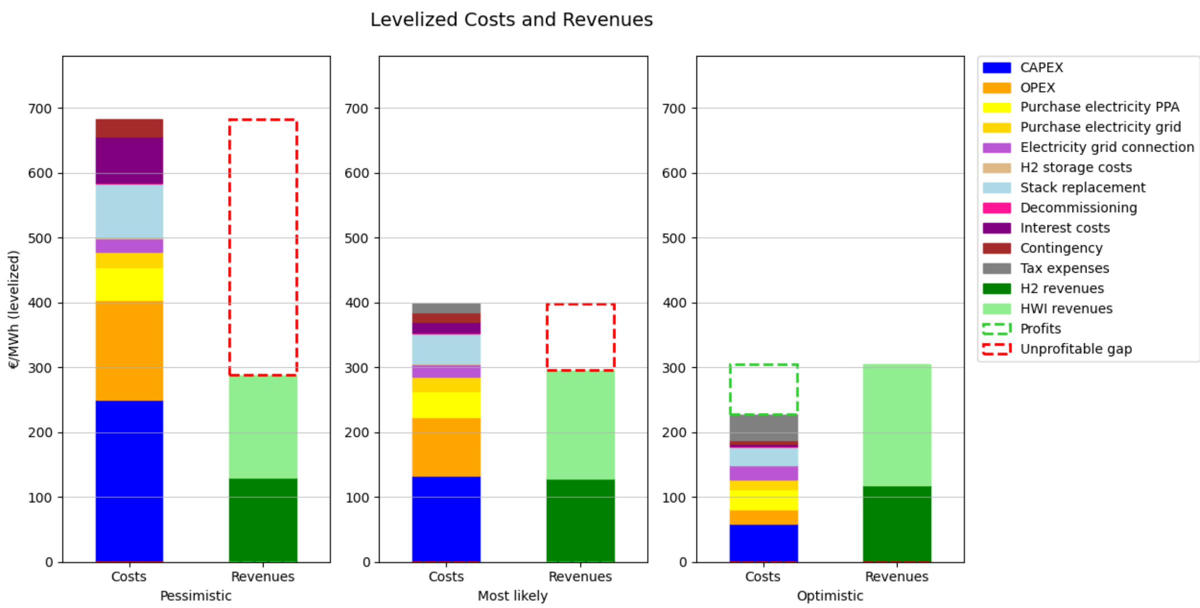
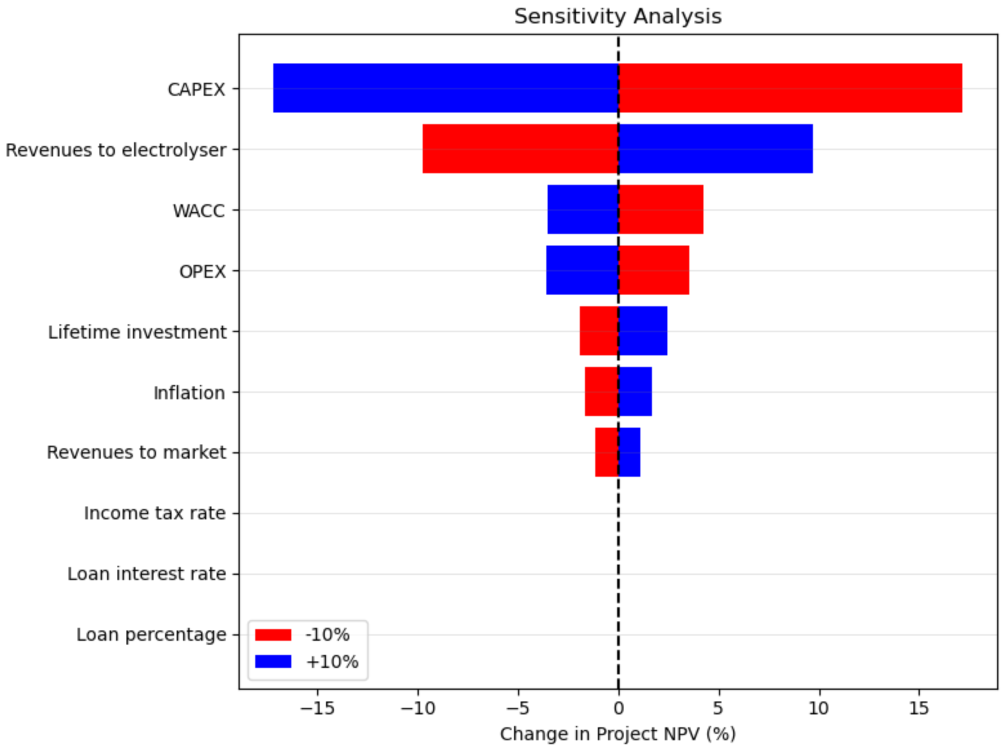
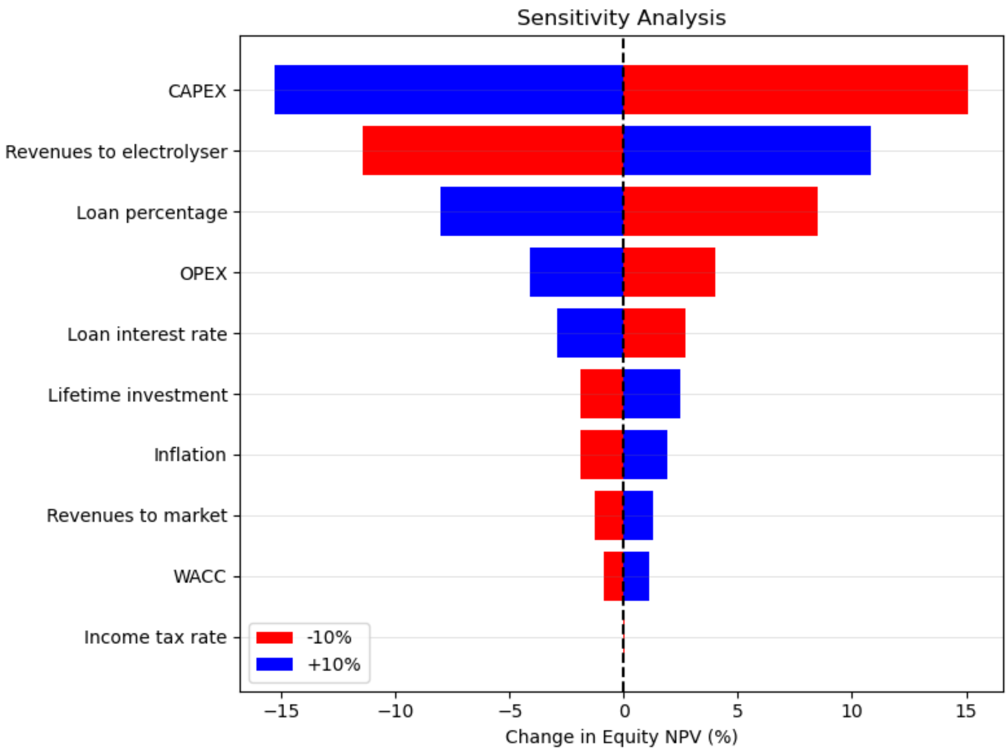


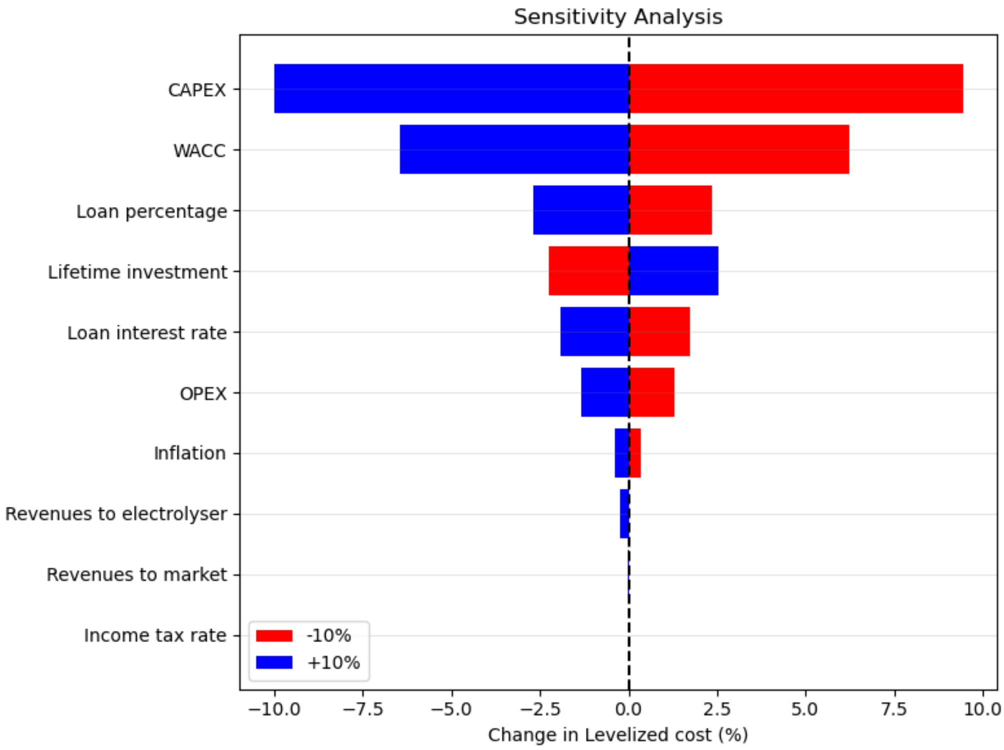
Figure 33: Levelized costs and revenues for offshore 5x100MW electrolyser market-following.

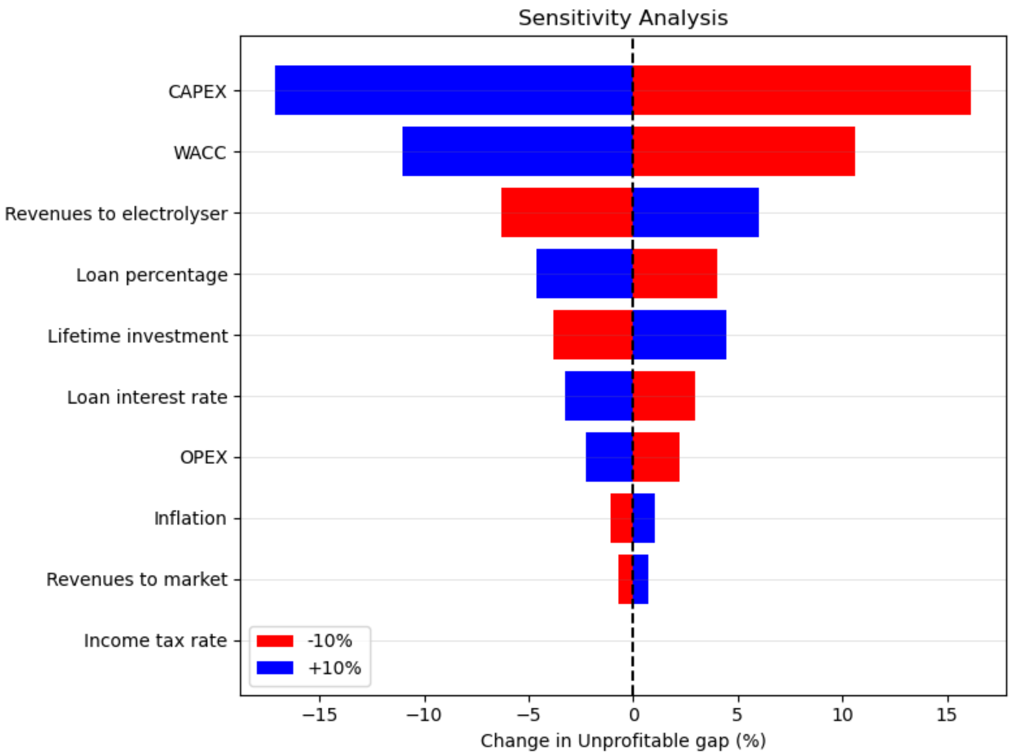
Appendix C: Sensitivity analysis figures

C.1 Offshore Windfarm

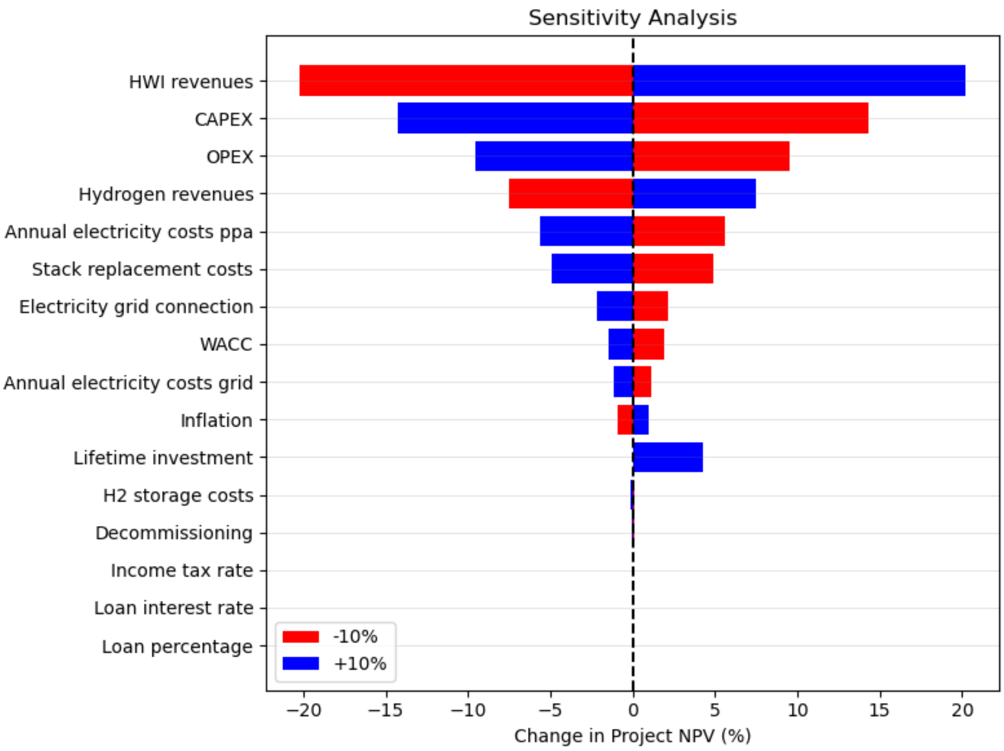


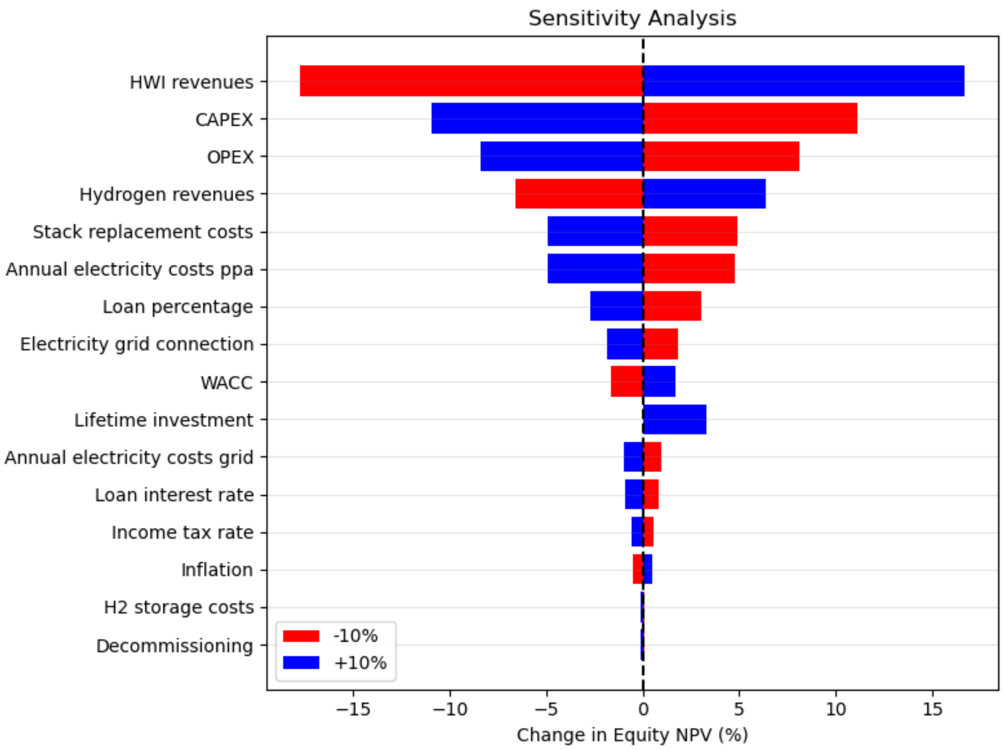


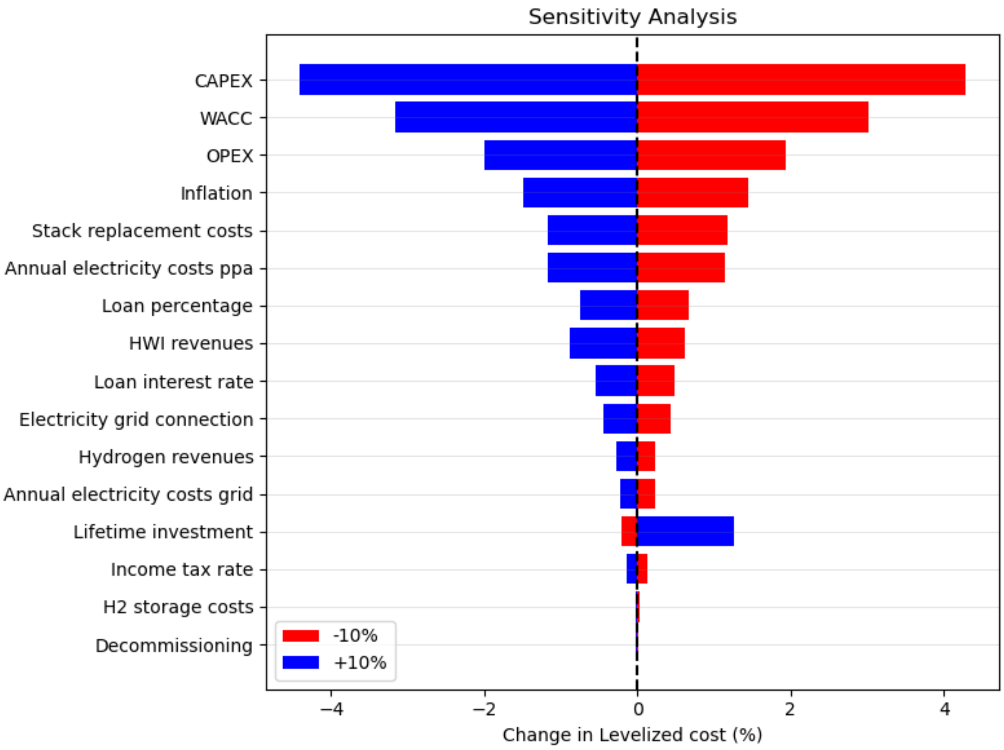

Sensitivity Analysis
CAPEX
WACC
Loan percentage
Lifetime investment
Loan interest rate
OPEX
Inflation
Revenues to electrolyser
Revenues to market
Income tax rate
-10%
+10%
−10.0
−7.5
−5.0
−2.5
0.0
2.5
5.0
7.5
10.0
Change in Levelized cost (%)

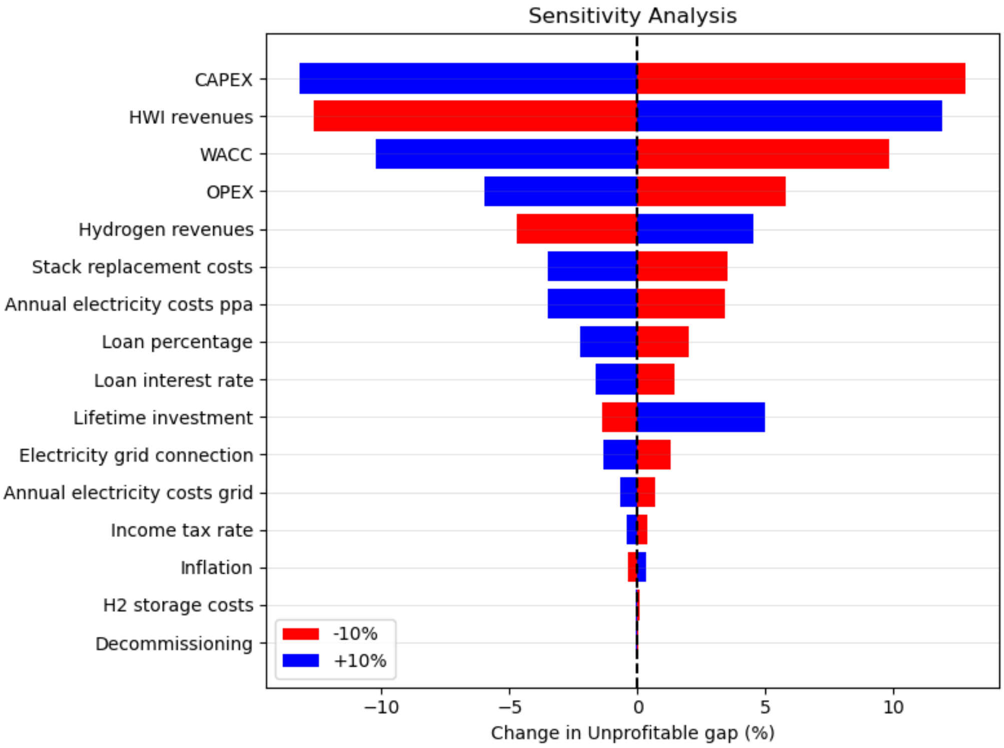

Sensitivity Analysis
CAPEX
WACC
Revenues to electrolyser
Loan percentage
Lifetime investment
Loan interest rate
OPEX
Inflation
Revenues to market
Income tax rate
-10%
+10%
−15
−10
−5
0
5
10
15
Change in Unprofitable gap (%)

C.2 Offshore electrolyser (100 MW)

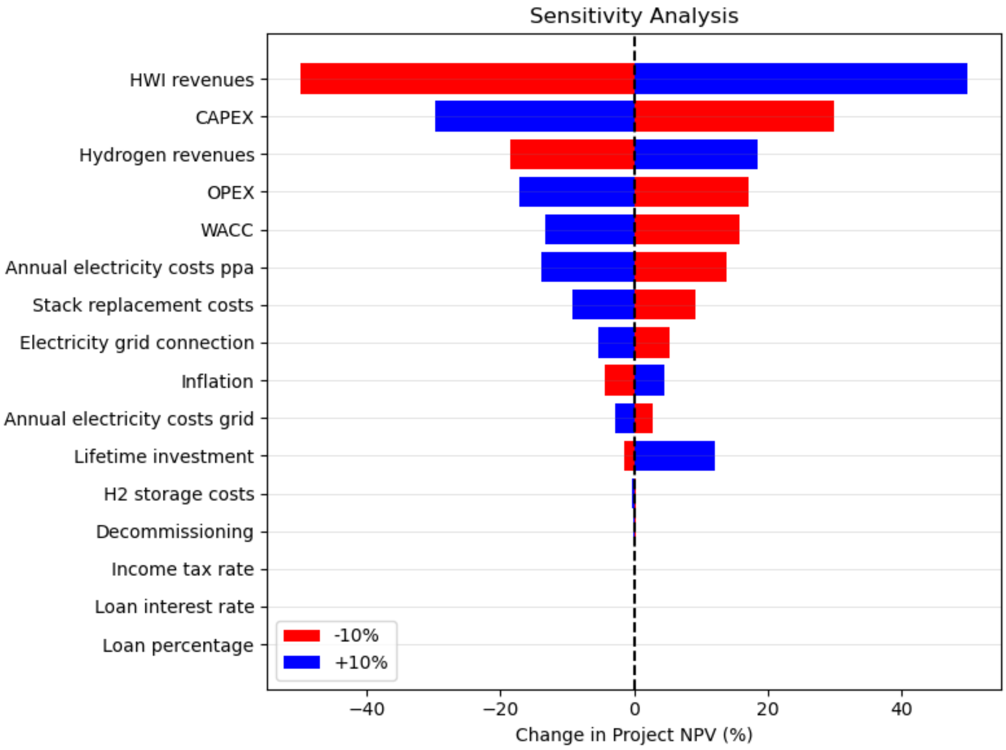


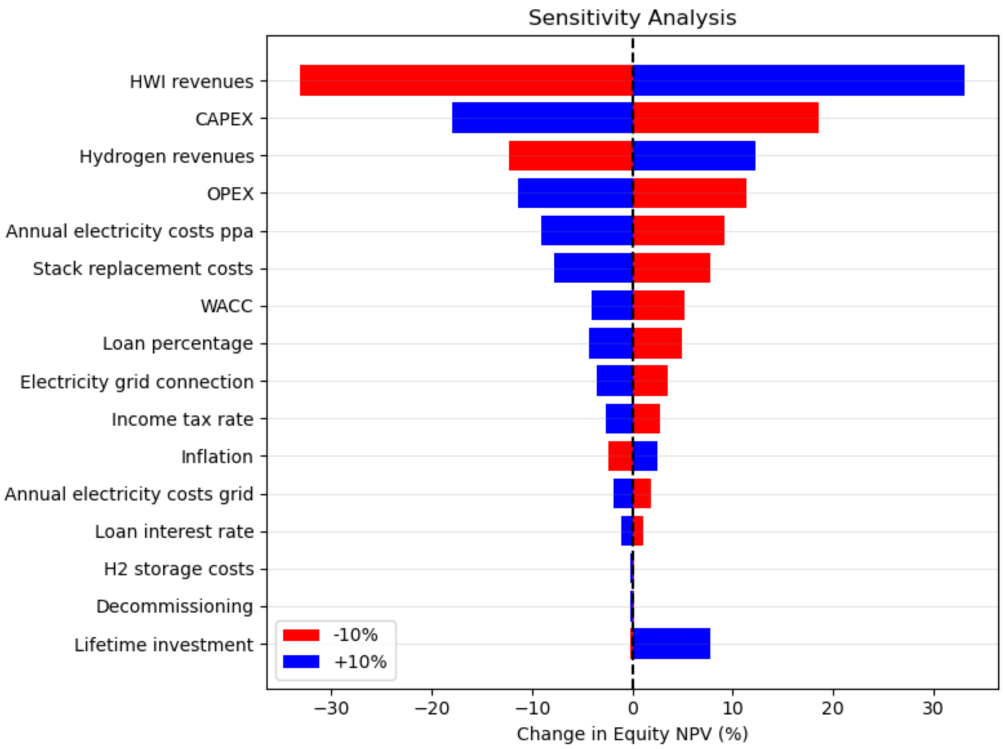


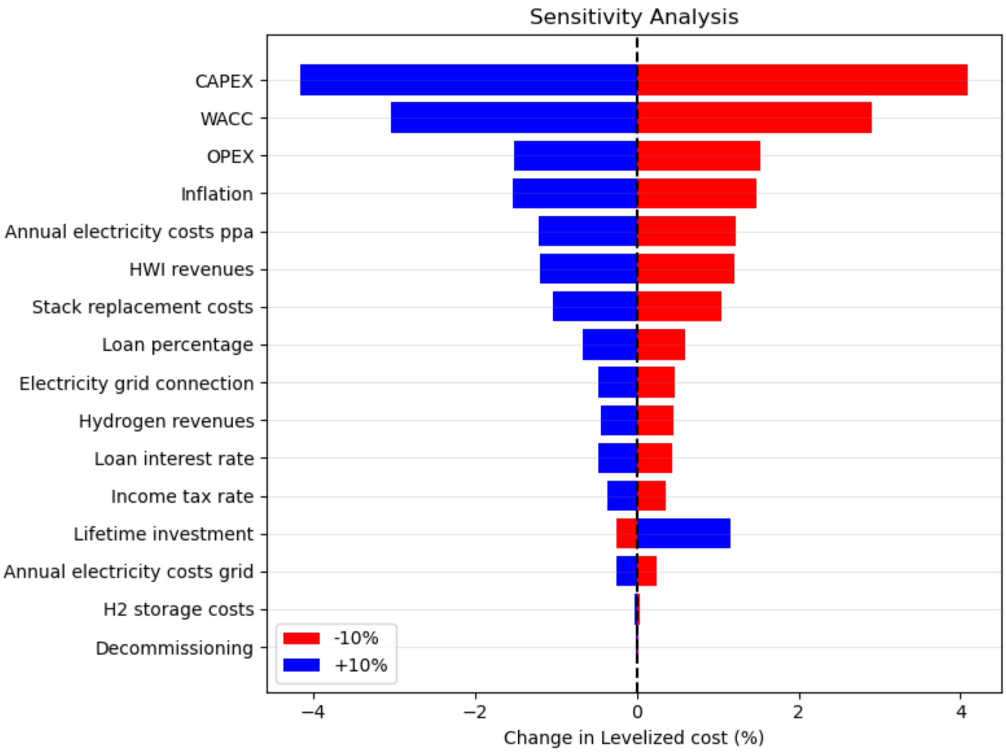

Sensitivity Analysis
CAPEX
WACC
OPEX
Inflation
Stack replacement costs
Annual electricity costs ppa
Loan percentage
HWI revenues
Loan interest rate
Electricity grid connection
Hydrogen revenues
Annual electricity costs grid
Lifetime investment
Income tax rate
H2 storage costs
Decommissioning
-10%
+10%
−4
−2
0
2
4
Change in Levelized cost (%)

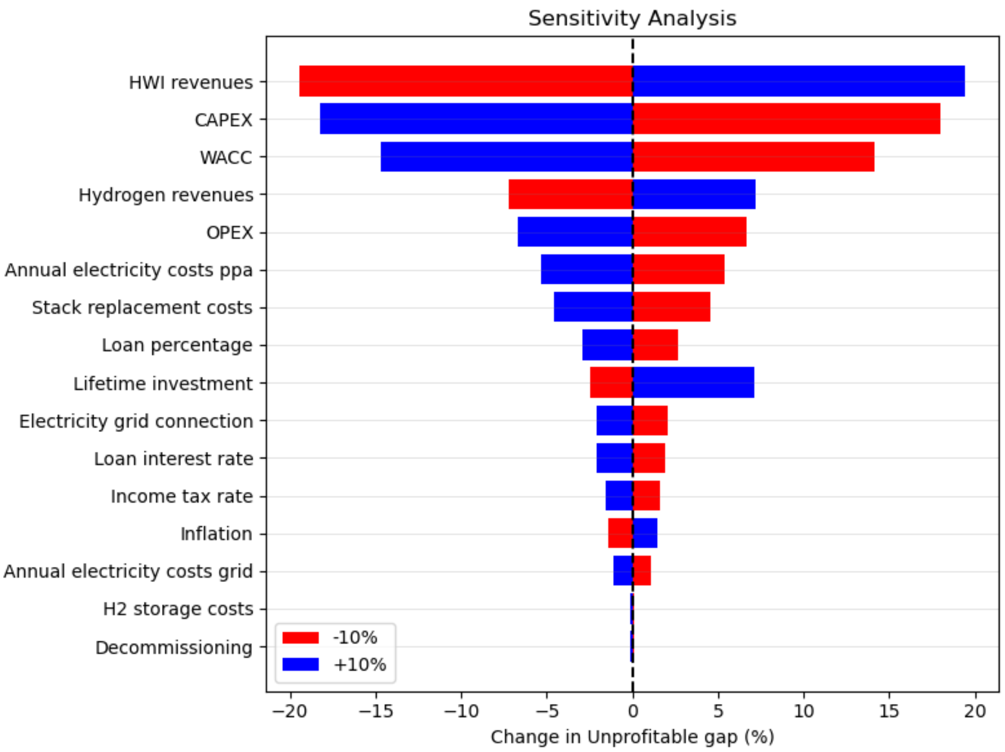

Sensitivity Analysis
CAPEX
HWI revenues
WACC
OPEX
Hydrogen revenues
Stack replacement costs
Annual electricity costs ppa
Loan percentage
Loan interest rate
Lifetime investment
Electricity grid connection
Annual electricity costs grid
Income tax rate
Inflation
H2 storage costs
Decommissioning
-10%
+10%
−10
−5
0
5
10
Change in Unprofitable gap (%)

C.3 Offshore electrolyser (500 MW)

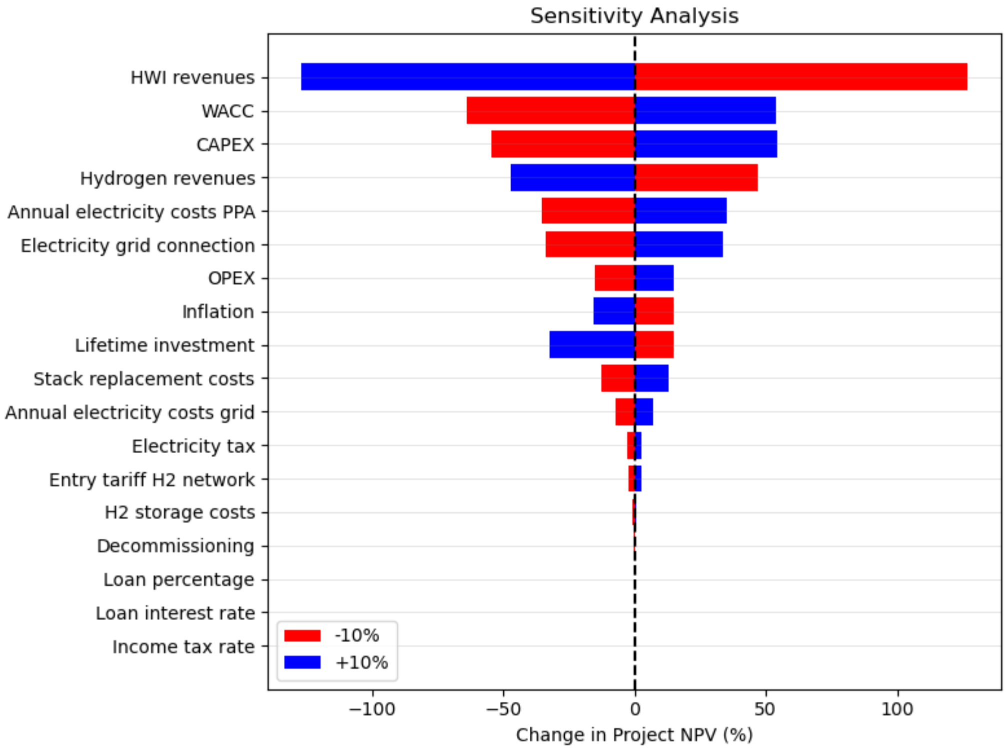


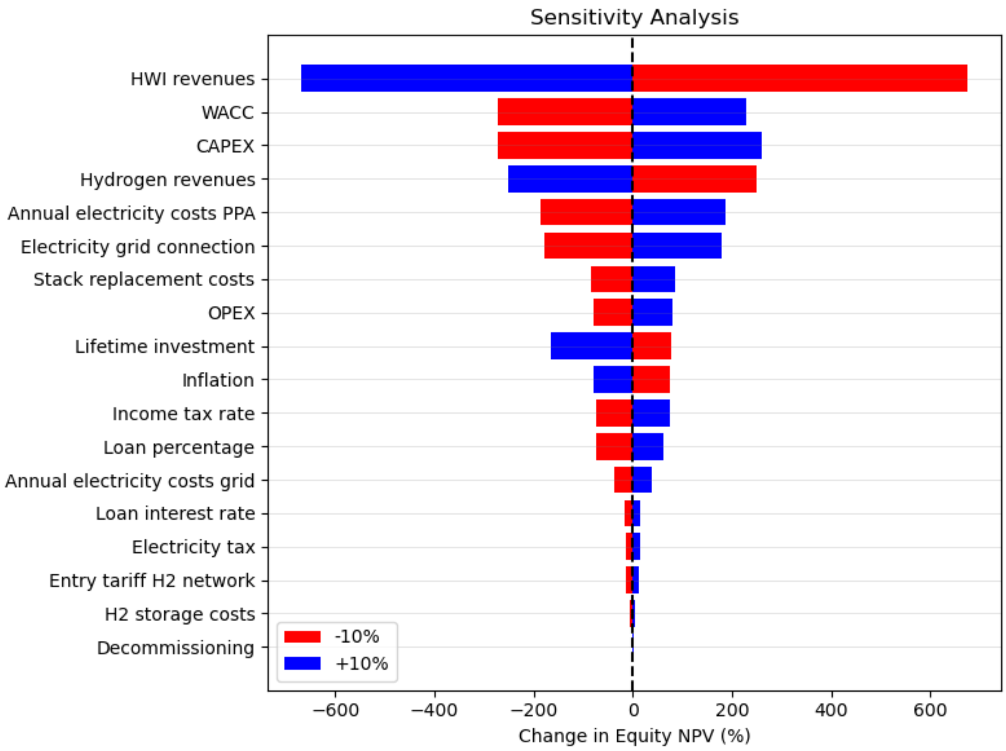


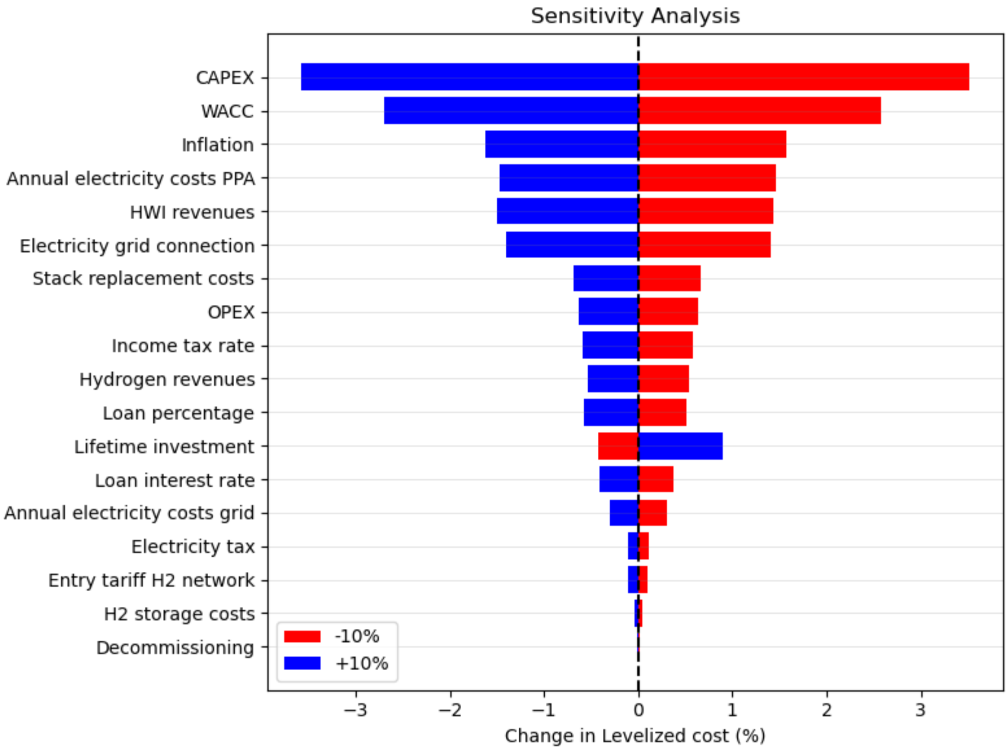

Sensitivity Analysis
CAPEX
WACC
OPEX
Inflation
Annual electricity costs ppa
HWI revenues
Stack replacement costs
Loan percentage
Electricity grid connection
Hydrogen revenues
Loan interest rate
Income tax rate
Lifetime investment
Annual electricity costs grid
H2 storage costs
Decommissioning
-10%
+10%
−4
−2
0
2
4
Change in Levelized cost (%)

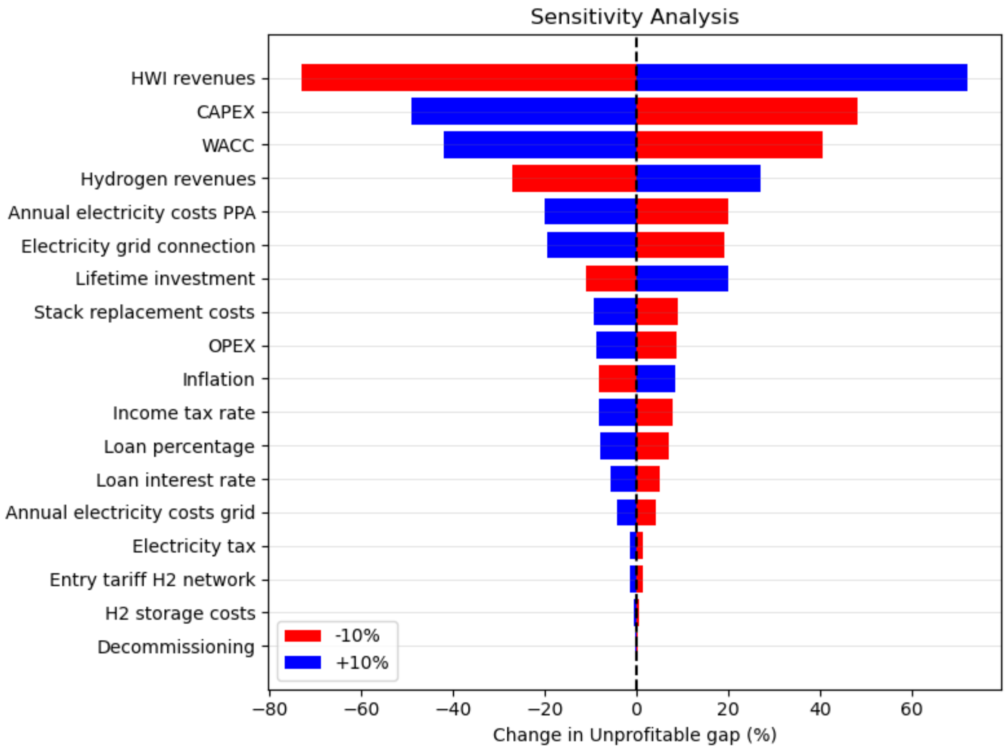

Sensitivity Analysis
HWI revenues
CAPEX
WACC
Hydrogen revenues
OPEX
Annual electricity costs ppa
Stack replacement costs
Loan percentage
Lifetime investment
Electricity grid connection
Loan interest rate
Income tax rate
Inflation
Annual electricity costs grid
H2 storage costs
Decommissioning
-10%
+10%
−20
−15
−10
−5
0
5
10
15
20
Change in Unprofitable gap (%)

C.4 Onshore electrolyser (100 MW)

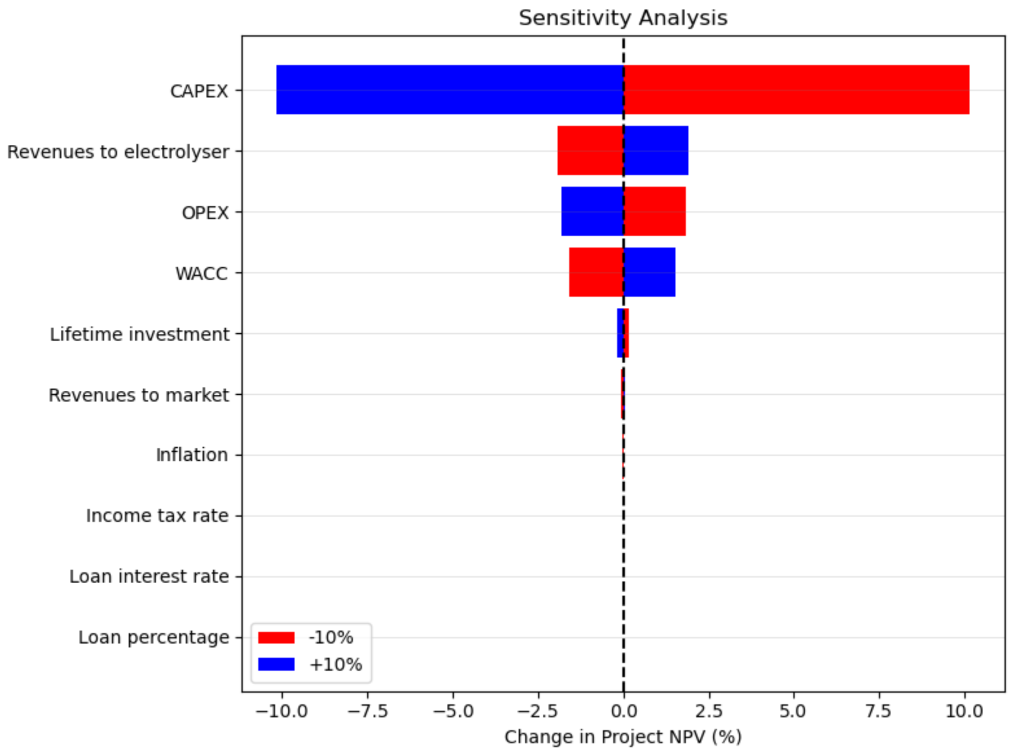


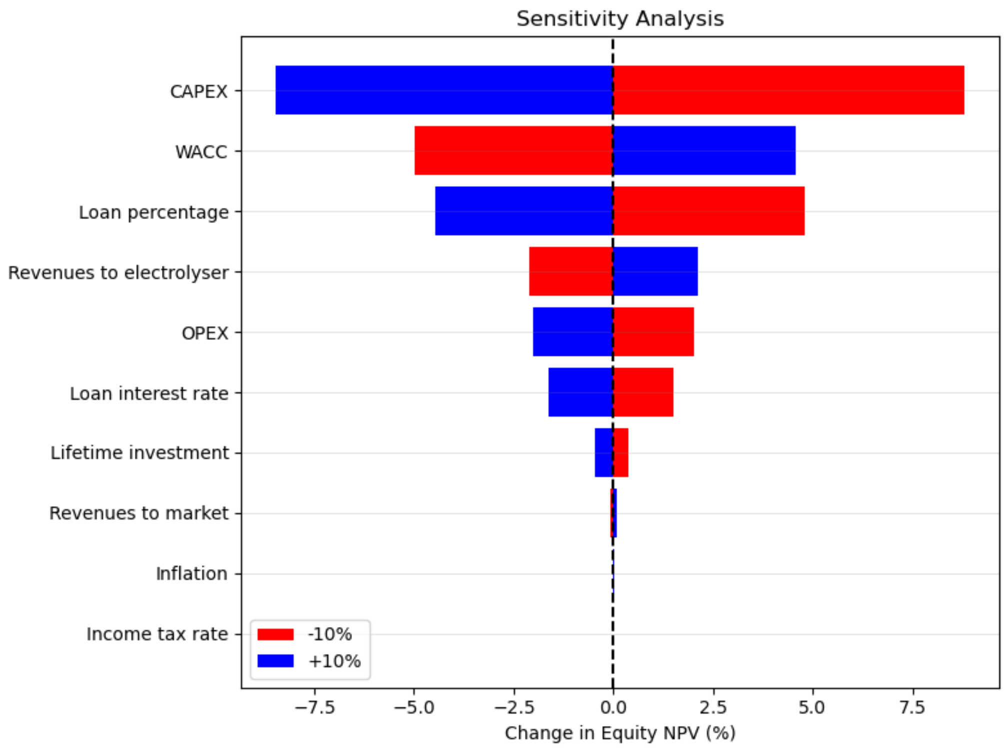


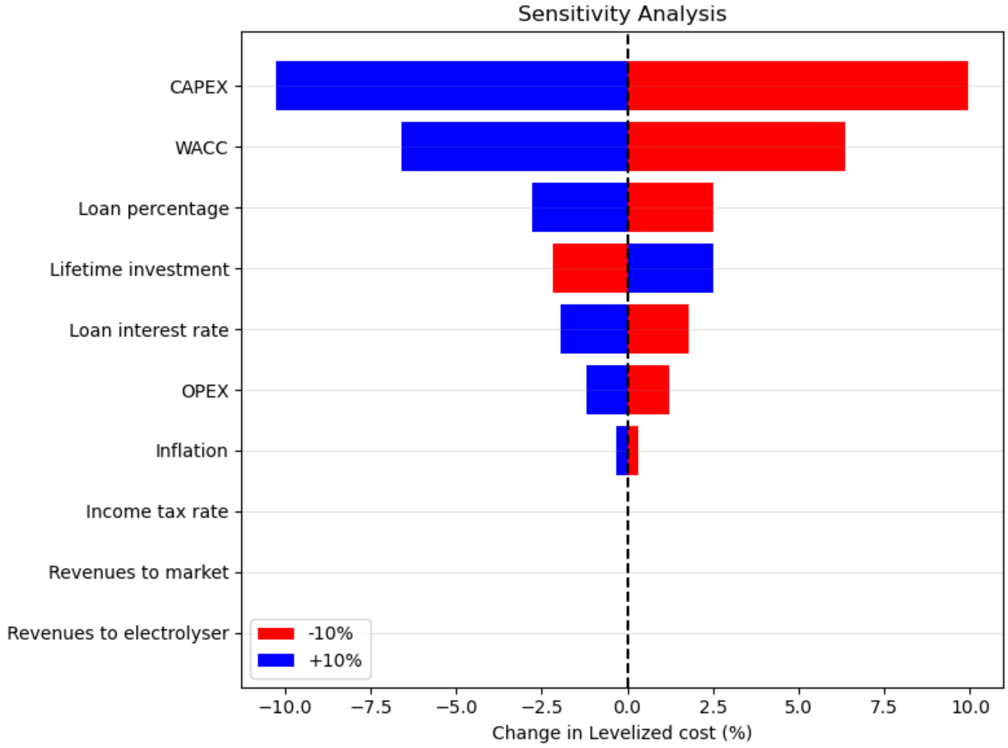

Sensitivity Analysis
CAPEX
WACC
Inflation
Annual electricity costs PPA
HWI revenues
Electricity grid connection
Stack replacement costs
OPEX
Income tax rate
Hydrogen revenues
Loan percentage
Lifetime investment
Loan interest rate
Annual electricity costs grid
Electricity tax
Entry tariff H2 network
H2 storage costs
Decommissioning
-10%
+10%
−3
−2
−1
0
1
2
3
Change in Levelized cost (%)

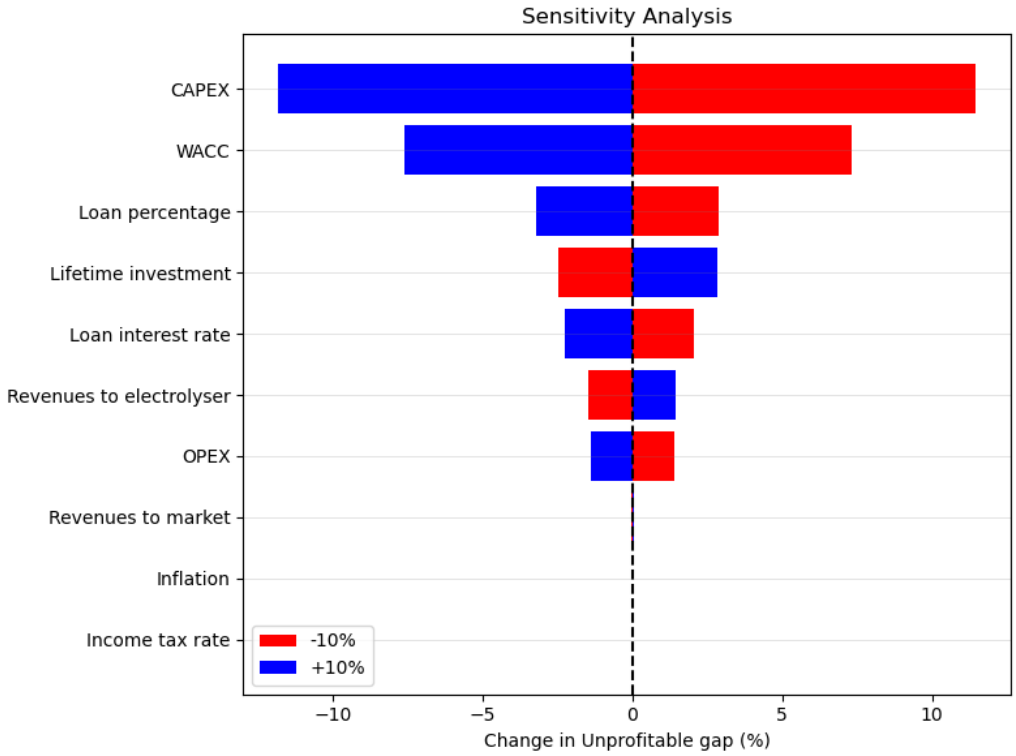

Sensitivity Analysis
HWI revenues
CAPEX
WACC
Hydrogen revenues
Annual electricity costs PPA
Electricity grid connection
Lifetime investment
Stack replacement costs
OPEX
Inflation
Income tax rate
Loan percentage
Loan interest rate
Annual electricity costs grid
Electricity tax
Entry tariff H2 network
H2 storage costs
Decommissioning
-10%
+10%
−80
−60
−40
−20
0
20
40
60
Change in Unprofitable gap (%)

C.5 Offshore Solar

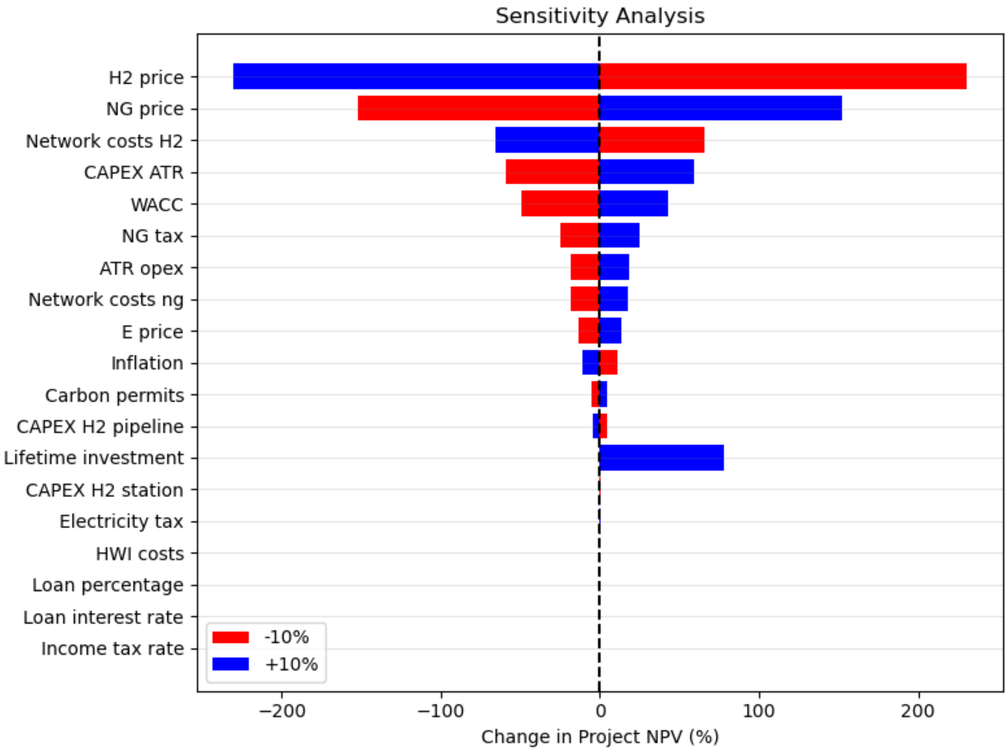


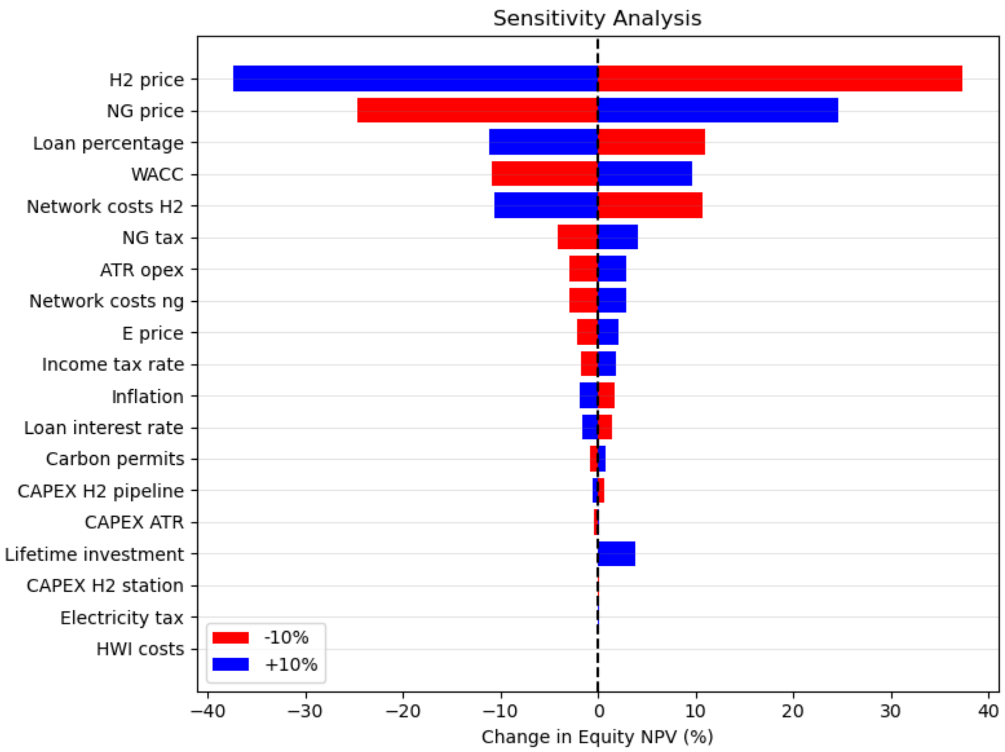


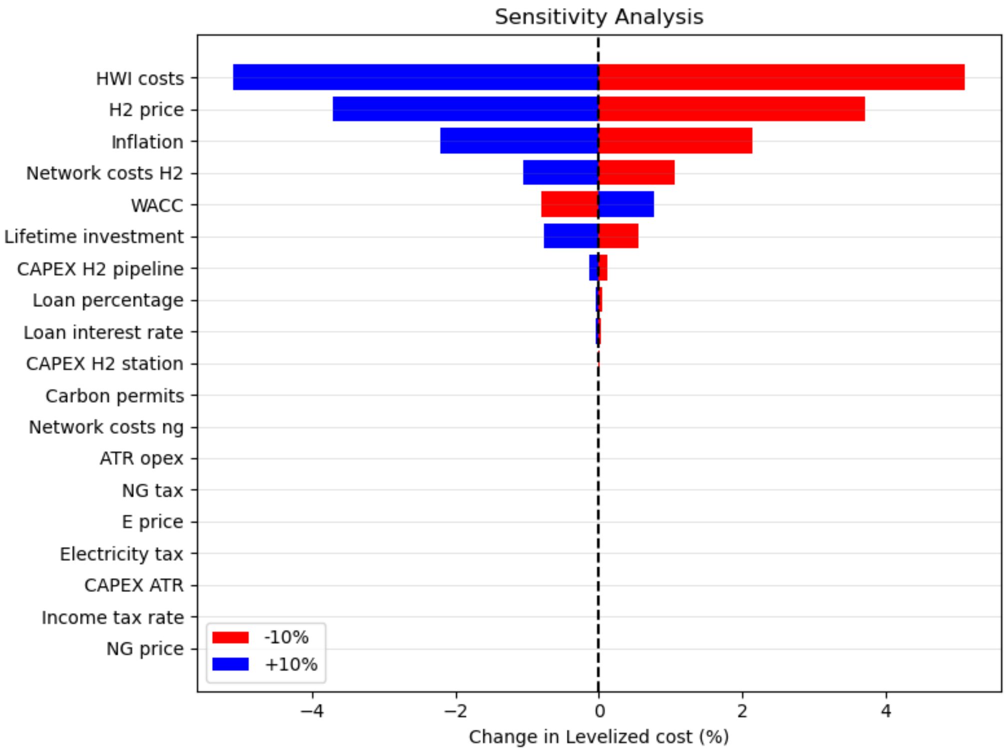

Sensitivity Analysis
CAPEX
WACC
Loan percentage
Lifetime investment
Loan interest rate
OPEX
Inflation
Income tax rate
Revenues to market
Revenues to electrolyser
-10%
+10%
−10.0
−7.5
−5.0
−2.5
0.0
2.5
5.0
7.5
10.0
Change in Levelized cost (%)

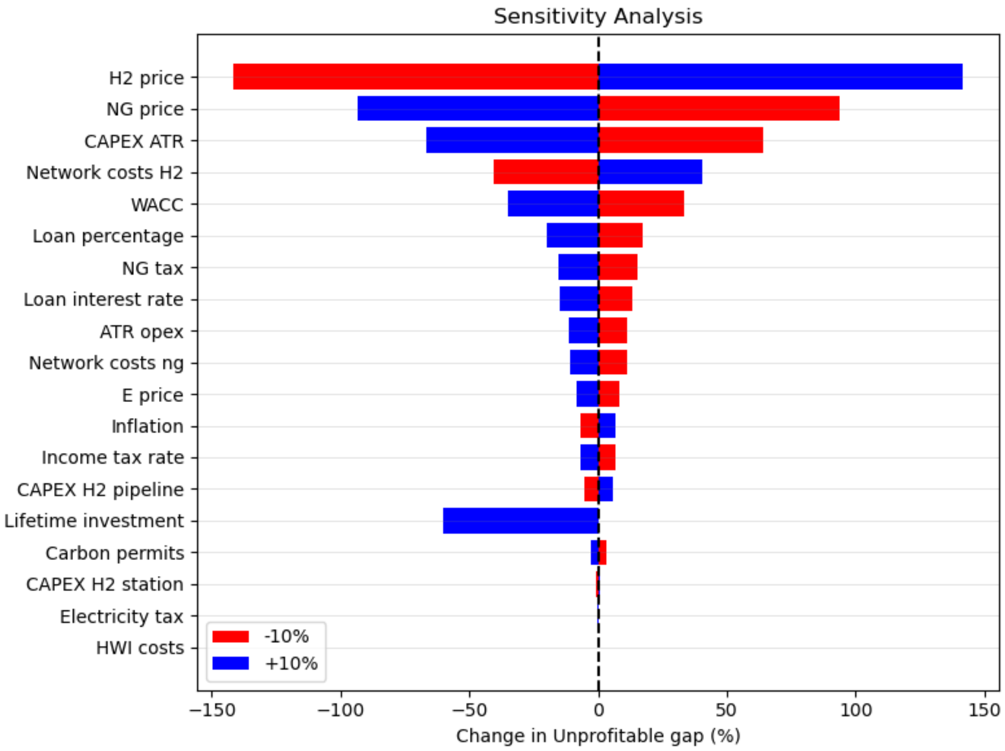

Sensitivity Analysis
CAPEX
WACC
Loan percentage
Lifetime investment
Loan interest rate
Revenues to electrolyser
OPEX
Revenues to market
Inflation
Income tax rate
-10%
+10%
−10
−5
0
5
10
Change in Unprofitable gap (%)

C.6 Onshore off-taker (Grey Hydrogen)

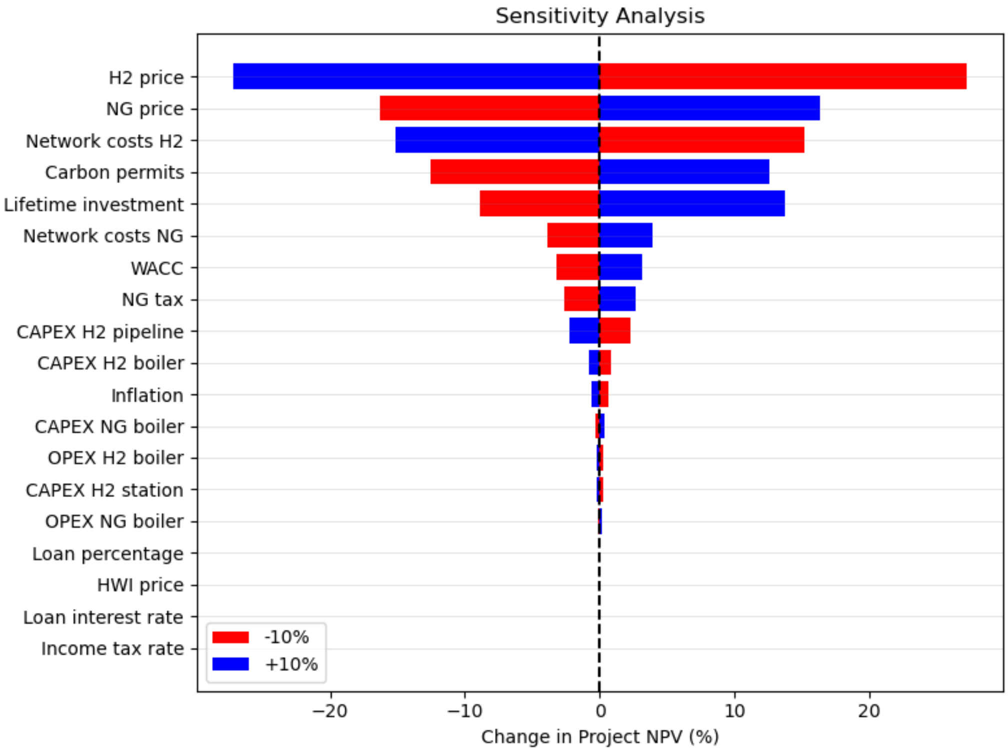


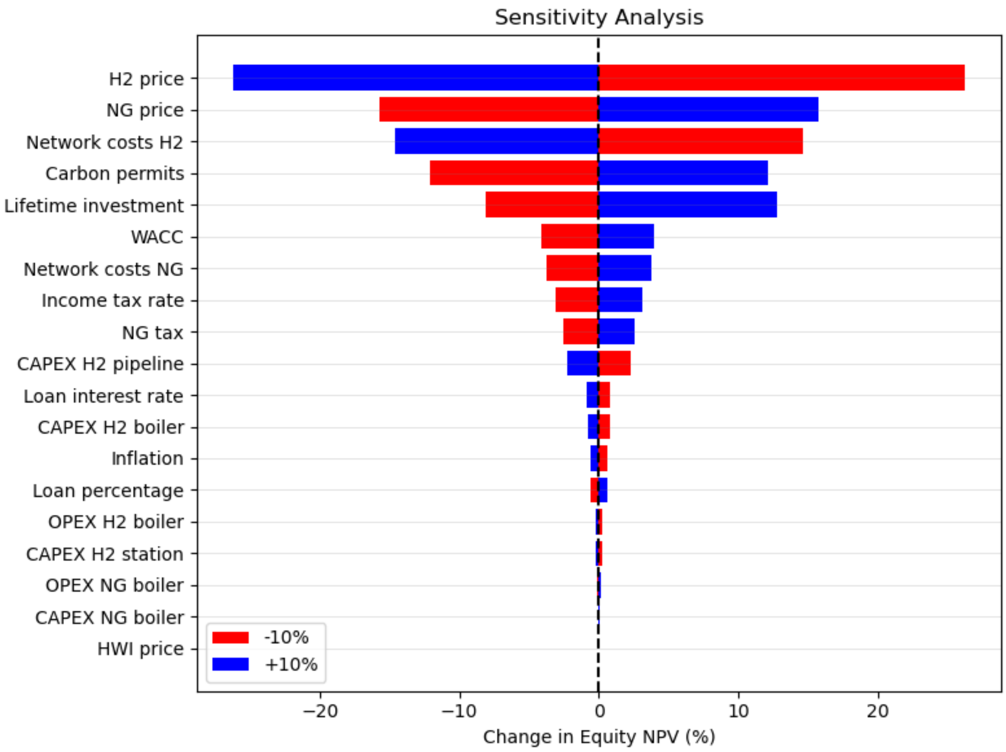


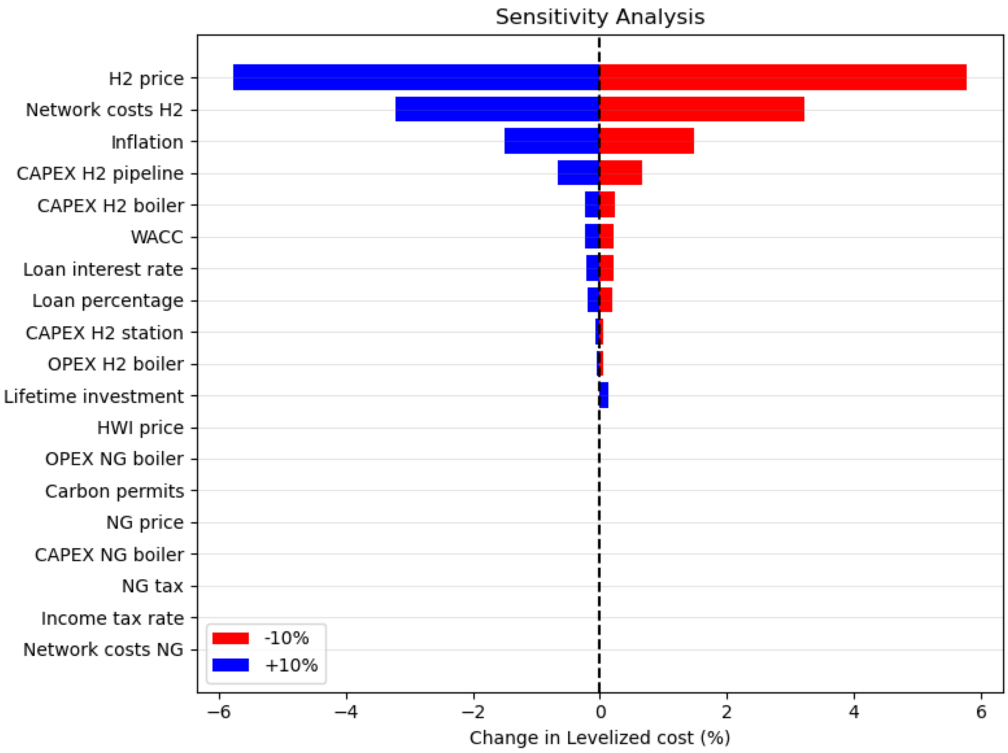

Sensitivity Analysis
HWI costs
H2 price
Inflation
Network costs H2
WACC
Lifetime investment
CAPEX H2 pipeline
Loan percentage
Loan interest rate
CAPEX H2 station
Carbon permits
Network costs ng
ATR opex
NG tax
E price
Electricity tax
CAPEX ATR
Income tax rate
NG price
-10%
+10%
−4
−2
0
2
4
Change in Levelized cost (%)

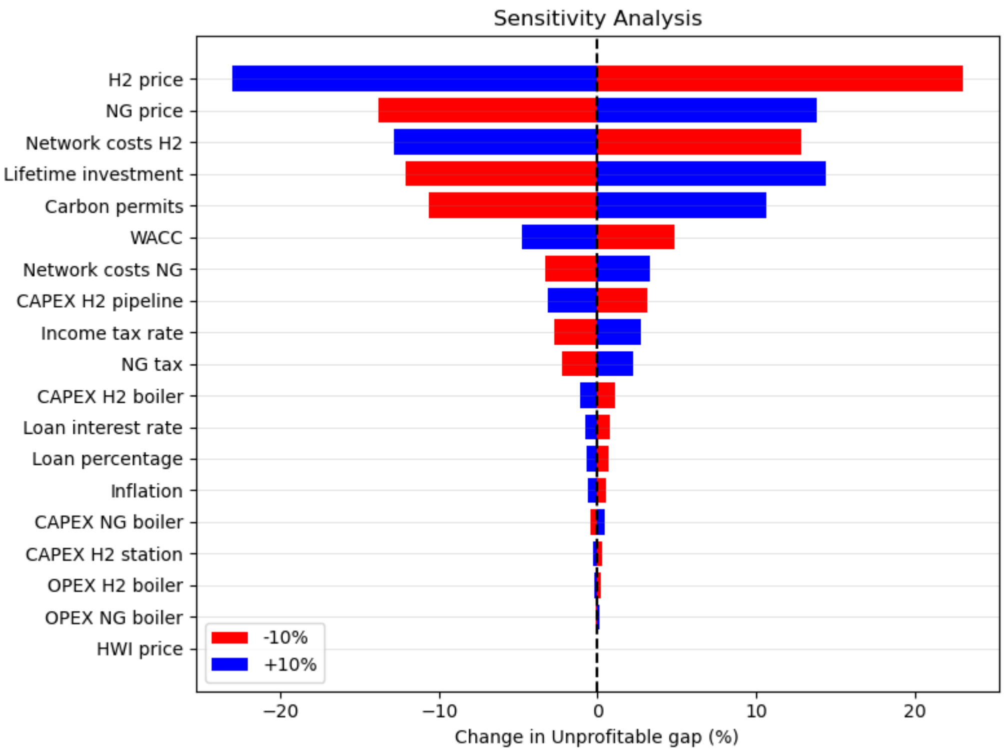

Sensitivity Analysis
H2 price
NG price
CAPEX ATR
Network costs H2
WACC
Loan percentage
NG tax
Loan interest rate
ATR opex
Network costs ng
E price
Inflation
Income tax rate
CAPEX H2 pipeline
Lifetime investment
Carbon permits
CAPEX H2 station
Electricity tax
HWI costs
-10%
+10%
−150
−100
−50
0
50
100
150
Change in Unprofitable gap (%)

C.7 Onshore off-taker (Natural Gas)



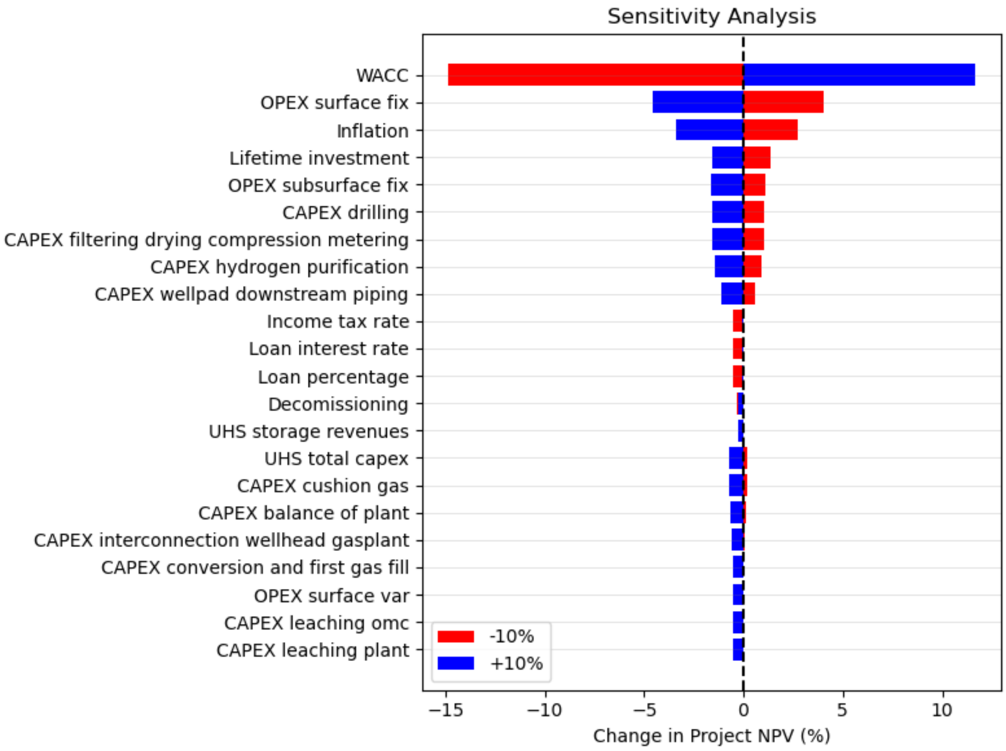


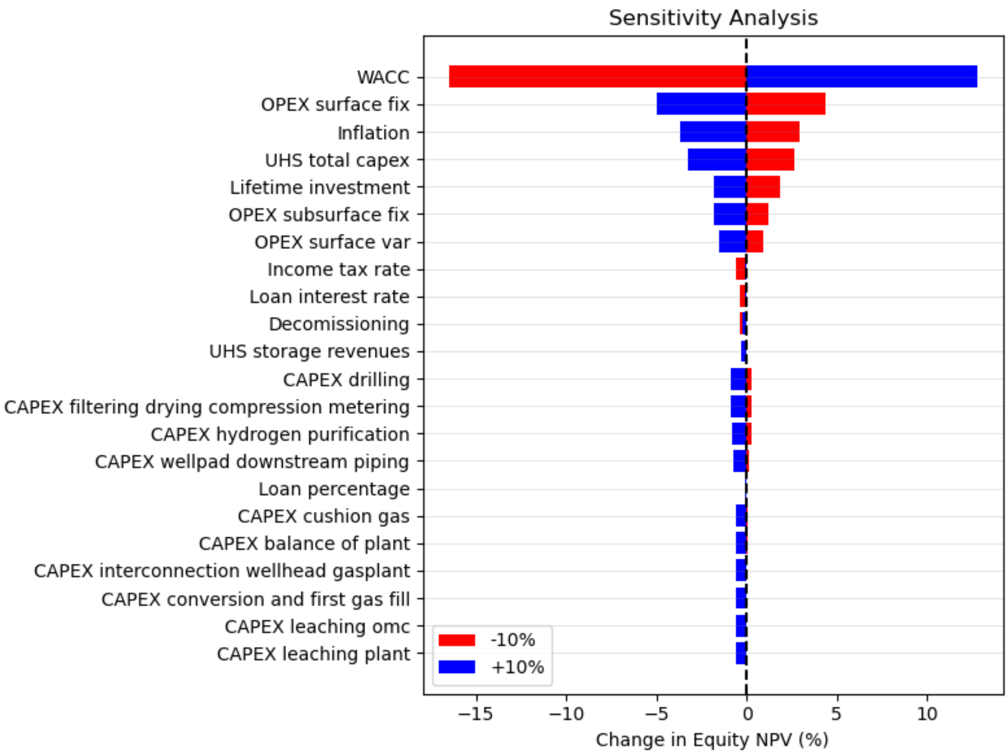

Sensitivity Analysis
H2 price
Network costs H2
Inflation
CAPEX H2 pipeline
CAPEX H2 boiler
WACC
Loan interest rate
Loan percentage
CAPEX H2 station
OPEX H2 boiler
Lifetime investment
HWI price
OPEX NG boiler
Carbon permits
NG price
CAPEX NG boiler
NG tax
Income tax rate
Network costs NG
-10%
+10%
−6
−4
−2
0
2
4
6
Change in Levelized cost (%)

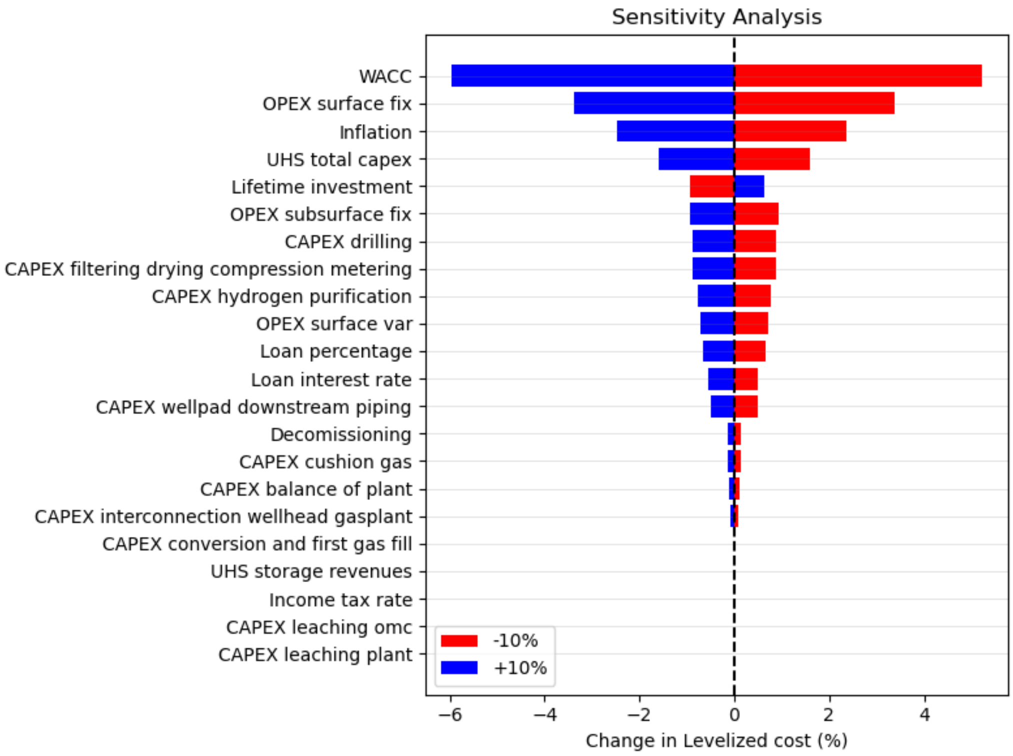

Sensitivity Analysis
H2 price
NG price
Network costs H2
Lifetime investment
Carbon permits
WACC
Network costs NG
CAPEX H2 pipeline
Income tax rate
NG tax
CAPEX H2 boiler
Loan interest rate
Loan percentage
Inflation
CAPEX NG boiler
CAPEX H2 station
OPEX H2 boiler
OPEX NG boiler
HWI price
-10%
+10%
−20
−10
0
10
20
Change in Unprofitable gap (%)

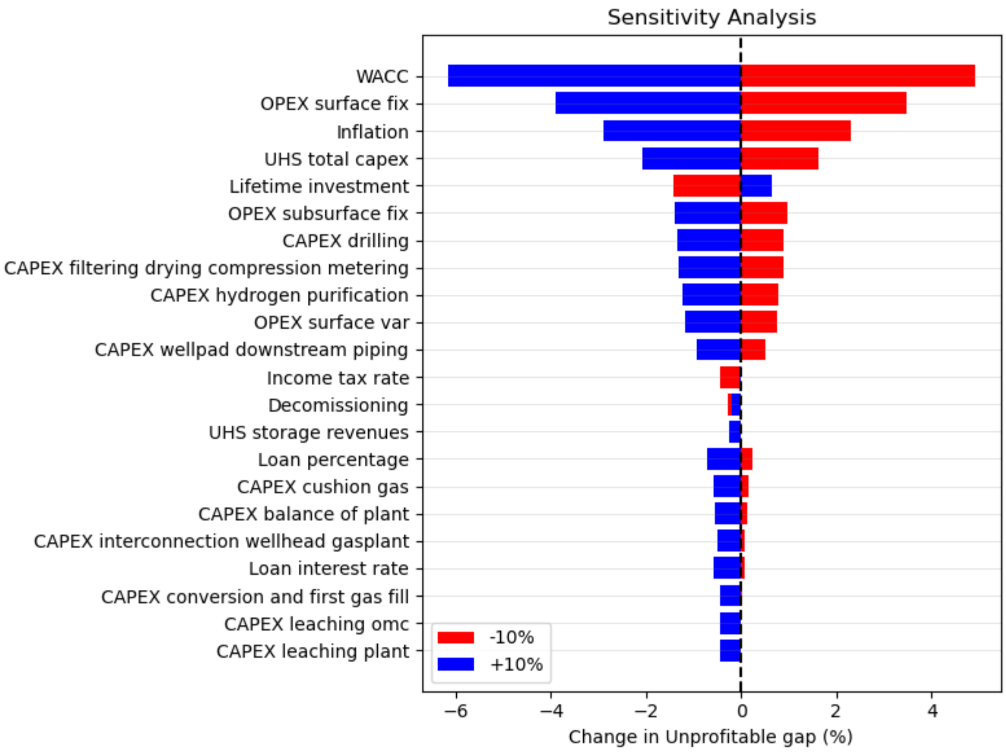
C.8 Underground Hydrogen Storage

Depleted Gas Field onshore:

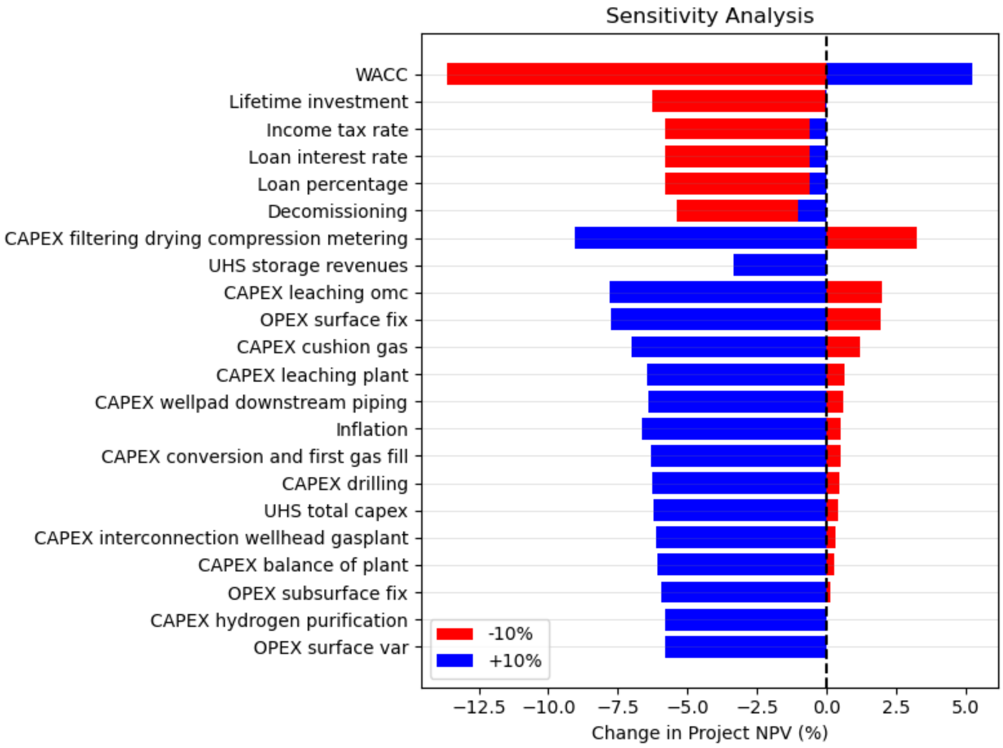


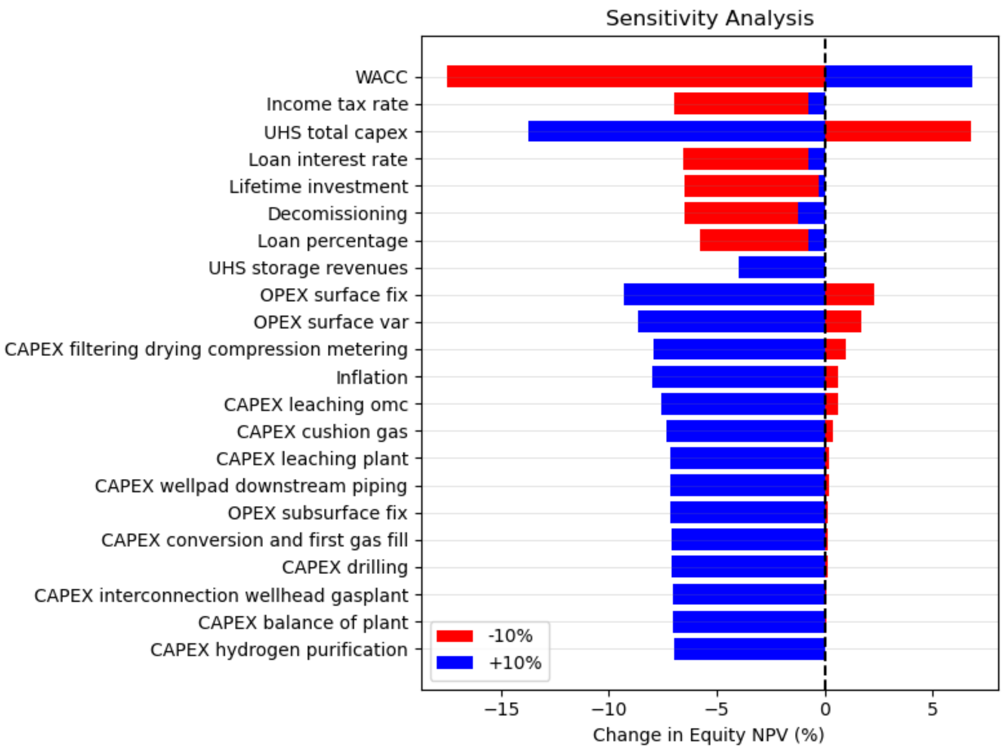


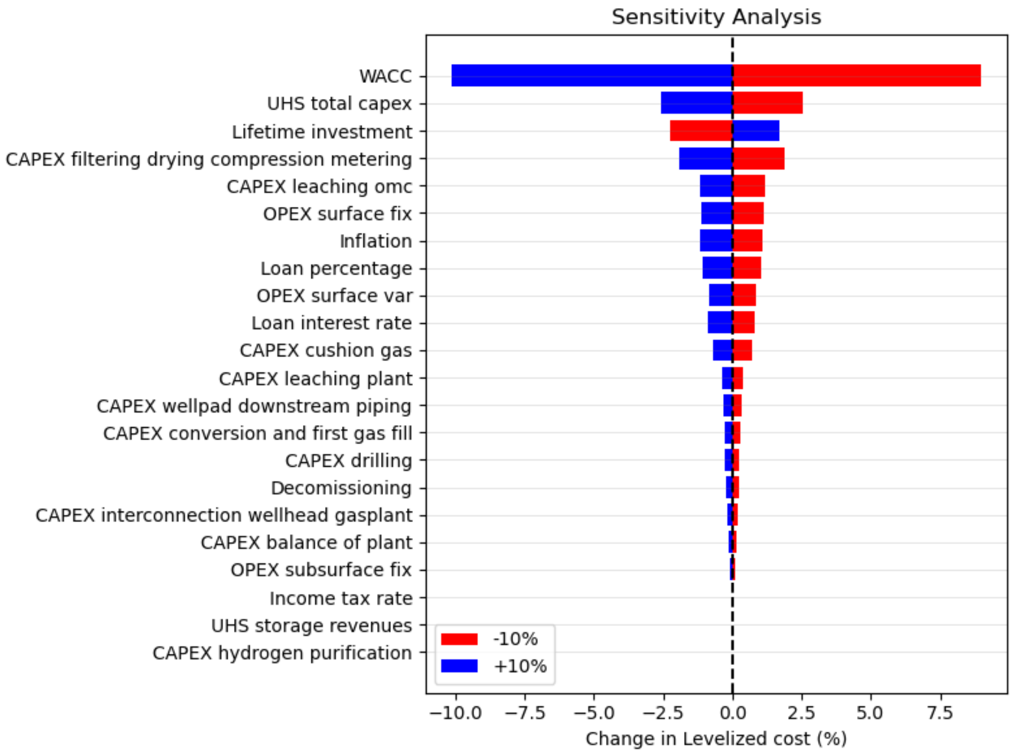

Sensitivity Analysis
WACC
OPEX surface fix
Inflation
UHS total capex
Lifetime investment
OPEX subsurface fix
CAPEX drilling
CAPEX filtering drying compression metering
CAPEX hydrogen purification
OPEX surface var
Loan percentage
Loan interest rate
CAPEX wellpad downstream piping
Decomissioning
CAPEX cushion gas
CAPEX balance of plant
CAPEX interconnection wellhead gasplant
CAPEX conversion and first gas fill
UHS storage revenues
Income tax rate
CAPEX leaching omc
CAPEX leaching plant
-10%
+10%
−6
−4
−2
0
2
4
Change in Levelized cost (%)

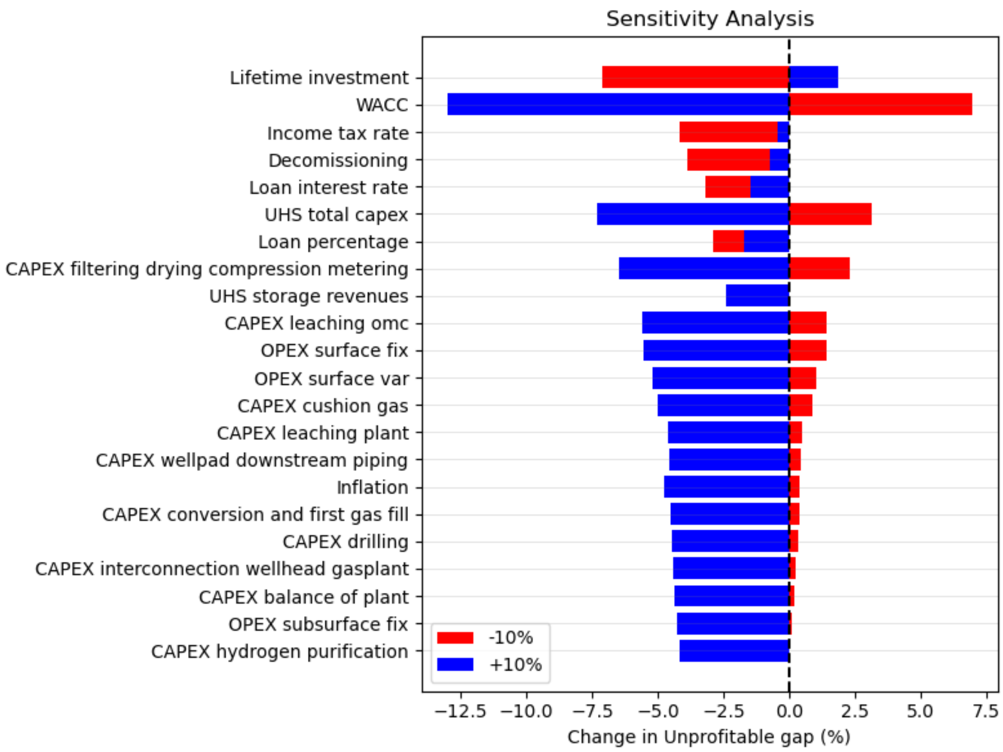

Sensitivity Analysis
WACC
OPEX surface fix
Inflation
UHS total capex
Lifetime investment
OPEX subsurface fix
CAPEX drilling
CAPEX filtering drying compression metering
CAPEX hydrogen purification
OPEX surface var
CAPEX wellpad downstream piping
Income tax rate
Decomissioning
UHS storage revenues
Loan percentage
CAPEX cushion gas
CAPEX balance of plant
CAPEX interconnection wellhead gasplant
Loan interest rate
CAPEX conversion and first gas fill
CAPEX leaching omc
CAPEX leaching plant
-10%
+10%
−6
−4
−2
0
2
4
Change in Unprofitable gap (%)

Salt cavern onshore:

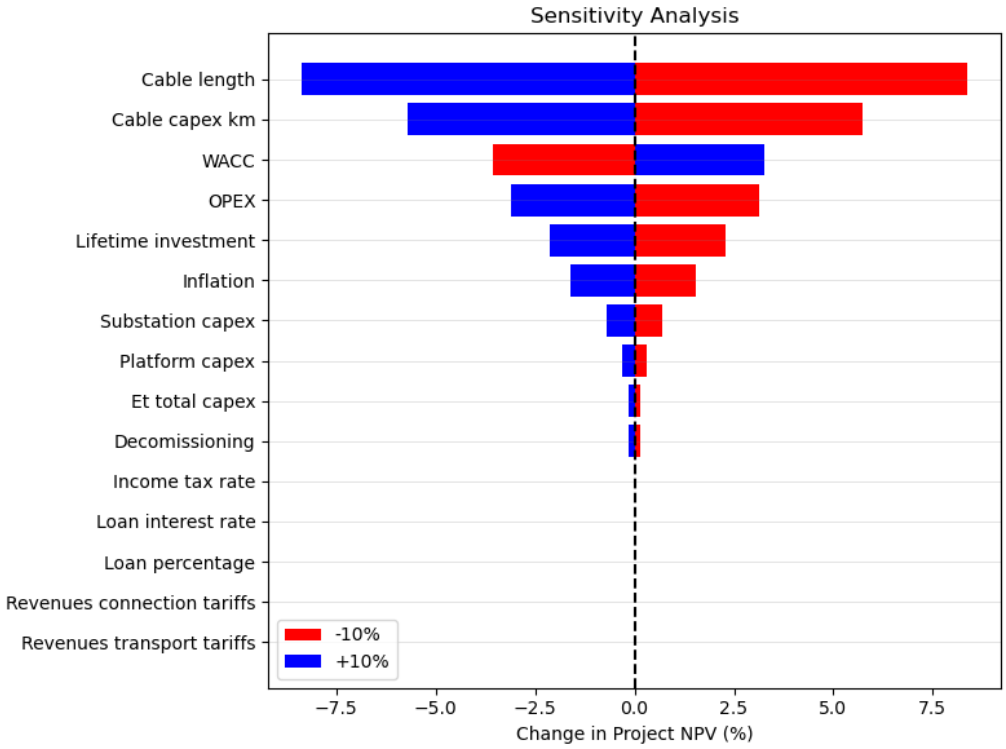


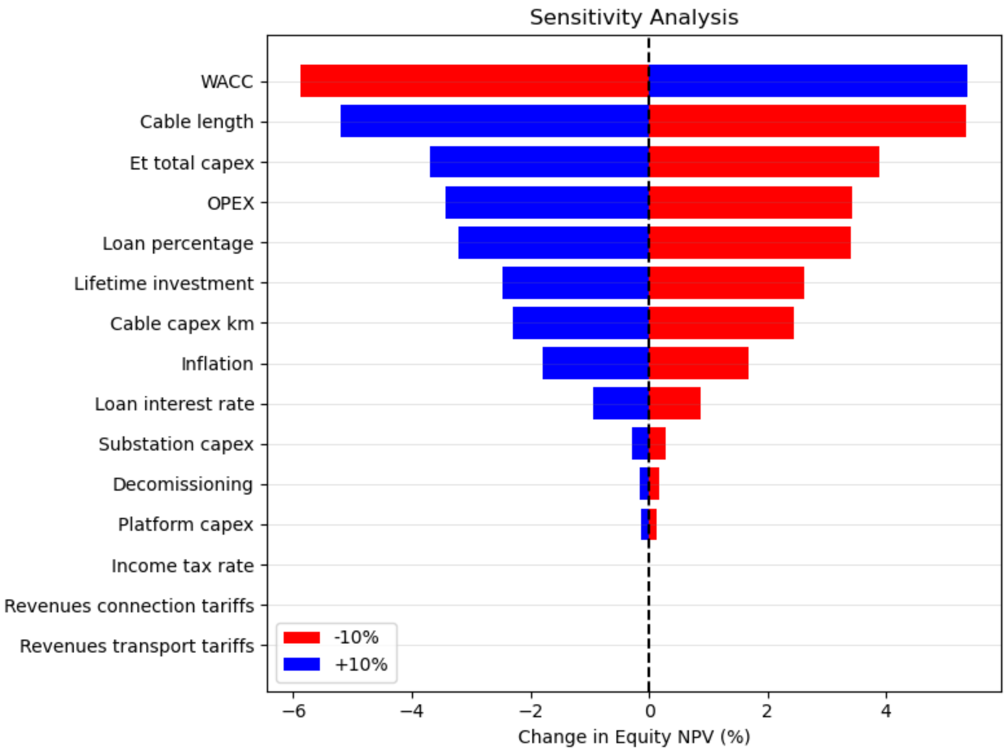


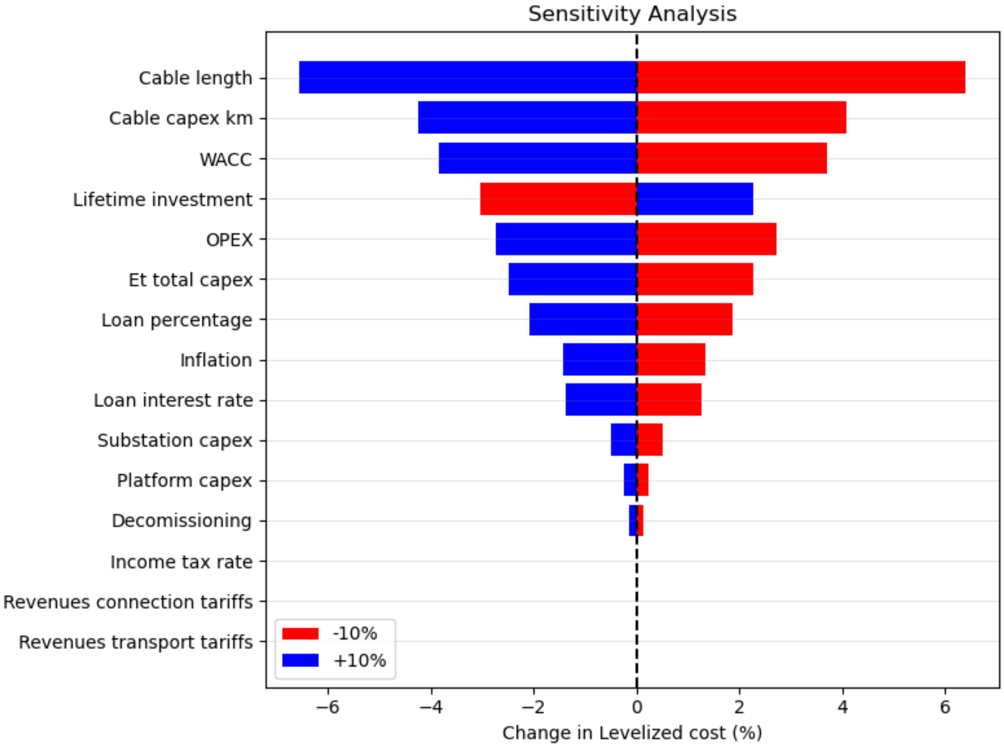

Sensitivity Analysis
WACC
UHS total capex
Lifetime investment
CAPEX filtering drying compression metering
CAPEX leaching omc
OPEX surface fix
Inflation
Loan percentage
OPEX surface var
Loan interest rate
CAPEX cushion gas
CAPEX leaching plant
CAPEX wellpad downstream piping
CAPEX conversion and first gas fill
CAPEX drilling
Decomissioning
CAPEX interconnection wellhead gasplant
CAPEX balance of plant
OPEX subsurface fix
Income tax rate
UHS storage revenues
CAPEX hydrogen purification
-10%
+10%
−10.0
−7.5
−5.0
−2.5
0.0
2.5
5.0
7.5
Change in Levelized cost (%)

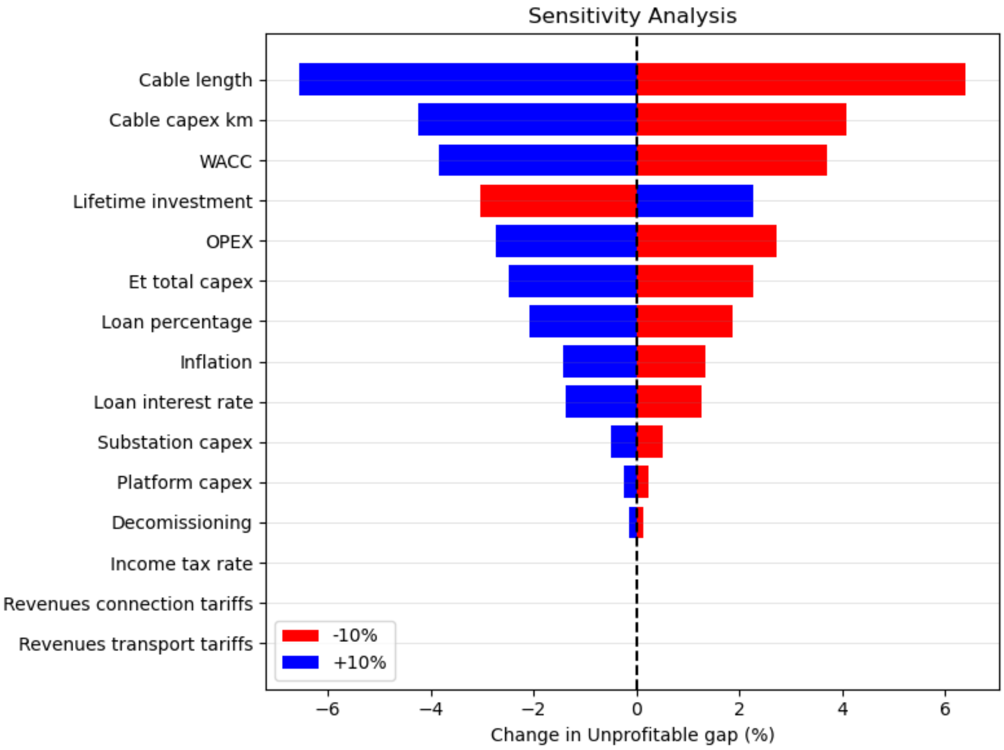

Sensitivity Analysis
Lifetime investment
WACC
Income tax rate
Decomissioning
Loan interest rate
UHS total capex
Loan percentage
CAPEX filtering drying compression metering
UHS storage revenues
CAPEX leaching omc
OPEX surface fix
OPEX surface var
CAPEX cushion gas
CAPEX leaching plant
CAPEX wellpad downstream piping
Inflation
CAPEX conversion and first gas fill
CAPEX drilling
CAPEX interconnection wellhead gasplant
CAPEX balance of plant
OPEX subsurface fix
CAPEX hydrogen purification
-10%
+10%
−12.5
−10.0
−7.5
−5.0
−2.5
0.0
2.5
5.0
7.5
Change in Unprofitable gap (%)

C.9 Electricity Transport entire network



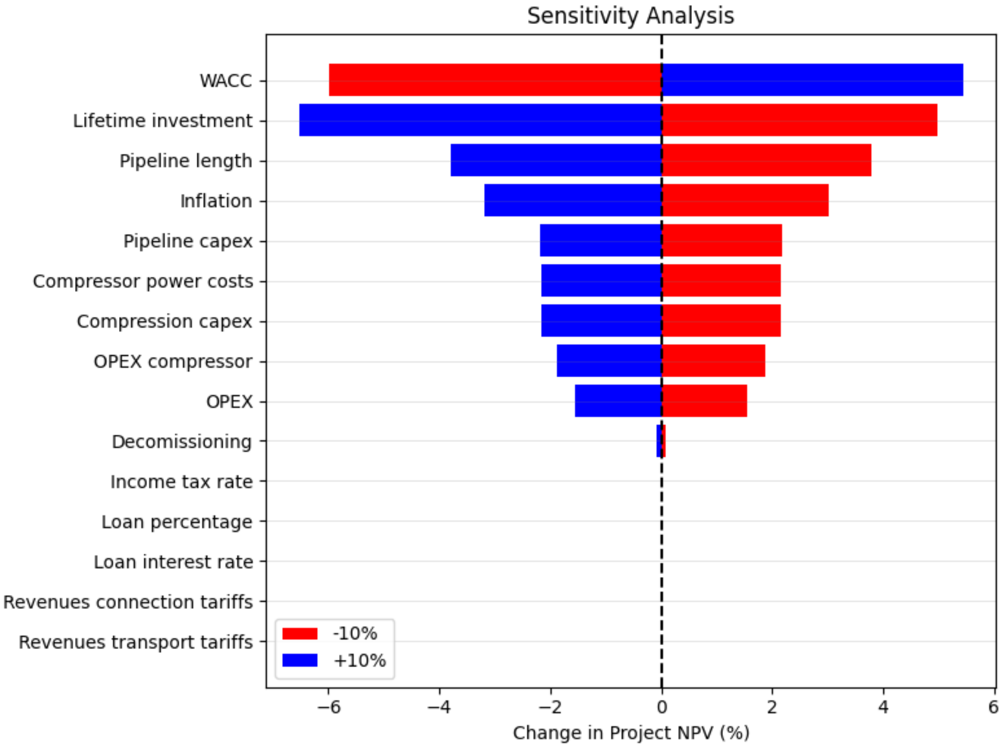


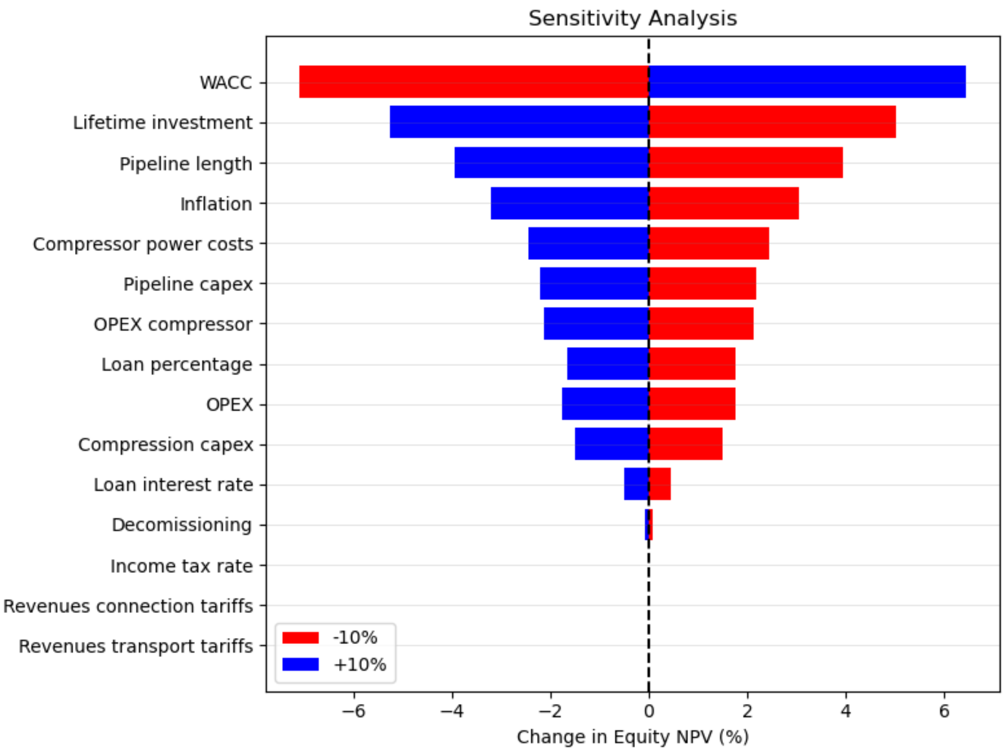

Sensitivity Analysis
Cable length
Cable capex km
WACC
Lifetime investment
OPEX
Et total capex
Loan percentage
Inflation
Loan interest rate
Substation capex
Platform capex
Decomissioning
Income tax rate
Revenues connection tariffs
Revenues transport tariffs
-10%
+10%
−6
−4
−2
0
2
4
6
Change in Levelized cost (%)

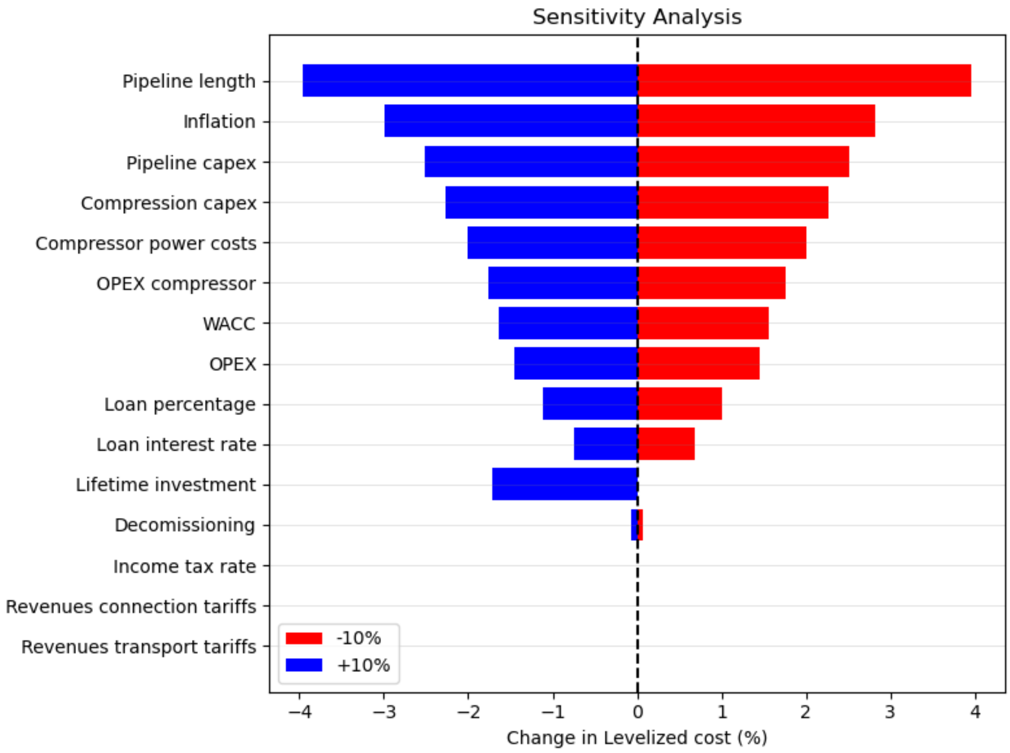

Sensitivity Analysis
Cable length
Cable capex km
WACC
Lifetime investment
OPEX
Et total capex
Loan percentage
Inflation
Loan interest rate
Substation capex
Platform capex
Decomissioning
Income tax rate
Revenues connection tariffs
Revenues transport tariffs
-10%
+10%
−6
−4
−2
0
2
4
6
Change in Unprofitable gap (%)

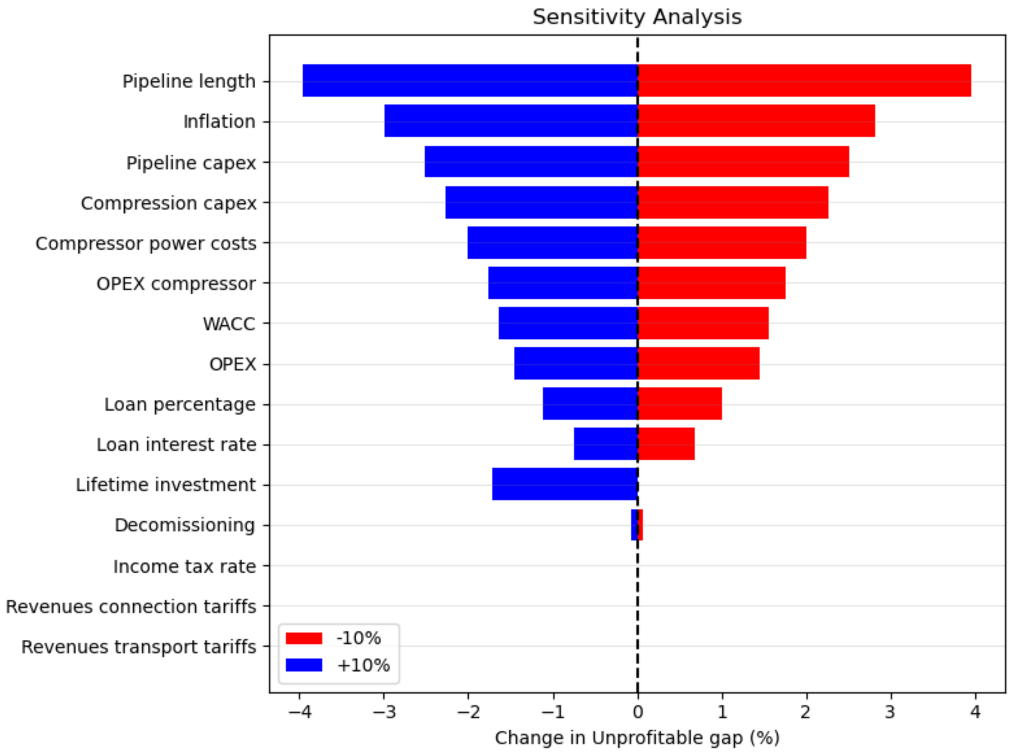
C.10 Hydrogen Transport

Entire network based on new pipelines only

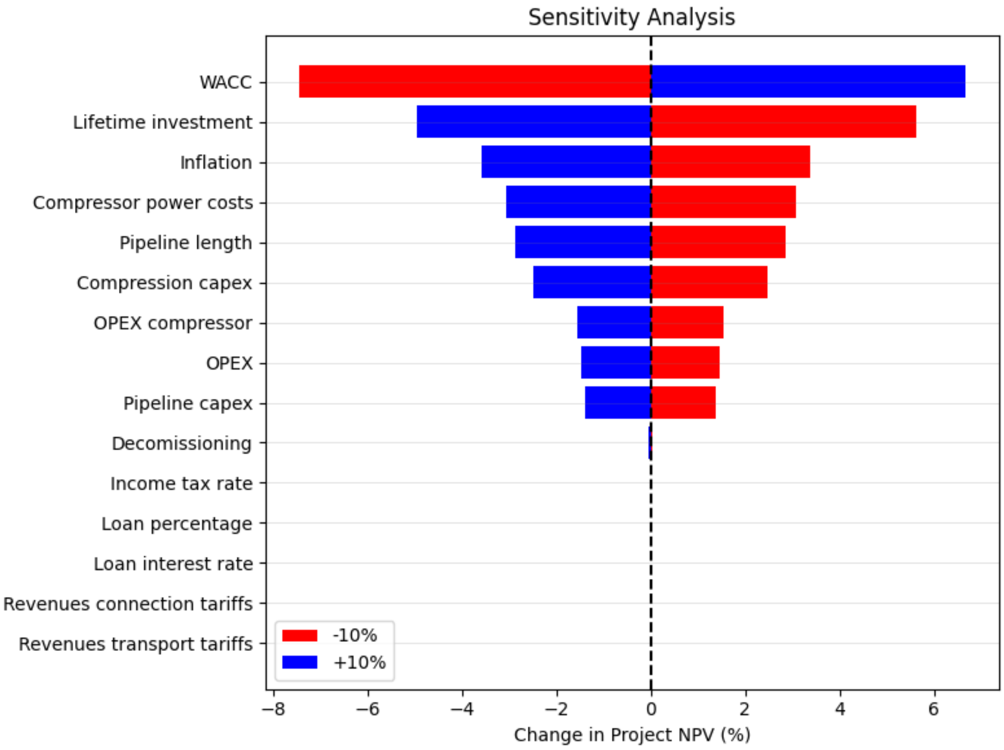


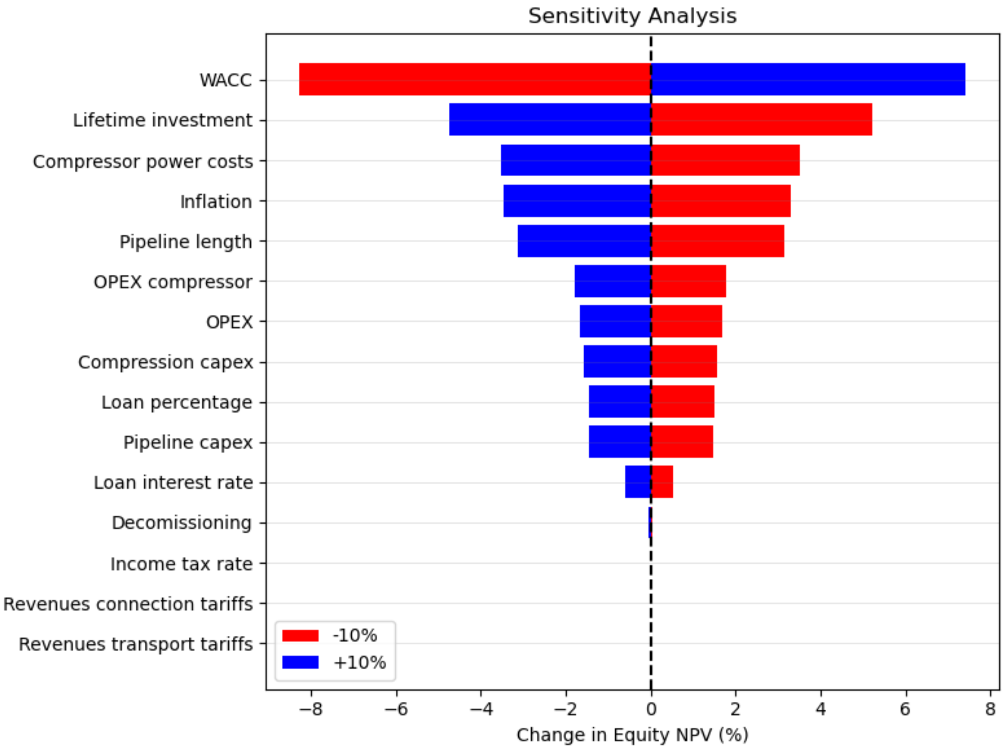


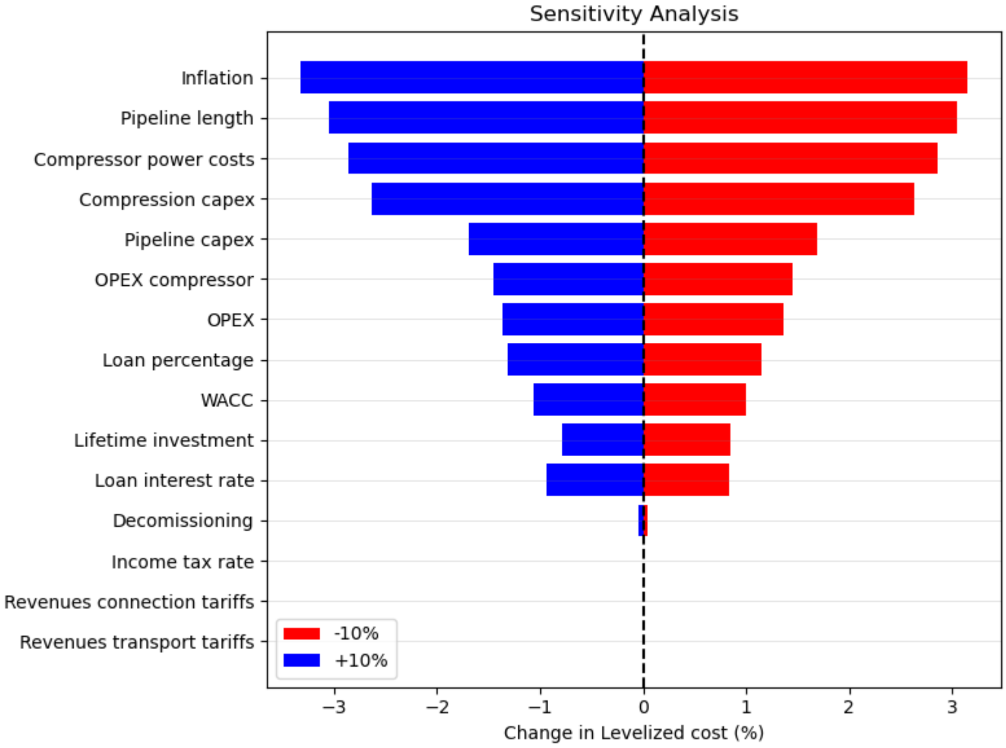

Sensitivity Analysis
Pipeline length
Inflation
Pipeline capex
Compression capex
Compressor power costs
OPEX compressor
WACC
OPEX
Loan percentage
Loan interest rate
Lifetime investment
Decomissioning
Income tax rate
Revenues connection tariffs
Revenues transport tariffs
-10%
+10%
−4
−3
−2
−1
0
1
2
3
4
Change in Levelized cost (%)

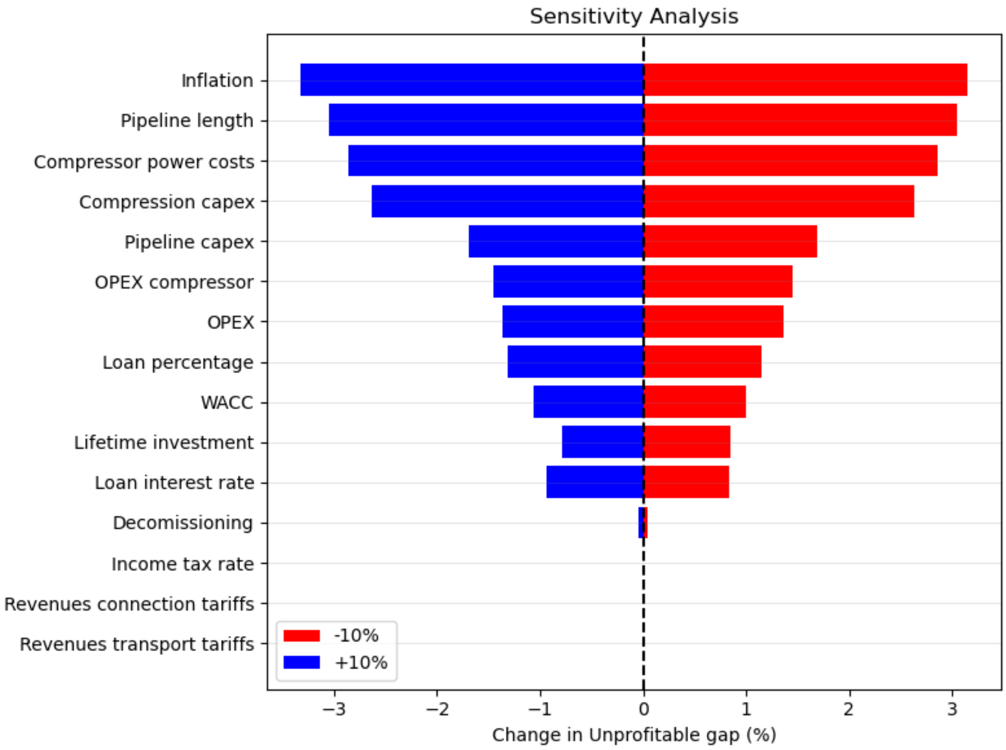

Sensitivity Analysis
Pipeline length
Inflation
Pipeline capex
Compression capex
Compressor power costs
OPEX compressor
WACC
OPEX
Loan percentage
Loan interest rate
Lifetime investment
Decomissioning
Income tax rate
Revenues connection tariffs
Revenues transport tariffs
-10%
+10%
−4
−3
−2
−1
0
1
2
3
4
Change in Unprofitable gap (%)

Entire network based on a combination of new and reused pipelines






Sensitivity Analysis
Inflation
Pipeline length
Compressor power costs
Compression capex
Pipeline capex
OPEX compressor
OPEX
Loan percentage
WACC
Lifetime investment
Loan interest rate
Decomissioning
Income tax rate
Revenues connection tariffs
Revenues transport tariffs
-10%
+10%
−3
−2
−1
0
1
2
3
Change in Levelized cost (%)


Sensitivity Analysis
Inflation
Pipeline length
Compressor power costs
Compression capex
Pipeline capex
OPEX compressor
OPEX
Loan percentage
WACC
Lifetime investment
Loan interest rate
Decomissioning
Income tax rate
Revenues connection tariffs
Revenues transport tariffs
-10%
+10%
−3
−2
−1
0
1
2
3
Change in Unprofitable gap (%)

Appendix D: KPI tables

D.1 Offshore windfarm

		Pessimistic	Base	Optimistic	Unit
Project KPI's					
Net present value	NPV	-1974	**-786**	19	M€
Internal rate of return	IRR	-	**1**	9	%
Return on investment	ROI	-207	**-13**	129	%
Payback period	PP	-	**-**	23	years
Discounted return on investment	DROI	-86	**-53**	3	%
Discounted payback period	DPP	183	**53**	29	years
Equity KPI's					
Net present value	NPV	-1509	**-657**	-43	M€
Internal rate of return	IRR	-35	**-2**	8	%
Return of investment	ROI	-214	**53**	413	%
Payback period	PP	-	**47**	7	years
Discounted return on investment	DROI	-221	**-134**	30	%
Discounted payback period	DPP	-	**-**	23	years
Output KPI's					
Levelized cost	LCOE	144	**78**	53	€/MWh
Levelized revenues		29	**35**	42	€/MWh
Levelized profits		-115	**-43**	-11	€/MWh

D.2 Offshore electrolyser (100 MW)

		Pessimistic	Base	Optimistic	Unit
Project KPI's					
Net present value	NPV	-4022	**-1191**	1565	M€
Internal rate of return	IRR	-	**-1**	17	%
Return on investment	ROI	-250	**-48**	413	%
Payback period	PP	-	**-**	7	years
Discounted return on investment	DROI	-131	**-68**	144	%
Discounted payback period	DPP	-	**77**	12	years
Equity KPI's					
Net present value	NPV	-3499	**-1188**	1000	M€
Internal rate of return	IRR	-59	**-6**	15	%
Return of investment	ROI	-212	**17**	725	%
Payback period	PP	-	**145**	4	years
Discounted return on investment	DROI	-206	**-112**	206	%
Discounted payback period	DPP	-	**-**	10	years
Output KPI's					
Levelized cost	LCOE	693	**394**	235	€/MWh
Levelized revenues		267	**265**	280	€/MWh
Levelized profits		-426	**-128**	46	€/MWh

D.3 Offshore electrolyser (500 MW)

		Pessimistic	Base	Optimistic	Unit
Project KPI's					
Net present value	NPV	-2856	**-460**	1959	M€
Internal rate of return	IRR	-	**6**	21	%
Return on investment	ROI	-185	**44**	553	%
Payback period	PP	-	**56**	5	years
Discounted return on investment	DROI	-109	**-31**	212	%
Discounted payback period	DPP	-214	**36**	10	years
Equity KPI's					
Net present value	NPV	-2514	**-590**	1315	M€
Internal rate of return	IRR	-55	**3**	18	%
Return of investment	ROI	-143	**155**	932	%
Payback period	PP	-14	**16**	3	years
Discounted return on investment	DROI	-171	**56**	306	%
Discounted payback period	DPP	-28	**57**	7	years
Output KPI's					
Levelized cost	LCOE	578	**338**	216	€/MWh
Levelized revenues		267	**265**	280	€/MWh
Levelized profits		-311	**-72**	65	€/MWh

D.4 Onshore electrolyser (100 MW)

		Pessimistic	Base	Optimistic	Unit
Project KPI's					
Net present value	NPV	-265	**234**	1525	M€
Internal rate of return	IRR	6	**12**	20	%
Return on investment	ROI	48	**191**	533	%
Payback period	PP	42	**13**	6	years
Discounted return on investment	DROI	-22	**23**	200	%
Discounted payback period	DPP	26	**20**	10	years
Equity KPI's					
Net present value	NPV	-331	**59**	1032	M€
Internal rate of return	IRR	3	**10**	18	%
Return of investment	ROI	142	**373**	903	%
Payback period	PP	14	**7**	3	years
Discounted return on investment	DROI	30	**19**	8	%
Discounted payback period	DPP	30	**19**	8	years
Output KPI's					
Levelized cost	LCOE	328	**284**	231	€/MWh
Levelized revenues		267	**265**	280	€/MWh
Levelized profits		-61	**-18**	49	€/MWh

D.5 Offshore solar

		Pessimistic	Base	Optimistic	Unit
Project KPI's					
Net present value	NPV	-539	**-252**	-147	M€
Internal rate of return	IRR	-	**-**	-	%
Return on investment	ROI	-283	**-134**	-81	%
Payback period	PP	-	**-**	-	years
Discounted return on investment	DROI	-105	**-99**	-86	%
Discounted payback period	DPP	-	**1681**	178	years
Equity KPI's					
Net present value	NPV	-384	**-229**	-133	M€
Internal rate of return	IRR	-29	**-15**	-8	%
Return of investment	ROI	-266	**-267**	-123	%
Payback period	PP	-	**-**	-	years
Discounted return on investment	DROI	-257	**-315**	-270	%
Discounted payback period	DPP	-	**-**	-	years
Output KPI's					
Levelized cost	LCOE	576	**240**	155	€/MWh
Levelized revenues		22	**32**	41	€/MWh
Levelized profits		-554	**-208**	-114	€/MWh

D.6 Onshore off-taker (grey hydrogen)

		Pessimistic	Base	Optimistic	Unit
Project KPI's					
Net present value	NPV	-328	**-72**	400	M€
Internal rate of return	IRR	21	**13**	-	%
Return on investment	ROI	266	**96**	-255	%
Payback period	PP	9	**26**	-	years
Discounted return on investment	DROI	-3	**19**	-94	%
Discounted payback period	DPP	13	**21**	453	years
Equity KPI's					
Net present value	NPV	-512	**-330**	11	M€
Internal rate of return	IRR	68	**-31**	13	%
Return of investment	ROI	-1637	**-916**	312	%
Payback period	PP	-	**-**	8	years
Discounted return on investment	DROI	573	**337**	-13	%
Discounted payback period	DPP	4	**6**	29	years
Output KPI's					
Levelized cost	LCOE	214	**204**	193	€/MWh
Levelized revenues		210	**208**	212	€/MWh
Levelized profits		-4	**4**	19	€/MWh

D7. Onshore off-taker (natural gas)

		Pessimistic	Base	Optimistic	Unit
Project KPI's					
Net present value	NPV	-73	**-43**	14	M€
Internal rate of return	IRR		**-8**	13	%
Return on investment	ROI	-639	**-307**	1898	%
Payback period	PP	-	**-**	1	years
Discounted return on investment	DROI	-480	**-338**	137	%
Discounted payback period	DPP	-	**-**	11	years
Equity KPI's					
Net present value	NPV	-56	**-33**	10	M€
Internal rate of return	IRR	-63	**-9**	13	%
Return of investment	ROI	-1710	**-778**	5200	%
Payback period	PP	-	**-**	0.5	years
Discounted return on investment	DROI	-1438	**-1000**	420	%
Discounted payback period	DPP	-	**-**	5	years
Output KPI's					
Levelized cost	LCOE	244	**228**	213	€/MWh
Levelized revenues		106	**106**	116	€/MWh
Levelized profits		-138	**-122**	-97	€/MWh

North Sea Energy offshore system integration

In collaboration and appreciation to

Consortium members
TNO
Bureau Veritas
Total E&P Nederland
Shell Nederland
NAM
EBN
Nederlandse Gasunie
ONE-Dyas
DEME Dredging
Neptune Energy Netherlands (after ENI)
HINT Global
Noordgastransport
NOGAT
Peterson Offshore Group
Port of Den Helder
Port of Amsterdam
Groningen Seaports
Equinor Energy
ElementNL
Port of Rotterdam
SmartPort
Net Zero Technology Centre
Stichting Dutch Marine Energy Centre
BP Offshore Renewables
RWE Offshore Wind
Wintershall Carbon Management Solutions (WDCMS)
Arcadis Nederland
Van Oord Offshore
Norce Norwegian Research Center
H2Sea
Aquaventus
MSG Sustainable Strategies
Stichting New Energy Coalition
TU Eindhoven
Deltares
Taqa Energy
Subsea7

Sounding Board members
Bluespring (Dutch Energy from Water Association)
Energy Innovation NL – Topsector Energie
Branche Organisatie Zeehavens
ECHT regie in tranisitie
IRO – The Association of Dutch Suppliers in the Offshore Energy Industry
Jonge Klimaatbeweging
Ministerie Klimaat Groene Groei (KGG)
Nexstep
NLHydrogen
Noordzeeoverleg
De Nederlandse WindEnergie Associatie (NWEA)
Stichting Natuur & Milieu
Stichting De Noordzee
Tennet TSO

North Sea Energy

offshore system integration