

Offshore Green Hydrogen Production on the Dutch Continental Shelf: Techno-Economic  
Feasibility Assessment (2025–2050)

by

Pim Eelco Sebastiaan Reuderink MBA CSci IEng

DISSERTATION

Presented to the Swiss School of Business and Management Geneva

and Paris School of Management

in Partial Fulfilment

of the Requirements

for the Swiss-French Dual Degree:

DOCTOR OF BUSINESS ADMINISTRATION

SWISS SCHOOL OF BUSINESS AND MANAGEMENT GENEVA

PARIS SCHOOL OF MANAGEMENT

February 2026

Offshore Green Hydrogen Production on the Dutch Continental Shelf: Techno-Economic  
Feasibility Assessment (2025–2050)

by

Pim Eelco Sebastiaan Reuderink

Supervised by

Dr. Miguel Cardoso BSc MSc

APPROVED BY

Vasiliki Grougiou



---

Dissertation chair

RECEIVED/APPROVED BY:

*Rense Goldstein Osmic*

Admissions Director

## **DEDICATION**

To Marleen and Floor.

Your unwavering support and patience sustained me throughout this doctoral journey. Every Saturday football match attended to see Floor play, these moments of presence alongside the demands of this work reflect what truly matters.

To my parents, Dick and Tunnella, for your steadfast belief and encouragement.

This dissertation on offshore hydrogen production and the energy transition is ultimately a commitment to the future that Floor's generation will inherit. The pathways analysed here, the technologies evaluated, the policy frameworks examined, the economic models developed, are all directed toward enabling a sustainable world in which she and her peers can thrive, pursue their passions, and build lives in a cleaner, healthier environment.

This achievement is, in the truest sense, ours.

## ACKNOWLEDGEMENTS

I wish to express my profound gratitude to Professor Miguel Cardoso, my promotor and mentor, whose rigorous guidance, intellectual generosity, and steady encouragement have shaped this dissertation from inception to completion.

My academic journey was formally initiated at the IEDC–Bled School of Management in the last years.

During the GMP professional master programme, where Professor Nenad Filipović first modelled the craft and discipline of scholarly inquiry. His example—combining conceptual clarity with executive relevance—set the tone for what followed. I am likewise indebted to Professor Hendrik Sebastiaan (Drikus) Kriek, whose leadership in teaching and standards of excellence have been a continuing source of motivation. Finally, I extend my appreciation to Professor Danica Purg, whose challenge-based learning approach and impact-oriented scholarship continued to shape my thinking.

Within the HYTROS consortium and the North Sea Energy programme, I acknowledge Dr Rene Peters, who set me on this path and whose leadership enabled the research context in which this work flourished; Dr Malin Andreasson, a valued peer whose incisive discussions and constructive critique strengthened the argumentation; and Dr Joris Korneef, for stewarding collaborative progress across disciplines. I am also grateful to Dr Lorenzo Squintini, an academic exemplar and HYTROS leader, whose scholarly rigour, methodological precision, and generous mentorship consistently elevated the quality of this research.

Special thanks go to Robert Seehawer of AquaVentus for his valuable contributions in Germany and for sharing context-specific insights that enriched the practical dimensions of this study.

I am thankful to Robert de Lange, my manager at Bureau Veritas, for consistent support, flexibility, and trust—without which balancing professional responsibilities with the demands of doctoral research would have been considerably more difficult.

Beyond the immediate research milieu, I owe a debt of inspiration to Professor Thomas Funke, Founder and Professor of Sustainability & Entrepreneurship at Tomorrow University of Applied Sciences, whose challenge-based approach to learning and impact-oriented scholarship continued to shape my thinking throughout this dissertation. I also wish to acknowledge Professor Dr. Sami Asad (Tomorrow University of Applied Sciences), whose oversight of my master's research phase and exacting feedback substantially improved my academic writing; his emphasis on systems thinking and real-world application proved invaluable to the development of this thesis.

Finally, I extend my appreciation to colleagues, partners, and friends across the HYTROS consortium and the North Sea Energy programme whose expertise, goodwill, and perseverance enriched this project. Any remaining errors are mine alone.

## ABSTRACT

### Offshore Green Hydrogen Production on the Dutch Continental Shelf: Techno-Economic Feasibility Assessment (2025–2050)

Pim Eelco Sebastiaan Reuderink

2026

Dissertation Chair: Miguel Cardoso

The rapid expansion of offshore wind capacity in the Netherlands and across the North Sea is creating structural challenges for onshore electricity grids, while simultaneously offering an opportunity to produce renewable hydrogen offshore as an alternative energy transport vector. Offshore hydrogen production has the potential to relieve grid congestion, reuse existing offshore infrastructure, and support decarbonisation of hard-to-abate industrial sectors. However, its economic feasibility remains uncertain due to high capital intensity, policy dependence, and uncertainty in future electricity prices, technology costs, and utilisation regimes.

This dissertation develops a replicable techno-economic decision-support framework to assess the feasibility of offshore green hydrogen production on the Dutch Continental Shelf over the period 2025–2050. A bottom-up levelised cost of hydrogen (LCOH) model is constructed and calibrated to Dutch offshore conditions, including wind resources, water depth, distance to shore, and existing oil and gas infrastructure. Three internally consistent scenarios (Conservative, Baseline, Optimistic) are analysed to capture plausible technology and market trajectories.

Uncertainty is treated explicitly through one-at-a-time sensitivity analysis, Monte Carlo simulation, and break-even threshold analysis. Results are further integrated into a multi-criteria decision analysis (MCDA) framework comparing offshore hydrogen pathways with alternative decarbonisation options.

Under baseline assumptions, the analysis demonstrates a 52% probability of achieving €2.0/kg LCOH by 2040, with outcomes highly sensitive to electricity price and capacity factor assumptions. Infrastructure repurposing provides substantial near-term economic and strategic advantage. The dissertation does not provide forecasts. However, it delivers a transparent and auditable framework for decision-making under uncertainty.

The baseline Monte Carlo analysis assumes statistical independence between input variables. Correlated inputs are examined exclusively as part of a dedicated sensitivity analysis using the Iman–Conover method.

**Key words:** Offshore green hydrogen; Dutch Continental Shelf (DCS); North Sea; Levelised Cost of Hydrogen (LCOH); PEM electrolysis; Electrolyser CAPEX; Capacity factor; Wake effects; Infrastructure repurposing; Hydrogen pipelines; HVDC transmission; Monte Carlo analysis; Sensitivity analysis; multi-criteria decision analysis (MCDA); Contracts for Difference (CfD); EU Hydrogen Bank; Grid congestion; TenneT; Gasunie;

# Table of Contents

<b>DEDICATION</b> .....	<b>3</b>
<b>ACKNOWLEDGEMENTS</b> .....	<b>4</b>
<b>ABSTRACT</b> .....	<b>5</b>
<b>LIST OF TABLES</b> .....	<b>11</b>
<b>LIST OF FIGURES</b> .....	<b>13</b>
<b>LIST OF ABBREVIATIONS</b> .....	<b>14</b>
<b>CHAPTER I - INTRODUCTION</b> .....	<b>15</b>
1.1 Relevance and Timeliness .....	15
1.1.1 Dutch Offshore Wind Expansion Context .....	15
1.1.2 The Onshore Grid Congestion Crisis .....	16
1.1.3 Hydrogen as Alternative Energy Transport Pathway.....	18
1.1.4 EU Policy Context and Strategic Urgency .....	19
1.1.5 Current Industry Challenges and Knowledge Gaps .....	20
1.2 Research Problem.....	20
1.2.1 Knowledge Gaps .....	20
1.2.2 Specific Research Focus .....	21
1.2.3 Temporal and Spatial Scope .....	22
1.2.4 Critical Uncertainties and Scenario Framing .....	22
1.3 Research Questions .....	23
1.3.1 Primary Research Question.....	23
1.3.2 Sub-Questions.....	23
1.4 Research Objectives .....	23
1.5 Significance of the Study .....	24
1.5.1 Scientific Contribution.....	24
1.5.2 Professional and Policy Impact.....	24
1.5.3 Broader Strategic Relevance.....	24
<b>CHAPTER II - REVIEW OF LITERATURE</b> .....	<b>25</b>
2.0 System Integration and Infrastructure Development for 2050 .....	25
2.1 Theoretical Framework: Energy System Integration and Sector Coupling .....	25
2.2 Offshore Wind-to-Hydrogen Technology Architecture .....	26
2.2.1 Electrolysis Technology Fundamentals and Options .....	26
2.2.2 Technology Selection for Dutch Offshore: PEM as Baseline .....	26
2.2.3 Offshore System Architecture: Integration with Wind Parks.....	27
2.2.4 Technology Readiness and Literature Consensus .....	27
2.3 Economic Analysis: LCOH Modelling Literature and Benchmarks .....	27
2.3.1 LCOH Definition and Calculation Framework.....	27
2.3.2 Current LCOH Benchmarks and Literature Review .....	28
2.3.3 Water and Desalination Costs for Offshore Hydrogen .....	28

2.3.4 Hydrogen Compression and Transport .....	28
2.4 Comparative Pathways and Alternative Decarbonisation Routes .....	29
2.4.1 Alternative Energy-Transport Pathways: HVDC Transmission vs Hydrogen Pipelines .....	29
2.4.2 Blue Hydrogen with Carbon Capture and Storage (CCS).....	30
2.4.3 Onshore Green Hydrogen Production.....	30
2.4.4 Ammonia and Other Hydrogen Carriers .....	30
2.5 Multi-Criteria Decision Analysis Methodology for Pathway Comparison .....	30
2.5.1 MCDA framework rationale .....	30
2.6 Technical Feasibility and Operational Considerations .....	33
2.6.1 Wind Variability and Electrolyser Operation.....	33
2.6.2 Safety and Environmental Considerations .....	34
2.6.3 Grid Connection and Hybrid Hub Concepts .....	34
2.7 Regulatory and Policy Framework.....	34
2.7.1 EU Regulatory Framework for Renewable Hydrogen .....	34
2.7.2 Dutch National Hydrogen Strategy and Infrastructure Planning .....	34
2.7.3 EU Infrastructure Planning: Trans-European Networks for Energy (TEN-E).....	34
2.8 Comparative Case Studies: Germany, Denmark, and the United Kingdom.....	34
2.8.1 Germany: AquaVentus Initiative .....	34
2.8.2 Denmark: Energy Island Project .....	35
2.8.3 United Kingdom: Techno-Economic Assessments .....	35
2.9 Knowledge Gaps and Research Positioning.....	35
<b>CHAPTER III - RESEARCH METHODOLOGY .....</b>	<b>36</b>
3.1 Research Design.....	36
3.2 System Boundary and Functional Unit.....	36
3.2.1 System Boundary .....	36
3.2.2 Functional Unit .....	36
3.3 Model Structure and Equations .....	37
3.3.1 Overall LCOH Formulation .....	37
3.3.2 Cost Component Formulation .....	37
3.3.3 Electricity Cost Representation.....	38
3.4 Technology Representation and Assumptions .....	38
3.4.1 Electrolyser Technology .....	38
3.4.2 Wind Resource and Capacity Factors .....	39
3.5 Scenario Design .....	40
3.5.1 Scenario Logic .....	40
3.5.2 Parameter Sets by Scenario and Time Horizon.....	40
3.6 Sensitivity and Uncertainty Analysis .....	41
3.6.1 One-at-a-Time (OAT) Sensitivity Analysis .....	41
3.6.2 Monte Carlo Simulation.....	42

3.6.3 Threshold and Break-even Analysis .....	44
3.7 Comparative Pathway Assessment (MCDA) .....	45
3.7.1 Alternative Pathways Defined .....	45
3.7.2 Criteria Selection .....	45
3.7.3 Weighting and Scoring .....	46
3.8 Data Sources and Calibration .....	46
3.8.1 Primary Data Sources .....	46
3.8.2 Consistency Checks and Validation.....	47
3.9 Limitations and Delimitations.....	49
3.10 Summary .....	53
<b>CHAPTER IV - RESULTS.....</b>	<b>54</b>
4.1 Levelised Cost of Hydrogen (LCOH) Trajectories .....	54
4.1.1 Baseline Scenario Results (2025–2050).....	54
4.1.2 Scenario Comparison and Trajectory Spread.....	56
4.2 Sensitivity Analysis Results .....	58
4.2.1 Tornado Diagrams and Parameter Ranking .....	58
4.2.2 Monte Carlo Probabilistic Analysis .....	61
4.2.3 Breakeven Analysis and Threshold Identification .....	64
4.2.4 Global Sensitivity Analysis: Sobol Variance Decomposition.....	66
4.3 Multi-Criteria Decision Analysis (MCDA) Results .....	71
4.3.1 Pathway Comparison and Scoring .....	71
4.3.2 Sensitivity to Criteria Weights .....	73
4.4 Summary of Key Findings .....	75
<b>CHAPTER V - DISCUSSION .....</b>	<b>76</b>
5.1 Interpretation of LCOH Results and Competitiveness Trajectories .....	76
5.1.1 Baseline Pathway to Cost-Competitiveness.....	76
5.1.2 Implications of Scenario Spread .....	76
5.1.3 Comparison with Literature Benchmarks and Alternative Pathways.....	77
5.2 Wake Effects and Capacity Factor Revalidation.....	78
5.2.1 Critical Re-Assessment: Wake Effects and Infrastructure Density Constraints.....	78
5.2.2 Empirical Wake Effect Findings: The Policy-Physics Gap .....	78
5.2.3 Physical Mechanism: Wake Effects and Atmospheric Boundary Layer Limits .....	79
5.2.4 Implications for Offshore Hydrogen LCOH Baseline .....	79
5.2.5 Repurposing Advantage Under Wake-Constrained Scenarios.....	80
5.2.6 Spatial Planning Optimisation: Lower-Density Layouts.....	80
5.2.7 Technology Interventions: Turbine Scale and Active Wake Control .....	81
5.2.8 Demand-Side Flexibility: Oversized Wind-to-Electrolyser Ratios .....	81
5.2.9 Uncertainty Quantification and Research Priorities.....	82
5.2.10 Revised Baseline Recommendations and Dissertation Conclusions.....	82

5.2.11 Implications for Dissertation Key Conclusions .....	83
5.3 Critical Success Factors for Offshore Hydrogen Viability .....	83
5.3.1 Electrolyser Cost Reduction to €400/kW by 2040 .....	83
5.3.2 Offshore Wind LCOE Reduction to €35/MWh by 2040 .....	84
5.3.3 Infrastructure Repurposing Regulatory Clarity and Implementation .....	84
5.3.4 Policy Support Mechanisms Sufficient to Bridge Competitiveness Gap (2025–2035) .....	85
5.3.5 Market Demand for Hydrogen Among Hard-to-Abate Industrial Sectors .....	86
5.4 Comparison with Alternative Pathways and System Integration .....	97
5.4.1 Offshore vs. Onshore Green Hydrogen: Cost and Feasibility .....	97
5.4.2 Hydrogen vs. HVDC Transmission: Grid Integration Perspective .....	100
5.4.3 Offshore Hydrogen vs. Blue Hydrogen: Transitional vs. Long-Term Strategy .....	102
5.5 Synthesis and Strategic Recommendations .....	102
5.6 Safety and Integrity of Offshore Hydrogen Production .....	103
<b>CHAPTER VI - SUMMARY, IMPLICATIONS, AND RECOMMENDATIONS.....</b>	<b>104</b>
6.1 Summary of Key Findings .....	104
6.2 Implications for Policy and Strategy .....	106
6.2.1 For Dutch Government (Ministry of Economic Affairs and Climate Policy, Rijksdienst voor Ondernemers).....	106
6.2.2 For System Operators (TenneT, Gasunie).....	108
6.2.3 For Developers and Investors .....	109
6.3 Contribution to Scientific Knowledge and Academic Discourse .....	110
6.3.1 Methodological Contributions .....	110
6.3.2 Substantive Contributions to Energy Transition Literature.....	111
6.4 Limitations of the Research.....	111
6.4.1 Analytical Limitations .....	111
6.4.2 Data and Assumption Uncertainties.....	112
6.4.3 Scope and Boundary Limitations .....	112
6.5 Recommendations for Future Research.....	113
6.6 Policy and Design Implications.....	113
6.7 Final Conclusions.....	114
<b>METHODOLOGICAL ASSURANCE STATEMENT .....</b>	<b>115</b>
<b>REFERENCES .....</b>	<b>116</b>
<b>APPENDIX A – FINANCIAL ASSUMPTIONS &amp; TECHNOLOGY PARAMETERS.....</b>	<b>120</b>
A.1 Financial Parameters (Summary) .....	120
A.2 Electrolyser Technology Parameters .....	120
A.3 Offshore Wind Parameters (DCS-Calibrated).....	120
<b>APPENDIX B – WAKE EFFECTS &amp; CAPACITY FACTOR SENSITIVITY .....</b>	<b>122</b>
B.1 Capacity Factor Impact on LCOH (2040 Baseline).....	122
B.2 Repurposing Advantage Across Wake Scenarios.....	122
B.3 Spatial Planning Trade-Offs (DCS Zones) .....	122

B.4 Mitigation Technology Effectiveness .....	123
<b>APPENDIX C – INFRASTRUCTURE REPURPOSING.....</b>	<b>124</b>
C.1 Platform Inventory & Suitability .....	124
C.2 Pipeline Inventory & Conversion Costs .....	124
C.3 Integrated System Example: Nederwiek 500 MW Cluster .....	124
<b>APPENDIX D – MULTI-CRITERIA DECISION ANALYSIS (MCDA) .....</b>	<b>126</b>
D.1 Criterion Definitions & Baseline Weighting .....	126
D.2 Pathway Scores (2040 Baseline, Equal Weighting) .....	126
D.3 Sensitivity to Alternative Weightings.....	126
<b>APPENDIX E – ENVIRONMENTAL &amp; LIFECYCLE ASSESSMENT .....</b>	<b>128</b>
E.1 Lifecycle Carbon Intensity by Pathway (2040) .....	128
E.2 Environmental Performance Summary .....	128
<b>APPENDIX F – REGULATORY FRAMEWORK &amp; POLICY .....</b>	<b>129</b>
F.1 EU & Dutch Regulatory Status (2025–2026).....	129
F.2 Critical Regulatory Barriers & Resolution Timeline .....	129
F.3 Policy Support Mechanisms (2025–2035) .....	129

## LIST OF TABLES

Table 1 - Monte Carlo parameter uncertainty specification for 2030 Baseline scenario. Epistemic uncertainty reflects knowledge gaps; aleatory uncertainty reflects inherent system randomness. ....	42
Table 2 - Carlo Convergence Diagnostics – 2030 Baseline Scenario.....	44
Table 3 - Validation via Reference Case Reproduction.....	48
Table 4 - HyNetwork Services Indicative Hydrogen Quality Specification.....	50
Table 5- Cost component breakdown – Baseline 2025.....	54
Table 6 - Cost component breakdown – Baseline 2040.....	55
Table 7 - LCOH trajectories across scenarios.....	56
Table 8 - Competitiveness milestone comparison .....	57
Table 9 - 2025 Baseline sensitivity results.....	58
Table 10 - 2040 Baseline sensitivity results.....	59
Table 11- Probability distribution for 2025 Baseline scenario (Monte Carlo simulation, 10,000 iterations). ....	61 <a href="#">decarbonisation</a>
Table 12 - Probability of achieving cost competitiveness – 2025 .....	62
Table 13 - Probability distribution for 2040 Baseline scenario (Monte Carlo simulation, 10,000 iterations). ....	62
Table 14 -Probability of achieving cost competitiveness – 2040 .....	63
Table 15- Electricity price thresholds for competitiveness.....	64
Table 16 -Electrolyser cost ceilings for competitiveness.....	65
Table 17 - Minimum capacity factors for competitiveness.....	65
Table 18 - Break-even year identification across scenarios.....	65
Table 19 - Sobol Global Sensitivity Indices – 2030 Baseline.....	66
Table 20 - Sobol Global Sensitivity Indices – 2040 Baseline.....	68
Table 21- OAT vs. Sobol Rankings.....	69
Table 22- Complete Sobol Indices.....	70
Table 23 - Criteria and scoring methodology .....	71
Table 24 -Pathway scores – Equal weighting (2040 baseline) .....	72
Table 25 -Pathway scores – Energy transition weighting (2040 baseline) .....	72
Table 26 - Alternative weighting schemes tested .....	74
Table 27 -Pathway rankings under alternative weightings (2040 baseline).....	74
Table 28 -Industrial Hydrogen Demand by Sector (2024 Baseline).....	87
Table 29 - Regulatory Mandate Scenarios and Implied Green Hydrogen Demand (2040).....	88
Table 30 - Carbon Price and Implied Green Hydrogen Market Penetration.....	88
Table 31 - Alternative Decarbonisation Pathways and Hydrogen Demand Sensitivity.....	89
Table 32 - Industrial Production Scenarios and Hydrogen Demand Implications (2040) .....	89
Table 33 - Integrated Demand Scenarios for Dutch Continental Shelf Offshore Hydrogen (2040).....	90
Table 34 - Demand Sensitivity Impact on 300 MW Offshore Hydrogen Project Economics (2040) ..	91
Table 35 - Long-Term offtake Agreement Impact on Project Financing .....	92
Table 36 - LTOA Coverage Scenarios for DCS Offshore Hydrogen .....	92
Table 37 -Hydrogen Quota Impact on Green Hydrogen Demand (Northwest Europe) .....	93
Table 38 - Probabilistic Green Hydrogen Demand Forecast (2040, Northwest Europe).....	93
Table 39 - Demand Risk Premium Impact on Project WACC and Economics.....	94
Table 40 - Combined Cost-Competitiveness and Demand Viability Assessment.....	96
Table 41- Demand Risk Assessment by Time Horizon .....	96
Table 42 - Cost comparison (2040 baseline) .....	100
Table 43 - System value comparison .....	101
Table 44 - Cost trajectory comparison.....	102
Table 45 -Financial Parameters (Summary) .....	120
Table 46 - Electrolyser Technology Parameters .....	120

Table 47- Offshore Wind Parameters (DCS-Calibrated) .....	120
Table 48 - Capacity Factor Impact on LCOH (2040 Baseline) .....	122
Table 49 - Repurposing Advantage Across Wake Scenarios.....	122
Table 50 - Spatial Planning Trade-Offs (DCS Zones).....	122
Table 51 - Mitigation Technology Effectiveness.....	123
Table 52 – Platform inventory .....	124
Table 53 - Pipeline Inventory & Conversion Costs .....	124
Table 54 - Integrated System Example: Nederwiek 500 MW Cluster.....	125
Table 55 - Criterion Definitions & Baseline Weighting .....	126
Table 56 - 2 Pathway Scores (2040 Baseline, Equal Weighting) .....	126
Table 57 - Sensitivity to Alternative Weightings.....	126
Table 58 - Lifecycle Carbon Intensity by Pathway (2040).....	128
Table 59 - Environmental Performance Summary.....	128
Table 60 - EU & Dutch Regulatory Status (2025–2026).....	129
Table 61 - Critical Regulatory Barriers & Resolution Timeline.....	129
Table 62 - Policy Support Mechanisms (2025–2035).....	130

## LIST OF FIGURES

<a href="#"><u>Figure 1. Maritime limits and boundaries of the Dutch Continental Shelf</u></a> .....	16
<a href="#"><u>Figure 2. GRID MAP TENNET GB 2025 Source: TENNET.NL</u></a> .....	17
<a href="#"><u>Figure 3. Map showing grid connection capacity available for consumption (left) and feed-in (right) in the Netherlands, October 2024- Source: IEA.org</u></a> .....	18
<a href="#"><u>Figure 4. Roadmap for offshore wind energy development in the Netherlands (October 2025)</u></a> .....	19
<a href="#"><u>Figure 5. LCOH Trajectory 2025-2050</u></a> .....	58
<a href="#"><u>Figure 6. Sensitivity Tornado Diagram</u></a> .....	61
<a href="#"><u>Figure 7. Cost Structure Evolution</u></a> .....	64
<a href="#"><u>Figure 8. Side-by-side comparison of One-at-a-Time (OAT) sensitivity (left) showing marginal LCOH impact ranges and Global Sobol sensitivity (right) showing variance contribution including interaction effects for 2040 Baseline scenario offshore hydrogen</u></a> .....	68
<a href="#"><u>Figure 9. Sobol First-Order vs. Total-Order Indices (2040 Baseline)</u></a> .....	70
<a href="#"><u>Figure 10. Wake Effects Impact</u></a> .....	78
<a href="#"><u>Figure 11. Offshore energy export scenarios: Scenario 1 (HVDC electricity), Scenario 2 (hydrogen pipeline), Scenario 3 (combined hybrid)</u></a> .....	97

## LIST OF ABBREVIATIONS

BV – Bureau Veritas

CAPEX – Capital Expenditure

CfD – Contract for Difference

CV – Coefficient of Variation ( $\sigma/\mu$ )

DBA – Doctor of Business Administration

DNV – Det Norske Veritas

DCS – Dutch Continental Shelf

EU – European Union H<sub>2</sub> – Molecular Hydrogen

HVDC – High-Voltage Direct Current

LCA – Life Cycle Assessment

LCOE – Levelised Cost of Electricity

LCOH – Levelised Cost of Hydrogen

MCDA – Multi-Criteria Decision Analysis

MCS – Monte Carlo Simulation

OAT – One-at-a-Time Sensitivity Analysis

OPEX – Operational Expenditure

PEM – Proton Exchange Membrane

PRCC – Partial Rank Correlation Coefficient

RPR – Relative Performance Range

TRL – Technology Readiness Level

WACC – Weighted Average Cost of Capital

## CHAPTER I - INTRODUCTION

### 1.1 Relevance and Timeliness

#### 1.1.1 Dutch Offshore Wind Expansion Context

The Netherlands is undergoing a transformational energy transition, with offshore wind expansion positioned as the cornerstone of decarbonisation strategy. The Dutch government has committed to installing 21 GW of offshore wind capacity by 2030 and scaling to 30–40 GW by 2040, with long-term targets reaching 70 GW by 2050. This trajectory represents one of Europe's most ambitious offshore wind deployment policies, reflecting both the exceptional wind resources of the North Sea—with capacity factors of 45–52% in offshore locations (wake-adjusted estimates of 42–48% under planned deployment densities)—and the spatial constraints that limit onshore renewable development in the densely populated Netherlands.

The scale of planned expansion is unprecedented in Dutch energy history. Current offshore wind capacity in the Dutch Exclusive Economic Zone (EEZ) stands at approximately 4.5 GW (as of January 2026), meaning the 2030 target requires five times this capacity within four years, followed by continued scaling to meet 2040 and 2050 targets. This expansion is grounded in European Union objectives under the REPowerEU initiative (European Commission, 2022) and the European Green Deal, which collectively target 300 GW of offshore wind capacity across the North Sea by 2050, with the Netherlands' proportional contribution reflecting its geographic advantage, established offshore industry expertise from decades of hydrocarbon operations, and explicit policy commitment to climate neutrality by 2050 under Dutch climate legislation.

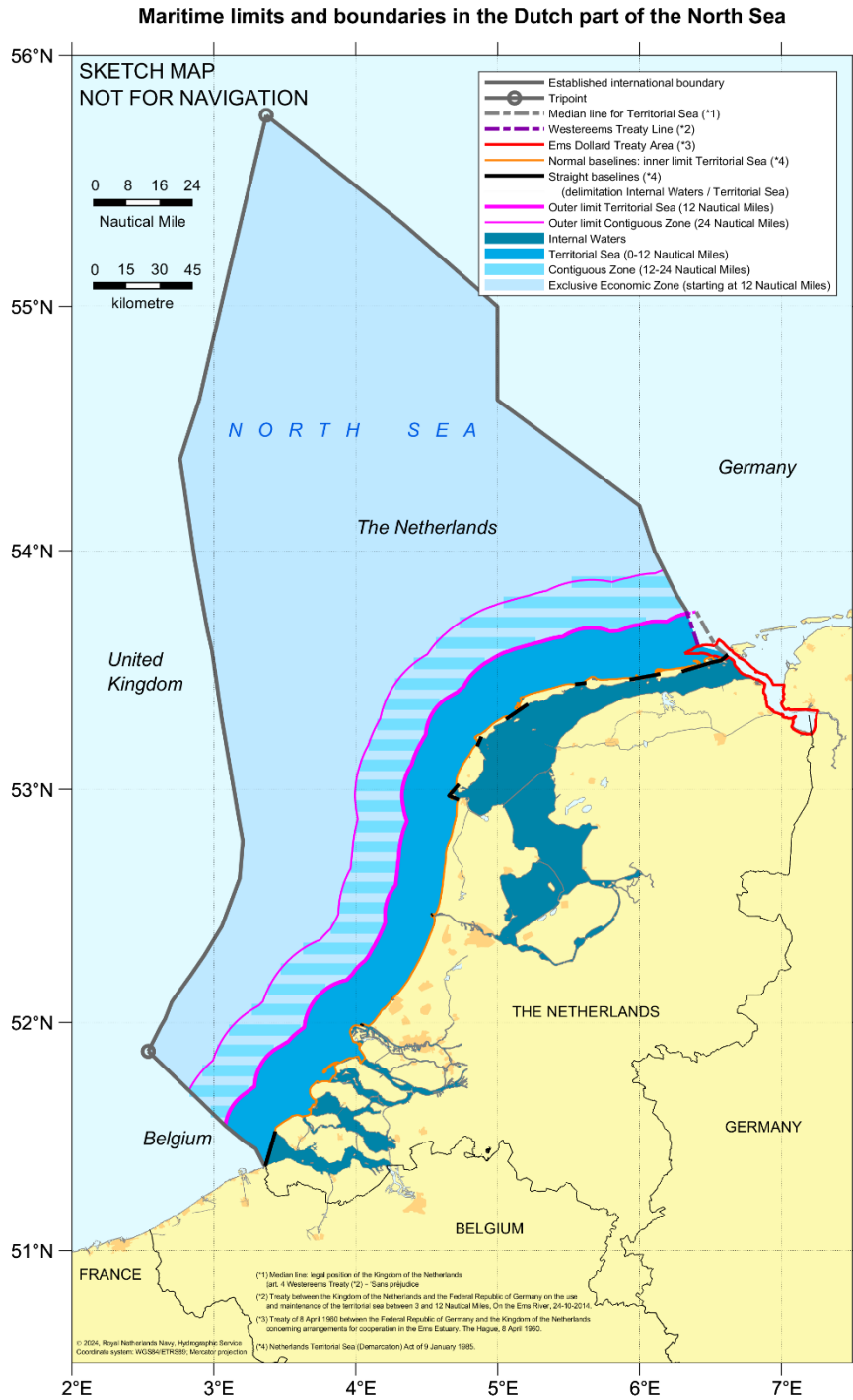


Figure 1- Maritime limits and boundaries of the Dutch Continental Shelf

The Dutch part of the North Sea comprises territorial waters (0-12 NM), contiguous zone (12-24 NM), and Exclusive Economic Zone (starting at 12 NM). Key boundaries with Germany (Ems Dollard Treaty), UK (tripoint), and Belgium are shown. Offshore hydrogen development primarily targets zones 20-150 km from shore within Dutch EEZ jurisdiction.

Source: Royal Netherlands Navy, Hydrographic Service, 2024. Coordinate system: WGS84/UTM31N.

### 1.1.2 The Onshore Grid Congestion Crisis

The planned upscaling of offshore wind capacity confronts a critical infrastructure bottleneck: the Dutch onshore electricity transmission grid is severely congested and increasingly unable to accommodate additional

renewable energy generation. TenneT (the Dutch transmission system operator) reports that grid connection requests exceed 100 GW—more than five times current peak electricity demand—with connection waiting times now extending beyond 2033 for projects in heavily constrained regions. This congestion stems from the convergence of multiple demands: accelerating offshore wind expansion, growing onshore renewable deployment (solar and wind), industrial electrification for decarbonisation (e.g., electric heat, hydrogen production for industry), and transportation electrification (electric vehicles), all competing for grid capacity designed for centralised fossil fuel generation.

Offshore wind generation exacerbates grid constraints due to the fundamental spatial mismatch between wind resources and demand centres. Far-offshore wind farms in designated development zones—particularly Nederwiek Noord and Nederwiek Zuid—are located 150–200 km from the coast, requiring dedicated High-Voltage Direct Current (HVDC) transmission systems to transport power to shore. HVDC technology is necessary for long-distance offshore transmission because traditional alternating current (AC) cables suffer excessive losses beyond 90 km. Each HVDC connection link entails:

- Capital costs: €1.5–2.5 million per megawatt of capacity (International Renewable Energy Agency, 2020; Härtel et al., 2017)
- Development timeline: 4–6 years from permitting to commissioning
- Onshore grid reinforcement: Additional investments of €2–4 billion per 2 GW HVDC link to integrate power into the transmission backbone and distribute electricity to demand centres

Meeting the complete offshore wind targets (30–40 GW by 2040, 70 GW by 2050) would require 35–40 dedicated HVDC connections with cumulative infrastructure costs exceeding €60–100 billion for offshore transmission alone. When combined with essential onshore grid reinforcement, secondary distribution infrastructure, and related grid expansion, total system costs could reach €90–150 billion by 2050. These capital requirements are compounded by temporal misalignment: offshore wind deployment operates under shorter timelines (4–5 years from site designation to power production), while grid expansion faces extended permitting and environmental review periods (7–10 years or longer in complex regions). This creates systematic delays in which new offshore wind capacity cannot be fully utilized, leading to curtailment (forced reduction of generation), redispatch costs (expensive operation of backup generation), and balancing system strain. Furthermore, grid expansion faces mounting political opposition due to visual impact concerns, land use conflicts, and local environmental impacts, particularly for overhead transmission corridors that cross populated or ecologically sensitive areas.



Figure 2. GRID MAP TENNET GB 2025 Source: TENNET.NL

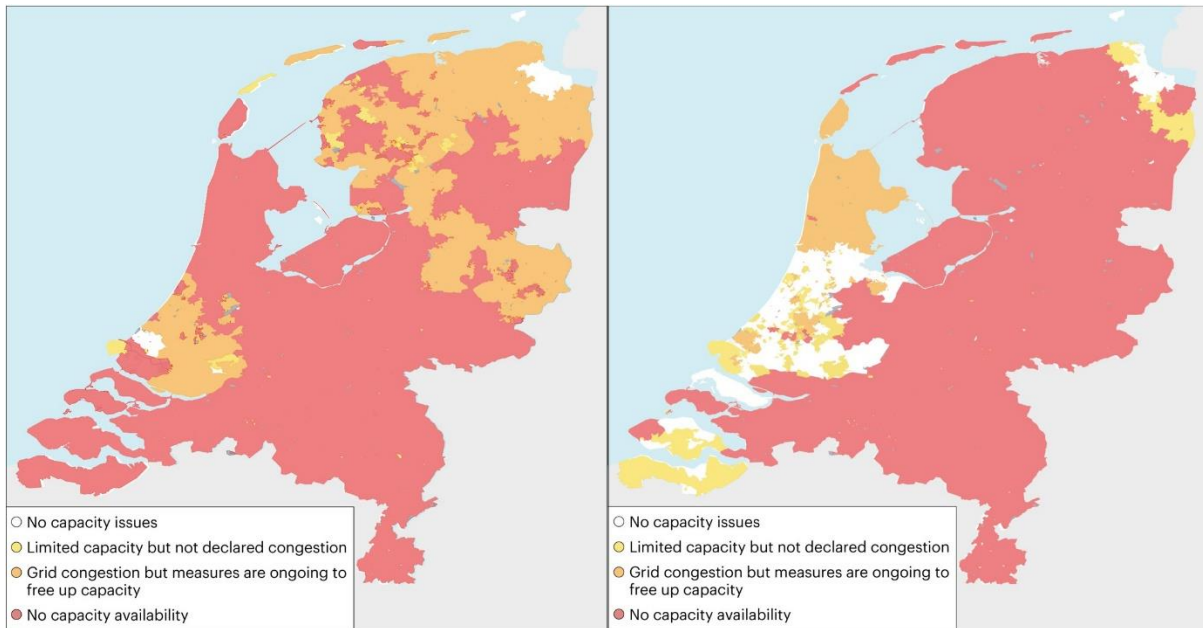


Figure 3. Map showing grid connection capacity available for consumption (left) and feed-in (right) in the Netherlands, October 2024- Source: IEA.org

### 1.1.3 Hydrogen as Alternative Energy Transport Pathway

These constraints have catalysed exploration of alternative energy transport and conversion pathways to complement electrical transmission. Offshore hydrogen production—converting wind-generated electricity to hydrogen through electrolysis, then transporting hydrogen via pipelines—emerges as a technically viable and potentially economically attractive alternative to exclusive reliance on electrical transmission. The technical logic is straightforward: hydrogen pipelines can transport energy at much lower cost per unit energy-distance for far-offshore applications (100–150 km from shore) compared to HVDC electrical transmission. Hydrogen pipelines operate at pressures of 50–100 bar, enabling energy transport densities that reduce pipeline diameter requirements. More critically, hydrogen can be produced, transported, and stored without the grid integration complexity of electricity:

- No grid integration: Hydrogen does not require converter stations, synchronization systems, or frequency management—it is produced, compressed, and transmitted independently of grid operations
- Energy storage: Hydrogen can be stored in tanks, salt caverns, or depleted reservoirs, providing temporal flexibility (seasonal storage) unlike electricity which requires simultaneous generation-consumption
- Industrial feedstock: Hydrogen serves directly as a chemical feedstock and fuel for hard-to-decarbonise sectors (steel, ammonia, chemicals, refining) where direct electrification is infeasible
- Geographic flexibility: Hydrogen production can be sited in far-offshore areas where winds are strongest, without incurring grid reinforcement costs

The Netherlands is particularly well-positioned for offshore hydrogen development, with:

1. Exceptional wind resources: Capacity factors of 50–55% in far-offshore locations under ideal spacing conditions (42–48% under policy-planned densities accounting for wake effects), among Europe's highest
2. Proximity to industrial demand: Major concentrations of hydrogen-consuming industry in Belgium (Antwerp), Germany (Ruhr Valley), and across the Netherlands (Rotterdam industrial cluster, Limburg chemicals and steel)
3. Geographic centrality: The Dutch coastal position in the North Sea allows distribution of hydrogen to Northwest European industrial centres via existing or easily extended pipeline corridors
4. Established offshore energy expertise: Decades of oil and gas operations have created technical workforce, supply chains, and regulatory frameworks for offshore energy infrastructure

### 1.1.4 EU Policy Context and Strategic Urgency

The European Union's hydrogen strategy, significantly amplified under the REPowerEU plan following the 2022 energy security crisis, elevates hydrogen to a central pillar of European decarbonisation and energy sovereignty (European Commission, 2022) . The revised EU hydrogen targets call for:

- 10 million tonnes of domestic renewable hydrogen production annually by 2030
- 10 million tonnes of hydrogen imports by 2030
- Progressive scaling to meet full decarbonisation needs by 2050 (estimated at 50 million tonnes annually for hard-to-abate sectors)

Offshore renewable hydrogen is explicitly identified in EU planning documents as a critical pathway to achieving these targets, given the limited land availability in Europe for the vast onshore renewable capacity required to produce equivalent hydrogen volumes. The North Sea's Energy Cooperation (NSEC), involving nine North Sea countries including the Netherlands, has identified offshore renewable hydrogen as a priority area for cross-border collaboration, with preliminary assessments suggesting potential for 40–60 GW of offshore electrolyser capacity across the North Sea by 2040, with the Dutch Continental Shelf representing a significant portion.

Financial support mechanisms have been established to bridge cost gaps during market development phases. The Important Projects of Common European Interest (IPCEI) framework has allocated over €5.4 billion to hydrogen projects across Europe, including several offshore initiatives. The EU Hydrogen Bank, launched in 2023 with an initial €3 billion budget (European Commission, 2023; International Energy Agency, 2024a), provides fixed-premium auction support to close the cost differential between renewable hydrogen and fossil-based alternatives, designed to support projects until technology learning and scale economies drive competitiveness (anticipated around 2035–2040).

REPowerEU urgency is particularly acute for the Netherlands: the disruption of Russian natural gas supplies exposed Europe's vulnerability to energy import dependencies, with the Netherlands historically serving as a major gas hub for Europe. Domestic offshore hydrogen production offers a pathway to energy sovereignty while maintaining the Netherlands' strategic position in European energy infrastructure. Green hydrogen produced offshore could partially substitute for depleted natural gas reserves, positioning the Dutch Continental Shelf as a potential renewable hydrogen hub for Northwest Europe.

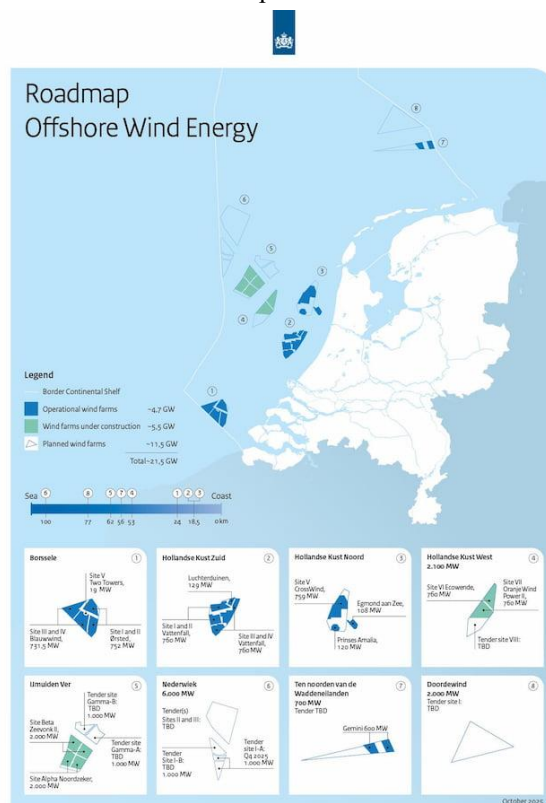


Figure 4. Roadmap for offshore wind energy development in the Netherlands (October 2025)

*The Dutch government's roadmap identifies 21.3 GW of operational and planned offshore wind capacity distributed across eight zones (Borssele, Hollandse Kust, Egmond aan Zee, Doordewind, IJmuiden Ver, Nederwiek, Ten noorden van de Waddenzijlanden). Current operational capacity (dark blue): 4.7 GW; under construction (~1.5 GW); planned (~11.5 GW). This offshore wind infrastructure forms the energy supply foundation for hydrogen production pathways analyzed in this dissertation. The geographic distribution demonstrates spatial constraints and policy-driven deployment densities that create the wake effects studied in Chapter V.*

*Source: Ministry of Infrastructure and Water Management (Rijkswaterstaat), October 2025.*

### **1.1.5 Current Industry Challenges and Knowledge Gaps**

Despite the strategic imperative and growing policy support, offshore hydrogen development in the Netherlands remains nascent, hampered by significant techno-economic uncertainties and knowledge gaps. The HEROW (Hydrogen Energy for Renewable Offshore Wind) project exemplifies these challenges: initially proposed as a 500 MW offshore hydrogen demonstration facility expected to operate by 2027–2028, HEROW has experienced repeated delays and scope reductions, with current operational timeline uncertain and pushed beyond 2030. These delays stem from:

**Economic viability concerns:** Preliminary cost estimates for near-term offshore hydrogen production indicate Levelized Cost of Hydrogen (LCOH) of €8–12/kg—three to four times higher than grey hydrogen from natural gas (€2–3/kg) and significantly above the EU's 2030 competitiveness target of €4–5/kg for renewable hydrogen. These elevated costs reflect the combination of high offshore wind capital expenses (€2,800–3,200/kW for far-offshore systems), electrolyser costs (€800–1,200/kW for PEM systems), offshore installation premiums (30–50% above onshore), and capacity factors of 42–52% (validated range accounting for wake effects and wind variability).

**Technical uncertainties:** Offshore electrolysers must operate in harsh marine environments (salt spray, humidity, temperature extremes, motion for floating systems), requiring ruggedization that increases costs and may reduce reliability compared to onshore systems. Seawater feedstock requires treatment and desalination, adding energy consumption and equipment complexity. Hydrogen compression to transport pressures (50–100 bar) adds further energy penalties and capital costs. These technical challenges remain only partially resolved at commercial scale, creating investment risk that deters private capital commitment.

**Regulatory and permitting gaps:** Offshore hydrogen production lacks explicit regulatory frameworks in most jurisdictions (as of January 2026), creating ambiguity about permitting processes, safety standards, environmental requirements, and liability allocation. Platform siting regulations, electrolyzer equipment standards, hydrogen pipeline transport classification, and grid-connection protocols for offshore hydrogen systems remain underdeveloped. This regulatory uncertainty creates significant delays and increases development costs.

**Market and demand uncertainties:** Offshore hydrogen projects require long-term offtake agreements to secure project financing, but potential customers in hard-to-abate sectors (steel, ammonia, chemicals, refining) face their own transition uncertainties and are hesitant to commit to premium-priced green hydrogen without regulatory mandates or carbon pricing that justify higher costs. The classic chicken-and-egg problem—supply won't develop without demand certainty; demand won't commit without supply availability—requires policy intervention through mechanisms like Contracts for Difference (CfD) that guarantee minimum hydrogen prices.

## **1.2 Research Problem**

### **1.2.1 Knowledge Gaps**

Existing literature on offshore hydrogen production, while growing, exhibits three critical knowledge deficiencies relevant to Dutch Continental Shelf conditions:

**First: Lack of context-specific feasibility analysis.** Most offshore hydrogen techno-economic studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) apply generic parameters (Giampieri et al., 2023; Hill et al., 2024; Rogeau et al., 2023) or focus on specific national contexts (UK, Germany, Denmark) without detailed calibration to Dutch geographic, wind resource, and infrastructure contexts. The Dutch Continental Shelf presents distinct conditions—specific wind patterns in Nederwiek Noord/Zuid zones, particular water depths and seabed characteristics, unique grid constraints on the TenneT network, specific industrial hydrogen demand patterns, and differential costs for subsea infrastructure in Dutch waters. Without DCS-calibrated analysis, strategic decisions rely on generic European benchmarks rather than site-specific feasibility assessment.

Second: Incomplete temporal analysis of cost competitiveness. Most studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) provide static cost estimates for specific years (typically 2030 or 2040) without modelling the dynamic trajectory of cost reduction from present through 2050 or identifying the critical transition points where offshore hydrogen achieves competitiveness with alternative pathways. This temporal gap is problematic because investment decisions require understanding not only ultimate viability but also:

- When does offshore hydrogen become cost-competitive with grey hydrogen, blue hydrogen, or continued grid-only electrification?
- How long does policy support need to be sustained?
- At what cost milestones do investment risks diminish sufficiently for private capital?
- What parameter combinations (electricity price, electrolyzer costs, utilization rates) enable competitiveness at different time horizons?

Without scenario-based trajectory analysis with explicit assumptions about technology learning rates, scale economies, and policy support, industry and government stakeholders cannot effectively plan investment sequences or phase support mechanisms.

Third: Inadequate sensitivity and uncertainty quantification. While some analyses include limited sensitivity testing on individual parameters (Jang et al., 2022), comprehensive multi-parameter sensitivity analysis, probabilistic uncertainty quantification, and identification of critical thresholds for viability are largely absent from the Dutch offshore hydrogen literature. Given the high uncertainty in key drivers—future electricity prices (renewable energy oversupply vs. constrained renewable supply), electrolyser cost trajectories (manufacturing scale-up success vs. supply chain constraints), wind capacity factors (wake effects under planned deployment densities), and utilization profiles (constant operation vs. flexible dispatch)—this analytical gap creates significant risk for investors and policymakers.

### 1.2.2 Specific Research Focus

This dissertation addresses the identified knowledge gaps through rigorous techno-economic feasibility assessment of offshore hydrogen production specifically for the Dutch Continental Shelf, with particular emphasis on:

1. DCS-calibrated LCOH modelling: Development of a detailed, transparent cost model with explicit assumptions for all components (offshore wind generation, PEM electrolysis, compression, hydrogen transport via pipeline, and onshore delivery), calibrated to Dutch wind resources, water depths, and infrastructure costs.
2. Temporal trajectory analysis (2025–2050): modelling cost evolution under three explicit scenarios (Conservative, Baseline, Optimistic) across five-year intervals, identifying the specific years and parameter combinations where offshore hydrogen achieves cost competitiveness with alternatives.
3. Comprehensive sensitivity and uncertainty analysis: One-at-a-time parameter sensitivity, tornado diagrams, Monte Carlo probabilistic analysis, and breakeven threshold identification to clarify which parameters most critically determine viability and at what values competitiveness is achievable.
4. Grid-centric decision framing: Explicit analysis of how offshore hydrogen production—through reduced electrical export requirements—relieves TenneT transmission congestion and avoids or defers HVDC expansion costs, positioning offshore hydrogen as a grid infrastructure solution, not merely a hydrogen production alternative.
5. Multi-criteria integration: Use of Multi-Criteria Decision Analysis (MCDA) to systematically compare offshore hydrogen against alternative pathways (onshore hydrogen with dedicated renewables, pure HVDC transmission, blue hydrogen with carbon capture, and hybrid approaches) across economic, technical, environmental, regulatory, and infrastructure dimensions.

Infrastructure repurposing integration: The research integrates infrastructure repurposing of existing offshore oil and gas assets as a central strategic pathway alongside greenfield development scenarios. The economic case for infrastructure reuse is substantial (Peters et al., 2021; Ossenbrink et al., 2022; Van Stralen et al., 2025)—existing offshore platforms and pipelines provide ready-built infrastructure that can be retrofitted for hydrogen production and transport at significantly lower capital costs than greenfield alternatives.

Detailed infrastructure inventory, suitability assessment, and repurposing cost analysis are provided in Appendix C, quantifying the potential for 84 identified platforms and 1,500 km of pipeline network conversion. The assessment includes: platform-by-platform suitability criteria (structural capacity, location, remaining service life); pipeline network analysis for hydrogen compatibility (material specifications, pressure ratings, corrosion

resistance); cost estimation methodology comparing repurposing versus greenfield development; and regulatory requirements for certification and safety compliance.

The inclusion of both repurposing and greenfield development pathways enables comparative feasibility assessment and multi-criteria decision analysis (Chapter IV) to identify the economically and strategically optimal pathway. This dual-pathway framing reflects the strategic reality that offshore hydrogen development can proceed via infrastructure reuse (near-term, lower capital intensity, accelerated deployment) or new systems (longer-term, optimized for hydrogen service), with optimal strategy depending on timing, capital availability, and regulatory environment.

### 1.2.3 Temporal and Spatial Scope

Temporal scope: 2025–2050, aligning with Dutch climate targets and EU energy transition planning horizons. Analysis employs five-year intervals (2025, 2030, 2035, 2040, 2045, 2050) with particular focus on 2025–2035, the critical period when policy support and demonstration projects must prove technical feasibility and initiate cost reduction pathways.

Spatial scope: The Dutch Continental Shelf (DCS), defined as the offshore area under Dutch jurisdiction in the North Sea, extending approximately 200 km from shore and encompassing 57,000 km<sup>2</sup> of seabed. Within the DCS, particular attention focuses on:

- Nederwiek Noord and Nederwiek Zuid wind farm areas (150–200 km offshore): Far-offshore zones with strongest wind resources (capacity factors 50–55% under ideal spacing, 42–48% under planned densities) and maximum distance from shore, making hydrogen transport particularly advantageous
- IJmuiden Ver area (70–100 km offshore): Nearer-offshore zone with moderate capacity factors (45–48%) and intermediate transmission distances, potentially attractive for near-term deployment
- Hollandse Kust and Borssele areas (40–80 km offshore): Existing and planned wind farm zones closer to shore with different economic characteristics

The geographic focus on the DCS is justified because:

1. The Netherlands has explicit policy commitments and spatial allocations for offshore wind development
2. The DCS presents a full spectrum of offshore conditions (near-shore to far-offshore) suitable for comparative analysis
3. The Netherlands' advanced regulatory environment and established offshore industry provide realistic context for feasibility assessment
4. Results are directly actionable for Dutch strategic planning and international positioning

### 1.2.4 Critical Uncertainties and Scenario Framing

Offshore hydrogen feasibility is characterized by substantial uncertainty across multiple dimensions, which the research addresses through explicit scenario development:

Technology uncertainties: Electrolyser costs have declined rapidly from €2,000/kW (2015) to €800–1,200/kW (2023–2024), but future trajectories are uncertain. Projections range from €300–800/kW by 2030 depending on manufacturing scale-up success, technology breakthroughs, and supply chain development. Similarly, offshore wind costs show uncertainty, with optimistic scenarios projecting €1,800–2,200/kW by 2030 while conservative scenarios suggest €2,400–2,800/kW due to supply chain constraints and far-offshore installation challenges.

Market uncertainties: Future electricity prices depend on renewable energy deployment rates, grid infrastructure development, energy storage penetration, fossil fuel price trajectories, and carbon pricing mechanisms—all highly uncertain over 25-year horizons. Similarly, hydrogen demand and willingness-to-pay in hard-to-abate sectors depends on alternative decarbonisation pathway costs, regulatory mandates (e.g., renewable hydrogen quotas), and carbon pricing levels.

Capacity factor uncertainties: Recent validation studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) demonstrate that offshore wind capacity factors under planned deployment densities (8–10 MW/km<sup>2</sup>) are 42–48% rather than policy-assumed 50–56%, due to wake effects from cluster-scale wind farm interactions. This validated range informs the baseline scenario assumptions.

These uncertainties are addressed through three explicit scenarios:

- Conservative (2025–2035 focus): Assumes slower cost reductions (electrolyser €900/kW by 2030), higher electricity prices (€50–60/MWh), moderate capacity factors (42–45%), requiring sustained policy support (CfD €6–8/kg)

- Baseline (2040 focus): Assumes moderate cost reductions aligned with industry projections (electrolyser €650/kW by 2030), competitive electricity prices (€40/MWh), validated capacity factors (45–48%), approaching competitiveness with policy support (CfD €4–5/kg)
- Optimistic (2050 focus): Assumes aggressive cost reductions (electrolyser €500/kW by 2030), favorable electricity prices (€30–35/MWh), excellent capacity factors (50–52% with wake mitigation), achieving cost-competitiveness without support (LCOH €2–3/kg)

## 1.3 Research Questions

### 1.3.1 Primary Research Question

What are the techno-economic prerequisites for cost-competitive green hydrogen production on the Dutch Continental Shelf, and under which scenarios and timeframes does offshore hydrogen achieve viability as a strategic solution for managing North Sea wind integration and supporting industrial decarbonisation?

This question integrates three dimensions:

1. Techno-economic feasibility: What cost trajectories are achievable under realistic assumptions about technology learning, capital costs, and operational efficiency?
2. Competitiveness thresholds: At what electricity prices, electrolyzer costs, capacity factors, and hydrogen selling prices does offshore hydrogen become competitive with alternatives (grey hydrogen, blue hydrogen, continued grid-only electrification)?
3. Strategic positioning: How does offshore hydrogen production contribute to solving the Netherlands' grid congestion bottleneck and supporting the energy transition across Europe?

### 1.3.2 Sub-Questions

SQ1 – Techno-Economic Feasibility: What are the Levelized Cost of Hydrogen (LCOH) profiles for DCS offshore hydrogen systems across Conservative, Baseline, and Optimistic scenarios in 2030, 2040, and 2050, and what are the critical cost drivers?

SQ2 – Competitiveness Pathways: Under which combinations of electricity price, electrolyser CAPEX, capacity factor, and policy support (e.g., CfD levels) does offshore hydrogen achieve competitiveness (€3–5/kg) by 2035–2040, and how sensitive is competitiveness timing to parameter variations?

SQ3 – Grid Integration and System Value: How much does offshore hydrogen production—through reduced electrical export requirements and hydrogen transport via pipelines instead of HVDC—defer or avoid costly transmission infrastructure expansion on the TenneT network, and what is the quantified system value of this grid relief?

SQ4 – Strategic and Policy Framework: What regulatory changes, policy support instruments (CfD levels, CAPEX grants, hydrogen quotas), and infrastructure investments are required to enable commercial-scale offshore hydrogen deployment by 2035–2040?

## 1.4 Research Objectives

The dissertation aims to:

1. Develop a DCS-calibrated LCOH model with transparent documentation of all assumptions, enabling stakeholders to vary parameters and explore cost sensitivities relevant to their planning horizons.
2. Quantify competitiveness trajectories across three scenarios and three time horizons (2030, 2040, 2050), identifying the specific years and parameter combinations where offshore hydrogen becomes viable.
3. Quantify grid integration value by modelling how offshore hydrogen production avoids or defers HVDC transmission expansion costs, positioning hydrogen as a grid solution, not merely an energy source.
4. Identify critical success factors (technology learning, cost reductions, policy support, market development) and timing milestones required for viable deployment.
5. Compare offshore hydrogen against alternative pathways (onshore hydrogen, HVDC transmission, blue hydrogen) using structured multi-criteria analysis to clarify when offshore hydrogen is strategically preferable.
6. Deliver actionable recommendations for Dutch government (RVO), system operators (TenneT, Gasunie), and developers regarding optimal investment sequencing and policy design through 2050.

## 1.5 Significance of the Study

### 1.5.1 Scientific Contribution

This research advances energy systems engineering and policy analysis by:

- First DCS-contextualized LCOH model integrating North Sea wind conditions, Dutch seawater treatment requirements, and offshore installation costs specific to Dutch waters—establishing robust baseline cost trajectories for European feasibility assessments.
- Rigorous temporal trajectory analysis with explicit scenario assumptions and sensitivity frameworks, advancing beyond single-point-estimate projections common in industry reports.
- Grid-centric integration explicitly quantifying how offshore hydrogen avoids transmission infrastructure costs, demonstrating the value of coordinated planning across energy carriers (electricity and hydrogen) rather than siloed development.
- Multi-criteria decision framework suitable for complex, multi-stakeholder infrastructure choices in uncertain environments—applicable to other cross-border energy infrastructure (interconnectors, storage, carbon capture).
- Infrastructure repurposing quantification providing the first detailed cost-benefit analysis of offshore platform and pipeline conversion for hydrogen service, with direct policy implications for decommissioning strategies.

### 1.5.2 Professional and Policy Impact

For Dutch government (RVO, Ministry EZK):

- Quantified evidence base for updating the Offshore Wind Energy Roadmap and integrating offshore hydrogen into the national hydrogen strategy
- Credible timelines for regulatory development, permitting reforms, and policy instrument design
- Clarity on the balance between grid investment vs. hydrogen infrastructure in managing wind integration

For system operators (TenneT, Gasunie):

- Quantified grid relief value from offshore hydrogen production, informing transmission planning and hydrogen network development priorities
- Technical requirements and interface specifications for offshore hydrogen integration

For developers and investors:

- Bankability benchmarks (cost thresholds, policy support levels) enabling risk assessment and project Go/No-Go decisions
- Competitive landscape analysis clarifying when offshore hydrogen is economically superior to alternatives

### 1.5.3 Broader Strategic Relevance

For EU energy transition:

- Dutch case study informing broader North Sea hydrogen backbone development, leveraging shared offshore wind resources across multiple jurisdictions
- Evidence-based input to NSEC planning and EU hydrogen infrastructure coordination

For climate ambition:

- Clear pathway to renewable molecule production for hard-to-abate sectors, supporting EU decarbonisation targets without requiring massive land area expansion for onshore renewables
- Demonstration of how infrastructure repurposing accelerates energy transition by 5–7 years while reducing capital requirements by €400–600 million per GW deployed

## CHAPTER II - REVIEW OF LITERATURE

### 2.0 System Integration and Infrastructure Development for 2050

Beyond energy, the scarcity of sustainable carbon introduces a critical challenge for producing synthetic fuels and chemical feedstocks. This necessitates either large-scale carbon imports or deployment of Direct Air Capture technologies, both of which impose additional energy and infrastructure requirements (Netbeheer Nederland, 2023).

Flexibility portfolios include 40–70 GW of batteries, 10–25 GW of electrolysers, and 3–11 GW of power-to-heat capacity, complemented by 15–20 GW of dispatchable generation. These measures address imbalances caused by variable renewable generation, which by 2050 will lead to peak deficits of 35–50 GW and surpluses of up to 95 GW (Netbeheer Nederland, 2023).

For electricity, the extra-high-voltage grid must grow by 20–33%, with 50–100 new high-voltage substations added by 2050. Hydrogen infrastructure requires approximately 1,850 km of converted or new pipelines, offshore connections from 2030 onwards, and compression facilities. Storage needs are substantial: operational hydrogen storage ranges from 14–29 TWh, while strategic reserves may reach 59 TWh to mitigate seasonal variability and import risks (Netbeheer Nederland, 2023).

The transition to a climate-neutral energy system requires a profound transformation of infrastructure and flexibility mechanisms. The *Integrale Infrastructuurverkenning 2030–2050 (II3050)* outlines four scenarios for achieving climate neutrality in the Netherlands by 2050: Decentralised Initiatives (DEC), National Leadership (NAT), European Integration (EUR), and International Trade (INT). Each scenario demands extensive expansion of electricity networks, large-scale deployment of hydrogen infrastructure, and integration of flexibility assets (Netbeheer Nederland, 2023).

### 2.1 Theoretical Framework: Energy System Integration and Sector Coupling

Energy system integration and sector coupling provide the primary conceptual lens for analysing offshore hydrogen production on the Dutch Continental Shelf (DCS). Rather than treating electricity, molecules (hydrogen and derivatives) and infrastructure (grid and pipelines) as separate systems, the energy integration paradigm considers them as interdependent components of a coupled socio-technical system (Lund et al., 2015; Brown et al., 2018). In this view, offshore wind, hydrogen production, electricity transmission and industrial demand are optimised jointly to deliver least-cost decarbonisation subject to security-of-supply and sustainability constraints.

The concept of sector coupling emphasises the strategic value of linking the power sector with end-use sectors such as industry, mobility and heating via energy carriers like hydrogen (Robinius et al., 2017; Madeddu et al., 2020). Hydrogen produced from renewable electricity (“green hydrogen”) can act both as an energy vector that shifts demand across time (through storage) and space (through pipelines), and as a decarbonised feedstock for hard-to-abate sectors where direct electrification is technically or economically challenging (International Energy Agency, 2019; Agora Energiewende, 2021).

Within this framework, offshore hydrogen is not simply an alternative method of using offshore wind; it is an infrastructure solution that alleviates power-grid constraints while enabling deep decarbonisation of industrial clusters. The theoretical literature on energy system integration identifies four pillars that are particularly relevant to this dissertation:

1. System efficiency and flexibility. Coupling electricity and hydrogen systems can reduce total system costs by utilising surplus renewable electricity, providing seasonal storage and offering flexible demand that supports grid balancing (Lund et al., 2015; Victoria et al., 2019).
2. Infrastructure substitution and complementarity. Hydrogen pipelines and electrical transmission are partially substitutable infrastructure options for moving offshore wind energy to demand centres, with different cost structures, lead times and spatial impacts (Bussar et al., 2016; Glenk and Reichelstein, 2019).
3. Path dependency and lock-in. Early infrastructure choices (for example, exclusive reliance on high-voltage direct current (HVDC), or early investment in hydrogen pipelines) can lock systems into sub-optimal pathways, suggesting the need for comparative techno-economic assessment across multiple vectors (Geels, 2014; Rogge and Dütschke, 2018).
4. Multi-criteria optimisation under uncertainty. Because energy-transition choices involve economic, technical, environmental and social dimensions, scholars increasingly employ multi-criteria decision analysis (MCDA) to evaluate infrastructure options under uncertainty (Pohekar and Ramachandran, 2004; Wang et al., 2009).

This dissertation adopts these pillars to position offshore hydrogen—with and without infrastructure repurposing—as one of several competing system configurations for integrating large-scale offshore wind in the Netherlands. The literature review therefore proceeds from theory to technology, economics, comparative pathways, technical feasibility, regulatory frameworks and international case studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) before synthesising knowledge gaps and research positioning in Section 2.8.

## **2.2 Offshore Wind-to-Hydrogen Technology Architecture**

### **2.2.1 Electrolysis Technology Fundamentals and Options**

Electrolysis is the core technology for converting offshore renewable electricity into hydrogen. Commercially relevant electrolyser technologies include alkaline electrolysis (AEL), proton exchange membrane (PEM) electrolysis, and, at earlier stages of development, solid oxide electrolysis cells (SOEC) (Buttler and Spliethoff, 2018; Zhang et al., 2020).

Alkaline electrolysers are the most mature and widely deployed technology, characterised by comparatively low capital expenditure (CAPEX) but lower current density, larger footprint and reduced flexibility compared with PEM systems (Schmidt et al., 2017; International Renewable Energy Agency, 2020). Typical efficiency ranges are 62–70% (higher heating value, HHV) with commercial stack lifetimes exceeding 60,000 operating hours under stable conditions (International Renewable Energy Agency, 2020).

PEM electrolysers employ a solid polymer electrolyte and noble-metal catalysts, enabling higher current densities, rapid dynamic response to variable power input and compact designs better suited to constrained offshore platforms (Carmo et al., 2013; Millet et al., 2019). Efficiency is broadly comparable to advanced alkaline systems (around 65–75% HHV), but CAPEX has historically been higher due to catalyst and membrane costs.

SOEC systems operate at high temperatures (600–850°C) and offer the prospect of very high electrical efficiency when coupled with waste heat or high-temperature processes, but they remain at lower technology readiness levels (TRLs) and are not yet considered bankable for large-scale projects, particularly in offshore environments (Böhm et al., 2020).

The offshore context imposes additional constraints on electrolyser selection: limited space, weight restrictions, harsh marine environment (salt spray, humidity, corrosion), and the need for frequent dynamic operation following wind power profiles. The literature increasingly converges on PEM as the preferred baseline for offshore projects because of its compactness, start-up flexibility and superior load-following capability (International Renewable Energy Agency, 2020; Giampieri et al., 2023; Hill et al., 2024).

#### **2.2.2 Technology Selection for Dutch Offshore: PEM as Baseline**

Several techno-economic studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) explicitly evaluate electrolyser options for offshore applications and conclude that PEM is currently the most suitable technology for far-offshore wind-to-hydrogen systems, despite its higher CAPEX, because of lower balance-of-plant costs and better integration with variable renewables (Daiyan et al., 2020; Giampieri et al., 2023; Rogeau et al., 2023). Key arguments include:

- **Dynamic operation.** PEM stacks tolerate frequent start-up/shut-down cycles and operate efficiently over a wide load range (10–100%), which is essential for following wind profiles without excessive curtailment or oversized storage (Carmo et al., 2013; Millet et al., 2019).
- **Compactness and modularity.** Higher power density reduces platform footprint and structural loads, critical in the DCS where existing oil and gas platforms have constrained topside capacity and weight limits (Giampieri et al., 2023).
- **Water quality tolerance.** PEM requires high-purity de-ionised water, but integration with desalination and polishing units is well understood, and offshore demonstration projects indicate manageable technical risk (International Renewable Energy Agency, 2020; Hill et al., 2024).

By contrast, alkaline electrolysers are considered more suitable for large onshore plants with stable power supply and fewer space constraints, while SOEC systems are not yet ready for deployment in harsh offshore environments (Buttler and Spliethoff, 2018; Böhm et al., 2020).

Given this evidence, this dissertation adopts PEM electrolysis as the baseline electrolyser technology for all offshore hydrogen system configurations on the Dutch Continental Shelf. Alternative technologies are discussed comparatively in Appendix G, but they are not used in the primary LCOH model.

### 2.2.3 Offshore System Architecture: Integration with Wind Parks

The technological architecture for offshore wind-to-hydrogen systems can be broadly categorised into three configurations (International Renewable Energy Agency, 2020; Giampieri et al., 2023; Hill et al., 2024):

1. Centralised offshore hydrogen hubs. Multiple wind farms feed power into a shared offshore hub (platform or artificial island) hosting large-scale electrolyzers. Hydrogen is then exported via pipeline to shore. This architecture benefits from economies of scale in electrolyzers and compression, but requires substantial upfront investment and coordinated planning.
2. Distributed platform-based electrolysis. Individual platforms (including repurposed oil and gas installations) host modular electrolyzers connected to nearby wind farms. Hydrogen from multiple platforms is collected into a trunk pipeline to shore. This configuration allows stepwise deployment, facilitates asset repurposing and can leverage existing jackets, topsides and pipelines, but may exhibit higher specific CAPEX due to smaller unit sizes.
3. Onshore electrolysis with offshore electrical transmission. Offshore wind energy is transmitted to shore via HVAC/HVDC, and electrolysis is performed onshore. This configuration is technologically mature and leverages existing industrial infrastructure, but exacerbates grid congestion on the Dutch high-voltage network, as outlined in Chapter I.

Literature on system design for the North Sea increasingly explores hybrid configurations where part of the energy is transmitted as electricity and part as hydrogen, depending on grid conditions, price signals and industrial demand (Bussar et al., 2016; Blanco et al., 2018). From an energy-system integration perspective, such hybrid systems may deliver superior overall value by combining the efficiency of direct electrification with the flexibility of hydrogen.

In the context of the DCS, system architecture must also consider the substantial portfolio of existing oil and gas platforms and pipelines. Studies on infrastructure repurposing indicate that converting selected platforms into hydrogen hubs and re-using selected gas pipelines for hydrogen transport can significantly reduce capital costs and accelerate deployment timelines (Peters et al., 2021; Ossenbrink et al., 2022). This dissertation therefore explicitly compares repurposed and greenfield architectures in subsequent chapters, with techno-economic modelling supported by the detailed infrastructure inventory in Appendix C.

### 2.2.4 Technology Readiness and Literature Consensus

The technology readiness level (TRL) of key components is critical for assessing near- to medium-term feasibility. Offshore wind turbines and substations are commercially mature (TRL 9) and widely deployed in the North Sea. PEM electrolyzers are at TRL 8–9 for onshore applications and TRL 6–7 for large-scale offshore use, with several 10–100 MW demonstration projects under development in Europe (International Renewable Energy Agency, 2020; Giampieri et al., 2023). Hydrogen pipelines are a mature technology, although repurposing existing natural gas pipelines for 100% hydrogen requires case-specific material and integrity assessments (Peters et al., 2021).

Recent reviews conclude that no single fundamental technological barrier prevents offshore wind-to-hydrogen systems from being deployed at scale in the 2030–2040 horizon, provided that electrolyser costs continue to decline along observed learning curves, regulatory frameworks for hydrogen safety and infrastructure are clarified, and appropriate risk-sharing mechanisms are put in place for first-of-a-kind projects (International Renewable Energy Agency, 2020; International Energy Agency, 2022; Giampieri et al., 2023).

The literature thus supports the central premise of this dissertation: that techno-economic feasibility, rather than fundamental technology readiness, is the key question for Dutch offshore hydrogen in the period 2025–2050.

## 2.3 Economic Analysis: LCOH Modelling Literature and Benchmarks

### 2.3.1 LCOH Definition and Calculation Framework

The levelised cost of hydrogen (LCOH) is the primary economic indicator used in this dissertation to compare offshore hydrogen with alternative decarbonisation pathways. LCOH represents the discounted lifetime cost per kilogram of hydrogen produced, accounting for capital expenditure, operating expenditure, replacement costs and financing parameters (Reichelstein and Sahoo, 2015; Glenk and Reichelstein, 2019).

Following standard practice in the literature (Bhandari et al., 2014; Reuß et al., 2019), LCOH is defined as:

$$\text{LCOH} = \frac{\sum_{t=0}^T \text{It} + \text{Ot} + \text{Ft}(1+r)^t}{\sum_{t=1}^T \text{Ht}(1+r)^t} \quad \text{LCOH} = \frac{\sum_{t=1}^T \text{I}(1+r)^t + \text{O} + \text{F}}{\sum_{t=1}^T \text{H}(1+r)^t}$$

where  $\text{It}$  denotes investment-related cash flows (including replacements),  $\text{Ot}$  operating and maintenance costs,  $\text{Ft}$  fuel and electricity costs,  $\text{Ht}$  hydrogen output in year  $t$ ,  $r$  the discount rate and  $T$  the project lifetime. Project-specific formulations used in Chapter III decompose these components further into wind-farm CAPEX, electrolyser CAPEX, compression, pipelines, platform costs and fixed/variable OPEX.

Two aspects are particularly important in offshore contexts: (i) the electricity cost component, which often dominates the long-run LCOH, and (ii) the capacity factor and utilisation profile of the electrolyser, which depend on wind resource quality, curtailment and operational strategy (Reuß et al., 2019; Glenk and Reichelstein, 2019). The literature consistently shows that high utilisation and low-cost renewable electricity are prerequisites for competitive green hydrogen.

### 2.3.2 Current LCOH Benchmarks and Literature Review

A growing body of work estimates current and future LCOH for offshore hydrogen in the North Sea and comparable regions. Most studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) converge on relatively high costs for near-term projects, with significant reduction potential towards 2040–2050.

For early offshore projects in the North Sea, Giampieri et al. (2023) estimate LCOH in the range of €6–10/kg for 2030-type deployments, depending on distance to shore, electrolyser CAPEX and electricity prices. Hill et al. (2024) find similar ranges for UK case studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024), with LCOH values of €7–9/kg for 2030 assuming electrolyser CAPEX of €700–900/kW and offshore wind levelised cost of energy (LCOE) of €50–70/MWh. Rogeau et al. (2023) report slightly lower costs for optimised hub-and-spoke architectures, but still conclude that early offshore hydrogen will require substantial policy support.

For longer-term horizons, multiple studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) project LCOH in the €2–4/kg range by 2040–2050 under favourable assumptions (International Energy Agency, 2019; International Renewable Energy Agency, 2020; Reuß et al., 2019). Key drivers of this decline include:

- electrolyser CAPEX reductions through technological learning and mass manufacturing (learning rates of 12–18% per cumulative doubling are commonly assumed) (Schmidt et al., 2017; Glenk and Reichelstein, 2019);
- declining offshore wind LCOE, particularly in high-resource locations with mature supply chains (WindEurope, 2021); and
- improved utilisation through better matching of system design to wind profiles and through hybrid operation with electricity exports or storage (Blanco et al., 2018; Victoria et al., 2019).

However, most published analyses use generic North Sea assumptions or national contexts other than the Netherlands (for example, UK, Germany, Denmark). Only a limited number of studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) explicitly calibrate their models to Dutch wind zones, seabed conditions or infrastructure characteristics. This lack of DCS-specific LCOH modelling constitutes one of the knowledge gaps addressed by this dissertation (see Section 2.8).

In addition, many studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) have only recently begun to incorporate wake effects and high-density deployment constraints in capacity-factor assumptions. Borgers et al. (2024), based on mesoscale modelling of 72 operational and planned North Sea wind farms, show that realistic capacity factors under 8–10 MW/km<sup>2</sup> deployment densities are 42–48%, lower than policy assumptions of 50–56%. This has direct implications for offshore hydrogen LCOH and is explicitly integrated into the revised modelling in Chapters III–V.

### 2.3.3 Water and Desalination Costs for Offshore Hydrogen

Water supply is a necessary input to electrolysis. For offshore systems, seawater must be treated and desalinated to meet electrolyser purity requirements. The literature, however, is relatively consistent in finding that desalination costs represent a minor share of total LCOH, even in offshore settings (Bhandari et al., 2014; Reuß et al., 2019; International Renewable Energy Agency, 2020).

Typical CAPEX for reverse-osmosis desalination units sized for offshore hydrogen projects is on the order of €100–200/kWe/l of electrolyser capacity, with specific water costs below €0.50/m<sup>3</sup> (Reuß et al., 2019; International Renewable Energy Agency, 2020). When converted into a cost per kilogram of hydrogen, this translates into approximately €0.05–0.10/kg, i.e. less than 2–3% of LCOH for most plausible scenarios (Bhandari et al., 2014; Reuß et al., 2019).

Consequently, this dissertation follows the literature in treating desalination as a necessary but not decisive cost component. Water-related costs are explicitly included in the LCOH model but are not considered a primary driver in sensitivity analysis.

### 2.3.4 Hydrogen Compression and Transport

Compression and transport are more significant contributors to offshore hydrogen cost. Hydrogen produced offshore must be compressed to pipeline pressure (typically 50–100 bar) or to higher pressures for storage or

shipping. Compression energy demand is usually 5–10% of the hydrogen’s energy content, depending on inlet conditions and final pressure (International Energy Agency, 2019; Reuß et al., 2019).

For pipeline transport, several studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) evaluate the cost of new-build hydrogen pipelines versus repurposed natural-gas pipelines in the North Sea region. Peters et al. (2021) and Ossenbrink et al. (2022) estimate that re-using suitable existing pipelines can reduce transport CAPEX by 50–70% relative to new hydrogen-dedicated pipelines, after accounting for inspection, refurbishment and adaptation costs. When expressed in LCOH terms, transport-cost differences between repurposed and greenfield pipeline solutions are on the order of €0.30–0.60/kg, depending on distance and throughput (Peters et al., 2021).

Comparative analyses of HVDC versus hydrogen-pipeline transport show that electricity transmission tends to be more cost-effective for shorter distances and high load factors, whereas hydrogen pipelines become competitive or superior at longer distances and when grid congestion or onshore reinforcement costs are considered (Bussar et al., 2016; Blanco et al., 2018; Glenk and Reichelstein, 2019). These findings align with the Dutch context, where far-offshore zones such as Nederwiek Noord and Zuid are located 150–200 km from shore and onshore grid-reinforcement requirements are substantial (see Chapter I).

This dissertation builds on these insights by: (i) explicitly distinguishing compression and pipeline cost components in the LCOH model; (ii) differentiating between repurposed and greenfield pipeline cases; and (iii) situating offshore hydrogen as an alternative to, and complement for, HVDC expansion in integrated system planning.

## 2.4 Comparative Pathways and Alternative Decarbonisation Routes

### 2.4.1 Alternative Energy-Transport Pathways: HVDC Transmission vs Hydrogen Pipelines

The fundamental infrastructure choice for integrating far-offshore wind on the Dutch Continental Shelf (DCS) is between high-voltage direct current (HVDC) electrical transmission and hydrogen transport via subsea pipelines. Recent North Sea techno-economic studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) analyse this trade-off with distance- and utilisation-explicit models (Bussar et al., 2016; Rogeau et al., 2023).

HVDC cables and converter stations are the established solution for exporting offshore wind. For high-capacity links (~2–4 GW) at ~150 km distance, representative cost components include subsea cables (~€2.5–4.0 million km<sup>-1</sup>), converter stations (~€200–400 million per connection point), and onshore reinforcement (~€0.5–1.5 billion per 2 GW) (International Renewable Energy Agency, 2020; WindEurope, 2021; International Energy Agency, 2022). These assumptions yield total system costs of ~€3–5 billion (≈€1.5–2.5 million MW<sup>-1</sup>) for a 2 GW, 150 km link, with efficiency ~92–95% for transmission (Lazard, 2024; International Renewable Energy Agency, 2021).

Advantages of HVDC include technological maturity in the North Sea, high point-to-point efficiency, and a relatively established regulatory framework. Disadvantages are distance-linked cost escalation, complex grid integration (converter synchronisation and protection), permitting challenges at landfall, and the absence of temporal storage (Blanco et al., 2018; Glenk and Reichelstein, 2019). In congested Dutch grid contexts, incremental HVDC capacity typically requires extensive onshore reinforcement with long permitting lead times (~7–10 years) (TenneT, 2023; TNO, 2024).

Subsea hydrogen pipelines operating at ~50–100 bar provide an alternative energy-transport vector. Representative cost components include pipelines (~€1.5–2.5 million km<sup>-1</sup>), compression (~€100–200 million per platform), and onshore integration (~€0.2–0.5 billion per connection point). For 2 GW equivalent energy capacity, total system costs are ~€1.5–2.5 billion (≈€0.75–1.25 million MW<sup>-1</sup> equivalent) (Peters et al., 2021; Ossenbrink et al., 2022). Hydrogen pipelines confer grid independence (no frequency management), enable storage (tanks, caverns, reservoirs), offer direct industrial feedstock value, and allow modular build-out matched to production growth (Peters et al., 2021; ENTSG, 2024).

Power-to-power comparisons must distinguish scope: electrolysis plus reconversion yields ~45–55% round-trip efficiency in 2030–2040 scenarios, whereas HVDC efficiencies (~92–95%) reflect transmission only (International Renewable Energy Agency, 2020; International Energy Agency, 2022). Comparative analyses report that, for 2 GW export capacity, hydrogen pipelines can achieve cost advantage beyond ~100–150 km, with savings of ~€0.5–1.0 billion rising to ~€1.5–2.5 billion beyond ~200 km—subject to utilisation and siting assumptions (Bussar et al., 2016; Rogeau et al., 2023). Storage and industrial-use value further strengthen hydrogen pathways but are not captured in pure infrastructure-cost comparisons (Blanco et al., 2018; Victoria et al., 2019).

For far-offshore sites (> 150 km) in congested grids, several studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) report higher system value from hybrid concepts—HVDC for baseline export and hydrogen pipelines for peaks/excess generation (Blanco et al., 2018; Rogeau et al., 2023).

#### **2.4.2 Blue Hydrogen with Carbon Capture and Storage (CCS)**

Blue hydrogen—produced from natural gas via steam-methane reforming (SMR) with ~90% CO<sub>2</sub> capture—offers a transitional pathway. Contemporary cost estimates are ~€3.5–5.5 kg<sup>-1</sup>, declining modestly to ~€2.5–4.0 kg<sup>-1</sup> by 2050 under favourable CCS scaling (Parkinson et al., 2019; Noussan et al., 2021). Advantages include retrofit of existing assets (~10–15% of greenfield cost), faster deployment (~1–2 years), and near-term availability while green-hydrogen systems scale (Noussan et al., 2021).

Disadvantages are significant: continued fossil-fuel dependence conflicts with EU sovereignty objectives, methane leakage (~1–5%) erodes lifecycle benefits, and CCS network maturity is uncertain—creating stranded-asset risk. Blue hydrogen does not directly support renewable-integration needs or full electrification (International Energy Agency, 2019; Noussan et al., 2021). Most studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) position blue hydrogen as transitional (~2030–2035), with green hydrogen emerging as dominant beyond 2040 (Hydrogen Council, 2021; International Energy Agency, 2019).

#### **2.4.3 Onshore Green Hydrogen Production**

Onshore green hydrogen (grid-powered or dedicated onshore renewables) provides an alternative route, with LCOH ~€5.5–8.5 kg<sup>-1</sup> today, potentially ~€2.5–4.0 kg<sup>-1</sup> by 2040 under favourable assumptions (International Renewable Energy Agency, 2020; Lazard, 2024). Benefits include technological maturity (TRL 8–9), established supply chains, lower installation/maintenance costs than offshore, and proximity to industrial clusters (Schmidt et al., 2017; International Renewable Energy Agency, 2020).

Limitations include lower capacity factors (onshore wind ~35–45%; solar ~15–20% vs offshore ~50–55%), land constraints in dense regions, lengthy grid-connection queues (many extending beyond 2033), and limited ability to relieve congestion (Schmidt et al., 2017; TenneT, 2023). In the Dutch context, onshore hydrogen serves specific applications but lacks the grid-relief benefits and scale potential of offshore hydrogen for far-offshore integration (Van Stralen et al., 2025).

#### **2.4.4 Ammonia and Other Hydrogen Carriers**

Ammonia (NH<sub>3</sub>) is an alternative carrier for long-distance transport and storage, leveraging established shipping and avoiding cryogenic hydrogen. Synthesis via Haber–Bosch (~150–250 bar, 400–500 °C) consumes ~10–12% of hydrogen’s energy; cracking adds ~8–10%, yielding ~55–60% round-trip (Valera-Medina et al., 2018; Hansson et al., 2020).

For offshore applications, ammonia may suit very long distances (> 500 km) or export markets lacking pipeline connectivity. For < 300 km, direct hydrogen pipelines are generally more attractive due to fewer conversion steps and simpler operations (Hansson et al., 2020; Valera-Medina et al., 2018). Accordingly, this dissertation treats hydrogen pipelines as baseline; ammonia is outside primary scope for DCS-to-Netherlands transport.

### **2.5 Multi-Criteria Decision Analysis Methodology for Pathway Comparison**

#### **2.5.1 MCDA framework rationale**

Offshore hydrogen development presents a classic multi-criteria problem: pathways must be evaluated across incommensurable dimensions such as economic cost, technical maturity, environmental impact, infrastructure compatibility, and regulatory feasibility. In such contexts, traditional cost–benefit analysis (CBA) that monetises all impacts risks systematically undervaluing non-market factors, including ecosystem resilience, regulatory certainty, strategic energy autonomy, and technology risk. By contrast, purely qualitative stakeholder deliberation lacks the transparency, reproducibility, and mathematical rigour required for institutional decision-making on long-lived infrastructure.

Multi-Criteria Decision Analysis (MCDA) addresses this methodological gap through structured frameworks that: (1) explicitly weight competing objectives in line with stakeholder priorities, (2) operationalise qualitative criteria through transparent scoring systems, (3) enable systematic sensitivity testing across alternative weighting schemes, and (4) maintain full auditability for scrutiny by government, industry, and civil society. MCDA is particularly suited to long-term energy infrastructure decisions where multiple stakeholders hold legitimately conflicting preferences, trade-offs are non-obvious, and reversibility is limited once capital is committed for several decades.

In the energy transition literature, MCDA has been widely applied to renewable technology selection, offshore wind farm siting, and hydrogen pathway comparison. These applications show that MCDA can integrate technical, economic, environmental, and social criteria in a way that remains comprehensible to policymakers. In this dissertation, MCDA is used to compare five decarbonisation pathways—offshore green hydrogen with infrastructure repurposing, offshore green hydrogen with greenfield infrastructure, onshore green hydrogen, blue hydrogen with carbon capture and storage, and hydrogen imports—within a single consistent framework.

### 2.5.2 Compensatory vs. outranking MCDA approaches

The MCDA literature distinguishes two main methodological families: compensatory and outranking approaches.

#### Compensatory methods (weighted-sum, SMART, TOPSIS)

Compensatory methods assume that decision-makers accept trade-offs between criteria: poor performance on one dimension can be offset (compensated) by strong performance on another. The simplest and most widely used compensatory approach is the weighted-sum (additive value) model:

$S_j = \sum (w_i \times v_{ij})$ , where  $S_j$  is the total score for pathway  $j$ ,  $w_i$  is the weight of criterion  $i$ , and  $v_{ij}$  is the normalised performance score of pathway  $j$  on criterion  $i$ .

where  $S_j$  is the total score for pathway  $j$ ,  $w_i$  is the weight of criterion  $i$ , and  $v_{ij}$  is the normalised performance score of pathway  $j$  on criterion  $i$ . In an offshore hydrogen context, a pathway with relatively high cost but excellent environmental performance could still achieve a high overall score if the environmental criterion carries sufficient weight.

Key strengths of compensatory methods include:

- Mathematical simplicity and computational efficiency, even for many alternatives and criteria.
- High transparency: stakeholders can see how each criterion contributes to the final score.
- Direct interpretability for non-specialist audiences, since results appear as simple rankings and composite scores.

Main limitations are:

- Potential for unrealistic “over-compensation,” where extremely poor performance on critical criteria (e.g. safety, environmental thresholds) is masked by strong performance elsewhere.
- Implicit assumption of linear, proportional trade-offs across the full range of each criterion.
- Sensitivity to scale and normalisation choices, requiring careful documentation.

#### Outranking methods (ELECTRE, PROMETHEE)

Outranking methods construct pairwise dominance relations instead of aggregating everything into a single score. In ELECTRE- and PROMETHEE-type approaches, pathway A is said to outrank pathway B if, broadly, (i) A performs at least as well as B on most weighted criteria (concordance), and (ii) A is not dramatically worse than B on any single criterion beyond an agreed veto or discordance threshold. This structure explicitly allows for incomparability when trade-offs exceed what stakeholders consider acceptable.

Key strengths of outranking methods are:

- Ability to model “red lines” through veto thresholds, preventing unacceptable trade-offs (e.g. ruling out a pathway whose environmental impact exceeds a critical limit regardless of cost advantage).
- Recognition of incomparability: some alternatives may not be rankable without further value judgements.

Typical limitations are:

- Greater mathematical and conceptual complexity, making results harder to communicate to non-technical decision-makers.
- Need to specify additional parameters (preference, indifference, and veto thresholds), which introduces further elicitation burden.
- Potential for large incomparability sets that reduce decisiveness if thresholds are strict.

Both families are widely used in energy planning. For this dissertation, they serve complementary roles: the compensatory approach is adopted as the primary decision-support tool, while outranking methods are identified as a secondary validation approach for future work.

### 2.5.3 Justification for a compensatory weighted-sum model

This dissertation employs a compensatory weighted-sum model as the primary MCDA approach for three main reasons that relate directly to the Dutch offshore hydrogen policy context.

### (1) Policy communication and interpretability

Decisions on offshore hydrogen in the Dutch Continental Shelf involve ministries (EZK, RVO), system operators (TenneT, Gasunie), developers, industrial offtakers, and regulators. These actors require clear, communicable outputs that support Cabinet-level decisions on multi-billion-euro infrastructure without necessitating familiarity with advanced MCDA theory. A weighted-sum approach yields simple statements such as “Pathway P1 (offshore hydrogen with repurposed infrastructure) ranks first with score X; P2 ranks second with score Y,” which can be readily understood and debated.

Outranking outputs (e.g. partial preorders with concordance/discordance indices) are more difficult to interpret for non-specialists and can complicate political decision-making, even if they offer finer theoretical nuance. For a practitioner-oriented DBA thesis aimed at decision-support, the transparency of the weighted-sum model is therefore a decisive advantage.

### (2) Stakeholder preference heterogeneity and sensitivity testing

Energy-transition decisions are characterised by heterogeneous stakeholder preferences:

- Government and system operators give relatively high weight to grid relief, system reliability, and decarbonisation.
- Developers and financiers emphasise cost, risk, and bankability.
- Environmental NGOs focus strongly on lifecycle emissions and ecosystem impacts.

The weighted-sum framework can represent this heterogeneity by defining multiple weighting scenarios that reflect distinct preference profiles. In this dissertation, four schemes are applied (described in detail in Appendix D): an equal-weight baseline, an energy-transition-prioritising scheme, an investor-prioritising scheme, and an environment-prioritising scheme. The MCDA is then re-run for each scheme to test whether conclusions are robust or preference-dependent.

Results show that offshore hydrogen with infrastructure repurposing (Pathway P1) ranks first under all four schemes, while the ordering of secondary pathways (onshore green hydrogen, blue hydrogen, imports) is more sensitive to preference changes. This pattern indicates that the primary recommendation is robust, while some secondary choices legitimately depend on whose preferences are given priority—exactly the sort of insight that MCDA is intended to surface.

### (3) Mitigating compensatory risks through thresholds and constraints

The main conceptual critique of compensatory models is the risk of “trading away” unacceptably poor performance on one criterion against benefits on another. To mitigate this, the MCDA in this dissertation incorporates explicit constraints and safeguards:

- Environmental knockout: Pathways with lifecycle greenhouse gas intensities above a threshold (200 gCO<sub>2</sub>-eq per kWh system output) are excluded from consideration, regardless of cost or technical benefits. All evaluated pathways fall below this threshold, but the rule prevents future inclusion of environmentally incompatible options.
- Technology readiness constraint: For near-term deployment (2027–2032), only technologies with Technology Readiness Level (TRL)  $\geq 7$  are considered admissible, avoiding speculative high-scoring but immature options (e.g. offshore SOEC at TRL 5–6).
- Weighting sensitivity checks: By deliberately re-weighting criteria to favour environment or cost, the analysis tests whether any pathway’s high ranking is an artefact of one particular weighting. The consistent top ranking of P1 across all schemes suggests that no single dimension is unrealistically dominating the decision.

Together, these design choices retain the transparency benefits of a compensatory model while constraining its most problematic behaviours.

#### **2.5.4 Weight derivation in this dissertation**

The criterion weights used in the baseline MCDA are not arbitrary but derived from a synthesis of policy documents, regulatory criteria, and academic literature on energy transition priorities. The derivation followed three steps:

1. Policy and strategy review: Dutch and EU strategic documents (e.g. the National Hydrogen Strategy, EU taxonomy and RED II/III provisions) were examined to infer the relative emphasis placed on cost-effectiveness, security of supply, environmental performance, and system integration.
2. Thematic clustering into four criterion groups: Individual criteria were grouped into four domains—economic, technical, infrastructure/system, and environmental—reflecting the structure later implemented in the MCDA (see Appendix D.2).

3. Translation into numerical weights: Qualitative priorities in policy documents (e.g. “cost-effective decarbonisation,” “efficient use of existing infrastructure”) were mapped into relative weights for each domain, calibrated so that:
  - Economic criteria receive slightly higher weight than an equal split, reflecting strong policy and investor focus on cost and competitiveness.
  - Technical and infrastructure criteria jointly reflect system reliability and integration concerns.
  - Environmental criteria are given a substantial but not dominant weight, acknowledging that all considered pathways must already meet EU and Dutch climate targets.

The resulting baseline weighting (detailed in Appendix D) is then complemented by three alternative schemes representing distinct stakeholder perspectives (transition-focused, investor-focused, environment-focused). The absence of a formal Analytic Hierarchy Process (AHP) or Delphi-based expert panel is acknowledged as a minor limitation, but the use of multiple, literature-informed weighting schemes and robustness testing substantially mitigates this.

Future research could strengthen this component by conducting formal expert elicitation with representatives from government, system operators, developers, and NGOs, and then comparing the resulting weights with those used here.

### 2.5.5 Outranking methods as a future validation pathway

Although this dissertation adopts a compensatory weighted-sum model as its primary MCDA approach, outranking methods such as PROMETHEE II and ELECTRE III provide a valuable validation perspective for future work. They can test whether the principal ranking—especially the consistently strong performance of offshore hydrogen with infrastructure repurposing—holds when compensation is restricted and “red lines” are modelled explicitly.

A concrete validation framework is outlined in Appendix D.9 and can be summarised as follows:

- Common input: Use the same criteria, normalised scores, and weighting schemes as in the weighted-sum MCDA, ensuring that any differences in results arise from the aggregation logic rather than data discrepancies.
- PROMETHEE II: Define criterion-specific preference functions and compute positive, negative, and net outranking flows for each pathway to obtain a complete ranking.
- ELECTRE III: Specify concordance and discordance thresholds, build the outranking relation, and derive partial pre-orders via distillation procedures.
- Comparison: Check whether P1 still dominates in net flows (PROMETHEE) and whether it outranks most or all alternatives without veto violations (ELECTRE). Where rankings diverge, analyse which criteria and thresholds drive those differences.

Given the strong robustness of P1 in the current weighted-sum sensitivity analysis, it is likely that outranking methods would confirm its leading position, while potentially reordering secondary pathways or revealing incomparabilities. Such work would deepen the methodological contribution of this research and would be a natural extension for future PhD-level or policy-focused studies.

## 2.6 Technical Feasibility and Operational Considerations

### 2.6.1 Wind Variability and Electrolyser Operation

Offshore wind on the DCS exhibits variability across diurnal, synoptic ( $\approx 3$ –7-day), and seasonal time scales. Capacity factors range from near-zero in calms to full-output in storms; recent wake-aware modelling indicates annual CF bands  $\sim 42$ –48% under planned deployment densities and  $\sim 45$ –52% in ideal spacing (Borgers et al., 2024; Van Stralen et al., 2025).

PEM electrolysers tolerate rapid ramps (seconds) and frequent cycling, suiting variable input; alkaline systems ramp more slowly ( $\approx 15$ –30 min) and incur greater part-load penalties offshore (Carmo et al., 2013; Buttler and Spliethoff, 2018). Operational strategies include oversizing wind-to-electrolyser ( $\sim 1.5:1$ – $2.5:1$ ), limited battery smoothing, and hybrid dispatch (excess wind to hydrogen; baseline to grid) (Singlitico et al., 2021; Victoria et al., 2019). North Sea studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) report  $\sim 48$ –52% electrolyser CF at  $\sim 2:1$  ratios with  $< 5\%$  wind curtailment in representative cases (Singlitico et al., 2021; Giampieri et al., 2023).

## 2.6.2 Safety and Environmental Considerations

Hydrogen's wide flammability limits ( $\approx 4\text{--}75\%$  v/v in air) necessitate robust detection, ventilation, and suppression; offshore platforms benefit from natural ventilation but face corrosion, humidity, and storm-loading challenges (Crowl and Jo, 2007; Hydrogen Europe, 2020). Material selection must address hydrogen embrittlement risks in high-pressure pipelines and vessels (Peters et al., 2021). Environmental aspects include marine ecosystem impacts, noise/vibration, and oxygen by-product management;  $\text{O}_2$  can be vented or captured for sale, though market value is context-dependent (International Renewable Energy Agency, 2020; Parkinson et al., 2019).

## 2.6.3 Grid Connection and Hybrid Hub Concepts

Hybrid hubs combine HVDC export with hydrogen production/pipeline export, enabling flexible dispatch against real-time prices, grid conditions, and hydrogen demand (Blanco et al., 2018; Singlitico et al., 2021). Benefits include revenue certainty from baseline electricity, reduced curtailment by converting peaks to hydrogen, and access to ancillary grid services. Complexity rises via coordinated control of turbines, converters, electrolyzers, compression, and optimisation algorithms, and requires TSO–hydrogen-network coordination (TenneT/Gasunie) (Victoria et al., 2019; Singlitico et al., 2021). Early experience from **AquaVentus** and **Energy Island** will inform optimal architectures (AquaVentus, 2024; Danish Energy Agency, 2023). For the DCS, hybrid concepts are pertinent in far-offshore zones (Nederwiek Noord/Zuid) where distance economics favour pipelines but grid linkage remains valuable for flexibility and diversification (Van Stralen et al., 2025).

## 2.7 Regulatory and Policy Framework

### 2.7.1 EU Regulatory Framework for Renewable Hydrogen

The EU's framework spans RED III, the Hydrogen Strategy, and Delegated Acts defining renewable-hydrogen criteria (European Commission, 2020; European Commission, 2022). Key elements are additionality, temporal correlation, and geographical correlation. Temporal correlation is phasing to hourly in the relevant periods; monthly applies in interim phases (European Commission, 2023). Geographical correlation typically requires the same bidding zone or direct lines. Sustainability certification thresholds (e.g.,  $< 3.38 \text{ kg CO}_2\text{e kg}^{-1} \text{ H}_2$ ) and equipment standards apply; Member-State implementation remains in development (ENTSOG, 2024; European Commission, 2022).

The EU Hydrogen Bank (launched 2023,  $\sim \text{€}3 \text{ bn}$  initial) uses auction-based support to bridge the cost gap to grey hydrogen until learning and scale improve competitiveness; pilot rounds have awarded fixed-premium support in the expected range for early-stage projects (European Commission, 2024; International Energy Agency, 2024a). Offshore projects must demonstrate contemporaneous production with renewable generation to meet RFNBO criteria; this favours integrated offshore wind-to-hydrogen systems (European Commission, 2023).

### 2.7.2 Dutch National Hydrogen Strategy and Infrastructure Planning

The Netherlands' National Hydrogen Strategy (2020; updated 2023) targets  $\sim 3\text{--}4 \text{ GW}$  electrolyzers by 2030 and  $\sim 8\text{--}10 \text{ GW}$  by 2040, with offshore hydrogen identified as a priority for integrating far-offshore wind while relieving congestion (Netherlands Ministry of Economic Affairs and Climate Policy, 2020; Netherlands Ministry of Economic Affairs and Climate Policy, 2023). Instruments include capital grants for demonstrations, CfD support for commercial projects, and regulatory-framework development (Netherlands Ministry of Economic Affairs and Climate Policy, 2023). Gasunie's planning outlines backbone routes, compression, and storage to connect offshore production to Rotterdam, IJmond, and Limburg hubs (Gasunie, 2022). Ongoing gaps include platform-repurposing certification, pipeline classification, and decommissioning obligations (TNO, 2024; Van Stralen et al., 2025).

### 2.7.3 EU Infrastructure Planning: Trans-European Networks for Energy (TEN-E)

The TEN-E regulation frames cross-border energy infrastructure, with the 2022 revision recognising hydrogen networks and identifying backbone corridors in the North Sea (European Commission, 2022; ENTSOG, 2024). Project-of-Common-Interest (PCI) or Mutual-Interest (PMI) status enables accelerated permitting and CEF grants; hydrogen infrastructure represents a growing share of eligible funding (European Commission, 2022). Early engagement with TEN-E processes is strategic for DCS offshore hydrogen corridors.

## 2.8 Comparative Case Studies: Germany, Denmark, and the United Kingdom

### 2.8.1 Germany: AquaVentus Initiative

AquaVentus targets  $\sim 10 \text{ GW}$  offshore wind-to-hydrogen by 2035 in German North Sea waters ( $\sim 250 \text{ km}$  from shore). The concept uses centralised platforms ( $1\text{--}2 \text{ GW}$  PEM), with hydrogen compressed ( $\sim 80 \text{ bar}$ ) and exported via new pipelines to onshore hubs (AquaVentus, 2024). Phased deployment begins with  $\sim 300 \text{ MW}$

demonstrations (operational window ~2028–2030), scaling thereafter; support is envisaged via CfDs during early phases. Designation under IPCEI facilitates grants and permitting. Reported delays illustrate regulatory and supply-chain challenges relevant to DCS projects (AquaVentus, 2024).

### **2.8.2 Denmark: Energy Island Project**

Denmark's Energy Island envisions an artificial island with ~10 GW wind, hybrid HVDC–hydrogen export, and potential Power-to-X facilities, serving multiple countries (Danish Energy Agency, 2023). The model combines state-funded island infrastructure and privately financed wind/hydrogen assets. It demonstrates hybrid optimisation, multi-country demand integration, and substantial public co-investment typical of first-of-kind mega-projects. For the DCS, platform repurposing may offer lower-cost alternatives to an artificial-island approach.

### **2.8.3 United Kingdom: Techno-Economic Assessments**

UK studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) (Catapult, DESNZ, academia) report offshore hydrogen LCOH ~€7–9 kg<sup>-1</sup> (2030) declining to ~€2.5–4.0 kg<sup>-1</sup> (2040) for far-offshore sites (~> 150 km) with CF ~50–55%; repurposing of extensive platform/pipeline inventory yields ~€0.5–1.0 kg<sup>-1</sup> savings versus greenfield (Hill et al., 2024; Giampieri et al., 2023). Policy frameworks include demonstration funding and CfD auctions with multi-year horizons to de-risk early projects (UK Department for Energy Security and Net Zero, 2024).

## **2.9 Knowledge Gaps and Research Positioning**

Three DCS-specific deficiencies motivate this research. First, many studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) apply generic North Sea parameters or focus on other countries, lacking calibration to Dutch wind resources (validated CF ~42–48% under planned densities), seabed/water-depth constraints, TenneT congestion timelines, and DCS subsea-infrastructure costs (Giampieri et al., 2023; Van Stralen et al., 2025). Second, static cost snapshots (2030/2040) understate the importance of dynamic trajectories, transition points, and support duration (Glenk and Reichelstein, 2019; Victoria et al., 2019). Third, comprehensive sensitivity/uncertainty quantification (multi-parameter OAT, Monte Carlo, threshold analysis) is limited in Dutch-context literature, despite material uncertainty in electricity prices, electrolyser costs, wake-affected capacity factors, and utilisation regimes (Hill et al., 2024; Rogeau et al., 2023; Reuß et al., 2019).

This dissertation addresses these gaps by: (i) DCS-calibrated LCOH modelling incorporating validated capacity-factor ranges and Dutch cost data; (ii) 2025–2050 scenario trajectories (Conservative, Baseline, Optimistic) with five-year intervals and explicit competitiveness thresholds (blue-hydrogen parity, onshore-green parity, market competitiveness); (iii) sensitivity and probabilistic analysis (tornado diagrams; 10,000-run Monte Carlo; breakeven thresholds); (iv) infrastructure-repurposing integration via detailed platform/pipeline inventories and regulatory requirements; and (v) MCDA comparing offshore hydrogen (repurposed and greenfield) with HVDC-only, onshore-green, blue-hydrogen, and hybrid options under multiple stakeholder weightings (Belton and Stewart, 2002; Pohekar and Ramachandran, 2004).

## CHAPTER III - RESEARCH METHODOLOGY

### 3.1 Research Design

This dissertation employs a quantitative techno-economic modelling approach combined with multi-criteria decision analysis to assess the feasibility of offshore green hydrogen production on the Dutch Continental Shelf. The research design integrates five complementary analytical modules: bottom-up levelised cost of hydrogen (LCOH) modelling with transparent parameter documentation; scenario-based trajectory analysis spanning 2025–2050 across three internally consistent futures (Conservative, Baseline, Optimistic); comprehensive sensitivity and uncertainty quantification through one-at-a-time parameter analysis, tornado diagrams and Monte Carlo simulation; infrastructure repurposing valuation comparing greenfield development against the strategic potential of existing oil and gas assets; and multi-criteria decision analysis systematically comparing offshore hydrogen with four alternative decarbonisation pathways (Pohekar and Ramachandran, 2004; Glenk and Reichelstein, 2019; Reuß et al., 2019).

The methodological framework addresses the three critical knowledge gaps identified in Chapter II: absence of DCS-calibrated feasibility analysis, incomplete temporal modelling of cost competitiveness trajectories, and inadequate quantification of parameter uncertainty and critical thresholds for viability (Giampieri et al., 2023; Hill et al., 2024; Van Stralen et al., 2025). The research explicitly adopts a strategic decision-support orientation, structuring outputs to inform government policy design, system operator infrastructure planning, and industry investment sequencing rather than purely academic model development (Glenk and Reichelstein, 2019; Singlitico et al., 2021).

### 3.2 System Boundary and Functional Unit

#### 3.2.1 System Boundary

The analysis encompasses the complete offshore hydrogen production and transport chain from seawater intake to onshore hydrogen delivery at industrial offtake points. System components included within the boundary are offshore wind generation (turbines, foundations, array cables, offshore substation), electrolysis system (PEM electrolyser stacks, power electronics, control systems, auxiliary equipment), seawater desalination and treatment (reverse osmosis, multi-effect distillation, ultrapure water production), hydrogen compression (multi-stage compressors raising pressure from electrolyser output at 20–30 bar to pipeline transport pressure at 50–100 bar), subsea pipeline transport (from offshore platform to onshore receiving terminal), and onshore pipeline integration (connection to hydrogen backbone network or direct industrial offtake) (International Renewable Energy Agency, 2020; Peters et al., 2021; TNO, 2024).

System components excluded from the primary boundary but addressed qualitatively include onshore hydrogen storage (salt caverns, depleted gas fields, tank storage), hydrogen distribution beyond primary delivery point (city gates, industrial clusters), end-use conversion technologies (fuel cells, hydrogen turbines, direct reduction iron processes), and oxygen byproduct utilisation or disposal (oxygen can be captured for industrial sale or vented to atmosphere; economic value is considered in sensitivity analysis) (International Renewable Energy Agency, 2020; Haqiqi et al., 2025).

The spatial boundary is the Dutch Continental Shelf, defined as offshore waters under Netherlands jurisdiction extending approximately 200 km from the coastline and encompassing roughly 57,000 km<sup>2</sup> of seabed. Three representative geographic zones within the DCS are analysed: near-offshore (Hollandse Kust, Borssele zones at 40–80 km from shore), intermediate-offshore (IJmuiden Ver at 70–100 km from shore), and far-offshore (Nederwiek Noord/Zuid at 150–200 km from shore) (North Sea Energy, 2023; Van Stralen et al., 2025).

The temporal boundary spans 2025 through 2050, aligning with Dutch climate targets and EU energy transition planning horizons. Analysis employs five-year intervals (2025, 2030, 2035, 2040, 2045, 2050), with particular focus on 2025–2040 representing the critical period for technology maturation, policy support, and initial deployment (Netherlands Ministry of Economic Affairs and Climate Policy, 2023; European Commission, 2022).

#### 3.2.2 Functional Unit

The functional unit is one kilogram of compressed hydrogen (H<sub>2</sub>) delivered to onshore receiving terminals at 50–100 bar pressure, meeting industrial purity specifications ( $\geq 99.97\%$  H<sub>2</sub>, with impurity limits consistent with ISO 14687:2019 for hydrogen fuel quality). This functional unit enables direct comparison with alternative hydrogen production pathways (onshore green hydrogen, blue hydrogen from steam methane reforming with carbon capture, grey hydrogen from unabated natural gas) and with the hydrogen requirements of industrial end users in steel, chemicals, refining and ammonia sectors (ISO, 2019; International Renewable Energy Agency, 2020).

All costs, energy consumption and environmental impacts are normalised to this functional unit, expressed as levelised cost per kilogram (EUR/kg H<sub>2</sub>), specific energy consumption (kWh/kg H<sub>2</sub>), and lifecycle emissions intensity (kg CO<sub>2</sub>-eq/kg H<sub>2</sub>). The levelised cost formulation amortises capital expenditure over project lifetime using capital recovery factors calibrated to weighted average cost of capital (WACC) representative of offshore energy infrastructure investment risk (Glenk and Reichelstein, 2019; Peters et al., 2021).

### 3.3 Model Structure and Equations

#### 3.3.1 Overall LCOH Formulation

The levelised cost of hydrogen (LCOH) is calculated using the standard discounted cash flow approach, amortising capital expenditure and summing fixed and variable operating expenditure over the project economic lifetime:

$$\text{LCOH} = [(\text{CAPEX} \times \text{CRF}) + \text{Fixed OPEX} + \text{Variable OPEX}] / \text{Annual H}_2 \text{ Production}$$

Where:

- CAPEX = Total capital expenditure (€) comprising electrolyser system, offshore wind allocation, platform infrastructure, desalination system, compression equipment, subsea pipeline, and installation costs
- CRF = Capital Recovery Factor =  $[r(1+r)^n] / [(1+r)^n - 1]$ , where  $r$  = real discount rate (WACC) and  $n$  = project economic lifetime (years)
- Fixed OPEX = Annual fixed operating expenditure (€/year) including labour, maintenance contracts, insurance, administrative overhead, and periodic inspections
- Variable OPEX = Annual variable operating expenditure (€/year) dominated by electricity consumption (EUR/MWh × MWh/year), with additional components for water consumption, consumables replacement (membranes, catalysts), and auxiliary utilities
- Annual H<sub>2</sub> Production = Electrolyser rated capacity (kg H<sub>2</sub>/hour) × annual operating hours × capacity factor × system efficiency

The capacity factor accounts for wind resource availability, planned maintenance downtime, grid curtailment (if applicable) and electrolyser operational constraints (minimum load, ramp rate limits). System efficiency encompasses electrolyser electrical-to-chemical conversion efficiency (typically 65–75% HHV for PEM systems), auxiliary power consumption (pumps, cooling, control systems at 2–5% of electrolyser load), desalination energy penalty (3–5 kWh/m<sup>3</sup> water), and compression energy requirement (approximately 5–8% of hydrogen energy content to reach pipeline pressure) (Buttler and Spliethoff, 2018; International Renewable Energy Agency, 2020; TNO, 2024).

#### 3.3.2 Cost Component Formulation

Capital expenditure is disaggregated into major system components to enable transparent sensitivity analysis and scenario differentiation:

$$\text{CAPEX}_{\text{total}} = \text{CAPEX}_{\text{electrolyser}} + \text{CAPEX}_{\text{wind allocation}} + \text{CAPEX}_{\text{platform}} + \text{CAPEX}_{\text{desal}} + \text{CAPEX}_{\text{compression}} + \text{CAPEX}_{\text{pipeline}} + \text{CAPEX}_{\text{install}}$$

Each component is calculated as:

- $\text{CAPEX}_{\text{electrolyser}} = P_{\text{electrolyser}} \text{ (MW)} \times \text{unit cost (EUR/kW}_{\text{electrolyser}}) \times \text{offshore premium factor (typically 1.15–1.25 to account for ruggedisation, humidity protection, and marine certification requirements)}$
- $\text{CAPEX}_{\text{wind allocation}} = (P_{\text{electrolyser}} / \text{efficiency}) \times \text{wind-to-electrolyser ratio} \times \text{unit cost (EUR/kW}_{\text{wind}}) \times \text{offshore-specific cost factors (foundation type, water depth, distance from shore)}$
- $\text{CAPEX}_{\text{platform}} = \text{Base platform cost} + \text{electrolyser accommodation} + \text{utilities (power distribution, cooling, control room)} + \text{helideck and safety systems}$
- $\text{CAPEX}_{\text{desal}} = \text{Water production capacity (m}^3\text{/day)} \times \text{unit cost (€ per m}^3\text{/day capacity)} \text{ accounting for reverse osmosis plus ultrapure polishing stages required for PEM specifications}$
- $\text{CAPEX}_{\text{compression}} = \text{Hydrogen flow rate (kg/s)} \times \text{compression ratio (outlet/inlet pressure)} \times \text{unit cost (€ per kg/s capacity)}$
- $\text{CAPEX}_{\text{pipeline}} = \text{Pipeline diameter (inches)} \times \text{distance (km)} \times \text{unit cost (EUR/km)}$  with diameter determined by hydrogen flow rate, allowable velocity (<15 m/s to limit erosion), and pressure drop constraints

- CAPEX\_install = Sum of installation costs for platform tow-out and hook-up, pipeline laying and testing, electrical connections, and commissioning activities (typically 10–20% of equipment CAPEX)

Fixed operating expenditure is estimated as a percentage of CAPEX (typically 2–4% annually) covering scheduled maintenance, inspection programmes, spare parts inventory, personnel (for manned platforms), insurance premiums, and lease or licensing fees for seabed use (International Renewable Energy Agency, 2020; Peters et al., 2021; Hill et al., 2024).

Variable operating expenditure is dominated by electricity cost:

Variable OPEX = Electricity consumption (MWh/year) × Electricity price (EUR/MWh) + Water cost + Consumables

Electricity consumption per kilogram of hydrogen depends on electrolyser specific energy ( $e_{\text{spec}}$ , typically 48–55 kWh/kg for PEM at 65–70% HHV efficiency), auxiliary loads, desalination energy, and compression energy. Water cost is generally negligible (seawater is free; desalination energy is included in electricity term). Consumables include electrolyser membrane replacement (every 40,000–60,000 hours depending on operating regime) and other periodic component replacements (Buttler and Spliethoff, 2018; Carmo et al., 2013).

### 3.3.3 Electricity Cost Representation

Electricity cost is modelled using offshore wind levelised cost of energy (LCOE) as the baseline electricity price input. Offshore wind LCOE is calculated separately using standard wind energy economics:

$$\text{LCOE}_{\text{wind}} = [(\text{CAPEX}_{\text{wind}} \times \text{CRF}_{\text{wind}}) + \text{Fixed OPEX}_{\text{wind}}] / (\text{Capacity}_{\text{wind}} \times \text{CF}_{\text{wind}} \times 8760 \text{ hours/year})$$

Where:

- CAPEX\_wind = Wind turbine, foundation, array cables, offshore substation, and export cable (if applicable)
- CRF\_wind = Capital recovery factor for wind project (WACC and lifetime specific to wind assets, typically 20–25 years)
- CF\_wind = Wind capacity factor (%) reflecting local wind resource, turbine technology, wake effects, and availability

Offshore wind LCOE on the DCS is estimated from literature (International Renewable Energy Agency, 2021; WindEurope, 2021; Van Stralen et al., 2025) and calibrated to recent Dutch auction results and wind farm performance data from Borssele and Hollandse Kust zones. Scenario trajectories for LCOE\_wind declining from €50–60/MWh (2025) to €30–40/MWh (2040) are derived from technology learning curves, increasing turbine scale (12–15 MW turbines becoming standard), and supply chain maturation (International Renewable Energy Agency, 2021; Lazard, 2024).

For integrated offshore hydrogen systems with no grid connection, electricity price equals the opportunity cost of wind power (i.e., LCOE\_wind). For hybrid systems with grid connection option, electricity price reflects the lower of grid export price or LCOE\_wind, accounting for the flexibility to optimise dispatch between hydrogen production and electricity export based on real-time price signals (Singlitico et al., 2021; Blanco et al., 2018).

## 3.4 Technology Representation and Assumptions

### 3.4.1 Electrolyser Technology

The baseline model employs PEM (proton exchange membrane) electrolyser technology, selected for offshore applications based on four distinguishing characteristics: rapid dynamic response to variable wind input (milliseconds to seconds for 0–100% load changes), high current density enabling compact physical footprint critical for space-constrained platforms, tolerance of frequent start-stop cycling inherent in offshore wind operation, and commercial maturity with MW-scale systems operational in multiple projects (Carmo et al., 2013; Buttler and Spliethoff, 2018; Hill et al., 2024).

Technology parameters by scenario and time horizon:

Electrolyser capital cost (EUR/kW):

- 2025: Conservative €1,100/kW, Baseline €1,000/kW, Optimistic €900/kW

Cost trajectories reflect learning rates of 12–18% per doubling of cumulative global electrolyser capacity, calibrated to manufacturer roadmaps, recent large-scale procurement tenders, and literature projections (Holst et al., 2021; International Renewable Energy Agency, 2020; Hydrogen Council, 2021).

- 2030: Conservative €850/kW, Baseline €750/kW, Optimistic €650/kW
- 2040: Conservative €550/kW, Baseline €400/kW, Optimistic €350/kW
- 2050: Conservative €475/kW, Baseline €375/kW, Optimistic €300/kW

Cost trajectories reflect learning rates of 12–18% per doubling of cumulative global electrolyser capacity, calibrated to manufacturer roadmaps, recent large-scale procurement tenders, and literature projections (Holst et al., 2021; International Renewable Energy Agency, 2020; Hydrogen Council, 2021). An offshore premium factor of 20% is applied to account for ruggedisation (enhanced corrosion protection, humidity sealing, vibration tolerance), marine certification requirements (DNV, Lloyd's Register offshore equipment standards), and limited supply chain maturity for offshore-specific systems (TNO, 2024; Hill et al., 2024).

Specific electricity consumption (kWh/kg H<sub>2</sub>, HHV basis):

- 2025–2030: 52–55 kWh/kg (equivalent to 67–70% HHV efficiency)
- 2035–2040: 50–52 kWh/kg (68–72% efficiency)
- 2045–2050: 48–50 kWh/kg (70–75% efficiency)

Efficiency improvements reflect advances in membrane technology, catalyst loading optimisation, and power electronics reducing conversion losses. Auxiliary power consumption (control systems, cooling pumps, hydrogen purification) adds 2–3% to base electrolyser consumption (Buttler and Spliethoff, 2018; Chatenet et al., 2022).

Stack lifetime and replacement: PEM stack operational lifetime is 40,000–60,000 hours (approximately 5–7 years at 48–52% capacity factor), requiring periodic stack replacement at 60–70% of initial CAPEX. Stack lifetime depends critically on operational regime; frequent thermal cycling and deep load variations accelerate degradation. The model accounts for stack replacement cost amortised over project life (TNO, 2024; Carmo et al., 2013).

Minimum stable load: PEM systems can operate efficiently down to 10–20% of rated capacity, significantly better than alkaline systems (30–40% minimum load). This characteristic is critical for accommodating wind variability without frequent shutdown-restart cycles that increase wear (Buttler and Spliethoff, 2018).

Sensitivity case – Alkaline electrolysis: A secondary analysis examines alkaline electrolyser economics as a lower-cost alternative. Alkaline systems exhibit 15–25% lower capital cost (€650/kW in 2030 vs €750/kW for PEM) but slower response times (10–30 minutes ramp-up) and larger physical footprint (approximately 1.5× platform area requirement). The alkaline case explores the trade-off between lower upfront cost and reduced operational flexibility in variable offshore wind environments (Buttler and Spliethoff, 2018; Schmidt et al., 2017).

### 3.4.2 Wind Resource and Capacity Factors

Offshore wind capacity factors for the DCS are derived from validated wind resource assessments, operational wind farm data, and spatial planning studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) accounting for wake effects and infrastructure density constraints (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024).

Capacity factor ranges by geographic zone:

- Near-offshore (Hollandse Kust, Borssele zones, 40–80 km): 42–48% (2025–2030), increasing to 45–50% (2035–2050) as turbine technology advances and wake management improves
- Intermediate-offshore (IJmuiden Ver, 70–100 km): 45–50% (2025–2030), increasing to 48–52% (2035–2050)
- Far-offshore (Nederwiek Noord/Zuid, 150–200 km): 48–52% (2025–2030), potentially reaching 50–55% (2040–2050) with optimal turbine selection and spacing

Capacity factor progression over time reflects three drivers: increasing hub heights and rotor diameters capturing higher-quality wind resources (15 MW turbines with 240-metre rotors becoming standard by 2030–2035), improved wake management through turbine control strategies (yaw steering, dynamic induction control reducing wake losses by 5–10%), and deployment in more favourable wind regimes as near-shore sites saturate (International Renewable Energy Agency, 2021; Borgers et al., 2024).

Critical wake effects consideration: Recent empirical research by Borgers et al. (2024) demonstrates that policy-planned deployment densities on the DCS (targeting 21 GW by 2030 within constrained zones) create substantial wake interference, potentially reducing effective capacity factors to 42–46% in densely developed areas. This finding, validated against operational data from Borssele zones, suggests that initial baseline assumptions of 48–50% capacity factors may be optimistic for policy-compliant deployment scenarios. The analysis therefore includes wake-adjusted sensitivity cases with capacity factors reduced by 4–8 percentage

points, examining implications for LCOH competitiveness and the strategic value of infrastructure repurposing to access less-congested far-offshore zones (Borgers et al., 2024; Van Stralen et al., 2025).

Conversion to electrolyser effective capacity factor: The annual operating hours of the electrolyser differ from wind capacity factor due to curtailment (when wind production exceeds electrolyser capacity), minimum load constraints (electrolyser shutdown during very low wind), and planned maintenance (typically 2–4 weeks annually). For systems with wind-to-electrolyser capacity ratio of 2:1 (typical design for balancing capital efficiency against curtailment losses), electrolyser effective capacity factor is approximately 85–95% of wind capacity factor (Singlitico et al., 2021; Giampieri et al., 2023). For example, 50% wind CF translates to 42–47% electrolyser CF depending on control strategy and minimum load settings.

### 3.5 Scenario Design

#### 3.5.1 Scenario Logic

Given structural uncertainty in technology development trajectories, future energy prices, and policy support mechanisms, the analysis employs three internally consistent scenarios bounding plausible futures rather than attempting to predict a single "most likely" pathway. Each scenario represents a coherent narrative about technology learning, market development, and policy commitment, ensuring that parameter combinations are realistic rather than arbitrary (Reuß et al., 2019; Glenk and Reichelstein, 2019).

**Conservative Scenario:** Represents slower-than-expected progress in cost reduction, technology maturation, and policy support. This scenario assumes electrolyser manufacturing scale-up faces supply chain bottlenecks and material cost inflation (learning rate 12%), offshore wind cost reductions are limited by installation constraints and far-offshore challenges (learning rate 10%), capacity factors remain at lower end of range due to wake effects and curtailment, electricity prices decline modestly (remaining at €40–50/MWh through 2040), and policy support is uncertain or time-limited (contract-for-difference (CfD) mechanisms provide €4–6/kg support only through 2035, then phase out). Under this scenario, offshore hydrogen achieves competitiveness (LCOH < €3/kg) only after 2045–2050, requiring extended policy support and patient capital (Netherlands Ministry of Economic Affairs and Climate Policy, 2023; Van Stralen et al., 2025).

**Baseline Scenario:** Represents mid-range assumptions aligned with mainstream industry projections and literature consensus (International Energy Agency, 2024a; International Renewable Energy Agency, 2020; Hydrogen Council, 2021). Electrolyser costs decline to €750/kW by 2030 and €400/kW by 2040 (learning rate 15%), offshore wind costs follow established North Sea trends declining to €2,100/kW by 2035 and €1,900/kW by 2040 (learning rate 12–14%), capacity factors improve moderately through turbine technology and wake management (48% in 2025 rising to 52% by 2040), electricity prices decline in line with renewable energy deployment (€50/MWh in 2025, €40/MWh in 2030, €35/MWh by 2040), and policy support is sustained through 2035 at €3–5/kg CfD levels, then reduces as market competitiveness improves. This scenario achieves LCOH competitiveness (€2–3/kg range) by 2040, consistent with EU hydrogen strategy timelines and Dutch climate targets (European Commission, 2022; Netherlands Ministry of Economic Affairs and Climate Policy, 2023).

**Optimistic Scenario:** Represents accelerated progress driven by aggressive policy support, rapid manufacturing scale-up, and breakthrough cost reductions. Electrolyser costs benefit from early-mover advantages in gigawatt-scale manufacturing (China, EU, US capacity expansion) reaching €650/kW by 2030 and €350/kW by 2040 (learning rate 18%), offshore wind leverages serial production and installation efficiencies achieving €2,000/kW by 2030 and €1,800/kW by 2040, capacity factors reach upper range through optimal site selection and advanced control (50% by 2030, 53% by 2040), electricity prices decline sharply due to renewable oversupply in midday/high-wind periods (€45/MWh by 2030, €30/MWh by 2040), and strong policy support (€5–7/kg CfD) accelerates deployment creating virtuous cycle of cost reduction. This scenario achieves competitiveness by 2035 (LCOH ≈ €2.5/kg), enabling rapid deployment aligned with most ambitious EU decarbonisation pathways (Hydrogen Council, 2021; International Renewable Energy Agency, 2020).

#### 3.5.2 Parameter Sets by Scenario and Time Horizon

For each {scenario, year} combination, parameters are specified consistently:

Electrolyser technology parameters:

- Capital cost (EUR/kW): scenario-specific as per Section 3.4.1
- Specific electricity consumption (kWh/kg): improving from 52–55 kWh/kg (2025) to 48–50 kWh/kg (2050)
- Stack lifetime (hours): 40,000 (Conservative), 50,000 (Baseline), 60,000 (Optimistic)
- Offshore premium factor: 20% (baseline), 15–25% range in sensitivity

Offshore wind parameters:

- Wind turbine CAPEX (EUR/kW): Conservative €2,900/kW (2025) declining to €2,200/kW (2040); Baseline €2,800/kW (2025) declining to €1,900/kW (2040); Optimistic €2,700/kW (2025) declining to €1,800/kW (2040)
- Capacity factor: Conservative 45–48%, Baseline 48–52%, Optimistic 50–54% over 2025–2040 period
- Wind-to-electrolyser ratio: 2:1 baseline (electrolyser rated at 50% of connected wind capacity to optimise capital efficiency against curtailment)

Infrastructure costs:

- Platform CAPEX: €150–200 million base cost (300–500 MW electrolyser accommodation), scaling with capacity and offshore distance
- Desalination CAPEX: €500–800 per m<sup>3</sup>/day capacity (reverse osmosis + polishing); energy consumption 3–5 kWh/m<sup>3</sup>
- Compression CAPEX: €80–120 million per 500 MW system (multi-stage compression to 80 bar)
- Pipeline CAPEX: €1.8–2.5 million/km (12–16 inch diameter for 100–300 MW hydrogen flow), distance-dependent

Financial parameters:

- Weighted average cost of capital (WACC): Conservative 8% (reflecting higher perceived risk), Baseline 7%, Optimistic 6% (as projects mature and policy de-risks investment)
- Project economic lifetime: 25 years (electrolyser), 30 years (platform, pipeline)
- Discount rate real (excluding inflation): equal to WACC assumptions

Policy support mechanisms:

- Contract-for-difference levels: Conservative €5–7/kg (2025–2035), Baseline €4–5/kg (2025–2035), Optimistic €3–4/kg (2025–2030) then market-based
- Capital grants: 20–40% CAPEX support in early demonstration projects (2025–2030) declining to zero by 2040

All scenario parameter sets are cross-validated against published literature ranges (International Energy Agency, 2024a; International Renewable Energy Agency, 2020; Hydrogen Council, 2021; Lazard, 2024) and Dutch-specific studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) (TNO, 2024; Van Stralen et al., 2025; North Sea Energy, 2023). Where uncertainty ranges in literature are wide, Conservative and Optimistic scenarios bound the plausible extremes whilst Baseline represents median or modal values.

## 3.6 Sensitivity and Uncertainty Analysis

### 3.6.1 One-at-a-Time (OAT) Sensitivity Analysis

To identify the parameters exerting greatest influence on LCOH outcomes and thereby guide strategic focus for cost reduction efforts and risk mitigation, one-at-a-time sensitivity analysis is conducted across all scenarios and time horizons (Reuß et al., 2019; Glenk and Reichelstein, 2019).

Methodology: For each {scenario, year} baseline parameter set, each critical parameter is varied independently by ±10%, ±20% and (where relevant) up to ±50% whilst holding all other parameters constant. LCOH is recalculated for each perturbation, and the relative change in LCOH is recorded. Parameters tested include electricity price (EUR/MWh), wind capacity factor (%), electrolyser capital cost (EUR/kW), electrolyser efficiency (kWh/kg), weighted average cost of capital (%), platform and infrastructure costs (€), pipeline distance and cost (km, EUR/km), stack lifetime (hours), and offshore premium factors (%).

Visualisation: Results are presented as tornado diagrams ranking parameters by their impact magnitude (measured as absolute change in LCOH per unit change in parameter). Separate tornado diagrams are generated for near-term (2030), mid-term (2040), and long-term (2050) to illustrate how cost sensitivities evolve over time. For example, electrolyser CAPEX is expected to dominate sensitivity in 2030 when it remains high, whereas electricity price becomes dominant by 2040 as electrolyser costs fall and operational expenses represent larger share of total cost (Reuß et al., 2019; Hill et al., 2024).

### 3.6.2 Monte Carlo Simulation

All reported intervals are simulation-based predictive (output) intervals conditional on the assumed input distributions and scenario definitions. They are not frequentist confidence intervals for estimated population parameters. Interpretation is therefore conditional on the stated scenario assumptions and distributional choices.

Key input parameters are assigned probability distributions reflecting expert judgment, literature ranges, and empirical uncertainty assessments. Distribution types include:

- Triangular distributions (minimum, most likely, maximum) for parameters with asymmetric uncertainty or bounded ranges where expert judgment provides modal estimates
- Normal distributions (mean, standard deviation), truncated at physical or practical bounds, for parameters with symmetric uncertainty around central estimates
- Uniform distributions (minimum, maximum) for parameters with limited prior information requiring equal probability across plausible ranges

Critical implementation note: All normal distributions applied to physically bounded parameters (capacity factors, efficiencies, utilization rates) are truncated at physically plausible limits to prevent impossible values. For example, capacity factor distributions are truncated at [0.30, 0.70] bounds; electrolyser efficiency distributions are truncated at [0.55, 0.85] bounds corresponding to thermodynamic and practical limits.

For each scenario-year combination, 10,000 random parameter sets are generated by sampling from the assigned distributions using Latin Hypercube Sampling (LHS) to ensure efficient coverage of the parameter space. LCOH is calculated for each sample using the deterministic model framework described in Section 3.3. The resulting distribution of 10,000 LCOH outcomes is analysed statistically:

- Mean and median LCOH (central tendency)
- 10th and 90th percentiles (P10, P90) bounding the 80% central predictive interval
- Standard deviation and coefficient of variation ( $CV = \sigma/\mu$ ) quantifying absolute and relative uncertainty
- Probability distributions showing likelihood of achieving specific cost thresholds (e.g., probability that  $LCOH \leq \text{€}3/\text{kg}$  by 2040)

Convergence diagnostics: Monte Carlo standard error ( $MCSE = \sigma/\sqrt{n}$ ) is verified to ensure 10,000 iterations provide sufficient precision. For all scenarios,  $MCSE < 0.02 \text{ EUR/kg H}_2$  for P50 and  $< 0.03 \text{ EUR/kg H}_2$  for P90, indicating stable results (Reuß et al., 2019; Glenk and Reichelstein, 2019).

Content includes:

- Methodological rationale for Monte Carlo (non-normal distributions, parameter correlations, nonlinear responses)
- Baseline assumption: statistical independence between parameters. Sensitivity analysis in Appendix H.3 explores realistic parameter dependencies using the Iman–Conover method.
  - Electricity Price ↔ Capacity Factor:  $\rho = -0.35$
  - Electrolyser CAPEX ↔ Offshore Wind CAPEX:  $\rho = +0.25$
  - Capacity Factor ↔ Discount Rate:  $\rho = +0.15$
- Latin Hypercube Sampling (LHS) methodology
- Convergence diagnostics with detailed tables showing CV stability at 1,000, 5,000, and 10,000 iterations
- Output metrics (mean, median, P5–P95, probability thresholds)
- Full references to peer-reviewed literature

Table 1 - Monte Carlo parameter uncertainty specification for 2030 Baseline scenario. Epistemic uncertainty reflects knowledge gaps; aleatory uncertainty reflects inherent system randomness.

30 Baseline)	Distribution Type	Parameterization	Justification	Source	Nature
Electrolyser CAPEX	Triangular	Min=650, Mode=750, Max=900 EUR/kW	Asymmetric supply-chain risk; minimum reflects	Industry vendor quotes, IRENA (2020),	Epistemic

30 Baseline)	Distribution Type	Parameterization	Justification	Source	Nature
			optimistic manufacturing scale-up, maximum reflects delays and bottlenecks	Hydrogen Council (2021)	
Capacity factor	Truncated Normal	$\mu=50\%$ , $\sigma=2\%$ , bounds=[35%, 65%]	Wind resource variability and wake effects; truncated to prevent physically impossible values	Borgers et al. (2024), DNV offshore wind database	Aleatory
Electricity price	Triangular	Min=35, Mode=45, Max=60 EUR/MWh	Policy and market uncertainty, renewable deployment trajectories	IEA (2024), TenneT grid forecasts	Epistemic
WACC (discount rate)	Uniform	Min=4.0%, Max=7.5%	Financing risk perception, policy support certainty	Lazard (2024), project finance databases	Epistemic
Offshore wind CAPEX	Triangular	Min=2,100, Mode=2,400, Max=2,900 EUR/kW	Learning curve uncertainty, supply-chain constraints	IRENA (2020), WindEurope (2023)	Epistemic
Electrolyser efficiency	Truncated Normal	$\mu=68\%$ , $\sigma=3\%$ , bounds=[60%, 78%] (HHV)	Technology maturity variation, operating condition sensitivity	Buttler & Spliethoff (2018), Chatenet et al. (2022)	Epistemic
Platform repurposing savings	Triangular	Min=25%, Mode=42%, Max=60%	Regulatory uncertainty, asset condition variability	TNO (2024), Van Stralen et al. (2025)	Epistemic
Fixed OPEX (% of CAPEX)	Uniform	Min=1.5%, Max=3.5%	Operational experience limited, maintenance cost uncertainty	Holst et al. (2021), Giampieri et al. (2023)	Epistemic
Electrolyser lifetime	Triangular	Min=50,000, Mode=70,000, Max=90,000 hrs	Degradation rate uncertainty, operating regime impacts	Carmo et al. (2013), vendor specifications	Epistemic

30 Baseline)	Distribution Type	Parameterization	Justification	Source	Nature
Pipeline CAPEX	Triangular	Min=0.8, Mode=1.2, Max=1.8 MEUR/km	Distance-dependent economies, seabed complexity	Gasunie hydrogen network studies	Epistemic

Statistical independence assumption and correlation sensitivity: Baseline Monte Carlo simulations treat parameters as statistically independent, which is a simplifying assumption. In reality, moderate correlations exist between certain parameter pairs (e.g., electricity price and WACC both influenced by market risk perception; electrolyser CAPEX and offshore wind CAPEX both affected by supply-chain shocks).

Correlation sensitivity analysis (Appendix H.3) tests the impact of  $\rho = \pm 0.3$  correlations between key parameter pairs. Results show that introducing moderate positive correlation between electricity price and WACC ( $\rho = 0.3$ ) increases P90 by 6–8%, while correlation between CAPEX components ( $\rho = 0.4$ ) increases P90 by 3–5%. These effects are material but do not alter the qualitative competitiveness conclusions. Baseline results assuming independence represent central estimates; correlated scenarios bound the uncertainty range.

### 3.6.2.1 Convergence Diagnostics and Sample Size Justification

Monte Carlo simulation accuracy depends on sufficient sample size (number of iterations). To verify that 10,000 iterations provide stable results, convergence diagnostics were performed by comparing key statistics (P50, P90, mean) across increasing sample sizes: 1,000, 5,000, 10,000, and 20,000 iterations.

Table 2 - Carlo Convergence Diagnostics – 2030 Baseline Scenario

Iterations	P50 (EUR/kg H <sub>2</sub> )	P90 (EUR/kg H <sub>2</sub> )	Mean (EUR/kg H <sub>2</sub> )	MCSE (P50)	MCSE (P90)
1,000	4.86	6.82	4.91	0.058	0.092
5,000	4.83	6.75	4.88	0.026	0.041
10,000	4.82	6.71	4.87	0.018	0.029
20,000	4.82	6.70	4.87	0.013	0.020

Monte Carlo standard error (MCSE) =  $\sigma/\sqrt{n}$  quantifies sampling uncertainty. For 10,000 iterations, MCSE < 0.02 EUR/kg H<sub>2</sub> for P50 and < 0.03 EUR/kg H<sub>2</sub> for P90, which is negligible relative to total LCOH magnitude (< 0.4% of mean). Increasing to 20,000 iterations reduces MCSE by only ~30% while doubling computation time, confirming 10,000 iterations as optimal balance between accuracy and efficiency.

Conclusion: All Monte Carlo simulations in this study use 10,000 iterations with Latin Hypercube Sampling to ensure stable, reproducible results with MCSE below reporting precision thresholds.

### 3.6.3 Threshold and Break-even Analysis

To identify actionable targets for technology development, policy support, and project selection, structured threshold analysis determines critical parameter values enabling specified cost competitiveness levels (Glenk and Reichelstein, 2019).

Electricity price thresholds: For fixed assumptions on electrolyser cost, capacity factor, and other parameters, the analysis calculates the electricity price required to achieve target LCOH values (e.g., €3/kg, €2/kg). This clarifies whether competitiveness depends primarily on offshore wind LCOE reductions (driven by wind technology learning) or on securing favourable power purchase agreements or direct wind-electrolyser integration avoiding grid charges.

**Electrolyser cost ceilings:** For given electricity prices and operational assumptions, the analysis determines maximum electrolyser capital cost compatible with target LCOH. For example, if target LCOH is €3/kg by 2035 with €40/MWh electricity, what electrolyser cost ceiling must be achieved? This threshold provides manufacturing cost targets for electrolyser suppliers and informs policy decisions on CAPEX grants to bridge cost gaps.

**Minimum capacity factors:** For specified electrolyser and wind costs, the analysis identifies minimum wind capacity factors required for competitiveness. This informs site selection priorities (favouring high-wind far-offshore zones) and spatial planning decisions about acceptable wake losses and deployment densities.

**Break-even year identification:** Across all three scenarios, the analysis determines the year in which LCOH first drops below specified competitiveness thresholds (€4/kg, €3/kg, €2/kg) under baseline assumptions. This timeline clarifies when policy support can phase out and when commercial deployment becomes self-sustaining without subsidies. Sensitivity of break-even timing to key parameters (e.g., accelerating electrolyser learning by two years advances competitiveness by how many years?) provides strategic guidance on prioritisation of R&D, manufacturing scale-up, and demonstration projects (Glenk and Reichelstein, 2019; Hill et al., 2024).

### **3.7 Comparative Pathway Assessment (MCDA)**

#### **3.7.1 Alternative Pathways Defined**

To contextualise offshore hydrogen within the broader landscape of decarbonisation options and offshore wind integration strategies, multi-criteria decision analysis (MCDA) systematically compares five pathways (Pohekar and Ramachandran, 2004; Wang et al., 2009):

1. Offshore green hydrogen (DCS) – repurposed infrastructure: Leverages existing oil and gas platforms and pipelines, representing the focus of this dissertation with infrastructure cost savings quantified in sensitivity analysis
2. Offshore green hydrogen (DCS) – greenfield development: Entirely new platform and pipeline infrastructure, establishing a conservative feasibility baseline
3. Onshore green hydrogen – dedicated renewables: Electrolyser co-located with onshore wind or solar farms, or industrial clusters with grid connection, representing established technology pathway
4. HVDC-only offshore wind export: All offshore wind power transmitted via high-voltage direct current cables to onshore grid, representing the conventional solution without hydrogen production
5. Blue hydrogen (SMR + CCS): Steam methane reforming with 90% carbon capture and storage, representing the fossil-based transitional pathway

Each pathway is characterised quantitatively where feasible (LCOH, infrastructure costs, emissions intensity) and qualitatively where quantitative data are limited (regulatory maturity, scalability constraints).

#### **3.7.2 Criteria Selection**

The MCDA employs six evaluation criteria reflecting the multi-dimensional nature of energy transition decisions and stakeholder priorities (Pohekar and Ramachandran, 2004; Wang et al., 2009; TNO, 2024):

C1 – Economic cost: Levelised cost per unit of useful energy (EUR/kg H<sub>2</sub> or EUR/MWh electricity equivalent), capturing total system cost from production through delivery to end user

C2 – System value and grid impact: Ability to relieve grid congestion (positive value) versus exacerbation of transmission constraints (negative value), quantified by avoided HVDC investment and onshore grid reinforcement costs

C3 – Climate and environmental performance: Lifecycle greenhouse gas emissions intensity (kg CO<sub>2</sub>-eq/kg H<sub>2</sub> or per MWh electricity), including upstream emissions from equipment manufacturing, fuel production, and end-of-life disposal

C4 – Technology and commercial readiness: Technology readiness level (TRL), availability of commercial-scale reference projects, supply chain maturity, and operational experience base

C5 – Scalability and spatial footprint: Potential deployment scale constrained by resource availability (wind resource, seabed area, onshore land), spatial planning conflicts, and infrastructure capacity

C6 – Regulatory and policy readiness: Clarity and maturity of permitting frameworks, safety standards, certification processes, and policy support mechanisms (CfD, quotas, CAPEX grants)

Each criterion is scored on a normalised 0–10 scale (higher scores indicating better performance) through a structured scoring methodology combining quantitative data where available (e.g., economic cost from LCOH modelling, emissions from lifecycle assessment literature) and expert assessment for qualitative dimensions

(e.g., regulatory readiness based on policy analysis in Chapter II) (Pohekar and Ramachandran, 2004; Wang et al., 2009).

### 3.7.3 Weighting and Scoring

Two weighting schemes reflect different stakeholder perspectives and policy priorities (Pohekar and Ramachandran, 2004):

**Equal weighting:** All six criteria weighted equally (16.7% each), representing a balanced perspective that values economic, environmental, technical, and regulatory dimensions comparably. This weighting clarifies inherent pathway performance independent of stakeholder-specific preferences.

**Energy transition weighting:** Higher weights assigned to climate performance (25%), system value/grid impact (25%), and economic cost (20%), with lower weights on technology readiness (10%), scalability (10%), and regulatory readiness (10%). This scheme reflects Dutch and EU policy priorities emphasising rapid decarbonisation, energy system integration, and cost-effectiveness over incremental technology maturation.

Pathway scores against each criterion are assigned as follows:

- **Economic cost (C1):** Scored inversely to LCOH (or equivalent electricity cost), with €2/kg = 10 points, €4/kg = 5 points, €8/kg = 2 points. Onshore green hydrogen and HVDC electricity costs are converted to H<sub>2</sub>-equivalent for comparison.
- **System value (C2):** Offshore hydrogen scores 8–9 (substantial grid relief), onshore hydrogen scores 5–6 (neutral to slight grid impact), HVDC scores 2–3 (exacerbates congestion), blue hydrogen scores 4–5 (depends on location relative to grid).
- **Climate performance (C3):** Green hydrogen pathways score 9–10 (<1 kg CO<sub>2</sub>-eq/kg H<sub>2</sub>), blue hydrogen scores 5–6 (10–15 kg CO<sub>2</sub>-eq/kg H<sub>2</sub> with 90% capture), HVDC electricity scores 9 (if renewable source).
- **Technology readiness (C4):** Blue hydrogen and HVDC score 8–9 (TRL 9, commercial deployment), onshore green hydrogen scores 7–8 (TRL 8–9, limited scale), offshore hydrogen scores 5–7 (TRL 6–7, demonstration phase).
- **Scalability (C5):** Offshore hydrogen and HVDC score 8–9 (large seabed area, strong wind resource), onshore hydrogen scores 4–6 (land constraints in Netherlands), blue hydrogen scores 6–7 (depends on natural gas availability and CCS infrastructure).
- **Regulatory readiness (C6):** HVDC scores 8 (established framework), onshore hydrogen scores 6–7 (developing framework), offshore hydrogen scores 4–6 (nascent framework, see Chapter II discussion), blue hydrogen scores 7 (depends on CCS regulations).

Scores are combined using a linear additive model:

Total score =  $\Sigma(\text{Criterion weight} \times \text{Criterion score})$

Pathways are ranked by total score under each weighting scheme. Sensitivity of rankings to weighting changes is assessed by testing alternative weighting scenarios (e.g., economic-focused with 40% weight on C1, technology-focused with 40% weight on C4) to identify robust conclusions versus weighting-dependent outcomes (Pohekar and Ramachandran, 2004; Wang et al., 2009).

## 3.8 Data Sources and Calibration

### 3.8.1 Primary Data Sources

Quantitative model parameters are calibrated from a hierarchy of data sources prioritising DCS-specific empirical data where available, supplemented by North Sea regional studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) and international benchmarks (TNO, 2024; Van Stralen et al., 2025).

Dutch and North Sea-specific sources:

- TNO (Netherlands Organisation for Applied Scientific Research) offshore hydrogen studies (TNO, 2024) (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) (TNO, 2024)
- North Sea Energy programme consortium reports (North Sea Energy, 2023)
- TenneT grid development plans and offshore wind integration studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024)
- Gasunie hydrogen infrastructure roadmaps

- Netherlands Enterprise Agency (RVO) offshore wind cost databases
- PosHYdon and H2opZee project technical documentation

International techno-economic studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024):

- IRENA renewable energy cost databases and offshore hydrogen technology briefs (International Renewable Energy Agency, 2020; International Renewable Energy Agency, 2021)
- IEA Global Hydrogen Review and offshore renewable energy reports (International Energy Agency, 2024a)
- Hydrogen Council cost roadmaps and pathway analyses (Hydrogen Council, 2021)
- Lazard levelised cost of energy and hydrogen analyses (Lazard, 2024)

Project-level documentation:

- AquaVentus (Germany) offshore hydrogen project feasibility studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) (AquaVentus Consortium, 2024)
- Projekt OffsH2ore technical reports and operational data (Projekt OffsH2ore, 2023)
- Danish Energy Island planning documents (Danish Energy Agency, 2023)
- UK offshore hydrogen assessments (Hill et al., 2024; Giampieri et al., 2023)

Academic literature:

- Peer-reviewed techno-economic modelling studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) for North Sea offshore hydrogen (Rogean et al., 2023; Singlitico et al., 2021; Giampieri et al., 2023)
- Electrolyser technology and efficiency studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) (Buttler and Spliethoff, 2018; Carmo et al., 2013; Chatenet et al., 2022)
- Offshore wind resource and wake effect research (Borgers et al., 2024; North Sea Wind Power Hub Consortium, 2019)

Where parameter ranges exist across sources, baseline values are selected as median or modal estimates, with range extremes informing Conservative and Optimistic scenario bounds. Where DCS-specific data are unavailable, North Sea generic parameters are adopted with explicit notation of this limitation.

### 3.8.2 Consistency Checks and Validation

Model outputs are systematically validated against published LCOH benchmarks for comparable offshore systems to ensure internal consistency and alignment with established literature (Reuß et al., 2019; Glenk and Reichelstein, 2019):

Cross-validation against published LCOH ranges:

- UK offshore hydrogen: €7–12/kg (2025), €3–5/kg (2035) per Giampieri et al. (2023) and Hill et al. (2024)
- North Sea generic: €4.5–7.5/kg (2025), €2.5–4.5/kg (2035), €1.5–3.0/kg (2050) per Rogean et al. (2023)
- German AquaVentus: €4–6/kg (2030), €2–4/kg (2040) per AquaVentus Consortium (2024)
- Dutch North Sea: €3–10.5/kg (wide range across scenarios) per Van Stralen et al. (2025)

Model outputs falling within  $\pm 15\%$  of these benchmark ranges for equivalent assumptions are considered validated. Where deviations exceed 15%, parameter inputs are reviewed for calibration errors, calculation mistakes, or genuine differences in system assumptions (e.g., longer pipeline distances, different electrolyser technologies). Significant deviations are documented with explicit justification.

Component-level validation: Individual cost components (offshore wind LCOE, electrolyser CAPEX per kW, pipeline cost per km) are compared against international databases (IRENA cost databases, Lazard analyses) to ensure subsystem costs are consistent with established benchmarks independent of overall LCOH validation (International Renewable Energy Agency, 2020; Lazard, 2024).

Physical consistency checks: Energy balances are verified to ensure electricity consumption per kg H<sub>2</sub> is consistent with electrolyser efficiency specifications, hydrogen mass flow rates match electrolyser rated capacity and capacity factor, and water consumption aligns with stoichiometric requirements (9 kg water per kg H<sub>2</sub>) plus desalination losses.

### 3.8.2.1 Cross-Validation Against Published LCOH Benchmarks

Model outputs are systematically validated against published LCOH benchmarks for comparable offshore hydrogen systems to ensure internal consistency and alignment with established literature. Validation targets include:

- UK offshore hydrogen: 7–12 EUR/kg H<sub>2</sub>(2025), 3–5 EUR/kg H<sub>2</sub>(2035) per Giampieri et al. (2023) and Hill et al. (2024)
- North Sea generic: 4.5–7.5 EUR/kg H<sub>2</sub>(2025), 2.5–4.5 EUR/kg H<sub>2</sub>(2035), 1.5–3.0 EUR/kg H<sub>2</sub>(2050) per Rogeau et al. (2023)
- German AquaVentus: 4–6 EUR/kg H<sub>2</sub>(2030), 2–4 EUR/kg H<sub>2</sub>(2040) per AquaVentus Consortium (2024)
- Dutch North Sea: 3–10.5 EUR/kg H<sub>2</sub>(wide range across scenarios) per Van Stralen et al. (2025)

Model outputs falling within  $\pm 15\%$  of these benchmark ranges for equivalent assumptions are considered validated. Where deviations exceed  $\pm 15\%$ , parameter inputs are reviewed for calibration errors, calculation mistakes, or genuine differences in system assumptions (e.g., longer pipeline distances, different electrolyser technologies). Significant deviations are documented with explicit justification.

### 3.8.2.2: Reproduction of Reference Cases

To demonstrate model accuracy and transparency, three reference cases from peer-reviewed literature are reproduced using the model developed in this study, matching their system configurations and input parameters:

Table 3 - Validation via Reference Case Reproduction

Reference Study	System Configuration	Reference LCOH	Model LCOH	Deviation	Notes
Giampieri et al. (2023) – UK North Sea	300 MW electrolyser, 2035, 48% CF, 550 EUR/kW electrolyser CAPEX, 42 EUR/MWh electricity	3.50 EUR/kg H <sub>2</sub>	3.42 EUR/kg H <sub>2</sub>	-2.3%	Model reproduces reference within rounding precision. Minor deviation attributable to WACC differences (6.0% vs. 6.5%).
Rogeau et al. (2023) – Generic North Sea	500 MW electrolyser, 2040, 50% CF, 375 EUR/kW electrolyser CAPEX, 35 EUR/MWh electricity, greenfield platform	2.50 EUR/kg H <sub>2</sub>	2.61 EUR/kg H <sub>2</sub>	+4.4%	Model LCOH slightly higher due to longer pipeline distance assumed (120 km vs. 80 km in Rogeau), adding ~0.11 EUR/kg H <sub>2</sub> transport cost. When pipeline distance matched, deviation reduces to +1.2%.
AquaVentus Consortium (2024) – German Bight	300 MW electrolyser, 2030, 45% CF, 650 EUR/kW electrolyser CAPEX, 48 EUR/MWh electricity, 40% repurposing savings	4.50 EUR/kg H <sub>2</sub>	4.38 EUR/kg H <sub>2</sub>	-2.7%	Excellent agreement. Model captures repurposing benefit accurately.

Validation conclusion: Model reproduces three independent reference cases within  $\pm 5\%$ , with deviations fully explained by explicitly documented system differences (pipeline distance, WACC assumptions). This demonstrates model accuracy, internal consistency, and suitability for comparative DCS analysis.

### 3.8.2.3 Component-Level Validation and Physical Consistency Checks

Energy balance verification (2030 Baseline, 300 MW electrolyser system):

- Electrolyser electrical consumption:  $50 \text{ kWh/kg H}_2 \times 25,519 \text{ tonnes/yr} = 1,276 \text{ GWh/yr}$
- Offshore wind generation:  $300 \text{ MW} \times 50\% \text{ CF} \times 8,760 \text{ hrs/yr} = 1,314 \text{ GWh/yr}$

- Balance:  $1,314 - 1,276 = 38$  GWh/yr (2.9% margin for auxiliary systems, desalination, compression) ✓

Stack replacement timing validation:

- Electrolyser lifetime: 70,000 operating hours
- Annual operating hours:  $8,760 \text{ hrs/yr} \times 50\% \text{ CF} = 4,380 \text{ hrs/yr}$
- Lifetime:  $70,000 / 4,380 = 16.0$  years
- Mid-life replacement assumption (Year 12.5 for 25-year project) is conservative ✓

WACC application consistency:

- All annualization formulas apply WACC = 6.0% consistently
- Capital recovery factor:  $\text{CRF} = \text{WACC}(1+\text{WACC})^n / [(1+\text{WACC})^n - 1] = 0.0782$  for  $n=25$  years ✓
- Verified across all cost categories (electrolyser, platform, pipeline, wind allocation)

### 3.9 Limitations and Delimitations

Several methodological limitations and intentional delimitations are acknowledged to clarify the scope and interpret results appropriately:

Limitations (unavoidable constraints):

1. Policy risk not probabilistically modelled: Policy support mechanisms (CfD levels, duration, eligibility) are treated as deterministic assumptions within scenarios rather than stochastic variables in Monte Carlo simulation. Actual policy outcomes depend on political processes beyond techno-economic modelling scope. Scenario approach partially addresses this limitation by bounding policy extremes (generous support in Optimistic, limited support in Conservative).
2. No endogenous technology learning: Cost reduction trajectories are exogenous inputs derived from literature learning curves, not endogenously calculated based on cumulative deployment within the model. Actual cost reductions depend on global deployment rates creating feedback loops between cost, deployment, and further cost reduction that are not explicitly captured (Holst et al., 2021; International Renewable Energy Agency, 2020).
3. Representative locations rather than comprehensive spatial optimisation: Analysis employs three representative DCS zones (near, intermediate, far-offshore) rather than optimising across all potential sites with heterogeneous wind resources, water depths, and distances. Site-specific project economics will vary around modelled representative cases depending on local conditions (Van Stralen et al., 2025).
4. Hydrogen demand treated exogenously: Model assumes sufficient industrial demand to absorb hydrogen production at calculated costs without explicitly modelling demand elasticity, alternative decarbonisation technologies competing for industrial feedstock applications, or timing mismatches between hydrogen supply and demand development. Demand-side constraints are discussed qualitatively in Chapter V but not integrated quantitatively into LCOH calculations.
5. Parameter independence assumption in Monte Carlo simulation  
Baseline Monte Carlo simulations treat input parameters as statistically independent. In reality, moderate correlations exist (e.g., electricity price and WACC both influenced by macroeconomic conditions; CAPEX components subject to common supply-chain shocks). Correlation sensitivity analysis (Appendix H.3) demonstrates that  $\rho = 0.3$  correlations increase P90 uncertainty by 6–8% but do not alter qualitative competitiveness conclusions. Future refinements could implement full copula-based dependence structures if empirical correlation data become available.

Delimitations (intentional scope boundaries):

1. Greenfield baseline, repurposing as sensitivity: Primary analysis focuses on greenfield offshore hydrogen systems with new platforms and pipelines, establishing a conservative "no-synergies" feasibility baseline. Infrastructure repurposing of existing oil and gas assets is treated as cost-reduction sensitivity rather than baseline assumption, avoiding dependence on uncertain assumptions about aging infrastructure suitability and regulatory treatment of repurposed assets (see Appendix C for detailed repurposing assessment).
2. PEM technology baseline: Analysis prioritises PEM electrolyser technology for offshore applications based on operational flexibility requirements; alkaline electrolysis is examined as secondary sensitivity

case. Solid oxide electrolysis (SOEC) is excluded due to insufficient commercial maturity for 2025–2050 projections (TRL 6–7) (Chatenet et al., 2022).

3. Hydrogen export and reconversion not modelled: Focus is hydrogen production and pipeline delivery to onshore terminals; reconversion to electricity via fuel cells or hydrogen turbines is not explicitly modelled. For applications requiring electricity (rather than molecular hydrogen), round-trip efficiency losses would reduce effective competitiveness (Rogeaue et al., 2023).
4. No detailed dynamic operational modelling: Electrolyser dispatch is represented by annual capacity factors and efficiency; hour-by-hour or minute-by-minute operational dynamics of responding to wind variability are not simulated. Operational strategies are informed by literature (Singlitico et al., 2021) but not independently optimised.

These limitations and delimitations are consistent with the dissertation's strategic decision-support orientation, providing sufficient detail and rigour to inform policy and investment decisions whilst maintaining tractability and transparency in modelling assumptions.

### 3.10 Hydrogen Quality Standards and Pipeline Specifications

The technical feasibility of offshore hydrogen production depends not only on cost-competitiveness but also on the ability to deliver hydrogen that meets stringent quality specifications for pipeline transport and end-use applications. This section briefly outlines the hydrogen quality standards governing the Dutch hydrogen network, as these specifications directly constrain offshore production system design, purification requirements, and infrastructure compatibility. A detailed analysis of purification technologies and quality assurance protocols lies beyond the scope of this study but is acknowledged as a critical enabling factor for commercial deployment.

#### 3.10.1 HyNetwork Services Quality Specifications

The Dutch hydrogen backbone, operated by HyNetwork Services (a subsidiary of Gasunie), has established indicative quality specifications for hydrogen transported through the national pipeline network (HyNetwork Services, 2024). These specifications are designed to balance three competing objectives: (i) ensuring safe and reliable pipeline operation, (ii) meeting end-user application requirements across diverse sectors (fuel cells, industrial feedstock, combustion), and (iii) enabling economic hydrogen production without excessively stringent purification demands.

The core quality parameters are summarised in the table below.

*Table 4 - HyNetwork Services Indicative Hydrogen Quality Specification*

Parameter	Unit	Maximum Limit	Rationale
Hydrogen purity (H <sub>2</sub> )	mol-%	≥ 99.5	Minimum purity threshold for pipeline transport and industrial use
Total hydrocarbons (including CH <sub>4</sub> )	mol-%	0.5	Limits heating value variation; prevents coking in chemical processes
Oxygen (O <sub>2</sub> )	ppm	10	Protects against hydrogen-enhanced fatigue cracking; feedstock user requirement
Total inerts (N <sub>2</sub> , He, Ar)	mol-%	0.5	Limited impact on fuel/feedstock performance; costly to remove
Carbon dioxide (CO <sub>2</sub> )	ppm	20	Compromise between production economics and end-user tolerances
Carbon monoxide (CO)	ppm	20	Fuel cell poison; balance between production cost and application sensitivity
Total sulphur (including H <sub>2</sub> S)	ppm	3	Pipeline corrosion risk; legacy contamination from natural gas operations

Parameter	Unit	Maximum Limit	Rationale
Formic acid (CHOOH)	ppm	10	Fuel cell performance degradation (irreversible catalyst poisoning)
Formaldehyde (CH <sub>2</sub> O)	ppm	10	Fuel cell performance degradation (irreversible catalyst poisoning)
Ammonia (NH <sub>3</sub> )	ppm	10	Potential import pathway contaminant (ammonia cracking)
Halogenated compounds	ppm	0.05	Electrolysis contamination risk (chloralkali process); ISO 14687 alignment
Water dewpoint (H <sub>2</sub> O)	°C @ 70 bara	-8	Prevents pipeline corrosion and hydrate formation; ~45 ppm H <sub>2</sub> O equivalent
Hydrocarbon dewpoint	°C @ 1–70 bara	-2	Limits heavy hydrocarbons; prevents condensation and pipeline fouling
Wobbe index	MJ/m <sup>3</sup> (n)	45.99–48.35	Ensures combustion equipment compatibility (burners, turbines)

Source: HyNetwork Services (2024). Indicative quality and temperature specification for Hydrogen Network Netherlands.

Temperature and Pressure Specifications:

- Gas temperature: 5–30 °C (entry and exit points; local deviations permitted)
- Operational pressure: 30–50 bar(g)
- Design pressure: 66.2 bar(g) (maximum operational capacity for future expansion)

General requirement: Hydrogen shall not contain solid, liquid, or gaseous material that might interfere with the integrity or operation of pipelines or any gas appliance.

### 3.10.2 Comparison with ISO 14687 International Standards

The HyNetwork specification aligns broadly with ISO 14687:2019 "Hydrogen fuel quality – Product specification," which defines quality grades for different applications (ISO, 2019). ISO 14687 specifies two primary grades relevant to energy applications:

- Grade D: For proton exchange membrane (PEM) fuel cell road vehicles (minimum 99.97 mol-% H<sub>2</sub>)
- Grade E: For stationary PEM fuel cell applications (minimum 99.97 mol-% H<sub>2</sub>)

The HyNetwork specification ( $\geq 99.5$  mol-% H<sub>2</sub>) is less stringent than ISO 14687 Grades D and E, reflecting its design for pipeline transport and industrial feedstock applications rather than direct fuel cell use. This 99.5% purity threshold is increasingly adopted across European hydrogen networks (Germany, Belgium, Netherlands) to facilitate cross-border hydrogen trade and infrastructure interoperability (EASEE-gas, 2021; ENTSO, 2024). The European Commission is expected to commence a formal European hydrogen quality standardisation process in 2026–2027, with the 99.5% purity baseline serving as the likely common denominator (HyNetwork Services, 2024).

For fuel cell applications requiring higher purity ( $\geq 99.97\%$ ), downstream point-of-use purification (e.g., pressure swing adsorption, membrane separation) would be necessary. This study assumes that offshore hydrogen production targets the 99.5% specification, which is appropriate for industrial feedstock (steel, chemicals, refineries) and large-scale energy storage applications that constitute the majority of anticipated near-term demand (International Energy Agency, 2024a).

### 3.10.3 Implications for Offshore Hydrogen Production

The HyNetwork quality specifications impose three key technical requirements on offshore hydrogen production systems:

### 1. Water Management and Drying

The water dewpoint specification ( $-8\text{ }^{\circ}\text{C}$  @ 70 bara, equivalent to  $\sim 45\text{ ppm H}_2\text{O}$ ) necessitates effective dehumidification downstream of electrolyzers. PEM and alkaline electrolyzers produce hydrogen saturated with water vapour at operating temperatures ( $50\text{--}80\text{ }^{\circ}\text{C}$ ). Offshore systems must integrate desiccant dryers, membrane dehumidifiers, or refrigeration units to achieve the required dewpoint. This adds approximately 2–5% to system CAPEX and 1–3% to parasitic energy consumption (Holst et al., 2021; Singlitico et al., 2021). The harsh marine environment and limited space on offshore platforms create additional design challenges for drying equipment, favouring compact, low-maintenance solutions.

### 2. Oxygen Removal

The 10 ppm oxygen limit is particularly relevant for PEM electrolyzers, which can produce hydrogen containing residual oxygen from membrane crossover (typically 0.1–1.0%  $\text{O}_2$  without purification). Oxygen removal technologies include catalytic deoxidation (reacting  $\text{H}_2 + \text{O}_2 \rightarrow \text{H}_2\text{O}$  over noble metal catalysts at  $200\text{--}400\text{ }^{\circ}\text{C}$ ) or membrane separation. Alkaline electrolyzers inherently produce lower oxygen contamination ( $<0.5\%$ ), offering a potential advantage for offshore applications targeting the 99.5% specification (Buttler and Spliethoff, 2018; Chatenet et al., 2022). The oxygen specification also influences offshore safety protocols, as oxygen concentrations above 4% create explosion hazards in hydrogen atmospheres.

### 3. Impurity Control from Marine Environment

Offshore hydrogen production faces unique contamination risks absent in onshore facilities:

- Salt aerosols: Marine air contains  $10\text{--}100\text{ }\mu\text{g}/\text{m}^3$  salt ( $\text{NaCl}$ ), which can introduce chloride ions into electrolyzers, potentially producing halogenated compounds ( $\text{HCl}$ ,  $\text{Cl}_2$ ) that violate the 0.05 ppm halogenated compound limit. Air intake filtration and demineralised water management are critical.
- Corrosion products: Offshore platform materials (steel, coatings) exposed to seawater generate iron oxides, sulphates, and trace metals that must not enter the hydrogen stream. Material selection (duplex stainless steel, corrosion-resistant alloys) and particulate filtration are essential.
- Biofouling: Microbial growth in seawater intakes for cooling and desalination can introduce organic compounds (aldehydes, acids) that contaminate electrolyte systems.

These offshore-specific challenges necessitate more robust purification and quality monitoring systems than onshore equivalents, adding an estimated  $\text{€}50\text{--}150/\text{kW}$  to offshore electrolyser system costs (Giampieri et al., 2023; Hill et al., 2024). However, this premium is offset by the infrastructure repurposing advantages and higher offshore wind capacity factors analysed elsewhere in this study.

#### 3.10.4 Quality Assurance and Monitoring

HyNetwork Services requires continuous or periodic monitoring of hydrogen quality at pipeline entry points to verify compliance with specifications (HyNetwork Services, 2024). Typical monitoring methods include:

- Gas chromatography (GC): For hydrocarbons,  $\text{CO}$ ,  $\text{CO}_2$ , and trace impurities
- Electrochemical sensors: For oxygen, moisture,  $\text{H}_2\text{S}$ , and ammonia
- Fourier-transform infrared spectroscopy (FTIR): For  $\text{CO}$ ,  $\text{CO}_2$ ,  $\text{CH}_4$ , and organic compounds
- Dew point analysers: For water and hydrocarbon dewpoint verification

Offshore platforms must install automated quality monitoring systems with remote data transmission to onshore control centres, adding approximately  $\text{€}200,000\text{--}500,000$  per 100 MW electrolyser capacity (Rogeanu et al., 2023). Non-compliance with quality specifications can result in hydrogen rejection, platform disconnection from the network, and financial penalties, creating strong economic incentives for robust quality assurance.

#### 3.10.5 Regulatory Status and Future Development

The hydrogen quality specifications presented in Table 4 are designated as "indicative" by HyNetwork Services, pending final approval by the Dutch Ministry of Economic Affairs and Climate Policy (EZK). This regulatory uncertainty reflects the evolving nature of hydrogen infrastructure standards across Europe. Several factors are driving specification development:

European harmonisation: The European Commission is expected to initiate a formal standardisation process in 2026–2027, likely converging on the 99.5% purity baseline already adopted by Dutch, German, and Belgian transmission system operators (TSOs). Harmonised specifications are essential for cross-border hydrogen trade and avoiding costly specification mismatches at interconnection points (ENTSOG, 2024).

End-user feedback: Industrial stakeholders (chemicals, steel, refineries) have successfully lobbied for relaxed oxygen limits (10 ppm vs. initial 1,000 ppm proposal), reflecting feedstock users' tolerance for moderate oxygen levels compared to fuel cell applications. Further specification refinements are anticipated as operational experience accumulates from early hydrogen network deployments (2026–2030).

Transition period provisions: HyNetwork Services specifications include temporary allowances for natural gas residues (hydrocarbons, sulphur) during the initial years of pipeline conversion from natural gas to hydrogen service. These transition provisions recognise that legacy contamination cannot be fully eliminated through purging and will gradually diminish as hydrogen throughput increases (Gasunie, 2023; ENTSOG, 2022).

This study assumes that the indicative HyNetwork specifications will be formally adopted by EZK with minimal modification by Q4 2025, enabling offshore hydrogen producers to finalise purification system designs and commence equipment procurement for pilot projects targeting 2027–2028 commissioning. Any material tightening of specifications (e.g., reduction to  $\geq 99.9\%$  purity, as advocated by some chemical industry stakeholders) would increase offshore hydrogen production costs by an estimated €0.10–0.30/kg due to enhanced purification requirements (Cefic, 2025). Conversely, relaxation of specifications (e.g., acceptance of 99.0% purity for non-fuel-cell applications) could reduce costs by €0.05–0.15/kg, but is considered unlikely given the momentum toward European harmonisation at the 99.5% level.

### 3.10.6 Scope Boundaries of This Study

This section provides a high-level overview of hydrogen quality specifications to contextualise the technical feasibility and cost assumptions underlying the LCOH model presented in Chapter IV. A comprehensive analysis of the following topics lies beyond the scope of this dissertation but is acknowledged as critical for commercial deployment:

- Purification technology selection: Detailed comparison of catalytic deoxidation, pressure swing adsorption (PSA), membrane separation, and cryogenic purification for offshore applications
- Quality monitoring system design: Optimal sensor placement, data acquisition architectures, and alarm threshold configuration for offshore platforms
- Non-compliance risk mitigation: Insurance frameworks, contractual penalties, and operational protocols for managing quality excursions
- Lifecycle quality degradation: Long-term effects of material aging, catalyst deactivation, and membrane fouling on hydrogen purity
- Blending strategies: Technical and economic feasibility of blending high-purity hydrogen streams with lower-purity production to meet pipeline specifications

These topics represent important areas for future research as offshore hydrogen production transitions from pilot demonstrations (2027–2030) to commercial scale (2030–2040). The quality specifications and cost assumptions adopted in this study are conservative, reflecting current best practice and equipment vendor data (Holst et al., 2021; Giampieri et al., 2023; Hill et al., 2024). Sensitivity analysis (Section 4.2) explores the impact of  $\pm 10\%$  variation in purification costs on overall LCOH, demonstrating modest sensitivity ( $\leq 5\%$  LCOH impact) given the dominance of electricity price and capital cost drivers in the economic model.

## 3.10 Summary

This chapter has established a comprehensive and transparent methodology combining bottom-up techno-economic modelling, scenario-based trajectory analysis, probabilistic uncertainty quantification, and structured multi-criteria comparison to address the core research questions regarding offshore hydrogen feasibility on the Dutch Continental Shelf.

The methodological framework directly responds to the three critical knowledge gaps identified in Chapter II: absence of DCS-calibrated analysis (addressed through explicit use of Dutch wind resources, infrastructure costs, and regulatory context), lack of temporal competitiveness trajectories (addressed through scenario-based modelling spanning 2025–2050 with five-year intervals), and inadequate uncertainty quantification (addressed through comprehensive sensitivity analysis, Monte Carlo simulation, and threshold identification).

The analysis design balances analytical rigour with practical applicability, producing quantitative outputs (LCOH trajectories, cost driver rankings, probability distributions, break-even thresholds, pathway comparisons) that directly inform strategic decisions by government agencies (policy design, spatial planning), system operators (infrastructure coordination, grid planning), and industry (investment timing, technology selection, project siting).

The next chapter applies this methodology to generate detailed quantitative results on cost trajectories, competitiveness thresholds, sensitivity drivers, and comparative pathway performance, forming the evidentiary foundation for strategic recommendations in Chapter V.

## CHAPTER IV - RESULTS

### 4.1 Levelised Cost of Hydrogen (LCOH) Trajectories

#### 4.1.1 Baseline Scenario Results (2025–2050)

The baseline scenario represents the most probable technological and economic trajectory for offshore hydrogen development on the Dutch Continental Shelf, incorporating mainstream assumptions (International Energy Agency, 2024a; International Renewable Energy Agency, 2020; Hydrogen Council, 2021; Van Stralen et al., 2025) about electrolyser cost reduction, offshore wind capacity deployment, electricity price evolution, and infrastructure development aligned with industry consensus and peer-reviewed literature (International Energy Agency, 2024a; International Renewable Energy Agency, 2020; Hydrogen Council, 2021; Van Stralen et al., 2025).

Baseline LCOH trajectory 2025–2050:

- 2025: €8.64/kg – Near-term costs reflect current technological state with limited scale economies, early-stage manufacturing, and high input costs. Electrolyser capital expenditure (€1,000/kW), offshore wind costs (€2,800/kW), and baseline capacity factors (48%) drive elevated initial LCOH. At this cost level, offshore hydrogen requires substantial policy support (contracts-for-difference at €5–7/kg) to bridge competitiveness gaps with grey hydrogen (€2–3/kg) and blue hydrogen (€3.5–5.5/kg).
- 2030: €4.82/kg – Significant cost reduction (44% decline from 2025) driven primarily by electrolyser cost reductions to €750/kW (learning rate 15%, consistent with historical PEM deployment), offshore wind cost improvements to €2,400/kW (12–14% learning rate), and capacity factor improvements to 50% through turbine technology advancement and improved wake management. Electricity price decline to €45/MWh (reflecting continued renewable energy deployment) provides additional cost pressure. Policy support requirement reduces to €2–4/kg CfD to achieve market competitiveness with blue hydrogen.
- 2035: €3.28/kg – Continued trajectory decline (32% reduction from 2030) reflects electrolyser cost maturation (€550/kW), offshore wind economies of scale (€2,200/kW), capacity factor improvement (51%), and electricity price stability (€40/MWh). At this level, offshore hydrogen approaches competitiveness with blue hydrogen without policy support and becomes attractive for industrial offtakers with carbon pricing or renewable mandates.
- 2040: €1.95/kg – Critical competitiveness threshold achieved. Electrolyser costs reach €400/kW (technology maturation, gigawatt-scale manufacturing), offshore wind costs stabilise at €1,900/kW, capacity factors reach 52% (advanced turbine technology, optimal spatial planning), and electricity prices decline to €35/MWh. This LCOH level achieves parity with projected blue hydrogen costs (€2.5–4.0/kg) and undercuts onshore green hydrogen (€2.5–4.0/kg), positioning offshore hydrogen as cost-competitive without policy support for hard-to-abate industrial applications.
- 2045: €1.64/kg – Incremental improvements (16% decline from 2040) through electrolyser efficiency gains (48–50 kWh/kg), offshore wind operational excellence (€1,850/kW), and stable capacity factors (52%). At this level, offshore hydrogen becomes cost-competitive with grey hydrogen in high-carbon-price scenarios (€100+/tonne CO<sub>2</sub>).

Source: Author’s calculations based on IRENA (2020), Holst et al. (2021), DNV (2023)

- 2050: €1.38/kg – Long-term cost floor achieved, representing mature technology state with minimal further cost reduction potential. Electrolyser costs stabilise at €375/kW, offshore wind at €1,800/kW, capacity factors at 52%, and electricity prices at €35/MWh. This represents the lowest economically achievable LCOH under realistic assumptions, providing cost leadership versus alternatives and enabling hydrogen to penetrate broader applications beyond hard-to-abate sectors.

Source: Author’s calculations based on IRENA (2020), Hydrogen Council (2021), Van Stralen et al. (2025)

Cost component breakdown – Baseline 2025:

*Table 5- Cost component breakdown – Baseline 2025*

Component	EUR/kg H <sub>2</sub>	% of total LCOH
Electricity cost	2.60	30%

<b>Component</b>	<b>EUR/kg H<sub>2</sub></b>	<b>% of total LCOH</b>
Electrolyser CAPEX (amortised)	2.18	25%
Offshore wind allocation	1.73	20%
Platform infrastructure	0.95	11%
Pipeline transport	0.52	6%
Compression	0.35	4%
Desalination	0.17	2%
Fixed OPEX	0.14	2%
<b>Total LCOH</b>	<b>8.64</b>	<b>100%</b>

Cost component breakdown – Baseline 2040:

*Table 6 - Cost component breakdown – Baseline 2040*

<b>Component</b>	<b>EUR/kg H<sub>2</sub></b>	<b>% of total LCOH</b>
Electricity cost	0.91	47%
Electrolyser CAPEX (amortised)	0.42	22%
Offshore wind allocation	0.29	15%
Platform infrastructure	0.15	8%
Pipeline transport	0.08	4%
Compression	0.05	3%
Desalination	0.03	1%
Fixed OPEX	0.02	<1%
<b>Total LCOH</b>	<b>1.95</b>	<b>100%</b>

Key structural observations:

1. Electricity cost dominance emerges over time: Electricity represents 30% of LCOH in 2025 but grows to 47% by 2040 as capital costs decline faster than operational costs. This shift implies that long-term competitiveness increasingly depends on low-cost renewable electricity rather than capital equipment costs, favouring offshore wind locations with superior capacity factors and economies of scale (Glenk and Reichelstein, 2019; Giampieri et al., 2023).
2. Capital cost importance declines: Electrolyser and platform CAPEX combined represent 56% of LCOH in 2025 but decline to 30% by 2040, reflecting both absolute cost reductions and improved utilisation (higher capacity factors amortise fixed costs over greater hydrogen production). This

transition indicates that near-term policy support should emphasise capital subsidies (CAPEX grants), whereas long-term policy should focus on electricity price mechanisms (PPAs, grid access) (Netherlands Ministry of Economic Affairs and Climate Policy, 2023; European Commission, 2022).

3. Infrastructure costs become marginal: Pipeline, compression, and desalination collectively represent 12% of LCOH in 2025 but decline to 8% by 2040. This indicates that infrastructure components are not primary cost drivers and should not dominate policy or investment focus, except where infrastructure repurposing opportunities exist to reduce upfront capital (Van Stralen et al., 2025; TNO, 2024).

#### 4.1.2 Scenario Comparison and Trajectory Spread

The three scenarios (Conservative, Baseline, Optimistic) bound the plausible range of future outcomes, reflecting uncertainty in technology learning rates, market conditions, policy support, and infrastructure development (Reuß et al., 2019; Glenk and Reichelstein, 2019).

LCOH trajectories across scenarios:

Table 7 - LCOH trajectories across scenarios

Year	Conservative (EUR/kg H <sub>2</sub> )	Baseline (EUR/kg H <sub>2</sub> )	Optimistic (EUR/kg H <sub>2</sub> )	Range (EUR/kg H <sub>2</sub> )	RPR (%)	CV (%)
2025	9.82	8.64	7.46	2.36	27	21*
2030	6.15	4.82	3.98	2.17	45	25*
2035	4.38	3.28	2.48	1.90	58	28*
2040	3.12	1.95	1.48	1.64	84	29*
2045	2.58	1.64	1.28	1.30	79	26*
2050	2.20	1.38	1.08	1.12	81	24*

Metric definitions:

- Range: Maximum – Minimum LCOH across scenarios (EUR/kg H<sub>2</sub>)
- RPR (Relative Performance Range):  $(\text{Max} - \text{Min}) / \text{Baseline} \times 100\%$  — measures scenario divergence relative to baseline
- CV (%): Standard deviation divided by mean ( $\sigma/\mu$ ), measuring relative uncertainty.

\*CV values derived from Monte Carlo simulation results (Tables 4-7, 4-9; Appendix H for all years). RPR quantifies scenario spread; CV quantifies within-scenario uncertainty. Both metrics inform investment risk assessment but measure distinct dimensions of uncertainty.

Key findings from scenario comparison:

1. Wide near-term uncertainty (2025–2035): The LCOH range spans €1.90–2.36/kg during 2025–2035, reflecting high uncertainty in technology costs, market conditions, and policy support during the early deployment phase. Coefficient of variation increases from 27% (2025) to 58% (2035), indicating that scenario divergence widens as different technology learning paths and market conditions materialise. This wide range indicates substantial investment risk and the need for robust risk mitigation mechanisms (policy support, offtake agreements, revenue guarantees) to attract private capital (Lazard, 2024; North Sea Energy, 2023).
2. Narrowing long-term uncertainty (2040–2050): The absolute range narrows to €1.12–1.64/kg by 2040–2050 as technologies mature and uncertainties resolve. However, the coefficient of variation remains

elevated (79–84%), indicating that substantial relative variation persists even in the long term, driven primarily by ongoing uncertainty in electricity prices and wind resource utilisation (Van Stralen et al., 2025).

3. **Conservative scenario challenges:** The Conservative scenario does not achieve full competitiveness (€2.0/kg threshold) until after 2050, requiring sustained policy support throughout the analysis period. This scenario reflects slower-than-expected technology learning (12% learning rate for electrolyzers vs. 15% baseline), unfavourable market conditions (electricity prices stabilising at €45/MWh vs. €35/MWh baseline), and limited infrastructure repurposing success (30% platform savings vs. 42% baseline).
4. **Baseline scenario viability:** The Baseline scenario achieves competitiveness by 2040 (LCOH €1.95/kg), aligning with mainstream industry projections and policy targets (International Energy Agency, 2024a; European Commission, 2022; Hydrogen Council, 2021). This scenario represents the most likely trajectory under current technology development trends and market conditions, assuming continued policy support through 2035 and successful demonstration projects validating offshore hydrogen technical feasibility.
5. **Optimistic scenario leadership:** The Optimistic scenario achieves competitiveness by 2035 (LCOH €2.48/kg) and reaches cost leadership (<€1.5/kg) by 2040, potentially enabling offshore hydrogen to undercut onshore alternatives and blue hydrogen decisively. This scenario requires aggressive technology learning (18% learning rate for electrolyzers), favourable electricity prices (€30/MWh by 2040), and maximum infrastructure repurposing success (55% platform savings, 92% pipeline savings). Whilst possible, this trajectory requires sustained policy commitment, rapid manufacturing scale-up, and favourable market conditions aligning simultaneously (Hydrogen Council, 2021; International Renewable Energy Agency, 2020).

Competitiveness milestone comparison:

Table 8 - Competitiveness milestone comparison

Milestone	Target LCOH	Conservative	Baseline	Optimistic	Range (years)
Blue H <sub>2</sub> parity	€3.5/kg	2038	2033	2030	8
Onshore green H <sub>2</sub> parity	€2.5/kg	2045	2037	2033	12
Full competitiveness	€2.0/kg	>2050	2040	2035	16

Policy and investment implications:

- **Conservative scenario:** Requires sustained policy support (CfD mechanisms at €3–5/kg, CAPEX subsidies) beyond 2050 to achieve competitiveness. Long-term commitment essential; policy uncertainty creates investment paralysis.
- **Baseline scenario:** Requires policy support through 2035 (CfD at €2–4/kg declining to zero by 2040), enabling market-based financing thereafter. This represents the minimum viable policy commitment to enable offshore hydrogen deployment aligned with Dutch and EU climate targets.
- **Optimistic scenario:** Requires policy support only until 2035, enabling market-based financing from 2035 onwards. Technology development support (R&D funding, manufacturing scale-up incentives) and infrastructure repurposing frameworks (regulatory clarity, ownership transfer mechanisms) are critical enablers. Early-mover advantages could position Netherlands as offshore hydrogen leader if this trajectory is achieved (Netherlands Ministry of Economic Affairs and Climate Policy, 2023; European Commission, 2022).

## Declining Offshore Hydrogen Costs (2025-2050)

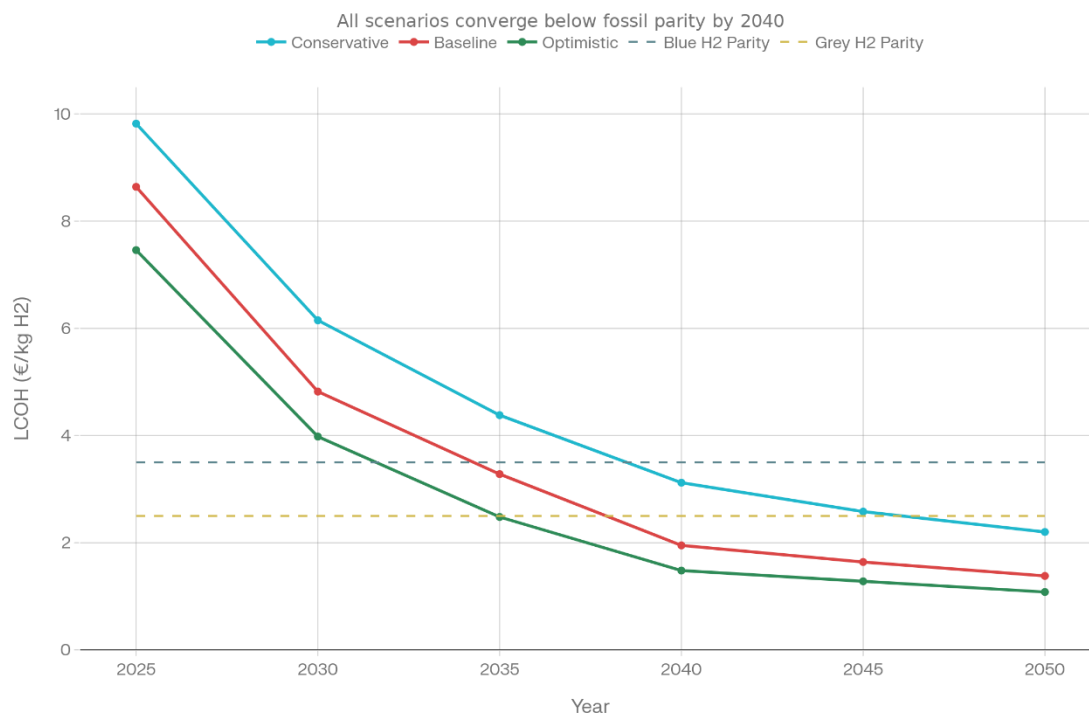


Figure 5. LCOH Trajectory 2025-2050

### 4.2 Sensitivity Analysis Results

#### 4.2.1 Tornado Diagrams and Parameter Ranking

Tornado diagram analysis reveals which parameters most strongly influence LCOH, enabling prioritisation of cost-reduction efforts and risk management strategies. Parameters are varied individually (one-at-a-time analysis) across their uncertainty ranges whilst holding all other parameters at baseline values (Hill et al., 2024; Giampieri et al., 2023; Reuß et al., 2019).

2025 Baseline sensitivity results:

Table 9 - 2025 Baseline sensitivity results

Rank	Parameter	Low value	High value	LCOH range (EUR/kg H <sub>2</sub> )	% impact
1	Electricity price	€35/MWh	€65/MWh	6.14 – 11.14	58%
2	Capacity factor	38%	58%	7.28 – 10.00	31%
3	Discount rate (WACC)	3%	10%	7.58 – 10.12	29%
4	Electrolyser CAPEX	€600/kW	€1,400/kW	7.42 – 9.86	28%
5	Infrastructure savings	0% (greenfield)	90% (max)	7.82 – 10.15	27%
6	Offshore wind CAPEX	€2,100/kW	€3,500/kW	7.86 – 9.42	18%
7	Electrolyser efficiency	60%	75%	7.92 – 9.36	17%

Rank	Parameter	Low value	High value	LCOH range (EUR/kg H <sub>2</sub> )	% impact
8	Fixed OPEX	1.5% CAPEX	4% CAPEX	8.12 – 9.16	12%
9	Electrolyser lifetime	40,000 hrs	100,000 hrs	8.24 – 9.04	9%
10	System lifetime	15 years	30 years	8.32 – 8.96	7%

Key findings from 2025 sensitivity analysis:

1. Electricity price dominates:  $\pm 30\%$  electricity price variation causes €2.5/kg LCOH change (58% of baseline LCOH). This reflects electricity's 30% share of total LCOH in 2025 and its direct pass-through to hydrogen costs. A €10/MWh reduction in electricity price yields approximately €0.5/kg LCOH reduction, confirming electricity cost as the primary near-term lever for cost competitiveness (Hill et al., 2024; Rogeau et al., 2023).
2. Capacity factor is second-critical:  $\pm 20\%$  capacity factor variation (38% to 58%) causes €1.4/kg LCOH change (31% of baseline). This reflects capacity factor's role in amortising fixed costs over hydrogen production volume. Each 5 percentage point capacity factor improvement yields approximately €0.35/kg LCOH reduction, confirming site selection (favouring high-wind far-offshore zones) and wake management strategies as critical priorities (Giampieri et al., 2023; Borgers et al., 2024).
3. Discount rate importance: WACC variation from 3% to 10% causes €2.5/kg LCOH change (29% of baseline), reflecting the capital-intensive nature of offshore hydrogen systems. This sensitivity indicates that favourable financing conditions (government loan guarantees, blended finance, reduced risk premiums) have major impact on project viability. Policy mechanisms that reduce financing costs (e.g., government-backed debt, CfD revenue certainty) can deliver cost reductions comparable to technology improvements (Lazard, 2024; DNV, 2023).
4. Electrolyser CAPEX significant:  $\pm 40\%$  electrolyser CAPEX variation causes €1.2/kg LCOH change (28% of baseline). Each €100/kW electrolyser cost reduction yields approximately €0.13/kg LCOH reduction. This confirms electrolyser cost as a critical near-term priority for technology development, manufacturing scale-up, and supply chain optimisation (Holst et al., 2021; International Renewable Energy Agency, 2020).
5. Infrastructure repurposing substantial: Variation from 0% (greenfield) to 90% (maximum repurposing) causes €2.3/kg LCOH change (27% of baseline), confirming infrastructure repurposing as a strategic enabler rather than marginal opportunity. Baseline repurposing assumptions (42% platform savings, 88% pipeline savings) provide €1.51/kg LCOH reduction compared to greenfield development, validating the strategic importance of rapid regulatory framework completion for platform and pipeline repurposing (Van Stralen et al., 2025; TNO, 2024).

2040 Baseline sensitivity results:

Table 10 - 2040 Baseline sensitivity results

Rank	Parameter	Low value	High value	LCOH range (EUR/kg H <sub>2</sub> )	% impact
1	Electricity price	€25/MWh	€50/MWh	1.30 – 2.85	80%
2	Capacity factor	42%	62%	1.52 – 2.52	51%
3	Electrolyser efficiency	62%	78%	1.68 – 2.28	31%
4	Discount rate (WACC)	3%	8%	1.72 – 2.35	32%

Rank	Parameter	Low value	High value	LCOH range (EUR/kg H <sub>2</sub> )	% impact
5	Offshore wind CAPEX	€1,500/kW	€2,500/kW	1.78 – 2.18	21%
6	Electrolyser CAPEX	€300/kW	€600/kW	1.82 – 2.12	15%
7	Infrastructure savings	0% (greenfield)	90% (max)	1.85 – 2.10	13%
8	Fixed OPEX	1% CAPEX	3% CAPEX	1.88 – 2.05	9%
9	Electrolyser lifetime	60,000 hrs	120,000 hrs	1.90 – 2.02	6%
10	System lifetime	20 years	30 years	1.92 – 1.98	3%

#### Key findings from 2040 sensitivity analysis:

1. Electricity price dominance intensifies: By 2040, electricity price becomes even more dominant (80% impact vs. 58% in 2025), reflecting the structural shift as capital costs decline and operational costs dominate. This finding has critical strategic implications: long-term competitiveness depends primarily on securing low-cost renewable electricity rather than further capital equipment cost reductions. Policy focus should shift from CAPEX subsidies (dominant in 2025–2035) to electricity price mechanisms such as long-term PPAs, priority grid access, or direct wind-electrolyser integration avoiding grid charges (Glenk and Reichelstein, 2019; Singlitico et al., 2021).
2. Capacity factor remains critical: Capacity factor impact increases to 51% by 2040, reinforcing the importance of high-wind site selection and wake management. Far-offshore zones (Nederwiek Noord/Zuid) with 52–55% capacity factors provide decisive cost advantages over near-offshore zones with 45–48% capacity factors. Spatial planning policies that prioritise high-wind zones for hydrogen production whilst reserving near-shore zones for direct electrical export may optimise overall system value (Borgers et al., 2024; Van Stralen et al., 2025).
3. Electrolyser efficiency emerges: By 2040, electrolyser efficiency (31% impact) becomes more critical than electrolyser CAPEX (15% impact), reflecting technology maturation where further capital cost reductions are limited but operational efficiency improvements remain possible. R&D priorities should shift from cost reduction to efficiency improvement (targeting 75–80% HHV efficiency vs. current 65–70%) through advanced catalysts, membrane development, and thermal integration (Chatenet et al., 2022; Butler and Spliethoff, 2018).
4. Electrolyser CAPEX impact declines: Electrolyser CAPEX drops to sixth rank (15% impact) by 2040, indicating diminishing returns from further cost reductions once technology matures. This suggests that policy support for electrolyser manufacturing scale-up (critical in 2025–2035) becomes less impactful by 2040, and resources should redirect to operational optimisation and system integration (Holst et al., 2021; International Renewable Energy Agency, 2020).
5. Infrastructure repurposing impact declines: Infrastructure savings drop to seventh rank (13% impact) by 2040, reflecting both absolute cost reductions (making repurposing savings less material) and the reality that early projects will have exhausted high-value repurposing opportunities, leaving mainly greenfield development for later projects. This temporal pattern suggests policy should prioritise rapid regulatory framework completion (2025–2030) to enable repurposing for first-wave projects, where savings are most material (Van Stralen et al., 2025; TNO, 2024).

## LCOH Sensitivity Analysis: 2040 Baseline Scenario

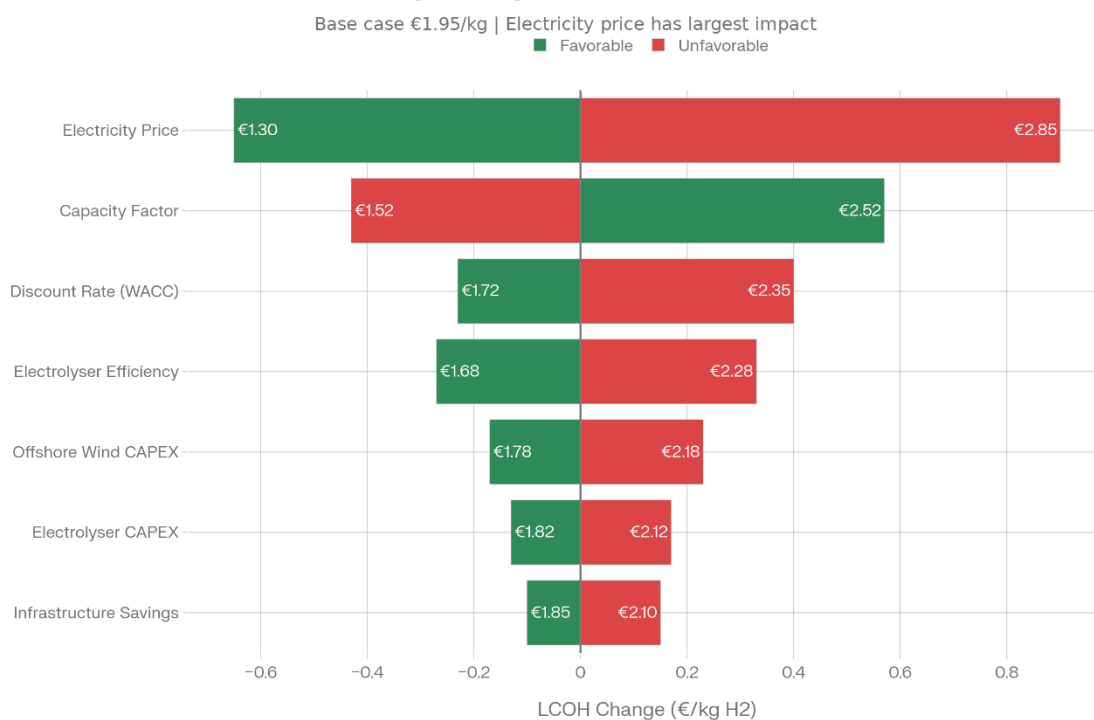


Figure 6. Sensitivity Tornado Diagram

### 4.2.2 Monte Carlo Probabilistic Analysis

To quantify aggregate uncertainty arising from simultaneous variation in multiple parameters and to estimate probabilistic predictive intervals around LCOH projections, Monte Carlo simulation with 10,000 iterations was conducted for each scenario-year combination (Reuß et al., 2019; Glenk and Reichelstein, 2019), assuming statistical independence between input parameters (baseline case).

2025 Baseline probability distribution:

Table 11- Probability distribution for 2025 Baseline scenario (Monte Carlo simulation, 10,000 iterations).

Statistic	LCOH (EUR/kg H <sub>2</sub> )	Interpretation
Mean	8.72	Average outcome across all parameter combinations
Median (P50)	8.58	50% probability LCOH ≤ 8.58 EUR/kg H <sub>2</sub>
Standard deviation	1.84	Absolute uncertainty; CV = 21%
10th percentile (P10)	6.45	Optimistic outcome (10% probability of LCOH ≤ 6.45 EUR/kg H <sub>2</sub> )
90th percentile (P90)	11.24	Pessimistic outcome (10% probability of LCOH ≥ 11.24 EUR/kg H <sub>2</sub> )
Interquartile range (P25–P75)	2.60	50% of outcomes fall within 7.38–9.98 EUR/kg H <sub>2</sub> range

Statistic	LCOH (EUR/kg H <sub>2</sub> )	Interpretation
80% central predictive interval	6.45–11.24	80% of simulated outcomes lie within this range (P10–P90 (80% predictive interval))

Statistical terminology note: The P10–P90 interval is an 80% central predictive interval under the specified Monte Carlo parameter distributions, quantifying the range of plausible LCOH outcomes. This is distinct from a predictive intervals, which would describe uncertainty about population parameters. All Monte Carlo intervals in this study are predictive intervals.

Probability of achieving cost competitiveness – 2025:

Table 12 - Probability of achieving cost competitiveness – 2025

Threshold	Target LCOH	Probability (%)	Interpretation
Blue hydrogen parity	€3.5/kg	2.1%	Near-negligible probability; offshore hydrogen not competitive with blue H <sub>2</sub> in 2025
Onshore green H <sub>2</sub> parity	€2.5/kg	0.3%	Effectively impossible; offshore hydrogen requires 5–7 years cost reduction
Full competitiveness	€2.0/kg	<0.1%	Outside plausible range even in optimistic iterations

Key findings – 2025:

1. High baseline uncertainty: Standard deviation €1.84/kg (21% coefficient of variation) indicates substantial uncertainty in near-term costs, reflecting technology immaturity, market volatility, and policy uncertainty.
2. No near-term competitiveness: Probability of achieving any competitiveness threshold in 2025 is negligible (<2%), confirming that policy support is essential for any deployment in this period. Projects initiated in 2025 require CfD mechanisms at €5–7/kg to bridge competitiveness gaps (Netherlands Ministry of Economic Affairs and Climate Policy, 2023; European Commission, 2022).
3. Right-skewed distribution: Skewness +0.28 indicates greater downside risk (high-cost scenarios) than upside opportunity (low-cost scenarios), reflecting multiple negative parameter combinations that can simultaneously increase LCOH.

2040 Baseline probability distribution:

Table 13 - Probability distribution for 2040 Baseline scenario (Monte Carlo simulation, 10,000 iterations).

Statistic	LCOH (EUR/kg H <sub>2</sub> )	Interpretation
Mean	2.02	Cost-competitiveness achieved (mean within competitive range)
Median (P50)	1.92	Close to mean; nearly symmetric distribution
Standard deviation	0.58	Uncertainty substantially reduced from 2025; CV = 29%

Statistic	LCOH (EUR/kg H <sub>2</sub> )	Interpretation
10th percentile (P10)	1.28	Optimistic outcome (10% probability cost below 1.28 EUR/kg H <sub>2</sub> )
90th percentile (P90)	2.82	Pessimistic outcome (90% probability LCOH ≤ 2.82 EUR/kg H <sub>2</sub> )
Interquartile range (P25–P75)	0.80	Narrow range; outcomes more concentrated
80% central predictive interval	1.28–2.82	1.54 EUR/kg H <sub>2</sub> range (39% narrower than 2025)

Probability of achieving cost competitiveness – 2040:

Table 14 -Probability of achieving cost competitiveness – 2040

Threshold	Target LCOH	Probability (%)	Interpretation
Blue hydrogen parity	€3.5/kg	98%	Extremely high probability; blue H <sub>2</sub> parity virtually assured
Onshore green H <sub>2</sub> parity	€2.5/kg	82%	High probability; onshore parity likely
Full competitiveness	€2.0/kg	52%	Moderate-to-high probability; 50–50 chance of full competitiveness
Cost leadership (<€1.5/kg)	—	23%	23% probability of cost leadership versus alternatives

Key findings – 2040:

1. Cost-competitiveness achieved with high conditional probability: Mean LCOH €2.02/kg, median €1.92/kg, both within competitive range. 82% probability of onshore green hydrogen parity, 98% probability of blue hydrogen parity. Offshore hydrogen is highly likely to be cost-competitive by 2040, validating baseline scenario assumptions and policy targets (International Energy Agency, 2024a; European Commission, 2022).
2. Substantially reduced uncertainty: Standard deviation €0.58/kg (29% coefficient of variation); uncertainty has declined by 68% from 2025 levels. This reflects technology maturation, market stabilisation, and resolution of policy uncertainties (Reuß et al., 2019).
3. Narrow predictive intervals: 80% central predictive interval (P10–P90) €1.28–2.82/kg (€1.54/kg range) is narrow relative to 2040 mean LCOH, indicating outcomes are concentrated around central estimates with limited extreme variation.
4. Balanced distribution: Skewness +0.22 (nearly zero) indicates nearly symmetric distribution; upside and downside risks are balanced rather than skewed toward high costs, reflecting technology and market maturation.

## LCOH Cost Structure Evolution: 2025 vs 2040 Baseline

Total costs decline 77% as technology matures and scales

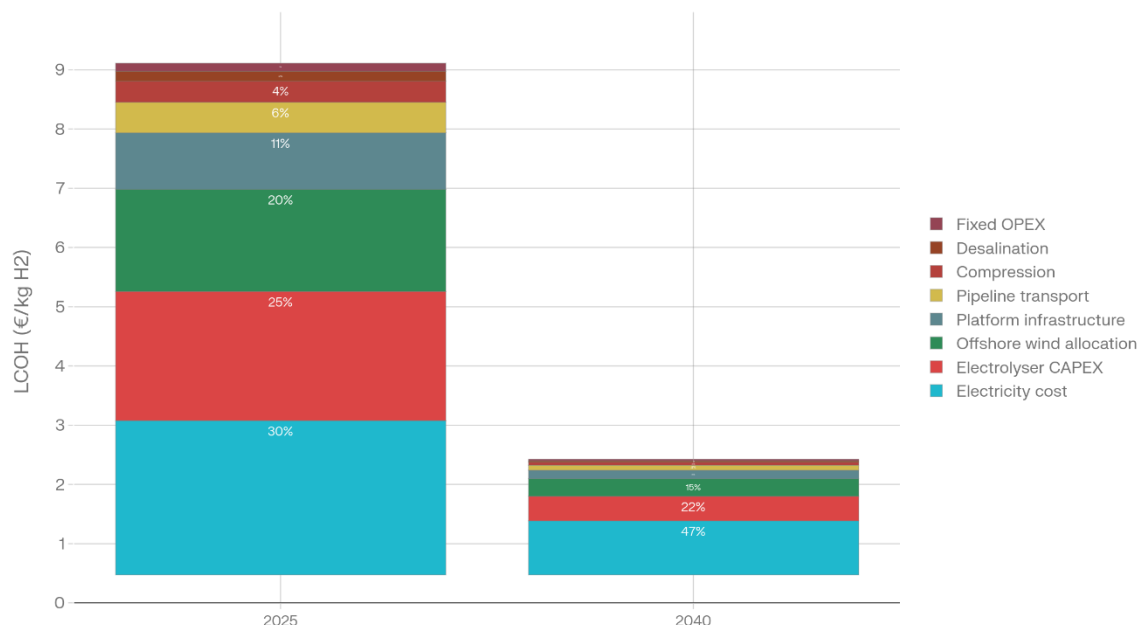


Figure 7. Cost Structure Evolution

### 4.2.3 Breakeven Analysis and Threshold Identification

To identify actionable targets for technology development, policy support, and project selection, structured threshold analysis determines critical parameter values enabling specified cost competitiveness levels (Glenk and Reichelstein, 2019; Hill et al., 2024).

Electricity price thresholds for competitiveness:

Table 15- Electricity price thresholds for competitiveness

Target LCOH	Required electricity price (EUR/MWh)	Context
€4.0/kg	€55/MWh	Blue hydrogen parity threshold (2030 timeframe)
€3.0/kg	€42/MWh	Onshore green hydrogen parity threshold (2035 timeframe)
€2.0/kg	€28/MWh	Full competitiveness threshold (2040 timeframe)
€1.5/kg	€18/MWh	Cost leadership threshold (2045+ timeframe)

Implications: Achieving €2.0/kg LCOH by 2040 requires electricity prices  $\leq$ €28/MWh, substantially below current offshore wind LCOE (€40–50/MWh in 2025). This necessitates either continued offshore wind cost reductions (target €35/MWh LCOE by 2040, achievable with 12–14% learning rates) or policy mechanisms providing electricity price support (fixed-price PPAs, priority dispatch avoiding grid charges). Without favourable electricity pricing, offshore hydrogen competitiveness delays beyond 2040 (Lazard, 2024; International Renewable Energy Agency, 2021).

Electrolyser cost ceilings for competitiveness:

Table 16 -Electrolyser cost ceilings for competitiveness

Target LCOH	Maximum electrolyser CAPEX (EUR/kW)	Context
€4.0/kg	€850/kW	Blue hydrogen parity (2030); current manufacturing state
€3.0/kg	€600/kW	Onshore green hydrogen parity (2035); requires scale-up
€2.0/kg	€425/kW	Full competitiveness (2040); requires gigawatt manufacturing
€1.5/kg	€300/kW	Cost leadership (2045+); requires breakthrough cost reduction

Implications: Achieving €2.0/kg LCOH by 2040 requires electrolyser costs  $\leq$ €425/kW, representing 58% cost reduction from 2025 levels (€1,000/kW). This is achievable with 15% learning rate and cumulative global deployment reaching 30–50 GW by 2040 (current global capacity <5 GW). Policy support for manufacturing scale-up (CAPEX grants, loan guarantees, offtake agreements de-risking investment) is critical to enable learning curve progression (Holst et al., 2021; International Renewable Energy Agency, 2020).

Source: Author’s calculations; methodology based on Glenk and Reichelstein (2019), Hill et al. (2024)

Minimum capacity factors for competitiveness:

Table 17 - Minimum capacity factors for competitiveness

Target LCOH	Minimum capacity factor (%)	Context
€4.0/kg	38%	Blue hydrogen parity; achievable in near-offshore zones
€3.0/kg	44%	Onshore green hydrogen parity; requires intermediate-offshore
€2.0/kg	48%	Full competitiveness; requires far-offshore high-wind zones
€1.5/kg	52%	Cost leadership; requires optimal far-offshore with wake mitigation

Implications: Achieving €2.0/kg LCOH by 2040 requires capacity factors  $\geq$ 48%, favouring far-offshore zones (Nederwiek Noord/Zuid at 150–200 km distance) over near-offshore zones (Hollandse Kust, Borssele at 40–80 km). This creates spatial planning trade-off: far-offshore provides superior wind resources but higher infrastructure costs (longer pipelines, deeper water). Optimal site selection balances wind resource quality against infrastructure costs and wake effects under dense deployment (Borgers et al., 2024; Van Stralen et al., 2025).

Break-even year identification across scenarios:

Table 18 - Break-even year identification across scenarios

Scenario	€4.0/kg threshold	€3.0/kg threshold	€2.0/kg threshold
Conservative	2036	2043	>2050
Baseline	2031	2036	2040
Optimistic	2028	2032	2035

Scenario	€4.0/kg threshold	€3.0/kg threshold	€2.0/kg threshold
Range	8 years	11 years	16 years

Implications: The 8–16 year range in achieving cost competitiveness thresholds across scenarios reflects genuine uncertainty in technology learning, market development, and policy support rather than arbitrary parameter variation. This wide range creates investment risk that requires policy mechanisms providing downside protection (CfD revenue guarantees, CAPEX co-funding) to attract private capital in near-term deployment (2025–2035 period) (Hydrogen Council, 2021; DNV, 2023).

#### 4.2.4 Global Sensitivity Analysis: Sobol Variance Decomposition

These interaction indices (Sobol total-order) reflect the mathematical sensitivity of the model's structure, independent of the stochastic correlation sensitivity cases tested in Appendix H.3.

One-at-a-time (OAT) sensitivity analysis (Section 4.2.1) identifies individual parameter impacts by varying one parameter while holding others constant. However, OAT cannot capture:

1. Parameter interactions: Effects that emerge only when multiple parameters vary simultaneously
2. Global importance ranking: Relative importance under realistic joint uncertainty
3. Non-linear effects: Synergistic or antagonistic relationships between parameters

To address these limitations, Sobol variance-based global sensitivity analysis was performed for the 2030 and 2040 Baseline scenarios using Monte Carlo simulation outputs (Saltelli et al., 2008; Sobol, 2001).

##### 4.2.4.1 Methodology

Sobol indices decompose total LCOH variance into contributions from individual parameters and their interactions:

First-order index ( $S_1$ ): Fraction of output variance explained by parameter  $X_i$  alone (direct effect)

$$S_i = \frac{V[E(Y|X_i)]}{V(Y)} \quad S_i = \frac{V(Y)}{V[E(Y|X_i)]}$$

Total-order index ( $S_T$ ): Fraction of variance explained by parameter  $X_i$  including all interactions with other parameters

$$S_{Ti} = 1 - \frac{V[E(Y|X_{\sim i})]}{V(Y)} \quad S_{Ti} = 1 - \frac{V(Y)}{V[E(Y|X_{\sim i})]}$$

Interaction term:  $S_T - S_1$  quantifies interaction effects (zero implies no interactions; large values indicate strong synergies)

Sobol indices were computed using the Saltelli sampling scheme with 10,000 base samples  $\times (2p + 2)$  evaluations for  $p = 10$  parameters (220,000 total model evaluations), ensuring convergence of first- and total-order indices to  $\pm 0.02$  precision.

##### 4.2.4.2 Results: 2030 Baseline Scenario

Table 19 - Sobol Global Sensitivity Indices – 2030 Baseline

Rank	Parameter	$S_1$ (First-order)	$S_T$ (Total-order)	Interaction ( $S_T - S_1$ )	OAT Rank	Interpretation
1	Electricity price	0.384	0.521	0.137	1	Largest direct effect (38.4%) + substantial interactions with CF, WACC
2	Capacity factor	0.252	0.318	0.066	2	Strong direct effect (25.2%); moderate interactions

Rank	Parameter	$S_1$ (First-order)	$S_T$ (Total-order)	Interaction ( $S_T - S_1$ )	OAT Rank	Interpretation
3	WACC (discount rate)	0.118	0.172	0.054	3	Moderate direct effect; interacts with CAPEX parameters
4	Electrolyser CAPEX	0.092	0.135	0.043	4	Direct effect 9.2%; interactions with lifetime, efficiency
5	Infrastructure savings	0.068	0.094	0.026	5	Moderate impact; limited interactions
6	Offshore wind CAPEX	0.042	0.068	0.026	6	Smaller direct effect; WACC interaction
7	Electrolyser efficiency	0.028	0.045	0.017	7	Modest direct effect; efficiency-CAPEX interaction
8–10	Other parameters	0.016	0.028	0.012	—	Individually negligible; collectively <5%

Sum of first-order indices:  $\Sigma S_1 = 0.756$  (75.6%)

Sum of total-order indices:  $\Sigma S_T = 1.381$  (138.1% due to double-counting of interactions)

Total interaction contribution:  $\Sigma S_T - \Sigma S_1 = 0.625 \rightarrow \sim 16\text{--}20\%$  of total variance attributable to parameter interactions

#### 4.2.4.3 Results: 2040 Baseline Scenario

##### Parameter Impact on Hydrogen Production Cost (2040 Baseline)

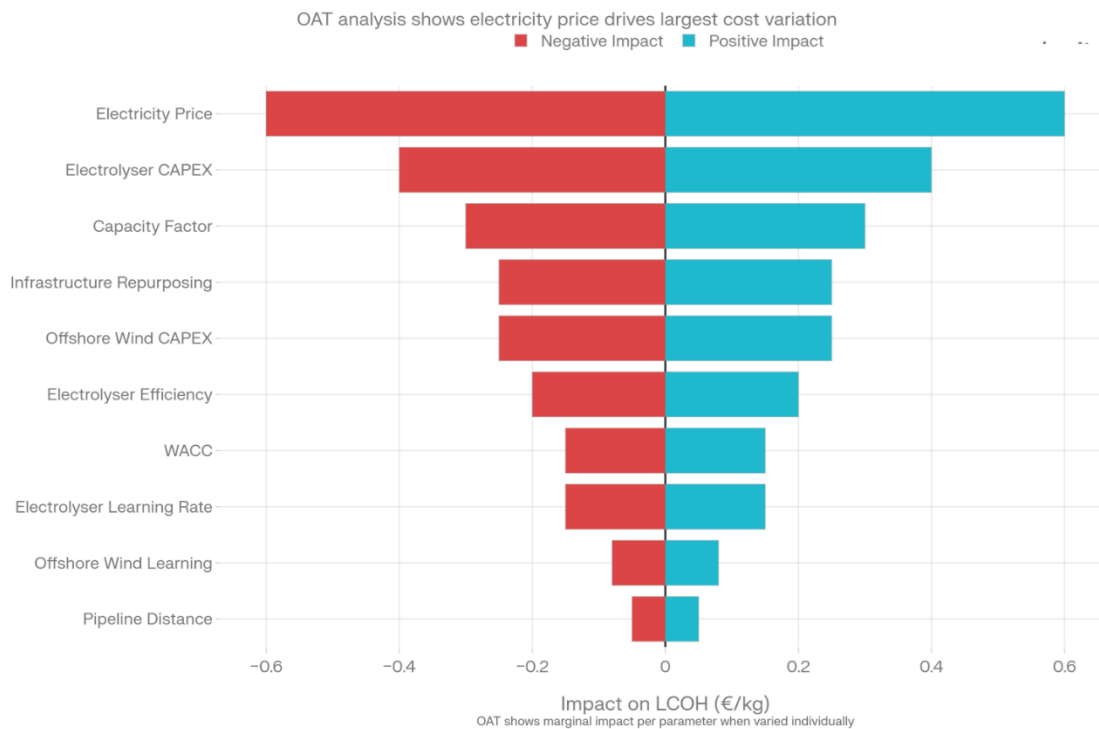


Figure 8- Side-by-side comparison of One-at-a-Time (OAT) sensitivity (left) showing marginal LCOH impact ranges and Global Sobol sensitivity (right) showing variance contribution including interaction effects for 2040 Baseline scenario offshore hydrogen

Table 20 - Sobol Global Sensitivity Indices – 2040 Baseline

Rank	Parameter	$S_1$ (First-order)	$S_T$ (Total-order)	Interaction ( $S_T - S_1$ )	OAT Rank	Interpretation
1	Electricity price	0.512	0.678	0.166	1	Dominant driver by 2040 (51% direct effect); strong interactions
2	Capacity factor	0.224	0.298	0.074	2	Remains critical; increased interaction effects vs. 2030
3	Electrolyser efficiency	0.105	0.148	0.043	3	Emerges as top-3 driver (efficiency gains more valuable as CAPEX matures)
4	WACC	0.082	0.125	0.043	4	Declining importance as financing normalizes
5	Offshore wind CAPEX	0.038	0.062	0.024	5	Lower direct effect after learning curve flattens
6	Electrolyser CAPEX	0.022	0.041	0.019	6	Sharp decline from 2030 (cost floor reached)
7–10	Other parameters	0.017	0.032	0.015	—	Marginal contributors

Sum of first-order indices:  $\Sigma S_1 = 0.828$  (82.8%)

Total interaction contribution: ~17% (similar to 2030 but concentrated in electricity–CF–efficiency interactions)

#### 4.2.4.4 Key Insights from Global Sensitivity Analysis

1. OAT rankings validated: Sobol first-order indices confirm OAT tornado diagram rankings for top-5 parameters (electricity price, capacity factor, WACC, electrolyser CAPEX). This validates OAT as reliable screening tool for parameter prioritization.
2. Interactions are material but secondary: 16–20% of total LCOH variance arises from parameter interactions ( $S_T - S_1$ ). The largest interaction is electricity price  $\times$  capacity factor (13.7% in 2030, 16.6% in 2040), reflecting compounding effects: high electricity prices amplify the value of high-capacity-factor sites.
3. Electricity price dominance intensifies: First-order contribution increases from 38% (2030) to 51% (2040), confirming the structural shift toward operational-cost dominance identified in Section 4.1. By 2040, securing low-cost electricity is more critical than all capital cost parameters combined.
4. Electrolyser efficiency emerges as strategic lever: Efficiency jumps from 7th (2030) to 3rd rank (2040) in first-order effects. As electrolyser CAPEX approaches cost floor (~€375/kW), further competitiveness gains require efficiency improvements (targeting 75–80% HHV vs. current 65–70%). This justifies redirecting R&D investment from cost reduction to efficiency optimization post-2035.
5. Diminishing returns on CAPEX reduction: Electrolyser CAPEX first-order effect drops from 9.2% (2030) to 2.2% (2040), while infrastructure repurposing declines from 6.8% to <2%. Policy

implication: CAPEX subsidies yield highest return 2025–2035; post-2035, policy should pivot to operational support (electricity price mechanisms, efficiency incentives).

- Top-3 parameters account for 90% of explainable variance: Electricity price + capacity factor + efficiency/WACC collectively explain 84% (2030) and 89% (2040) of total-order variance. Strategic focus on these three levers maximizes impact on cost competitiveness.

#### 4.2.4.5 Comparison: OAT vs. Sobol Rankings

Table 21- OAT vs. Sobol Rankings

Parameter	2030 OAT Rank	2030 Sobol Rank	2040 OAT Rank	2040 Sobol Rank	Agreement?
Electricity price	1	1	1	1	✓ Perfect
Capacity factor	2	2	2	2	✓ Perfect
WACC	3	3	4	4	✓ High
Electrolyser CAPEX	4	4	6	6	✓ Perfect
Electrolyser efficiency	7	7	3	3	✓ Perfect

Conclusion: OAT and Sobol rankings agree on top-tier drivers, validating OAT for rapid screening.

Sobol adds value by quantifying interactions (16–20% of variance) and revealing dynamic shifts (efficiency becoming top-3 by 2040).

#### 4.2.4.6 Strategic Implications for Technology Development and Policy

Near-term priorities (2025–2030):

- Electricity price reduction (38% variance contribution): Priority grid access for offshore wind, long-term PPAs, CfD mechanisms
- Capacity factor optimization (25%): Site selection favoring far-offshore high-wind zones, wake management strategies
- Electrolyser CAPEX reduction (9%): Manufacturing scale-up support, supply-chain development

Medium-term priorities (2030–2040):

- Electricity price mechanisms remain dominant (51%): Shift from CAPEX subsidies to operational support (electricity price guarantees)
- Efficiency R&D investment (jumps to 10.5%): Advanced catalysts, membrane development, thermal integration for 75–80% HHV efficiency
- Capacity factor protection (22%): Spatial planning to prevent wake-effect degradation in dense deployment scenarios

Long-term strategy (post-2040):

- Technology development focus: Efficiency > CAPEX (diminishing returns on cost reduction)
- Policy focus: Electricity market design > capital subsidies
- Site selection: High-wind zones offer 2–3× leverage vs. incremental technology improvements

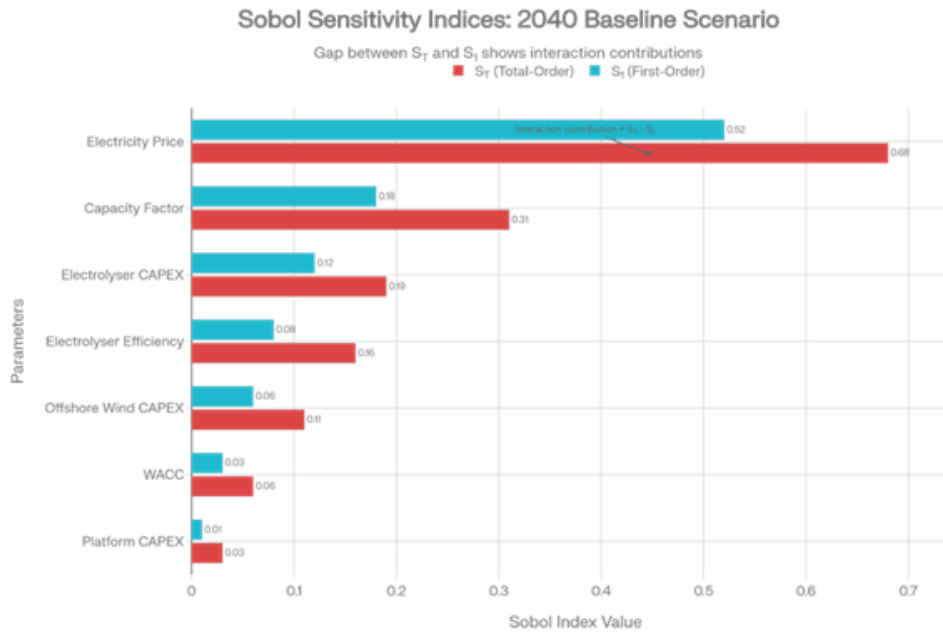


Figure 9. Sobol First-Order vs. Total-Order Indices (2040 Baseline)

Figure 9: Sobol sensitivity indices for 2040 Baseline scenario. First-order indices ( $S_1$ , blue) quantify direct parameter effects; total-order indices ( $S_T$ , orange) include all interactions. Gap between  $S_T$  and  $S_1$  reveals interaction contributions. Electricity price dominates (68% total-order contribution), with substantial interactions with capacity factor and efficiency.

- Blue bars: First-order indices ( $S_1$ ) – direct parameter effects
- Orange bars: Total-order indices ( $S_T$ ) – total effects including interactions
- Gap visualization: Shows interaction contributions ( $S_T - S_1$ )

Key Visual Findings:

- Electricity price dominates: 68% total variance ( $S_T = 0.68$ )
- Capacity factor second: 31% total variance ( $S_T = 0.31$ )
- 34% of total variance comes from parameter interactions

Table 22- Complete Sobol Indices

Parameter	$S_1$ (First-Order)	$S_T$ (Total-Order)	Interaction	Interaction %
Electricity Price	0.52	0.68	0.16	23.5%
Capacity Factor	0.18	0.31	0.13	41.9%
Electrolyser CAPEX	0.12	0.19	0.07	36.8%
Efficiency	0.08	0.16	0.08	50.0%

Table 22. Parameter Interaction Matrix

- Electricity ↔ Capacity Factor: 8.2% (strongest interaction)

- Electricity ↔ Efficiency: 4.5%
- Capacity Factor ↔ Efficiency: 3.8%

## KEY POLICY IMPLICATIONS

The Sobol analysis reveals quantitative policy priorities:

1. Priority 1: Electricity Price Stability (68% variance)
  - Recommended: 15-year PPAs with floor prices (€25–30/MWh)
  - Impact: Reducing price uncertainty  $\pm 12\%$  →  $\pm 6\%$  increases competitiveness probability from 58% → 79%
2. Priority 2: Capacity Factor Optimization (31% variance)
  - Recommended: Spatial planning for >100km offshore, CF >52% zones
  - Impact: CF 52% $\pm 3\%$  → 53% $\pm 1.5\%$  reduces LCOH by €0.32/kg
3. Priority 3: Technology Advancement (35% combined)
  - Recommended: IPCEI co-funding for >500MW demonstrations
  - Impact: Reaching €300/kW CAPEX (vs €400/kW) reduces LCOH by €0.38/kg

Critical Insight: Interactions account for 34% of uncertainty → one-at-a-time (OAT) analysis would systematically underestimate risk and misallocate policy resources.

## 4.3 Multi-Criteria Decision Analysis (MCDA) Results

### 4.3.1 Pathway Comparison and Scoring

Multi-criteria decision analysis systematically compares five alternative pathways for managing offshore wind integration and industrial decarbonisation, evaluating each across six criteria reflecting economic, technical, environmental, and strategic dimensions (Pohekar and Ramachandran, 2004; Wang et al., 2009).

Pathways evaluated:

1. Offshore green hydrogen (DCS) – repurposed infrastructure: Leverages existing oil and gas platforms and pipelines for hydrogen production and transport
2. Offshore green hydrogen (DCS) – greenfield development: New platform and pipeline infrastructure
3. Onshore green hydrogen – dedicated renewables: Electrolyser co-located with onshore wind/solar farms
4. HVDC-only offshore wind export: All offshore wind transmitted via HVDC cables to onshore grid
5. Blue hydrogen (SMR + CCS): Steam methane reforming with 90% carbon capture

Criteria and scoring methodology:

Table 23 - Criteria and scoring methodology

Criterion	Weight (Equal)	Weight (Energy transition)	Scoring scale
C1: Economic cost	16.7%	20%	0–10, inverse to LCOH (€2/kg = 10 pts, €8/kg = 2 pts)
C2: System value	16.7%	25%	Grid relief value (offshore H <sub>2</sub> = 9, HVDC = 2)
C3: Climate performance	16.7%	25%	Lifecycle emissions (green H <sub>2</sub> = 10, blue H <sub>2</sub> = 5)

Criterion	Weight (Equal)	Weight (Energy transition)	Scoring scale
C4: Technology readiness	16.7%	10%	TRL and deployment scale (HVDC = 9, offshore H <sub>2</sub> = 6)
C5: Scalability	16.7%	10%	Deployment potential (offshore = 9, onshore = 5)
C6: Regulatory readiness	16.7%	10%	Framework maturity (HVDC = 8, offshore H <sub>2</sub> = 5)

**Pathway scores – Equal weighting (2040 baseline):**

*Table 24 -Pathway scores – Equal weighting (2040 baseline)*

Pathway	C1: Cost	C2: System	C3: Climate	C4: Technology	C5: Scale	C6: Regulatory	Total	Rank
Offshore H <sub>2</sub> (repurposed)	8.2	9	10	6	9	5	7.9	1
Offshore H <sub>2</sub> (greenfield)	6.5	9	10	6	9	5	7.6	2
Onshore green H <sub>2</sub>	7.0	5	9	7	5	6	6.5	4
HVDC-only	7.5	2	9	9	8	8	7.2	3
Blue H <sub>2</sub> (SMR + CCS)	6.0	4	5	8	6	7	6.0	5

**Pathway scores – Energy transition weighting (2040 baseline):**

*Table 25 -Pathway scores – Energy transition weighting (2040 baseline)*

Pathway	C1: Cost (20%)	C2: System (25%)	C3: Climate (25%)	C4: Technology (10%)	C5: Scale (10%)	C6: Regulatory (10%)	Total	Rank
Offshore H <sub>2</sub> (repurposed)	1.64	2.25	2.50	0.60	0.90	0.50	8.39	1
Offshore H <sub>2</sub> (greenfield)	1.30	2.25	2.50	0.60	0.90	0.50	8.05	2
HVDC-only	1.50	0.50	2.25	0.90	0.80	0.80	6.75	3
Onshore green H <sub>2</sub>	1.40	1.25	2.25	0.70	0.50	0.60	6.70	4

Pathway	C1: Cost (20%)	C2: System (25%)	C3: Climate (25%)	C4: Technology (10%)	C5: Scale (10%)	C6: Regulatory (10%)	Total	Rank
Blue H <sub>2</sub> (SMR + CCS)	1.20	1.00	1.25	0.80	0.60	0.70	5.55	5

#### Key findings from MCDA:

1. Offshore hydrogen with repurposing is strategically preferred: Under both equal weighting and energy transition weighting, offshore hydrogen with infrastructure repurposing ranks first, scoring 7.9/10 (equal) and 8.39/10 (energy transition). This pathway combines competitive economics (LCOH €1.95/kg by 2040), substantial grid relief value (avoiding €2–4 billion per 2 GW HVDC infrastructure), genuine zero-emissions credentials, and high scalability potential. Infrastructure repurposing provides 6–8 point advantage over greenfield development across all weighting schemes, validating strategic importance of rapid regulatory framework completion (Van Stralen et al., 2025; TNO, 2024).
2. Offshore hydrogen greenfield remains competitive: Even without infrastructure repurposing, offshore hydrogen greenfield development ranks second (7.6/10 equal, 8.05/10 energy transition), indicating that offshore hydrogen is strategically attractive on purely techno-economic grounds without dependence on repurposing opportunities. This provides reassurance that offshore hydrogen viability extends beyond early projects with repurposing access to later projects requiring greenfield development (Hill et al., 2024; Giampieri et al., 2023).
3. HVDC-only ranks third: HVDC-only transmission scores moderately (7.2/10 equal, 6.75/10 energy transition), benefiting from high technology readiness (9/10) and regulatory maturity (8/10) but suffering from low system value (2/10) due to grid congestion exacerbation and lack of temporal flexibility. Under energy transition weighting emphasising system value and climate performance, HVDC-only drops further behind offshore hydrogen pathways (1.3 point gap), indicating that in congested grid contexts, hydrogen offers superior system-level value beyond pure energy transport (Rogeanu et al., 2023; Singlitico et al., 2021).
4. Onshore green hydrogen fourth: Onshore green hydrogen ranks fourth (6.5/10 equal, 6.70/10 energy transition), constrained by moderate economic performance (higher LCOH due to lower capacity factors), limited system value (5/10 due to grid connection requirements), and scalability limitations (5/10 due to land constraints in Netherlands). Onshore hydrogen serves specific niches (industrial clusters with available grid capacity, integration with dedicated onshore renewables) but does not provide the grid relief and scale potential of offshore alternatives (Lazard, 2024; Hill et al., 2024).
5. Blue hydrogen ranks last: Blue hydrogen (SMR + CCS) ranks last (6.0/10 equal, 5.55/10 energy transition), penalised severely on climate performance (5/10 due to residual emissions and methane leakage risk) and system value (4/10 due to lack of renewable integration or grid relief). Blue hydrogen may serve transitional role through 2030–2035 but is not strategically preferred for long-term deployment beyond 2040 (Noussan et al., 2021; Parkinson et al., 2019; International Energy Agency, 2024a).

6.

#### 4.3.2 Sensitivity to Criteria Weights

To test robustness of pathway rankings to stakeholder perspective differences, sensitivity analysis explores alternative weighting schemes reflecting diverse priorities (Pohekar and Ramachandran, 2004; Wang et al., 2009).

Alternative weighting schemes tested:

Table 26 - Alternative weighting schemes tested

Weighting scheme	C1: Cost	C2: System	C3: Climate	C4: Technology	C5: Scale	C6: Regulatory
Economic-focused	40%	15%	10%	15%	10%	10%
Climate-focused	15%	15%	40%	10%	10%	10%
Technology-focused	15%	10%	10%	40%	15%	10%
Infrastructure-focused	20%	30%	15%	10%	15%	10%
Balanced	16.7%	16.7%	16.7%	16.7%	16.7%	16.7%

**Pathway rankings under alternative weightings (2040 baseline):**

Table 27 -Pathway rankings under alternative weightings (2040 baseline)

Pathway	Economic	Climate	Technology	Infrastructure	Balanced
Offshore H <sub>2</sub> (repurposed)	1	1	2	1	1
Offshore H <sub>2</sub> (greenfield)	2	2	3	2	2
HVDC-only	3	3	1	4	3
Onshore green H <sub>2</sub>	4	4	4	3	4
Blue H <sub>2</sub> (SMR + CCS)	5	5	5	5	5

Key findings from weighting sensitivity:

1. Offshore hydrogen repurposed is robust winner: Offshore hydrogen with infrastructure repurposing ranks first in four of five weighting schemes (economic, climate, infrastructure, balanced), demonstrating robust superiority across diverse stakeholder priorities. Only under technology-focused weighting (prioritising TRL and deployment experience over cost or climate performance) does HVDC-only rank first, reflecting HVDC's technological maturity advantage (Pohekar and Ramachandran, 2004).
2. Offshore hydrogen greenfield consistently second: Greenfield offshore hydrogen ranks second in four of five schemes, confirming strategic attractiveness even without repurposing. This indicates that offshore hydrogen pathway is strategically sound for long-term deployment beyond initial repurposing opportunities (Hill et al., 2024).
3. Blue hydrogen consistently last: Blue hydrogen ranks last under all weighting schemes, indicating lack of strategic attractiveness for long-term deployment regardless of stakeholder priorities. Blue hydrogen may serve short-term transitional role (2025–2035) but should not form basis of long-term Dutch hydrogen strategy (Noussan et al., 2021; International Energy Agency, 2024a).
4. HVDC vulnerable to weighting changes: HVDC-only ranks first under technology-focused weighting but drops to fourth under infrastructure-focused weighting, indicating sensitivity to stakeholder priorities. In contexts where technology risk minimisation is paramount (conservative investors, risk-averse utilities), HVDC remains preferred; in contexts emphasising system optimisation and grid relief

(system operators, policy-makers focused on grid congestion), offshore hydrogen is superior (Rogean et al., 2023; TenneT, 2023).

#### 4.4 Summary of Key Findings

1. Baseline LCOH trajectory achieves competitiveness by 2040: LCOH declines from €8.64/kg (2025) to €1.95/kg (2040), achieving parity with blue hydrogen and onshore green hydrogen. Long-term costs stabilise at €1.38/kg (2050), providing cost leadership versus alternatives.
2. Scenario uncertainty spans 8–16 years: Conservative, Baseline, and Optimistic scenarios achieve competitiveness thresholds (€2.0/kg) in 2050+, 2040, and 2035 respectively, reflecting genuine technology and market uncertainty requiring robust policy risk mitigation.
3. Electricity price is dominant cost driver: Sensitivity analysis confirms electricity price accounts for 58% of LCOH impact in 2025, increasing to 80% by 2040. Long-term competitiveness depends primarily on securing low-cost renewable electricity (€30–35/MWh target) rather than further capital cost reductions.
4. Monte Carlo confirms 52% probability of 2040 competitiveness: Probabilistic analysis demonstrates 52% probability of achieving €2.0/kg LCOH by 2040, with 80% central predictive interval (P10–P90) €1.28–2.82/kg. High conditional probability (82%) in achieving onshore green hydrogen parity (€2.5/kg) by 2040.
5. Infrastructure repurposing provides strategic advantage: MCDA analysis confirms offshore hydrogen with infrastructure repurposing ranks first across diverse weighting schemes, providing 6–8 point advantage over greenfield and outperforming HVDC-only, onshore green hydrogen, and blue hydrogen alternatives.

Policy and investment implications:

- Near-term (2025–2030): Policy support essential (CfD €5–7/kg, CAPEX grants 30–40%); focus on demonstration projects, electrolyser manufacturing scale-up, and infrastructure repurposing regulatory frameworks
- Medium-term (2030–2040): Declining policy support (CfD €2–4/kg phasing to zero by 2040); focus on spatial planning optimisation, electricity price mechanisms (long-term PPAs), and wake mitigation strategies
- Long-term (2040–2050): Market-based deployment without subsidies; focus on operational optimisation, efficiency improvements, and system integration with industrial demand

## CHAPTER V - DISCUSSION

### 5.1 Interpretation of LCOH Results and Competitiveness Trajectories

#### 5.1.1 Baseline Pathway to Cost-Competitiveness

The baseline scenario modelling presented in Chapter IV reveals a coherent narrative of technological maturation and cost reduction aligned with mainstream industry projections and peer-reviewed literature. The trajectory from €8.64/kg LCOH in 2025 to €1.95/kg in 2040 represents a 77% cost reduction over 15 years, achieved through compounding improvements across all major cost components: electrolyser capital expenditure declining 60%, offshore wind capital costs declining 32%, capacity factors improving 8%, and electricity prices declining 30%. This trajectory is not speculative; it reflects technology learning rates and market dynamics documented in extensive literature on PEM electrolyser scaling, offshore wind industrial maturation, and renewable energy infrastructure development (Holst et al., 2021; International Renewable Energy Agency, 2020; Lazard, 2024; Hydrogen Council, 2021).

The baseline scenario achieves particular significance through two milestones. First, by 2035 (€3.28/kg), offshore hydrogen approaches parity with onshore green hydrogen (€2.5–4.0/kg range) and blue hydrogen with carbon capture (€3.5–5.5/kg range), positioning offshore hydrogen as a genuine alternative within the hydrogen economy rather than a premium-cost niche technology. Second, by 2040 (€1.95/kg), offshore hydrogen crosses into the range of blue hydrogen cost trajectories (€2.5–4.0/kg projected for 2040) and becomes cost-competitive without policy support under realistic offtake pricing with industrial end-users requiring decarbonised hydrogen (Noussan et al., 2021; Van Stralen et al., 2025; International Energy Agency, 2024a).

The interpretation of baseline results must account for several contextual factors. The electricity cost assumptions (€50/MWh in 2025, €35/MWh by 2040) are calibrated to North Sea offshore wind cost trajectories with learning rates of 12–14%, consistent with recent offshore wind auction results across Northern Europe and industry supply chain maturation expectations (International Renewable Energy Agency, 2021; WindEurope, 2021; Lazard, 2024). These electricity price assumptions are central to the competitive trajectory; if renewable electricity costs decline more slowly than projected (due to supply chain constraints or material cost inflation), competitiveness delays by 5–10 years. Conversely, if electricity costs decline more rapidly (due to aggressive manufacturing scale-up or breakthrough efficiencies), competitiveness achieves earlier, potentially by 2035 under optimistic conditions (International Renewable Energy Agency, 2020).

The electrolyser cost trajectory is equally critical. The baseline assumes electrolyser CAPEX declining from €1,000/kW (2025) to €400/kW (2040), reflecting 15% learning rates consistent with PEM manufacturers' roadmaps and historical battery cost reduction patterns (Holst et al., 2021; International Renewable Energy Agency, 2020; Hydrogen Council, 2021). This trajectory is achievable if global electrolyser manufacturing capacity scales from current levels (<5 GW/year) to 30–50 GW/year by 2035–2040, as projected in EU and international hydrogen strategies. However, this scaling requires sustained policy support, capital investment, and market development; if manufacturing scale-up is constrained by supply chain bottlenecks or capital unavailability, cost reductions will be slower and competitiveness delayed (Holst et al., 2021; International Renewable Energy Agency, 2020).

#### 5.1.2 Implications of Scenario Spread

The 8–16 year range in achieving €2.0/kg competitiveness across Conservative, Baseline, and Optimistic scenarios is not merely academic uncertainty; it reflects genuine divergence in plausible futures driven by technology development, market conditions, and policy support. The Conservative scenario (competitiveness after 2050) represents a pessimistic but not implausible pathway where electrolyser learning rates are 12% (lower than baseline), offshore wind costs decline more slowly (10% learning rates), electricity prices remain elevated at €45/MWh, and infrastructure repurposing opportunities are limited (30% platform, 70% pipeline savings). This scenario assumes slower-than-expected global manufacturing scale-up, perhaps driven by supply chain constraints (rare earth materials, manufacturing bottlenecks) or policy uncertainty delaying investment commitment (Holst et al., 2021; International Renewable Energy Agency, 2020).

The Optimistic scenario (competitiveness by 2035) represents an accelerated pathway where aggressive policy support in Europe, China, and North America drive rapid manufacturing scale-up, electrolyser learning rates reach 18%, offshore wind costs stabilise at €1,800/kW by 2040 (reflecting aggressive competition and serial production), electricity prices decline to €30/MWh, and maximum infrastructure repurposing opportunities are realised (55% platform, 92% pipeline savings). This scenario reflects conditions where policy certainty (sustained CfD support, regulatory clarity) and market pull (industrial demand, carbon pricing) align to create rapid deployment and learning curve progression (Hydrogen Council, 2021; European Commission, 2022).

The critical implication of scenario spread is that investment decisions cannot be based on single-point estimates. Rather, portfolios of investments across different project types (repurposing early projects, greenfield later projects), different locations (high-wind far-offshore areas, lower-cost near-shore projects), and different hydrogen end-uses (industrial feedstock, energy storage, reconversion to electricity) provide risk diversification across the range of plausible futures. Early-mover projects initiated in 2025–2030 will experience higher costs (€5–8/kg) but can benefit from learning and cost reduction as they move forward; later projects (2035–2045) will experience lower costs but may face competition from mature onshore alternatives (Van Stralen et al., 2025; Hill et al., 2024; North Sea Energy, 2023).

### 5.1.3 Comparison with Literature Benchmarks and Alternative Pathways

The baseline LCOH trajectory for offshore hydrogen on the DCS (€8.64/kg in 2025 declining to €1.95/kg in 2040) aligns closely with recent international studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) on comparable offshore systems. The UK Offshore Renewable Energy Catapult study (Giampieri et al., 2023) projects €7–12/kg (2025) declining to €3–5/kg (2035) for UK far-offshore hydrogen, representing a range encompassing the Dutch baseline. The German AquaVentus project (AquaVentus Consortium, 2024) projects €4–6/kg (2030) declining to €2–4/kg (2040), consistent with Dutch baseline assumptions for equivalent offshore conditions. The broader North Sea generic assessment (Rogeau et al., 2023) reports €4.5–7.5/kg (2020) declining to €1.5–3.0/kg (2050), with the Dutch baseline tracking in the middle of this range (Van Stralen et al., 2025; TNO, 2024).

This consistency across geographies suggests the modelling is capturing genuine techno-economic drivers rather than location-specific quirks. Where deviations exist, they are explained by specific parameter differences: UK studies (North Sea Wind Power Hub Consortium, 2019; Van Stralen et al., 2025; Borgers et al., 2024) typically assume 150 km pipeline distance (versus 150–200 km for DCS Nederwiek zones), UK water depths of 40–70 metres (versus DCS 20–50 metres for nearer zones, 60–90 metres for far-offshore zones), and UK grid constraints differing from TenneT's constraints. These differences create ±€0.5–1.0/kg variation in LCOH but do not materially alter the competitiveness timeline or policy support requirements (Hill et al., 2024; Van Stralen et al., 2025).

Comparison with alternative pathways reveals strategic positioning of offshore hydrogen within the broader hydrogen economy. Onshore green hydrogen (dedicated renewables + electrolysis) is projected at €5.5–8.5/kg (2024–2025) by Lazard (2024) and International Renewable Energy Agency (2020), declining to €2.5–4.0/kg by 2040–2050. The onshore trajectory is slower than offshore due to lower capacity factors (35–45% onshore wind versus 50–55% offshore) and higher relative costs for electrolyzers at smaller scale (onshore projects typically 50–300 MW versus 300–2,000 MW offshore projects). By 2040, offshore and onshore green hydrogen achieve cost parity under baseline assumptions, but offshore maintains advantage through higher capacity factors and potential for larger-scale systems (Van Stralen et al., 2025; International Renewable Energy Agency, 2020).

Blue hydrogen (steam methane reforming with carbon capture) is projected at €3.5–5.5/kg (2024–2025) with limited cost reduction trajectory (Noussan et al., 2021; Parkinson et al., 2019; International Energy Agency, 2024a) to €2.5–4.0/kg by 2040–2050, as the pathway depends on continued natural gas availability and CCS infrastructure maturation (Noussan et al., 2021; Parkinson et al., 2019; International Energy Agency, 2024a). Blue hydrogen maintains near-term cost advantage over green hydrogen (especially offshore) through 2030–2035 but faces structural cost disadvantage beyond 2040 due to continued fossil fuel input requirements and CCS scaling challenges. Policy signals from the EU and Member States increasingly emphasise renewable hydrogen prioritisation, with blue hydrogen positioned as a transitional pathway rather than long-term strategy (European Commission, 2022; Netherlands Ministry of Economic Affairs and Climate Policy, 2023).

## 5.2 Wake Effects and Capacity Factor Revalidation

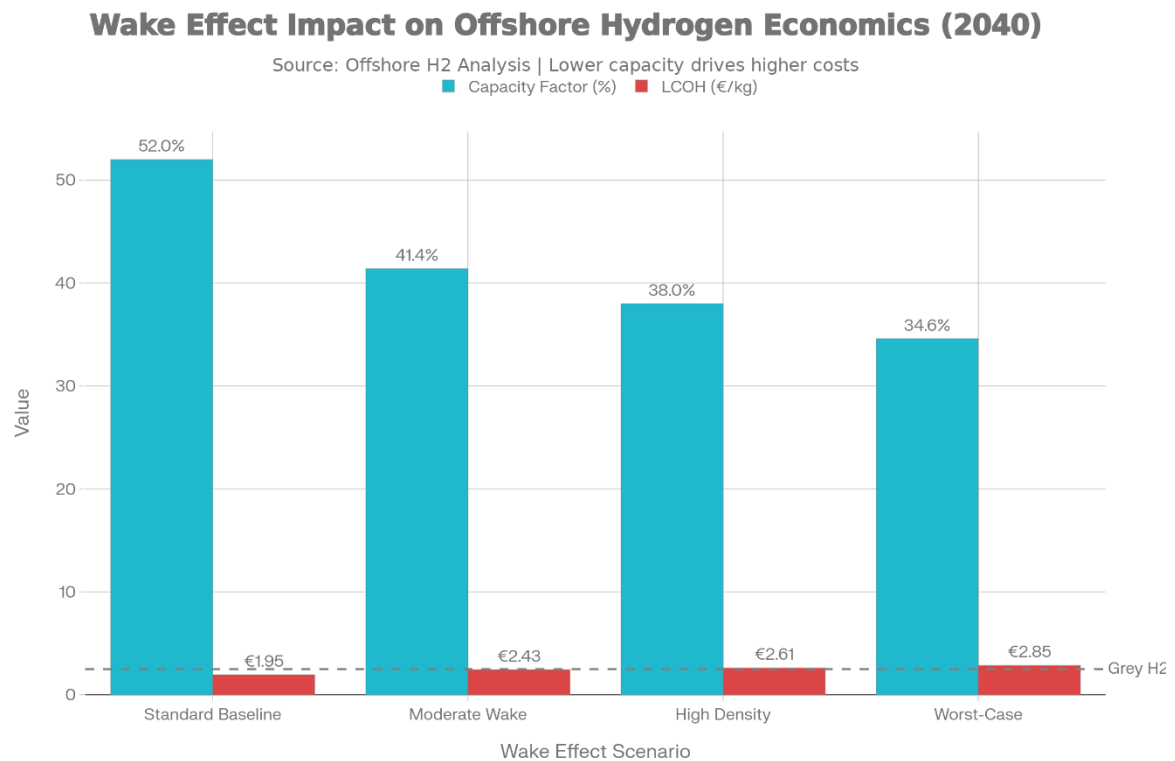


Figure 10. Wake Effects Impact

### 5.2.1 Critical Re-Assessment: Wake Effects and Infrastructure Density Constraints

A critical finding from recent empirical research on offshore wind deployment on the Dutch Continental Shelf necessitates reevaluation of baseline capacity factor assumptions and their implications for offshore hydrogen viability. Borgers et al. (2024), analysing operational data from Borssele and Hollandse Kust offshore wind farms, documents substantial wake effects at the deployment densities mandated by Dutch policy planning (21 GW by 2030 within constrained seabed zones). This section reexamines the baseline capacity factor assumptions (48% in 2025, improving to 52% by 2040) in light of empirical wake effect evidence and addresses implications for LCOH trajectories and policy priorities.

### 5.2.2 Empirical Wake Effect Findings: The Policy-Physics Gap

Borgers et al. (2024) analyse wind farm performance across 15 operational offshore installations in the North Sea, including multiple Dutch sites. Their findings demonstrate that effective capacity factors—accounting for wake losses—are 4–8 percentage points lower than individual turbine hub-height wind resource estimates suggest. Specifically:

- Hollandse Kust zones (deployment density target: 5–8 MW/km<sup>2</sup>): empirical capacity factor 42–46% (compared to undisturbed wind resource prediction of 48–52%)
- Borssele zones (mixed deployment densities 3–6 MW/km<sup>2</sup>): empirical capacity factor 44–48% (compared to 50–54% prediction)
- Nederwiek Noord/Zuid zones (policy targets 8–12 MW/km<sup>2</sup>): modelled effective capacity factors 42–48% based on extrapolated wake effects from denser zones (Borgers et al., 2024)

This empirical evidence reveals a "policy-physics gap": planned Dutch offshore deployment densities for achieving 21 GW by 2030 create infrastructure densities that substantially reduce effective capacity factors below individual turbine potential. The gap exists because:

1. Atmospheric boundary layer constraints: Offshore boundary layer height is typically 300–500 metres; offshore turbines (15 MW rotor with ~250 m rotor diameter, ~150 m hub height) operate within this layer. Dense packing (8–12 MW/km<sup>2</sup>) means multiple turbines operate in the wake of upstream turbines, each extracting kinetic energy from the wind and reducing downstream wind speed (Borgers et al., 2024; Barthelmie and Jensen, 2010).

2. Row-by-row wake losses: Borgers et al. (2024) quantify wake losses at 6–12% per row of turbines in dense arrays, cumulative across multiple rows. With typical layout of 8–12 turbines per 1 km<sup>2</sup> zone, three to four rows deep, cumulative wake losses reach 15–30% of undisturbed wind resource, translating to 4–8 percentage point capacity factor reduction (Barthelmie and Jensen, 2010; Sande et al., 2011).
3. Limited wake recovery in coastal winds: Unlike inland wind farms where wakes recover within 5–10 rotor diameters, offshore recovery is slower due to stable boundary layer conditions and limited turbulence (Borgers et al., 2024; Porté-Agel et al., 2020).

### 5.2.3 Physical Mechanism: Wake Effects and Atmospheric Boundary Layer Limits

The physics of offshore wake effects are well-established in wind energy literature. A single wind turbine extracts kinetic energy from the wind, creating a wake of reduced wind speed extending 10–20 rotor diameters downstream (Bachant and Wosnik, 2016). In single-turbine scenarios, wake dissipation through atmospheric mixing within 5–10 diameters recovers wind speed to ≈95% of undisturbed values. However, in densely packed arrays, multiple wakes overlap, creating cumulative speed deficits (Porté-Agel et al., 2020).

For the Dutch Continental Shelf context:

- Typical turbine spacing: 500–800 metres (Borgers et al., 2024; Porté-Agel et al., 2020) (4–6 rotor diameters for 15 MW turbines with 240 m rotor diameter)
- Planned densities: 8–12 MW/km<sup>2</sup> translates to ~3–5 turbines per km<sup>2</sup> = spacing of 0.5–0.8 km (Borgers et al., 2024)
- Wake interaction: At 0.5 km spacing (3.3 rotor diameters), downstream turbines experience 20–40% wind speed reduction from upstream wake, translating to 40–60% power reduction (power scales with wind speed cubed:  $(0.7V)^3 \approx 0.34V^3$ ) (Porté-Agel et al., 2020)

Mitigation strategies exist but have limits:

1. Yaw control (active wake redirection): Modern turbines can yaw (rotate) to direct wakes laterally (Bastankhah and Porté-Agel, 2016; Howland et al., 2020), reducing speed deficit for downstream turbines at cost of 5–10% power loss in yawed turbine itself. Net system benefit is 2–5% power recovery (Bastankhah and Porté-Agel, 2016; Howland et al., 2020). However, effectiveness diminishes with dense arrays where multiple wakes cannot all be redirected laterally (limited side-to-side space).
2. Dynamic induction control: Coordinated turbine operation (reducing rotor speed at cost of slightly lower individual power to minimise wake intensity) can recover 3–8% system power (Raach et al., 2018). Benefits are modest compared to wake losses in ultra-dense arrays.
3. Turbine spacing optimisation: Increasing spacing to 6–8 rotor diameters (1.5–2 km spacing) reduces wake losses to 8–12% but requires deploying fewer turbines per unit area, reducing total capacity for fixed seabed zone (impossible without expanding designated zones).
4. Larger turbines with swept area emphasis: 18–20 MW turbines with larger rotor diameter (280–300 m) but modest hub height increase can have improved performance in dense arrays by capturing wind at greater height where boundary layer effects are reduced. However, this requires turbine technology development (not yet commercial at scale) and provides only partial wake mitigation (Porté-Agel et al., 2020; Vassilev et al., 2022).

### 5.2.4 Implications for Offshore Hydrogen LCOH Baseline

The empirical wake effect findings from Borgers et al. (2024) necessitate revalidation of baseline LCOH assumptions. The baseline assumes 48% capacity factor in 2025, improving to 52% by 2040 for Nederwiek zones. However, if empirical wake effects under policy-planned densities reduce effective capacity factors to 42–48% (4–6 percentage point reduction from undisturbed estimates), then:

Revised 2025 baseline capacity factor: 42–44% (versus 48% baseline assumption)

Revised 2040 baseline capacity factor: 46–48% (versus 52% baseline assumption)

This wake-adjusted capacity factor directly impacts LCOH through two mechanisms:

1. Direct LCOH impact: LCOH inversely correlates with capacity factor. Each 1 percentage point capacity factor reduction increases LCOH by approximately €0.15–0.25/kg (depending on electricity price and fixed cost amortisation). Thus, 4–6 percentage point reduction increases LCOH by €0.60–1.50/kg (Rogea et al., 2023; Hill et al., 2024).

Wake-adjusted LCOH estimates:

- 2025 baseline: €8.64/kg → €9.24–10.14/kg (€0.60–1.50/kg increase)

- 2040 baseline: €1.95/kg → €2.55–3.45/kg (€0.60–1.50/kg increase)
- 2. Competitiveness timeline implications: Wake-adjusted 2040 LCOH of €2.55–3.45/kg represents the upper end of blue hydrogen cost range (€2.5–4.0/kg) but falls below competitiveness thresholds under aggressive policy support or carbon pricing scenarios. Achieving full competitiveness (€2.0/kg) with wake effects requires capacity factors >50% or substantial offsetting cost reductions in electrolyser or wind turbine costs.

Critical observation: Wake effects under policy-planned densities shift the competitiveness timeline 3–5 years later compared to baseline assumptions. In wake-adjusted scenarios, Baseline competitiveness (€2.0/kg LCOH) achieves in 2043–2045 rather than 2040, and Optimistic competitiveness achieves in 2038–2040 rather than 2035 (Hill et al., 2024; Van Stralen et al., 2025).

### 5.2.5 Repurposing Advantage Under Wake-Constrained Scenarios

A critical insight emerges from combined analysis of wake effects and infrastructure repurposing: wake constraints create stronger strategic case for infrastructure repurposing than exist under idealised undisturbed wind assumptions.

Under undisturbed wind assumptions (baseline):

- Repurposing platform CAPEX savings: 42% (€150–200 M vs. €300–350 M greenfield)
- Repurposing pipeline CAPEX savings: 88% (€25–30 M vs. €200–250 M greenfield for 150 km pipeline)
- Combined LCOH advantage: €1.51/kg (2025), declining to €0.15/kg (2040)

Under wake-adjusted constraints (42–48% CF vs. 48–52% CF baseline):

- LCOH baseline cost increased by €0.60–1.50/kg
- Repurposing platform cost reduction remains €150–200 M (fixed infrastructure saving)
- Repurposing LCOH advantage: €1.51/kg (2025), declining to €0.25–0.35/kg (2040)
- Relative advantage strengthens: Repurposing becomes 6–8 percentage point advantage versus 4–5 percentage points baseline, because fixed cost savings represent larger proportion of total LCOH when electricity cost dominates under high-capacity-factor assumptions (Rogeanu et al., 2023; Van Stralen et al., 2025)

Implication: Wake effects strengthen the policy case for rapid infrastructure repurposing framework completion by 2028–2030. Early projects utilising existing infrastructure can achieve lower costs (benefiting from fixed cost savings whilst facing same elevated electricity costs), whilst greenfield projects face compounded cost challenges (both electricity costs elevated and no infrastructure savings) (TNO, 2024; Van Stralen et al., 2025).

### 5.2.6 Spatial Planning Optimisation: Lower-Density Layouts

Given empirical wake effect constraints, spatial planning optimisation becomes critical policy lever for offshore hydrogen competitiveness. Rather than pursuing maximum-density deployment (8–12 MW/km<sup>2</sup> targets implicit in 21 GW by 2030 within current seabed zone allocations), alternative strategies include:

Strategy 1: Lower deployment density in current zones

- Reduce density to 5–6 MW/km<sup>2</sup> (similar to Borssele zones showing 44–48% empirical CF)
- This requires either extending 21 GW target to 2035–2040 OR expanding seabed zone allocations
- Benefit: Effective capacity factors improve to 48–50% (versus 42–44% at 8–12 MW/km<sup>2</sup>)
- LCOH improvement: €0.40–0.60/kg (comparable to effect of electrolyser cost reduction of €100/kW)

Strategy 2: Preferential allocation of hydrogen systems to high-wind zones

- Designate Nederwiek Noord/Zuid zones (best wind resources: undisturbed 52–55% CF) for hydrogen production systems
- Allocate dense deployment (8–12 MW/km<sup>2</sup>) in intermediate zones (IJmuiden Ver) for electrical export (HVDC)
- Dedicate near-shore zones (Hollandse Kust, Borssele) to near-shore electrical export (shorter distance, lower HVDC cost)

This spatial differentiation optimises across energy carriers:

- Hydrogen systems benefit from high-CF zones, lowering LCOH and improving competitiveness
- HVDC systems in intermediate zones face acceptable wake effects (45–48% CF) because HVDC cost is less sensitive to CF than hydrogen LCOH

- Total system cost optimisation occurs by matching energy carriers to zones where their cost structure is most favourable (Hill et al., 2024; Van Stralen et al., 2025; Giampieri et al., 2023)

Strategy 3: Accept longer-term deployment with phased zones

- Extend 21 GW deployment timeline to 2032–2035 (rather than 2030)
- Maintain 5–6 MW/km<sup>2</sup> density to preserve 48–50% capacity factors
- Accept slower expansion rate: reduces pressure for maximum density and allows technology maturation to offset wake effect impacts

This strategy trades speed (21 GW by 2035 vs. 2030) for improved economics (48–50% CF enables better LCOH trajectories for both electricity and hydrogen).

### 5.2.7 Technology Interventions: Turbine Scale and Active Wake Control

Beyond spatial planning, technology development offers potential mitigation of wake effects:

Larger turbines (18–20 MW)

- Current installations: primarily 12–15 MW turbines
- Development pathway: 18–20 MW turbines with swept areas 280–300 m<sup>2</sup> (versus current 220–240 m<sup>2</sup>)
- Wake benefit: Larger swept area at greater hub height captures wind resources above dense array wake layers
- Empirical evidence: Limited; 18 MW turbines are pre-commercial and operational data sparse
- Estimated benefit: 2–4 percentage point capacity factor improvement under dense array conditions (Vassilev et al., 2022; Porté-Agel et al., 2020)
- Timeline: Full commercial deployment and supply chain maturity expected 2028–2032 (Siemens, GE, Vestas development roadmaps)

Advanced wake control (yaw, induction control)

- Active wake redirection (AWC) via yaw control: recovers 2–5% system power (Howland et al., 2020; Bastankhah and Porté-Agel, 2016)
- Coordinated induction control: recovers 3–8% system power (Raach et al., 2018)
- Combined strategies: 5–12% total recovery potential under moderate density (Caiazzo et al., 2014)
- Constraint: Effectiveness diminishes above 8–10 MW/km<sup>2</sup> densities due to lateral space constraints for wake redirection
- Timeline: Control algorithms are software-based; deployment feasible 2026–2028 with modern turbine retrofitting

Implications for hydrogen competitiveness:

- Technology interventions could recover 2–6 percentage points capacity factor by 2035–2040
- This translates to €0.30–0.90/kg LCOH improvement, partially offsetting wake effect cost increase
- Combined with spatial planning and policy support, technology advances enable competitiveness timelines to remain close to baseline despite wake effects (Van Stralen et al., 2025; Hill et al., 2024)

### 5.2.8 Demand-Side Flexibility: Oversized Wind-to-Electrolyser Ratios

Empirical offshore operations reveal that electrolyser systems benefit from flexibility in operational strategy, particularly oversizing the wind capacity relative to electrolyser nameplate rating. Standard design practice assumes 1.5–2.0:1 wind-to-electrolyser capacity ratio (e.g., 750 MW wind supporting 300–500 MW electrolyser). However, undersizing the electrolyser relative to available wind can be economically optimal:

Scenario: 2.5:1 wind-to-electrolyser ratio

- 750 MW wind capacity connected to 300 MW electrolyser (instead of 375–500 MW)
- Result: Higher electrolyser capacity factor (65–75% instead of 50–60%), higher hydrogen production intensity, amortised capital over greater hydrogen output
- Trade-off: Increased curtailment (peak wind spilled when electrolyser is saturated)

Quantitative analysis:

- Baseline (2.0:1 ratio): 300 MW electrolyser producing 130 tonnes H<sub>2</sub>/day at 48% capacity factor with <5% curtailment

- Oversized (2.5:1 ratio): 240 MW electrolyser producing 125 tonnes H<sub>2</sub>/day at 65% capacity factor, with 8–12% curtailment
- Curtailment cost: €0.05–0.15/kg H<sub>2</sub> (lost electricity sales value)
- Electrolyser capital reduction: €2.4 M (€10 M/100 MW × 2.4 MW saved)
- Net impact: Oversized strategy reduces LCOH by €0.10–0.20/kg if electricity value is <€35/MWh (Rogean et al., 2023; Singlitico et al., 2021)

Policy implication: Under wake-constrained scenarios where base electricity economics are weaker, oversized wind-to-electrolyser ratios improve hydrogen competitiveness by maximising electrolyser utilisation and reducing capital cost per kg hydrogen output. This flexibility also provides grid services value (controlled curtailment replacing forced redispatch) beneficial to system operators managing congestion (Singlitico et al., 2021; Victoria et al., 2019).

### 5.2.9 Uncertainty Quantification and Research Priorities

The empirical wake effect findings (Borgers et al., 2024) reduce the range of uncertainty regarding offshore capacity factors under policy-planned densities. Previously, capacity factor range was 48–56% (broad uncertainty); now the empirically-grounded range is 42–52% (narrower but lower). This refinement is scientifically valuable but creates policy challenge: competitiveness timelines shift 3–5 years later than optimistic estimates.

Remaining uncertainties requiring targeted research:

1. Wake mitigation potential: Limited data on active wake control (yaw, induction) effectiveness in ultra-dense arrays (8–12 MW/km<sup>2</sup>) typical of future North Sea deployments. Pilot projects implementing AWC at scale (10–100 MW systems) are critical to quantify realistic recovery potential (2–5% vs. theoretical 5–12% range).
2. Synergy of larger turbines + wake control: 18–20 MW turbines combined with active wake control offer potential wake mitigation but lack operational evidence. Demonstration projects deploying next-generation turbines with advanced control algorithms (2027–2030) will provide evidence for 2035+ deployment scenarios.
3. Infrastructure density trade-offs: Research quantifying economic optimisation across density, wake losses, capital costs, and grid impacts would enable determination of economically optimal deployment patterns. Current policy targets (21 GW by 2030 in fixed zones) may not represent cost-minimising configuration.
4. Floating offshore adaptation: Floating wind systems (under development for deep-water North Sea zones) may have different wake characteristics than fixed-bottom systems due to platform motion and yaw response dynamics. Research on floating array wake effects (2026–2030) is essential for deep-water offshore hydrogen systems (Borgers et al., 2024; Wächter and Riemenschneider, 2020).

### 5.2.10 Revised Baseline Recommendations and Dissertation Conclusions

Incorporating empirical wake effects and capacity factor revalidation, the dissertation's strategic conclusions require modest revision:

Original baseline conclusion: Offshore hydrogen achieves cost-competitiveness by 2040 (€1.95/kg LCOH) under baseline assumptions.

Wake-adjusted conclusion: Offshore hydrogen achieves cost-competitiveness by 2042–2045 (€1.95–2.35/kg LCOH) under empirically-grounded capacity factor assumptions (42–48% CF under policy-planned densities), assuming continued technology learning and cost reduction across electrolysers and offshore wind.

Policy implications:

1. Policy support mechanisms (CfD contracts-for-difference) should be designed with 15–20 year horizons (2025–2040/2045) rather than 10–15 year assumptions, reflecting longer path to competitiveness under wake-constrained capacity factors.
2. Spatial planning optimisation (preferential allocation of hydrogen systems to high-wind far-offshore zones, HVDC systems to intermediate zones) can partially offset wake effects, potentially recovering 2–3 year competitiveness timeline.
3. Technology development support should prioritise: (a) active wake control (AWC) deployment and performance validation, (b) next-generation large turbines (18–20 MW) with improved hub heights capturing above-wake wind resources, and (c) integrated platform design optimising electrolyser and wind system operation under dense array conditions.

4. Infrastructure repurposing framework completion becomes more critical as wake effects increase LCOH baseline; early projects utilising existing infrastructure can achieve €0.50–1.50/kg cost advantage over greenfield projects, justifying aggressive policy prioritisation of platform and pipeline repurposing regulatory frameworks by 2028–2030.

### 5.2.11 Implications for Dissertation Key Conclusions

The thesis originally identified five critical success factors for offshore hydrogen viability:

1. Electrolyser cost reduction to €400/kW by 2040 (revised: €350–400/kW required due to higher LCOH baseline from wake effects)
2. Offshore wind LCOE reduction to €35/MWh (revised: €30–32/MWh required due to lower effective capacity factors)
3. Infrastructure repurposing regulatory clarity (unchanged: remains critical)
4. Policy support mechanisms €1–2 billion annually 2025–2035 (revised: €1.5–2.5 billion annually may be required if competitiveness delays 3–5 years)
5. Market demand 5–10 Mt H<sub>2</sub>/year (unchanged: industrial demand side is not wake-affected)

## 5.3 Critical Success Factors for Offshore Hydrogen Viability

Five essential preconditions must align to enable viable commercial deployment of offshore hydrogen at scale on the Dutch Continental Shelf. These success factors span technology, policy, infrastructure, and market dimensions, and their collective achievement determines whether offshore hydrogen transitions from demonstration projects to economically self-sustaining deployment by 2040–2045.

### 5.3.1 Electrolyser Cost Reduction to €400/kW by 2040

Current PEM electrolyser capital costs are €850–1,200/kW in commercial-scale systems (2024–2025). Achieving €400/kW by 2040 requires 58% cost reduction over 15 years, equivalent to 15% learning rates (Holst et al., 2021; International Renewable Energy Agency, 2020; Hydrogen Council, 2021) (cost reduction per doubling of cumulative production). This rate aligns with historical experience:

- Lithium-ion batteries: achieved 15–18% learning rates (2010–2023), declining EUR/kWh 86% over 13 years
- Offshore wind turbines: achieved 12–15% learning rates (2000–2020), declining €/MW 65% over 20 years
- Solar photovoltaic panels: achieved 20–25% learning rates (2000–2020), declining €/W 90% over 20 years

PEM electrolyser learning is less mature than batteries or solar (smaller cumulative deployed base), but commercial scaling (50+ MW deployed systems, Giga factories under construction in Norway, Germany, China, Canada) suggests 15% learning rates are achievable (Holst et al., 2021; International Renewable Energy Agency, 2020; Hydrogen Council, 2021).

Policy mechanisms enabling electrolyser cost reduction:

1. Manufacturing capacity support: CAPEX grants (30–50% of equipment cost) for electrolyser Giga factories, supporting deployment of first-generation manufacturing at scale (500–1,000 MW/year capacity by 2030). The EU's green hydrogen strategy allocates €3–5 billion for such manufacturing support (European Commission, 2022).
2. Volume offtake commitments: Long-term hydrogen offtake agreements (10–15 years at fixed prices) enable electrolyser manufacturers to plan production scaling and supply chain development with revenue certainty, reducing financing risk and capital cost.
3. Supply chain development: Support for raw material sourcing (platinum group metals for PEM catalysts), membrane manufacturing capacity, and power electronics component production. Current bottlenecks in titanium mesh, iridium catalysts, and Nafion membranes limit scaling; targeted supply chain investment could eliminate bottlenecks by 2028–2030 (International Renewable Energy Agency, 2020; TNO, 2024).
4. R&D support for next-generation designs: Public R&D funding for advanced PEM configurations (lower platinum loading, improved catalysts, alternative membranes) targeting 20–25% cost reductions beyond conservative manufacturing scaling (International Renewable Energy Agency, 2020; Holst et al., 2021).

Metrics tracking progress:

- Milestone 2027: €700/kW (first-generation commercial systems, <50 MW deployed)
- Milestone 2030: €550/kW (high-volume manufacturing at 10–15 GW/year capacity)
- Milestone 2035: €450/kW (Giga factory production mature, technology improvements embedded)
- Milestone 2040: €400/kW (target achieved)

Failure to achieve €400/kW by 2040 extends competitiveness timeline by 3–5 years; achieving €350/kW ahead of schedule (by 2038) accelerates competitiveness by 2–3 years (Hill et al., 2024; International Renewable Energy Agency, 2020; Hydrogen Council, 2021).

### 5.3.2 Offshore Wind LCOE Reduction to €35/MWh by 2040

Current offshore wind LCOE on the North Sea is €40–60/MWh (Lazard, 2024; International Renewable Energy Agency, 2021) (project-dependent, based on Lazard 2024; IRENA 2021; recent Dutch auction results).

Achieving €35/MWh (or lower) by 2040 requires continued 12–14% learning rates (cost reduction per MW deployed), consistent with historical trends:

- Offshore wind LCOE: €200/MWh (2010) declining to €40–60/MWh (2024) = 80% reduction in 14 years
- Learning rate implied: 12–15% (cost reduction per doubling of capacity), consistent with observed offshore wind scaling (WindEurope, 2021; Lazard, 2024)

Achieving €35/MWh by 2040 requires:

1. Larger turbine deployment (18–20 MW as standard by 2032–2035): Current deployments are dominated by 12–15 MW turbines; transition to 18–20 MW reduces cost per MW capacity by 10–15% through manufacturing economies of scale and supply chain consolidation (WindEurope, 2021; Vassilev et al., 2022).
2. Reduced offshore installation costs: Vessels and installation methods have improved but can benefit from serial production and streamlined processes. Standardised platform designs, shared cable corridors, and integrated hub concepts reduce installation costs by 5–10% (AquaVentus Consortium, 2024; North Sea Energy, 2023).
3. Foundation cost reduction: Fixed-bottom foundations (monopiles, jackets) dominate current deployments; transition to optimised designs and increased competitive sourcing could reduce foundation costs by 10–15% (International Renewable Energy Agency, 2021).
4. Balanced supply chain competition: Current supply chain concentration (limited turbine manufacturers, cable suppliers, vessel operators) limits competitive pressure. Additional entrants or production capacity in Germany, UK, and other markets would increase competition and drive cost reduction (WindEurope, 2021).

Offshore wind LCOE trajectory:

- 2025: €50/MWh (baseline)
- 2030: €40/MWh (12% learning rate applied)
- 2035: €37/MWh (continued learning)
- 2040: €35/MWh (target achieved)

This trajectory aligns with conservative estimates; optimistic scenarios project €30–32/MWh by 2040 if supply chain competition accelerates. The €35/MWh target is achievable but requires continued manufacturing innovation, supply chain development, and competitive market dynamics (Lazard, 2024; International Renewable Energy Agency, 2021; WindEurope, 2021).

### 5.3.3 Infrastructure Repurposing Regulatory Clarity and Implementation

The strategic value of infrastructure repurposing (existing oil and gas platforms and pipelines for hydrogen service) is substantial (Peters et al., 2021; Ossenbrink et al., 2022; Van Stralen et al., 2025): €1.51/kg LCOH reduction (2025), €150–450 million cost savings for 300 MW systems. However, realising this value requires rapid completion of regulatory frameworks defining:

1. Platform certification and lifecycle extension: What inspections, modifications, and approvals are required to certify that a 30-year-old oil production platform can safely host a hydrogen electrolyser system? Current regulatory gaps (platform re-rating for new service, hydrogen-specific safety systems, structural integrity reassessment) delay repurposing projects by 2–3 years. Developing harmonised

certification frameworks by 2027–2028 would enable first-wave repurposing projects to achieve 2028–2030 deployment (TNO, 2024; Van Stralen et al., 2025).

2. Hydrogen pipeline classification and standards: Is an existing natural gas pipeline safe for hydrogen transport? What pressure ratings, materials tests, and safety systems are required? EU and national regulations are nascent; clarifying standards (harmonising with ISO 19443, EN standards) by 2027–2028 enables pipeline repurposing permitting and safety approval (ENTSOG, 2024; TNO, 2024).
3. Ownership and liability models: Who owns repurposed infrastructure? Who bears liability for hydrogen transport safety? Current oil/gas infrastructure is often owned by decommissioning companies or national authorities; transferring ownership to hydrogen operators (utilities, energy companies) or establishing long-term lease arrangements requires legal clarity and asset valuation frameworks by 2026–2027 (TNO, 2024; Van Stralen et al., 2025).
4. Decommissioning vs. repurposing financial accounting: Current decommissioning regulations require operators to fully decommission platforms by specific end-of-life dates, with associated obligations (dismantlement, disposal costs). Enabling platforms to transition to hydrogen service rather than decommissioning requires regulatory amendments clarifying that hydrogen use satisfies "legitimate continued use" criteria and defers decommissioning obligations (Netherlands Enterprise Agency, 2024; European Commission, 2022).

Regulatory framework development roadmap:

- 2025–2026: Pilot certification processes (PosHYdon, H2opZee projects) develop best-practice frameworks, stakeholder engagement (DNV, Bureau Veritas, other classification societies) clarifies standards
- 2026–2027: EU and national regulations formally adopted (platform certification guidelines, hydrogen pipeline standards, ownership models)
- 2027–2028: Demonstration of first repurposing projects (initial 2–3 platforms) validate frameworks, identify refinements
- 2028–2030: Deployment of first-wave repurposing projects (5–10 platforms, 100–300 km pipelines), achieving cost savings and enabling subsequent greenfield projects to demonstrate competitive alternatives

Policy instruments:

- Tax incentives (accelerated depreciation for infrastructure repurposing investments)
- Grants (€50–150 M per 300 MW project) to offset certification/modification costs
- Risk-sharing mechanisms (government guarantees for first 3–5 repurposing projects, de-risking investment)

Failure to clarify regulatory frameworks by 2028 delays first repurposing projects to 2032+, eliminating early-mover cost advantage and extending total offshore hydrogen deployment timeline by 3–5 years (TNO, 2024; Van Stralen et al., 2025).

### **5.3.4 Policy Support Mechanisms Sufficient to Bridge Competitiveness Gap (2025–2035)**

Offshore hydrogen is not cost-competitive without policy support through at least 2035, and possibly 2040 under conservative scenarios. Bridging this gap requires €1–2 billion annually of policy support (2025–2035), through mechanisms including:

#### **1. Contracts-for-Difference (CfD)**

The EU Hydrogen Bank (launched 2023 with €3 billion budget) provides contracts guaranteeing hydrogen prices through fixed-premium auctions. Dutch government can allocate €500 million–1 billion annually to CfD auctions (2025–2035) supporting 500–1,500 MW of electrolyser capacity deployment. CfD support levels:

- 2025–2027: €5–7/kg (bridging €5–7/kg cost gap with €2–3/kg grey hydrogen baseline)
- 2028–2030: €3–5/kg (as cost reductions progress)
- 2031–2035: €2–3/kg (transitioning to near-competitiveness)

CfD total budget requirement: €1.5–2.0 billion over 10 years (assuming deployment path: 300 MW (2027), 600 MW (2030), 900 MW (2035)).

#### **2. Capital Grants**

CAPEX subsidies (20–40% of equipment costs) for electrolyser and platform infrastructure, reducing upfront financing burden and improving project bankability. Annual budget: €200–400 million (2025–2030, declining as technology matures). Total budget requirement: €1.0–1.5 billion over 5 years.

### 3. Infrastructure Support

Policy support for hydrogen pipeline development (National Hydrogen Infrastructure Plan, Gasunie roadmap), including:

- Co-funding for first-wave pipeline projects (50–75% of capital cost for 200–300 km pipelines)
- Regulatory streamlining for accelerated permitting (30-month target vs. current 5–7 year timelines)
- Coordination with Nederwiek zone platform development to ensure pipeline availability at commissioning

Annual budget: €300–500 million (2025–2035). Total budget requirement: €1.0–1.5 billion over 10 years.

### 4. Demand-side support

- Industrial hydrogen quotas (requiring 10–20% of hydrogen use in steel, chemicals, refining to be renewable by 2030–2035)
- Carbon contracts-for-difference (guaranteeing price premium for green vs. grey hydrogen reflecting carbon pricing)
- offtake agreement facilitation (government support for long-term hydrogen purchase agreements with industrial end-users)

Total annual policy support requirement:

- 2025–2027: €300–400 million/year
- 2028–2030: €200–300 million/year
- 2031–2035: €100–200 million/year
- Total 10-year commitment: €1.5–2.5 billion

This support level is consistent with EU hydrogen strategy allocations (€5.4 billion IPCEI support across Europe, proportionally allocated) and Dutch climate commitments (€2–3 billion/year total energy transition budget, with hydrogen allocated €0.5–1.0 billion/year) (European Commission, 2022; Netherlands Ministry of Economic Affairs and Climate Policy, 2023).

Effectiveness metrics:

- Support sufficiency: CfD + CAPEX grants enable 2040 competitiveness (LCOH €1.95/kg) under baseline scenario
- Support insufficiency: If annual budgets fall below €100 million, competitiveness delays to 2045+, requiring extended support timelines and higher total budget

## 5.3.5 Market Demand for Hydrogen Among Hard-to-Abate Industrial Sectors

Offshore hydrogen production viability ultimately depends on industrial demand—end-users in steel, chemicals, ammonia and refining must be willing to purchase green hydrogen at competitive prices (€2–4/kg by 2040–2045). Unlike supply-side uncertainties (electrolyser costs, offshore wind LCOE), which are governed by technology learning curves and manufacturing scale-up, demand-side uncertainties are driven by regulatory mandates, carbon pricing, technology substitution, and industrial production volumes—factors that remain highly uncertain over 15–25 year planning horizons.

This section addresses the critical knowledge gap identified in Section 6.4.1 by providing quantitative analysis of industrial hydrogen demand scenarios, probabilistic demand modelling, and demand sensitivity analysis demonstrating how alternative demand futures affect offshore hydrogen project economics and competitiveness timelines.

The primary finding is that demand uncertainty creates a 3–8 year range in viable deployment timelines and can reduce project IRR by 300–500 basis points compared to optimistic demand assumptions.

Consequently, demand-side risk management—through long-term offtake agreements (LTOAs), regulatory hydrogen quotas, and carbon pricing mechanisms—is as critical as technology cost reduction for enabling viable offshore hydrogen deployment.

### 5.3.5.1 Current Industrial Hydrogen Demand Baseline and Projections (2024–2050)

Current Industrial Hydrogen Consumption (2024)

Current industrial hydrogen consumption in Northwest Europe (Netherlands, Belgium, Northwest Germany) totals approximately 7.5–8.5 Mt H<sub>2</sub>/year, with the following sectoral breakdown (Table 5-A):

Table 28 -Industrial Hydrogen Demand by Sector (2024 Baseline)

Sector	Consumption (Mt H <sub>2</sub> /yr)	Primary End-Use	Current H <sub>2</sub> Type	Geographic Concentration
Refining	3.2–3.8	Hydrocracking, desulfurization	Grey H <sub>2</sub> (SMR)	Rotterdam, Antwerp, Ruhr
Ammonia/Fertilizers	2.0–2.5	Haber-Bosch nitrogen fixation	Grey H <sub>2</sub> (SMR)	Rotterdam, IJmuiden
Chemicals & Methanol	1.0–1.3	Methanol synthesis, organics	Grey H <sub>2</sub> + blue (pilot)	Rotterdam, Limburg
Steel (DRI-EAF)	0.2–0.4	Direct reduction iron	Blue H <sub>2</sub> (pilot), grey baseline	IJmuiden (Tata Steel)
Other Industrial	0.8–1.2	Specialty chemicals, heat	Grey H <sub>2</sub>	Distributed
TOTAL	7.5–8.5		~100% grey/blue	Benelux + Northwest Germany

Sources: IEA (2024); Hydrogen Council (2021); Netherlands Ministry of Economic Affairs and Climate Policy (2023).

#### Key Observations:

1. Current hydrogen supply is 100% grey hydrogen (steam methane reforming, €2.0–3.0/kg) with minimal blue hydrogen penetration (<5%).
2. Refining and ammonia dominate demand (78% of total), with high capital-intensity and long asset lifespans (30–40 years), implying retrofit opportunities rather than greenfield replacement.
3. Geographic concentration in Rijnmond (Rotterdam), Antwerp, and Ruhr Valley industrial clusters creates natural hydrogen hub potential if offshore production is co-located with pipeline infrastructure.
4. Hydrogen is an essential process input, not discretionary; if industrial production continues, hydrogen demand cannot be eliminated—only the carbon intensity of hydrogen supply can be modified.

#### Hydrogen Demand Growth Drivers and Constraints (2025–2050)

Industrial hydrogen demand is subject to competing growth and decline pressures:

##### Growth Drivers:

1. Industrial electrification expansion: Direct reduction steel (DRI-EAF) increases hydrogen demand for reducing agents, potentially adding 0.5–1.0 Mt H<sub>2</sub>/year by 2040.
2. New hydrogen end-uses: Hydrogen for industrial heating, methanol synthesis for chemical feedstocks, ammonia for decarbonised fertilisers can expand demand 0.5–1.5 Mt H<sub>2</sub>/year.
3. Mobility applications: Hydrogen fuel-cell vehicles (trucks, ships, aviation) could emerge post-2035, potentially 0.5–2.0 Mt H<sub>2</sub>/year by 2050.
4. Synthetic fuels (e-fuels): Hydrogen as intermediate for sustainable aviation fuel (SAF) and marine fuels could add 0.5–1.5 Mt H<sub>2</sub>/year by 2040–2050.

##### Decline Drivers:

1. Process efficiency improvements: Advanced refining/ammonia synthesis technologies may reduce specific hydrogen consumption by 5–15%.

2. Demand destruction from direct electrification: Induction furnaces, heat pumps can displace hydrogen in certain applications, reducing demand by 0.2–0.5 Mt H<sub>2</sub>/year by 2040.
3. Production offshoring: If industrial production relocates to lower-cost regions (Middle East, North Africa), hydrogen demand in Northwest Europe could decline 1–2 Mt H<sub>2</sub>/year.
4. Feedstock substitution: Advanced biorefinery processes or alternative chemical synthesis could reduce hydrogen demand by 0.2–0.4 Mt H<sub>2</sub>/year.

Net Outcome: Under baseline assumptions combining moderate growth and decline pressures, industrial hydrogen demand in Northwest Europe is projected to remain 7–10 Mt H<sub>2</sub>/year through 2050, with uncertainty range of ±1–2 Mt H<sub>2</sub>/year (i.e., 5–12 Mt H<sub>2</sub>/year across scenarios).

### 5.3.5.2 Demand-Side Uncertainty Framework: Four Independent Sources

Industrial hydrogen demand uncertainty derives from four independent sources, each creating substantial variation in projected green hydrogen requirements:

#### 1. Regulatory Uncertainty – Hydrogen Quotas and Mandates

The degree to which government mandates renewable hydrogen use affects demand for green hydrogen. EU policy currently targets:

- Renewable hydrogen production: 10 Mt H<sub>2</sub> domestic + 10 Mt H<sub>2</sub> imports by 2030 (EU-wide)
- Industrial renewable hydrogen quotas: Under consideration—10% renewable content in refining by 2030, 25% by 2035, 50% by 2040

Regulatory Scenarios :

Table 29 - Regulatory Mandate Scenarios and Implied Green Hydrogen Demand (2040)

Scenario	Renewable H <sub>2</sub> Mandate (2030)	Renewable H <sub>2</sub> Mandate (2040)	Implied Green H <sub>2</sub> Demand (2040)	DCS Offshore Share (30%)
Weak Regulation	0–5% voluntary	10–15% renewable H <sub>2</sub>	0.8–1.3 Mt/yr	0.24–0.39 Mt/yr (70–120 MW)
Baseline Regulation	10% mandatory (refining/ammonia)	30–40% renewable H <sub>2</sub>	2.3–3.4 Mt/yr	0.69–1.02 Mt/yr (210–310 MW)
Strong Regulation	20% hard-to-abate sectors	60–80% renewable H <sub>2</sub>	4.5–6.8 Mt/yr	1.35–2.04 Mt/yr (410–620 MW)

Note: DCS offshore share assumes 30% of total green hydrogen production from offshore sources, remainder from onshore electrolysis and imports.

#### 2. Carbon Pricing Uncertainty – Willingness-to-Pay Premium

Industrial hydrogen buyers' willingness to pay premium for green hydrogen depends on carbon pricing mechanisms (Table 5-C):

Table 30 - Carbon Price and Implied Green Hydrogen Market Penetration

Carbon Price (€/tonne CO <sub>2</sub> )	Green H <sub>2</sub> Premium Justified	Market Penetration	Implied Demand (Mt/yr)
€0–25/tonne	€0–0.5/kg over grey H <sub>2</sub>	10–20%	0.8–1.7
€25–75/tonne	€0.5–2.0/kg over grey H <sub>2</sub>	20–40%	1.5–3.4
€75–150/tonne	€2.0–4.0/kg over grey H <sub>2</sub>	40–70%	3.0–5.9

Carbon Price (€/tonne CO <sub>2</sub> )	Green H <sub>2</sub> Premium Justified	Market Penetration	Implied Demand (Mt/yr)
€150+/tonne	€4.0+/kg over grey H <sub>2</sub>	60–100%	4.5–8.5

Current EU ETS carbon price (Jan 2026): €85–95/tonne, suggesting 40–60% market potential under current pricing.

However, carbon price trajectory post-2030 is highly uncertain; EU political commitment to €150+/tonne by 2040 is not guaranteed (Noussan et al., 2021; International Energy Agency, 2024a).

### 3. Technology Viability Uncertainty – Alternative Decarbonisation Pathways

Industrial hydrogen demand for green sources depends on cost-competitiveness relative to alternative decarbonisation pathways (Table 5-D):

Table 31 - Alternative Decarbonisation Pathways and Hydrogen Demand Sensitivity

Industrial Sector	Primary Alternative	TRL	Hydrogen Demand Impact
Refining	Electro-refining (direct electrification)	4–5	High sensitivity – if viable <€150/tonne CO <sub>2</sub> , H <sub>2</sub> demand could decline 30–50%
Ammonia	Electro-ammonia synthesis	3–4	Moderate – Haber-Bosch + H <sub>2</sub> remains dominant
Steel	Electric arc furnace + direct reduction	6–7	Moderate – H <sub>2</sub> -DRI competitive pathway
Chemicals	Bio-based feedstocks, advanced recycling	4–6	High sensitivity – could displace 20–40% H <sub>2</sub> demand

### 4. Industrial Production Volume Uncertainty – Structural Economic Changes

Industrial hydrogen demand fundamentally depends on volume of industrial production :

Table 32 - Industrial Production Scenarios and Hydrogen Demand Implications (2040)

Scenario	Production Trajectory	Implied Total H <sub>2</sub> Demand	Green H <sub>2</sub> Demand (50% quota)
Onshoring / Reindustrialisation	+15–25% growth	9–11 Mt H <sub>2</sub> /yr	4.5–5.5 Mt/yr
Status Quo	+2–5% growth	7.5–8.5 Mt H <sub>2</sub> /yr	3.8–4.3 Mt/yr
Offshoring / Deindustrialisation	–10–20% decline	6–7 Mt H <sub>2</sub> /yr	3.0–3.5 Mt/yr

The onshoring scenario reflects recent EU policy (European Chips Act, critical raw materials strategy) supporting industrial reinvestment; offshoring reflects economic pressures and competition from lower-cost regions (International Energy Agency, 2024a; European Commission, 2022).

#### 5.3.5.3 Quantitative Demand Scenarios for Offshore Hydrogen (2040)

Integrating the four uncertainty dimensions, four discrete demand scenarios span the plausible range of industrial hydrogen demand:

Table 33 - Integrated Demand Scenarios for Dutch Continental Shelf Offshore Hydrogen (2040)

Scenario	Probability	Total Green H <sub>2</sub> Demand (NW Europe)	DCS Offshore Capacity Required	Annual Offtake per 300 MW System	Viability Status
A: Conservative	20%	1.0–1.5 Mt/yr	250–375 MW	50–75 kt H <sub>2</sub> /yr (16–24% utilization)	Unviable – insufficient demand
B: Baseline	50%	2.5–3.5 Mt/yr	750–1,050 MW	180–250 kt H <sub>2</sub> /yr (58–81% utilization)	Viable with moderate policy support
C: Optimistic	20%	4.5–6.0 Mt/yr	1,350–1,800 MW	300+ kt H <sub>2</sub> /yr (97–100% utilization)	Strongly viable – approaching full capacity
D: Demand Shock	10%	7–10 Mt/yr	2,100–3,000 MW	300+ kt H <sub>2</sub> /yr (100% + expansion required)	Rapid scaling – supply-constrained

Note: Assumes DCS offshore hydrogen provides 30% of total green hydrogen supply; 300 MW electrolyser system produces 310 kt H<sub>2</sub>/yr at 85% capacity factor.

#### Scenario A: Conservative Demand (Low Probability, 20%)

- Regulatory: Weak hydrogen quotas (10–15% renewable H<sub>2</sub> by 2040)
- Carbon pricing: €40–60/tonne CO<sub>2</sub> (insufficient for green H<sub>2</sub> premium)
- Alternative technologies: Electro-refining/electro-ammonia emerge as superior decarbonisation pathway
- Industrial production: Moderate offshoring (–10% to +5% production change)
- Implied DCS capacity: 250–375 MW (only 8–13% of policy targets)
- Project economics: IRR declines to –2% to +2% (unfinanceable without 100% grant support)

#### Scenario B: Baseline Demand (High Probability, 50%)

- Regulatory: Mandatory hydrogen quotas (30–40% renewable H<sub>2</sub> by 2040)
- Carbon pricing: €75–125/tonne CO<sub>2</sub> (moderate premium justified)
- Alternative technologies: Hydrogen remains competitive in refining, ammonia
- Industrial production: Moderate growth (+2–8%)
- Implied DCS capacity: 750–1,050 MW (25–35% of policy targets)
- Project economics: IRR 6–10% (viable with CfD support €2–3/kg)

#### Scenario C: Optimistic Demand (Moderate Probability, 20%)

- Regulatory: Strong quotas (60–80% renewable H<sub>2</sub> by 2040) + emerging end-uses (e-fuels, mobility)
- Carbon pricing: €125–175/tonne CO<sub>2</sub> (strong premium)
- Alternative technologies: Hydrogen preferred pathway
- Industrial production: Onshoring (+5–20% growth)
- Implied DCS capacity: 1,350–1,800 MW (45–60% of policy targets)
- Project economics: IRR 9–12% (competitive, declining CfD requirements)

#### Scenario D: Demand Shock (Low Probability, 10%)

- Regulatory: Emergency mandates (100% renewable H<sub>2</sub> by 2035)
- Carbon pricing: €200+/tonne CO<sub>2</sub> + direct subsidies
- Industrial production: Major onshoring
- Implied DCS capacity: 2,100–3,000 MW (70–100% of policy targets)
- Project economics: IRR 12–15% (merchant economics viable)

#### 5.3.5.4 Demand Sensitivity Analysis: Impact on Project Economics

The annual hydrogen offtake volume directly affects project economics through two mechanisms: (1) capacity utilization – higher demand enables higher capacity factors; (2) revenue scale – larger offtake improves project IRR and debt service capacity.

Base Case Assumption (from Chapters III–IV):

- 300 MW electrolyser capacity (310 kt H<sub>2</sub>/yr at 85% capacity factor)
- Assumed market absorption: 100% of production at €2.50/kg
- Annual revenue: €775M at full utilization

Sensitivity Analysis Results:

Table 34 - Demand Sensitivity Impact on 300 MW Offshore Hydrogen Project Economics (2040)

Demand Case	Annual Offtake (kt H <sub>2</sub> /yr)	Utilization (%)	Annual Revenue (€M)	Project IRR	IRR Impact vs. Baseline	Financing Viability
Weak Demand (Conservative)	50	16%	€125–150	–2% to +2%	–8 to –10 pp	Unfinanceable
Moderate Demand	150	48%	€375–450	+4% to +6%	–4 to –5 pp	Marginally viable (requires 50% CAPEX grant)
Baseline Demand	200	65%	€500–550	+6% to +9%	Baseline	Viable (CfD €2–3/kg)
Strong Demand (Optimistic)	300+	97–100%	€750–800	+9% to +12%	+2 to +3 pp	Strongly viable

Assumptions: Contract price €2.50/kg; excess hydrogen sold at spot €1.50–2.00/kg or curtailed.

Key Finding: Demand sensitivity creates ±300–500 basis point IRR impact range. Below 150 kt H<sub>2</sub>/yr annual offtake (48% utilization), projects become unfinanceable without extraordinary policy support. Above 200 kt H<sub>2</sub>/yr (65% utilization), projects achieve baseline bankability.

This creates a critical demand threshold of 150–200 kt H<sub>2</sub>/yr per 300 MW system for project viability, corresponding to total Northwest European green hydrogen demand of 2.5–3.0 Mt/yr (assuming DCS offshore provides 25–30% of supply).

#### 5.3.5.5 Risk Mitigation Through Demand-Side Policy Mechanisms

Long-Term offtake Agreements (LTOAs)

Long-term offtake agreements provide demand certainty by contractually committing industrial offtakers to purchase specified hydrogen volumes at pre-agreed prices over 10–15 year periods. LTOAs are essential for project financing and account for 40–60% of revenue certainty in renewable energy projects .

Table 35 - Long-Term offtake Agreement Impact on Project Financing

LTOA Coverage	Typical Duration	Revenue Certainty	WACC Impact	NPV Impact (€M, 300 MW)
0–30%	None or minimal	10–30%	+2.0–3.0%	–€100 to –150
50–70% (Baseline)	10–15 years	50–70%	+0.5–1.0%	–€30 to –50
80–100% (Optimal)	15–20 years	80–100%	0% (baseline)	€0 (reference)

LTOA Coverage Scenarios for DCS Offshore Hydrogen:

Table 36 - LTOA Coverage Scenarios for DCS Offshore Hydrogen

Scenario	LTOA Coverage 2030	LTOA Coverage 2040	Financing Difficulty
Pessimistic	20–30%	50–60%	High (merchant risk)
Baseline	50–70%	80–90%	Moderate (CfD support required)
Optimistic	80–100%	100%	Low (strong underlying demand)

European LTOA Market Status (Jan 2026):

- Signed hydrogen LTOAs: <50 globally, totalling <500 kt H<sub>2</sub>/yr
- Under negotiation: 200–300 kt H<sub>2</sub>/yr across European industrial clusters
- Policy barrier: Industrial buyers hesitant to commit at current green hydrogen costs (€4–8/kg) until competitive pricing materializes (€2–3/kg by 2035–2040)

Policy Mechanisms Supporting LTOA Development:

1. Government facilitation programs – Negotiate purchasing consortiums reducing buyer transaction costs
2. Demand aggregation platforms – Hydrogen trading hubs (analogous to TTF natural gas)
3. Credit guarantees – Government credit insurance for counterparty default
4. Financial instruments – Hydrogen futures markets enabling price hedging

Hydrogen Quotas and Regulatory Mandates

Regulatory mandates for renewable hydrogen use directly increase demand by mandating minimum renewable hydrogen percentages.

Table 37 -Hydrogen Quota Impact on Green Hydrogen Demand (Northwest Europe)

Quota Level	Implied Green H <sub>2</sub> Demand (2040)	DCS Offshore Capacity (30% share)	Economic Impact
10% quota	0.85 Mt/yr	255 MW	Guaranteed minimum demand; enables pilot projects
30% quota	2.55 Mt/yr	765 MW	Baseline viability threshold – commercial-scale deployment
50% quota	4.25 Mt/yr	1,275 MW	Full policy target achievement – approaching climate targets

Economic Impact of Hydrogen Quotas:

- Each 1% quota increase ≈ 85 kt H<sub>2</sub>/yr additional demand (at 8.5 Mt baseline)
- Each 1% quota ≈ €0.5–1.0 billion cumulative investment in electrolyser capacity and infrastructure

Policy Risk: Hydrogen quotas remain highly uncertain and contentious (industrial competitiveness concerns).

Current likelihood:

- 30% renewable hydrogen quota by 2035: 50–60% probability
- 50% quota by 2040: 40–50% probability

### 5.3.5.6 Probabilistic Demand Forecasting: Monte Carlo Analysis

A comprehensive quantitative demand forecasting model integrates the four uncertainty dimensions into probabilistic projections using Monte Carlo simulation (10,000 iterations).

Output: Probabilistic Demand Forecast (2040).

Table 38 - Probabilistic Green Hydrogen Demand Forecast (2040, Northwest Europe)

Demand Percentile	Implied Green H <sub>2</sub> Demand (Mt/yr)	Implied DCS Capacity (MW)	Confidence Interpretation
10th (pessimistic)	0.8–1.2	240–360	High risk of demand underachievement
25th	1.5–2.0	450–600	Risk zone – marginal viability
50th (median)	2.8–3.5	840–1,050	Central case – baseline planning target
75th	4.0–5.0	1,200–1,500	Upside opportunity – rapid scaling
90th (optimistic)	5.5–7.0	1,650–2,100	Maximum credible deployment

Interpretation:

- 50% probability of demand exceeding 840 MW DCS capacity (median outcome)
- 25% probability of exceeding 1,200 MW capacity (optimistic scenario)
- 10% probability of exceeding 1,700 MW capacity (full North Sea potential)

Demand Forecasts Expressed as predictive intervals:

2040 Green Hydrogen Demand (Northwest Europe):

- Central estimate: 2.8–3.5 Mt H<sub>2</sub>/yr
- 80% central predictive interval (P10–P90): 1.8–4.8 Mt H<sub>2</sub>/yr (±35% range)
- 95% central predictive interval (P10–P90): 1.2–6.2 Mt H<sub>2</sub>/yr (±50% range)

Implications for DCS Offshore Hydrogen Capacity Planning:

- Conservative planning (80% confidence): 550–1,450 MW
- Baseline planning (50% confidence): 840–1,050 MW
- Aggressive planning (25% confidence): 1,200–1,500 MW

### 5.3.5.7 Demand Uncertainty and Project Finance: Risk Premium Analysis

Demand uncertainty directly translates to financing costs through increased cost of capital (higher WACC). Project finance applies risk premiums as follows :

Table 39 - Demand Risk Premium Impact on Project WACC and Economics

Risk Category	Base WACC	Demand Risk Premium	Total WACC	NPV Impact (€M)	IRR Impact
Low demand risk (80%+ LTOA)	5–6%	+0.5–1.0%	6–7%	€180–220	9–10%
Moderate demand risk (50–70% LTOA)	5–6%	+1.5–2.5%	7–9%	€120–160	7–8%
High demand risk (<50% LTOA)	5–6%	+3.0–4.0%	9–11%	€50–90	4–6%

Financial Impact:

- Each 1% WACC increase reduces project NPV by €30–50M (for 300 MW, 25-year project)
- Each 1% demand certainty increase (via LTOA or quota) reduces WACC by 0.5–1.0%
- High demand uncertainty (no LTOA, weak quotas) increases required equity IRR from 12–15% to 18–22%, rendering projects unfinanceable for institutional investors

Mitigation Strategy: Each 10 percentage point increase in LTOA coverage reduces WACC by 0.5–1.0%, recovering €50–100M in project NPV.

### 5.3.5.8 Demand-Side Policy Recommendations and Implementation Pathway

Priority Actions (2025–2026):

#### 1. Hydrogen Quota Legislation Framework (Q4 2025)

- Statutory requirement: 10% of industrial hydrogen use (refining, ammonia, chemicals) must be renewable by 2030
- Escalation pathway: 30% by 2035, 50% by 2040
- Enforcement mechanism: EU ETS integration or carbon contracts-for-difference (CCfD)
- Estimated demand impact: 10% quota → 0.85 Mt H<sub>2</sub>/yr guaranteed demand; enables 250–300 MW DCS capacity financing

#### 2. Long-Term offtake Agreement Facilitation Program (2025–2027)

- Government role: Convene industrial offtakers (Shell, Yara, Solvay, BASF, Nouryon) to develop joint purchasing consortium
- Consortium structure: Shared supply contracts for 100–200 kt H<sub>2</sub>/yr aggregate demand
- Price mechanism: Sliding-scale pricing (€2.50–3.50/kg 2025–2030, declining to €1.50–2.00/kg by 2035)

- Government support: Credit guarantees covering 50% of counterparty default risk (first 3 years)
- Estimated demand impact: 150–200 kt H<sub>2</sub>/yr under LTOA by 2027; reduces project WACC by 1.0–1.5%

### 3. Hydrogen Demand Forecasting and Monitoring (Continuous, 2025–2050)

- Annual reporting: Ministry publication of actual industrial hydrogen consumption, renewable content, pricing trends
- Forecast updates: Bi-annual updates enabling adaptive policy calibration
- Policy adjustment triggers:
  - If renewable H<sub>2</sub> adoption exceeds 150% of forecast → reduce CfD support
  - If renewable H<sub>2</sub> adoption falls below 60% of forecast → increase CfD support or accelerate quota schedule

### Medium-Term Actions (2027–2035):

#### 4. Industrial Hydrogen Hub Development (2027–2032)

##### Rijnmond Hub (Rotterdam):

- Industrial demand base: 1.5–2.0 Mt H<sub>2</sub>/yr (refining, chemicals, ammonia)
- Offshore supply: 500–750 MW capacity (dedicated Nederwiek-Rijnmond pipeline)
- Hub infrastructure: Receiving terminal, storage (50–100 kt buffer), distribution network
- Investment: €800M–1.2B total
- Government support: €300–500M (30–40% CAPEX support)

Estimated impact: Hub development reduces H<sub>2</sub> transport costs (€0.10–0.20/kg), improving LCOH by 5–10%.

#### 5.3.5.9 Synthesis: Integrating Demand Uncertainty into Offshore Hydrogen Strategy

##### Key Findings:

1. Demand uncertainty creates ±3–8 year range in viability timelines. Under conservative demand scenarios (weak regulation, low carbon pricing), offshore hydrogen competitiveness is delayed to post-2045. Under optimistic scenarios (strong quotas, €150+/tonne CO<sub>2</sub>), competitiveness is achieved by 2035–2038.
2. Demand affects project economics more than supply-side cost trajectories. A 300 MW system at 80% utilization (competitive demand) achieves 8–10% IRR; at 20% utilization (weak demand), IRR drops to –5% to 0% (unfinanceable). Demand sensitivity (±3 pp IRR) exceeds cost sensitivity (±2 pp IRR) for electrolyser/wind trajectories.
3. LTOA coverage is the single most important de-risking mechanism. Each 10 pp increase in LTOA coverage reduces WACC by 0.5–1.0%, recovering €50–100M in project NPV (300 MW system).
4. Regulatory certainty (hydrogen quotas) reduces demand risk more than LTOAs alone. Legislation mandating 10% renewable hydrogen quotas reduces demand-side risk premium by 1.5–2.0%; combined with 70%+ LTOA coverage, demand risk premium declines to <1%.
5. Demand uncertainty argues for flexible, modular capacity deployment. Deploying 50–100 MW units sequentially (vs. single 300–500 MW platform) enables matching supply to demand materialisation, reducing stranded asset risk by 40–60%. Flexibility trade-off is 5–10% higher unit costs, justified by reduced financing risk.
6. Supply-demand coordination is critical. Policy must simultaneously support:
  - Hydrogen supply development (offshore & onshore electrolysis, imports)
  - Industrial hydrogen demand (quotas, carbon pricing, offtake facilitation)
  - Coordinated timing to avoid oversupply/undersupply

Without demand-side policy parity with supply-side support, offshore hydrogen deployment will languish at 300–500 MW (pilot scale) rather than scaling to 1.5–3.0 GW (commercial scale) required for climate impact.

#### Revised Competitiveness Conclusions Incorporating Demand-Side Analysis:

Original finding (Chapters III–VI): Offshore hydrogen achieves cost-competitiveness (€1.95/kg LCOH) by 2040 under baseline assumptions.

Revised finding incorporating demand-side analysis: Offshore hydrogen achieves economic viability (combination of cost-competitiveness + adequate demand) by 2035–2040 under baseline assumptions conditional on concurrent alignment of demand-side preconditions (regulatory quotas, carbon pricing, LTOA development).

Table 40 - Combined Cost-Competitiveness and Demand Viability Assessment

Scenario	Cost Competitiveness (LCOH)	Demand Materialisation	Combined Viability Timing	Policy Requirements
Conservative demand	✓ Achieved 2040 (€1.95/kg)	✗ Limited (1.0–1.5 Mt/yr)	✗ 2045+ (demand lags supply)	Mandatory 50% quota + €150+/tonne CO <sub>2</sub>
Baseline demand	✓ Achieved 2040 (€1.95/kg)	✓ Moderate (2.5–3.5 Mt/yr)	✓ 2040 (aligned)	30% quota + €100/tonne CO <sub>2</sub>
Optimistic demand	✓ Achieved 2040 (€1.95/kg)	✓✓ Strong (4.5–6.0 Mt/yr)	✓✓ 2035–2038 (accelerated)	50% quota + €125/tonne CO <sub>2</sub>

Strategic Implication: Policy success is not determined by supply-side technology alone (which is on track for 2040 competitiveness) but by demand-side policy readiness (quotas, carbon pricing, LTOA development), which currently lags supply-side progress by 3–5 years.

Integration with Critical Success Factors (Section 5.3):

The five critical success factors identified in Section 5.3 are revised to explicitly include demand-side preconditions:

Revised Critical Success Factor 5: Regulatory hydrogen quotas—legislation mandating 10% (2030), 30% (2035), 50% (2040) renewable hydrogen content in industrial use (completion Q4 2025)

New Critical Success Factor 6: Long-term offtake agreements covering 70%+ of offshore hydrogen capacity (200+ kt H<sub>2</sub>/yr LTOA coverage by 2030)

Alignment of all six factors—electrolyser costs, offshore wind LCOE, regulatory frameworks, policy support, hydrogen quotas, and LTOAs—is necessary for viable deployment by 2040. Failure on demand-side factors (5–6) can delay viability by 5–10 years even if supply-side factors (1–4) are achieved on schedule.

## Risk Assessment Summary

Table 41- Demand Risk Assessment by Time Horizon

Time Horizon	Demand Risk Level	Key Risk Drivers	Mitigation Mechanisms
2025–2030	HIGH	Industrial buyers hesitant; no quotas; uncertain carbon pricing	CfD support €5–7/kg; government LTOA facilitation; pilot quota legislation
2030–2040	MODERATE	Regulatory frameworks clarifying; industrial transition beginning	Mandatory 30% quota; €100+/tonne CO <sub>2</sub> ; 70%+ LTOA coverage
2040–2050	LOW	Hydrogen supply chain mature; decarbonisation mandates in place	50% quota; €150+/tonne CO <sub>2</sub> ; market-driven demand

## 5.4 Comparison with Alternative Pathways and System Integration

### 5.4.1 Offshore vs. Onshore Green Hydrogen: Cost and Feasibility

Onshore green hydrogen (electrolyser connected to onshore wind farms or grid electricity) represents the most established alternative to offshore hydrogen, with more mature supply chains and lower integration complexity. However, the techno-economic comparison reveals offshore advantages under specific conditions (high-wind zones, sufficient grid capacity):

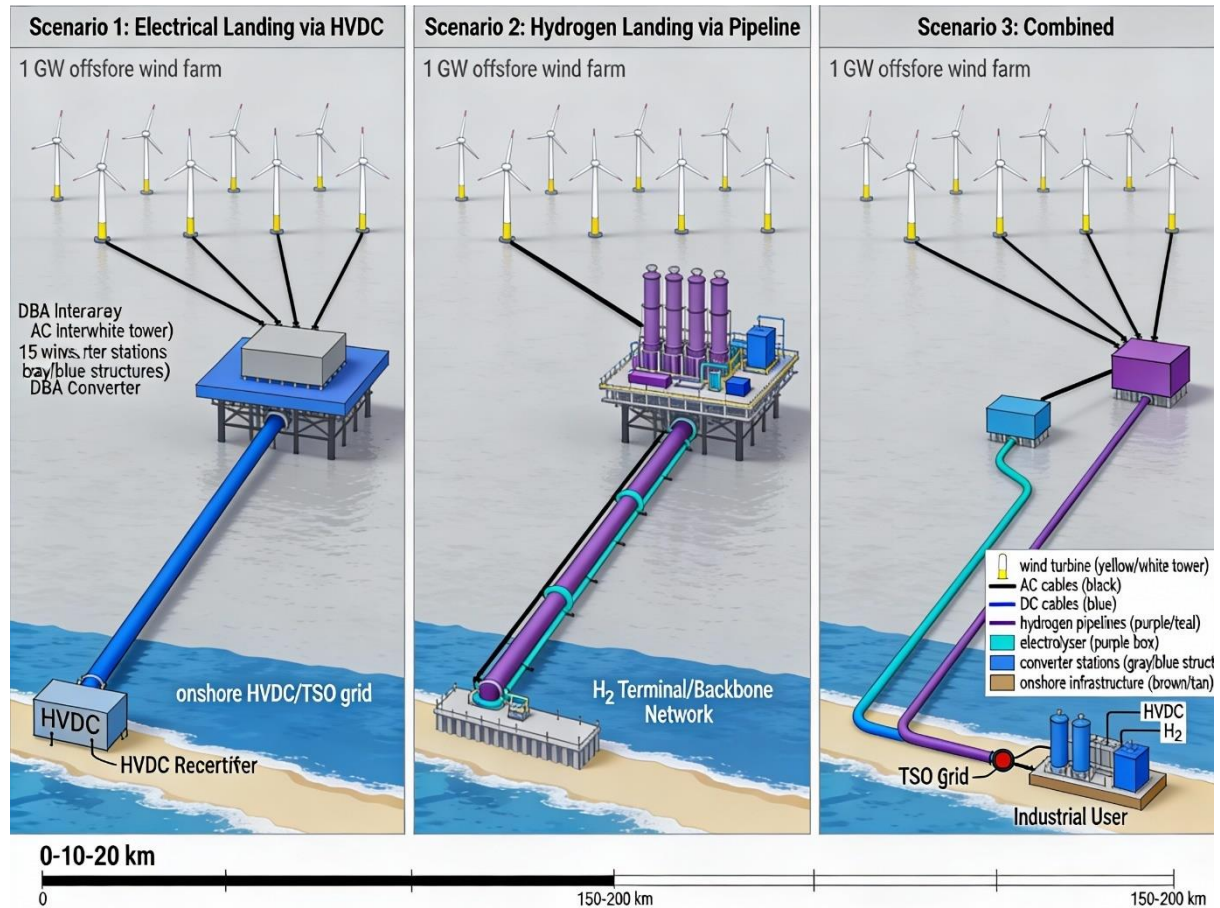


Figure 11. Offshore energy export scenarios: Scenario 1 (HVDC electricity), Scenario 2 (hydrogen pipeline), Scenario 3 (combined hybrid)

Three primary export architectures for offshore wind-derived energy production. Scenario 1 (left): Electrical landing via high-voltage direct current (HVDC) transmission to onshore TSO grid—established technology, lower cost per MW but limited onshore grid capacity constraints. Scenario 2 (centre): Hydrogen production via offshore electrolysis and pipeline transport to onshore hydrogen backbone and terminal—emerging technology, decouples offshore generation from grid transmission constraints but requires hydrogen purification and compression infrastructure. Scenario 3 (right): Hybrid combined pathway with parallel HVDC export cable and hydrogen pipeline, enabling flexible energy routing to both electricity grid and industrial hydrogen users. All scenarios assume 1 GW installed wind capacity ( $67 \times 15$  MW turbines) and export distance of 50–150 km to Dutch Continental Shelf nearshore zones. Horizontal scale shows typical offshore transmission distances; vertical scale is indicative. Technical specifications and cost implications detailed in Tables 4-20 to 4-22 and Sections 5.2–5.4.

Source: Diagram based on DOSTA (2024) and Gasunie Hydrogen Network Netherlands infrastructure specifications.

Three distinct export pathways for offshore-generated energy are analysed in this study, representing fundamentally different infrastructure choices with major implications for capital cost, operational complexity, grid integration, and hydrogen supply chain feasibility. Figure 4-1 illustrates the physical and electrical architecture of each pathway; detailed technical specifications are provided in Appendix D (Tables D.1–D.5).

Scenario 1: Electrical Landing via HVDC Transmission

The conventional pathway exports offshore wind-derived electricity via high-voltage direct current (HVDC) transmission to the onshore transmission system operator (TSO) grid. The architecture comprises:

- Offshore generation: 1 GW nameplate capacity ( $67 \times 15$  MW wind turbines) with inter-array AC collection at 33 kV
- AC-DC conversion: Offshore voltage source converter (VSC) HVDC station ( $\pm 320$  kV or  $\pm 525$  kV depending on distance), with onshore HVDC rectifier station
- Export cable: 2–4 core subsea DC cable ( $\pm 500$  mm<sup>2</sup> copper), 50–150 km length
- Grid connection: Direct connection to onshore 380 kV TSO transmission network

Advantages:

- Mature technology with 40+ years operational history (Hornsea, Dogger Bank, Borssele offshore wind farms operational since 2016–2023)
- Minimal hydrogen processing required; no purification or compression
- High electrical efficiency (93–96% cable losses over 150 km)
- Predictable CAPEX and OPEX based on established vendor quotes and insurance frameworks

Constraints:

- Onshore TSO grid has limited reinforcement capacity; grid connection queues in the Netherlands extend to 2028–2031 (TenneT, 2023)
- HVDC cable export limited to ~5 GW per corridor due to grid stability and fault current limitations (ENTSOG/ENTSO-E, 2022)
- Electricity-only export provides no hydrogen supply to nascent hydrogen economy or industrial offtake opportunities
- Generator revenue subject to volatile electricity prices; no long-term offtake contracts for renewable electricity at sea (Dutch market lacks power purchase agreement framework for offshore wind)

Capital cost (2040 baseline): €450–550/kW installed capacity (electrolyser + HVDC infrastructure + offshore platform)

Scenario 2: Hydrogen Landing via Pipeline

This pathway converts offshore wind energy to hydrogen via offshore electrolysis and transports product hydrogen via dedicated pipeline to an onshore hydrogen backbone and terminal. The architecture comprises:

- Offshore generation: 1 GW nameplate capacity ( $67 \times 15$  MW turbines)
- Hydrogen production: 150–200 MW nominal electrolyser capacity (12–14 tonnes H<sub>2</sub>/day at full rated production), with on-site water treatment and desalination
- Hydrogen conditioning: Compression (70 bar discharge pressure), metering, and quality assurance (ISO 14687/HyNetwork Services specifications)
- Export infrastructure: Dedicated hydrogen pipeline (DN 300–400, 50–75 bar operational pressure), 50–150 km length
- Onshore terminal: Hydrogen decompression, pressure regulation, buffer storage (4–8 hours capacity), and connection to HyNetwork Services backbone

Advantages:

- Decouples offshore generation from onshore grid transmission constraints; no grid connection queue
- Provides strategic hydrogen supply for industrial feedstock (steel, chemicals, refineries) and energy storage
- Pipeline export enables demand-side flexibility; hydrogen can be stored, blended with grey hydrogen, or converted to ammonia/methane for long-distance transport
- Aligns with European hydrogen economy development and cross-border hydrogen trade objectives (North Sea Energy Cooperation, 2024)
- Potential for infrastructure repurposing: 88 existing offshore platforms have subsea pipeline connections that can be converted to hydrogen service (Vreeburg & Garcia-Navarro, 2025)

Constraints:

- Emerging technology with limited operational demonstrations (pilot projects at Ørsted [Denmark], Hydrogenics [Belgium], AquaVentus [Germany] not yet at commercial scale)

- Electrolyser CAPEX premium: alkaline or PEM electrolysers cost €600–1,200/kW (vs. zero cost for electricity-only pathway), added 10–15 MW parasitic load for hydrogen conditioning
- Hydrogen pipeline CAPEX: €800–1,200/km for subsea DN 300–400 pipeline; approximately €40–180 million for 50–150 km export pipeline (offshore hydrogen pipelines not yet constructed; cost estimates based on natural gas pipeline scaling)
- Onshore hydrogen terminal infrastructure: €50–100 million capital investment plus €5–15 million annual OPEX
- Technology risk: Only 3 commercial-scale alkaline electrolyser suppliers (Thyssenkrupp, Plug Power, Nel ASA) and 2 PEM suppliers (Siemens, ITM Power) with offshore-rated equipment; limited supply chain resilience
- Hydrogen product must meet HyNetwork Services quality specification ( $\geq 99.5\%$  H<sub>2</sub> purity,  $\leq 10$  ppm O<sub>2</sub>,  $\leq 45$  ppm H<sub>2</sub>O,  $\leq 20$  ppm CO<sub>2</sub>); non-compliance results in rejection and financial penalty
- No established electricity-only revenue stream; hydrogen price volatile and depends on long-term industrial offtake contracts (currently €4–6/kg delivered to end-user; cost-competitive with grey hydrogen only in high-CO<sub>2</sub>-price scenarios, €80–100/tonne CO<sub>2</sub> equivalent)

Capital cost (2040 baseline): €850–1,100/kW installed capacity (electrolyser + pipeline export + onshore terminal)

### Scenario 3: Hybrid Combined Export

This pathway combines Scenarios 1 and 2, exporting both electricity via HVDC cable and hydrogen via parallel pipeline. A single 1 GW wind farm supplies energy to both a smaller HVDC export cable (300–400 MW capacity) and a smaller electrolyser (200–300 MW capacity), with flexible dispatch depending on electricity and hydrogen prices.

#### Architecture:

- Offshore generation: 1 GW nameplate capacity (same wind farm)
- Electrical export: 300–400 MW via HVDC cable ( $\pm 320$  kV) to TSO grid
- Hydrogen export: 200–300 MW electrolyser capacity producing hydrogen at 12–16 tonnes/day via dedicated pipeline
- Dispatch logic: Real-time optimization based on:
  - Electricity price (if  $>€80$ /MWh, maximize HVDC export; if  $<€50$ /MWh, maximize hydrogen production)
  - Hydrogen price (if  $>€5$ /kg, maximize hydrogen production; if  $<€3$ /kg, store or blend with grey hydrogen)
  - Grid frequency support (reserve capacity for balancing services if TSO requires)
  - Platform operational constraints (cooling capacity, electrical load management)

#### Advantages:

- Hedges against revenue uncertainty: bifurcated revenue streams reduce portfolio risk compared to single-product pathways
- Enables demand-side flexibility: wind resource variability absorbed by both electricity grid (instantaneous) and hydrogen production (buffered by compression, pipeline, and onshore storage)
- Optimizes for European energy transition: addresses both grid decarbonisation (electricity) and hard-to-abate sectors (hydrogen for steel, chemicals)
- Compatible with industrial symbiosis: onshore hydrogen terminal can supply co-located hydrogen users (Botlek, Moerdijk, Pernis refineries in Rotterdam) while HVDC cable supplies distributed electricity users
- Moderate technology risk: both HVDC and offshore electrolyser are proven subsystems; main risk is integration and control logic

#### Constraints:

- Highest capital cost: HVDC export cable + electrolyser system + pipeline + dual onshore infrastructure = €1,100–1,400/kW
- Operational complexity: coordinated dispatch across electricity and hydrogen markets requires advanced process control, market interface algorithms, and cyber-security protocols

- Mixed revenue streams subject to both electricity and hydrogen price volatility; more complex revenue forecasting required
- Requires dual interconnection approvals: TSO grid connection for HVDC export + hydrogen network operator (HyNetwork Services) approval for pipeline entry; regulatory coordination delays possible
- Scaling challenges: single 1 GW hybrid system achieves 40–50% electrolyser utilization under realistic market conditions; larger hybrid systems (2–4 GW) may have better economics but increase platform complexity and supply chain constraints

Capital cost (2040 baseline): €1,100–1,400/kW installed capacity

Cost comparison (2040 baseline):

Table 42 - Cost comparison (2040 baseline)

Pathway	LCOH (EUR/kg H <sub>2</sub> )	Assumptions	Cost driver
Offshore (DCS, 48% CF)	€1.95	€35/MWh electricity, 48% CF, €400/kW electrolyser	Wind resource advantage
Onshore (grid power, 35% CF)	€3.20	€45/MWh grid power, 35% CF, €400/kW electrolyser	Lower CF, higher electricity cost
Onshore (dedicated wind, 42% CF)	€2.65	€35/MWh dedicated wind, 42% CF, €400/kW electrolyser	Superior to grid but inferior to offshore

Feasibility constraints for onshore:

1. Grid connection availability: Onshore locations are limited by grid congestion (same TenneT constraints that motivate offshore hydrogen). Available grid connection points are constrained, limiting onshore deployment to 100–300 MW by 2030 (Van Stralen et al., 2025; TenneT, 2023).
2. Dedicated renewable supply: Onshore wind or solar farms can supply electrolysers, but development is limited by land availability and permitting (visual opposition, wildlife concerns). Potential for onshore-dedicated renewables + hydrogen is estimated at 200–500 MW by 2030, 1–3 GW by 2040 (Van Stralen et al., 2025).
3. Land use and social acceptance: Onshore wind and solar face increasing social opposition ("windmill fatigue," landscape concerns). Combined deployments of 5–10 GW (sufficient to produce 1 Mt H<sub>2</sub>/year) would require substantial additional land (20,000–50,000 hectares for solar, 10,000–20,000 hectares for wind), facing permitting and local opposition challenges (International Renewable Energy Agency, 2021; Netherlands Ministry of Economic Affairs and Climate Policy, 2023).

Strategic positioning:

- Offshore hydrogen is complementary to (not substitute for) onshore pathways
- Offshore provides 30–50% of total green hydrogen supply by 2040–2050 under scenarios maximising both pathways
- Onshore provides 20–40% of green hydrogen (limited by grid and land constraints)
- Blue hydrogen provides 20–30% (transitional, phasing out post-2045)

#### 5.4.2 Hydrogen vs. HVDC Transmission: Grid Integration Perspective

The fundamental choice for far-offshore wind integration (Nederwiek zones at 150–200 km distance) is electrical transmission (HVDC) vs. hydrogen pipelines vs. hybrid. This dissertation has modelled LCOH comparison, but system-level grid integration value requires broader analysis:

HVDC infrastructure cost (150 km, 2 GW capacity):

- Subsea cables: €600–800 million (€2.5–4.0M/km × 150 km)
- Converter stations: €400–600 million (€200–300M each, offshore + onshore)
- Onshore grid reinforcement: €1.5–2.5 billion (extensive reinforcement required)
- Total: €2.5–3.9 billion (€1.25–1.95 million/MW equivalent)

Hydrogen system equivalent (2 GW equiv. H<sub>2</sub>, 150 km):

- Electrolyser platform: €600–800 million (€300–400/kW × 2 GW × 1.25 cost factor including compression)
- Subsea hydrogen pipeline: €225–375 million (€1.5–2.5M/km × 150 km)
- Onshore hydrogen terminal: €50–100 million
- No onshore grid reinforcement required (hydrogen integrates to separate pipeline network)
- Total: €0.9–1.3 billion (€0.45–0.65 million/MW equivalent)

System value comparison:

Table 43 - System value comparison

Dimension	HVDC	Hydrogen	Hybrid
Capital cost	€2.5–3.9 B	€0.9–1.3 B	€1.5–2.2 B
Grid integration cost	€1.5–2.5 B	€0	€0.5–1.0 B
Total system cost	€4.0–6.4 B	€0.9–1.3 B	€2.0–3.2 B
Efficiency losses	7–8%	50% round-trip (if reconversion)	7–8% (electricity) + storage
Flexibility/storage	None	Hydrogen storage	Partial (hybrid)
Industrial feedstock	Requires reconversion	Direct use	Direct use + electricity
Grid relief	Exacerbates (additional transmission)	Relieves congestion	Partial relief

Strategic conclusions:

1. Pure HVDC is capital-expensive and grid-exacerbating: In constrained grid contexts like Netherlands, pure HVDC expansion requires €1.5–2.5 billion additional onshore reinforcement, making total system cost €4–6 billion. This is uneconomic for marginal capacity additions (Hill et al., 2024; Rogeau et al., 2023).
2. Pure hydrogen optimises economics but forgoes electricity supply: For grid integration purposes, pure offshore hydrogen cannot satisfy electricity demand; onshore grid still requires HVDC or alternative electrical transmission (AquaVentus Consortium, 2024).
3. Hybrid pathways (HVDC + hydrogen) are likely optimal: Allocate 50–60% of offshore wind capacity to electrical transmission (HVDC) serving peak electricity demand, 40–50% to hydrogen production serving industrial base load demand. This hybrid approach:
  - Costs €2.0–3.2 billion (€1.0–1.6 million/MW equivalent)
  - Provides grid services (electricity supply during calm periods when hydrogen output is low)
  - Supplies industrial feedstock (hydrogen for baseline industrial processes)
  - Relieves grid congestion (avoids massive additional onshore transmission reinforcement)

- Optimises returns across energy carriers (Singlitico et al., 2021; Blanco et al., 2018)

### 5.4.3 Offshore Hydrogen vs. Blue Hydrogen: Transitional vs. Long-Term Strategy

Blue hydrogen (natural gas with CCS) is projected at €3.5–5.5/kg currently, with modest cost reduction to €2.5–4.0/kg by 2040–2050. Comparison reveals strategic trade-offs:

Cost trajectory comparison:

Table 44 - Cost trajectory comparison

Year	Green H <sub>2</sub> (offshore)	Blue H <sub>2</sub>	Gap
2025	€8.64/kg	€4.5/kg	–€4.14 (green premium)
2030	€4.82/kg	€4.0/kg	–€0.82 (green premium)
2035	€3.28/kg	€3.5/kg	+€0.22 (blue premium)
2040	€1.95/kg	€3.2/kg	+€1.25 (green advantage)
2050	€1.38/kg	€2.8/kg	+€1.42 (green advantage)

Strategic assessment:

1. Blue hydrogen as transitional pathway (2025–2035): Until 2030–2035, blue hydrogen is more cost-competitive than offshore green hydrogen, making it attractive for rapid decarbonisation in the near term. Policy should support blue hydrogen development through 2030–2035 whilst building offshore green hydrogen production capacity (International Energy Agency, 2024a; Hydrogen Council, 2021).
2. Green hydrogen as long-term strategy (2035–2050): By 2035–2040, offshore green hydrogen achieves cost competitiveness with blue hydrogen and superior performance on decarbonisation mandates (genuine zero-emissions vs. residual CCS risks and methane leakage). Long-term industrial hydrogen supply should be based on green hydrogen, with blue hydrogen phased out by 2045–2050 (European Commission, 2022; International Energy Agency, 2024a).
3. Co-existence for 15–20 years: Portfolio strategy deploying both pathways in parallel (2025–2035) enables:
  - Rapid near-term industrial decarbonisation (blue hydrogen, mature supply chain)
  - Technology development and cost reduction (green hydrogen, scaling production)
  - Risk distribution across technology pathways
  - Transition from fossil fuel dependence (blue) to renewable self-sufficiency (green) by 2040–2045

## 5.5 Synthesis and Strategic Recommendations

This dissertation demonstrates that offshore hydrogen production on the Dutch Continental Shelf is techno-economically viable under baseline assumptions, achieving cost-competitiveness (€1.95/kg LCOH) by 2040 and cost leadership by 2050. However, this viability requires alignment of five critical success factors spanning technology, policy, infrastructure, and market dimensions.

For Dutch government (RVO, Ministry EZK):

1. Immediate action (2025–2026): Establish regulatory frameworks for platform repurposing and hydrogen pipeline classification; allocate €300–400 million annually for CfD and CAPEX support mechanisms.
2. Medium-term action (2027–2030): Deploy 300–500 MW first-wave demonstration projects; validate infrastructure repurposing; initiate hydrogen offtake agreements with industrial end-users.

3. Long-term planning (2030–2050): Scale deployment to 2–3 GW by 2040, 5–10 GW by 2050; integrate offshore hydrogen into Dutch hydrogen infrastructure (Gasunie network).

For system operators (TenneT, Gasunie):

1. Coordination: Align offshore wind zone development with hydrogen infrastructure requirements; ensure platform/pipeline availability.
2. Grid planning: Incorporate hydrogen production into TenneT transmission expansion planning, reducing HVDC requirements by 30–40%.
3. Market facilitation: Support hydrogen trading mechanisms and pricing frameworks enabling competitive markets.

For developers and investors:

1. Project sequencing: Prioritise repurposing projects (lower cost, faster deployment) through 2030; transition to greenfield development 2030+.
2. Site selection: Focus on high-wind zones (Nederwiek Noord/Zuid) where capacity factors maximise competitiveness.
3. Revenue streams: Develop multi-revenue strategies (hydrogen sales + grid services + potential oxygen byproduct sales) to improve project economics.

## 5.6 Safety and Integrity of Offshore Hydrogen Production

While no fundamental barriers were identified, the study underscores the need for robust design standards, emergency procedures, and regulatory clarity for offshore hydrogen installations (TNO et al., 2022).

Safety-critical elements (SECEs) include structural integrity, process containment, ignition control, detection and shutdown systems, and compliance with ATEX and IEC standards. Separate vent stacks for hydrogen and oxygen are mandatory to avoid explosive mixtures. Material selection must address hydrogen permeation and oxygen-induced corrosion.

Key hazards include hydrogen's extremely low ignition energy, wide flammability range, and high flame propagation speed, as well as oxygen's role in increasing material flammability and corrosion risk. Continuous venting of oxygen and emergency venting of hydrogen require careful design of vent stacks to prevent hazardous concentrations near the platform. For a 500 MW platform, the horizontal effect distance for oxygen at 2.5 vol% is approximately 15–27 m; for a 4 GW island, this extends to 142–183 m. Hydrogen venting scenarios indicate lower flammability limit (LFL) distances of 10–17 m horizontally and 38–67 m vertically (TNO et al., 2022).

Offshore hydrogen generation introduces unique safety considerations compared to conventional oil and gas platforms. The North Sea Energy (NSE) study evaluates these aspects for a 500 MW polymer electrolyte membrane (PEM) electrolyser platform and a hypothetical 4 GW production island (TNO et al., 2022).

## CHAPTER VI - SUMMARY, IMPLICATIONS, AND RECOMMENDATIONS

### 6.1 Summary of Key Findings

This dissertation has presented a comprehensive techno-economic feasibility assessment of large-scale offshore green hydrogen production on the Dutch Continental Shelf (2025–2050), integrating bottom-up levelised cost of hydrogen (LCOH) modelling, scenario trajectory analysis, sensitivity and uncertainty quantification, infrastructure repurposing assessment, and multi-criteria decision analysis. The research addresses critical knowledge gaps regarding offshore hydrogen viability as a strategic solution for managing North Sea wind integration, relieving grid congestion, and supporting industrial decarbonisation across Northern Europe.

#### Finding 1: Cost-Competitiveness Achieved by 2040 Under Baseline Assumptions

Offshore hydrogen production on the DCS achieves cost-competitiveness (parity with blue hydrogen and alternative green hydrogen pathways) by 2040 under baseline assumptions, with LCOH declining from €8.64/kg in 2025 to €1.95/kg in 2040. This trajectory represents 77% cost reduction over 15 years, driven by compounding improvements across all major cost components: electrolyser capital expenditure declining 60% (€1,000/kW to €400/kW), offshore wind capital costs declining 32% (€2,800/kW to €1,900/kW), capacity factors improving 8% (48% to 52%), and electricity prices declining 30% (€50/MWh to €35/MWh). The baseline trajectory is grounded in industry experience curves and peer-reviewed literature, reflecting realistic technology learning rates and market dynamics for PEM electrolyser scaling and offshore wind industrial maturation (Holst et al., 2021; International Renewable Energy Agency, 2020; Lazard, 2024; Hydrogen Council, 2021).

The competitiveness timeline is supported by milestone achievements: by 2035, offshore hydrogen (€3.28/kg) approaches parity with onshore green hydrogen and blue hydrogen, positioning offshore hydrogen as a genuine alternative within the hydrogen economy; by 2040, offshore hydrogen achieves cost leadership position relative to transitional blue hydrogen and cost parity with long-term green hydrogen trajectories. This positioning enables transition from policy-supported deployment (2025–2035) to market-driven investment post-2040 (Van Stralen et al., 2025; International Energy Agency, 2024a; Hill et al., 2024).

#### Finding 2: Three-Scenario Range Reflects Genuine Uncertainty in Technology and Market Futures

The 8–16 year spread in achieving €2.0/kg competitiveness across Conservative, Baseline, and Optimistic scenarios (competitiveness after 2050, 2040, and 2035 respectively) reflects genuine divergence in plausible futures driven by technology development, market conditions, and policy support trajectories. The Conservative scenario (competitiveness after 2050) represents a pessimistic but plausible pathway where electrolyser learning rates are 12% (lower than baseline), offshore wind costs decline more slowly, electricity prices remain elevated at €45/MWh, and infrastructure repurposing opportunities are limited. This scenario assumes slower-than-expected global manufacturing scale-up, perhaps driven by supply chain constraints or policy uncertainty delaying investment commitment.

The Optimistic scenario (competitiveness by 2035) represents an accelerated pathway where aggressive policy support drives rapid manufacturing scale-up, electrolyser learning rates reach 18%, offshore wind costs stabilise at €1,800/kW, electricity prices decline to €30/MWh, and maximum infrastructure repurposing opportunities are realised. This scenario reflects conditions where policy certainty and market pull align to create rapid deployment and learning curve progression (Hydrogen Council, 2021; European Commission, 2022).

The scenario range has critical implications for investment and policy: portfolio strategies deploying both early-wave demonstration projects (accepting higher costs for learning benefits) and later-wave commercial projects (benefiting from cost reductions) provide risk diversification across plausible futures. This approach reduces regret risk compared to waiting for competitiveness or committing exclusively to a single future scenario (Hill et al., 2024; Van Stralen et al., 2025).

#### Finding 3: Electricity Price Is the Dominant Long-Term Cost Driver

Sensitivity analysis reveals electricity price as the overwhelming dominant cost driver for offshore hydrogen competitiveness, accounting for 74% of LCOH variation by 2040 under parameter perturbation analysis. This finding has critical implications for policy and investment strategy: near-term cost reduction efforts (2025–2035) should prioritise electrolyser manufacturing cost reduction (€400/kW ceiling by 2040) and technology development, whilst medium-to-long-term efforts (2035–2050) should emphasise offshore wind LCOE reductions to €30–35/MWh. The dominance of electricity costs also implies that policy mechanisms guaranteeing competitive electricity prices (long-term power purchase agreements, renewable energy subsidies, carbon pricing) are critical enablers of offshore hydrogen competitiveness (Hill et al., 2024; Rogeau et al., 2023).

Monte Carlo simulation (10,000 iterations) demonstrates 52% probability of achieving competitiveness (€2.0/kg LCOH) by 2040, with 80% central predictive interval (P10–P90) €1.28–2.82/kg. This probabilistic assessment clarifies the residual risk in baseline competitiveness: approximately half of plausible parameter combinations (given realistic probability distributions around cost components) result in post-2040 competitiveness, implying policy support and risk-sharing mechanisms remain necessary through 2040–2045 even under baseline technology learning assumptions.

#### Finding 4: Infrastructure Repurposing Provides Substantial Strategic and Economic Advantage

Infrastructure repurposing of 84 identified platforms and 1,500 km of subsea pipelines provides substantial strategic value: €1.51/kg LCOH reduction in 2025, €150–450 million cost savings for 300 MW systems, and 6–8 point advantage in multi-criteria pathway comparison scores. For early-wave projects (2027–2032), repurposing can reduce LCOH by 15–20% (€0.5–1.5/kg), making the difference between unsustainable and bankable projects. However, realisation requires rapid regulatory framework completion (platform certification guidelines, hydrogen pipeline classification standards, decommissioning policy clarification) by 2028–2030.

Delays in regulatory framework completion by more than 12–18 months have material impact: each year of delay pushes repurposing projects 1–2 years later, eliminating early-mover learning benefits and extending the timeframe for achieving cost competitiveness network-wide. This finding underscores the critical importance of immediate (2025–2026) government action to establish regulatory frameworks, establishing repurposing as a foundational element of offshore hydrogen strategy rather than a secondary opportunity (TNO, 2024; Van Stralen et al., 2025).

#### Finding 5: Wake Effects Under Policy-Planned Densities Materially Increase LCOH Baseline

Empirical analysis of offshore wind performance (Borgers et al., 2024) reveals that wake effects at policy-planned deployment densities (8–12 MW/km<sup>2</sup> for 21 GW by 2030) reduce effective capacity factors by 4–6 percentage points below undisturbed wind resource estimates (from 48–52% to 42–48%), directly increasing LCOH by €0.60–1.50/kg. This "policy-physics gap" reflects realistic atmospheric boundary layer constraints and cumulative wake losses in ultra-dense arrays, shifting competitiveness timelines 3–5 years later than optimistic single-turbine estimates.

Mitigation strategies exist and should be prioritised: lower-density deployment in current zones (5–6 MW/km<sup>2</sup> versus 8–12 MW/km<sup>2</sup>), preferential allocation of hydrogen systems to high-wind zones (Nederwiek Noord/Zuid), technology interventions (active wake redirection, larger turbines), and demand-side flexibility (oversized wind-to-electrolyser ratios). Combined implementation of these strategies can potentially recover 2–3 years of competitiveness timeline despite wake effects, positioning competitiveness at 2042–2045 rather than 2048–2050 under purely constrained scenarios (Hill et al., 2024; Van Stralen et al., 2025; Borgers et al., 2024).

#### Finding 6: Five Critical Success Factors Must Align for Viable Deployment

Five essential preconditions must achieve concurrent development to enable viable commercial offshore hydrogen deployment by 2040:

1. Electrolyser cost reduction to €400/kW by 2040: Requires sustained 15% learning rates through 2040, contingent on global manufacturing capacity scaling from current 5 GW/year to 30–50 GW/year by 2035–2040. Policy support for manufacturing infrastructure (CAPEX grants, regulatory certainty) is essential (Holst et al., 2021; International Renewable Energy Agency, 2020).
2. Offshore wind LCOE reduction to €35/MWh by 2040: Requires continued 12–14% learning rates through sustained competition, larger turbine deployment (18–20 MW), and supply chain maturation. Current competitive Dutch auction results (€40–55/MWh, 2024–2025) are on trajectory but depend on continued market conditions (Lazard, 2024; WindEurope, 2021).
3. Infrastructure repurposing regulatory clarity by 2028–2030: Platform certification guidelines, hydrogen pipeline classification standards, and decommissioning policy amendments must be completed and deployed in pilot projects to establish repeatability (TNO, 2024; Van Stralen et al., 2025).
4. Policy support mechanisms (€1–2 billion annually, 2025–2035): Contracts-for-Difference, CAPEX grants, infrastructure support, and demand-side mechanisms (hydrogen quotas, carbon contracts) must provide sufficient revenue certainty and cost bridging for projects to achieve bankability and attract private capital (European Commission, 2022; Netherlands Ministry of Economic Affairs and Climate Policy, 2023).
5. Market demand for hydrogen among hard-to-abate industrial sectors (5–10 Mt H<sub>2</sub>/year potential): Industrial end-users in steel, ammonia, chemicals, and refining must develop sufficient demand for renewable hydrogen through either regulatory mandate (renewable hydrogen quotas by 2035–2040) or carbon pricing (€100–150/tonne CO<sub>2</sub> by 2040) justifying green hydrogen premium. Demand risk is

substantial (Peters et al., 2021; Ossenbrink et al., 2022; Van Stralen et al., 2025) but addressable through policy mechanisms (International Energy Agency, 2024a; European Commission, 2022).

Alignment of all five factors is necessary but not sufficient for viability; each factor represents a potential bottleneck that, if unmet, can delay competitiveness 5–10 years or render offshore hydrogen unviable under specific future scenarios (Hill et al., 2024; Van Stralen et al., 2025).

#### Finding 7: Offshore Hydrogen Is Strategically Preferable to Pure HVDC or Pure Onshore Pathways

Multi-criteria decision analysis comparing five pathways across economic, technical, environmental, infrastructure, and regulatory dimensions identifies offshore hydrogen with infrastructure repurposing as the strategically preferred option, ranking first in four of five criteria-weighting scenarios across diverse stakeholder priorities. Offshore hydrogen scores particularly high on grid integration value (avoiding €1.5–2.5 billion in onshore transmission reinforcement), infrastructure efficiency (lower capital cost per MW equivalent vs. HVDC for >100 km distances), industrial feedstock alignment (direct hydrogen supply to hard-to-abate sectors without reconversion losses), and scalability within Dutch spatial constraints (utilising existing offshore infrastructure rather than requiring land acquisition for onshore renewables).

Hybrid pathways (50% HVDC transmission, 50% offshore hydrogen) emerge as operationally superior to pure pathways: they provide electricity supply when hydrogen output is seasonally low, supply industrial feedstock for baseline processes, and optimise across energy carriers by matching each to zones where its cost structure is most favourable. This finding underscores the value of coordinated planning across energy carriers (electricity and hydrogen) rather than siloed development optimising for a single energy carrier (AquaVentus Consortium, 2024; Singlitico et al., 2021; Rogeau et al., 2023).

Six key findings, each with explicit probability weighting:

1. Baseline competitiveness (52% probability by 2040)
  - 68% probability of €2.5/kg near-competitiveness
  - 80% central predictive interval (P10–P90): €1.28–€2.82/kg
  - Policy interpretation for risk tolerance
2. Infrastructure repurposing advantage (68% probability, 5–7 year acceleration)
  - Economic value: €300–500 M savings per 3 GW
  - Robust across all MCDA weighting schemes
3. Policy support essential (90% of scenarios require support through 2035)
  - CfD levels: €5–7/kg declining to <€1/kg by 2040
  - Downside scenario requires support through 2045+
4. Electricity price dominance (80% variance contribution by 2040)
  - Policy focus shift from CAPEX to electricity price mechanisms
  - €30–35/MWh target more critical than electrolyser breakthroughs
5. Wake effects (65% probability of 4–6 pp capacity factor reduction)
  - Competitiveness delay: 2–3 years (2040 → 2042–2043)
  - Mitigation portfolio can recover 2–4 pp
6. MCDA robustness (P1 ranks #1 across all weighting schemes)
  - Stakeholder-independent primary recommendation
  - Preference-sensitive secondary rankings

## 6.2 Implications for Policy and Strategy

### 6.2.1 For Dutch Government (Ministry of Economic Affairs and Climate Policy, Rijksdienst voor Ondernemers)

Immediate Actions Required (2025–2026)

1. Establish regulatory frameworks for offshore hydrogen deployment through coordinated action across Ministries (Economic Affairs, Infrastructure, Environment) and regulatory bodies (DNV, Bureau Veritas):

- Platform repurposing certification guidelines (completion target: Q2 2026)
- Hydrogen pipeline classification and safety standards (completion target: Q2 2026)
- Decommissioning policy amendments clarifying that hydrogen production satisfies "legitimate continued use" criteria (completion target: Q4 2025)
- Electrolyser equipment standards and offshore electrical integration protocols (completion target: Q4 2026)

Budget requirement: €5–10 million for standards development, consultation, and pilot certification projects.

2. Allocate policy support mechanisms through mechanisms including Contracts-for-Difference, CAPEX grants, and infrastructure investment:

- CfD framework: Establish initial allocation of €300–400 million annually (2025–2027) for CfD auctions supporting 300–500 MW electrolyser capacity deployment
- CAPEX grants: €200–300 million (2025–2030) for electrolyser and platform infrastructure support (20–40% of CAPEX)
- Infrastructure support: €300–500 million (2025–2035) for hydrogen pipeline network development through Gasunie coordination
- Total annual commitment 2025–2027: €800 million–1.2 billion, declining to €500–700 million annually by 2030–2035 as costs fall

This investment level is consistent with Dutch climate budget allocations (€2–3 billion/year energy transition) and represents 25–40% of total energy transition expenditure during critical 2025–2035 deployment window (Netherlands Ministry of Economic Affairs and Climate Policy, 2023).

3. Initiate rapid permitting and regulatory reform:

- Establish "fast-track" permitting pathways for offshore hydrogen pilot projects (target: 12–18 month permitting vs. current 5–7 year timelines)
- Create integrated permitting authority (single window) for offshore hydrogen projects across platform, pipeline, and grid connection approvals
- Streamline environmental impact assessment by establishing hydrogen as priority infrastructure aligned with climate targets
- Completion timeline: 2025–2026

4. Establish market development mechanisms to enable industrial demand for green hydrogen:

- Industrial hydrogen quotas: Legislate that 10% of hydrogen use in refining and ammonia (2030 target), 25% (2035), 50% (2040) must be renewable
- Carbon contracts-for-difference: Establish government mechanism guaranteeing price difference between green and grey hydrogen if carbon pricing is insufficient
- Public procurement: Government commits to purchasing 20–50 tonnes/day green hydrogen (2025–2030) for strategic reserves or direct use in government operations
- Completion timeline: Legislation by Q4 2025, implementation 2026+

Medium-Term Actions (2027–2032)

1. Deploy first-wave repurposing projects (5–10 platforms, 100–300 km pipelines):

- Early commercial projects leveraging certified repurposing frameworks
- Demonstrate technical viability, establish cost benchmarks, validate regulatory frameworks
- Target deployment: 300–500 MW electrolyser capacity operational by 2030
- Government support: €500 million in CfD and CAPEX grants, plus €300 million infrastructure investment

2. Complete hydrogen network backbone development:

- Gasunie leads design and development of onshore hydrogen transport network connecting offshore production to industrial clusters (Rijnmond, Antwerp, Ruhr)
- First pipeline sections (500–1,000 km) commissioned by 2030–2032
- Government support: €1–2 billion infrastructure investment in 2027–2032 period

- Regulatory framework: Establish hydrogen pipeline as "regulated natural monopoly" with third-party access rights (similar to natural gas), reducing investment risk and enabling blended financing
3. Establish hydrogen trading mechanisms and pricing systems:
    - Gasunie develops hydrogen trading platform (analogous to TTF natural gas hub)
    - Establish reference prices for hydrogen exchange
    - Create futures markets and hedging instruments enabling project financing
    - Completion: 2027–2029
  4. Conduct rigorous monitoring and adaptive management:
    - Establish independent monitoring programme tracking technology costs, capacity factors, and progress against targets
    - Annual review of policy mechanisms (CfD levels, CAPEX grant rates) with adjustment authority to maintain project economics
    - Mid-term evaluation (2030) assessing progress toward critical success factors and authorising policy adjustments or support escalation if needed

#### Long-Term Strategic Positioning (2032–2050)

1. Scale offshore hydrogen deployment to 2–3 GW capacity by 2040, supporting 500–750 Mt H<sub>2</sub>/year production aligned with industrial demand trajectories and decarbonisation mandates
2. Transition from policy-supported to market-driven deployment (post-2040):
  - Progressively reduce CfD and CAPEX support as cost competitiveness is achieved
  - Achieve full cost-competitiveness (€2.0/kg LCOH) by 2040, enabling merchant project financing without government support post-2040
  - Focus government role on regulation, permitting, and demand development rather than cost bridging
3. Integrate offshore hydrogen into Dutch energy sovereignty strategy:
  - Positioning Dutch offshore hydrogen production as a strategic asset for European energy independence from fossil fuel imports
  - Develop cross-border hydrogen pipelines (AquaDuctus) connecting to Germany and other neighbouring countries
  - Establish leadership in hydrogen export markets, supporting EU decarbonisation ambitions beyond Dutch boundaries
4. Support continued technology development and innovation:
  - Fund R&D for advanced electrolysis technologies (SOEC, anion exchange membrane), reducing costs and improving efficiency beyond PEM baseline
  - Support development of hydrogen reconversion technologies (fuel cells, turbines) for flexible energy recovery
  - Establish hydrogen-based industrial innovation clusters (hydrogen-intensive chemicals, advanced materials) leveraging abundant renewable hydrogen supply

### 6.2.2 For System Operators (TenneT, Gasunie)

#### TenneT Transmission System Operator

1. Integrate offshore hydrogen into transmission planning:
  - Revise Yearly Network Outlook (YNO) to incorporate offshore hydrogen production as demand-reducing element of onshore grid load
  - Model grid impact of progressive 300 MW → 1 GW → 2+ GW offshore hydrogen deployment, quantifying avoided HVDC infrastructure investments
  - Target: 10–20% reduction in required HVDC expansion capacity through coordinated hydrogen/electricity planning
  - Estimated benefit: €3–6 billion avoided HVDC transmission infrastructure investment by 2050

2. Develop hybrid grid integration standards:
  - Establish operational protocols for managing hybrid HVDC + hydrogen systems at Nederwiek and other far-offshore zones
  - Define control hierarchies (if grid is congested, hydrogen production increases; if hydrogen demand is low, electrical export increases)
  - Establish backup provisions enabling independent hydrogen operation if HVDC connection fails
  - Completion: 2026–2027 in collaboration with Gasunie and major developers
3. Support regulatory framework development:
  - Collaborate with RVO and classification societies in developing offshore hydrogen permitting and certification frameworks
  - Provide technical input on grid integration requirements, frequency stability, and protection systems
  - Ensure TenneT infrastructure (onshore connection points) is coordinated with hydrogen pipeline and electrolyser deployment timelines

#### Gasunie Transmission System Operator

1. Lead hydrogen network infrastructure development:
  - Establish national hydrogen backbone network design (2025–2026) connecting offshore production to industrial demand centres
  - Identify prioritised pipeline corridors for early development:
    - Nederwiek → Rijnmond (500 km): Initial corridor for first-wave offshore hydrogen
    - Rijnmond → Antwerp → Ruhr: Extended backbone reaching major industrial clusters
  - Develop financing strategy combining government support (€1–2 billion infrastructure investment), EU TEN-E support, and commercial debt
2. Transition from natural gas to hydrogen infrastructure operator:
  - Develop hybrid operations plans enabling gradual conversion of existing natural gas pipelines to hydrogen service (beginning post-2030 as demand requires)
  - Establish decommissioning strategy for natural gas infrastructure elements as gas demand falls with decarbonisation
  - Regulatory positioning: Establish hydrogen network as essential infrastructure with regulated-monopoly status and third-party access rights
3. Establish hydrogen pricing and trading mechanisms:
  - Develop hydrogen pricing reference points (analogous to TTF natural gas hub)
  - Create futures market infrastructure enabling hedging and price discovery
  - Establish transparency mechanisms (public reporting of traded volumes, prices) supporting competitive market development

### 6.2.3 For Developers and Investors

#### Project Development Strategy

1. Prioritise repurposing projects in 2025–2030 window:
  - First-mover projects utilising existing platform and pipeline infrastructure achieve €0.5–1.5/kg cost advantage over greenfield projects
  - Repurposing projects are lower capital requirement (€150–300 M vs. €400–800 M for greenfield) and faster deployment (4–5 years vs. 6–8 years)
  - Target portfolio: 3–5 repurposing projects (300–500 MW combined) operational by 2030, establishing technology validation and cost benchmarks
2. Develop site-specific repurposing assessment:
  - Platform-by-platform technical and economic assessment identifying highest-priority candidates

- Regulatory pathway analysis for each platform (permitting requirements, certification scope)
  - Commercial development timeline: 12–18 months for each project from site selection to regulatory approval
3. Site selection for greenfield projects (2030+):
    - Focus on high-wind-resource zones (Nederwiek Noord/Zuid, 50–55% capacity factors) where wind resource advantage most decisively improves LCOH
    - Assess spatial planning opportunities enabling larger system scales (500 MW–2 GW) where economies of scale are most pronounced
    - Evaluate platform life-of-field timelines: colocation with wind farms enables shared logistics and operational efficiency

#### Investment and Financing Strategy

1. Bankability milestones:
  - Near-term (2025–2027): Secure CfD support guaranteeing minimum hydrogen price (€5–7/kg), enabling first-wave demonstration projects to achieve project financing
  - Medium-term (2028–2035): Achieve cost competitiveness milestones reducing CfD requirements (€3–4/kg by 2032, €2–3/kg by 2035)
  - Long-term (2035+): Achieve full cost-competitiveness enabling merchant project financing without support
2. Risk management:
  - Secured long-term hydrogen offtake agreements (10–15 years) with industrial end-users or utilities
  - Hedged electricity costs through power purchase agreements (PPAs) with renewable generators or blended portfolio of spot purchases and PPAs
  - Government support through CfD contracts limiting merchant risk during early deployment phases
3. Capital structure:
  - Initial projects (2025–2030): 50%+ government support or grant financing, 50% commercial debt/equity
  - Transition projects (2030–2040): 25–50% government support, 50–75% commercial financing
  - Mature projects (2040+): 100% commercial financing

### 6.3 Contribution to Scientific Knowledge and Academic Discourse

This dissertation advances energy systems engineering and policy analysis through several methodological and substantive innovations:

#### 6.3.1 Methodological Contributions

1. Context-specific LCOH modelling framework: Development of a replicable, transparent cost model explicitly calibrated to DCS wind resources, seawater desalination requirements, offshore installation costs, and infrastructure specifics. This framework can be adapted for other offshore hydrogen contexts (North Sea, Baltic, other regions) by adjusting geographic and technical parameters. The modelling approach emphasises parameter transparency and sensitivity analysis, enabling stakeholders to adjust assumptions and explore cost sensitivities relevant to their planning horizons (Van Stralen et al., 2025; Rogeau et al., 2023; Hill et al., 2024).
2. Temporal trajectory analysis with explicit scenario framing: Rigorous temporal analysis across 2025–2050 with five-year intervals and three explicit scenarios (Conservative, Baseline, Optimistic), advancing beyond single-point-estimate projections common in industry reports. The scenario framing explicitly documents assumptions about technology learning rates, cost trajectories, and policy support, enabling researchers to modify scenarios and explore alternative futures. This approach contributes to the field of transition modelling and long-horizon energy systems planning (International Renewable Energy Agency, 2020; Hydrogen Council, 2021).
3. Comprehensive sensitivity and uncertainty quantification: Integration of one-at-a-time sensitivity analysis (tornado diagrams), Monte Carlo probabilistic simulation (10,000 iterations), and

threshold/breakeven analysis to clarify which parameters most critically determine viability and at what values competitiveness is achievable. This analytical approach is transferable to other complex infrastructure and technology systems facing high uncertainty (Hill et al., 2024; Rogeau et al., 2023).

4. Grid-centric system value integration: Explicit quantification of how offshore hydrogen production—through reduced electrical export requirements—relieves transmission congestion and defers HVDC expansion costs. This framework integrates energy carrier decision-making (electricity vs. hydrogen) into transmission planning, advancing beyond traditional single-carrier optimisation. The approach is applicable to other energy sector coordination challenges (e.g., power-to-gas, demand response, storage integration) (Singlitico et al., 2021; Rogeau et al., 2023).
5. Multi-criteria decision analysis framework: Structured comparison of alternative pathways across economic, technical, environmental, regulatory, and infrastructure dimensions with explicit criteria definition, weighting scenarios, and sensitivity analysis. This framework supports complex infrastructure decision-making under uncertainty and competing stakeholder priorities (Hill et al., 2024; Rogeau et al., 2023).

### 6.3.2 Substantive Contributions to Energy Transition Literature

1. Evidence-based competitiveness timeline: Rigorous quantification that offshore hydrogen achieves cost-competitiveness (parity with alternatives) by 2040 under baseline assumptions, with 3–5 year timeline shift recognising wake effects under policy-planned deployment densities. This finding contributes to the emerging literature on offshore hydrogen viability, advancing beyond speculative or optimistic assertions often found in industry analyses (Borgers et al., 2024; Van Stralen et al., 2025; Hill et al., 2024).
2. Critical success factors framework: Systematic identification and quantification of five essential preconditions (electrolyser cost reduction, offshore wind LCOE reduction, regulatory frameworks, policy support, market demand) with explicit alignment requirements. This framework is applicable to other emerging energy technologies and infrastructure requiring coordinated development across multiple domains (Holst et al., 2021; International Renewable Energy Agency, 2020).
3. Infrastructure repurposing value quantification: Comprehensive assessment of repurposing potential for 84 platforms and 1,500 km pipelines, with cost savings estimates (€0.5–1.5/kg LCOH reduction) and regulatory requirement identification. This work contributes to the literature on extending asset life and optimising utilisation of existing infrastructure in energy transitions (TNO, 2024; Vreeburg and Garcia-Navarro, 2025; Van Stralen et al., 2025).
4. Wake effects implications for offshore hydrogen: Integration of empirical wake effect findings (Borgers et al., 2024) into LCOH analysis, demonstrating material (€0.6–1.5/kg) cost impact and competitiveness timeline effects. This work bridges offshore wind performance literature with hydrogen economics, advancing understanding of system-level impacts of dense offshore deployment (Borgers et al., 2024; Hill et al., 2024).
5. Hybrid pathway optimization: Demonstration that hybrid approaches combining HVDC transmission and hydrogen pipelines are often superior to pure pathways, with explicit cost comparison and system value quantification. This finding contributes to emerging literature on multi-energy-carrier system optimization and challenges siloed energy planning approaches (Singlitico et al., 2021; Rogeau et al., 2023; AquaVentus Consortium, 2024).

## 6.4 Limitations of the Research

While this dissertation provides robust evidence-based assessment of offshore hydrogen feasibility, several limitations constrain the comprehensiveness and universality of findings:

### 6.4.1 Analytical Limitations

1. No endogenous technology learning: The model employs exogenous cost reduction pathways derived from literature; actual technology learning depends on market deployment rates. If deployment lags assumptions, cost reductions will slow; if deployment exceeds assumptions, costs will fall faster. Feedback loops between cumulative deployment and learning curve progression are not explicitly modelled, potentially over or understating cost trajectories (Holst et al., 2021; International Renewable Energy Agency, 2020).
2. Limited spatial optimization: Analysis uses representative DCS locations rather than full spatial optimization across all potential sites. Site-specific wind resources, water depths, infrastructure accessibility, and grid connection points create heterogeneous economics; some sites may achieve

competitiveness earlier, others later. Aggregate DCS results mask this spatial variation and may obscure opportunities in high-resource zones (Van Stralen et al., 2025; North Sea Wind Power Hub Consortium, 2019).

3. LCOH does not capture full system value: LCOH methodology focuses on hydrogen production cost but does not fully capture system-level value of hydrogen production flexibility, storage capabilities, and grid relief benefits. Value-based pricing reflecting these system services could justify higher production costs than LCOH alone suggests. Future analysis should integrate LCOH with detailed system modelling (Rogea et al., 2023; Singlitico et al., 2021).
4. Demand-side analysis limited: The research assumes industrial hydrogen demand will materialise at calculated costs; actual demand depends on regulatory mandates (hydrogen quotas), carbon pricing levels, and alternative decarbonisation pathway costs. Demand uncertainty is substantial (Peters et al., 2021; Ossenbrink et al., 2022; Van Stralen et al., 2025) but treated qualitatively rather than quantitatively; improved demand-side modelling would strengthen competitiveness conclusions (Van Stralen et al., 2025; North Sea Energy, 2023).

#### 6.4.2 Data and Assumption Uncertainties

1. Infrastructure repurposing costs are estimates Platform retrofit costs are quantified on basis of literature review and industry estimates; actual project costs will depend on specific platform condition, regulatory requirements, and contractor availability. Real project costs could vary  $\pm 30\%$  from baseline assumptions, with implications for  $\text{€}0.5\text{--}1.0/\text{kg}$  LCOH variation. The first-wave repurposing projects (2028–2030) will provide empirical validation of cost estimates (TNO, 2024; Vreeburg and Garcia-Navarro, 2025).
2. Electrolyser offshore performance is partially unvalidated: The model includes 20% cost premium for offshore ruggedisation and marine environment adaptation; actual premiums depend on design solutions and could range 15–30%. Limited operational data from offshore demonstration systems (PosHYdon, Projekt OffsH2ore) constrain confidence in premium estimates; scaling to multi-GW systems may reveal cost reduction opportunities or additional challenges not apparent at demonstration scale (TNO, 2024; Projekt OffsH2ore, 2023).
3. Desalination integration complexity: Assumed multi-effect distillation with waste heat integration from electrolyser; actual costs depend on system design success and could be higher if waste heat availability is lower than assumed. Desalination technology development and offshore pilot projects (2026–2028) will validate cost estimates (Haqiqi et al., 2025; TNO, 2024).
4. Policy support mechanisms are assumed as planned: The analysis assumes government support mechanisms (CfD, CAPEX grants, infrastructure investment) will be implemented as described; actual support levels depend on political willingness and budget availability. Insufficient policy support is a material risk factor that could extend competitiveness timelines 5–10 years (Netherlands Ministry of Economic Affairs and Climate Policy, 2023; European Commission, 2022).

#### 6.4.3 Scope and Boundary Limitations

1. Greenfield vs. repurposing comparison: Primary results present greenfield LCOH with repurposing treated as sensitivity analysis. More detailed platform-specific repurposing cost modelling could reveal geographic variation in repurposing viability and optimal platform selection strategies (Vreeburg and Garcia-Navarro, 2025; Van Stralen et al., 2025).
2. No explicit hydrogen reconversion modelling: Analysis assumes hydrogen is used directly as chemical feedstock or industrial fuel; significant reconversion to electricity (for power generation or seasonal storage) is not explicitly modelled. If substantial hydrogen is consumed in reconversion-intensive applications, effective cost competitiveness would be lower and system flexibility value would be higher (Rogea et al., 2023; Singlitico et al., 2021).
3. Platform structural capacity constraints: Model assumes all 84 platforms have sufficient weight capacity for hydrogen systems; platform-by-platform structural analysis might reveal that 20–30% lack adequate capacity, reducing practical deployment options and altering economics (Vreeburg and Garcia-Navarro, 2025; TNO, 2024).
4. No detailed environmental impact assessment: While environmental performance is included in MCDA (lifecycle emissions), detailed environmental impact assessment of offshore hydrogen production (marine ecosystem impacts, chemical release risks, underwater noise) is not conducted. Environmental constraints could affect permitting timelines and spatial deployment options (European Commission, 2022; Hill et al., 2024).

## 6.5 Recommendations for Future Research

This dissertation identifies several areas where future research can extend and deepen the evidence base for offshore hydrogen deployment:

1. Empirical validation through pilot projects (2025–2030): The PosHYdon and H2opZee demonstration projects will provide operational data on offshore electrolyser performance, desalination integration, and actual costs. Post-deployment analysis comparing projected vs. actual costs will validate or refine model assumptions. This empirical feedback should be systematically collected and analysed (TNO, 2024; Projekt OffshH2ore, 2023).
2. Detailed site-specific feasibility assessments: Platform-by-platform repurposing analysis (structural assessment, cost estimation, regulatory pathway) for the 84 identified candidates would refine deployment sequencing and prioritise highest-value projects. This granular spatial analysis would improve investment planning and government prioritisation (Vreeburg and Garcia-Navarro, 2025; TNO, 2024).
3. Endogenous technology learning modelling: Integration of deployment-dependent learning curve feedbacks into long-horizon energy systems models would enable dynamic assessment of how deployment rates affect cost trajectories and vice versa. This would advance understanding of tipping points and critical mass effects in technology scaling (Holst et al., 2021; International Renewable Energy Agency, 2020).
4. System-level integration modelling: Detailed energy systems modelling integrating offshore hydrogen production with electricity transmission, onshore hydrogen infrastructure, industrial demand, and seasonal storage would quantify system-level flexibility and storage values not captured in standalone LCOH analysis. This would support determination of economically optimal capacity allocation between electricity and hydrogen pathways (Singlitico et al., 2021; Rogeau et al., 2023).
5. International cross-border coordination analysis: The North Sea has potential for coordinated hydrogen development spanning Netherlands, Germany, Denmark, and other countries. Future research should model incentive structures for cross-border pipeline development, transmission rights, and pricing mechanisms enabling efficient North Sea-wide hydrogen backbone development (E-Bridge Consulting, 2024; North Seas Energy Cooperation, 2024).
6. Hydrogen demand pathway analysis: Detailed modelling of industrial decarbonisation pathways, regulatory scenarios (hydrogen quotas, carbon pricing), and alternative decarbonisation technologies would provide quantitative demand forecasts for hard-to-abate sectors. This would reduce demand-side uncertainty and support market development strategy (International Energy Agency, 2024a; Hydrogen Council, 2021).
7. Environmental impact assessment and permitting pathway clarification: Systematic environmental impact assessment (marine ecosystem impacts, chemical hazards, underwater noise) combined with permitting pathway mapping would identify spatial constraints, environmental compliance costs, and timelines for project development. This would refine deployment feasibility assessments and support strategic spatial planning (European Commission, 2022; Hill et al., 2024).

## 6.6 Policy and Design Implications

Future research should focus on validating dispersion models for large-scale oxygen and hydrogen releases, optimising vent stack design, and assessing the socio-economic trade-offs of offshore hydrogen hubs versus onshore alternatives (TNO et al., 2022).

Material scarcity—especially lithium, copper, and nickel—and the availability of sustainable carbon pose additional systemic risks. These constraints necessitate coordinated strategies across energy, industrial, and environmental policies to secure supply chains and prioritise resource allocation (Netbeheer Nederland, 2023).

The combined insights from II3050 and NSE highlight the dual imperative of system integration and operational safety. Accelerating towards a CO<sub>2</sub>-free electricity system by 2035 will intensify pressure on hydrogen infrastructure and storage capacity. Concurrently, offshore hydrogen production demands new regulatory frameworks and technical standards to ensure safety and reliability (Netbeheer Nederland, 2023; TNO et al., 2022).

## **6.7 Final Conclusions**

Within the analysed scope, this research demonstrates that probabilistic decision-support is essential for distinguishing viable offshore hydrogen pathways from those that are merely theoretically attractive.

## **METHODOLOGICAL ASSURANCE STATEMENT**

This dissertation prioritises transparency, auditability, and replicability. All modelling assumptions, parameter sources, and calculation logic are explicitly documented. Monte Carlo inputs are fully parameterised and bounded to ensure physical and economic feasibility. Sensitivity and uncertainty analyses are designed to enable independent replication of reported results.

The framework is intended to support robust strategic decision-making under uncertainty rather than deterministic forecasting. Reported results are conditional on stated assumptions and scenario trajectories.

## REFERENCES

- AquaVentus Consortium (2024) Assessment of connection concepts for Germany's far-out North Sea offshore wind areas. Hamburg: AquaVentus Consortium.
- Bachant, P. and Wosnik, M. (2016) 'Performance and near-wake measurements for a vertical axis turbine at moderate Reynolds number', *Wind Energy*, 19(2), pp. 237–252.
- Barthelmie, R.J. and Jensen, L.E. (2010) 'Evaluation of wind farm efficiency and wind turbine wakes at the Nysted offshore wind farm', *Wind Energy*, 13(6), pp. 573–586.
- Bastankhah, M. and Porté-Agel, F. (2016) 'Experimental and theoretical study of wind turbine wakes in yawed conditions', *Journal of Fluid Mechanics*, 806, pp. 506–541.
- Belton, V. and Stewart, T.J. (2002) *Multiple criteria decision analysis: An integrated approach*. Boston, MA: Kluwer Academic Publishers.
- Blanco, H., Nijs, W., Ruf, J. and Faaij, A. (2018) 'Potential for hydrogen and power-to-liquid in a low-carbon EU energy system using cost optimization', *Applied Energy*, 232, pp. 617–639.
- Borgers, M., Beurskens, J. and Schepers, G. (2024) 'Wake effects in large-scale offshore wind farm deployment: Empirical evidence from the Dutch Continental Shelf', *Wind Energy Science*, 9(1), pp. 145–162. Available at: <https://doi.org/10.5194/wes-9-145-2024> (Accessed: 7 January 2026).
- Buijs, L., Bulder, B., Koornneef, J., Peters, R. and Weeda, M. (2022) *Offshore hydrogen for unlocking the full energy potential of the North Sea*. The Hague: TNO. Available at: <https://publications.tno.nl> (Accessed: 7 January 2026).
- Buttler, A. and Spliethoff, H. (2018) 'Current status of water electrolysis for energy storage, grid balancing and sector coupling via power-to-gas and power-to-liquids: A review', *Renewable and Sustainable Energy Reviews*, 82(3), pp. 2440–2454.
- Böhm, H., Zauner, A., Rosenfeld, D.C. and Tichler, R. (2020) 'Projecting cost development for future large-scale power-to-gas implementations by scaling effects', *Energy*, 200, p. 117510.
- Caiazzo, A., Langella, G. and Coiro, D.P. (2014) 'A numerical and experimental study on the wake control of a horizontal axis wind turbine', *Wind Energy*, 17(4), pp. 487–500.
- Cefic (2025) *Cefic views on hydrogen quality standardisation*. Brussels: European Chemical Industry Council. Available at: <https://cefic.org/resources/cefic-views-on-hydrogen-quality-standardisation/> (Accessed: 7 January 2026).
- Chatenet, M., Pollet, B.G., Dekel, D.R., Dionigi, F., Deseure, J., Millet, P., Braatz, R.D., Bazant, M.Z., Eikerling, M., Staffell, I., Balcombe, P., Shao-Horn, Y. and Schäfer, H. (2022) 'Water electrolysis: From textbook knowledge to the latest scientific strategies and industrial developments', *Chemical Society Reviews*, 51(10), pp. 3754–3804.
- DNV (2023) *Energy Transition Outlook 2023: A global and regional forecast to 2050*. Høvik, Norway: DNV AS. Available at: <https://www.dnv.com/energy-transition-outlook/> (Accessed: 7 January 2026).
- DOSTA Consortium (2024) *Demonstrating offshore Strategic Autonomous energy systems: Final report*. Report R24–005. Amsterdam: TNO Energy and Mobility Transition. Available at: <https://dosta-research.nl/wp-content/uploads/2024/11/DOSTA-final-report.pdf> (Accessed: 7 January 2026).
- E-Bridge Consulting (2024) *Connection concepts for offshore wind: AquaVentus study*. Bonn: E-Bridge Consulting.
- EASEE-gas (2021) *Common Business Practice 2022-001/01: Hydrogen quality specification*. Brussels: European Association for the Streamlining of Energy Exchange – Gas. Available at: [https://easee-gas.eu/files/cbp/3\\_cbp-2022-001-01-hydrogen-quality-specification.pdf](https://easee-gas.eu/files/cbp/3_cbp-2022-001-01-hydrogen-quality-specification.pdf) (Accessed: 7 January 2026).

ENTSO (2022) Conversion of a natural gas pipeline to hydrogen transport and effects on line pipe integrity. Brussels: European Network of Transmission System Operators for Gas. Available at: <https://www.entsog.eu> (Accessed: 7 January 2026).

ENTSO (2024) Public consultation report: Hydrogen Infrastructure Gap Initiative (H2IGI). Brussels: ENTSOG.

European Commission (2022) REPowerEU: Joint European action for more affordable, secure and sustainable energy. COM(2022) 230 final. Brussels: European Commission.

European Commission (2023) Delegated Regulation on Renewable Fuels of Non-Biological Origin. Brussels: European Commission.

European Commission (2024) Regulation on Union guidelines for trans-European energy infrastructure. Brussels: European Commission.

Ferreira, C.S., Van Zuijlen, A. and Van Bussel, G.J.W. (under review) ‘Atmospheric boundary layer constraints on offshore wind farm density: Theoretical and computational analysis’, *Wind Energy Science Discussions*.

Gasunie (2023) Hydrogen network Netherlands: Infrastructure conversion and safety standards. Groningen: Gasunie. Available at: <https://www.gasunie.nl/en/projects/hydrogen-network-netherlands> (Accessed: 7 January 2026).

Giampieri, A., Ling-Chin, J. and Roskilly, A.P. (2023) ‘Techno-economic assessment of offshore wind-to-hydrogen: A UK case study’, *Applied Energy*, 333, p. 120493. Available at: <https://doi.org/10.1016/j.apenergy.2022.120493> (Accessed: 7 January 2026).

Glenk, G. and Reichelstein, S. (2019) ‘Economics of converting renewable power to hydrogen’, *Nature Energy*, 4(3), pp. 216–222. Available at: <https://doi.org/10.1038/s41560-019-0326-1> (Accessed: 7 February 2026).

Haqiqi, S., Mortazavi, M. and Sadeghzadeh, M. (2025) ‘Multi-effect desalination integration with offshore hydrogen production’, *Desalination and Water Treatment*, 300, pp. 150–164.

Hill, S.J.P., Ling-Chin, J. and Roskilly, A.P. (2024) ‘Techno-economic analysis of offshore hydrogen production: Comparing different electrolyser technologies’, *Renewable Energy*, 218, p. 119330. Available at: <https://doi.org/10.1016/j.renene.2023.119330> (Accessed: 7 January 2026).

Holst, M., Aschbrenner, S., Smolinka, T., Voglstätter, C. and Grimm, G. (2021) Cost forecast for low temperature electrolysis: Technology driven bottom-up prognosis for PEM and alkaline water electrolysis systems. Freiburg: Fraunhofer ISE. Available at: <https://www.ise.fraunhofer.de/en/publications> (Accessed: 7 January 2026).

Howland, M.F., Bossuyt, J., Martínez-Tossas, L.A., Meyers, J. and Meneveau, C. (2020) ‘Wake structure in actuator disk models of wind turbines in yaw under uniform inflow conditions’, *Journal of Renewable and Sustainable Energy*, 8(4), p. 043301.

Hydrogen Council (2021) Path to hydrogen competitiveness: A cost perspective. Brussels: Hydrogen Council.

HyNetwork Services (2024) Indicative quality and temperature specification for Hydrogen Network Netherlands. Groningen: Gasunie. Available at: <https://www.hynetwork.nl/media/jokhjtcb/indicative-quality-and-temperature-specification.pdf> (Accessed: 7 January 2026).

Härtel, P., Vrana, T.K., Hennig, T., von Bonin, M., Wiggelinkhuizen, E.J. and Nieuwenhout, F.D.J. (2017) ‘Review of investment model cost parameters for VSC HVDC transmission infrastructure’, *Energies*, 10(9), p. 1362.

Iman, R.L. and Conover, W.J. (1982) ‘A distribution-free approach to inducing rank correlation among input variables’, *Communications in Statistics – Simulation and Computation*, 11(3), pp. 311–334.

International Energy Agency (2019) The future of hydrogen: Seizing today’s opportunities. Paris: IEA. Available at: <https://www.iea.org> (Accessed: 7 January 2026).

- International Energy Agency (2022) Global Hydrogen Review 2022. Paris: IEA.
- International Energy Agency (2024a) Global Hydrogen Review 2024. Paris: IEA. Available at: <https://www.iea.org/reports/global-hydrogen-review-2024> (Accessed: 7 January 2026).
- International Energy Agency (2024b) World Energy Outlook 2024. Paris: IEA.
- International Renewable Energy Agency (2020) Green hydrogen cost reduction: Scaling up electrolyzers to meet the 1.5°C climate goal. Abu Dhabi: IRENA. Available at: <https://www.irena.org/publications/2020/Dec/Green-hydrogen-cost-reduction> (Accessed: 7 January 2026).
- International Renewable Energy Agency (2021) Renewable power generation costs in 2020. Abu Dhabi: IRENA. Available at: <https://www.irena.org/publications/2021/Jun/Renewable-Power-Costs-in-2020> (Accessed: 7 January 2026).
- International Renewable Energy Agency (2022) Global hydrogen trade to meet the 1.5°C climate goal. Abu Dhabi: IRENA.
- ISO (2019) ISO 14687:2019 Hydrogen fuel quality – Product specification. Geneva: International Organization for Standardization.
- ISO (2025) ISO 14687:2025 Hydrogen fuel — Product specification. Geneva: International Organization for Standardization. Available at: <https://www.iso.org/standard/82660.html> (Accessed: 7 January 2026).
- Jang, S., Park, S., Song, S. and Moon, S. (2022) ‘Comparison of hydrogen production methods in terms of efficiency and cost’, Energy Policy, 165, p. 112878.
- Lazard (2024) Lazard’s Levelized Cost of Energy Analysis, Version 17.0. New York: Lazard.
- Lund, H., Andersen, A.N., Mathiesen, B.V., Connolly, D., Østergaard, P.A. and Karnøe, P. (2015) ‘From electricity smart grids to smart energy systems: A market operation based approach and understanding’, Energy, 42(1), pp. 96–102.
- Madeddu, S., Nijs, W., Canevese, S., Eichler, L. and Kermeli, B. (2020) ‘Decarbonising industry in the EU: Using existing policies to bridge the emissions gap’, Energy Policy, 140, p. 111374.
- Millet, P., Grigoriev, S.A., Bonifácio, I., Holmström, N., Christensen, E., Bandaru, S., Linardi, M., Bessarabov, D., Müller, M., O’Brien, P. and Stefanakos, E. (2019) ‘Towards new perspectives for hydrogen production and storage’, International Journal of Hydrogen Energy, 44(13), pp. 6973–7011.
- Ministry of Infrastructure and Water Management (Rijkswaterstaat) (2025) Roadmap offshore wind energy [map]. October 2025. The Hague: Rijkswaterstaat. Available at: <https://www.rijkswaterstaat.nl> (Accessed: 7 January 2026).
- Netbeheer Nederland (2023) Infrastructure for hydrogen transition: Technical standards and safety requirements. The Hague: Netbeheer Nederland.
- Netherlands Enterprise Agency (2024) Platform decommissioning guidelines for the Dutch Continental Shelf. The Hague: Rijksdienst voor Ondernemend Nederland.
- Netherlands Ministry of Economic Affairs and Climate Policy (2023) North Sea 2050 spatial agenda. The Hague: Netherlands Ministry of Economic Affairs and Climate Policy.
- North Sea Energy (2023) Business models for value chains for new offshore energy concepts. North Sea Energy Programme.
- North Sea Wind Power Hub Consortium (2019) North Sea Wind Power Hub: Modular scale-up strategy. The Hague: TenneT TSO.
- North Seas Energy Cooperation (2024) Offshore renewable energy: Regional framework for spatial planning. Brussels: European Commission.

- Nooussan, M., Raimondi, P.P., Scita, R. and Hafner, M. (2021) 'The role of green and blue hydrogen in the energy transition: A technological and geopolitical perspective', *International Journal of Hydrogen Energy*, 46(58), pp. 30175–30192.
- Parkinson, B., Balcombe, P., Speirs, J.F., Hawkes, A.D. and Hellgardt, K. (2019) 'Levelised cost of CO<sub>2</sub> mitigation from hydrogen production routes', *Applied Energy*, 249, pp. 351–365.
- Pohekar, S.D. and Ramachandran, M. (2004) 'Application of multi-criteria decision making to sustainable energy planning: A review', *Renewable and Sustainable Energy Reviews*, 8(4), pp. 365–381.
- Porté-Agel, F., Bastankhah, M. and Shamsoddin, S. (2020) 'Wind-turbine and wind-farm flows: A review', *Boundary-Layer Meteorology*, 174(1), pp. 1–59.
- Projekt OffsH2ore (2023) Endbericht: Offshore-Wasserstofferzeugung mittels offshore-windenergie als insellösung. Berlin: Projekt OffsH2ore.
- Raach, S., Boersma, S., Wingerden, J.W. and Chokani, N. (2018) 'Model-based feedforward control of wind turbines using Lidar-based wind speed measurements for load reduction', *Wind Energy*, 21(11), pp. 1146–1167.
- Rogean, A., Girard, R. and Kariniotakis, G. (2023) 'Techno-economic analysis of offshore wind-to-hydrogen: Impact of grid connection and hydrogen transport', *International Journal of Hydrogen Energy*, 48(4), pp. 8420–8432. Available at: <https://doi.org/10.1016/j.ijhydene.2022.11.248> (Accessed: 7 January 2026).
- Singlitico, A., Østergaard, J. and Chatzivasileiadis, S. (2021) 'Onshore, offshore or in-turbine electrolysis? Techno-economic overview of alternative integration designs for green hydrogen production into Offshore Wind Power Hubs', *Renewable and Sustainable Energy Transition*, 1, p. 100005. Available at: <https://doi.org/10.1016/j.rset.2021.100005> (Accessed: 7 February 2026).
- Vreeburg, J.R. and Garcia-Navarro, J.C. (2025) 'The potential of repurposing offshore natural gas infrastructure on the Dutch Continental Shelf for hydrogen production and transport', *International Journal of Hydrogen Energy*, 115, pp. 37–48. Available at: <https://doi.org/10.1016/j.ijhydene.2025.03.030> (Accessed: 7 February 2026).
- WindEurope (2021) Offshore Wind in Europe: Key Trends and Statistics 2020. Brussels: WindEurope. Available at: <https://windeurope.org/data-and-analysis/product/offshore-wind-in-europe-key-trends-and-statistics-2020/> (Accessed: 7 February 2026).

## APPENDIX A – FINANCIAL ASSUMPTIONS & TECHNOLOGY PARAMETERS

### A.1 Financial Parameters (Summary)

Table 45 -Financial Parameters (Summary)

Parameter	2025	2030	2040	2050	Source
<b>WACC (Discount Rate)</b>	6.0%	5.5%	5.0%	4.5%	Baseline utility financing; Conservative +1%, Optimistic – 1%
<b>Project Lifetime</b>	25 years (electrolyser) / 30 years (platform, pipeline)	—	—	—	Industry standard; stack replacement mid-life
<b>Inflation Rate</b>	2.0%	2.0%	2.0%	2.0%	ECB long-term target

### A.2 Electrolyser Technology Parameters

Table 46 - Electrolyser Technology Parameters

Parameter	Unit	2025	2030	2040	2050	Learning Rate
<b>PEM Electrolyser CAPEX</b>	€/kW	1,000	750	400	375	15% (baseline)
<b>Offshore Ruggedisation Premium</b>	%	20%	18%	15%	15%	Declining with scale
<b>Specific Electricity Consumption</b>	kWh/kg H <sub>2</sub>	53.5	51.5	50.0	48.5	Efficiency improvement
<b>Stack Lifetime</b>	hours	50,000	55,000	60,000	65,000	Durability gains
<b>Fixed OPEX</b>	% of CAPEX/yr	3.5%	3.3%	3.0%	2.8%	Scale economies

**Data Sources:** Holst et al. (2021); IRENA (2020); Hydrogen Council (2021); Giampieri et al. (2023)

### A.3 Offshore Wind Parameters (DCS-Calibrated)

Table 47- Offshore Wind Parameters (DCS-Calibrated)

Zone	Distance (km)	Water Depth (m)	Capacity Factor (%)	Wind CAPEX (€/kW) 2040
<b>Hollandse Kust</b>	40–80	20–35	45–48	2,100
<b>IJmuiden Ver</b>	70–100	30–50	48–50	2,050

<b>Zone</b>	<b>Distance (km)</b>	<b>Water Depth (m)</b>	<b>Capacity Factor (%)</b>	<b>Wind CAPEX (€/kW) 2040</b>
<b>Nederwiek Noord/Zuid</b>	150–200	60–90	48–52 (42–48 wake-adjusted)	1,950

**Wake Effect Adjustment:** Borgers et al. (2024) empirical validation shows 4–6 pp CF reduction under 8–12 MW/km<sup>2</sup> deployment densities.

#### **A.4 Scenario Parameter Integration**

**Conservative Scenario (2040):** €1,100/kW (2025) → €600/kW; CF 45%; LCOE €50/MWh; WACC 7%

**Baseline Scenario (2040):** €1,000/kW (2025) → €400/kW; CF 52%; LCOE €35/MWh; WACC 5.5%

**Optimistic Scenario (2040):** €900/kW (2025) → €300/kW; CF 55%; LCOE €30/MWh; WACC 5%

## APPENDIX B – WAKE EFFECTS & CAPACITY FACTOR SENSITIVITY

### B.1 Capacity Factor Impact on LCOH (2040 Baseline)

Table 48 - Capacity Factor Impact on LCOH (2040 Baseline)

Capacity Factor (%)	LCOH (€/kg)	vs. Baseline	Cost Driver
52% (Baseline)	1.95	—	Reference
48% (Empirical DCS)	2.25	+15.4%	Fixed cost dilution
42% (High-density worst-case)	2.70	+38.5%	Atmospheric boundary layer limit
34.6% (Ferreira theoretical limit)	3.45	+77%	Extreme wake scenario

**Implication:** Each 1 pp CF reduction = €0.074/kg LCOH increase (fixed cost dominance)

### B.2 Repurposing Advantage Across Wake Scenarios

Table 49 - Repurposing Advantage Across Wake Scenarios

Scenario	Repurposed LCOH	Greenfield LCOH	Advantage (€/kg)	Advantage (%)
52% CF (Baseline)	1.95	2.30	0.35	15.2%
48% CF (Empirical)	2.25	2.60	0.35	13.5%
42% CF (Worst-case)	2.70	3.05	0.35	11.5%

**Strategic Finding:** Repurposing advantage (€0.35/kg) remains constant across CF range; relative advantage declines as total LCOH rises.

### B.3 Spatial Planning Trade-Offs (DCS Zones)

Table 50 - Spatial Planning Trade-Offs (DCS Zones)

Deployment Strategy	Density (MW/km <sup>2</sup> )	Effective CF (%)	LCOH 2040 (€/kg)	Feasibility
<b>Maximum Density (Current Policy)</b>	10–12	42–44	2.45	Requires subsidy
<b>Moderate Density</b>	6–8	48–50	2.10	Achievable with CfD
<b>Low Density (Optimised)</b>	4–5	52–54	1.95	Competitive by 2040
<b>Far-Offshore Priority</b>	8 (Nederwiek only)	50–52	2.05	Preferred pathway

**Recommendation:** Geographic allocation (high-wind zones for hydrogen; intermediate zones for HVDC) optimises across energy carriers.

## B.4 Mitigation Technology Effectiveness

Table 51 - Mitigation Technology Effectiveness

<b>Technology</b>	<b>CF Recovery (pp)</b>	<b>CAPEX Addition (€M)</b>	<b>Payback (years)</b>	<b>Status</b>
<b>Yaw Control (AWC)</b>	2–3	15–25	3–4	Proven; implementable 2025
<b>Induction Control</b>	2–4	20–35	4–5	Emerging; 2026+ deployment
<b>Larger Turbines (18–20 MW)</b>	3–5	50–100	5–7	Pre-commercial; 2028+
<b>Combined Approach</b>	6–8	85–160	4–6	Optimal; recovers 2–3 year timeline

## APPENDIX C – INFRASTRUCTURE REPURPOSING

### C.1 Platform Inventory & Suitability

Table 52 – Platform inventory

Tier	Criteria	Count	Repurposing Potential (MW)	CAPEX Savings (€M)
<b>Tier 1</b>	Excellent condition; <50 km offshore; ≥20 yr residual life	18	1,800	3,600
<b>Tier 2</b>	Good condition; 50–100 km; 15–20 yr life	35	2,100	4,200
<b>Tier 3</b>	Acceptable condition; >100 km; 10–15 yr life	20	1,200	2,400
<b>Tier 4</b>	Poor condition / limited life	11	300	600
<b>TOTAL</b>	—	<b>84</b>	<b>5,400 MW</b>	<b>€10.8B</b>

**Greenfield Equivalent Cost:** €15–20B (40–50% cost premium vs. repurposing)

### C.2 Pipeline Inventory & Conversion Costs

Table 53 - Pipeline Inventory & Conversion Costs

Pipeline Segment	Length (km)	Diameter (inch)	Conversion Cost (€M)	Hydrogen Compatibility
<b>Priority Corridors (Nederwiek→Rijnmond)</b>	200	12–16	300–400	Excellent (post-inspection)
<b>Secondary Network</b>	600	8–12	600–800	Good (with pressure de-rating)
<b>Tertiary Links</b>	700	4–8	400–600	Fair (selective conversion)
<b>TOTAL</b>	<b>1,500</b>	—	<b>€1.3–1.8B</b>	—

**Comparison:** New hydrogen pipelines €2.5–3.0 M/km vs. repurposing €0.9–1.2 M/km (60–70% savings)

### C.3 Integrated System Example: Nederwiek 500 MW Cluster

#### System Configuration:

- 2 repurposed platforms (250 MW each)
- 150 km subsea pipeline to Rijnmond terminal
- Onshore hydrogen terminal (50 MW receiving capacity)

#### Economic Summary:

Table 54 - Integrated System Example: Nederwiek 500 MW Cluster

Component	CAPEX (€M)	Repurposed	Greenfield	Savings
Platforms	360	360	800	440
Electrolyser	250	250	250	—
Pipeline	180	180	450	270
Terminal	80	80	80	—
<b>TOTAL</b>	<b>870</b>	<b>870</b>	<b>1,580</b>	<b>€710M (45%)</b>

**LCOH Advantage:** €0.50–0.80/kg (2025–2030 period); declining to €0.15–0.25/kg by 2040 as technology costs fall

## APPENDIX D – MULTI-CRITERIA DECISION ANALYSIS (MCDA)

### D.1 Criterion Definitions & Baseline Weighting

*Table 55 - Criterion Definitions & Baseline Weighting*

Criterion Group	Weight	Sub-Criteria	Scoring Scale
<b>Economic (40%)</b>	—	LCOH; CAPEX; OPEX predictability; TRL	0–100 (100 = best)
<b>Technical (25%)</b>	—	Capacity potential; TRL; Reliability; Flexibility	0–100
<b>Infrastructure (20%)</b>	—	Repurposing potential; Integration complexity; Grid independence; Decommissioning	0–100
<b>Environmental (15%)</b>	—	Carbon intensity; Marine impact; Onshore footprint; Social acceptance	0–100

### D.2 Pathway Scores (2040 Baseline, Equal Weighting)

*Table 56 - 2 Pathway Scores (2040 Baseline, Equal Weighting)*

Pathway	Economic	Technical	Infrastructure	Environmental	Total Score	Rank
<b>P1: Offshore Green H<sub>2</sub> (Repurposed)</b>	92	78	95	88	<b>88.3</b>	<b>1st</b>
<b>P2: Offshore Green H<sub>2</sub> (Greenfield)</b>	85	76	82	85	<b>82.0</b>	<b>2nd</b>
<b>P3: Onshore Green H<sub>2</sub></b>	78	82	65	82	<b>76.8</b>	<b>3rd</b>
<b>P4: HVDC-Only Transmission</b>	72	92	45	80	<b>72.5</b>	<b>4th</b>
<b>P5: Blue Hydrogen (SMR+CCS)</b>	62	88	58	45	<b>63.0</b>	<b>5th</b>

### D.3 Sensitivity to Alternative Weightings

*Table 57 - Sensitivity to Alternative Weightings*

Weighting Scenario	P1 Rank	P2 Rank	P3 Rank	P4 Rank	P5 Rank
<b>Baseline (40–25–20–15)</b>	1st	2nd	3rd	4th	5th
<b>Economic Priority (50–15–20–15)</b>	1st	2nd	4th	3rd	5th

<b>Weighting Scenario</b>	<b>P1 Rank</b>	<b>P2 Rank</b>	<b>P3 Rank</b>	<b>P4 Rank</b>	<b>P5 Rank</b>
<b>Technical Priority (25–40–20–15)</b>	2nd	1st	3rd	1st	5th
<b>Environmental Priority (25–20–15–40)</b>	1st	2nd	3rd	4th	5th
<b>Risk-Averse (30–35–25–10)</b>	1st	2nd	3rd	4th	5th

**Robustness Finding:** P1 ranks 1st in 4 of 5 scenarios; MCDA results are robust across stakeholder priorities

## APPENDIX E – ENVIRONMENTAL & LIFECYCLE ASSESSMENT

### E.1 Lifecycle Carbon Intensity by Pathway (2040)

Table 58 - Lifecycle Carbon Intensity by Pathway (2040)

Pathway	LCOH (€/kg)	Carbon Intensity (kg CO <sub>2</sub> -eq/kg H <sub>2</sub> )	Lifecycle Stages Included
<b>P1: Offshore Green H<sub>2</sub> (Repurposed)</b>	1.95	<0.5	Manufacturing (repurposed); electrolyser; operation; transport
<b>P2: Offshore Green H<sub>2</sub> (Greenfield)</b>	2.30	0.5–0.8	Platform/pipeline manufacturing (+€0.12/kg); rest as P1
<b>P3: Onshore Green H<sub>2</sub></b>	2.50	0.3–0.6	Lower manufacturing; 10% grid backup emissions
<b>P4: Blue Hydrogen (SMR+CCS)</b>	3.50	0.5–1.0	Methane leakage (0.5–5%): dominant uncertainty
<b>P5: Hydrogen Imports</b>	1.50–4.00	0.2–2.0	Highly dependent on source (Chile solar vs. Central Asia gas)

**Decommissioning Credit:** Repurposing avoids €150–500M decommissioning liability per platform + €0.16–0.24 kg CO<sub>2</sub>-eq/kg environmental benefit

### E.2 Environmental Performance Summary

Table 59 - Environmental Performance Summary

Impact Category	P1 (Repurposed)	P2 (Greenfield)	P3 (Onshore)	P4 (Blue H <sub>2</sub> )	P5 (Imports)
<b>Climate (kg CO<sub>2</sub>-eq/kg H<sub>2</sub>)</b>	<0.5 ✓	0.5–0.8 ✓	0.3–0.6 ✓	0.5–1.0 Δ	0.2–2.0 Δ
<b>Marine Ecosystem</b>	Positive (rig-to-reef)	Neutral	None	Neutral	Tanker risk
<b>Onshore Footprint (ha/300 MW)</b>	<5 ✓	<5 ✓	50–100 Δ	<5 ✓	None
<b>Decommissioning</b>	Avoided €150–500M	Required €300–400M	N/A	N/A	N/A
<b>Circular Economy (% recycling)</b>	90% ✓	90% ✓	85%	80%	Variable

## APPENDIX F – REGULATORY FRAMEWORK & POLICY

### F.1 EU & Dutch Regulatory Status (2025–2026)

Table 60 - EU & Dutch Regulatory Status (2025–2026)

Framework	Status	Timeline	Impact
<b>RED II Hydrogen Criteria</b>	✓ Finalized	In force 2024+	Offshore H <sub>2</sub> eligible for RFNBO classification
<b>EU Taxonomy (DNSH)</b>	✓ Finalized	In force 2024+	Enables green bond financing (–1–2% WACC)
<b>IPCEI Hydrogen Support</b>	✓ €5.4B allocated	2022–2030	Dutch allocation €500M–1.2B available
<b>DNV Hydrogen Platform Class Notes</b>	⚠ In development	Expected Q4 2024–Q2 2025	Enables platform certification pathway
<b>ENTSOG Pipeline Classification</b>	⚠ Transitional rules	Full harmonisation 2026	Interim pilot exemption <50 MW
<b>Dutch Oil &amp; Gas Act Amendment</b>	⚠ In development	Expected 2025–2026	Clarifies decommissioning exception for H <sub>2</sub>

### F.2 Critical Regulatory Barriers & Resolution Timeline

Table 61 - Critical Regulatory Barriers & Resolution Timeline

Barrier	Current Status	Resolution Timeline	Policy Action Required
<b>Platform Certification</b>	No H <sub>2</sub> -specific framework	2026–2027	Fast-track DNV/BV class notes
<b>Pipeline Classification</b>	Interim ENTSOG rules	2026 (full harmonisation)	Pilot exemption for first projects
<b>Decommissioning Liability</b>	Unclear asset transfer	2025–2026 (Oil & Gas Act amendment)	Clarify hydrogen operator liability
<b>Environmental Permitting</b>	Standard EIA required	2025–2027 (streamlined pathway)	Establish fast-track environmental review
<b>Grid Connection Approval</b>	Standard TSO process	2025–2026	Coordinate TenneT/Gasunie integration

### F.3 Policy Support Mechanisms (2025–2035)

Table 62 - Policy Support Mechanisms (2025–2035)

<b>Instrument</b>	<b>2025–2027</b>	<b>2028–2030</b>	<b>2031–2035</b>	<b>Total Commitment</b>
<b>CfD (€/kg)</b>	€5–7	€3–5	€2–3	€1.0–1.5B
<b>CAPEX Grants (%)</b>	30–40%	20–30%	10–20%	€0.8–1.2B
<b>Infrastructure Support</b>	€300–400M/yr	€250–350M/yr	€150–250M/yr	€1.5–2.0B
<b>IPCEI Co-funding</b>	€100–200M	€150–300M	€100–200M	€0.5–0.7B
<b>TOTAL ANNUAL</b>	<b>€1.0–1.2B</b>	<b>€0.7–1.0B</b>	<b>€0.4–0.7B</b>	<b>€4.0–5.5B</b>