EU's Hydrogen Infrastructure Planning: Addressing the Impact of Demand Uncertainty

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***Abstract*—Green hydrogen will play a key role to decarbonize the future European energy mix. However, the demand for green hydrogen is highly uncertain, influencing investment and policy implications. We perform a meta-study of future hydrogen demand scenarios for the year 2050 based on 32 empirical studies. With this foundation, we develop scenarios to examine how uncertainty in hydrogen demand affects the need for European infrastructure expansion using a linear optimization model covering the European electricity and hydrogen sectors.**

***Index Terms*: Infrastructure Expansion Planning, Stochastic Programming, Uncertainty**

I. INTRODUCTION

The European "Green Deal" in 2022 pushed new initiatives such as the REpowerEU plan and the EU's hydrogen strategy drawing a roadmap towards the continent's carbon neutrality in 2050 [1], [2], [3]. Therefore, a major transition of the EU's energy infrastructure is planned with green hydrogen expected to become essential for the EU's future energy system. To support the EU's 2050 policy goals, a divers set of actors such as British Petroleum, McKinsey, the ENTSO-G, the Fraunhofer Institute for Systems and Innovation Research, and the European Hydrogen Backbone, are developing different future pathways to influence and guide to business and policymakers. The European Hydrogen Observatory provides and overview of the most recent studies summarizing 32 studies about hydrogen demand scenarios for 2050 [4]. This summary clearly illustrates the highly scattered projections, ranging from 5 to 131 Gt hydrogen per year for the European energy system in 2050[1], emphasizing the significant uncertainty surrounding future demand [4]. Among other reasons, such as lobbyism or strategic interest guiding communication, hydrogen demand is influenced by several uncertain future key factors including (i) degree of electrification, (ii) competing technologies such as the scalability of carbon capture and storage and (iii) resource constraints like limited biomass availability and CO_2 sequestration potential [5].

This uncertainty complicates the EU's decision-making process and increases costs. One reason for that is that infrastructure planning and construction takes years and must begin in the short term. This requires committing to projects before critical parameters, such as the hydrogen demand, can be observed – "wait and see" is not an option.

With this paper, we contribute twofold to the current literature. Firstly, we statistically analyze the communicated hydrogen demand scenarios of the 32 studies, providing a bigger picture of the current estimates. Secondly, we quantify the impact of hydrogen demand uncertainty on long-term infrastructure planning and investment decisions in Europe. Therefore, we use a hydrogen-electricity sector coupled energy system model, optimizing investment in generation and transmission infrastructures considering operation decisions and the net zero emission constraint for the target year 2050. Furthermore, we identify no-regret investment options for different hydrogen related technologies.

The paper is structured as follows: Section 2 encompasses the statistical analysis of the empirical hydrogen demand prospects. Section 3 describes the European energy system modeling setup. Section 4 presents and discusses the results, focusing on the implications of hydrogen demand uncertainty on infrastructure decisions. Finally, Section 5 concludes with key insights and policy recommendations, while highlighting areas for future research.

II. STATISTICAL ANALYSIS

In the following we statistically analyze the empirical hydrogen demand estimations derived from the 32 studies. We investigate the data set, analyze and estimate the distribution of the projections and derive scenarios of a future hydrogen demand for our study.

A. Data

The hydrogen demand forecast summary of the European Hydrogen Observatory includes studies from 15 institutions or

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[1] excluding the electrical power sector

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companies from 2018 to 2023 which provide different scenario forecasts for the year 2030, 2040 and 2050. The hydrogen demand forecast encompasses four sectors: industry, transport, building and power. As we model the power sector endogenously, we exclude the hydrogen demand form this sector in the meta-analysis of the literature. For the year 2050, 32 different hydrogen demand forecasts from the literature are presented in Figure 1. Besides one outlier, Figure 1 shows a symmetrical distribution of the demand values, with an average of 1254 TWh, a median of 1380 TWh and a standard deviation of the demand of around 660 TWh. The extreme value of 4389 TWh is reported in a study published in 2016 and released on EU publications website in 2019 [6]. However, the hydrogen demand of the referenced "Ambitious 2050" from this study is stated as 2251 TWh. Since we were unable to verify the 4389 TWh figure, we excluded this outlier from further analysis.

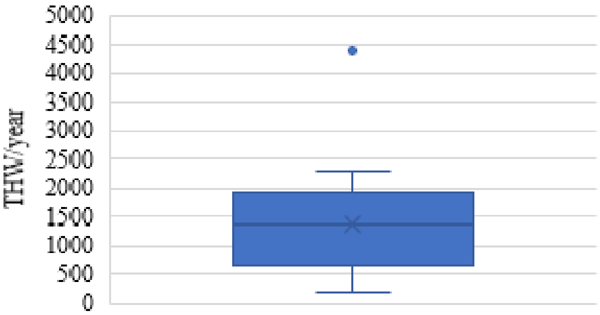

Figure 1: Hydrogen demand distribution taken from the European Hydrogen Observatory [4]

As a next step we visually analyze the distribution of the demand values using a Q-Q plot shown in Figure 2 below. The Q-Q plot compares two distributions by plotting their quantiles against each other on an x-y diagram. This method indicates that if two distributions are similar, the points fall with a certain tolerance along the dotted line of y = x. The calculation of the underlying values can be found in Table IV in the Appendix section. The Q-Q plot partially supports that the underlying data follows a normal distribution, despite visual deviations due to the "S" shape of the points. To validate this assumption analytically, we perform the Shapiro-Wilk test in the next section.

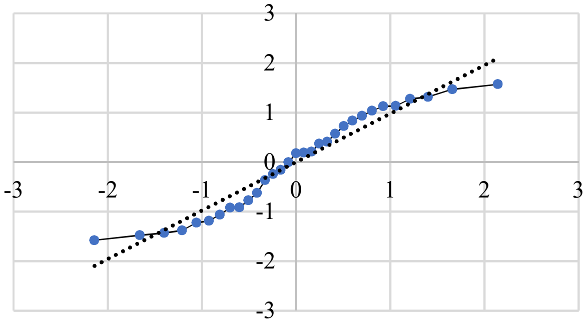

Figure 2:Q-Q plot normal distribution vs. forecast values

B. *Shapiro-Wilk-Test & Normal Distribution Approximation*

We employ the Shapiro-Wilk test to validate our hypothesis that the demand forecasts are normally distributed given a certain significance level. We use the test because the test is well suited for smaller samples. Therefore, we calculate W following [7] as:

$$W = \frac{(A'X)^2}{(n-1)s^2},$$

where X corresponds to the vector of the ordered demand values, n is the sample size, s^2 to the approximation of the sample variance σ^2 and A is a vector of coefficients calculated for this statistic by Shapiro and Wilk. The data and the calculation for each element is provided in Table V in the Appendix section. With $W \approx 0.9375$ and the corresponding $p \approx 0.0703$ to be bigger than the testes significance level of 0.05 our hypothesis cannot be rejected, and we assume the forecast data to follow a normal distribution shown in Figure 3 below.

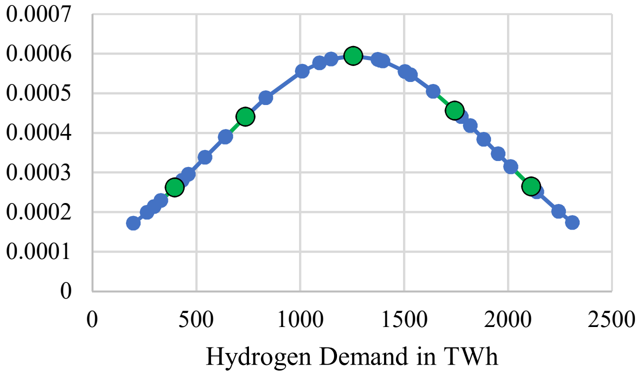

Figure 3: Approximated normal distribution

C. *Scenarios*

Based on the predetermined distribution of the 2050 hydrogen demand forecast, we derive five hydrogen demand scenarios that correspond to the 10 %, 25 % 50 % 75% and 90 % quantile Q_p of this distribution. These scenarios are depicted by the green dots in Figure *3*. The resulting values can be calculated using the following formula:

$$Q_p = \mu + z_p \cdot \sigma,$$

where μ is the average of the distribution and z_p the Z-score. The resulting scenario specific hydrogen demands are listed in Table I below. As a basis for comparison, we also model a reference scenario (Ref.), for which the exogenous hydrogen demand is zero.

Table I: Scenario specific hydrogen demand

Scenario	***Q10***	***Q25***	***Q50***	***Q75***	***Q90***
Hydrogen demand [TWh]	397.3	737.4	1256.6	1775.9	2115.9

III. TRANSMISSION AND GENERATION EXPANSION

Our linear generation and transmission expansion planning model focuses on the electricity and hydrogen energy sector in

Europe with the target year 2050. In the following we briefly describe the main elements of the model including objective function, geographical coverage and resolution and the investment and operation variables with a more detailed view on the hydrogen supply options.

A. *Model*

Our model minimizes the total costs of investments in electricity and hydrogen generation capacities, the corresponding technology specific operation costs and investments in electricity and hydrogen transmission and transport technologies. We assume that hydroelectric and nuclear generation capacities remain constant, using their 2024 values as exogenous inputs.

The modelled system covers the EU member states, the United Kingdom, Norway, Switzerland, Bosnia Herzegovina, Serbia, Albania, North Macedonia, the Kosovo and Montenegro with one node per country and 37 nodes in total. The countries are connected by two separate grid infrastructures, the electricity and the hydrogen gird. The model computes a whole year with a two-hour resolution. Each node has an individual renewable capacity factor time series based on an average weather year. Furthermore, each country has its own hydrogen and electricity demand time series, with the latter amounting to a total of 4500 TWh for the entire system, as reported in [8].

Options to serve the hydrogen demand include (1) pipeline imports from Marrocco, Algeria and Turkey, (2) imports of liquid hydrogen via ship and (3) the domestic production.

We assume, that die existing natural gas pipeline connection between Marrocco and Spain, Algeria and Spain, Algeria via Tunesia to Italy and Turkey to Greece and Bulgaria can be refurbished to hydrogen pipelines. In general, we limit the expandable hydrogen pipeline capacity between the countries to a maximum value taken from the upper bound of the ENTSO-G's 2024 Ten-Year Network Development Plan (TYNDP) for the year 2050. The decision to expand up to this limit is endogenous in our model.

Regarding the liquid hydrogen import option, we consider that for each country with a coast in our system is able to build a hydrogen import terminal. As the hydrogen import cost depends on the exporting countries as well as the shipping distance to each importing terminal, we compute individual import costs curves to each terminal. Therefore, we consider the hydrogen supply potential of Marrocco, Tunesia, Algeria Australia, the Arabic Emirates, Namibia, Saudi Arabia and the United States of America. Figure 4 below exemplary illustrates the average supply cost cure for Europe, differentiating in each supplier between the production and transport costs. This cost data is incorporated into the model exogenously.

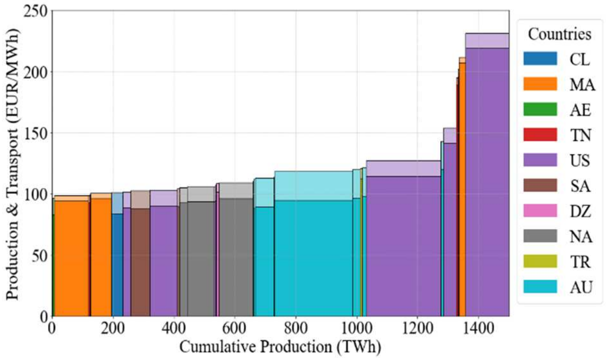

Figure 4: Liquid hydrogen supply cost for Germany in 2050. Cost breakdown into production (solid color) and transport (lighter shade).

Finally, the hydrogen demand can also be supplied by the domestic production of each country. Therefore, the countries can decide to invest in electrolysis and electricity generation capacity. An overview of all investment and operation decisions is provided by Table II. A more detailed model formulation as well as our input data can be found at our github.website[2].

Table II: Overview of investment and operation variables

Investment Variables	***Operation Variables***
• Wind onshore capacity • Wind offshore capacity • Solar PV capacity • Battery storage capacity • Electricity lines capacity • Electrolyzer capacity • H2 fired OCGT capacity • H2-storage capacity • H2-pipelines capacity • H2-Terminals capacity	• Electricity generation • Hydrogen generation • Hydrogen import • Electricity & hydrogen transport • Electricity & hydrogen storage operation • Electricity load shedding

IV. RESULTS

In the following we analyze the model results, starting with the objective values of the specific scenarios, followed by the electricity and hydrogen technology specific investments and the regret analysis.

A. *Objective Values and Hydrogen Cost*

The objective value is the sum of all investment and operation costs in the system. Table III shows the objective values and the hydrogen supply costs. As expected, a higher hydrogen demand leads to a higher objective value. We compute the hydrogen costs as the difference between our five Q %-scenarios with the reference scenario. To normalize these costs to EUR/MWh, we also divided by the scenario specific hydrogen demand (bottom row in Table III). While Figure 4 showes the cost for importing hydrogen start at around 100 EUR/MWh, the hydrogen supply costs of the whole system are significantly lower. We find two main reasons for this result. First, most of the hydrogen is produced domestically. This leads to cross-sector distribution effects of the

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[2] https://github.com/bernemax/H2_Demand_Uncertainty-EEM_2025-/tree/main

technologies, highlighting the importance of looking at hydrogen supply costs on an overall system perspective instead of island solutions. Second, also the reference system builds hydrogen infrastructures such as electrolyzers to cover the electricity demand using hydrogen-fired OCGT during low renewable availability periods, reducing investments to cover the additional exogenous hydrogen demand. We analyze this in more detail in the following sections.

Table III: Objective value and hydrogen cost comparison

Scenario	***Ref***	***Q10***	***Q25***	***Q50***	***Q75***	***Q90***
Objective value [bill. EUR]	320.6	339.2	357.8	389.1	423.6	447.2
Hydrogen cost [EUR/MWh]	32.7	47.2	50.6	54.6	58.1	59.9

B. *Electricity Technology Investments*

The scenario specific annual investment costs of electricity generation technologies are shown in Figure 5. In addition to the general increase in total investment associated with hydrogen demand, two key findings can be derived. Firstly, annual investment in H2-fired OCGT generation capacity is the only technology where investment decreases with increasing hydrogen demand. This is because additional demand outside of the electricity system increases the marginal cost of hydrogen, making electricity production from H2-fired OCGTs more expensive.

Secondly, the investment mix of the generation technologies and their proportion is the same among all scenarios with wind generation technology (wind onshore bevor wind offshore) making the biggest share of the investments followed by solar PV. Battery storage is also a significant part of the energy technology investment mix, varying only between 24 and 30 billion EUR/year across all scenarios, followed by investment in OCGT generation capacity.

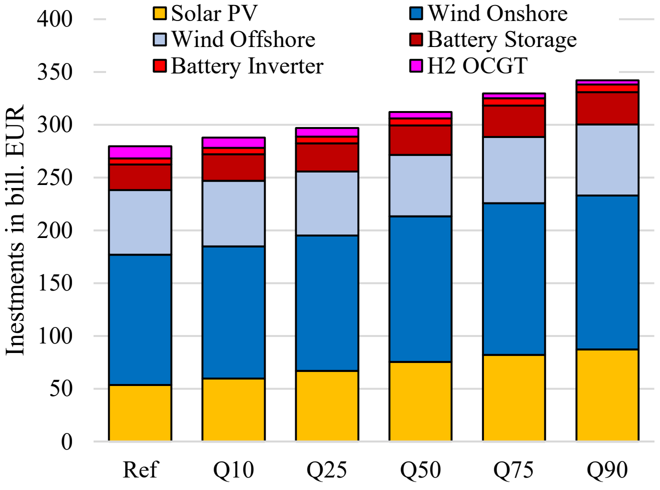

Figure 5: Scenario specific electricity technology investments

C. *Hydrogen Technology Investments*

Figure 6 illustrates the annual technology-specific investments in hydrogen related infrastructure, including generation (electrolyzer), transport (H2-pipelines), storage and import terminals. Note that the annual investment costs of the H2-import terminals are depicted on the secondary axis due to the low capital cost compared to the other technologies.

We find that all models invest in hydrogen production and distribution technologies in all scenarios. It is interesting to see that a fivefold increase in exogenous hydrogen demand from the Q10 scenario to the Q90 scenario results in only a fourfold increase in hydrogen technology investments. As hydrogen demand grows, electrolyzer utilization rises, improving the plant's economic efficiency.

Another interesting observation is that the investment costs of all technologies but import terminal are increasing with the higher hydrogen demand. This can be attributed to the jump in investments in pipelines from scenario Q50 to Q75. This is mainly because the model built new capacities starting from the Q75 scenario including mainly new pipeline connections between Finland and Germany and Finland and Sweden. Interestingly these connections are also promoted as a PCI project of the EU (PCI number 11.3). As the PCI projects are selected based on ENTSO-G's Ten-Year-Network-Development-Plan, we find that the Q75 hydrogen demand scenario lies between the two promoted "Distributed Energy" and "Global Ambition" scenarios. This indicates a regret potential of this hydrogen pipeline connection as it is only realized above the average hydrogen demand expectation for 2050.

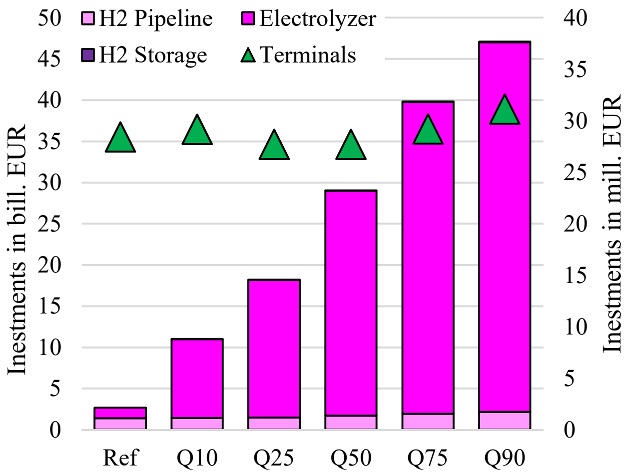

Figure 6: Scenario specific hydrogen technology investments

D. *No-Regret Options*

In order to investigate the no-regret investment options, we calculated the minimum expanded capacity of the hydrogen import terminals, electrolyzes option and the hydrogen pipelines across the five Q % scenarios. Figure 7 therefore provides an overview of the no-regret hydrogen import terminals, including their importing capacities and locations, the deployment of the no-regret electrolyzers and their nominal generation capacities as well as the expanded no-regret

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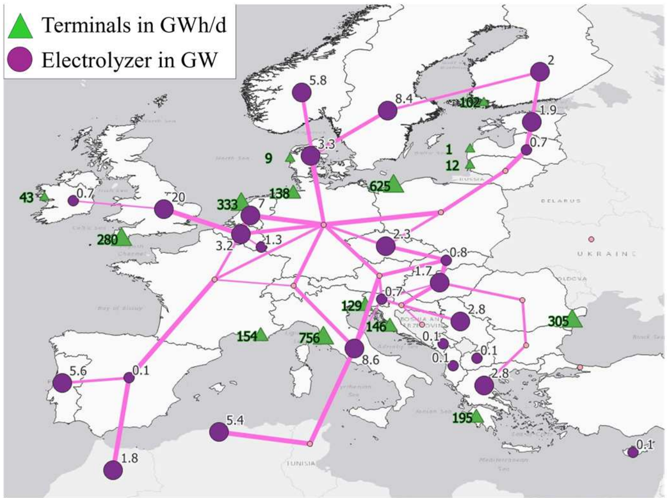
Identify applicable sponsor/s here. *(sponsors)* hydrogen pipelines. Additionally, the table below the map summarizes the annual investments in these technologies for each scenario and the no-regret options. From this it becomes clear that the biggest regret potential lies in the expansion of the electrolyzers as they are the main source for the hydrogen supply and thus directly connected to the hydrogen demand realization. The hydrogen pipelines as well as the import terminals are facing a lower regret potential.



Technology	Q10	Q25	Q50	Q75	Q90	No Regret
Electrolyzer [Bill. EUR]	3.709	6.460	10.560	14.644	17.372	3.641
Terminals [Bill. EUR]	0.029	0.028	0.028	0.029	0.031	0.019
H2 Pipeline [Bill. EUR]	1.429	1.478	1.722	1.946	2.162	1.206

Figure 7: Hydrogen infrastructure map based on no-regret expansion, depicting pipelines, terminals and electrolyzer locations

Interestingly, big countries such as France, Germany and Poland do not have any no-regret electrolyzer capacity. That's because in the low demand scenario Q10, the cheapest hydrogen production locations are leveraged first, while the import terminals enable a cheap supply for such low quantities avoiding expensive infrastructure investments. We find the largest no-regret import terminal capacity is built in Italy followed by Poland and the Netherlands. In the case for Italy that's because Italy serves as a distribution hub for hydrogen importing from Algeria via pipeline while also handling hydrogen imports from Saudi Arabia due to its relatively short shipping distance and strong integration into the European hydrogen grid. In contrast, Poland's hydrogen infrastructure is less integrated, as its pipeline connections to Germany and the Czech Republic reach their upper capacity limit, as defined by the ENTSOG's TYNDP for 2050. To compensate, Poland relies more heavily on import terminal capacity.

V. CONCLUSIONS

In this paper, we conducted two analyses on the hydrogen demand uncertainty in 2050. Firstly, we investigated statistically the distribution of hydrogen demand forecast taken from 32 studies. We found the hydrogen demand forecasts can be considered normally distributed with a mean of 1254 TWh, which is significantly lower than the forecast values that are underlying the PCI project assessments. Secondly, we investigate the impact of the hydrogen demand uncertainty on the infrastructure expansion needs of a future European energy system in 2050. We analyzed in detail five quantiles out of the approximated normal distribution of the hydrogen demand forecasts.

We find that the electricity investment costs are largely consistent across scenarios, with wind dominating and solar plus batteries providing essential support but decreasing H2-fired OCGT investments with rising hydrogen demand. We also demonstrate that the cost of meeting the scenario-specific exogenous hydrogen demand remains relatively low. This is partly due to system portfolio effects and partly because a system without additional demand would still invest in hydrogen technologies. As a result, also the increased utilization of existing infrastructure reduces the cost of an additional unit of hydrogen demand.

Furthermore, we find, as the hydrogen demand is highly uncertain, the electrolyzer investments show the biggest regret potential while pipelines and terminals investments vary less between the scenarios.

Our further research will focus on assessing the impact of the identified hydrogen demand forecast distribution by endogenously accounting for that uncertainty in a hybrid stochastic robust optimization model investigating robust investment options. Furthermore, we aim to also include other energy carriers for hydrogen such as ammonia or methanol.

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APPENDIX

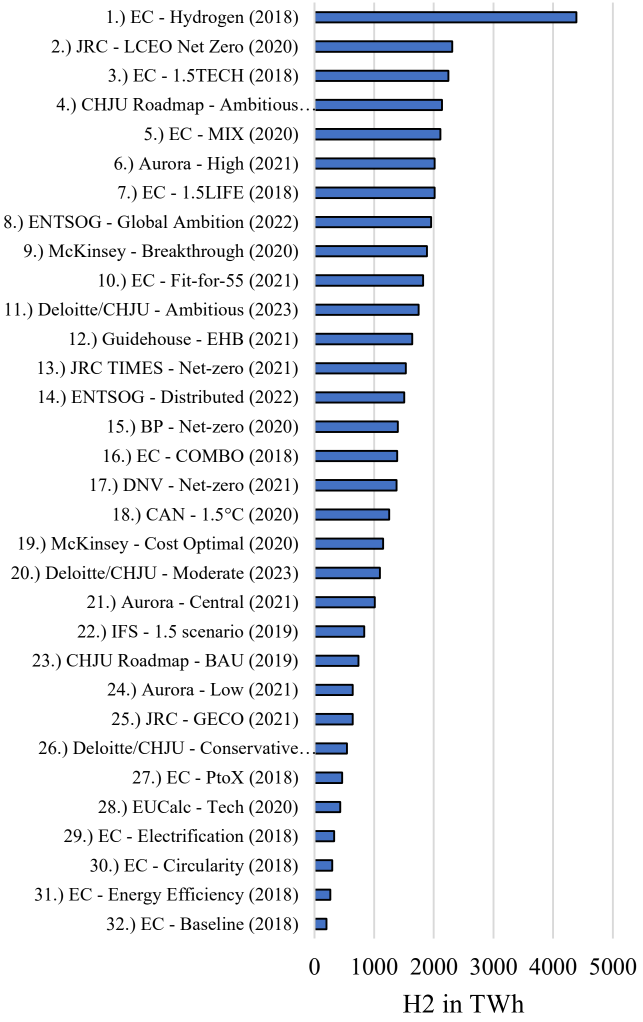

Figure 8:Scenario Specific Hydrogen Demand taken from [4]

Table IV: Q-Q-Diagramm data

Study	Demand	Rank	Rank-0,5/n	Theoretical Z-Value	Real Z-Value
1.)	198.0	1	0.016	-2.141	-1.577
2.)	264.0	2	0.048	-1.661	-1.479
3.)	297.0	3	0.081	-1.401	-1.429
4.)	330.0	4	0.113	-1.211	-1.380
5.)	433.4	5	0.145	-1.057	-1.226
6.)	462.0	6	0.177	-0.925	-1.184
7.)	543.0	7	0.210	-0.808	-1.063
8.)	638.7	8	0.242	-0.700	-0.920
9.)	642.0	9	0.274	-0.600	-0.915
10.)	737.0	10	0.306	-0.506	-0.774
11.)	835.7	11	0.339	-0.416	-0.627
12.)	1010.0	12	0.371	-0.329	-0.367
13.)	1094.0	13	0.403	-0.245	-0.242
14.)	1148.8	14	0.435	-0.162	-0.161
15.)	1252.0	15	0.468	-0.081	-0.007
16.)	1374.3	16	0.500	0.000	0.175
17.)	1386.0	17	0.532	0.081	0.193
18.)	1398.0	18	0.565	0.162	0.211
19.)	1505.0	19	0.597	0.245	0.370
20.)	1530.5	20	0.629	0.329	0.408
21.)	1640.0	21	0.661	0.416	0.571
22.)	1745.0	22	0.694	0.506	0.728
23.)	1819.4	23	0.726	0.600	0.838
24.)	1884.4	24	0.758	0.700	0.935
25.)	1953.0	25	0.790	0.808	1.037
26.)	2013.0	26	0.823	0.925	1.127
27.)	2015.0	27	0.855	1.057	1.130
28.)	2112.0	28	0.887	1.211	1.274
29.)	2139.0	29	0.919	1.401	1.314
30.)	2244.0	30	0.952	1.661	1.471
31.)	2310.0	31	0.984	2.141	1.569

Table V: Shapiro-Wilk-Test data

Study	Demand (x_i)	$(x_i - \bar{x})^2$	$\boldsymbol{a}$	$\boldsymbol{a \cdot x_i}$
1.)	198	1120598.1	0.422	83.56
2.)	264	985221.1	0.2921	77.11
3.)	297	920799.6	0.2463	73.15
4.)	330	858556.2	0.2141	70.65
5.)	433	678289.1	0.1874	81.14
6.)	462	631362.2	0.1641	75.81
7.)	543	509200.8	0.1433	77.81
8.)	638	382645.0	0.1243	79.30
9.)	642	377712.3	0.1066	68.44
10.)	737	269966.6	0.0899	66.26
11.)	835	177732.3	0.0739	61.71
12.)	1010	60803.2	0.0585	59.09
13.)	1094	26433.3	0.0435	47.59
14.)	1148	11790.3	0.0289	33.18
15.)	1251	31.2	0.0144	18.01
16.)	1374	13786.7	0	0.00
17.)	1386	16748.7	-0.0144	-19.96
18.)	1397	19716.9	-0.0289	-40.37
19.)	1505	61711.0	-0.0435	-65.47
20.)	1530	74756.8	-0.0585	-89.51
21.)	1640	147008.6	-0.0739	-121.20
22.)	1745	238551.1	-0.0899	-156.88
23.)	1819	316312.8	-0.1066	-193.91
24.)	1884	393652.0	-0.1243	-234.18
25.)	1953	484996.6	-0.1433	-279.86
26.)	2013	572166.6	-0.1641	-330.33
27.)	2015	575196.3	-0.1874	-377.61
28.)	2112	731738.1	-0.2141	-452.18
29.)	2139	778659.7	-0.2463	-526.84
30.)	2244	974992.2	-0.2921	-655.47
31.)	2310	1109687.3	-0.422	-974.82