Appendix 1. Electricity and hydrogen demand in the harbour regions

The future demand estimations for mobility; built environment; utility; datacentre; agriculture and fishery are retrieved for the regions of Den Helder and Amsterdam (8) and for Groningen (10). Reduction from the emissions from fisheries, which are very much present in Port of Den Helder region. The total CO_2 emissions per port area for 2017 for vessels are identified by Marin (22). Savings on these CO2 emissions could be realised by replacing traditional fossil-based fuels with synthetic fuels. Under the assumption that the number of vessels remain constant toward 2030 and 2050, the demand for hydrogen from shipping could easily grow to some to 3.6PJ_h/y by 2050 (see also Table 2). The assumption was made that the current shipping fleet is fuelled by diesel. The CO_2 content of diesel (74100 ton/PJ) was used to estimate the volume of diesel used by the shipping sector and to estimate the hydrogen demand required to replace the current fuel intake. The combined demand for hydrogen within the three harbour areas sums up to some 5% of the total potential demand for hydrogen in Netherlands and Germany (e.g. 1800 PJ_h/Y). The yearly data is converted to monthly values by applying seasonality patterns. The assumption is that the seasonality for hydrogen demand by households shows a similar pattern as the current monthly profile for natural gas consumption as provided by CBS (23). The seasonality is only applicable to sectors in which strong variation in hydrogen demand can be expected. Typically, the build environment has strong seasonality, though, in comparison to the current volume of natural gas uptake this is expected to be rather small. As a result, and given the rather continuous uptake of hydrogen in mobility (incl. aviation) and industry, the monthly consumption pattern is rather stable. We are aware that these profiles might differ per geographical region, though, for reasons of simplicity, this is not considered. Apart from being a potential major energy consumer of molecules, the local uptake potential for renewable electricity for local decarbonisation is very important. The electrical demand data is depicted in Table 1. The yearly electricity demand data is, like the hydrogen consumption pattern, converted to monthly values by applying seasonality patterns as provided by CBS (23). The seasonality is only applicable to sectors in which strong variation in electricity demand can be expected. Typically, the build environment has strong seasonality leading in this case to more demand for electricity in the winter periods than during summer. The application of historic seasonality patterns may lead to an under-estimation of summer-winter spread, which may be caused by strong increase of electricity demand in the build environment. It is expected that relatively more electricity would be required in the winter-period to provide sufficient energy of electric heating. Before being led to the model, the local electricity supplied in the region is subtracted from the monthly demand data. The projected energy supply in the harbour regions is considered available for local consumption and taken into account in the analysis (Table 3).

Table 1: Energy demand in the harbour regions in PJ/Y based on (8) and (10)[1]

	Hydrogen demand			Electricity demand		
Sector	Port of den Helder	Groningen Seaports	Port of Amsterdam	Port of den Helder	Groningen Seaports	Port of Amsterdam
Mobility	1,0	0,4	6,4	0,9	0,3	10,1
Build environment	0,5	0,9	6,1	1,4	0,8	20,0
Utility	0,1	0	0,6	1,3	0,0	11,9
Datacentre				12,6	0,0	19,3
Agriculture				0,1	0,1	0,1
Industrial	0,1	50	13,2	0,5	50,0	117,8
Shipping	0,9	0.3	0,8			
Aviation[2]			14.3			
Total	2.1	53.3	42.8	16.8	51.3	179.3

Table 2: CO_2 emissions shipping in tonnes based on (22)

	CO_2 emissions non-fishery vessels		CO_2 fishing vessels	
	Berthed	Sailing	Berthed	Sailing
Amsterdam	117578	32429	4572	1289
Den Helder	13084	10492	3689	3170
Eemshaven	4	42228	951	1006

Table 3: supply of intermittent resources within regions in PJ/Y retrieved from (8) & (10)[3]

	Port of Den Helder region	Port of Amsterdam region	Groningen Seaports region
Onshore wind	14,83	20,02	1,72
Rooftop PV	1,07	11,94	0,511
Solarfields	2,88	10,05	0,589
Total	18,78	42,01	2,82

[1] The demand for hydrogen for decarbonized bunker fuels for shipping (biomethanol, synthetic kerosene and/or ammonia are not included in the analysis. The demand for bunker fuels in the Port of Amsterdam region is expected to grow from 1 to 1,5Mton. Replacing just half of these bunker fuels, for instance with synthetic methanol, could easily let regional annual hydrogen demand grow with some 20PJ[1].

2 Apart from synthetical kerosene, cryogene or liquid hydrogen may play a role in the provision of clean fuel provision.

3 The yearly data is converted to monthly values by applying seasonality patterns. The seasonality for onshore wind shows a similar pattern as the current monthly profile provided by CBS (24), and the seasonality pattern for solar power is retrieved from Essent (25).

Appendix 2. Cost factors

Carbon neutral hydrogen production

Offshore wind is a valuable resource for the production of carbon neutral hydrogen. The capacity of the electrolyser is in this case directly coupled with the capacity of an offshore windfarm set at a minimum 2GW and 5250 running hours. There might be an economic potential to produce hydrogen cheaper in other parts of the world (abundance of low-cost renewable energy production), for instance the Sahara, and transport the hydrogen to the Netherlands. The potential to produce low-cost electricity from solar photovoltaic has been stipulated by Ad van Wijk (23). The LCOE of solar photovoltaic is expected to decrease to some 12.5€/MWh by 2050 (24) which positively influence the operational costs for hydrogen production. The relatively low load factor of solar photovoltaic is a downside as it increases the capital costs in €/KWh. The PEM electrolyser is selected, since, with a load range of 0-160% relative to nominal load, it is able to handle the flexibility demand brought forward by the wind and solar production. The assumptions on production cost for hydrogen in the North Sea and Sahara region are reflected in Table 4.

Table 4: Carbon neutral hydrogen production by 2040

	North Sea Region	Sahara Region	Unit	Source
Cost of electricity	35	12.5	€/MWh	(24), (22)
Run time	5250	3400	Hours/year	(23)
Electricity consumed	37.8	24.5	PJ/year	
Water demand	3214	2082	Mliter	(15)
H_2 produced	25.7	16.7	PJ/year	(15), (23)
Electricity consumed by desalination unit	0.05	0.03	PJ/year	(15)
Investment costs for PEM electrolyser, incl. desalination, auxiliary components, contingency, installation etc.)	1150		M€ / 2GW	(23)
Total financing costs	3930		M€	
CAPEX Factor	5.1	7.9	M€/PJ_{h2}	
Total Opex	407	108	M€	(15), (22)
OPEX Factor	15.2	6.5	M€/PJ_{h2}	

Low carbon hydrogen supply

Large-scale hydrogen production via ATR is considered together with carbon storage as a potential source of hydrogen supply in the future. The ATR system requires electricity for the provision of pure oxygen (ASU) and has therefore a higher power demand than for instance a SMR system. The ATR technology has moreover a higher CO_2 capture rate as more than 92% of the CO_2 can be captures, which is only about 71% for the SMR technology. This has been the main reason for choosing the ATR unit as a reference case. The techno-economic parameters assessment by Jacobsen and Atland of an ATR plant with a daily production capacity of 500ton/day has been used to determine the cost factor (24).

Table ***5*** gives an overview of the results comparing an ATR system located in the Netherland or in Russia, which was used as input in the modelling.

Table 5: Overview of ATR production systems. All efficiencies are lower heating value based.

	Netherlands	Russia	Units	Source
Cost of natural gas	0.0115	0.109	€/std m^3	(20) & (21)
Cost of electricity	35		€/MWh	(20)
Cost of CO_2 emitted	31.9		€/ton	(22)
Run time	8700		hours/year	Assumption
Natural gas consumption	76776		Std m^3 /h	(24)
Total electricity consumed	0.85		PJ/year	(24)
CO_2 captured/emitted	3816/318		Tonnes/day	(24)
H_2 produced	21.75	20.7	PJ/year	(24)
Total investment costs (Hydrogen production plant, Air Seperation Unit, Compressors, Auxilliary components, Installation and Engineering)	520		M€	(24)
Total investment costs of carbon capture facility. Drilling and injection well	240		M€	(24)
Total financing costs	2600		M€	
CAPEX Factor	4	4.2	M€/PJ_{h2}	
Total OPEX	114,5	110.5	M€	(24)
OPEX Factor	5.3	5.3	M€/PJ_{h2}	

Unit Technical Cost for Carbon Storage

The harbours have some unique characteristics when it comes to carbon storage. These characteristics are summarised in the table below. The technical costs comprises of the capital investment costs, the operational costs for the whole period and the 2017 price-level. The Unit Technical Cost will lay below the commercial cost level as economic elements such as inflation and risk- and profit margins are not accounted for. A study from the UK has shown that the commercial price may be a factor 4 higher, because of the uncertainties and involved risk-margin (21). The UTC consist of the following elements: offshore transport, injection, mottenballen, onshore transport and onshore compression.

The analysis of EBN and Gasunie (26 p. 62) shows that total cost for compression and storage do not significantly differ with increasing economics of scale, though, that transport costs are affected. In the Eemshaven scenario, CO_2 has to be transported over a relatively large distance, explaining the high share of transport costs. The Amsterdam scenario, has some shorter distances, but there are only two fields (Q1 and Q4) that have a direct connection to the Amsterdam region, resulting in higher transport and storage costs (20 p. 63). The potential UTC of offshore transport and injection costs may be lower for Den Helder, given that Den Helder is well connected via existing pipelines to the K-block, which were identified to hold significant volumes for CO_2 storage (estimated as some 275Mton). An important cost aspect is that the installation of new offshore installations (incl. welding) is at least twice as expensive as re-use (20). An UTC of 9€/ton has been assumed for the Den Helder location, given that the UTC for transport and storage will be lower due to the re-use and direct connection to offshore fields. **The UTC for den Helder is a rather broad assumption, and future research would be required to quantify the potential with more detail.** An important aspect in this will be the actual availability of other local CO_2 sources. For Eemshaven we took a UTC of 11€/ton as an input and for Amsterdam a UTC of 13.5€/ton (14). The UTC price for Amsterdam and Eemshaven are shown in the figure below. Note that these costs may be rather conservative since they established on a minimum start-up basis.

Table 6: CO_2 storage location characteristics based on (20) & (22)

	Port of Amsterdam Region	Port of Den Helder Region	Groningen Seaports Region
Connected to offshore storage facilities by:	The Q8 pipeline transporting gas from the western part of the DCS, size 10", length 14 km, The Q-helm pipeline transporting oil from the western part of the DCS, size 20", length 65 km.	1) The LoCal pipeline transporting low caloric gas from the central western part of the DCS, size 24", length 74 km; 2) The West Gas Transportleiding (WGT) transporting high caloric gas from the central western part of the DCS, size 36", length 121 km; 3) The Noordelijke Offshore Gastransportleiding (NOGAT) transporting high caloric gas from the north eastern part of the DCS, size 36", length 144 km.	The Noord Gas Transportleiding (NGT) transporting high caloric gas from the north western part of the DCS, size 36", total length 470 km. The L10 lays at some 178km
Storage volume capacity	Large storage potential in Q1 and Q4 fields (123.6MT) accessible with current infrastructure.	Large storage potential in K14/K15 and K7/K8 fields (171,2 & 104MT) accessible with current infrastructure (mainly WGT)	Large storage potential in L10 and K12 fields (103,4 & 37MT) accessible with current infrastructure (NGT)
Available CO_2 resources	Advantage of other local CO_2 sources that may help to realise economics of scale in CO_2 transport.	No significant local CO_2 resources	Advantage of other local CO_2 sources that may help to realise economics of scale in CO_2 transport.

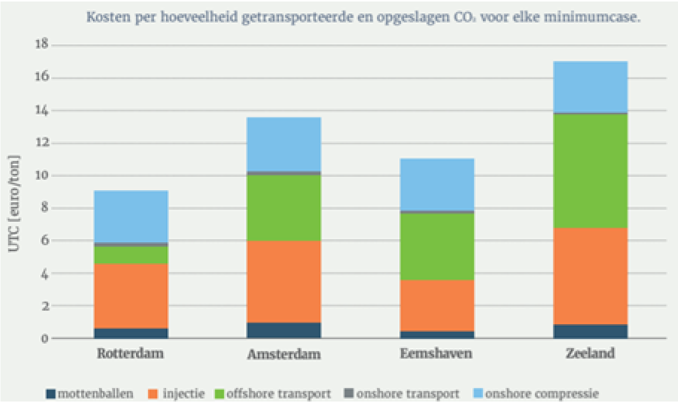

Figure 1: minimum CO2 transport and storage costs (EBN, Gasunie, 2017)

Import by ship

The harbours are logical points of hydrogen unloading, storing and injection, which can unlock the potential economic advantages of hydrogen import, presumably by ship. In the coming decades the naval transport of hydrogen will be boosted if the hydrogen economy grows, therefore explorative studies are already done on the prospected feasibility of hydrogen carriers and corresponding import terminals (27) (28). The hydrogen retrieval costs are still significant for carriers, but as distance increases these relatively decrease in the total shipping costs making longer transport routes more favourable for shipping solutions than shorter ones. Deciding factors, which determine the feasibility of import, are generally considered to be: production costs on production location (electricity and electrolyser costs), conversion/reconversion costs when considering hydrogen carriers and the costs of shipment. Based on the knowledge from these reports, an estimation is made on hydrogen import from the Sahara region by ship, using LOHC as a carrier.

The requirements for the local harbours to import hydrogen from external sources and distribute hydrogen gas have technical and financial implications. In practice, area is needed to discharge the ships and store/pressurize the hydrogen prior to delivering it to the grid. The practical requirements for hydrogen import terminals are estimated in some studies, and are strongly dependent on the considered carrier. The terminal consists mainly of a storage facility to discharge the (hydrogen carrying) load of the ship and the reconversion system to retrieve pure hydrogen. Reconverting liquid hydrogen requires little to no external energy input as it reaches gaseous state at room temperature, therefore a relatively simple pipeline, jetty and storage system is required for the import terminal. When LOHC is used to implement external produced hydrogen in the system, a reconversion system is required after the storage of the discharged hydrogen carrier. The specifications of the system differ per chemical consistency of the LOHC, which influences the pressure or temperature requirements of the recovery process. The size of the skids, however, can be considered in the same size range, depending on their conversion capacity. The cost of land-use based on the skid size of the reconversion and storage facilities has been taken into consideration. Table 7 provides an overview of the main cost elements.

Table 7: Overview of import infrastructure in harbour considered

	Value	Units	Source
Conversion in Sahara	23	M€	(20)[4]
Reconversion in port	23	M€	(20)
Shipping facilities	85	M€	(20)
Storage terminal in port	51	M€	(20)
Total financing cost for capex	622	M€	
CAPEX Factor	1.3	M€/PJ_h	
OPEX	10	M€	(20)
OPEX Factor	0.6	M€/PJ_h	

These studies are the foundation for the assumptions made in this report concerning the cost and potential of hydrogen import terminals in the considered harbours. It should be stated that the Kalavasta/ISPT report attempts to give an insight in the developments of costs of hydrogen transport based on extrapolated data, and therefore have a considerable uncertainty on the future developments of costs. Kalavasta/ISPT reported the expected cost per kg hydrogen transported from a large variety of countries based on domestic demand (taking into account the expected population growth), distance to the Netherlands' main economic harbour, renewable energy potential and WACC. From the results is concluded that shipping becomes more interesting if the distances are large, because the storage and transport costs increase less than the linear increase for pipelines. This is also confirmed in the findings on transport costs of hydrogen (carriers) by IEA (27). Hydrogen can be transported in various ways, which are currently in an early TRL level as a carrier technique, like liquid hydrogen, ammonia, methanol or $NaBH_4$. Currently there are barely liquid hydrogen bunker ships (the world's first carrier is launched in Japan, 2019 (27)) due to the extreme temperature levels in which the storage needs to operate, and its corresponding losses in energy and material complications. The losses in the energy requirements of retrieving the hydrogen from the 'carrier' liquids are also still too high to develop a feasible business case compared to pipelines. In all the technologies, the endeavour is to pursue the minimization of carbon footprint, process costs and energy losses per kg of transported hydrogen. The shipping costs are based on the cost estimations for a conventional chemical tanker (Cajun Sun) and a LOHC reconversion unit as depicted in HyChain study (20) (see also the table below)

Table 8: Indicative sizes and capacities of a LOHC release unit and a chemical tanker. Based on ISPT (20).

Import terminal unit	Value	Unit
Hydrogen outlet	1.5	t/d
LOHC demand	1400	l/h
Heat demand	780	kWt
Size (skid)	12x2.5x2.5	M (lxwxh)
Surface	30	m^2
Storage tank volume	50.000	m^3
(max.) Amount of terminals needed to store monthly capacity	4	

[4] *scaled with factor 0.54

CAPEX	12,5	M€
Ship (Cajun Sun) Capex	44	MEUR
Speed	17	km/h
Distance	6.000	Km
Days of travel (retour)	15	Days, i.e. 2 retours per month
Receiving capacity terminal per month	1,38	PJ/month
Capacity ship	52.560	m3
Density LOHC	57	kg h/m3LOHC
Hydrogen Tonnes eq. Ship	2.996	Tonnes H2/tanker
Hydrogen ship capacity	0.36	PJ/tanker
Hydrogen shipping capacity per month (2 retours)	0.72	PJ/month shipment cap
Ships necessary	2	
Construction storage terminal	12.5	M€
Opex Ship	7876	EUR/day
Opex	€2,87	MEUR/y
OPEX Factor	€0,17	MEUR/PJ_{h2}/y
(max.) Amount of terminals needed to store monthly capacity	4	

Pipeline import

Hydrogen import from Russia via pipeline might be an alternative to local low-carbon hydrogen production. The main advantage of this that is part of the existing European pipeline infrastructure may be re-used for hydrogen transport. Compression of hydrogen is required in order to transport it over (large) distances to the onshore point of connection. Higher pressure levels result in higher volumetric energy contents and require smaller pipeline diameters. To stabilize pressure, a compression station is located at every 100km. The output pressure of each single compressor is set to 60 bar, which is also similar to the operating pressure of an ATR unit (29). Regarding the costs of hydrogen compressors, one can distinguish between the required capital investment for the compressor itself and the operating costs, which typically consist of maintenance and energy costs. To identify the CAPEX of a compressor one needs to estimate the required work of compression, the compressor type and drive efficiency needed. For the purpose of this study, a compression power denoted by W, is calculated as (30),

$$\dot{W} = \dot{m} \cdot \frac{R\,T_1}{M_w} \cdot \frac{\gamma}{\gamma - 1} \cdot \frac{Z_1 + Z_2}{2} \cdot \frac{1}{\eta_s\,\eta_m}\left[\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} - 1\right]$$

Where:

- the mass flow rate (in [kg/s])
- the pressure of the compressor at suction (1) and discharge (2),
- the hydrogen compressibility factor at suction (1) and discharge (2),
- the inlet temperature of the compressor (333.15 K),
- the specific heat ratio (1.4),
- the molecular mass of hydrogen (2.016 kg/kmol),
- the isentropic compressor efficiency (80%),
- the mechanical losses from the driver (98%),
- the universal constant of ideal gas R = 8314 J/(K kmol).

When faced with the situation of estimating compressor costs, diverse published methods turn out with significant differences in their projected results. Moreover, most of the literature uses a single parameter for cost estimation, which is the compressor power. This study follows the line of research in NSE WP 3.1 (31).

$$\text{CAPEX}_{\text{compression}}[€] = 2{,}655.04^{5} \times \text{kW}$$

The CAPEX calculated by this formula includes the entire compressor package, i.e. driver and ancillary equipment. Concerning the operational expenditures, the recommendation is to consider 8% per year for planned maintenance on average over 15 years. The annual maintenance fee of 8% of the CAPEX is added to the electricity costs to estimate the total annual cost of running the compressor skid:

$$\text{OPEX}_{\text{compression}} = \left(A_0 \times H_{\text{year}} \times e/\text{DTE}\right) \times W + 0.08 \times \text{CAPEX}_{\text{compression}}$$

where:

- Utilisatiton - variable by case (60%-90%)
- Hours per year (8760h),
- the electricity costs (0.035 €/kWh),

[5] According to the European Central Bank consumer price index, today's prices in 2019 are 4.32% higher than average prices throughout 2014. The euro experienced an average inflation rate of 0.85% per year during this period. Therefore, 2,655.04 EUR is today's equivalent for 2,545 EUR in 2014.

- the Driver efficiency (90%).

The methodology used to construct associated costs follows the series of estimations made by EBN and Gasunie in their report 'Transport en opslag van CO2 in Nederland' (17). It states that on average, besides the pipeline material, two major factors are crucial for pipeline investments costs: the diameter and the distance to be covered. A pipeline diameter of 32-inch over a distance of 1700 km is chosen. The volume of production is chosen such that the max. volume of the pipeline is fulfilled. The CAPEX of the pipeline is shown in Table 9 below. It is important to mention that there are more costs related to the installation of pipelines, which are not taken into account in this study due to undefined locations.

Table 9: 32-inch import pipeline under the operational conditions: 60 bar, 10 °C, and <20 m/s

Max. flow rate[kg/h] / (PJh)	CAPEX pipeline [M€]	Cap. Comp. [MW] (No.)	CAPEX comp. [M€]	OPEX comp. [M€]	Financing costs CAPEX(M€)	CAPEX Factor M€/PJh	OPEX Factor M€/PJh
228115 (218)	€ 2.652	23,3 (15)	€1396	€87	13833	3.06	0.93

Backbone

The existing injection capacities per region were retrieved from the "gastransportkaart GTS 2015 Final (3)" and converted toward volumes of hydrogen transported to year. Pipelines may offer an economical way to store part of the hydrogen in the pipeline (35). As a basis for the line pack, we use a 1.5 á 2 bar buffer to provide a flexibility marge of some 5% (37). The provision of flexibility by pipelines reduces the need for additional investments in storage facilities. An indication of the hydrogen transportation capacities for pipelines is provide in Table 10.

Table 10: Hydrogen transportation capacities for pipelines with different diameters and operating pressures

		NPS	DN	Flow Rate	Monthly Capacity	Monthly capacity incl. flexibility
30 barg		[-]	[-]	[kg/h]	[PJ pm.]	[PJ pm.]
Den Helder	A616	48	1200	152000	15.8	16.6
Regio	A591	42	1050	116000	12	12.6
	A593	36	900	82000	8.5	8.9
Eemshaven	A543	48	1200	152000	15.8	16.6
regio	A610	42	1050	116000	12	12.6
	A542	42	1050	116080	12	12.6
Amsterdam	A803	48	1200	152000	15.8	16.6
regio	A553	42	1050	116000	12	12.6
	A551	36	900	82000	8.5	8.9
50 barg						
Den Helder	A616	48	1200	251000	26	27.3
Regio	A591	42	1050	191000	19.8	20.8
	A593	36	900	135000	14	14.7
Eemshaven	A543	48	1200	251000	26	27.3
region	A610	42	1050	191000	19,8	20.8
	A542	42	1050	191000	19,8	20.8
Amsterdam	A803	48	1200	251000	26	27.3
region	A553	42	1050	191000	19,8	20.8
	A551	36	900	135000	14	14.7

Storage

The development of a hydrogen economy to facilitate the integration of offshore wind requires an infrastructure with facilities for small- and large-scale storage. Large-scale storage will typically take place in the subsurface, most likely in salt caverns, and is therefore limited by geographical conditions. Looking at the Netherlands, these geographical conditions are present in the northern part of the Netherlands.

The Ministry of Economic Affairs and Climate commissioned in 2018 a technical assessment (40) on the various options for subsurface storage in the Netherlands. The estimation of onshore hydrogen storage capacity (working volume) in salt caverns is concentrated on the Zechstein group at a depth range of 1000 to 1500m (39). The analysis (40) provides an estimated energy content of the potential hydrogen storage in salt caverns, given that the effective number of caverns is set to 50% of the theoretical potential and the minimum distances required, a maximum operational pressure of 180 bar, and a working volume to cushion volume ratio of 1 to 1. The outcome indicates a potential storage for a single cavern in the order of 45 million m^3.

DNV GL (41) has made a similar analysis on the most feasible options for hydrogen solution, including pressurized subsurface storage. The levelized cost of underground hydrogen storage is around 0.30-0.35€/kg, based on an average of 9 cycles/year. These costs include the specific system investment of compressing the hydrogen from 60 to 250 bar, which are in the order of 950€/KWe. Some margin should be taken into account, as the compression cost are based on a very low electricity price (0). In general, the electricity consumption for compression lies around 0.5-2kWh/kg and with an electricity price of €35/MWh you will reach a €/kg price in the order of 0.02-0.07 €/kg. This data has been applied to the model.

In addition to these capital and operational costs, a reservation should be made for the use of the surface. The diameter was set at 30 metres, and thus a total surface requirement of some 12000m.[6] The compensation for spatial use is set at 10% of the ownership value, as storage will take place in the underground, it is expected that the are above ground can for a great extent still be used for e.g. agriculture. The fee for land-use adds some 0.02€/PJ to the total price.

Table 11: Overview of underground storage costs

	Value	Units	Source
Cycles per year	9 (6-12)	No. of cycles	(30 S. 50)
Total capacity	5	PJ_{h2}	(30 S. 50)
CAPEX cavern	180	M€/PJ_{h2}	(30 S. 50)
CAPEX compression	140	M€/PJ_{h2}	(30 S. 14)
Total financing cost for capex	1094	M€/PJ_{h2}	
CAPEX Factor	4.05	M€/PJ_{h2}	
OPEX compression power	0.38	M€/PJ_{h2}	Assumption based in the above
OPEX other	0.11	M€/PJ_{h2}	(30 S. 50)
OPEX Factor	0.49	M€/PJ_{h2}	

[6] Surface area is calculated as pi*60^2

Appendix 3. Economies of scale

Some industrial equipment costs are subject to economies of scale, which implies that the cost of capital does not increase with the same rate as the size of the capacity. In other words, the costs per produced unit of energy decreases if the capacity increases [1]. For blue hydrogen production technology, some studies have been done on the scaling of SMR production units, and it is assumed that the effects are comparable to ATR technology since the equipment is comparable as well, despite the addition of air separation units. Electrolyzers are commonly produced with modular capacity, and only have economies of scale in the upscaling of their balance of plant. For import of hydrogen, no scaling effects are considered since the various modular assets necessary for an import system can be considered to have scaling effect per element, but these are of minor impact on the system level. From the system perspective, scaling characteristics make it more advantageous to locate the production facilities on one location at a large scale, and supply the other demand locations via the backbone.

Considered scaling factors for economies of scale	Scaling factor	Source
Electrolyzers	0.95	(30)
ATR/SMR reformers	0.8	(30) , (31)

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