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Prospects for offshore hydrogen production in the Netherlands

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Prospects for offshore hydrogen production in the Netherlands

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Abstract

Using a technology-rich optimization model for the Netherlands, we analyse the potential role of offshore energy options for system integration purposes. Our focus is on offshore hydrogen production produced by wind power in the Dutch Exclusive Economic Zone of the North Sea. We conclude that large-scale offshore green hydrogen development is a robust outcome of our scenarios. We also find that offshore green hydrogen production dominates over onshore hydrogen generation with green electricity delivered to shore through power lines in the North Sea. The main reason is the avoidance of elevated costs associated with a high voltage electricity grid at sea. We observe a large range of possible offshore hydrogen production levels, from 40 to 250 TWh yr⁻¹ in 2050, depending e.g. on the level of total hydrogen demand, the availability of competing emission abatement options, and the offshore wind energy potential. After 2040 it becomes optimal to transport most energy from newly installed offshore wind capacity to shore in the form of hydrogen. Because of the long lead times involved in infrastructure planning, offshore hydrogen production and transportation should be put high on political and industrial agendas.

1. Introduction

Several years after the Paris Agreement (UNFCC 2015), the European Commission declared that it aims to be climate-neutral by 2050 (EC 2020). As an important milestone towards climate neutrality the European Commission adopted the Green Deal, which describes a strategy for reducing net greenhouse gas (GHG) emissions by 55% in 2030 as compared to 1990 (EC 2021).

The scientific and policy communities have recently confirmed in the sixth Assessment Report of the IPCC that our global GHG emission reduction ambitions need to be stepped up (IPCC 2022). Furthermore, the war in Ukraine has increased the urge to phase out fossil fuels in the European Union. To reduce the dependency on Russian fossil fuels, the European Commission published the REPowerEU plan in May 2022, which is based on three pillars: saving energy, producing clean energy and diversifying energy supply (EC 2022a).

A few months after the publication of the REPowerEU plan, members of the North Seas Energy Cooperation (NSEC)⁴ set ambitious (non-binding) targets for offshore wind energy: 76–81, 164–189 and 260–290 GW in 2030, 2040 and 2050 respectively (NSEC 2022). For the Netherlands the short term targets increased significantly from 11.5 GW in 2030 (GoNL 2019) to 21 GW (in 2031). The Dutch targets for 2040 and 2050 are now respectively 30–50 GW and 40–70 GW (NSEC 2022). Several studies demonstrate that wind offshore is one of the working horses to make the Netherlands climate neutral in 2050 (Ros and Daniëls 2017, NBN 2021, Scheepers *et al* 2022a). A recent study confirmed that the physical potential for such large wind offshore capacity is available, even when considering space limitations and multiple sustainability conditions (Taminiau and van der Zwaan 2022).

⁴ Belgium, Denmark, France, Germany, Ireland, The Netherlands and Norway.

In the transition towards a low-carbon economy, hydrogen is considered an important energy carrier (IEA 2019, IRENA 2019a, 2022). In the Green Deal, ambitions for a significant share of green hydrogen in total energy use have been expressed. The REPowerEU's objective to reduce the dependency on Russian fossil fuels has further increased the future importance of green hydrogen (EC 2022b), since it will diversify the EU's energy supply mix, both via domestic hydrogen production and via imports of hydrogen from countries other than traditional oil and gas exporting countries (van der Zwaan *et al* 2021).

Current hydrogen demand in North-West Europe is over 4 Mt yr⁻¹ (IEA 2022). Given its large chemical and refinery sectors, the Netherlands represents a large part of this: 1.5 Mt yr⁻¹ (Weeda and Segers 2020). While the current domestic hydrogen production in the Netherlands is almost exclusively produced from unabated fossil fuels, a target for 3–4 GW of electrolysis capacity in 2030 was set in the Dutch Climate Agreement (GoNL 2019).

Challenges related to variable renewable energy sources (VRESs) solar and wind energy have been recognized for a long time (Klinge Jacobsen and Schröder 2012). Solutions can be found on both the supply side via energy storage, increased interconnections with neighboring countries and curtailment of VRES, as well as on the demand side via demand response, an increased rate of electrification and application of power-to-X (Sijm *et al* 2017). For the power-to-X applications, power-to-hydrogen in the form of electrolysis, combined with hydrogen storage, is seen as an important solution to accommodate the variable character of solar and wind energy (IRENA 2019b).

In the short term, limitations in the expansion of the electricity infrastructure on land put a cap on onshore large scale VRES in the Netherlands of 35 TWh in 2030 (PBL 2022). Restrictions of the electricity grid on land also result in issues for electricity generation offshore. In Germany, for example, increased electricity grid congestion near landing points has already resulted in high curtailment and related costs over the past years (BNA 2021). A fast enforcement of the onshore and offshore grid in the short term is not very likely, due to long permitting lead times, a shortage of skilled installation personnel and the space of landing for wind offshore (Guidehouse and Berenschot 2021).

The ambition to develop more wind farms and at a higher rate will require resolving these issues with higher urgency. In particular the increased offshore wind ambitions for 2030 will require a high amount of flexibility in the energy system already before 2030. Furthermore, sustainable business cases for offshore wind developers are under pressure if consumption of electricity and the electrification of the energy system lag behind, since the electricity price will, on average, be low during hours when there is a lot of wind production (Gonzalez-Aparicio *et al* 2020).

New policies are being designed that are not solely focused on producing electricity from wind offshore at the lowest cost per MWh. A balanced integration of new wind offshore farms in the energy system (and beyond) is being recognized for a sustainable growth of the offshore wind industry. Therefore, the most recent Dutch offshore auctions focus heavily on non-price criteria, including integration in the Dutch energy system (Wind Europe 2022).

Producing hydrogen offshore might be a good solution to above mentioned issues, since the Netherlands already possesses an extensive natural gas network offshore. A part of this network could be retrofitted to hydrogen pipelines, even though retrofitting of such pipelines for hydrogen transport can be challenging and not possible in all circumstances (Ohaeri *et al* 2018, Sandana *et al* 2022, Kappes and Perez 2023, Pigon *et al* 2023). Furthermore, the amount of energy that can be transported through standard high pressure gas pipelines is significantly more than typically sized high voltage (HV) electricity cables, which makes the transport per GW/km significantly cheaper. Furthermore, hydrogen is an energy carrier that can be stored effectively at low cost in salt caverns and empty gas fields (Groenenberg *et al* 2020). Last but not least, offshore hydrogen production could serve as a significant source of green hydrogen thanks to the large offshore wind potential.

One can wonder why the hydrogen should be produced offshore and not being produced onshore (close to a connection point). In the short term it would be most logical to produce hydrogen onshore, since hydrogen production via electrolysis needs a more mature development in general, while offshore hydrogen production has some additional challenges. For example, sea water first needs to be converted into demineralized water before it can be converted into hydrogen. However, there are several projects in preparation from which it is clear that project developers and energy companies consider offshore hydrogen production as a serious option. These initiatives range from 1 MW scale pilot projects such as the Poshydron project (Poshydron 2024) to GW scale projects such as AquaVentus (AquaVentus 2024). The NorthH₂ consortium wants to produce hydrogen onshore in 2030, using electricity from wind offshore, and possibly after 2030 extend its plans to offshore hydrogen production (NorthH₂ 2023).

Only a few studies have thus far analysed offshore hydrogen production using an integrated energy system model. Martínez-Gordón *et al* analysed the entire North Sea area for 2050, focusing on the benefits of an integrated power and hydrogen offshore grid for this area (Martínez-Gordón *et al* 2022a).

Gea-Bermúdez *et al* studied *where* hydrogen should be produced (offshore or onshore) in Northern-Central Europe for the period 2030–2050 using an integrated energy system model (Gea-Bermúdez *et al* 2023).

These two studies cover several European countries, but the geographical resolution per country was low, while this aspect might be important. Switching from bringing offshore electricity to shore to offshore electrolysis will be a tradeoff, in which distance is an element to consider. A new element of this study is that both the onshore and offshore parts of the Netherlands are presented in some geographical detail to capture this distance related balance. The current study used the report of Scheepers *et al* (2022b) as a starting point, but we delve into the topic of offshore hydrogen production much deeper. In the present study we reconsider the parameters of key technologies that determine the role of offshore hydrogen production and we include designed sensitivity cases to specifically test the role of offshore hydrogen. The research questions we want to investigate in this study are: (1) under what scenario boundary conditions will offshore hydrogen production in the Dutch part of the North Sea be deployed (2) what parameters have an important impact on the role of offshore hydrogen production and (3) how much hydrogen is produced offshore in optimized energy system scenarios? For addressing these questions, we use a national integrated energy system model.

In section 2 the methodology used in our study is described, including a description of the sensitivity analysis that we undertook. We present our results in section 3 and put them into perspective in section 4. Final conclusions and policy recommendations are given in section 5.

2. Methodology

The main part of the analysis presented in the current paper has been performed using the OPERA model: see section 2.1. Other important aspects of our modeling efforts are the scenarios (section 2.2), the regions (section 2.3), the techno-economic parameters (section 2.4), and the sensitivity tests that we inspected (section 2.5).

2.1. Modeling tools

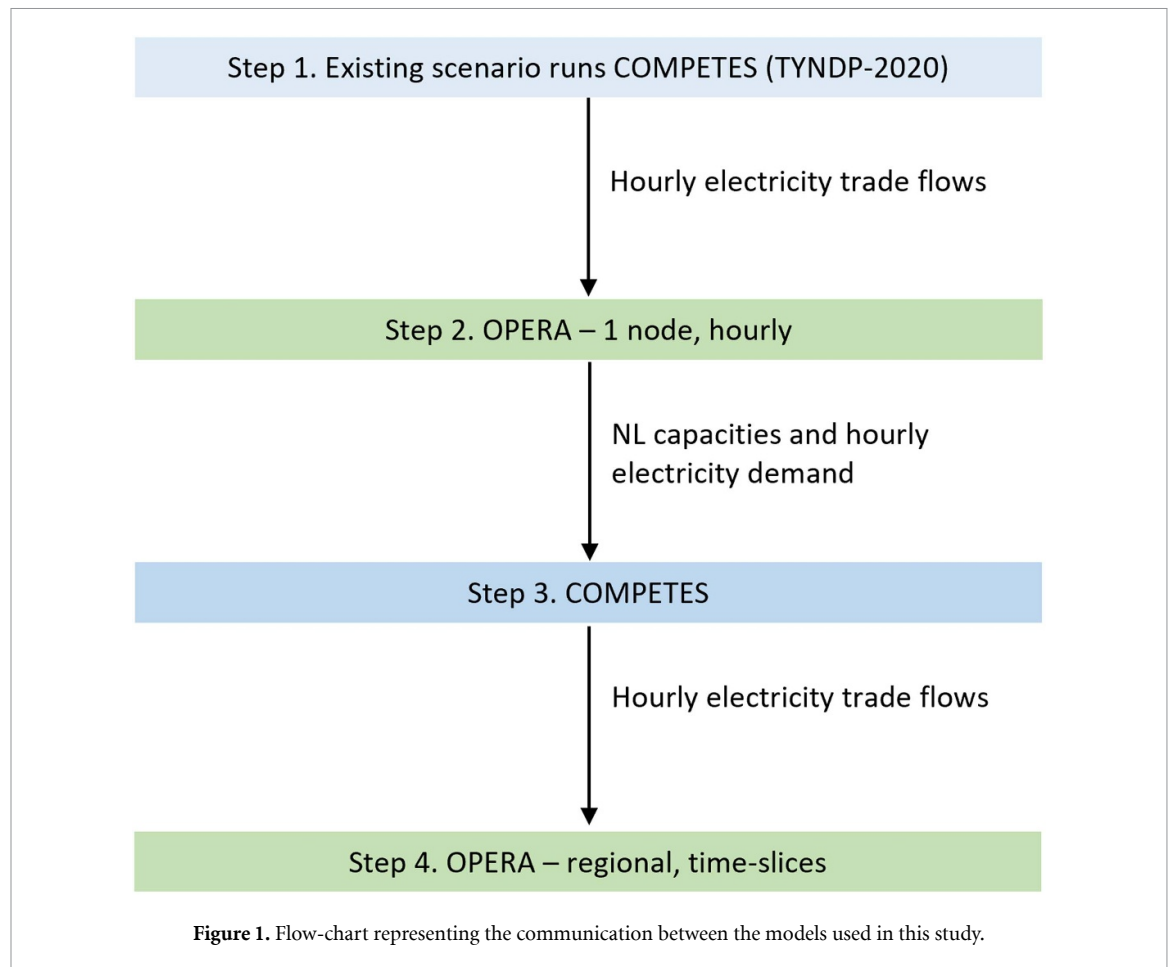
The main tool used is the OPERA model (van Stralen *et al* 2021). OPERA is an optimization model based on linear programming (LP). It represents the entire energy system of the Netherlands, including bunker fuels, feedstocks and all domestic GHG emissions. The optimization is done from a societal perspective and therefore a low discount rate is used, in this study 2.25%. Myopic optimization is done for the period 2030–2050, with time-steps of 5 years. This means that the optimization is done for individual years, but installed capacity is transferred to the next period. Capacity for which the lifetime is reached is phased out.

OPERA makes use of time-slices, in which hours with a similar character are grouped in the same time-slice. OPERA's possibility to run on hourly or n-hourly resolution, using chronological order, has only been limited to one sensitivity case, to avoid excessive calculation times, and for 1-region runs. The same time-slice recipe as used by Sijm *et al* (2017) has been used in our study, only the number of time-slices has been increased to 85. Data items with an hourly resolution are aggregated in these time-slices. Examples of hourly input data are hourly wind speeds and the hourly electricity demand profile for the household sector. For all hourly profiles, 2015 is the reference year. This means that for any modelled year, the profile follows the same hour to hour variation as the 2015 profile, but the annual volume is unique for each year. Since the model can apply additional electrification, demand shifts or curtailment, the resulting profile for a modelled year might deviate from the 2015 profile.

Import and export of electricity with neighbouring countries is not determined endogenously, but calculated using the European electricity market model COMPETES (Lise *et al* 2010) via data exchange between OPERA and COMPETES as illustrated in figure 1. As a first step, existing hourly electricity trade flows, which are extracted from the Dutch Climate and Energy Outlook 2020 (PBL 2020), are used. In that study COMPETES has been used as well, with TYNDP-2020 (ENTSO-E 2020) based electricity demand for other European countries and Dutch electricity demand and capacities according to the Outlook 2020. Capacities for other European countries are determined endogenously. The electricity trade flows are used in OPERA in step 2, in which OPERA has been run without regions on an hourly basis. The installed capacities and hourly electricity demand for the Netherlands from step 2 were sent to COMPETES. In step 3, the COMPETES model was used to calculate new hourly electricity trade flows with neighbouring countries. In this, COMPETES is allowed to optimize the capacities for all countries, except for the Netherlands, since they are determined in step 2. Electricity demand of other European countries is from TYNDP-2020 as well. As fourth step, a final OPERA run was done, using the updated electricity trade flows.

2.2. Scenarios

In this study the ADAPT and TRANSFORM scenarios have been used. An extensive description of the storylines of those scenarios can be found in (Scheepers *et al* 2020, Scheepers *et al* 2022a). ADAPT reflects a



future in which the Dutch economy builds on existing infrastructure and strengths, while preserving current lifestyles. TRANSFORM, on the other hand, reflects a future in which behavioural changes in Dutch society support a radical shift to a more sustainable economy, making the Netherlands a less energy intensive economy overall. ADAPT and TRANSFORM are well known scenarios for Dutch policy makers and stakeholders as reflected for example in the explicit use of those scenarios in the National Plan Energy system (NPE 2023).

The update of the ADAPT and TRANSFORM scenarios, as presented in Scheepers *et al* (2022b) has been used for our current analysis. This update covers a revision of demand figures, supply volumes and capacities, a significant amount of technology updates and requiring net zero domestic GHG emissions in 2050 for both ADAPT and TRANSFORM. For the TRANSFORM scenario an additional requirement is that in 2050 90% of all feedstock production should be based on non-fossil carbon. Another important difference between ADAPT and TRANSFORM is that GHG emissions reductions of international aviation and shipping are far more severe in TRANSFORM than in ADAPT⁵.

Maximum supply volumes and capacities used in our optimization are given in table 1. In general, values for 2035 and 2045 are based on interpolation, with the exception of nuclear energy, which is zero in 2035 and the CO₂ storage potential of TRANSFORM in 2045, which is 7.5 Mt yr⁻¹. Demand values, border prices, baseline emission of non-CO₂ GHGs, indirect CO₂ and LULUCF can all be found in the report of Scheepers *et al* (2022b). The same applies for the imposed reduction targets for domestic GHG emissions, international shipping and aviation GHG emissions and targets for circular carbon for feedstock production.

2.3. Regions

To make a proper comparison between offshore and onshore conversion of electricity to hydrogen, regions offshore and onshore have been defined. Energy infrastructure is needed to connect supply and demand of energy. Transmission infrastructure costs can only be calculated properly if distances and distance specific

⁵ GHG emission of international aviation should be reduced by 95% in TRANSFORM and 50% in ADAPT compared to 2005 emissions. For international shipping GHG emissions, the same reduction % apply, but compared to 2008 emissions.

Table 1. Maximum supply volumes and capacities used in ADAPT and TRANSFORM (Scheepers *et al* 2022b).

Maximum	Unit	ADAPT			TRANSFORM		
		2030	2040	2050	2030	2040	2050
CO ₂ storage	Mt yr ⁻¹	7.5	35	50	7.5	7.5	15
Wind offshore capacity	GW	11.5	36	40	14.5	45	70
Wind onshore capacity	GW	7.8	7.8	7.8	7.8	10	12
PV capacity	GW	29.6	63.2	106.8	40.5	78.2	132.1
Nuclear capacity	GW	0.5	2.5	5.0	0.5	2.5	5.0
Biomass domestic	PJ yr ⁻¹	160.5	234.7	308.8	146.3	169.5	192.7
Biomass import	PJ yr ⁻¹	193.7	646.9	1100	155.8	415.4	675
Geothermal heat (>500 m depth)	PJ yr ⁻¹	50	125	200	50	125	200
Additional onshore electricity transmission capacity between regions as compared to current capacities	%	20%	100%	150%	20%	100%	150%
Hydrogen admixture % in the natural gas grid ^a	%	0.5%	10%	15%	0.5%	10%	15%

^a This corresponds to the energetic admixture % of hydrogen in the natural gas grid. The % applies to the natural gas that is exclusively used for energetic applications. These percentages are not mentioned in Scheepers *et al* (2022b), but the same values have been used.

infrastructure costs are included. OPERA allows for the transmission of electricity, hydrogen and natural gas between regions. The regionalization of OPERA is described in Sahoo *et al* (2022).

In the current study we use seven onshore and seven offshore regions, as shown in figure 2. In this figure trajectories for offshore cables and pipelines have been assumed, based on potential areas for wind farms according to Matthijssen *et al* (2018). HV electricity cables and pipelines are assumed to follow identical trajectories in which the trajectories of HV electricity cables are leading, since they are much more expensive per unit of energy and distance. The only exception is the connection between North NL and North-Holland: in line with the current infrastructure, only a pipeline is assumed. The onshore HV trajectories are derived from Tennet (2021) and follow the existing HV transmission lines as closely as possible. The resulting map is used to determine the distances between regions, see table 2 for the distances and for the type of transmission connections. Note that for all offshore regions, except offshore A, we allowed for offshore hydrogen production and transmission to shore. Offshore A, corresponding to the existing Borssele wind farms (Noordzeeloket 2022), is a relatively small area and is already connected to shore via electricity cables. Offshore natural gas extraction and transport has been left outside the scope of our analysis.

As given in table 1, the wind offshore potentials in 2050 are 40 and 70 GW for respectively ADAPT and TRANSFORM. These potentials are distributed over the seven offshore regions according to scenario IV from (Matthijssen *et al* 2018). The potentials per offshore region can be found in table 3. The corresponding windspeeds at hub height are extracted from Ruijgrok *et al* (2019).

The data sources that are used to distribute other renewable energy sources over onshore regions can be found in van Stralen *et al* (2020). The feasibility of distributing the energy and service demand over regions depends a lot on the demand type, and in the case of industrial activities on the number of sites where certain products are made. For the built environment and domestic transport, a distribution of the electricity, fuel and heat demand based on the population distribution has been applied. For industrial energy demand, each product and final electricity and heat demand have been distributed over the regions. The geographical distribution of the five main energy intensive industrial activities, ethylene production, production of other chemicals, fertilizer production, fuel refining and steel production, are given in table 4. The approach and data sources for all demand sectors can be found in van Stralen *et al* (2020).

2.4. Techno-economic parameters

Cost and efficiencies of technologies are the same as used by Scheepers *et al* (2022b), with a few exceptions particularly relevant for this study. Techno-economic parameters of the following technologies have been re-examined and updated according to the most recent insights:

- HVDC offshore cables
- Onshore substation
- Onshore HVAC cables



Figure 2. Offshore and onshore regions used in this study. The red lines indicate the assumed trajectories of transmission cables and pipes and are used to determine distances.

- Large scale electrolyzers, including the additional cost offshore
- Hydrogen pipelines, including the additional cost offshore
- Wind offshore

The data of those technologies and components can be found in table A1.

2.5. Sensitivity analysis

To check the robustness of our results a large set of sensitivity cases has been calculated. An overview of the sensitivity cases can be found in table 5. Note that some cases were only calculated for one of the scenarios. The sensitivity cases can be categorized as follows:

- Type A: cases in which the competition between offshore electricity and hydrogen is tested;
- Type B: cases that have a potential impact on green hydrogen production. These cases can be further subdivided in:
 - B.i: high demand for green hydrogen;

Table 2. Distances between regions in km and possibility of transport of electricity, hydrogen and natural gas between regions.

Region I	Region II	Distance [km]	Transport of energy carrier between regions		
			Electricity	Hydrogen	Natural gas
Offshore A	Zeeland	69	✓		
Offshore B	South Holland	60	✓	✓	
Offshore C	South Holland	132	✓	✓	
Offshore C	North Holland	94	✓	✓	
Offshore D	Offshore C	72	✓	✓	
Offshore E	Offshore D	97	✓	✓	
Offshore F	Offshore E	76	✓	✓	
Offshore F	Offshore G	137	✓	✓	
Offshore G	North NL	99	✓	✓	
North NL	Mid NL	179	✓	✓	✓
North NL	North Holland	258		✓	✓
Mid NL	Limburg	185	✓	✓	✓
Mid NL	North Holland	117	✓	✓	✓
Limburg	North Brabant	143	✓	✓	✓
North Brabant	Zeeland	113	✓	✓	✓
North Brabant	South Holland	96	✓	✓	✓
South Holland	North Holland	121	✓	✓	✓

Table 3. Wind offshore potentials [GW] in ADAPT and TRANSFORM in 2050.

Offshore region	Wind offshore potential	
	ADAPT	TRANSFORM
A	1.5	1.5
B	7.2	7.2
C	12.5	12.5
D	5.5	7.3
E	4.6	7
F	0	25.8
G	8.7	8.7
Total	40	70

Table 4. Distribution of the main energy intensive industrial production activities over onshore regions.

	Ethylene	Other chemicals	Fertilizer	Fuel refining	Steel
Limburg	40%	4%	38%		
Mid NL		2%			
North Brabant		3%			
North Holland		5%			100%
North NL		20%			
South Holland	20%	48%		86%	
Zeeland	40%	18%	62%	14%	

- B.ii: low demand for green hydrogen or high supply for alternative sources of hydrogen;
- B.iii: high demand for electricity or low supply of alternative sources of electricity supply;
- B.iv: low demand for electricity or high supply of alternative sources of electricity supply;
- Type C: a case in which the effect of time-resolution is tested.

3. Results

Since the input data used are the same as used by Scheepers *et al* (2022b), except from an update of a few technologies which are of key importance for addressing the role of offshore hydrogen (section 2.4), the high-level results of the base scenarios are also almost identical to that study. Therefore, in this section general results on the energy system, like primary and final energy mixes, are not presented. The interested

Table 5. Description of the sensitivity cases used in this study.

Name of sensitivity	Type of sensitivity ^a	ADAPT	TRANSFORM	Difference compared to the base scenario
No H ₂ offshore	A	x	x	Offshore hydrogen production is excluded
Low cost offshore HVDC	A	x	x	Cost of offshore HVDC is halved
High cost offshore H ₂	A	x	x	Cost offshore electrolysis is doubled
No electricity to sea	A		x	Electricity flow from onshore to offshore (for electrolysis) is excluded
No cables far from shore	A		x	No HVDC cables >150 km from onshore connection point
High wind offshore	A		x	Potential wind offshore 100 GW (Taminiau and van der Zwaan 2022) instead of 70 GW
Low CCS	B.i	x		Potential CCS lowered from 50 to 35 Mt yr ⁻¹
Low bio	B.i/B.ii	x	x	Wood import potential lowered with 50% for ADAPT and 25% for TRANSFORM
No LS H ₂ storage	B.ii	x	x	Large scale hydrogen storage is excluded
H ₂ Import	B.ii	x	x	Import of hydrogen is possible up to 250 PJ yr ⁻¹ in 2050
RES fuel & feedstock import	B.ii	x	x	Allow for import of biogenic bunker fuels & synthetic methanol at a low price
High CCS & no circ C	B.ii		x	CCS potential 25 Mt yr ⁻¹ instead of 15 Mt yr ⁻¹ and no circular carbon share
No nuclear	B.iii		x	New nuclear power plants after 2035 onwards are excluded
Low electricity trade	B.iv		x	The electricity import and export is halved
High nuclear	B.iv		x	Gen III nuclear power plants potential in 2050 increased from 4.5 to 12 GW
High time res	C	x	x	Time-resolution is 3 h instead of 85 time-slices

^a Type A represents cases in which the competition between offshore electricity and hydrogen production is tested. Type B represent cases that have a potential impact on green hydrogen production, in which B.i cases represent a high demand for green hydrogen, B.ii cases a low demand for green hydrogen or high supply of alternative sources of hydrogen, B.iii cases a high demand for electricity or low supply of alternative sources of electricity supply and B.iv cases a low demand for electricity or high supply of alternative sources of electricity supply. Type C represents cases in which the effect of time-resolution is tested.

reader can look them up in that study. In section 3.1 first results on electricity and hydrogen supply will be presented, followed by subsequently results on hydrogen demand (section 3.2), regional results and flows (section 3.3), the role of electricity and hydrogen production far from shore (section 3.4), cost analysis (section 3.5) and finally in section 3.6 an analysis of the sensitivity cases. In sections 3.3–3.5 use is already made of some specific sensitivity cases, because they facilitate the analysis.

3.1. Electricity and hydrogen supply

The results for electricity and hydrogen supply for 2050 are combined in figure 3. The hydrogen supply includes only tradable hydrogen, so hydrogen production and use that is integrated in industrial processes, is

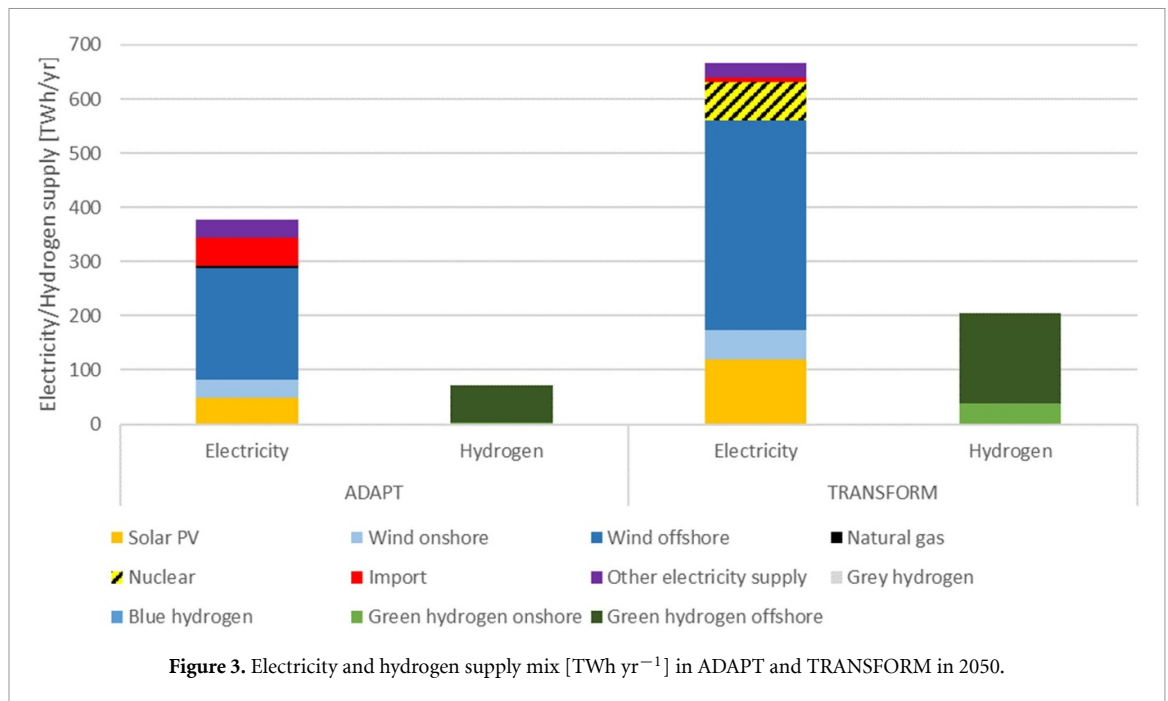


Figure 3. Electricity and hydrogen supply mix [TWh yr⁻¹] in ADAPT and TRANSFORM in 2050.

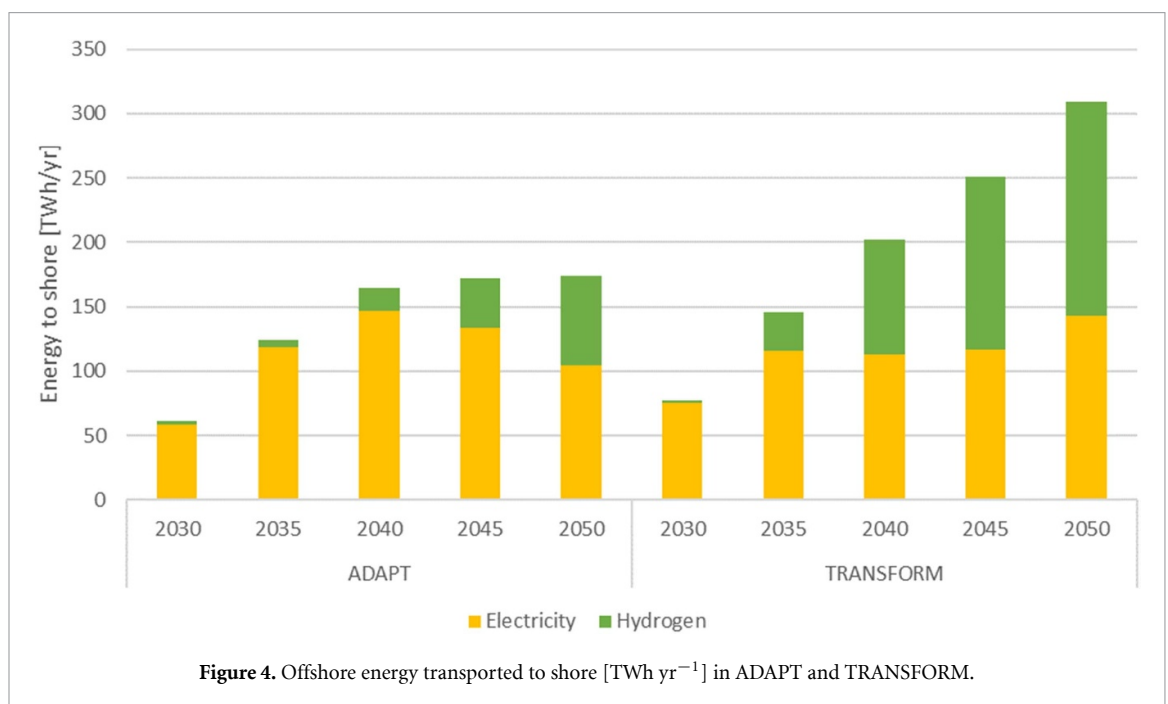


Figure 4. Offshore energy transported to shore [TWh yr⁻¹] in ADAPT and TRANSFORM.

not included in the results. An example of such a process is ammonia production with integrated hydrogen production.

Detailed discussion of the trend for electricity supply from 2030 until 2050 for the ADAPT and TRANSFORM scenarios can be found in Scheepers *et al* (2022b). Figure B1 in appendix B shows the trend for hydrogen supply over this period.

Both in ADAPT and TRANSFORM, wind offshore is the main electricity supply source, with 207 and 386 TWh yr⁻¹ in 2050 respectively. Green hydrogen production is 72 and 204 TWh yr⁻¹ respectively, of which respectively 70 and 166 TWh yr⁻¹ is produced offshore. Tradable grey and blue hydrogen are almost negligible. Apparently green hydrogen is more cost effective given the stringent GHG reduction targets, the resulting high CO₂ price, and given the limited amount of CO₂ that is allowed to be stored per year in both scenarios (Scheepers *et al* 2022b).

Figure 4 shows the energy that is produced offshore and transported to shore over the period 2030 until 2050. Infrastructural electricity losses and energy losses of electrolysis are excluded from this figure. In 2030

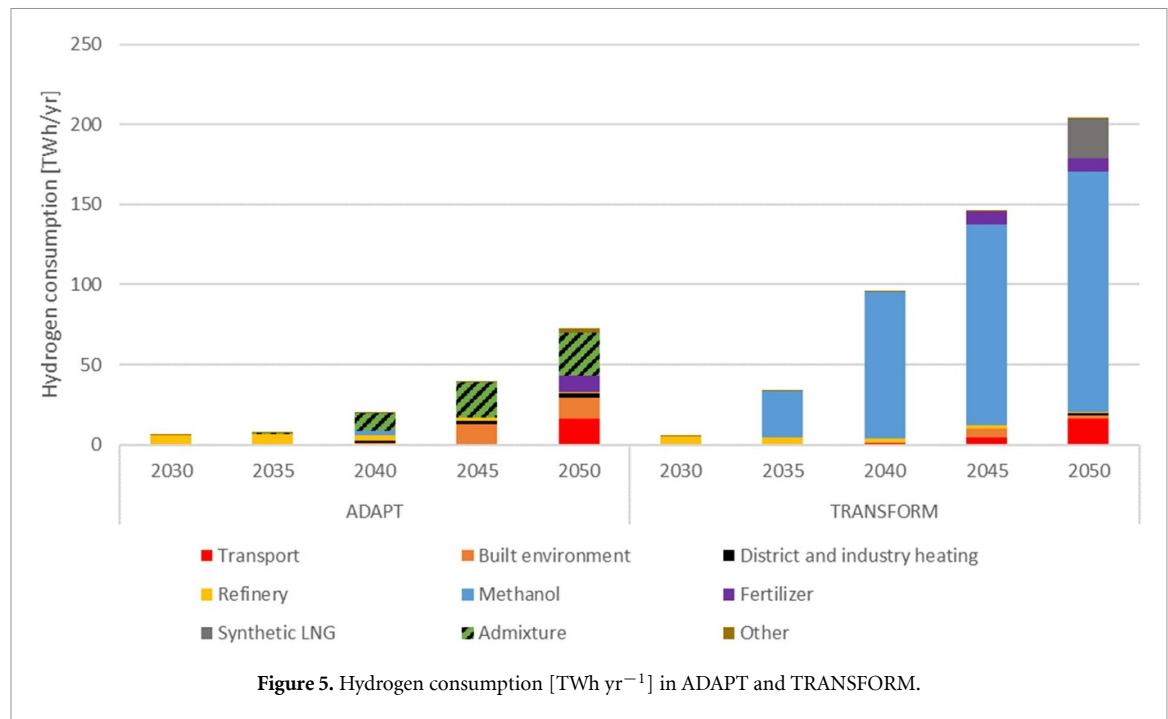


Figure 5. Hydrogen consumption [TWh yr^{-1}] in ADAPT and TRANSFORM.

practically all energy that arrives to shore is electricity. In 2035 the amount of hydrogen in the ADAPT scenario is still modest, while the amount of hydrogen in TRANSFORM is already substantial (30 TWh yr^{-1}). Between 2035 and 2045 a transition takes place: the additional wind offshore power that is brought to shore as hydrogen increases significantly. In TRANSFORM the amount of electricity brought to shore in 2040 is lower than in 2035, while the amount of hydrogen shows a large growth. From this we can conclude that from 2040 onwards most of the energy from newly installed wind power is brought to shore as hydrogen. In the ADAPT scenario this is realized 5 years later.

In ADAPT the electricity that is brought to shore decreases from 146 TWh yr^{-1} in 2040 to 104 TWh yr^{-1} in 2050. A main driver for this drop is the change in trade characteristics: in 2040 import and export electricity volumes are, respectively, 9 and 66 TWh yr^{-1} , in 2050 these figures are 53 and 32 TWh yr^{-1} . This means that from 2040 to 2050 a lower amount of electricity supply is needed for export and therefore less electricity from wind offshore is needed for export. In TRANSFORM there is a small reduction in electricity brought to shore after 2035 (from 116 to 113 TWh yr^{-1} in respectively 2035 and 2040) and an increase in 2050— 143 TWh yr^{-1} . This can, again, be attributed to a change in trade characteristics and furthermore to a strong electricity demand increase of the chemical industry. From 2040 to 2050 the import of electricity remains largely unchanged but, the export of electricity increases from 74 to 85 TWh yr^{-1} . The electricity demand in the chemical sector increases from 26 TWh yr^{-1} in 2040 to 55 TWh yr^{-1} in 2050.

3.2. Hydrogen demand

In figure 5 the consumption of tradable hydrogen over the period 2030–2050 is shown for the ADAPT and TRANSFORM scenarios. Admixture stands for the admixture of hydrogen in the natural gas grid of which the used upper limits can be found in table 1. A clear difference in type of utilization is seen between the two scenarios. In the ADAPT scenario initial consumption of hydrogen is mainly attributed to the refinery sector and for admixture purposes, followed by applications in the built environment in 2040 and finally complemented by the transport and fertilizer sector in 2050. Hydrogen use in the refineries is for conventional refineries and bio-refineries (in South Holland and Zeeland) and in the transport sector for trucks.

In the TRANSFORM scenario, synthetic methanol becomes a significant energy carrier. In 2040 60% of this methanol is used for feedstocks, the rest for international shipping. Towards 2050 the share and absolute volume of methanol used for feedstocks increases. The large production of synthetic methanol is mainly a result of the assumed limited availability of carbon capture and storage (CCS), complemented by the additional requirement that an increasing share of carbon for feedstocks should be based on non-fossil carbon, and more severe GHG reduction targets for international bunker fuels.

Between 2035–2045 more than 85% of hydrogen is used for synthetic methanol production in TRANSFORM. In 2050 the amount of synthetic methanol increases further, but given a strong increase of

hydrogen use for synthetic LNG (for shipping) and transport (for trucks), the relative share of hydrogen for methanol decreases to 74%. In TRANSFORM a large amount of hydrogen is an essential ingredient to reach the stringent climate goals. In ADAPT hydrogen enables a more cost-efficient energy system and is used since there is a significant amount of excess electricity, resulting in low-cost green hydrogen (Scheepers *et al* 2022b). This results in a share of hydrogen in the final energy demand for heating of 13% in 2050 in ADAPT, pre-dominantly occurring in the services sector.

A significant amount of hydrogen in ADAPT is admixed in the natural gas grid. The indirect hydrogen consumption in final energy applications can be calculated via the admixture percentage and the natural gas consumption for energetic purposes. In ADAPT 2050, the three applications that consume most natural gas for energetic applications are international shipping, boilers in the built environment and boilers in the agricultural sector. The hydrogen demand for those applications are 19.1, 2.8 and 1.4 TWh yr⁻¹ respectively.

3.3. Regional results and flows

Offshore and onshore electricity and hydrogen flows in 2050 are given in figure 6 for ADAPT and TRANSFORM. These flows correspond to net annual flows between the regions via transmission grids and pipelines. Note that in the most Southern offshore region we did not allow electrolysis (section 2.3) and that in ADAPT there is no offshore wind in region F (see table 3). Offshore wind and electrolysis capacity, in respectively GWe and GW_{H₂}⁶, can be found in figure 7.

For ADAPT, we can observe that from the region most far from shore, region E, hardly any electricity is transported. For close to shore regions on the Western part, region B and C, the amount of electricity produced offshore is larger than the amount of hydrogen, while for region D they are comparable. Interestingly, all the hydrogen from offshore region D goes via the North-East route to shore. The reason is that salt caverns, for hydrogen storage, are only situated in the Northern part of the Netherlands (North NL), which also explains the hydrogen flow from North NL to North-Holland. Using the salt caverns, hydrogen can also be delivered at moments when there is no or hardly any wind energy. The annual amount of hydrogen stored in salt caverns is 25 TWh yr⁻¹. In the region closest to North NL, region G, more electricity is produced than hydrogen. From this we can conclude that for close to shore regions, electricity production dominates. For far from shore regions, hydrogen production dominates.

In general, the electricity and hydrogen flows are significantly larger in TRANSFORM than in ADAPT. Similarly to ADAPT, for close to shore offshore regions, B, C and G, more electricity is transmitted to shore than converted to hydrogen. For the intermediately far from shore region D, more electricity is converted to hydrogen than is transmitted to shore. In the far from shore regions, E and F, clearly more electricity is used for hydrogen production than for transmission. Similarly to ADAPT, but only with much larger flows, the North-East offshore flows dominate over the Western offshore to shore flows. Again, large flows are observed from North NL to the Western part of the Netherlands. For TRANSFORM, annually 48 TWh yr⁻¹ of hydrogen is stored in salt caverns, while the storage capacity is 7.7 TWh⁷. The storage capacity is high, but lower than the practically realizable potential of 15 TWh according to van Gessel *et al* (2021).

The offshore transmission capacities, figure 7, show at first sight a similar pattern as the offshore flows. But combining figures 6 and 7 leads to some counterintuitive results. If one determines the annual utilization rate of the offshore transmission lines, HVDC cables close to shore, for example Offshore B to South Holland, show a larger utilization than the close to shore hydrogen pipelines. This is expected since HVDC cables are expensive and therefore they should be utilized at a high rate. Far from shore transmission lines show the opposite behaviour, for example between offshore F and G, since the annual utilization of hydrogen pipelines is larger than for HVDC cables. This is probably due to the large dependency of the Dutch energy system on offshore wind, which needs to deliver electricity at moments of low to medium wind speeds, combined with a low production of solar PV (see section 3.4), therefore the far from shore transmission capacity is still relatively high.

The hydrogen flows onshore can be explained by the dominant onshore consumers and where they are located. As described in section 3.2, in TRANSFORM, most hydrogen is used for methanol production. Since the chemical and refinery sectors are pre-dominantly located in the provinces Limburg, South Holland and Zeeland (table 4), those are the regions where the largest in-flux of hydrogen can be observed (figure 6). For ADAPT, the in-flux of hydrogen is more distributed over the onshore regions, because hydrogen is consumed more by applications that are determined by the population distribution (built-environment and transport). Exceptions are the use of hydrogen for the fertilizer sector (located in Limburg and Zeeland, see table 4) and LNG for shipping (the harbour of Rotterdam in South Holland).

⁶ H₂ is hydrogen.

⁷ The 7.7 TWh of storage capacity corresponds to the 3-hourly sensitivity run, since time-slice based run underestimate the storage capacity.

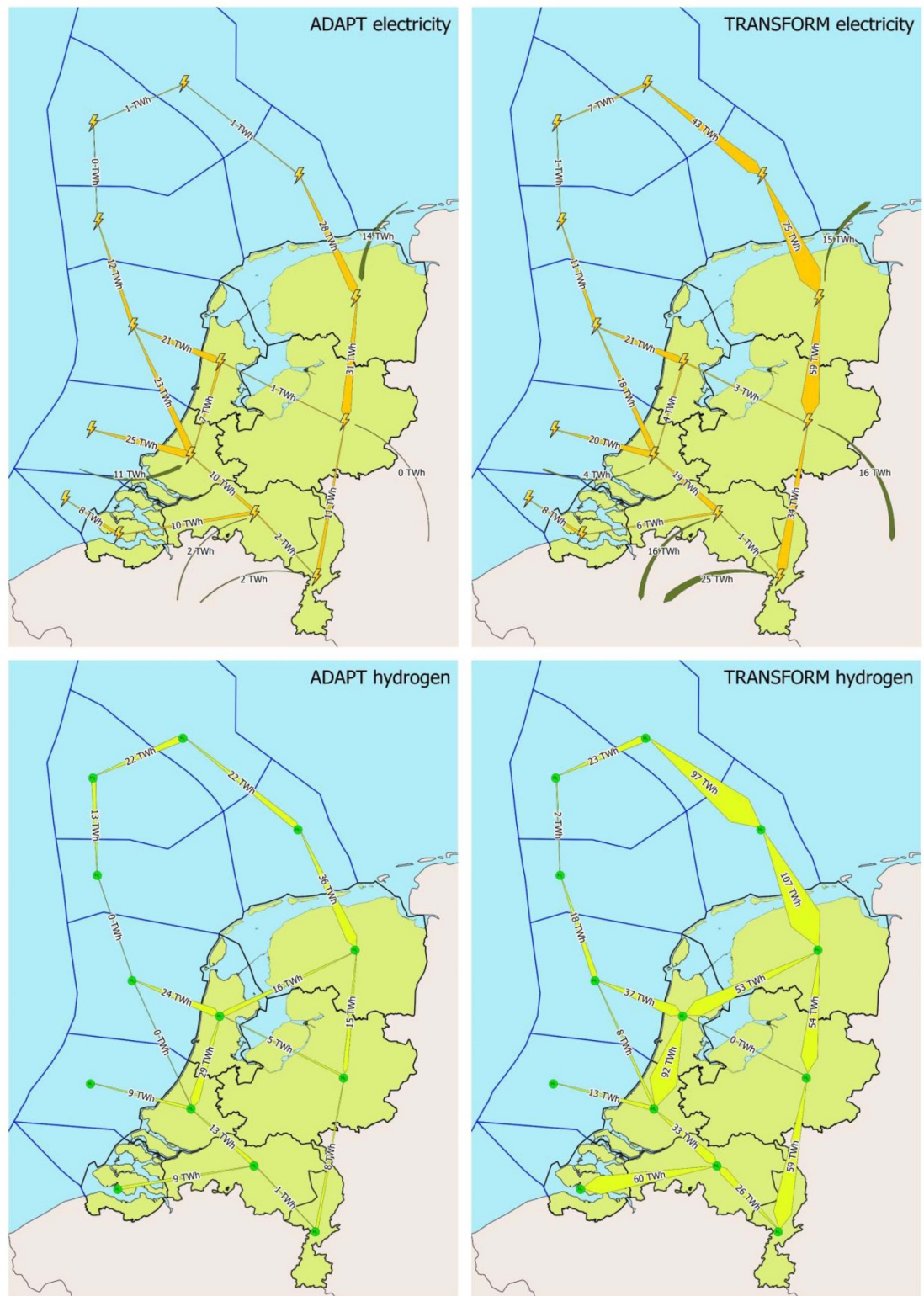


Figure 6. Net electricity and hydrogen flows [TWh yr^{-1}] between onshore and offshore regions in 2050 in ADAPT and TRANSFORM.

3.4. Role of electricity and hydrogen far from shore

As was shown in the previous section, hydrogen production dominates in far from shore regions (offshore regions E and F), but electricity production remains significant. The role of electricity versus hydrogen production has been analysed in more detail for the offshore region E. For this analysis a scenario variant with 3 h time-resolution, 'High Time Res', has been used. A higher time-resolution allows for a more refined analysis of the competition between electricity and hydrogen production.

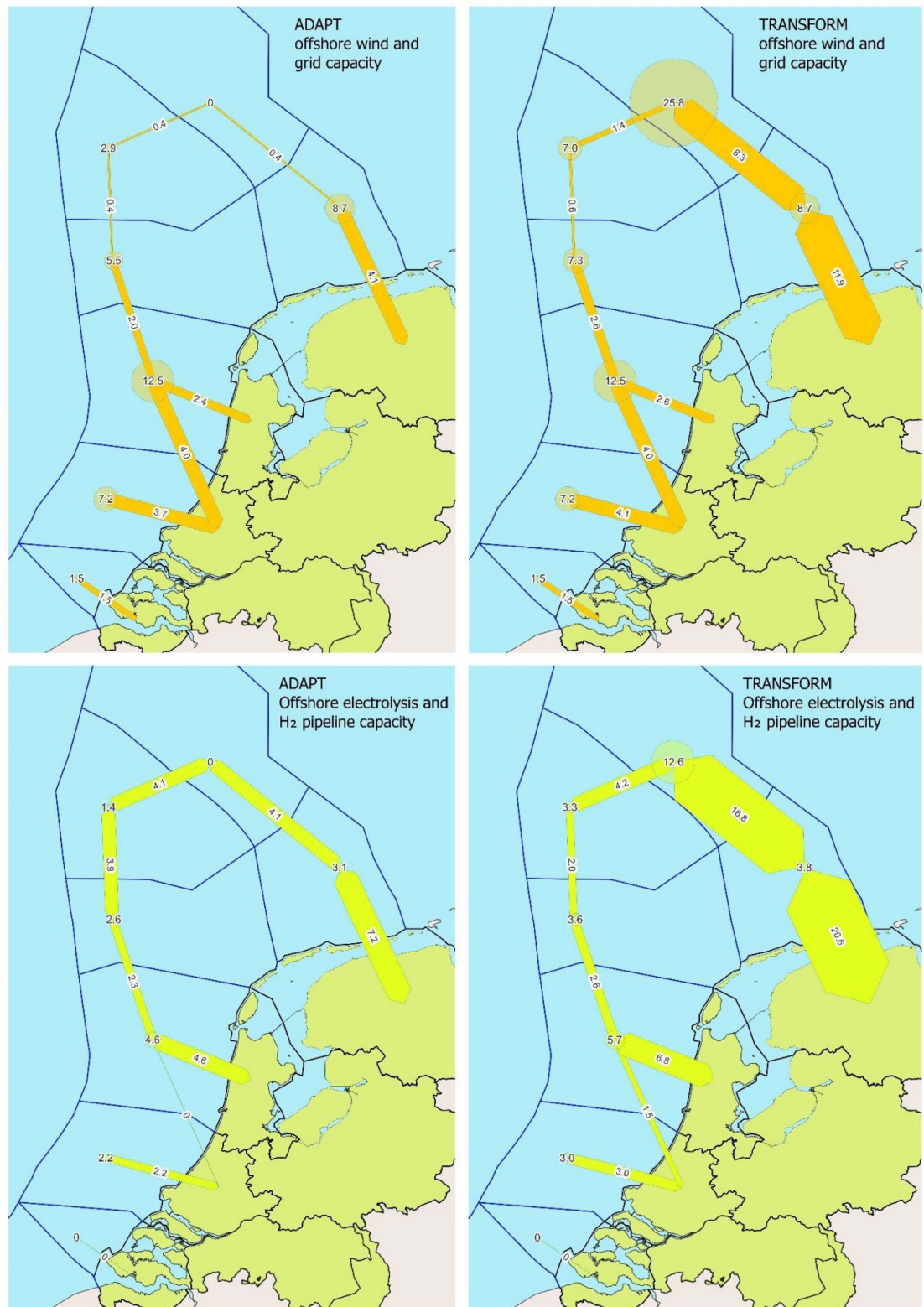
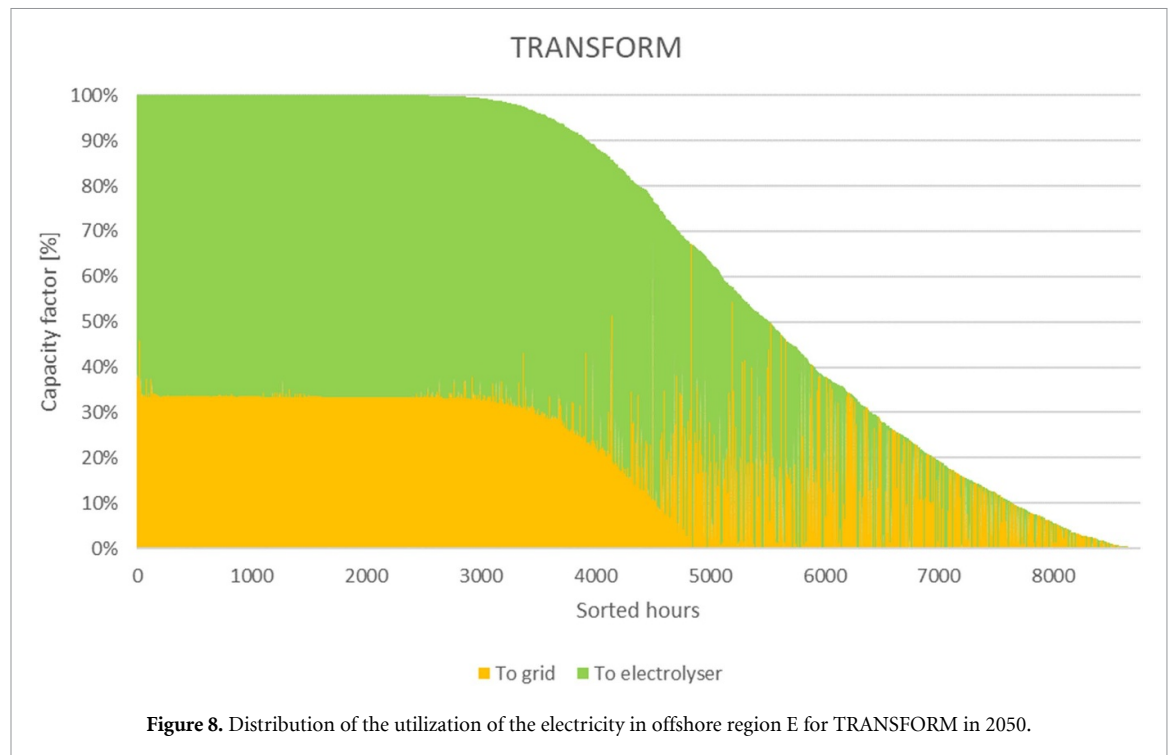


Figure 7. Top: offshore wind capacity per offshore region and electrical grid capacity between offshore regions and to shore, both in GW_e for ADAPT (left) and TRANSFORM (right) Bottom: offshore electrolysis capacity and hydrogen pipeline capacity between offshore regions and to shore, both in GW_{H2}. All maps correspond to 2050.

In figure 8 a normalized capacity factor for offshore wind power generation is shown for TRANSFORM in 2050. The hours are sorted from hours with a high capacity factor to hours with a low capacity factor. Furthermore, a split is made between power that is fed into the grid and power that is fed into the electrolyser. The overall annual capacity factor for offshore wind power generation is high, 64.5%, resulting in 5648 full load hours. These full load hours are excluding electricity cable losses. Until 3000 h, the capacity



factor is $>99\%$ and the distribution between electrolysis and grid is quite constant: 34% for the grid and 66% for electrolysis. After around 4000 h, so when the capacity factor drops significantly (i.e. when wind speeds are lower), the share of electricity that is fed into the grid increases significantly. This is probably related to the following factors:

- The total capacity of wind offshore is high,
- The electricity demand for other applications in the energy system is high,
- In case of low wind speeds, onshore wind production is, on average, significantly lower⁸,
- Solar PV has low or no production in significant parts of the year.

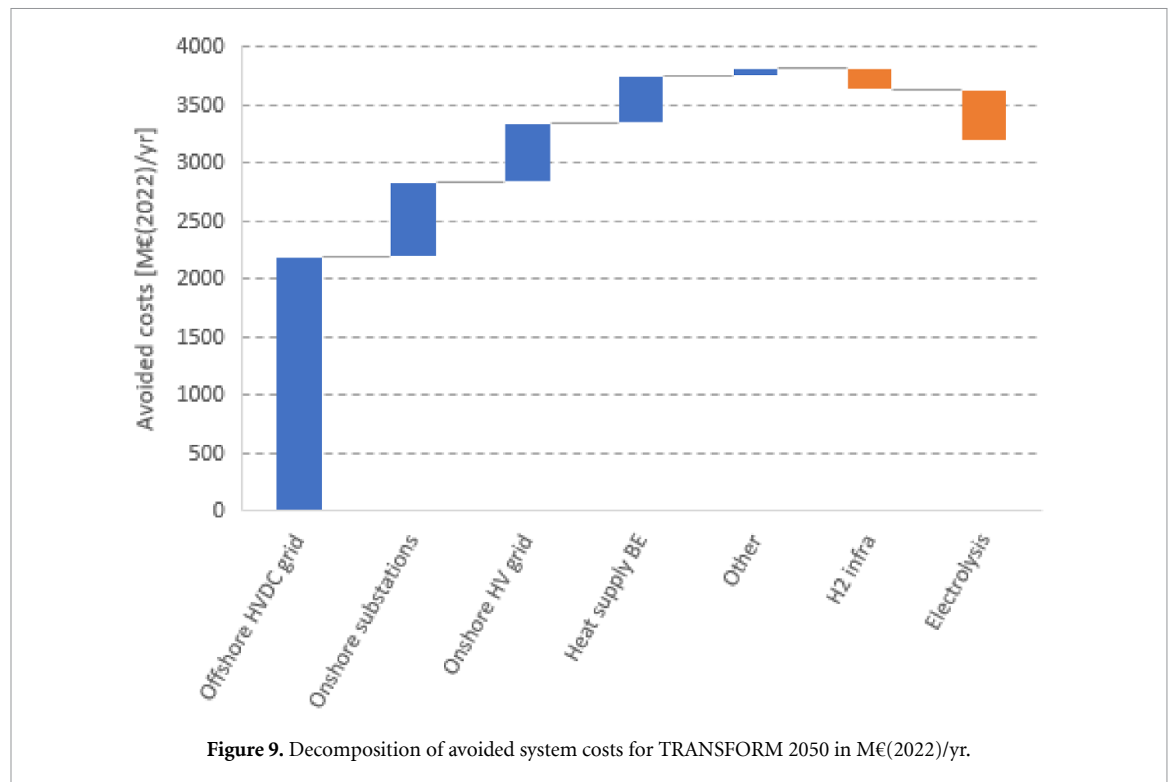
This means that at relatively low wind speeds, wind offshore needs to provide a significant amount of electricity to the onshore energy system. Interestingly, the maximum capacity factor that is fed into the grid is significantly higher for several hours in the area after 3000 h, than in the area before 3000 h. The maximum capacity factor fed into the grid is 77%, resulting in electricity cables with a relatively high capacity.

3.5. Avoided system costs of offshore hydrogen production

Instead of producing hydrogen offshore, one can also bring all the offshore produced energy to shore as electricity and convert it to hydrogen onshore. The sensitivity case 'No H₂ Offshore' allows to make a cost comparison in case offshore hydrogen is excluded, and therefore to calculate the avoided system costs of offshore hydrogen production. In figure 9 a breakdown of the avoided costs is presented.

The avoided annual system costs of offshore hydrogen production are 3200 mln €(2022)/yr. From the figure it can clearly be seen that the offshore HVDC grid makes by far the largest contribution, though the additional cost in onshore substations and the onshore HV grid are substantial as well. The avoided costs of heat supply in the built environment are due to a shift in the energy system. The necessity of offshore hydrogen pipelines results in additional cost. However, these are minor compared to the avoided costs for the offshore HVDC grid. The costs for electrolysis offshore are the only significant additional costs, but still much smaller in relative terms. Overall, we can conclude that the avoided costs of electricity infrastructure, in particular offshore, are the main driver making the production of hydrogen offshore a cost-effective solution for the Dutch energy system. It also explains that further from shore hydrogen production is more attractive than close to shore: due to the larger distance the avoided offshore HVDC cost are larger.

⁸ In case of low wind speeds at sea at hub heights, the production of wind onshore will, on average, be even much lower, because wind speeds in general are lower onshore and because the hub height onshore is lower, resulting in lower wind speeds at hub height.

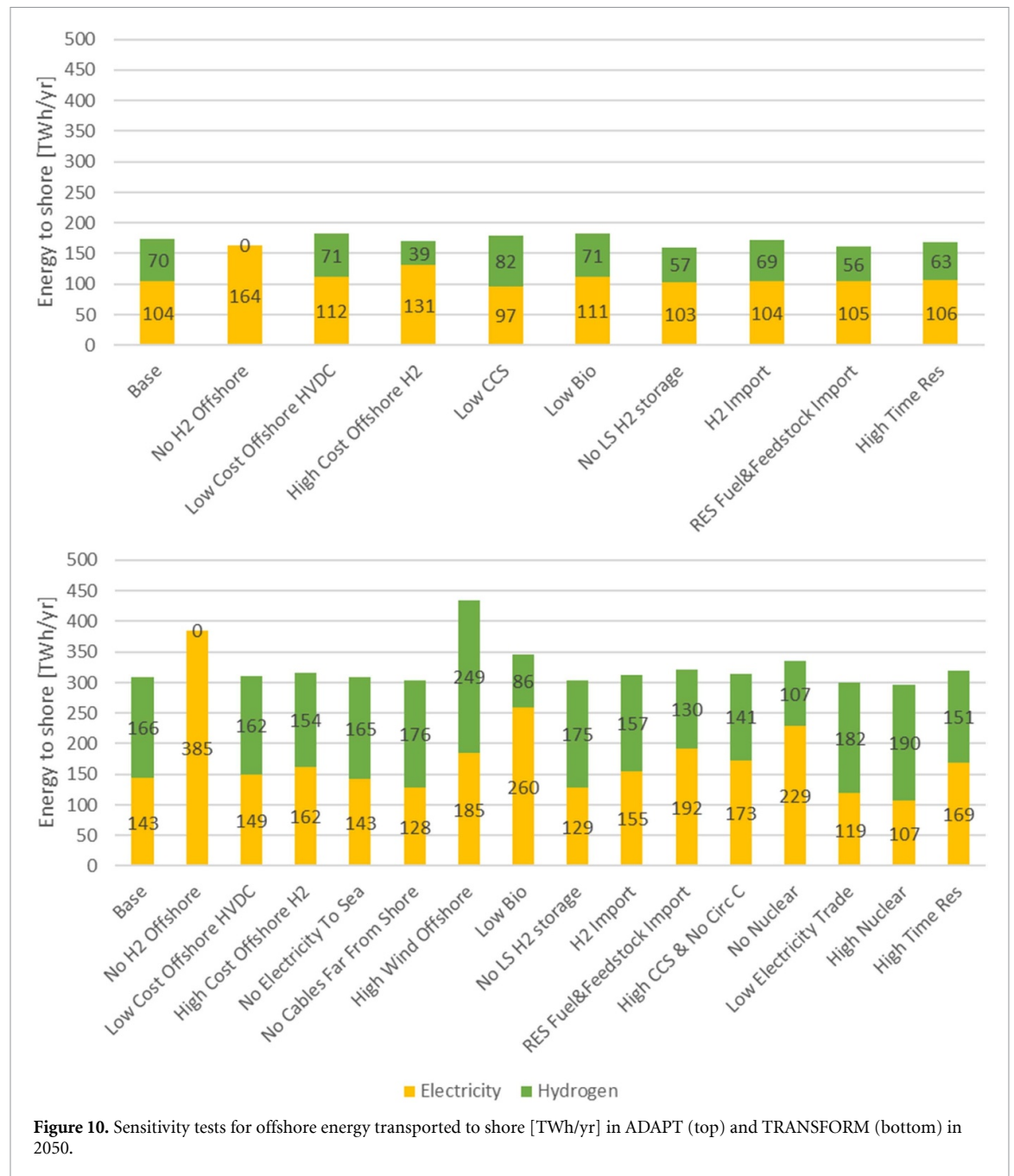


3.6. Sensitivity analysis

The amount of electricity and hydrogen that is landed in 2050 for all sensitivity cases is presented in figure 10. For ADAPT it can be observed that offshore hydrogen production is quite stable for all cases. The case ‘High Cost Offshore hydrogen’ gives the least offshore hydrogen production (56% of the Base), while the case ‘Low CCS’ gives the most (118% of the Base). For TRANSFORM, offshore hydrogen production is high for all sensitivity cases, but differences between the cases are larger than for ADAPT. ‘Low Bio’ gives the lowest amount of offshore hydrogen production (52% of the Base), while the case ‘High Wind Offshore’ gives the most (150% of the Base).

Some sensitivity cases have a different effect on the outcome on ADAPT than they have on TRANSFORM. This can partially be explained by the role offshore hydrogen production has for both scenarios and partially by the offshore regions where the majority of hydrogen is produced. In ADAPT the demand for hydrogen is relatively low and offshore electrolysis is an important flexibility option. In TRANSFORM offshore hydrogen production is simply the most important option to supply the large demand for hydrogen. For ADAPT offshore hydrogen production is more sensitive to a doubling of offshore electrolysis cost, case ‘High Cost Offshore hydrogen’ since offshore electrolysis apparently becomes an expensive flexibility option. For ADAPT an increase in curtailment of wind energy is observed. In TRANSFORM most of the hydrogen is produced far from shore and doubling offshore electrolysis cost does not have decisive effect on the cost, see figure 9.

Another important factor for explaining the total amount of energy that is brought to shore for ADAPT is the installed capacity of wind offshore. The capacity in 2050 for the base case and sensitivity cases of ADAPT is presented in figure 11. It can clearly be seen that not in all cases, including the base case, the full potential of 40 GW is used. Hydrogen production plays an important role in absorbing a large amount of wind energy offshore. By excluding offshore hydrogen production or excluding large scale hydrogen storage, the system has difficulties in using the excess electricity production from wind offshore and therefore prefers to reduce the installed capacity (cases ‘No offshore H₂’ and ‘No LS H₂ storage’). The case ‘No offshore H₂’ illustrates that offshore hydrogen benefits the utilization of the available offshore wind capacity. If the availability of other abatement options is lower, cases ‘Low CCS’ and ‘Low Bio’ respectively, all wind offshore potential is needed. Vice versa if the availability of other abatement options is higher, case ‘RES Fuel&Feedstock Import’ and to a much lesser extent ‘H₂ import’, the capacity of wind offshore decreases. The important role of the offshore HVDC costs are reflected in the offshore wind capacities as well, since low cost for offshore HVDC results in utilization of the full offshore wind potential.



In appendix C additional sensitivity results can be found. The distribution of hydrogen supply over grey, blue, onshore green and offshore green can be found in figure C1. The consumption of hydrogen for different applications for the sensitivity cases can be found in figure C2. An interesting observation is that for both ADAPT and TRANSFORM, the relative change in onshore green hydrogen production is larger than in offshore green hydrogen production. Onshore hydrogen production is clearly the marginal green hydrogen supply option.

Overall, one can conclude that the level of electricity demand (including export), the availability of alternative electricity supply options, the demand level of hydrogen and the availability of alternative hydrogen supply options, all have an impact on the results. Same cases with clear effects are described in appendix C.

4. Discussion

In our study two distinctive scenarios have been included, that show a different role for offshore hydrogen production, but in both scenarios it is the most dominant method of hydrogen production. The main reason for the preference of offshore hydrogen production is the avoidance of expensive offshore HVDC cables.

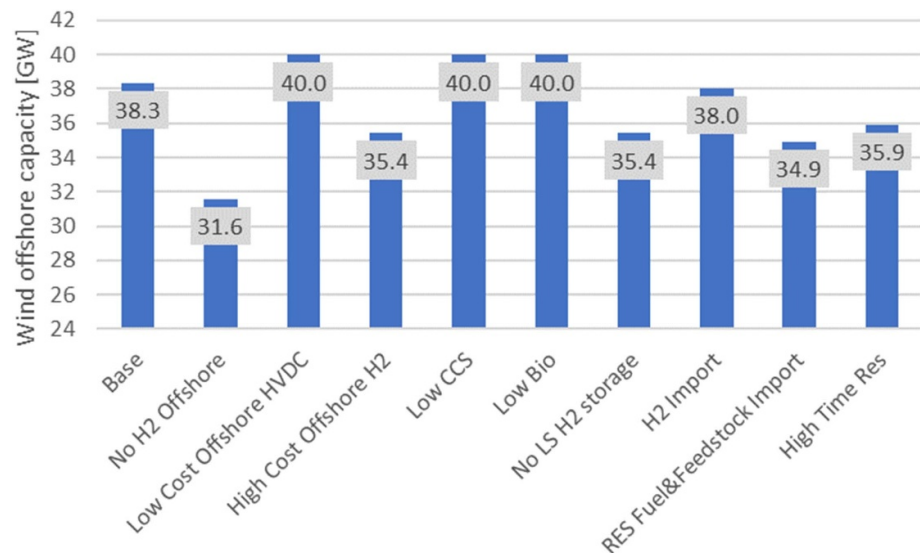


Figure 11. Wind offshore capacity for the base case and sensitivity cases of ADAPT in 2050 in GW. Note that an offset of 24 GW has been used.

The total demand for hydrogen is an important driver for offshore electrolysis. In the TRANSFORM scenario this hydrogen is mainly used for methanol production, which is used for the production of plastics and marine bunkering. This demand for methanol would be different if the restriction that most of the carbon should be circular would be absent and if the availability of biomass would be higher. The effect of such assumptions has been tested in the sensitivity case ‘RES Fuel & Feedstock Import’ (see figure C1). Note that the demand for hydrogen itself is also an uncertain factor.

Other important scenario parameters that likely have a strong impact on the results are the import of secondary energy carriers and semi-finished products in large quantities, like hydrogen, bunker fuels and ammonia. Also, the assumed large amount of bunkering in the Netherlands might change, resulting in a significant impact on the energy demand.

To test robustness of our outcomes it would be good if we could perform our analysis with a series of weather years for solar and wind, including corresponding demand profiles. However, this was outside the scope of our study and demand profiles for other years are, to a large extent, simply missing.

In our optimization approach it has not been possible to also optimize the topology of the infrastructure, due to the computational burden of such inclusion. The distances between the nodes are fixed, while the model can optimize the needed transmission capacities between those nodes. Also, some additional connections (like offshore B and Zeeland, and a direct connection from offshore E to North NL) would have reduced the system cost and therefore impact the outcome. Mixed integer programming (MIP) optimization could potentially allow for a more proper modeling of infrastructure, though according to Gea-Bermúdez *et al* the impact is limited.

Our results are not in line with the results from Gea-Bermúdez *et al* (2023), who found a limited role of offshore hydrogen production and strong preference of electrolysis onshore over offshore for ten Northern-central European countries. The study from Martínez-Gordón *et al* (2022a) shows a significantly larger role of offshore hydrogen production than the study from Gea-Bermúdez *et al*, but in relative terms, significantly lower than according to our results. In the cases that allow for offshore hydrogen, they found a contribution of offshore hydrogen of 10%–15% of the total hydrogen production.

Our study and the two studies mentioned above show differences in methodology, scope, data, scenario assumptions and results between each other. An overview of relevant differences is given in table 6. The current study and the study from Martínez-Gordón (using the IESA-NS model, Martínez-Gordón *et al* 2022b) are performed with similar types of models. Both OPERA and IESA-NS optimize the energy system using LP. In both models the energy demand is modelled endogenously and a GHG target (net zero in 2050) is used. The BALMOREL model as used by Gea-Bermúdez *et al* (Wiese *et al* 2018) is also an optimization model, but it is not a full integral model. The applications (including the volume and profile) that use hydrogen and electricity are set in advance. The exception are technologies that use hydrogen and consume electricity and vice-versa (for example, electrolysis).

Table 6. Comparison between different energy system studies that include offshore H₂ production.

	This study	Gea-Bermúdez <i>et al</i> (2023)	Martínez-Gordón <i>et al</i> (2022a)
Methodological			
Time-resolution	85 time-slices (3-hourly applied in one case)	192 snap shots	Hourly (for electricity and H ₂)
Optimization method	LP	LP and MIP ^a	LP
Static vs dynamic optimization	Static	Semi-dynamic	Static
Integral energy system model	Yes	Semi	Yes
Demand for electricity and H ₂	Endogenous	Exogenous	Endogenous
Geographical scope: countries	The Netherlands only	Northern Central Europe	North Sea countries
Geographical scope: subnational	Regions, including transmission between regions	No detail (copperplate assumed)	No detail (copperplate assumed)
Time horizon	2030–2050	2025–2045	2050
GHG target or CO ₂ price	GHG target	CO ₂ price	GHG target
Data			
Offshore grid cost	High. Offshore grid cost higher than onshore	About half of the current study. Offshore not more expensive than onshore.	Lower than the current study.
Full load hours offshore	Including future turbine developments (5600 h year ⁻¹)	In line with currently installed turbines (4600 h year ⁻¹)	Low. In line with turbines installed around 2015 (3700 h year ⁻¹)
Offshore electrolysis	1.25x onshore CAPEX. No desalination	Only additional desalination cost, which are low.	Unclear
Cost reduction electrolysis	Low (efficiency improvements included)	Significant	Unclear
Excess heat electrolyser	Not included	Included onshore for district heating	Not included
Scenarios			
VRES mix (potential assumptions)	High abundance wind offshore	Wind offshore is high, but solar PV and wind onshore are also very prominent (much higher than the current study)	Wind offshore is high, but solar PV and wind onshore are also very prominent (much higher than the current study)
Volume H ₂ demand	High (for TRANSFORM)	Relatively low	High
Number of scenarios	Two and sensitivity cases	One and sensitivity cases	One and sensitivity cases
Results			
Role offshore H ₂ production in the total H ₂ mix	High (>80%)	Small (3%)	Medium (10–15%)

^a MIP is a mixed integer program.

Both other studies include several countries, which allows for a more flexible system and the possibility to source energy in countries where it is cheapest. In the current study only trade of electricity is included and not in a fully converged way, since the energy market model was only used for one iteration. In our study a more consistent modelling of trade is likely to affect the results, since the system would be more flexible, reducing the role of offshore hydrogen as a flexibility option. This would also impact the resulting use of hydrogen in certain sectors. One likely example in which a change of hydrogen use is expected, is in the built environment in the ADAPT scenario. In the review of Rosenow (2024), out of 54 studies, a median of only 1% of hydrogen usage for heating applications in the built environment is found. Significantly lower than the 13% in ADAPT in 2050. Currently, work is in progress to couple the OPERA model to the Western-European

electricity-gas market model I-ELGAS (Koirala *et al* 2021). On the other hand, the two other studies do not include subnational regions onshore and for offshore only a few nodes/hubs are applied, resulting in a lower representation of distance dependent tradeoffs.

Our optimization runs used 85 time-slices. Using a 3-hourly time-resolution reduces the role of offshore hydrogen by about 10%, while increasing the role of onshore hydrogen production (see figure C1). It is likely that the use of an hourly resolution, as was done by Martínez-Gordón *et al* (2022a) for electricity, would reduce the role of offshore hydrogen production a bit further. Comparing our results with the two other integral modelling studies, it is striking that data items that are crucial for addressing the role of offshore hydrogen production show large differences and additional marinization cost are either ignored or treated differently. The offshore HVDC costs used by us are higher than what has been assumed in the other studies. In section 3.5 we saw that high costs of offshore HVDC are an important driver for producing hydrogen offshore. Other data differences appear in the full load hours of offshore wind, the cost of electrolysis and the possibility of excess heat utilization from electrolysis for district heating (Gea-Bermúdez *et al*).

Costs for electrolysis are still uncertain and costs for offshore hydrogen production are even more uncertain. Outcomes of pilot and demonstration projects are important to test and verify these assumptions. Main activities in Europe are focused in and around the North Sea. The Lhyfe project (Lhyfe 2025), tested a 1 MW pilot in the French waters in 2022/2023. The Netherlands has the Poshydron pilot (Poshydron 2024) with 1 MW offshore electrolysis starting in 2025 and two demonstration projects planned with 20–50 MW (DEMO 1) to be operational around 2030 and the latter with a capacity under 500 MW, named DEMO 2, to be operational around 2033. Germany is also preparing for offshore electrolysis demonstration at a 10 MW initial scale and progressing to larger, even GW, scale later.

In this study we assumed that the CAPEX and OPEX of offshore electrolysis are 1.25 times higher than onshore electrolysis. In the NSWPH study (NSWPH 2024), the offshore hydrogen investment costs decrease from the reference in 2030 of 1.46 to 1.06 mln €/MW in 2050. The offshore multiplication factor compared to onshore increases between 2030 and 2050 from 1.58 to 1.98. In a study for the Aquaventus consortium (Schwaeppe *et al* 2024), the following assumptions regarding offshore electrolysis were assumed: 2.3 mln €/MW in 2035 towards 2.0 mln €/MW in 2040.

According to figure 9 and sensitivity case ‘High Cost Offshore H₂’, this assumption is important for the results, but does not change our conclusions that offshore hydrogen is a cost-effective option for the Dutch energy system, since the results are also highly impacted by the offshore HVDC cost assumptions.

A strong change in electricity mix would probably have a large impact on the results. However, due to the geographic situation of the Netherlands, the role of offshore electricity is expected to be large in the future anyway. In our study the role of wind onshore is small and also the contribution of solar PV is limited (about 25%–30% of wind offshore’s contribution (see figure 3)). In the other integral studies mentioned above, wind onshore and solar PV play a prominent role. In the study of Gea-Bermúdez *et al* solar PV produces a similar amount of electricity as wind offshore, while wind onshore is about half this amount. In the study of Martínez-Gordón *et al* the electricity mix per country is only given for the reference case (without offshore hydrogen production). The different electricity mix is probably also an explanation for the resulting difference in capacity factor of electrolyzers. In the other studies the capacity factors are low (In the study from Gea-Bermúdez *et al* electrolysis production follows the profile of solar PV), while in our study the capacity factor of electrolysis is high.

Our study did not include other offshore options that are currently being described in literature or for which plans have already been made that are part of future offshore integration options. Among these offshore options are floating PV systems (van Unen *et al* 2022), CO₂ storage (Kawale *et al* 2022), hydrogen storage (Caglayan *et al* 2020), ammonia and methanol production (Kee *et al* 2020) and energy islands (van der Veer *et al* 2020). One can expect that inclusion of such options will increase the role of offshore hydrogen production.

The security, and related to this the availability and insurability of offshore assets (pipelines, substations, cables), is a very important subject in this era. This could incur loss of transmission capacity and or higher project costs due to security measures or insurance and liability costs. Our model does not include such cost factors for any of the offshore assets included in the model.

Finally, other factors that could be an important determinant for the adoption and location of electrolysis, both onshore and offshore, are the availability of space, potential environmental impacts and societal perception. The Netherlands is a densely populated country and is spatially stressed offshore as well.

Large-scale electrolysis will use a significant amount of space. The technology will need to discharge heat and oxygen as by-product and will require (cooling) water intake for the electrolysis process. Offshore, the discharge of brine and heat are important items of attention (van der Mart 2024). This factor should be considered when performing future implementation potentials for onshore and offshore hydrogen. Inclusion of spatial and environmental footprints and spatial analysis as input to modelling would be an important additional research component.

Our study shows a large potential for offshore hydrogen production, however, that does not mean that it can be expected to simply materialize. The government, but also industrial strategist, will have an important role in this. Since infrastructural planning is accompanied by long lead times, it is important that governments get started with offshore hydrogen on a short term. The pilot plants mentioned above are a good starting point. Lessons learned from such projects will streamline the roll out. Many support policies are focusing on supply, however, there should also be an incentive to use the hydrogen. Therefore demand needs to be supported as well. It can be expected that the electrolysis capacity itself will always be more expensive than onshore electrolysis capacity, it is important that the cost and benefits are distributed fairly over all actors, to make the production and consumption attractive for all actors. This in particular, means that the avoided cost of building offshore HVDC infrastructure are distributed as a benefit over the actors.

5. Conclusion

Offshore wind energy is seen as a crucial option to make the Netherlands climate neutral in 2050. The main reason for this is its relatively large potential. It is challenging to expand the onshore electricity grid significantly and on time, and since there is a large demand for hydrogen foreseen, the question arises whether offshore hydrogen production has the potential to play an important role for the Dutch energy system. Two recently developed scenarios, ADAPT and TRANSFORM, are used to analyse the potential role of offshore hydrogen production in the Dutch context using the energy system optimization model OPERA.

Our study shows that offshore hydrogen production is a cost-effective option for the Dutch energy system. From a system point of view, it will be much cheaper if green hydrogen is predominantly produced offshore instead of onshore. The main reason is the avoidance of offshore HV cables, which are relatively expensive. The additional costs needed for offshore electrolysis, as compared to onshore electrolysis, and the additional costs for hydrogen pipelines, are significantly lower than the cost savings in offshore HV cables. The farther from shore, the larger the avoided cost. The additional costs for offshore hydrogen production are under the assumption that offshore electrolysis is not so much more expensive than onshore electrolysis. A sensitivity test with significantly more expensive costs for offshore electrolysis still shows a favourable role for offshore electrolysis. Outcomes of pilot and demonstration projects will tell if marinization of hydrogen production does not result in excessive cost escalation for electrolysis.

Factors that have an important role on volume of offshore hydrogen production are the potential for offshore wind, the demand for hydrogen, and the potential of other abatement options, such as the use of CCS, alternative sources of electricity production, such as nuclear energy, and the availability of biomass. For the ADAPT scenario, which has a modest potential for wind offshore and also a modest demand for hydrogen, the hydrogen produced offshore ranges from 39 to 70 TWh yr⁻¹. For the TRANSFORM scenario, which has a large potential for wind offshore, and a large demand for hydrogen, the hydrogen produced offshore ranges from 86 to 249 TWh yr⁻¹. For ADAPT and TRANSFORM the share of electricity that is converted to hydrogen offshore ranges between 31%–55% and 33%–72% respectively. Most of the wind farms that will be built until 2030 are relatively close to shore and are expected to predominantly bring electricity to shore. After 2040, almost all additional energy from sea needs to be brought to shore in the form of hydrogen. Interestingly, our analysis shows that even far from shore part of the energy needs to be transported via electricity cables. A mix between hydrogen pipelines and electricity cables is optimal from a system costs point of view. During hours with low wind speeds, and therefore low generation, the capacity far from shore is also needed to supply the demand for electricity onshore.

The offshore hydrogen volumes are large and are not a prediction, but a cost optimal outcome for two distinctive future scenarios. Several potentially important elements are tested only to a limited extent, neglected or were outside the scope of this study to include. The role of international trade in electricity and hydrogen is a potentially important factor, that has been analysed, but not at the same level of detail as the

rest of the Dutch energy system. Enlarging the geographical scope to neighbouring countries might result in a different outcome for offshore hydrogen production and would definitely be a point for further research. Other points of consideration for future research are the use of a higher time-resolution in the energy system optimization, the use of demand and supply profiles for different reference years, even more drastic scenario choices, including an extensive role for import of energy carriers and semi-finished products and the inclusion of other offshore integration options, such as offshore solar PV.

The volumes in our current study indicate that offshore hydrogen production has the potential to be an important option for the Dutch energy system. From a system point of view, it results in lower cost and should therefore result in lower cost for society. Since infrastructural planning is often time-consuming, it is important that governments and strategists put offshore hydrogen production high on the agenda. Pilot plants and lessons learned from these are important. Furthermore, not only supply of green hydrogen production should be supported, but also the demand. And last, but not least, the cost and benefits of offshore hydrogen should be distributed over all actors in such a way that it is attractive for all actors in the hydrogen demand-supply chain. An important element will be to implement market design and energy taxes in such a way that the avoided offshore HVDC infrastructural cost are distributed over all actors to make offshore hydrogen beneficial for the entire hydrogen value chain.

Data availability statement

The data that support the findings of this study are available upon reasonable request from the authors.

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Conflict of interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

CRediT authorship contribution statement

Joost van Stralen: Conceptualization, Methodology, Software, Formal analysis, Writing—original draft, Writing—review & editing.

Gaby Janssen: Methodology, Software, Writing—review & editing.

Joris Koornneef: Conceptualization, Methodology, Writing—review & editing, Funding acquisition.

Martin Scheepers: Writing—review & editing, Funding acquisition.

Jeffrey Sipma: Methodology, Visualization.

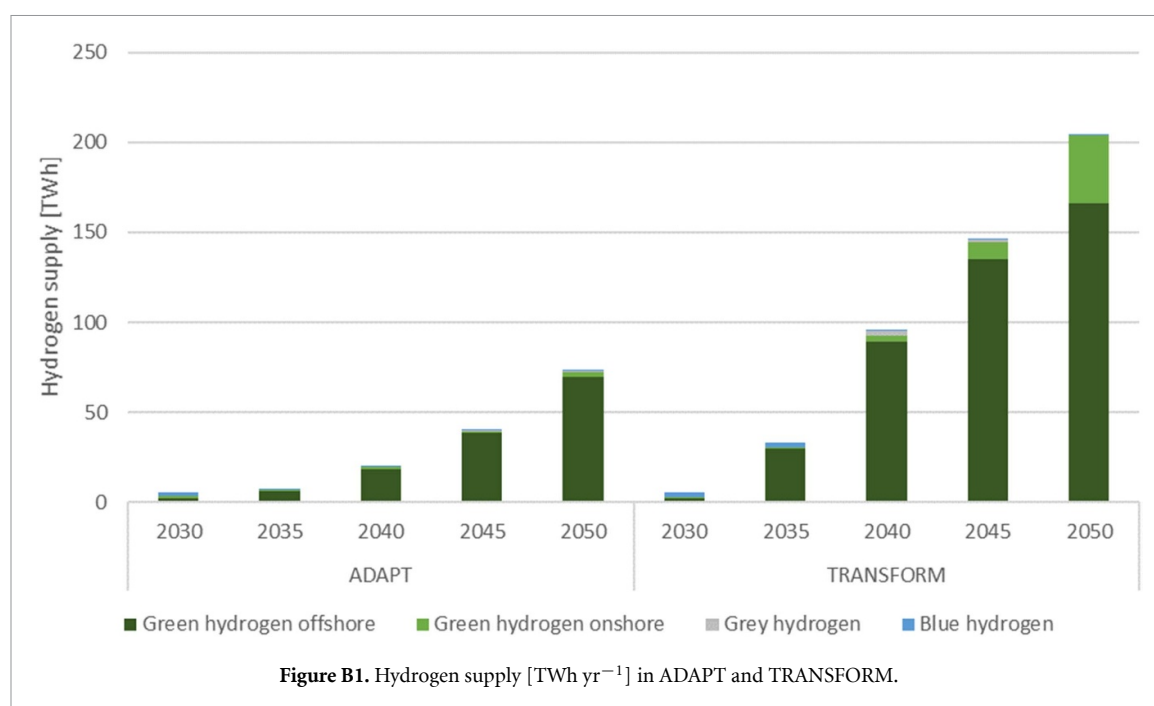
Bob van der Zwaan: Writing—original draft, Writing—review & editing.

Appendix A. Techno-economic data

As indicated in section 2.4 the techno-economic parameters are the same as used in the study of Scheepers *et al* (2022b), with some exceptions. The values for the exceptions are presented in table A1.

Table A1. Techno-economic data used in this study that differs from what is used in Scheepers *et al* (2022b). Costs are given in €(2022).

Technology	Techno-economic parameter	Unit	2030	2040	2050	Offshore multiplication factor	Source
HVDC offshore cables	Investment cost	k€/(MW*km)	5.10	5.10	5.10	—	van der Veer <i>et al</i> (2020)
	Losses	%/km	0.0033%	0.0033%	0.0033%	—	
Onshore substation	Investment cost	M€/GW	205.7	205.7	205.7	—	van der Veer <i>et al</i> (2020)
	Efficiency	%	98.5%	98.5%	98.5%	—	
HVAC onshore cables	Investment cost	k€/(MW*km)	2.60	2.60	2.60	—	TNO (2022) (Cost correspond to lines that are 50% underground and 50% above ground)
	Losses	%/km	0.035%	0.035%	0.035%	—	
Large scale electrolysis	Investment cost	M€/GW_H2	859	859	859	1.25	TNO (2022)
	Fixed O&M cost	M€/(GW_H2*yr)	24.6	18.4	12.3	1.25	
	Efficiency	%	66.7%	67.3%	68.0%	—	
Hydrogen pipelines	Investment cost	k€/(inch*km)	61.4	61.4	61.4	1	van Schot and Jepma (2020)
	Losses	%/km	0%	0%	0%	—	
Wind offshore	Investment cost	M€/GW	1989	1909	1829	—	TNO (2022)
	Fixed O&M cost	M€/(GW*yr)	28.7	28.1	27.5	—	
	Variable O&M cost	M€/TWh	7.4	7.4	6	—	



Appendix B. Hydrogen production in ADAPT and TRANSFORM

In figure B1 the tradable hydrogen production for ADAPT and TRANSFORM scenarios for the period 2030–2050 is presented.

Appendix C. Sensitivity analysis

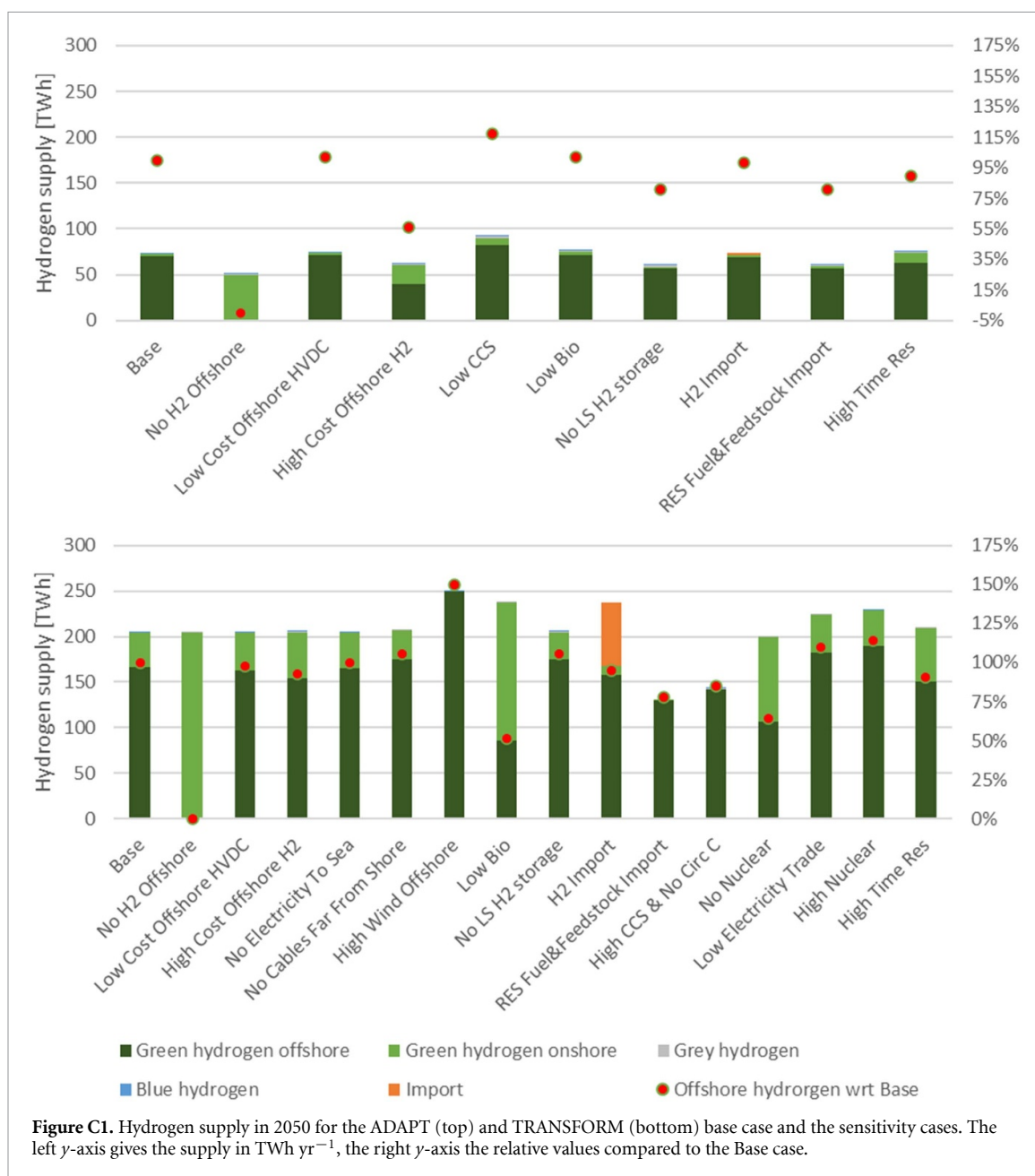
In this appendix additional results of the sensitivity analysis are shown (figures C1 and C2) and the results of some of the sensitivity cases are described in more detail.

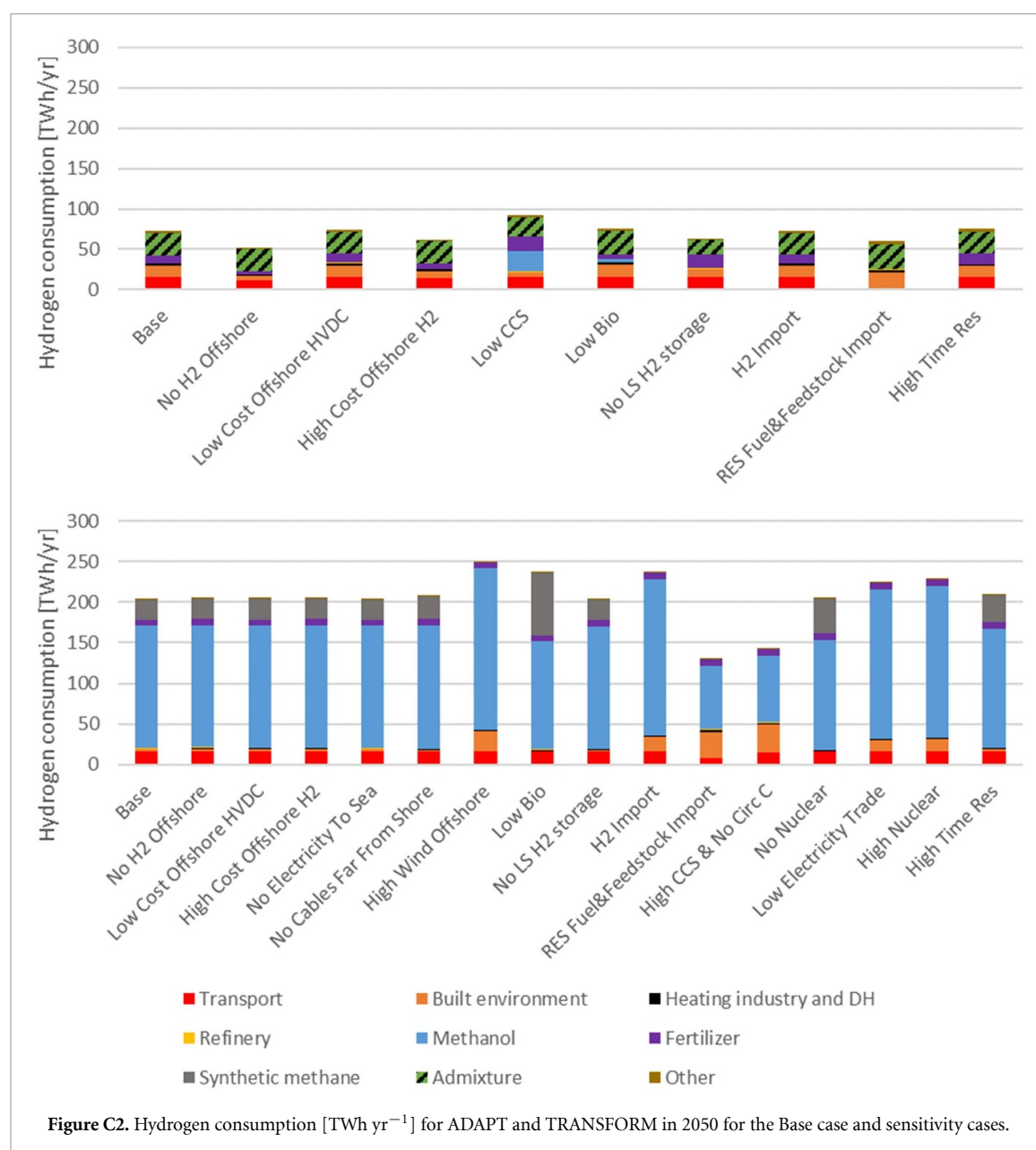
For ADAPT, the case ‘Low CCS’ has the highest contribution of offshore hydrogen production. In the base ADAPT scenario, the large amount of CCS can cover a large amount of the emission reduction of the energy system. By lowering CCS, alternatives need to be sought. This is partially filled in by hydrogen, produced both offshore and onshore. The additional hydrogen is used for methanol production, which is subsequently mainly used as feedstock. Part of the captured CO₂ that is stored underground (CCS) is now used in combination with hydrogen to methanol.

An interesting sensitivity case of TRANSFORM is ‘Low Bio’. In this sensitivity case the total amount of green hydrogen increases by 33 TWh yr⁻¹, while offshore produced hydrogen almost halves compared to the base case. In this sensitivity case the CO₂ shadow price almost doubles, indicating that the energy system is under large stress. Given the shortage of biomass, the system seeks for options that are efficient, and for renewables that are not fully utilized in the base TRANSFORM case. Therefore an increase in utilization of heat pumps can be observed, geothermal heat, solar thermal, etc., but also a partial shift of the type of electrolyzers. In the ‘Low Bio’ case, part of the green hydrogen is produced using Solid Oxide electrolyzers (SOEC). Solid oxide electrolyzers are more expensive, need additional heat input, but can convert the electricity more efficiently to hydrogen (Rasmusson *et al* 2020). Since SOEC is not available offshore, it needs to be produced onshore. Due to the lower full load hours of wind onshore and solar PV, also a decrease in full load hours of electrolysis is observed.

For TRANSFORM, both cases ‘RES Fuel & Feedstock Import’ and ‘High CCS & No Circ C’ show a significant reduction in methanol demand and therefore demand for hydrogen. As a consequence the production of offshore hydrogen production drops significantly, a clear indication that the demand for hydrogen is an important driver for offshore hydrogen production. Note that in those two cases, the energy production from offshore remains high, so more electricity comes to shore.

Similarly, has the demand for electricity and the availability of alternative electricity supply sources a large impact on the results. In case of a restricted trade of electricity, resulting in a lower amount of export for TRANSFORM, offshore hydrogen increases (case Low Electricity Trade). While the consequence of absence of nuclear power is that offshore wind needs to supply more electricity to the system (case ‘No Nuclear’), the opposite effects are observed for a high availability of nuclear power (case ‘High Nuclear’).





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