North Sea
Wind Power Hub
Programme

Technical Feasibility

Grid-integrated offshore Power-to-Gas

A feasibility review and discussion of power grid-integrated offshore Power-to-Gas

Discussion paper

#1

Co-financed by the Connecting Europe Facility of the European Union

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About this paper

Why read this discussion paper

Learn why green hydrogen production via grid-integrated Power-to-Gas is an essential part of the European energy transition, and why it goes hand-in-hand with electrification via renewables. This paper is meant to contribute to the development of an effective offshore energy infrastructure and stimulate discussion and crosslearning about how to achieve this.

See what offshore Power-to-Gas on platforms can look like, how such a concept enables a modular build-out and dive into some of the details. Understand the technical challenges and join an open innovation dialogue about incremental or even game-changing development opportunities.

Observe the techno-economic systemic comparison between onshore and offshore Power-to-Gas and get excited about how offshore opportunities can limit environmental impacts, onshore infrastructure and help accelerate the energy transition.

Understand the urgency to get started with the development of a first large-scale offshore grid-integrated Power-to-Gas pilot by viewing some indicative schedules.

Highlights

The build-out of grid-integrated Power-to-Gas enables the continued build-out of offshore wind (and other renewables) well beyond baseload electricity consumer demand. This continued renewable build-out is needed for further grid-decarbonisation, also during less favourable weather conditions.

The offshore Power-to-Gas platform concept is promising and judged as technically feasible. The platform could be an attractive addition to onshore Power-to-Gas for certain energy transition scenarios, enabling cost-effective offshore modular build-out.

By co-developing power grid-integrated offshore Power-to-Gas and electrical power infrastructure to shore, significant systemic (economic) benefits can be achieved when compared to stand-alone PtG.

In a Western-European context, Grid-integrated offshore Power-to-Gas is desired at large scale, before offshore wind resources are allocated to stand-alone Power-to-Gas.

Structure of the discussion paper

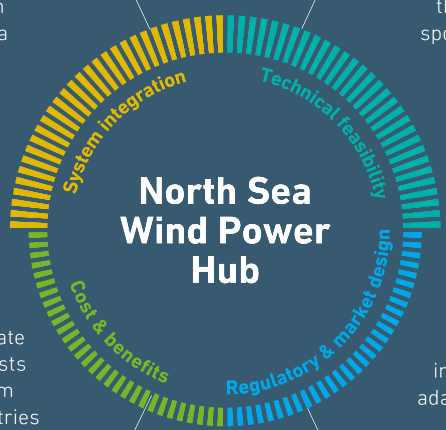
The big picture

The North Sea is a powerhouse of wind energy. Harnessing this power requires us to cooperate across countries and borders to build an efficient network. To show that a solution can be achieved in a cost-effective and secure manner, the North Sea Wind Power Hub is working within four key areas.

This discussion paper explores key topics within technical feasibility and system integraton.

How to adapt the energy systems in Northern Europe to integrate a large volume of offshore wind from the North Sea.

How to design and build the physical hubs and spokes that will collect, transform and distribute energy from the North Sea.



How to ensure that the chosen solution maximises benefits for society and climate while minimising costs and distributing them fairly between countries and stakeholders.

How to ensure a stable and reliable investment climate by adapting regulation and creating an efficient market design.

Executive summary

The North Sea is a powerhouse of wind energy. Connecting this huge offshore wind potential to the energy needs of Europe, implies realizing a very significant contribution to the European climate goals, but requires vast infrastructure to be erected.

The timing of energy supply and energy needs are often not aligned due to the intermittent nature of renewables and forecast uncertainty, which showcases the need for flexibility of various sorts including large-scale flexible electricity consumption, interconnection with other countries demand response within the current grid and time-shifted flexibility. Green hydrogen produced through electrolysis, acting as a large-scale flexible consumer, is an important addition to the energy system, enabling the timely alignment of electrical supply and demand. This in turn reduces infrastructure costs and enables energy transport at large scale, as well as decarbonization of sectors that cannot be directly electrified.

This paper highlights that producing green hydrogen offshore, could be cost competitive with producing green hydrogen onshore – and – that this appears to be technically feasible. Obviously, there are technical challenges to overcome, developments and scale-ups need to take place, but all seem within reach. With offshore grid-integration it is feasible to reach systemic benefits and goals, which are not feasible with stand-alone offshore hydrogen production. The optimal configuration and ratios of onshore & offshore PtG are energy transition scenario dependent. This study has focussed on a radially connected 10GW hub.

Using modular build-out with platforms is proposed here as one solution to enable a cost-effective and rapid build-out of the infrastructure (both hydrogen and power), which is needed to connect offshore wind to the energy needs of Europe. The most suitable hub foundation type depends on the chosen location and selected functionalities, which may impose additional requirements that favors another foundation type.

In addition to this core storyline above, this paper shares details about the offshore platform design, the technical challenges and identified opportunities to stimulate open innovation as well as support developments around regulation and market designs.

Schedules have been developed for both large scale roll out of offshore Power-to-Gas starting in 2035, as well as a first large scale offshore PtG pilot. In order to gather 1 year of pilot operation experience, and de-risk fast succeeding and large scale investment decisions starting in 2030, a pre-FEED phase for the pilot should start in approximately 2022.

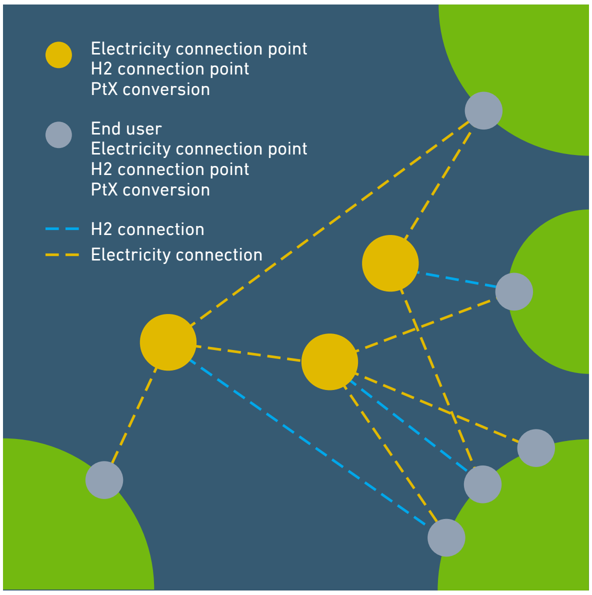
1 Introduction

The Paris Climate Agreement sets out a global framework to avoid climate change by limiting the rise of the global temperature to well below 2°C and pursuing efforts to limit the temperature increase to 1.5°C. To keep the promises made in the Paris Agreement, a significant decarbonisation challenge lies ahead of us.

Large-scale offshore wind deployment in the North Sea has a significant potential for providing a cost-efficient decarbonisation pathway for the North West European (NWE) energy system. To meet the Paris Agreement, the European Commission estimates that at least 300 GW of offshore wind power is necessary by 2050, of which approximately 180 GW of offshore wind power capacity can be installed in the North Sea by 2050.[1] According to the European Commission's Energy System Integration Strategy, coupling of energy systems and conversion of electricity to other energy-carriers will be necessary to:[2]

1. reduce greenhouse gas emissions from sectors that are hard-to-abate;
2. provide 'part of the' (required demand and supply flexibility) to deal with the intermittent nature of some renewable energy sources; and;
3. maintain system resilience and security of supply.

Figure 1: Hub and spoke project



In hybrid projects, offshore wind grid connection and interconnection are combined. Electrolysis can be added either onshore or offshore to facilitate incorporating the large capacities of offshore wind in the European energy system.

[1] European Commission: An EU strategy to harness the potential of offshore renewable energy for a climate neutral future, 2020: Link
Navigant: Integration routes North Sea offshore wind 2050, 2020: Link
[2] European Commission: Powering a climate-neutral economy - an EU strategy for energy system integration, 2020: Link

The aim of the North Sea Wind Power Hub consortium is to facilitate an accelerated deployment of large-scale offshore wind in the North Sea with minimum environmental impact and at the lowest cost for society, while maintaining security of supply. The solution is twofold (see Figure 1):

- Combining offshore wind grid connection with efficient landing and interconnection of EU electricity markets in hybrid projects in order to maximise efficient use of electricity;
- Coupling energy sectors at scale to enable energy system integration and provide large scale flexibility.

To enable a cost-efficient integration of large-scale offshore wind from the North Sea into the Northwest European energy system, a new approach to offshore wind connection, grid integration and energy infrastructure is required. With increasing offshore wind capacity, the case for offshore hydrogen production becomes of increasing interest, due to limitations to the onshore electrical grid, baseload demand of green hydrogen, managing intermittency of wind.

The value of hybrid or grid-integrated power and hydrogen projects is introduced below by means of duration curves. A duration curve shows the power production of a windpark for one year, but organized from high to low load, rather than chronologically.

Figure 2 below shows a duration curve for a system of renewable energy production (10GW), baseload power consumption via the electrical grid (4GW) and flexible power consumer (electrolysis 6GW).

In the stand-alone scenario shown in figure 2a, 4GW of offshore wind is dedicated to baseload power consumption[3] to the grid, while 6GW is dedicated to Power-to-Gas. The missing hours for baseload power are supplemented by a powerplant. This is done e.g. by Gas-to-Power fueled by either hydrocarbon fuel or hydrogen. In the "grid-integrated" scenario shown in 2b, all windpower capacity is used to supply baseload power consumption, with excess used for flexible power consumers (electrolysis). The figure shows that both the missing hours and hours for flex-consumers have reduced in the integrated case –eliminating inefficiencies of the Power-to-Gas-to-Power cycle for that time period.

[3] Note that baseload is a simplified concept. In reality electricity demand varies throughout the day and the year.

Figure 2a: Duration curve – stand-alone scenario

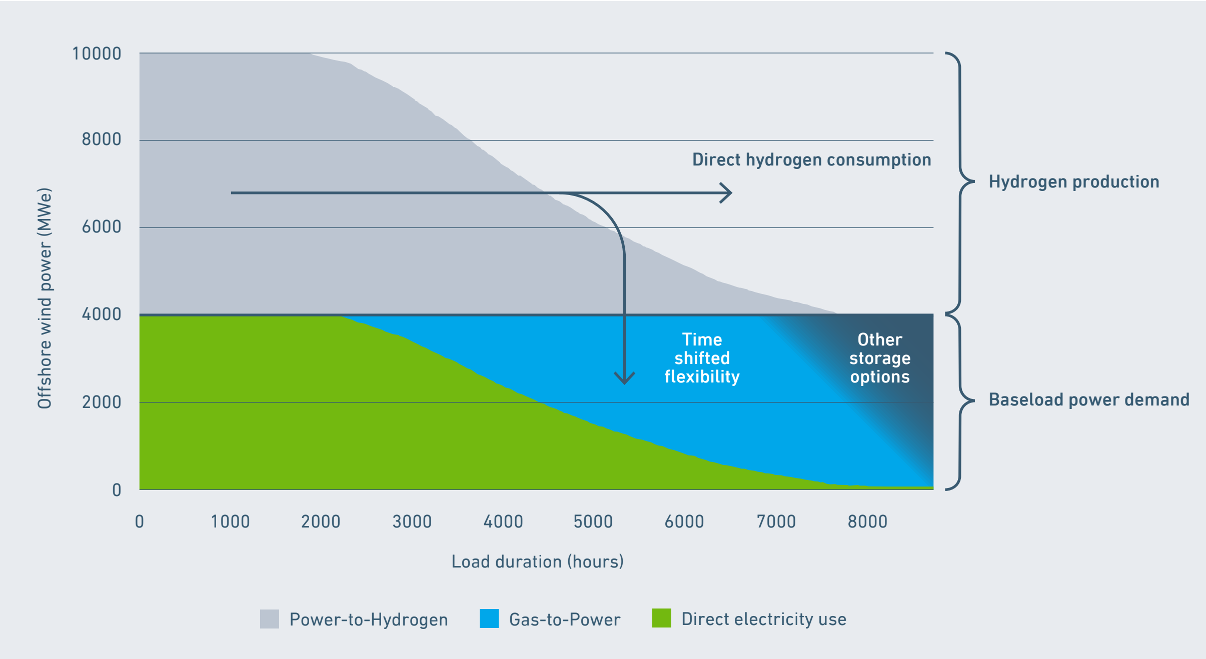
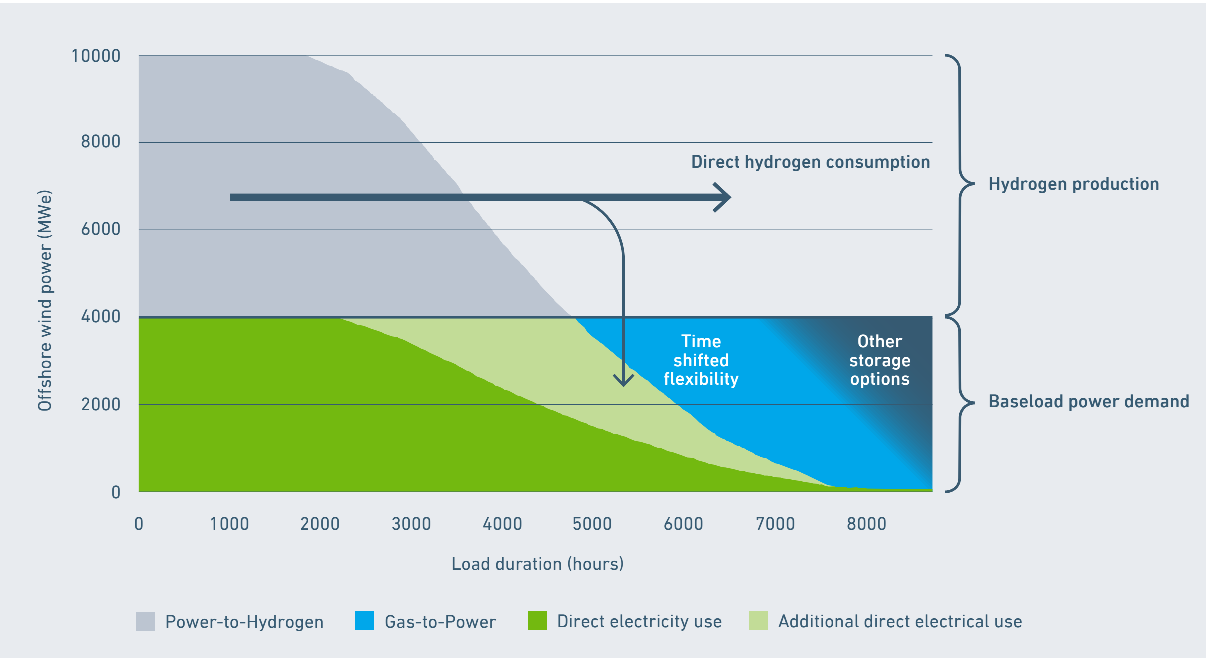


Figure 2b: Duration curve – grid-integrated scenario



The above figures show typical load duration curves for offshore wind. A load duration curve is a way of organizing the annual power production from maximum to minimum rather than in chronological order. It shows a short duration of no wind power, a period of peak wind capacity and intermediate period with partial power yield. Figure 2a shows stand-alone wind for Power-to-Gas and electricity production – hence two stacked load duration curves. To produce baseload power, powerplants are required. Figure 2b shows a combined load duration curve for grid-integrated Power-to-Gas and electricity production. As can be seen, a significant part of the powerplant duty can be replaced by redirecting windpower from PtG to electricity directly at the appropriate times.

The concept of grid-integrated electrolysis and systemic considerations for the integration of offshore wind is further elaborated upon in Chapter 2. For an in-depth presentation of electrolysis from an energy system perspective, we refer to our discussion paper on *How flexible consumption could benefit the integration of large-scale offshore wind*.[4] Here the focus is on the entire value chain and explains the need for flexibility, sector coupling and electrolysers in a future energy system, while providing four guiding principles for efficient integration of offshore wind in the energy system.

Offshore energy hubs are planned to have a wide range of functionalities. This includes not only transferring power from an offshore windfarm to shore, but also providing interconnection capacity, managing power flows, converting Power-to-Gas, and potentially also other energy storage by other means (e.g. batteries, CAES). Therefore, in order to maximize the technical performance benefits and minimize equipment cost, offshore energy hubs must be implemented in a way that addresses all known and foreseeable dependencies between a hub and spoke concept envisioned by the NSWPH. A modular approach when developing an international system of offshore hubs in the North Sea enables discrete expansion steps of sufficiently large size to achieve economies of scale whilst respecting the limits imposed due to technology developments and system integration limits. In this context, a modular approach to a hub development must allow one to manage these uncertainties and facilitate development where the end state is not perfectly known. Furthermore, offshore hubs are expected to evolve with time. This means expanding by means of connecting additional offshore wind generation, becoming connected to other hubs or new onshore points, or adding new functionalities such as Power-to-Gas conversion. This expandability is an inherent property of the proposed modular planning approach.

Large scale green hydrogen produced through electrolysis is maturing. A dedicated effort is required to scale-up and demonstrate the offshore readiness. The NSWPH has contributed towards this by developing a semi-optimized concept design for both onshore and offshore Power-to-Gas, and investigating their technological feasibility. The offshore platform concept is introduced as a way to support modular development of large scale offshore hydrogen production. Central to both designs is the concept of grid-integrated electrolysis, which yields significant systemic (economic) advantages and contributes towards full decarbonisation of the electricity sector. Throughout 2022, the NSWPH consortium will further develop and assess a semi-optimized PtG concept design for caisson islands as well as grid-integrated hydrogen turbine[5] Power-to-Gas, thus enabling a detailed comparison across the developed concepts to identify pros and cons for each foundation type and location.

This paper seeks to present the developed grid-integrated platform concept, while discussing the technical development requirements to enable the successful deployment of such a concept and offshore Power-to-Gas in general. Furthermore, the present paper aims to elaborate on the foreseen incremental technical improvements to such an grid-integrated offshore Power-to-Gas concept, and to discuss potential technological game-changers that could impact the future of (grid-integrated) offshore Power-to-Gas.

[4] www.northseawindpowerhub.eu/knowledge/discussion-paper-integration-of-offshore-wind: Link
[5] This refers to Power-to-Gas equipment being located at the foot of the windturbine. It is often referred to as in-tower, as locating the PtG equipment is potentially located inside the pillar of the windturbine. Alternatively it is named 'physically integrated', due to potential synergies enabled by the physical co-location of the wind-turbine and electrolysers.

2 Systemic considerations for the integration of offshore wind

This discussion paper focusses on the role of power grid-integrated Power-to-Gas (PtG) as a large-scale flexible electricity consumer as well as the physical location of a large-scale PtG facilities. A technically sound strategy to limit the impact on electricity grids is to place Power-to-Gas closer to the source and surplus of renewable power and thereby limit requirements for additional grid reinforcement on top of the already significant reinforcements to facilitate electrification.

When considering large scale offshore wind development in the North Sea, a first step is to locate Power-to-Gas near coastal regions where offshore power lands onshore (see Figure 4 on the left). Here the power can either be converted to hydrogen in a Power-to-Gas plant or exported as electricity to the main electricity grid. The summation of capacity of the PtG and export capacity would need to be equal to (or exceed) the rating of the maximum electricity capacity exported from the wind to shore to fully utilize the energy output of the windpark.[6]

A secondary step would be to locate the Power-to-Gas at an offshore location, e.g. on a platform or caisson island closer to the production of the offshore wind energy. The primary advantage is that electrical peak-transmission capacity from offshore to onshore can be reduced. This option, however, is only considered realistic for wind parks which are far out at sea and require High Voltage Direct Current (HVDC) connections due to their distance. Pipeline connections for hydrogen are required instead of the electrical connections[7]. Pipelines are well suited for transporting high amounts of energy.

Figure 4: Onshore PtG

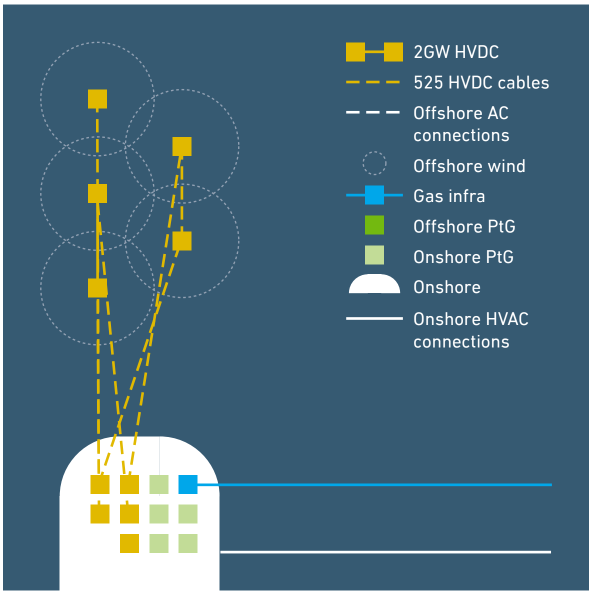
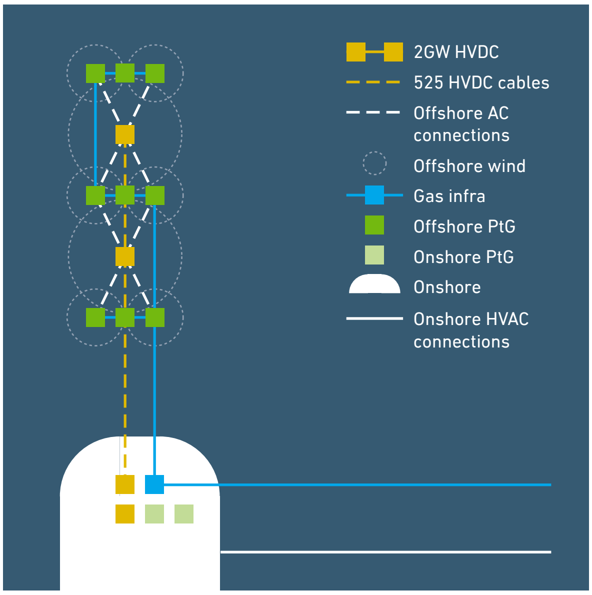


Figure 5: Offshore PtG



[6] Note that wind energy output of a windpark is already capped at the windturbines based on economic tradeoff between curtailment and investment cost.
[7] The option of full offshore reconversion to electricity as a means of time-shifted flexibility only, is not considered here.

When comparing the offshore option to the onshore option, the following considerations are of relevance:

Table 1: Considerations for onshore and offshore location of PtG

Consideration	Onshore landing zone	Offshore
Costs	HVDC cables Offshore HVDC and transformers Onshore HVDC and transformers Compression cost Operational and maintenance costs	Marinization costs Substructure and topside costs Pipeline cost Compression cost Operational and maintenance costs Power infra - PtG interconnections
Performance	Electrical transmission losses Onshore utilities	Offshore utilities, (incl. desalination) Availability considerations
Trading	Grid connection capacity Heat integration in district system	Grid connection capacity
Environmental and OSBL	Cables and cable crossings to shore. Availability of onshore land. Re-use of side products Oxygen and low temperature heat (e.g. for residential heating).	Offshore structures Cooling water and salt water discharge.

As table 1 shows, the extra cost for offshore installed PtG needs to be lower than the savings on the electrical infrastructure to make it economically viable. From an economic viewpoint, relocating Power-to-Gas from onshore to offshore can make sense only if accompanied with a capacity reduction of the electrical transmission capacity[8]. This raises an important question for the feasibility of grid-integrated offshore Power-to-Gas: *Which fraction of the peak offshore wind capacity is required to realize the systemic benefits of grid-integration?*

Before diving into this question directly, let us take a step back and reflect on the background and context of Figure 2 in a bit more detail. What are the benefits of grid-integration and does it actually justify the additional complexity?

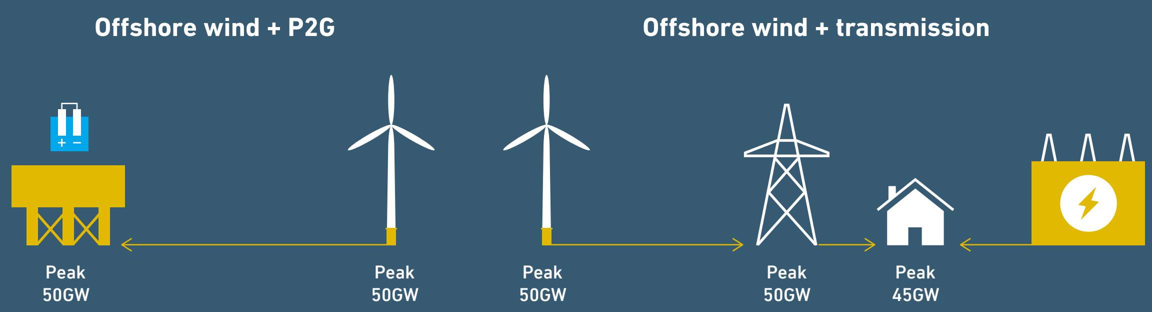
The following chapters discuss the pathway towards grid and energy neutrality with large scale build-out of offshore wind and grid-intergrated Power-to-Gas: First, it re-iterates the win-win situation of grid-intergrating Power-to-Gas by contrasting two hypothetical carbon neutral endpoints – somewhere around 2050. Next, the roadmap towards grid neutrality is shown, with a focus on relative quantities of renewables, Power-to-Gas and curtailment. The NSWPH view of why the grid-integrated PtG needs to be prioritized over stand-alone PtG - is explained.

[8] One exception to this observation could be the desire to import larger peak capacities of electrical power from the grid, e.g. during periods with very large amounts of solar power generated as well as small amount of offshore wind. Current expectation is that this will not justify even larger electrical connections

End-picture(s) of carbon neutral energy

Figure 6 and Figure 7 below compare two hypothetical future situations with significant build-out of offshore wind as well as offshore Power-to-Gas[9]. The year 2050 is mentioned for the sole reason that carbon neutrality is aspired in this year. In Figure 6 offshore wind is installed as stand-alone wind + Power-to-Gas and the one side, and wind connected to the onshore grid on the other. Here there are moments throughout the year when the stand-alone offshore Power-to-Gas system is operating at part-load, while the future onshore system is using hydrogen to generate carbon neutral power, at the same moment in time.

Figure 6: Stand-alone offshore Power-to-Gas



Offshore wind + P2G

Time series	Offshore wind	H2 production te/h
...	...	...
1/1/2050 13:00	50 GWh	1,038
1/1/2050 14:00	5 GWh	104
1/1/2050 15:00	25 GWh	519
...	...	...
2050 year total	27,5 GWyr	5,000 kt/y

Offshore wind + transmission

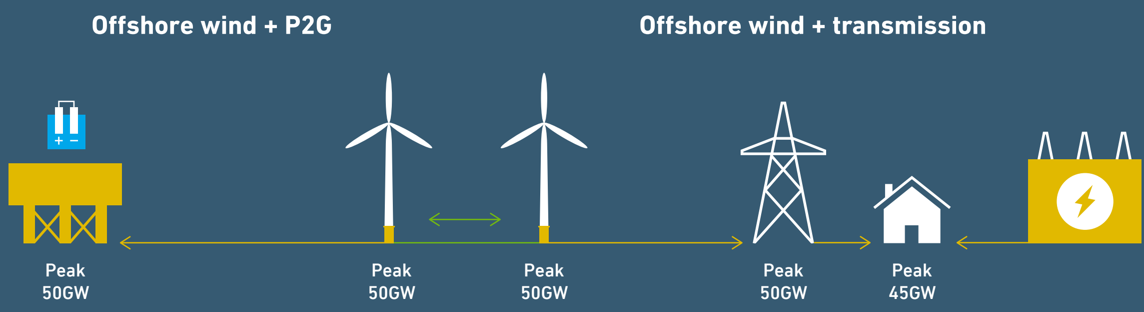
Time series	Offshore wind	Demand GWh	Power plant GWh	H2 use te/h
...	...	...	...	...
1/1/2050 13:00	50 GWh	40 GWh	0 GWh	0
1/1/2050 14:00	5 GWh	25 GWh	20 GWh	1,016
1/1/2050 15:00	25 GWh	30 GWh	5 GWh	256
...	...	...	...	...
2050 year total	27,5 GWyr		11.6 GWyr	5,160 kt/yr

50 GW non-integrated offshore P2G will be consumed by power plant requirements for grid balancing...

In Figure 7 offshore wind is installed in a power grid-integrated manner, supplying both offshore Power-to-Gas and the onshore grid. At peak capacity there is no optionality how to route the power, given the limited offshore Power-to-Gas as well as offshore electrical infrastructure, but all power is utilised[10]. At partial wind speeds however, there is flexibility to route all available power directly to the grid, resulting in a power plant fuel saving. There is a loss of H2 production at the (offshore) Power-to-Gas installation, but the fuel savings at the power plants far exceed these production losses due to efficiency reasons.

[9] Calculation example to convey main point, the numbers are not detailed modelling results but are similar to system modelling results.
[10] Curtailment of offshore wind is applicable, but is generally done inside the windturbine itself to make the windturbine design and downstream system more economical.

Figure 7: Power grid-integrated offshore Power-to-Gas



Offshore wind + P2G

Time series	Offshore wind	H2 production te/h
...	...	...
1/1/2050 13:00	50 GWh	1,038
1/1/2050 14:00	5 GWh	~~104~~ 0
1/1/2050 15:00	25 GWh	~~519~~ 415
...	...	...
2050 year total	27,5 GWyr	~~5,000~~ 3,730

Offshore wind + transmission

Time series	Offshore wind	Demand GWh	Power plant GWh	H2 use te/h
...	...	...	...	...
1/1/2050 13:00	50 GWh	40 GWh	0 GWh	0
1/1/2050 14:00	5 GWh	25 GWh	~~20~~ 15	~~1,016~~ 762
1/1/2050 15:00	25 GWh	30 GWh	~~5~~ 0	~~256~~ 0
...	...	...	...	...
2050 year total	27,5 GWyr	25,7 GWyr	~~11.6 Gwyr~~ 4.6 GWy	~~5,160 kt/yr~~ 2,060 kt/yr

Grid-integrated system produces additional 1700 kton/y of H2 at the cost of an offshore electrical interconnection

In addition to the highlighted advantage of fuel savings, the grid connection allows for import of excess renewable power from the grid, making up for some of the lost running hours. This is excluded in the calculation example above, adding further advantages of grid-integration.

As can be seen, grid-integration yields significant systemic efficiency benefits, which introduces potential for lowering the hydrogen price, power price or any combination of the two.

One may also observe that these systemic benefits of grid-integrated Power-to-Gas, as depicted in Figure 7, are achieved without additional Power-to-Gas capacity, additional cables landing onshore nor additional onshore grid reinforcement compared to the non-integrated scenario of Figure 6.

The win-win of grid-integrated Power-to-Gas build out

When grid-integrating more and more renewables, several phases are foreseen:

- Initially renewables are connected to the grid, to supply electrical energy to grid-consumers.
- At some point it is reasonable to accept curtailment of renewable peaks by designing a lower grid connection capacity than the renewable peak capacity.
- With more renewables, the inclusion of flex consumers – most notably grid integrated Power-to-Gas – can help to integrate these surplus energies into the energy system.
- At very large amounts of renewables and flex consumers like PtG, the benefits of further grid-integration diminishes and stand-alone renewables + PtG may become of interest.[11]

We like to understand;

- *How much renewable capacity is required before PtG makes sense?*
- *Roughly how much grid-integrated PtG is required before stand-alone PtG is sensible?*

Of course there is not one definitive answer to these questions. Different viewpoints and models have been developed and are being developed. The question is e.g., partially addressed by a theoretical framework developed by prof G.J. Kramer of Utrecht University, shown in Figure 8, which is focused on renewables and grid-integrated electrolysis. The analysis is based on a model of limited scope, excluding batteries and international interconnectors, and uses the Dutch context as a case study.[12]

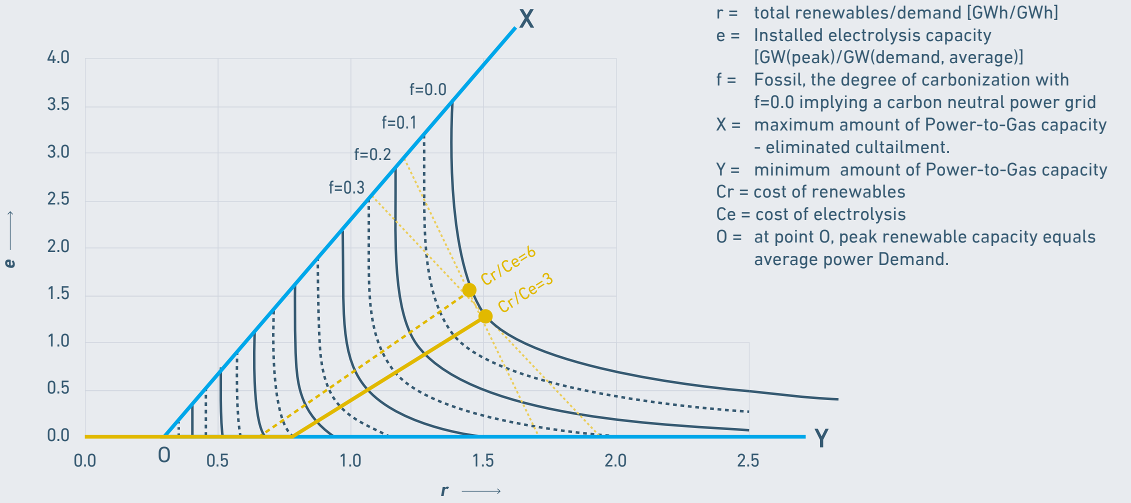
In Figure 8 the yellow line indicates a minimum-cost trajectory for the combined build-out of renewables and PtG in a Dutch context[13] to decarbonize the power grid.

The x-axis shows the installed renewables *r*, which is normalized by the annually averaged electrical power demand[14]. For example, *r*=1.5 implies that the annual renewable energy yield is 1.5x the annual average power demand. The y-axis shows the installed grid-integrated electrolyser peak capacity. The XY-lines indicate the possible solution space, where the Y-line is the minimum PtG capacity (i.e. no PtG, *e*=0), and the X-line is the maximum PtG capacity where the PtG capacity is such that there is zero curtailment of renewables at any time. Between the X- and Y-line, the degree of decarbonization is indicated (black curved lines), on the assumption that all PtG is used for hydrogen production, the hydrogen can be stored unlimited and that all PtG hydrogen is used to generate back-up power[15]. The *f* number ranging between 1.0 and 0.0 indicates the

[11] The description of these phases is generic. No statement is given here whether this last phase is or is not applicable in the Dutch, Danish, German or EU context. It will, for example surely be applicable for locations aiming for large scale hydrogen export and small power grids.
[12] G.J. Kramer, presentation to NSWPH on June 8, 2021, and G.J. Kramer and V. Koning, Fundamentals of hydrogen production and use in a renewable power system, to be published (2022)
[13] Dutch climate and an assumed 75:25 wind:solar mix
[14] Baseload electrical power demand refers to the annually averaged electricity demand by non-flexible users. It hence excluded batteries, power-to-gas as well as other parties which flexibly adjust their consumption profile based on supply.
[15] Note that produced hydrogen may also be used for other decarbonization applications than back-up power first. This does not significantly affect the main storyline given here. For a more detailed understanding, please study the article of Kramer and Koning.

fraction of the electrical power produced from fossil fuels. The yellow lines are the cost-optimized build-out trajectories for different capital cost ratios between renewables and electrolysers. The costs ratios *Cr/Ce* 3 and 6 are shown.[16]

Figure 8: Projected ratio electrolysis and renewables



The trajectory of the yellow lines should be understood as follows; Renewables are initially built to the point where peak renewable energy production equals baseload power demand; this is point *O* in the figure. However, the degree of decarbonization of the considered energy system is still low and demands for a further expansion of renewable capacities. As expansion of renewables continues, curtailment is unavoidable during peak renewable energy production due to the non-dispatchable and intermittent character of these technologies. However, it is not yet cost effective to build electrolysers to take-up the surplus of renewables, i.e. the more effective way to further decarbonization remains the allocation of additional capital to solar and wind capacity build-out, while accepting some renewable energy amounts to be curtailed. Based on cost assumptions, this changes around *r*=0.75, when *f*= 0.35, and a remaining 35% of electricity comes from fossil, a state that the Netherlands hope to achieve in the late 2020s. From this point on, there is sufficient energy surplus in sufficient hours of the year foreseen to attract the installation of the first electrolyser capacities, assuming the *Cr/Ce* cost ratio. (Note that offshore wind has a cumulative annual production of roughly 0.50-0.55x its peak production. Hence, an *r*=0.75 value for offshore wind only implies a peak production of 0.75/0.55=1.35x baseload demand).

The subsequent build-out of additional renewables and electrolysis goes hand in hand[17] – additional renewable capacities increase the times with surplus energy

[16] To note: the dotted lines that touch the *f* contours are lines of equal total capital cost (of renewables and PtG) for the respective *Cr/Ce* ratios. Where they tough the *f*-contour, we find the lowest cost combination of renewables and electrolysers to achieve a certain level of decarbonization.)

[17] Please note that the model assumes a constant technological mix for renewables as well as abstracts from technological advances. One the one hand, the mix of renewables, i.e. wind onshore, wind offshore, photovoltaics, might change over time driven, for instance, due to adjusted political priorities or technology-

and therefore support the case for electrolysis as well as other flexibilities. Moreover, the combination of flexible electrolysis (or other flexibilities), operating during times with RES surplus, can support the business case of renewables: *The symbiotic development of renewables and flexible consumers like grid-integrated Power-to-Gas, batteries and other flex consumers as well as international exchanges, enables deeper levels of grid decarbonization.*

Prioritize grid-integration over stand-alone

Based on the theoretical considerations depicted in Figure 8, a potential picture for carbon neutrality in a self-sufficient energy system – shows peak Power-to-Gas and annually averages renewable capacities to be higher than annual average power demand, i.e. factor 1.3 for peak Power-to-Gas capacity and 1.5 for annually averaged renewables. For an annual average power demand of e.g. 250 TWh/yr (e.g. for 2050 in the Netherlands), this would, for the Netherlands, imply 37 GWe of grid-integrated PtG capacity.

The main takeaway from this assessment, is the significant amount of grid-integrated PtG that is desirable for an self-sufficient energy system with limited flexibilities. It is foreseen that even larger amounts of PtG are desired to satisfy the domestic green hydrogen demand for other hard-to-abate sector and applications, like industry or long-haul transport. This may be achieved by a mix of additional grid-integrated PtG, stand-alone PtG produced locally and hydrogen import. Either way the position is taken here that, from a socio-economic as well as grid decarbonization perspective, grid-integrated Power-to-Gas should be prioritized over stand-alone and build-out to the order of magnitude described above, before stand-alone PtG is developed on large scale in the North Sea, to create sufficient flexible consumer demand in the grid.[18] Continued build-out of grid-integrated (rather stand-alone) power-to-gas to boost LoCal hydrogen production continues to yield systemic benefits beyond these capacities, albeit with diminishing benefits[19].

More extensive system studies focused on the Dutch context, point to similar order of magnitudes of Power-to-Gas for specific scenario definitions, like II3050 (51 GW)[20] and Pathway study (31GW), in addition to large quantities of batteries and interregional / international interconnections.

For the German context, systemic studies show significant amounts of Power-to-Gas. Depending on the assumptions, scenario definition as well as model specification, capacities for power-to-gas in carbon-neutral energy system are in the range of 24[21] to 75 GW[22]. However, these studies only consider infrastructures on an international/European level and mostly abstract from a detailed analysis of national infrastructure implications.

[18] Note that dedicated offshore power-to-gas is affected to a limited degree by distance to the coast, given small incremental cost for a longer pipeline. Power projects and tosome degree grid-integrated offshore power-to-gas projects, are preferrably close to shore due to the impact of cable costs on the economics.
[19] G.J. Kramer and V. Koning – Fundamentals of Hydrogen production in a renewable power system, to be published 2022.
[20] www.netbeheernederland.nl/_upload/files/NetbeheerNL_Rapport-Energiesysteem_A4_FC.pdf: Link
[21] dena-Leitstudie: Aufbruch Klimaneutralität: Link
[22] Wege zu einem klimaneutralen Energiesystem (Fraunhofer ISE): Link

However, some studies analyse this aspect more detailed and show that the location of PtG devices have a big influence on necessary grid extension over the already planned extensions in the electrical and the H2 grid. For example the "Quo vadis, Elektrolyse?"[23] study is a common study from TenneT, Gasunie and Thyssengas. It shows, that from an overall view in the German TenneT control zone new PtG devices should be built mainly in Schleswig-Holstein and in parts of Lower Saxony, which are very near to the coast. The optimal locations depend of course on the expectations of increase of RES. The possibility of PtG even further upstream – offshore – was not taken into account in this study.

In the following sections, we will shed further lights on which conditions are favorable for Power-to-Gas to be located offshore, while also retaining the systemic benefits of grid-integration.

Grid connection capacities

As introduced in Table 1, the investment in offshore Power-to-Gas rather than onshore PtG can be justified only if the capacity of electrical HVDC connections to shore is limited, i.e. the installed renewable capacity exceeds the HVDC connection capacity.

This can be obtained with stand-alone offshore power-to-gas, but offshore windparks with a limited grid connection combined with offshore PtG allow for additional systemic benefits. A limited grid-connection can result in either large or negligible reduction of the systemic benefits, depending on the context. The primary factor determining which grid connection capacity limitation between offshore and onshore is suitable, is the amount of structural overcapacity of renewable energy in the grid at high wind speeds offshore. The desired grid connection capacity for offshore wind with offshore PtG is hence scenario dependent:

- Scenarios with few local renewables and significant H2 import and green gas will show a preference for onshore Power-to-Gas only, e.g. the II3050 European and International scenarios, which rely heavily on H2 import and green methane gas for power generation.
- Scenarios with larger amounts of local renewable energy production will show larger degrees of structural overcapacity of renewable energy. In this scenarios, it can be interesting to move Power-to-Gas offshore, e.g. as indicated in the Dutch II3050 regional and national scenarios. More detailed studies are therefore necessary.

First studies indicate that a renewables mix with large amounts of (offshore) wind further can advance the move towards offshore PtG, since the correlation between wind and the overall energy supply is strengthened. Up to now the fraction of offshore Power-to-Gas is unknown and can range – based on initial considerations - between 0% and 60%. Further system and scenario studies, incl. other flexibilities such as batteries and electrical interconnectors, are required to substantiate the potential range. Such kind of studies are part of the research agenda of the NSWPH.

[23] www.tennet.eu/fileadmin/user_upload/Company/Innovation/Hydrogen/Quo-Vadis-Elektrolyse_DIN-A4_quer_V8_download.pdf: Link

For scenarios with some degree of structural overcapacity of renewable energy, it is observed that fully rated offshore grid-connection capacities show lower utilization compared to partial ratings. For example in a radially connected 10GW offshore wind hub, the 1st 2GW connection shows high utilization exceeding the utilization of the 2nd 2GW, which exceeds the 3rd 2GW, which subsequently exceeds the utilization of 4th and 5th 2GW connection to the onshore grid: The initial connections connect supply with electrical demand for a many hours in the year, while the latter for few. Besides utilization, other factors like security supply, trading and stability and control considerations contribute to the value of a connection. These are especially relevant for meshed network structures. All these factors need to be taken into consideration when assessing the desired grid connection capacity in pending system studies.

Additional local green hydrogen production, as proposed for example by REpowerEU[24], implies higher local renewables and PtG capacities, supporting the case for offshore grid-integrated Power-to-Gas. Import is foreseen as inevitable in most European countries, but these political developments may stimulate higher amounts of local production.

As stated earlier, it is observed that grid-integrated offshore PtG will show significant systemic benefits compared to stand-alone offshore PtG. When considering the presence of electrical infrastructure to, it is also observed that grid-integration of offshore PtG to this electrical infrastructure is judged to come relatively minor costs. At very large capacities of Power-to-Gas, systemic benefits will start to decline and stand-alone PtG is likely preferred. There is, however, a vast opportunity window for grid-integrated offshore Power-to-Gas in between onshore PtG on the one hand and stand-alone offshore Power-to-Gas on the other.

In order to justify the pre-investment for offshore hydrogen pipelines, an outlook towards reasonable amounts of offshore Power-to-Gas is desired. Is it noted that the total amount of offshore PtG in a region - rather than the total amount of PtG in one project – is of relevance for this pre-investment. Multiple projects with a smaller amount of Power-to-Gas can also suffice to overcome this pre-investment. For this reason, grid-integrated Power-to-Gas can contribute to both flexible power demand and hydrogen production for a fairly wide range of scenarios – albeit scenarios with higher degrees of local hydrogen production will show the largest added value.

A modular build-out of grid-integrated offshore is foreseen as the best approach to move forward. The modular approach acknowledges the uncertainties between scenarios by allowing build-out to various ratios, and avoids pre-investments that rely on future predictions.

[24] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A108%3AFIN: Link

3 Offshore power-to-gas design

As part of the NSWPH project scoping activity, onshore and offshore (platform) Power-to-Gas concepts have been designed and cost estimated. The NSWPH consortium will further develop and assess a semi-optimized PtG concept designs for caisson islands as well as grid-integrated hydrogen turbine throughout 2022. The most suitable hub foundation type depends on the chosen location and selected functionalities, which may impose additional requirements that favors one foundation type over another. This chapter describes the offshore Power-to-Gas platform concept design, and how this can be used to develop large scale offshore wind parks up to 10 GW (peak capacity).

What does an offshore PtG platform look like?

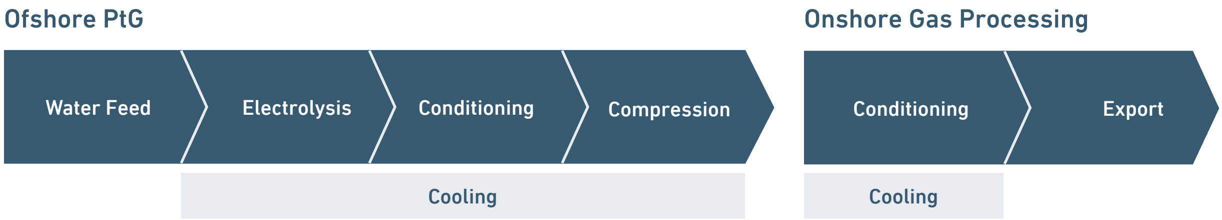
The offshore system scenario considered here, includes construction of 10 GW of offshore wind turbine generation (WTG), which delivers 60% (6 GW) of the capacity to the offshore PtG platforms and 40% (4 GW) electrical transmission to onshore HVDC. However, the platform design considered here has an initial capacity of 4 GW WTG, with the potential for future expansion to larger capacities (e.g. 6 GW WTG).

The offshore PtG platforms are identical, each containing their own hydrogen production facility and supporting power infrastructure to condition the incoming wind power. The conditioned power is supplied to an electrolyser, which splits purified water into hydrogen and oxygen gas. The hydrogen produced on the platforms is exported via a subsea pipeline, for further gas processing onshore.

A typical process flow chart for the developed offshore PtG concept is shown below, showing both the offshore and onshore components of this design. Post-conditioning and export metering could be done either onshore or on the platform[25]. This discussion paper focuses on the offshore components only. General specifications and requirements of each of the offshore blocks for 4 GW WTG peak capacity power supply is included below.

[25] Note that this decision is largely motivated by pipeline infrastructure considerations, which is somewhat beyond the scope of this discussion paper.

Table 2: Offshore Concept Flowchart



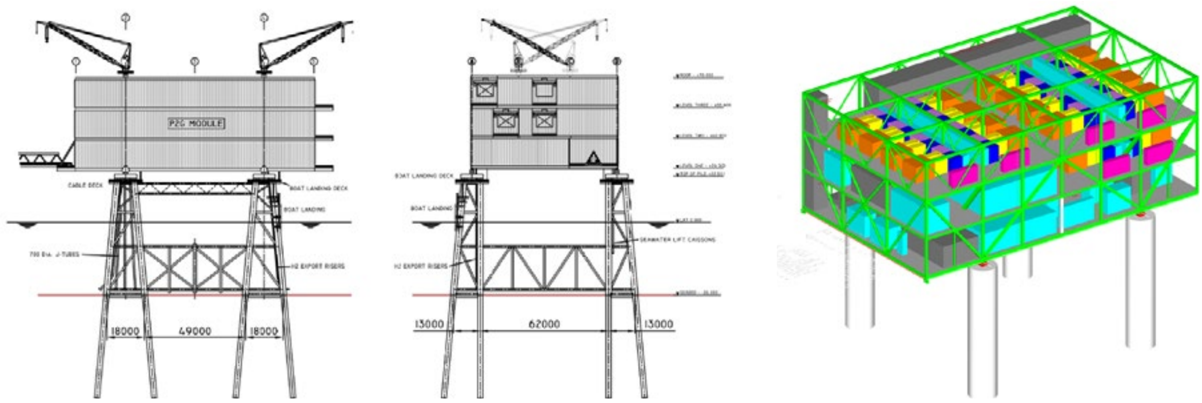
Offshore Block	Total (4 GW WTG)
Water Feed	1,600 – 2,100 m3/h seawater to be desalinated and then demineralised
Electrolysis	3.8 GW electrolysis capacity for 4 GW WTG 30 barg operating pressure
Conditioning	63 – 83 te/h hydrogen (dry) O2 injection to 0.1 mol% O2 Dehydration to no free water in subsea pipeline
Compression	Up to 50 – 60 MW compression power* 63 – 83 te/h hydrogen (dry)
Cooling	0.6 – 1.4 GW cooling capacity 57,000 – 125,000 m3/h seawater
Power Infrastructure	48 x 66 kV array cables collecting power from WTG. On platform infrastructure includes 66 kV switchgear, 66 kV/LV transformers and rectifiers.

* For maximum export pressure of 120 barg. It is foreseen that peak export pressure rises with each platform installed and connected to the export pipeline.

Footprint and weight constraints are more prevailing for offshore PtG plants compared with onshore PtG, due to the limitations of the offshore platform. Design must therefore be adjusted for a constrained offshore environment. For this concept, the platform limitations are:

- Dimensions: 115 m (L) x 70 m (W) x 45 m (H)
  Over three levels, total available footprint is 24,150 m2
- Maximum dry weight: 26,000 tonnes, resulting in maximum dry weight of process equipment of roughly 13,000 tonnes.
- Maximum operating weight: 35,000 tonnes
- Centre of gravity: within 10m of platform centre

Figure 11: Single platform layout with 3 levels of process plant, exterior and interior.



The platform is proposed to be split into 3 levels, with water and gas processing located on the bottom two levels and electrolysis on the top two levels (middle level shares water processing and electrolysis). Based on the constraints, a platform capacity of 500 MW WTG has been proposed. The associated footprint for the 500 MW WTG PtG concept is 20,000 m2 (over 3 floors).

Dry weight is 7,000 tonnes and operating weight is 27,000 tonnes. There is potential scope to increase the equipment weight, however footprint is currently a limiting factor and there will need to be further definition of the existing design plus incremental improvements and optimisation of the equipment and layout to increase the overall platform capacity above 500 MW WTG.

Figure 12: Platform power rating vs limits (footprint, dry and operational weight).

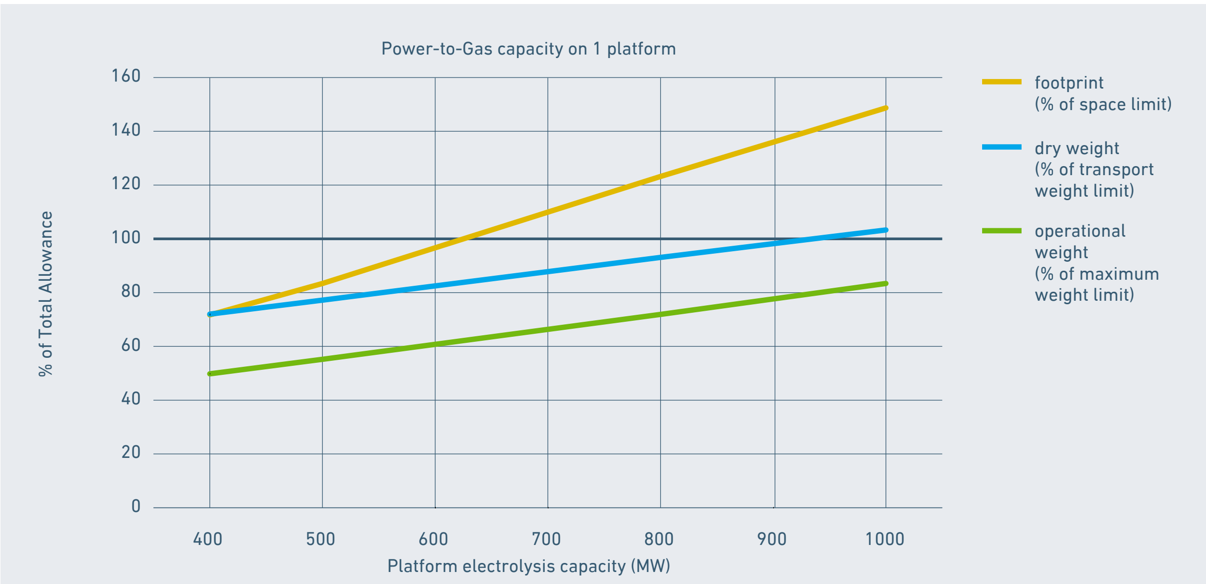
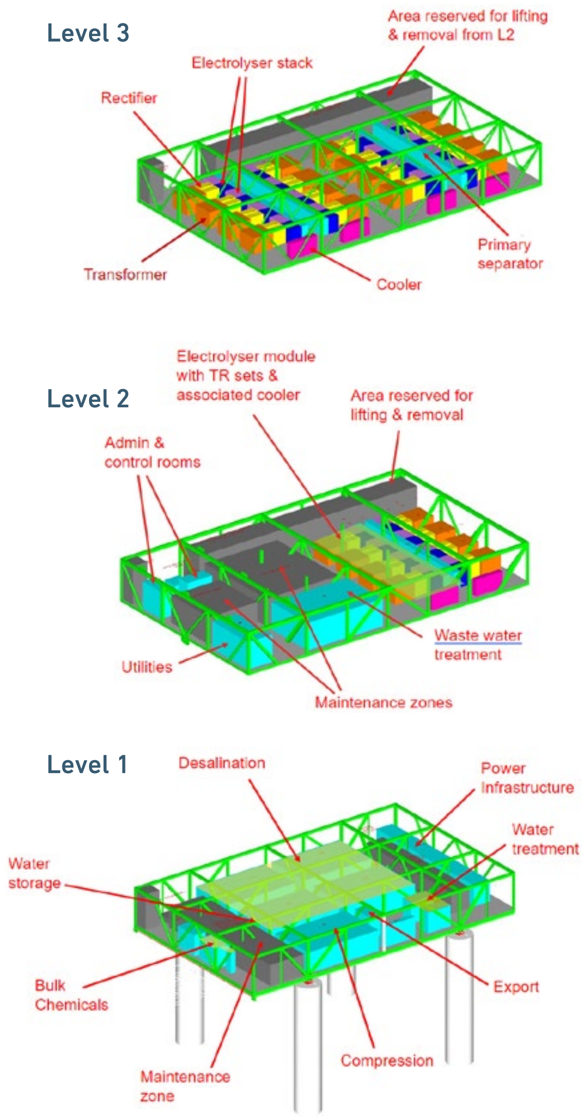


Table 3: Single 500 MW WTG platform specifications and requirements, exploded view

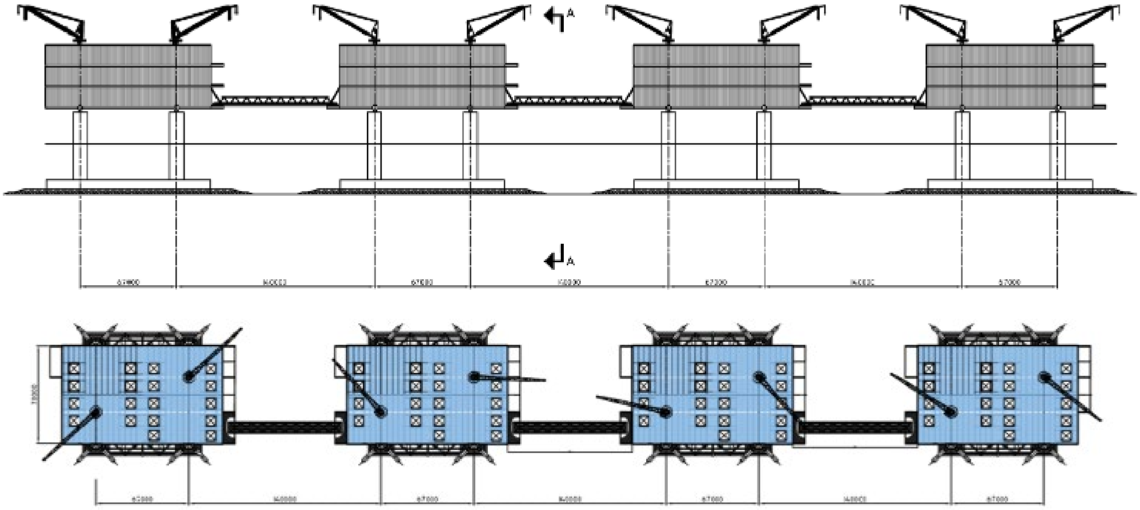
Offshore Block	Platform (500 MW WTG)
Water Feed	200 – 260 m3/h seawater to be desalinated and then demineralised
Electrolysis	500 MW electrolysis capacity 10 PEM electrolysers with IGBT rectifiers* 30 barg operating pressure
Conditioning	8 – 10 te/h hydrogen (dry) O_2 injection to 0.1 mol% O_2 Dehydration to no free water in subsea pipeline
Compression	6 – 8 MW compression power 8 – 10 te/h hydrogen (dry)
Cooling	70 – 170 MW cooling capacity 7,000 – 16,000 m3/h seawater
Power Infrastructure	66kV switchboard 24 20MW 66kV/LV transformers 48 10MW rectifiers
Overall Footprint Constraints	115 m (L) x 70 m (W) x 45 m (H) 24,150 m2 over 3 floors
Overall Weight Constraints	Maximum dry weight of process equipment: 13,000 t Maximum operating weight: 35,000 t Centre of gravity: within 10 m of platform centre

*GBT rectifiers are preferred over thyristor rectifiers due to power quality and harmonic filtering considations: mainly due to plot space and weight considerations. (In addition, the active power control of IGBT rectifiers may aid with offshore grid stability, but more work on this is required).



The platforms are expected to be grouped into clusters of 4 platforms (i.e. 2 GW WTG clusters), with process and electrical interconnections for operational flexibility.

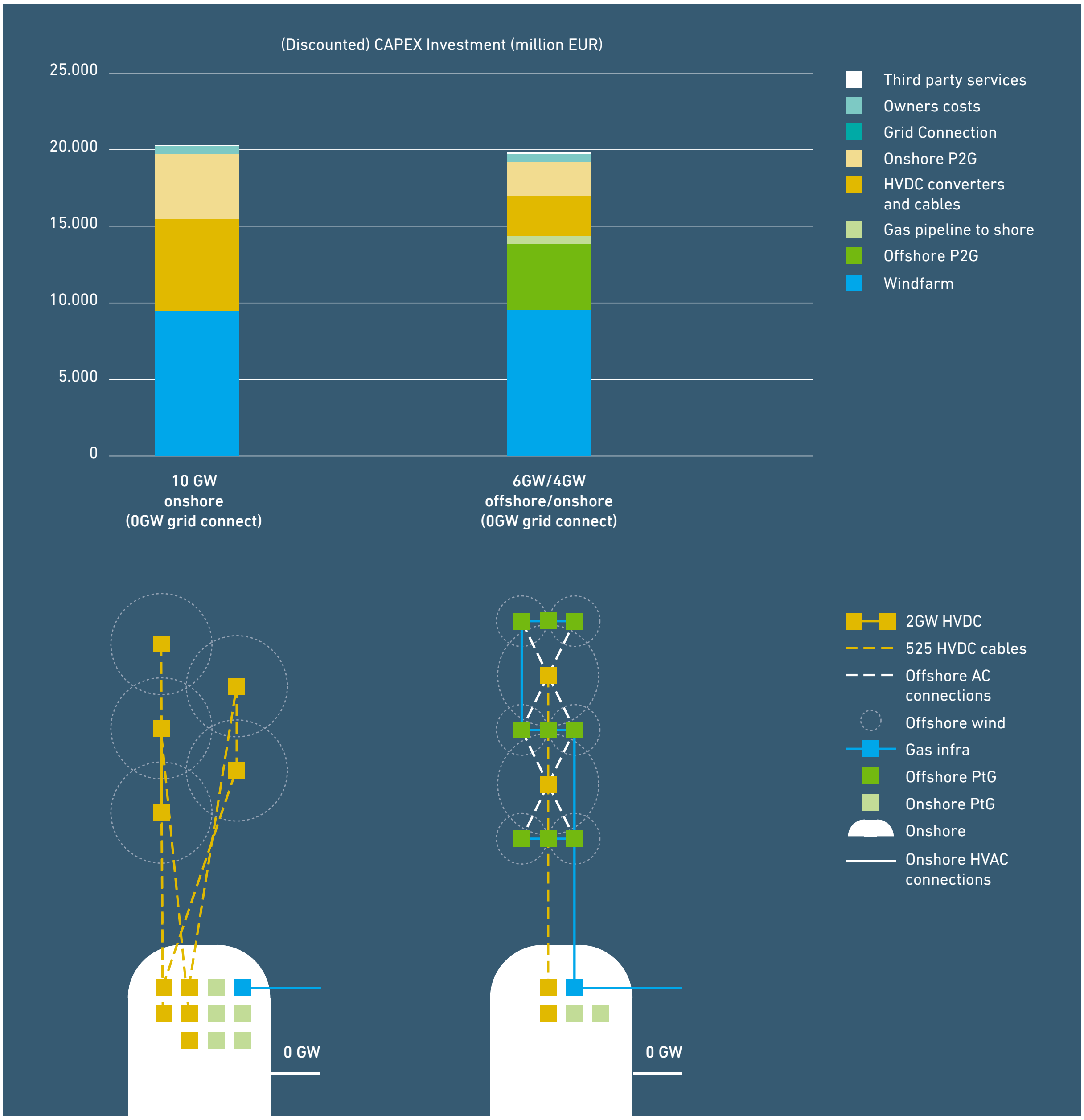
Figure 13: Platform cluster with interconnects



Techno-economic viability of offshore grid-integrated Power-to-Gas
Techno-economics of offshore grid-integrated PtG needs to be evaluated in a wider energy system context, including alternative configurations such as standalone offshore PtG with pipe to shore and standalone offshore wind with electric only route to shore. There are several trade-offs to consider. Piping gas to shore saves the cost of HVDC converters and cabling, however placing PtG offshore raises PtG costs. At the same time, providing optionality of routing wind power to shore in the form of electricity brings trading benefits which can offset additional costs.

The NSWPH consortium has built an integrated techno-economic evaluation model which considers the cost and performance of different PtG configurations, with different access to trading opportunities. The techno-economic model is limited to a radial windpark connection.

Figure 14: Discounted CAPEX for 10GW PtG project



The modelling[26] predicts that there is similar total CAPEX[27] for configurations between those configurations with only onshore PtG and those with a large share of offshore PtG, although the build-up is different. The onshore option has a lower PtG share than the offshore option but incurs much higher electrical infrastructure costs. Offshore faces a small additional cost for pipeline infrastructure. See Figure 14.

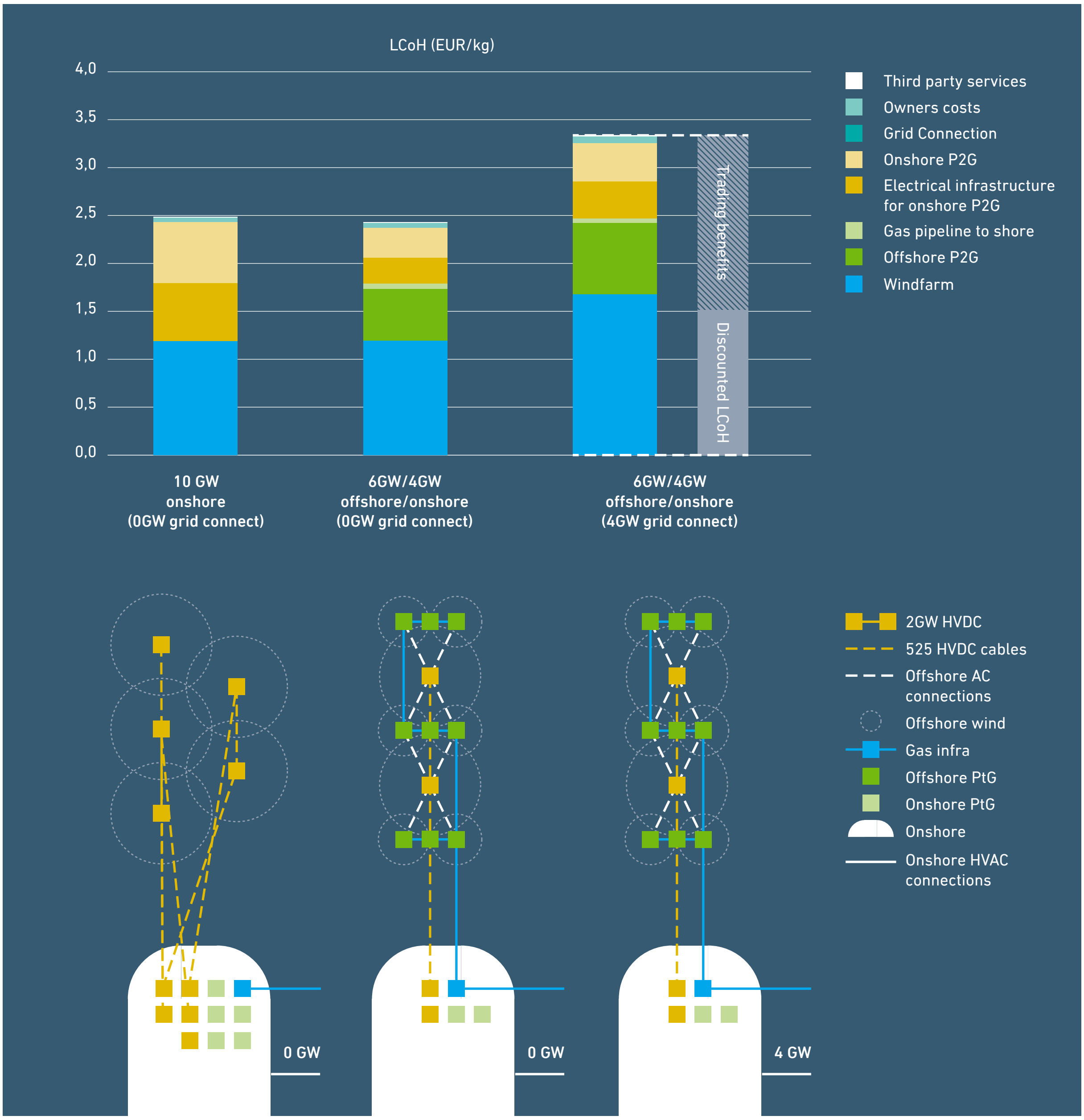
When comparing the overall levelized cost of hydrogen for the configuration with only onshore PtG compared to that of mainly offshore PtG, numbers are again similar between onshore concepts and offshore concept – for the initial comparison without electricity trading. See Figure 15 below.

Again, the build-up does vary with the electrical infrastructure component being much higher for the onshore option. However, once a substantial grid interconnection is included and trading is allowed, the systemic gains from trading are seen to more than offset the uplift in LCoH arising from reduced throughput of hydrogen (which reduces fixed cost dilution). Note the trading gains shown in the chart are gross gains and would need to take into account grid access charges and other transaction costs. Nevertheless, the trading gains are likely to be a critical factor in driving the PtG (socio-) economics, both onshore as well as offshore. Important to note here, is that the gains are system benefits, which are likely to result in some combination of reduced electrical power price and hydrogen prices.

[26] Note: simple calculus is sufficient for the CAPEX comparison only.

[27] This is for a project consisting of 10GW WTG, PtG and power infra. Costs are in EUR2021. Project is assumed to start in 2031 with 1GW per year expansion. Onshore PtG first, followed by offshore PtG. Discounting is based on 4% discount rate (1 EUR2021= 1.42 EUR2030 = 1.73 EUR2035). Power-to-Gas learning rates are included, with different learning rates for PEM (offshore) and alkaline (onshore) based on best available NSWPH insights. Note: Overall onshore vs offshore comparison is quite similar when comparing raw EUR2021 numbers with discounted numbers incl learning rates

Figure 15: **Levelized Cost of Hydrogen comparison for onshore and offshore configuration as well as configuration with grid connection for power exchange with grid.**



Levelized Cost of Hydrogen comparison for onshore and offshore configuration as well as configuration with grid connection for power exchange with grid. The calculated LCoH numbers are in the range of 2.0-3.5 EUR/kg excl. trading benefits.

The LCoH numbers on the y-axis in Figure 15 reflect cost (not market) prices, based on a set of assumptions like depreciation, project location, wind-year references, project lifetime as well as projections of energy transition – which are not described in adequate detail to enable fair comparison with other studies. Please also note that by definition an LCoH calculation assumes a flat hydrogen price over the full project lifetime of e.g. 30 years, while in reality green H2 prices are foreseen to decrease throughout the project lifetime. This implies a hydrogen price above the LCoH at the beginning of the project will be required. The calculated LCoH numbers are in the range of 2.0-3.5 EUR/kg excl. trading benefits.

4 Development requirements for grid-integrated offshore PtG

The proposed large scale grid-integrated offshore PtG electrolyser facility is a first of its kind. Besides scale challenges for hydrogen production, offshore production introduces additional technical obstacles to overcome. Design must consider marine environments, unmanned operation, space and weight limitations. Electrical offshore lay-outs need to be developed for grid-integration, balancing cost, reliability, flexibility and electrical design considerations like faults and harmonics. Offshore grid frequency control by means HVDC and rectifier needs further development.

The following section identifies the technical development requirements for grid-integrated offshore PtG. Further discussion is later provided around technical improvements that would enable offshore PtG to become more cost effective over time.

General Design Criteria

A 4 GW offshore PtG design consists of eight identical platforms, each rated to 500 MW WTG. The rating is based on footprint and weight limitations provided by the platform. All PtG process equipment and supporting infrastructure, including power infrastructure, must be within the platform limitation.

Control and operations of the facility is an important consideration when targeting a minimal facility footprint. An unmanned platform reduces additional non-process or electrical plant related facilities and associated required safety zoning. As such, the current design requires the platform to be under complete remote operation. Understanding that remote control and operations for a scaled plant that is the first of its kind presents a challenge and there will need to be learnings, potentially gleaned from onshore scaled and manned electrolyser facilities or pilot projects, that could be adapted for offshore PtG.

The platform concept is an entirely enclosed design, however, equipment will still need to be compatible with weather conditions (including saline air) and high humidity experienced offshore. This may involve marinization of equipment and materials selection.

Electrolysers

There are 6 modules per platform, and each module is comprised of eight x 10 MW stacks.

Figure 16: Platform electrolyser building block example.

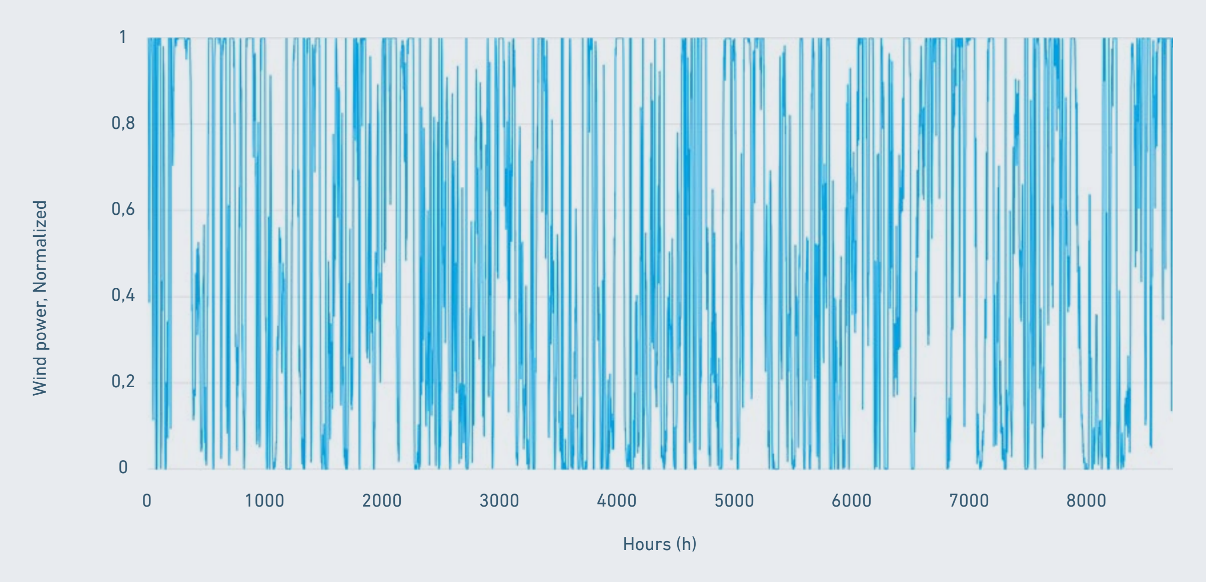
	Quantity / Size					
Platform	**480 MW**					
Module	80 MW	80 MW	80 MW	80 MW	80 MW	80 MW
Stack	10 MW 10 MW 10 MW 10 MW 10 MW 10 MW 10 MW 10 MW	10 MW 10 MW 10 MW 10 MW 10 MW 10 MW 10 MW 10 MW	10 MW 10 MW 10 MW 10 MW 10 MW 10 MW 10 MW 10 MW	10 MW 10 MW 10 MW 10 MW 10 MW 10 MW 10 MW 10 MW	10 MW 10 MW 10 MW 10 MW 10 MW 10 MW 10 MW 10 MW	10 MW 10 MW 10 MW 10 MW 10 MW 10 MW 10 MW 10 MW

Electrolyser stack and module design improvements should focus on increasing stack size (target 10 MW) and minimising weight and footprint. Current PEM electrolyser stack sizes reach 2.5 MW, however, it is anticipated that stack sizes up to at least 10 MW will be developed, which will promote larger module sizes in the future. It is also understood that a larger stack size promotes a smaller footprint.

The electrolyser footprint for this concept has been developed from a 10 MW stack size, scaled from existing stacks with anticipated size reductions applied (due to increased current density, optimisation of build and materials, etc). Electrolyser suppliers need to target electrolyser stack footprint of 2.7 m2/MW to achieve the layout provided in this concept (stack plus immediate surrounding access for maintenance, while a footprint of 6.3 m2/MW is required if separators and manifolding etc. are included). For alkaline electrolysis to be feasible for offshore, the footprint must be significantly reduced from the current status quo. This could be aided by vertical orientation of the stacks. Dry weight of the stacks should not exceed 6 te/MW.

The electrolysers will be powered by renewable energy, so the operation of individual stacks and/or modules must be able to follow the varying conditions of typical wind profiles, considering ramp rates and turn down rates. An example of a wind profile is provided below in Figure 17. Electrolyser operation must be able to follow this profile, with minimum impact on safety and degradation rates.

Figure 17: Example wind profile for typical wind-year



Electrolyser efficiency is anticipated to increase up to 3.8 kWh/Nm3[28] towards the plant end of life, as a result of improved stack efficiency when replaced after <60,000 operating hours. This will result in an increase in hydrogen production (and thus increase in feed water) and decrease in cooling requirement over the life of the plant, such that seawater cooling flow rate is halved (from 120,000 m3/h to 51,000 m3/h for 4 GW WTG). The downstream equipment sizing in this concept has been rated for worst-case start-of-life electrolyser stack efficiency of 5 kWh/Nm3, while the downstream equipment sizing and techno-economic analysis anticipates an increase in efficiency up to 3.8 kWh/Nm3 for end-of life[29].

Balance of Plant

In general, balance of plant will need to process hydrogen produced at a rate that follows the wind profile (as shown above). Due to the electrical connection and market requirements, the variation may even be slightly steeper than the wind profile. Suppliers must consider these varying load conditions, including ramp up and turn down, when equipment is used for this application.

Based on current understanding, electrolyser ramp-up and ramp-down rates of electrolysers are adequate, but turndown vs stop and re-start can benefit somewhat from a more advanced strategy with regard to degradation management.

[28] For new stacks in 2050, and excluding stack degradation
[29] IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C Climate Goal, International Renewable Energy Agency, Abu Dhabi.

Feed Water / Desalination

Feed water for offshore PtG must come from the sea, so offshore scaled desalination is required. It is understood that offshore desalination is a fairly new application for the technology; Particularly for large scale desalination, brine management may become a challenge.

Up to 2,100 m3/h seawater overall, or 260 m3/h seawater per platform, is required to be desalinated and then demineralised for electrolysis. With an expected recovery rate of 40%, a large portion of this water is returned to the sea as brine (up to 1,300 m3/h overall, or 170 m3/h per platform).

Effective management of brine will be required to ensure environmental regulations are met. Brine management could e.g. include dilution by mixing the brine with the cooling water effluent, as the cooling water flow rate is expected to be over 50x the feed water flow rate. It should be noted that cooling water flow varies with hydrogen production and may be out of sync with desalination brine production at certain periods if not designed with care.

Gas Conditioning / Purification

Two main hydrogen gas conditioning/purification processes required for the concept are dehydration and oxygen removal. In the design made, dehydration is carried out on the platform to ensure no free water in the subsea pipeline. Oxygen removal may be carried out onshore to ensure that the hydrogen meets the onshore grid quality specifications.

At the time of design, some remaining oxygen in the pipeline is considered favourable with regard to mechanical integrity and pressure fluctuations in the pipelines. Future insights may arise affecting the decision to do this post-treatment offshore or onshore.

Numerous technologies are available for dehydration of gases, although dehydration specifically of hydrogen currently only exists at a small scale, e.g. for up to 10 MW electrolysis. Smaller electrolyser modules typically employ adsorption (TSA/PSA) for dehydration, however, absorption (TEG) is generally preferred for scaled applications due to cost and robustness. TEG dehydration of hydrogen is still in development. At least one of the technologies (adsorption or absorption) needs to be further developed so that it is commercially available for scaled hydrogen applications offshore, taking advantage of economies of scale as well as considering turndown and variability.

Typical hydrogen gas flow rates for the concept are up to 83 te/h dry H2 overall (10 te/h dry H2 per platform). The electrolyser will be operating at pressure, so feed pressure can be up to 30 barg. In addition, equipment should not be a bottleneck on the hydrogen production (i.e. should be able to follow the wind profile with respect to varying load conditions). As such, suppliers will also need to ensure their developments consider turndown and fluctuating conditions.

Likewise, oxygen removal via catalytic reactor is currently employed for small scale electrolysis, e.g. up to 10 MW. This technology will also need to be developed, taking advantage of economies of scale, for hydrogen production rates of up to 83 te/h dry H2 or more. As with dehydration, the flow rates will be variable, and the reactors must be able to operate with these varied load and turndown conditions. A specification break between the offshore and onshore pipeline system is expected, with the latter having a lower design pressure. To safely operate the onshore facilities and equipment where the landing pressure could potentially reach the maximum offshore pressure (120 barg), hence an overpressure protection system should be established.

Compression

A total of 50-60 MW of installed compression capacity is required for the 4 GW WTG offshore PtG concept. This is 6-8 MW per platform, to compress 10 te/h dry H2 from 30 barg to 60-120 barg.

Reciprocating compressors have been proposed for the concept due to their suitability for hydrogen (high compression ratio) and commercial availability. Vibration can become a concern for offshore applications. Design must aim to minimise compressor vibrations (e.g. compressor placement relative to platform). In addition, lubricants can lead to explosion risks and contaminate the hydrogen. Seal-less or oil free compressors are preferred where possible, alternatively, suppliers should focus on minimising leakage and contamination.

Compressor control must be achieved over the range 0-100% to remove any requirement for gas buffer storage on the platform (when considering the variable wind profile) and a time-lag is to be considered in backpressure.

This is expected to be achieved from a compressor load control system (HydroCOM or equivalent) and a recycle loop. Recycle loops decrease the efficiency of the system, so ideally a control system would be able to work to low turn down ratios. Suppliers should look at developing compressor control over a wide range, with a target of 0-100% range ability.

Power Infrastructure

The following is defined for the power infrastructure:

- The voltage is defined by the voltage of the wind turbines and array cable system (66 kV).
- The sizing of the IGBT rectifiers is defined by the electrolyser stack size (10 MW). It has been assumed that the electrolyser will be supplied at Low Voltage DC power (<1500 V).
- Due to space constraints the use of IGBT based rectifiers has clear advantages to the alternative option of thyristor based rectifiers with harmonic and reactive power compensation.
- Due to space constraints the use of GIS switchgear has clear advantages to alternative option of air insulated switchgear.

Electrical switchgear and cables

66 kV GIS switchgear has been developed for offshore application by a number of manufacturers. It is anticipated that as 66 kV array cable voltage develops, this market will grow and become more mature. The same is true of “wet type”/ no lead sheath” 66 kV submarine cables required for the array cables.

Non-SF6 gas technologies for both the busbar insulation (e.g. Green Gas) and the interruption medium (e.g. Vacuum circuit breakers) are available at 66 kV and can be used in place.

Rectifiers and transformers

The sizing of the transformer is defined by an assumption that only one IGBT rectifier may be connected to a secondary winding and that two secondary winding is the maximum conventionally available. The number of transformers, and hence overall dry weight, could be reduced if suppliers develop 66 kV/LV transformers with a greater number of secondary windings.

The sizing of the rectifiers at 10 MW is based on market feedback on the maximum size. 10 MW will result in large currents at LVDC and the 10 MW rectifiers may need to be split into sections (e.g. 4 x 2.5 MW) to ensure that the LVDC currents can be accommodated by LVDC switchgear. Larger sizes of IGBT rectifiers may be technically feasible if the DC voltage is increased or if higher current LVDC circuit breakers are developed.

Optimising interconnection of electrical systems

Section 3 indicates that systems that allow trading (e.g. the switching between the production of hydrogen and export of electricity) appear to offer the most economical solution. To facilitate this trading, it is necessary to allow power to flow from a wind turbine to either the HVDC or the P2G plant. This requires interconnection of the electrical systems. At the scale of GWs this offer challenges including:

- **Control of power flows |** This is both from a safety and equipment loading perspective. For safety it is essential to ensure any item of equipment worked on is earthed and is safe. If this can be fed from more than one direction, complex interlocking may be required to ensure equipment is safe to work on. For equipment loading, current flows must be understood for all potential operational configurations and loading to ensure overloads do not occur, this becomes more complex as interconnection increases. It may be necessary to include (and manage) open points to reduce system complexity to manage both issues.

- **Fault level |** As more equipment is interconnected the total potential fault input to the system increases. In multi GW systems, even for solely asynchronous loads and generation, this can cause maximum fault level to exceed the capabilities of equipment. This requires consideration in the design of systems. Designs will be required that consider this in layouts. Technological solutions are also possible, fault current limiters (such as those using superconductors) have been tested in the past for these applications.

- **Requirements for switching equipment |** Switching equipment may enable some cost reductions in the offshore electrical interconnections, and some switches may be required to operate frequently and on-load. This is not typical, particularly for equipment at the WTG. Typically, WTGs have ring main units (RMUs) switchgear (2 switches and 1 circuit breaker) this may require replacement with more complex RMUs (e.g. 3 circuit breakers, or 2 on-load switches and 1 circuit breaker). These are available on the market but are not typically applied at WTGs.

Offshore grid stability / managing frequency

Generally, the electrical system frequency of HVDC connected offshore windfarms are managed by the HVDC converters. As these can ramp power up and down extremely quickly, the converter can manage the system frequency (e.g. balancing the load and generation offshore). However, in systems where more than one HVDC converter is connected, the control of the two converters must be coordinated. This is complex and not (particularly between multiple manufactures) common in operation. The project envisioned in this document does not propose an interconnected systems simultaneously supplying two HVDC converters and, as such, avoids this issue. However, having the possibility to supply multiple HVDC converters would allow the potential to export electricity to multiple sites and/or manages outages more easily.

Another potential method for managing the frequency would be the use of WTG with grid forming inverters. In this instance it may be possible to have some, or all of the offshore system disconnected from an onshore electrical network and operating independently. This could allow for future P2G systems to be able to operate independently from a electrical connection to shore (e.g. by HVDC) or even to a platform (P2G installed at the WTG). This is an active area of development.

Safety

Hydrogen and oxygen both introduce a risk of flammable atmosphere, which could lead to fire and/or explosion. Safety has been considered at a conceptual level, with general industry standards and practice applied from high-level qualitative perspective. Safety considerations need to be developed in later project phases, and should include risk reviews (HAZID, HAZOP, LOPA) and DSEAR (ATEX) assessments.

As part of this, further definition and confirmation of safety zoning is required, including further review of safety distances, blast protection and equipment separation. Currently, the platform is proposed to be entirely enclosed and under positive pressure to displace any hydrogen leaks, and ventilation requirements and rates have been considered at high level. Electrolyser suppliers and other hydrogen equipment suppliers need to confirm the safety requirements of their equipment, including safety distances and ventilation requirements.

Dispersion analysis should be performed to define exclusion zones around vents and ensure appropriate positioning. Safe and continuous venting of large amounts of oxygen must also be managed appropriately. In addition, equipment selection must consider hydrogen embrittlement of high strength steels, especially for equipment with variable operating conditions such as the compressors.

5 Incremental improvements to grid-integrated offshore PtG

Opportunities for improvement of the presented design exist. Below a selected number of opportunities are discussed.

Increases in platform capacity will reduce the number of platforms required and reduce overall costs, which could be realised though equipment and layout optimisation. A target of 700 MW WTG per platform is foreseen as a desirable next step. Equipment optimisation could include, but is not limited to:

- Equipment weight and footprint reductions,
- Equipment placement and/or or clearance height/distance reductions, to introduce an additional level or mezzanine levels,
- Increases in efficiencies,
- Alternative technologies for e.g. desalination and compression.

Caisson Island
This offshore PtG design considers offshore platforms, however there is potential for a caisson island to be used instead of platforms. The feasibility of a caisson island design is included in the ongoing studies for this project, and this paper may be updated following the study outcomes for a caisson island.

XXL Piles
XXL piles (eXtra, eXtra Large) are now being introduced as offshore wind turbine generator foundations, so extending the application of the monopile foundation into deeper water and supporting the largest production turbines. Manufacturers are therefore now able to produce piles of 10m diameter and are developing the capability to produce 12m diameter piles. Similarly, transport and installation capability already exist for XXL piles. Whilst XXL piles may weigh more than an equivalent jacket foundation solution, the fabrication effort in their production is comparatively low compared with a jacket and our study has shown that they are potentially the most cost-effective foundation option for the offshore Power-to-Gas platform concept.

Using 4 XXL piles as platform supports is an application that has not been tried before but can result in cost reductions. It is necessary to confirm the feasibility of their use as proposed, not only regarding their structural performance, but also regarding their durability, manufacture, transport and installation to tight tolerances by discussion with potential suppliers and installers.

Electrolysers

The concept design proposes an electrolyser operating pressure of 30 barg, as this is currently the highest operating pressure available. Operating at pressure reduces compression requirements downstream. There is potential to further reduce or eliminate compression requirements if electrolysers can operate at even higher pressures. There is suggested that above 80 barg operating pressure, significant savings could be available. It is also well possible that higher pressures actually lower the capacity per platform due to safety, plot space and//or turndown considerations.

Whilst both PEM and alkaline electrolysers can currently operate up to 30 barg, high pressure alkaline electrolysis promotes diffusion of gases across the membrane, leading to an increase in risk of explosion. Evaluation of re-design of alkaline electrolyser design to be more intrinsically safe with respect to mixing risks of hydrogen and oxygen could allow alkaline electrolysis to be used a higher pressure.

Although slightly more challenging, offshore Power-to-Gas designs based on Alkaline electrolysers are potentially more cost effective than offshore PEM, especially on the short term. For the long term, alkaline may provide more certainty around cost projections than PEM systems

Balance of Plant

Feed Water / Desalination

The concept developed proposes seawater reverse osmosis (SWRO) for the desalination technology, as some offshore applications already exist. However, the RO membranes have a disadvantage for applications in renewable energy because they ideally operate at steady state, providing limitations with the wind profile. Due to technical limitations of the desalination system a water buffer storage should instead be employed, which adds to the overall platform weight (albeit mainly the wet weight which is currently not foreseen as limiting).

It is understood there are alternative distillation technologies available (e.g. multi-effect distillation (MED)), which are able to follow the wind profile and output less concentrated brine (although this indicates a lower recovery / high feed flow) but are less technologically mature than SWRO. There is potential for MED or other alternative desalination technologies to be employed if the technology can be proved feasible for offshore at scale and if additional benefits can be realised (e.g. if electrolysers can operate at higher temperatures, the waste heat could be recovered for MED). The use of MED is foreseen to impact the electrolyser cooling design, as integration will be required

Compression

Should alternative compression technologies, such as ionic liquid compression, become more developed, they may be more desirable than reciprocating compressors for offshore PtG. Ionic liquid compression already has applications in small scale hydrogen with low maintenance requirements and vibrations, and no lubrication oil. A focus on scaled production of alternative compressor technology with reduced vibrations, maintenance and footprint, or potentially with liquid seals, could be of interest also for offshore PtG in the long term.

Cooling

A significant cooling load is required to maintain optimal operating temperatures at the electrolysers. This translates to a large seawater supply for cooling. Heat exchangers are currently installed on the platform decks for closed-loop cooling.

Subsea cooling (i.e. heat exchangers installed subsea) takes advantage of the convective cooling provided by the surrounding current, as a result less water is required. Some subsea cooling methods also require no pumps, removing any requirements for pump maintenance. If this technology could be scaled and commercialised, this could remove the footprint and decrease the cooling weight as well as eliminate/reduce the energy used for pumping cooling water upwards to the platform – which is significant. This solution may interfere also with brine disposal management, as the cooling seawater effluent may be one means to dilute the brine reject.

Offshore floating solar

The inclusion of offshore floating solar, has the potential of increasing the energy yield per km2 of offshore 'wind' parks.[30] Adding offshore solar to offshore wind is seen as an improvement for both the total energy recovered per km2 as well as the utilization of the (offshore) electrical and PtG infrastructure. Some deferment of the added solar will be unavoidable, but utilization of the majority of the renewable power produced offshore appears achievable if ratio of solar vs wind is chosen properly.

If the ratio of solar vs wind is chosen too high, this either results in higher deferment or – more problematically – lower utilization of costly offshore infrastructure: Offshore wind profiles annual capacity factors of 50-55% is typical, where for solar this capacity factor is in the order of 15%.[31]

The inclusion of offshore batteries in addition to offshore solar can potentially boost the economically feasible amount of offshore solar somewhat further. Note that offshore solar still requires significant technical development prior to commercial application.

Power plant integration

There are potential improvements to the grid-integrated offshore Power-to-Gas project by introducing new elements to primarily the onshore Power-to-Gas system. This could include:

Power generation within the battery limits of the onshore site including:

- Onshore peaking generating plant. To provide power at times when wind generation is low and/or demand is high. This could either be hydrogen powered generation, large scale hydrogen fuel cells, energy from waste, bioenergy.

[30] www.tno.nl/en/focus-areas/energy-transition/roadmaps/renewable-electricity/solar-energy/solar-farm/floating-solar/: Link

[31] Golroodbari et al.; Pooling the cable: A techno-economic feasibility study of integrating offshore floating photovoltaic solar technology within an offshore wind park; Solar Energy 219 (2021) 65-74. Golroodbari and Van Sark; Simulation of performance differences between offshore and land-based photovoltaic systems; Prog Photovolt Res Appl. 28 (2020) 873–886.

One advantage of installing the generation at the onshore site is sharing the use and costs of the connection to the electrical transmission network. This is particularly advantageous for peaking plant, that would typically be operating at times of scarce wind. As such the wind and peaking plant could "share" the export capacity and the two generation types could use the same grid connection.

A further synergy would apply if hydrogen peaking plants were used, thus utilising the co-location of gas pipeline infrastructure. It is foreseen that at some point, H2 fuel supply to hydrogen fired power plants, may become the governing case for H2 transport capacity. CAPEX-OPEX optimizations for peak-power-powerplants may be feasible, based on foreseen running hours.

Energy storage within the battery limits of the onshore or optionally offshore site including:

- Lithium-ion battery storage.
- Thermal energy storage

Co-locating energy storage at the onshore site has the same advantage as co-locating generation. E.g. energy storage discharge is more likely to be required at times of low wind and charge is required at times of high winds.

There is a further potential advantages, if a longer duration storage technology requiring heat (e.g. project Malta) is used, the waste heat from the hydrogen generation process could potentially be used to provide some initial heat/charge. This would improve the efficiency of the storage. Technologies of this type have the potential to offer 10+ hours of energy storage. Longer duration storage technologies are likely to become more economic as renewable penetration increases.

Load within the battery limits of the onshore site. Co-locating loads at the onshore site allows potentially lower costs of grid connection and high security of supply (particularly if combined with energy storage or onsite generation).

6 Game changers for grid-integrated offshore PtG

This section describes concepts that are immature or require significant technical development, but potentially have a significant impact on the case for grid-integrated offshore Power-to-Gas. These ideas are not pursued at the moment but shared to stimulate research and development.

Electrolyser system voltage increase

A (PEM) electrolyser stack voltage increase[32] can reduce the cost, weight and space requirements of offshore electrical balance of plant, most notably the transformer and rectifier from 66 kV to electrolyser operating voltage. Given the impact on especially dry weight of this electrical equipment, it could be conceivable to install more than 1,000 MW of PEM electrolyser capacity on a single platform without exceeding the dry-weight limitation of the platform, although it would impact plot space.

Besides larger stack sizes to achieve higher voltages, stacks in series may be considered to increase the system voltage. For Alkaline systems (including AEM), operating stacks at different voltage levels is foreseen as more challenging, due to the conductive nature of the alkaline fluid. This may imply physical separation of the liquid supplies for the different voltage levels is required. For PEM however, the fluid is demineralized and deionized water with negligible conductivity and the water system may feed stacks operating at different voltage.

Placing stacks in series is likely to impact system availability. Configurations enabling cripple mode operation (with any one failing stack bypassed) may be considered to find acceptable trade-off between costs, availability and weight.

Grid-integrated hydrogen turbine

Hydrogen turbine concepts, as alternative to platform concepts, aim to install the Power-to-Gas equipment at the base of, or physically integrated within the wind turbine (tower/shaft). The main advantages seen are (1) removal of the need for separate Power-to-Gas platforms and (2) optimizations opportunities related to the physical integration.

A simplified 7-step description of a wind turbine generator is given here to explain to concept of a (grid-integrated) hydrogen turbine.

1. Turbine blades catch wind and rotate.
2. The generator at the centre of the blades converts the energy into an AC current with the frequency of the rotation.
3. The AC current is converted into a low voltage DC current.
4. The DC current is converted into a grid frequency AC voltage.
5. The AC voltage is transformed to a medium voltage (e.g. 66kV).
6. The power is transported over inter array cables to a central point.
7. And converted to e.g. HVAC, HVDC or used for Power-to-Gas.

[32] e.g. by larger stacks by stacks in series.

For a normal wind turbine, an economic optimum is determined from balancing the costs of wind turbine blades vs generator and transformer size, inter array cables and other downstream equipment. This typically results in a generator which achieves peak capacity at approximately 12 m/sec windspeed. When integrating Power-to-Gas at the wind-turbine and utilising DC power generated in the wind turbine (3), several steps have the potential to be skipped (4, 5, 6) and a new economic trade-off between generator size (2) and Power-to-Gas user (7) may be found, resulting in higher peak power and also higher cumulative power generated from the wind turbine.

Besides several technical challenges to be resolved (not discussed in detail here), there remains an economic trade-off between generator size and Power-to-Gas investment. With significant cost reductions for electrolysers as well as a synergy of higher electrolyser efficiencies at part-load, it is foreseen that the economic balance will shift towards more electrolyser capacity and larger generators. Electrolysers will operate at significantly lower cumulative running hours, which is fine if electrolyser investment costs are sufficiently low.

Besides the downside of operation and maintenance (costs) at a lot more locations (and several technical challenges), hydrogen turbines are a less obvious match with grid-integration: A gas gathering network of pipes is needed to gather the produced hydrogen for this solution, so grid-integration requires an additional electrical network. However, given the long-term potential of physical integration as well as systemic benefits of grid-integration, a system that is both grid and physically integrated should not be discarded too lightly.

An example system could consist of:

- “15 MW typical” wind turbine(s)
- With 21 MW Generator(s) instead of 15 MW generator(s)
- 16 MW of PEM electrolysis installed at each WTG
- And 5 MW transformer and electrical connection installed

The network would consist of:

- Low pressure gas gathering network (e.g. 30 barg), for example of composite pipes
- Inter array cables for connecting turbines (up to 18 for 5 MW example and 66 kV, thereby enabling a signficant increase of the central location.)
- A central location with hydrogen compression, HVDC converter and optionally also centralized water purification and gas treatment to reduce operational and maintenance requirements at the WTG’s
- Optionally water supply network
- High pressure pipeline to shore

There are many aspects that could be investigated in further detail:

- How do costs and systemic/trading benefits of including grid-integration compare vs ‘only’ physical integration in a hydrogen turbine? Considering both power export to grid in case of shortage and power import in case of excess.

- How do costs and benefits of including physical integration compare vs 'only' grid-integrated Power-to-Gas on platform?
- What synergies can be found in combining gas gathering with power distribution networks, as well as optionally water distribution from a central location? E.g. combined or integrated cable laying activities.
- How can grid-integration reduce scope e.g. for back-up power generation, battery requirements, aid in technical challenges related to power fluctuations of a single WTG for the physically integrated PtG concept?
- What are the options and advantages for combining normal wind turbines with electrically + physically integrated PtG turbines in a single network?
- What about offshore networks also containing floating solar?
- How is electrolyser turndown managed in hydrogen turbines, and how can turndown management benefit from grid-integration?
- What windpark lay-out optionality and improvements are feasible for (grid-integrated) hydrogen turbines and how does that compare to the centralized option?

Solid state transformers

Solid state transformers offer potential for significant weight and plot space reduction for transformers and rectifiers feeding electrolysers. The technology is already applied at low capacities, e.g. in powering laptops, however at lower energy flows and lower voltages.

The basic concept involves transforming 50/60Hz AC power, via DC and very high frequency AC, (e.g. 10 kHz), towards low voltage DC.

A first 100 kW medium-frequency transformer has been developed and tested successfully demonstrating very significant plot space and weight reductions.20 Full controllability can be achieved according to references.

Solid state transformers have the potential to significantly reduce plot space and (dry) weight of the platform and enable a signficant capacity increase per platform.

7 Modular build-out

The build-out of up to 180GW[33] of offshore wind at the North Sea prior to 2050 is a massive endeavour. The cumulative investment costs will likely exceed 500 billion euro. The transformation both offshore as well as onshore, e.g. with shore landings, will be prominent. The time period for construction needs to be both intense and long-lasting in order to meet the climate aspirations.

Given the nature of wind and solar, harvesting of renewable energy will be distributed over many locations. Large central locations for power conversion (to either DC or hydrogen) will result in additional infrastructure to transport the distributed wind power to this central location often at substantial additional costs, for example transformation to higher voltages for transport.

Construction of large central locations, is time consuming and costly on its own, while economy of scale benefits for both electrical conversion (to HVDC) as well as Power-to-Gas are limited at higher capacities. Hydrogen pipeline infrastructure is a clear exception here; very significant economies of scale are seen between 2 and 50 GW of equivalent wind power. Besides time consuming to construct, large central locations require upfront investments to facilitate the foreseen future expansions.

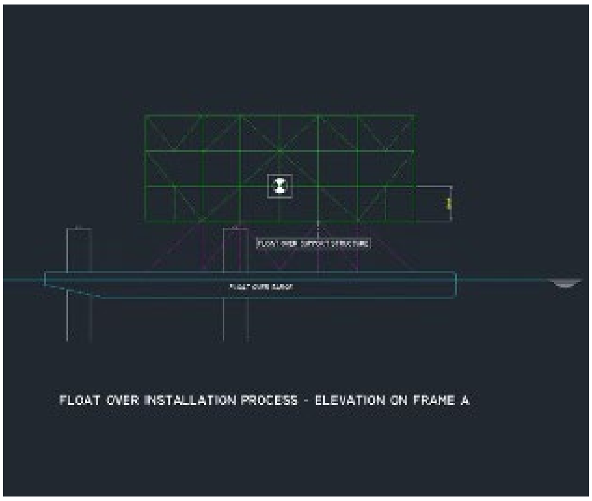
Furthermore, the required safety distance between Power-to-Gas units[34] and critical electrical infrastructure will lead to larger plot areas. This land may however be used for other purposes depending on the caisson island design. These factors will need to be weighted against benefits of an multi-functional artificial island.

[33] European Commission: Powering a climate-neutral economy - an EU strategy for energy system integration, 2020: Link
[34] Installations with pressurized pure hydrogen and oxygen in close proximity.

A modular offshore Power-to-Gas approach on platforms may offer cost, speed and de-risking advantages. Some advantages of the proposed modular approach on platforms are described below;

Onshore construction
Platforms are constructed in shipyards anywhere in the world, where conditions and quality are assured, labour costs are low and factory acceptance tests can be executed.

Industry standard solution
Float-over platform solutions are proven technology and have been the default solution in offshore oil & gas. Installation via float-over is considered one of the most cost-effective solutions. Float over support structures can be re-used for multiple installations.



Adequate scale
Power-to-Gas systems of 500MW, though ideally slightly larger, are considered roughly the right capacity. No compelling scale advantages are seen above this size[35], other than reduced platform costs.

Economy of scale and economy of numbers
Despite large scale, the number of platforms required (for the North Sea alone) enable a supply chain of platforms from multiple shipyards to develop yielding economy of numbers as well as economy of scale.

Interlinking platforms with bridges
Bridge links between a number of platforms enable an overall reliability increase. It also allows low-cost safety distances between platforms (thereby practically eliminating escalation potential) and certainty about continued operation of the adjacent platforms during major overhauls or outages at a single platform. During Power-to-Gas maintenance electrical systems may remain in operation to minimize effective downtime.

[35] With exception of reliability and availability aspects, which can be resolved with interlinking via bridge links as well as electrically.

Physical locations in the wind park

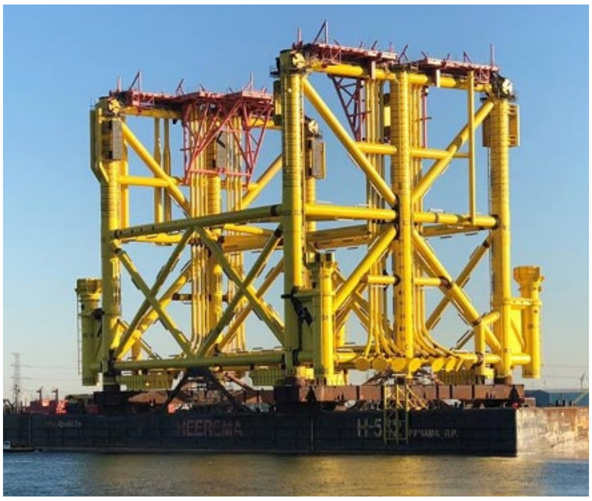
Platforms can be distributed alike HVDC converter platform stations, throughout the wind park, limiting the electrical infrastructure to bring power to a central location as well as the associated environmental impact.

Decommissioning and replacements

Platforms can be fully replaced at end of lifetime.

Phased investment

With exception of a pipeline, no major pre-investments are required. After a first Power-to-Gas platform is successfully in operation or piloted, further investment are significantly de-risked due to a repeatable, identical platform design. This allows for large scale simultaneous scale-up of production and roll-out without impeding further innovation like XXL piles, platform capacity increases, or alike.

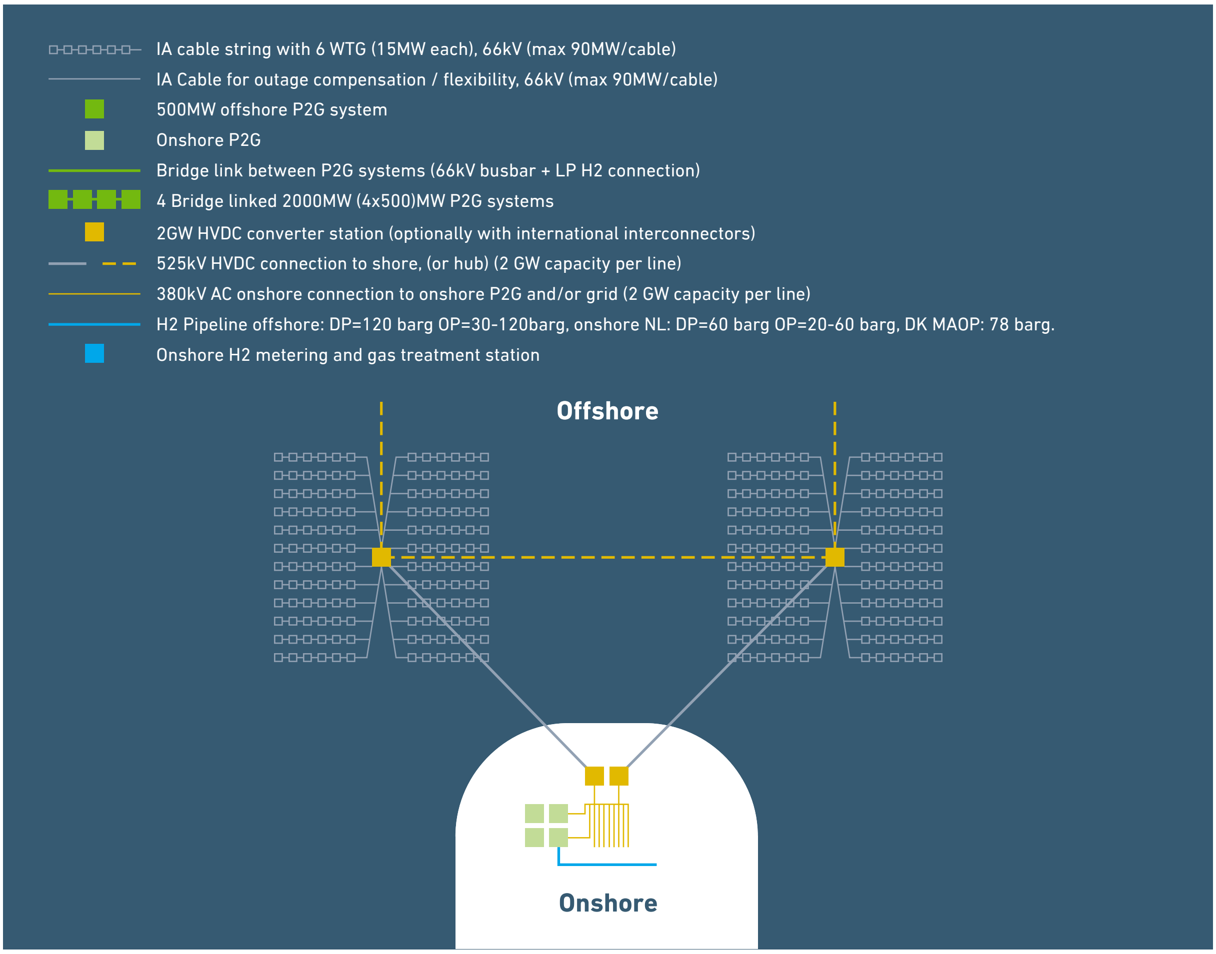


Modular expansion

Construction of a hub can be initiated without pre-determining the exact amounts of grid-integrated Power-to-Gas in the hub. Phased decision and expansion allows for flexibility and allignment of the hub design with the energy transition developments.

In the section below, a cartoon-like wind park expansion is shown. It shows the expansion of a full electrical 4 GW wind park with 2x2GW HVDC converter stations to a 10GW hub containing an additional 6GW of Power-to-Gas platforms.

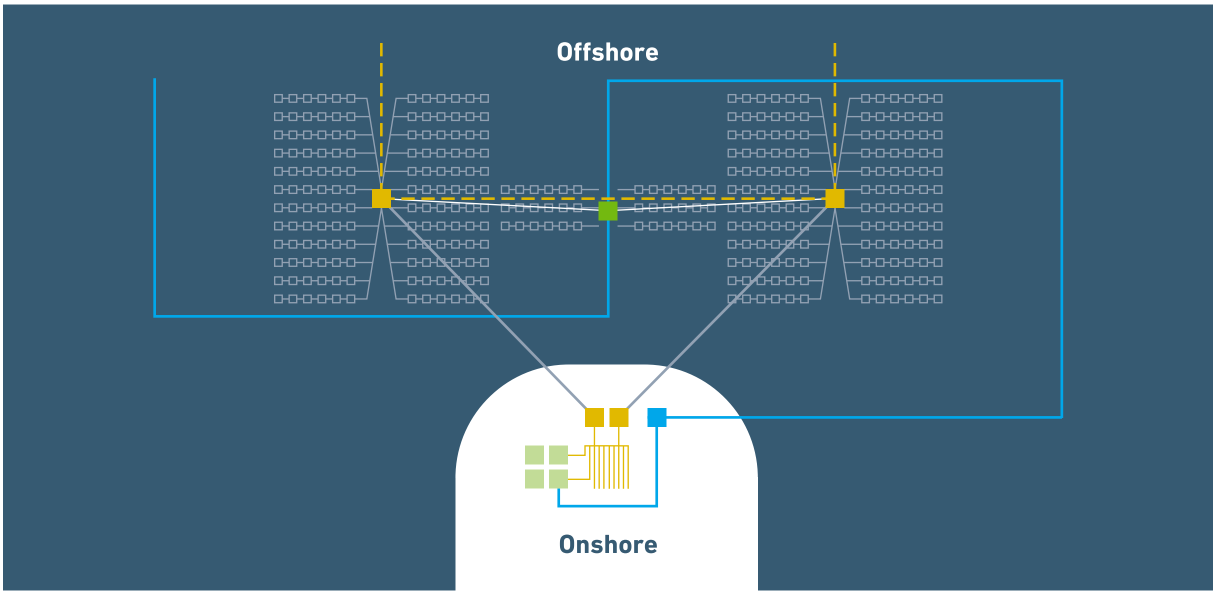
Figure 18: Modular offshore PtG build-out example



Start offshore PtG build-out with full electrical infrastructure and onshore Power-to-Gas designs and anticipate future expansion with offshore Power-to-Gas.

Note: There is a maximum of 90MW or 6 WTG for a single inter array cables of 66kV. This makes blocks of 2 GW a fitting size for a single central point. With larger central points, the impact of inter-array cable length on the overall cost of the wind park increases. The strings of this 2GW example are roughly 10km (6x1.5km), but some of the cable lengths are 20 km, due to the distance between the first wind turbine and the central point. Any extension beyond 2GW – at 66kV level – implies that the inter array cable will be more than twice the minimum length of the string.

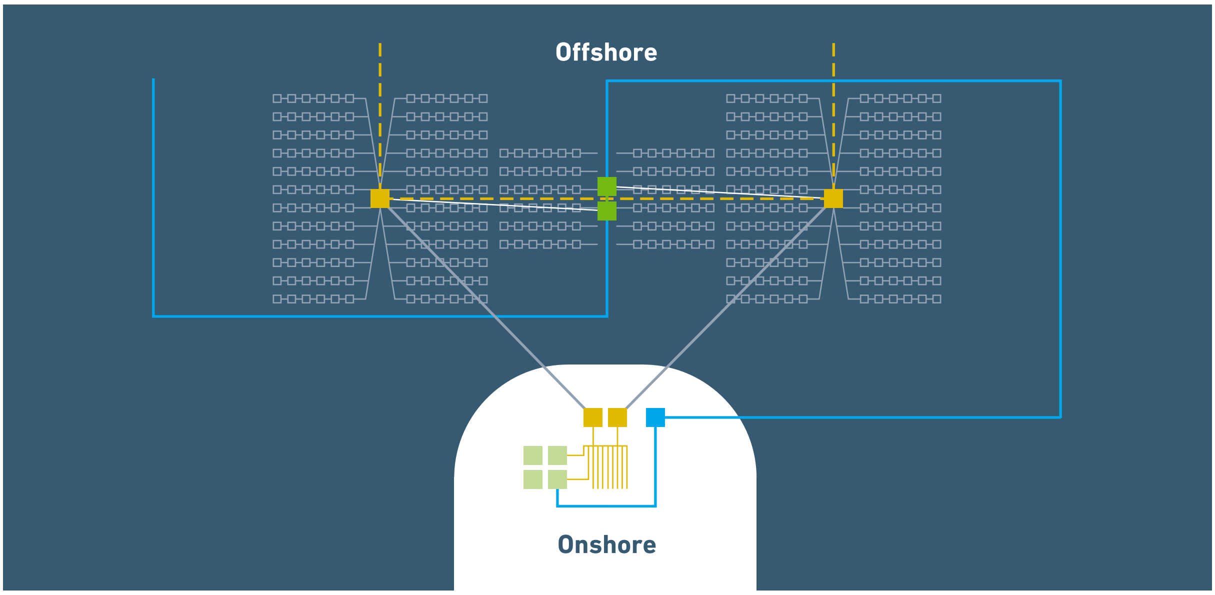
Figure 18a: Modular offshore PtG build-out example



Start with first platform and pipeline connection.

Note: Windfarm can be expanded at same rate as the offshore Power-to-Gas construction. Electrical interconnection with HVDC converter stations are made for first platform, yielding reliability improvements already for the first platform.

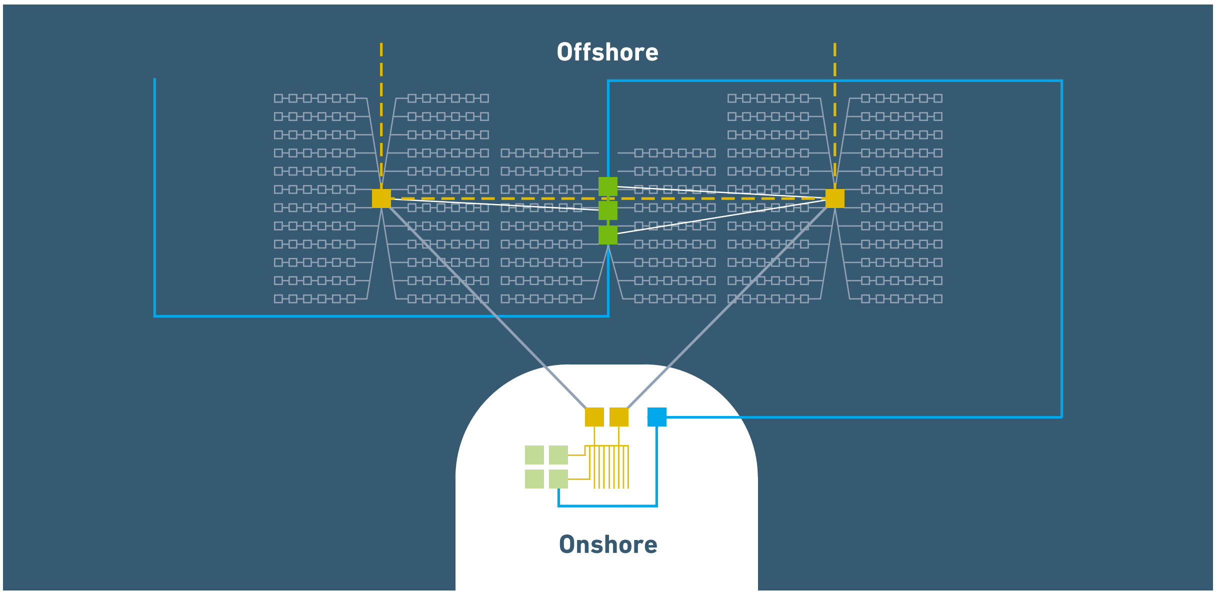
Figure 18b: Modular offshore PtG build-out example



Extend with second platform and windfarm and interconnect via bridge link.

Note: Grid forming of the offshore AC electrical system, including the interconnection of windturbines with the PtG platform can be done via HVDC converter station.

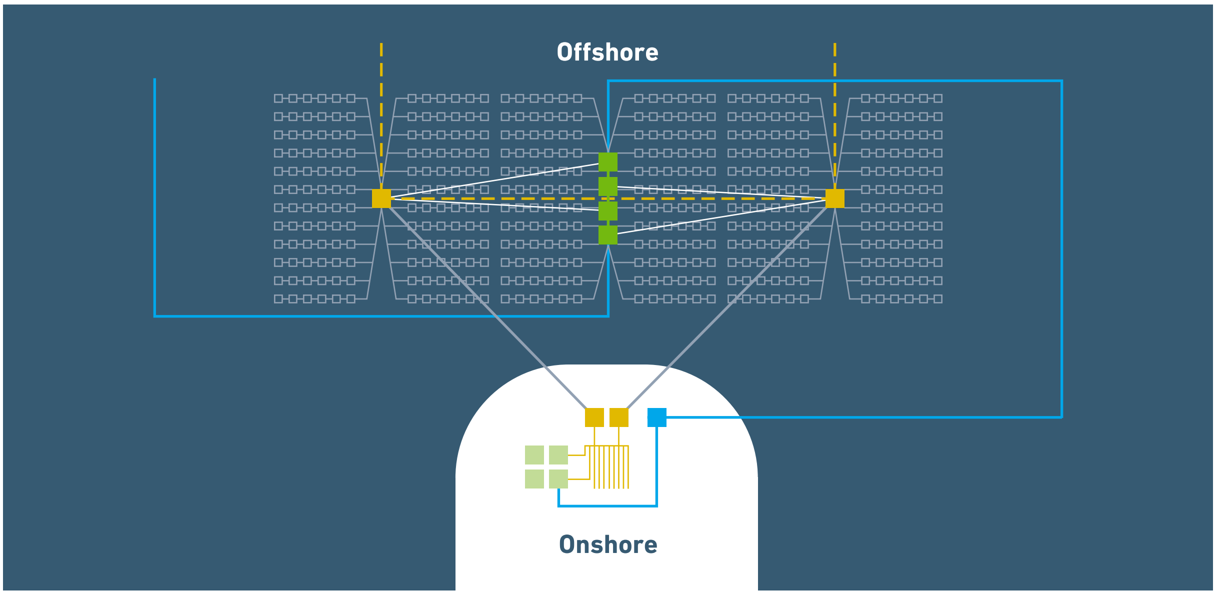
Figure 18c: Modular offshore PtG build-out example



Extend with 3rd and 4th platform (or alternatively first start with new cluster).

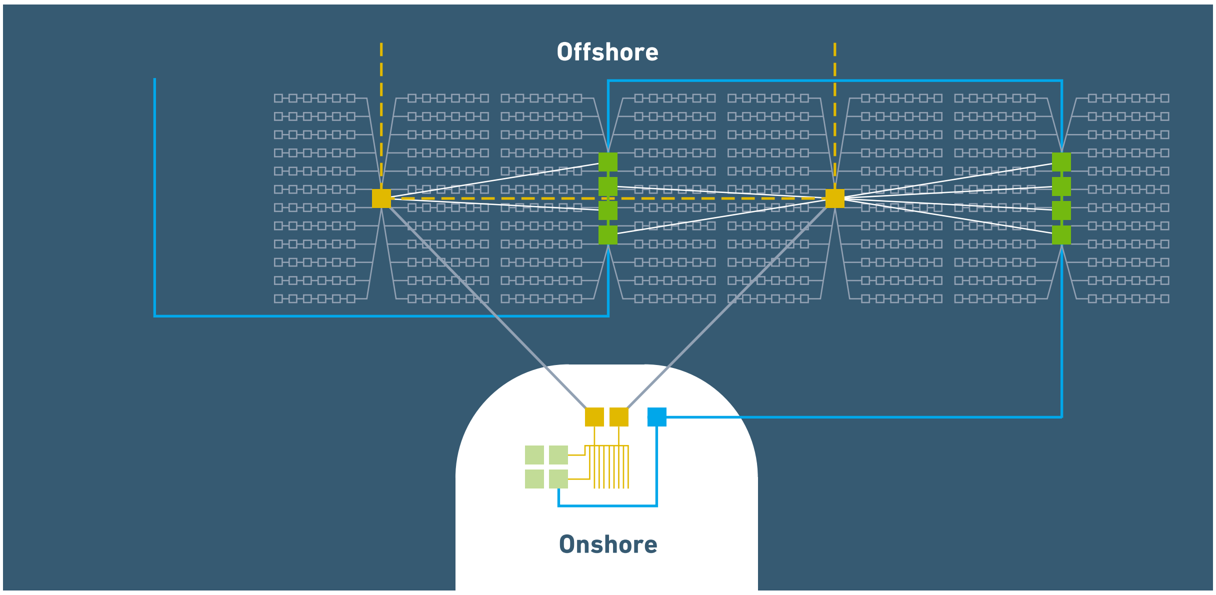
Note: Construction and installation rate of 2 platforms each year is considered realistic. This installation rate already requires a total of 4 simultaneous shipyards constructing platforms.

Figure 18d: Modular offshore PtG build-out example



Note: the electrical interconnection capacity between HVDC converter platform and bridge linked PtG platforms is a fraction of its peak WTG capacity, e.g. 40% of 2GW = 800 MW. The distance is approximately (2x6+3+margin) *1.5km ~25km.

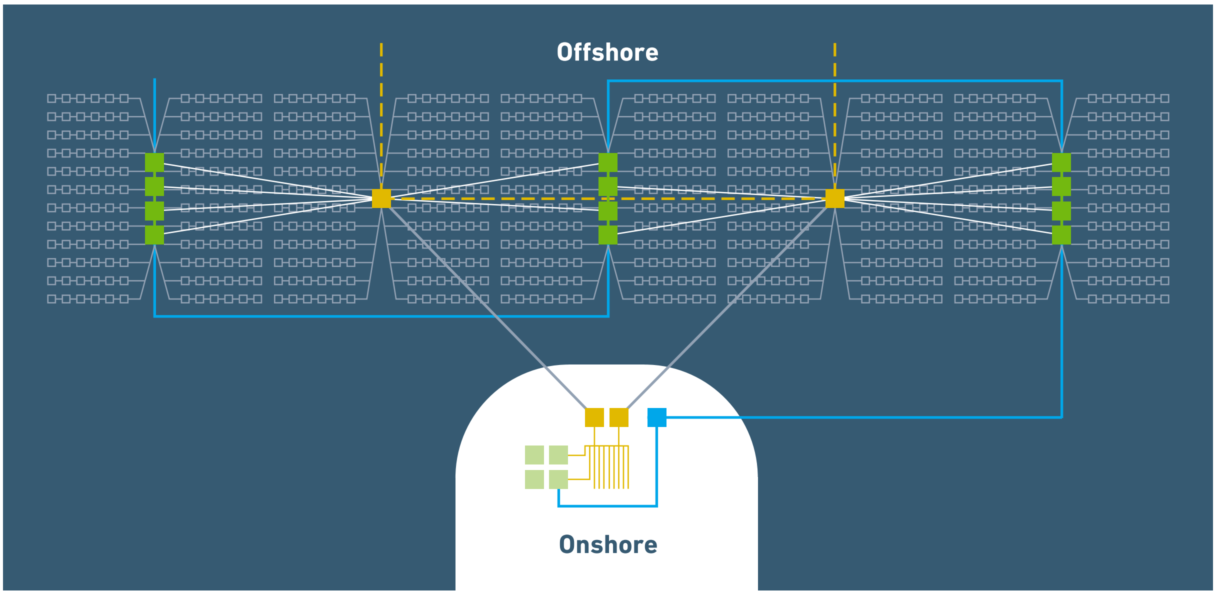
Figure 18e: Modular offshore PtG build-out example



Extend until full capacity is installed.

Note: Consider deliberately slow build-out of Power-to-Gas, simultaneously at multiple project locations, to maximize systemic value throughout the energy transition.

Figure 18f: Modular offshore PtG build-out example



Note: hydrogen pipeline capacities can far exceed a single project location, even for 10GW project. Pipeline infrastructure connecting multiple projects yield the best economy of scale. From strategic security of supply considerations, and relatively minor cost impact of pipelines, a secondary export route may to be considered in the long run.

8 Schedules and pilot plant

In order to get some sense for timing, several project schedules have been prepared at part of the onshore and offshore Power-to-Gas designs.

In addition to project schedules, a specific schedule for a first large scale grid-integrated pilot plant has been developed. The size of the pilot plant is the same as a single full size platform.

A pilot is considered of importance for a number of technical and non-technical reasons. Some of the key technical aspects are;

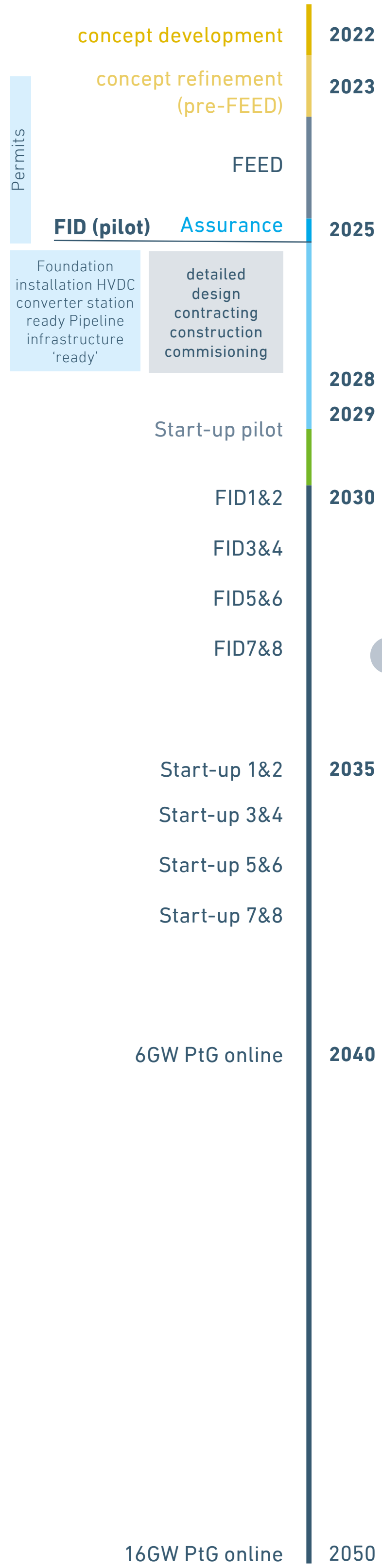
- Gain experience with the set-up and construction
- Scale up and offshore-readiness of electrolysers and other Power-to-Gas technology as discussed in chapter 4.
- Insight in design, operational and availability aspects.
- Risk management, including financial risk management and insurance.
- Offshore electrical design – how to physically design the offshore electrical network (cabling, transformers, busbars, switches, safety, cost effectiveness, flexibility, availability, grid harmonics etc)
- Control system design – how will HVDC grid stability control and rectifiers of electrolyser interact/collaborate?
- Learnings on desired division of roles – what is desired or required to be public, and what is preferably privately owned.

Non-technical aspects revolve mainly around the de-risking of large scale investments. A large scale roll-out starting in 2035 implies Final Investment Decisions (FID) for two platforms each year from roughly 2030 onwards. It is assessed as not credible that significant commercial investments (e.g. 20 billion Euro) are made at the desired rate, prior to seeing similar systems being in operation successfully.

On the right, an approximate schedule is shown. It shows a large scale pilot in operation in 2029, one year prior to the first Final Investment Decisions required for 2035 onwards. This year is considered as operational time required to gain some experience and have sufficient learnings to justify the decision making.

Working back through the construction, detailed design, a final investment decision for the pilot is required no later than 2025. In order to meet the 2025 FID deadline, a FEED phase and concept refinement phase (or pre-FEED phase) is required in parallel to Permit applications and environmental impact assessments. The perceived deadline for starting with pre-FEED is estimated around Q3 2022.

In this schedule the details of especially the permit trajectory and environmental impact assessment (and interactions with design efforts) requires further attention. It is likely that this causes some further delays, when assuming the conventional approach.



9 Conclusion

The offshore Power-to-Gas platform concept is assessed as technically feasible and an economically attractive addition to onshore Power-to-Gas installations for some energy transition scenarios. Modular build-out with platforms enables a cost-effective, flexible and rapid build-out of the infrastructure (both hydrogen and power), and allows for reaping socio-economic benefits of grid-integration.

Large scale green hydrogen produced through electrolysis is maturing, but a dedicated effort is required to scale-up and demonstrate the offshore readiness. However, there is a significant cost benefit for producing offshore hydrogen together with electrical power, compared stand-alone power-to-hydrogen as well as stand-alone offshore electrical power. The NSWPH has contributed towards this concept by developing a semi-optimized concept design for an offshore Power-to-Gas platform concept, investigating the technological feasibility, and exploring how such a modular approach can support the development of large-scale offshore hydrogen production. Using modular build-out with platforms is proposed here as one solution to enable a cost-effective and rapid build-out of the infrastructure (both hydrogen and power), which is needed to connect offshore wind to the energy needs of Europe. The most suitable hub foundation type depends on the chosen location and selected functionalities, which may impose additional requirements that favors another foundation type.

This discussion paper has presented the concept of grid-integrated offshore hydrogen production on platforms which is judged at this stage to be technically and economically feasible, while discussing the technical development requirements to enable the successful deployment of such a concept and offshore Power-to-Gas in general. Furthermore, the foreseen incremental technical improvements and potential technological game changers that could have a significant impact on the concept have been introduced.

The technical challenges and identified opportunities are presented to stimulate open innovation as well as support developments around regulation and market designs. Throughout 2022, the NSWPH consortium will further develop and assess semi-optimized PtG concept design for caisson islands as well as grid-integrated hydrogen turbines, thus enabling a detailed comparison across the developed concepts to identify pros and cons for each foundation type and location.

Abbreviations

ABEX	Abandonment Expenditure
AC	Alternative Current
AEM	Anion Exchange Membrane
Barg	Bar gauge, pressure
CAES	Compressor air energy storage
CAPEX	Capital Expenditure
DC	Direct Current
DSEAR	Dangerous Substances and Explosive Atmospheres Regulations 2002
FEED	Front-end Engineering Design
FID	Final Investment Decision
GW(e)	Giga Watt (Electrical) - 109
GWh	Giga Watt hour (1GWh = 3.6 TJ)
GW WTG	Giga Watt of Wind Turbine Generation equivalent
H2	Hydrogen
HAZID	Hazard Identification
HAZOP	Hazard and Operability Study
HVAC	High Voltage Alternative Current
HVDC	High Voltage Direct Current
Hz	Hertz (frequency)
IGBT	Insulated Gate Bipolar Transistor
ISBL	Inside Battery Limits
kHz	kilo Hertz (frequency)
kV	kilo Volt
kW(e)	kilo Watt (Electrical) - 103
LCoH	Levelized cost of Hydrogen – total depreciated H2 production divided by total depreciated cost (TOTEX)
LOPA	Layers Of Protection Analysis
LVDC	Low Voltage Direct Current

L, W, H	Length, Width, Height
m3/h	Cubic meters per hour
MED	Multi-Effect Distillation
MM(D)	Mott MacDonald – Engineering Contractor
Mol%	Mole percent
MW(e)	Mega Watt (Electrical) - 10^6
NSWPH	North Sea Wind Power Hub
O2	Oxygen
OPEX	Operational Expenditure
OSBL	Outside Battery Limits
PEM	Proton Exchange Membrane
P2G	Power-to-Gas (mainly hydrogen)
P2X	Power to X (X referring to any hydrogen derived product)
PSA	Pressure Swing Adsoprtion
PtG	Power-to-Gas (mainly hydrogen)
RO	Reverse Osmosis
RES	Renewable Energy Supply
SF6	Sulphur HexaFluoride
SWRO	Sea Water Reverse Osmosis
t	Tonnes
te/hr	tonnes per hour
te/MW	tonnes per Mega Watt
TEG	TriEthylene Glycol
TJ	Terra Joule (1012 Joule)
TOTEX	Total Expenditure
TSA	Temperature Swing Adsorption
WTG	Wind Turbine Generator
XXL	eXtra eXtra Large
Xoo10GW	Xoo10GW refers to out of (X referring to a capacity in GW)

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