BVGAssociates

Offshore renewable energy export potential for Ireland

Workstream 4: Export viability, policy considerations, trade and investment opportunities

A report for the Department of Environment, Climate and Communications

January 2024

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1.1. Introduction

This workstream builds on the output of Workstreams 1 to 3 to document the viability and local economic impact of exporting renewable generation and/or hydrogen produced from renewables, as well as identifying what developments in policy may be required in Ireland to achieve this, noting accompanying risks and mitigations.

Seven scenarios were presented in workstreams 1 to 3:

- The Domestic Net Zero (DNZ) scenario which included 16 GW offshore wind deployment and 10 GW interconnection.
- A 37 GW scenario for Offshore Renewable Energy (ORE) deployment, with three different levels of interconnect: 10 GW 'DNZ', 12 GW Well connected and 17 GW Stretch.
- A 50 GW offshore wind scenario, with the same three interconnect scenarios overlaid.

For the purposes of this workstream, we have chosen to narrow our focus to four of the seven scenarios deemed most feasible. The lower interconnect variants of the 37 GW and 50 GW scenarios have been eliminated, as work streams 1-3 showed that a higher level of interconnection would likely be necessary to export excess generation in these scenarios. The scenarios considered in this report are:

- The DNZ scenario, with 10 GW fixed, 6 GW floating offshore wind and 10 GW interconnection
- The 37 GW 'well connected' scenario, with 10 GW fixed, 27 GW floating offshore wind and 12 GW interconnection
- The 37 GW 'stretch' scenario, with 10 GW fixed, 27 GW floating offshore wind and 17 GW interconnection
- The 50 GW 'stretch' scenario, with 10 GW fixed, 40 GW floating offshore wind and 17 GW interconnection.

1.2. Economic impact of offshore renewable energy deployment

1.2.1 Introduction

This section considers the economic impact of each of the scenarios listed in 1.1, presented in terms of:

- Local gross value added (GVA)
- Direct and indirect employment, and
- Tax take.

We consider five technology areas:

- ORE projects with associated export systems (sub-divided fixed and floating offshore wind)
- Local hydrogen production, storage and distribution, and
- Irish scope of interconnectors.

Additional to these, but beyond scope, is the impact of industries using lower-cost power and hydrogen from ORE and opportunities for Irish companies to export products and services related to these areas, which we discuss only qualitatively.

1.2.2 Methodology

Local Content Assumptions

In order to assess local economic benefits, we agreed a description of activity and percentage local content under each scenario.

The scenario descriptors below represent eventual 2050 deployment totals of volume scenarios. In all scenarios, it is assumed that individual facilities are futureproofed or incremental investments are made to maintain throughput numbers as turbines become larger over time.

Appendix A contains the percentage local content for each supply chain category for 2030, 2040 and 2050 across the four scenarios for fixed and floating offshore wind.

Fixed offshore wind

Fixed offshore wind assumptions are held constant across all four scenarios, as capacity is constant across scenarios at 10 GW total. Our assumptions are:

- Ireland has a strong share of project development and O&M activities, but all major components are imported.
- The pre-existing construction port in Northern Ireland, Belfast D1, will deliver fixed Irish projects, with an assumed maximum throughput capability 100 turbines per year. We assume this capability is split so that 40% of this is service the Irish market, 40% the UK market and 20% is unused (or serves other markets).
- If the pipeline exceeds 40 turbines per year, we assume that investment will be triggered in Republic of Ireland ports to serve additional installation requirements.[1] Once port upgrades are triggered, it is assumed that the pipeline is split 2 to 1 between Republic of Ireland ports and Belfast up to Belfast's 40 turbine limit, thereafter domestic ports will service all domestic installation.
- A tower manufacturing facility is constructed that supplies from the start of 2030
    - Throughput is assumed at 150 towers per year (based on planned GRI facility in Gdansk), with scale-up investments to enable 150 larger towers to be supplied per year, as larger turbines are used.
    - Steel plate and flanges are imported.
    - The facility is assumed to have a maximum 2/3 market share within Irish projects. 50% of any additional capacity is used for export; the rest is unused.

Floating offshore wind

DNZ scenario: 10 GW fixed, 6 GW floating offshore wind and 10 GW interconnection

- As in fixed offshore wind, Ireland has a strong share of project development and O&M activities.
- All floating offshore wind turbines are assembled on to floating foundations from jack up vessels in Irish ports or sheltered Irish waters until the start of 2038. Vessels and crew are assumed to be non-Irish. If Irish ports have the space, then they can have 100% market share.
- Investment in a single Irish construction port for floating offshore wind operational from the start of 2038 for installation from Irish quayside. If port has the space, then they can have 100% market share.

[1] National Ports Study, GDG on behalf of Wind Energy Ireland, September 2022, available online at https://windenergyireland.com/images/files/final-national-ports-study.pdf

37 GW scenario: 10 GW fixed, 27 GW floating offshore wind and 12 to 17 GW interconnection

As Scenario 1, except:

- Ireland has a higher share of project development, O&M activities than in scenario 1.
- A synthetic rope and mooring line manufacturing facility is constructed that supplies from the start of 2035
    - Throughput is assumed at 160 km synthetic mooring line per year.[2]
    - The facility is assumed to have a maximum 2/3 market share within Irish projects. 50% of any additional capacity is used for export; the rest is unused.
- Investment occurs in all three suitable ports for floating offshore wind construction or assembly, operational from the start of 2032. Two are dedicated construction ports and the third is dedicated to floating foundation assembly. If Irish ports have the space, then they can have 100% market share.

50 GW scenario: 10 GW fixed,40 GW floating offshore wind and 17 GW interconnection

As Scenario 2, except:

- Synthetic rope and mooring line manufacturing facility moves forward so that first supply is at the start of 2032.
- Investment occurs in all three suitable ports for floating wind construction and assembly, operational from the start of 2032. All ports are initially dedicated construction ports as all port capacity is required to serve the domestic pipeline. If Irish ports have the space, then they can have 100% market share.
- From the start of 2035, a fourth floating port comes online. This is dedicated to foundation assembly (or one of the preexisting ports switches to foundation assembly, while the new port focusses on construction). In either case, this leaves Ireland with 3 construction ports and one foundation assembly facility. If Irish ports have the space, then can have 100% market share.

Floating port capability assumptions

- There is strong logic for using local construction ports, due to the technical and economic challenges associated with towing integrated floating wind turbines in open seas. There are three ports in Ireland with plan to service this requirement and the required technical characteristics, with investment: Cork, Moneypoint, Shannon Foynes Island.[1]
- There may be opportunity for a fourth port, for example in Bantry Bay. Any fourth port is at least 10 years away from operation as nothing is currently in development.
- The assumed maximum throughput of each port is 35 turbines per year. This is approximately 1 turbine per week over 8 month installation window.
- If the delivery pipeline is greater than 30 turbines per year, then it is assumed that spare facilities not dedicated to construction can be used for foundation assembly, each with maximum throughput 50 foundations per year.[3] Excess capacity is exported.
- If the delivery pipeline less than 30 turbines per year, it is assumed that assembled foundations are imported from elsewhere.
- In all scenarios, it is assumed that modular foundation components are manufactured elsewhere, before final assembly in Ireland. Ireland has little of the type of heavy manufacturing industries which would carry out this work, and there is no strong logic for local supply as components are designed to be transportable. We assume Ireland will not be an investment location of choice for new facilities of this kind due to its

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[2] Lankhorst euronete Brasil exceeds 800 km mooring ropes production, *Press release*, Lankhorst, 26 April 2018, available online at https://www.lankhorstoffshore.com/about-us/news-events/lankhorst-euronete-brasil-exceeds-800-km-mooring-ropes-production.

[3] *Floating Offshore Wind Taskforce: Industry Roadmap 2040*, RoyalHaskoningDHV on behalf of RenewableUK, March 2023 available online at https://cdn.ymaws.com/www.renewableuk.com/resource/resmgr/docs/flow_tf_-_inegrated_report_f.pdf

comparative lack of existing capability coupled with relatively high wages, which mean investment will more likely flow to other markets.

Hydrogen production, storage and distribution

Hydrogen assumptions are constant across scenarios:

- Development of hydrogen facilities is centred in large-scale hubs serving customer industries and interconnection sites.
- A large share of development activities are captured by domestic suppliers.
- Specialist international suppliers provide serialised production and delivery of electrolyser systems at 100 MW unit size.
- Domestic content of the electrolyser system is limited to handling and logistics.
- Salt cavern storage facilities are developed with 10-year lead times to serve storage requirement.
- A strong share of salt cavern development content is secured by Irish suppliers.
- An export pipeline is developed for operation in 2035, capable of exporting 20 TWh of Hydrogen per year.
- A small fraction of pipeline CAPEX is captured as domestic content.
- Operational activities for the pipeline are shared with the partner interconnect country.

Interconnection

Interconnection assumptions are constant across scenarios due the limited scope for domestic content and relatively high maturity of the industry (meaning that Irish activity is unlikely to trigger any significant manufacturing investment decisions).

- Established domestic transmission and distribution network suppliers gain a strong share of the development and installation activities with content split evenly with the partner interconnect country.
- Onshore and offshore interconnect cables and high voltage electrical equipment are sourced from international suppliers.
- Offshore interconnect cable installation is provided by an international supplier with limited Irish content.
- Interconnect maintenance is delivered through domestic suppliers with content split evenly with the partner interconnect country.

Export assumptions

- In deriving estimates of the export opportunity for Ireland, the following assumptions have been used:
- Domestic development and project management services companies are assumed to sell services abroad at a rate of 50% of domestic revenues. As domestic project development activity begins to tail off from the mid-2040s in all scenarios, the maximum level of export benefit reached is assumed to be maintained to 2050 as Irish firms continue to sell services abroad despite falling domestic activity.
- Where facilities for manufactured goods exist, such as towers and synthetic mooring lines, these facilities are assumed to service domestic pipeline first, with a maximum domestic market share of two-thirds. Half of any excess capacity is exported, the rest is assumed unused due to periods of less than full capacity operation.
- Fixed and floating construction and assembly ports are assumed to serve the domestic market first, due to the benefits of proximity to overall cost. There is no limit on their market share and they are not expected to export. Where excess capacity exists in floating foundation assembly, any excess capacity may be exported.
- There is assumed to be some export of operations and maintenance related services. This could include monitoring software, maintenance and safety equipment or advisory services. Irish firms are assumed to export at a rate of 10% of domestic revenues.

Local gross value added and direct and indirect employment

Methodology

Conventional modelling of economic impacts for most industrial sectors relies on government statistics, for example those based on industry classification codes and use input-output tables and other production and employment ratios.

Industry classification code data can be appropriate for traditional industries at a national level. The development of new codes for a maturing sector, however, takes time. This means that conventional industry classification analyses of ORE, transmission and hydrogen need to map existing data onto these activities, which is not easy and a source of error. Analyses using industry classification codes also have to rely on generalized data.

ORE transmission and hydrogen sectors are better suited to a more robust approach that considers current and future capability of local supply chains because ORE projects tend to:

- Be large and have distinct procurement processes from one another; and
- Use comparable technologies and share supply chains.

It therefore enables a realistic analysis of the local content of projects even where there are gaps in the data.

The methodology used here was developed jointly by BVGA and Steve Westbrook of the University of the Highlands and Islands, UK, and has been used in many published studies.

The methodology's first input is the cost per MW of each supply chain category listed in Table 15.

The second stage is to assess the local content for each category, that is the net local expenditure considering that:

- Locally sourced products will have non-local supply chains, and
- Non-local sourced products may have local supplier.

The remaining expenditure is analogous to the direct and indirect GVA created. GVA is the aggregate of labour costs and operational profits. We can therefore model FTE employment from GVA, provided we understand some key variables. In our economic impact methodology, employment impacts are calculated using the following equation:

$$FTE_a = \frac{(GVA - M)}{Y_a + W_a}$$

Where:

FTE_a = Annual FTE employment

GVA = Gross value added

M = Total operating margin

Y_a = Average annual wage, and

W_a = Non-wage average annual cost of employment.

To make robust assessments, therefore, we consider each supply chain category and estimate typical salary levels, costs of employment, and profit margins, bringing together specific sector knowledge and research into typical labour costs for the work undertaken in each level 2 category listed below.

FTEs relate to full time equivalent job years, with part-time or part-year work considered appropriate. A full-time job would normally be at least 7 hours per day over 230 working days of the year. If an individual works significantly more than this over a year, FTE attribution would be more than 1 FTE (for example, 1.5 FTEs if working long hours over 7 days per week).

FTEs are by workplace rather than by residence and will include migrant/temporary resident workers.

Where work in a local area (for example, on an assembly site) is carried out by people who have moved temporarily from elsewhere in Ireland, or overseas and live in temporary accommodation while working on site, their daily expenditures on accommodation, food, and drink, leisure and the like create employment impacts locally and within Ireland more widely. These impacts have been considered in the indirect impacts because these payments are likely to be covered through subsistence expenses rather than personal expenditures.

The GVA to gross earnings ratio for a business can be relatively high where it is charging for use of expensive plant, equipment, boats, etc. If a specialist vessel, for example, has been built in Ireland for offshore renewables work, the prior employment and earnings impacts from this could be additional to what it has been possible to capture in the analysis carried out for this report.

In this report, GVA and earnings impacts have not been discounted prior to aggregation.

The economic analysis was structured around theoretical projects with characteristics typical of those anticipated in Ireland. We considered projects installed in 2025, 2030, 2040 and 2050 and interpolated costs for intermediate years. We developed the cumulative impact by scaling project impact by the capacity of projects anticipated to be installed each year in each of the three scenarios modelled.

For each of the theoretical projects, we made judgements of local content for each of the supply chain categories defined below. To simplify this analysis, we assumed that there is no real term increase in salaries and that changes in cost for the projects between 2025 and 2050 are due to changes to technology and industry learning. As a result, the analysis is likely to underestimate the GVA.

We considered:

- Total impacts from projects in Ireland, and
- Irish impacts from projects in Ireland.

We modelled direct and indirect impacts. Direct impacts are defined as those associated with project developers and their main contractors. Indirect impacts are defined as those associated with their sub-suppliers.

Total impacts from projects in Ireland

We established the total full-time equivalent (FTE) employment years and gross value added (GVA) by year created for each market scenario if there was 100% local content (that is, there is no import of materials, components, and services).

We used BVGA's in-house model that uses multipliers to convert expenditure to FTE years and GVA.

Charts are to 2060, recognizing that there is further economic benefit for the full lifetime of each project, with more operation, maintenance service (OMS) spend, followed by a one-year peak during decommissioning (not shown).

Irish impacts from projects in Ireland

We established the impacts in Ireland by considering the current and potential future capability of the supply chain in Ireland and assessed the likely percentage of local content for each supply chain category in each scenario, varying linearly between estimates every 5 years. Local content is defined as the percentage of project expenditure that is spent in Ireland. It excludes the value of imports to an Irish supplier and includes the value of Irish exports to a non-Irish supplier. The capability of the supply chain in Ireland, opportunities for growth and impact of different scenarios are discussed earlier in this section. Our resulting estimates of local content for each scenario are presented in Table 1 to Table 4.

Local content may be higher or lower, depending on scenario, government policy, relative attractiveness of different markets for investment and the supply chain's appetite for investment.

Table 1 Trajectory of local content for each supply chain category for fixed offshore wind across all scenarios.

	DNZ Scenario (%)			37 GW and 50 GW scenarios		
Supply chain level 1 category	2030	2040	2050	2030	2040	2050
Development and project management	66	66	66	67	69	71
Turbine	2	2	2	2	2	2
Balance of plant	4	4	4	4	4	4
Installation and commissioning	8	9	11	8	10	11
Operations, and maintenance	51	51	51	52	56	59
Decommissioning	5	5	5	5	5	5
Overall local content	20	18	19	21	20	21

Table 2 Trajectory of local content for each supply chain category for floating offshore wind across all scenarios.

	DNZ Scenario (%)			37 GW scenarios			50 GW scenarios		
Supply chain level 1 category	2030	2040	2050	2030	2040	2050	2030	2040	2050
Development and project management	66	66	66	67	69	71	67	69	71
Turbine	3	3	3	3	3	2	3	2	2
Balance of plant	2	5	5	2	12	11	2	9	9
Installation and commissioning	12	14	14	12	14	14	12	14	14
Operations and maintenance	51	51	51	53	56	60	53	56	60
Decommissioning	5	5	5	5	5	5	5	5	5
Overall local content	17	17	17	18	21	21	18	20	20

Table 3 Local content for each supply chain category for hydrogen electrolyser across all scenarios.

Supply chain level 1 category	All scenarios and years (%)
Development and project management	80
Device	5
Balance of plant	29
Installation and commissioning	65
Operations and maintenance	35
Decommissioning	80
Overall local content	38

Table 4 Local content for each supply chain category for interconnectors across all scenarios.

Supply chain level 1 category	All scenarios and years (%)
Development and project management	30
Balance of plant	9
Installation and commissioning	18
Operations and maintenance	20
Decommissioning	5
Overall local content	13

Tax take

In deriving Irish Government tax take, we have considered:

- Corporation tax, at 12.5% of nominal profits.[4] This is calculated using local GVA to derive nominal profits.
- Income tax, at an assumed 34.6% of labour cost.[5] This is calculated using local gross salary.
- Social insurance at an assumed aggregate of 11.05% of gross salary (for employee and employer contributions)[6], and
- VAT, at an assumed rate of 71% of income tax receipts, based on Irish ratio of income tax receipts to VAT receipts in 2021.[7]

We derived nominal profit by applying a different profit margin for each cost element to annual Irish GVA, based on industry experience.

We derived labour cost at direct and indirect supply chain levels by stripping profit margin and the cost of employment (tax and pension) incurred by businesses from GVA.

Simplifications in this approach include:

- Single estimate of profit margin over time for each cost element, over time.
- Simple derivation of labour cost
- Simple estimation of VAT impacts, based on ratio of total Irish income tax receipts to VAT receipts, and
- Single tax rate for each tax type, where actual rates depend on, for example, distribution of salary levels for each cost element.
- We have assumed no impact of import duty. In practice, there is some import duty likely to be applicable to import of componentry. However, much of this may be sourced from other EU nations or countries with which Ireland has trade agreements which reduce or remove such charges. In practice therefore the impact of import duty is likely to be minimal, and arriving at a sound estimate is challenging.

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[4] Tax Foundation, available online at https://taxfoundation.org/location/ireland/#:~:text=Ireland%20has%20a%20low%20corporate,taxed%20on%20their%20average%20profitability.

[5] *Taxing Wages – Ireland*, OECD, April 2023, available online at https://www.oecd.org/tax/tax-policy/taxing-wages-ireland.pdf.

[6] 'How much does it cost to hire an employee in Ireland', *Borderless*, 31 August 2023, available online at https://www.hireborderless.com/post/how-much-does-it-cost-to-hire-an-employee-in-ireland.

[7] *Government Income and Expenditure July 2021*, Central Statistics Office, July 2021, available online at https://www.cso.ie/en/releasesandpublications/er/giea/governmentincomeandexpenditurejuly2021/.

These simplifications are justified based on uncertainty in costs, levels of local content and market development.

1.2.3 Results

Single project impacts

This section shows the local impacts of single projects for each of the four technologies for projects installed in 2040 and in the mid scenario. These show typical results that then vary with installation year and scenario and are aggregated in later sections. It also shows how local content fraction and total GVA varies for each technology installed.

For readability, charts display individual project impacts to 2050 and cumulative economic impacts to 2060. Project lives extend beyond 2060. There is additional O&M spend (at the level shown) and decommissioning at end of project life which is not displayed on these charts.

Figure 1 shows a comparison of the overall lifetime domestic GVA impact of the different technologies considered in this report, broken down by cost category. Figure 2 shows a comparison of domestic FTE years, broken down on the same basis. There is significant variation in overall domestic GVA and employment between technologies.

Both fixed and floating offshore wind are characterised by a high share of overall value and employment in the O&M stage. This reflects the high share of overall project cost in the O&M stage, alongside Ireland's high levels of local supply. Irish value from the reference floating offshore wind project is about 41% higher than a comparable fixed project, and employment 47% higher. Much of this difference can be attributed to greater supply in balance of plant and installation and commissioning, due to floating foundation assembly, synthetic line manufacture and floating offshore wind construction port provision.

A 1 GW hydrogen electrolyser project delivers the most domestic value and employment, at around €1.6 billion GVA and 20,000 FTE years over its lifetime. The increased domestic content in the installation and commissioning and decommissioning phases relative to offshore wind and interconnectors is a result of the onshore nature of the works, which require civil engineering skills, an area of Irish strength.

The local value and employment associated with interconnector projects is markedly lower than for other technologies, at around €170 million GVA and 2,100 FTE years over the project lifetime. This reflects the relatively high share of overall cost associated with cable manufacturing and offshore installation in interconnector projects. We do not expect Ireland to play a significant role in either activity.

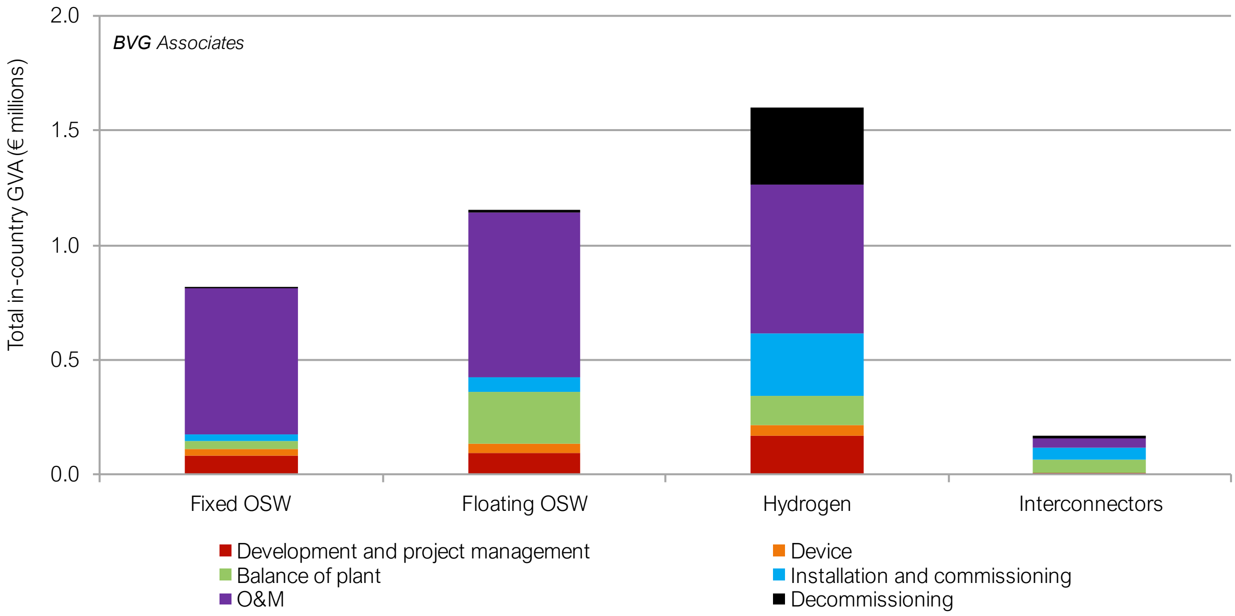

Figure 1 Total Irish lifetime GVA for single 1 GW fixed offshore wind, floating offshore wind, interconnector and hydrogen electrolyser projects installed in 2040, split by supply chain level 1 category.

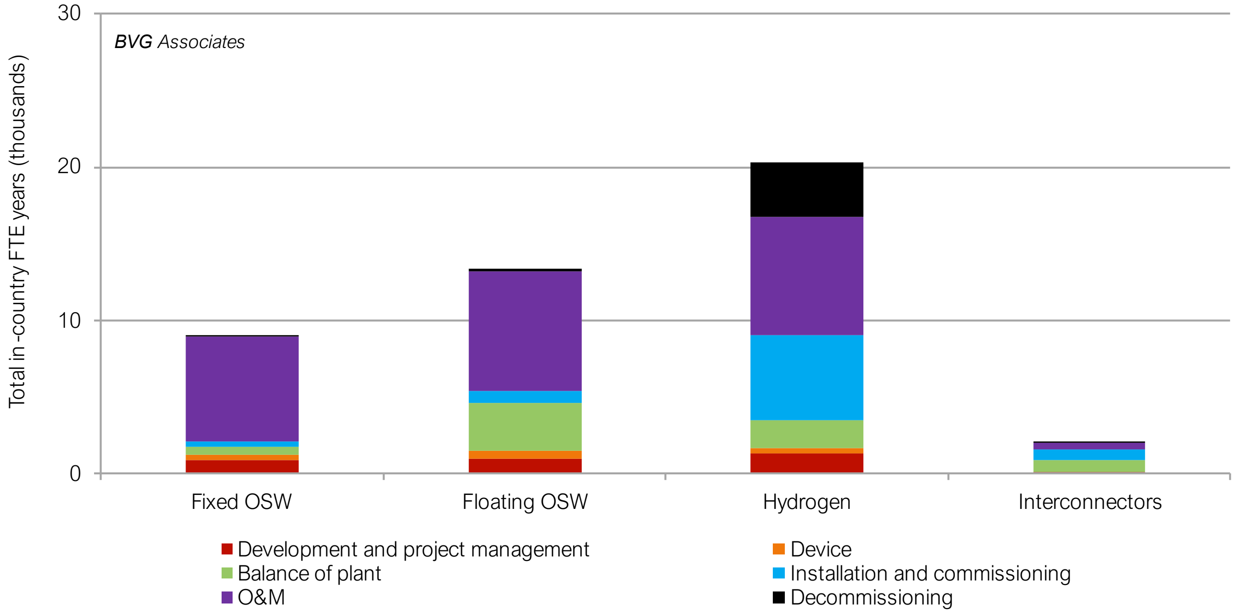

Figure 2 Total Irish lifetime FTE years for single 1 GW fixed offshore wind, floating offshore wind, interconnector and hydrogen electrolyser projects installed in 2040, split by supply chain level 1 category.

Fixed offshore wind

Figure 3 shows the total global annual GVA generated by a 1 GW fixed offshore wind project installed in 2040 in the 37 GW well connected scenario. The peak annual GVA in 2039 is about €1.2 billion. The total GVA over the lifetime of the project is about €4.1 billion.

Figure 4 shows the Irish GVA generated by this single project. The peak annual Irish GVA in 2039 is about €51 million. The total Irish GVA over the lifetime of the project is about €820 million.

Figure 5 shows the Irish FTE years employment created annually for this single project. It shows that Irish annual employment peaks in 2039 at about 650 FTE years, when there is significant turbine and balance of plant manufacture as well as installation. Total Irish employment for the project is about 9,000 FTE years over the lifetime of the project. 45% of these are direct jobs.

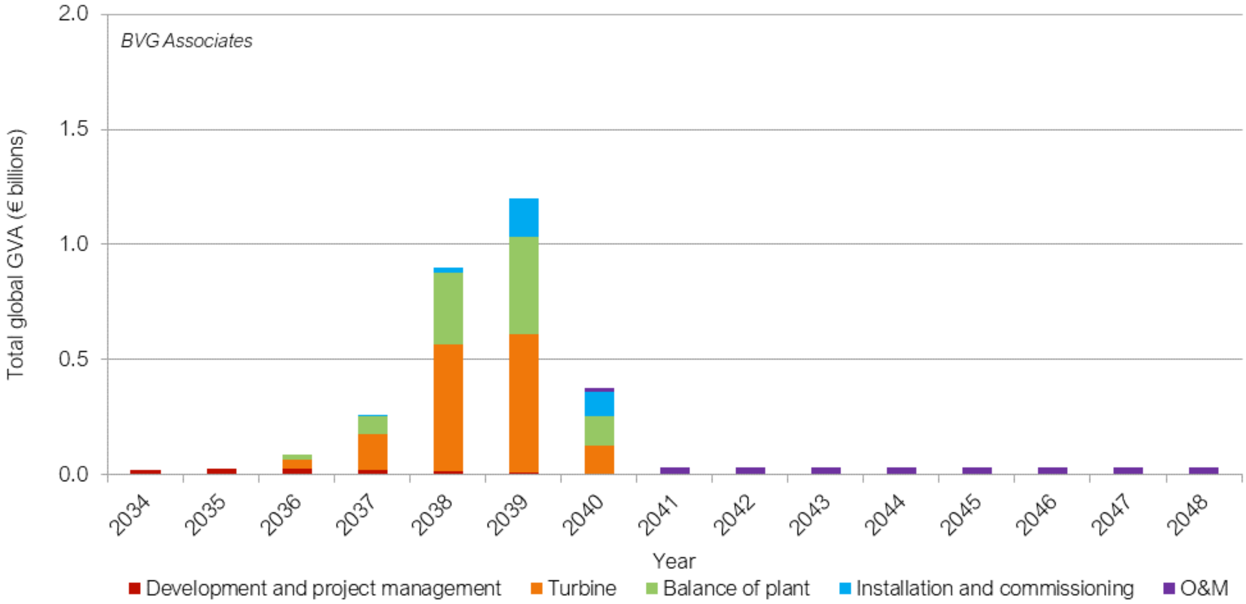

Figure 3 Global annual GVA for a single 1 GW fixed offshore wind project installed in 2040, split by supply chain level 1 category.

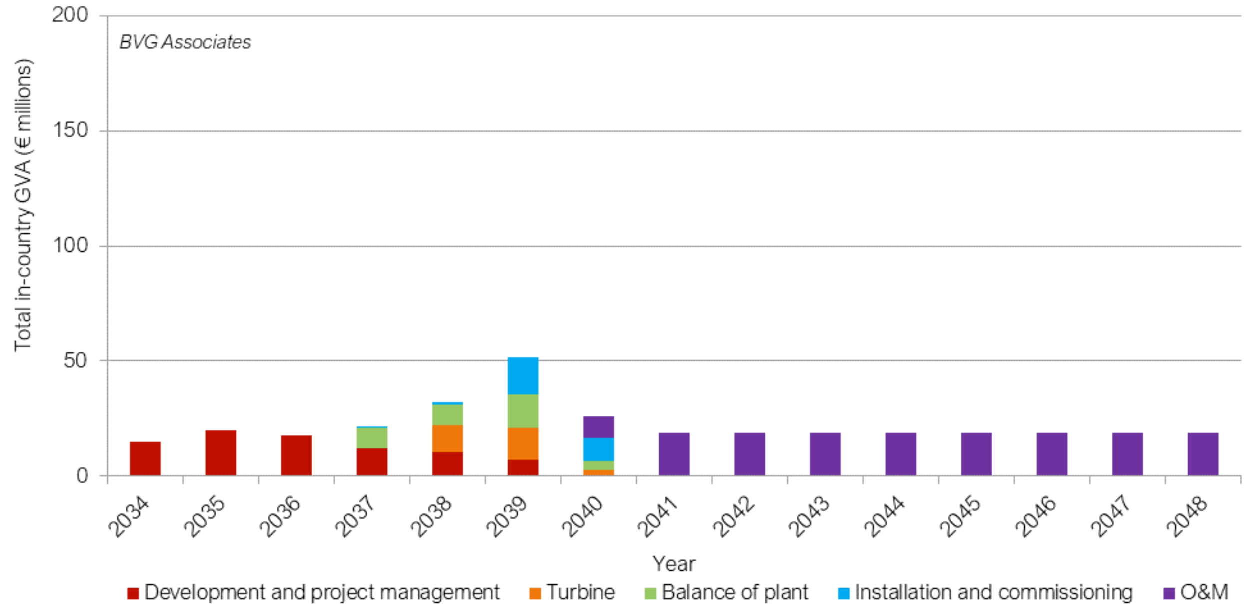

Figure 4 Irish annual GVA for a single 1 GW fixed offshore wind project installed in 2040, split by supply chain level 1 category.

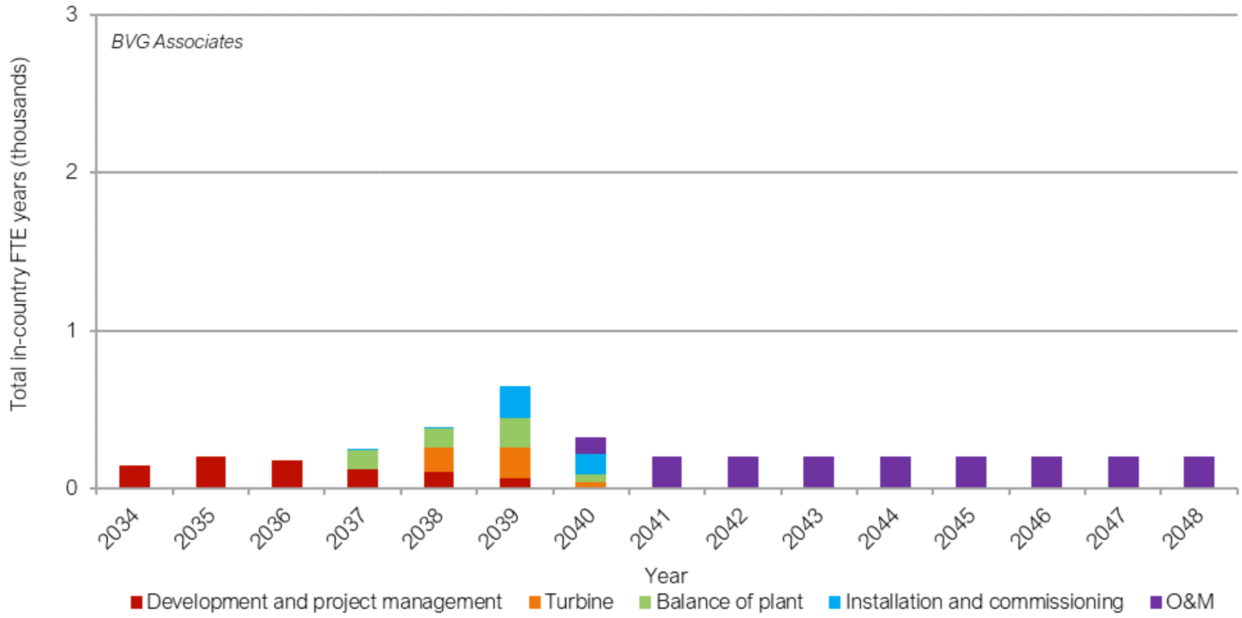

Figure 5 Irish annual FTE years employment for a single 1 GW fixed offshore wind project installed in 2040, split by supply chain level 1 category.

Floating offshore wind

Figure 6 shows the total global GVA generated by this single 1 GW floating offshore wind project installed in 2040 in the 37 GW well connected scenario. The peak GVA in 2039 is about €1.8 billion. The total GVA over the lifetime of the project is about €5.6 billion.

Figure 7 shows the Irish GVA generated by this single project. The peak GVA in 2039 is about €170 million. The total Irish GVA over the lifetime of the project is about €1.2 billion.

Figure 8 shows the Irish FTE years employment created annually for this single project. It shows that employment peaks in 2039 at about 2,200 FTE years, when there is significant turbine and balance of plant manufacture as well as installation. Total Irish employment for the project is about 13,000 FTE years over the lifetime of the project. 50% of these are direct jobs.

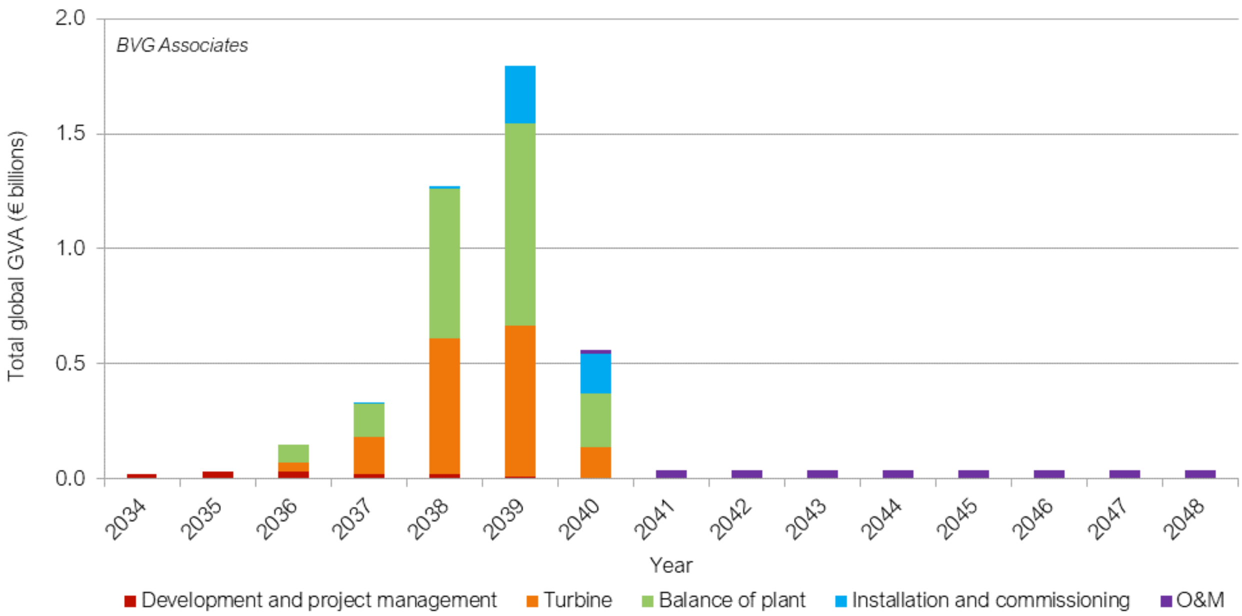

Figure 6 Global annual GVA for a single 1 GW floating offshore wind project installed in 2040, split by supply chain level 1 category.

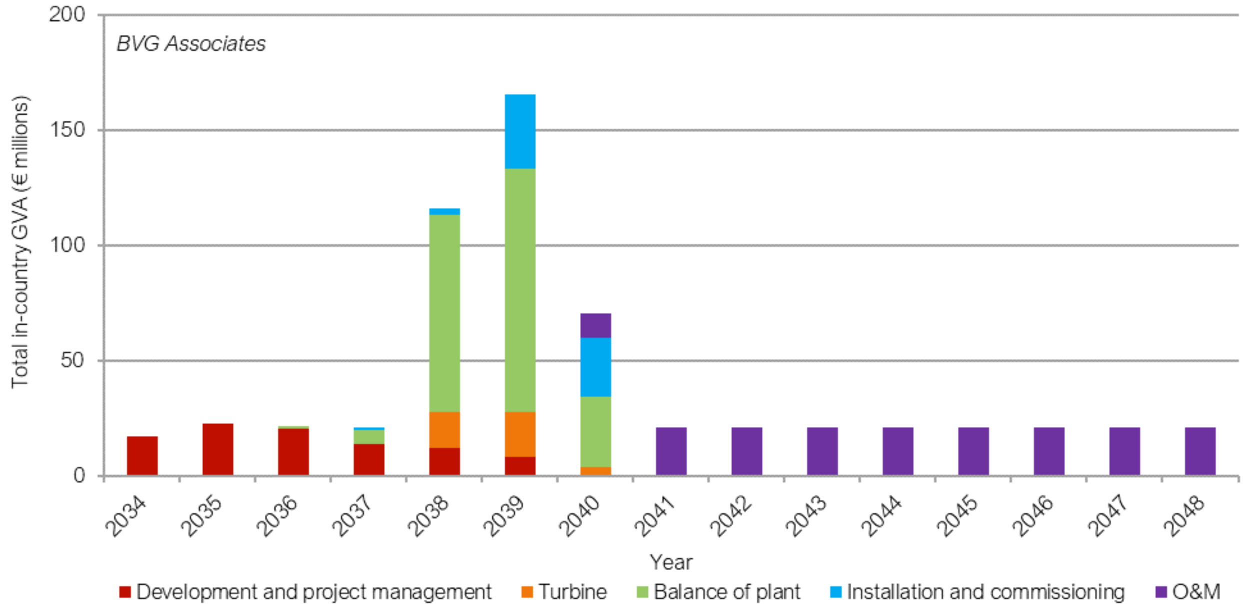

Figure 7 Irish annual GVA for a single 1 GW floating offshore wind project installed in 2040, split by supply chain level 1 category.

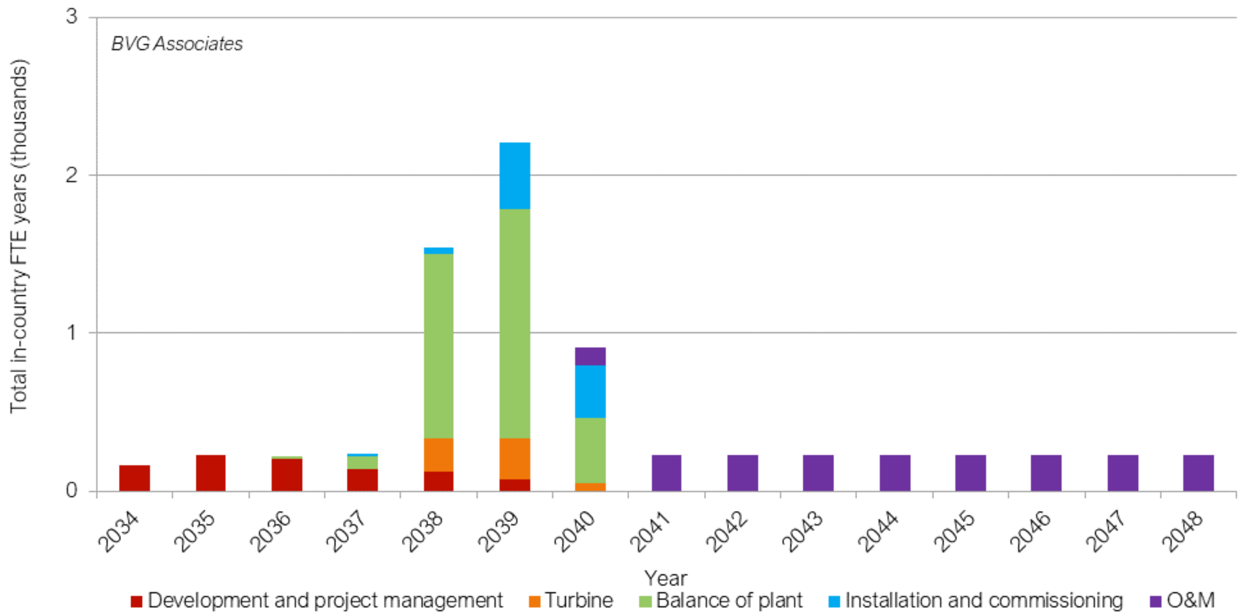

Figure 8 Irish annual FTE years employment for a single 1 GW floating offshore wind project installed in 2040, split by supply chain level 1 category.

Local hydrogen production, storage and distribution

Figure 9 shows the total global GVA generated by a single 1 GW hydrogen electrolyser project installed in 2040 in the 37 GW well connected scenario. The peak GVA in 2040 is about €710 million. The total GVA over the lifetime of the project is about €4.3 billion.

Figure 10 shows the Irish GVA generated by this single project. The peak GVA in 2040 is about €190m. The total Irish GVA over the lifetime of the project is about €1.6 billion.

Figure 11 shows the Irish FTE years employment created annually for this single project. It shows that employment is mainly in 2038, 2039 and 2040 with a peak of at about 3,000 FTE years, when there is significant manufacturing and installation activity. Total Irish employment for the project is about 20,000 FTE years over the lifetime of the project. 59% of these are direct jobs.

These figures do not include the economic impact of associated storage and distribution infrastructure, though these impacts are included in overall figures presented when looking at scenarios, later in this section.

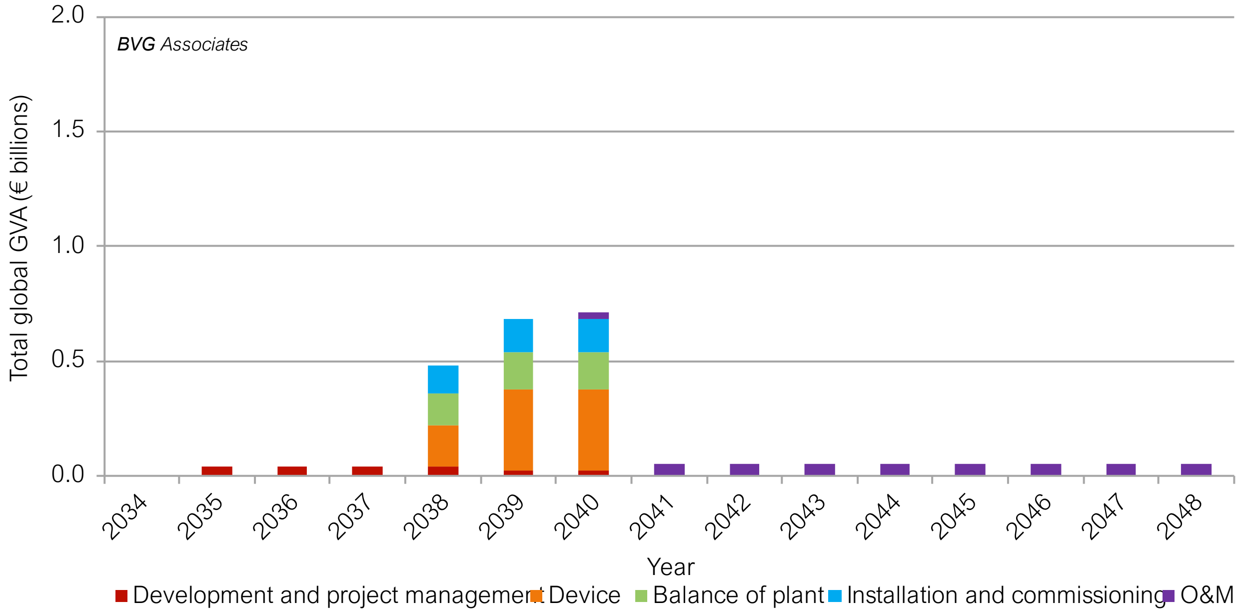

Figure 9 Global annual GVA for a 1 GW hydrogen electrolyser installed in 2040, split by supply chain level 1 category.

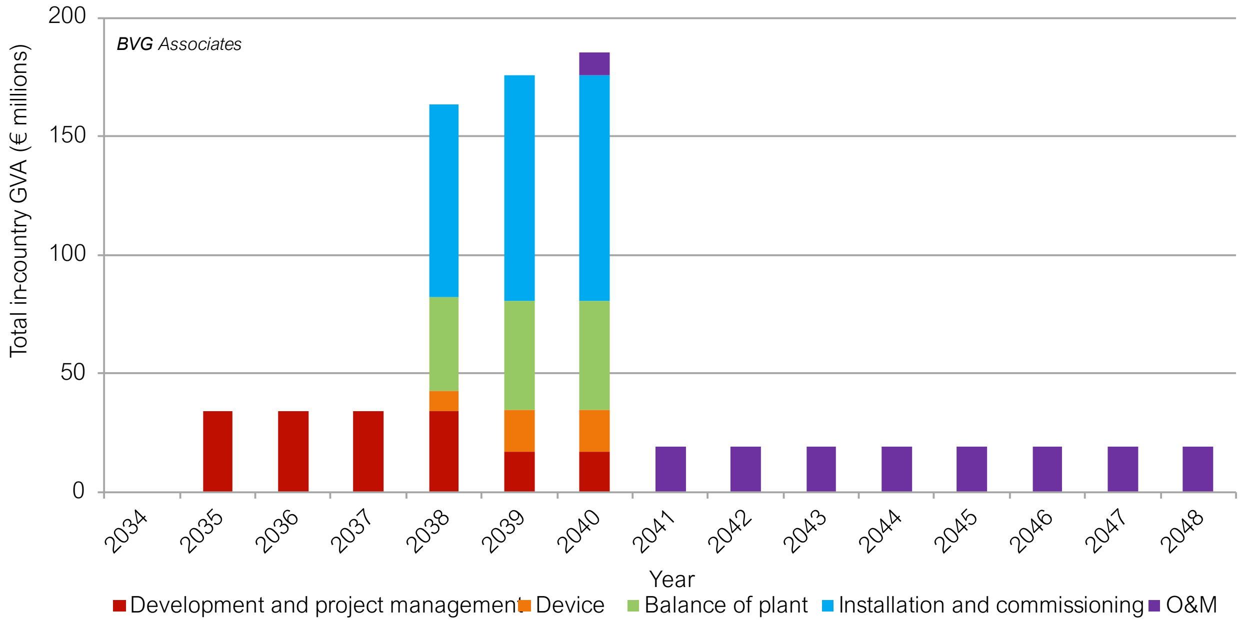

Figure 10 Irish annual GVA for a 1 GW hydrogen electrolyser installed in 2040, split by supply chain level 1 category.

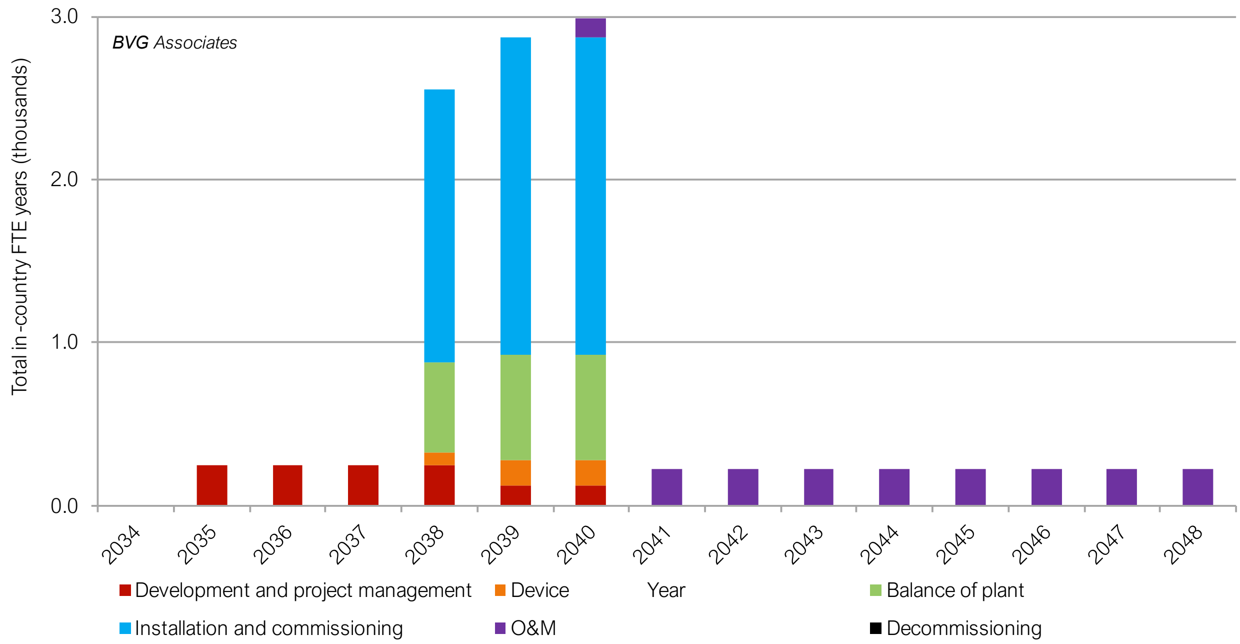

Figure 11 Irish annual FTE years employment for a 1 GW hydrogen electrolyser installed in 2040, split by supply chain level 1 category.

Interconnectors

Figure 12 shows the total global GVA generated by a single 1 GW interconnector project installed in 2040 in the 37 GW well connected scenario. The peak GVA in 2039 is about €620 million. The total GVA over the lifetime of the project is about €1.8 billion.

Figure 13 shows the Irish GVA generated by this single project. The peak GVA in 2039 is about €57 million. The total Irish GVA over the lifetime of the project is about €170 million.

Figure 14 shows the Irish FTE years employment created annually for this single project. It shows that employment peaks in 2039 at about 740 FTE years, when there is significant construction and installation activity. Total Irish employment for the project is about 2,100 FTE years over the lifetime of the project. 33% of these are direct jobs.

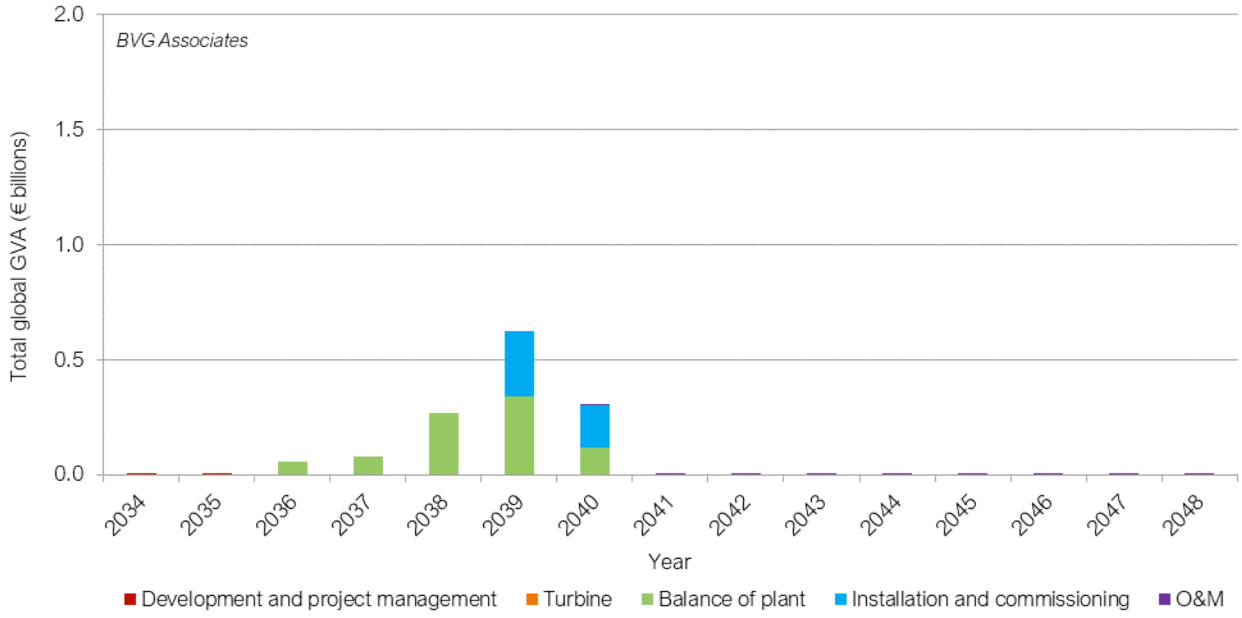

Figure 12 Global annual GVA for each 1 GW interconnector installed in 2040, split by supply chain level 1 category.

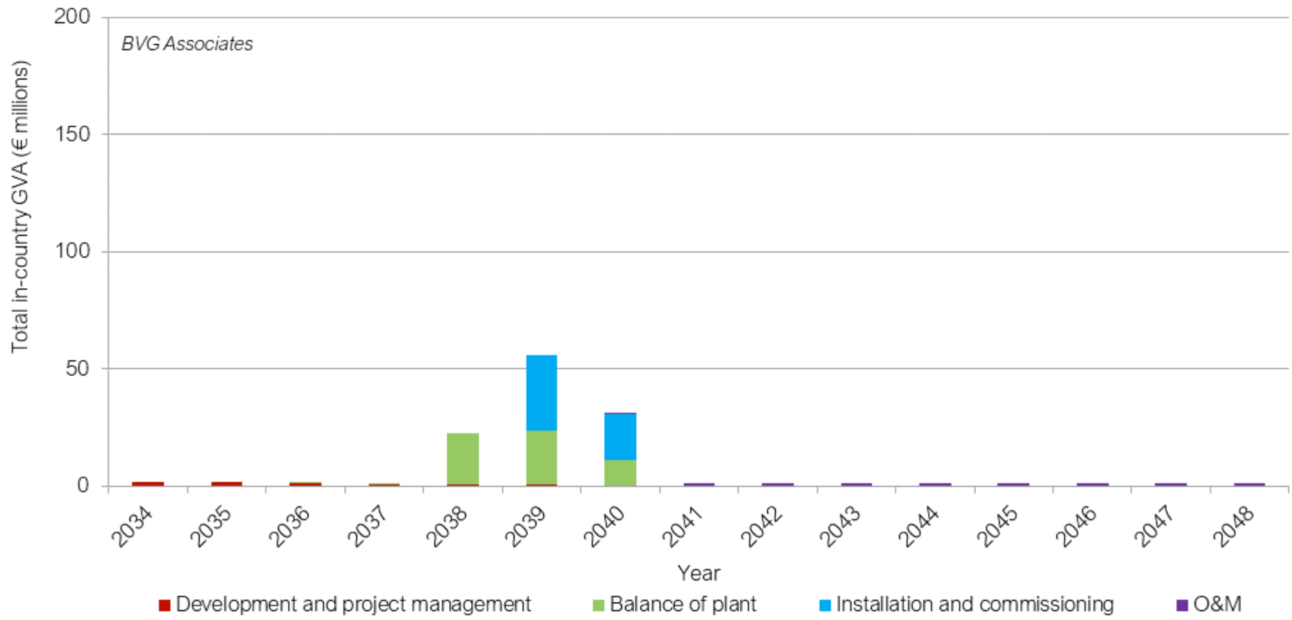

Figure 13 Irish annual GVA for each 1 GW of interconnector installed in 2040, split by supply chain level 1 category.

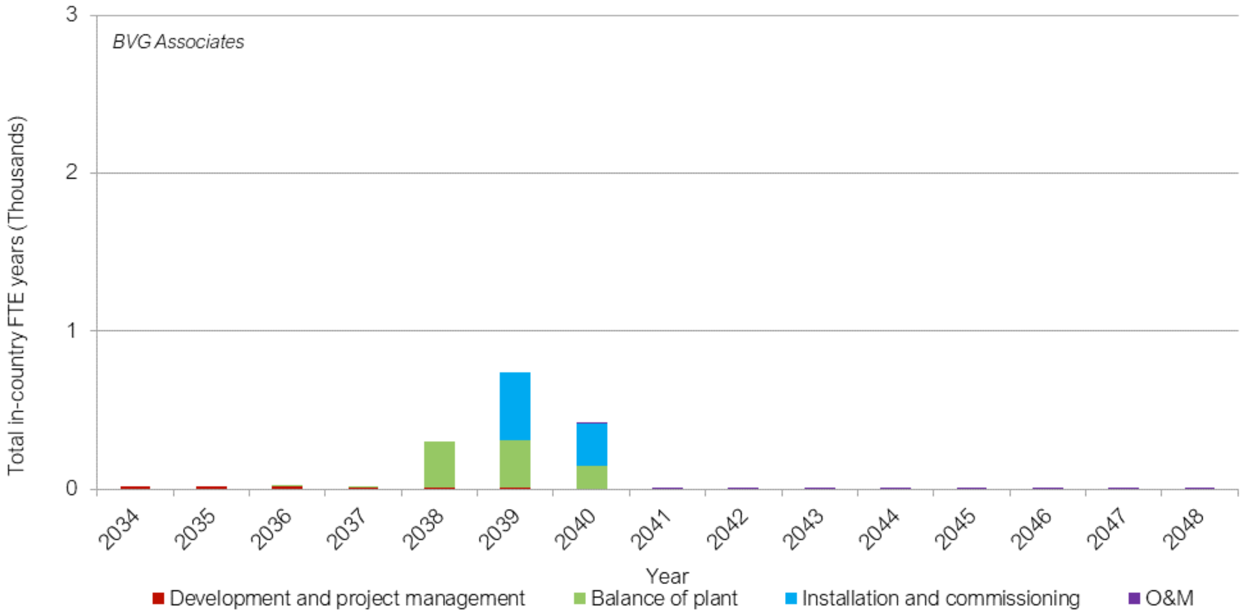

Figure 14 Irish annual FTE years employment for each 1 GW of interconnector installed in 2040, split by supply chain level 1 category.

Scenario impacts

This section combines data presented in the previous section to provide a summary of impact for each scenario. It shows the cumulative GVA and jobs impacts of the four scenarios to 2060.

Figure 15 shows a comparison of cumulative GVA impacts across the four scenarios, split by technology. It shows that overall GVA benefits are strongly linked to offshore wind deployment. Floating offshore wind provides a large share of GVA benefits on higher deployment scenarios. The overall GVA benefits of the 37 GW stretch scenario are less than the 37 GW well connected scenario, as additional interconnection reduces the need for investment in hydrogen infrastructure.

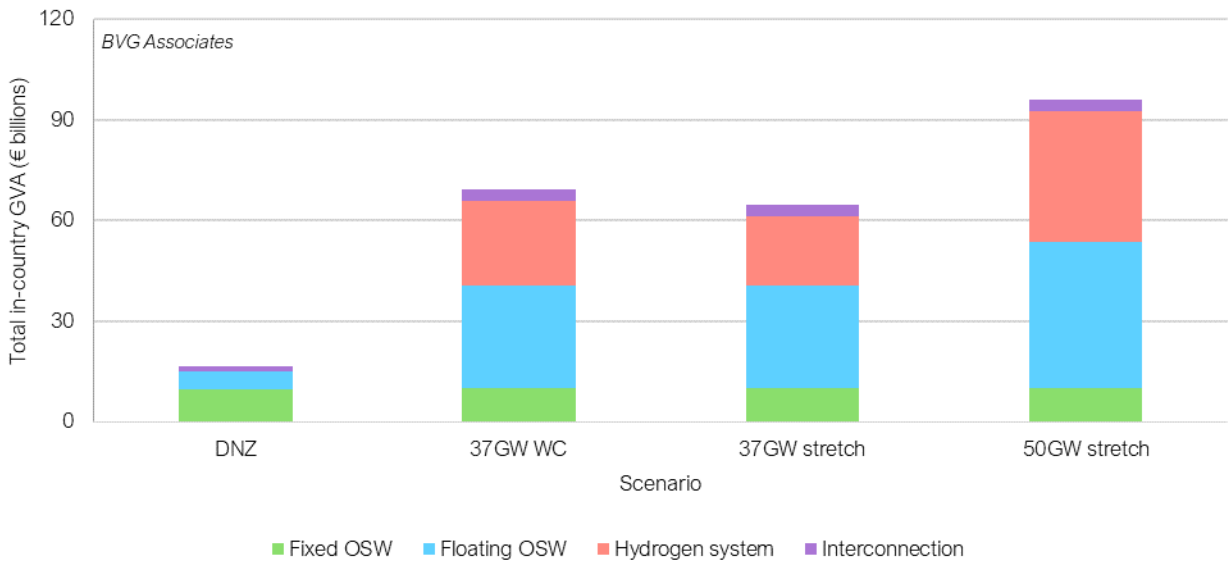

Figure 15 Comparison of lifetime Irish GVA benefits across scenarios, split by technology.

DNZ scenario

Figure 16 and Figure 17 show annual GVA reaching a peak of about €690 million in 2049. Over the lifetime of the projects €17 billion GVA is generated in Ireland, about 19% of the total generated globally from these projects. 57% of this is in fixed offshore wind, 32% in floating offshore wind, and 11% in interconnection.

Figure 18 and Figure 19 show annual FTE years employment reaching a peak of about 8,300 in 2049. Over the lifetime of the projects 19,000 FTE years of employment are created in Ireland, about 15% of the total created globally by Irish projects. 56% of this is in fixed offshore wind, 32% in floating offshore wind and 12% in interconnection. 44% of these are direct jobs.

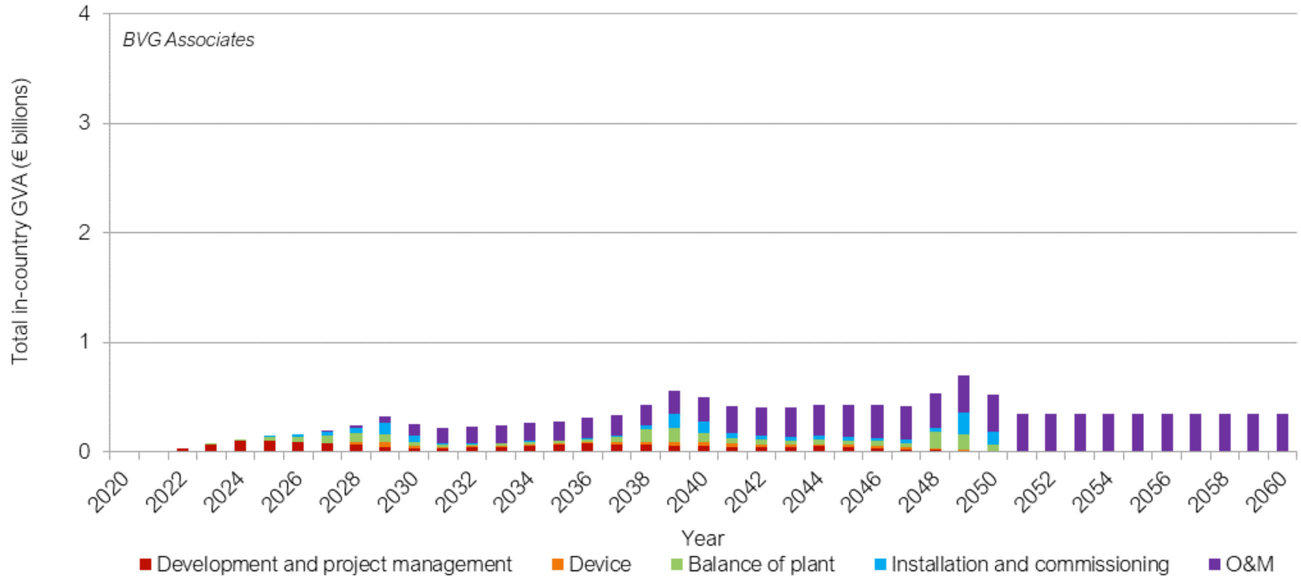

Figure 16 Irish annual GVA for DNZ scenario to 2060, split by supply chain level 1 category.

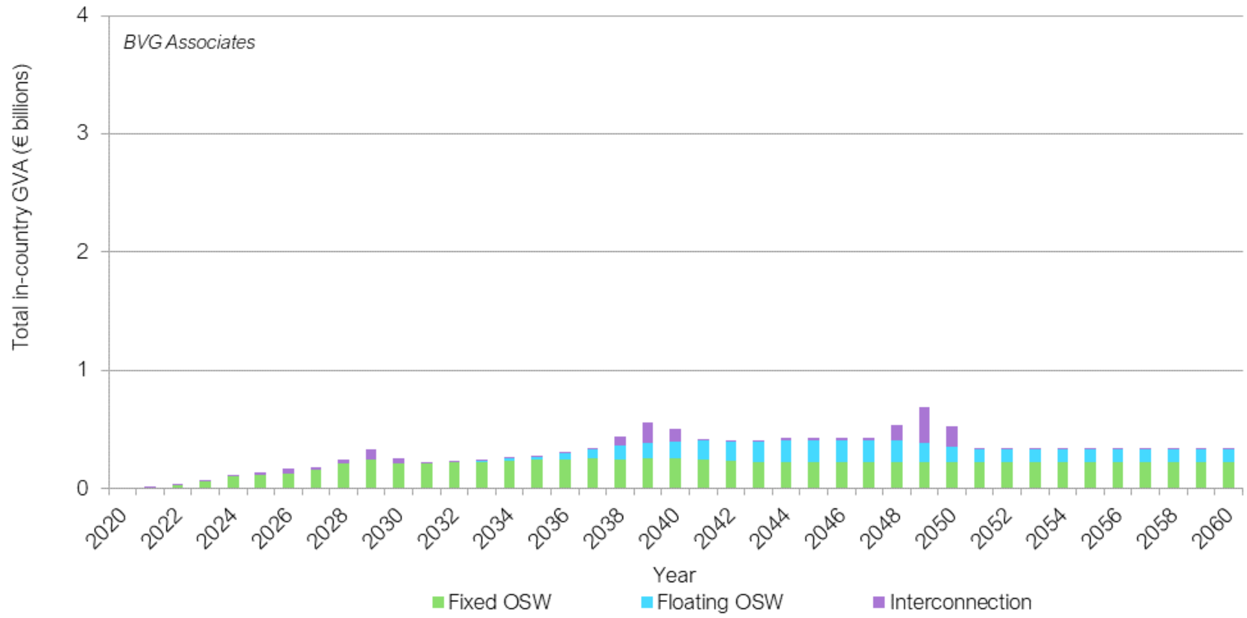

Figure 17 Irish annual GVA for DNZ scenario to 2060, split by technology.

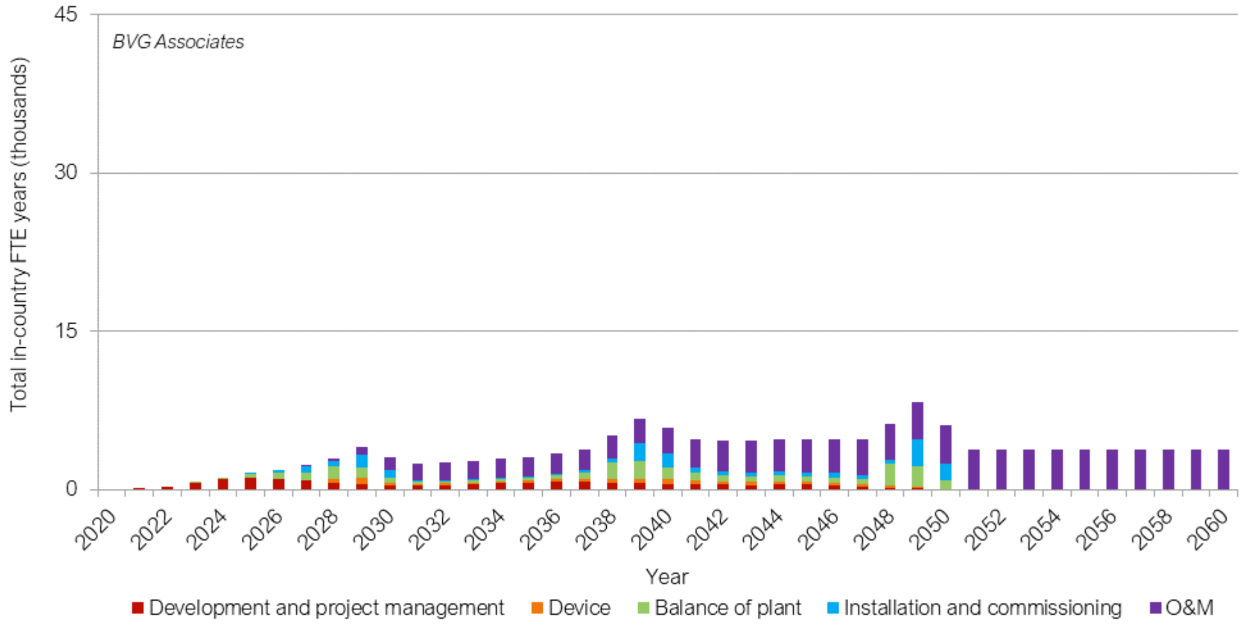

Figure 18 Irish annual FTE years employment for DNZ scenario to 2060 split by supply chain level 1 category.

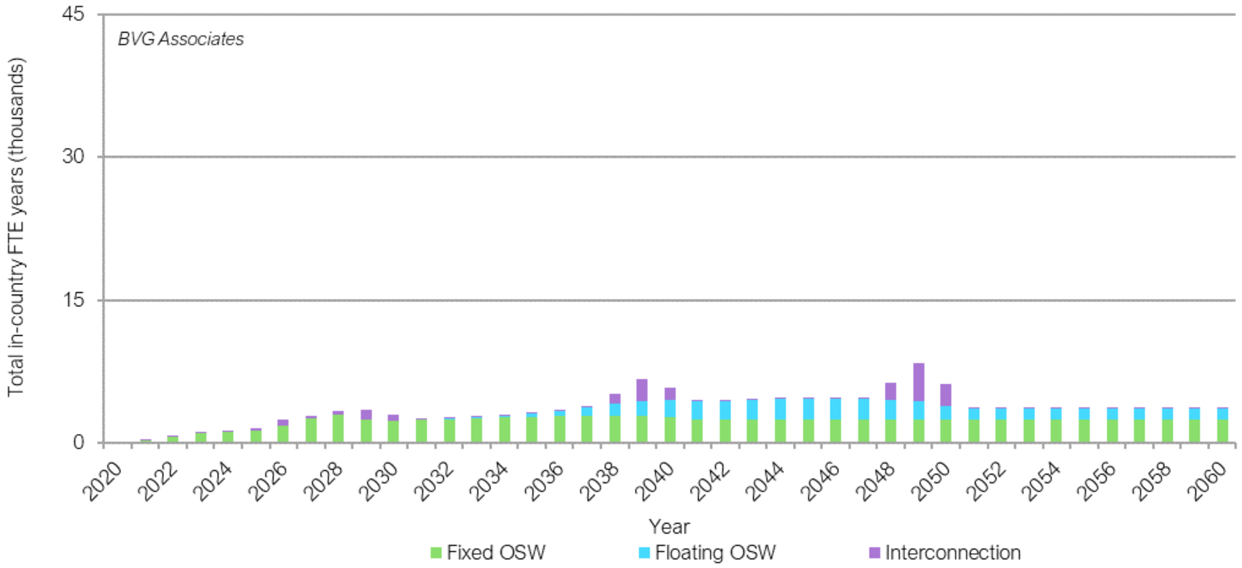

Figure 19 Irish annual FTE years employment for DNZ scenario to 2060, split by technology.

37 GW well connected scenario

Figure 20 and Figure 21 show annual GVA reaching a peak of about €2.4 billion in 2049. Over the lifetime of the projects €69 billion GVA is generated in Ireland, about 21% of the total generated globally from these projects. 14% of this is in fixed offshore wind, 45% in floating offshore wind, 36% in hydrogen production, storage and transmission and 5% in interconnection.

Figure 22 and Figure 23 show annual FTE years employment reaching a peak of about 31,000 in 2049. Over the lifetime of the projects 820,000 FTE years of employment are created in Ireland, about 20% of the total created globally by Irish projects. 13% of this is in fixed offshore wind, 43% in floating offshore wind, 39% in hydrogen production, storage and transmission and 5% in interconnection. 52% of these are direct jobs.

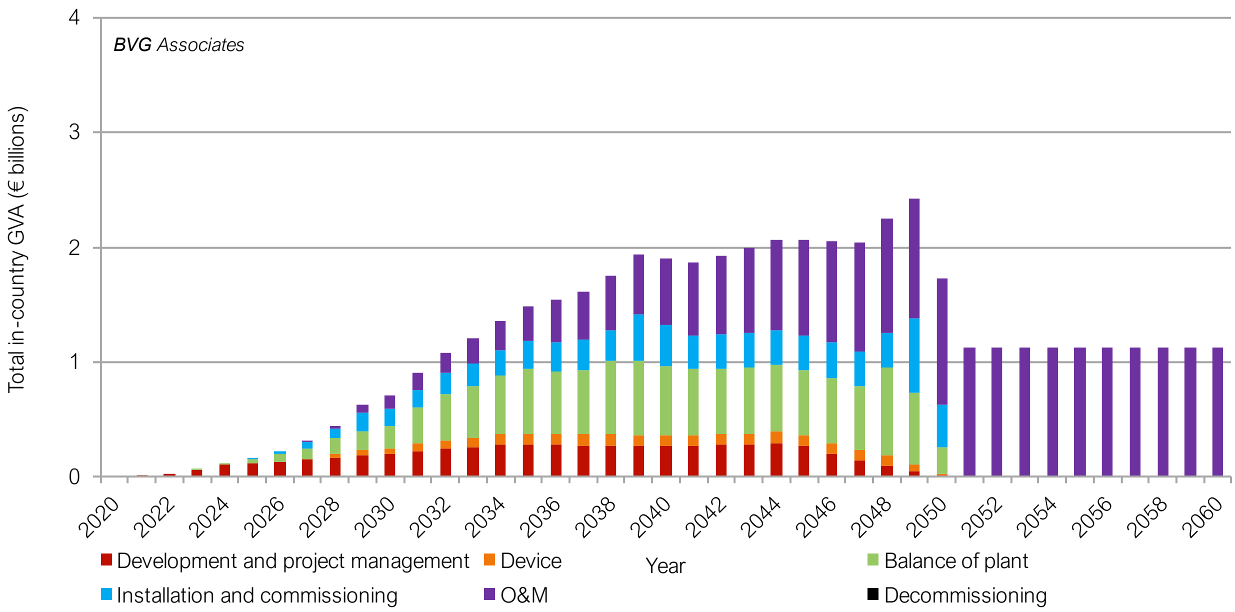

Figure 20 Irish annual GVA for 37 GW well connected scenario to 2060, split by supply chain level 1 category.

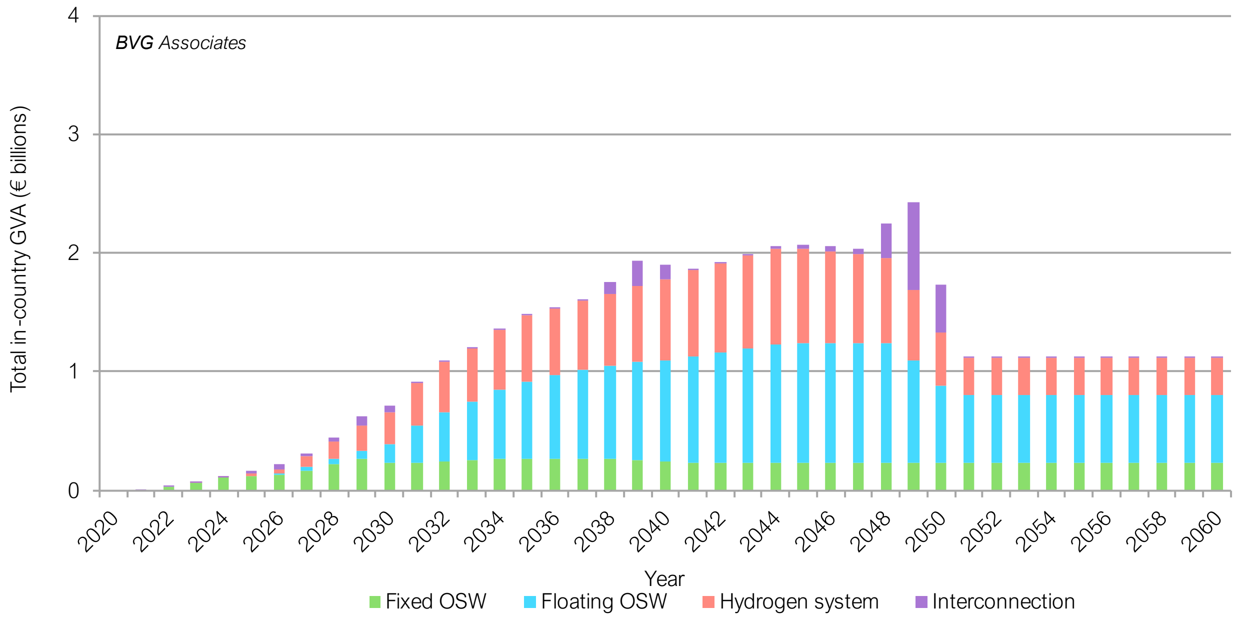

Figure 21 Irish annual GVA for 37 GW well connected scenario to 2060, split by technology.

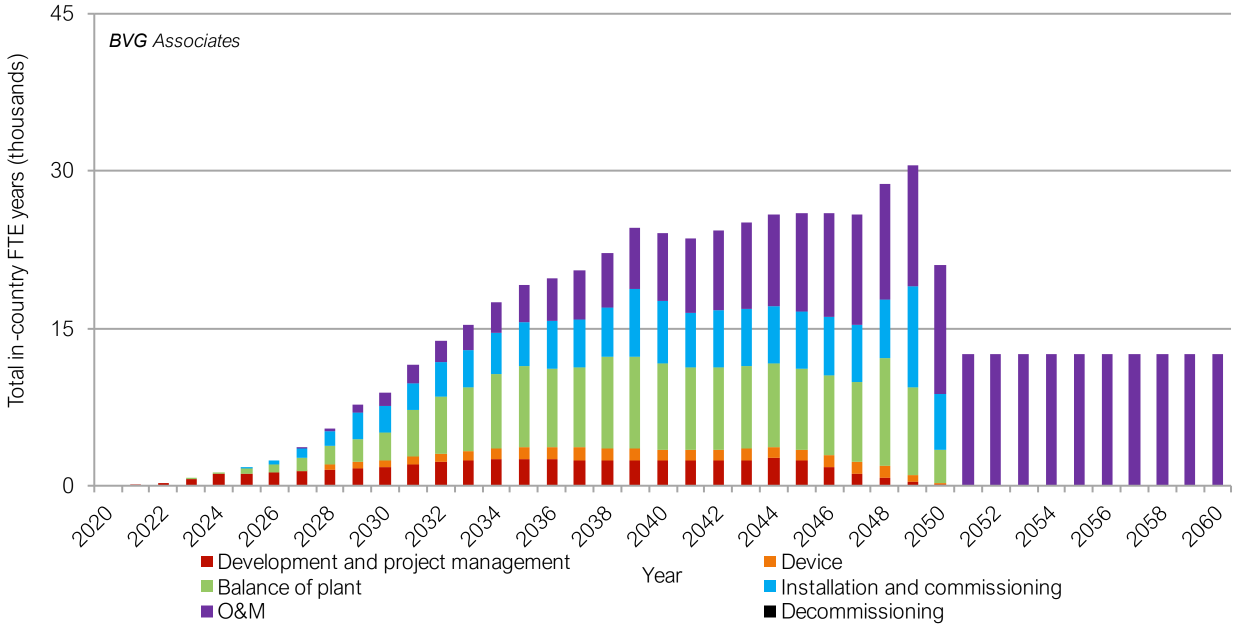

Figure 22 Irish annual FTE years employment for 37 GW well connected scenario to 2060 split by supply chain level 1 category.

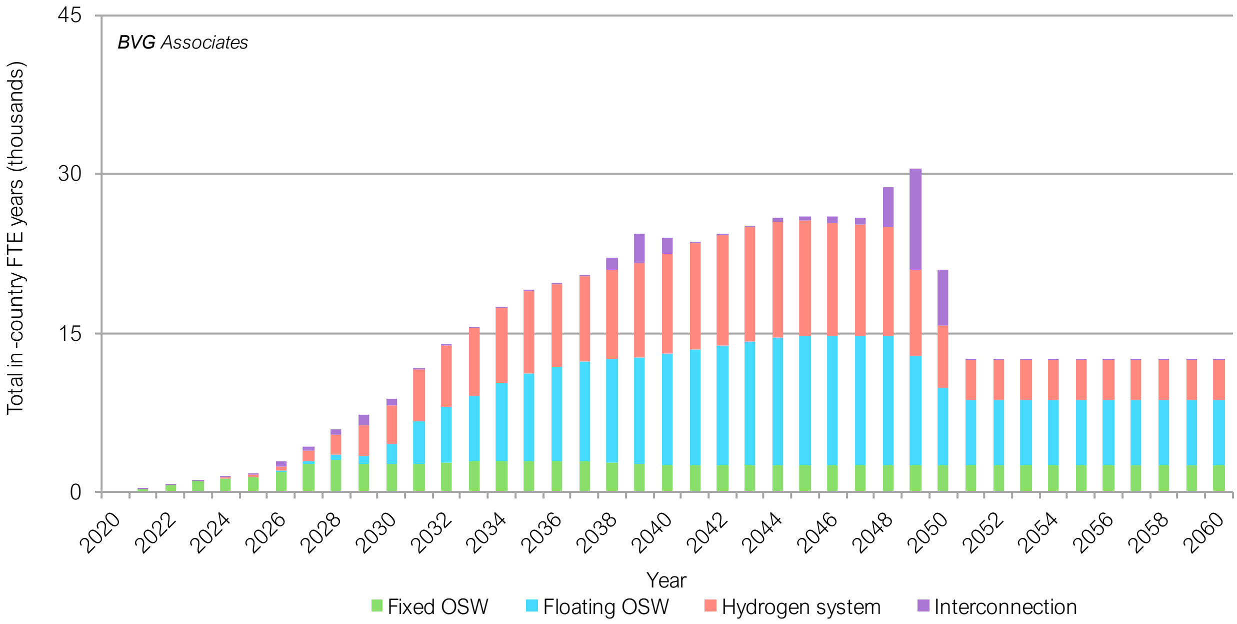

Figure 23 Irish annual FTE years employment for 37 GW well connected scenario to 2060, split by technology.

37 GW stretch scenario

Figure 24 and Figure 25 show annual GVA reaching a peak of about €2.2 billion in 2049. Over the lifetime of the projects €65 billion GVA is generated in Ireland, about 20% of the total generated globally from these projects. 15% of this is in fixed offshore wind, 48% in floating offshore wind, 5% in interconnection and 32% in hydrogen production, storage and transmission.

Figure 26 and Figure 27 show annual FTE years employment reaching a peak of about 27,000 in 2049. Over the lifetime of the projects 770,000 FTE years of employment are created in Ireland, about 19% of the total created globally by Irish projects. 14% of this is in fixed offshore wind, 46% in floating offshore wind, 6% in interconnection and 34% in hydrogen production, storage and transmission. 51% of these are direct jobs.

Overall, lifetime GVA and employment benefits are around 6% lower in the 37 GW stretch scenario versus the 37 GW well connected scenario. This is due to the increased interconnector capacity in the stretch scenario, which necessitates less investment in hydrogen production, storage and transport infrastructure. Per gigawatt, the local GVA benefits of hydrogen infrastructure are greater than that of interconnection, as shown in Figure 1.

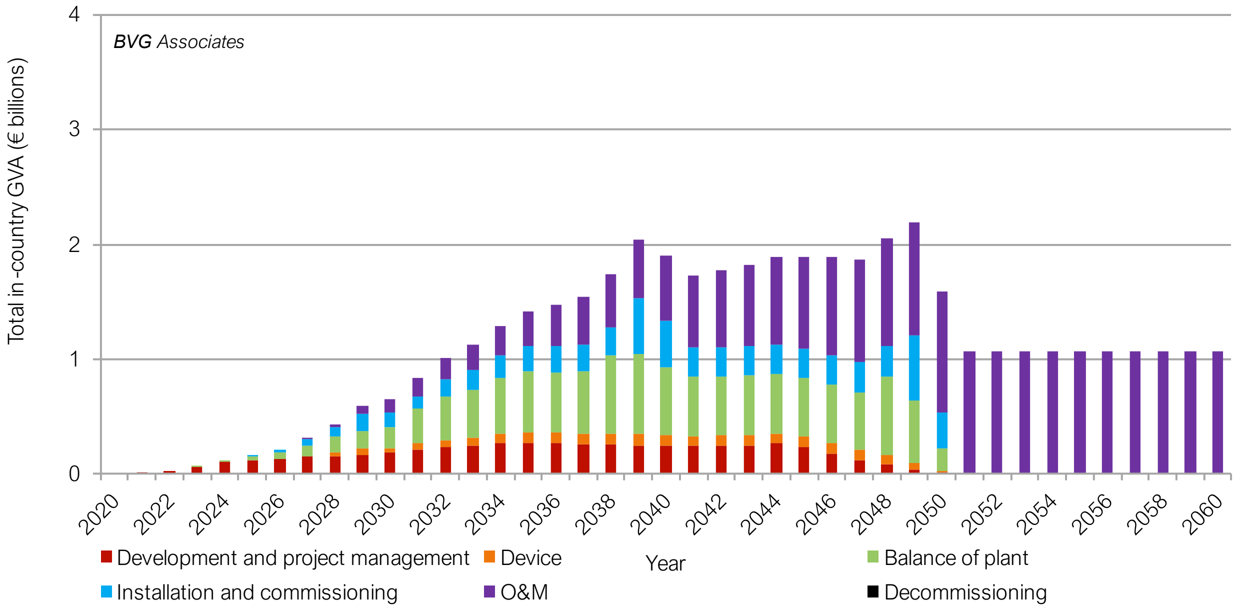

Figure 24 Irish annual GVA for 37 GW stretch scenario to 2060, split by supply chain level 1 category.

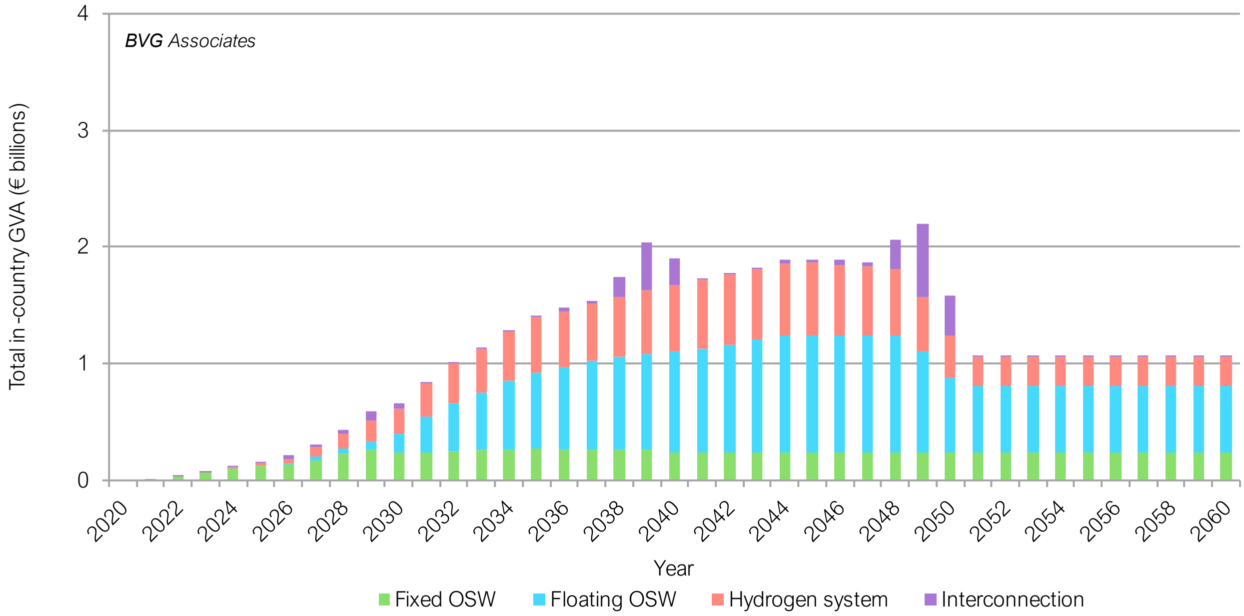

Figure 25 Irish annual GVA for 37 GW stretch scenario to 2060, split by technology.

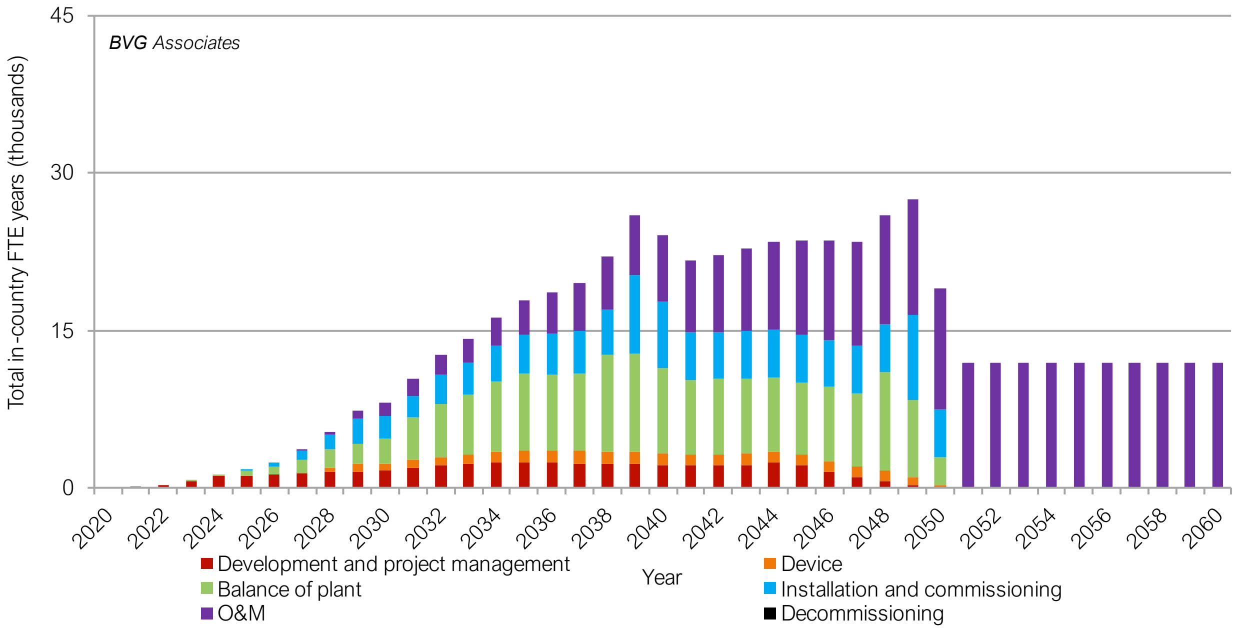

Figure 26 Irish annual GVA for 37 GW stretch scenario to 2060, split by technology.

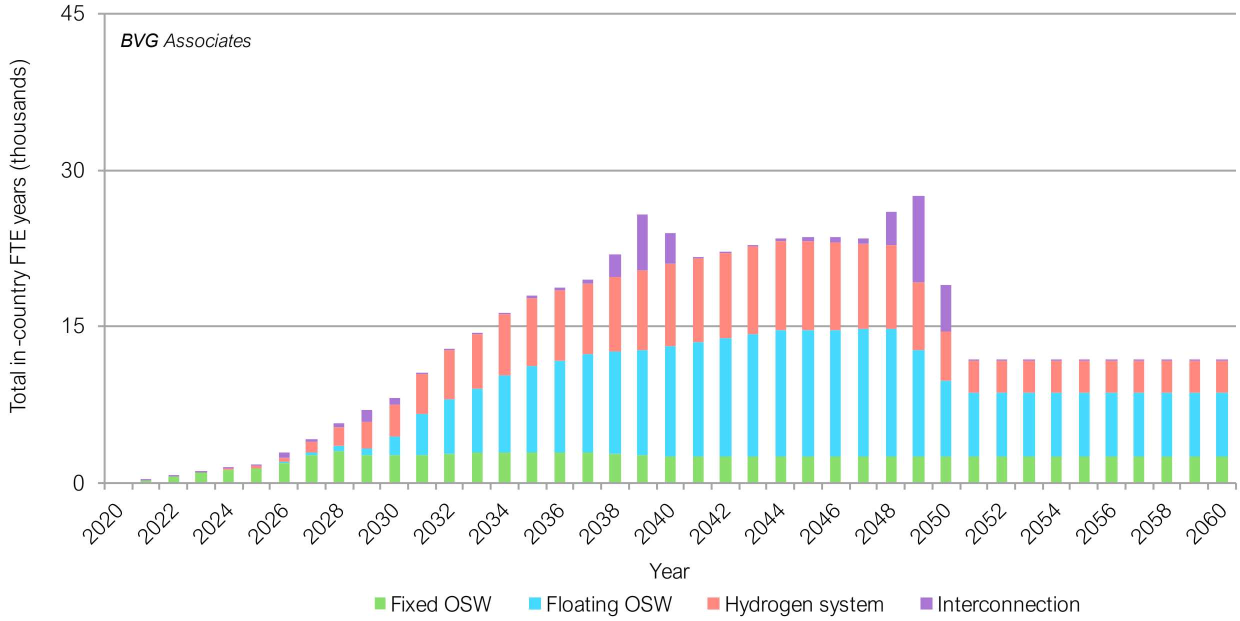

Figure 27 Irish annual FTE years employment for 37 GW stretch scenario to 2060, split by technology.

50 GW stretch scenario

Figure 28 and Figure 29 show annual GVA reaching a peak of about €3 billion in 2048. Over the lifetime of the projects €96 billion GVA is generated in Ireland, about 22% of the total generated globally from these projects. 10% of this is in fixed offshore wind, 45% in floating offshore wind, 40% in hydrogen production, storage and transmission and 4% in interconnection.

Figure 30 and Figure 31 show annual FTE years employment reaching a peak of about 39,000 in 2048. Over the lifetime of the projects 1.1 million FTE years of employment are created in Ireland, about 21% of the total created globally by Irish projects. 9% of this is in fixed offshore wind, 44% in floating offshore wind, 43% in hydrogen production, storage and transmission, and 4% in interconnection. 52% of these are direct jobs.

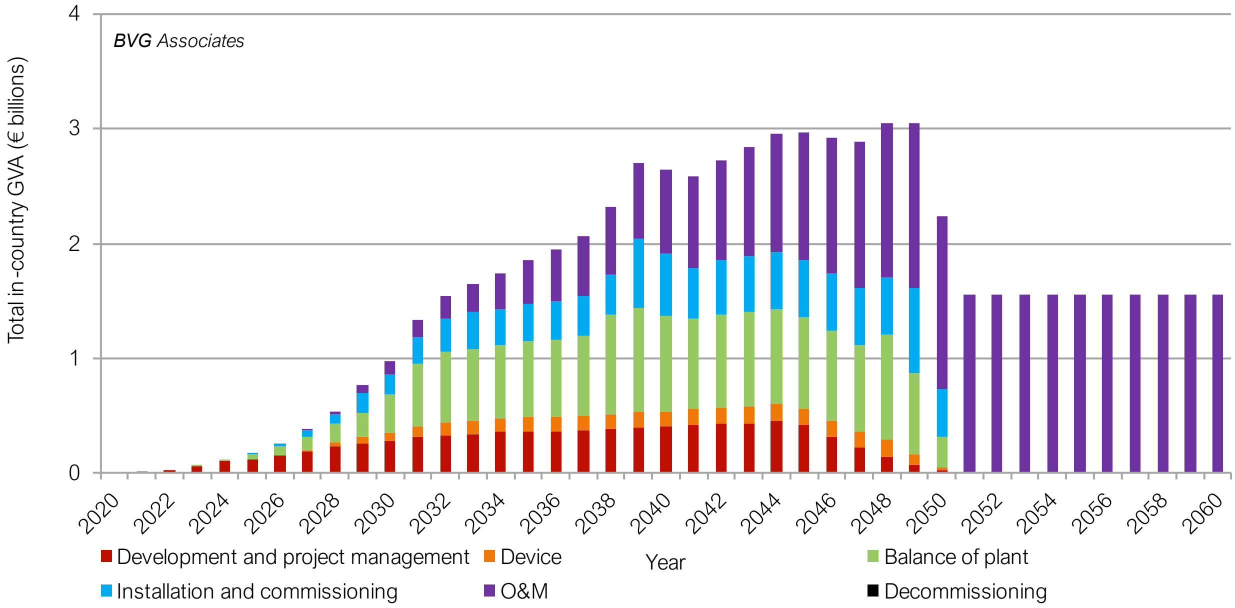

Figure 28 Irish annual GVA for 50 GW stretch scenario to 2060, split by supply chain level 1 category.

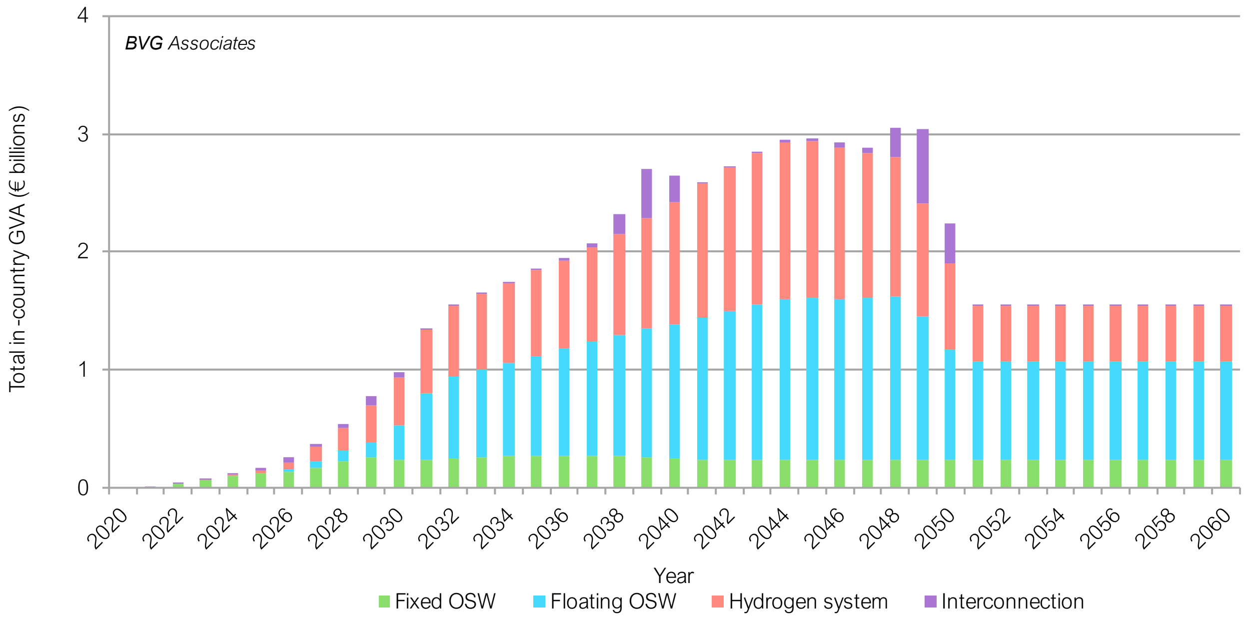

Figure 29 Irish annual GVA for 50 GW stretch scenario to 2060, split by technology.

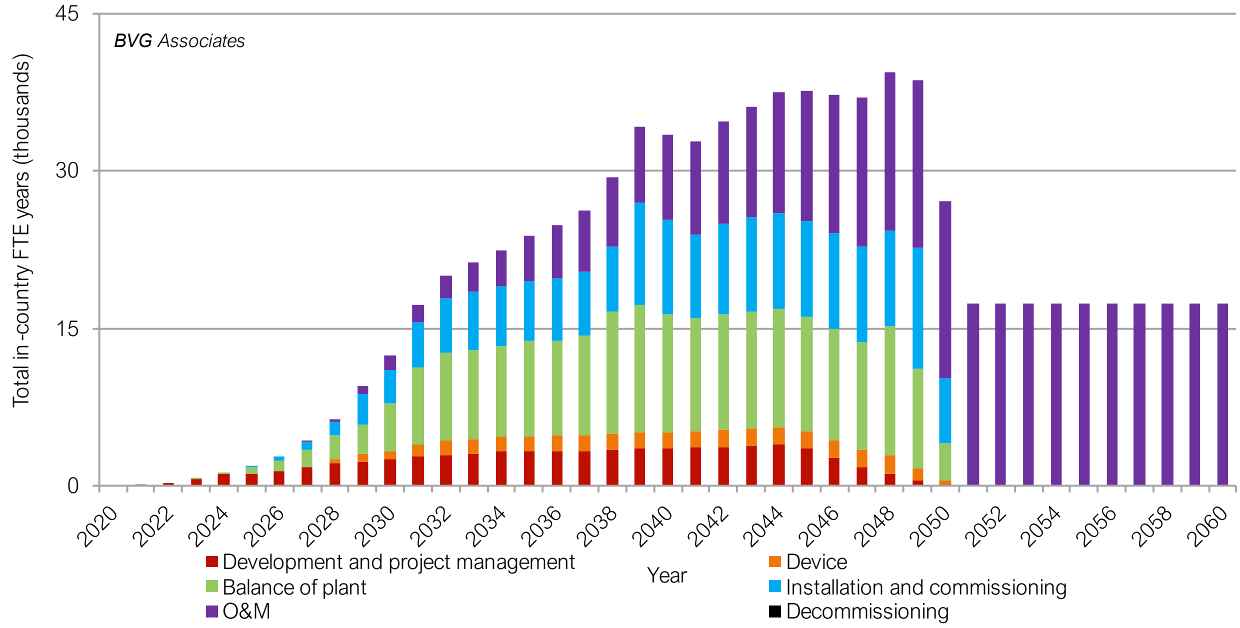

Figure 30 Irish annual FTE years employment for 50 GW stretch scenario to 2060, split by supply chain level 1 category.

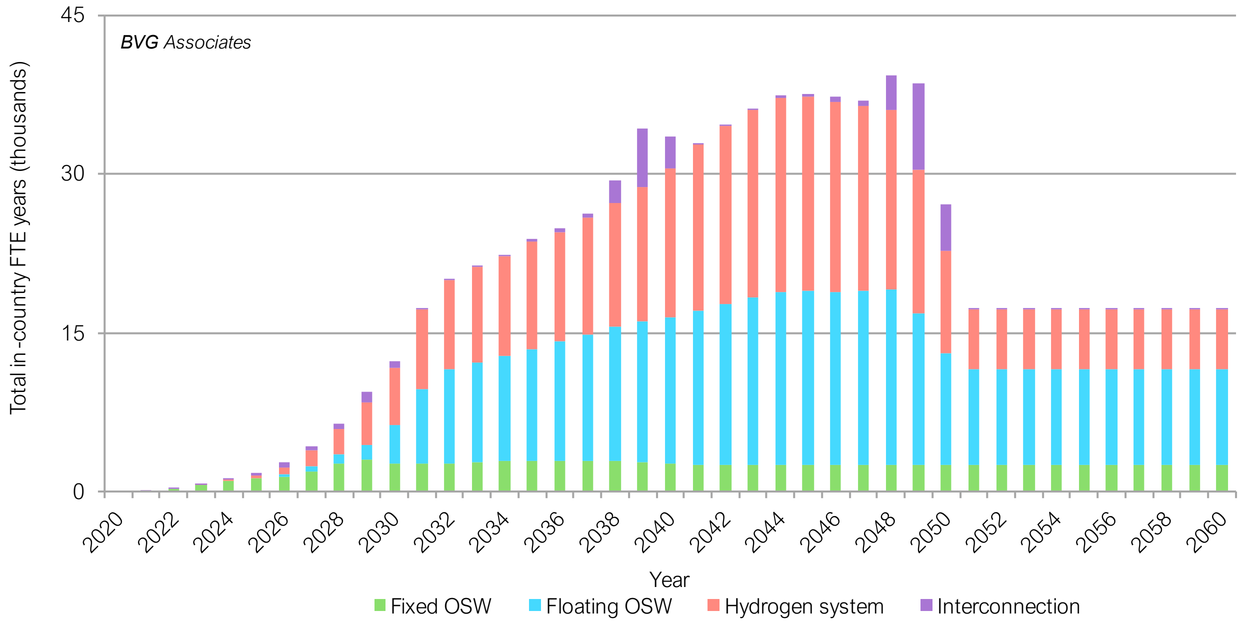

Figure 31 Irish annual FTE years employment for 50 GW stretch scenario to 2060, split by technology.

Tax take results

Table 5 to Table 8 show the total cumulative tax take in each of the four scenarios, broken down by technology as well as by tax type. They show the total tax take in the DNZ scenario is about €4 billion. This rises to around €22 billion in the 50 GW stretch scenario.

Across all scenarios, Income tax represents just under 50% of the total tax take, social insurance 15%, VAT 33% and the remainder is corporation tax.

The distribution of tax take over time for the DNZ scenario is shown in Figure 32. This shows annual tax take peaking in 2049 at €290 million.

The distribution of tax take over time for the 37 GW well connected scenario is shown in Figure 33. This shows annual tax take peaking in 2049 at €1 billion.

The distribution of tax take over time for the 37 GW stretch scenario is shown in Figure 34. This shows annual tax take peaking in 2049 at €920 million.

The distribution of tax take over time for the 50 GW stretch scenario is shown in Figure 35. This shows annual tax take peaking in 2048 at €1.3 billion.

Table 5 Split of tax take across technologies and types to 2050 in DNZ scenario.

Technology	Corporation tax (€ million)	Income tax (€ million)	Social insurance (€ million)	VAT (€ million)	Total (€ million)
Fixed offshore wind	93	1,166	372	827	2,458
Floating offshore wind	34	456	146	324	960
Local hydrogen generation and distribution	0	0	0	0	0
Interconnection	23	266	85	189	563
Total	150	1,888	603	1,340	3,981

Table 6 Split of tax take across technologies and types to 2050 in 37 GW well connected scenario.

Technology	Corporation tax (€ million)	Income tax (€ million)	Social insurance (€ million)	VAT (€ million)	Total (€ million)
Fixed offshore wind	98	1,230	393	873	2,594
Floating offshore wind	224	3,264	1,042	2,317	6,847
Local hydrogen generation and distribution	199	2,652	847	1,883	5,581
Interconnection	40	455	145	323	963
Total	561	7,601	2,427	5,396	15,985

Table 7 Split of tax take across technologies and types to 2050 in 37 GW stretch scenario.

Technology	Corporation tax (€ million)	Income tax (€ million)	Social insurance (€ million)	VAT (€ million)	Total (€ million)
Fixed offshore wind	98	1,230	393	873	2,594
Floating offshore wind	224	3,264	1,042	2,317	6,847
Local hydrogen generation and distribution	162	2,157	689	1,532	4,540
Interconnection	43	494	158	351	1,046
Total	527	7,145	2,282	5,073	15,027

Table 8 Split of tax take across technologies and types to 2050 in 50 GW stretch scenario.

Technology	Corporation tax (€ million)	Income tax (€ million)	Social insurance (€ million)	VAT (€ million)	Total (€ million)
Fixed offshore wind	98	1,230	393	873	2,594
Floating offshore wind	315	4,499	1437	3,195	9,446
Local hydrogen generation and distribution	305	4,058	1,296	2,881	8,540
Interconnection	43	494	158	351	1046
Total	761	10,281	3,284	7,300	21,626

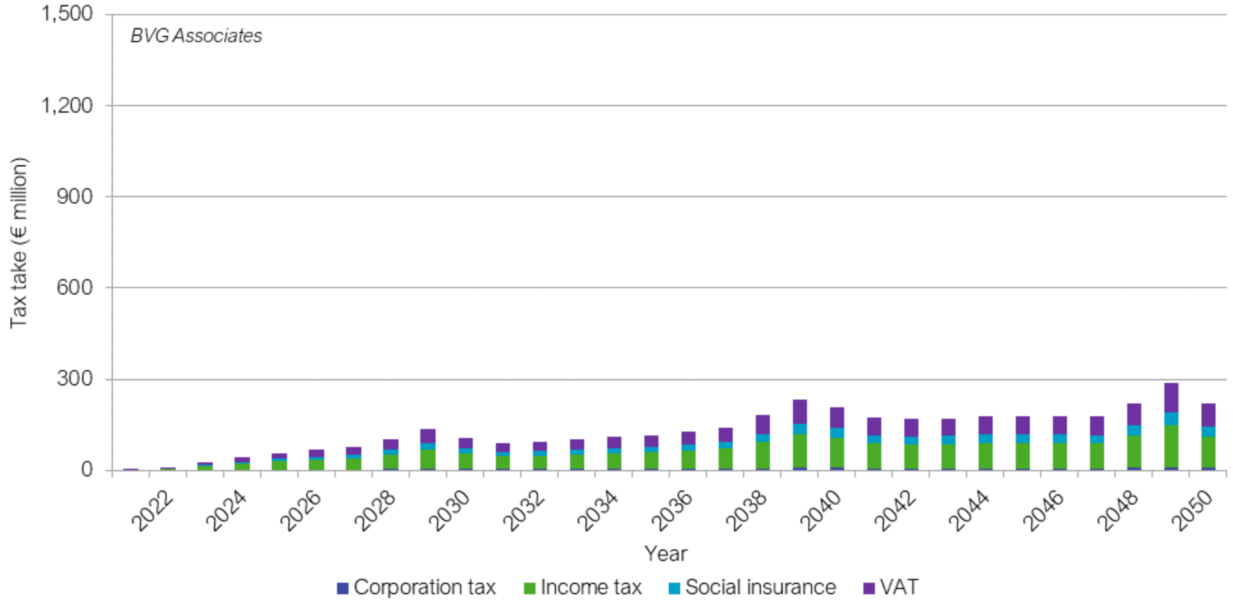

Figure 32 Tax take by tax type in the DNZ scenario to 2050.

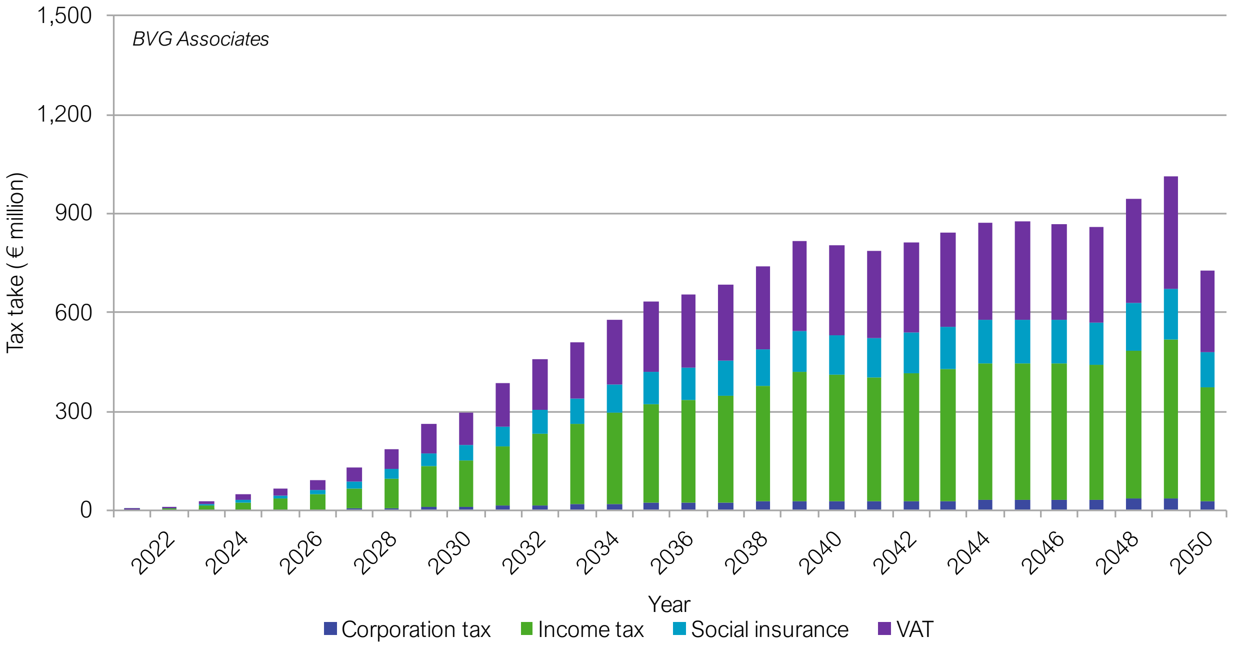

Figure 33 Tax take by tax type in the 37 GW well connected scenario to 2050.

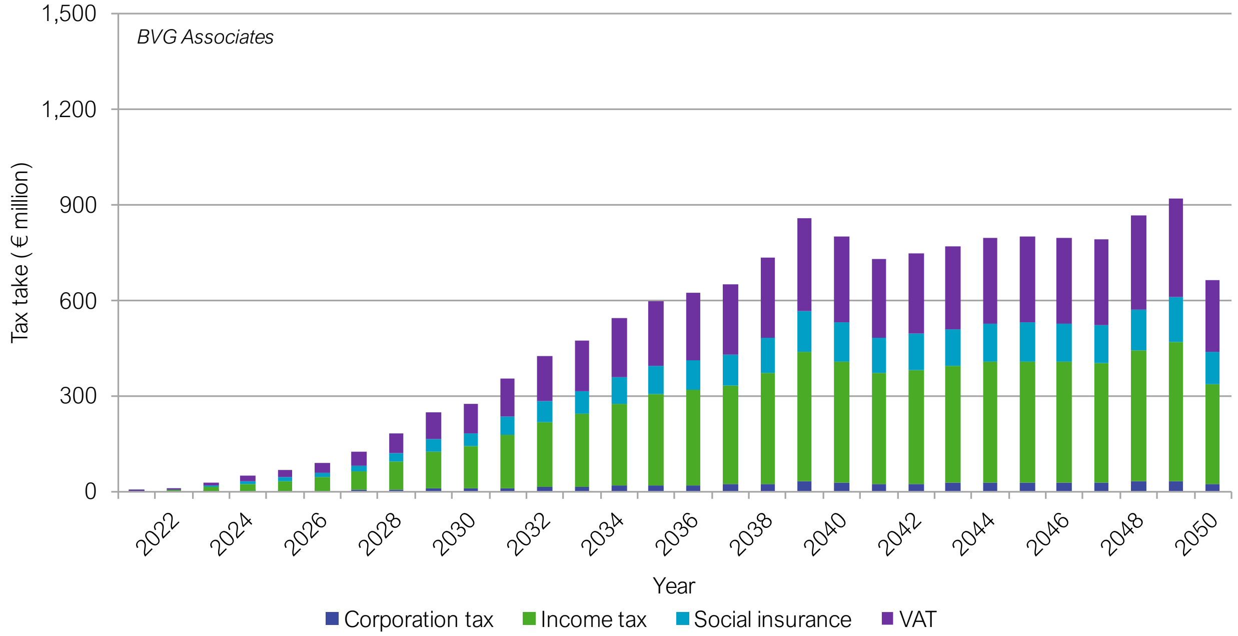

Figure 34 Tax take by tax type in the 37 GW stretch scenario to 2050.

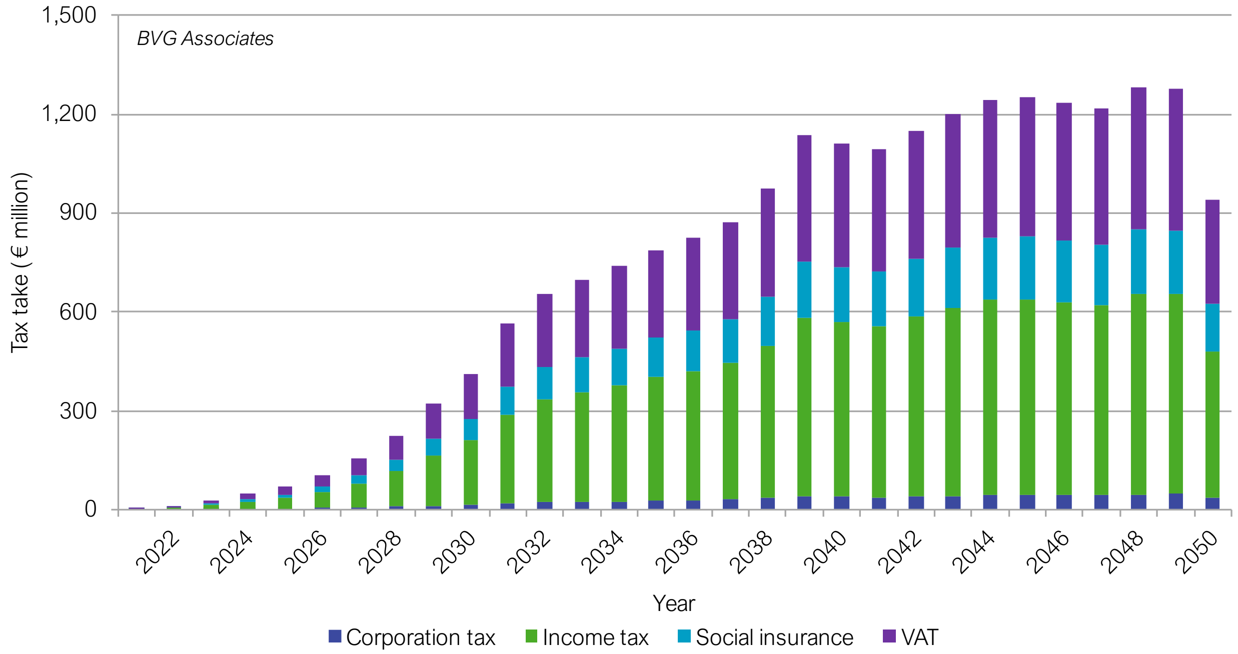

Figure 35 Tax take by tax type in the 50 GW stretch scenario to 2050.

Additional impacts

Beyond the Irish jobs, GVA and tax benefits discussed above, there will be significant impact from industries using lower-cost power and hydrogen from ORE. Full economic analysis of these opportunities lies outside of the scope of this report. We discuss these qualitatively, below.

Industries using lower-cost power and hydrogen from offshore renewable energy

All of the 37 GW and 50 GW deployment scenarios considered in this report show a considerable generation surplus from ORE deployment which cannot be absorbed by domestic demand, following an expected progression.

This report focusses chiefly on whether Ireland should pursue an ambitious ORE deployment programme to benefit from the export of the additional surplus, via electricity interconnection or hydrogen and its derivatives. Although Ireland may become a significant energy exporter under these scenarios, the benefits of doing so are uncertain and depend on assumptions about European wholesale electricity and hydrogen prices.

It is likely that some of this surplus could be employed to greater benefit of the Irish economy through the creation of new industrial energy users within Ireland, providing a boost to jobs and investment. If Ireland wishes to pursue an ambitious ORE rollout programme as outlined in the 37 GW and 50 GW scenarios, we recommend the Government explores measures to attract inward investment by such energy intensive industries. A non-exhaustive list of promising avenues to explore, many of which have already been identified in preceding work packages, includes:

- Industries to boost electricity demand:
  - Data centres: Ireland already hosts a number of significant data centres and is well placed to attract more investment in this area due to its strong digital capabilities and strategic location for transatlantic data traffic.
- Industries to boost hydrogen demand:
  - Sustainable aviation fuel (SAF) production: Ireland is well placed to target this activity due to its strong aviation sector and strategic position on transatlantic aviation routes.
  - Ammonia production for fertiliser: Ireland is well placed to target this activity due to its significant domestic agricultural sector, which would provide a local source of demand.
  - Methanol production for maritime fuel: Ireland has a strong maritime sector and there is an opportunity to target additional demand for clean maritime fuel produced from hydrogen as the sector seeks to decarbonise.
  - Clean steel production: The case for Ireland to pursue this is less clear, due to limited existing heavy industry. However, energy costs are a key consideration for producers in this industry.

Trade opportunities

This section considers the trade opportunities associated with each scenario, including export of products and services, export of electricity and hydrogen and its derivatives.

Domestic net zero scenario

In the DNZ scenario, exports of products and services related to offshore wind, hydrogen and interconnection create an additional €3.7 billion in GVA. Figure 36 shows annual GVA including exports reaching a peak of about €880 million in 2049. Up to 2050, €13 billion GVA is generated, about 35% higher than from just the pipeline of projects in Ireland.

Figure 37 shows a breakdown of export activity. 23% of this comes from development and project management services, 64% from tower manufacturing, and 13% from operational phase supply. This shows only the value captured domestically from servicing foreign projects. It does not include supply to Irish projects.

Figure 38 shows a comparison of export benefits in 2030, 40 and 50. Note that for the DNZ scenario, no export benefits from hydrogen export are envisaged, and interconnect trade is assumed to be net neutral. This is consistent with the DNZ scenario's assumption of a domestic net zero system.

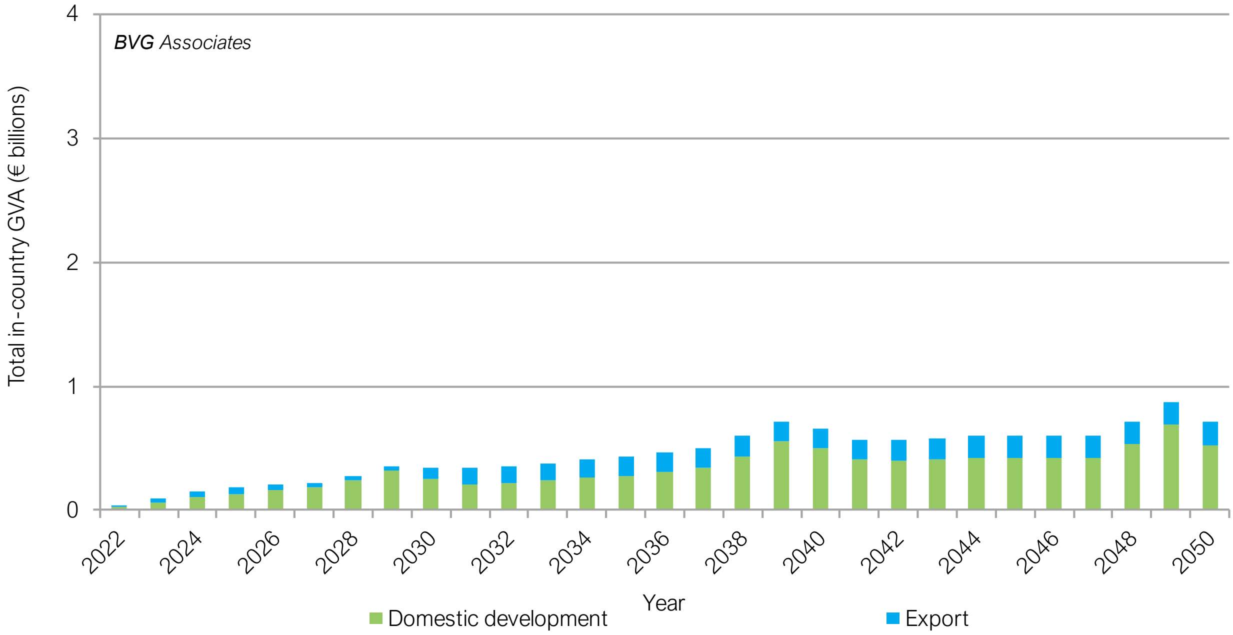

Figure 36 Annual local gross value added by Irish and overseas projects in the DNZ scenario, split by domestic and export spend.

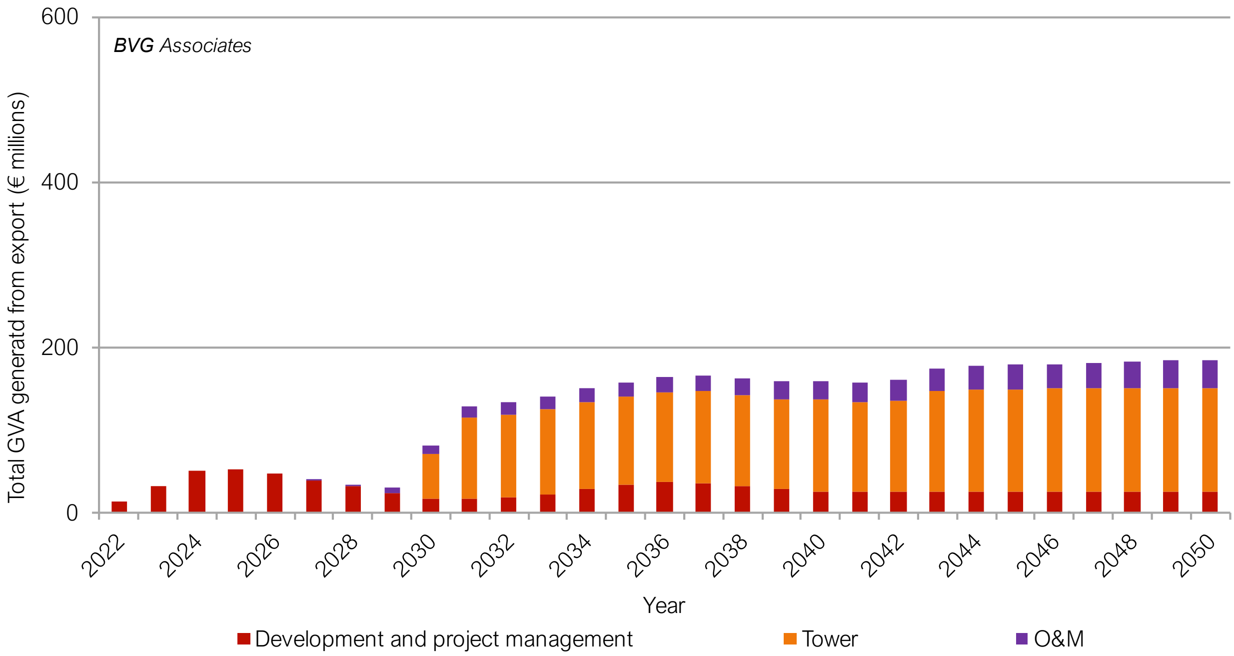

Figure 37 Annual local gross value added by overseas projects in the DNZ scenario, split by cost element.

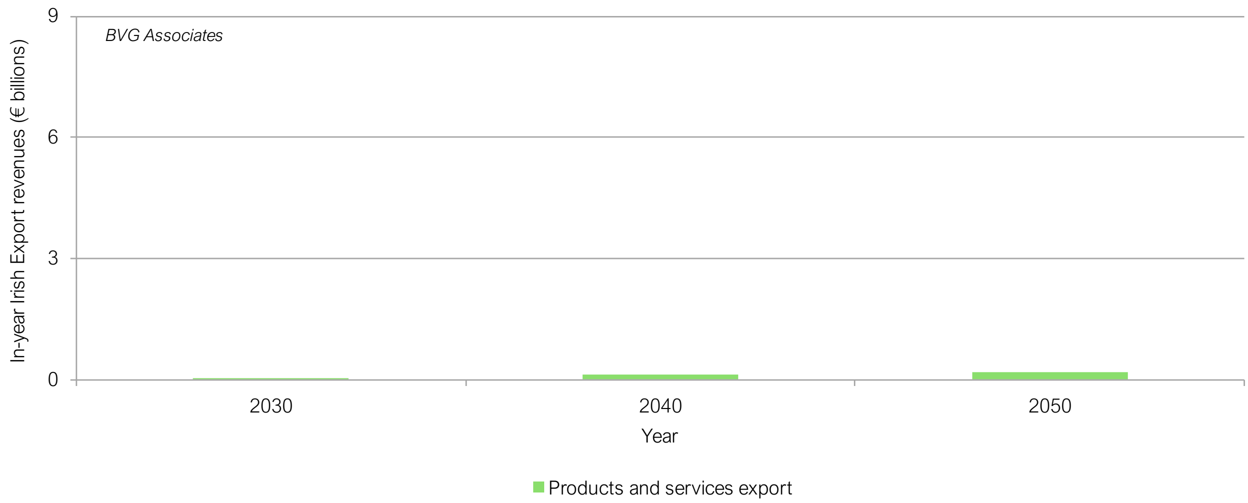

Figure 38 Total export opportunity, including electricity and hydrogen trade in the DNZ scenario, in 2030, 2040 and 2050.

37 GW well connected scenario

In the 37 GW well connected scenario, exports of products and services related to offshore wind, hydrogen and interconnection create an additional €8.8 billion in GVA. Figure 39 shows annual GVA including exports reaching a peak of about €2.9 billion in 2049. Up to 2050, €47 billion GVA is generated, about 23% higher than from just the pipeline of projects in Ireland.

Figure 40 shows a breakdown of export activity. 37% of this comes from development and project management services, 17% from tower manufacturing, 3% from floating foundation assembly, 29% from mooring line manufacture and 14% from operational phase supply. This shows only the value captured domestically from servicing foreign projects. It does not include supply to Irish projects.

Figure 41 shows a comparison of export benefits in 2030, 40 and 50, including export benefits from the operation of interconnectors and trade in hydrogen. It shows that total in-year export benefits rise to €5.2 billion in 2050. 80% of this is due to hydrogen export, 10% interconnector rent and 10% export of products and services.

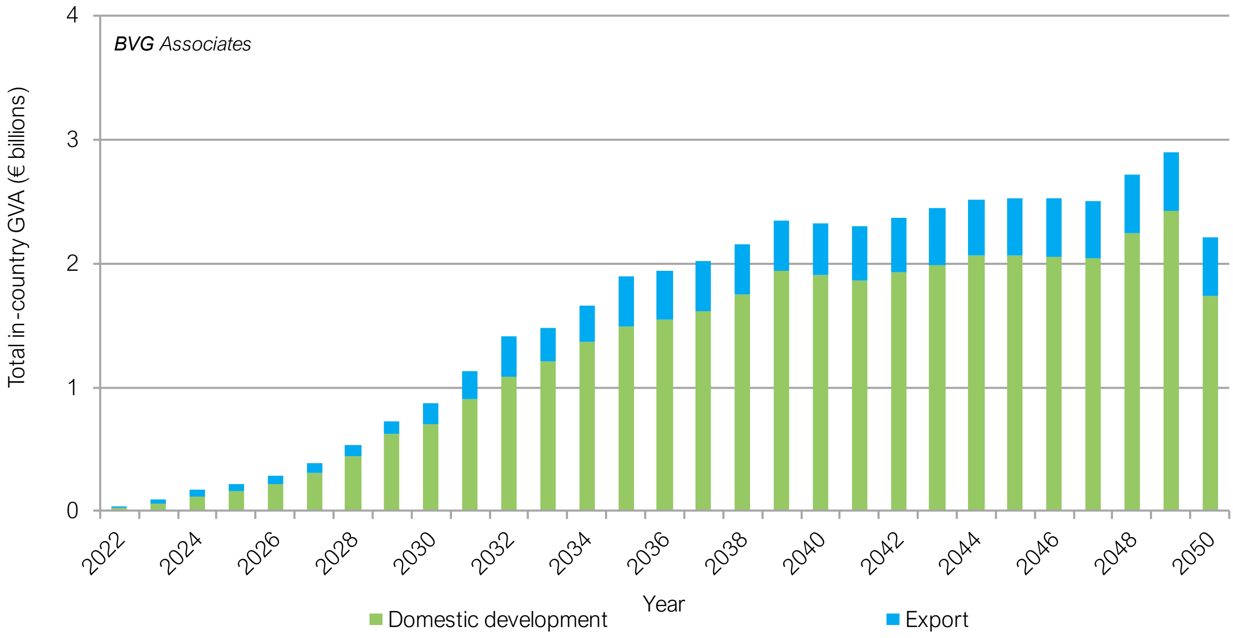

Figure 39 Annual local gross value added by Irish and overseas projects in the 37 GW well connected scenario, split by domestic and export spend.

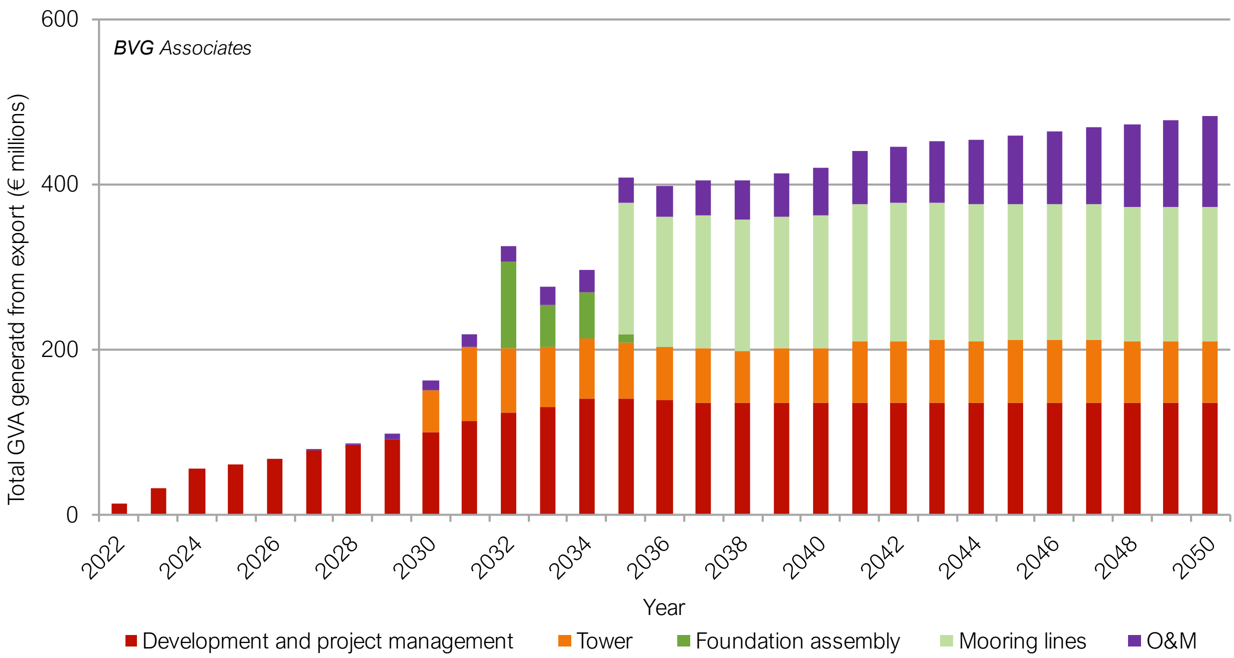

Figure 40 Annual local gross value added by overseas projects in the 37 GW well connected scenario, split by cost element.

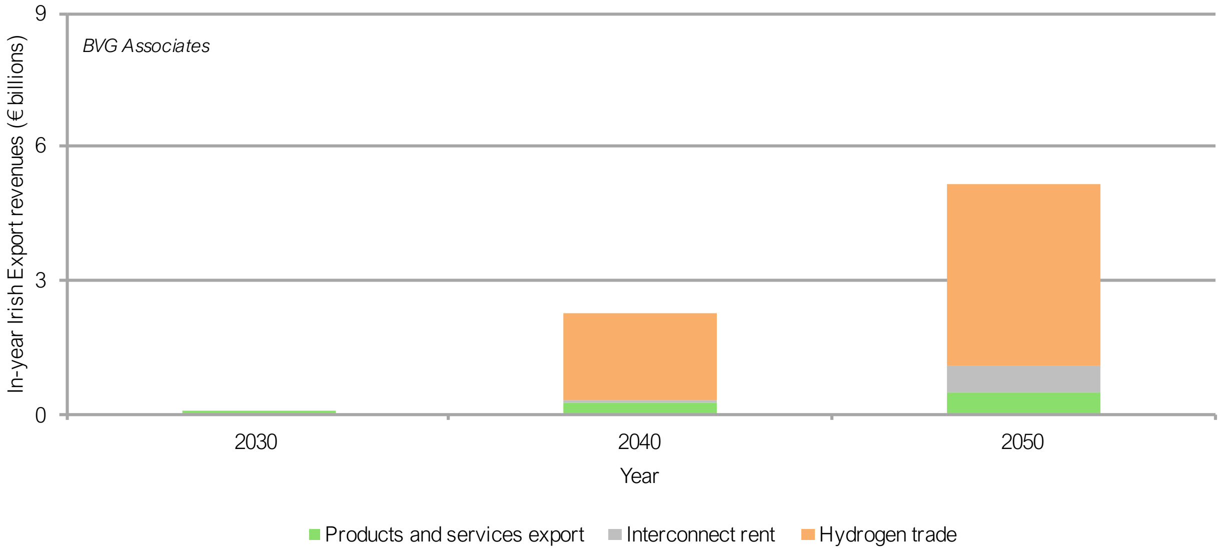

Figure 41 Total export opportunity, including electricity and hydrogen trade in the 37 GW well connected scenario, in 2030, 2040 and 2050.

37 GW stretch scenario

In the 37 GW stretch scenario, exports of products and services related to offshore wind, hydrogen and interconnection create an additional €8.6 billion in GVA. Figure 42 shows annual GVA including exports reaching a peak of about €2.7 billion in 2049. Up to 2050, €44 billion GVA is generated, about 19% higher than from just the pipeline of projects in Ireland.

Figure 43 shows a breakdown of export activity. 35% of this comes from development and project management services, 18% from tower manufacturing, 3% from floating foundation assembly, 30% from mooring line manufacture and 14% from operational phase supply. This shows only the value captured domestically from servicing foreign projects. It does not include supply to Irish projects.

Figure 44 shows a comparison of export benefits in 2030, 40 and 50, including export benefits from the operation of interconnectors and trade in hydrogen. It shows that total in-year export benefits rise to €4.3 billion in 2050. 76% of this is due to hydrogen export, 13% interconnector rent and 11% export of products and services.

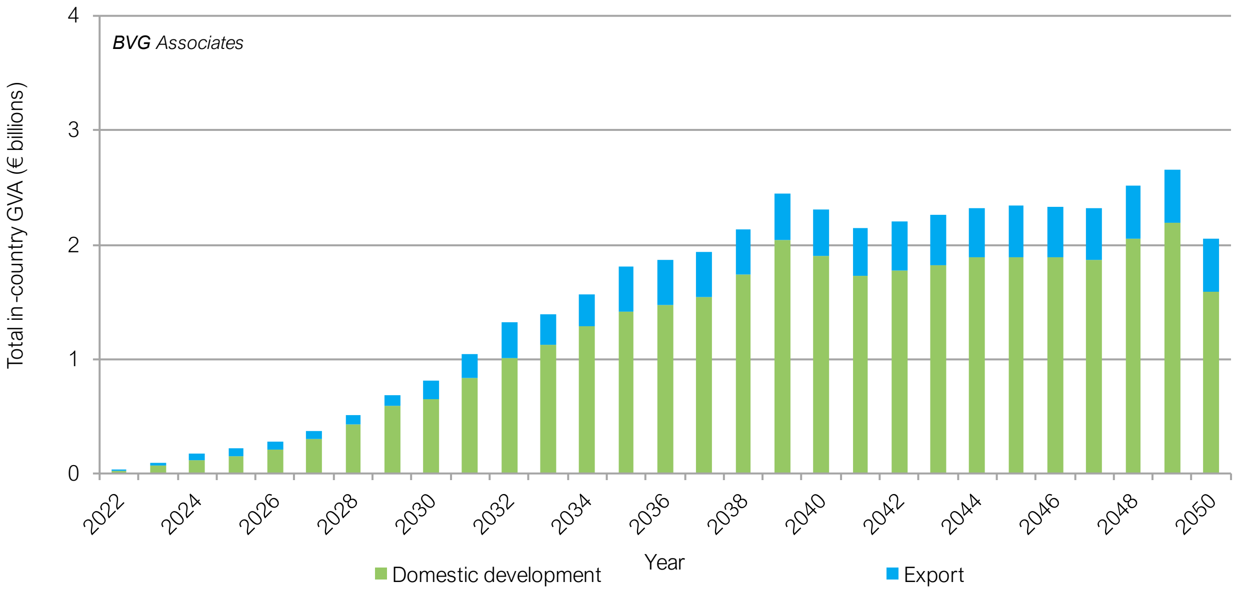

Figure 42 Annual local gross value added by Irish and overseas projects in the 37 GW stretch scenario, split by domestic and export spend.

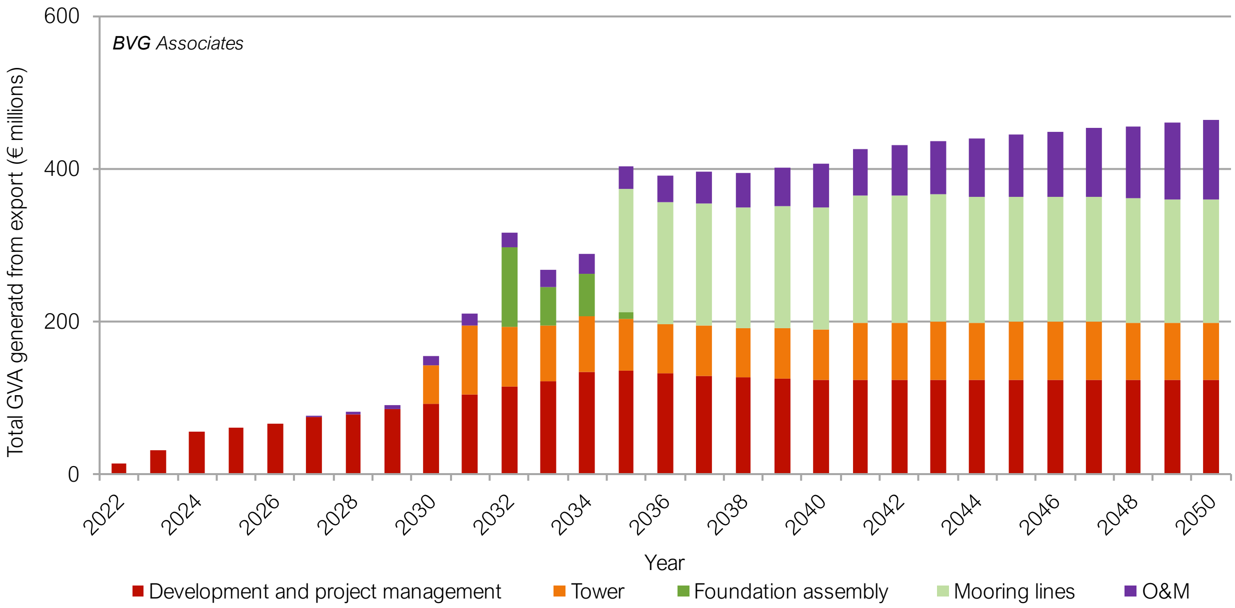

Figure 43 Annual local gross value added by overseas projects in the 37 GW stretch scenario, split by cost element.

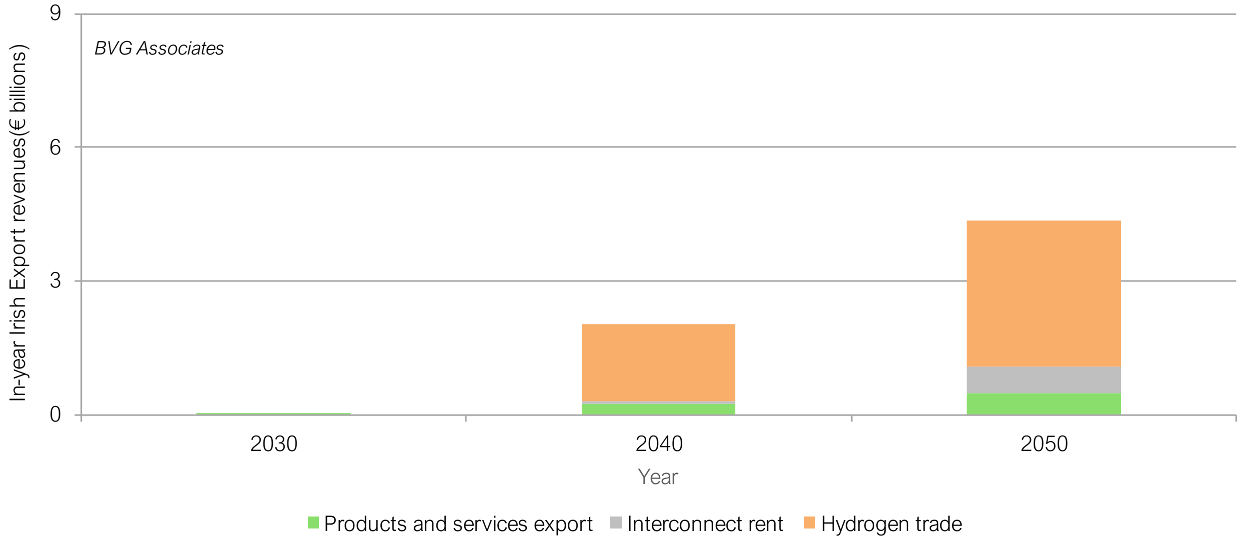

Figure 44 Total export opportunity, including electricity and hydrogen trade in the 37 GW stretch scenario, in 2030, 2040 and 2050.

50 GW stretch scenario

In the 50 GW stretch scenario, exports of products and services related to offshore wind, hydrogen and interconnection create an additional €10 billion in GVA in Ireland. Figure 45 shows annual GVA including exports reaching a peak of about €3.6 billion in 2048. Up to 2050, €62 billion GVA is generated, about 20% higher than from just the pipeline of projects in Ireland.

Figure 46 shows a breakdown of export activity. 44% of this comes from development and project management services, 12% from tower manufacturing, 28% from mooring line manufacture and 15% from operational phase supply. Ireland does not capture value from export of floating foundations as capacity is used to service the domestic pipeline. This shows only the value captured domestically from servicing foreign projects. It does not include supply to Irish projects.

Figure 47 shows a comparison of export benefits in 2030, 40 and 50, including export benefits from the operation of interconnectors and trade in hydrogen. It shows that total in-year export benefits rise to €8.9bn in 2050. 85% of this is due to hydrogen export, 8% interconnector rent and 7% export of products and services.

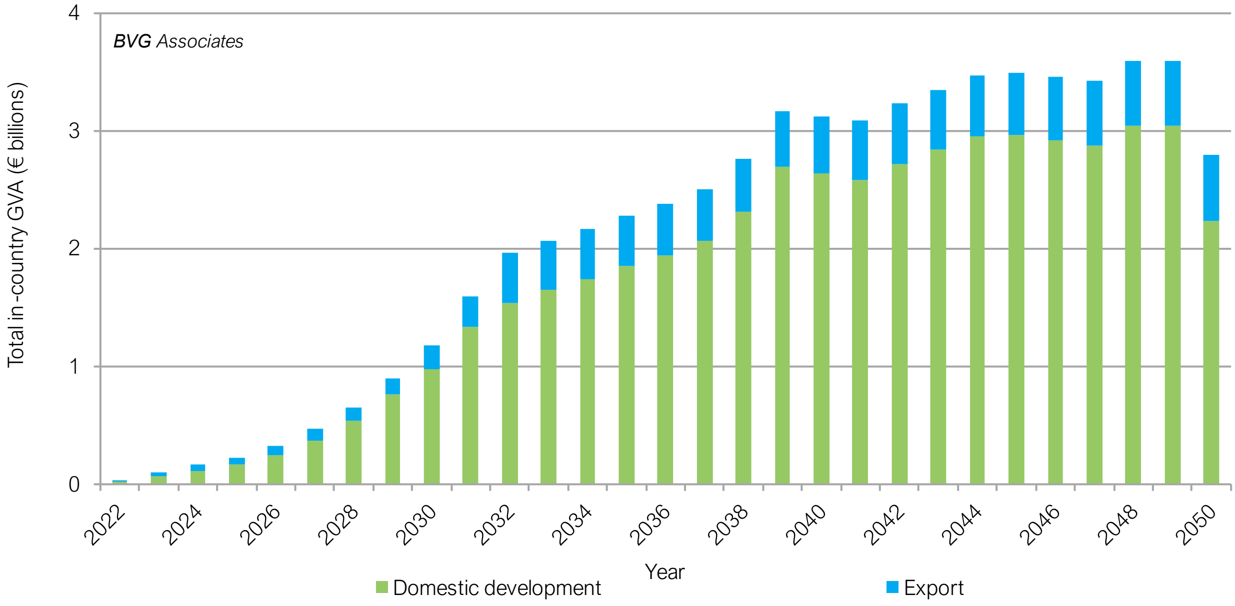

Figure 45 Annual local gross value added by Irish and overseas projects in the 50 GW stretch scenario, split by domestic and export spend.

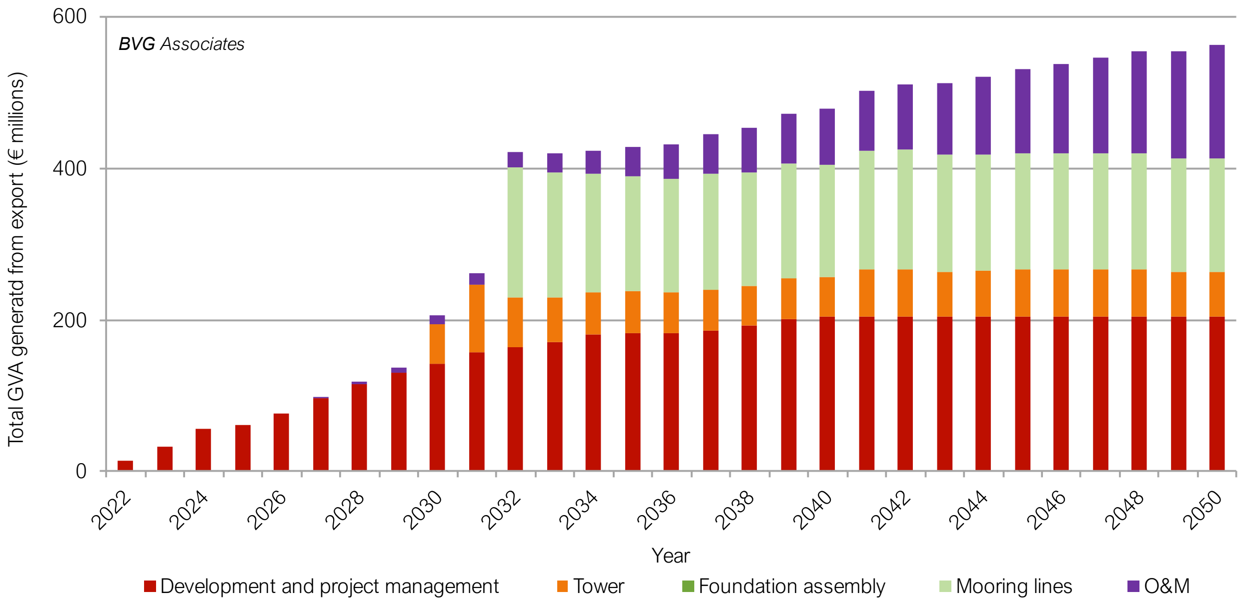

Figure 46 Annual local gross value added by overseas projects in the 50 GW stretch scenario, split by cost element.

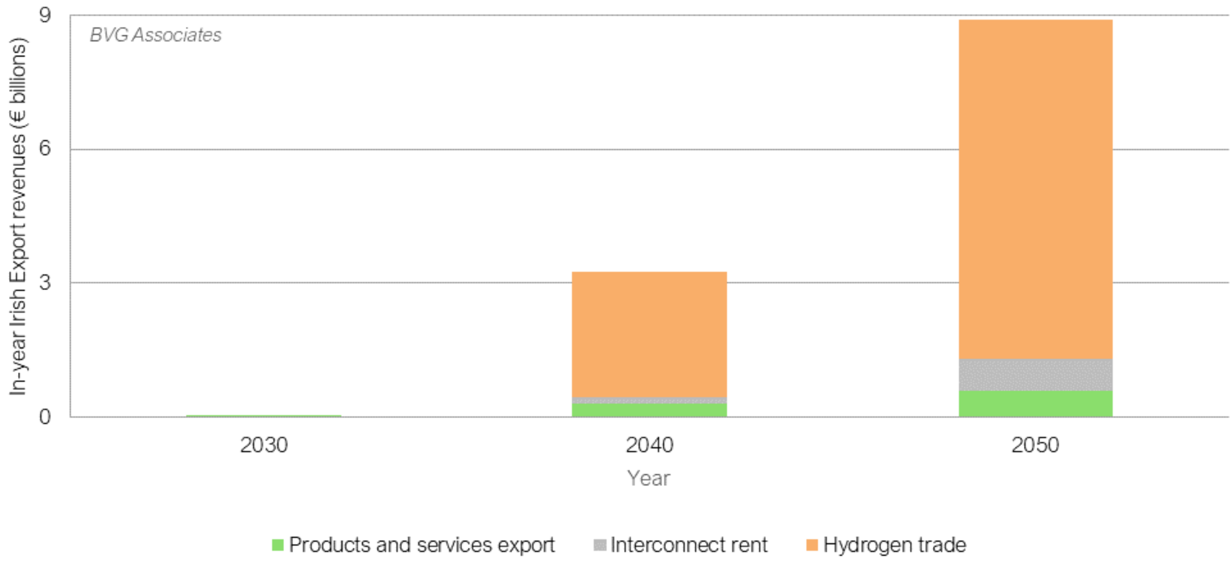

Figure 47 Total export opportunity, including electricity and hydrogen trade in the 50 GW stretch scenario, in 2030, 2040 and 2050.

Investment opportunities

This section considers the foreign direct investment (FDI) opportunities from investments especially in renewable energy projects.

Foreign direct investment opportunities

Large ORE projects typically involve syndicated investments by a range of international investors. The Irish market is likely to be financed through a majority of FDI. There are also opportunities for FDI in the Irish supply chain, as it strengthens to deliver local content of Irish projects and competes in the export market.

To estimate FDI, we derived overall investment figures from our domestic GVA analysis for each scenario, and estimated the investment opportunity associated with supply chain investments using evidence from existing facilities and their development plans.

We then applied an assumed ratio of 80% FDI to domestic investment across the total investment figures. This reflects Ireland's status as a developed country with a strong finance sector, well connected to international markets. It broadly reflects evidence of the domestic and foreign ownership split within the UK offshore wind sector, a comparable market.[8]

Project investment

Table 9 shows a comparison of FDI inflows for project CAPEX and OPEX expenditure, compared across the four scenarios. Total project FDI rises from €16.6 billion in the DNZ scenario to €76.8 billion in the 50 GW stretch scenario, an increase of over 5.5 times, in line with the increased investment in offshore wind, interconnection and hydrogen seen in this scenario.

Ireland already has a reputation as a good destination for FDI, as the most popular destination in the EU for FDI, on a per-capita basis.[9] It should build upon this reputation to capture the full extent of the FDI opportunity outlined in this report by signalling strategic intent to deploy these technologies through statements of ambition,

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[8] *Power to the People: The Case for a Publicly Owned Generation Company*, Common Wealth, 2022, available online at https://www.common-wealth.org/publications/power-to-the-people-the-case-for-a-publicly-owned-generation-company.

[9] *Foreign Direct Investment in Ireland,* New Zealand Foreign Affairs and Trade, June 2023. Available online at https://www.mfat.govt.nz/en/trade/mfat-market-reports/foreign-direct-investment-in-ireland-june-2023/.

backed up by bankable frameworks. This includes clear, timely and predictable frameworks for leasing, permitting, offtake and grid connection.

Table 9 Total foreign direct investment in project development across all technologies by scenario.

	DNZ	37 GW well-connected	37 GW stretch	50 GW stretch
Total project lifetime foreign direct investment (€ billion)	16.6	55.2	51.6	76.8

Supply chain investment

In Section 1.2.2, we identified a number of opportunities for Ireland to capture investment in facilities to increase local participation in projects. Table 10 shows our assumptions regarding overall investment figures for each one of these facilities, based on evidence from existing and planned facilities of a similar kind.

Table 11 shows the expected number of facilities Ireland will secure in each scenario. Facility FDI rises from around €500 million in the DNZ scenario to €1.2 billion in the 50 GW stretch scenario, an increase of around 2.5 times.

To secure this FDI as envisaged, the same considerations apply as outlined in above. In addition, in the context of a competitive international landscape in which many countries are seeking to secure such mobile investments, we recommend that the Government explore implementing investment incentives such as investment grants, tax incentives or preferential financing arrangements.

Table 10 Foreign direct investment in domestic supply chain facilities by type.

	Synthetic mooring lines factory	Tower factory	Fixed OSW construction port	Floating OSW construction or foundation assembly port
Total facility development cost (€ million)	25	200	120	300
Total foreign direct investment (€ million)	20	160	96	240

Table 11 Total foreign direct investment in domestic supply chain facilities by scenario.

	DNZ	37 GW scenarios	50 GW stretch
Number of mooring line factories	-	1	1
Number of Tower factories	1	1	1
Number of Fixed OSW construction ports	1	1	1
Number of Floating OSW construction or foundation assembly ports	1	3	4
Total foreign direct investment (€ million)	496	996	1,236

1.3. Policy and regulatory frameworks

1.3.1 Introduction

In this section, we address the current state of policy and regulatory frameworks in Ireland for:

- Offshore renewable energy deployment
- Hydrogen production, storage, transport and trade, and
- Interconnector deployment and cross border electricity trade.

For each of these three areas, we examine the comparable frameworks in key partner nations, and in the case of hydrogen and interconnection, opportunities for alignment to facilitate seamless trade. We then examine the implications of this for Ireland, and draw recommendations to inform Irish policy.

Our assessment of ORE frameworks also includes an assessment of the relative cost and benefits of two different plan-led regimes, a hybrid model and a fully integrated model.

1.3.2 Offshore renewable energy deployment frameworks

Irish frameworks

Ireland supports renewable energy projects though the Renewable Electricity Support Scheme (RESS). It is planned that offtake for phase 2 will be offered to developers in an auction format, with seabed rights in the form of MACs to be secured subsequently by winning bidders, though this remains subject to change for future phases.

The support mechanism is a two-way CfD, giving the developer security by earning a flat rate on the energy it produces. The rate is index linked up until the start of construction, using a formula which includes consideration of steel prices and the Harmonised Index of Consumer Prices (HICP), and during operation based on HICP. The length of support under ORESS 1 was 20 years.

DECC oversees RESS offtake auctions, with the state state-owned TSO EirGrid facilitating the process. EirGrid also acts as the contracting agency.

Ireland is moving to operate a one-competition model. In ORESS 2.1, it is expected that offtake contracts for a given location will be offered in a competitive auction, with developers then required to secure a seabed lease (Maritime Area Consent (MAC)) through a non-competitive process within a time limited period. Although still under consultation, it is planned that these two aspects will be administered by two different independent authorities (DECC and the Maritime Area Regulatory Authority (MARA)). It is expected that the competitive auction will be largely price-led, though certain other non-price criteria may also apply.

MACs are awarded by MARA having regard to specified criteria set out in the MAP Act.[10] For ORESS 2.1, DECC has set out its expectation that MACs will be awarded within 4 months of the conclusion of the ORESS auction.[11]

Once a developer has acquired a MAC, it must submit a planning application to An Bord Pleanála, Ireland's national independent planning body, to receive development consent. The developer is responsible for preparing a robust Environmental Impact Assessment Report (EIAR) to enable An Bord Pleanála to carry out an Environmental Impact Assessment (EIA).

In August 2023, the Commission for Regulatory Utilities (CRU) published the *Offshore Grid-Connection Pathway for Phase 2 Proposed Decision.*[12] This set out the CRU's intention to offer ORESS 2 projects priority access to

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[10] Government of Ireland, 'Maritime Area Planning Act 2021'. 2021 [Online]. Available at: https://www.irishstatutebook.ie/eli/2021/act/50/enacted/en/html.

[11] Government of Ireland, 'ORESS 2.1 Indicative Roadmap'. [Online]. Available at: https://www.gov.ie/pdf/?file=https://assets.gov.ie/277705/e8b1ddf7-7692-477c-a9ed-3c70dd27fe1e.pdf#page=null.

[12] CRU, 'Offshore Grid Connection Pathway – Phase 2'. 2023 [Online]. Available at: https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/Offshore-Grid-Connection-Pathway-for-Phase-2-Proposed-Decsion.pdf.

the grid, subject to a MAC, ORESS notice of CfD award and planning consent from An Bord Pleanála. The Proposed Decision did acknowledge that there may be Phase 2 projects that have a viable route to market other that ORESS but this needs further consideration, particularly given that ORESS 2 support will be a pre-requisite to obtaining a MAC.

The proposed structure for Phase 2 envisages EirGrid providing a grid feasibility scenario (GFS) for use by all potential bidders in the ORESS, to inform developers of likely grid connection solutions. The GFS has not yet been published for ORESS 2.1. Successful bidders will then be required to apply for a full grid connection offer (FCO). An applicant will be eligible for a FCO where they hold a MAC, planning permission for the associated development and an ORESS Notice of Award.

International comparators

This section examines examples of best practice in ORE deployment frameworks from marine spatial planning, leasing and revenue support and permitting across a number of comparator countries. These countries have been chosen either because they are recognised leaders in offshore wind deployment, or, in the case of the USA, because of the important role it is likely to play in the future of the global industry.

These best practice examples are intended to inform Ireland's approach to ORE deployment. Unlike within hydrogen and Interconnection, regulatory alignment with trading partners is not a key issue, as frameworks are domestically focussed. It is important, however, that Irish frameworks deliver cost effective ORE through good competition, not burdened with excessive restriction or risk.

Great Britain

Marine spatial planning

Marine spatial planning within Great Britain is managed separately by England, Wales and Scotland for their area of the UK Exclusive Economic Zone (EEZ). For England and Wales, The Marine Management Organisation is responsible for marine spatial planning in England with six regional marine spatial plans published between 2014 and 2021 that provide a complete marine planning framework for England. Welsh Ministers are responsible for Welsh marine spatial planning, publishing the first National Marine Plan in 2019 to provide a complete marine planning framework for Wales.

To identify lease areas the Crown Estate uses technical and constraint data from the marine planning frameworks for England and Wales and stakeholder engagements to identify lease areas through the following process:

- Technical resource modelling is undertaken to define the most favourable areas for OSW development based upon water depth, wave conditions and geology.
- Exclusion modelling removes areas where development would not be possible because of environmental reasons, existing infrastructure, health and safety reasons or existing sea bed rights.
- Restriction modelling identifies where development might be constrained, but not precluded, by variables such as environmental designations, fishing and viewshed.

For Scotland, Marine Scotland is responsible for marine spatial planning publishing Scotland's National Marine Plan in 2015. Marine Scotland uses technical and constraint data from the Scotland's National Marine Plan and stakeholder engagement to identify lease areas in the Sectoral Marine Plan for Offshore Wind Energy. It uses the following process to identify lease areas:

- Iterative opportunity and constraint analysis is carried out to identify potential lease areas.
- A Sustainability Appraisal consisting of a Strategic Environmental Assessment (SEA), Habitats Regulations Appraisal (HRA) and Environmental and Social Impact Assessment (ESIA) is carried out to assess the impacts of the potential lease areas.
- Stakeholder consultation is undertaken to ensure the views of statutory and non-statutory stakeholders inform that lease area identification.

- The results of the previous stages identify lease areas that the Crown Estate Scotland will offer through the seabed leasing process.

Leasing and revenue support

Great Britain operates a two-competition system in which seabed leases and revenue support are awarded separately. The Crown Estate and Crown Estate Scotland own the development rights for the UK EEZ and are responsible for managing the seabed leasing process offering Agreements for Lease (England and Wales) or Option Agreements (Scotland) through competitive auctions known as leasing rounds. Both agreements set out the terms on which the Crown Estate/Crown Estate Scotland will grant a lease if the developer succeeds in obtaining all the necessary consents giving the developer seabed rights for 60 years. Once the agreement has been signed, the developer must meet certain milestones. Failure to meet a milestone by the deadline will give Crown Estate Scotland the right to reduce the option period or Crown Estate the right to terminate the Agreement for Lease.

Great Britain offers a two-way Contract for Difference (CfD) as a revenue support mechanism managed by the Department for Energy Security and Net Zero (DESNZ). Under the two-way CfD, the developer sells electricity into the wholesale market. Through the CfD mechanism, the LCCC pays the developer the difference between the wholesale electricity price and bid price if the wholesale price is lower than the bid price and the developer pays the LCCC the difference between the wholesale electricity price and bid price if the wholesale price is higher than the bid price. The CfD gives the developer revenue support for 15 years.

Permitting

Permitting is carried out separately in England and Wales and in Scotland.

- In England and Wales, the Planning Inspectorate (PINS) sponsored by the department for Levelling Up, Housing and Communities acts as a one stop shop for permitting with the primary permit needed being a Development Consent Order which includes a number of onshore and offshore consents.
- In Scotland, Marine Scotland is responsible for managing the permitting process for the offshore assets of the wind farm. The primary permits are a Section 36 consent to construct and operate an electricity generation station and a marine licence.

Denmark

Marine spatial planning

The Danish Maritime Authority is responsible for marine spatial planning in Danish waters. Denmark launched its Maritime Spatial Plan in March 2021, which covers the entire Danish marine area establishing which zones can be used for offshore wind. A developer can either bid to develop within one of these offshore wind zones through a tender process or propose a potential site outside of the zone for offshore wind development through the open-door process.

Leasing and revenue support

- Denmark is a one-competition model whereby through either of these processes the leasing and offtake agreement are awarded simultaneously.
- Most new offshore wind farms are developed through the tender procedure led by the Danish Energy Agency (DEA), a Danish Government agency responsible for the national energy industries and Denmark's carbon reduction efforts, where developers bid for a specific site with a defined capacity. Within this system the majority of site surveys are undertaken by the national transmission system operator (TSO) Energinet prior to the tender. The developers bid based on a two-way CfD agreement guaranteeing the developer a fixed price per kWh of energy generated for a period of about 12 years (depending on total generation).
- Until recently, developers have also had the opportunity to develop an offshore wind farm through the open-door procedure led by the developer who can propose to the DEA the location and capacity of potential sites. Through this system the developer undertakes all surveys and is awarded a predetermined fixed

electricity price premium on top of the wholesale price. This procedure is currently on hold due to a rapid increase in demand and challenge about competitiveness from the European Commission.

- The most recently completed auction for the Thor offshore wind farm, launched in March 2020, addressed the challenge of competition in an environment where no subsidy was needed:
- Applications for prequalification were submitted and six developers were confirmed to have prequalified to participate in the auction.
- Developers then bid a price premium that they would receive through the CfD mechanism with multiple developers bidding the equivalent of €1.3/MWh which was the lowest allowable bid. The winner (RWE) was then decided by a lottery and a concession agreement including the seabed lease was awarded.
- Effectively, the developer will pay an upfront sum of €375 million over the first few years of operation to then sell power however it wants for the remaining life. This is because it will pay the Government the difference between the average annual electricity price from the previous year (likely to be about €40/MWh) and its bid (€1.3/MWh) until a spend cap of the equivalent of €375 million is reached. After this there are no financial transactions between the developer and the state, and the developer will secure commercial terms for the ongoing operation of the wind farm.

Permitting

The permitting process in Denmark is run by the DEA acting as a one stop shop for permitting with four licences needed to establish an offshore wind farm:

- A preliminary investigation licence giving developers permission to undertake preliminary investigations, valid for one year,
- A construction license to construct the offshore wind farm,
- A wind power exploitation license giving the developer the right to produce electricity from wind.
- An electricity production license required for all electricity generation assets greater than 25MW capacity.

Germany

Marine spatial planning

The Federal Ministry of the Interior and Community (Bunderministerium des Innern und für Heimat (BMI)) is responsible for marine spatial planning for the German Exclusive Economic Zone (EEZ). In practice, Federal Maritime and Hydrographic Agency (Bunderamt für Seeschifffahrt und Hydrographie (BSH)) prepares marine spatial plans on behalf of BMI.

BSH is responsible for the site development plan (Flächenentwicklungsplan (FEP)). The FEP is based on the marine spatial plans, stakeholder engagement and a Strategic Environmental Assessment. BSH is responsible for carrying out preliminary site surveys for the project sites defined in the FEP.

The FEP defines:

- The areas for OSW development and project sites within these areas that will be auctioned
- The timeline over which sites will be auctioned
- The expected capacity of the sites
- The year of commissioning for projects, and
- The location of export system infrastructure.

Leasing and revenue support (post 2022)

In 2023, legislative changes were made to the offshore wind tender process to allow site which have not been pre-surveyed to be tendered. The central model introduced in 2017 sought to accelerate the development of offshore wind deployment and the grid connection system by bringing marine spatial planning and pre-investigation of potential sites under the responsibility of the state. The state recognised that it did not have the adequate resource to carry out site investigations for all sites needed to meet the country's increased offshore wind target. Germany therefore currently operates two models in parallel:

- For pre-surveyed sites, exclusivity through a one-off payment auction, also with 40% non-price criteria. The winning bidder then progresses development and secures a subsidy-free corporate PPA.
- For non-pre-surveyed sites, exclusivity through a per MWh premium-only auction

BNetzA is the responsible organisation for managing the competitive process.

BNetzA offers developers opportunities to secure offtake agreements, grid connection agreements, and the exclusive right to undertake the procedure to secure planning approval for the tendered site through the competitive auctions. If the developer receives planning approval, it is granted sea bed rights for 25 years (extendable by five years).

Once the contract has been signed following the auction, the developer must meet milestones to ensure the project is on schedule. Failure to meet a milestone will result in the developer paying a financial penalty to the TSO. In the event that certain milestones are missed, BNetzA has the right to terminate the contract.

Permitting

BSH is responsible for managing the permitting process, and acts as a one-stop-shop. The key permit is the planning approval (Planfeststellungsbeschluss) which included a number of onshore and offshore consents. In principle, all required public permits are concentrated in and granted by the planning approval.

Netherlands

Marine spatial planning

Marine spatial planning in the Netherlands is based on the National Water Plan the legal basis of which is the Water Act. The Ministry of Economic Affairs and Climate (MEAC) is responsible for allocating offshore wind zones in Dutch territorial waters with potential sites outlined in Offshore Wind Energy Roadmaps providing a schedule for site development, projected site capacity and year of installation and operation. Potential sites are subject to environmental and social impact assessments and site surveys before the MEAC designates them OSW sites. The National Enterprise Agency (RVO) on behalf of the government carries out the ESIA, site surveys and coordinates the auction process. Previously the Government has paid for the ESIAs and site surveys but in the upcoming auction rounds the winning bidder will reimburse the Government for these costs.

Leasing and revenue support

After a potential site has been designated as an OSW site, it is awarded by the Minister of Economic Affairs and Climate Policy to a developer through an a one-competition process which includes the seabed lease for a maximum of 40 years, grid connection and revenue support, based on detailed surveys and provisional permits.

The tender process ranks bidders against evaluation criteria with non-price criteria used extensively within the last auction emphasizing ecology and system integration. There are two tender models used: subsidy free tender and tender with subsidy.

- The subsidy free tender process runs first with the developer with the best feasibility offer awarded the permit – criteria can vary but in recent times have been related to deliverability, energy production, ecology and system integration. Although no subsidy is involved a financial offer for the permit may be considered consisting of a one-off payment paid to RVO by the developer for the right to develop the OSW farm. The financial offer can make up as much as 10% of the scoring for the evaluation criteria.
- If the subsidy free tender does not result in a winning bid a tender with subsidy process is initiated. The permit and associated subsidy are awarded to the party that tenders the lowest per MWh subsidy amount. The stimulation of Sustainable Energy Production Scheme (SDE) forms the basis for the subsidy operating as a one-way contract for difference scheme meaning RVO will pay producers the difference between the wholesale electricity price and the bid price if the wholesale price is lower than the bid price. The subsidy is granted for a maximum of 15 years.

Permitting

After the ESIA and site surveys have taken place, MEAC publish the Wind Farm Site Decision (WFSD). The WFSD is the cornerstone of the Dutch Law Wind Energy at Sea. This law stipulates that offshore wind farms can only be built after a permit, based on the WFSC, has been issued. A WFSD is, therefore, the necessary consent required to build a wind farm. It specifies the location for the wind farm and the conditions under which it may be constructed and operated. These conditions can be related to project design, including minimum power, maximum tip height, minimum tip height and wind farm site boundaries. The WFSD, however, leaves some flexibility for the design of the wind farm. This means that project developers can choose the latest technical innovations to develop and operate the wind farm at the lowest possible cost.

USA

Marine spatial planning

The Bureau of Ocean Energy Management (BOEM) is responsible for allocating areas for future OSW development in federal waters of the Outer Continental Shelf (OCS). The OCS is defined as the sea bed area between the seaward extent of the states' jurisdiction and the seaward extend of federal jurisdiction. BOEM identifies suitable areas for OSW leasing through collaborative, consultative and analytical processes that engage stakeholders and state and federal government agencies.

BOEM is responsible for conducting an Environmental Assessment (EA). The EA considers the potential impacts of the proposed development on the environment and suggests alternatives or mitigations that may reduce or eliminate these impacts. The EA also addresses subsea cable corridors associated with potential lease areas.

Leasing and revenue support

Leasing in managed nationally by BOEM via competitions, then each state runs a separate competition for revenue support.

Lease auctions offer developers opportunities to secure commercial leases. A commercial lease gives the developer the exclusive right to subsequently seek BOEM approval for the development of the leasehold. Once all required permitting and surveys have been completed, the commercial lease grants an operations term of 25 years.

To begin the lease auction process, BOEM publishes the Proposed Sale Notice (PSN) which provides detailed information about potential WEAs, lease conditions and the auction process.

Revenue support competitions vary between states. A good example is in New York State where New York State Energy Research and Development Authority (NYSERDA) allocates Offshore Renewable Energy Certificate (OREC) contracts through competitive auctions known as solicitations. In the 2019 and 2020 solicitations, an evaluation committee scored bids, with 70% of the marks awarded for their price per MWh, 20% for the local economic benefit offered and 10% for the project viability. The applicant with the highest aggregate score is awarded the OREC contract.

Permitting

In the US, a developer must submit a Construction and Operation Plan (COP) to BOEM following the award of a commercial lease. The COP describes how the developer will construct and operate the project, and it supported by stakeholder engagement carried out by the developer. The Project Design Envelope (PDE) (based on the Rochdale Envelope used in the UK) approach is used to grant the developer a degree of flexibility because some project details may not have been finalised when submitting a COP. Once a COP has been deemed complete and sufficient, BOEM undertakes a two-year review and approval process. Once the COP has been approved or approved with modification, the developer must submit a Facility Design Report (FDR), detailing the design of all the major components of the project, and a Fabrication and Installation Report (FIR), describes the fabrication and installation plans of the equipment. A no objection determination on the FDR and FIR from BOEM is needed for the developer to begin project construction. There are several other Federal and State permits that are required for offshore wind projects.

Comparative analysis of plan-led regimes

Ireland is currently moving from a developer-led to a plan-led regime for ORE development, whereby the state rather than a developer identifies a project site for development.

Advantages of a plan led regime

The advantages of a plan-led regime are:

- It facilitates strategic planning of generation and grid assets and shared use of transmission infrastructure. This allows the state greater strategic control of the future energy mix.
- Strategic offshore transmission planning allows the sharing of assets, delivering efficiency in offshore connection assets and preventing wasted effort through developers planning multiple grid connection scenarios.
- The baseline data gathered in initial surveys both can inform spatial planning, sensitivity mapping, and site selection to reduce environmental and social risks to individual projects. This can reduce the lead-in time for individual projects, reduce mitigation costs, and facilitate access to international finance.

The disadvantages are:

- The state takes on greater risk in the project development process. There is greater risk that misalignment between state and industry can lead to negative outcomes.
- The increased responsibilities of the state in a plan-led model are associated with increased resourcing needs and administrative costs. If resourcing is not sufficient, state agencies can become a bottleneck, slowing deployment and impacting investor confidence. Currently, employing suitable resources in competition with developers in a supply-limited jobs market, is a significant challenge.
- Developers may see the market as less attractive as a lack of control over project locations makes it harder to develop a continuous project pipeline.

Different models of plan led regime

We have considered the relative benefits of pursing two different models of a plan-led regime, as defined in the recent report for DECC, *Deliverable 2: Options for Plan-led ORE Regime:*[13]

- A hybrid model, and
- A fully integrated model.

Hybrid model

With the hybrid model, the Irish Government prepares DMAPs, selects sites and undertakes detailed preliminary environmental and geotechnical surveys, making this data available to developers to inform bidding in ORESS auctions, which it designs and operates. Responsibility for transmission planning falls to EirGrid, which is responsible for capacity planning, offshore and onshore substations, collector hubs (where more than one project is present in the area) and export cables. The successful developer then has responsibility for undertaking supplementary surveys, designing the project, securing the necessary permits from relevant bodies then constructing the project. The developer is responsible for the array cabling between turbines and the wind farm offshore substation. This approach is similar to the German model, for pre-surveyed sites, except that:

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[13] *Deliverable 2: Options for Plan-led ORE Regime,* AARC and MacCabe Durney Barnes on behalf of DECC, September 2023. Not available online.

- In Germany, the developer is responsible for the wind farm offshore substation. The TSO is responsible for the export cable and any offshore DC converter station, which can act as a hub where multiple projects are co-located.[14]

It is also similar to the approach in the Netherlands, where:

- The Netherland Government only carries out preliminary design and permitting
- The Netherlands TSO is responsible for the wind farm offshore substation and export system beyond that, but is not responsible for the wind farm array cables, and
- The developer that wins the auction completes the design considering its supply chain choices and using its expertise and optimisation processes, then seeks final permits.

Fully integrated model

With the fully integrated model, the Irish Government takes responsibility as described for the hybrid model and for wind farm design and permitting. EirGrid takes responsibility as described for the hybrid model and for design, supply and installation of array cables. The fully integrated model as proposed in *Deliverable 2: Options for Plan-led ORE Regime* entails a role for the state in the wind farm's design, permitting and array cabling that goes beyond anything which has successfully been employed in other markets. This approach more state-focussed than in any other existing offshore wind market.

Comparative analysis of hybrid and fully integrated models

Table 12 shows the relative advantages and disadvantages of the hybrid and full integrated models. Although the fully integrated model could in theory lead to lower strike prices relative to the hybrid, through reducing permitting cost to developers, there is little evidence to substantiate this.[15, 16] Under any model, some residual cost will remain in these spend categories, and coupled with the increased cost to the state of delivering the additional responsibilities associated with the fully integrated model, any benefit to Irish consumers is likely to be negligible when also considering differences in developer uncertainty at the bidding stage. Development and consenting costs make up a small proportion of overall project spend, so any savings are likely to be limited. Missing from the analysis in *Deliverable 2: Options for Plan-led ORE Regime* is the developer viewpoint, critical for accessing industry expertise and competitive financing.

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[14] A variety of different approaches have been employed in Germany to date. By 'German model' we refer to the so-called 'centralised model' which applies to projects becoming operational from 2026 onwards, as discussed in Bastian et al., *Offshore Wind in Germany: Status Quo and Prospects*, Adelphi, October 2022, available online at https://adelphi.de/en/publications/offshore-wind-in-germany.

[15] Michelle Lewis, The Netherlands just launched a mega 1.5 GW offshore wind farm', Electrek, 29 September 2023, available online at https://electrek.co/2023/09/29/netherlands-mega-1-5-gw-offshore-wind-farm/.

[16] Alex Blackburn and Camilla Nashert, 'Germany's He Dreiht forges blueprint for subsidy-free offshore wind', S&P Global, 4 April 2023, available online at https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/germany-s-he-dreiht-forges-blueprint-for-subsidy-free-offshore-wind-74917864.

Table 12 Advantages and disadvantages of hybrid and fully integrated models.

Advantages of hybrid model (compared to fully integrated model)	Advantages of fully integrated model (compared to fully integrated model)
• Developer responsibility for project design and permitting puts less cost, risk and resource requirement on the state. • As the state has fewer responsibilities, there is less risk that the state becomes a bottleneck to deployment, especially in more ambitious scenarios. • Making a developer responsible for project design and permitting ensures its commercial expertise can be used, promoting efficient delivery and taking benefit of its supply chain relationships to deliver lower LCOE, hence lower bid prices. • Industry has positive experience of such models in other markets and has learnt how to deliver effectively under them, as long as industry has confidence in the quality of survey and other data provided by the state.	• There are opportunities for efficiency gains in the permitting process through close collaboration and building strong relationships between government agencies involved.
Disadvantages of hybrid model	**Disadvantages of fully integrated model**
• Still needs significantly more state resource than developer-led regime. Adequate resourcing is a challenge, as demonstrated by the German experience.	• Unless permits leave room for project design flexibility, then developers may be limited to non-optimal solutions, adding cost and risk. • One state actor seeking permitting approval from another introduces potential conflicts of interest. • It is unclear how the state can deliver detailed designs without making supply chain choices on behalf of the winning developer, introducing increased cost and risk to developer. Optimised array cable design depends on turbine choice. • Developers are likely to prefer to hold responsibility for their own array cable designs and installation, reducing interfaces with state activities. • The fully inclusive model is not used elsewhere, introducing new uncertainties and risks to industry, especially for early projects where it knows the Irish Government is inexperienced.

Implications for Ireland

The extension of the state's responsibility to full project design, permitting and delivery of array cables is likely to yield little value. It is more likely to lead to inefficiencies in design and delivery, and make Ireland a less attractive market for investment due to the additional project risk and complexities it introduces. The body of international best practice examined in Section 1.3.2 demonstrates that it is better to leave detailed wind farm design and array cables to industry. This is what industry is comfortable with and experienced in delivering.

Under a plan-led regime, it is critical that relevant state bodies are properly resourced and hold the right expertise to take on technical tasks such as site surveys, project design and permitting, and deliver them in a timely manner.

If pursuing either model, we recommend that:

1. DECC carries out significant industry consultation, especially before any choice for the fully integrated model is finalised.
2. DECC and EirGrid ensure that good international industry practice (GIIP) is followed regarding industry consultation and collaboration in the development of specifications for baseline environmental surveys, geotechnical and geophysical surveys, transmission network and export system planning and reporting to ensure that outputs meet developer needs and avoid duplication of effort or rejection of opportunities.
3. DECC, EirGrid and MARA ensure that they have appropriate resources and expertise to deliver the required pipeline of projects to hit deployment targets. This resourcing need will increase in higher deployment scenarios, and in the fully integrated model relative to the hybrid.
4. DECC ensures that long term clarity and stability of frameworks is assured to facilitate investor confidence.

If pursuing the hybrid model, we recommend that:

5. DECC implements a one-to-shop approach to permitting, which has been shown to ease communication, simplify and accelerate the permitting process in other markets.

If pursuing the fully integrated model, we recommend that:

6. DECC modifies the proposed regime so that TSO responsibility ends at the wind farm substation, while the developer retains responsibility for array cable design and installation.
7. DECC ensures that project designs developed centrally leave some flexibility in final design, as in the Netherlands' WFSD. As in the Netherlands model, this should involve some final permitting for the developer to undertake to validate design choices.

1.3.3 Hydrogen frameworks

In this section, we examine current Irish policy frameworks governing hydrogen production, storage, transport trade and usage.

We then examine the policy environments in key potential export markets. Depending on transport costs via pipelines and vessels, the market for hydrogen could be relatively localised or truly global. In line with our finding that Irish hydrogen is more likely to be internationally competitive using a pipeline distribution model, we focus on key nearby partner markets, but also look at the USA as an example of a significant, more distant trade partner.

Finally, we draw conclusions for Ireland, including recommendations for government.

Irish frameworks

In July 2023, the Government of Ireland released its *National Hydrogen Strategy* which detailed the approach Ireland will take to develop a hydrogen economy.[17] This is a key part of the *Energy Security in Ireland to 2030* plan which outlines Ireland's strategy to ensure energy security this decade, while transitioning to a sustainable

[17] DECC, *National Hydrogen Strategy,* July 2023, https://www.gov.ie/en/publication/624ab-national-hydrogen-strategy/. Last accessed December 2023.

carbon neutral energy system by 2050.[18] Both strategies are aligned with the EU's hydrogen strategy and regulations.[19]

The *National Hydrogen Strategy* aims to provide the long-term strategic vision of what role hydrogen will play in Ireland's future economy. It defines actions to remove barriers, such as gaps in the policy landscape, which could inhibit early hydrogen projects from progressing and to develop the sector through targeted research and innovation across the value chain. This includes development of hydrogen safety standards in line with EU standards.

Ireland is targeting green hydrogen which will be produced via grid connected electrolysis from surplus renewable energy supply. As stated in the *National Hydrogen Strategy*, Ireland aims to see 2 GW of offshore wind capacity dedicated to hydrogen production in development by 2030. Beyond this, any excess renewable energy for hydrogen production is expected to be exported in the near term.

The deployment of renewable hydrogen in Ireland will focus on hard-to-decarbonise sectors where energy efficiency and direct electrification are not feasible or cost-effective solutions. Beyond heavy duty transport and flexible power, hydrogen usage in aviation and maritime are expected to be the next big growth sectors for hydrogen use. Ireland expects that domestic demand will be between 45 and 39 TWh by 2050. By including aviation and shipping this could rise to between 20 and 75 TWh.

Outside of the *National Hydrogen Strategy*, there are no further detailed hydrogen specific plans for Ireland. It is expected that further policy announcements will be made, outlining the actions that must be taken to address hydrogen transport and storage. This is likely to include the use of the Southwest Kinsale reservoir for storage and reusing existing offshore infrastructure for transport given the difficulty in getting onshore landings approved. In addition, a study is set to be published on repurposing the gas grid for hydrogen transportation, if decommissioned.

Target market considerations

Great Britain

In 2021, the UK published the *UK Hydrogen Strategy*.[20] The strategy committed to providing annual updates. As outlined in the 2023 strategy update, the UK aims to deliver up to 10 GW of low carbon hydrogen production capacity by 2030.[21] The strategy update summarises funding support and hydrogen policy developments. It also details progress in designing new support mechanisms, such as transport and storage business models, moving forward with negotiations with hydrogen projects across both CCUS and electrolytic allocation, and developing wider policy and market frameworks across the hydrogen value chain.

The UK aims to become self-sufficient in terms of hydrogen supply, without the need for imports. This may be achievable, especially with its own large offshore wind resource, but will likely not apply to Northern Ireland because the funding for low-carbon projects, including hydrogen production, will be directed at industrial clusters in England, Scotland and Wales.

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[18] DECC, *Energy Security in Ireland to 2030*, November 2023, https://www.gov.ie/en/publication/5c499-energy-security-in-ireland-to-2030/, last accessed December 2023.

[19] *Energy systems integration: Hydrogen,* European Commission, available online at https://energy.ec.europa.eu/topics/energy-systems-integration/hydrogen_en

[20] *UK Hydrogen Strategy*, Secretary of State for Business, Energy & Industrial Strategy for HM Government, August 2021, available online at https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1175494/UK-Hydrogen-Strategy_web.pdf

[21] *Hydrogen Strategy Update to the Market: August 2023*, Department for Energy Security & Net Zero, August 2023, available online at https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1179651/hydrogen-strategy-update-to-the-market-august-2023.pdf

It is unclear whether the UK will implement hydrogen standards that align with EU standards from the start, but it is expected that over time there will be global alignment on hydrogen standards (or agreed rules to facilitate alignment) to ensure a global market develops. This is expected around 2040. By this time, it is likely that the network would allow hydrogen produced in Ireland to be transported to the UK and Europe via pipeline.

Although implementation has been slow, the UK is recognised as a good example of supportive hydrogen policies. The UK has developed a standard business model for production transport and storage, a certification scheme and has run various competitions to increase hydrogen demand. EU policy has drawn on the UK's experience but is developing its own regulation and policy.

Germany

In 2020, the Federal Cabinet approved a *National Hydrogen Strategy* for Germany.[22] The *National Hydrogen Strategy* sets out a target vision for the use of hydrogen in Germany from 2030, outlines the Federal Government's support measures and sets out state guidelines for the production, transport and use of hydrogen and its derivatives in all sectors. It also describes the development of a hydrogen infrastructure, including a hydrogen network comprising more than 1,800 km of new and converted pipelines to be built in Germany by 2028. The strategy lists short-term measures for 2023, medium-term measures for 2025 and long-term measures to be completed by 2030. The supply of hydrogen is important in terms of Germany's goal of achieving climate neutrality by 2045.

Germany is leading the way on developing frameworks and policy that enables imports of hydrogen and the transition of heavy industry to hydrogen. There is an opportunity for Ireland to influence the EU's regulatory frameworks before they are finalised through bi-lateral agreements with Germany. Ireland's influence is potentially limited by its relative geographic position within the EU, since Germany's neighbours likely to have greater influence on import policy and regulation.

The EU

In 2020, the EU adopted *A Hydrogen Strategy for a Climate- neutral Europe.*[23] The strategy outlined policy action points in five areas: investment support; support production and demand; creating a hydrogen market and infrastructure; research and cooperation and international cooperation.

The EU has recognised that it will need to support hydrogen and is developing a series of frameworks that incentivise its use. In the meantime, it has focussed more on push factors through tightening of existing policy and targets as part of RePower EU, Fit for 55, REDIII and other initiatives.[24,25,26] This will create an initial demand for hydrogen in each member state which will drive international trade. Imports have not been the focus but as previously mentioned individual states, such as Germany, are developing plans for imports to meet its targets whilst others such as the Netherlands and Norway plan on being exporters.

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[22] *The Federal Government*, The National Hydrogen Strategy, available online at https://www.bmwk.de/Navigation/EN/hydrogen/national-hydrogen-strategy.html

[23] *A hydrogen strategy for a climate-neutral Europe*, European Commission, July 2020, available online at https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0301

[24] REPowerEU, *European Commission*, available online at https://commission.europa.eu/strategy-and-policy/priorities-2019-2024/european-green-deal/repowereu-affordable-secure-and-sustainable-energy-europe_en

[25] Fit for 55, *European Council*, available online at https://www.consilium.europa.eu/en/policies/green-deal/fit-for-55-the-eu-plan-for-a-green-transition/

[26] Renewable Energy Directive (RED II), *European Parliament*, available online at https://www.europarl.europa.eu/committees/en/renewable-energy-directive-red-ii-/product-details/20220214CDT09123

The USA

In 2023, the U.S. Department of Energy released the *U.S. National Clean Hydrogen Strategy and Roadmap*.[27] This provides an overview of hydrogen productions, transport, storage and use in the USA, and outlines a strategic framework for achieving large-scale production. The roadmap was delivered in response to the Infrastructure Investment and Jobs Act (Public Law 117-58), also known as the Bipartisan Infrastructure Law (BIL) which was passed in 2021. It legislated a roadmap be developer and updated every three years. The BIP also committed to investing in the following initiatives:

- US$1 billion for a clean hydrogen electrolysis program, improving the efficiency and cost-effectiveness of electrolysis technology through funded research and development
- US$500 million for clean hydrogen manufacturing and recycling research and development activities, supporting the manufacturing of clean hydrogen equipment
- US$8 billion for regional clean hydrogen hubs, aiming to create networks of hydrogen producers, consumers and transport and storage infrastructure, and
- The development of a clean hydrogen production standard.

In addition to the BIL provisions above, the Inflation Reduction Act, signed into law in August 2022, provides a Hydrogen Production Tax Credit (PTC) that will further incentivise the production of clean hydrogen in the U.S. IRA also supports the development of demand sectors for clean hydrogen through additional programs.

Implications for Ireland

It is critical for ORE that Ireland continues to implement the long-term strategic vision set out in the National Hydrogen Strategy to build confidence within the market. Ireland has a small demand for hydrogen in relation to its potential so it is important that Government continues to define how hydrogen will be used domestically and exported internationally. Given hydrogen projects have long lead times and require large-scale investment, long-term supportive policies will help investor confidence. Ireland will need to consider the price of imported energy, such as hydrogen or ammonia, when considering their viability as exporters and/or importers.

The production of hydrogen through to its end use has the potential to create significant job opportunities. Policies should be used to ensure Ireland secures the economic benefits that come with industry growth. Encouragement of local supply chain content, which conform to EU rules, could be a suitable vehicle for achieving such policy aims, by requiring services and products to come from Ireland. This could, however, increase the costs of projects and slow the growth of the market so careful consideration should be given to balancing low cost production and local economic benefits.

It is important that Ireland implements clear and robust legislation with regard to hydrogen standards so that it can be sold internationally. It is expected that Ireland will follow EU standards, however, there may be advantages in implementing further national standards if there are economic benefits.

In summary, we recommend:

1. DECC brings forward an updated regulatory regime for hydrogen, aligned with international efforts at an EU level and building on the UK's example, to facilitate seamless trade.
2. DECC implements supportive policies to encourage deployment of hydrogen infrastructure and build investor confidence, with consideration of measures to encourage proportionate local content within EU rules.
3. DETE explores opportunities for Ireland to benefit from the development of local supply chains for green hydrogen.

[27] *U.S. National Clean Hydrogen Strategy and Roadmap,* available online at https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf

1.3.4 Frameworks for interconnection

In this section, we begin by examining the current policy frameworks governing interconnection in Ireland, the existing and planned interconnectors and their commercial status.

We then examine policy frameworks in potential trading partner nations identified in work package 2, before drawing conclusions for Ireland's future interconnection strategy, including specific recommendations.

Irish frameworks

Ireland aims to generate 80% of its electricity from renewable sources by 2030. With an increased share of variable renewable energy supply on the electricity grid, the need for interconnection becomes increasingly significant. Ireland is, however, one of the EU Member States with the lowest expected share of interconnection capacity. The relative lack of interconnection between Ireland's Integrated Single Electricity Market (I-SEM) and other markets presents a challenge to increasing renewable energy penetration.

Under the previous policy, interconnector development was primarily initiated by developers. Projects were assessed using case-by-case cost benefit analyses conducted by the CRU. Interconnector development decisions were largely based on the availability and suitability of connections to the existing grids. The process lacked strategic centralised, forward-looking direction.

In July 2023, the Government released the *National Policy Statement on Electricity Interconnection 2023* which outlined its ambition to strengthen interconnections with neighbouring countries.[28] This strategy is driven by the need to create export opportunities that align with Ireland's increasing renewable energy capacity. It aims to create the required legal and regulatory frameworks to enhance interconnectivity.

According to the *National Policy Statement on Electricity Interconnection 2023*, integrated planning for interconnection and ORE will be set out in an Offshore Transmission Strategy. This will be updated every five years. It will first be published 2024 and will state:

- The number, capacity and indicative locations of interconnection cable requirements
- The appropriate option each interconnect cable, including traditional Point to Point or Multi-Purpose Interconnectors (MPIs), and
- The prioritisation and sequencing of interconnection cables.

The *National Policy Statement on Electricity Interconnection 2023* emphasizes the need for a structured framework to direct project developers toward state needs and manage competition or sequencing conflicts among developers.

The Irish interconnection strategy needs to adapt to the growing ORE sector and transmission network expansion in Ireland, neighbouring countries and the wider EU. The initial step is to create a framework for MPIs, defining their role in Ireland's offshore grid and generation plans. While MPIs can offer broader benefits, their potential in an Irish context must be confirmed, and appropriate regulations need to be established. The next phases of policy development will integrate interconnection planning with ORE, terrestrial, and international transmission networks, establishing a transparent and predictable planning context for future delivery. The existing and planned Irish interconnectors are outlined in Table 13.

[28] *National Policy Statement on Electricity Interconnection 2023*, DECC, July 2023, available online at https://www.gov.ie/pdf/?file=https://assets.gov.ie/265251/7b3080d8-fa48-4011-9a77-1580abf8a9ff.pdf#page=null

Table 13 Existing and potential Irish interconnectors.

Interconnector	Connection destination (from Ireland unless stated)	Route to market	Status	Notes
Moyle Interconnector (500 MW)	Northern Ireland to Great Britain	Merchant	Operating	Owned and operated by Mutual Energy.
East West Interconnector (EWIC) (500 MW)	Great Britain	Fully regulated[29]	Operating	Owned and operated by EirGrid Interconnector Designated Activity Company (EIDAC). Under Regulation (EU) 2019/943, EIDAC is obligated to issue its "Use of Revenue Statement" annually[30] All costs associated with EWIC are paid for by the TUoS customer. Costs are offset by income from congestion rent and provision of ancillary services.[31]
Greenlink (500 MW)	Great Britain	Cap and floor[32]	Planned	Planned by Partners Group. CRU operates a different regulatory regime to the GB regulator, Ofgem, and the draft and final licence templates developed are reflective of the CRU approach.[33]
Celtic Interconnector (700 MW)	France	Fully regulated	Planned	Planned by EirGrid and RTE (French TSO). The anticipated regulatory framework for RTE's investment in the Celtic Interconnector is expected to mirror all previous investments. The Celtic Interconnector will be incorporated into RTEs Regulatory Asset Base (RAB). The same is true for EirGrid.[13]

[29] East West Interconnector Revenue Requirement Public Information Note, *Press release*, The Commission for Energy Regulation, 7 September 2012 available online at https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/cer12149.pdf

[30] EirGrid Interconnector Designated Activity Company Use of Revenue Statement 1 January - 31 December 2020, *Press release*, EirGrid, 29 January 2021, available online at https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/CRU21054a-EIDAC-Use-of-Revenues-Statement-1-Jan-31-Dec-20.pdf

[31] Celtic Interconnector Project Investment Request File, *EirGrid RTE*, 7th September 2018, available online at https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/CRU18265a-Celtic-Investment-Request.pdf

[32] The Cap and Floor Regime is an arrangement introduced to promote the development, financing and construction of electricity interconnectors where demonstrably beneficial to consumers. A cap and floor mechanism regulates how much money a developer can earn once in operation, providing developers with a minimum return (floor) and a limit on the potential upside (cap) for a 25-year period.

[33] Commission for Regulation of Utilities. (2022). Decision Paper: Licence for an Interconnector operating with a Cap and Floor regime. Dublin: CRU.

Target market considerations

Great Britain

The Government's *Energy Security Plan* published in March 2023 reaffirmed the UK's target to have at least 18 GW of interconnection capacity installed by 2030. [34,35] Currently, there is 8.4 GW of operating interconnector capacity between Great Britain and Belgium, France, Ireland, Netherlands and Norway.

The UK's interconnection and electricity trading are regulated by Ofgem and the National Grid ESO. Ofgem oversees market competition and consumer protection, while the ESO manages the electricity system. The Electricity Interconnectors License governs cross-border connections, fostering international collaboration. The Balancing and Settlement Code (BSC) and the Connection and Use of System Code (CUSC) establish rules for market participants, ensuring fair practices. These frameworks collectively aim to promote efficiency, competition, and a secure electricity supply, maintaining a reliable and transparent energy market in the UK.

Following an interconnector policy review in 2020, Ofgem concluded that:

- The cap and floor regime has been successful in delivering its objectives to date
- Further interconnection is needed
- The principles of the cap and floor regime remain appropriate to incentivise further interconnector capacity development, and
- The cap and floor regime is a suitable mechanism to support the development of MPIs.[36]

The *Energy Act 2023* passed into law in October 2023. This introduced a new legal definition for MPIs and established a new independent government entity that would take a whole system approach to strengthen energy security and help deliver net zero.[37]

France

France aims to double its interconnection capacity from around 15 GW to around 30 GW by 2035). By 2030, France aims to have an import capacity to 26 GW. This means that France will have enough interconnector capacity to allow 16.5% of the electricity produced on its territory to be transported across its borders to neighbouring countries, which is above the 15% EU 2030 target.[38]

The TSO, RTE, holds responsibility for facilitating the interconnection of the national network with other countries. An entity seeking to develop and operate interconnection is required to seek a derogation, which is subject to evaluation by the CRE. Multiple derogations have been approved for interconnections connecting France with the UK, Italy, and Spain[39]. In general, French interconnectors work on a fully regulated basis. One example of a merchant interconnector is ElecLink.

There is good opportunity for Ireland to build interconnectors with France, given its ambitions interconnection targets. In additions, the cooperation between Ireland and France on the Celtic Interconnector project will continue to contribute to alignment between the two countries on regulatory frameworks and requirements.

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[34] *The Energy White Paper: Powering our Net Zero Future*, UK Government, December 2020, available online at https://assets.publishing.service.gov.uk/media/5fdc61e2d3bf7f3a3bdc8cbf/201216_BEIS_EWP_Command_Paper_Accessible.pdf

35 *Powering Up Britain: Energy Security Plan*, Department for Energy Security & Net Zero, March 2023, available online at https://www.gov.uk/government/publications/powering-up-britain/powering-up-britain-energy-security-plan

36 *Interconnector Policy Review: Decision,* Ofgem, December 2021, available online at https://www.ofgem.gov.uk/sites/default/files/2021-12/ICPR%20Decision%20Paper.pdf

37 *Energy Act 2023*, 26 October 2023, available online at https://www.legislation.gov.uk/ukpga/2023/52/contents/enacted

38 IEA, available online at https://www.iea.org/countries/france

[39] Michel Guénaire et al, Electricity regulation in France: overview, *Thomson Reuters*, November 2020, available online at https://uk.practicallaw.thomsonreuters.com/7-629-7567?contextData=(sc.Default)&transitionType=Default&firstPage=true

Political uncertainties, with regard to the French parliament's criticism of European energy frameworks, and public objections could, however, be barriers for projects. RTE have announced that they are two years behind schedule with respect to their 2030 targets due to project delays. [40]

Belgium

With commissioning of the ALEGrO interconnection with Germany in November 2020, Belgium is already compliant with the 2030 objectives set by the European Commission. The European Commission recommends using a figure of €2/MWh (annual average) price difference between markets as a relevant threshold for considering the development new interconnectors. This guiding principle is discussed in the Belgian Federal Development Plan 2024 – 2034.

Under Belgian law, Elia is responsible for the management of the transmission system. This includes operating, maintaining, and developing the transmission system, including interconnectors. The cap and floor mechanism was initially developed between CREG and Ofgem for Nemo Link. Other transmission infrastructure operates under a fully regulated basis.

Belgium is not a good target market for Ireland, Belgium has already met its interconnector targets and EU interconnector requirements. It also has two MPI projects underway (Nautilus and Triton Link). While both are signatories of the Ostend Agreement which can act as a basis for regulatory collaborations, there has been no previous interconnector projects between the Ireland and Belgium and therefore they have no experience navigating regulatory challenges together.

Spain

Spain's location, surrounded by coastline and separated from the rest of Europe, has limited its interconnection developments. Spain has about 3 GW of interconnection capacity with France, about 3 GW with Portugal, and about 700 MW with Morocco. This means it has a total interconnector capacity of about 7 GW which is reduced to around 80% in summer due to temperature constraints. The National Energy and Climate Plan (NECP) includes three new interconnection projects between Spain and France by 2030, resulting in a further 8 GW of capacity. Interconnection plans with France have previously been difficult to implement, with long technical, economic, environmental and political discussions.

The TSO, Red Eléctrica, is responsible for developing for grid development, including interconnectors. The current interconnectors all operate under a fully regulated financing model.

With no current interconnectors between Ireland and Spain, however, there is no precedent for regulatory processes, licensing procedures and market arrangements specific to Spain-Ireland interconnection. Regulatory bodies would therefore need to develop and adapt frameworks without past project to draw upon. This lack of experience is likely to impact investor confidence in projects. In addition, Spain's history of slow political negotiations with regard to interconnector agreements also highlights another area of concern.

The EU

The EU has established a goal for interconnection, aiming for a minimum of 15% by the year 2030. Insufficient cross-zonal trading capacity among member states emerged as a significant challenge to the integration of European electricity markets, as highlighted in the Clean Energy Package (CEP). The Agency for the Cooperation of Energy Regulators (ACER) emphasizes that market integration is pivotal for attaining European energy objectives. The augmentation of cross-zonal trading capacities fosters cross-border competition and contributes to the integration of renewable energy resources. Europe has established a mandatory goal, known as the 'minimum 70% target,' for electricity interconnector capacity dedicated to cross-zonal trading. This target, requiring compliance from all EU TSOs, became legally binding from the beginning of 2020.

[40] Elise Wu, France to miss 2030 interconnector targets – TSO, *Montel*, 4 October 2023, available online at https://www.montelnews.com/news/1525872/france-to-miss-2030-interconnector-targets--tso

With regard to financing models, most interconnectors are developed on a fully regulated basis by a TSO. Cap and floor mechanisms with Great Britain exist. Merchant interconnectors require exemption. Few projects have been granted exemptions, though BritNed and ElecLink were.[41] The latest high-profile application to be denied is the Aquind Interconnector between Great Britain and France.

In the interest of energy security, EU member states must meet the EU 15% interconnection target, which means both Ireland and other EU member states would benefit from interconnector developments. In addition, there is political support for regulatory alignment and market integration across the EU member states, as well access to funding opportunities, such as through the Connecting Europe Facility. There are, however, complex legal trade rules to negotiate and it has been argued that European Commission's regulatory approach increases the administrative burden, resource demand and cost for National Grid authorities, which could impact projects.

Implications for Ireland

The considerations associated with interconnections between EU Member States are dictated by historical collaboration, regional dynamics and the characteristics of each energy market. Understanding these challenges and opportunities is crucial for effective planning and successful implementation of interconnection projects.

Ireland will benefit from the EU's commitment to establish an interconnected European energy market by sharing regulatory principles and objectives with EU Member States. This will streamline the integration process, fostering efficient cross-border energy trading. In addition, the regulatory landscape is complemented by funding opportunities. Ireland will have access to EU funding mechanisms that incentivise and support the development of interconnectors. Such funding will be aligned with broader EU energy and climate goals.

Ireland-GB interconnectors are characterised by a history of collaboration, shared regulatory experiences, and ongoing efforts to deepen energy ties through bilateral agreements. These strengths and opportunities may sustain collaboration with GB despite the challenges associated with the UK leaving the European Economic Area.

In summary, we recommend that:

1. DECC seeks to influence emerging EU wide interconnection policy to best facilitate construction of further interconnections with Ireland.
2. DECC and EirGrid explore further interconnection with Great Britain and France as a priority, as these are the most attractive markets from an Irish perspective.

1.4. Technology innovation

1.4.1 Introduction

- This section summarises the innovation landscape and considers the potential benefit to Ireland of technology innovation delivered in Ireland in terms of:
- Reduced cost of electricity compared a counterfactual where no Irish innovation materialises
- Benefit to Irish economy in actually delivering innovation, and
- Improving Irish competitiveness with respect to export due to innovation.

We consider these in the context of four technology areas:

- ORE projects with associated export systems (sub-divided fixed and floating offshore wind)
- Irish scope of interconnectors, and
- Local hydrogen generation and distribution.

[41] 'Access to infrastructure, exemptions and derogations', *European Commission*, available online at https://energy.ec.europa.eu/topics/markets-and-consumers/wholesale-energy-market/access-infrastructure-exemptions-and-derogations_en.

The Sustainable Energy Authority of Ireland (SEAI) plans to publish its *Offshore Renewable Energy Roadmap for 2050* which contains a technology assessment describing the three main ORE technologies relevant to Ireland as well as a group of technologies that have less potential to contribute significantly to the Irish energy system. The assessment includes technology readiness, expected future development, levelized cost of energy, environmental considerations and system impacts and is in the context of four deployment scenarios. These are closely related to the scenarios in this study, with scenarios 1 to 3 considering 10 GW, 37 GW and 50 GW of offshore wind installed by the end of 2050 and scenario 4 with has wave energy replacing about 10% of the volume of offshore wind installed by the end of 2050.

It also contains a research and research skills assessment considering the current ORE research landscape in Ireland, including where there are gaps that may impact delivery of scenarios or local supply opportunities.

For the purposes of this study, we have used evidence from this draft document to inform our assessment of likely impacts of Irish innovation in fixed and floating offshore wind. We have not considered the impact of innovation in wave technology, as the scenarios considered here do not envisage a significant role for wave technology in Ireland's energy mix.

The SEAI study does not consider the impact of innovation on hydrogen or interconnection. With regard to hydrogen, we have used DECC's *National Hydrogen Strategy* and InnovateUK's *Highlighted research themes to enable UK Hydrogen Adoption* report to inform this section.[42, 43]

1.4.2 Summary of the innovation landscape

Offshore wind

Fixed offshore wind

Fixed offshore wind projects are those using wind turbines on monopile, jacket or gravity-base foundations fixed to the seabed. To date, fixed projects have been installed in water depths of up to 45 m, but maximum depths will likely continue to increase for at least the next decade.

Readiness

The fixed offshore wind market is fully commercial. Worldwide, there is approximately 62 GW operational fixed offshore wind in about 250 projects operating in 16 national markets. A further 214 GW have been awarded exclusive rights for development.

In Ireland, the only project in operation is the 25 MW Arklow Bank phase 1 project. A further 3.1 GW offshore wind energy have been awarded exclusive rights for development.[44]

There is a pipeline of technology innovations in fixed offshore wind at a range of TRLs and CRIs that are reducing LCOE. These are supported by public and private investment. Many innovations are relevant to all markets, though some are specific to a subset of markets, for instance increased typhoon or earthquake resistance.

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[42] DECC, *National Hydrogen Strategy,* July 2023*,* https://www.gov.ie/en/publication/624ab-national-hydrogen-strategy/. Last accessed December 2023.

[43] *Highlighted Research Themes to enable UK Hydrogen Adoption*, InnovateUK, October 2022. Available online at https://www.ukri.org/wp-content/uploads/2023/02/EPSRC-IUK-230223-Funding-Opp HydrogenHubEngagementWorkshopOutcomeReport.pdf.

[44] *Renewable Electricity Support Scheme*, EirGrid, June 2023, available online at https://www.eirgridgroup.com/site-files/library/EirGrid/ORESS-1-Final-Auction-Results-(OR1FAR).pdf.

Expected future developments

Fixed offshore wind technology is by far the most mature of the technologies assessed. It has established a place in the current and future renewable energy mix, making up 11% of the new wind plant capacity installed globally in 2022.[45]

Over recent years, large fixed offshore wind projects have been progressed effectively 'subsidy free' in a range of established markets with good wind conditions.[46] LCOE has reduced to being lower than many onshore wind projects constrained in size by environmental and social considerations.

Key areas of future technology development are:

- Larger turbines, including knock-on consequences elsewhere in the supply chain
- Increased turbine reliability and maintainability
- More optimised foundations in deeper waters
- Lower cost export system and higher voltage array cables, and
- More optimised offshore operations

Key cross-cutting technology development themes relevant to fixed offshore wind are:

- Materials development, additive and advanced manufacturing
- Big data, analytics and digital twins
- On-site robotics and autonomous technology
- Internet of things and sensing technology, and
- Artificial intelligence (AI) and machine learning (ML).

Ireland's research and innovation opportunity

Key areas of opportunity for Ireland include:

- Research of the Irish environment (environmental, social and technical) and collaborating with international technology providers in developing solutions needed in response.
- Site testing in harsh offshore conditions
- Composites, sensing and reliability (cross-over from aerospace)
- Information and communications technology (ICT) and software, and
- Manufacturing and process technology in tower manufacturing, as envisaged in the 37 GW and 50 GW scenarios, used in the analysis presented in Section 1.2.3.

Floating offshore wind

Floating offshore wind projects use turbines mounted on floating hulls, attached to the seabed through mooring systems and anchors. So far, the same turbines as for fixed offshore wind have been used, except for changes in tower design and control systems to account for different loading patterns. Key differentiators are the floating foundation on which the turbine is mounted, the mooring and anchoring systems used to tether the turbine to the seabed, and the dynamic array cables used to export power to the substation.

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[45] Global Wind Energy Council, (2023), https://gwec.net/globalwindreport2023/.

[46] 'Subsidy free' meaning that power purchase contracts are at revenues no higher than anticipated wholesale power revenues.

Readiness

Floating offshore wind technology is much less well established than fixed, having a total global installed capacity of less than 300 MW at time of writing, compared to more than 50 GW of fixed bottom wind.

All key concepts are at pre-production stage with models demonstrated at full scale and under relevant conditions, offshore. They now face the difficult challenge of scaling up to the next CRI level of scaled-up commercial deployment. Making this transition is challenging because the technology remains high cost in comparison to fixed offshore wind and other established technologies. Scaling up project size is critical to unlock the economies of scale and volume which will help drive down LCOE, but scaling up projects entails greater spending on the project and infrastructure.

Expected future developments

Floating wind will benefit from many of the fixed offshore wind developments and key cross-cutting technology development themes listed above, as well as opportunities specific to floating offshore wind:

Key areas of future technology development specific to floating offshore wind are:

- Rationalisation and refinement of concepts.
- Industrialisation of hull manufacturing
- Improvements to dynamic cabling systems
- Improvements to mooring and anchoring systems, and
- Development of new installation, operation and maintenance methods

Ireland's research and innovation opportunity

Beyond the areas listed for fixed offshore wind key areas of opportunity for Ireland in floating offshore wind include:

- Products and processes to facilitate O&M work on floating turbines in Irish sea conditions
- Industrialised foundation assembly and turbine integration processes, and
- Manufacturing and process technology in the areas where manufacturing facilities are established in Ireland. For the 37 GW and 50 GW scenarios, used in the analysis presented in Section 1.2.3, these areas are:
    - Synthetic cable manufacturing, and
    - Floating foundation assembly.

Hydrogen production, storage and distribution

Hydrogen electrolysis splits water into its constituent elements, hydrogen and oxygen. It is conducted using an electrolyser, which consists of two electrodes immersed in an electrolyte solution. An electrical current is required to conduct electrolysis and produce hydrogen. When this current is generated from renewable energy sources, this is called green hydrogen.

In this study, we have assumed salt caverns will be used as a storage solution for hydrogen. Salt cavern storage is a form of underground storage where hydrogen gas is stored in large caverns created within salt formations. This method uses the natural, self-sealing properties of salt formations to provide a secure and potentially cost-effective storage solution. It is particularly well-suited for applications where large-scale, seasonal storage is required, and so is suited to green hydrogen production.

We have also assumed pipelines will be used for transport and distribution of hydrogen. Hydrogen pipelines are typically made of materials that can safely contain and transport hydrogen gas, such as high-strength steel, plastic, or composite materials.

Readiness

The electrolyser technologies that have systems proven in an operational environment level (TRL 9) are proton exchange membrane (PEM), pressurised alkaline (ALK), and solid oxide electrolysers (SOE).

Salt cavern storage has also been proven in an operational environment. This has only been proven on a small scale however, with four sites operating worldwide. The purity of hydrogen when stored and the limited number of potential sites are the main bottlenecks facing salt cavern storage.

While proven in an operational environment, pipeline technology for transport of hydrogen is less mature due to the difficulty of transporting hydrogen at a large scale.

Expected future developments

Green hydrogen production and distribution is yet to be deployed on a commercial scale. Numerous advances are required for it to be cost effective. The key innovations expected in hydrogen are:

- Electrolysis technology and manufacturing, with improvements in efficiency, durability, and cost-effectiveness
- Catalyst materials and designs to improve the efficiency of electrolysers
- Hydrogen transport infrastructure, including innovations in materials for pipelines, and novel transportation methods, and
- Hydrogen storage technologies, including solid-state hydrogen storage materials and high-density storage solutions, such as liquefaction, to improve the economic viability of storing large quantities of hydrogen.

Ireland's research and innovation opportunity

Key areas of opportunity for Ireland in hydrogen include:

- Electrolyser efficiency and materials science
- Pipeline engineering and design
- Development of international standards and best-practice, and
- Lifecycle assessments to review the environmental impact of large-scale green hydrogen production, storage and distribution.

Ireland also published its National Hydrogen Strategy in July 2023. [47] This set out Ireland's approach to innovation in hydrogen technology including:

- Enabling infrastructure including pipeline and storage solutions
- Safety and regulation, and
- Skills development.

Interconnection

Interconnectors link the transmission networks of countries together via high voltage cables. They allow export and import of energy depending on supply and demand. Generally, the high power transfer demands mean HVDC cables are used.

[47] DECC, *National Hydrogen Strategy,* July 2023, https://www.gov.ie/en/publication/624ab-national-hydrogen-strategy/. Last accessed December 2023.

Readiness

The interconnector market is well established and fully commercial. Worldwide, there is over 250 GW of interconnectors operational or in development.

In Ireland, there is one operational interconnector to the UK, the 500 MW East-West Interconnector installed in 2012. Two more are planned for 2024 and 2026 respectively, the 500 MW Greenlink to the UK and the 700 MW Celtic Interconnector to France.

The HVDC technology typically used in interconnectors is well understood and fully commercial. HVDC transmission is widely used for interconnectors, and in export cables for power generation globally. HVDC interconnectors therefore have a TRL of 9.

Expected future developments

As onshore transmission networks become more constrained, a possible mitigation is to build offshore networks. In this scenario, interconnectors could become a vital part of network design, transferring power between or within countries without having to significantly upgrade onshore transmission networks.

The design and sizing of interconnectors is generally based on the peak import/export capacity required and the thermal loads this creates. Key areas of future technology development are:

- Sizing of cables based on dynamic thermal ratings, rather than steady state
- Materials development, particularly in insulation and armouring
- High-temperature superconducting solutions, and
- Increased capability of continuous cables monitoring, including cable movement, insulation degradation (and pinpointing of locations where this is taking place), and distributed thermal loading.

Ireland's research and innovation opportunity

Key areas of opportunity for Ireland include:

- Cable design and sizing
- Continuous monitoring solutions, and
- Materials development for high voltage cables.

1.4.3 Impact of Irish innovation on electricity costs

To assess the benefit of Irish innovation, for each technology we considered the total impact of technology innovation on LCOE between a project installed in 2030 and a project installed in 2050 for fixed and floating offshore wind in scenario 2. For each cost element, we estimated the fraction of cost reduction that will be due to an increase in project scale, industry scale and progress outside of where funded research and innovation can be expected to impact.

We then considered the synergy between the scope of innovation needed and Irish innovation strength relative to elsewhere and the logic for innovation to be based in Ireland compared to elsewhere.

This enabled us to derive a percentage impact on LCOE of Irish research and innovation compared to the counterfactual of no Irish innovation.

We then derived an overall, whole life energy cost saving for ORE projects installed up to 2050 in the 37 GW scenario based on this. We recognise significant uncertainty in results, but suggest they provide a useful focus when considering research and innovation funding.

Fixed offshore wind

We calculated the impact of Irish research innovation on electricity cost from fixed offshore wind for the lifetime of projects in the 37 GW scenario to about €8 million. We would expect this to be relatively low, as the bulk of cost reduction over time is due to:

- Technology development within major components and processes, often related to the use of larger wind turbines, led by key suppliers and by research organisations in the counties where the key suppliers have design or manufacturing facilities.
- Learning-by-doing and increases in market and project scale as the global offshore wind industry matures, led by similar suppliers and research organisations.

The reductions modelled here are due (in order of magnitude) to research and innovations in:

- Operation and maintenance, including understanding and responding to the harsh Irish metocean conditions
- Project development and Installation, again especially including understanding and responding to Irish metocean conditions and port arrangements, and
- Tower manufacture, assuming that a manufacturing facility is established in Ireland.

The overall reduction in LCOE for a project installed in Ireland in 2040 due to research and innovation in Ireland is estimated to be less than 0.1%. This is likely to be an underestimate when considering local innovation in manufacturing processes which is somewhat separate from the global analysis performed here.

The savings in other scenarios will scale with volume of fixed offshore wind.

Floating offshore wind

We calculated the impact of Irish research innovation on electricity cost from floating offshore wind for the lifetime of projects in the 37 GW scenario to about €170 million. This is much higher than for fixed offshore wind, as there is much more opportunity for LCOE reduction and there is more floating than fixed offshore wind installed in this scenario.

The reductions modelled here are due (in order of magnitude) to research and innovations in:

- Foundations, moorings and anchors, especially if a hull and mooring line manufacturing facilities are established
- Operation and maintenance, including understanding and responding to the harsh Irish metocean conditions, and
- Project development and Installation, again especially including understanding and responding to Irish metocean conditions and port arrangements.

The overall reduction in LCOE due to innovation in Ireland is estimated to be about 0.1%. Again, this is likely to be an underestimate when considering local innovation in manufacturing processes which is somewhat separate from the global analysis performed here.

The savings in other scenarios will scale with volume of floating offshore wind.

1.4.4 Benefit to Irish economy in delivering innovation

To assess the benefit to the Irish economy of delivering innovation, we sought evidence of the benefit of relevant innovation. From our experience of evaluating, delivering and designing government innovation programmes we also identified the associated support alongside direct funding of a specific innovation that has helped improve the likelihood of successful commercialisation of innovation.

Assessment of benefits

Delivering innovation results in benefits due to innovator salaries and local spend during the innovation activity and due to value created in the supply chain through revenue earnt due to the innovation. UK Government stated that for Innovate UK's whole innovation portfolio covering many sectors, £7 was returned for every £1 invested.[48]

A good return from innovation funding can be expect but only if the similar disciplines are applied as those by Innovate UK and BEIS. These include:

- Using independent assessors who are industry experts without a conflict of interest. This means finding those in the industry so know enough about the state of the art, internationally, to be able to assess but not a direct competitor or stand to benefit directly from the grant award
- Setting a relatively high pass mark for funding to be granted.
- Assessing the full context of innovation. Beyond requiring conditions of contract including for equality, diversity and inclusion, InnovateUK usually assesses:
    1. Need or challenge
    2. Idea
    3. Team, resources and delivery
    4. Market awareness
    5. Outcomes and route to market
    6. Risks
    7. Costs
    8. Added value (that is likely to be LCOE reduction), and
    9. Value for money.
- Applying state aid rules which mean that the closer the innovation is to market the proportionately less grant is awarded. That way the grant holder has to provide their own funding and they only tend to do that for core activity that they wish to succeed.
- Rewarding collaboration with a higher state aid grant fraction, as long as consortium agreements that meet a prescribed standard are in place.
- Making payment of grants against completed agreed milestones so the grant holder focusses on achieving results.
- Funding a portfolio of projects, to spread risk.
- Focussing on specific gaps of clear industry need.
- Supporting companies doing the innovation by providing more than grant funding. the common design features of the most successful programmes include support to:
    - Leverage funding, enhancing the effectiveness of grant funding
    - Enable knowledge sharing and cohort development – peer to peer learning and support, and
    - Form industrial partnerships utilising networks and networking events, and a deep understanding of technology commercialisation put into practice.

Successful programmes also have:

- Business support bespoke to the needs of the company
- Funding events
- Longevity and consistency so industry learns how best to interact with the programme

[48] *UK Innovation Strategy Leading the future by creating it*, BEIS, London July 2021, page 9, available online at https://assets.publishing.service.gov.uk/media/61110f2fd3bf7f04402446a8/uk-innovation-strategy.pdf. Last accessed December 2023.

- International collaboration, and
- Support and buy-in from top-level industry executives.

The BEIS Energy Entrepreneurs Fund (EEF) included many of these features and was praised for the way it looked holistically at improving the business environment associated with the innovation. The internal BEIS evaluation of EEF showed that the value of the innovation grant was significantly enhanced as a result of the incubation support. BEIS (now DESNZ) expanded the EEF approach into sectors beyond those of just energy in the UK's flagship £1 billion Net Zero Innovation Portfolio fund.[49]

Improving Irish competitiveness with respect to export

The 37 GW and 50 GW ORE deployment scenarios drive the establishment of major manufacturing facilities in Ireland, and the development of an ecosystem of other suppliers of components and services.

In these scenarios, Ireland captures investment in:

- A tower manufacturing facility
- A synthetic cable manufacturing facility, and
- A floating foundation assembly facility.

These investments are assumed to be captured by our analysis, but they are not certain, and intervention on the part of Government will be required to ensure these benefits are delivered, as discussed in Section 1.2.3.

There is a strong body of evidence within academic literature that innovation is a driver of export competitiveness in manufacturing industries.[50, 51] Establishing an exact value of innovation to Irish exports is challenging, as it is highly context specific. There is evidence that export is a driver of innovation, as well as being driven by it, in a virtuous cycle.[52]

To drive growth in innovation and deliver export benefits, which will in turn lay the ground for further export and innovation growth we recommend:

1. DETE puts in place inward investment incentives to attract desired supply chain elements with export capability to Ireland
2. SEAI reinforces this investment with targeted R&D funding to encourage innovation in products and production techniques, especially to linked to inward investment.

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[49] Net Zero Innovation Portfolio, *Department for Energy Security and Net Zero and Department for Business, Energy and Industrial Strategy*, March 2021, available online at https://www.gov.uk/government/collections/net-zero-innovation-portfolio

[50] Malgorzata Stefania Lewandowska and Tomasz Goleblowski, Innovation and International Competitiveness of Manufacturing Firms: Evidence from Bulgaria, Czech Republic, Hungary, Polan, and Romania, Geo-Regional Competitiveness in Central and Eastern Europe, the Baltic Countries, and Russia, page 26, available online at https://www.igi-global.com/chapter/innovation-and-international-competitiveness-of-manufacturing-firms/109142,

[51] Zixin Dou et al, The competitiveness of Manufacturing and Its Driving Factors: A Case Study of G20 Participating Countries, *Sustainability*, Issue 13, (2021), available online at https://www.mdpi.com/2071-1050/13/3/1143#sec4-sustainability-13-01143

[52] Richard Harris and John Moffat, R&D, Innovation & Exporting in Britain: An Empirical Analysis, available online at https://www.gla.ac.uk/media/Media_232346_smxx.pdf.

1.5. Financial viability and risk analysis

1.5.1 Financial viability of scenarios

In considering the financial viability of Ireland pursuing an export led ORE strategy, our study has shown that the critical consideration is Ireland's cost-competitiveness in hydrogen production on international markets.[53] This means the cost of production of hydrogen and its derivatives from offshore renewables in Ireland and delivery to the customer in mainland Europe must be lower the marginal cost source of production of green hydrogen required in mainland Europe, which sets the market price.

In this regard, Workstream 3 concluded that Ireland should be competitive against potential international sources of green hydrogen that may be required to satisfy European demand, provided export is via pipeline and continental Europe does not meet all its demand for hydrogen through domestic production.

Our analysis also suggests a high demand for green hydrogen in Europe. In a scenario where overall hydrogen demand is lower than expected or where blue hydrogen from natural gas can effectively compete with green hydrogen from renewables, the financial viability of an export led ORE strategy will be less clear.

In the DNZ and 37 GW scenarios, the volume of hydrogen and derivatives production in are likely insufficient to be at risk of exceeding European demand for imports, irrespective of whether additional sources of domestic demand are developed. Estimates for German hydrogen import dependence in 2045 are in the range of 200 to 400 TWh.[54] This compares to total hydrogen production in Ireland of approximately 50 TWh and up to 36 TWh of potential domestic consumption in our 37 GW scenarios. This is supportive of the view that the 37 GW ORE scenarios could be financially viable.

In the 50 GW scenarios, Irish hydrogen production could reach almost 80 TWh in the 50 GW stretch scenario. It is likely that all of the additional production above that of the 37 GW scenarios would have to be exported. This makes the question of Irish hydrogen competitiveness, and the size of the market for green hydrogen in Europe even more important factors. Consequently, although the 50 GW scenarios could be financially viable, it is a higher risk strategy to pursue them.

To de-risk an export-led ORE strategy, we recommend the Government explores the creation of new sources of domestic electricity and hydrogen demand. New sources of demand would reduce Ireland's reliance on uncertain assumptions of European green hydrogen demand. This would also somewhat mitigate against the risk of competitive pressure from hydrogen imported from the Middle East.

We have identified ammonia production, methanol and sustainable aviation fuels as potential supply chains of interest. A recent study commissioned by Amazon[55] suggests (albeit noting the conflict of interest) further evaluation of the merits of expanding the data centre sector would also be worthwhile.

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[53] For the purposes of this report, we consider a scenario to be financially viable if it can lead to net welfare gains to Ireland, including the state, the population and local businesses.

[54] Dena-Leitstudie Aufbruch Klimaneutralität, *DENA*, October 2021, available online at https://www.dena.de/fileadmin/dena/Publikationen/PDFs/2021/Abschlussbericht_dena-Leitstudie_Aufbruch_Klimaneutralitaet.pdf, Klimaneutrales Deutschland 2045, *Agora*, June 2021, available online at https://www.agora-energiewende.de/fileadmin/Projekte/2021/2021_04_KNDE45/A-EW_231_KNDE2045_Langfassung_DE_WEB.pdf, TYNDP 2022: Scenario Report, *ENTSO-E and ENTSOG*, April 2022, available online at https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP2022_Joint_Scenario_Full-Report-April-2022.pdf. Langfristszenarien Für Die Transformation Des Energiesystems In Deutshchland, BMWK, available online at https://langfristszenarien.de/enertile-explorer-wAssets/docs/LFS3_T45_Szenarien_15_11_2022_final.pdf.

[55] 'Five ways AWS data centres benefit local communities in Ireland', *Amazon Web Services*, 26 October 2023, available online at https://www.aboutamazon.eu/news/aws/five-ways-aws-data-centres-benefit-local-communities-in-ireland

1.5.2 Risk analysis

Table 14 details our assessment of the risks and uncertainties associated with pursuing an energy export economic model, as outlined in this report. For each risk, we considered impact, likelihood, ownership, mitigation and contingency.

Table 14 Summary of key risks of energy export approach.

Risk Type	Risk	Impact	Likelihood	Mitigation	Contingency
Market competition	Demand for green hydrogen is lower than anticipated, with domestic production in continental Europe sufficient to satisfy demand.	High	Medium	DETE develops additional domestic sources of demand.	DECC reduces planned ORE deployment levels and seeks to export primarily via interconnection.
	Ireland is not price competitive as a source of imported green hydrogen into continental Europe.	High	Medium	DETE develops additional domestic sources of demand	DECC reduces planned ORE deployment levels and seeks to export primarily via interconnection
	Ambitious rollout of solar and onshore wind in continental Europe lowers electricity prices in target markets, impacting business case for interconnection.	High	Medium	None	DECC monitors costs and incentivises further hydrogen deployment to offset reduced interconnection or reduces planned ORE deployment.
	Low cost green or blue hydrogen from the Middle East delivered via pipeline enters the continental European market.	High	Medium	DECC pushes for effective carbon pricing and/or carbon border adjustment mechanisms to be implemented at EU level.	DECC reduces planned ORE deployment levels and seeks to export primarily via interconnection.
Volatility	Unforeseen event leads to a slump in European energy demand.	Medium	Medium	DECC develops long term storage options for excess hydrogen production such as salt caverns to allow excess supply to be absorbed during economic downturns.	DECC implements a temporary subsidy for hydrogen producers or acts as a buyer of last resort to survive downturn. DECC facilitates large scale hydrogen storage.
Social / political	Ambitious deployment programme generates public opposition holding back permitting and impacting investor confidence.	Medium	Medium	DECC implements robust community benefit and engagement practices as part of ORE deployment frameworks.	DECC moderates deployment plans, explores higher cost options such as projects father from shore and reducing

Risk Type	Risk	Impact	Likelihood	Mitigation	Contingency
					the visual impact of onshore transmission by use of underground cables.
	Deployment of interconnectors and sale of electricity or hydrogen is held back by political opposition in partner countries due to concerns over negative welfare impacts.	Medium	Medium	EirGrid progresses interconnector plans with a range of partner markets to spread risk.	DECC incentivises further hydrogen deployment to offset reduced interconnection.
	Delays in putting in place effective trading frameworks for hydrogen within the EU result in smaller market or increased trading costs.	Medium	Medium	DECC works through the EU to accelerate the development of robust EU-wide hydrogen regulation.	DECC seeks to work bilaterally with key countries such as Germany and the UK to move ahead of EU frameworks.
	The EU develops a strategic plan to pursue another source of clean hydrogen for example from north African solar.	High	Medium	DECC promotes the importance of domestic energy security within EU, and the risk of over-reliance on non-EU suppliers.	DECC Reduces planned ORE deployment levels and seeks to export primarily via interconnection.
	The EU reduces focus on decarbonisation and decides to extend use of fossil fuel technologies.	Medium	Low	DECC continues to promote the importance of addressing climate change within the EU and other international fora, and works with other EU members to develop robust energy transition strategies.	DECC reassesses energy export plans. Ireland's low cost renewable energy will still compete with fossil fuel based electricity, but hydrogen export is likely to suffer.
Technology	Floating offshore wind technology does not achieve forecast cost reductions	High	Low	DFHERIS and SEAI support technological development of floating offshore wind through collaborative R&D funding. DECC facilitates development of further capacity of fixed offshore wind, in time.	DECC explores potential for further fixed bottom deployment beyond the 10 GW envisaged in this report, noting likely environmental and social challenges.
	Hydrogen electrolysers do not achieve expected cost reductions and efficiency improvements.	Medium	Medium	DFHERIS and SEAI support technological development through R&D funding, and engage with multilateral efforts at EU level.	DECC reduces planned ORE deployment levels and seeks to export primarily via interconnection

Risk Type	Risk	Impact	Likelihood	Mitigation	Contingency
Delivery	Ireland struggles to secure investment in floating wind construction ports as envisaged in deployment scenarios, holding back floating offshore wind deployment.	Medium	Medium	DFT implements financial incentives to support port infrastructure development DECC creates long term certainty over timing and volume of floating offshore wind projects to build investor confidence.	Floating offshore wind construction takes place using jack-up vessels, adding to cost, reducing local content and slowing delivery.
	Ireland does not secure investment in envisaged offshore wind manufacturing facilities.	Low	High	DETE implements investment incentives such as grants tax incentives or preferential financing arrangements to promote investment DECC ensures long term clarity of pipeline and frameworks to build investor confidence.	Ireland proceeds using non-Irish componentry. Jobs and export benefits are not secured but costs are broadly unchanged.
	Due to supply chain bottlenecks, Ireland does not secure the components and services needed to reach deployment targets.	Medium	Low	DECC establishes frameworks which deliver early certainty for developers, allowing them to make early contracts with suppliers to secure scarce capacity.	DETE identifies key risk areas and establishes incentives to encourage local investment in these areas.

Appendix A Further economic benefit assumptions

Table 15 presents the cost categories considered for each technology as discussed in Section 1.2.2.

Table 15 Cost categories considered in economic benefit methodology for each technology.

Phase	Level 1	Level 2
Fixed offshore wind		
DEVEX	Development and project management	Development and consenting services
		Environmental surveys
		Resource and metocean assessment
		Geological and hydrographical surveys
		Engineering and consultancy
		Project management
CAPEX	Turbine	Nacelle and Hub
		Blades
		Tower
		Electrical system
	Balance of plant	Array cables
		Export cables
		Monopile foundation
		Offshore substation
		Onshore substation
	Installation and commissioning	Offshore substation
		Offshore cables
		Onshore export cables
		Turbine and foundation
		Inbound transport
		Construction port - fixed
		Offshore logistics
		Onshore substation
OPEX	Operations and maintenance	Operations
		Maintenance
		Major repair
		Offshore vessels and logistics
		Operations port
DECEX	Decommissioning	Decommissioning

Floating offshore wind		
DEVEX	Development and project management	Development and consenting services
		Environmental surveys
		Resource and metocean assessment
		Geological and hydrographical surveys
		Engineering and consultancy
		Project management
CAPEX	Turbine	Nacelle and hub
		Blades
		Tower
		Electrical system
	Balance of plant	Array cables
		Export cables
		Semi-submersible floating foundation
		Mooring system
		Offshore substation
		Onshore substation
	Installation and commissioning	Offshore substation
		Offshore cables
		Onshore export cables
		Mooring system
		Turbine and foundation
		Inbound transport
		Marshalling and integration
		Offshore logistics
		Onshore substation
OPEX	Operations and maintenance	Operations
		Maintenance
		Major repair
		Offshore vessels and logistics
		Operations port
DECEX	Decommissioning	Decommissioning

Hydrogen		
DEVEX	Development and project management	Development and project management
CAPEX	Device	Electrolyser system
	Balance of plant	Hydrogen compression
		Salt cavern storage
		Pipeline CAPEX
		Site electrical
		Other balance of plant
	Installation and commissioning	Civils and construction
		Equipment installation and commissioning
OPEX	Operations and maintenance	Operations
		Electrolyser system maintenance and service
		Balance of plant maintenance and service
		Salt cavern OPEX
		Pipeline OPEX
DECEX	Decommissioning	Decommissioning
Interconnection		
DEVEX	Development and project management	Development and project management
CAPEX	Transmission assets	Cable supply
		Substation supply
	Installation and commissioning	Offshore cable installation
		Onshore cable installation
		Substation installation
OPEX	Operations and maintenance	Transmission maintenance
DECEX	Decommissioning	Decommissioning