SUSTAINABLE ENERGY AUTHORITY OF IRELAND

Rialtas na hÉireann
Government of Ireland

Decarbonised Electricity System Study (DESS)

Forecasts of plausible rates of generation technology deployment 2024 – 2040

January 2025

Forecasts of plausible rates of generation technology deployment 2024 - 2040

Method, results and conclusions for the SEAI expert elicitation

Preliminary findings shared with stakeholders, June 2024.

Sustainable Energy Authority of Ireland
SEAI is Ireland's national energy authority investing in, and delivering, appropriate, effective and sustainable solutions to help Ireland's transition to a clean energy future. We work with the public, businesses, communities and the Government to achieve this, through expertise, funding, educational programmes, policy advice, research and the development of new technologies.

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Contents

Executive Summary

This study forecasts the cumulative installed capacity (in MW) for onshore wind, offshore wind, solar photovoltaic (PV), thermal plant combusting hydrogen or ammonia, and Carbon Capture and Storage (CCS) for the period 2024–2040. The initial aim was to support Sustainable Energy Authority of Ireland's (SEAI) contribution to the Carbon Budgets Working Group, which in turn supported the Climate Change Advisory Council (CCAC) Ireland in setting the national Carbon Budgets for the period 2030–2040. In addition, this study is also the first output from a larger research programme to report on a decarbonisation pathway for the electricity system. DECC tasked SEAI with the latter in the Climate Action Plan 2023.

SEAI generated the forecasts by pooling expert opinion. Thirty highly regarded experts participated in the study, drawn from state agencies, industry (power generation and networks), electricity and gas system operators, and universities across Ireland and the UK. Participants provided probabilistic quantitative forecasts, and a qualitative description of the conditions associated with their low and high forecasts. The forecasts were pooled to form an Expert Pooled Opinion (EPO) with each participant's forecasts weighted equally. From this we drew forecasts that span an 80% confidence interval as per *Table 1*.

Table 1: Expert Pooled Opinion forecasts for technology deployment

Forecast	Definition	Qualitative meaning
EPO90	Linear weighted average of individual Cumulative Distribution Functions (CDF) for each year @ p = 0.1 (that is, there is a 9 in 10 chance that deployment will be *higher*)	The lowest plausible bound for future deployment that captures the idea of being 'almost certain' that deployment would in fact be <u>higher</u>. Anything below this could be considered unbelievable, far-fetched, or unimaginable.
EPO50	Linear weighted average of individual CDFs for each year @ p = 0.5 (that is, a 1 in 2 chance that deployment will be lower or higher)	A median or 'best estimate.'
EPO10	Linear weighted average of individual CDFs for each year @ p = 0.9 (that is, there is a 1 in 10 chance that deployment will be *higher*)	The highest plausible bound for future deployment that captures the idea of being 'almost certain' that deployment will be <u>lower</u>. A very unlikely but conceivable rate of deployment. Anything above this could be considered unbelievable, far-fetched, or unimaginable.

Table 2 summarises the quantitative results. There are significant uncertainties in the deployment of mature and new generation technologies in Ireland. Expert pooled opinion deems 2030 target attainment for renewables either very unlikely (for onshore wind and solar PV) or unimaginable (for offshore wind). Furthermore, it deems any deployment of BECCS or gas-CCS before 2040 very unlikely, forecasting no more than a few hundred MW of thermal plant fuelled with green/blue hydrogen or ammonia deployed by 2040.

The gap between plausible technology deployment rates and carbon budget requirements may be large. If implausible rates of technology deployment are assumed (or any other form of optimism bias accepted) in the power sector, the true requirement to decarbonise other areas is missed. We recommend a comparison between current carbon budget solutions and the expert pooled opinion to quantify the gap between what is deemed plausible and what is required for the power sector. Furthermore, alternative pathways to power sector decarbonisation need to be considered, as expert pooled opinion deems it unlikely that the set of technologies currently under consideration will deliver the desired emissions reductions by 2040.

Table 2: Expert elicitation results. Expert Pooled Opinion (EPO) forecasts for cumulative installed generation capacity (GW) of offshore wind, onshore wind, solar PV, thermal plant with hydrogen or ammonia fuel, thermal gas with carbon capture and storage (gas-CCS), and bio-energy or waste-to-energy with carbon capture and storage (BECCS, WtE-CCS), under low (EPO90), median (EPO50), and high (EPO10) deployment 2024–2040. The hydrogen/ammonia EPO10* forecast is adjusted to exclude one outlier, with further information in the results section.

	Offshore Wind			Onshore Wind			Solar PV			Hydrogen or Ammonia			BECCS or WtE-CCS			gas-CCS		
	EPO90	EPO50	EPO10	EPO90	EPO50	EPO10	EPO90	EPO50	EPO10	EPO90	EPO50	EPO10*	EPO90	EPO50	EPO10	EPO90	EPO50	EPO10
2024	0.0	0.0	0.0	5.0	5.1	5.3	1.4	1.8	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	5.2	5.4	5.9	1.8	2.5	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	5.4	5.7	6.4	2.2	3.3	4.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	5.6	6.1	6.9	2.6	4.0	5.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.4	5.8	6.4	7.5	3.0	4.8	6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	1.3	6.0	6.8	8.0	3.4	5.5	7.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	1.4	3.7	6.2	7.1	8.5	3.8	6.3	8.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	2.0	4.4	6.5	7.5	9.0	4.2	6.9	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.4	2.5	5.2	6.8	7.9	9.6	4.6	7.5	9.8	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.8	3.1	6.0	7.1	8.4	10.1	5.0	8.1	10.7	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0
2034	1.0	3.7	6.9	7.4	8.8	10.7	5.4	8.6	11.6	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0
2035	1.0	4.5	7.7	7.6	9.2	11.2	5.4	9.2	12.5	0.0	0.1	0.9	0.0	0.0	0.1	0.0	0.0	0.0
2036	2.0	5.2	8.9	7.8	9.4	11.7	5.7	9.7	13.3	0.0	0.1	1.2	0.0	0.0	0.1	0.0	0.0	0.0
2037	2.8	6.1	10.1	8.1	9.8	12.1	6.0	10.2	14.1	0.0	0.2	1.4	0.0	0.0	0.1	0.0	0.0	0.2
2038	3.4	7.0	11.3	8.3	10.1	12.5	6.2	10.6	15.0	0.0	0.3	1.7	0.0	0.0	0.1	0.0	0.0	0.3
2039	4.0	7.9	12.6	8.5	10.4	12.9	6.5	11.1	15.9	0.0	0.4	2.0	0.0	0.0	0.2	0.0	0.0	0.4
2040	4.5	8.8	14.2	8.7	10.7	13.3	7.1	11.6	16.8	0.0	0.7	2.4	0.0	0.0	0.2	0.0	0.0	0.6

1. Introduction

This study responds to two policy drivers. Firstly, it provides data input to a larger SEAI work programme to generate a decarbonisation pathway for the power sector. Secondly, it provides data input to SEAI's contribution to the Carbon Budgets Working Group.

In the 2023 Climate Action Plan, the Department for Environment, Climate and Communications (DECC) tasked SEAI to provide the Government with an evidence-based pathway for decarbonising the Irish electricity system. A programme of work to generate this evidence base commenced in 2023 and will be completed by the end of 2026. This study completes one work package within the Decarbonised Electricity System Study, aimed at an initial approximation of supply side risks to sectorial decarbonisation up to 2040. This will be followed in 2025 with a detailed analysis of a larger set of technologies against a larger set of factors that are likely to determine sectorial decarbonisation up to 2040 and 2050. More information on this programme of work can be found on the SEAI website.[1]

The Climate Change Advisory Council (CCAC) Ireland is responsible for setting national Carbon Budgets. SEAI is a member of the Carbon Budgets Working Group, which is responsible for supporting the CCAC in the budgeting process. In December 2023, SEAI reviewed the first iteration of model solutions for the third and fourth budgets to identify the technologies on which the heaviest reliance is placed for power sector decarbonisation up to 2040. This study validates assumptions on plausible deployment rates (i.e. cumulative installed capacity) between 2024–2040, and technology availability (that is, the earliest year of first deployment for new technologies) for each of these technologies. The Carbon Budgets Modelling Review, SEAI's formal submission to the Carbon Budgets Working Group, used the forecasts for renewables from this study for its risk scenarios. This report can be found on the CCAC website.[2]

SEAI completed an *expert elicitation* to generate the forecasts in this study. Pooling the subjective judgments of experts to draw out the wisdom of the crowd is common; it's often employed during long-term power sector planning: at times when other sources of data provide only limited information about the future; where there is a need to supplement other methods of forecasting; or where there is a need to validate model solutions. We explain our approach and method in detail in Section 2. Experts participated on condition of anonymity and their forecasts do not necessarily represent the position of their institutions (where such positions exist). However, we included a broad set of interests and range of expertise hailing from institutions that will be central to the decarbonisation of the Irish power sector.

Two caveats to the results are noted upfront. Firstly, there is no evidence that expert elicitations offer more accurate forecasts than other methods. Secondly, the expert pooled opinion results do not represent power sector scenarios. That is, they do not represent a generation mix to meet a specified demand subject to an emissions constraint and a set of internally consistent assumptions. Rather, each set of results should be interpreted as a plausible range for generation technology buildout. The range internalises the widest possible set of drivers/conditions affecting deployment up to 2040 in the most extreme manifestations that experts could conceive (both best- and worst-case extremes), even though experts held conflicting views of what possible futures could look like.

[1] https://www.seai.ie/renewable-energy/decarbonised-electricity-system-study
[2] https://www.climatecouncil.ie/carbonbudgets/carbonbudgetsworkinggroup2023-2024/

2. Method

Seeking the subjective judgment of a pool of experts is common in certain contexts: where other sources of data provide only limited information about the future; where there is a need to supplement other methods of forecasting; or where there is a need to validate model solutions.[3] Expert elicitation has been applied frequently to energy and power sector planning where uncertainty stems from insufficient, contradicting, low-quality or unattainable data. It is used most frequently to forecast technology costs over the medium to long-term.[4] It has also been used to establish the likelihood of scenarios and their timing; as input to least-cost optimisation models; and to validate the output of such models.[5] In the latter use case, expert elicitations may be particularly helpful in validating least-cost model solutions for decarbonisation against solutions considered plausible by a wider group of subject/sectorial experts.[6]

2.1. Expert elicitation design

In November 2023, SEAI reviewed the first iteration of carbon budget modelling outputs to identify the technologies that primarily support the mitigation effort in the power sector up to 2040. These technologies are onshore wind, offshore wind, solar PV, hydrogen, and Biomass with Carbon Capture and Storage (BECCS). Our Working Group agreed that plausible deployment rates (that is, cumulative installed capacity) between 2024–2040, and technology availability (that is, the earliest year of first deployment for new technologies like offshore wind power, hydrogen and BECCS) ought to be validated.

The expert elicitation produced time series data with annual granularity of cumulative installed capacity for each technology (MW). In addition, based on feedback from the Working Group and the Department, it was noted that qualitative data justifying or explaining the assumptions behind the forecasts would also be useful. Table 3 presents the formulation of the elicitation questions.

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[3] Anthony O'Hagan, Caitlin E. Buck, Alireza Daneshkhah, J. Richard Eiser, Paul H. Garthwaite, David J. Jenkinson, Jeremy E. Oakley, Tim Rakow. 2006. Uncertain Judgements: Eliciting Experts' Probabilities. Online ISBN:9780470033319. DOI:10.1002/0470033312

[4] Diaz Anadon L, Bunn M, Narayanamurti V, eds. Transforming US Energy Innovation. Cambridge University Press; 2014:36-80

[6] Ian Durbach, Bruno Merven, Bryce McCall. 2017. Expert elicitation of autocorrelated time series with application to e3 (energy-environment-economic) forecasting models. Environmental Modelling & Software. Vol. 88. p. 93–105. http://dx.doi.org/10.1016/j.envsoft.2016.11.007

[6] Mariësse A.E. van Sluisveld, Mathijs J.H.M. Harmsen, Detlef P. van Vuuren, Valentina Bosetti, Charlie Wilson, Bob van der Zwaan. 2018. Comparing future patterns of energy system change in 2 °C scenarios to expert projections, Global Environmental Change, Volume 50, pp. 201–211, ISSN 0959-3780, https://doi.org/10.1016/j.gloenvcha.2018.03.009

[7] Deciding on the number of timepoints and the number of points within each distribution involves a trade-off between obtaining an accurate representation of the entire judgmental time series, and the effort that experts are willing to expend.

[8] Some experts prepared annual timeseries forecasts in advance, based on existing analysis they (or their institution) had undertaken, making Question 4 redundant in some instances.

Questions 1–3 elicit nine quantitative data points: low, median, and high cumulative deployment for 2030, 2035, and 2040.[7] Question 4 elicits qualitative data to interpolate an annual timeseries for the period 2024–2040 from the nine points.[8] This design provides a credible or plausible interval (90% confidence interval for each expert), and a mode forecast at each time point. This probability distribution for technology deployment for each expert (a cumulative distribution function) can be pooled into an Expert Pooled Opinion (EPO).[9] Multiple probabilistic deployment scenarios can be drawn from the EPO to validate TIMES-Ireland Model (TIM) results against a plausible envelope for technology deployment.

Table 3: Expert elicitation interview questions

QUESTIONS (in general form)
1. **Low deployment forecast**: "For [technology X] in [2030, 2035, 2040] what is a plausible **low** estimate for cumulative installed capacity (MW) such that there is only a 5% probability it could be lower? That is, you are almost certain it could not be lower."
2. **Most likely deployment forecast**: "For [tech X] in [2030, 2035, 2040], what is a plausible **median** estimate for cumulative installed capacity (MW) such that it is equally likely that the actual value will be higher or lower?"
3. **High deployment forecast**: "For [tech X] in [2030, 2035, 2040] what is a plausible **high** estimate for cumulative installed capacity (MW) such that there is only a 5% probability it could be higher? That is, you are almost certain it could not be higher."
4. **Interpolation of annual data: "**For [tech X] between [2023–2030, 2031–2035, 2036–2040] what is the deployment trajectory? Is it linear or non-linear? Do you have an average rate of deployment (MW/annum) in mind? For [new technologies] when is the earliest year of availability? Are there step changes in installed capacity in particular years as large projects connect?"
5. **Qualitative scenario description:** "What conditions drive or constrain the deployment of [tech X] up to [2030, 2035, 2040] in your [low / high] forecast?" Alternatively: "What are the assumptions that underpin your [low and high] forecast for [2030, 2035, 2040]?"

Question 5 sought a justification for the low and high forecasts. The latter was not intended to offer precise data on all or particular technical points, but rather initiated open-ended conversations for experts to explain the broad assumptions underpinning their forecasts. The general question would be followed with more specific questions on the conditions thought to limit/enable technology deployment.

2.2. Expert selection

The Working Group selected experts based on tangible evidence of their expertise and knowledge of the power sector, either demonstrated through publications (in the case of academic or other researchers) or due to their extensive professional career and reputation within the Irish power sector. We also sought to achieve a balanced set of views, selecting individuals from state agencies (n=6), electricity and gas system operators (n=3), academic institutions (n=8), and industry (n=13). Industry includes wind and solar industry associations, generators (thermal, wind and solar), grid development and connection, and engineering, economic and legal services. Participants were affiliated with a broad set of institutions as set out in *Table 4*. However, individuals participated anonymously and did not necessarily represent the position of their institutions.

As a general guideline, expert elicitation practitioners recommend a sample of six to twelve experts for an elicitation (Knoll et al 2010). Fewer than six experts may undermine the robustness of the results and acceptance by decision makers. Experience indicates that beyond 12 experts, the benefit of including additional experts begins to drop off quickly. We achieved samples in this range, six to twelve, for each technology (refer to *Table 4*). For CCS, eight participants offered qualitative feedback, but only six were willing to provide quantitative forecasts. Two participants were specialist geologists with deep knowledge on geological storage options in Ireland, but insufficient knowledge of the power sector to forecast the unit of interest. None of the participants for the elicitations on renewables participated in the elicitations on hydrogen, ammonia, and CCS, and vice versa. Most participants for the renewable elicitations provided forecasts for more than one of the three renewable technologies.

The Working Group followed three steps to select the pool of experts. Firstly, the group discussed and agreed on the types of expertise relevant to the study and how to identify the appropriate experts. Once a common framework was agreed, each Working Group member could nominate experts for each of the selected technologies by providing a brief description of their expertise (including links to their online profile and publications). Thirdly, the list of all nominees was circulated with the group for approval. Working Group members could veto any nominees they deemed inappropriate (for instance, if they thought a nominee had insufficient expertise, or that their commercial interests and character could fundamentally undermine their better judgement). Working Group members then ranked the nominees if there were more than twelve. Finally, the principal researcher sent invitations to the ranked shortlist of nominees to participate, starting with the most highly ranked until the target sample of participants were obtained.

It should be noted that there is currently a scarcity of experts with a deep knowledge of both CCS and the Irish power sector. Working Group members had trouble nominating a sufficient sample for this technology. One participant is a specialist on CCS in the UK power sector, using this as a reference case for an opinion on deployment in Ireland. A further two are geologists with specialist knowledge of geological storage options for hydrogen or CCS in Ireland, but not the power sector.

Table 4: Participants, their type of organisation and the technologies on which they issued an opinion. Numbers in brackets indicate where experts gave qualitative input, but no quantitative forecast.

	Organisation	OFW	ONW	SPV	H2/NH3	CCS
Expert 1	State agency	Y	Y	Y	N	N
Expert 2	Industry	Y	Y	Y	N	N
Expert 3	Academic	Y	Y	N	N	N
Expert 4	Industry	N	N	Y	N	N
Expert 5	State agency	Y	N	N	N	N
Expert 6	Academic	Y	N	N	N	N
Expert 7	Industry	N	Y	Y	N	N
Expert 8	Academic	Y	Y	Y	N	N
Expert 9	Industry	Y	Y	N	N	N
Expert 10	System Operator	N	Y	Y	N	N
Expert 11	State agency	Y	N	N	N	N
Expert 12	Industry	N	Y	N	N	N
Expert 13	State agency	N	Y	Y	N	N
Expert 14	Industry	Y	Y	Y	N	N
Expert 15	System Operator	(Y)	(Y)	(Y)	N	N
Expert 16	Industry	N	N	N	Y	N
Expert 17	Academic	N	N	N	Y	N
Expert 18	Academic	N	N	N	Y	N
Expert 19	Industry	N	N	N	Y	N
Expert 20	Academic	N	N	N	Y	Y
Expert 21	State Agency	N	N	N	Y	N
Expert 22	Industry	N	N	N	Y	N
Expert 23	Academic	N	N	N	(Y)	Y
Expert 24	Industry	N	N	N	Y	Y
Expert 25	Industry	N	N	N	Y	Y
Expert 26	System Operator	N	N	N	Y	Y
Expert 27	Academic	N	N	N	N	(Y)
Expert 28	State Agency	N	N	N	(Y)	(Y)
Expert 29	Industry	N	N	N	Y	N
Expert 30	Industry	N	N	N	Y	Y
		9 (10)	10 (11)	8 (9)	12 (14)	6 (8)

2.3. Mitigating biases

Judgements of probability are subject to systematic biases that may lead to substantial judgement errors. Protocols for mitigating bias in the elicitation of probability distributions are well-established (O'Hagan et al. 2006). These protocols required substantial time and effort from participating experts.

We carried out key informant interviews with individuals, rather than group elicitation or an online survey. Interviews are preferable to surveys, given the calibre of expert we engaged with and the nature of the topic.[10] Group discussions risk inappropriate dominancy of influential experts; the implicit suggestion of the need to achieve consensus; and other biases depending on the make-up of the group. Individual interviews allow for more targeted questions, detailed explanations, and slower consideration of complex issues. However, in several instances participants preferred to include other experts from their institution. In such instances they issued a joint forecast which was counted as 'one expert' in the study. Interviews generally lasted 1.5–3 hours depending on how many technologies were considered.

In the initial invitation to participate in this study, SEAI explicitly noted that individuals were approached based on their expertise and not as a representative of an institution. They were therefore expected to present their personal judgements and not 'the company line.' All interviews were confidential, and forecasts are anonymised.

In preparation for the interview, experts were asked to read a brief prepared by SEAI that included an overview of the factors influencing power generation technology deployment in Ireland. This brief also compiled the latest relevant data to aid forecasting (for example, different electricity demand forecasts out to 2040 and historical deployment rates of technologies in Ireland and elsewhere). The brief served as a starting point for the interview discussions and ensured appropriate preparation from participants, but did not imply any forecasts. The briefing note can be accessed on the SEAI website.[11]

Participants were also asked to read a slide deck prepared by SEAI on common systematic biases that influence subjective probability judgements, including examples of overconfidence bias, optimism bias, and anchoring and adjustment bias. The deck included questions for participants, such as:

- Have your judgements been anchored or conditioned by related work (for example, RES-E or emissions reduction targets)?
- Could you be reluctant to modify your existing views in the light of new evidence? e.g. For example, where you, or the institution you are affiliated with, have made strong public claims on the matter previously?
- What value are you using as a baseline or reference case? What if you chose another?
- Can you think of conditions under which more extreme values might occur? How easily?

The final question in the list was often repeated during the interview when low and high forecasts were given.

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[10] Experts tend to be more motivated to participate in one-to-one interviews where the importance of their expertise is explicitly recognised. They may also feel a greater sense of responsibility to provide informed judgements to an interviewer rather than to an email query or anonymous online questionnaire.

[11] https://www.seai.ie/renewable-energy/decarbonised-electricity-system-study

Participants used heterogeneous forecasting methodologies and assumptions, with almost no participants making unassisted forecasts. That is, almost all forecasts were made with recourse to extant, sometimes proprietary, data, projections, and/or models. For example, forecasts for wind and solar PV deployment up to approximately 2030 was often based on data from the system operators and/or industry on the 'pipeline of projects' currently in the planning system at various stages of permitting. Long-term historical data on the deployment of onshore wind power and the more recent historical data on solar PV deployment in Ireland also assisted some of the forecasting.

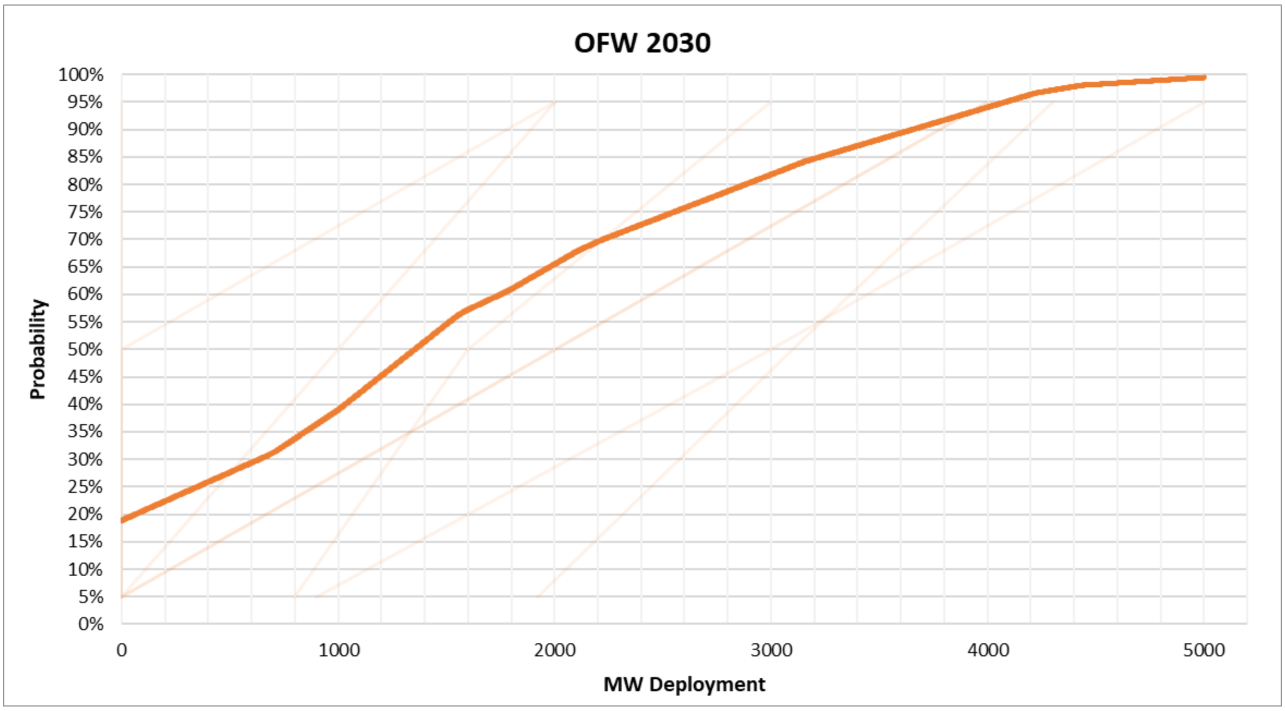
Forecasts for hydrogen/ammonia deployment up to the early 2030s were most often based on knowledge of the number of pilot or demonstration projects under development in Ireland, as well as knowledge of some of their own or other actors' intention to develop projects. This often served to furnish median or 'best guess' forecasts to 2030, from which a confidence interval was derived. For the long-term (generally from about 2035 to 2040), participants' forecasting strategies shifted from extant data to a set of different heuristics. Some participants made use of EirGrid's Tomorrow's Energy Scenarios (TES) for a set of anchors or heuristics (for example, peak demand in 2040 or installed gas thermal capacity) from which they then made further adjustments based on their own critical judgement. One participant made explicit use of a power system dispatch model. Most participants did not employ back-casting techniques. That is, they did not assume that net zero would be achieved by a specified date from which they back-cast technology deployment to meet that constraint in an uncritical fashion. However, a few participants did assume a net zero power system by 2040 without considering or justifying the plausibility of this assumption. In such instances, experts assigned this forecast to their high deployment scenario, arguably introducing a significant anchoring and/or over optimism bias. This bias is most observable in the EPO10 forecast for hydrogen and ammonia plant.

2.4. Pooling expert opinion

We used the wisdom of the crowd to validate carbon budget solutions. We generate this by creating a linear Cumulative Distribution Function (CDF) for each expert from their three forecast data points for each year 2024–2040. We then calculate the weighted average of individual CDFs, weighing each expert's forecast equally—a standard linear opinion.[12] *Figure 1*shows an example of the expert pooled opinion for offshore wind deployment in 2030, with individual CDFs noted in light faded orange.

[12] O'Hagan, et al. 2006. Uncertain Judgements: Eliciting Experts' Probabilities. DOI:10.1002/0470033312

Figure 1: Generating the linear opinion pool (cumulative distribution function) from individual forecasts for 2030



From the annual pooled CDFs, we draw three Expert Pooled Opinion (EPO) forecasts for each technology for three scenarios that span an 80% confidence interval *(Table 5)*. This represents our recommendation to the Climate Change Advisory Council Working Group on Carbon Budgets for lower and upper bounds with which to constrain model solutions. The anonymised forecasts of all participants, from which the EPO forecasts are constructed, are also available on request.

It is possible to draw different forecasts at any value of $0.05 < p < 0.95$ given the phrasing of the questions (refer to *Table 3*). However, we advise against values of $p < 0.1$ or $p > 0.9$. This is because we did not eliminate extreme outliers from our participant forecasts. For some of the technologies, one or two very extreme forecasts (at either the top or bottom end of the spectrum) create long tails beyond 0.1 and 0.9.

Table 5: EPO scenarios for technology deployment

Forecast name	Definition	Qualitative meaning
EPO90	Linear weighted average of individual CDFs for each year @ p = 0.1 (that is, there is a 9 in 10 chance that deployment will be higher)	The lowest plausible bound for future deployment that captures the idea of being 'almost certain' that deployment would in fact be higher. Anything below this could be considered unbelievable, far-fetched, or unimaginable.
EPO50	Linear weighted average of individual CDFs for each year @ p = 0.5 (1 in 2 chance)	A median or 'best estimate'.
EPO10	Linear weighted average of individual CDFs for each year @ p = 0.9 (that is, there is a 1 in 10 chance that deployment will be *higher*)	The highest plausible bound for future deployment that captures the idea of being 'almost certain' that deployment will be lower. A very unlikely but not impossible rate of deployment. Anything above this could be considered unbelievable, far-fetched, or unimaginable.

Finally, it should be emphasised that neither the forecasts from individual participants, nor the final EPO results, present coherent scenarios. In other words, they do not represent a generation mix to meet a specified demand subject to a decarbonisation constraint and a set of coherent underlying assumptions. The elicitation results have a fundamentally different interpretation from the results of least-cost optimisation models, hence why this method provides an independent sense check. Firstly, for each participant, their low, median, and high forecasts represent very different worlds at points in time. For instance, high electricity demand growth was one necessary condition (amongst other conditions) for most (but not all) participants' high forecasts, and conversely low demand growth was a necessary condition (amongst other conditions) for most (but not all) low demand forecasts, whereas the assumed demand differed for median forecasts. Secondly, across the pool of experts there are widely differing conditions tied to low, median, and high forecasts for different technologies. For instance, participants had widely different opinions on when net zero would be achieved, and the technical feasibility or economic viability of large-scale geological storage for hydrogen.

Rather, the forecasts should be read as upper and lower constraints and median best guesses on individual technology buildout that consider the widest possible set of drivers or conditions that could affect deployment up to 2040; the forecasts also come from a wide range of experts with different (and often conflicting) views of what the future could look like. EPO90 forecasts should be interpreted as portraying a world where all the worst-case conditions for deployment of a particular technology stack up. Shifting worst-case configurations of conditions up to 2040 drive the lowest and slowest conceivable deployment of a generation technology. Conversely, EPO10 should be interpreted as portraying a world where all the best-case conditions for deployment of a particular technology stack up. Shifting best-case configurations of conditions drive the fastest and highest conceivable deployment of a generation technology.

3. Results

This section presents the three Expert Pooled Opinion (EPO) forecasts for each technology according to *Table 5*. Results are presented for each technology in turn, with the quantitative forecasts followed by a synthesis of the qualitative feedback for that technology.

As noted, participants described their own low and high deployment scenarios for each technology and there are differing degrees of overlap or agreement/disagreement between these scenarios. The syntheses presented below roughly focus on the points that all or most participants agree on, followed by a selection of points shared by only some, a few or one participant. It does not offer an exhaustive account. Throughout the text, indications are given on the extent to which the pool of participants agree with certain statements, according to *Table 6*.

Table 6: Qualitative qualifiers and proportion of agreement within the sample of participants for each technology

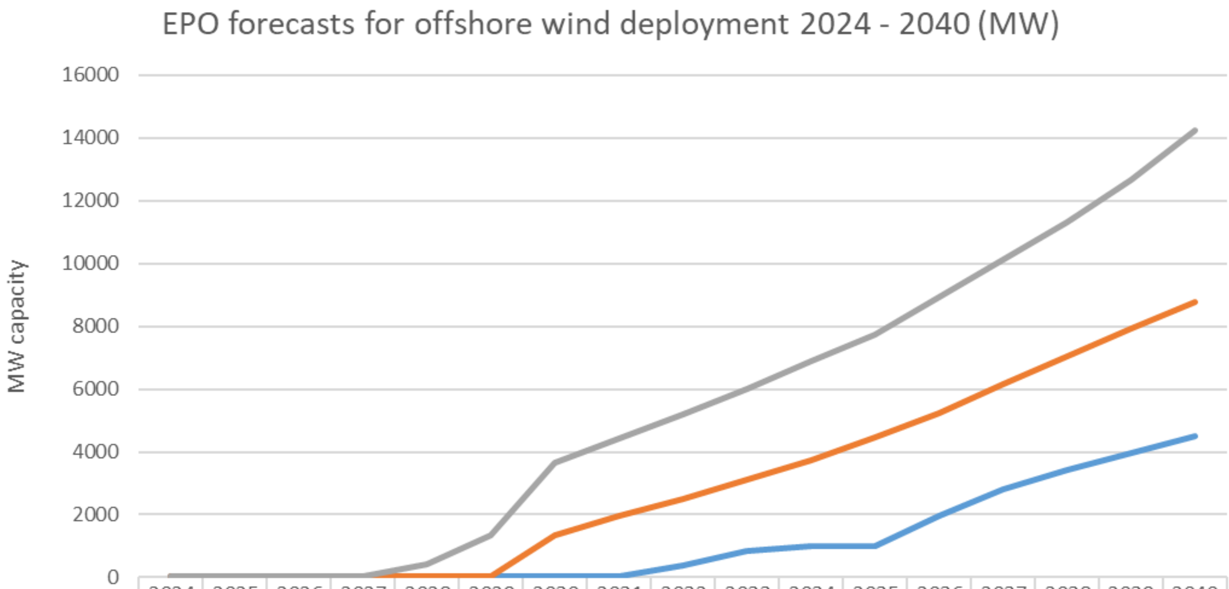
Qualifier	Proportion of participants
No/none	0%
A couple/few	0–25%
Several/some	25–50%
Most	50–75%
Almost all	75–100%
All	100%

The interview notes and transcripts are not available on request as they contain confidential information, and full anonymisation is not possible.

3.1. Offshore wind

Figure 2 presents the EPO forecasts for offshore wind.

Figure 2: Expert elicitation results for plausible deployment of offshore wind power (MW) 2024–2040



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
EPO90	25	25	25	25	25	25	25	25	400	834	980	1008	1978	2815	3433	3977	4500
EPO50	25	25	25	25	25	25	1354	1952	2516	3118	3727	4481	5215	6140	7039	7928	8790
EPO10	25	25	25	25	407	1338	3654	4428	5204	6020	6873	7730	8922	10142	11318	12648	14226

EPO90 EPO50 EPO10

- There is a wide confidence interval between plausible low and high bounds of offshore wind power deployment in 2030, 2035 and 2040. This reflects wide confidence intervals for most participants (they are very uncertain about the future) and wide distribution between participants.
- Most participants think it plausible (though unlikely) that no offshore wind will be connected by 2030 (pooled opinion: there is a 20% chance that no offshore wind will be installed by 2030). All but one participant thinks attaining the 5 GW target (of installed offshore wind energy) in 2030 is far beyond plausible (pooled opinion: there is a 90% chance that less than 3.7 GW will be installed by 2030).
- By 2040, participants think it plausible that anywhere between 4.5 GW and 14.2 GW will be installed, with a pooled best guess of 8.8 GW.

Where offshore wind power is concerned, all participants divide their qualitative account between separate factors. These are a) the factors that are determining the deployment of the seven projects designated as Relevant Projects in 2020 under the transitional protocol from a developer-led planning regime (also referred to as Phase 1 projects following the granting of Maritime Area Consents in 2022), and b) the drivers of offshore wind deployment for all other projects following Phase 1 projects.[13] Accounts on Phase 1 projects tend to terminate between 2030 and 2035, whereas the drivers for projects developed under the subsequent Phase 2 and Future Framework regimes tend to commence in 2024 with the development of the first Designated Marine Area Plan (DMAP) and then expand into more general drivers for offshore wind deployment over the 2030s.[14]

Conditions for low deployment

In a low deployment scenario, almost all participants agree that legal, planning and/or supply chain challenges could coincide to delay most or all Phase 1 projects, while successful Judicial Review (JR) challenges could lead to at least one Phase 1 project being abandoned. All participants agree that none of the Phase 1 projects will be deployed before 2029 but differ on the subsequent speed of deployment. The most optimistic participant forecasts deployment from 2029 onwards, while the most pessimistic participants forecast no deployment up to 2035. In particular:

- Some participants think that a lack of specialist resources and capacity in planning and permitting agencies could delay the consenting of Phase 1 projects. For some Phase 1 projects, these delays may affect them a second time if developers must resubmit applications for planning consent following successful JR proceedings.
- All but one participant agree that most or all Phase 1 projects could be delayed by 18 months to four years by Judicial Review proceedings. Most participants think that JR proceedings would merely delay Phase 1 projects, but that most or all Phase 1 projects would connect after 2030. Some experts think that one or more JRs could be successful and that some Phase 1 projects could ultimately be unconsentable and abandoned.
- Some participants think that bottlenecks in international supply chains—especially long lead times to schedule installation vessels, secure cable, or secure/develop necessary port facilities—will delay construction further for most Phase 1 projects (following consenting and JR-related delays).

Due to the above conditions, most participants think it plausible that no offshore wind (OFW) capacity will be connected by 2030, but some experts think that at least one or two Phase 1 projects may still connect by 2030 in a low deployment scenario. In addition, most participants think it plausible (but unlikely) that the 'developer-led' planning regime ultimately delivers only one or two of the Phase 1 projects. A couple of experts think it plausible that the basis for legal challenge to Phase 1 projects could be systemic, leading to all projects being unconsentable.

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[13] The Relevant Projects are the seven offshore wind projects that had applied for or had been granted a lease under the Foreshore Act 1933, or had been eligible to be processed to receive a valid grid connection offer in 2020 (more information at: https://www.gov.ie/en/press-release/07331-transition-of-offshore-renewable-projects-announced/)

[14] More information at: https://consult.decc.gov.ie/en/consultation/future-framework-public-consultation

Some participants think that the failure of the developer-led regime will coincide with delays in implementing the plan-led regime. Learning could be slow, and it could take several years to establish the plan-led regime through DMAPs. For example, the Oireachtas may not adopt the south coast DMAP in 2024 and/or there may be a JR against the first DMAP. Technical uncertainties and risks remain with linking the first DMAP to a route to market. For instance, there could be unfavourable geophysical and geotechnical conditions; complications with developing appropriate terms for and executing Offshore Renewable Electricity Support Scheme (ORESS) 2.1; or delays with the necessary grid development. In short, some participants think it plausible that the learning on the first DMAP will be relatively slow, so that only one project connects under the DMAP by 2035.

On the other hand, some participants think it implausible that the failure of the developer-led planning regime could coincide with extensive delays in the plan-led regime. On the contrary, failure of the former will expediate political effort to implement the latter. The capacity and resource constraints faced by state agencies in the short-term will be resolved more quickly, leading to relatively rapid development of more than one DMAP. However, even in such a scenario, only one or two projects may be connected by the early 2030s in the south coast DMAP, with subsequent DMAPs delivering capacity after 2035.

A few participants noted that delays in deploying Phase 1 projects in the run-up to 2030 could coincide with greater policy support for onshore renewables to meet the 2030 RES-E target. If successful, this could lead to a political deprioritisation of OFW in the medium term, particularly in a scenario of low electricity demand growth. Low electricity demand growth could cap OFW as a residual source of electricity up to 2040, with only one or two projects connected by 2035.

However, even in such a scenario, most participants think there will be a step up in the deployment of OFW from 2036 onwards, with approximately one project annually connecting to the grid. These projects will be located in multiple DMAPs. A few participants highlight that a lack of market reform to protect revenues for OFW and a lack of investment in RD&D in long duration storage and hydrogen production and usage (in the late 2020s and early 2030s) could contribute to limiting OFW deployment up to 2040.

Conditions for high deployment

In a high deployment scenario, most participants think it plausible that most or all Phase 1 projects will be connected by the early 2030s. Most Phase 1 projects may not face a combination of two or more types of delay related to planning consent, JR, or supply chain bottlenecks; alternatively, these delays could be of shorter duration than in a low deployment scenario.

- Most participants think it plausible (though unlikely) that all Phase 1 projects receive planning consent within nine months from application. This assumes that the Oireachtas reforms legislation to impose time limits on planning decisions for national strategic infrastructure, and that An Bord Pleanála (ABP) and National Wildlife and Parks Services (NWPS) establishes additional capacity for processing applications as a matter of urgency.
- Even in a high deployment scenario, most participants assume that JRs will be brought against most Phase 1 projects. However, almost all participants think it plausible that these projects could suffer minimal delays between 18 months and two years, with no JRs resulting in abandoned projects. This assumes that most or all JRs are rejected or that they all run concurrently. Some participants noted that

this necessitates legislative reform to implement both time limits on JR decisions and additional capacity for the High Court to deal with several Phase 1 JRs concurrently.

- Most participants think it plausible (though unlikely) that supply chain related bottlenecks may not delay some or most Phase 1 projects. This assumes that some developers, who have already secured installation vessels for their international portfolio, could deploy these to Ireland at shorter notice when they receive consent or resolve their JR, or that there will be sufficient capacity in Belfast Port to commence construction of the earlier projects in 2027, following which port facilities are established in the Republic of Ireland.

Even in a high deployment scenario, all participants agree that offshore wind capacity dedicated to hydrogen production is implausible by 2030.

In a high deployment scenario, most participants think that the short-term capacity constraints in relevant state agencies could resolve by the mid- to late-2020s; they also think that the DMAP regime could mature to offer a steady flow of consented projects from the early 2030s onwards. This assumes a seamless transition from the developer-led to the plan-led approach, which requires the Oireachtas to adopt the south coast DMAP in 2024; the first auction (ORESS2.1) to happen in 2025; and subsequent auctions (for example, ORESS 2.2) to happen in a timely manner in this zone. It also assumes that the cycle for developing and adopting subsequent DMAPs lasts around 18 months and that more than one could be developed in parallel from the late 2020s onwards.

Most participants think it plausible that one or two projects will be connected under the plan-led regime by 2035 (from the south coast DMAP) and that projects from other DMAPs will only connect after with acceleration of connected projects from 2036 to 2040. It also requires completion of the connection infrastructure for the south coast DMAP by the early 2030s and the necessary grid development for several GW to connect from other DMAPs by the mid-2030s. Some participants assume that the south coast DMAP could offer several projects totalling up to 5 GW (but that not all will connect by 2035).

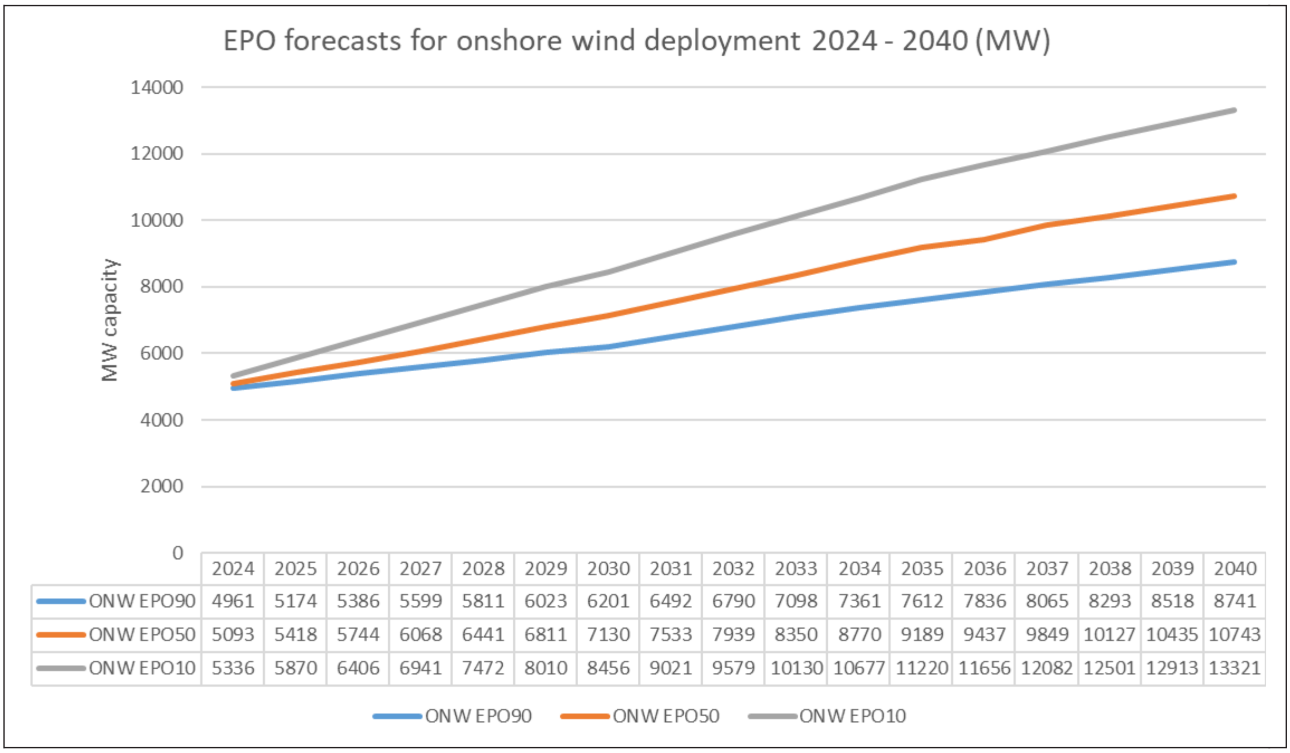
A few participants think a high deployment scenario is only plausible if electricity demand growth is high (because of the price premium for OFW over onshore renewables), or if the deployment of onshore renewables faces significant challenges in the mid- to late-2020s. In other words, for some participants, their high deployment scenario for onshore renewables is mutually exclusive to their high deployment scenario for OFW, given their assumption about demand growth.

For a couple of participants, a high deployment scenario also requires further maturation of technologies. This includes declining costs of fixed bottom OFW in deeper waters. Some participants think that floating offshore wind could start connecting in the late 2030s under a high deployment scenario, with one participant noting spatial constraint to fixed bottom offshore wind at around 10 GW. No participants assume that a high deployment scenario includes dedicated offshore wind capacity for hydrogen production, although one participant assumes that hydrogen production would have to be in place as a partial guard against significant constraints.

3.2. Onshore wind

Figure 3 presents the EPO forecasts for onshore wind.

Figure 3: Expert elicitation results for plausible deployment of onshore wind power (MW) 2024–2040



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
ONW EPO90	4961	5174	5386	5599	5811	6023	6201	6492	6790	7098	7361	7612	7836	8065	8293	8518	8741
ONW EPO50	5093	5418	5744	6068	6441	6811	7130	7533	7939	8350	8770	9189	9437	9849	10127	10435	10743
ONW EPO10	5336	5870	6406	6941	7472	8010	8456	9021	9579	10130	10677	11220	11656	12082	12501	12913	13321

- Experts are more certain about the deployment of onshore wind than other renewable technologies up to 2030. This reflects a similar ‘project pipeline stacking’ heuristic employed by most participants, historical precedent, and technological maturity in Ireland.
- By 2030 it is plausible that between 6.2 and 8.5 GW of onshore wind capacity will be installed. The expert pooled opinion is that attaining the 9 GW target by 2030 is not plausible.
- By 2040 it is plausible that anywhere between 8.7 GW and 13.3 GW will be installed, with a pooled best guess of 10.7 GW.

For onshore wind, accounts tend to be divided between projects already in the planning system, which largely make up the forecasts for 2030 (through a pipeline stacking heuristic), and more general drivers of deployment from 2030 onwards.

Conditions for low deployment

Most participants think the continuation of the current planning and consenting regime and increasingly restrictive measures in spatial designation will result in a low deployment scenario. Such measures include:

- A continuation in the current trend for County Development Plans to decrease land designated as suitable for wind development and increase land designated as not normally permissible for wind development;

- More stringent noise limits and increase setback distances in the Wind Energy Development Guidelines (currently being updated);
- Evolution and more stringent application of nature conservation and restoration laws;
- Continuation of the current laws that affords broad grounds for objectors to bring JR against projects; and
- Continuation of current laws that fail to place a time limit on consenting decisions and legal proceedings.

Some participants think it plausible that there could be a political de-prioritisation of onshore wind in 2025 with a change in government. Such a de-prioritisation would be characterised by delays in obtaining state aid approval for extending the Renewable Electricity Support Scheme (RESS) and scheduling subsequent auctions, particularly RESS-5 to RESS-7, but would also relate to delays or abandoning legislative reform for planning —for instance, transposing the Third Renewable Energy Directive (RED 3) into Irish law. Some participants think that such a de-prioritisation would affect wind deployment even prior to 2030, but others think it will only affect deployment after 2030.

A couple of participants think it plausible that worsening grid constraints could contribute to lower deployment of onshore wind (ONW) before 2030. For instance, this may happen if Enduring Connection Policy (ECP) constraint forecast reports continue to send negative signal to the market and there is a delayed implementation of the system services for 95% System Non-Synchronous Penetration (SNSP).

Although supply chain bottlenecks are not generally noted as a risk for the mature onshore industry, a couple of participants noted that significant increase of lead times for materials (such as transformers and switchgear) could contribute to a low deployment scenario, as well as the systemic shortage of skilled labour in planning and permitting authorities that could persist over the short term.

Moving to the 2030s, most participants noted that a low deployment scenario for onshore wind in the early- to mid-2030s would be due to policy decisions taken from 2025 onwards. Examples of these decisions might include: a continuation of the current legislation enabling a high rate of objections; and/or continuation of the trend in County Development Plans to issue restrictive spatial designation incompatible with Climate Action and Low Carbon development Act; and/or new Wind Energy Development Guidelines imposing more stringent setback and noise constraints.

Most participants think it plausible that older wind power sites could fail to repower, and that some may not receive life planning consent extensions at the end of their consented life; this would increasingly affect cumulative deployment of onshore wind power from 2030 onwards. Repowering could be further limited by a trend towards larger turbines, re-designation or expansion of protected sites, and the lack of grid capacity for extant sites.

Some participants think that EirGrid's transmission network development plan, Shaping Our Electricity Future (SOEF), is not sufficient to enable high deployment of renewables, or alternatively that it is plausible that the Transmission System Operator (TSO) could fail to implement SOEF successfully. Grid-related challenges may increasingly limit onshore wind deployment in the 2030s, whether from new sites or the repowering of extant sites. Furthermore, lack of grid development in the northwest region will limit further expansion of onshore wind in areas there (for example, Mayo and Donegal) during the 2030s.

For most participants, the period from 2036–2040 in a low deployment scenario sees the continuation of conditions highlighted above. Most think it plausible that a political pivot away from ONW in in the late 2020s and early 2030s could occur if OFW deploys successfully, and that this could have a sustained effect on onshore wind deployment through to 2040. This political pivot away from onshore wind would be characterised by a lack of substantial new state aid routes to market after RESS (and onshore wind relying largely on corporate power purchase agreements and merchant routes over this period) and lack of action to resolve planning or grid-related challenges.

Conditions for high deployment

In the short term, most participant think it plausible that legal reform shortens delays that can be inflicted by objectors; restricts grounds for JR; bring consenting timelines in line with RED 3; and requires ABP to perform its function consistent with climate action objectives. A few think that it is plausible (and necessary) that the new Wind Energy Development Guidelines (WEDG) do not impose more stringent noise and setback distance terms, and that the national renewables target is passed down and disaggregated through the planning system to County Development Plans—ensuring sufficient designation of land suitable for wind development to meet a county-level target. However, for some it is implausible that systemic skilled labour shortages in planning and permitting agencies could be resolved in the short term to enable significantly greater deployment of onshore wind by 2030.

Some participants think it plausible that grid-related inhibitors could be removed in a high deployment scenario. These included bottlenecks with the system operator in managing and processing outages (significantly increasing the number of outages), the successful delivery of most of SOEF, and/or that bulk energy time shifting auctions (allowing different forms of flexibility) commence by 2025.

Most participants think that a seamless extension of RESS from 2025 onwards is plausible, including resolution of some of the challenge facing RESS. For instance, providing appropriate revenue certainty against constraint risks and incentivising long duration storage. Some participants think it plausible (though unlikely) that wind projects with grid connection under ECP rounds in 2025 and 2026 and routes to market through RESS-6 and RESS-7 auctions in 2026 and 2027, could still connect by 2030. Other participants found this scenario implausible.

For most participants, the period from 2036–2040 saw the continuation of the conditions highlighted above. However, some additional conditions distinguish some forecasts. For some participants it is plausible (though unlikely) that extensive new grid infrastructure enables connection of wind resources in the northwest region after 2035, which, if coupled with further long-duration storage, would enable significant increase in wind power up to 2040. The current assumption is that all high-voltage direct current (HVDC) will be buried or there may even be a 'bootstrap' cable long the coast. However, other participants do not think it plausible that such grid development would support significantly greater capacity of onshore wind in the northwest before 2040. Regardless, most participants agree that the system operator would have to change its network reinforcement strategy in the mid-2020s and that planning on such infrastructure should be progressed as a matter of urgency. However, they disagree on the timeframes for deploying such grid infrastructure (with estimates ranging from 10–20 years). A few note that the northwest could be opened up for significantly more wind from 2036 onwards; others do not think this plausible prior to 2040.

Most participants think that the growth in ONW starts to taper towards the end of the decade under a high deployment scenario as it reaches a natural saturation point in Ireland, with an increasing proportion of new capacity coming from repowering existing sites towards the end of the decade. While some think such a natural saturation point might be reached by 2040 in a high deployment scenario, there is a wide envelope of estimates on the capacity of the saturation point from between 10 to 15 GW.

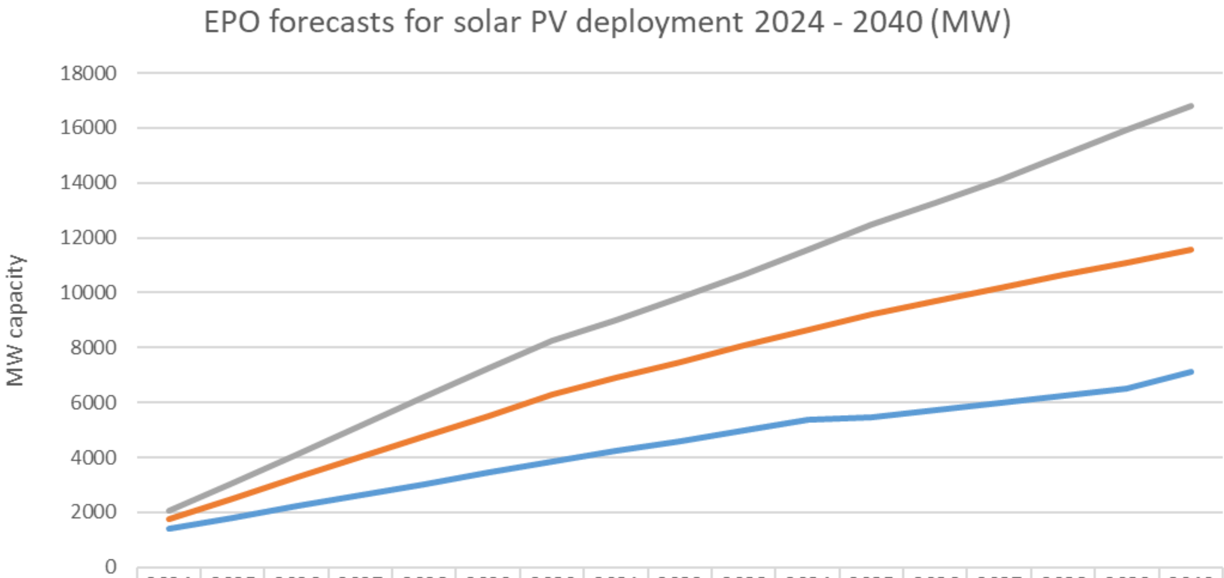
Some participants think it plausible that repowering contributes a net gain in installed capacity as existing sites increase capacity. This in turn assumes additional grid development to enable increased capacity at extant sites. For some, the increasing deployment of long-duration storage up to 2040 is plausible and necessary for a high deployment scenario.

Some argue that high demand growth, driven by electrification of heat and transport, coupled with a delay in OFW deployment, is essential for ONW to continue its high deployment trajectory to 2040.

3.3. Solar PV

Figure 4 presents the EPO forecasts for solar PV.

Figure 4: Expert elicitation results for plausible deployment of solar PV power (MW) 2024–2040



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
EPO90	1405	1811	2217	2622	3028	3433	3839	4221	4602	4984	5369	5439	5706	5974	6241	6508	7132
EPO50	1754	2507	3261	4014	4768	5521	6279	6883	7476	8061	8639	9222	9703	10175	10641	11099	11551
EPO10	2039	3078	4117	5156	6195	7234	8273	9010	9825	10667	11581	12487	13288	14103	15010	15942	16813

- There is a wide confidence interval between plausible low and high bounds of solar PV deployment in 2030, 2035 and 2040. This reflects wide confidence intervals for most participants (they are very uncertain about the future) and wide distribution between participants.
- Most participants think it plausible (though unlikely) that the 8 GW target can be attained in 2030 (pooled opinion: there is a 90% chance that less than 8.3 GW will be installed by 2030).
- By 2040 it is plausible that anywhere between 7.1 GW and 16.8 GW will be installed, with a pooled best guess of 11.6 GW.

Participants noted a greater uncertainty in forecasting solar PV than onshore wind, given the relative immaturity of the sector in the Republic of Ireland (ROI) and the different drivers of utility-scale, micro-scale (residential rooftop) and mini and small-scale (sometimes referred to as commercial and industrial scale) deployment. For instance, it is difficult to define and track or forecast the deployment of private wire sites, industrial, schools or other small-scale deployment. In this study, low deployment scenarios are therefore plausible (though unlikely) scenarios where the worst-case conditions for each scale of deployment stack up; that is, the worst-case for mini, micro/small, and utility-scale solar PV coincide. Conversely, the high deployment scenario is a plausible (though unlikely) scenario where best-case conditions stack up for solar PV across the scales.

For utility scale solar PV, accounts tend to be divided between projects already in the planning system, which largely make up the forecasts for 2030 (through a pipeline stacking heuristic), and more general drivers of deployment from 2030 onwards.

Conditions for low deployment

Over the medium term (roughly up to 2030), a plausible low deployment scenario for utility-scale solar PV sees the coincidence of more than one of the following conditions:

- Several macro-economic drivers may limit deployment. Some participants noted that CAPEX and OPEX costs for solar PV in Ireland could remain high, with fewer projects finding a route to market through future rounds of the RESS (if more onshore wind power capacity competes). If electricity prices decline and interest rates remain high, there could be a higher attrition rate of speculative projects, and the economics of CPPAs could also become unviable for more projects.
- Some participants noted that it is implausible that grid capacity could limit solar PV expansion over the medium term in a low deployment scenario. There is roughly 3.5 GW capacity available on the distribution grid. With flexible siting, solar PV projects will use this capacity over the next few years, without paying for network upgrade costs. However, some participants think that other grid-related constraints could plausibly limit solar PV deployment prior to 2030. Such constraints might include scenarios in which renewable hubs do not alleviate challenges with grid connection; grid connection costs increase; system operators do not facilitate timely grid connections; and/or there are delays in the deployment of substations. These issues might limit utility scale solar to a low deployment rate.
- Supply chain risks could also affect solar PV deployment, including delays in sourcing transformers or switchgear (which could for instance range from 18 to 36 months). As noted, the risk of a bottleneck in the manufacturing of transformers only becomes a significant constraint once the existing grid capacity is exhausted and new substations need to be built. A few participants noted that, more generally, it was the larger utility-scale projects that anchored the supply chain for smaller projects, especially in the construction sector.

Almost no participants think that lack of social acceptance, political de-prioritisation, or lack of short duration storage could plausibly limit utility-scale solar PV deployment prior to 2030. However, these risks could shift from around 2030 onwards. A couple of participants think that planning and land-use constraints could start to limit deployment of utility solar PV from the early 2030s onwards. Like onshore wind power, some participants think that there could be a political pivot away from utility solar PV over this period if the deployment of OFW is successful in the early 2030s.

Most participants think it plausible that poorly designed and/or slow rollout of incentives for demand flexibility, short and medium duration storage and subsequent slow deployment could limit utility-scale solar PV throughout the 2030s and up to 2040. Some think that high rates of dispatch down and/or constraints may not be resolved, and generators revenue may not be appropriately protected against these risks; this would make some parts of the country un-investable due to regional dispatch down.

Most participants think that low electricity demand growth, whether due to low economic growth or low electrification of heating and/or transport, may be a limiting condition for solar PV throughout the 2030s. Peak summer demand in a low demand growth scenario could ultimately be the limiting factor.

For micro-scale and small-scale solar, the coincidence of several conditions could plausibly limit deployment:

- A labour shortage, especially a shortage of electricians and roofers. Most think that labour shortages will be resolved over the medium term, while only a couple think that labour shortages could plausibly persist beyond 2030;
- The cessation of the Micro-generation Support Scheme (MSS) and/or the Small-scale Renewable Electricity Support Scheme (SRESS). Most participants think that cessation of these grants anytime in the next decade will limit deployment rates subsequently;

- Installation cost increases or difficulties and inefficient administration of grants; and
- Low electricity prices and/or low export rates for self-consumers, which could also negatively affect consumer interest and curb small and/or micro-scale deployment.

Conditions for high deployment

In a plausible high deployment scenario for utility scale solar, participants think that some of the following conditions could coincide:

- Grid-related constraints do not limit solar PV deployment over the medium term (up to the early 2030s). Projects utilise all the existing capacity on the distribution grid with flexible siting close to existing substations with capacity.
- Planning and consenting lead times for grid and generation infrastructure are resolved. System operators support a connection batch every six months without caps and coordinate this with planning consent, while network outage availability is optimised to 12 months.
- Sustained political prioritisation by a new government is present from 2025 onwards, including seamless extension of RESS with auctions in 2026 and 2027.
- There is a continuously high level of social acceptance; that is, low rates of objections or JRs to utility-scale projects, projects not subject to an Environmental Impact Assessment Report and a continuance of fewer siting constraints than onshore wind power. Most participants think that utility-scale solar PV could still ultimately approach a saturation point by 2040 because of spatial constraints.
- There is sufficient deployment of short-duration storage (up to 1GW).

From the late 2020s onwards, drivers for continued high deployment of solar PV shifts. Most participants think that appropriate incentivisation of short and medium duration storage, flexibility and demand-side management would be necessary for a high deployment scenario. Some participants think it plausible that appropriate incentives for short and medium duration storage could be implemented in time to see a more rapid expansion from the late 2020s onwards. In addition, the use of the existing grid needs to be maximised and connection costs brought down (for example, the Distribution System Operator could take a less 'protectionist' stance).

For most participants, high electricity demand growth is necessary for the high deployment scenario. However, even in a high electricity demand scenario, some think that peak summer demand will ultimately limit utility-scale solar PV deployment over the 2030s.

For micro and small-scale solar, participants that certain conditions are both plausible and sufficient for their high-deployment scenario. Some of the conditions highlighted by participants include:

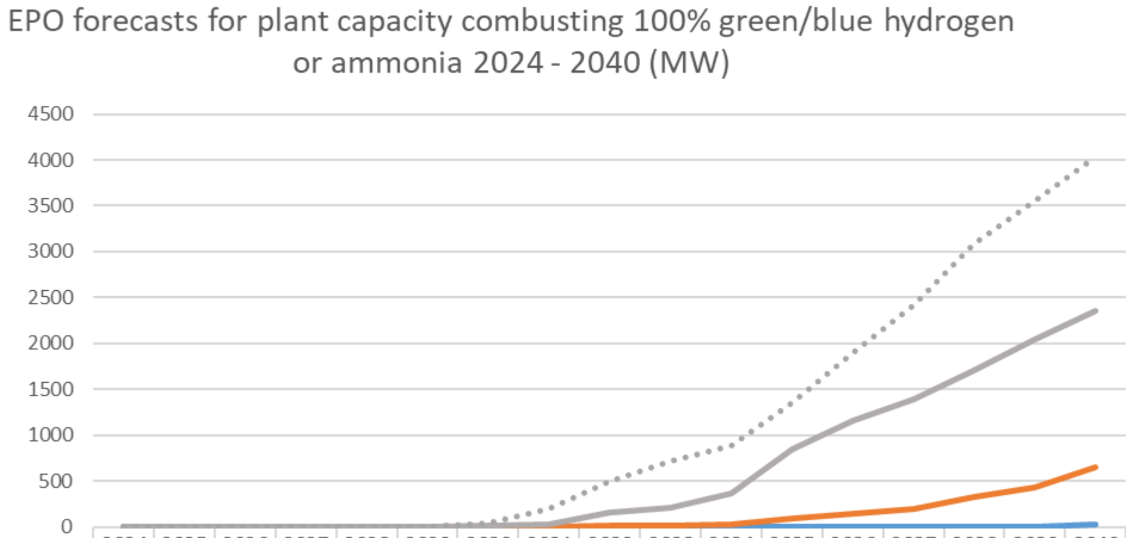
- The labour market for installers (particularly electricians and roofers) growing at a rapid rate over the medium term to enable high deployment;
- The indefinite continuation of MSS and SRESS grants. Some participants think that the continuation of such grants would be necessary for at least the next decade to support high deployment; and
- Consumer interest remaining high because of increased uptake of Electric Vehicles, self-consumption and enabling of private wires, and persistence of building regulations.

In a high deployment scenario, one participant thought that residential rooftop could reach a saturation point by 2035 in a high deployment scenario, while others thought this saturation point would be reached by 2040.

3.4. Power generation with hydrogen or ammonia

Figure 5 presents the EPO forecasts for power generation capacity running on 100% green/blue hydrogen or ammonia. Twelve participants offered their judgement on the deployment of hydrogen in the Irish power sector up to 2040. Many of these discussions included consideration of ammonia as an alternative fuel for zero-carbon dispatchable generation, while some forecasts explicitly disaggregated the two technologies. The summary forecasts add them together.

Figure 5: Expert elicitation results for plausible deployment of thermal plant capacity with green/blue hydrogen or ammonia (MW) 2024–2040. The EPO10-adj forecast adjusts EPO10 to exclude one participant that presented an extreme outlier



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
EPO90	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	23
EPO50	0	0	0	0	0	0	0	0	9	20	28	86	146	202	324	425	657
EPO10-adj	0	0	0	0	0	0	12	32	154	213	361	852	1155	1391	1704	2049	2356
EPO10	0	0	0	0	0	0	34	190	493	722	881	1354	1898	2420	3077	3554	4028

EPO90 EPO50 EPO10-adj EPO10

- There is a relatively narrow confidence interval for deployment of thermal plant with hydrogen/ammonia in 2030 and 2035. Experts are almost certain there will be no commercial scale capacity installed by 2030 and less than 850 MW installed in 2035 (when removing an extreme outlier forecast).
- The confidence interval becomes much wider for deployment between 2035 and 2040, as uncertainty (and disagreement between participants) increases concerning plausible technology pathways. By 2040 it is plausible that anywhere between no commercial capacity and 2.4 GW of thermal plant on hydrogen/ammonia will be installed (when removing an extreme outlier forecast).
- The plausibility of having no (or very little) commercial generation capacity on green/blue hydrogen/ammonia by 2040 reflects agreement between most participants that the use of hydrogen in the power sector represents a high-risk technology pathway for decarbonisation, dependent on delivering at least one mega-infrastructure project (such as geological storage or a dedicated hydrogen network).

Within the pool of participants there are significantly different opinions on the plausible envelope of hydrogen and/or ammonia usage in the power sector, in terms of scale (GW) and availability (earliest date) in 2040. Even where the forecasted quantum is 'in the same ballpark' (for example, in terms of scale and availability), the anticipated technology pathways differ. This is an area of significant contestation and competition where participants disagree on many assumptions and judgements, and institutional interests currently drive different (and sometimes mutually exclusive) visions and strategies. There appears to be little agreement between actors from different generators (thermal and renewable), project developers (electrolysis, storage, and power plant), system operators (gas and electricity) and government on either feasibility or viability of different technology options up to 2040. Wide divergence and lack of agreement on a coherent pathway between key actors may itself pose a significant risk in the short term to progressing a plan-led approach to hydrogen deployment in the power sector. In the meantime, market players are taking bets and advancing projects along different pathways.

Some participants think that deployment will happen first through hydrogen production in Ireland coupled with large geological storage associated to a first demand cluster (for example, in Cork) (whether that is before or after 2040). Others think that such a pathway is very unlikely or implausible (at least before 2040) and that a repurposed interconnector (IC1) connecting to the European hydrogen backbone via the UK's Project Union will be available before large geological storage in Ireland, and the means through which the thermal gas generation fleet around Dublin, decarbonises, followed by a dedicated line to Cork.

Many participants think that both the aforementioned technologies (which are reliant on different types of mega infrastructure projects, whether that is repurposing a depleted gas field, constructing submarine salt caverns, or building a dedicated hydrogen network) are implausible or very unlikely before 2040. Instead, they think a pathway will develop around imported green ammonia with more widely distributed storage and combustion around extant port infrastructure. Alternatively, one participant proposes that several smaller projects that co-locate grid connected electrolysis with terrestrial long-duration storage and power plant can circumvent the need for highly risky mega projects. This participant argues that such an approach could be viable with extant planning legislation and regulations and terrestrial storage technologies. This mitigates some risks associated with establishing the new policy and regulatory framework for a plan-led or centralised approach (refer to Section 4 for more information on a plausible timeline for net zero mega infrastructure) and deploying large new marine geological storage technologies.

The remaining discussion is structured around hydrogen production, storage, transport and fuel switching (turbines) in the Irish context.

Hydrogen production

Almost all participants believe that production in Ireland would first be driven by demand from sectors other than the power sector and that such demand and supply would only emerge with massive state subsidies and complex policy coordination efforts. Participants do not expect the power sector to be an anchor tenant, generating significant or early demand for hydrogen, but instead may piggyback on demand if it emerges from industry and transport sectors at sufficient scale. However, there is uncertainty and disagreement on the plausible scale of demand from transport and industry that may materialise during the 2030s. For instance, Ireland has no blast furnaces and few high temperature industrial applications where hydrogen has a clear advantage over electrification for decarbonisation. Alumina production could opt for either green hydrogen or electrification. Electrification could be more cost competitive than hydrogen in lower temperature industrial processes such as in the food and beverage industry. In transport, electrification may also eat into the heavy goods vehicle (HGV) market, given Ireland's relatively small size and tendency to follow EU policy direction. Currently the clearest policy signal and interest is for green hydrogen as input to Sustainable Aviation Fuel (SAF) and Hydrotreated Vegetable Oil (HVO) production. Some participants anticipate the construction of several electrolysis demonstration or pilot projects in Ireland by the early 2030s but feel that all or most of the hydrogen would go into fuel production. Many participants note that there are already policy signals for hydrogen offtake for SAF (for example, a binding EU target for using 1.2% synthetic aviation fuels from renewable hydrogen and captured carbon in EU airports by 2030, rising to 35% in 2050).[15] Some developers are exploring colocation of carbon capture, electrolysis and offtake agreements for e-SAF production alongside power purchase agreements (PPA) with renewable plant. Some participants think that none of the green hydrogen produced in Ireland would go to the power sector prior to 2040, while others think it plausible that large power sector offtake will emerge before 2040.

All participants agree that massive state subsidies will be needed to bridge the cost differential between green hydrogen and the extant fossil fuel alternatives in the transport, industry, and power sectors, with many expecting the cost differential to remain large throughout the 2030s. However, most participants expect a slow evolution of support mechanisms in Ireland and accept massive uncertainty about state willingness to subsidise at significant cost to taxpayers or consumers. Some anticipate that subsidies may start slowly with grants for pilot projects in the late 2020s, noting expectations that such sources (from the European Innovation Fund for example) are unlikely to reach Irish projects before 2027/28. Added to this, many developers are concerned that the conditions for the classification of Renewable Fuels of Non-Biological Origin set by the EU will restrict the delivery of green hydrogen projects from 2028 onwards.[16]

In addition, Irish developers note that potential customers may prefer to avoid being locked into long-term contracts at a high price, but that producers will need long-term revenue security to justify investment. Some developers advocate for a state agency to take on risks to bridge long-term offtake agreements with producers and short-term offtake agreements with consumers, citing the German approach. Ultimately there is an expectation that Ireland will follow learning from other first and early movers in offering Contracts for Difference (CFDs) for hydrogen production in Ireland, but also uncertainty on when this may occur.

Many participants note the relatively high levelised cost of electricity (LCOE) in Ireland as a key determinant of the viability of hydrogen production here. The recent European Hydrogen Bank auction results underscored this concern, with all winning projects located in Spain, Portugal, Norway, and Finland.[17] Participants are currently uncertain on whether Irish production could compete with imports (either via an interconnector or an alternative carrier such as green ammonia) and what the price differential would be. A

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[15] https://transport.ec.europa.eu/transport-modes/air/environment/refueleu-aviation_en

[16] There are three cumulative conditions, namely additionality, temporal correlation and geographic correlation, that must be satisfied to classify hydrogen as 'green'. Collectively, these pose onerous requirements on project developers that will impact the timing, location and business cases of such projects. For instance, to satisfy the additionality requirement, the renewable energy production installation must not have come into operation earlier than 36 months before the hydrogen plant. Delegated regulation 2023/1184 available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2023.157.01.0011.01.ENG&toc=OJ%3AL%3A2023%3A157%3ATOC

[17] Auction results available at: https://ec.europa.eu/commission/presscorner/detail/en/IP_24_2333

key political question is how much future governments will value energy security over least-cost, technology-neutral approaches to decarbonising over the period in question.

Storage

Almost all participants emphasise that storage is the biggest challenge to deploying hydrogen in Ireland. However, they disagree on the likely technology pathways that will resolve or circumvent this issue. In particular, there is disagreement and uncertainty over the feasibility, viability, and availability of large-scale geological storage.

Most participants think that large-scale geological storage, either in the form of salt caverns, depleted gas fields or saline aquifers, is a necessary precursor for the deployment of hydrogen in the Irish power sector. However, most participants do not think it likely that any of these storage options will be available by 2040. For instance, most participants do not think it likely that the Kestrel Project (including the depleted Southwest Kinsale and Ballycotton gas fields) will be available by 2040 to supply hydrogen at scale for generation plant to form what is known as a 'Cork cluster'. Most participants agree that utilising depleted gas fields for hydrogen storage is a very immature technology. There are currently no examples in the world where a depleted gas field has been successfully used to store and supply hydrogen. Firstly, to progress assessment of these fields (and any salt caverns or saline aquifers), legislation needs to be passed (or amended) to enable the issuing of new marine drilling licences (currently prohibited). Then significant and costly further assessment is required to establish the technical feasibility of the fields. Some argue that progressing this will require a state-guaranteed return on investment in the storage asset, which would require new legislation that mandates national hydrogen reserves (similar to the National Oil Reserve Agency [NORA] Act) and the establishment of a NORA-type institution to procure hydrogen storage. In addition, almost all participants agree that conducting the legislative gap analysis and developing the regulatory framework necessary for large marine geological storage will take approximately five years. It currently appears unlikely that discussion on if/how a state-backed financial support scheme should be designed for large marine geological storage will be on the political agenda before 2030. There are other technical risks to consider; for example, the Kinsale fields may leak significant amounts of hydrogen through well heads or geological structures such as the main Kinsale field (which is too large for hydrogen storage and recovery), and/or flow rates from these fields may not be sufficient to supply a large capacity for power plant. Ultimately, establishing its feasibility will require billions of investment as new pipeline and well heads will have to be installed, and cushion gas will have to be pumped in to test it. A couple of participants think it plausible that the Kestrel Project could bring the Kinsale fields online as a natural gas store by the early 2030s and commence a transition to hydrogen from 2035 with pure hydrogen fuelling modified plant at Whitegate and Aghada by 2040.

A few participants think that salt caverns in the Irish Sea may be a more likely storage solution than depleted gas fields because with this approach, several of the risks associated with depleted gas fields are mitigated; for example, risks of leakage and uncertainty on flow rates. Caverns would be bespoke and modular constructions serving Irish demand. However, most participants do not think it likely that such salt caverns would be available for large scale hydrogen supply in Ireland by 2040 either, given that current geological knowledge on these is rudimentary and the necessary surveying (for example, gathering and analysing seismic data and core samples) will be much more costly than depleted gas fields with the same lack of certainty regarding a route to market for a potential storage asset. A couple of participants think it plausible, though unlikely, that salt caverns in the Irish Sea could provide bespoke, modular hydrogen storage of up to

1 TWh by 2040 to a ‘Dublin cluster’. Like depleted gas fields, the exploration of salt caverns will require new legislation in the first instance to licence the necessary marine drilling to progress surveying, followed by an extensive programme to establish the necessary regulatory framework for its construction and usage.

A couple of participants think that large-scale geological storage is not a necessary component to significant uptake of hydrogen in the power sector before 2040. One participant thinks that repurposing the gas interconnector (IC1) and importing hydrogen from the European backbone is a more plausible solution that could provide 100% hydrogen to plant in a Dublin cluster by 2040 (refer to the next section on transport and blending). Another participant thinks that distributed, terrestrial hydrogen storage provides a viable solution at an intermediary scale between large (offshore) geological storage and tankered storage (which everyone agrees will remain prohibitively expensive at the required scale). This technology pathway envisions several projects at different points in the 220kV network that link grid-connected electrolysis to 100–200 hours storage capacity for plant up to 700 MW. These Long Duration Energy Storage (LDES) projects could function through a reformed capacity market.

Finally, several participants think that the challenges related to storing (and producing and transporting) hydrogen in Ireland for use in the power sector are sufficient to warrant a pivot to imported green ammonia as a zero-carbon fuel (for the power sector), at least for the period up to 2040. Please refer to the ammonia subsection for more information on this.

Fuel switching for thermal fleet

Several participants highlighted the techno-economic uncertainties and complexity of switching the current fleet of CCGT plant. The age of the current CCGT fleet is key to timing of fuel switching. Many CCGT are between 10 and 15 years old and will approach end of current life around the mid-2030s. In the anticipated decarbonised system of the future, there may not be incentive to repower these plants to run on hydrogen, given low expected run hours. Significant reforms in the capacity market would be required. Currently, competition in the capacity market is sensitive to fuel costs, while incentives would have to be of the scale to bring green hydrogen cost in line with natural gas to drive uptake. However, there is currently no techno-economic studies on the impact of hydrogen costs on consumers in such a market.

In addition, all gas turbines in Ireland are out of manufacturer warranty. The risk of modifications for blending hydrogen will be borne by owners. Not all owners will be willing to take on the risk and may defer investment to new turbines. Generators currently do not think it likely that there will be sufficient green hydrogen available (whether produced in Ireland or imported) to make the switch during the window for life extension/repowering of the current CCGT fleet in the mid-2030s, even if market design incentivised this (as noted in the previous paragraph).

New gas plant in Ireland, to be completed by 2030, will be hydrogen ready but generators note that this is a poorly defined term. They will be able to take up to 50% hydrogen blends with certain more or less significant modifications. However, it is expected that blending may start at some of these stations at very small scale in the early to mid-2030s. Irish generators are expecting some RD&D delays from original equipment manufacturers (OEMs), such as Mitsubishi and General Electric, in bringing the first 100% hydrogen turbines to market. These are not expected to become available to the Irish market before 2030.

Most participants think that there will be a low level of hydrogen blended into the extant gas network up to 2040 via IC1. This may start slowly in the early to mid-2030s at around 1% and is not likely to exceed a 5% volumetric blend. Generators confirm that existing plant can take variable blending up to 5% but would require a very constant blending rate beyond that. Participants do not think higher blending in the extant gas network is plausible.

Ammonia

Several participants find it implausible that significant amounts of Irish generation capacity will use green/blue hydrogen before 2040. Instead, a few think it plausible that imported green/blue ammonia will be deployed in the Irish power sector as a zero-carbon fuel, instead of hydrogen, prior to 2040. This is largely because ammonia is comparatively easier to store and transport (owing to the higher energy density); the associated transport/storage infrastructure is also better-established and reliant on mature technologies.

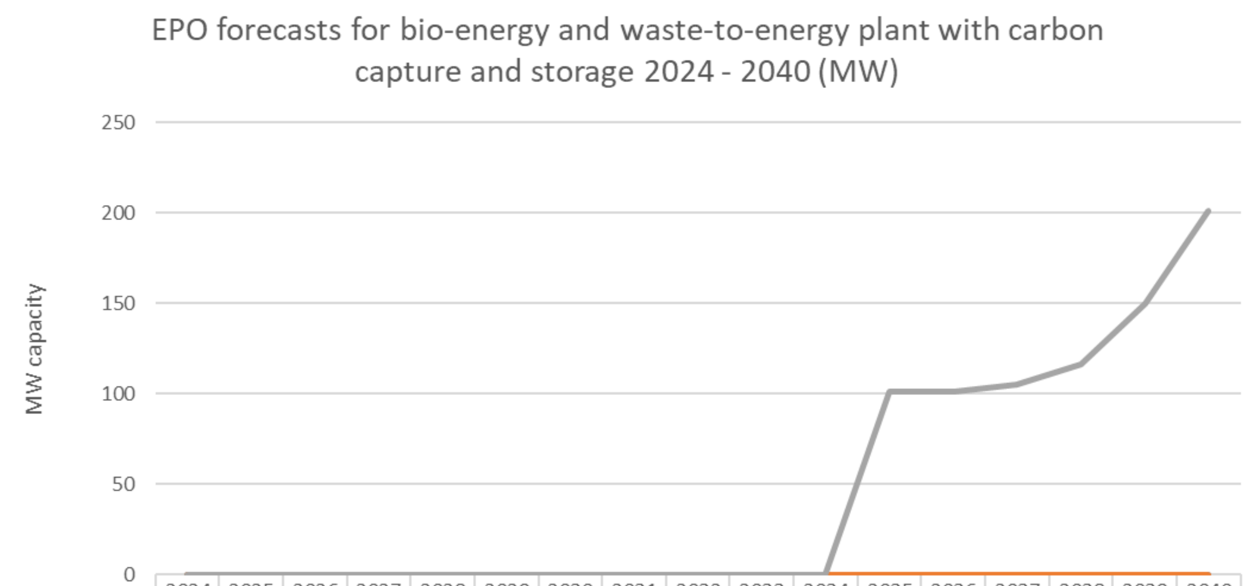
Some participants anticipate there will be a global shortage of green/blue ammonia for several years and that 100% ammonia turbines will only become available by the early 2030s. However, from 2035 onwards, they find it plausible that a few thermal plant (perhaps at Whitegate, Ballylongford, and potentially Moneypoint) could run on imported ammonia. They anticipate that international competition and innovation from first movers (in locations where the LCOE for renewables is significantly cheaper than Ireland) will drive down the cost of green ammonia, while the fact that it can be transported and stored more easily than hydrogen means it will become a global commodity faster than green hydrogen. Additionally, participants do not think it plausible that the Irish State will bridge the anticipated price differential between green hydrogen (produced in Ireland) and natural gas for uptake in the power sector prior to 2040.

A few participants think that several different low-carbon fuels will emerge in the 2030s and that ammonia will be used alongside hydrogen in the Irish power sector before 2040. Generators close to extant port facilities and far from a dedicated hydrogen network or geological storage, such as locations on the west coast, will opt for combusting green ammonia first, whereas plant in a Cork or Dublin cluster may opt for hydrogen, depending on the rollout of a dedicated interconnector or geological storage.

3.5. Power generation with carbon capture and storage

Eight participants offered their judgement on the future deployment of CCS in Ireland. However, two were specialist geologists who only commented on geological storage and did not issue forecasts on the uptake of CCS in the power sector. The EPO therefore consists of six forecasts. Participants were asked for an opinion on gas with CCS (gas-CCS) and/or bio-energy with CCS (BECCS). In addition, some participants think it plausible that Waste-to-Energy with CCS (WtE-CCS) could be deployed prior to 2040. We present BECCS and WtE together (and separate from gas-CCS), given their negative emissions potential for the power sector. *Figure 6* presents the EPO forecasts for BECCS and WtE-CCS.

Figure 6: EPO forecasts for BECCS and WtE-CCS



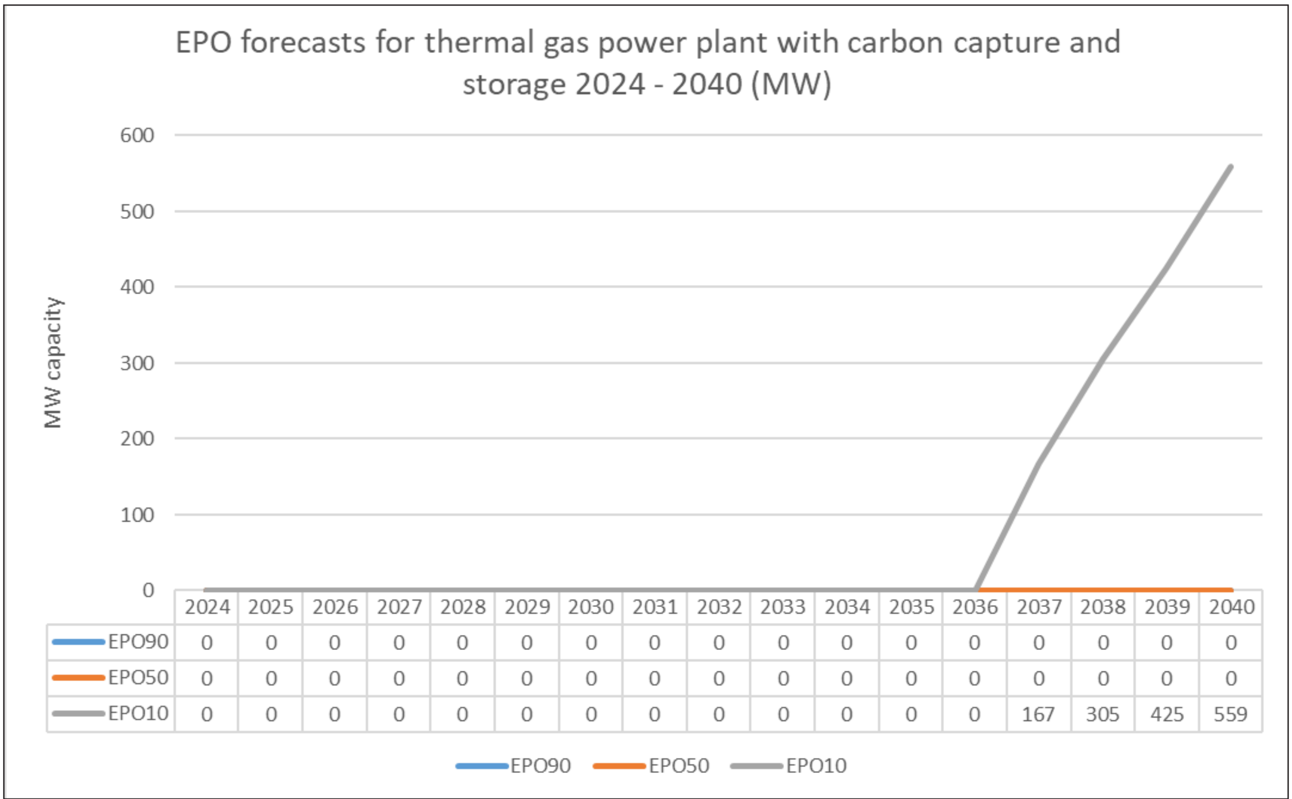
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
EPO90	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EPO50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EPO10	0	0	0	0	0	0	0	0	0	0	0	101	101	105	116	150	201

EPO90 EPO50 EPO10

- There is a very narrow confidence interval for BECCS and WtE-CCS compared to other technologies. All participants are almost certain that none or very little of either technology will be deployed in Ireland by 2040.
- It is plausible (but unlikely) that about 100 MW could be deployed in 2035. This either involves the conversion of Edenderry to BECCS, or a couple of WtE-CCS plant clustering with large industrial emitters (like cement producers) on the coast with access to transport and storage in other jurisdictions like the UK.

Figure 7 presents the EPO forecasts for gas-CCS.

Figure 7: EPO forecasts for installed gas-CCS capacity



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
EPO90	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EPO50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EPO10	0	0	0	0	0	0	0	0	0	0	0	0	0	167	305	425	559

- There is a narrow confidence interval for gas-CCS compared to other technologies. All participants are almost certain that no or very little thermal gas plant with CCS will be deployed in Ireland by 2040.
- It is plausible (but unlikely) that about 600 MW could be deployed between 2037 and 2040.

All participants agree that CCS is one of the last actions to be taken on a pathway to decarbonise the Irish power sector and that generation plant with CCS are unlikely to be connected before 2040. Two participants think that significant capacity of either gas-CCS or BECCS is plausible (but unlikely) before 2040 if there is significant and sustained political effort to achieve a net zero power sector by 2040, and political willingness to drive this at great cost to consumers or taxpayers.

In addition, the decarbonisation of industry and the evolution of industrial clusters at sufficient scale and density also constrain deployment of CCS within the Irish power sector. Most participants think that anchor demand from high industrial emitters, such as cement producers and refineries, are necessary precursors to establish CCS and that the power sector will not be a first mover. These are industries where, unlike the power sector, there is a definite and unavoidable need for carbon capture. However, there is significant uncertainty on whether Ireland will have such industrial demand for CCS at sufficient scale before 2040. Some high industrial emitters may opt for alternative decarbonisation strategies to CCS. For instance, Aughinish Alumina Refinery may opt for green hydrogen or electrification. Perhaps only Whitegate Refinery and a couple of cement producers proximate to extant ports (for example, Irish Cement's Platin and Castlemungret sites) provide potential sites around which clusters of sufficient scale could evolve with access to store (in the case of Cork) or export carbon dioxide (CO_2). In such cases, new power plant (gas, WtE, or bio-energy) would have to co-locate at such sites, with Cork providing the only potential cluster that already has significant industry and power plant co-location. In addition, new port infrastructure needs to be developed for export. Future industrial clustering at the necessary scale is plausible were cheap electricity, a permissive planning environment and optimal route to market align, but all participants think this is unlikely to result in significant power sector uptake of CCS before 2040.

It is also plausible that the economics for utilising CO_2 as feedstock for fuel manufacturing may be more favourable than transport and storage, in which case the negative emission from BECCS or WtE may not be classified as power sector emissions. For instance, Edenderry Power Station (which presents the most plausible opportunity for BECCS in Ireland now) may opt to use captured biogenic carbon as a feedstock for production of SAF, if it was to pursue carbon capture. It therefore cannot be assumed that negative emissions from BECCS or WtE would accrue to the power sector's carbon budget. All stakeholders acknowledge the immense uncertainties surrounding this technological pathway.

Conditions for low deployment

In a low deployment pathway for CCS in the power sector, all participants except one think it very unlikely that there will be any power generation with CCS by 2040. This is due to a configuration of several conditions. Firstly, the industrial sector will decarbonise slowly and/or will largely take alternative routes to decarbonise (that do not include CCS). This is driven by a lack of sustained policy to drive cement producers and refineries to capture their carbon emissions. Industry will therefore not provide the anchor demand for CCS to warrant investment in transport and/or storage infrastructure in the 2030s into which new power plant can connect. Two participants think there would be at least one WtE plant (approximately 50 MW) with carbon capture connecting into an industrial cluster by 2040, potentially co-locating with Platin Works cement and exporting CO_2 to UK-based storage (Hynet) from Drogheda.

Secondly, the unfavourable economics for gas-CCS plant with low run hours continue in a future generation fleet with high penetrations of wind, solar and storage; successive governments are unwilling to subsidise its deployment to achieve net zero by 2040. As mid-merit plant with low run hours, the cost of gas-CCS remains relatively more expensive than other mitigation options or only emerge after 2040. Techno-economic constraints continue to undermine the case for gas-CCS peaking plant as well (for example, the trade-off between ramp-up and capture rates). Cheaper mitigation alternatives are exhausted first (including in other sectors), and gas-CCS only emerge after 2040. Successive governments maintain a largely technology neutral approach to decarbonising the power sector and do not design technology-specific price support instruments for CCS.

Furthermore, two conditions stop any BECCS capacity being completed before 2040. A shortage of a sustainable feedstock undermines the negative emissions case for BECCS or limits it to approximately 100 MW in Ireland (from indigenous and sustainable feedstock). Alternatively, captured biogenic carbon in Ireland is utilised rather than stored and negative emissions therefore do not accrue to the power sector. For instance, under a low deployment scenario, it is plausible that Edenderry Power Station is the only site in Ireland to add carbon capture technology by 2035, but Bord na Móna may opt to utilise the captured carbon for production of e-SAF or similar fossil fuel replacement.

Conditions for high deployment

High deployment pathways for CCS in the power sector were roughly split between participants who thought it plausible that some BECCS plant, but no gas-CCS, would connect prior to 2040, and those who thought that significant amounts of gas-CCS, but no BECCS, would connect prior to 2040. Both scenarios are firstly characterised by aggressive decarbonisation of the Irish industrial sector, with large emitters (cement producers and refineries) growing in scale and number and opting to decarbonise via CCS. This is driven by sustained willingness and ability of successive governments to implement policy to drive industrial decarbonisation and clustering to draw in the co-location of power plant to new clusters.

In addition, it requires a sustained political drive to achieve a net zero power sector by 2040 with successive governments sustaining a technology-specific approach to decarbonising the power sector and implement technology-specific price support instruments for CCS. This could enable the commercial viability of gas-CCS in the 2030s with some mid-merit plant with relatively high run hours operational in a net zero system by 2040. In such an unlikely scenario, BECCS is deployed at approximately 100 MW, and/or a few small WtE plant co-locate with industrial clusters, also approximately 100 MW in total.

3.6. Timeline heuristic for net-zero mega infrastructure in Ireland

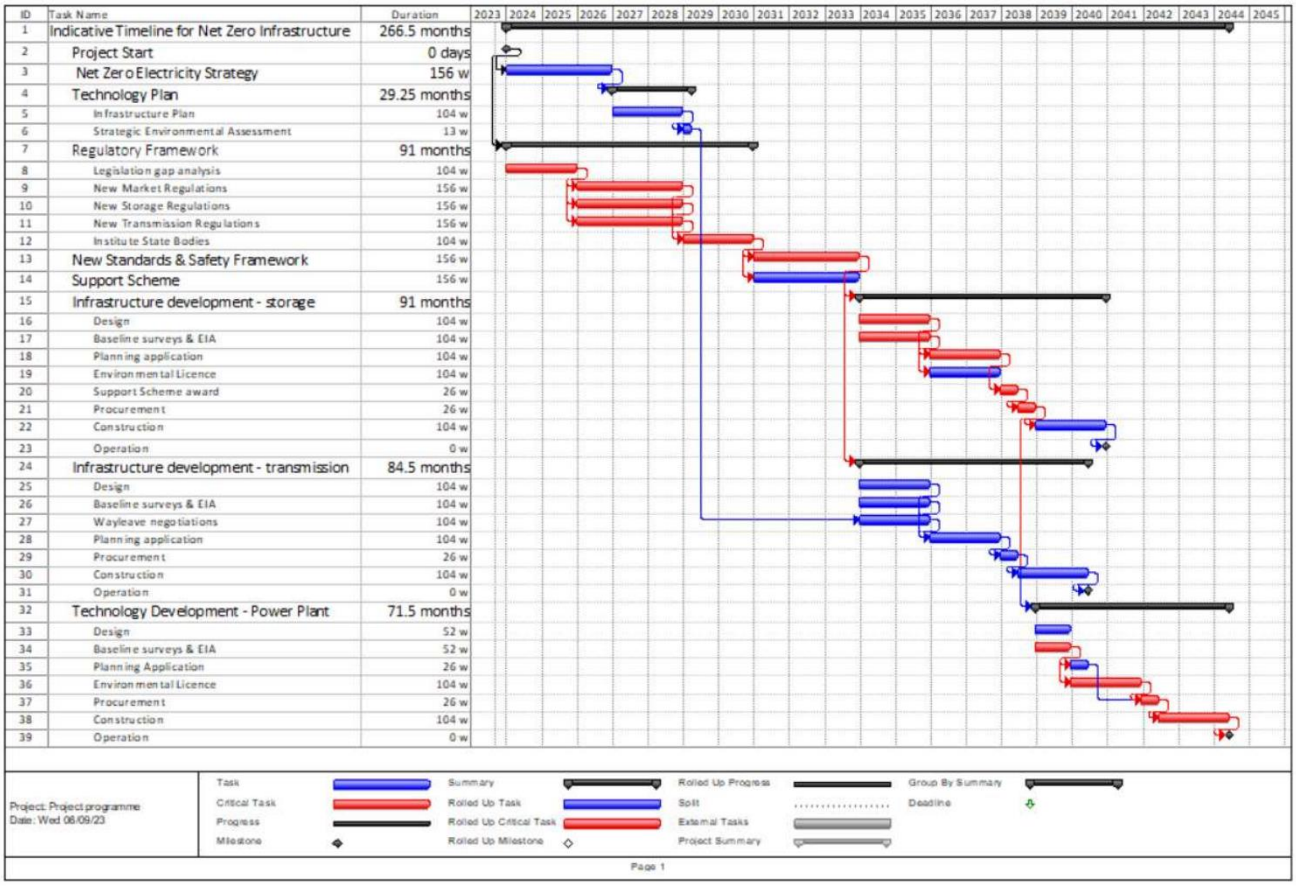
Most participants in the elicitation on hydrogen and CCS think that deployment of either of these technologies in the power sector at a significant scale depends on the completion of at least one mega-infrastructure project. This could be either large scale geological storage in the form of repurposing a depleted gas field or constructing marine salt caverns and linking it to new electrolysis and generation capacity or building a dedicated hydrogen network. SEAI presented a generic Gantt chart to participants as a heuristic to aid discussion on the availability of such a piece of mega-infrastructure (that is, the earliest plausible date of its completion). This was done after participants issued their initial forecasts so as not to introduce an anchoring bias.

Participants gave feedback on the timeline, questioning its assumptions and offered some refinements with reference to a particular type of infrastructure project (for example, salt caverns). Almost all participants agreed that the timeline was reasonable. This culminated in the chart presented in *Figure 8*.

Only a few participants think it plausible (if unlikely) that this timeline could be shortened significantly. One participant thinks it plausible (but unlikely) that the construction of salt caverns to store about 1 TWh of hydrogen in the Irish Sea could be completed in 11 years. In their opinion, it could take as little as two years to establish the regulatory framework and five years to complete the infrastructure development cycle (from design to operation). Another participant thinks it plausible that the Kestrel Project could be providing 50% hydrogen blend to about 1 GW of plant in the Cork cluster by 2035 from storage in the southwest Kinsale and Ballycotton fields. These present outlier estimates in our sample of participants.

Two participants think that there can be significant deployment of hydrogen in the power sector without the need for mega-infrastructure. One participant contests the claim that a dedicated network counts as 'mega-infrastructure' (with the associated timeline proposed below). They think it plausible that one interconnector (IC1) can be converted to hydrogen and a dedicated hydrogen line completed between Cork and Dublin by 2040. Another participant thinks that there can be significant deployment of hydrogen in the power sector without either a dedicated hydrogen network or large-scale geological storage (as noted in the previous results section). In this pathway, several smaller energy park projects (co-locating electrolysis with terrestrial long-duration storage and power plant at strategic points in the power grid) may prove economically viable in future capacity markets. According to one participant, this pathway can proceed within the current planning legislative framework and as soon as the capacity market offers appropriate incentives for 100–200 hours LDES. It does not need a plan-led approach to net zero, with the associated time allocation (roughly five to 10 years) to develop a national strategy, technology plan (including Strategic Environmental Assessment), and complex regulatory framework as envisaged in *Figure 8*. Again, as of Q2 2024, these represent outlier views in our sample of participants.

Figure 8: Indicative timeline for completing generic mega-infrastructure project necessary for a net zero power sector in Ireland



4. Conclusions

At the time of this study (Q1 and Q2 2024), expert pooled opinion confirmed significant uncertainties in the deployment rates (cumulative installed capacity) of some mature and new generation technologies in Ireland, and comparative certainty on some other generation technologies, for the periods up to 2030 and/or 2040.

Deployment of **offshore wind power is very uncertain** over the short term (up to 2030) and long term (up to 2040). Expert pooled opinion deems it plausible that between zero and 3.7 GW will be installed by 2030, with a **best guess of 1.4 GW**. Expert pooled opinion does not find the 5 GW target in 2030 plausible. The plausibility of the With Additional Measures (WAM) policy scenario assumption (4 GW by 2030) is also at risk, while attaining the With Existing Measures (WEM) policy scenario assumption (2.7 GW by 2030) is deemed plausible but unlikely. By 2040 it is plausible that anywhere between 4.5 GW and 14.2 GW will be installed, with a pooled **best guess of 8.8 GW**.

Deployment of **solar PV is somewhat more certain** than offshore wind power for 2030, but less certain than onshore wind power for 2030 and 2040. Expert pooled opinion deems it plausible that between 3.8 GW and 8.3 GW will be installed by 2030, with a **best guess of 6.3 GW**. Most participants think it plausible (though unlikely) that the 8 GW target can be attained in 2030. The collective best guess broadly aligns with the WEM and WAM scenario solar PV forecasts for 2030. By 2040 it is plausible that anywhere between 7.1 GW and 16.8 GW will be installed, with a pooled **best guess of 11.6 GW**.

Deployment of **onshore wind power is comparatively more certain** than offshore wind and solar PV in the short term (up to 2030 and up to 2040); that is, the confidence intervals are significantly narrower. By 2030 it is plausible that between 6.2 and 8.5 GW of onshore wind capacity will be installed. Expert pooled opinion does not find the 9 GW target for 2030 plausible. The collective **best guess of 7.1 GW** broadly aligns with the WEM and WAM scenario forecasts for 2030. By 2040 it is plausible that anywhere between 8.7 GW and 13.3 GW will be installed, with a pooled **best guess of 10.7 GW**.

Table 7 presents a summary of the difference between the EPO50 forecasts (pooled best guess); the 2024 Climate Action Plan variable renewable generation technology targets for 2030; and the 2024 WEM and WAM forecasts as presented in SEAI's National Energy Projections (NEP) 2024. A negative figure indicates that the pooled best guess is less than the target or policy scenario, while a positive figure indicates the EPO50 forecast is more than the target or policy scenario. Appendix A presents graphs for annual comparisons between expert pooled opinion and current policy scenarios.

Table 7: Difference between EPO50 forecasts (pooled best guess) for 2030, the 2030 Climate Action Plan targets, and policy scenarios for Offshore Wind (OFW), Onshore Wind (ONW) and Solar PV (SPV) in GW

	OFW	ONW	SPV
CAP24	-3.6	-1.9	-1.7
WAM	-2.6	0.0	-0.2
WEM	-1.3	0.3	0.6

The **availability, scale and technology pathway for green/blue hydrogen and/or ammonia deployment** as zero-carbon fuels in the Irish power sector is **very uncertain between 2035 and 2040**. Lack of consensus on plausible technology pathways for hydrogen/ammonia deployment (and competition between actors backing different alternatives) may problematise policy making in the short term. Expert pooled opinion is certain there will be no commercial scale power generation running on either fuel by 2030, but there may be a couple of small demonstration projects. By 2035 it is plausible that between zero and an equivalent of 850 MW of thermal plant may utilise 100% green/blue hydrogen or ammonia, with a pooled **best guess of around 80 MW**.[18] The confidence interval becomes much wider for deployment between 2035 and 2040, as uncertainty (and disagreement between participants) concerning plausible technology pathways increases. By 2040 it is plausible that between almost zero and the equivalent of 2.4 GW of thermal plant will utilise 100% green/blue hydrogen/ammonia. The pooled **best guess is that an equivalent of 650 MW** of thermal plants will utilise 100% green/blue hydrogen or ammonia by 2040.

Most (but not all) participants agree on a forecast for the plausibility of having no or very little commercial generation capacity on either fuel by 2040. Most participants think that this represents a **high-risk technology pathway for decarbonisation, dependent largely on immature technologies;** delivering at least one **mega-infrastructure project** (such as geological storage or a dedicated hydrogen network); and sustained political support for subsidising the aforementioned at significant cost to electricity consumers and taxpayers.

Compared to the aforementioned technologies, the deployment of **carbon capture and storage in the Irish power sector is relatively certain up to 2040**. The pooled **best guess is that there will be no** BECCS, WtE-CCS or gas-CCS before 2040. It is plausible (but unlikely) that up to 100 MW of BECCS or WtE-CCS could be deployed in 2035, increasing to 200 MW by 2040. It is plausible (but unlikely) that about 600 MW of gas-CCS could be deployed between 2037 and 2040.

Deployment of CCS in the Irish power sector depends on the decarbonisation of industry and the evolution of industrial clusters at sufficient scale and density to make CCS economically viable. However, there is significant uncertainty on whether Ireland will have such industrial demand for CCS at sufficient scale before 2040, while some high industrial emitters may opt for alternative decarbonisation strategies to CCS. Furthermore, it currently seems likely that the utilisation of captured carbon in Ireland may prove more commercially viable than transport and storage.

Expert pooled opinion demonstrates wide ranges of uncertainty (often spanning several gigawatt) in the cumulative installed capacity of generation technologies in Ireland over the period of spanning the second, third and fourth carbon budgets. However, the results appear to offer **significantly lower forecast ranges for all technologies than what Paris Agreement-compliant scenarios require**. The study did not incorporate a systematic quantitative comparison with carbon budget results, but the expert elicitation has highlighted that the gap between plausible technology deployment rates (especially pooled best guess forecasts) and carbon budget requirements may be large. We recommend a comparison between current carbon budget solutions and the results of the expert elicitation to **quantify the gap between what is deemed likely or plausible, and what is currently required or proposed** for the power sector. If implausible rates of technology deployment are assumed in the power sector (or any other form of optimism bias accepted), the **true requirement to decarbonise other areas is missed**.

[18] These figures present the zero-carbon equivalent capacity, but, in practice, the fuels could be used across a fleet with a larger aggregate generation capacity at lower, plant-specific volumetric blend rates.

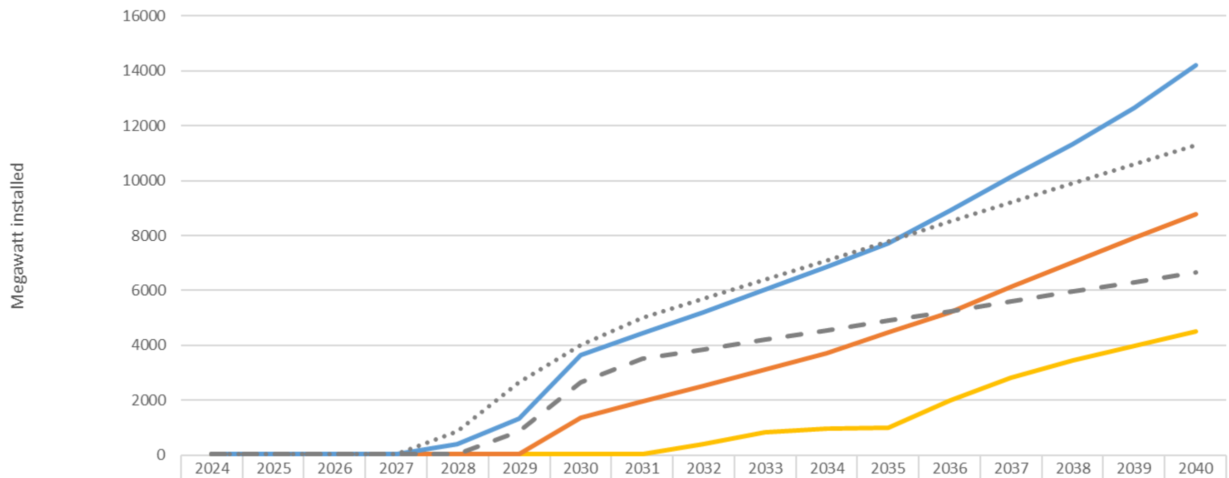
Furthermore, the expert elicitation provides **strong support for the consideration of alternative pathways to power sector decarbonisation**. It is very unlikely that the currently anticipated portfolio of technologies (variable renewables, green/blue hydrogen/ammonia and carbon capture and storage) offer a complete solution to delivering the desired emissions reductions up to 2040. This is because it is unlikely that these technologies will be available soon enough (for immature technologies) and deployed fast enough (for mature and new technologies) due to configurations of diverse conditions noted by experts in this study. A more comprehensive consideration of technologies is merited, both in power generation and the increasingly coupled electrified heat and transport systems, that may complement the core characteristics of the anticipated power system dominated by variable renewables.

Due to inclusion of a hard carbon budget constraint, decarbonisation modelling can involve consideration of both mature and unproven technologies on an equal footing. This is particularly the case for negative emissions technologies, which, for smaller budgets, are required to offset greenhouse gas pollution in earlier parts of a modelled horizon. However, there are significant risks around the availability, cost and performance characteristics of immature technologies and any underpinning infrastructure. These **risks must be incorporated in models to effectively apply a discount to those technologies' potential future contribution**. While it is imperative for the first iteration of a decarbonisation modelling exercise to involve analysing the obligations of the Climate Action and Low Carbon Development (Amendment) Act 2021 and/or the latest Intergovernmental Panel on Climate Change (IPPC) recommendations, it is necessary for secondary iterations to **incorporate feedback or constraints from sector-specific muti-faceted feasibility assessments** to understand what firm energy policies should be pursued.

Appendix: Comparison with policy scenarios

This appendix presents the Expert Pooled Opinion (EPO) forecasts for variable renewable energy deployment from this study, alongside two policy scenario forecasts. These are the With Existing Measures (WEM) and With Additional Measures (WAM) scenarios as used in SEAI's National Energy Projections (NEP) 2024. These two policy scenarios are used by the EPA and SEAI for European reporting, which broadly aligns with 70% RES-E and 80% RES-E respectively in 2030.

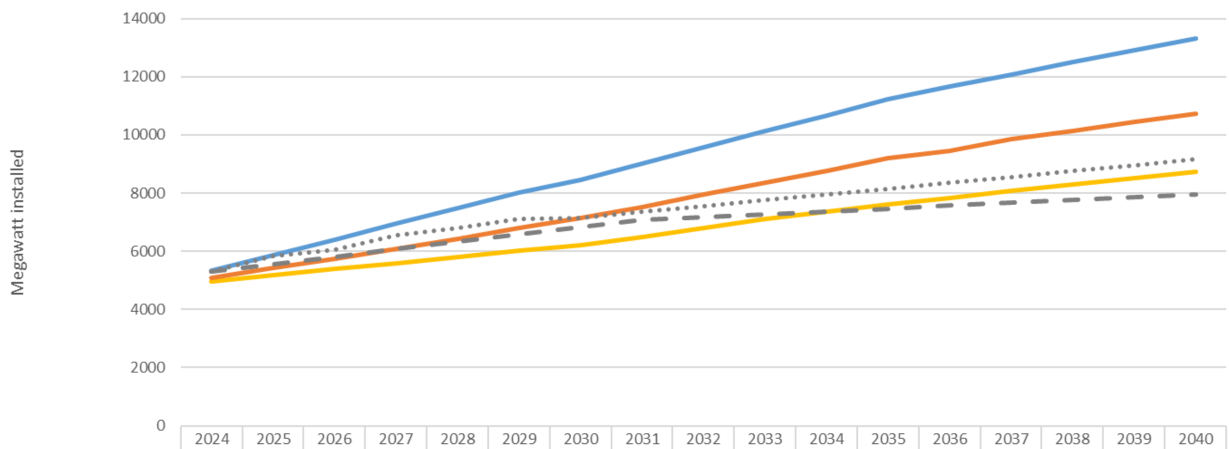
Forecasts for the deployment of electricity generation capacity from offshore wind in Ireland (MW) 2024 - 2040



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
EPO90	25	25	25	25	25	25	25	25	400	834	980	1008	1978	2815	3433	3977	4500
EPO50	25	25	25	25	25	25	1354	1952	2516	3118	3727	4481	5215	6140	7039	7928	8790
EPO10	25	25	25	25	407	1338	3654	4428	5204	6020	6873	7730	8922	10142	11318	12648	14226
WEMNEP2024	25	25	25	25	25	850	2650	3500	3850	4200	4550	4900	5250	5600	5950	6300	6650
WAMNEP2024	25	25	25	25	850	2650	4000	5000	5700	6400	7100	7800	8500	9200	9900	10600	11300

EPO90 EPO50 EPO10 WEMNEP2024 WAMNEP2024

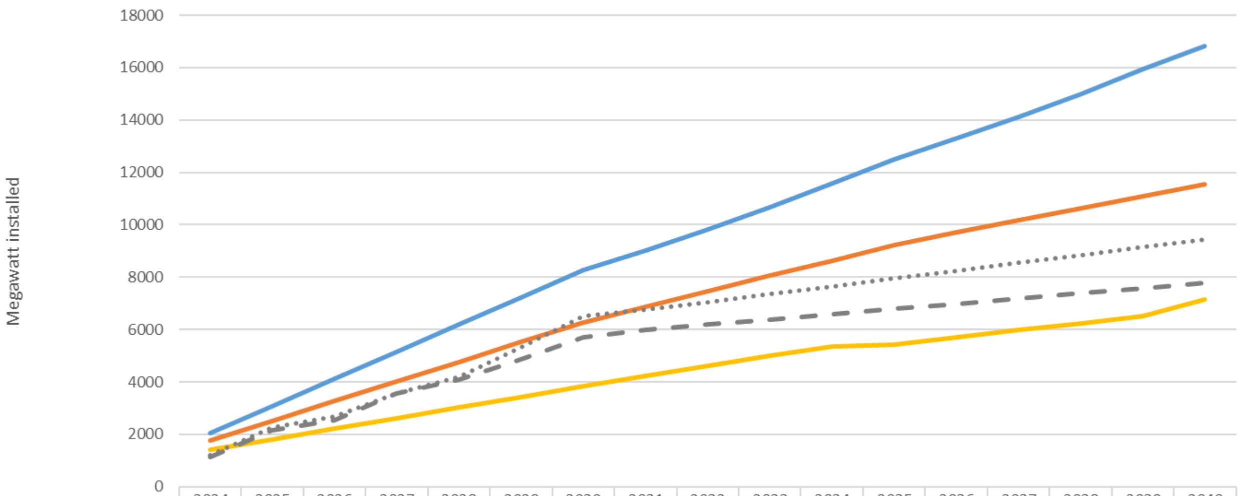
Forecasts for the deployment of electricity generation capacity from onshore wind in Ireland (MW) 2024 - 2040



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
EPO90	4961	5174	5386	5599	5811	6023	6201	6492	6790	7098	7361	7612	7836	8065	8293	8518	8741
EPO50	5093	5418	5744	6068	6441	6811	7130	7533	7939	8350	8770	9189	9437	9849	10127	10435	10743
EPO10	5336	5870	6406	6941	7472	8010	8456	9021	9579	10130	10677	11220	11656	12082	12501	12913	13321
WEMNEP2024	5318	5568	5818	6068	6318	6568	6818	7068	7168	7268	7368	7468	7568	7668	7768	7868	7968
WAMNEP2024	5318	5824	6065	6565	6805	7105	7155	7355	7555	7755	7955	8155	8355	8555	8755	8955	9155

EPO90 EPO50 EPO10 WEMNEP2024 WAMNEP2024

Forecasts for the deployment electricity generation capacity from solar PV in Ireland (MW)
2024 - 2040



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
EPO90	1405	1811	2217	2622	3028	3433	3839	4221	4602	4984	5369	5439	5706	5974	6241	6508	7132
EPO50	1754	2507	3261	4014	4768	5521	6279	6883	7476	8061	8639	9222	9703	10175	10641	11099	11551
EPO10	2039	3078	4117	5156	6195	7234	8273	9010	9825	10667	11581	12487	13288	14103	15010	15942	16813
WEMNEP2024	1140	2151	2524	3544	4079	4864	5700	5984	6184	6384	6584	6784	6984	7184	7384	7584	7784
WAMNEP2024	1194	2249	2687	3575	4192	5324	6500	6750	7050	7350	7650	7950	8250	8550	8850	9150	9450

EPO90 EPO50 EPO10 WEMNEP2024 WAMNEP2024

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