REPORT

Accelerating Renewables in Northern Ireland

High Level Design of a Support Scheme

March 2024

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Acknowledgements

'Accelerating Renewables in Northern Ireland' is a project of Aurora Energy Research on behalf of the Department for the Economy, Northern Ireland. Aurora Energy Research and the Department for the Economy would like to thank all network operators, network regulators, government bodies and renewable stakeholders for their valuable insight and engagement in the stakeholder workshop and expert interviews.

General Disclaimer

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List of Abbreviations

Abbreviation	Definition
AR	Allocation Round
BESS	Battery Energy Storage System
CAPEX	Capital Expenditures
CHP	Combined Heat and Power
COD	Commercial Operation Date
CPI	Consumer Price Index
CRU	Commission for Regulation of Utilities
DA	Day Ahead
DESNZ	Department for Energy Security and Net Zero
ECP	Enduring Connection Policy
EfW	Energy from Waste
EU	European Union
FIP	Feed in Premium
FiT	Feed in Tariff
GB	Great Britain
GM	General Meeting
GW	Gigawatt
HICP	Harmonised Indices of Consumer Prices
ID	Intraday
IP	Imbalance Price
LCCC	Low Carbon Contracts Company

LCOE	Levelised Cost of Electricity
Min-Gen	Minimum-generation constraint
MSP	Maximum Strike Price
MW(h)	Megawatt(-hour)
NI	Northern Ireland
NIEN	Northern Ireland Electricity Network
NIRO	Northern Ireland Renewables Obligation
NPV	Net Present Value
OPEX	Operating Expenses
OREAP	Offshore Renewable Energy Action Plan
ORESS	Offshore Renewable Electricity Support Scheme
PPI	Producer Price Index
PSO	Public Service Obligation
PV	Photovoltaic
QCPC	Qualifying Partial Curtailment
REMA	Review of Electricity Market Arrangements
REPD	Renewable Energy Planning Database
RES	Renewable Energy Sources
RESS	Renewable Electricity Support Scheme
RO	Renewables Obligation
ROC	Renewables Obligation certificates
RoI	Republic of Ireland
I-SEM	Integrated Single Electricity Market

SNSP	System Non-Synchronous Penetration
SOEF	Shaping our Electricity Future
SONI	System Operator for Northern Ireland
SPPS	Strategic Planning Policy Statement
SRMC	Short-Run Marginal Costs
TBD	To Be Determined
TW(h)	Terawatt(-hour)
UAEC	Unrealised Available Energy Compensation
UK	United Kingdom
WACC	Weighted average cost of capital

Executive Summary

Policy context: a new support scheme to deliver the 80% RES-E target

Northern Ireland's Energy Strategy, published in December 2021, established a target of 70% of electricity consumption from a diverse mix of renewable sources by 2030. This target has since increased to 80% through the Climate Change Act (Northern Ireland) 2022. To deliver on the 80% target, the Department for the Economy (DfE) plans to introduce a new support scheme for renewable electricity and has published a consultation on design considerations for such a scheme in February 2023. In this consultation, the following objectives of the scheme were established:

1. **80% by 2030:** incentivise sufficient renewable electricity generation to ensure that at least 80% of electricity consumption is from renewable sources by 2030.
2. **Low Cost:** ensure that consumer costs remain at an affordable level due to locally produced electricity, leading to stable electricity prices.
3. **Energy Security:** encourage a wide range of renewable sources to diversify the technology mix to support security of supply.

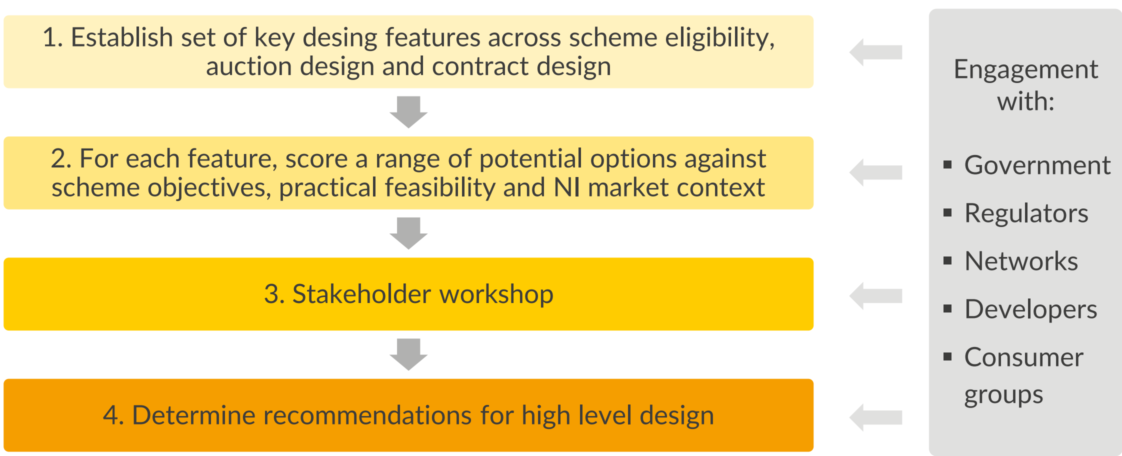
Project context

Aurora Energy Research has been commissioned by the DfE NI to provide **recommendations for the scheme design**, based on techno-economic analysis, literature review, and stakeholder engagement. The project builds on previous studies commissioned by the DfE as well as the responses to the Consultation on the Design of the Support Scheme conducted in 2023.

The Consultation confirmed the contract for difference (CfD) as the form of support preferred by power sector stakeholders, due to its proven ability to de-risk investment and protect consumers from price volatility. Hence, **this project aims to determine an optimal design of a CfD-type support scheme**, tailored to the Northern Irish context and building on the experience of similar schemes in GB and the Republic of Ireland.

This first phase of the project provides high-level recommendations. A detailed design phase will follow over the course of 2024, which will analyse potential auction outcomes and their impact on consumers in greater detail. Recommendations developed in this first phase should be seen as preliminary, with refinements to be made during the detailed design stage.

Aurora's approach to the high-level design



Recommended Design Options

Table 1– Aurora's key recommendations on eligibility, auction design, and contract design

Design Feature	Recommended Option
Eligibility	
Eligible Technologies	Onshore wind, solar PV, hydro, tidal & wave, hybrid sites (RES + BESS), geothermal, anaerobic digestion, landfill gas, energy-from-waste, biogas, biomass. Further analysis required to determine the nature of offshore wind participation.
Eligibility Criteria	Planning permission and grid connection offer
Minimum Size	Minimum size of 5MW – *to be confirmed*
Existing sites	Potential inclusion of existing sites in case of complete repowering – *further analysis required*
Auction Design	
Pot Structure	Pot 1: onshore wind and solar; Pot 2: all other technologies except offshore wind; Pot 3: offshore wind *(to be confirmed)*
Pot Size	Fixed by energy volume to be procured
Maximum Strike Price	Technology specific maximum strike prices disclosed ahead of auctions
Auction Frequency	Biennial (2025/27/…)
Pricing Mechanism	Pay-as-clear auctions
Delivery Year	2 years after the auction, long stop date 1 year after delivery year
Community Benefits	*To be determined*
Contract Design	
Contract Length	15 years (fixed length)
Indexation	Strike price 100% linked to inflation
Dispatch Down Compensation	Compensation for oversupply and curtailment; recommendation regarding compensation for constraints requires further analysis
Non-Delivery Penalties	Financial penalties (bid bonds and performance bonds)
Floor Price	Cease support in any period when the wholesale price is negative
Reference Price	I-SEM Day-Ahead hourly price
Funding	*To be determined (funding by taxation or via energy bills under consideration)*

Scale of the challenge: procurement of 3.5 TWh

Electricity demand in Northern Ireland is expected to increase by 20% from today's levels by 2030, reaching more than 10 TWh in SONI's Central Scenario and requiring around 8TWh of renewable electricity to reach the 80% target. Given 3 TWh of existing generation, around 5TWh of additional renewable generation is required. 1.5TWh, is expected to be met by non-subsidised generators, based on trends in merchant renewables financing. This leaves **3.5TWh of generation which will require a CfD**. However, there is considerable uncertainty around 2030 demand; the generation volume that must be procured through the scheme varies by +/-1 TWh depending on demand projections in SONI's High/Low forecasts respectively.

Offshore wind

The Energy Strategy Action Plan 2022 identified a target of 1GW of offshore wind capacity from 2030. The Department and key stakeholders continue to refine the timeline for offshore wind delivery. At this stage in development, it is not possible to outline with certainty the scale and timing of offshore wind deployment in NI. Therefore, the nature of offshore wind's participation in the scheme cannot be outlined until more information is available. However, the development of the support scheme will align with the critical path timeline for offshore renewable energy and draw input from the OREAP Steering Group.

Auction Roadmap

The below chart shows preliminary auction timelines and volumes for the first two auctions. Only projects procured in these first two auctions will become operational before 2030.

Auction	Auction Year	Delivery Year	Volume
1	2025	2027	1,000 GWh (~500 MW)
2	2027	2029	2,500 GWh (~1250 MW)
TBD	…	…	…

1 Introduction

1.1 Policy Context

Northern Ireland's Energy Strategy, published in December 2021, established a target of 70% of electricity consumption from a diverse mix of renewable sources by 2030. This target has since increased to 80% through the Climate Change Act (Northern Ireland) (1,2).

The Energy Strategy Action Plan 2022 was published in January, outlining 22 commitments for the year. The plan included an action to consult on a renewable electricity support scheme (Action Point 12) (3).

In February 2023 the Department published a consultation on design considerations for a Renewable Electricity Support Scheme for Northern Ireland, and in March 2023 the new Energy Strategy Action Plan 2023 highlighted the priority areas for year 2 of the delivery of the Energy Strategy programme. Action 7 committed the Department to launching the design of a renewable electricity support scheme in 2023 (4).

Northern Ireland's overarching economic strategy, published in 2021 in the 'A 10X Economy: Northern Ireland's Decade of Innovation' document, established sustainability as one of its three key pillars with the objective to 'double the size of NI's low carbon and renewable energy economy to more than £2bn turnover'. The renewable electricity support scheme is among the initiatives of the government to deliver on this objective.

1.1.1 Objectives of the renewable electricity support scheme

In the 2023 consultation on the renewable electricity support scheme, the DfE established the objectives of the scheme (7), which relate to the energy trilemma:

1. **80% by 2030:** incentivise sufficient renewable electricity generation to ensure that at least 80% of electricity consumption is from renewable sources by 2030.
2. **Low Cost:** ensure that consumers pay a fair price for electricity produced locally and that prices are more stable than in recent years.
3. **Energy Security:** encourage a wide range of renewable sources to diversify the technology mix to support security of supply.

These objectives were reiterated in the 10X delivery plan 2023/24 (5,6).

<u>Context and purpose of this report</u>

Aurora Energy Research has been commissioned by the DfE to provide recommendations for the design of the renewable electricity support scheme based on techno-economic analysis, literature review, and stakeholder engagement.

This report is the deliverable of the first phase of the project and summarises the recommended high-level design of the scheme. A key focus of this phase was engagement with stakeholders of the power system in Northern Ireland complemented by literature review and high-level quantitative analysis.

The recommendations in this report are based on the preliminary assessment in the first phase of the project and require further research for confirmation. To help finalise the scheme design Aurora will continue to advise the DfE over the course of 2024 conducting more in-depth technical analysis of potential auction outcomes and their impact on consumer costs.

1.2 Prior research underpinning the High-Level Design

The analysis and stakeholder engagement undertaken in this project builds on the following research and evidence previously collected or commissioned by the Department for the Economy (DfE):

- Queen's University Belfast in collaboration with DfE published a study titled *'Support scheme options to incentivise renewables investment in Northern Ireland: Report for the Department for the Economy as evidence for the Northern Ireland Energy Strategy 2021'* which focused on various types of support for low carbon electricity generation and their merits and flaws (8).
- DfE commissioned a scoping report from Cornwall Insight titled '*Department for the Economy (DfE) Renewable Electricity Support Scheme for Northern Ireland (NI): Design Considerations*', published in 2023. This report focused on key considerations for a support scheme for Northern Ireland and the key questions which should be addressed in a public consultation (9).
- Most recently DfE held a '*Consultation on design considerations for a Renewable Electricity Support Scheme for Northern Ireland*' asking power sector stakeholders for their views regarding possible design choices of a support scheme (10).

1.3 Research and stakeholder engagement

The research for the Renewable Electricity Support Scheme for Northern Ireland started with an extensive literature review on the design of renewable electricity support schemes. Since such support schemes have been rolled out across several countries, in particular in Europe, a significant body of literature was available. This consisted of academic and grey literature as well as reports commissioned by governments. Various support schemes currently implemented, particular those in GB and ROI, were examined and evaluated, as well as multiple reports on support schemes and auction design.

Qualitative analysis was conducted on all design features, with some design parameters supported by quantitative analysis. All resulting features will be corroborated by further analysis in the next two phases of the support scheme design.

The key research method in this first phase of the project has been stakeholder engagement with power sector experts. Initial assessments of different scheme design options were discussed in expert interviews to gain feedback and test preliminary conclusions. Furthermore, the interviews were used to gain insights on the particularities of the Northern Irish market and to inform decisions on which design options would be the best fit for the Northern Irish context. The interviewed experts included market regulators, network operators, renewable developers, and policy makers.

Finally, a stakeholder workshop was held in Belfast to present and gain feedback on the recommended high level scheme design from a wider group of stakeholders from the renewable industry, network operators, regulators, policy makers, and consumer interest groups. The workshop included a presentation of the high-level design as well as structured discussions allowing different interest groups to share and explain their views. All feedback received at the workshop was integrated into the assessment of design options and refinement of recommendations presented in this report.

1.4 Scale of the challenge

1.4.1 Additional RES generation required to meet the Climate Change Act 2030 target

Electricity demand in Northern Ireland is expected to reach between 8.9 – 11.3 TWh in 2030 according to the Low and High Scenarios respectively in SONI's 2023 Generation and Capacity Statement (11). This represents a 6 - 34% increase compared to current demand (8.4 TWh in 2022). Meeting the 2030 target would correspondingly require renewable generation of between 7.1 and 9.0 TWh (see Figure 1 below). Given the generation of existing renewable capacity of 3.4 TWh, this corresponds to approximately 4 – 6 TWh of additional generation being required.

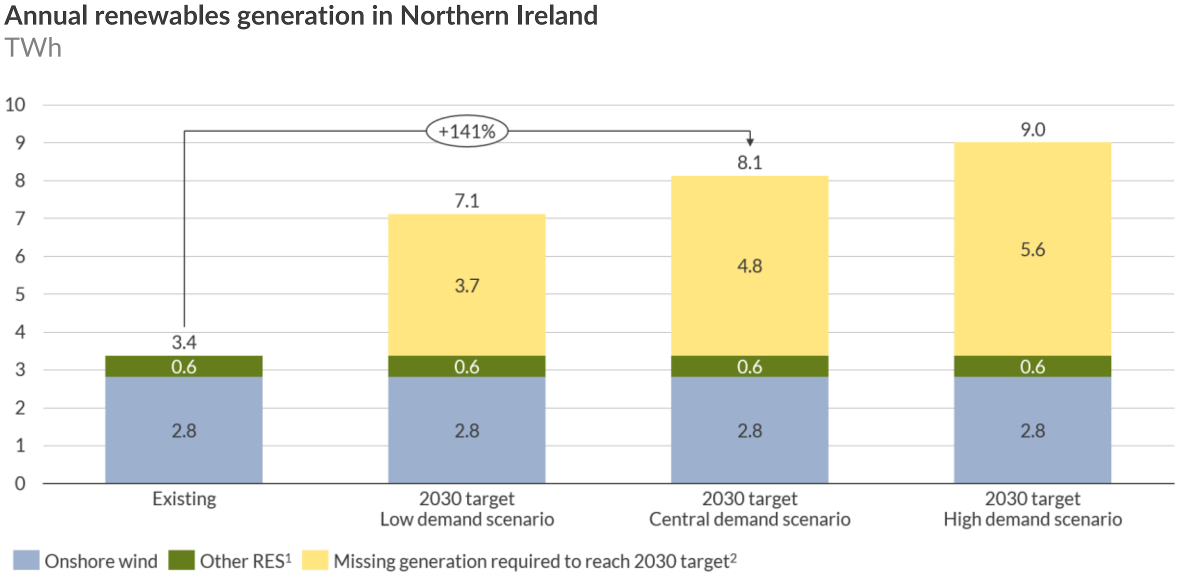


Figure 1: Existing and required additional renewable generation to meet the 2030 target[3]

[1] Other RES includes solar PV, biomass, waste fuel generation, landfill gas, tidal stream, anaerobic digestion and advanced conversion technologies

[2] Based on Low/Central/High total electricity requirement of 8.9/10.2/11.3 TWh respectively

[3] Sources: SONI (2030 Total Electricity Requirement)(77), DfE – existing generation Jul-22 to Jun-23(69)

1.4.2 Generation volumes to be procured through the support scheme

Of the ~5TWh of additional RES generation required to meet the 2030 target in the System Operator for Northern Ireland's (SONI) Central Demand Scenario (11), ~1.5TWh is assumed to become operational under a merchant business model (i.e. without a CfD). Hence, **3.5 TWh of renewable generation must be procured through the Scheme** based on the 2030 electricity demand in SONI's Central Scenario (11).

The assumption on 2030 merchant volumes is based on historical volumes becoming operational solely on a PPA business model in Northern Ireland. Around 300GWh of merchant renewable volumes have secured corporate PPA financing since the closure of the NIRO scheme (12). This will represent around 10% of total RES generation in 2025, and this share is expected to grow with declining RES CAPEX and growing interest in green PPAs from industry and commercial offtakers (13). This is evidenced by a growing number of PPA contracts in the Republic of Ireland (c. 2.5TWh since 2018 (12)), as well as a trend of large support-free renewables projects being financed internationally[4]. As a result of these trends, it is assumed that 30% of new generation between now and 2030 will not need to be supported by the government. This would lead to around 18% of total renewables generation in 2030 being accounted for by non-supported generators[5]. This value is benchmarked against the non-government-supported share of RES generation in GB in 2022[6]. Volumes without government support are assumed to be lower in NI than in GB because of lower liquidity in the Northern Irish PPA market (according to market participants).

Table 2: Share of RES generation made up by supported and non-supported generation.

Support type	GB 2022[6]	GB 2030[7]	NI 2022[8]	NI 2030[9]
RO	60%	33%	~95% (NIRO)	40% (NIRO)
FiT	7%	4%	N/A	N/A
CfD	15%	40%	N/A	42%
No support	18%	24%	~5%	18%

[4] E.g. 980MW offshore wind farm in Germany.

[5] While the cost of support is sensitive to the assumption on the share of generation requiring support, the total cost of generation is broadly similar since it is assumed that fixed-price PPA contracts – the most common alternative route to market - would be benchmarked to the CfD strike price.

[6] Sources: (78–81).

[7] Assumes same RO and FiT volumes as in 2022, with 70% of new generation volumes between 2022 and 2030 under CfD and 30% becoming operational without support. New generation volumes are based on Aurora Jan-24 Central forecast.

[8] Source: Ofgem Renewables & CHP register (82).

[9] Aurora projection based on proposed Support Scheme design.

1.5 Renewables pipeline in Northern Ireland

Since the closure of the Northern Ireland Renewable Obligation (NIRO) scheme for new entrants in 2017, no significant renewables capacity has become operational in Northern Ireland.

The renewables pipeline in Northern Ireland is dominated by onshore wind. There is good visibility on the capacity of plants having submitted planning applications, as they are listed in the UK government's Renewable Energy Planning Database (REPD). Onshore wind accounts for around 900 MW (76%) of capacity currently in the planning stage or beyond (grid connection and construction). Solar PV accounts for 13% with around 150 MW.

There is less visibility on the plants in the pipeline which have not yet submitted application for planning permission. According to industry estimates, around 1,000 MW of onshore wind and 600 MW of solar PV are currently in the pre-planning stage and are expected to submit planning application in the near future (14). Taken together, the renewable capacity in the pre-planning stage and in the subsequent planning stages, are sufficient to meet the approximately 5 TWh of additional renewable generation required to meet the 2030 target. However, significant acceleration of planning approval and a very high delivery rate of the projects in the pipeline are required. More detail on the renewables pipeline and its potential development is provided in section 3.1 'Pipeline analysis'.

1.6 Principle form of support

The NIRO scheme, a renewable obligation scheme, ran in NI from 2005-2017 (15). Given significant experience with and successful implementation of alternative support schemes there is an opportunity to introduce a different form of support in NI.

The consultation confirmed that a CfD, as implemented in schemes in GB and the Republic of Ireland, is the principal form of support preferred by power sector stakeholders. The CfD, also referred to as a two-way floating feed in premium, is explained in Section 1.7.

Crucially, a CfD reduces risks for investors as well as for consumers. CfDs eliminate price-risk for investors, since they are guaranteed a fixed price, while also protecting consumers from price volatility. Furthermore, a CfD is a form of operational support, providing support payments only for generation delivered. It thus avoids the risk of support being provided to projects which don't get completed, as can be the case with CAPEX support in the form of grants, loans, and tax breaks. Finally, investors and developers in the UK are familiar with the mechanism and are prepared to use it as a basis for financing projects.

Due to the wide consensus among sector stakeholders, a detailed assessment of various principal forms of support is not the focus of this project. Rather the aim is to determine an optimal design of a CfD-type support scheme tailored to the Northern Irish context and market, while drawing from the experience of similar schemes across Europe. A high-level analysis of various support schemes can be found in the appendix (Section 4.1) to supplement this decision.

1.7 The CfD mechanism explained

The below chart illustrates the support payments paid to generators in a CfD support mechanism as the market price changes over the course of 24 hours. It is assumed that no dispatch down occurs, and that the generator produces power across the entire period.

CfD support payments for generation during an illustrative day
£/MWh

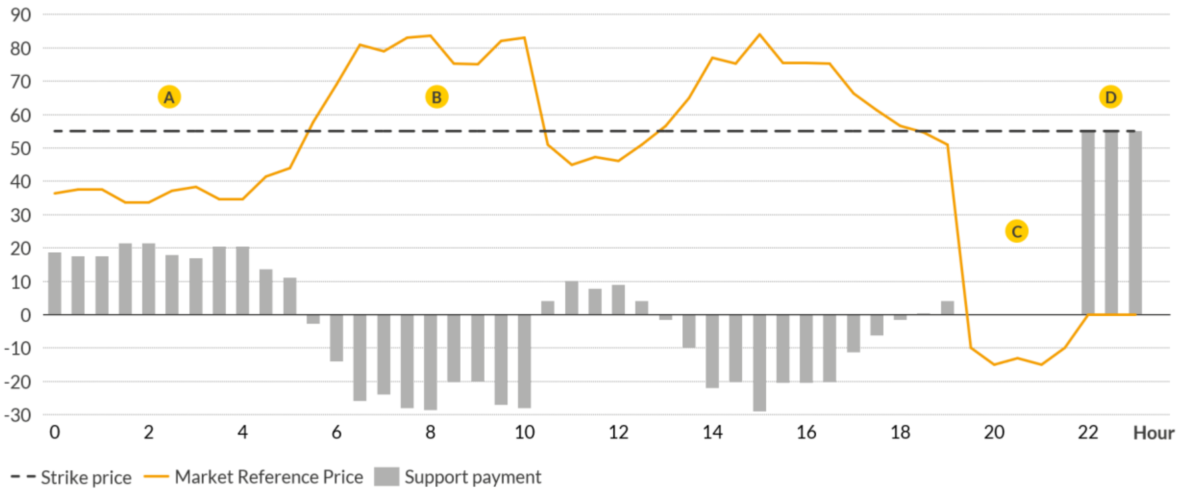


Figure 2: The CfD Mechanism explained

Region of chart	Price environment	Explanation of support payment
A	Market price < strike price	Generators receive the market reference price and are paid the difference to the strike price.
B	Market price > strike price	Generators receive the market reference price but must pay back the difference to the strike price.
C	Negative prices	Support payments cease during negative price periods since the floor price of the CfD is zero (as defined in Section 2.3.5). Hence, if generators continue producing power during negative prices, they will not receive support payments. However, if generators stop producing, then they are compensated at the strike price during negative price periods (see Section 2.3.3).
D	Market price = 0	Since the price is not negative, the same remuneration occurs as in (**A**).

2 Support Scheme Design

In this chapter we assess different options for several key features of a CfD-type support scheme design. The features which are investigated can be grouped into the following three groups:

- **Eligibility (Section 2.1):** eligible technologies, inclusion of existing sites, eligibility criteria, minimum size
- **Auction design (Section 2.2):** pot structure, pot size, maximum strike price, auction frequency, pricing mechanism, community benefits, delivery dates
- **Contract design (Section 2.3):** contract length, indexation, curtailment compensation, floor price, reference price, funding of scheme

Each option for a design feature or parameter is assessed against the assessment criteria described below. The first three are aligned with the objectives of the renewable electricity support scheme (see section 1.1.1) while the fourth addresses further practical considerations.

Table 3 - criteria for evaluation of design choices

Criterion	Description
80% by 2030	How does the design choice help or hinder renewable deployment at the scale and pace required to reach the 2030 renewable electricity target?
Low Cost	How does the design choice help ensure sufficient competition such that consumers pay a fair price for electricity produced locally and that prices are more stable?
Energy Security	How does the design choice help to encourage a wide range of renewable sources to diversify the technology mix to support security of supply?
Practicality	How practical is this design choice? Can it be implemented easily? Will it add significant complexity or administrative burden? Does it preserve the future adaptability of the scheme?

A design choice is assigned a score of either 0% (Low), 50% (Medium), 100% (High) for each of the four criteria. The **total score** is then calculated as the average score across the first three criteria, which is then multiplied by the score for the practicality criterion.

We note the ongoing debate about significant reforms of the CfD scheme with contributions from academia (Newbery, Hirth) as well as industry stakeholders and government (REMA consultations and responses). However the suggested reforms mentioned are at an early stage and not ready to be implemented. We recommend monitoring this debate and will consider any changes made to the GB CfD during further phases of the NI support scheme design.

2.1 Eligibility

2.1.1 Eligible technologies

Recommendation

Eligible technologies:

- Onshore wind
- Solar PV
- Hydro
- Tidal & wave
- RES + Battery Energy Storage (BESS)
- Geothermal
- Anaerobic digestion (AD)
- Landfill gas
- Energy from waste (EfW)
- Biogas
- Biomass
- Offshore wind – subject to further alignment with the Government's Offshore Renewable Energy Action Plan workstream

All technologies analysed are recommended for inclusion, as growth of inefficient/expensive technologies will be prevented by competition and the pot structure.

For further information which technology is eligible for which pot, see Section 2.2.1 Pot Structure.

Country	Eligible technologies
GB	CfD AR6: Onshore wind (>5MW), offshore wind, solar PV (>5MW), Hydro (>5MW and <50MW), tidal, geothermal, anaerobic digestion, landfill gas, energy from waste, biogas, biomass
Republic Of Ireland	RESS: Onshore wind, solar PV, hybrid wind and solar PV, hybrid wind and storage, hybrid solar PV and storage, hydro, energy from waste[10], biomass, biogas

[10] Only eligible as high efficiency (CHP)

-- In-depth analysis of options --

Option	80% by 2030	Low Cost	Energy Security	Practicality	Total Score
Onshore wind	100%	100%	50%	100%	83%
Offshore wind	50%	100%	50%	50%	33%
Solar PV	100%	100%	50%	100%	83%
Hydro[11]	0%	50%	100%	50%	25%
Tidal	0%	0%	100%	50%	17%
RES + BESS[12]	50%	50%	100%	50%	33%
Geothermal	0%	50%	100%	50%	25%
AD[13]	50%	0%	100%	100%	50%
Landfill gas	50%	50%	100%	100%	67%
EfW[14]	50%	0%	100%	100%	50%
Biogas	100%	0%	100%	100%	67%
Biomass	100%	50%	100%	100%	83%

80% by 2030: meeting the 2030 80% RES-E target requires the near-term installation of renewable technologies. Hence, this criterion is mainly scored according to the production volumes of each technology in the pipeline (i.e. in the planning or construction phases of development). Onshore wind and solar PV dominate the pipeline (16), with less established technologies scoring lower.

Low Cost: technologies were scored according to their projected levelised cost of electricity (LCOE) in 2030 according to reporting by the Department for Energy Security and Net Zero (DESNZ), based projects in the UK (17)[15]. Onshore wind, offshore wind and solar PV score most highly, with 2030

[11] Non-dispatchable Hydro.

[12] Co-located RES & Battery Energy Storage (BESS); BESS cannot charge from the grid and can only charge from the RES asset.

[13] Anaerobic digestion

[14] Energy from Waste

[15] An updated LCOE specific to Northern Ireland will be calculated in the next phase of the Support Scheme design.

LCOEs of under £40/MWh (17). Biogas and tidal stream have the highest 2030 LCOEs, at around £200/MWh, while the other technologies fall in between, with the average LCOE across all technologies in 2030 being £111/MWh. Note this metric does not take account of the varying system integration costs of different technologies.

Energy Security: the potential contribution of a renewable technology to the security of the electricity system depends on its average annual load factor, and the extent to which procuring a marginal unit of capacity contributes to the diversification of the supply mix. More diverse energy systems lead to a more secure energy system, and technologies contribute to diversification if their generation profiles do not correlate with that of the existing renewables fleet. Since onshore wind generation already constitutes 84% of renewable production in Northern Ireland, additional procurement does not greatly contribute to improved energy security. Offshore wind generation is to an extent correlated with existing onshore wind generation, while solar PV has a low annual average load factor. All other technologies are scored highly since they are dispatchable and/or have reliable and high load factors.

Practicality: onshore wind, solar PV are the most established technologies and hence score highly on feasibility/ease of implementation. Anaerobic digestion, landfill gas, energy from waste (EfW) and biogas score highly based on their low land requirements, while geothermal, tidal and hydro score lowly as a result of not being established technologies in Northern Ireland.

Co-located RES & BESS: RES assets with co-located BESS will be eligible to participate in the pot corresponding to the RES technology. To be eligible, the co-located BESS will only be allowed to charge from the co-located RES installation, to ensure that only renewable electricity is supported. The hybrid site – like all sites in the scheme – will ultimately receive the strike price for any output sold. As a result, the only incentive to use the battery under the scheme will be to charge those curtailed volumes that are not compensated (i.e. curtailment resulting from network constraints; see 2.4.3 Curtailment Compensation), to later discharge these volumes and receive the strike price. Sites with co-located BESS might be able to bid at lower prices than those without BESS and similar levels of network constraints as they will receive the strike price for a higher volume. They will also be able to operate the BESS independently from the RES after the support period. If these upsides outweigh the additional cost of BESS, these sites will have a commercial advantage. Sites will also be allowed to install co-located BESS charging from the grid, but in this case no output from the RES installation may be discharged to the BESS, and the BESS discharge volumes will not be remunerated under the scheme[16].

Offshore wind: The Energy Strategy Action Plan 2022 identified a target of 1GW of offshore wind capacity from 2030 (3). The Department and key stakeholders continue to refine the timeline for offshore wind delivery. At this stage in development, it is not possible to outline with certainty the scale and timing of offshore wind deployment in NI. Therefore, the nature of offshore wind's participation in the scheme cannot be outlined until more information is available. However, the development of the support scheme will align with the critical path timeline for offshore renewable energy and draw input from the OREAP Steering Group.

[16] The treatment of BESS largely follows the approach taken in the ROI RESS scheme (19).

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2.1.2 Inclusion of existing sites

#	Option	Explanation	Overall Score
1	Allow existing	▪ Allow existing sites to participate in the scheme	0%
2	Do not allow existing	▪ Existing sites are not allowed to participate in the scheme	75%
3	Allow existing only if repowering	▪ Only allow existing sites to join if they undergo a complete repowering. In the case of NIRO assets this would only be for assets at the end of their contract	75%

Country	Implemented Option
Great Britain	▪ Existing capacity is not eligible (18) ▪ Repowering is not permitted but is being considered for Allocation Round 7 (AR7) (18)
Republic of Ireland	▪ Existing capacity is not eligible (19) ▪ Renewable Electricity Support Scheme (RESS) 1 included repowered projects, with repowering defined as a >50% increase in energy output and a 300 EUR/kW investment (20)

Recommendation

- To be defined during the detailed design phase based on quantitative analysis of the extent to which both existing and repowering sites could contribute to the aims of the scheme by 2030 and in the longer term. Further analysis will also include an assessment of the consequences of any potential reforms to the NIRO scheme and the potential of allowing existing sites to exit their NIRO contracts early and switch to the new Support Scheme

-- In-depth analysis of options --

Option	80% by 2030	Score
1 Allow existing	× Does not lead to additional renewable generation	0%
2 Do not allow existing	✓ Does not crowd out support for new generation × Existing capacity may go offline if unable to repower without support (though this will only happen post 2030, given length of NIRO contracts)	50%

Option	80% by 2030	Score
3 Allow existing only if repowering	✓ Reduces delivery risk, as existing infrastructure can be used ✓ Repowering requires significant upfront investment and hence requires support in many cases × NIRO plants are only expected to repower after 2030 and hence repowering sites are not expected to contribute to the 2030 target × Repowering many small sites could lead to inefficient use of space compared to building new, larger sites	50%

Option	Low Cost	Score
1 Allow existing	× Existing sites are commercially viable without support given high near-term merchant revenues; including them increases the long-term cost to consumer (21)	0%
2 Do not allow existing	✓ Existing sites are commercially viable without support, not allowing them to participate ensures the cost to consumer is only for new RES assets	100%
3 Allow existing only if repowering	✓ Repowering is a low-cost route to securing capacity, with lower or no costs of connection and of infrastructure upgrades (this was highlighted in conversations with energy regulators) × Some generators may be able to repower without support	100%

Energy Security: Inclusion of existing sites is not expected to have any impact on the diversification and security of electricity supply. Thus, this design feature was not assessed in terms of the energy security criterion.

Option	Practicality	Score
1 Allow existing	× Increased administrative burden of processing applications from existing sites	0%
2 Do not allow existing	✓ No practical barriers	100%
3 Allow existing only if repowering	✓ Few practical barriers	100%

2.1.3 Eligibility criteria

Planning approval and grid connection timelines in Northern Ireland

Typically, it takes 7-9 years to bring a renewable plant online in Northern Ireland, including pre-planning, planning, grid connection, and construction phases (22). Planning permission can take up to three years to obtain and is a pre-requisite for receiving a grid connection offer. Therefore, there are significantly more developments at the planning permission stage in the pipeline than at the grid connection stage (16). The renewable industry claims shortening of the planning approval process to one year and allowing planning approval and grid connection processes to progress in parallel are necessary to meet the 2030 target (23).

#	Option	Explanation	Score
1	Planning Permission	▪ Projects are required to gain planning permission prior to the auction	50%
2	Grid connection	▪ Projects are required to gain a grid connection offer prior to the auction	50%
3	Supply chain sustainability	▪ Developments must source materials for the development locally and sustainably	0%
4	Local employment	▪ Developments must employ local workers and businesses for construction of the projects	25%

Country	Implemented Option
GB	▪ Sites required to have planning permission and grid connection agreement (implying acceptance and payment for a grid connection offer) ▪ Projects with capacity greater than 300MW must have a supply chain plan
Republic Of Ireland	▪ Projects must have final grant of planning permission ▪ In RESS 2 projects were required to have either a grid connection offer, or grid connection agreement (24) ▪ In RESS 3, projects must secure a grid connection and planning permission within 90 days of the issued support start date (19) ▪ No specific requirement for sustainable supply chain in scheme design, but community benefit fund could be used for sustainable projects within the local community (26)

Recommendation

- Planning permission and a grid connection offer should be required to be eligible to participate in auctions to ensure coordination of renewable support with planning and connection processes and to exclude speculative bids.
- Planning permission: eligible projects must evidence a full and final grant of planning permission for the construction of the plant from the relevant planning authority, and this permission must not have an expiry date prior to the end of the support contract.
- Grid connection offer: eligible projects must evidence receipt of an offer of a valid grid connection contract from the DNO or TSO (as applicable).

Notes

- There are currently consultations by the Department of Infrastructure to parallelise planning requirements and grid connection, however this is outside the scope of the scheme design.
- The recommendation is subject to change dependent on further analysis of the pipeline to be conducted in the next phase of this project.
- The criteria may be relaxed in return for shifting more financial risk to developers via bid and performance bonds.
- The criteria may be made more stringent, by requiring acceptance of the grid connection offer.

-- In-depth analysis of options --

Option	80% by 2030	Score
1 Planning permission	✓ Requiring planning permission reduces the substantial risk that projects successful in the auction are not realised ✓ Projects at an earlier stage of development competing in the auction are less likely be operational by the 2030 target ✓ Reduces the likelihood of speculative bidding from developers	100%
2 Grid connection	✓ Planning permission analysis is also applicable here	100%
3 Supply chain sustainability	× Inclusion of this criteria may increase the number of supply chain bottlenecks in an already constrained market (27) × This would delay project development timelines meaning the target is less likely to be met × The carbon abatement from this requirement would likely be lower than that due to an earlier commissioning date of the RES asset	0%
4 Local employment	× Requiring investment in local skills could increase complexity for developers and timelines of projects potentially reducing the likelihood of meeting the target	0%

Energy Security: Eligibility criteria are not expected to have any impact on the diversification and security of electricity supply. Thus, they were not assessed in terms of the energy security criterion.

Option	Low Cost	Score
1 Planning permission	× Inclusion of this criteria will exclude a share of projects in development from auction, which could limit competition and thus increase costs to the consumer × Planning permission (for generation unit and connection) is required after receiving a grid connection offer, meaning it is at a later stage in the project development timeline, thus excludes a larger proportion of the competition compared to requiring only a grid connection offer (28)	0%
2 Grid connection	× Like requiring planning permission, requiring a grid connection offer could reduce competition in auctions	0%
3 Supply chain sustainability	× Requiring a sustainably sourced supply chain could increase costs for developers which will be passed on to consumers	0%
4 Local employment	× Requiring local employment could lead to additional costs for developers which will be passed on to consumers ✓ The requirement of local employment could stimulate the local economy which could partially offset the additional costs	50%

Option	Practicality	Score
1 Planning permission	✓ Ensures successful coordination between the auctions and planning authorities ✓ Both utility regulators and industry agree for this to be a criterion to ensure project delivery	100%
2 Grid connection	✓ Ensures successful coordination between the auctions and grid connection process ✓ Industry stakeholders agree that both planning permission and grid connection should be requirements for the auction as development processes may change; requiring both ensures auction criteria would not be impacted by any such changes	100%
3 Supply chain sustainability	× Determining compliance with supply chain sustainability requirements would place additional administrative burden on the government for which sufficient resources might not be available	50%
4 Local employment	× Would lead to similar administrative burdens as for including sustainable supply chain requirements	50%

2.1.4 Minimum Size

#	Option	Explanation	Overall Score
1	No min size	Accepting projects of any size to the scheme	0%
2	>1MW	Accepting only projects above 1 MW to the scheme	50%
3	>5MW	Accepting only projects above 5 MW to the scheme	83%
4	>10MW	Accepting only projects above 10 MW to the scheme	50%

Country	Implemented Option
Great Britain	▪ >5MW for onshore wind, solar PV, hydro and anaerobic digestion ▪ No limit for energy from waste with combined heat and power (CHP), landfill gas, sewage gas, advanced conversion technologies, dedicated biomass with CHP, floating offshore wind, geothermal, tidal stream, wave and offshore wind
Republic of Ireland	▪ RESS1, RESS2, RESS3: minimum size of 0.5MW

Recommendation

- Given DfE's priority for the first auction to bring capacity onto the system at high speed and scale, a 5MW minimum size is recommended across all technologies.
- This could be reduced to 1 MW, if further analysis on land, planning, and connection resources to be conducted in the next phase of this project determines no negative impact on reaching the 2030 target.

Table 4- Distribution of pipeline capacity and number of projects across sizes

Minimum size	Share of total number of pipeline RES projects excluded[17]	Share of capacity excluded	Share of generation excluded
1MW	65%	3%	4%
5MW	73%	6%	6%
10MW	76%	9%	10%

[17] Based on REPD (including projects in pre-planning but excluding projects with low likelihood of being developed).

-- In-depth analysis of options --

Option	80% by 2030	Score
1 No min size	× Ineffective use of land given planning constraints on neighbouring renewable installations × Small projects might use up planning, connection, and land resources which could otherwise have been used for larger projects (14)[18]	0%
2 >1MW	✓ Pipeline freed up for larger projects that enable more and faster progress towards the 80% target × Exclusion of small-scale projects (3% of pipeline generation), some at advanced stage of development which could have been delivered quickly × Projects between 1MW and 5MW could delay larger projects in planning	50%
3 >5MW	✓ Most effective use of available space given constraints on land and planning resources × Exclusion of small-scale projects (6% of pipeline generation) which could potentially be delivered at fast pace due to no requirement for network reinforcement	100%
4 >10 MW	× Exclusion of too large a portion of the renewable pipeline (9% of generation)	0%

Option	Low Cost	Score
1 No min size	✓ Embedded (distribution connected) generation typically implies reduced need for transmission reinforcement compared to large scale generation × Small projects cannot access economies of scale	0%
2 >1MW	✓ Cost effectiveness improved compared to no size limit as CAPEX/MW significantly reduces above 1MW × Some economies of scale and synergies of larger projects not accessible for projects below 5MW	50%
3 >5MW	✓ Economies of scale: e.g. less land and fewer turbines required for same onshore wind generation	100%
4 >10 MW	✓ Economies of scale: e.g. less land and fewer turbines required for same onshore wind generation	100%

[18] Further analysis is required to corroborate this point.

Option	Energy Security	Score
1 No min size	✓ Mix of distributed generation and large-scale plants increases grid resilience	50%
2 >1MW	✓ Mix of distributed generation and large-scale plants increases grid resilience	50%
3 >5MW	× System more vulnerable if there are larger single points of failure	50%
4 >10 MW	× System more vulnerable if there are larger single points of failure	0%

Option	Practicality	Score
1 No min size	× Increased administrative burden in processing applications	0%
2 >1MW	✓ Reduces administrative burden while excluding only very small share of generation	50%
3 >5MW	✓ Significant reduction of administrative burden while excluding only a small share of generation	100%
4 >10 MW	✓ Significant reduction of administrative burden × Excluding significant share of generation	0%

2.2 Auction Design

2.2.1 Pot Structure

#	Option	Explanation	Overall Score
1	Technology neutral pot	▪ All technologies compete in the same pot	25%
2	Technology neutral pot with single technology caps	▪ All technologies compete in the same pot ▪ A maximum procurement volume is set for each technology. If this cap is reached for a given technology, further projects of that technology will not be successful, meaning projects of different technologies can be successful even if they have higher bid prices	50%
3	**Three pots:** *Pot 1* – onshore wind and solar PV *Pot 2* – all eligible technologies apart from onshore wind, solar PV, and offshore wind *Pot 3* – offshore wind	▪ Each auction is split into three separate pots ▪ Each pot has its own procurement targets	50%
4	One pot per technology	▪ Separate pots for projects of each technology type, each with its own procurement target ▪ This option differs from tech-neutral pots with single technology caps, as it guarantees some ringfenced support for every technology	25%

Country	Implemented Option
Great Britain	▪ Multiple pots are used, whose composition can vary between auction rounds ▪ Several parameters are used to tune competition, such as caps, budgets and minimum and maximum tech-specific eligibility requirements (9)
Republic of Ireland	▪ Technology neutral pots but Evaluation Correction Factor used to tune auction bid stack ▪ Separate auctions for offshore wind ▪ Use of separate community pot in RESS1 and RESS2

Recommendation

	Pot 1	Pot 2	Pot 3
Purpose of pot	Fast delivery and low cost	Diversification of supply	Offshore wind
Technologies	Onshore wind Solar PV	*All other eligible techs*	Offshore wind

- This recommended pot structure may be adapted following further analysis during the detailed design of the Support Scheme
- Pot structure may also change based on the outcomes of the first auction and future pipeline developments (e.g. Pot 2 may be divided into further pots if the need for ringfenced support for emerging technologies arises in the future)
- The inclusion of offshore wind in the scheme is subject to further alignment with the Government's Offshore Renewable Energy Action Plan workstream
- Note that not every auction will procure all three pots. For information on the allocation of procurement volumes across pots in each auction, see Section 3.2 Auction Timetable

-- In-depth analysis of options --

80% by 2030: The same renewable energy volumes can be procured with each option. Hence, the 80% by 2030 criterion was not deemed to be applicable to the assessment of options for this design feature.

Option	Low Cost	Score
1 Tech-neutral pot	✓ Lowest cost of generation as only the cheapest technologies are successful (9)	100%
2 Tech-neutral with single tech caps	✓ Inter-technology competition within limits set by caps × If technology cap is exceeded, then more expensive technologies are successful; this could increase auction cost depending on level of caps	50%
3 Three pots	✓ Inter-technology competition within pots × Some procurement volumes allocated to more expensive technologies	50%
4 One pot per technology	× Guarantees support to even the most expensive technologies	0%

Option	Energy Security	Score
1 Tech-neutral pot	✓ Lowest risk of underprocurement × Can lead to dominance of one technology (29)	0%
2 Tech-neutral with single tech caps	✓ Allows some level of diversification and control over technology mix	50%
3 Three pots	✓ Allows improved level of diversification and control over technology mix (29)	50%
4 One pot per technology	✓ Ringfenced support guarantees diversification	100%

Option	Practicality	Score
1 Tech-neutral pot	✓ Only one procurement target needed ✓ Some technology discrimination can also be achieved by tuning auction eligibility criteria, which may lighten the administrative burden compared to organising multiple pots (9) × Investors of higher LCOE technologies may be deterred (29)	50%
2 Tech-neutral with single tech caps	✓ No practical barriers	100%
3 Three pots	✓ No practical barriers	100%
4 One pot per technology	× Increases administrative burden[19]	50%

[19] Prior to 2021, technology-specific auctions were precluded by EU State Aid Guidelines. However, this restriction has been lifted in recognition of the need for national governments to diversify the renewable generation mix (83), so there is no longer a legal barrier to this option.

2.2.2 Pot Size

#	Option	Explanation	Overall Score
1	Fixed by budget to be spent in each auction	▪ A budget is set for each pot, with projects being procured until the cumulative expenditure reaches the budget cap	50%
2	Fixed by energy volume to be procured	▪ A target energy procurement volume in GWh is set for each pot, with projects being procured until this cumulative total volume is reached	75%
3	Fixed by competition ratio	▪ The procurement volume is set at a pre-defined fraction of the total volume that participates in the auction	25%

Country	Implemented Option
Great Britain	▪ £170 million expenditure cap in AR 5 for technologies in Pot 1 for delivery year 2026/7, £35m for Pot 2 (less established technologies, including £10m for tidal) ▪ In some auctions, minimum and maximum capacity targets are also published prior to the auction (e.g. AR4 set capacity target in addition to an auction budget (30)) ▪ Budget is determined by considering likely auction volumes and competitiveness, and is constrained by the Control for Low Carbon Levies, which limits the total available budget for low-carbon levies until 2025 (31)
Republic of Ireland	▪ RESS auctions determine pot size by a competition ratio. Capacity procurement targets are set but are not disclosed until after the auction to reduce chances of strategic bidding in the auction

Recommendation

- Pot size should be determined by setting energy volume procurement targets (in GWh) for each pot
- Procurement volume targets for each pot will be set by considering likely auction participation volumes and competition levels, as well as likely total auction cost. Conversations with policymakers underscored the importance of considering these various criteria in combination
- See section 3 – Auction Roadmap – for further information on procurement volumes and timelines

-- In-depth analysis of options --

Option	80% by 2030	Score
1 Fixed by budget to be spent in each auction	× May not achieve the required energy volumes	0%
2 Fixed by energy volume to be procured	✓ Only mechanism which ensures that enough capacity will be procured in each auction to meet the 2030 target	100%
3 Fixed by a competition ratio	× Considerable uncertainty in procuring the required energy volumes (32)	0%

Option	Low Cost	Score
1 Fixed by budget to be spent in each auction	✓ Provides certainty on the overall cost of each auction	100%
2 Fixed by energy volume to be procured	✓ Uncertainty of cost of auction can be mitigated by using maximum strike prices × Less certainty on the cost of the auction	50%
3 Fixed by a competition ratio	✓ Uncertainty of cost of auction can be mitigates by using maximum strike prices ✓ The nature of a competition ratio ensures a sufficient level of competition leading bidders to bid in at low prices × Less certainty on the cost of the auction	50%

Energy Security: pot sizes are not expected to have any impact on the diversification and security of electricity supply. Thus, they were not assessed in terms of the energy security criterion.

Option	Practicality	Score
1 Fixed by budget to be spent in each auction	✓ Greater developer confidence in predicting auction dynamics if announced before the auction	100%
2 Fixed by energy volume to be procured	✓ Greater developer confidence in predicting auction dynamics if announced before the auction	100%
3 Fixed by a competition ratio	✓ Reduces opportunity for strategic bidding × Introduces more uncertainty around appropriate bidding strategies, which may deter some developers from participating, particularly in early auctions	50%

2.2.3 Maximum Strike Price

#	Option	Explanation	Overall Score
1	Maximum strike price (MSP) per technology, disclosed ahead of auction	▪ Each technology has its own MSP; bids cannot exceed this price ▪ The MSP for each technology is published in advance of each auction	33%
2	Maximum strike price per technology, undisclosed	▪ Each technology has its own MSP; bids cannot exceed this price ▪ The MSPs are not disclosed in advance of the auction and are only published with the auction results	17%
3	No maximum strike price	▪ There is no limit on the bids that can be submitted by developers	0%

Country	Implemented Option
Great Britain	Maximum strike price per technology, referred to as "Administrative Strike Price", published ahead of auction
Republic of Ireland	Maximum strike price across all technologies, referred to as "Maximum Offer Price Considered", set to €110/MWh in RESS 3 (19)

Recommendation

- Technology specific maximum strike prices should be introduced to avoid excessive strike prices in the auction and to better forecast the budget required (as implemented across the major power markets in Europe)
- The MSPs should be disclosed in advance of each auction to reduce uncertainty for

Notes

- MSPs must strike a balance between attracting a sufficient number of projects and protecting consumers from excessive costs.

How will the maximum strike price be determined?

- The methodology will broadly be based on modelling of the LCOEs of projects in the pipeline to determine likely minimum viable bid prices, with the maximum strike prices being set such that only an adequate proportion of projects would be excluded if they were to bid at their minimum viable bid price. Note that this methodology is subject to ongoing refinement and will be the focus of the next phase of this project.
- The modelled total auction cost under various scenarios will also be considered to ensure the scheme remains within budgetary constraints.

-- In-depth analysis of options --

Option	80% by 2030	Score
1 Disclosed tech-specific MSP	× Risk of low auction participation if MSP is set too low (e.g. GB CfD AR5), though this can be mitigated by gauging investor interest before auction	50%
2 Undisclosed tech-specific MSP	× Risk of underprocurement if MSP is too low × This could be exacerbated if investors are deterred by uncertainty on undisclosed MSP	50%
3 No MSP	✓ Does not restrict auction participation or success rates	100%

Option	Low Cost	Score
1 Disclosed tech-specific MSP	✓ Rules out excessive strike prices ✓ Allows inter-technology competition without greatly differential profits between technologies ✓ Risk of price gouging towards MSP is lower if pay-as-clear is used	100%
2 Undisclosed tech-specific MSP	✓ Rules out excessive strike prices ✓ Could reduce bid prices; helps avoid participants bidding close to MSP, e.g. South African RES auctions (32)	100%
3 No MSP	× Risk of higher cost to consumer, particularly if auction is pay-as-clear	0%

Option	Energy Security	Score
1 Disclosed tech-specific MSP	× Low data availability on strike prices necessary for a viable business case for less established technologies; could lead to underprocurement of these technologies if their MSP is set too low	50%
2 Undisclosed tech-specific MSP	× Low data availability on strike prices necessary for a viable business case for less established technologies; could lead to underprocurement of these technologies if their MSP is set too low	50%
3 No MSP	✓ Does not restrict auction participation or success rates	100%

Option	Practicality	Score
1 Disclosed tech-specific MSP	× Administrative burden: detailed analysis of likely project LCOEs required	50%
2 Undisclosed tech-specific MSP	× Administrative burden: detailed analysis of likely project LCOEs required	50%
3 No MSP	× Risk to cost of support may delay regulatory approval of scheme budget	0%

-- Quantitative analysis --

Indicative bid stack based on projects in the Renewable Energy Planning Database

The below chart compares auction outcomes under technology-neutral clearing and technology-specific strike prices. 'Technology-neutral clearing' refers to the use of only one maximum strike price for all technologies, rather than individual maximum strike prices for each technology. The bid stacks presented are based on projects in the REPD, with bid prices calculated as the strike price required for zero Net Present Value (NPV) business cases given CAPEX, operating expenses (OPEX), and location-specific load factors (17).

The first bid stack (labelled 'Auction bid stack'), simply shows all bids arranged in order, with the auction clearing at 945GWh, as the inclusion of the next project would exceed the pot size (set to 1,000GWh in this example).

The second stack (labelled 'Tech-neutral clearing') shows that all projects would receive a strike price equal to the highest successful bid.

The third stack (labelled 'Tech-specific strike prices'), shows solar PV projects clearing at the highest solar PV bid (which in this example is equal to the maximum strike price for solar PV), while onshore wind projects clear at the highest onshore wind bid.

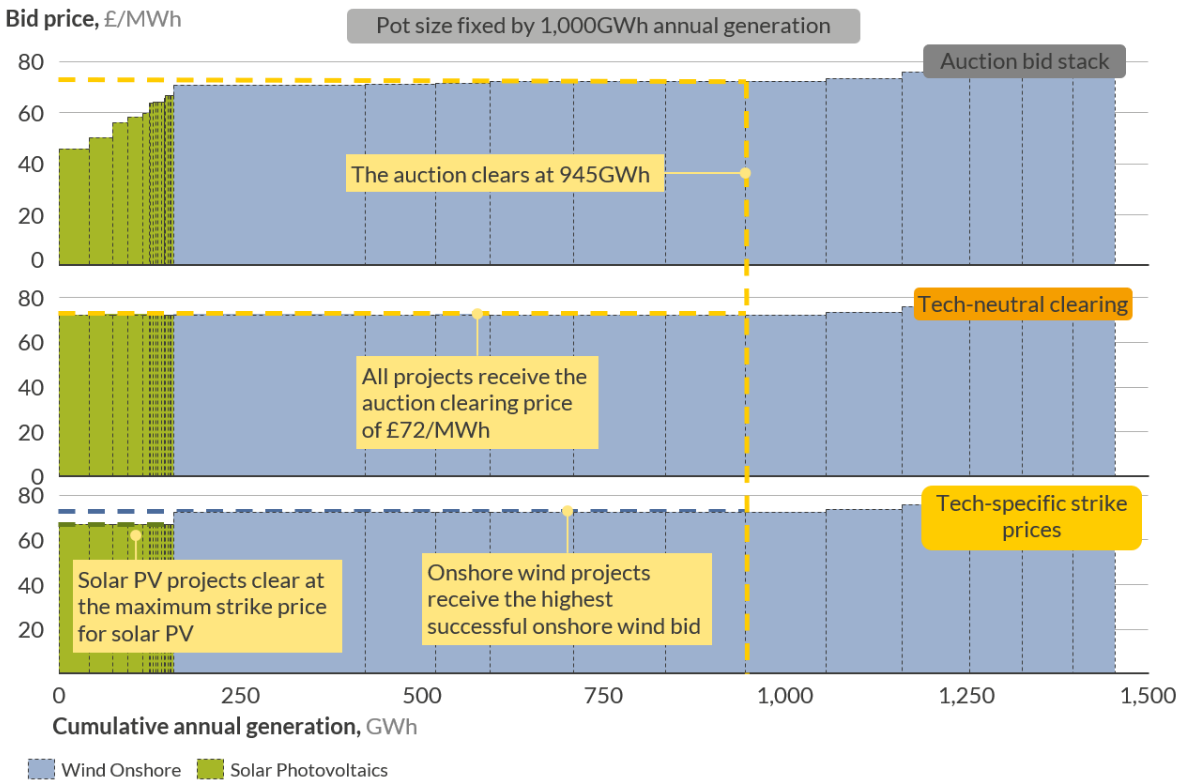

Figure 3: Bid price of auction when pot size is fixed by 1,000GWh

The two below charts show the annual support payments paid to each successful project, under tech-neutral clearing and tech-specific strike prices. Annual average support payments were calculated as the difference between the strike price and the average annual capture price of each technology over the duration of the contract (as forecast by Aurora). The charts illustrate that clearing different technologies in the same pot but at different (technology-specific) strike prices reduces overall auction cost while maintaining inter-technology competition.

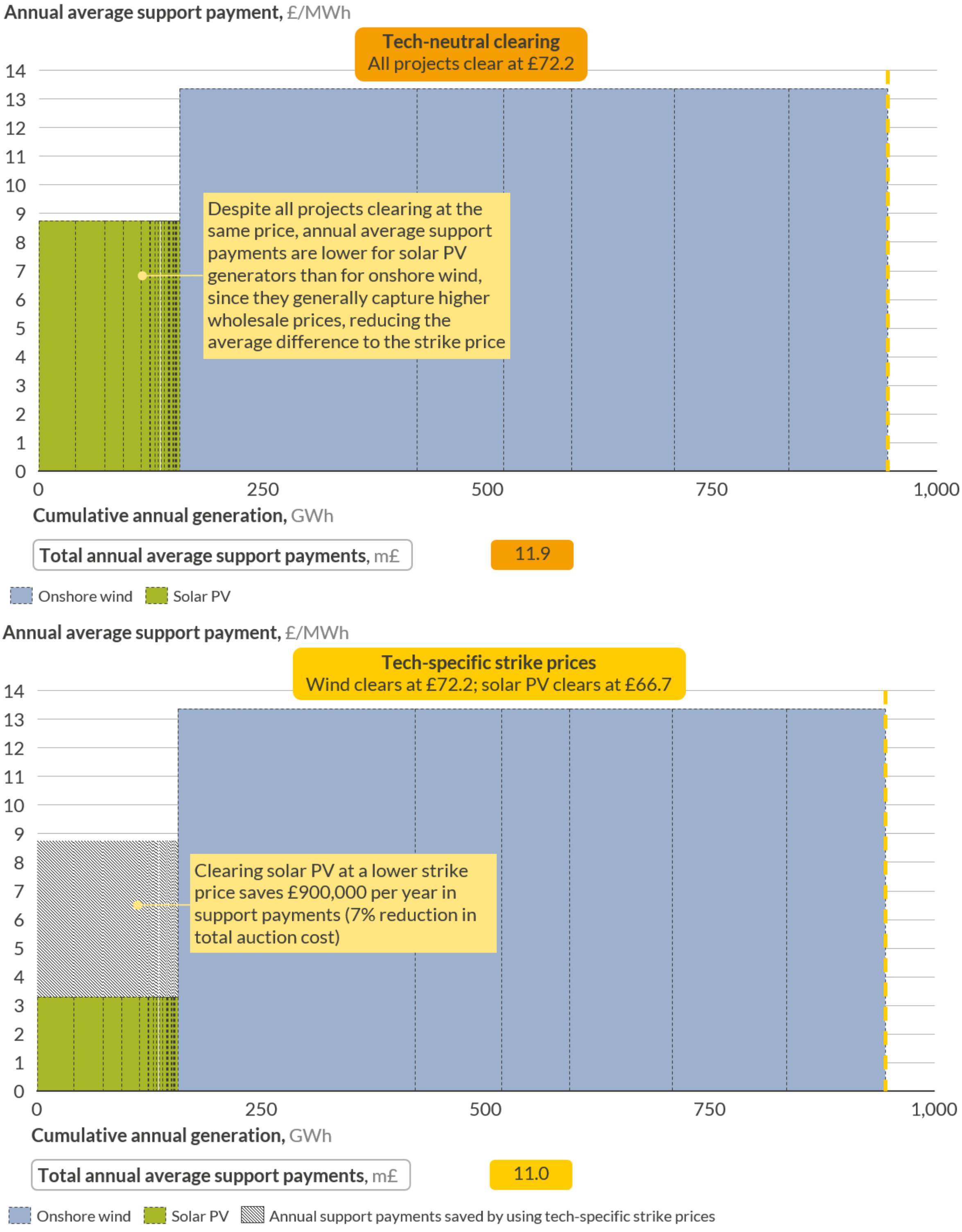

Figure 4: Strike prices for different pot structures

2.2.4 Auction Frequency

#	Option	Explanation	Overall Score
1	Biennial	▪ An onshore auction would occur every two years	75%
2	Annual	▪ An onshore auction would occur every year	38%
3	Twice a year	▪ An onshore auction would occur twice a year	0%
4	Ad-hoc frequency	▪ Auctions would occur as frequently as deemed necessary	17%

Country	Implemented Option
Great Britain	▪ Prior to AR5, auctions were run approximately every two years ▪ From AR5 to the upcoming AR6, the Government is shifting to annual frequency to accelerate decarbonisation (21)
Republic of Ireland	▪ RESS auctions are annual ▪ Offshore RESS auctions appear to be biennial or ad-hoc, according to published auction dates of Offshore Renewable Electricity Support Scheme (ORESS) 1 (2023) and the upcoming ORESS 2 (2024/2025) (33)

Recommendation

Biennial auctions (i.e. occurring once every two years), are recommended, as they result in higher competition rates and allow enough time for administrative and legal changes to be made between auctions if necessary.

-- In-depth analysis of options --

Option	80% by 2030	Score
1 Biennial	✓ Systematic and regular auctions attract a larger number of bidders (32,34) × A biennial auction can potentially delay project rollout × Constitutes harsher penalisation if a project is excluded from an auction due to a non-delivery penalty; if auction is biennial project must wait two years for the next eligible auction round (34)	50%
2 Annual	✓ Systematic and regular auctions are attractive to investors ✓ Would ensure timely project rollout to meet the target ✓ As highlighted at the stakeholder workshop, some industry representatives believe that annual auctions would provide more flexibility and opportunity for bringing assets online	100%
3 Twice a year	✓ Systematic and regular auctions are attractive to investors ✓ Would ensure timely project rollout to meet the target	100%
3 Ad-hoc frequency	× Ad-hoc auctions could deter investors given their less predictable schedule (34)	0%

Option	Low Cost	Score
1 Biennial	✓ Biennial auctions could improve competition rates in each auction round. This is particularly important in NI's relatively small market	100%
2 Annual	× Annual auctions are potentially too frequent for a small market like Northern Ireland and can lead to too few bidders in each auction, leading to limited competition and higher strike prices	50%
3 Twice a year	× Auctions with high frequency in a small market can lead to fewer bidders per round, reducing competition and increasing risk of speculative bidding, bidder collusion and price manipulation (32)	0%
3 Ad-hoc frequency	✓ Auction frequency can be adjusted to increase competition	100%

Energy Security: auction frequency is not expected to have any impact on the diversification and security of electricity supply. Thus, it was not assessed in terms of the energy security criterion.

Option	Practicality	Score
1 Biennial	✓ Regular auctions with low frequency are easier to organize and allow for ample time for market participants to prepare	100%
2 Annual	✓ Regular auctions are easier to organise and are desired by stakeholders × Limited time between auctions to prepare market participants or implement changes	50%
3 Twice a year	× Unfeasible time period for administrators to make improvements to successive auctions	0%
3 Ad-hoc frequency	✓ Effective method to optimises competition in each round × Greater administrative burden to implement	50%

2.2.5 Pricing Mechanism

#	Option	Explanation	Overall Score
1	Pay as clear	▪ Under pay as clear, all successful generators receive a strike price equivalent to the highest successful bid	75%
2	Pay as bid	▪ Under pay as bid, contracts are awarded the submitted bid price	38%

Country	Implemented Option
Great Britain	CfD auctions operate under pay-as-clear but there are maximum strike prices per technology and a separate pot for offshore wind, which is more expensive than the other established technologies (onshore wind, solar)
Republic of Ireland	RESS auctions employ the pay-as-bid mechanism

Recommendation

A pay as clear mechanism with maximum strike prices per technology should be used to enable discovery of technology costs and allow for simpler optimal bidding strategies.

-- In-depth analysis of options –

80% by 2030: Pricing mechanisms are not expected to have any impact on achieving the 80% target by 2030. Thus, they were not assessed in terms of this criterion.

Option	Low Cost	Score
1 Pay as clear	✓ Projects are incentivised to bid close to their costs to increase likelihood of being accepted ✓ Therefore, auction bids reveal actual project costs and allow the government to adjust/lower administrative strike prices for future auctions and reduce cost to consumers ✓ Strike price is typically independent of a project’s bid and is determined by the most expensive accepted bid, reducing likelihood of strategic bidding × Can lead to disproportionately high profits for the lowest accepted bids × Lower cost technologies with a high chance of being accepted have few incentives to reduce costs	100%

Option	Low Cost	Score
2 Pay as bid	✓ Projects are awarded their bids, providing fair profit margins in line with their project costs × Typically leads to strategic bidding as bidders want to maximise their profits in line with their competitors × Increases the risk of collusion to drive up prices in the case of low competition × This mechanism is less likely to reveal actual project costs, leaving auctioneer unaware of a fair strike price ✓ These risks can be mitigated by a price cap; however, bidders are likely to bid close to the cap	50%

Option	Energy Security	Score
1 Pay as clear	× Pay as clear leads to disproportionate profits for low-cost technologies competing with high-cost technologies in the same pot, potentially discouraging investment in high-cost technologies ✓ This can be avoided to some extent with technology specific maximum strike prices and technology caps	50%
2 Pay as bid	✓ There is minimal discrepancy of profit margins between technologies using this mechanism, meaning a diverse technology mix is more fairly supported	100%

Option	Practicality	Score
1 Pay as clear	✓ Familiar to stakeholders in GB	100%
2 Pay as bid	✓ Familiar to stakeholders in RoI × Requires more resources to determine an optimal bid as bidding strategy depends on competitors’ bids, favouring larger developers	50%

2.2.6 Community Benefits

#	Option	Explanation	Overall Score
1	Community benefit fund	▪ All projects must establish a fund, into which they pay a certain amount per MWh of generation ▪ Funds can be spent to improve the environmental, social and cultural well-being of the local community ▪ Fund may be administered by developers with particular milestones to be achieved[20], or a separate community led administrative board may be responsible – dependent on further analysis	32%
2	Separate pot for community projects	▪ A separate pot to support community-led projects ▪ A community-led project can be defined as being 100% owned by a Renewable Energy Community	0%
3	Separate scheme for community projects	▪ A separate scheme only for the support of community led projects	13%
4	No targeted community benefits	▪ No initiative within the scheme to support local communities	25%

Country	Implemented Option
Great Britain	▪ Supporting local generators: feed in tariff for small scale generation and Smart Export Guarantee for installations of up to 5 MW (35) ▪ DESNZ is currently consulting on incentivising economically, environmentally, and socially sustainable supply chains for renewable electricity through a so-called Sustainable Industry Reward within the CfD scheme (36) ▪ One included suggestion is creating a fund for underdeveloped regions
Republic of Ireland	▪ In all RESS auctions successful projects had to contribute €2/MWh to a community benefit fund, which provides payments to households near renewable installations (€1,000/y to households within 1km distance) (26) ▪ RESS 1 and 2 had separate pots for community led (minimum share of 51% owned by energy communities) projects: 30 GWh and 200 GWh respectively; this was abandoned in RESS 3 (24) ▪ A micro-generation support scheme was introduced in 2022 (maximum size 50kW) (37) ▪ The government will decide on rolling out a small-scale renewable electricity support scheme in 2024, this would include projects of up to 6 MW size (38)

[20] To monitor continuous and on-going engagement

Recommendation

- Recommendation is still to be determined based on an in-depth analysis on the benefits of a community benefit fund on planning timelines and approval to be conducted in the next phase of this project.
- An evaluation of whether a community benefit fund should be administered by the developers, with specific milestones to meet, or by an independent body will also be conducted in the next phase.

Note

Community benefits as discussed in this section could help distribute benefits of the energy transition more evenly across the economy instead of concentrating them among a few large-scale market actors. Community energy projects could empower communities and strengthen cohesion within them. This is supported by the Strategic Planning Policy Statement for Northern Ireland (SPPS) which highlights that local communities should benefit from schemes in their area (39). However, support and development of local communities is not the primary objective of the renewable electricity support scheme. Furthermore, such support requires a transfer of funds from the public / bill payers to local communities close to renewable installations. Whether such transfers are justified or even required is a political question outside of the scope of this report. In our assessment we have thus focused on how different options help to deliver the scheme objectives rather than how they provide benefits to communities.

-- In-depth analysis of options –

Option	80% by 2030	Score
1 Community benefit fund	✓ May increase local communities' acceptance of RES assets, reducing the opposition that projects may face in the planning stage [21] ✓ The fund is straightforward to incorporate in a support scheme and should not lengthen the development timeline (32)	100%
2 Separate pot for community projects	✓ Allows a larger proportion of the market to participate in the auction × Community projects are typically small-scale projects, which deliver less generation at a slower rate than large scale projects × Community projects typically have fewer resources available to them leading to similar timelines as a larger development while delivering much lower capacity	50%

[21] It is currently unproven whether community benefits help to accelerate planning approval. It was brought up by renewable developers during stakeholder engagement that objectors to renewable projects are often not based close to the renewable installations but even abroad and that furthermore permission is often denied not due to community objections but due to planners deeming projects incompatible with planning guidelines. An alternative to community benefits could be clearer guidance to planners on the priority of renewable expansion compared to competing objectives (such as preservation of historically grown landscapes). This has been implemented in the Scotland onshore wind sector deal, where significant weight will be given to the global climate and nature crises when considering all development proposals. New onshore wind projects in Scotland will enhance biodiversity and optimise land use and environmental benefits (84).

Option	80% by 2030	Score
3 Separate scheme for community projects	✓ Allows a larger proportion of the market to participate in the auction, in a scheme specific to their needs ✗ Disadvantages of a separate community pot also apply here ✗ Developing a separate scheme requires additional time and resources	50%
4 No targeted community benefits	✗ Providing no benefits targeted at communities close to planned renewable installations could delay the installation[19]	0%

Option	Low Cost	Score
1 Community benefit fund	✗ Generators will pass on the fees paid into the community benefit fund to consumers by increasing their bid prices ✓ However, this cost can be more directly controlled in the scheme and kept to an acceptable value compared to a separate pot or scheme for community led projects.	50%
2 Separate pot for community projects	✗ Due to potentially low levels of experience, few communities might bid into auctions, leading to low levels of competition and high strike prices[22] ✗ Community projects are typically small scale and don't have access to economies of scale	0%
3 Separate scheme for community projects	✗ Disadvantages of separate pot for community projects also apply in this case ✗ A separate scheme would require additional administrative resources, which create additional costs	0%
4 No targeted community benefits	✓ No additional cost to the consumer	100%

[22] In Northern Ireland a comparably high share of RES projects are small scale projects, meaning communities and small-scale developers could have developed learnings and experience to deliver small projects at comparably low cost.

Option	Energy Security	Score
1 Community benefit fund	× No positive impact on energy security	0%
2 Separate pot for community projects	✓ Complementing large scale with small scale distributed renewable installations can increase energy security by reducing vulnerability to single points of system failure ✓ Diversifies renewable output patterns across the generation portfolio × Does not provide a significant amount of generation	50%
3 Separate scheme for community projects	✓ Advantages of separate pot for community projects also apply here × Disadvantages of separate pot for community projects also apply here	50%
4 No targeted community benefits	× No positive impact on energy security	0%

Option	Practicality	Score
1 Community benefit fund	✓ Impact on planning approval and timelines are to be assessed in the next phase of the scheme design × Will lead to additional administrative burden × Industry stakeholders believe it is unlikely there is a link between a community benefit fund and improving planning timelines × Additionally, many industry stakeholders already have internal policies on communicating and developing communities where their sites are situated	50%
2 Separate pot for community projects	× Least practical option due to different development timelines and characteristics compared to large scale projects and thus community projects are unlikely to be able to be integrated in the same scheme	0%
3 Separate scheme for community projects	✓ Would support community developments through a scheme set up specifically to assist them × Would significantly increase administrative burden	50%
4 No targeted community benefits	✓ No additional administrative burden	100%

2.2.7 Delivery years

The delivery year refers to the number of years between the auction and the commencement of the support scheme contract, unless the generator becomes operational sooner, in which case the contract can begin early.

The longstop date refers to the number of years between the delivery year and the cancellation of the support scheme contract if the generator is not operational.

#	Option	Explanation	Overall Score
1	1 year after auction	▪ Delivery date set one year after auction with a longstop period of one year for onshore assets and two years for offshore (if applicable)	25%
2	2 years after auction	▪ Delivery date set two years after auction with a longstop period of one year for onshore assets and two years for offshore (if applicable)	100%
3	3 years after auction	▪ Delivery date set three years after auction with a longstop period of one year for onshore assets and two years for offshore (if applicable)	50%
4	Flexible	▪ Delivery years varying from auction to auction and between pots depending on market conditions	50%

Country	Implemented Option
Great Britain	▪ Flexible: delivery years are determined prior to each allocation round, along with other auction parameters (40) ▪ Developers can choose between two delivery years which are typically 2-4 years after the auction for onshore assets (41,42) ▪ Onshore assets have a longstop period of 12 months after the end of the delivery year; for offshore wind, this period is set to 24 months (43). Assets which start operation after the end of the delivery year but before the long stop date don't lose their contract. However, the contract period starts at the end of the delivery year, i.e. their used contract period is reducing after the end of their delivery year
Republic of Ireland	▪ RESS-1 and RESS-2 had delivery years of one year after auction with a longstop period of 1.5 years from delivery date. However, RESS-2 delivery years have been extended by one year due to delays of grid reinforcement and connections (44) ▪ RESS-3 had delivery years of one year after auction with a longstop period of 2.5 years from delivery date (45,46) ▪ ORESS has a more flexible approach to accommodate offshore wind: ORESS-1 has a longstop date on December 31, 2031, 8 years after the auction closed in 2023 (45)

Recommendation

- Delivery year of two years, with a longstop period of one year for onshore assets (a longstop date of two years is recommended for offshore wind if it is to participate in the Scheme).
- Further analysis of supply chain bottlenecks, and lead times for components and connections, may lead to a revision of this recommendation in the next phase of the scheme

-- In-depth analysis of options --

Option	80% by 2030	Score
1 1 year after auction	✓ A shorter delivery date focuses the auction on more advanced projects in the development pipeline, increasing the certainty of delivery × Assuming the first auction to be in 2025, limiting the delivery date to one year may result in an insufficient number of projects competing in the first round × Projects may need a support contract more than one year ahead of commercial operation date (COD) to start construction, continue development or secure financing	50%
2 2 years after auction	✓ Increasing delivery date from 1 year to 2 years can result in significantly more eligible projects and capacity	100%
3 3 years after auction	✓ Further increase of the number of eligible projects[23] × Higher risk of non-delivery due to potentially many early-stage projects in auction × Later delivery years reduce the number of auctions which can procure capacity that can contribute to the 2030 target	50%
4 Flexible	✓ Allows management of trade-off between delivery certainty and volume procured ✓ Allows accommodation of differences in build times between technologies and shifting market conditions	100%

[23] During stakeholder engagement, renewable developers pointed to increased waiting times (18 months) for critical electrical components, whereas policy makers highlighted how grid connection waiting times can become a key determinant of delivery timelines and suggested delivery years might need to be adjusted according to grid connection availability.

Option	Low Cost	Score
1 1 year after auction	× Risk of excluding large share of pipeline leading to uncompetitive first auction, which could result in high clearing prices and skewed price expectations for subsequent rounds	0%
2 2 years after auction	✓ More time for delivery and less risk for developers, increasing competition in the auctions	100%
3 3 years after auction	✓ More time for delivery and less risk for developers, increasing competition in the auctions × Long delivery periods mean consumers are reliant on expensive and volatile fossil fuel prices in the electricity market for longer	50%
4 Flexible	✓ Implementing flexible dates that vary by technology and market conditions can help the auctioneer maintain competitiveness while minimising non-delivery risk	100%

Energy Security: Delivery years are not expected to have any impact on the diversification and security of electricity supply. Thus, they were not assessed in terms of the energy security criterion.

Option	Practicality	Score
1 1 year after auction	✓ A fixed delivery year minimises administrative burden × Current project development timelines indicate a 1-year delivery date would be unfeasible (see section 4.1.4 in appendix)	50%
2 2 years after auction	✓ A fixed delivery year minimises administrative burden	100%
3 3 years after auction	✓ A fixed delivery year minimises administrative burden	100%
4 Flexible	✓ Flexible delivery year and long stop dates present greater scope to optimise procurement strategy between auctions × Increased administrative burden from setting technology-specific delivery dates adapted to market conditions	50%

2.3 Contract Design

2.3.1 Contract Length

#	Option	Explanation	Overall Score
1	10 years (fixed length)	-	0%
2	15 years (fixed length)	-	75%
3	20 years (fixed length	-	50%
4	Fixed end date	▪ Following the RESS 3 and ORESS 1's frameworks: ▪ In RESS 3, projects can get a maximum duration of 16.5 years for a project that starts early and a minimum duration of 14 years. If a project does not reach the COD by the longstop date, it will no longer be eligible for the support payments. If a project achieves commercial operation before or on the target COD, the contract term is fixed to the maximum support period offered by the scheme and cannot be extended (9) ▪ In ORESS 1, projects can get support for up to 20 years and the minimum support term is 12 years.	25%
5	Lifetime of asset	-	38%

Country	Implemented Option
Great Britain	▪ Fixed length contract of 15-years (47)
Republic of Ireland	▪ RESS and ORESS projects have fixed end date contracts ▪ In RESS 3, projects can get a maximum duration of 16.5 years for a project that starts early and a minimum duration of 14 years ▪ In ORESS 1, projects can get support for up to 20 years and the minimum support term for a project is 12 years (47)

Recommendation

- A 15-year contract length is preferable
- This strikes the best balance between attracting investment and ensuring value for money for consumers in the long-term

-- In-depth analysis of options –

Option	80% by 2030	Score
1 10 years	× Reduces attractiveness to investors compared to GB and ROI; reduced participation decreases likelihood of meeting the decarbonisation target (10)	0%
2 15 years	✓ Equally attractive to investors as GB and ROI schemes[24] ✓ 15-year contracts are long enough for developers to obtain financing[25]	50%
3 20 years	✓ More attractive to investors than GB and ROI schemes	100%
4 Fixed end date	✓ Encourages RES assets to become operational as soon as possible × Risk of shortened contract length may reduce attractiveness to investors (10)	50%
5 Lifetime of asset	✓ Highly attractive to investors; eliminates price risk, see (33) and (47)	100%

Option	Low Cost	Score
1 10 years	✓ Total cost of scheme is lower with shorter contracts × Increases developers' exposure to merchant risk; lowers competition resulting in higher bids (9)	0%
2 15 years	✓ Total cost of Scheme is lower with shorter contracts	100%
3 20 years	× Longer contracts increase cost of support and total cost of generation; contracts longer than 15 years exceed the necessary duration of revenue certainty required for project finance[20] ✓ High attractiveness of 20 year contract could increase competition	50%
4 Fixed end date	× Scheme support period becomes dependent on COD, which introduces some risk to developers since grid connection approvals and planning times can vary (47); could lead to lower competition levels	50%
5 Lifetime of asset	× Locks consumers into long term fixed price contracts while lower cost alternatives might become available (48)	50%

[24] Industry stakeholders questioned whether a 15-year contract is sufficient for offshore wind developers, given the offshore wind support contract length is 20 years in ROI; further analysis will be required to determine whether offshore wind projects require a dedicated contract length.

[25] Based on conversations with policymakers.

Energy Security: Contract length is not expected to have any impact on the diversification and security of electricity supply. Thus, it was not assessed in terms of the energy security criterion.

Option	Practicality	Score
1 10 years	✓ Fixed length reduces complexity which reduces administrative burden and increases transparency (9)	100%
2 15 years	✓ Fixed length reduces complexity which reduces administrative burden and increases transparency (9)	100%
3 20 years	✓ Fixed length reduces complexity which reduces administrative burden and increases transparency (9) × Could be perceived as worse deal for consumers relative to GB, which could require lengthy government approval	50%
4 Fixed end date	× Increased administrative burden for individual contracts	50%
5 Lifetime of asset	× Increases administrative burden as contracts would require review or reopener provisions to enable contract terms to be changed if market conditions change; else consumers could be locked into potentially unfavourable terms for 30+ years (9,48)	50%

-- Quantitative analysis --

Bid price of a 10MW onshore wind farm, £/MWh

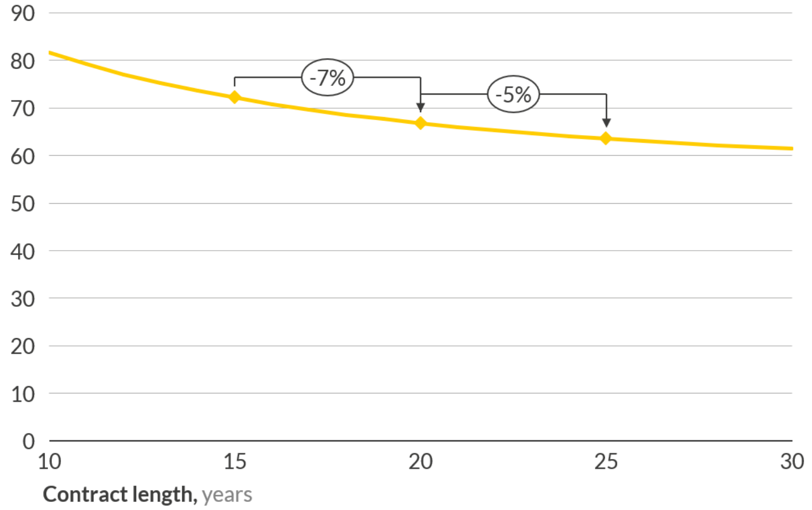

Figure 5: Impact of contract length on bid prices[26]

Total lifetime cost to consumer (undiscounted), £/MWh

[26] Bid price calculated based on an NPV=0 business case using project costs from the DESNZ Electricity Generation Cost Report 2023. CfD revenues discounted at 8.5%; merchant revenues discounted at 10.5%. Assumes a 30-year lifetime.

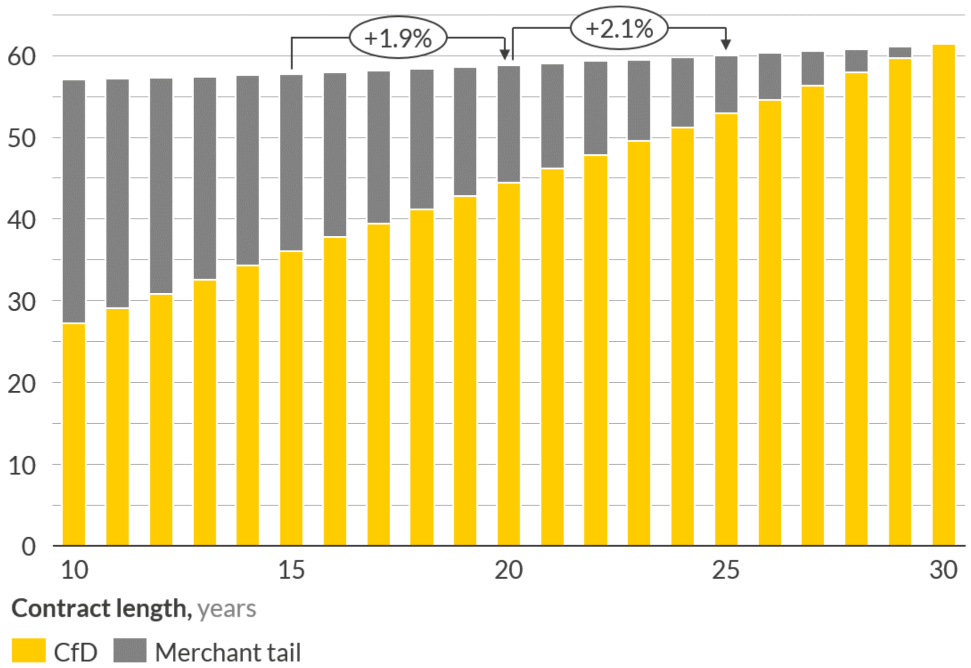

Figure 6: Lifetime cost of generation for an onshore wind plant for different CfD contract lengths [27]

The above figures illustrate the impact of contract lengths on consumer costs. Despite bid prices decreasing with longer contracts (Figure 6), the total cost to the consumer over a 30-year asset lifetime increases as a function of contract length (Figure 7). This is a consequence of: A) decreasing marginal reductions in bid price with contract length, and B) decreasing capture prices over time (resulting from increased renewables penetration), meaning the impact of locking consumers in at the strike price becomes increasingly costly. However, longer contracts attract more investment and could lead to higher levels of participation in the auctions, which could increase competition levels and the likelihood of meeting procurement targets in the auctions. This in turn would increase the renewables penetration in Northern Ireland and lower wholesale prices, with significant benefits to the consumer. Nevertheless, the impact of this is likely to be marginal and a 15-year contract is considered the optimal choice.

[27] Merchant revenues based on the Aurora Oct-23 forecast. This illustration does not assume higher levels of competition in auctions in case of longer contract lengths. Slightly increased competition is not expected to have a significant impact on the overall generation costs.

2.3.2 Indexation

#	Option	Explanation	Overall Score
1	Full indexation	▪ Strike price 100% linked to inflation	75%
2	Partial indexation	▪ Only a fraction of the strike price is linked to inflation, with the remainder being nominal	38%
3	No indexation	▪ Strike price not linked to inflation	0%

Country	Implemented Option
Great Britain	▪ Bid prices 100% indexed against the Consumer Price Index (CPI) (47) ▪ Indexation against Producer Price Index (PPI) in the construction phase, whilst retaining CPI-indexation during operational phase being considered by DESNZ for AR7 and future rounds (21)
Republic of Ireland	▪ In RESS 1 and RESS 2 no indexation was applied (47,48) ▪ In RESS 3, 30% of the strike price is indexed to the HICP[28] (9,47) ▪ For ORESS, bid prices were indexed partially to both the Steel Index and the HICP (9)

Recommendation

- Strike prices should be 100% indexed against a price index such as CPI, PPI, Steel Index, or other (TBC)
- A weighted average of relevant indexes should also be considered

-- In-depth analysis of options --

Option	80% by 2030	Score
1 Full indexation	✓ Eliminates inflation risk, increasing attractiveness to investors (48)	100%
2 Partial indexation	× Reduces attractiveness compared to full indexation as in GB (10)	50%
3 No indexation	× Highly reduced attractiveness compared to GB and ROI	0%

[28] Harmonised Index of Consumer Prices

Option	Low Cost	Score
1 Full indexation	✓ Removes risk of overestimated inflation priced into bids (10) × Allocates all inflation risk with the consumer (9)	50%
2 Partial indexation	✓ Investors are exposed to some level of inflation risk ✓ Large proportion of total scheme cost is known	100%
3 No indexation	× High risk for investors; increases cost of finance × Can lead to greatly inflated strike prices if inflation is overestimated	0%

Energy Security: Indexation is not expected to have any impact on the diversification and security of electricity supply. Thus, indexation was not assessed in terms of the energy security criterion.

Option	Practicality	Score
1 Full indexation	✓ Straightforward implementation; simple and transparent design	100%
2 Partial indexation	× Increases scheme complexity and could lead to sub-optimal bidding behaviour	50%
3 No indexation	✓ Straightforward implementation; simple and transparent design	100%

-- Quantitative analysis --

The below charts illustrate the discounted revenues of a 10 MW onshore wind plant over a 20-year CfD contract. The blue bars correspond to contracts in which CfD payments are fully linked to the CPI (Option 1 above), while the orange bars represent contracts in which payments are set in nominal terms and are not linked to inflation (Option 3 above). Revenues are modelled based on the strike price required for an NPV=0 business case, assuming project costs as outlined in the DESNZ Electricity Generation Costs Report 2023. In the case of nominal contracts, developers must increase their bids to account for the increased cost of financing their projects, which results from investors pricing inflation risk into the cost of capital. While it is possible that developers underestimate inflation in making their strike price bids, resulting in an 8% decrease in the cost to consumers (see high inflation scenario), it is more likely that developers will overestimate inflation (see low inflation scenario), which would increase cost to consumers by 15%. Even if developers accurately predict inflation, the increase in their cost of capital resulting from not hedging their contracts against inflation, would increase cost to consumers by around 6%.

Discounted revenues of a 10MW onshore wind plant over 20-year CfD contract
Real 2022 £m

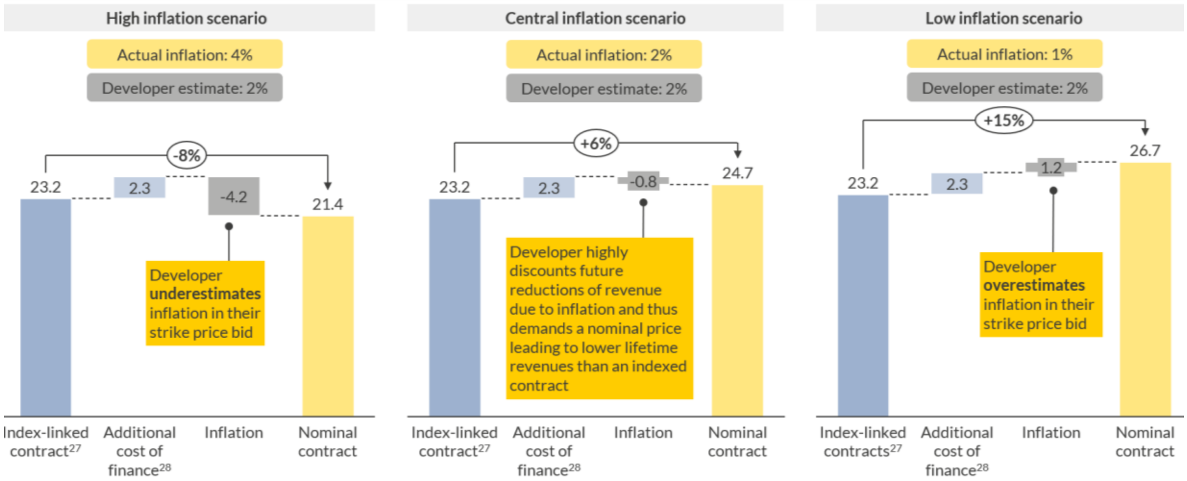

Figure 7: revenues of a 10MW onshore wind plant under nominal and index-linked contracts for three inflation scenarios

2.3.3 Dispatch down compensation

In the Integrated Single Electricity Market (I-SEM), three categories of dispatch down are distinguished:

- **Curtailment:** dispatch down due system wide operational limitations (e.g. System Non-Synchronous Penetration (SNSP) and Minimum Generation (Min-Gen))
- **Constraints:** dispatch down due to location specific network related limitations, typically the capacity of power lines
- **Oversupply:** dispatch down due to renewable generation exceeding demand which can lead to power prices becoming negative

SONI's central estimate for the dispatch down rate of renewables in NI in 2030 due to constraints is 5.4%, with oversupply and curtailment at 3% (49), i.e. constraints comprise more than 60% of dispatch down volumes in this central case. Note that this modelling is based on a 70% RES penetration in 2030. If offshore wind is deployed by 2030, oversupply is forecast to lead to a 14% dispatch down rate, with curtailment and constraints at 3% and 1% respectively (49).

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[29] CfD payments indexed to CPI.

[30] Project Weighted average cost of capital (WACC) is assumed to increase from 8% in the index-linked case to 9.5% if contracts are not index linked, due to increased risk (cf. merchant WACC assumption of 10.5%). All revenues are discounted at the social discount rate, assumed to be 3.5%.

#	Option	Explanation	Overall Score
1	Compensate all dispatch down	▪ All dispatch down volumes are remunerated, maximally at the strike price	25%
2	Compensate curtailment and oversupply	▪ Compensate all dispatch down volumes due to curtailment and oversupply, maximally at the strike price ▪ If prices are negative, generators must cease producing power to receive oversupply compensation ▪ Generators must have bid in at their marginal cost of generation (close to 0 for onshore wind) to be eligible for compensation ▪ Do not compensate for dispatch down due to constraints	25%
3	No compensation	▪ Generators are not compensated for dispatch down of any kind	0%

Country	Implemented Option
Great Britain	In the CfD scheme, projects are compensated for any type of dispatch down. Payments are made to the generator annually from the Low Carbon Contracts Company (LCCC) based on the Qualifying Curtailment and/or Qualifying Partial Curtailment (QCPC) reports (47).
Republic of Ireland	In RESS 3 and ORESS 1, projects are compensated for curtailment and oversupply following the Unrealised Available Energy Compensation (UAEC) methodology (50). Generators do not receive compensation if they are generating during negative price periods (9,51). Generators must have bid in at their marginal cost of generation (close to 0 for onshore wind) to be eligible for compensation.

-- In-depth analysis of options –

Option	80% by 2030	Score
1 Compensate all dispatch down	✓ Most favourable for attracting investment × Removing locational signals to developers may lead to inefficient grid utilisation	50%
2 Compensate curtailment and oversupply	✓ Maintaining locational economic signals incentivises renewable development in less constrained areas, allowing more efficient grid utilisation[31] × Significant uncertainty for developers if constraints remain high ×	50%
3 No compensation	× Remuneration for dispatch down volumes required for investor confidence	0%

Option	Low Cost	Score
1 Compensate all dispatch down	✓ Avoids developers having to price estimated constraints into their bids which could significantly reduce overall cost to the consumer × Loss of locational signal could lead to high congestion and system inefficiency	50%
2 Compensate curtailment and oversupply	✓ Maintain incentives for locational alignment between RES development and available grid capacity × Developers may price in overestimated volume of constraints into bids, given high historical rates of dispatch down due to constraints and no guarantee of timely reductions × May lead to higher cost of capital due to additional financial risk	50%
3 No compensation	× Bidders likely to price in overestimated dispatch down rate into bid leading to higher cost than with compensation	0%

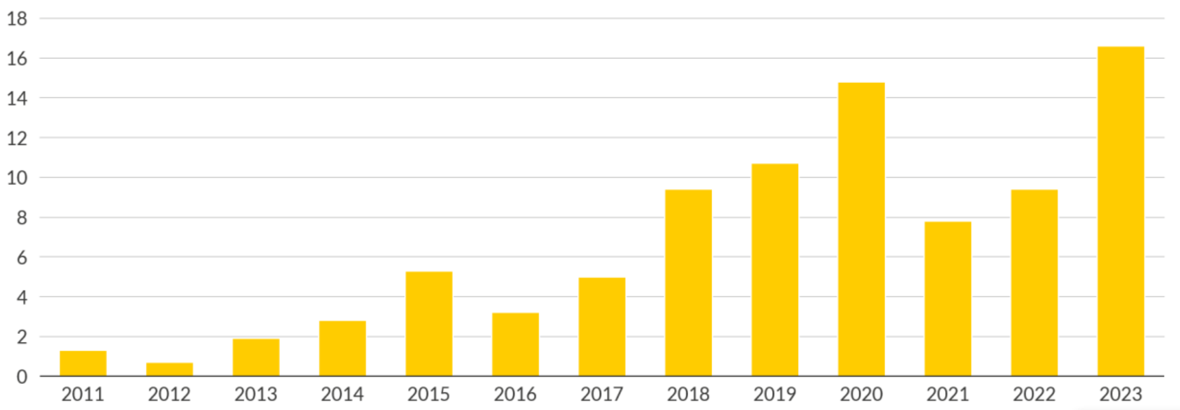
Energy Security: Dispatch down is not expected to have any impact on the diversification and security of electricity supply. Thus, it is not assessed in terms of the energy security criterion.

[31] It was brought up in engagement with stakeholders that wind developers in Northern Ireland might have limited ability to react to locational signals since constraint levels are significant across the country. This will be investigated further in the following phase of the project.

Option	Practicality	Score
1 Compensate all dispatch down	× Increased complexity; assessment of availability and dispatch down volumes for each generator increases administrative burden × Assessment of constraints at each node further increases administrative burden	50%
2 Compensate curtailment and oversupply	× Increased complexity; assessment of availability and dispatch down volumes for each generator increases administrative burden	50%
3 No compensation	× No implementation challenges	100%

-- Quantitative analysis –

Historical total dispatch down of onshore wind in Northern Ireland (52), % of generation potential



The chart above shows dispatch down rates increasing in Northern Ireland, from under 2% in the early 2010s to over 16% in 2023. Note, the 2023 average does not include Q4 2023.

The below figure shows dispatch down compensation for two 2030 scenarios modelled by SONI (49), as percentage of total revenues of renewable generators (left) and as a percentage of total support cost (right). Note that these numbers will be revised based on an updated 80% RES-E to be published by SONI.

Dispatch down compensation in 2030 by RES deployment scenario

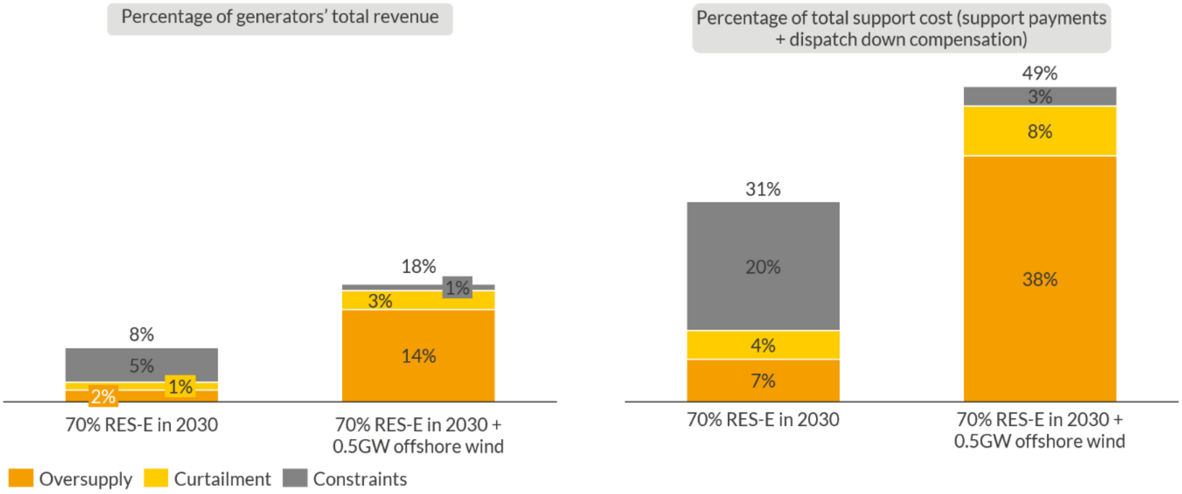


Figure 8: Modelled scenarios of dispatch down compensation

Key takeaways:

- Compensation for all dispatch down could hedge generators against losing out on 8% of their total revenues, corresponding to the 8% dispatch down rate in SONI's central scenario. Most of this dispatch down is caused by constraints.
- This means the compensation would increase the cost per utilised generation in the scheme by about 8% (left).
- Compensation for all dispatch down would make up 31% of the total support cost in 2030 (right).
- Given recent high rates of constraints and curtailment (15% in 2020), generators might overestimate the amount of dispatch down which would subsequently lead to an increase of the cost of generation by more than 8%. Allocating dispatch down risk with developers should be avoided if they do not have the ability to accurately estimate dispatch down rate[32].
- While constraints comprise most of the dispatch down in SONI's central scenario, oversupply makes up the vast majority in a scenario with additional 0.5GW offshore wind.

[32] Highlighted in conversation with government stakeholder

2.3.4 Non-Delivery Penalties

#	Option	Explanation	Overall Score
1	Financial penalties	Bid bonds required to participate in the auctions; performance bonds if successful	25%
2	Exclusion from future auctions	Exclusion from one or multiple subsequent auctions	12.5%
3	No penalties	No penalty for non-delivery	0%

Country	Implemented Option
Great Britain	• Until AR4, auctions were run biennially and non-delivery led to exclusion from the next auction • Since AR5, auctions are run annually and non-delivery leads to exclusion from the next two auctions
Republic of Ireland	▪ Bid bonds required to participate in RESS auctions (19) ▪ Performance bonds after securing RESS contract (19)

Recommendation

- Financial penalties (bid bonds and performance bonds) should be implemented to prevent speculative bids and incentivise timely delivery of projects
- More detailed analysis of the pipeline will be conducted to determine whether exclusion from subsequent auctions would be more effective without risking undermining the 80%

-- In-depth analysis of options --

Option	80% by 2030	Score
1 Financial penalties	✓ Excluding speculative bids from auctions and increasing likelihood of delivery of successful projects × Might deter smaller developers, for whom a bond is a large financial burden, from participating in the scheme	50%
2 Exclusion from future auctions	✓ Incentivising timely delivery without excluding smaller developers with limited access to finance × Exclusion of large projects could reduce likelihood of meeting 2030 target in a small market like Northern Ireland	0%
3 No penalties	× Risks speculative bids crowding out advanced projects with high delivery likelihood	0%

Option	Low Cost	Score
1 Financial penalties	✓ Higher delivery rates of renewable projects ensure cheap renewable power is available to consumers at an earlier date × Poses additional financial risk to investors which could lead to higher cost of capital and subsequently higher bid prices	50%
2 Exclusion from future auctions	✓ Higher delivery rates of renewable projects ensure cheap renewable power is available to consumers at an earlier date ✓ No additional risk to investors and thus no higher cost of capital × Exclusion of large projects could reduce competition levels in auctions	50%
3 No penalties	✓ Likely to lead to more participants in auctions, increasing levels of competition × Late or no delivery of projects could delay renewable growth prolonging exposure of consumers to volatile fossil fuel prices	50%

Energy Security: Non-delivery penalties are not expected to have any impact on the diversification and security of electricity supply. Thus, they were not assessed in terms of the energy security criterion.

Option	Practicality	Score
1 Financial penalties	× Increased administrative burden in processing asset specific bonds and granting exemptions due to delayed connections	50%
2 Exclusion from future auctions	× Exclusion of large projects could directly imply missing of the 2030 target due to low number of auctions and limited pipeline in small market	50%
3 No penalties	× Limited incentives for delivery could lead to large number of speculative bids in auctions and late delivery or non-completion of projects	0%

2.3.5 Floor price

#	Option	Explanation	Overall Score
1	Any hour	Cease of support in any periods when the wholesale price is negative	75%
2	Number of hours	Cease of support after a certain number of consecutive hours when the wholesale price is negative	25%

Country	Implemented Option
Great Britain	• Before AR4, no payments were provided when the DA power price was below zero for six or more consecutive hours (48) • Since AR4, no payment is provided during any hour when the DA price is below zero (10)
Republic of Ireland	▪ In both the RESS and the ORESS schemes, no support is provided during any negative price periods (48,51)[33]

Recommendation

Support should cease during any negative price periods, but generators should be compensated for foregone support during these periods as in the RESS scheme, in line with the recommendation for dispatch down. This approach strikes the best balance between attracting investment, protecting consumers, and reducing system oversupply.

-- Estimates on frequency of negative price periods --

Under SONI's Shaping Our Electricity Future (SOEF) scenario V1.0[34], the curtailment rate of renewables due to oversupply is estimated to be 1.8% in Northern Ireland in 2030, accounting for 21% of total curtailment. Furthermore, if an additional 500MW of offshore wind is connected by 2030, SONI estimates a curtailment rate of 14.3% due to oversupply, accounting for 78% of total curtailment (49).

[33] From RESS 3 and ORESS 1 onwards, generators are compensated for foregone support in negative price periods via the Unrealised Available Energy Compensation (UAEC) mechanism if they curtail their generation and have not bid into the market at negative prices (19).

[34] Corresponding to a 70% renewable penetration, updated analysis based on 80% renewable penetration is expected soon.

-- In-depth analysis of options --

Option	80% by 2030	Score
1 Any hour	✓ Preventing renewable assets from aggravating system operation challenges (48) which can help to accommodate more renewables in the system × Additional financial risk if loss of support not compensated, might thus attract less investment	100%
2 Number of hours	✓ Financial risk is lower compared to no support in any hour of negative prices which might attract more investment × Incentivises power feed-in at times of oversupply leading to inefficient dispatch and more challenging system operation (53)	50%

Option	Low Cost	Score
1 Any hour	✓ Lowering renewable integration cost as excess supply not remunerated (53) × If loss of support is not remunerated, bidders might price this loss into their bids based on an overestimated number of negative price periods × Additional financial risk might lead to higher cost of capital	50%
2 Number of hours	✓ Lower financial risk for investors and thus lower increase of bid price (53) × Leads to inefficient dispatch decisions and increases system operation challenges and costs (53) × Leads to increased costs of the scheme as difference between strike price and market price grows	50%

Energy Security: Floor price is not expected to have any impact on the diversification and security of electricity supply. Thus, it was not assessed in terms of this criterion.

Option	Practicality	Score
1 Any hour	✓ Simple and transparent rule to which market actors can adapt[35] ✓ Increased deployment of demand flexibility will reduce volatility of prices and help to reduce negative price periods (54)	100%
2 Number of hours	× More complex rule which makes it more difficult for market actors to react and for system operators to predict their behaviour	50%

[35] This was highlighted in conversations with policy makers as a key objective for any rule on cease of support payments whereas the actual threshold / floor price might be less relevant.

2.3.6 Reference Price

#	Option	Explanation	Overall Score
1	DA	Hourly I-SEM Day Ahead price	75%
2	ID	Hourly I-SEM Intraday price	25%
3	DA/ID/IP	Average of Day Ahead, Intraday, and Imbalance Price	38%

Country	Implemented Option
Great Britain	Reference price for intermittent CfD contracts is set hourly and is set at the weighted average of the settlement prices for the two day-ahead auctions (18). Reference price for baseload CfDs is set six-monthly and is the market price for the forward six-monthly season baseload contract.
Republic of Ireland	Reference price for intermittent generators is the DA I-SEM price. For baseload generators or non-variable projects, it is the time weighted average of the DA market over the Public Service Obligation (PSO)[36] levy year.

Recommendation

- The hourly day-ahead I-SEM price should be the reference price in the Northern Ireland scheme as this provides the best hedge to renewable generators.

[36] RESS is financed through the PSO levy, which is charged or credited to customers through their electricity bills (9).

-- In-depth analysis of options --

Option	80% by 2030	Score
1 DA	✓ DA represents bulk market for power, i.e. where most demand is met[37](55), thus most representative of system value of generation; thus, best price signal to guide operation and investment for intermittent and non-intermittent power × Higher forecasting risk compared to ID could be reduced through improved forecasting technology × Potential price distortion of markets closer to real time	50%
2 ID	✓ Would incentivise renewable generators to sell in the ID market which is closer to real time when better renewable forecasts are available which could improve renewable management and reduce imbalances (56) × However, moving significant share of power trade to real time leaves less time for suppliers/traders/system operators to manage system imbalances	50%
3 DA/ID/IP	× Could incentivise renewable generators to sell across various markets with unclear consequences on these markets and their prices	50%

Option	Low Cost	Score
1 DA	✓ Represents bulk market for RES, i.e. where most RES is traded; thus, most representative of RES revenue and providing best hedge for RES generator which can help to lower cost of capital ✓ High liquidity of DA leads to more predictable and reliable prices and cash flows for generators	100%
2 ID	× Smaller market closer to delivery than DA with higher volatility, lower liquidity, and no uniform pricing; more difficult to predict than DA, making support payments more volatile and potentially prone to manipulation (57).	50%
3 DA/ID/IP	✓ Could help avoid market distortions and opportunities for gaming, positively impacting market dynamics, system performance and cost to consumers (58).	100%

Energy Security: Different reference prices are not expected to have any impact on the diversification and security of electricity supply. Thus, they were not assessed in terms of the energy security criterion.

[37] Even though a large amount of power is traded in forward markets rather than spot markets (DA & ID), contracts in forward markets are often linked to DA prices.

Option	Practicality	Score
1 DA	✓ RESS scheme uses I-SEM DA price; aligning the reference price could help to coordinate renewable dispatch across Northern Ireland and ROI	100%
2 ID	× Different reference price than in ROI may result in uncoordinated renewable dispatch between Northern Ireland and the Republic of Ireland	50%
3 DA/ID/IP	× Increases complexity of scheme and administrative burden	50%

Price distortion example (DA as reference price): If the strike price is 80 €/MWh and the day-ahead price was 200 €/MWh, generators must pay 120 €/MWh for every MWh produced in that hour. If the intraday price drops to 119 €/MWh, it is rational for the renewable generator to curtail output to avoid the payment and pay another asset to generate in the intraday (58). The renewable generator would still receive the DA price of 200 €/MWh, but instead of paying back 120 €/MWh, it will pay 119 €/MWh, increasing its net profits. This would place upward pressure on intraday prices.

Price distortion example (ID as reference price): The same dynamic applies if the reference price is the intraday price. In this case, using the same values as in the example above for strike price and reference price, the generator would be incentivised to curtail output as soon as imbalance prices are below 120 €/MWh.

2.3.7 Funding

#	Option	Explanation	Overall Score
1	Taxes	Funding the support scheme through general taxation	38%
2	Energy bills	Funding the support scheme through green levies per MWh added to electricity bills	50%

Country	Implemented Option
Great Britain	▪ Green levy on energy bills per unit of consumption (9)
Republic of Ireland	▪ PSO[38] Levy on energy bills per unit of consumption (9)

Recommendation

- Recommendation still to be determined pending further assessment of the implications of this decision on electricity prices and economic incentives for electrification and energy

-- In-depth analysis of options --

Option	80% by 2030	Score
1 Taxes	✓ Reduced electricity retail cost encourages electrification in heat, transport and industry (59–61), enabling growth of flexible electricity demand that could help enable higher renewable penetration × Reduction of electricity retail cost decreases case for energy efficiency. This could lead to higher electricity demand compared to funding via bills and subsequently lower renewable share in total electricity consumption.	50%
2 Energy Bills	✓ Improves case for energy efficiency which could help reduce demand and subsequently increase renewable share in total electricity consumption × Increase of electricity retail cost discourages electrification × Increase of non-dynamic share of retail price as green levies don't vary with the time of the day. This reduces case for demand side response which could be crucial for a flexible power system (60) × Increases cost of electricity imports compared to revenues from exports for distributed flexibility technology like vehicle to grid which could be crucial for a flexible power system (60)	50%

[38] RESS is financed through the PSO levy, charged or credited to customers through their electricity bills. CRU, the regulator, calculates the PSO levy annually for a period starting from October every year (9).

Option	Low Cost	Score
1 Taxes	✓ Spreading costs over a wider group reducing cost per party (59,61,62) ✓ Better protection of low-income households: green levies increase energy bills. This has a more significant impact for poorer households who spend a larger share of their disposable income on energy bills[39]. This effect is compounded by the fact that poorer households often live in properties with worse thermal insulation than high income households leading to higher consumption (63) × Reduces case for energy efficiency which could increase consumer cost in the long term × Does not recover cost according to causation, could e.g. impose tax even on persons who don't consume electricity from the public grid	100%
2 Energy Bills	✓ Increased retail cost helps to incentivise energy efficiency which could help reduce consumer cost in the long term × Levy has higher impact on low-income households who spend a larger share of their disposable income on energy bills than high income households	50%

Energy Security: Different funding approaches are not expected to have any impact on the diversification and security of electricity supply. Thus, they were not assessed in terms of the energy security criterion.

Option	Practicality	Score
1 Taxes	× Might require additional approvals through regulation and be subject to legal challenges (though it has been implemented in major economies, e.g. Germany) × Potential backlash by industry and general public on tax increases	50%
2 Energy Bills	✓ Experience of funding support schemes through energy bills in GB and ROI	100%

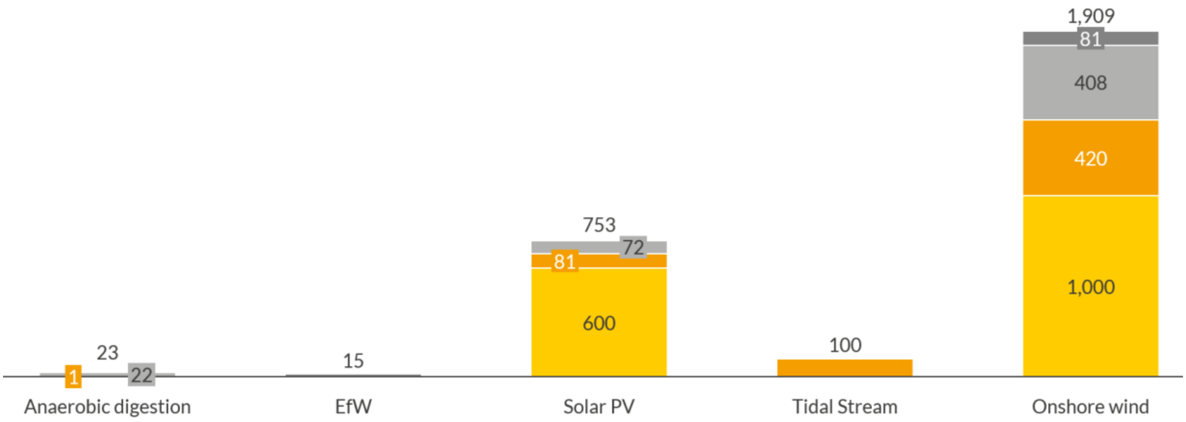
[39] In the UK, the share of energy bills in disposable income has risen from 12% in 2001-2010 to 16% in 2011-2019 for low-income households due to rising energy costs, while it has stayed relatively constant at 8% for high-income households (59)

3 Auction Roadmap

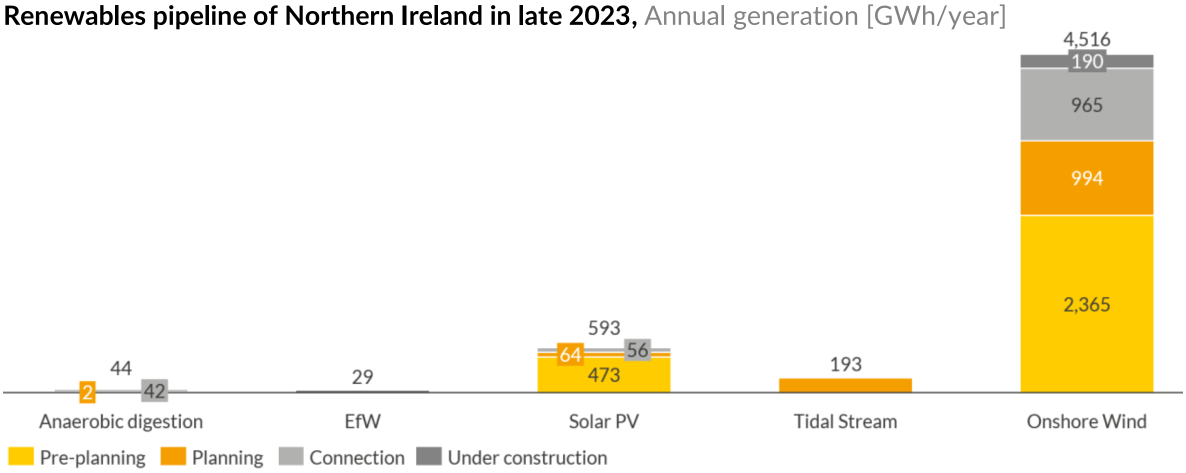
3.1 Pipeline analysis

3.1.1 Current Status of pipeline

Renewables pipeline of Northern Ireland in late 2023, Capacity [MW]



Renewables pipeline of Northern Ireland in late 2023, Annual generation [GWh/year]



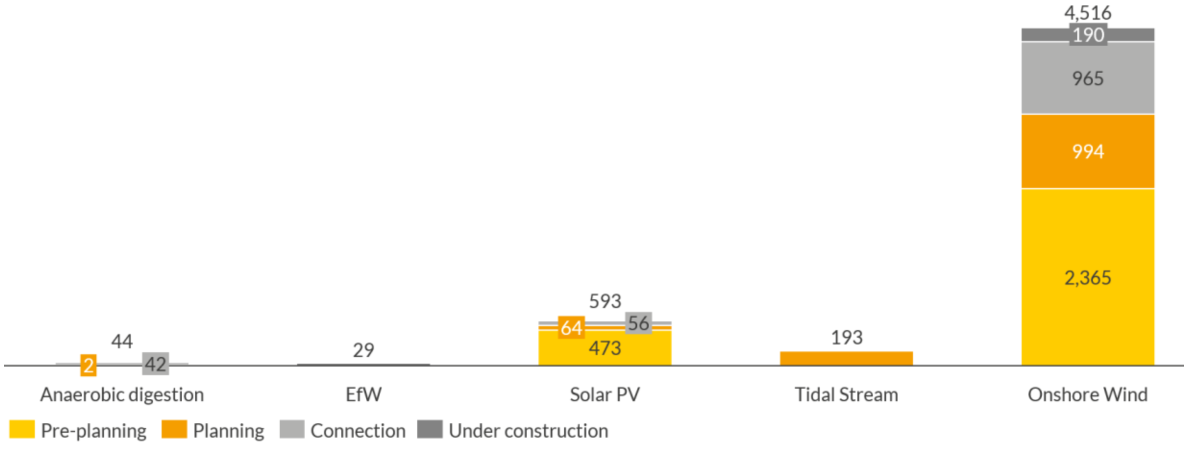


Figure 9: Renewable Pipeline in Northern Ireland as of end of 2023 9 shows the current pipeline of renewables in the pre-planning stage or beyond, based on the REPD. Onshore wind and solar PV contribute 84% and 11% respectively of the total pipeline of generation. 53% of the generation in the pipeline is in the pre-planning phase, while 23% is in the planning phase and 20% is in the connection phase, i.e. has received planning permission. Only 4% of the generation in the pipeline is under construction. This pipeline data was used to inform assumptions on the timelines of different development stages and the capacity likely to participate in auctions.

[40] Sources: DESNZ REPD (planning stage and beyond); RenewableNI (pre-planning). Planning includes all projects with an REPD status of 'planning application submitted', 'appeal lodged' and 'revised'; Connection includes 'planning permission granted', 'appeal granted' and 'Secretary of State granted'; Under construction includes 'under construction'.

3.1.2 Necessary conditions for future pipeline to deliver required volumes

The following conditions are required for the first two auctions to procure sufficient capacity for the 2030 target to be met. Section 4.7 illustrates a sensitivity on one of these conditions.

1. Onshore capacity requirements:
   - Capacity currently marked in the REPD as having submitted planning application will receive it
   - In addition to what is registered in the REPD, 1,000 MW of onshore wind and 600 MW of solar PV capacity is currently in the pre-planning stage (64). 50% of this capacity will receive planning permission in 2026 and 50% in 2027
2. Operational volumes:
   - All capacity procured in the auctions becomes operational (see auction timetable below)
   - It should be noted that the generation in the pipeline only narrowly exceeds the 5 TWh required to meet the 2030 (see *Figure 9*). Thus, a very high realisation rate of the projects in the pipeline (either with or without CfD) will be necessary to reach the target.
3. Development timeline (onshore renewables):
   - Planning: 1 year[41]
   - Connection: 2 years[42]
   - Construction: 1 year
4. Projects will delay construction to remain eligible for the next auction:
   - Projects eligible in 2024 remain in the connection phase to be eligible for the 2025 auction
   - Projects that are unsuccessful in the 2025 auction, and projects that become eligible in 2026, remain in the connection phase to be eligible for the 2027 auction
   - Projects unsuccessful in the 2027 auction will not wait for further auctions, as the procurement volume for auctions post 2027 will be small.

[41] This constitutes a two-year reduction in the time required for the planning phase (c.f. current onshore development timelines of 3/2/1 years for planning, connection and construction respectively, as outlined in Section 4.3). For the impact of a one-year extension of the planning phase on eligible volumes, see section 4.7.

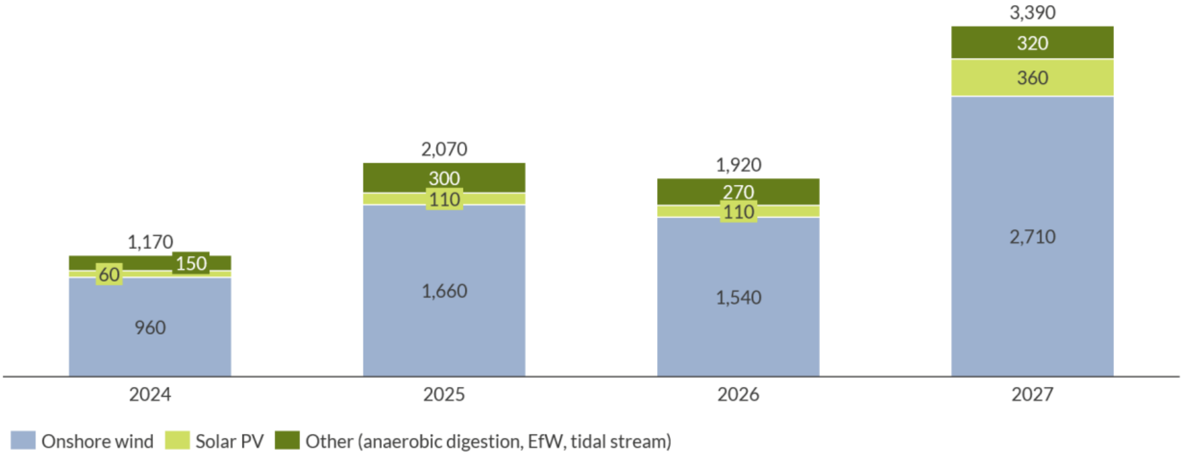
[42] Plants become eligible for the Scheme after one year in the connection phase, at which point they are assumed to have received their connection offer.

3.1.3 Onshore renewables capacity eligible for support scheme

The following charts outline the volumes of renewable energy eligible for the support scheme in each year (i.e. annual volumes of generators that have received planning permission), based on the requirements outlined above. All requirements must be satisfied if sufficient volumes are to be procured; for an illustration of the impact of a one-year extension of the planning phase on eligible volumes, see Section 4.7.

Offshore wind: the Energy Strategy Action Plan 2022 identified a target of 1GW of offshore wind capacity from 2030 (3). The Department and key stakeholders continue to refine the timeline for offshore wind delivery. At this stage in development, it is not possible to outline with certainty the scale and timing of offshore wind deployment in NI. Therefore, the nature of offshore wind's participation in the scheme cannot be outlined until more information is available. However, the development of the support scheme will align with the critical path timeline for offshore renewable energy and draw input from the OREAP Steering Group. Hence, **no offshore wind volumes are shown in the auction roadmap**.

Annual generation volumes eligible for support scheme
GWh/year



Capacity eligible for support scheme
MW

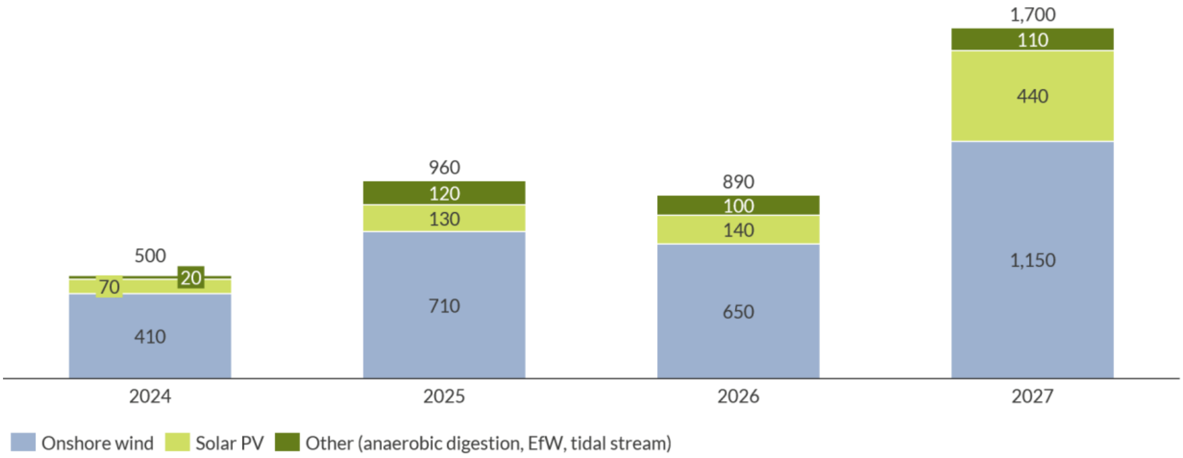


Figure 10: Onshore renewables capacity eligible for the Support Scheme (assuming 1 TWh is successful in 2025)

3.2 Auction timetable

This section outlines a potential roadmap for the auctions of the RES-E support scheme. The presented roadmap is for illustrative purposes; the presented volumes and timelines are subject to change given further quantitative analysis and market developments closer to the expected date of the auctions. Further, volumes and timings of later auctions may need to be adjusted based on the outcome of earlier auctions.

3.2.1 Basic parameters

1. Total auction volumes: **3.5 TWh of renewable generation must be procured through the Scheme before 2030** (see 1.4.2). This is based on SONI's Central Scenario for 2030 total electricity demand (11).
2. Auction dates: **2025** is considered the earliest feasible date for a first auction. **2027** is the latest date for an auction in which successful projects can become operational in time to contribute to the delivery of the 2030 target.
3. Auction frequency: auctions will occur **once every two years** (see Section 2.2.4). Depending on the market conditions and auction outcomes additional auctions could be scheduled if deemed necessary.
4. Pot structure:

	Pot 1	**Pot 2**	**Pot 3**
Purpose of pot	Fast delivery and low cost	Diversification of supply	Offshore wind
Technologies	Onshore wind Solar PV	*All other eligible techs apart from offshore wind*	Offshore wind

5. Offshore wind: The Department and key stakeholders continue to refine the timeline for offshore wind delivery. At this stage in development, it is not possible to outline with certainty the scale and timing of offshore wind deployment in NI. Therefore, the nature of offshore wind's participation in the scheme cannot be outlined until more information is available. However, the development of the support scheme will align with the critical path timeline for offshore renewable energy and draw input from the OREAP Steering Group.

3.2.2 Provisional auction dates and volumes

Indicative volumes are given for the first two auctions only; the auction roadmap for later auctions is subject to further analysis and will be published in due course. However, these first two auctions will be of greatest significance, since they will procure the renewable generation volumes required to meet the 2030 target.

Table 5 – Auction timetable[43]

Auction	Auction Year	Delivery Year	Volume Pot 1 & 2	Volume Pot 3	Main objectives
1	2025	2027	1,000 GWh (~500 MW)	0 GWh	▪ Procure projects at advanced stages of development ▪ Procure ~30% of the supported energy volumes required to meet 2030 target, mainly through Pot 1
2	2027	2029	2,500 GWh (~1250 MW)	TBD	▪ Procure remaining ~70% of supported energy volumes required to meet 2030 target ▪ Increase procurement volume of Pot 2 to diversify the supply mix
TBD	…	…	…	…	…

[43] Capacity is calculated based on a generation weighted average onshore renewables load factor of 23%.

3.3 Illustrative auction outcomes

The following are examples of potential auction outcomes for the first two auctions, based on the timetable set out above. They are constructed based on analysis of the pipeline of the REPD and associated costs, taken from the DESNZ Electricity Generation Costs Report (17). The way in which total procurement volumes are split between Pot 1 and Pot 2 is informed by available capacity in the pipeline. The split is only to be regarded as indicative and will be determined closer to the auction date based on further analysis of costs and benefits. The split across technologies within each pot will be determined by competition within the auction.

Auction 1

Table 6 – Illustrative allocation of volumes across pots for Auction 1 (GWh of annual generation)

Pot 1	Pot 2	Pot 3
1000	0	0

Table 7 – Illustrative outcome of Auction 1

Pot	Technology	Generation (GWh/year)	Generation (% of total)	Capacity (MW)
1	Onshore wind	800	80%	340
1	Solar PV	200	20%	255

Table 8 – Illustrative generation and support cost for Auction 1

Pot	Technology	Generation cost[44]		Support cost[45]			
		£m/year	£/MWh	£m/year	£/MWh	% of total	£/household/year[46]
1	Onshore wind	58	72	15	18	89	10
	Solar PV	13	67	2	9	11	1
Total		71	-	16	-	-	11

[44] Generation cost determined by calculating technology-specific strike prices required for zero NPV business cases using representative projects in the REPD and project costs from DESNZ Electricity Generation Costs 2023 (17).

[45] Support cost includes dispatch down (DD) payments based on the assumption of 8% DD (onshore wind: £5m/y; solar PV: £1m/y). Support cost is calculated as the difference between technology-specific strike prices (see above), and technology-specific annual average capture prices in the I-SEM Day Ahead Market, forecast by Aurora Energy Research (Oct-23 forecast). NB the cost of support does not consider wholesale price reductions brought about by the scheme (these will be considered in the next phase of the project).

[46] Assumes that households will meet 50% of the scheme costs: residential electricity demand is forecast to comprise 28% of electricity demand in 2030, the remainder being transport, commercial and industrial demand (77). However, industry typically receives exemption from levies to ensure international competitiveness, thus the costs of the scheme would need to be mainly recovered through levies on residential and commercial electricity demand. Assumes 769,000 households in NI (85).

Auction 2

Table 9 – Illustrative allocation of volumes across pots for Auction 2 (GWh of annual generation)

Pot 1	Pot 2	Pot 3
2,200	300	0

Table 10 – Illustrative outcome of Auction 2

Pot	Technology	Generation (GWh/year)	Generation (% of pot)	Generation (% of total)	Capacity (MW)
1	Onshore wind	1,760	80%	70%	744
1	Solar PV	440	20%	18%	558
2	Biomass	210	70%	8%	35
2	Tidal	60	20%	2%	30
2	Anaerobic digestion	30	10%	1%	5

Table 11 – Illustrative generation and support cost for Auction 2

Pot	Technology	Generation cost[42]		Support cost[43]			
		£m/year	£/MWh	£m/year	£/MWh	% of total	£/household/year[44]
1	Onshore wind	127	72	32	18	60%	21
1	Solar PV	29	67	4	9	7%	3
2	Biomass	17	81	2	11	4%	1
2	Tidal	17	279	13	209	23%	8
2	Anaerobic digestion	5	160	3	90	5%	2
Total		195	-	54	-	-	35

[42, 43, 44] See footnotes on previous page.

Notes on the cost of support:

- The cost of support does not consider wholesale price reductions brought about by the increased renewables penetration enabled by the scheme. These savings will be considered in detail during the next phase of the Support Scheme design process.

- Tidal and anaerobic digestion require a high amount of support per MWh of generation but provide highly regular or even dispatchable generation. The target procurement volume for these technologies will need to be determined by weighing up costs and benefits in the next phase of the project.

- The cost of support includes an assumption of 8% Dispatch Down (DD), based on SONI's forecast (49). This includes curtailment, oversupply, and constraints; compensation for the latter is not currently being recommended, but constraints are included in the DD assumptions for this cost calculation as a proxy for the increase in bid prices that results from no constraint compensation.

Cumulative procurement of Auctions 1 and 2

The chart below shows the cumulative generation volumes of capacity successful in the auctions by year given the auction outcomes above.

Cumulative operational generation volumes successful in first two auctions[48]
GWh/year

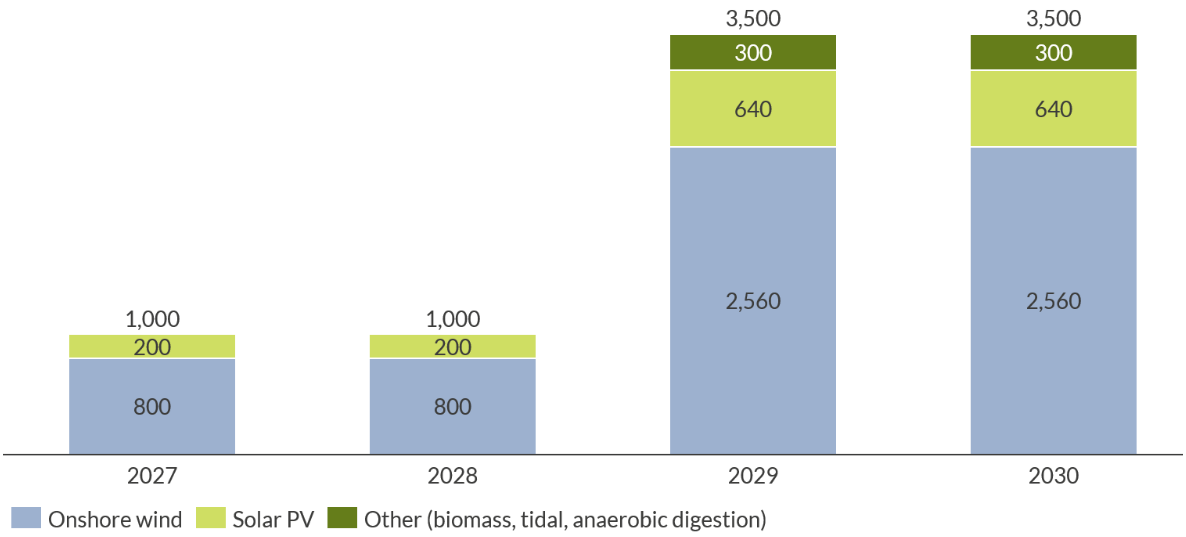


Figure 11: Cumulative operational generation volumes successful in first two auctions

[48] Assumes capacity becomes operational two years after each auction, see 3.1.2 – Assumptions on future pipeline.

4 Appendix

4.1 Principle form of support analysis

Table 12 – Principal forms of support

#	Form of support	Description
1	**Two-way floating feed in premium (FIP)**	A two-way floating FIP involves either a pay as bid or pay as clear auction, where renewable energy developers bid for fixed price contracts. When the market price is below the strike price, the counterparty pays the generator the difference. Conversely, if the market price exceeds the strike price, the generator returns the excess revenue to the counterparty.
2	**Sliding Feed in Premium**	In a Sliding FIP, the generator is paid based on the difference between a predetermined strike price and the market price of electricity. If the market price falls below the strike price, the counterparty compensates the generator for the shortfall, guaranteeing a minimum revenue stream. In the case of market prices above the strike price, the generator is not obliged to pay back the difference to the counterparty.
3	**Renewable obligation (RO) schemes**	Electricity suppliers are obligated to procure a certain proportion of their electricity from renewable sources. Renewable obligation certificates (ROCs) are issued per megawatt-hour (MWh) of eligible renewable output, to generators who sell them to electricity suppliers as additional revenue to the wholesale revenues. Suppliers need to show ROCs covering a given percentage of their total procured electricity; failure of suppliers to do so result in an additional charge.
4	**Feed-in-Tariff (FiT)**	In a FiT system, renewable generators are paid a fixed rate per unit of electricity fed into the grid for a fixed contract period, usually 15-20 years. FiT contracts are common for small scale energy generation.
5	**Feed-in-Premium**	In a FiP system, the generator receives a fixed premium on top of the market price for each unit of electricity produced.
6	**Investment Bonds, Loans, Grants**	Investment bonds are debt securities issued by governments, in this case, to raise capital, providing investors with periodic interest payments and the return of the principal at maturity. They are considered a stable and safe investment. Government can also provide grants and loans to projects to cover upfront costs.
7	**Tax incentives**	Tax incentives involve reducing taxes for renewable energy investors or energy consumers in exchange for specific actions or investments in designated technologies.

Table 13 – Strengths and weaknesses of principal forms of support

Option	Analysis
1 Two-way floating FIP	✓ Price risk of generator is minimised, in particular if strike price is linked to inflation ✓ Downsides for the consumer is limited as generator pays the excess to the counterparty in cases of high wholesale prices (52) ✓ High familiarity of scheme amongst developers, investors, lenders and operators within GB and Ireland × Limited market signals to renewable generators as they receive the same price per MWh regardless of the wholesale price (8)
2 Sliding FIP	✓ Low risk to investors/ developers as mechanism limits downside while allowing potential upside (53) × Consumers are not protected from high electricity wholesale prices, as generators do not pay back during high price periods
3 RO scheme	✓ Generators are exposed to wholesale market price signals which should encourage integration of renewable energy ✓ Centralised penetration target but no centralised procurement of renewable electricity which should lead to efficient allocation of resources by market actors × Consumers are not protected from high electricity wholesale prices × ROCs are susceptible to market manipulation due to their tradable nature (9)
4 FiT	✓ Provides a fixed income for generators, protecting them from market volatility × No market integration of renewables through this scheme as electricity is bought by transmission system operators and fed directly into the grid × Budgetary strain can occur as governments are committed to long term fixed payments (8)
5 FiP	✓ Generators are exposed to wholesale market price signals which should encourage integration of renewable energy ✓ Fixed Premium provides a guaranteed floor for revenues while allowing for a potential upside offering an attractive investment option which could reduce cost of capital × Consumers are not protected from high electricity wholesale prices
6 Investment Bonds, Loans, Grants	✓ Allows governments to directly provide access to low-cost finance to renewables × Support is provided upfront which could lead to allocation to projects which don't deliver (54)
7 Tax incentives	✓ Efficient mechanism in terms of government resources × Support is provided upfront which may be allocated to projects which don't deliver (55)

4.2 Technology LCOEs and shares of current renewables pipeline

Technology	LCOE in 2030 (£/MWh)[49](17)	Share of generation in current pipeline (56)
Onshore wind	36	83.5%
Offshore wind	39	0%
Solar	37	3.6%
Hydro (non-dispatchable)	91	0%
Tidal	203	0%
Co-located RES & BESS	-	N/A
Geothermal	129	0%
Anaerobic digestion, landfill gas and EfW	AD: 149 Landfill gas: 71 EfW: 113	1.5%
Biogas	197	6.4%
Biomass	102	4.5%

[49] Real 2021 £

4.3 Regulatory context of curtailment compensation and firm access in the I-SEM

4.3.1 Types of dispatch down actions

There are three types of dispatch down actions applied to renewables in the I-SEM:

1. Constraints: refers to the localised dispatch down to address local grid issues
2. Operational curtailment: refers to the dispatch down to address overall system security triggered by any one of three system limits. There are three main types of operational curtailment: SNSP, MinGen[50] and RoCoF[51].
3. Energy balancing or oversupply refers to dispatch down actions that are made to balance the system. These energy balancing actions are most common when renewable generation causes total system supply to exceed demand in the day-ahead market.

4.3.2 European Union energy policy framework

The European Union (EU) Clean Energy Package adopted in 2019 outlines the regulatory framework to decarbonize the EU's energy system in line with its Green Deal objectives. Article 13 (7) of the Regulation (EU) 2019/943 states that is now mandatory for renewable generators to be compensated for "non-market redispatch volumes" (operational curtailment and constraints) except in the case of producers that have accepted a non-firm connection agreement (57). Value of compensation should at least be equal to the greater[52] of:

1. Additional operating costs caused by the redispatch (Article 13, 7a)
2. Net revenues from the sale of electricity on the day-ahead market, including any financial support (Article 13, 7b)

The EU Clean Energy Package applies to both Northern Ireland and the Republic of Ireland.

4.3.3 Decision Paper on Dispatch, Redispatch and Compensation (SEM-22-009)

In September 2022, the SEM Committee issued new guidance on renewables dispatch and re-dispatch, as a result of the EU Clean Energy Package. This decision paper details how constraints and curtailment will be implemented in the I-SEM in accordance with EU regulations (58).

1. Dispatch down for all operational curtailment and constraints are classified as non-market based redispatch.
2. Operational curtailment will be applied pro-rata across the entire renewable fleet.
3. Constraints will be applied pro-rata within constrains groups.

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[50] The Minimum Generation requirement provides protection against emergency high frequency events and contributes to inertia via location-specific, must-run thermal units. In the context of renewables generation, the MinGen requirement is treated as 'curtailment'.

[51] Rate of change of frequency.

[52] Or a combination of both elements if applying the higher of the two alone would lead to an unjustifiably low or high compensation.

4. All firm units will be compensated for constraints and operational curtailment in accordance with the EU Clean Energy Package. Non-firm units are not eligible for dispatch down compensation under SEM-22-009.

4.4 Development timelines of onshore renewables

To inform the auction roadmap various sources on the development timelines have been investigated, including the historical data from the REPD, standard grid connection timelines and estimates reported by industry. The different stages of development have been summarised as follows:

Process step	Description	Typical duration (years)
Planning	▪ Planning spans the period between a planning application being submitted and planning permission being granted ▪ Includes all projects with a status of ‘planning application submitted’, ‘appeal lodged’ and ‘revised’ in the REPD	1 – 3
Connection	▪ Connection spans the period from obtaining a grid connection to the beginning of the construction process ▪ Includes all projects with a status of ‘planning permission granted’, ‘appeal granted’, and ‘secretary of state granted’ in the REPD	1 – 2
Construction	▪ Connection spans the period from the start of construction to the COD and includes the period of financing the project ▪ Includes all projects with a status of under ‘construction’	1

The consulted data suggests the following timelines for these three development stages:

- **Planning: 3 years**
  - The REPD indicates 70 projects submitted planning application since 2020 with 36 of these having not yet been granted permission. Assuming these projects will receive permission in 2024 leads to an average planning duration of 3 years across these 70 projects (22).
  - This is in line with an estimate reported by a report commissioned by the renewable industry (23).
- **Connection: 2 years**
  - Northern Ireland Electricity Network (NIEN) are responsible for connecting projects to the distribution network. This process can take from 6 months up to 2 years (28).
  - Once an application is made, the process for obtaining a connection to the distribution system includes:

  - NIEN ensures sufficient capacity is available on the distribution network, impact on the transmission system and an assessment of when firm access can be granted to a generator. These assessments typically take 90 days before a connection offer is made (28).
  - Following this the applicant has 90 days to accept the offer, which if accepted must be supported by a copy of their planning permission.
  - As each offer is made on a case-by-case basis there is no standard timeline for construction of the grid connection, and this can vary between projects.
  - **SONI** is responsible for connecting projects to the transmission system (59).
  - SONI aims to issue a connection offer within 90 days of the application date, however when a connection is complex this may not be possible and SONI may request an extension from the Utility Regulator. To make a connection offer to a project, SONI must complete connection studies, a financial assessment of infrastructure reinforcements, and a construction application to NIEN (59).
  - Following this the applicant has 90 days to accept the offer and follows the same process as in the case of a connection to the distribution network as outlined above.
  - The REPD indicates that all projects submitting planning application since 2015[53] have on average remained in the consented phase for 2 years before starting construction.
  - Due to the above estimates, we assume 2 years to be the average time for the grid connection phase.
- **Construction: 1 year**
  - The REPD indicates that 87% of projects that are awarded planning permission since 2015 have completed construction within 12 months.

4.5 Firm connections in the I-SEM

Firm access policy outlines how the network will accept available generation from connected assets, and is deeply linked to the condition and capacity of the network, how it is operated, and the overall market structure of the I-SEM.

Non-firm connection offers indicate that assets are not guaranteed to have their power accepted by the grid and removes the right to constraint and curtailment remuneration outlined in the SEM-22-009 decision paper (58).

In January 2023, the SEM Committee published a decision paper on a Firm Access Methodology in Ireland outlining the process for allocating firm access to generators (60). This set out several areas that require further consideration. In June 2023, the Commission for Regulation of Utilities in Ireland (CRU) published a consultation paper seeking feedback on which areas of the Firm Access Methodology require more detailed design.

[53] No projects that had entered the REPD in 2020 have reached construction, therefore developments which have entered the REPD since 2015 were used for the 'connection' and 'under construction' phase.

Lastly, in November 2023, the CRU published the Firm Access - Detailed Methodology (61), decision paper, with the goal of striking a balance between providing generators with firm access ahead of transmission reinforcement, providing certainty to investors/developers, and protecting consumers from high costs (62). According to the new Firm Access Methodology, a firm threshold of 2% network constraints will be applied to renewable energy only across the entire network. This means that if constraints in a given year are less than 2% (52), generators will be eligible for firm access and, as a result, compensation for operational curtailment and constraints, as specified in the SEM-22-009.

It is worth noting that in 2022 constraint levels in Ireland in some months were close to or over 6%, and the average was 4.8% (63). The consultation showed that most respondents suggested the firm threshold level should be set at 7% as a minimum (62), but the CRU describes 2% as a cautious approach.

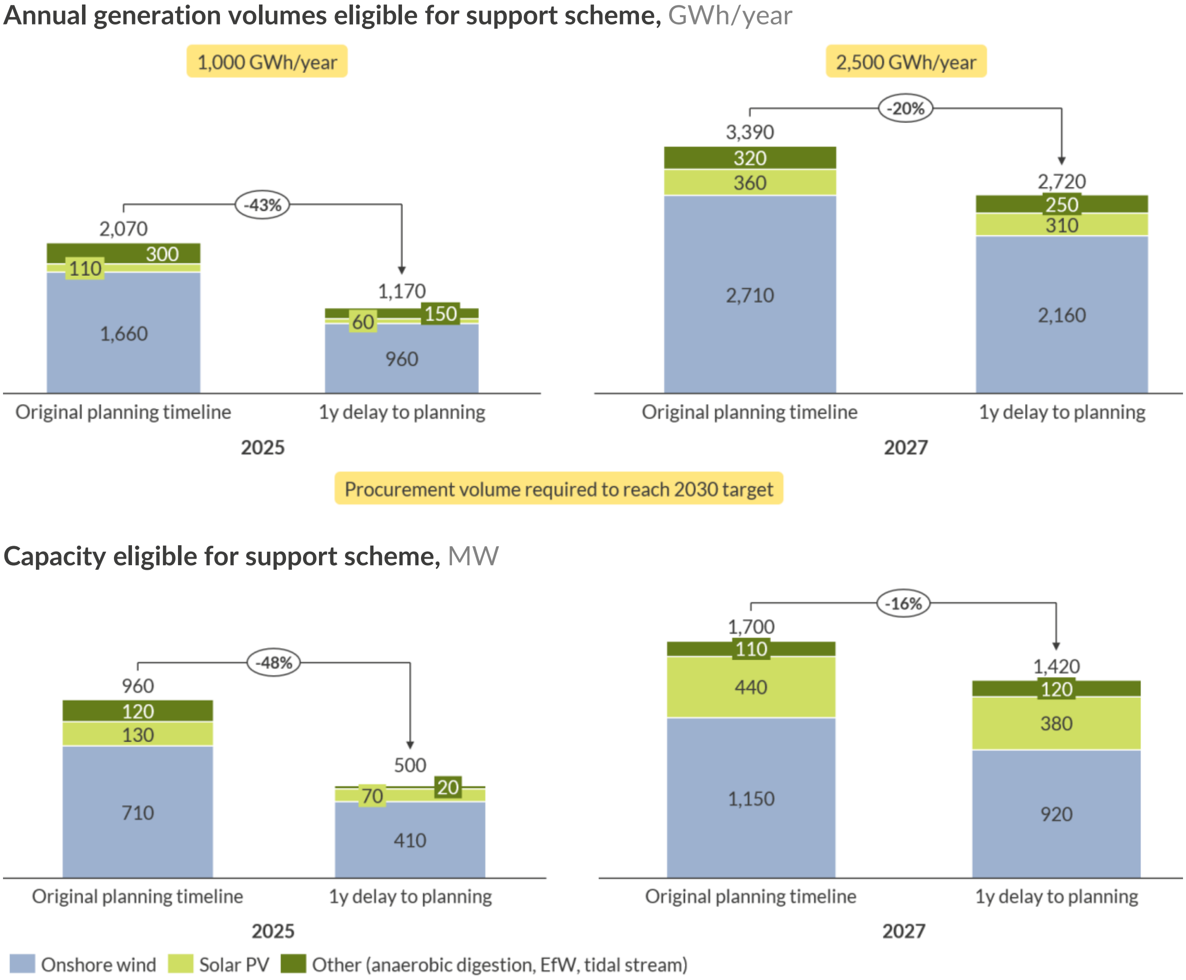
4.6 Implications of regulatory framework

According to the EU Clean Energy Package and the SEM-22-009 decision paper, all firm units in Northern Ireland must be compensated for constraints and operational curtailment. Conversely, non-firm units are not eligible for dispatch-down compensation. Curtailment and oversupply compensation within a support scheme, as in RESS3 and ORESS1 under the UAEC (Unrealised Availability Energy Compensation), could increase compensation for non-firm units, boosting investor confidence given the high level of curtailment expected in NI as renewable penetration increases.

4.7 Sensitivity on planning timeline

The below chart illustrates the effect of a one-year delay to planning timelines on the capacity and associated production volumes eligible for the Scheme[54] in the first auction (left) and second auction (right).

	Original planning timeline	1y delay to planning
Time for planning phase	1 year	2 years



Under a one-year delay to the planning timeline, both auctions could still procure sufficient volumes, but with a much lower competition ratio. The first auction would need to procure 85% of eligible volumes (up from 48% in the one-year planning scenario); similarly, the second auction would need to procure 92% of eligible volumes (up from 74%). This could result in greater strategic bidding, and higher strike prices.

[54] For all other assumptions, see Section 3.1.2

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