RenewableNI

Report produced by
CORNWALL INSIGHT
CREATING CLARITY

Supporting Renewables

Understanding policy impact on the cost to the consumers of renewable development in Northern Ireland

RenewableNI.com

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About RenewableNI

As the voice of the renewable electricity industry, RenewableNI is dedicated to achieving zero carbon electricity by 2035.

RenewableNI members are business leaders, technology innovators, and expert thinkers from right across industry. We are working together to build our future energy system, powered by clean electricity; a future which is better for industry, billpayers, and the environment.

RenewableNI engages, educates and stimulates debate in renewable energy. We facilitate crucial discussions, shape policy, and host events that propel the region towards a sustainable, low-carbon future.

The Vision

ZERO BY 2035
The International Energy Agency (IEA) states that all advanced economies must achieve zero carbon electricity by 2035. This is now reflected in UK Government policy.

Northern Ireland has one of the greatest wind resources in the world and is well positioned to meet this target.

80 BY 30
We currently have a 1.8GW renewable capacity. The NI Climate Change Act set a target of 80%renewables by 2030. This will require more than doubling the renewable electricity generation to meet the growth in demand as we electrify heat and transport.

Join us

RenewableNI is supporting our members to thrive, lead and innovate. For more information on how you can be part of this, email Membership@RenewableNI.com

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About Cornwall Insight

Getting to grips with the intricacies embedded in energy markets can be a daunting task. There is a wealth of information online to help you keep up to date with the latest developments, but finding what you are looking for and understanding the impact on your business can be tough. That's where Cornwall Insight comes in, providing independent and objective expertise. You can ensure your business stays ahead of the game by taking advantage of our:

Insight services
Covering the full breadth of the Irish energy industry, our Insight Services will help you keep pace with the fast moving, complex and multi-faceted markets by collating all the "must-know" developments and breaking-down complex topics.

Market research and insight
Providing you with comprehensive appraisals of the energy landscape helping you track, understand and respond to industry developments; effectively budget for fluctuating costs and charges; and understand the best route to market for your power.

Training, events and forums
From new starters to industry veterans, our training courses will ensure your team has the right knowledge and skills to support your business growth ambitions.

Consultancy
Energy market knowledge and expertise utilised to provide you with a deep insight to help you prove your business strategies are viable.

For more information about us and our services contact us on enquiries@cornwall-insight.com or contact us on +353 1 657 3420.

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2. Executive summary

This report has been prepared by Cornwall Insight Ireland on behalf of RenewableNI, industry body of renewable developers and investors in Northern Ireland. The objective of our analysis is to understand the impact of policy decisions on the Levelised Cost of Energy (LCOE) of renewable electricity technologies and consequently the possible bid prices under a proposed renewable electricity support scheme in Northern Ireland.

The Department for the Economy's (DfE's) primary objective in designing a support scheme for renewable development is to help Northern Ireland reach its 2030 targets of 80% renewable electricity consumption in the overall mix. The measure of success for DfE is in delivering this target at the lowest cost to consumers. A key element in reducing consumer costs is appropriate allocation of risk between investors and other parties. Too much risk on investors will reduce competition and increase bid prices; too little risk on investors will unnecessarily increase risk on consumers. Investors will approach this support scheme with a different set of objectives and success parameters. For developers, it is key to find an investable proposition in their sector, whether that be in Northern Ireland or another jurisdiction, and they will consider their investment successful if they are able to recover costs and make expected profits.

The current investor perception for renewable projects in Northern Ireland is not buoyant, driven by a gap in support schemes promoting renewable assets following closure of the Northern Ireland Renewables Obligation (NIRO) in 2017 and delays in planning and grid connections among others. These factors indicate a lack of policy focus in the renewable energy sector and its growth. Along with some of the design decisions being considered by DfE for the future support scheme, this is causing investor concern around the risks of developing renewable assets in the country. Thus, the support scheme needs to be designed with consideration around how to limit the risk in order to:

Boost investability of renewable projects in NI

Drive down risk premium and thus lower risk inflated bid prices

Reduce consumer cost by placing risk with entities responsible for the risk outturn where possible

We carried out market research, including stakeholder interviews, to understand the specific risks and concerns of developers of renewable assets in Northern Ireland. Seventeen specific risks were identified. We assessed how the impact of mitigating each risk would cause an impact on potential bid prices in a future Northern Ireland renewable electricity support scheme. The key objective of our analysis is to isolate LCOE, and consequently bid price impacts of specific risks, caused by policy decisions and their possible mitigations. Of the seventeen overall risks, we identified six risks that were assessed further in the study, as shown in Figure 1.

Figure 1: Risk factors

Selected for quantitative impact assessment

AGREEMENT LENGTH Period for which a project receives support under the NI support scheme	**INDEXATION** Risk of bid price being exposed to inflation due to not being indexed	**DISPATCH DOWN** Loss of revenue caused by dispatch down due to constraints, curtailment and oversupply
MANDATORY SCHEME Risk of no other routes to market being allowed other than through the support scheme	**GRID CONNECTION** Cost impact due to uncertainties around grid connection approvals and timelines	**PLANNING TIMELINES** Cost impact due to uncertainties around planning timelines and processes

Source: Cornwall Insight analysis

For these six key risk factors, we have carried out analysis including assessing treatment of those risk factors within the Contracts for Difference in Great Britain and the Renewable Electricity Support Scheme in Ireland (both onshore and offshore) to select possible risk mitigations to quantitatively test for impact on a base bid price (base case) where all the risks are present. We tested individual risk mitigations against the base case as well as a scenario where specific risk mitigations have all been applied together.

There are significant savings on the base bid price across all the scenarios, but the highest saving is when multiple mitigations are applied collectively as shown in Figure 2.

Figure 2: Overview of quantitative impact assessment of risk mitigation scenarios shown in terms of % reduction on base bid price

Risks and base case considerations

AGREEMENT LENGTH	INDEXATION	DISPATCH DOWN	MANDATORY SCHEME	PLANNING TIMELINES	GRID CONNECTION	COMBINED RISK MITIGATION SCENARIO
Base case: 15 year fixed-term contract	Base case: No indexation	Base case: No compensation for any dispatch down and grandfathering applied	Base case: Mandatory scheme participation for all assets, no other route to market	Base case: No mitigation exists within support scheme or outside it	Base case: No mitigation exists within support scheme or outside it	All base case arrangements considered in individual risks

% reduction on base bid price due to risk mitigation

AGREEMENT LENGTH	INDEXATION	DISPATCH DOWN	MANDATORY SCHEME	PLANNING TIMELINES	GRID CONNECTION	COMBINED RISK MITIGATION SCENARIO
20 year fixed-term contract -6.8% TO -7.8%	Partial indexation as per RESS 3 -6.4% TO -6.5%	Without grandfathering applied -1.9% TO -8.2%	Scheme not mandatory: Merchant tail exists -3.1% TO -9.5%	Simplified planning -1.8% TO -2.1%	Improved grid connection timelines -1.6% TO -1.9%	• 25 year fixed-term contract • 100% indexed to CPI • Compensation on curtailment and oversupply • Scheme not mandatory: Merchant tail exists and lower WACC • -41.3% to – 46.9%
25 year fixed-term contract -9.6% to -11.1%	Partial indexation as per ORESS 1 -11.1% to -11.2%	Compensation on curtailment and oversupply -10.9% to -22.9%	Scheme not mandatory: Merchant tail exists and lower WACC -6.9% to -14.2%			
	100% indexed to CPI -19.3% to -19.6%	Compensation on all dispatch down -11.2% to -23.6%				

Source: Cornwall Insight analysis

The key individual risks that have the highest impact on driving down the base bid price when mitigated are:

1. Indexation: Both partial indexation as per ORESS 1 methodology as well as 100% indexation against CPI have high impact on the base bid price. However, the difference between 100% indexation and partial indexation (ORESS 1 method) is ~8%, which is significant. Thus, there is a definite benefit to indexing 100% of the bid price as compared to partially indexing it.
2. Dispatch down: Constraints, curtailment, and oversupply: Compensation against dispatch down for just curtailment and oversupply will have almost as high an impact on the base bid price as compensation for all types of dispatch down including constraints.
3. Mandatory scheme: While the loss of merchant revenues is evident for a mandatory scheme, the impact on WACC tying back to the investability of the support scheme will be hard to pin down but may go up to more than what we have accounted for based on market sentiment. A mandatory scheme will add on costs and efforts which may not be recovered though a contract in Northern Ireland in case one is not won.

However, the combined risk mitigation scenario provides the highest savings against base case, even higher than if the Irish or British support scheme risk mitigations were to be applied to the base case, as shown in Figure 3.

Figure 3: Comparative between Ireland, Great Britain and Northern Ireland

Risks and base case considerations

Combined risk mitigation scenario	RESS3/ ORESS1 T&Cs	GB CfD T&Cs
All base case arrangements considered in individual risks	All base case arrangements considered in individual risks	All base case arrangements considered in individual risks

% reduction on base bid price due to risk mitigation

• 25 year fixed-term contract • 100% indexed to CPI • Compensation on curtailment and oversupply • Scheme not mandatory: Merchant tail exists and lower WACC	• 15/20 year fixed-term contract • Partially indexed to various indices • Compensation on curtailment and oversupply • Scheme not mandatory: Merchant tail exists and lower WACC	• 15 year fixed-term contract • 100% indexed to CPI • Compensation on all dispatch down • Scheme not mandatory: Merchant tail exists and lower WACC
-41.3% to – 46.9%	-16.5% to – 35.4%	-28.2% to – 37.8%

Source: Cornwall Insight analysis

Based on our analysis our key recommendations on the six risk areas are as in Figure 4.

Figure 4: Key recommendations

Risk	Recommended mitigation for NI support scheme	Timeline
Agreement length	A longer agreement length will be beneficial, of at least 20 years as mentioned during stakeholder interviews. However, 25 years will be ideal for capital intensive investments, especially offshore wind.	Quick win
Indexation	A 100% indexed bid price will be the most beneficial as it gives an 8% reduction in bid prices in addition to partial indexation. However, at least a partial indexation against related indices as in ORESS 1 is needed.	Quick win
Dispatch down	Compensation for dispatch down for curtailment and oversupply is the most viable, as it is a relatively quick win, and UAEC methodology can be utilised as a starting point to define compensation method. Additional compensation for constraints offers little added benefit and may turn a quick win into a medium-term implementation due to nodal considerations.	Quick win
Mandatory scheme	Making the support scheme mandatory will not only drive up the bid price, but also impact investor interest in the scheme as investors will be left with no option to seek other routes to market if they are unsuccessful in gaining a contract under the support scheme. Even if a contract was to be awarded, the loss of merchant revenues and higher WACC would make the risk difficult to justify.	Quick win
Planning timelines	Bulk of the mitigation for this risk will have to sit outside of the support scheme design. However, an allowance for flexibility in timelines for developers if delays are caused due to DfI's processes without any financial or contractual impact would partially de-risk developers. A middle ground approach may be prudent, under which intent is proven by developers through completed planning applications, acknowledged by DfI with further risk for planning timelines borne by DfI.	Medium to long term
Grid connection	Like planning timelines, a bulk of interventions to ease this risk sits outside of the support scheme design, such as grid expansion plans which look at solar potential along with wind, shortening of approval and connection timelines, etc. However, a provision to allow for delays to grid connection without financial or contractual implications for the developer would lower risk perception.	Quick win to medium term

Source: Cornwall Insight analysis

3. Background

Net zero goals and fast-tracking buildout of green energy portfolios needed to reach those goals is a key area of focus for countries internationally. In 2019, the United Kingdom (UK) became one of the first economies to commit to a 100% reduction in their greenhouse gas emissions by 2050. This signalled a need to drive significant change in Northern Ireland's (NI) energy outlook post the Strategic Energy Framework (SEF) in 2010. Northern Ireland responded by publishing the *Northern Ireland Energy Strategy - the Path to Net Zero Energy*[1] in December 2021, followed by the Climate Change Act (Northern Ireland) 2022 in March 2022[2]. The Climate Change Act (Northern Ireland) 2022 has committed Northern Ireland to reaching net zero by 2050[3], along with phased targets for 2030 and 2040. For the energy sector in particular there is a sectoral target for renewable electricity consumption: **80% of the overall electricity consumption by 2030 must be procured from renewable sources.** DfE has the responsibility for ensuring that this target is met[4].

In 2009, the Renewables Obligation Order (Northern Ireland)[5] was put in place as a part of the UK wide Renewables Obligation (RO). The main support scheme, Northern Ireland Renewables Obligation (NIRO), issued Renewable Obligation Certificates (ROCs) to registered generators, while the obligation to produce ROCs was placed on licenced suppliers for a specified quantity (in MWh) of electricity supplied to final consumers. Generators receive support under NIRO for 20 years from registration or until 2037, whichever is earlier. The NIRO scheme was discontinued for onshore wind on 30 June 2016 and for all other technologies on 31 March 2017. While the introduction of NIRO helped Northern Ireland reach its 2020 target of 40% share of renewable electricity consumption in overall annual electricity consumption[6], capacity addition of renewable electricity to the grid has more or less stagnated after its discontinuance. To take Northern Ireland from the 45.5% share of renewable electricity consumption reported for the year ending June 2023 to 80% by 2030, **a robust government backed support scheme incentivising additional renewable capacity addition is needed.**

In February 2023, DfE published a consultation on design considerations for a renewable electricity support scheme for Northern Ireland[7]. **DfE showed their understanding that it is essential for them to put in place a support scheme to reach their 2030 renewable electricity targets while protecting consumers.** The consultation brought up questions and options around the design of the overall support scheme backed by background research carried out by Cornwall Insight and published in a supporting document[8]. The renewable energy industry has now responded to the consultation and has been in discussions with DfE regarding their position on several design elements for the final support scheme, which is expected to progress during 2024.

In the consultation, DfE has identified the overarching principles that the support scheme is proposed to be designed to achieve, as shown in Figure 5.

[1]https://www.economy-ni.gov.uk/publications/energy-strategy-path-net-zero-energy
[2]https://www.legislation.gov.uk/nia/2022/31/contents/enacted
[3]Baseline for carbon dioxide, methane and nitrous oxide is 1990, and for hydrofluorocarbons, perfluorocarbons, sulphur hexafluoride and nitrogen trifluoride is 1995.
[4]This target is along with the overall responsibility to ensure actions/plans are in place to reach net zero targets for the energy sector for 2030, 2040 and 2050.
[5]https://www.legislation.gov.uk/nisr/2009/154/contents
[6]Target set as per SEF in 2010
[7]https://www.economy-ni.gov.uk/sites/default/files/consultations/economy/consultation-design-considerations-renewable-electricity-support-scheme-ni.pdf
[8]https://www.economy-ni.gov.uk/sites/default/files/consultations/economy/renewable-electricity-support-scheme-consultation-cornwall-insights.pdf

Figure 5: Proposed support scheme principles

Incentivise sufficient renewable electricity generation to ensure that at least 80% of electricity consumption is from renewable sources by 2030

Ensure that consumers pay a fair price for electricity produced locally and that prices are more stable

Encourage a wide range of renewable sources to diversify the technology mix to support security of supply

Source: DfE, Consultation on design considerations of the renewable electricity support scheme, 2023

While the principles identified by DfE are critical and keeping sight of them will ensure that additional renewable capacity is procured at the lowest cost to Northern Ireland energy consumers, it is important to note that boosting the investability of the support scheme to increase competition and achieve the actual targets will also drive down consumer costs. Post NIRO, renewable developers and investors have been investing in markets such as GB, Ireland, and other European countries with support mechanisms in place. Due to its lack of support scheme and poor investment environment, Northern Ireland has not been at the top of their minds for renewable development.

However, just the existence of a support scheme has not been adequate to create a robust investment environment as has been seen in recent support scheme rounds held internationally. In the third round of Renewable Electricity Support Scheme (RESS) in Ireland and Auction Round 5 (AR5) of the Contracts for Difference (CfD) in GB, we have seen high prices and low uptake with some technologies not participating at all. These trends can be tied back to the design of the support schemes, infrastructure support provided, and overall investment environment. Considering the cost pressures, supply chain issues, and overall state of the global economy, it is key that support schemes create an investment environment which lowers risks that developers and investors do not have sight of and cannot control. Failure to do so both reduces the likelihood of meeting decarbonisation goals and increases consumer costs.

Figure 6: Learnings from CfD AR5 and RESS 3

<table>
<tr><th rowspan="2">Support scheme and round</th><th colspan="3">Results</th><th rowspan="2">Our analysis</th></tr>
<tr><th>Technology</th><th>MW</th><th>Strike price</th></tr>
<tr><td rowspan="5">CfD AR5</td><td>Solar PV (>5MW)</td><td>1,928</td><td>£/MWh 47.00</td><td rowspan="5">• AR5 final strike prices higher than AR4 for all technologies
• No offshore wind projects cleared AR5
• Cost pressure compounded with risk of delays in planning and grid connection is causing prices to go up and lower uptake for certain technologies</td></tr>
<tr><td>Onshore Wind (>5MW)</td><td>1,481</td><td>£/MWh 52.29</td></tr>
<tr><td>Remote Island Wind (RIW)</td><td>224</td><td>£/MWh 52.29</td></tr>
<tr><td>Tidal Stream</td><td>53</td><td>£/MWh 198.00</td></tr>
<tr><td>Geothermal</td><td>12</td><td>£/MWh 119.00</td></tr>
<tr><td rowspan="2">RESS 3</td><td>Solar PV</td><td>498</td><td rowspan="2">€/MWh 100.47</td><td rowspan="2">• RESS 3 average strike price for all projects higher than RESS 2
• Low level of uptake as compared to pipeline
• Uncertainties around auction events and their timings, and planning and grid connection resulted in low investment appetite and higher prices</td></tr>
<tr><td>Onshore Wind</td><td>148</td></tr>
</table>

Source: Department for Energy Security and Net Zero and EirGrid

While making design decisions around the new support scheme, considering the direct connection between investability and success, DfE needs to keep in mind the perception around renewable investment in Northern Ireland to date and especially post NIRO.

1. **Northern Ireland's limited capacity potential:** The following factors all limit the future system size of the Norther Irish electricity sector:

   a. Small system size (~7.5 GWh consumed in 2022[9]) with conservative system demand outlook out to 2030 and beyond

   b. No planned and approved interconnectors directly between Northern Ireland and GB or mainland Europe

   c. Constraints on the tie line to Ireland

   d. Delays to and planned capacity of the North-South interconnector

   e. For offshore wind, where it is expected that there will be high potential, the availability of usable seabed limits the potential for build-out.

   All of these factors limit the overall scale of renewable development in Northern Ireland. Developers and investors, especially those without an existing pipeline, may not consider it a lucrative option to divert resources to the country with limited scalability and opportunity without a low perception of risk around that investment driven by a robust support scheme. More broadly, the Inflation Reduction Act is likely to draw capital to the USA and away from Europe. Investors who may have previously considered Northern Ireland as an adjacent market to others in Europe may no longer do so.

[9] https://www.northernireland.gov.uk/articles/electricity-consumption-and-renewable-generation-statistics

2. **Past policy gaps:** GB, Ireland, and other European countries have had continuous support for renewable capacity addition, regardless of whether it is through an auction mechanism or otherwise, creating continuity and predictability in the sector's investment outlook. Conversely, in Northern Ireland the actions taken to date have been more reactive to reach overarching targets, rather than being driven by a long-term focus for the sector. Renewable investments, especially to scale, are a capital and resource heavy investment for investors and the lack of a long-term outlook or commitment may cause them to focus elsewhere.

3. **Short runway to 2030 targets:** We expect final information around scheme design to start being published, at the earliest, by the end of Q4 2023 and details added further out through a large part of 2024. This provides a very short runway of five years or less for projects to secure planning, financing, grid connections, and start supplying to the grid. This timeline is especially challenging for offshore wind which will already be hard pressed to commission a project by 2030 from the current year. Clarity around planning and grid connections will go some way in easing the time pressure, but DfE and other responsible counterparties such as the System Operator Northern Ireland (SONI), Department for Infrastructure (DfI), etc. need to remain cognisant of the time pressure.

All the factors discussed above add on to the perception of risk around renewable electricity investment in Northern Ireland. A perception of high risk will drive up risk premia that the investors will factor in. A higher risk premium directly translates to higher bid prices which are then passed down to the consumer as a cost for supporting renewable capacity addition. Considering the renewable consumption targets for 2030, the support scheme is the key tool that DfE has to lower the risk premium where possible for investors. If implemented appropriately, risk mitigations will lower the overall cost passed onto consumers.

Thus, the support scheme needs to be designed with consideration around how to limit the risk in order to:

- Boost investability of renewable projects in NI
- Drive down risk premium and thus lower risk inflated bid prices
- Reduce consumer cost by placing risk with entities responsible for the risk outturn where possible.

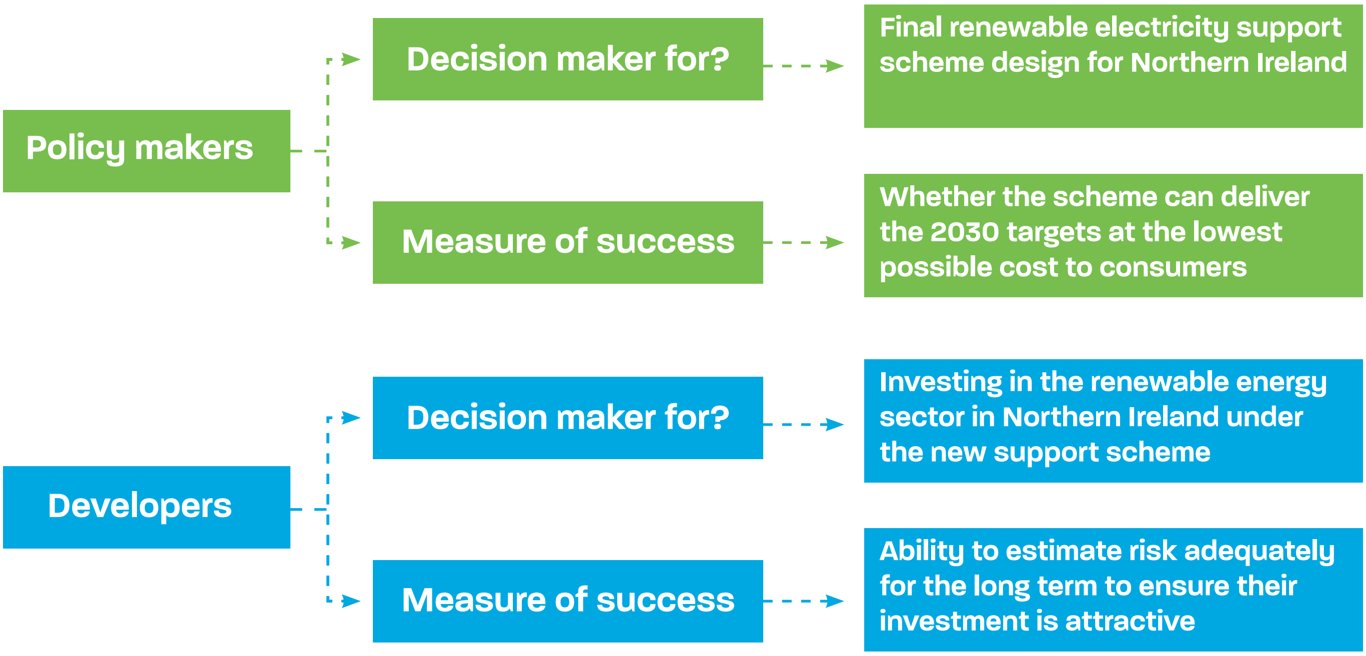
This paper has been written by Cornwall Insight Ireland on behalf of RenewableNI, seeking to build understanding around the impact of policy decisions related to renewable electricity support schemes on renewable electricity bid prices and consequently costs passed down to consumers.

3.1. Objective of this report

The overarching objective of our analysis is to **understand the impact of policy decisions on the Levelised Cost of Energy (LCOE) of renewable electricity technologies,** and consequently the possible bid prices under the support scheme in Northern Ireland.

The premise of this report is that the drivers and decision areas for policy makers and developers (and investors) are different, as shown in Figure 7, and finding middle ground and synergies between the measures of success will result in the optimal outcome for consumers.

Figure 7: Decision areas and outcome concerns for policy makers and developers



Source: Cornwall Insight analysis

The methodology we have used in the study behind this report is:

1. Building an understanding of risk factors for renewable development in Northern Ireland

To understand the risks faced by renewable project developers, we conducted stakeholder interviews with members of RenewableNI across renewable technologies, namely solar, onshore wind and offshore wind. The stakeholder interviews were used to understand:

- The risk factors which would likely impact LCOE both within the support scheme design and in the overall investment environment in Northern's Ireland renewable sector
- Specific concerns with aspects of the support scheme consultation from DfE
- Possible ways the risk factors mentioned can be mitigated through the support scheme which will drive down LCOE and therefore bid prices
- Learnings from schemes in other jurisdictions
- Key factors in the design of the support scheme which will drive investment decision for developers and impact success of the scheme

The learnings from these conversations and our understanding of DfE's priorities have then been used to arrive at a final list of risks that DfE can consider addressing within the overall support scheme design to improve its investability, drive down bid prices, and consequently consumer costs.

2. Drawing from lessons in comparable jurisdictions

We have looked at the considerations made by DfE within their support scheme consultation and the methodology through which GB and Ireland have addressed the risks identified in the previous step of the study. This analysis will be used to inform the possible risk mitigation methods tested through quantitative analysis.

3. Quantitative assessment of risks identified

Drawing from our conversations with stakeholders and research of comparable jurisdictions we have identified possible treatments within the support scheme for each of the risk factors identified. The impact on bid price for each possible treatment has been assessed individually using our Bid Price Calculator. In addition, we have looked at a best-case scenario of multiple risk mitigation measures around key risks identified being applied at the same time for each technology type considered. We have looked at solar PV, onshore wind, offshore wind (fixed), and offshore wind (floating) as separate technology types. The objective of this exercise is to understand the risk mitigation measures which will have the highest savings for consumers by driving the bid price down the most.

4. Understanding key learnings

The learning we arrive at in the conclusion of this study identifies the risk mitigation with the highest bid price impact, the counterparties that will have to be involved to implement measures, and the considerations for implementation.

4. Understanding risk factors for renewable development in Northern Ireland

We conducted interviews with 11 stakeholders spanning solar, onshore wind, and offshore wind technologies to inform this study. The focus of the discussions was to understand:

1. Their perceived overall risks of developing a renewable project in Northern Ireland
2. Risks that would drive up their risk premium and LCOE, and consequently would impact their bid prices under the Northern Ireland support scheme

In addition to the stakeholder conversations, we have also carried out desktop research to understand typical risks faced by renewable electricity developers participating in a support scheme. For each risk flagged during stakeholder conversations and our research we have identified whether risks can be addressed within and/or outside the support scheme.

The following table provides an overview of the identified risks.

Figure 8: Overview of identified risks

Risk Factor	Definition of risk	Addressed within scheme	Addressed outside scheme	Risk category
Auction setup	Overall auction set up, uncertainties around it, and design aspects that places risk on the developer during the auction and the lifetime of the asset.	✓	✗	• Counterparty • Auction • Operational • Financial
Agreement length	Period for which a project receives support under the scheme. Shorter term increases merchant exposure after the end of the term.	✓	✗	• Auction • Operational • Financial
Indexation	Indexation is applied to strike prices to adjust income payments by means of a price index in order to maintain the purchasing power after inflation. Without indexation renewable developers will need to include an adjustment for assumed future indexation in their bid price and an associated risk premium.	✓	✗	• Auction • Financial
Dispatch down due to constraints, curtailment, and oversupply	The risk of loss of revenue if the asset is dispatched down due to system constraints, curtailment or oversupply, and no compensation methodology exists to make up for the revenue loss.	✓	✓	• Counterparty • Operational • Financial
Mandatory scheme	A mandatory scheme would imply that developers do not have any other route to market other than under this support scheme. Therefore, they will have to bear the risk of recovering all costs and revenue expectations within the term of the support period. They will also have to bear the cost of a sunk investment if they do not win a contract under this support scheme after planning an asset.	✓	✗	• Auction • Operational • Financial
Planning timelines	Delays in planning process increases the risk of additional capex expenditure for the extension in timeline.	✓	✓	• Counterparty • Auction • Operational • Financial
Grid connection	Grid development not being planned in appropriate locations for all technologies increases the risk of developing certain technologies. Delays in obtaining grid connections drives up capex.	✓	✓	• Counterparty • Auction • Operational • Financial
Pot structure[10] / technology split	The structure of technology specific volume carve outs within a single auction round can impact the risk for technologies which are nascent or more expensive but do not have a separate pot.	✓	✗	• Auction
Floating milestones	Non-firm milestones for developers can decrease risk by adding flexibility for delays at their end.	✓	✓	• Counterparty • Auction • Financial

[10] Pot structures have been used both in the Irish RESS and GB CfD. A pot is created within an auction round where a specific capacity within that auction round is allocated for procuring a specific technology. This tool is used to drive uptake in a new, perhaps more expensive technology or to achieve a particular technology mix which may be beneficial to the overall electricity mix of that country.

Risk Factor	Definition of risk	Addressed within scheme	Addressed outside scheme	Risk category
Land / Seabed availability	Limited seabed availability for offshore projects and lack of appropriate land availability for certain technologies can add to risk	✗	✗	• Counterparty • Operational
Minimum capacity 1-5 MW	A minimum requirement of 1-5 MW to qualify for participation in the support scheme will increase the risk of a viable route to market for smaller assets.	✓	✗	• Counterparty • Auction • Financial
Non price factors (NPF)	Factors such as carbon reduction rates, supply chain impacts, community contributions, etc, included in the evaluation process can help improve differentiation within bids. This can reduce the risk to certain developers by allowing them to put in a stronger bid with defined parameters, provided NPFs are within developers' control and the associated evaluation methodologies are clearly defined and transparently implemented.	✓	✓	• Auction • Operational
Transport	Risk of the current port infrastructure for offshore technologies possibly not being capable of leading to buildout at scale in its current form.	✗	✓	• Counterparty • Operational • Financial
Setback distances and tip height	Wind generator specific risk. Current tip height restrictions and setback distances are limiting the efficiency of projects as tip heights of turbines that are being produced are higher than the current cap in NI, increasing the supply chain related risks.	✗	✓	• Counterparty • Operational • Financial
Shortage of skills	Risk of not being able to access appropriate skills needed to build renewable assets to scale as local talent needs to be upskilled to provide support for the scale of generation being planned and the timelines within which they are being planned.	✗	✓	• Operational
Supply chain	Global supply chains are strained and add cost and uncertainty around the build out of renewable projects.	✗	✓	• Counterparty • Operational • Financial

Source: Cornwall Insight analysis

4.1. Risk analysis

While some risks sit firmly outside the design structure of the support scheme, it is important to understand the nuances of those that can be addressed fully or partially through the support scheme. This section of the report looks at the risk factors, highlighted in Figure 8, that could potentially be addressed through the support scheme, under the following areas of assessment:

- Detailed description of the risk faced by stakeholders (developers/investors).
- Who can manage the risk and to what extent.
- Will there be an LCOE and consequently bid price impact of mitigating the risk.

4.1.1. Auction setup

Stakeholders flagged that the overall set-up of the support scheme and then the auction rounds are key to ensure success. For example, in RESS 3, amongst other reasons, auction set up and timings were a cause for low uptake as the auction cap was released after the date for withdrawal of bid. It is necessary to have high levels of competition to drive prices down, and low participation translated to higher price discovery. DfE can learn lessons from its neighbouring jurisdictions to understand what would encourage competition and what discourages competition and participation.

DfE will be responsible for understanding the risks attached to design decisions and should continue to engage with industry in order to know the possible implications of the decisions that they are making. Ultimately, once decisions are made, the risk burden passes on to the developer and its compounded effect will be reflected in levels of participation and bid prices.

4.1.2. Agreement length

Most stakeholders interviewed were of the opinion that longer contracts would be more beneficial. 15 to 20 years was the period of support that was mentioned by most stakeholders, which is in line with RESS and CfD. Offshore wind developers in particular were more comfortable with a 20 year support period. During a specific stakeholder interview, it was mentioned that a contract supporting the asset over its lifetime might prove to be beneficial as well. We believe that if DfE is minded to include a mandatory requirement within the support scheme then a support term covering the lifetime of the asset would be the option which mitigates some of the risk.

DfE will be making the decision regarding contract length. Depending on the agreement length, investors will calculate their bid price differently. A shorter support period will necessitate that the developer/investor recovers their cost over a shorter period with a burden on sharper market volatility. While a longer period allows the asset to ride out market cycles, spread their risk, and recover their costs over a longer period. This decision is key as the outcome of this burden will not only be felt by developers/investors but ultimately by the consumers as well.

4.1.3. Indexation

Across the stakeholders, indexation of some kind was raised as necessary. Many cited the CfD with its 100% indexation as being best practice, admitting that any indexation would at least encourage investment and minimise risk, taking the view that there would be no reason to deviate from the CfD method. It was noted that with partial indexation, developers would be able to shoulder some of the risk associated with inflation, but this would not be possible if there was no indexation at all. Another point raised was the added importance of indexation if the scheme is mandatory, as it would be the only revenue option for developers. If there is nothing in place to support developers with indexation there will be a much greater risk factor, and therefore the subsequent bid price would have to be increased.

The level of risk will be determined by DfE based on their decision regarding the level of indexation in the scheme. However, the risk itself will be on the developers; for example, if DfE decides not to index payments, then there would be a much greater risk to developers. It is therefore up to DfE to manage this risk for developers to ensure a competitive auction at a strike price that developers have not had to build a large risk factor into.

4.1.4. Dispatch down due to constraints, curtailment, and oversupply

The common view of stakeholders with regard to constraints, curtailment, and oversupply was that the biggest factor that would affect the success of the scheme was certainty around compensation. The way this certainty can be offered by DfE and mitigate the risk to developers/investors is through specific payments made to generators during periods of dispatch down. One of the stakeholders cited the importance of having certainty over payments for dispatch down periods such as the 'Unrealised Available Energy Compensation' (UAEC), as it is termed in Ireland's RESS. A mechanism such as this is also present in the CfD and was deemed important across the stakeholders in Northern Ireland, particularly as dispatch down levels as a percentage are in double digits in Northern Ireland[11]. The impact of constraints and curtailment is also expected to be compounded in Northern Ireland due to the impact of grandfathering, where older assets under NIRO with priority dispatch will be dispatched down last while new assets without priority dispatch will be dispatched down first[12]. However, the opinion on grandfathering of assets differs amongst stakeholders, with some stakeholders being wary of the levels of dispatch down with grandfathering applied and some pushing this further down their list of concerns. The other risk mentioned by stakeholders when discussing constraints, curtailment, and oversupply were grid related issues. Specific topics that were cited were the need for a North-South interconnector to be built, allowing for hybrid sites within the scheme, and general investment into grid infrastructure.

The TSO manage dispatch down on the Northern Ireland electricity system for curtailment, constraint, and oversupply reasons. Dispatch down is needed in case of system requirements such as crossing the System Non-Synchronous Penetration (SNSP) levels (termed as curtailment) when supply outstrips demand on the system (oversupply) and when there is network congestion (constraints). Whether or not dispatch down is compensated for can be defined within the support scheme terms and conditions that DfE will be defining. It should be noted that renewable developers in Northern Ireland will face a higher level of dispatch down, as per current levels, than developers in Ireland or GB.

[11]Source: SONI, EirGrid; Annual Renewable Energy Constraint and Curtailment Report 2022
[12]European Commission's Clean Energy Package; ACER, European Regulators White Paper on Renewables in the Wholesale Market

4.1.5. Mandatory scheme

Stakeholders were all in agreement that a mandatory scheme would severely restrict developers, due to the limited options for a route to market, and therefore believe that the scheme should not be mandatory. The overarching theme across the interviews is that by making the scheme mandatory, developers run the risk of incurring all of the costs to plan a project only to then be unsuccessful in a bid for participation in the scheme. It was highlighted that the sunk costs of developing a project in order to be ready for auction bid, could only be recovered in a mandatory scheme in the event of a successful bid as it is the only route to market. Stakeholders suggested that by imposing a mandatory scheme, developers will be inclined to only develop and plan a project to the minimum standard, to reduce the costs, thus limiting their risk.

Many of the stakeholders highlighted the importance of having the option for developers of new renewable projects to be able to pursue merchant Power Purchase Agreements (PPA) or Corporate Power Purchase Agreements (CPPA) as an alternative route to market. One of the stakeholders interviewed also noted that they had not realised how seriously a mandatory scheme was being considered and reiterated the importance of maintaining multiple route to market options. Another theme brought up from the stakeholders was the risk a mandatory scheme poses to reaching overall renewable generation targets. The discussed risks associated with a mandatory scheme may put developers off new renewable generation projects. This could significantly limit competition within the auction, making reaching the Northern Ireland renewable targets more challenging.

The decision taken by DfE on whether to make the scheme mandatory is what will determine the level of risk to the developers. In a mandatory scheme, developers would then have to incur the risk of losing out on the associate planning costs and not having any other routes to market. If DfE's decision is to make the scheme mandatory, then there is a higher risk to developers which will be factored into development costs and may lead to a lower standard of planning renewable assets.

4.1.6. Planning timelines

Planning timelines and processes, and the risks attached, was at the forefront of considerations for all developers[13]. From recent experience, developers are facing longer than traditional planning timelines. In addition, planning policy is taking a long time to be enacted and commercial opportunities are being lost with time-sensitive investors. Timing is a key aspect of planning, with delays leading to increased costs and higher risk sensitive investment rates. Having that understanding of upcoming policy elements and how these tie in with local planning designs form an important part of these timing elements, especially beyond 2030. Some stakeholders are of a view that planning at a policy level should be re-centralised, as due to being decentralised it is under-resourced with not enough planners at present. Overall, stakeholders are of the opinion that planning timelines are too long causing significant cost implications for developers who have projects on hold within the planning process. The respondents are therefore concerned that there is a mismatch between DfE and DfI in terms of planning and communication and realising 2030 and 2050 goals. Outside of the support scheme, certainty is necessary around the development of timelines around planning, with the need for definitive timelines and key performance indicators (KPI) on authorities.

There is a planning related stipulation that causes a design conundrum for onshore wind and solar assets. This was specifically mentioned by solar developers during stakeholder engagement discussions as this conundrum impacts them significantly. Assets below 30MW must apply to the local authority for planning permission whilst those 30MW and above must apply to DfI. The latter takes 1-2 years longer to make a determination than the local authority. If a developer chooses to wait for approval through DfI, another asset developer could capture grid capacity at the same 33kW substation, by building an asset of up to 29.9MW and obtaining planning permits from the local authority. However, a 33kW substation can accommodate upwards of 45MW, which implies that a 29.9MW asset will be utilising ~66% of the grid asset's capacity. In addition to underutilised grid infrastructure, the developers also have to face a higher cost burden for a 29.9MW asset as the cost of the cable will remain fixed. As per the stakeholder, this rule was introduced at a time when it was not conceived that technology would be as good as it is now ie, more MW on a smaller land area. This rule is therefore creating a choice between choosing a 29.9MW asset with a higher LCOE which is underutilising the grid, or risk the longer planning application timelines but have a more efficient project in the end. Amendments and standardisation in planning processes could solve this issue.

Developers have very little visibility of timelines, and the risk is managed by authorities in charge of creating planning guidelines and providing planning approvals. The onus of de-risking the planning process is entirely on government bodies and planning authorities. However, a review of this process, simplifying planning processes, and providing certainty around timelines will go a long way towards alleviating this risk and reduce cost pressures caused by uncertainty. If planning cannot be adequately simplified through the support scheme, flexibility around longstop dates and deadlines for developers tying back to planning delays may go some way towards easing the risk; however, it will not directly impact the cost that will need to be borne due to delays.

[13] RenewableNI, KPMG; Accelerating Renewables in Northern Ireland, 2023

4.1.7. Grid connection

Grid and planning issues are correlated, to an extent. The stakeholders identified a number of concerns regarding grid connection, predominantly citing planning and regulatory issues surrounding grid connections rather than the physical grid connections. Stakeholders also cited that to improve efficiency of timelines and the grid connection itself, the ability to co-locate assets within the scheme would be beneficial. A stakeholder developing solar projects mentioned that grid developments were being carried out predominantly in areas with high wind potential rather than looking at developing in areas conducive to a wider spread of technologies. In addition, the socialisation of grid costs and the need for reform around connections' pricing has been mentioned as an issue which is top of mind for renewable developers. They believe that socialisation of costs for grid connections across all generators would be beneficial across the board, as it would not put the risk burden along with a risk premium on a single generator.

EirGrid and SONI Ltd are responsible for the transmission development plans and need to look into development which is more technology inclusive and where capacity and timelines are in line with 2030 targets.

4.1.8. Pot structure/ technology split

Stakeholders had a clear view that there would have to be some form of pot structure, and not have all technologies in one pot for the auction design. Different stakeholders mentioned various but specific ideas on the technology split between pots, with most individual stakeholders just identifying two technologies that they believed should be in separate pots, rather than a complete view on the pot structures required for the scheme. It was noted that having solar in the same pot as onshore wind wouldn't be considered viable in Northern Ireland given that onshore wind makes up ~85% of the current renewable consumption share. Another stakeholder raised their desire for fixed offshore wind to have a standalone pot that does not include floating offshore wind, as prices have not yet merged for both. It was also noted that a separate pot for hybrid/co-located assets may be useful. Overall, there was no clear preferred pot structure set out by any stakeholder. However, there was a strong consensus that some form of pot structure will be required, with the successful pot structure approach in RESS and CfD being cited as something to build upon.

The decision regarding pot structures lies within DfE's auction design decision. The impact of the decision will be felt in the split between the technologies that emerge in the auction allocation or auction rounds. However, an inefficient pot structure or the lack of a pot structure may result in an inefficient generation mix and certain technologies not being built out in Northern Ireland.

4.1.9. Floating milestones

Floating milestones were mentioned by a small number of stakeholders, however those who mentioned it felt strongly about it. It follows the concept adopted in Ireland's Offshore RESS (ORESS) scheme, whereby there is some flexibility for dates of key project milestones to account for unpredictable delays, commonly in the supply chain. Floating milestones were cited as a positive as it allows developers more flexibility, with the suggestion that they should be considered by DfE. Especially in the case of the NI support scheme, the emphasis is on the role of floating milestones to account for grid and planning delays to move those risks away from developers as they can neither predict nor control.

The design decision lies with DfE, however the risk of achieving milestones lies with the developers during the asset build out and operation.

4.1.10. Land / seabed availability

Seabed availability in Northern Ireland was seen as very limited by all the offshore wind developers interviewed, and potentially a significant consideration for DfE. The stakeholders recognised that the very limited seabed availability would likely be filled within one or two rounds of auction, and therefore an auction process similar to the CfD would not be suitable for offshore wind. One stakeholder mentioned that there is growing demand for land for the purpose of solar farms, however this was not a common theme.

Land allocation will have to be managed by DfE, especially around the limited seabed, similar to the seabed auctions in GB and the Maritime Area Consent (MAC) processes in Ireland. The design that is proposed for allocation of seabed needs to be fit for purpose and the support scheme needs to tie into the leasing process whether the latter is auction based or award based.

4.1.11. Minimum capacity 1-5 MW

The decision around inclusion of smaller scale solar and onshore wind projects was discussed by a small number of stakeholders. Some were of the opinion that they should be included within the support scheme with a separate pot or evaluation criteria, and some thought any consideration whether within this support scheme or another subsidiary scheme would be beneficial. However, the option of not having any support mechanism was not considered efficient, as especially solar projects in NI would find interest under this category.

The design decision is DfE's, regarding the inclusion of small-scale assets within the support scheme and overall interest and uptake for these assets would depend on this decision.

4.1.12. Non price factors (NPF)

Some stakeholders mentioned that including NPFs, such as community contribution might add a layer onto the evaluation process which may be advantageous to some developers who are already considering inclusion of these factors for their projects, in line with requirements in other jurisdictions. Stakeholders have also pointed out that NPFs may be better suited for inclusion as a qualification criteria rather than an award criteria. This may align with the DfE's requirement that the scheme ensures that this benefit gets passed onto vulnerable customers. However, it should be noted that while such a criterion may benefit some of the larger developers who are already making similar considerations for NPFs across other jurisdictions they operate in may extend those to NI, it may not be advantageous to other developers who are not already providing NPFs in this fashion in other jurisdictions.

The risk of including NPFs in their asset planning would fall on developers and would be choice based in most instances. However, the setting and designing of these NPF requirements would be DfE's responsibility. Considering the timelines available to procure capacity for their 2030 targets and the subjectivity around designing NPFs requirements, this factor may not be one which is high on the DfE's list of inclusions for the initial round(s) of the support scheme.

4.1.13. Transport

Some stakeholders mentioned that the transport of parts and machinery was a risk in Northern Ireland due to underdeveloped road and port infrastructure.

DfI is responsible for overall road and port infrastructure development and will also be responsible for managing this risk. DfE should flag possible bottlenecks for renewable asset development to ensure that they are upgraded in line with requirements to meet the national renewable target.

4.1.14. Setback distances and tip height

A number of stakeholders highlighted that there should be increased flexibility in tip height of turbines. In Northern Ireland, it is currently difficult to get permission for a turbine with a tip height of above 150m. However, it is the view of a stakeholder that this should be in line with other nations at around 200m to allow developers to obtain the necessary technology at the least cost. Setback distances were mentioned by one stakeholder, stating they would likely have to be over 500m in order to achieve overall set back targets. Permitting increased tip heights will allow the developer to procure optimal and most efficient turbines at the lowest cost, thus reducing the cost to consumers of adding the overall capacity. The risk of the stipulation around setback distances and tip height is managed by the developer.

4.1.15. Shortage of skills

One stakeholder highlighted a lack of skills, in particular engineering for renewable assets within Northern Ireland, along with lack of resources for policy development and implementation.

The risk is managed outside the developer's purview, but to an extent can be managed by policy makers especially in terms of policy development and implementation.

4.1.16. Supply chain

There was some mention of supply chain issues from the stakeholders. The risks that were implied by stakeholders were comments on limitations on the size of the supply chain, and the potential for there to be delays within the supply chain. This concern was closely linked to the fact that there should be floating milestones in order to allow for these potential delays. This issue is not specific to Northern Ireland.

The risk is managed by the developers during asset planning and build-out stages.

4.2. Key risk factors

We assessed the risks and ranked them using a decision tree to arrive at the final risks factors to be considered through the remainder of the study. We used the decision tree to assess the seventeen risk factors against three criteria, and assigned them a score between one to three as follows:

1. Risk was identified during stakeholder engagement conversations: A score of three to a risk factor if it was identified by all the stakeholders interviewed. A score of two was assigned if more than three stakeholders identified a risk factor. A score of 1 was assigned if less than three stakeholders identified the risk factor.

2. Inclusion of risk mitigation within the support scheme in the GB CfD and Irish RESS: A score of three was assigned if the risk factor was fully mitigated in both or either GB or Ireland. A score of two was assigned if the risk factor was partially mitigated in both or either GB or Ireland. A score of one was assigned if the risk was not mitigated in either GB or Ireland.

3. Can it be included in the support scheme as a risk mitigation that has an impact on bid price: A score of three was assigned if the risk factor could be fully mitigated within the support scheme design. A score of two was assigned if the risk factor could be partially mitigated within the support scheme design. A score of one was assigned if the risk factor could not be mitigated within the support scheme design.

After scoring the risk factors based on the individual decision criteria, a risk factor receiving a cumulative score of between seven and nine was selected for further consideration.

The methodology analysis for selection of risks is detailed in Appendix 1 of this report. After the risk assessment, the final key risks that we will be studying and analysing through the rest of this report are:

1. Agreement length

2. Indexation

3. Dispatch down: Constraints, curtailment, and oversupply

4. Mandatory scheme

5. Planning timelines

6. Grid connection

5. Lessons from comparable jurisdictions

After arriving at the final risk factors that we will focus on for the rest of this study, we studied the terms and conditions (T&Cs) put in place for these factors within the GB CfD scheme and the Irish RESS and ORESS schemes. The risk treatment in these comparable support schemes have been used to inform the risk mitigation methodologies tested through quantitative analysis in this study.

5.1. Agreement length

5.1.1. How it is addressed in DfE's consultation

DfE's proposed support scheme acknowledges that length of the contracts will impact bidding strategies, investor confidence, and scheme costs. Numerous options have been considered within the consultation:

- **Payments based on the lifetime of the asset:** A longer contract than a standard CfD would see lower contract payments while providing the generator more certainty of return and less risk, alongside long-term price stability for the consumer. It may be difficult to determine the life of an asset, however a review or reopener provision in the contract could enable lifetime changes to be considered in the contract price.
- **Fixed agreement length:** This reduces administrative risk and lowers the cost to consumers the longer the pre-decided term is. However, it does not remove the uncertainty in revenues faced by investors at the end of the contract during the merchant tail.
- **Requiring the agreement length to be submitted by the applicant:** Competition between other applicants would reduce costs for consumers, however this requires careful estimation and can increase the risk of non-delivery.

Figure 9: Highlights from other jurisdictions

Country	Risk mitigation exists within support scheme?	Method of mitigation
GB	✓	Contracts have a fixed length of 15-years.
Ireland	✓	RESS 3 and ORESS 1 both offer fixed-term contracts. 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. ORESS 1 projects can get support for up to 20 years.
NI	✓	Three options are being considered in the consultation for support scheme design. All provide long term support for the renewable asset, however the exact methodology for arriving at the term of support has not been identified yet.

Source: Cornwall Insight market research

5.1.2. Case study on GB

A fixed term support of 15 years is provided to successful developers under the CfD. No extra support is given if the actual start date for the contract is earlier than the planned start date. However, developers can bring the planned start date forward to eliminate any wholesale market volatility risk. Alternatively, developers can enter the wholesale market without support until the CfD contract commences on the original planned start date.

Developers can also delay the start date of the contract if there are credible unforeseen delays and construction hold-ups. However, as of AR5, once a generator is operational the start date must be no later than 10 business days to prevent a generator capitalizing on short-term high wholesale energy prices before activating their CfD.

5.1.3. Case study on Ireland

All RESS and ORESS auctions to date offer a fixed-term contract with some caveats where a specific end date is identified in which the auctions support will cease. The support end date is fixed but can be extended by one year if the project experiences delay due to Force Majeure. The start date of the support is not fixed however and is dependent on when the project becomes commercially operational or when the TSO issues an Interim Operational Notification (ION). The ION is a notice provided by the system operator to generators, permitting them to temporarily operate and conduct compliance tests using the grid connection. Therefore, the contract's term can vary from project to project.

For example, in RESS 3, the support end date for a successful project is 30 April 2041 (subject to extension due to Force Majeure). The support start date begins 90 days after the project's ION is issued or when the project becomes commercially operational, whichever of the two occurs first.

If there are no delays to either of the processes and a project is eligible to receive payments from 2024 to the support end date (2041), then it will receive support for 16.5 years.

However, this process can be delayed up until the longstop date, which is 30 April 2027. Therefore, the minimum support term a project can achieve is 14 years.

The ORESS 1 auction support begins when the project becomes commercially operational and ends the earliest of either; 20 years after the target commercial operation date (the date which falls 60 months after the Planning Consent Date), or 20 years after the support start date (which is the date the project becomes commercially operational subject to the ORESS 1 T&Cs).

Therefore, if a project misses their target commercial operation date, their support term can be shortened. The longstop date for ORESS is 31 December 2031, so the minimum support term for a project in ORESS is 12 years. If a project does not achieve commercial operation by the longstop date, it will no longer be eligible for ORESS payments.

If a project achieves commercial operation earlier than their target commercial operation date, their contract term is fixed to 20 years and not extended. Similarly, if a project becomes operational on their target commercial operation date, they will receive support for 20 years.

5.2. Indexation

5.2.1. How it is addressed in DfE's consultation

DfE's consultation acknowledges that "a second major factor determining investor confidence will be the mechanism by which prices are adjusted throughout the life of the support scheme". It considers the treatment of indexation in various jurisdictions where strike prices are not indexed to inflation, partially indexed to inflation, or fully indexed to inflation using the consumer price index or other related indices such as the steel index, labour index, etc. It queries whether strike prices should be indexed in Northern Ireland, based on the examples available.

Figure 10: Highlights from other jurisdictions

Country	Risk mitigation exists within support scheme?	Method of mitigation
GB	✓	Bid prices are **100% indexed** against consumer price index **(CPI).**
Ireland	✓	Bid prices are **partially indexed** for both RESS and ORESS. For ORESS, bid prices were indexed partially to both the **steel index** and the Harmonised Index of Consumer Prices (HICP), and for RESS 3, **30% of the strike price** was indexed to the **HICP**.
NI	✓	The consultation for support scheme design is considering indexation but has **not specified that it will definitely include some form of indexation.**

Source: Cornwall Insight market research

5.2.2. Case study on GB

The strike price is adjusted to inflation on 1 April (1st day of the Summer Season) each year based on January's CPI rate. If this has not been published, then the most recently published CPI rate is used instead. The generator should be notified of this strike price adjustment no later than 5 business days after the 1 April.

5.2.3. Case study on Ireland

In previous auctions (RESS 1 & 2), indexation was not accounted for. In RESS 3, 30% of the strike price was indexed to the harmonised index of consumer prices (HICP), which is a measure of inflation that is comparable across 27 EU countries. The calculation for indexation in RESS 3 is as follows, and will be adjusted annually:

$$\text{Indexed price} = \text{Strike price} \times \left(0.70 + \left(\frac{\text{HICP rate at year of auction}}{\text{HICP rate at year of compensation}} \times 0.30\right)\right)$$

For ORESS 1 there are three calculations for adjusting the strike price to account for indexation. The first occurs 45 days after the support begins and is referred to as the 'Indexation Date (Commencement)'. This is indexed at 10% of the "Steel Index" – Platts TSI North European Plate and 30% of the HICP. This calculation uses the "Max" function to account for the possibility of the difference between the HICP at the time of the bid and the HICP at the time of the adjustment being negative ie, if inflation goes down, the strike price will remain the same and not be reduced.

$$\text{Indexed price (Commencement)} =$$

$$\text{Strike price} \times \left(\frac{\text{Steel index at time of adjustment}}{\text{Steel index at time of bid}} \times 0.10 \right.$$

$$+ \text{Max} \left(\frac{\text{HICP rate at year of auction}}{\text{HICP rate at year of compensation}}, 1 \right) \times 0.60 +$$

$$\left. \frac{\text{HICP rate at year of auction}}{\text{HICP rate at year of compensation}} \times 0.30 \right)$$

The second adjustment occurs on January 1 after the auction and is referred to as the 'Indexation Date (Interim)'. This calculation is the same as the one that is used in RESS 3, where 30% of the strike price is indexed to the HICP.

The final calculation adjustment, referred to as the 'Indexation date (Annual)' occurs every January 1 after the Indexation date (Interim), until the support ceases, its calculation is as follows:

$$\text{Indexed price} = \text{Strike price of the previous year}$$

$$\times \left(0.70 + \left(\frac{\text{HICP rate at year of adjustment}}{\text{HICP rate of the previous year}} \times 0.30 \right) \right)$$

5.3. Dispatch down: Constraints, curtailment, and oversupply

5.3.1. How it is addressed in DfE's consultation

Dispatch down is not specifically addressed in DfE's consultation. It is, however, mentioned that generators/developers engaging in the Balancing Market (BM) will not be able to earn revenue above the subsidy payment.

Figure 11: Highlights from other jurisdictions

Country	Risk mitigation exists within support scheme?	Method of mitigation
GB	✓	Dispatch down payments are made to the generator **annually** from the Low Carbon Contracts Company (LCCC) based on **QCPC** report.
Ireland	✓	Curtailment and oversupply are **compensated** in **RESS 3 and ORESS 1** by the Unrealised Available Energy Compensation **(UAEC)** payments.
NI	✗	Compensation for dispatch down has not been brought up as a consideration under the consultation for support scheme design.

Source: Cornwall Insight market research

5.3.2. Case study on GB

As a result of any dispatch down by the Electricity System Operator (ESO) to a CfD unit, the LCCC makes a payment to the generator, mitigating any financial loses they would otherwise have faced. The CfD unit must submit a report annually, containing key information on each qualifying curtailment or partial curtailment event within the contract year. This report is the Preliminary Annual QCPC[14] and must be submitted to the LCCC within three months of the end of each contract year, which ends 31st of December every year. Within 15 days of the report being submitted the LCCC and the generator must meet and agree upon the Preliminary Annual QPCP report. If this is not done, the generator is not entitled to any payment for the dispatch down periods from the LCCC. Once agreed upon, the curtailment payment is made by the LCCC to the generator. This can be done as a lump sum or in staged payments depending on the agreement and can be made on any day following the date at which the Preliminary Annual QCPC report becomes the Annual QPCP report.

The ESO will only issue qualifying dispatch down orders in order to manage the balance of the grid, all of which is done using the Balancing Settlement Code (BSC), which is managed by Elexon. The CfD T&Cs offer extra protection for generators by still paying them at the agreed strike price during any period of curtailment. Curtailment is considered in the T&Cs to be any period in which the grid ESO limit the output of the CfD unit, which therefore includes constraint to the network and turning down as a result of oversupply. Constraint can also be considered within the curtailment payments if any new constraint occurs due to a change in the law that does not act to minimise costs.

[14] Qualifying Curtailment and/or Qualifying Partial Curtailment

5.3.3. Case study on Ireland

The Unrealised Available Energy Compensation (UAEC) was introduced into RESS 3 and ORESS 1 which replaced the "Curtailment Compensation Arrangements" in the previous RESS auctions.

The UAEC compensates projects that are made unavailable due to curtailment or oversupply but does not cover constraints due to location factors like network constraints.

UAEC payments are a €/MWh amount in respect to an hour and is calculated as follows:

UAEC payment=(Unrealised Available Energy ×strike price)

-Other compensation for unrealised available energy outside of RESS

Where the "Unrealised Available Energy" is the energy that was not generated, it is calculated as the difference between the Loss-Adjusted Eligible Available Quantity, and the Loss-Adjusted RESS Metered Quantity in that specific hour. Eligible available quantity is defined as the amount of energy a project is eligible to generate in an hour, based on its "physical availability" which is a measure of the project's availability to produce active power. Eligible available quantity is exclusive of unavailability due to forced and planned outages, network constraints, and local stability constraints. However, UAEC is also linked to firmness of the assets connection, because of this it was found to be more beneficial for offshore wind assets where a firm connection is a certainty once the offshore wind farm is operational, as compared to onshore wind and solar assets. This may have contributed to the lower bid prices seen in ORESS 1 compared to RESS 3.

5.4. Mandatory scheme

5.4.1. How it is addressed in DfE's consultation

DfE's consultation considers the benefits of making the support scheme mandatory versus leaving it voluntary for generators. The reasoning behind considering a mandatory scheme is to have a cohesive energy market with consumers paying a fair and consistent price for locally produced renewable generation. However, within the consultation DfE seems to be approaching this consideration from their mandate to provide long-term, stable, and fair prices to NI consumers without trying to understand the investability considerations which will encourage new capacity to build under this scheme.

Figure 12: Highlights from other jurisdictions

Country	Risk mitigation exists within support scheme?	Method of mitigation
GB	✓	GB CfD is **not a mandatory scheme**
Ireland	✓	**ORESS is not a mandatory scheme.** Unsuccessful applicants in **ORESS 1** cannot bid into the next round as it will be location specific with the introduction of Designated Maritime Area Plans (DMAPs), unless their project is still within the next auction's DMAP, but they can become a **merchant project** via a **CPPA**. **RESS 3** is **not** a mandatory scheme, unsuccessful projects can bid into the next auction round or find an **alternative route to market.**
NI	✗	The consultation for support scheme design **considers the benefits of making the scheme mandatory.**

Source: Cornwall Insight market research

5.4.2. Case study on GB

If a generator is not awarded a CfD contract they will have to enter the wholesale market without support, but they can seek Power Purchase Agreements (PPAs), either with a utility or a corporate, to eliminate market volatility risk. The generator can also reapply at the next allocation round which currently occur annually.

5.4.3. Case study on Ireland

In RESS 3, there are no restrictions on bidding into the next auction round. Unsuccessful projects can also enter the wholesale market without support or find an alternative route to market. However, if a successful project withdraws from the scheme post-auction, they are excluded from participating in any RESS auctions until April 2027. This acts as a disincentive for the bidder to withdraw post-auction.

There is no specific clause addressing or excluding unsuccessful bidders from future ORESS auctions in the ORESS 1 T&Cs, however there is a government consultation out currently on the design of ORESS 2. It's proposed that future ORESS auctions will be plan led rather than developer led. Consequently, there will be an introduction of Designated Marine Area Plans (DMAPs), and a splitting of ORESS 2 into ORESS 2.1 and 2.2. The DMAP for the next auction, ORESS 2.1, will be on the south coast of the island, therefore only projects on the south coast, within the DMAP area can bid into the auction.

ORESS 1 was not a mandatory scheme and was developer led, however unsuccessful projects were given time until July 2024 to secure an alternative route to market, whereafter they would lose their grid connection agreement. This would result in them losing time, costs, and efforts invested in obtaining the agreement and would put them at a similar level as other Phase 2 projects who are less further along in their planning and development process.

5.5. Planning timelines

5.5.1. How it is addressed in DfE's consultation

Planning is mentioned in the eligibility section of DfE's consultation, which states that the qualifying criteria may include some planning requirements, but it is not considered in any further detail. Considering planning is a key risk highlighted by all developers interviewed as a part of this study, this may be an aspect that warrants consideration in the overall scheme design.

Figure 13: Highlights from other jurisdictions

Country	Risk mitigation exists within support scheme?	Method of mitigation
GB	✖	All applicable planning consents **must** be obtained to be considered eligible for any Allocation Round in the **CfD.**
Ireland	✖	All planning consents **must** be obtained to be considered eligible to bid into **RESS 3.** Only evidence of planning consent application was needed for **ORESS 1.** In **ORESS 2.1**, planning consents will not be required until post-auction
NI	✖	Including any mitigation and measures to de-risk developers from the risk of long planning timelines and delays is **not considered** in the consultation for support scheme design.

Source: Cornwall Insight market research

5.5.2. Case study on GB

In GB, a CfD auction bidder must be able to prove that all applicable planning consents have been obtained, as stated in the allocation requirements specified in each round of the CfD. Therefore, all planning for the construction of a new project aiming to become a CfD unit must be complete before bidding for a CfD. The planning phases of such large projects can take years. Such planning applications may also (depending on size) have to undertake an obligatory Environmental Impact Assessment, as well as undergoing public consultation. Large projects must also provide the UK government with a Supply Chain Plan which must be approved by the Secretary of State in order to qualify as an eligible CfD generator.

One large scale project began development in 2010, had a CfD bid accepted in AR5 (2019), and aims to be operational by 2023. Projects of such size have to commit significant time and money across many years to be developed, however there is also potential for a relatively quick delivery time once the CfD has been approved. All contracted capacity from AR 1-5, the latter of which took place in 2019, is on track to be delivered by 2027. The majority of AR5 capacity is expected to become operational in 2023, 2024, and 2025.

The types of projects that will occur in the CfD are often large scale and will therefore undergo time consuming planning processes which will also incur significant cost. The risk arises when such projects, that have already had large sums spent on them in the planning stage, come to bid in the CfD. If unsuccessful in their bid, such an asset may struggle be profitable outside the scope of the CfD. As the planning process must occur before the CfD auction, there are no support mechanisms in place to mitigate the financial risk.

5.5.3. Case study on Ireland

In ORESS 1, only evidence of the project's planning consent application was needed. If planning consent is not achieved by the planning longstop date, 30 June 2028, then the project's 'letter of offer' will be revoked.

In the next offshore auction, ORESS 2.1, only successful bidders will need to obtain planning permission consents. Post-auction, successful bidders will need to obtain their Maritime Area Consents (MAC) application which will then entitle them to priority planning permission application assessment from An Bord Pleanála. In ORESS 1, MAC applications were assessed by DECC. In ORESS 2.1 they will be assessed by a new agency, the Maritime Area Regulatory Authority (MARA).

In RESS 3, full planning consent must be obtained in order for a project to eligible to bid into the auction. This is a full and final grant of planning permission by An Bord Pleanála and must not have an expiry date or decommissioning date that occurs during the RESS support period. Obtaining planning consent can take over two years.

RESS 3 auction results obtained a higher average strike price than RESS 2, with only three wind farms clearing the auction. Planning timelines and inconsistencies have been identified as a contributor to the lack of uptake. Wind Energy Ireland (WEI) criticised this, highlighting that "in the same week of the auction results, it had been one year since the last onshore wind farm received planning permission from An Bord Pleanála, while the applicant is supposed to get their decisions in 18 weeks, the average decision time is well over 90 weeks"[15].

5.6. Grid connection timelines

5.6.1. How it is addressed in DfE's consultation

DfE's consultation does not contain any discussion, design consideration or recommendation for any aspect of grid connection timelines.

Figure 14: Highlights from other jurisdictions

Country	Risk mitigation exists within support scheme?	Method of mitigation
GB	✔	Grid connection agreement must be in place in order to bid in **CfD**. Can only be extended with no penalty if it is the fault of the system operator not the generator, or in the case of Force Majure no one is held liable and the **CfD** agreement will not be impacted.
Ireland	✘	A grid connection agreement must have been in place in order to qualify for the **RESS 3**. A grid connection assessment was needed for a project to eligible to participate in **ORESS 1**.
NI	✘	Including any mitigation and measures to de-risk developers from the risk of long grid connection timelines and delays is **not considered** in the consultation for support scheme design.

Source: Cornwall Insight market research

[15]Wind Energy Ireland; Disappointing energy auction highlights need for urgent reform; Sep 2023

5.6.2. Case study on GB

In GB, a grid connection offer has to be in place in order to be considered as an eligible CfD generator, and therefore must be in place when a bid is made. The generator must provide details of the type of connection the proposed project will have with the grid, the capacity of the project, and to which grid (transmission, distribution, or private wire) the connection will be. Floating offshore wind and remote island wind both have specific connection requirements but neither are offered extra support or mitigation based on the connection because of this.

Being connected to the grid is part of the Operational Conditions Precedent and is stated in the construction agreement. If a connection to the grid is not in place by the agreed longstop date the LCCC does not pay anything to the generator until it is connected, as well as potentially terminating the CfD completely. There are specific exceptions to this. If the grid connection is not in place by the agreed date but is a result of an error or lack of action by the ESO contrary to what was agreed in the construction agreement and there was nothing the generator could do to avoid it, the longstop date would continue to be extended without a penalty applying to the generator. There is also a Force Majeure clause, whereby, any unforeseen human or natural event that causes disruption will mean no one is deemed liable or in breach of the CfD contract.

The ESO stated that there are 220 projects waiting to be connected to the grid by 2026 (~40 GW). All contracted projects, ie those with a grid connection offer that are not yet connected are recorded on the Transmission Energy Capacity (TEC) Register. The TEC Register contains the longstop date by which each project should be operational, and therefore must be connected to the grid, the furthest away of which is currently 2039.

In 2023, ESO changed its methodology on how it manages the queue for grid connections in order to be more efficient and reduce waiting times for projects to connect to the grid. Despite this, in most places across GB, it is now considered very unlikely an asset would be able to connect to the grid at any time before 2030.

5.6.3. Case study on Ireland

In RESS 3, projects must be a grid contracted project to be deemed eligible to participate in the auction. This means that projects must hold a grid connection agreement or have a grid connection offer in place that must be accepted in the time specified in the contract. Grid connection arrangements must remain valid for the duration of the RESS support and the applicants must provide a grid contract reference number on their application to the auction as evidence.

Projects with a maximum export capacity (MEC) over 0.5kW must apply for a grid connection via the Enduring connection policy (ECP) process. The ECP application window opens yearly. ECP batches 2.1-2.3 aimed for 115 connections per batch, 85 of the offers were prioritised for generation, storage, and other system services technologies with a MEC of over 500kW, 25 of which were prioritised for the largest renewable applicants. The offers for each batch, post-auction (October) are processed and issued over the course of twelve months, starting in January of the year following batch formation. Only projects included in ECP rounds up to ECP 2.2 were allowed to bid into RESS 3.

ORESS phase 1 projects, bidding into ORESS 1 were required to hold a grid connection assessment (GCA) issued to them from the TSO.

In the GCA submitted to the TSO, the project/applicant had to declare their desired maximum export capacity (which could not be changed beyond the point of submitting the GCA), their desired node and connection point, the estimated cost of their connection, and declare any existing connection applications, among other things. If the applicants Maritime Area Consent application was denied, the GCA would have then been deemed invalid. Applicants holding a GCA who were successful in the auction are now eligible for a full grid connection offer. Unsuccessful applicants' GCA's remain valid for a ~12-month period post-auction (until July 2024), during this time the applicant has the opportunity to find an alternative route to market and if they are successful in doing so, they are then also eligible for a full grid connection offer. The processing of a GCA application took approximately 90 days.

The transmission grid has to be developed in tandem with these projects. As a result, there was uncertainty regarding who would undertake the grid construction and the financial arrangements for it. In ORESS 1, the responsibility for constructing the necessary grid and transmission connections falls on the applicant, who will essentially transfer ownership of these transmission assets to the TSO. This introduced an additional level of uncertainty for investors in these projects. This uncertainty extended not only to Transmission Use of System Charges (TUoS) charges following the TSO's acquisition of the developer's transmission assets, but also necessitated the applicant to allocate a significantly higher amount of funds to their initial investment.

As mentioned in the previous section (5.4.3 on mandatory schemes), ORESS 2 will be plan-led instead of developer-led, and each auction will be location specific with the introduction of auction DMAPs. As a result, the TSO is now better placed to develop the grid themselves, which alleviates ORESS 2 bidders from the grid connection uncertainties faced in ORESS 1. Therefore, in the upcoming auction, ORESS 2.1, applicants will no longer require a GCA. Instead, the TSO will release 'Grid Feasibility Scenarios' (GFS) before the auction. These GFSs will be developed in consultation with stakeholders, considering asset boundaries, network capacities, and different connection points. If a developer succeeds in the auction, they can select their preferred GFS, notify the TSO, and the TSO will then issue an Initial Connection Offer (ICO) based on the chosen GFS.

6. Quantitative risk assessment

Through the risk review we identified the key risks to renewable projects being developed under the new support scheme in Northern Ireland and the potential mitigations that could be applied to each.

To understand the extent of each risk and its impact, we have carried out a quantitative assessment. Our assessment commences with a base case, where all the risks exist, and the onus lies on the developer to assess them and include an appropriate risk premium within their bids. We have then analysed the bid price impact of applying possible mitigation methodologies to that base case.

The intent of this analysis is to understand the extent of the impact on LCOE and bid price if the identified risks were taken away from the developers and either placed on entities better placed to manage them or pinned to market indices which allow them to adjust their risk exposure over time. The mitigation methods we have tested in this study have been informed by our stakeholder interviews, our international review of comparable support schemes, and our market insights. The scenarios tested are shown in Figure 15 for the following technology archetypes:

1. **Solar**
2. **Onshore wind**
3. **Fixed offshore wind**
4. **Floating offshore wind**
5. **Small scale solar**
6. **Small scale onshore wind**

Figure 15: Scenarios tested in quantitative analysis

Risk Factor	Base case treatment of risk	Base case treatment of risk
Agreement length	15 year fixed-term contract	20 year fixed-term contract
		25 year fixed-term contract
Indexation	No indexation applied	Partial indexation as per RESS 3
		Partial indexation as per ORESS 1
		100% indexed to CPI
Dispatch down: Constraints, curtailment, and oversupply	No compensation for any dispatch down and grandfathering[16] applied	Without grandfathering applied
		Compensation for curtailment and oversupply dispatch down
		Compensation for all dispatch down
Mandatory scheme	Scheme participation is mandatory for all renewable assets being developed in NI and there is no other route to market	Scheme is not mandatory: Merchant tail exists but alternative routes to market are insufficient to reduce risk enough to lower WACC
		Scheme is not mandatory: Merchant tail exists and alternative routes to market are sufficient to reduce risk enough to lower WACC
Planning timelines	Issues with planning timelines persist with high capital costs	Simplified planning process leading to lower capital costs
Grid connection	Issues with grid connections (approval timelines) persist with high capital costs	Improved grid connection timelines leading to lower capital costs

Source: Cornwall Insight analysis

Along with testing the above mitigations individually against the base case we have also tested the cumulative impact of multiple mitigations being included at the same time. This is because the way various mitigation methods interact with each other may cause a different overall impact on the bid price as compared to each individual mitigation method applied on the base case.

The risk mitigations we have tested as a combined risk mitigation scenario are shown in Figure 16 and relate to agreement length, indexation, and dispatch down: constraints, curtailment, and oversupply. We have not included any risk mitigation against planning timelines or grid connection as we understand most measures to simplify the planning process or to improve grid connection timelines will have to sit outside the support scheme, and while they will have an isolated impact on the base case bid price it will not be a part of a combined effect of risk treatments added into the support scheme T&Cs.

[15]Grandfathering: As per EU Clean Energy Package, new renewable assets do not receive priority dispatch. Thus, any assets built under the new support scheme will not receive priority dispatch, while old NIRO assets still retain their priority dispatch status. Thus, when curtailment/oversupply related dispatch down occurs it will be the new assets with no priority dispatch which are dispatched down first, rather than the older "grandfathered" assets. This will compound the impact of dispatch down actions on the new assets.

Figure 16: Combined risk mitigation scenario

Risk mitigated	Mitigation method applied to combined risk mitigation scenario
Agreement length	25 year fixed-term contract
Indexation	100% indexed to CPI
Dispatch down: Constraints, curtailment and oversupply	Compensation on curtailment and oversupply
Mandatory scheme	Scheme is not mandatory: Merchant tail exists and lower WACC

Source: Cornwall Insight analysis

In addition to the risk mitigations tested for in Northern Ireland we have also compared the bid price impact of applying the RESS 3 (in case of onshore wind), ORESS 1 (in case of offshore wind), and GB CfD terms and conditions against the risk factors tested above for all technologies. The comparison has been made against the base case for Northern Ireland. The mitigation methods applied under each of the schemes is given in Figure 17.

Figure 17: Comparison of Irish, GB and Northern Irish combined risk mitigated schemes

Risk mitigated	Mitigation method applied to combined risk mitigation scenario	Mitigation method applied for onshore wind and solar under RESS 3	Mitigation method applied for offshore wind under ORESS 1	Mitigation method applied under GB CfD
Agreement length	25 year fixed-term contract	15 year fixed-term contract	20 year-fixed term contract	15 year fixed-term contract
Indexation	100% indexed to CPI	Partially indexed to HICP	Partially indexed to various indices	100% indexed to CPI
Dispatch down: Constraints, curtailment and oversupply	Compensation on curtailment and oversupply	Compensation on curtailment and oversupply	Compensation on curtailment and oversupply	Compensation for all dispatch down
Mandatory scheme	Scheme is not mandatory: Merchant tail exists and lower WACC	Scheme is not mandatory: Merchant tail exists and lower WACC	Scheme is not mandatory: Merchant tail exists and lower WACC	Scheme is not mandatory: Merchant tail exists and lower WACC

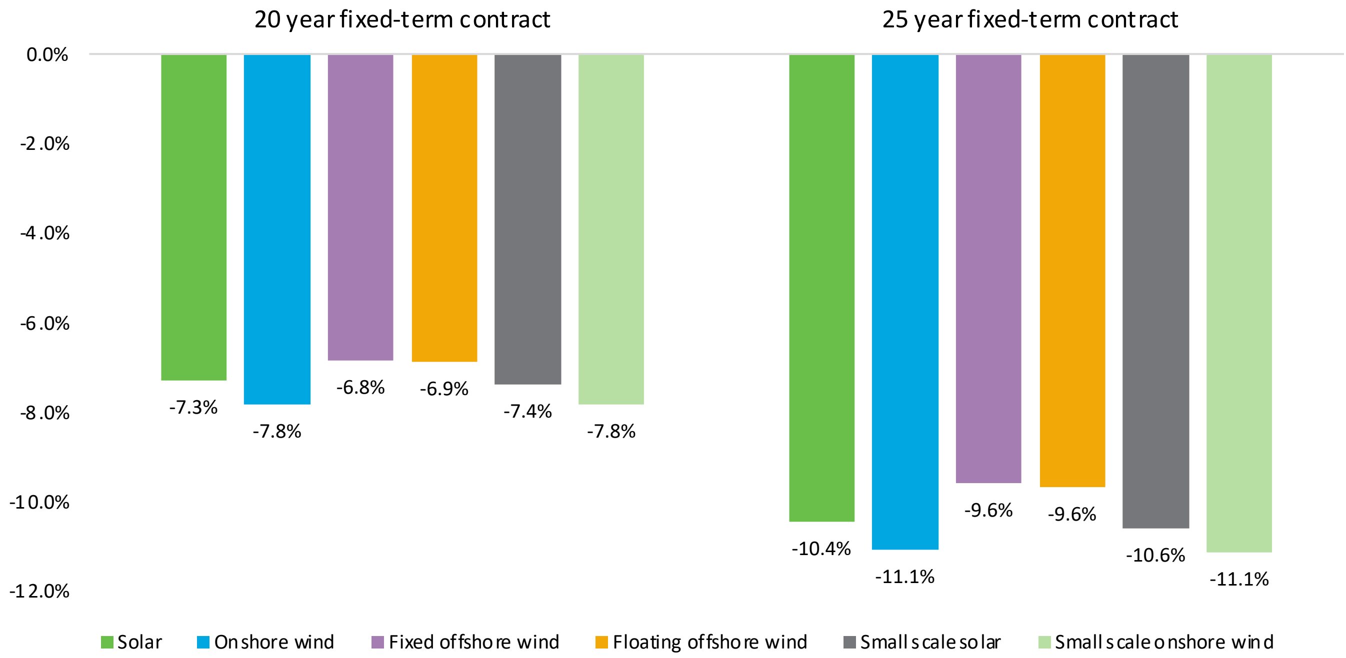
Source: Cornwall Insight analysis

The impact of all the mitigations is shown in terms of a percentage change (rise or fall) in the risk mitigated case as compared to the base case. For example, when testing the impact of increasing the support term to 20 years for solar we have shown that bid prices would fall by 7.3%, as compared to the base case (which is at 100% of the bid price). We should also note that our base case and mitigation cases considers average bidding behaviour and does not include outliers, where developers and investors may have aggressively higher or lower risk perception, the first to ensure almost no risk is borne by them and the latter to ensure they secure a contract under the support scheme.

6.1. Impact assessment: Risk mitigation for agreement lengths

Figure 18 shows the impact to bid price of extending the agreement length from 15 years in the base case scenario to 20 years and 25 years in the two risk mitigated scenarios.

Figure 18: Bid price impact of different agreement lengths



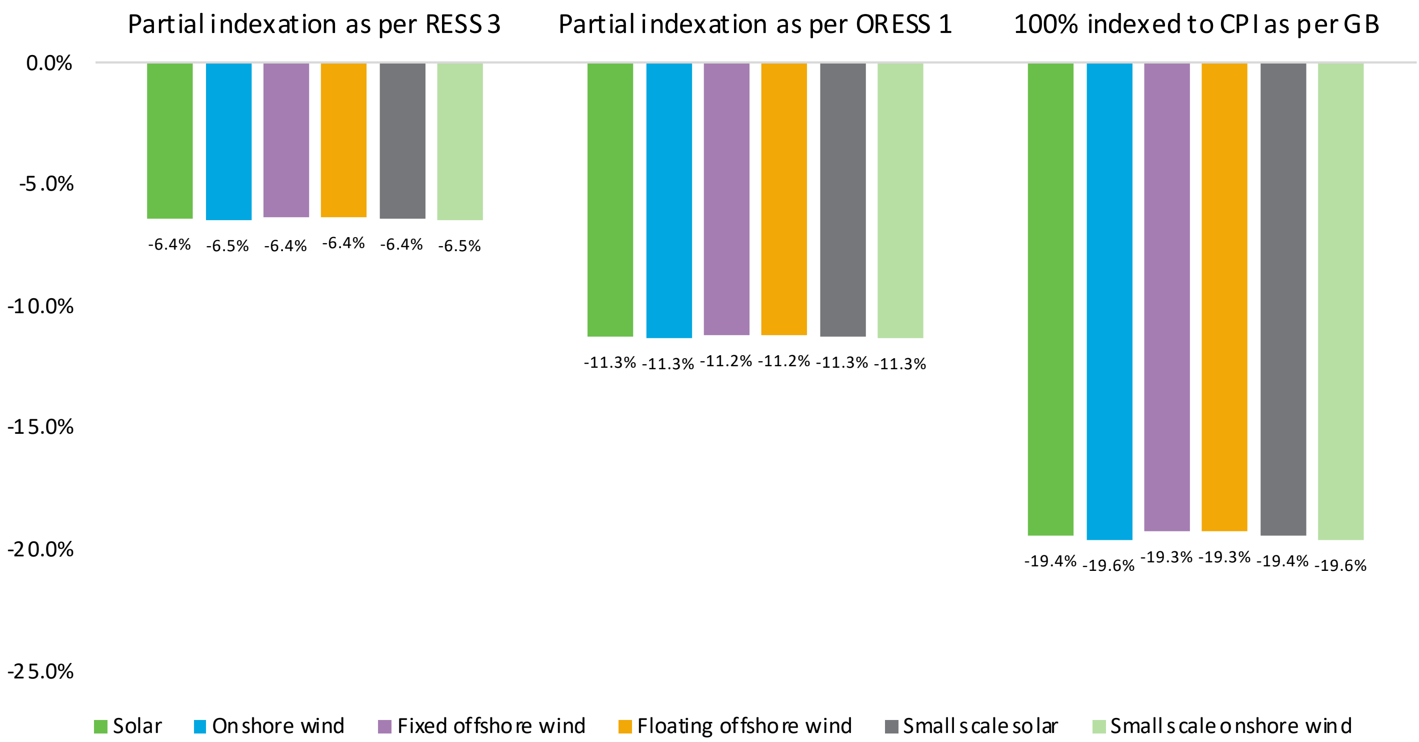
Source: Cornwall Insight analysis

The magnitude of impact of increasing the agreement length is the highest for onshore wind assets and the lowest for offshore wind assets. Overall, the impact of extending the agreement length to 20 years can drive down the bid price by between 6.8% and 7.8%. The impact of extending the agreement length to 25 years can drive down the bid price by between 9.6% to 11.1%. The incremental reduction in bid price if the agreement length is increased to 25 years as compared to 20 years is ~3%.

6.2. Impact assessment: Risk mitigation for indexation

Figure 19 shows the impact to bid price of three strike price indexation scenarios compared with no indexation of the strike price in the base case scenario.

Figure 19: Bid price impact of different indexation approaches



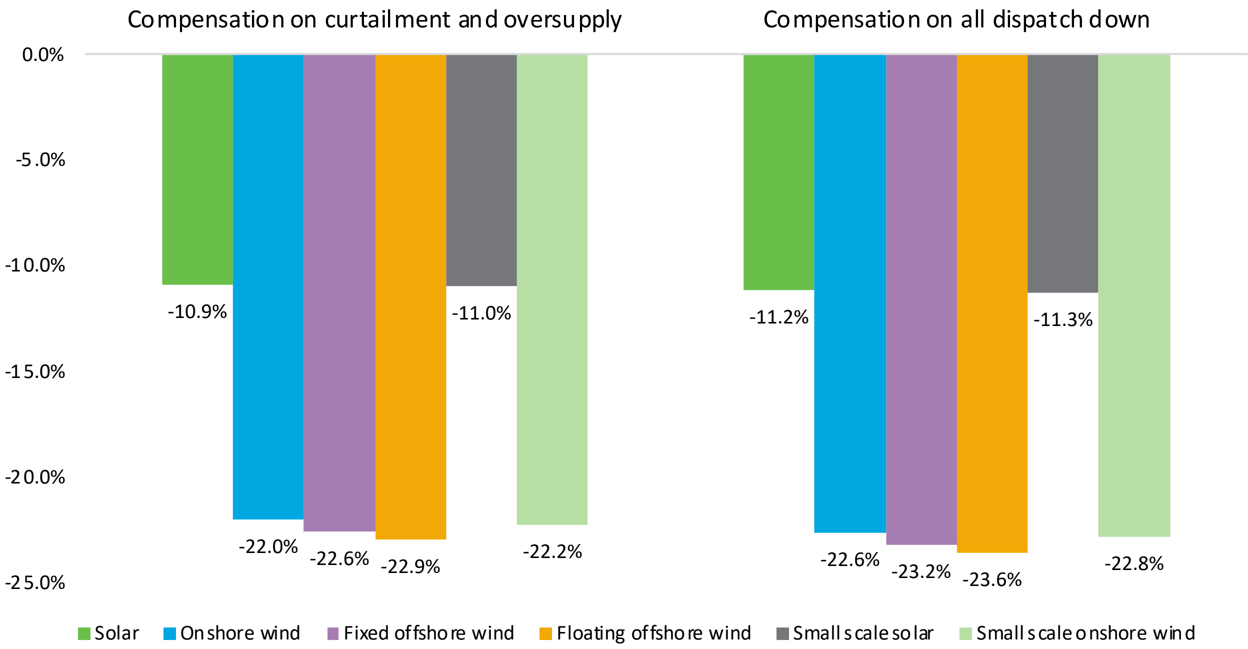
Source: Cornwall Insight analysis

The magnitude of impact of including indexation is similar for all technologies. Overall, the impact of applying partial indexation as per the methodology applied in RESS 3 can drive down the bid price by between 6.4% and 6.5%. The impact of partial indexation as per the methodology applied in ORESS 1 can drive down the bid price by between 11.1% to 11.2%. And finally, applying 100% indexation against CPI as per GB CfD can drive down the bid price by between 19.3% to 19.6%. The incremental reduction in bid price if partial indexation as per RESS 3's methodology is applied versus 100% indexation against CPI is applied is ~13%.

6.3. Impact assessment: Risk mitigation for dispatch down

Figure 20 shows the impact of the risk mitigation methods applied to the risk of being dispatched down due to constraints, curtailment, and/or oversupply for all technologies.

Figure 20: Bid price impact of different dispatch down approaches



Source: Cornwall Insight analysis

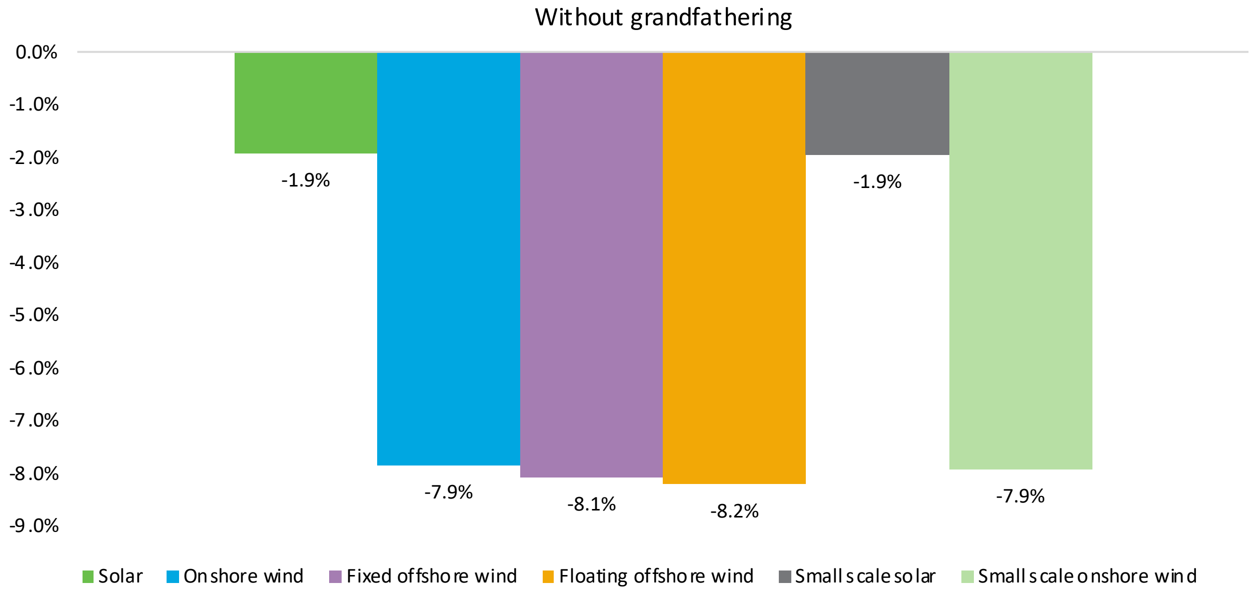
The magnitude of impact of protection against dispatch down is the highest for offshore wind, followed by onshore wind and is relatively low for solar. Solar also has an overall lower level of dispatch down[16] and therefore the impact of compensation is lower for the technology. The impact of compensating for any dispatch down due to curtailment and oversupply can drive down the bid price by between 10.9% to 22.9%. And compensating for all types of dispatch down regardless of whether it is being caused by curtailment, constraints, or oversupply can drive down the bid price by between 11.2% to 23.6%. The incremental reduction in bid price when compensating for all dispatch down (constraints, curtailment and oversupply) rather than just curtailment and oversupply, is marginal, at up to ~1%.

Figure 21 shows the incremental impact of not applying grandfathering to dispatch down of renewable assets due to curtailment, constraints or oversupply.

Overall, the incremental impact of not applying grandfathering while dispatching assets down can drive down the bid price by a further 1.9% and 8.2%.

[16]SONI, Northern Ireland Constraints Report, Solar and Wind, Q3 2023

Figure 21: Bid price impact of not including grandfathering during dispatch down

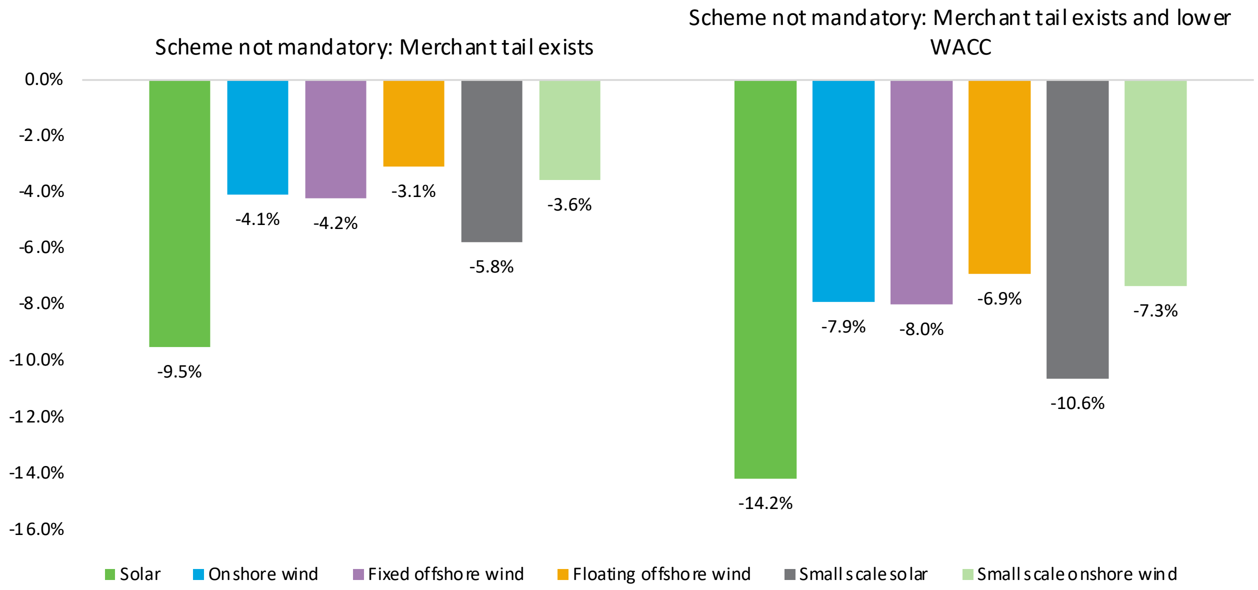


Source: Cornwall Insight analysis

6.4. Impact assessment: Risk mitigation for a mandatory scheme

Figure 22 shows the impact of the risk mitigation methods applied to the risk of mandatory participation for all renewable assets in Northern Ireland. The first risk mitigation scenario looks at merchant revenue (merchant tail) existing after the schemes support period ends, as the scheme is now not mandatory, however due to limited routes to market options the WACC remains at the same level. The second looks at a risk mitigation scenario where a merchant tail exists after the support period of the non-mandatory scheme ends and due to the optimal investment environment and robust routes to market there is a lower WACC that can be accessed.

Figure 22: Bid price impact of a mandatory scheme



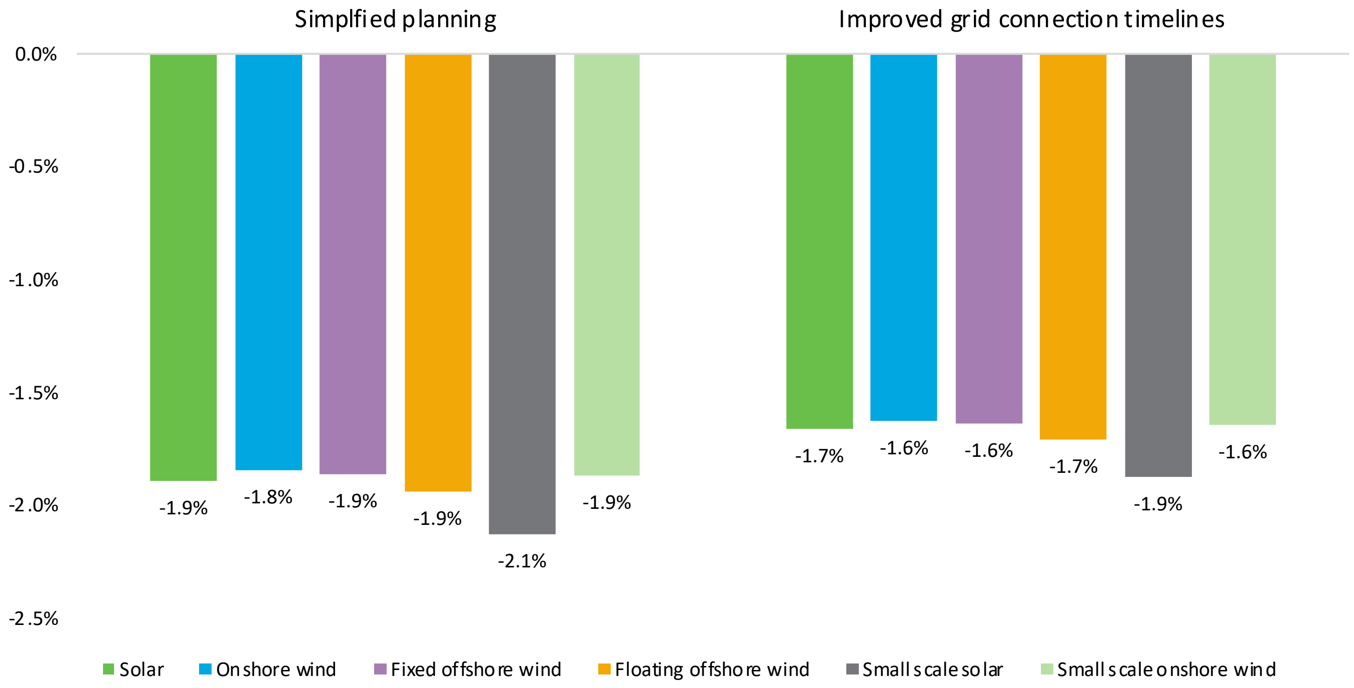
Source: Cornwall Insight analysis

The magnitude of impact of protection against a mandatory scheme is the highest for solar assets, which has multiple other business models to access the market and is the lowest for floating offshore wind which is unlikely to secure any alternative route to market which is compatible with the relatively high risk and high upfront CAPEX. Overall, the impact of the scheme not being mandatory and assets being able to have a merchant tail can drive down the bid price by between 3.1% and 9.5%. The impact of the scheme not being mandatory and assets being able to have a merchant tail and a lower WACC (caused by being able to access multiple routes to market if the support scheme is not the optimal route to market for the asset, or in case of not being able to win a contract under the support scheme during a particular auction round) can meanwhile drive down the bid price by between 6.9% to 14.2%. The incremental reduction in bid price between the having access to a merchant tail, verses having access to a merchant tail and a lower WACC is between 4% and 5%.

6.5. Impact assessment: Risk mitigation for planning and grid connection timelines

Figure 23 shows the impact of the risk mitigation methods applied to the risk around planning timelines and grid connections.

Figure 23: Bid price impact of simplified planning / grid connection



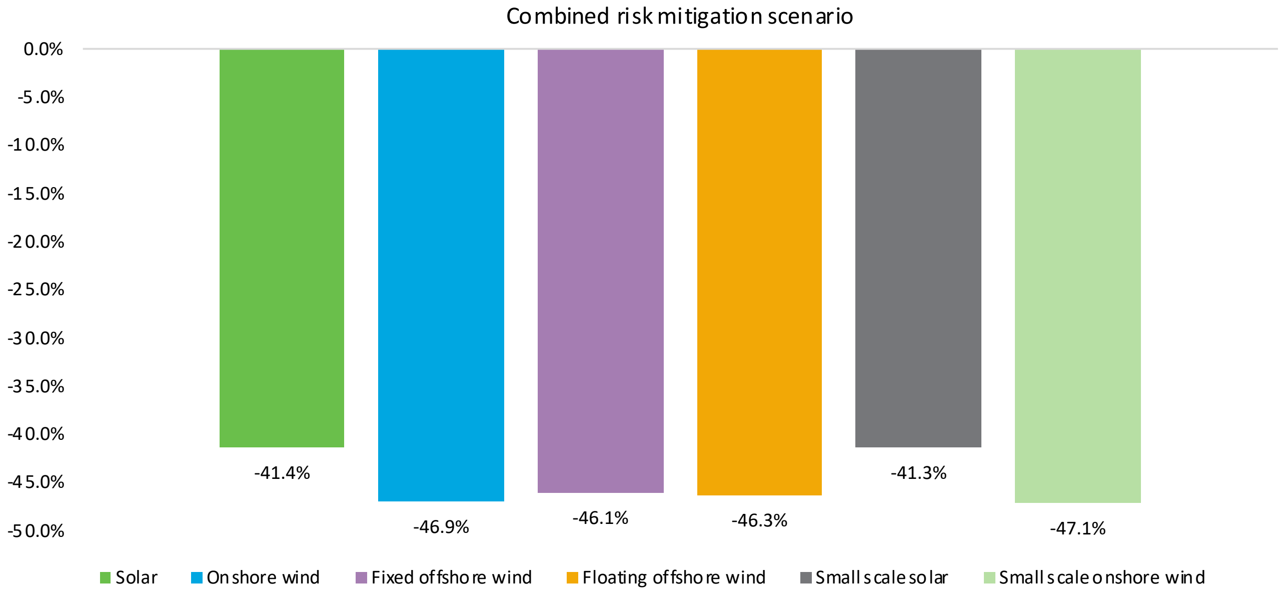
Source: Cornwall Insight analysis

The magnitude of impact of protection against planning and grid related issues is similar for all assets. Overall, the impact of lowered cost due to planning being simplified, ie clearer and shorter processes and timelines, can drive down the bid price by between 1.8% and 2.1%. The impact of lowered cost due to grid connection approvals being timely can meanwhile drive down the bid price by between 1.6% to 1.9%.

6.6. Impact assessment: Combined risk mitigation scenario

Figure 24 shows the impact of the combined risk mitigation scenario on the base case.

Figure 24: Bid price impact of combined policy changes



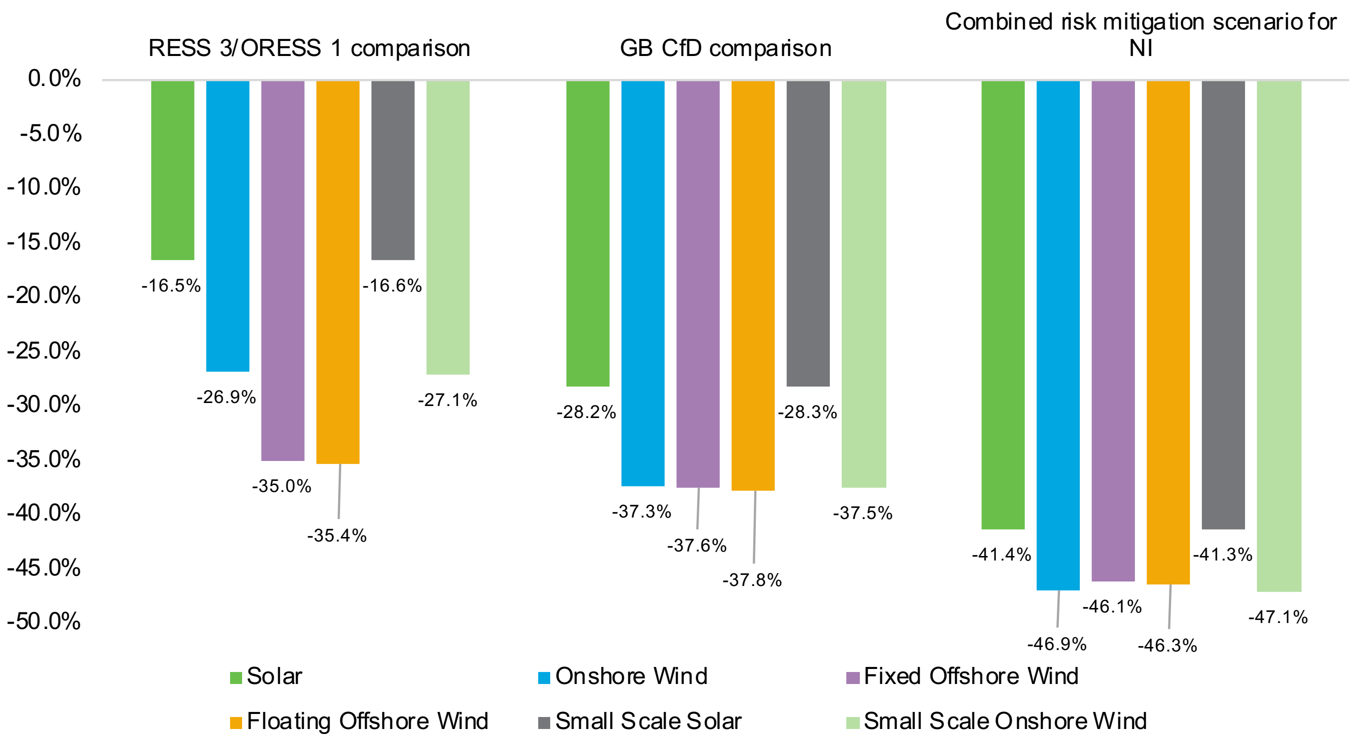
Source: Cornwall Insight analysis

There is a sizable impact on the bid price from mitigations across multiple risk factors, of between 41.3% and 46.9%. The extent of impact is similar for all technology types, which implies that they will all similarly benefit if certain mitigations are placed against all the high-risk factors at the same time under the support scheme, as compared to the differing levels of impact across technologies for when risk factors are individually mitigated against.

6.7. Impact assessment: Comparison of Ireland, GB and Northern Ireland

Figure 25 shows a comparison between the possible bid prices in Northern Ireland when applying risk mitigations as proposed in this report versus if the risk mitigations applied in RESS 3 (in the case of onshore wind) or ORESS 1 (in the case of offshore wind) in Ireland were applied in the Northern Ireland support scheme versus if the risk mitigations applied in the CfD in GB were applied in the Northern Ireland support scheme.

Figure 25: Ireland, GB and Northern Ireland support scheme risk mitigation comparison



Source: Cornwall Insight analysis

RESS 3 risk mitigations have the smallest impact compared to the base case, even though it is a relatively sizeable impact of between 16.5% to 27.1% reduction against base case for onshore wind and solar. For onshore wind and solar, applying GB CfD risk mitigations lead to a fall in bid prices of between 28.2% and 37.5% against base case. For offshore wind the impact of both ORESS 1 risk mitigations and GB CfD risk mitigations are similar, as they lead to a ~35% and ~37% reduction in bid price against base case, respectively.

However, this is the impact of both the Irish support schemes and the GB support scheme against base case. If we were to look at the combined risk mitigation scenario for Northern Ireland it leads to incremental reductions in bid price versus both the Irish and the GB support schemes. The combined risk mitigation scenario gives an incremental reduction of between 11% and 25% on the base case bid price when compared to the Irish electricity support schemes (RESS3/ORESS1) and between 8% to 13% compared to the GB CfD. The incremental reduction is shown in Figure 26.

Figure 26: Incremental bid price impact of combined risk mitigation scenario for NI

Incremental reduction in bid prices (%)	Solar	Onshore wind	Fixed offshore wind	Floating offshore wind	Small scale solar	Small scale onshore wind
RESS3/ORESS 1 to combined risk mitigation scenario for NI	-25%	-20%	-11%	-11%	-25%	-20%
GB CfD to combined risk mitigation scenario for NI	-13%	-10%	-9%	-8%	-13%	-10%

Source: Cornwall Insight analysis

Figure 27 summarises the results from the quantitative impact analysis. Mitigating individual risk factors can drive the bid price down by between 1.6% and 35.4%, while combining multiple risk mitigations for different risk factors, at the same time, drives bid prices down by between 41.3% and 46.9%.

Figure 27: Summary of bid price impact for all mitigations against base case

Risk mitigated	Mitigation method	Solar	Onshore wind	Fixed offshore wind	Floating offshore wind	Small scale solar	Small scale onshore wind
Agreement length	20 year fixed-term contract	-7.3%	-7.8%	-6.8%	-6.9%	-7.4%	-7.8%
	25 year fixed-term contract	-10.4%	-11.1%	-9.6%	-9.6%	-10.6%	-11.1%
Indexation	Partial indexation as per RESS 3	-6.4%	-6.5%	-6.4%	-6.4%	-6.4%	-6.5%
	Partial indexation as per ORESS 1	-11.3%	-11.3%	-11.2%	-11.2%	-11.3%	-11.3%
	100% indexed to CPI	-19.4%	-19.6%	-19.3%	-19.3%	-19.4%	-19.6%
Dispatch down: Constraints, curtailment and oversupply	Without grandfathering	-1.9%	-7.9%	-8.1%	-8.2%	-1.9%	-7.9%
	Compensation on curtailment and oversupply	-10.9%	-22.0%	-22.6%	-22.9%	-11.0%	-22.2%
	Compensation on all dispatch down	-11.2%	-22.6%	-23.2%	-23.6%	-11.3%	-22.8%
Mandatory scheme	Scheme not mandatory: Merchant tail exists	-9.5%	-4.1%	-4.2%	-3.1%	-5.8%	-3.6%
	Scheme not mandatory: Merchant tail exists and lower WACC	-14.2%	-7.9%	-8.0%	-6.9%	-10.6%	-7.3%
Planning timelines	Simplified planning	-1.9%	-1.8%	-1.9%	-1.9%	-2.1%	-1.9%
Grid connection	Improved grid connection timelines	-1.7%	-1.6%	-1.6%	-1.7%	-1.9%	-1.6%
Combined risk mitigation scenario	Mitigation against multiple risk factors	-41.4%	-46.9%	-46.0%	-46.2%	-40.8%	-47.1%

Source: Cornwall Insight analysis

7. Key findings

Additional renewable capacity will be needed in Northern Ireland if it is to achieve its 2030 renewable consumption target. DfE needs to put in place a new renewable support scheme as capacity addition has stagnated due to the lack of a support scheme for the past six years post NIRO. The support scheme designed by DfE has to ensure it improves the investment environment in Northern Ireland in light of the perceived risks of investing in renewable assets in Northern Ireland. These perceived risks will already provide an upward pressure to LCOEs for Northern Ireland's renewable assets.

A key part of DfE's mandate is to protect its consumers from high costs of energy. Reducing the risks that the developer has to factor into their project will create a downward pressure on LCOEs and bid prices, which will be ultimately passed on to consumers.

DfE needs to understand the nature of these risks, who can manage these risks, who has better visibility on them, the risk mitigation options available, and their possible impact on bid price. Ultimately, DfE needs to know whether including certain risk mitigations will result in a net benefit for consumers before making design decisions for their support scheme.

Our quantitative risk analysis shows that there are significant differences between mitigating certain risks, especially in mitigating them to a specific extent. However, combining multiple risk mitigations will have the highest overall impact across all technologies.

Figure 28 looks at the three risk mitigations which have the highest impact in driving down bid prices against the base case for each technology archetype.

Figure 28: Ranking individual risk mitigations by impact on base case bid prices for each technology archetype

Technology	Rank 1	Rank 2	Rank 3
Solar	100% indexed to CPI	Scheme is not mandatory: Merchant tail exists and lower WACC	Partial indexation as per ORESS 1
Onshore wind	Compensation on all dispatch down	Compensation on curtailment and oversupply	100% indexed to CPI
Fixed offshore wind	Compensation on all dispatch down	Compensation on curtailment and oversupply	100% indexed to CPI
Floating offshore wind	Compensation on all dispatch down	Compensation on curtailment and oversupply	100% indexed to CPI
Small scale solar	100% indexed to CPI	Partial indexation as per ORESS 1 and Compensation on all dispatch down	Compensation on curtailment and oversupply
Small scale onshore wind	Compensation on all dispatch down	Compensation on curtailment and oversupply	100% indexed to CPI

Source: Cornwall Insight analysis

The key individual risk mitigations that have the highest impact on driving down the bid price against the base case are:

1. Indexation: Both partial indexation as per ORESS 1 methodology as well as 100% indexation against CPI have high impact on the base bid price. If DfE is unable to justify indexing 100% of the bid price to the CPI, partially indexing the bid price will also have a significant impact. However, the difference between 100% indexation and partial indexation (ORESS 1 method) is ~8%, which is significant. Thus, there is a definite benefit to indexing 100% of the bid price as compared to partially indexing it. In addition, we must recognise that partial indexation similar to ORESS 1 will have certain administrative costs attached to implementation, which we have not included in our quantitative assessment which 100% indexation will not incur.

2. Dispatch down: Constraints, curtailment, and oversupply: Compensation against dispatch down for just curtailment and oversupply will have almost as high an impact on the base bid price as compensation for all types of dispatch down including constraints. The incremental impact of driving the base bid price down between including compensation for constraints and not including compensation for constraints is under 1%. However, there may be added administrative costs of implementing compensation for dispatch down due to constraints due to its locational nature where the cost to consumer could outweigh the bid price impact benefit.

3. Mandatory scheme: A mandatory scheme, would prove to be a risk for existing projects as well as new projects. For new generators who are planning to invest in Northern Ireland, all costs and efforts going into planning the project may be wasted if they do not win a contract under the scheme as they will then be left with no other route to market. Even if a contract is won under a mandatory scheme it would lead to a loss of merchant revenues after the support term ends. All of these risks would then impact the project's WACC, driving it upwards, if the scheme were to be mandatory. This ties back to the investability of the support scheme and the exact levels of increase in WACC will be hard to pin down, but it may easily go up to more than what we have accounted for based on market sentiment.

Based on our analysis our key recommendations are as in Figure 29.

Figure 29: Key recommendations

Risk	Recommended mitigation for NI support scheme
Agreement length	A longer agreement length will be beneficial, of at least 20 years as mentioned during stakeholder interviews. However, 25 years will be ideal for capital intensive investments, especially offshore wind.
Indexation	A 100% indexed bid price will be the most beneficial as it gives an 8% reduction in bid prices in addition to partial indexation. However, if DfE is unable to justify this, at least a partial indexation against related indices as in ORESS 1 is needed.
Dispatch down: Constraints, curtailment, and oversupply	Compensation for dispatch down for curtailment and oversupply is the most viable, as it is a relatively quick win, and UAEC methodology can be utilised as a starting point to define compensation method. Additional compensation for constraints offers little added benefit and may turn a quick win into a medium-term implementation due to nodal considerations. The UAEC methodology also allows NI to stay in line with and utilise the SEM changes that were made to allow for the UAEC methodology for RESS projects. However, the UAEC was more beneficial for offshore than onshore developers in Ireland due to stipulations linked to firmness of their connection, which must be considered if implementing in NI.
Mandatory scheme	Making the support scheme mandatory will not only drive up the bid price, but also impact investor interest in the scheme as investors will be left with no option to seek other routes to market if they are unsuccessful in gaining a contract under the support scheme. Even if a contract was to be awarded, the loss of merchant revenues and higher WACC would make the risk difficult to justify.
Planning timelines	Bulk of the mitigation for this risk will have to sit outside of the support scheme design. However, an allowance for flexibility in timelines for developers if delays are caused due to DfI's processes without any financial or contractual impact would partially de-risk developers. A provision such as in the CfD to only allow projects to participate which have full planning permission may be counterproductive considering the short run up to 2030 and the short pipeline of projects in NI. Conversely, allowing projects to enter the support scheme without planning may defer the issue by allowing projects to bid which may not have the capability to become operational. Focus should be on putting the onus of completion on the DfI rather than developers bearing the burden of requirements that they cannot control. A middle ground approach may be prudent, under which intent is proven by developers through completed planning applications, acknowledged by DfI. Further risk for planning timelines is borne by DfI with risk being shifted away from developers under the support scheme. This may be optimal and help drive down consumer costs.
Grid connection	Like planning timelines, a bulk of interventions to ease this risk sits outside of the support scheme design, such as grid expansion plans which look at solar potential along with wind, shortening of approval and connection timelines, etc. However, a provision to allow for delays to grid connection without financial or contractual implications for the developer would lower risk perception. As with planning a requirement for the project to have grid connection agreement in place may be counterproductive to the scheme's success. However, to show intent for a requirement for developers to have all applications and studies carried out prior to participating in the support scheme will help. Beyond that, the developer being held accountable for delays in grid would be sub-optimal and would drive costs higher.

Source: Cornwall Insight analysis

Timeline	Action points	Action owner(s)
Quick win	• Assess benefits of various agreement lengths through a Cost Benefit Analysis especially for its interaction with mandatory scheme requirements • Decision to be included in T&Cs for support scheme	• DfE
Quick win	• A cost benefit analysis prior to making a decision, as 100% indexation may be optimal for bid prices as well as administrative costs • During the publication of price caps and results it is important to ensure that the reference is made to a base year to ensure all prices across rounds are comparable, especially when communicated publicly • Decision to be included in T&Cs for support scheme	• DfE • Consumer Council for Northern Ireland
Quick win	• Assessment to understand whether RESS UAEC method can be utilised in NI • Understand SEM interactions and implications • Decision to be included in T&Cs for support scheme	• DfE • SONI • SEMC
Quick win	• Stakeholder engagement to understand possible uptake if the scheme is mandatory • Decision to be included in T&Cs for support scheme	• DfE
Medium to long term	• Changes to planning guidelines • Simplified planning process implementation, with a possible Single Window Clearance (SWC) for all support scheme assets • Inclusion of timeline extension for planning delays in T&Cs	• DfE • DfI • Local planning authorities
Quick win to medium term	• Assessment of potential for multiple technologies including solar, onshore wind and colocation with batteries, to revisit grid expansion plans • Mapping interventions outside of support scheme and liaising with implementors of those interventions • Inclusion of timeline extension for grid connection delays in T&Cs	• DfE • SONI • NIE Networks

8. Appendix 1: Methodology for choosing final risk factors for quantitative analysis

We have applied the decision tree given below to the responses identifying risks to renewable technology projects in Northern Ireland, received from our stakeholder engagement. The responses have been scored following the below parameters regardless of whether they were given unprompted or prompted through the questionnaire.

Figure 30: Decision tree for risk selection

Score	3	2	1
Risk identified during stakeholder engagement conversations	Identified by all stakeholders	Identified by more than 3 stakeholders	Identified by less than 3 stakeholders
Inclusion of risk mitigation within the support scheme in the GB CfD and Irish RESS	Yes, risk is fully mitigated in both/either	Risk is partially mitigated in both/either	Risk is not mitigated in either
Can it be included in the support scheme as a risk mitigation that has an impact on bid price?	Yes	Partially	No
Final score buckets	High 7-9	Medium 4-6	Low 1-3

Risks that are in the “high” bucket as per their score will be parameterized for risk mitigation measures

Figure 31: Key risks identified

Risk identified through stakeholder interactions	Number of respondents	Score	Inclusion of risk mitigation within the support scheme in the GB CfD and Irish RESS	Score	Can it be included in the scheme with an impact on bid price?	Score	Final score
Indexation	All	3	Mitigated fully in GB CfD and partially in RESS	3	Yes	3	9
Mandatory Scheme	All	3	Not a mandatory scheme	3	Yes	3	9
Agreement length	All	3	Partially mitigated	2	Yes	3	8
Dispatch down due to constraints, curtailment and oversupply	4	2	Mitigated fully under CfD and partially under RESS	3	Yes	3	8
Planning	All	3	Partially mitigated for certain technologies	2	Partially, through allowances in auction timelines	2	7
Grid	All	3	Partially mitigated for certain technologies	2	Partially, through allowances in auction timelines	2	7
Pot / Tiered structure	All	3	Exists in GB and through ECFs in RESS, but changes from round to round	2	No, not without a full scale auction simulation	1	6
Floating Milestones	3	1	Partially mitigated	2	No	1	4
Land / Seabed availability	3	1	Not mitigated, seabed auctions in GB and MAC in ORESS	2	No	1	4
Minimum capacity 1-5 MW	1	1	Lower minimum size	2	No	1	4
Non price factors (NPF)	3	1	Not introduced yet	1	No	1	3
Transport	2	1	No mention in scheme	1	No	1	3
Setback distances and tip height	1	1	Not mitigated/specified	1	No	1	3
Shortage of skills	1	1	Longer running schemes, skills shortage not envisioned	1	No	1	3
Supply Chain	1	1	Not mitigated through the scheme	1	No	1	3
Auction setup	1	1	No specific actions	1	No	1	3

9. Appendix 2: Modelling methodology

To calculate the bid price, the forecasted discounted costs and revenues of the generation asset are considered across the lifetime of the generation asset, and then divided by the discounted volume of electricity generated by the asset during the subsidy period.

The costs included are capital costs for building the asset, TUoS costs, and fixed and variable operations and maintenance costs. The revenues made by operating in the wholesale market after the subsidy period is over are included using technology specific capture prices. These revenues and costs are discounted based on the weighted average cost of capital (WACC) for the project.

The generation volume of the asset is calculated using technology specific load factors and transmission loss adjustment factors based on SONI data. The Northern Ireland Constraints Report published by SONI is used to inform the view of constraints, curtailment, and oversupply. These volumes are then discounted, incorporating both the WACC, inflation and any indexation for that scenario.

Figure 32: Assumptions for quantitative analysis

Assumption	Unit	Comment
Capex	£/kW	Based on range of latest publicly available data
Fixed O&M	£/kW/yr	Based on range of latest publicly available data
Variable O&M	£/MWh	Based on range of latest publicly available data
Project start date	-	2030
Load factors	%	Based on RESS 3 and ORESS auction parameters
TUoS	£/MW/mth	2023/24 SONI data - average of all generators
TUoS outlook	%	Average of historic annual price increases
TLAF	-	2023/24 SONI data - average of all regions
Average operating period	Years	35 years
Market power prices	£/MWh	Q3 2023 Cornwall Insight All Island Forward Curve report
Inflation - CPI	%	Long term forecast
Inflation - Steel	%	5 year average of wholesale price index for structural steel
Constraints	%	Based on Northern Ireland Constraints report, 2030 100% + 0.5GW offshore scenario
Curtailment	%	Based on Northern Ireland Constraints report, 2030 100% + 0.5GW offshore scenario

10. Appendix 3: Glossary

Abbreviation/Term	Definition
AR5	Allocation round five
BM	Balancing Market
BSC	The Balancing and Settlement Code
Capex	Capital expenditure
CfD	Contracts for Difference
Constraint	A restriction on the operation of the grid. Constraints can be due to factors such as transmission capacity, resource availability, or regulatory requirements, and they influence how electricity is generated, transmitted, and consumed
CPI	Consumer price index
CPPA	Corporate purchase power agreement
Curtailment	Curtailment refers to the reduction or interruption of electricity generation or consumption due to grid constraints or excess supply, to maintain the stability and reliability of the electrical system.
DfE	Department for the Economy
DfI	Department for Infrastructure
DMAPs	Designated Maritime Area Plans
ECP	Enduring connection policy
ESO	Electricity System Operator
GCA	Grid connection assessment
GFS	Grid Feasibility Scenarios
HICP	Harmonised Index of Consumer Prices
Indexation	Indexation is the adjustment of finances (such as payments) to a index, usually to account for inflation.
ION	Interim Operational Notification
LCCC	Low carbon contracts company
LCOE	Levelised cost of energy
MEC	Maximum export capacity
NIE Networks	Northern Ireland Electricity Networks
NIRO	Northern Ireland Renewables Obligation
NPF	Non price factors
ORESS	Offshore renewable electricity subsidy scheme
Oversupply	In the context of this report oversupply refers to the excess supply of energy on the grid a at given time
PPA	Purchase power agreement

Abbreviation/Term	Definition
RESS	Renewable electricity subsidy scheme
RIW	Remote island wind
RO	Renewables obligation
ROCs	Renewable obligation certificates
Ireland	Republic of Ireland
SEF	Strategic Energy Framework
SONI	System Operator for Northern Ireland
Small scale	1-5 MW
Support Term	Refers to the duration for which financial incentives or subsidies are provided
T&Cs	Terms and conditions
TEC	Transmission Energy Capacity
TUoS	Transmission Use of System charges
TSO	Transmission system operator
UAEC	Unrealised Available Energy Compensation
WACC	Weighted average cost of capital
WEI	Wind Energy Ireland

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