Call for Input: Financial Instrument Proposal

RenewableUK / Scottish Renewables response

November 2024

Q1: Please indicate whether you are either i) broadly supportive of our initial proposal for a financial instrument; ii) supportive of a financial instrument in principle but believe that our initial proposal requires further changes; or iii) believe that a financial instrument in any form is the wrong solution. Please explain.

A number of our members strongly oppose a Capacity Connection Fee (CCF), maintaining that User Commitment is the correct approach, while others support the principle of a CCF but believe NESO's current proposal is nonetheless highly disproportionate for the defect it intends to resolve. In general, the proposal appears to assume an oversimplification of committed and speculative developers, while appearing designed rather to target projects that may or may not prove viable.

Evidence-based existing processes and incoming TMO4+ reforms will mitigate against the risk of overly speculative 'resellers' if properly policed via Gate 2 criteria and Queue Management milestones. Notably, the perceived 'option value' of holding grid connections should be mitigated by the new reforms requiring non-transferable land to be related to any connection. Thus, the instrument, particularly in its current form, is inappropriate and risks introducing significant market distortions by placing an additional financial burden on developers.

In terms of net benefit, we would urge NESO to more closely consider the unintended, adverse financial implications of such a proposal. While some abortive grid cost may be saved from setting such a high filter, the number of valid projects that can no longer afford to be developed, especially by smaller developers, will materially reduce competition and ultimately lead to higher consumer costs recovered via higher Contracts for Difference (CfD) clearing prices. Furthermore, the negative impact on investor confidence for those with existing projects affected by such a blanket-level fee could jeopardise Clean Power's £40billion per year requirement.

We would encourage NESO to conduct a minimum level of manual verification of projects, for example checking for forgeries, including through contacting landowners to verify agreements, checking land owned corresponds to the area claimed for etc. Such verifications are all detailed within the TMO4+ proposals; however, NESO is yet to confirm its role in undertaking these verifications at an early stage.

Finally, the 'trading' of grid connections does not happen on the distribution network, where land rights and grid connection contracts are already linked.

Inappropriate solution

The proposals aim to remove 'perverse incentive for developers/projects to speculatively enter the queue', while avoiding 'a financial barrier to those projects that fully intend to connect and utilise their connection capacity'. We do not agree that a 're-seller' business model is an illegitimate part of the project development process and can lead to more renewable projects being developed; as such, we would welcome NESO's acknowledgment of this in the call for input. An overly negative emphasis on this business model indicates a bias towards large utility development model, which is not constructive in mitigating against the identified defect.

There are many companies that will take a project through the early stages of development before passing a valuable asset onto another company. We do agree that this should not result in projects being put 'on pause' while, for example, a suitable buyer is found, and therefore delaying other projects in the queue. However, we would stress that no developer, or even speculative seller, intends for project failure but all development risks cannot be predicted.

Furthermore, the proposal itself is not cost-reflective. For example, for projects with connection dates several years in the future, Transmission Owners (TOs) would realistically have undertaken minimal work in the short to medium term and the £20k/MW would not be reflective of TO spend 'at risk'. Likewise, projects with hugely different connection works (e.g., a very short, inexpensive connection versus a 40km grid connection) would face the same financial grid risk.

Under retained EU law, within the Regulation 2019/943 Section 2 Article 18 on 'Charges for access to the network, use of network and reinforcement', it states that charges should 'reflect actual costs' and 'should not include unrelated costs supporting unrelated policy objectives'. As per our above points, there are no costs incurred that NESO is addressing within this proposal and it could therefore be open to legal challenge.

Existing commitments

NESO's proposed methodology does not take into account significant expenditure in the form of DEVEX already spent by a developer, demonstrating project commitment. By way of example, the ScotWind and Celtic Sea projects have been required to place significant option fees and are already progressing against agreed milestones with The Crown Estate (TCE) and Crown Estate Scotland (CES), which require significant internal expenditure to ensure they can be achieved. We do not believe that layering on additional costs to projects helps achieve NESO's aims, nor is it aligned with our collective mission to reduce consumer costs. An alternative methodology might require evidence of this expenditure, which could be offset against a reduced capacity connection fee, as it demonstrates commitment and progression, as well as the reduced risk of non-delivery and NESO stranded assets.

Barrier to entry

NESO's proposed methodology disproportionately disadvantages emerging and innovative technologies. Development costs for these projects are typically much higher, and introducing an additional charge further compounds the challenges of developing these projects. The above corollary is that established technologies receive an advantage as development costs are lower. Different technologies require different levels of investment to reach the same stage of development due to differences in technology maturity. Adding a flat rate only compounds this difference and actively disincentivises innovation and project development.

Fee calculation

Another issue is the disconnect between the proposed capacities and network expenditure. Under s15/CMP192 process, should a project terminate there is a reconciliation of securities placed (and liability) and the actual expenditure on the required connection infrastructure, as the S-Curve liability has been adjusted throughout to reflect the actual spend. In addition, the total liability is based on the total projected spend (as adjusted by Strategic Investment Factor (SIF)/Local Asset Reuse Factor (LARF) etc).

By contrast, the proposed methodology adopts the broad process of s15/CMP192 without having the supporting rationale for the quantum of the security/liability. Any financial instrument and associated methodology for proposed drawdown on the security needs to have a transparent and rational link to actual financial loss (or required additional spend) as a result of the reasons for the drawdown (i.e., termination or capacity reduction), rather than simply the application of a blunt capacity multiplier.

Q2: What consequences do you anticipate from introducing a financial instrument in the form that we have proposed? Please explain your response.

The level proposed is wholly disproportionate and will negatively impact multiple types of projects. For smaller developers, i.e., those without significant balance sheets supporting projects, the cost requirements for the fee would have to be raised alongside other pre-consent development costs. This raise would amount to roughly a 100% increase in costs, at the most risk-intensive stage of the project, rendering projects unviable. Small to medium sized projects are key players in multiple grid reinforcements which Ofgem have approved, the failure of which would negatively impact pre-determined strategic projects.

The introduction of a CCF years ahead of TO consent would require developers to reassess if they can afford to apply post obtaining consent, meaning connection points would not be confirmed until Gate 2. As TOs and developers progress projects on similar timescales, a misalignment would be created by reinforcement processes starting at the relatively delayed point of site consent. In summary, the overall time taken for TOs to develop a grid offer would be extended and delayed, in turn delaying the connection of projects critical for Clean Power 2030 that Connections Reform is seeking to mitigate.

While larger developers may have the supporting capital background, they have stated they would be unwilling to spend significant sums pursuing consent without a firm grid connection offer.

The proposal fails to consider the high-risk nature of project development, where investments are at risk if projects encounter unforeseen issues or don't receive consent. Where projects do go ahead, this higher capital cost requirement will ultimately be recovered from the returns of the project's generation, a cost ultimately borne by the consumer. As such, NESO's proposed fee becomes a substantial premium paid by consumers to remove speculative projects from the connections queue.

Another consequence would be to 'lock-in' projects that would otherwise exit. Through the normal course of development, a previously viable project may discover a set of external circumstances which render it borderline for viability. Under the existing approach, the penalty for grid exit is User Commitment, which is proportionate to the system cost incurred. However, under a CCF, the user will be more reluctant to terminate due to the higher exit fee, prolonging the holding of capacity, looking for either a buyer with different assumptions, or just prolonging the issue in order to defer incurring the CCF cost – this is counter to the aims of Connections Reform.

Finally, as aforementioned, the application of the financial instrument introduces a market distortion, compounding the differences in the financial costs of the development of different technologies and creating additional barriers to entry for emerging/innovative technologies.

Q3: Do you agree that only parties that are currently subject to User Commitment obligations should be subject to the new requirement? Are there any additional

parties that it should be applicable to? Or should there be any exclusions? Please explain.

The User Commitment methodology only remains applicable if the rationale behind the level of financial commitment is sound (i.e., the cost of the required reinforcements to connect the user). Currently, this mechanism is flawed, as the reinforcements in connection agreements represent an inaccurate view of network reinforcement that is artificially inflated due to excessive capacity in the queue. It also does not account for the different timescales for the development of different technologies, i.e., those with a fixed trigger date process.

User Commitment obligations are proposed to begin at Gate 2, which is sensible as Gate 1 grid offers hold no value to developers, therefore they should not be required to pay securities until acceptance of a firm offer. As aforementioned, we believe the current User Commitment framework alongside Queue Management and other reform is sufficient. However, if CCF is implemented, exclusions to projects which have Ofgem/NESO approvals such as Holistic Network Design (HND)/Large Onshore Transmission Investment (LOTI) should be considered (see our open letter to Ofgem on securities for such projects).

If Ofgem and NESO have determined there is a need for a reinforcement, it is counterintuitive to place the projects supporting such reinforcements at risk. This issue is compounded by the fact that most of the Ofgem/NESO approved projects will be in development for many years. For example, the Skye Reinforcement has been in development since ~2014 and is currently due for delivery in 2029. With a CCF in place, such a project would be require to pay significant CCF for at least 15 years for one project. Hence, the current User Commitment framework is a far more appropriate measure for scaling securities to investment.

Q4: Please detail any existing financial security requirements you believe should be considered in the development of a financial instrument modification.

Existing methodology

Industry previously discussed the issue of an early financial security in CMP192, which already forms part of CUSC section 15, showing how early stage incurs a security obligation of initially £1/kW rising to a cap at £3/kW. Under CMP192, considerable analysis was undertaken to identify an evidenced-based, appropriate level of commitment that reflects the risk undertaken by all parties.

The existing User Commitment regime has in place a Cancellation Charge Secured Amount for grid connection offers. The User Commitment is designed to protect competition by limiting initial security requirements up until the point when the secured amount increases significantly in the last four years before connection. Projects that have limited likelihood of delivery less than 4 years out from connection are already highly incentivised to exit the queue, and under the current structure would lose an amount that is more appropriate for the abortive spend incurred on their behalf up to that point.

The current arrangements are cost reflective and proportional financial commitments that increase over time under the current security arrangements, providing a constant pricing signal to withdraw if confidence in delivery reduces sufficiently.

The new proposed CCF will be damaging because, unlike the User Commitment structure, it does not recognise the risk profile of projects pre planning determination and it instead sets an elevated, flat rate. The financial analysis used to calculate NESO's proposed commitment fee assumes Net Present Values (NPVs) and cost of capital for ready-to-build or operational projects, while the fee will be applied to pre-consented projects with a very different risk profile and much lower values.

Alternative solution arrangements

A more appropriate solution would be to limit the rate to a level that is more reasonable in relation to total DEVEX.

As referenced, if implemented, the liability should be stepped in synchronisation with the achievement of queue management milestones to reflect the increasing total financial commitment undertaken by the developer as a project progresses. This approach is more logical in terms of the aim of the CCF and also ensures that total DEVEX is not increased further without clear additional benefit to queue management. Such an approach more closely mirrors the application of such fees in Europe. However, this would create a secondary mechanism serving a similar purpose to the current securities regime, and as such, would be unnecessary alongside existing and incoming arrangements.

With regards to European examples, it should be noted that examples of grid bonds in Ireland and Spain are misleading and should not be used for comparison in this case. Irish bonds are placed much later in the process (post Financial Investment Decision (FID) when a project has been entirely de-risked) and in Spain, these bonds are not called upon should a project fail to get planning consent or where there is a grid delay. Generally, these cited examples sit within significantly different contexts from those of NESO's proposals.

If a CCF is implemented, a clear set of exceptions for changes outside of the developer's reasonable control that leads to an exit from the queue, as is the case in Spain, will be required. For example, given this liability will start before a planning consent application has been submitted, there needs to be an exemption or reduction to the liability if a project fails to get planning, or has to reduce their capacity as a result of a planning condition. Significant sums would be at risk based on planning capacity consent, which may be affected by political change either regionally or nationally, as well as the evolution of technologies.

Likewise, there need to be clear rules on how the liability is to be adjusted if there are changes to the project due to changes in the grid arrangements themselves. For example, due to a delay in connection date or location, or an increase in connection charges.

Q5: Do you see any risks to the profitability or financial viability of your projects arising from the introduction of the financial instrument? If so,

- **Please explain what those risks are, their cause and whether they are technology dependent;**
- **If possible, please provide a ranking of those risks in the order of their likely magnitude; and**
- **Outline any mitigations for those risks that should be considered.**

As aforementioned, the pre-consent stage of the project holds the highest risk, as planning approval is highly uncertain. Therefore, capital raised at this stage has the highest cost, which must either be recovered by reduced profits, or increases in the costs of energy imposed on consumers (most likely via the CfD). Generally, the fee will have a considerable impact on the profitability and financial viability of all development assets, and lead to many otherwise developable projects being abandoned.

The proposed fee will have a disproportionately greater impact on smaller developers in favour of global utilities with the balance sheets to secure this outlay of capital. The negative impact on Scottish small and medium enterprises (SMEs) and community developers, who are developing real projects but lack access to additional credit lines, will be detrimental to Clean Power and the national 8GW target of community-owned clean energy projects.

As mentioned in Q1, the proposal may also render changes in Transmission Entry Capacity (TEC) more expensive, thus deterring the freeing up of queue capacity, which Connections Reform has been designed to achieve. With offshore wind connections almost a decade away, defining a precise TEC is challenging. Precise designs and technologies will also not necessarily be determined at the point of connection application, which could impact project size. However, the proposal would effectively financially penalise developers for freeing up capacity on the grid queue in comparison to existing arrangements that incentivise this over time (see answer to Q4 and Q2).

Projects may also not have all the information they need to determine their viability at Gate 2 offers. In recent years, there has been an increase in re-opener clauses in offers and connection 'nodes' of unknown locations. Likewise, for distribution projects, pass-through transmission costs may be determined at a later stage or change during the development process such that a project loses viability. Such risks are outside the developers' control, but under these proposals, the developer would be liable for the security payment if the project can no longer be justified technically or economically.

Developing innovative and emerging technologies is more costly than established technologies, and adding a fixed CCF compounds the issues and introduces barriers to development. This is noted particularly in the context of the pathways in Clean Power by 2030 (CP30), which require a range of emerging technologies.

Likewise, this CCF is detrimental to newer entrants to the market who would have difficulties providing securities through Partial Credit Guarantees (PCGs) and, consequently, would be required to obtain security coverage from a third-party provider at significant cost. This cost would remain unrecoverable even on successful completion of the project (i.e., liability not called upon) and ultimately result in increased CfD strike prices, which would be borne by the consumer.

Finally, the overall impact on investor confidence (e.g., via those forced to abandon existing viable projects) could increase the cost of capital for future projects due to the perceived risk of retrospective change from the UK government for arguably unjustified reasons.

Questions regarding developers' approaches to financing the instrument

The following questions will help us understand the financial impact that the instrument may have on developers:

Q6: Please let us know how much you typically spend on DEVEX, identifying this by technology? Can you also let us know how much of a premium you would expect to pay on top of this if you were acquiring a Ready to Build (RTB) asset?

Pre-consent DEVEX for onshore wind: ~£20,000/MW

Q7: Please explain how you fund your DEVEX? As part of this, can you also comment on the point at which you would expect to secure debt finance (if at all)?

This varies by developer and size of project so, as trade associations, we cannot give a single, definitive answer. Larger developers may fund DEVEX from the balance sheet; smaller developers will raise funds via debt finance.

However, if cash securities are required, issues could arise for small to medium foreign investors. An option to post bonds would be necessary for some members to engage in this process for existing projects. However, bonds need to be issued by a UK branch, which can create artificial barriers for foreign companies. Such companies may have credit from overseas issuers but insufficient within the UK to issue bonds via the local entity. As such, we would urge NESO to consider this within the framework under allowable forms of securing the fee.

Q8: Do you expect that you would be able to raise finance to cover the cost of the financial instrument? If so, what sort of finance would this be and what sort of cost do you expect that it may have?

No. The current level of the Capacity Commitment Fee being proposed by NESO is set at an excessively high order of magnitude in relation to DEVEX. It is the same order of magnitude (i.e., 100%) as the total DEVEX, applying a very substantial increase to the total project cost at the development stage.

Due to the size of offshore windfarm developments and their duration, the fee required pre-consenting reaches astronomical heights. Offshore projects would be expected to pay an additional £20m/1000MW for a grid connection that could be decades away. Some existing members would be facing project fees of £40m to progress past Gate 2; an amount that we believe will halt the majority of projects that will be critical to government climate targets. Although larger developers may have the capital for the fee, such members have expressed that they would not be willing to accept the level of risk proposed.

For onshore wind farms, that cost on average £2-5 million to develop through to consent, the new proposal would roughly double the pre-consent DEVEX for an average 100MW onshore wind farm, which would also be the case for an average 50MW solar project.

Questions regarding parameters that we have included in our modelling

The below questions will help us sense-check the assumptions used in our analysis:

Q9: What is the typical cost of capital (real, project-level, pre-tax) that you use to perform an 'all-in' financial assessment of a project (i.e. from development

through to end of operation)? How much higher would the cost of capital be for just the development stage (which we define as covering all costs and activities prior to the start of construction)?

The general market cost of pre-consent development capital is c. 15-25% Internal Rate of Return (IRR), depending on development stage and time capital is outstanding (vs. blended cost of construction capital is more like 8-10% IRR, and operational capital is more like 6-8% IRR).

The pre-consent cost of capital for onshore wind farms that rely on highly uncertain planning consent approval largely outside of developers' control is incredibly high. By doubling the cost of capital (see answer to Q8), critical technology projects are being put at risk at odds with CP30 targets.

Q10: Do you agree that a 0.5% outperformance on cost of capital (project level) is a reasonable lower-end outperformance that developers would target? If not, what would it be?

No – we would recommend an entirely different approach is taken. As above, cost of pre-consent development capital (which is the relevant measure here) is 15-25%, measured in 'multiples of money', or IRR. Project developers do not, in general, think of 'lifetime cost of capital' as laid out above, but rather view projects in discrete stages. However, it is certainly true that the return required on development capital is likely to translate to a construction return above construction cost of capital that sits above 0.5%, given the high risks involved in development.

Q11: What proportion of all projects that make it to Gate 2 do you expect to fail – i.e. to drop out of the queue? Do you expect the drop-out rate to differ materially by technology, and if so, how?

For large scale pumped storage hydro (PSH) specifically, the proposal penalises larger developers while early-stage development costs and risk are similar across large and small projects. This is particularly true if PHS projects are subject to the financial instrument before they have progressed past the Initial Project Assessment phase under the proposed cap and floor process. Our members have expressed it is likely that almost no PSH developer could make the fee at its current rate, and would thus drop into a Gate 1 position, reducing investor confidence, delaying delivery and potentially culling legitimate projects.

More generally, developers may be forced to revert to Gate 1 for projects without consent, constituting >85% of TEC for some members. We believe there will be fairly consistent negative impact across a wide scope of technologies. Although many projects have spent years and significant sums in development, including currently holding high securities, the risk profile for a grid offer without consent would be unviable. Combined with increases to grid connection costs and TNUoS charges, the proposal risks culling swathes of development bar a number of large players that can afford the risk.

As such, the total number of projects competing for CfDs or capacity market contracts will be decreased, resulting in decreased competition and an increase in associated clearing prices and hence cost for consumers.

Q12: The speculative project archetype is a developer that incurs the absolute minimum amount of costs needed to secure a connection agreement. Do you have a view on:

- the proportion of speculative projects that get to Gate 2 that are likely to result in successful project development and how this compares to the proportion for non-speculative projects?
- the typical resale value (ideally by technology type and on a per MW basis) that such a speculative project may be able to command from selling the connection agreement?

If the expected Gate 2 requirements are implemented, the proportion of successful project developments should increase. However, the uncertainties around connection point, connection cost (which varies until point of connection) and connection date are all still key development challenges which will not be addressed by a CCF. Other reform helps reduce speculative projects while a CCF simply increases the barrier for developers who cannot afford the higher risk years in advance of confirming project viability.

However, as aforementioned, the idea of a 'speculative' project is overly reductive as all project development requires investment, and therefore any project entering the queue has the original aim of being developed. 'Resellers' will develop a project that is appealing to buyers to develop further and take to final delivery. The new connections process raises barriers to entry, but as noted in answer to Q1, 're-seller;' projects are perfectly valid business models, but only work if projects are viable.