**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.**

* We support the principle of a Capacity Commitment Fee, but believe NESO’s current proposal is highly disproportionate for the defect it intends to resolve.
* The incoming TMO4+ proposals should address the risk of ‘resellers’ if properly policed. Furthermore, the ‘‘trading’’ of grid connection does not happen on the distribution network, where land rights and grid connection contracts are already linked. We would encourage NESO to conduct a minimum of manual verification of projects, for example checking for forgeries, including through contacting landowners to verify agreements, , check the land owned matches the area claimed and others., All appropriate details within the TMO4+ proposals, but which NESO has yet to confirm it will properly undertake at an early stage.
* 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 in itself an illegitimate part of the project development process, and welcome NESO’s acknowledgment of this in the call for input. There are many companies that will take a project through the early stages of development, before passing a valuable asset on to 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 other projects in the queue held up.
* This is also not cost reflective – for example, for projects with connection dates several years in the future, TOs would realistically have completed very little work in the short to medium term and the £20k/MW would in no way be reflective of TO spend ‘at risk’. Likewise, projects with wildly different connection works (e.g., one with a very short, inexpensive connection and one with a 40km grid connection) would face the same financial grid risk.
* Finally, under retained EU law, under the EGBL 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’. There are no costs incurred that NESO is addressing. EGBL intent is to be reflective of the costs incurred by network operators, which is not the case in this proposal; it could therefore be open to legal challenge.

**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. For smaller developers, i.e. those without significant balance sheets backing projects, the cost requirements for the fee would have to be raised alongside other pre-consent development costs. This would amount to roughly a 100% increase in costs, at the riskiest stage of the project, rendering such projects and developments unviable. The proposal fails to take into account the high-risk nature of the development of the project, where investors risk losing their money when projects come up against 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. In effect, consumers will be paying a substantial premium to remove speculative projects from the connections queue.

**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.**

* Views welcome.

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

* Industry discussed this in CMP192 and already forms part of CUSC section 15 - which shows how early stage projects (here under a ‘Fixed’ profile option) incur a security obligation of initially £1/kW rising to a cap at £3/kW. Under CMP192, a great deal of work was undertaken to identify an 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 until the point when the secured amount increased significantly in the last 4 years before the connection date. The new proposed CCF will be damaging because, unlike the User Commitment structure, it doesn’t recognise the risk profile of projects pre planning determination.
  + The financial analysis in calculating the commitment fee assumes 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.
* Limit the rate to a level that is more reasonable in relation to total DEVEX. A maximum fee of £10k/MW would be more appropriate.
* The liability should be stepped in synchronisation with the achievement of queue management milestones, to reflect the increasing total financial commitment being evidenced by the developer as a project progresses. This approach is more logical in terms of the aim of the Capacity Commitment Fee and also ensures that total development costs are not increased still further without any clear additional benefit to queue management.
* This is reflective of the application of such fees used as a comparison in Europe. 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 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 – these examples sit within significantly different contexts from NESO’s proposals.
* There needs to be a clear set of exceptions for changes outside of the developer’s reasonable control that lead to an exit from the queue. For example, given this liability will start before an application for planning consent 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.
* 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 discussed, the pre-consent stage of the project holds the highest risk, as planning approval is far from certain. Therefore, capital raised at this stage has the highest costs. This cost of capital must either be recovered by reduced profits, or increases in the costs of energy imposed on consumers (most likely via the CfD).
* This will have a greater impact on smaller developers in in favour of global utilities with the balance sheets to secure this outlay of capital, while there is a disproportionate negative impact on SME and community developers, who are developing real projects, but who don’t have ready access to additional credit lines.
* The proposal may also render **changes in TEC more expensive**, thus deterring the freeing up of queue capacity. 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 penalise developers for freeing up capacity on the grid queue.
* Finally, 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 of the developers control, but under these proposals, would be the developer would be liable for the security payment if the can no longer justify the project technically or economically.
* Note response to question 4 on how these risks should be managed.

**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

Offshore wind: ~

**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.
* Larger developers may fund DEVEX from the balance sheet; smaller developers will raise funds via debt finance.

**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 a 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.

**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% 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).

**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

**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. 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 culling legitimate projects.

**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?
* No comments