RESPONSE TO CONSULTATION ON REGULATION OF TRANSMISSION CONNECTING NON-GB GENERATION TO THE GB TRANSMISSION SYSTEM

17 January 2014

Introduction

Bord na Móna (BnM) welcomes the opportunity to respond to the consultation paper *Regulation of transmission connecting non-GB generation to the GB transmission system*.

Company and Project Background

Bord na Móna plc. is a publicly owned company with 95% of its shares owned by the Irish State and held by the Minister of Finance. The company was established in 1946 to commercially develop a portion of Ireland's extensive peat resources on an industrial scale, primarily for fuel and energy and also for production of horticultural growing media. Since its foundation BnM has diversified into a number of industries. Its businesses currently include conventional and renewable energy generation, commercial and domestic fuels, horticultural media and garden care products, waste management and resource recovery, and air / wastewater treatment.

The strategic intent of the company is to decarbonise by developing a range of businesses with particular focus on new 'clean' energy, waste management and resource recovery technologies. BnM currently owns approximately 80,000 hectares of peatlands, with the majority of the land holding located mainly in the Irish midlands, on average just 130 miles from the UK coastline. A considerable fraction of the company's landing holding is now classified as 'cutaway', a term used to indicate that the area can no longer be harvested economically for energy supplies, and is now available for re-development for other purposes including renewable electricity generation from wind energy. These areas have characteristics that make them ideally suited as locations for wind farms given the advancement in wind energy technology for medium speed wind sites in the last few years.

Within this context BnM has an opportunity to develop wind generation assets (circa 2GW), capable of direct export to Great Britain[1], on suitable lands on and around its own landholding in the East Midlands of Ireland. The company is currently constructing 120 MW of wind energy capacity on cutaway peatland sites and has several other projects in the development pipeline for the domestic market. BnM does not hold a formal connection offer with National Grid and is not currently pursuing development of a dedicated transmission link to connect its wind farm to the GB network. We would therefore seek to secure long-term financially firm access to such a transmission asset. As such this response does not discuss the technical considerations associated with development of transmission assets in detail; instead this response considers the requirements and risks faced by a wind farm developer considering such a project, and the features of any potential regulatory regime that can help to mitigate those risks and secure value for money for the end consumer. Despite our focus on the development of a specific project, we note the potential offered by the export of Irish wind energy to contribute to GB and EU policy objectives in three

[1] Bord na Móna's Clean Energy Hub (CEH) project; see *http://www.cleanenergyhub.ie/*

important ways: enabling cost-effective access to renewable energy sources, enhancing regional electricity markets and delivering wider network benefits to consumers.

The project BnM is considering will require timely and cost effective access to the GB electricity system via a transmission asset whose owner or operator is able to make a financially firm long-term capacity offer. This means that the prospective wind farm will have priority access to a specified level of transmission capacity and that any failure of the connection, curtailment or constraint on access must result in adequate compensation. The regulatory environment must either provide for such an arrangement directly, or enable a license holder to offer a commercial agreement with such terms. BnM also seeks clarity on the costs and risks of transmission covering: GB connection charges, potential GB onshore gird reinforcement costs, GB transmission network charges, transmission losses, regulation of the access charge and the capacity allocation process. This is essential for the economic case for the project.

Our responses to the consultation paper’s specific questions are set out below. We have reflected on the requirements given both the constraint of delivery of all capacity in 2020 and what could be achievable over a longer timeline.

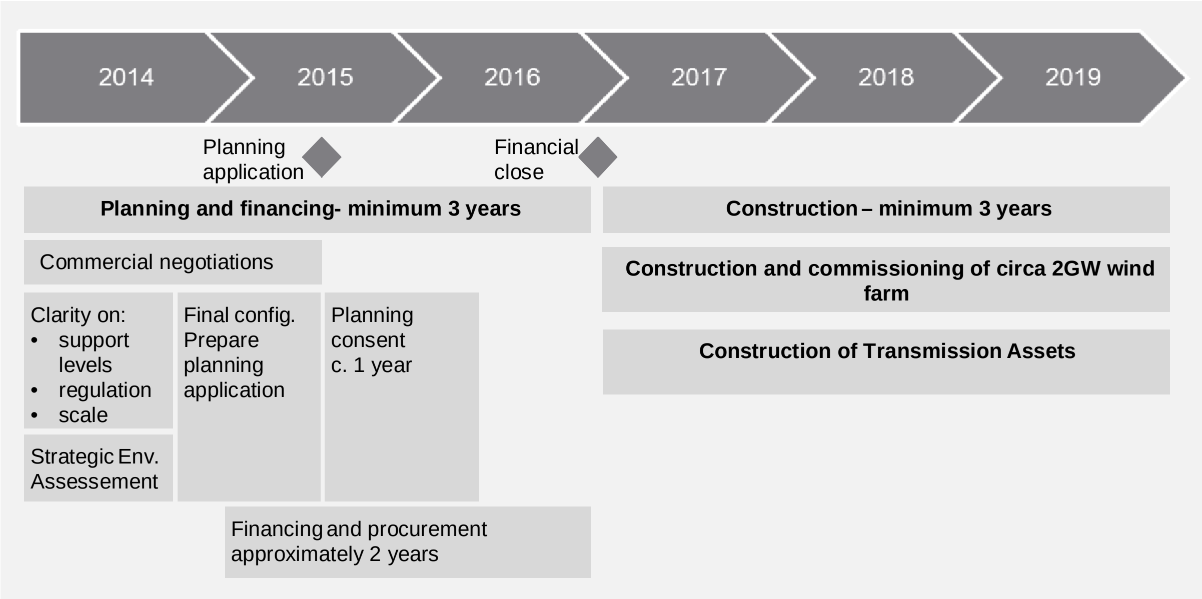
Chapter 1: Introduction

Question 1. What are the key milestones for the delivery of non-GB generation and connections pre-2020? How does the decision on the regulation and licensing of non-GB connection fit into this timeline?

Summary

- For a project of this scale to deliver all the contracted power by 1 January 2020, we consider an Irish planning application must be submitted by H1 2015. Hence this project faces a challenging timetable in terms of the time available for the planning, design, and financing to reach financial close by the end of 2016 and allow a 3 year construction period
- The planning application will need to detail the asset configuration including transmission to the GB system, hence regulatory certainty is required before the end of 2014 to enable a complete planning application to be submitted
- The planning application will also require significant progress on support arrangements and potentially on commercial agreements so that the application is based upon a clear configuration of generation and transmission assets

The key milestones for the project are set out in the diagram below.



The construction phase for a project of this scale will take at least 3 years. In order for the project to be operational by 2020 design, planning, financing and procurement must be fully committed by 31 December 2016. To get to that point we would expect the planning and financing stage to take a minimum of 3 years. The best case timeline is set out in the diagram above. The first stage represents a challenging period of planning and negotiation with several interdependent processes occurring concurrently; this challenge can be reduced by earlier clarity on the regulatory and support framework. We note that for a project of this scale, were the timeline not constrained to deliver all the contracted power in 2020, a phased approach would be advantageous with some phases of capacity coming online during and after 2020.

The upcoming milestone for the project is to submit a planning application by H1 2015. This planning application is driven by and dependent upon the regulatory arrangements for the whole project as the application will need to detail all components of the integrated project including the configuration and location of the generation and transmission assets to connect the generators to the GB grid. A decision on the regulation and licensing of the transmission assets is required as soon as possible so that any required commercial agreement on capacity and the terms of access can be reached in time to submit a detailed planning application.

We also note that in addition to certainty on the regulatory framework the project will also require certainty from Government on the level of support and the total capacity to be supported. The regulatory arrangements and level of support will influence the underlying economics of the project, along with the optimal scale and configuration of assets. It therefore stands to reason that as the details regarding the capacity and configuration of the generation and transmission assets are an integral part of the project; sufficient clarity must be delivered prior to a viable planning application being lodged.

Question 2. From the perspective of a non-GB project developer, how does the decision on the regulatory arrangements interact with Government decisions on renewable support (such as the award of a Contract for Difference (CfD)?

Summary

- The BnM project would require financially firm access to transmission capacity to underpin/guarantee support offered by Government and wholesale electricity market revenues. This must be either provided by the regulatory framework or a commercial agreement that can be supported under that regulatory framework and agreed by the time of financial close

- This access must be financially firm in the sense that investors can expect guaranteed revenue whenever the generating assets and wind conditions are physically able to generate electricity. Outages on the part of the transmission asset or curtailment or constraint for other reasons should result in compensation to preserve the expected revenues of the generating assets

- Costs of access to the GB network must be taken into account by Government when determining the support level as these are additional to the costs of a conventional GB-based project

- The scale and scope of government support is subject to ongoing inter-governmental discussions. However, given the interaction between the regulatory framework and the costs faced by developers, those discussions could usefully consider the components of project costs that will vary according to the regulatory framework

- This consideration could start with the support levels required for GB and Irish onshore wind, and specifically consider three additional components: 1) the costs of the connection and transmission assets required for renewable energy exports; 2) the influence of the regulatory framework on transmission costs; and; 3) any additional costs required to enable connection and transmission assets to provide wider benefits of market integration and network reinforcement

Renewable support is usually linked to generation assets, which are dependent upon access to transmission capacity. It is therefore critical that the regulatory framework clearly allocates transmission capacity to renewable projects in advance and provides long-term financially firm priority access to the GB transmission system.

In order to make this long-term access “financially firm” it must provide a secure revenue stream. It is therefore important that a compensation mechanism exists to reduce the risk to revenues (including wholesale electricity and renewable support revenue) in the event of a failure of third party equipment, or a constraint or curtailment of generation due to the management of the transmission assets or the national transmission systems to which they may be connected. Under different regulatory arrangements some of these features may be provided by commercial agreements rather than regulation itself, however the regulatory framework must enable such agreements (i.e. contain relevant exemptions from standard interconnector license conditions).

The level of support required for investments to recover their costs is also affected by the regulatory framework governing charging for transmission capacity, measurement of the system entry point (i.e. transmission losses), potential GB use of system charges, and risks of cable failure (or associated insurance costs). Notwithstanding the impact on potential developer's financing costs, different regulatory treatments can change the balance and allocation of these risks and costs. Hence it is important that the level of support is decided with these risks and costs in mind. We note that ,for conventional onshore wind projects, some of these cost elements are met by National Transmission Systems or otherwise 'socialised' across the sector rather than borne by generators or directly passed on to them.

The scale and scope of government support for Irish renewable energy exports is subject to ongoing discussion between the UK and Irish Governments and the support regime could adopt a range of possible models. We consider that some costs are likely to vary according to the regulatory framework, and hence these need to be considered through these inter-governmental discussions and feed into the ultimate decisions on the appropriate level of support.

The likely costs of Irish wind energy exports could be derived from the costs of conventional onshore wind farms and three additional components set out below, some of which are critically dependent upon the regulatory framework:

1. Additional costs related to the provision of the physical connection and transmission infrastructure
2. Potential additional costs to enable use of the transmission infrastructure to provide wider benefits of market integration and network reinforcement
3. Further transmission and connection costs including:
    a. Cost of providing revenue security in the event of transmission asset outages, curtailment or constraints
    b. GB connection and use of system charges
    c. Transmission losses

Question 3. Are there other factors that Ofgem should be aware of relating to the timing and development of non-GB connections?

Summary

- The scale of this project and the timeline for delivery will depend upon timely and efficient management of supply chain activities throughout the procurement and development phases (e.g. ordering and installing circa 650 3MW turbines for a 2GW presents a significant scheduling risk).

- These supply chain challenges might be greatest in relation to procurement of subsea cabling at a time when the cabling supply chain is predicted to be facing significant pressure.

Delivering a project of this scale according to the timeline set out in our answer to question 1 will require an ambitious programme of project management, negotiation, procurement and financing.

Our response to question 1 referred to planning requirements for the Irish system. We note that planning permission will also be required for onshore grid development and reinforcement work within GB, which could provide further delays to the connection process. This would be exacerbated in the absence of a 'Connect and Manage' derogation (this is discussed further in our answer to question 17).

Leaving aside the delivery of turbines (e.g. circa 650 3MW units for a 2GW project) the supply chain for subsea cabling in the run up to 2020 is facing significant challenges due to an expected increase in demand and, in the case of HVDC cabling, a limited number of suppliers. BVG Associates have suggested that that award of a significant interconnector project should occur four or more years ahead of delivery in order to trigger new supply chain capacity that may help relax the constraints. Hence, any delays to placing an order for subsea cable would represent a fundamental risk to the timetable and potentially the costs of developing the transmission asset.[2]

Chapter 2: Principles of transmission regulation

Question 4. Do you agree these are appropriate principles to take into account in relation to non-GB connections?

Summary

- We agree with the principles set out in the consultation document, and that those principles have important implications for the way the transmission asset(s) should be regulated

Irish wind exports have a role to play in protecting consumers from undue exposure to costs or risks; since, in the short term renewable energy can be sourced cost effectively, whilst in the longer term both the British and the 'All Island' system can reap wider benefits from increased market integration, network reinforcement and shared back-up generation capacity.

Promoting efficient capital and operational network costs is important in the case of a novel project where jurisdictional boundaries and an absence of pre-existing market and regulatory arrangements may lead to a project being considered as high risk by investors. In this case it is important to come up with a combination of regulatory and commercial arrangements that enables the efficient allocation of risk between developers of generation and transmission assets.

Promoting efficient and coordinated development of the network represents a major secondary benefit from developing Irish wind exports. In particular, dedicating a

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[2] http://www.bvgassociates.co.uk/Portals/0/publications/BVGA%20TCE%20Offshore%20Wind%20SC%20Health%20Check%201311.pdf

transmission asset to wind generation assets that operate at an average load factor of 30% will result in a significant amount of spare capacity. It would be efficient to consider using this capacity for wider market and network benefits as a cost effective alternative to further interconnection, or onshore or offshore network reinforcement. From an EU perspective enhancing market integration (both in trade of energy and renewables) has been supported as a beneficial 'low regret' policy choice[3].

Supporting the investment in low carbon electricity generation is a clear direct benefit of the development of Irish wind export projects, as this could enable cost efficient deployment of available renewable energy resources. To this end the regulatory framework should seek to support an investment environment that provides similar security to that which would be expected by investors in renewables projects aimed at domestic consumption.

Question 5. Are there other principles that we should also we consider?

We consider the principles set out in the document to adequately cover the considerations relevant to non-GB generation projects in general, and would again refer to our answer to question 4 which details in particular how RES exports from Ireland are aligned with Ofgem's stated principles.

Chapter 3: Legal classification and licensing

Question 6. We invite views on our interpretation of the different asset definitions/boundaries and interpretation of the legislation provided in this chapter. What implications does this have for the regulatory options presented in the next chapter?

Summary

- We agree with Ofgem's interpretation of current legislation that the cross-border transmission asset should be licensed as an interconnector
- We also believe that an interconnector licence will best enable the use of likely spare capacity for wider benefits of market and network integration that may offer significant benefits to consumers and networks in the future

We note that the EU definition[4] of an interconnector as a part of regulation No. 714/2009 could be seen to override the GB definition[5]. The EU definition could therefore provide a potential justification to consider the transmission asset to be something other than an interconnector. However, as the EU definition is effectively a

[3] http://ec.europa.eu/energy/infrastructure/studies/doc/20130902_energy_integration_benefits.pdf

[4] A connection between two **national transmission systems**.

[5] A wire that **conveys electricity** between Great Britain and a place within the jurisdiction of another country or territory.

subset of the GB definition, it could be argued that they are not in direct conflict. Further to this we believe that licensing the connection as something other than an interconnector may restrict potential future uses of the asset to provide wider benefits of improved market integration and network reinforcement by precluding any connection to the All Island transmission system.

The interpretation set out in the consultation document, i.e. to license the transmission asset as an interconnector, may have implications for the grid connection process and in particular the potential eligibility for connection under a 'Connect and Manage' derogation. Such a derogation may prove critical in securing firm access to a GB grid connection before 2020. Clarity on this point would be essential alongside a decision on the regulatory framework.

Further, as discussed in our responses to questions 12 and 13, it is likely that an interconnector used for these purposes will require some exemptions from the standard licence conditions. In particular exemptions may be required in respect of conditions relating to allocation of capacity and use of revenues.

Question 7. We are interested in views from stakeholders on what impact alternative interpretations would have on potential projects? Please provide detail where possible.

Summary

- Given the definition within the EU Regulation No. 714/2009 we believe that adopting a different interpretation of the asset boundaries may preclude future connection to the All Island transmission systems

- This may forego potential wider benefits of market and network integration which we see as an important potential longer term benefit of Irish wind export projects. Ruling out such a use could lead to inefficient network development should further reinforcement or market integration be deemed necessary

Given the definition within the EU Regulation No. 714/2009 we believe that licensing the connection as anything other than an interconnector would preclude future connection to the All Island transmission systems. This may forego potential wider benefits of market and network integration which we see as an important potential longer term benefit of Irish wind exports. Ruling out such a use could lead to inefficient network development should further reinforcement or market integration be deemed necessary.

BnM notes that in order that a potential interconnector operator can offer BnM the firm access to capacity required for our project to reach financial close (see response to question 2 above), that operator will most likely have had to secure exemptions to some standard conditions of the GB interconnector license (see our responses to questions 12 and 13).

Question 8. We seek input from stakeholders on how generation licensing for non-GB generation could ensure appropriate safeguards for the export of renewables to the GB transmission system?

We see no reason why existing CER generation licences could not provide the required safeguards. It would be prudent for Ofgem and CER to review the terms of the standard CER generation licences and establish whether any amendments are necessary to ensure compatibility with the GB system requirements, however we do not see this matter being a barrier to the delivery of an Irish export project.

Chapter 4: Asset configuration

Question 9. Are non-GB connections deliverable by 2020 via direct and exclusive connections?

Summary

- Direct and exclusive connections may simplify planning and financing; however, they face challenges in securing exemptions from interconnector licence conditions unless they build in some form of competitive allocation of capacity
- We also believe that direct and exclusive connections are less likely to result in efficient or coordinated network development, less likely to take advantage of spare capacity on the connection and less likely to maximise the potential cost-effective contribution of Irish wind resources to low carbon generation

A direct and exclusive connection may offer advantages in terms of speed of project design and planning. However, such a project may face challenges in acquiring an interconnector licence with exemptions from capacity allocation; as some form of competitive allocation mechanism may be preferable, or closer to the intentions of the standard licence condition.

In addition, we believe that such an approach would not necessarily lead to efficient or coordinated development of the network as it would focus on the specific needs of non-GB generators rather than the wider potential benefits of market integration and network development. Network development should be done in the context of the potentially significant amounts of spare capacity on such an interconnector, which could potentially reduce the need for other costly network developments.

Further, a direct and exclusive approach may not lead to optimal site selection for generation assets and therefore may not maximise the potential cost-effective contribution of Irish wind resources. This is due to the scarcity of cost-effective GB network connection capacity for Irish projects prior to 2020, which may drive inefficiency under a direct and exclusive approach.

Question 10. What are the technology challenges of delivering direct and exclusive connections? What are the technology challenges of delivering multi-purpose assets?

Summary

- BnM is not currently pursuing development of a dedicated transmission link to connect its wind farm to the GB network. The project's scale and complexity may provide significant technical challenges
- These challenges are not necessarily any greater than (and in some ways are not as complex as) those faced by existing interconnectors and some large offshore wind developments currently being planned
- We recognise that multi-purpose transmission assets will face additional challenges related to technical compliance with two transmission systems
- Multi-purpose assets aiming to contribute to wider grid reinforcement will require a different design to that of a direct and exclusive connection and may therefore incur additional costs. These costs could either be met by the national TSOs or passed on to the non-GB generators and will need to be considered by DECC in setting the level of support.

The technology associated with delivering a direct and exclusive connection to the UK grid is not different in principle from that which has been deployed previously on large offshore wind farms. It should be acknowledged that the scale of some of the proposed export projects would require careful design of the HVDC link to the UK and the onshore collection networks, given the challenge of operating an island AC network with largely non-synchronous generation attached to it.

Multi-purpose assets (which could deliver market-to-market trading as well as deliver wider network benefits) may require a different configuration to provide full capacity to flow power in both directions. In principle this would technically be similar to a conventional interconnector. The key additional requirement would be connection to the All Island transmission network. This connection will require at a minimum that the connection to the All Island transmission network and the HVDC "interconnector" would have to comply with Irish Grid Code, and possibly the collector network also, (depending on whether it connects to the transmission system). This could potentially alter the choices available for the interconnector technology, and impact the cost of the connection infrastructure over that which would be required for a direct and exclusive connection.

However, these technical challenges are not necessarily any greater than those faced by several large offshore wind developments current being planned. In fact the suitability of many of the sites that we have identified for turbines are likely to make the wind farm construction as straightforward as it can be for developments of this scale.

BnM does not hold a formal connection offer with National Grid and is not currently pursuing development of a dedicated transmission link to connect its wind farm to the GB network. We recognise that multi-purpose transmission assets will face additional challenges related to technical compliance with two transmission systems. However the system could be organised in such a way that this challenge mirrors that faced by existing interconnectors.

Were a co-ordinated approach to be adapted, multi-purpose assets aiming to contribute to wider grid reinforcement will require a different design to that of a direct and exclusive connection and may therefore incur additional costs. While a regulated regime for the transmission assets is preferable in either scenario, these costs will either be met by the national TSOs or passed on to the non-GB generators and will need to be considered by DECC in setting the level of support as discussed in our response to question 2 on the interaction between the regulatory arrangements and the level of support.

Question 11. What are the potential benefits and challenges of enabling flexibility for a non-GB connection to also be used for a) market-to-market trading; and b) GB network reinforcement? What are the implications for investment certainty?

Summary

- Development of a large transmission asset for intermittent generation will result in significant spare capacity. This capacity represents an opportunity for GB and the All Island markets and networks to become more integrated

- Irish wind exports could be of sufficient scale to support multiple subsea cables providing geographical flexibility as to where power could be landed. Such flexibility could be used to provide some network reinforcement and reduce the need for other onshore or offshore grid reinforcement projects in the future

- We believe that creation of a significant cross border connection without contributing to longer term market integration, system security and long-term network benefits could lead to a situation that is subsequently seen as a valuable opportunity missed

- Considering these potential wider benefits could have important implications for the configuration of the connection, and the need for additional onshore reinforcement either in Ireland or GB

- In terms of investment certainty, it may be challenging to monetise the wider benefits of market and network integration within the financing of individual projects. Hence it is important that the regulatory environment and the level of renewable support are designed to facilitate connection(s) that are capable of providing wider benefits

Again we would, in the first instance, refer back to 'Principles of Transmission Regulation' outlined in the Consultation paper and also highlight our response to question 4 which aligns RES export from Ireland with these principles. In addition to the delivery of RES electricity and contributing to security of supply, we believe that the transmission asset is likely to offer significant spare capacity that could be used to contribute towards long-term objectives of increasing integration in regional electricity markets, networks and utilisation of renewable energy sources. These benefits, whilst difficult to predict and monetise, could be seen as 'low regret' choices.

The potential scale of Irish wind exports could support different transmission configurations, for example with multiple connections with geographically distributed landing points. This flexibility could provide a cost effective alternative to other potential network reinforcements (such as additional bootstraps) or potential new interconnectors.

As noted in the response to question 10, a regulated regime for transmission is preferable. In the absence of such a regime the requirement for investment certainty depends critically upon support levels for renewables and whether they have factored in transmission charges that cover the costs of transmission access and any additional costs of a configuration that supports wider benefits. If these costs are passed on to non-GB generators without a corresponding increase in the support level for the non-GB developers then investors would not be able to finance developments that offer such benefits. Put simply, the wider benefits that could accrue to both national networks and markets are likely to be difficult to monetise and finance within any individual project. If any such costs and benefits are factored into renewable support levels, then the investments could be financeable via the charges paid by generators.

Chapter 5: Existing and potential regulatory options for application to non-GB connections

Question 12. Is the interconnector licence with exemption(s), as currently available, a feasible option for non-GB connections? If not, what are the key challenges of applying this route to non-GB connections? How could these challenges be addressed?

Summary

- We believe that an interconnector licence with the correct exemptions is a feasible option for non-GB connections provided that the licence allows the interconnector operator to offer wind generators financially firm access to capacity

Conditional on achieving the required Ofgem, CER and EU approvals and exemptions, the interconnector license is a feasible option (see answer to Q13 below for more detail). We note that the timescale for licensing may be tight as details on the configuration of the connection must feed into the planning application in H1 2015, as outlined in our response to question 1 above. This may also require some initial commercial negotiations between the interconnector operator and the non-GB generators to understand the basis of access and charging if this is not clearly provided by regulation or underpinned by the renewable support.

The asset owner and potential users would need to allocate capacity on a financially firm long-term basis and negotiate a commercial agreement covering allocation of capacity, usage charges and compensation mechanisms in the event of outages or transmission constraints. There are some precedents in terms of charging methodologies that might be adapted to the purpose; however capacity allocation may require a commercial negotiation between several potential parties.

Question 13. Under this route would an exemption (under Article 17 of the Electricity Regulation) be required? If so, which provisions would you seek exemption from? How would your project be affected if exemptions could not be applied for?

Summary

- BnM does not hold a formal connection offer with National Grid and is not currently pursuing development of a dedicated transmission link to connect its wind farm to the GB network; however it seems likely that exemptions relating to capacity allocation and use of revenues would be required

BnM is not proposing to take a direct role in constructing or operating the transmission connection asset so we would not seek exemptions ourselves. However it seems likely that key exemptions would include (but not necessarily be restricted to):

Use of revenues – it is likely that interconnector revenue would need to be retained by the operator and used to make financial re-payments if the transmission assets are funded commercially

Non-discriminatory capacity allocation and non-price terms and conditions – interconnector access for non-GB generators is critical for their investment decisions. This may require different (i.e., long-term, financially firm) access arrangements with different non-price terms and conditions for renewable generators compared to any users of residual capacity for market trading or network benefits.

Question 14. Given that an application of the regulated Cap and Floor or fixed revenue model would take time to implement for non-GB connections, should these still be explored further?

Summary

- The regulated revenue approaches seem likely to offer a more straightforward mechanism to support wider system benefits, if they could be fast-tracked in order to facilitate 2020 delivery, or if a phased approach were to be adopted.

Notwithstanding the suggestion of a phased approached discussed in response to question 1, and focusing on the current requirement to deliver power in 2020, we believe it is appropriate to reach certainty on the regulatory framework as soon as possible. Whilst the other regulatory approaches might have advantages over a longer time horizon, particularly to provide for wider benefits of market integration and network development, it is unlikely that these models can be developed in keeping with the timelines outlined in response to question 1.

We note, should Government still wish to deliver network connection(s) that maximise wider network benefits, increase market-to-market trading, improve regional integration and enhance security of supply, the expected additional costs (in the absence of a regulated revenue regime for transmission) could be factored into any consideration of the appropriate level of renewable support. Whilst this may not follow standard approaches to funding network developments, it may prove the most realistic support mechanism for a network configuration that is both delivered on time and capable of proving wider benefits in the future.

Question 15. If so, what are the main challenges and benefits of applying a regulated Cap and Floor or fixed revenue model to non-GB connections? How could these be addressed?

Summary

- The predictable element of transmission revenue likely to result from long-term agreements with non-GB renewable generators would be such that the variability in core revenues should not be a concern for the interconnector operator
- Revenues from other activities (sale of residual capacity) are likely to be uncertain and hence difficult to bank on at the outset unless regulated returns are provided
- Depending upon cost allocation and the charging methodology for long-term capacity agreements, it may be appropriate to recycle revenue from residual capacity back into reduced access charges for long-term agreements

It is expected that the majority of capacity on the interconnector would be allocated long-term and with priority to wind power generation export projects according to an agreed charging methodology. As such the scope for variable revenues would be restricted to additional uses that can be found for such spare capacity as is available. Since monetising the wider benefit available from users of residual capacity is likely to be challenging it seems that a regulated revenue stream is likely to be a more appropriate support mechanism.

A cost allocation methodology could, in principle, differentiate between the core costs of the transmission asset (and allocate these to long-term charges) and the costs incurred to support wider benefits (and allocate these costs to the trading or regulated revenue stream).

The primary benefit of these arrangements is that support for renewable generation can be separated from support for wider network and market integration. This could be considered by Government in the context of the potential components of the level of support required to fund both generation projects and a transmission asset that offers wider benefits. As mentioned above (see our response to question 14) this may be the best option to deliver a transmission asset by 2020 within an ‘Interconnector with exemptions' licensing framework that is also capable of offering wider benefits of market integration and network reinforcement.

Chapter 6: Other regulatory issues

Question 16. What is the appropriate mechanism for ensuring access to capacity for non-GB generation?

Summary

- BnM will require timely and cost effective long-term financially firm access to transmission capacity in order to secure financing for our project
- Capacity used for other purposes should be allocated on a 'residual' basis, that is to say the level should be conditional on providing the capacity required by wind generation or should take into account the level of compensation required

BnM will require timely and cost effective financially firm access to capacity in order to proceed with our project. This will require a mechanism that provides long-term transmission access and is capable of mitigating against revenue loss due to transmission outages and potential curtailment or constraint. This capacity allocation would have to be conducted before the planning application is submitted in H1 2015.

Allocating capacity for delivering wider market integration and network benefits may be more problematic. Renewable developers will almost certainly require long-term priority access to capacity, i.e. 'financially firm' access as described above. Other uses such as trading may therefore be restricted to residual capacity that is not required by wind farms but remains uncertain until the delivery period. The initial allocation could be the subject of a commercial negotiation or a formal auction process. To achieve value for money residual capacity options could be traded or auctioned in a secondary market.

Question 17. What are the implications of following the current connections process for non-GB connections? Should non-GB generators be treated differently to GB based generation? Should non-GB generators be treated differently to other interconnector users? If so, please provide your reasoning.

Summary

- The current connections process for non-GB generators is unclear as there is a potential inconsistency between the regulatory position outlined in this consultation and existing connection offers. A 'Connect and Manage' derogation may be critical to the connection timescales
- Both non-GB generators and a potential interconnector developer are likely to face a different balance of revenues, risks, costs and timescales to GB generators or other interconnector users. In order to provide a secure investment environment this may require a different connection process

- In particular the timescales may necessitate an interconnector connection with a 'Connect and Manage' derogation, and some progress towards understanding the commercial terms of capacity access before 2015
- The current process with multiple individual offers may lead to sub-optimal individual developments that do not necessarily provide an optimised or integrated network solution that reflects wider market integration and network reinforcement benefits

The current connections process for non-GB generators is unclear as there is a potential inconsistency between the regulatory position outlined in this consultation and existing connection offers. In particular the interpretation of the connection as an interconnector (on the part of this consultation) may not be compatible with existing grid connection offers. We note that a 'Connect and Manage' derogation may be critical to connection timescales as without this derogation any connection date for non-GB generation may have to follow the completion significant wider work to develop the onshore transmission grid.

Ideally non-GB generators would face the same balance of risks and costs and revenues as GB generators; however we note that this is unlikely to be the case if the transmission asset is to be licensed as an interconnector with its own capacity allocation and charging methodologies.

In order to preserve the investment incentives for non-GB developers, they will need to be treated differently to other interconnector users as they will require long-term 'financially firm' access to capacity, and a reasonable degree of certainty around charges or the charging methodology.

The specific connection process (including the eligibility for 'Connect and Manage') is critical to connection timescales and costs. Development of wind farm projects will require clarity on whether a 'Connect and Manage' derogation from the Security and Quality of Supply Standard applies, the treatment of transmission losses, use of system charges, and, access arrangements. The balance of all connection and interconnector capacity charges should be considered by Governments when deciding upon levels of support.

The is a risk that the current process, with multiple individual offers, could lead to exclusive developments that do not necessarily provide an optimised or integrated network solution that reflects wider market integration and network reinforcement benefits. Therefore this might compromise the realisation of some of the benefits associated with the principles of transmission regulation outlined in chapter 2 of the consultation document.

Question 18. How would the role of the interconnector operator need to adapt if a direct-connect asset was used for additional purposes – such as a) market-

to-market interconnection; or b) GB network reinforcement? Should the GB or non-GB NETSO have a role in operating these assets? If yes, what role?

Summary

- Market-to-market trading will require the operation of a connection to both networks that is compliant with the technical and regulatory conditions
- The interconnector owner will have to identify residual capacity after accounting for the 'financially firm' nature of wind generators access agreements, and allocate that residual capacity to traders, or notify availability to system operators
- The NETSOs may take a role in determining how any flexibility in landing of power in the GB grid is managed. This may directly influence the availability and nature of residual capacity

The interconnector operator will have to interface with two different markets' trading arrangements, networks, markets and system operators. They will potentially have to manage a system boundary in such a way as to comply with both networks.

The interconnector operator would need to identify the level of residual capacity, and allocate that capacity in such a way as to preserve the priority and long-term financially firm access of renewable generators or manage any compensation from curtailment. It could allocate residual capacity either to market-to-market traders or to either NETSO according to their system operation requirements.

The system operators should have a role in establishing any desired flexibility for system reasons, (i.e. the amount of power landed at any given landing point, the direction of the interconnector flows and the potential use of any spare capacity to flow power for network reinforcement purposes). This role should be restricted to the use of residual capacity after wind export power has been accommodated, or should be associated with the compensation payments discussed in the context of 'financial firmness' earlier in our response.

Question 19. Can the existing charging/cost allocation approaches used onshore or for interconnection be applied to non-GB connections? If not why not and what alternatives are available?

Summary

- In principle, existing cost allocation and charging methodologies could be adapted for this purpose
- They may require adaptation to deal with some unique characteristics of the interconnector such as transmission losses, use of system charges and potential costs to support wider market integration and network benefits

In principle existing charging methodologies could be applied to these assets. However, the charging methodology should be consistent with the regulatory status of the transmission asset. That is, if the connection is treated as an interconnector user, then it should correspondingly be exempt from GB costs such as transmission charges, transmission losses and potential GB use of system charges. If, on the other hand, it is treated as a GB-generator, it should be liable for these charges, but should be granted firm access and should have any risks of cable failure underwritten by consumers.

Moreover, additional costs of spare capacity incurred to support wider benefits could deter investment if recovered from generators, unless these costs have been allowed for by Governments in determining the level of support.

A cost allocation methodology could, in principle, differentiate between the core costs of the transmission asset (and allocate these to long-term charges) and the costs incurred to support wider benefits (and allocate these costs to the trading or regulated revenue stream).

If interconnector costs are to be partly recovered from generators and partly socialised via national transmission system charging, then an additional cost allocation step may be required.

Question 20. How can capacity allocation for direct and exclusive connections ensure consistency with European legislation and European Network Codes? How could this be achieved with the introduction of market-to-market connections?

Summary

- Long-term priority 'financially firm' access for renewable generators is unlikely to comply with European Network Codes, since it will potentially only be allocated to specific renewable projects. Hence the interconnector will need to receive some exemptions (as set out above).

It is unlikely that the allocation of capacity would comply with European Network Codes; hence an exemption for this purpose would probably be required. In particular interconnector capacity would potentially be allocated only to specific renewable projects, and they would have priority or 'financially firm' access.

The use of residual capacity for other purposes could be allocated according to a different mechanism that was compliant with the principles of European legislation.

Question 21. Are there other challenges we should be considering when looking at non-GB connections?

We have not yet identified any major further challenges in addition to those raised in the consultation and this response.

For and on behalf of Bord na Móna

Dr John MacNamara

Regulatory and Commercial Affairs Manager

Bord na Móna