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30 May 2013

Brian Mulhern
Utility Regulator
Queens House
14 Queen Street
Belfast
BT1 6ED

Dear Brian,

RE: Consultation on connection arrangements for offshore renewable generation

Thank you for the opportunity to respond to this consultation. First Flight Wind Ltd (FFWL) was awarded the exclusive development rights for the 600MW offshore wind farm site on the south east coast of County Down by The Crown Estate in 2012. The issues covered in this consultation document are crucial for the successful development of this offshore wind farm, both in terms of ensuring that the development programme can progress in a timely manner to contribute to the 2020 renewables target, and that the project is competitive with other offshore wind farms.

As set out in DECC's Electricity Market Reform policy overview document published in May 2012[1], renewables projects in Northern Ireland will continue to fall under the same support mechanisms as those in GB (the Contract for Difference, or CfD mechanism), with the option for Northern Ireland to amend the support level to ensure that NI projects remain competitive. There are many factors that affect the level of support required by a specific project, such as technology choices, distance from shore, water depth, and ground conditions. In addition to these project specific factors, the regulatory regime under which the project falls also has implications. In order for a Northern Irish project to be able to compete on the same terms as a GB offshore wind farm, the regulatory framework needs to have broadly similar cost implications. The ownership and cost allocation arrangements for transmission connection assets have direct consequences for this: choices that result in Northern Irish projects being less cost competitive than GB projects due to the regulatory treatment will be at a disadvantage, and will be more likely to require a NI-specific strike price to compensate for higher costs.

FFWL's high level conclusions are as follows:

- Our preferred option for the ownership and funding aspect of the connection is for NIE to purchase the connection assets in a regulated sales process (which does not

[1] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48371/5349-electricity-market-reform-policy-overview.pdf

need to mirror the GB OFTO process), and for the project to provide NIE with a low-risk revenue over the lifetime of the project.

- Given the experience from the GB market of the parties in the FFWL consortium, we believe the best option is for the developer to be responsible for the design and construction of the connection assets.
- It will be difficult to proceed with the project unless the requirement of having planning consent prior to making a grid connection application is removed. We believe a more appropriate option is for the generator to be able to apply once the exclusive development rights have been awarded by The Crown Estate.
- Any solution involving FFWL owning the transmission assets on a long term basis will introduce legal and regulatory uncertainty surrounding compliance with the EU Third Energy Package and further impact confidence investment confidence.

Please find our responses to the specific chapters below.

We believe that it is very important that a firm conclusion on the connection arrangements for offshore renewable generation is reached soon, in order to avoid project delays and uncertainty. The project programme for onshore environmental assessment is already significantly constrained by the current timeframe for this consultation (and potentially a subsequent consultation on Planning Standards). An early and clear conclusion to this consultation would therefore be welcomed to allow all parties to the connection process to engage fully in progressing decisions necessary for the project consenting process.

We would welcome having a meeting with you at your convenience if you consider that would be of help to clarify any of the points we raise in our consultation response.

Yours sincerely,

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Chapter 5: Options for physical connection arrangements and wider transmission system reinforcements

FFWL's response to this chapter will only address the physical connection arrangements for an offshore wind farm, that is the required connection assets and their configuration, and not the key issue of ownership which is addressed in detail in our response to Chapter 6.

In identifying a connection which is workable for the project, and optimal for the network, many options exist in terms of technology choice, voltage level, system redundancy etc., some of which have been identified in the consultation document. We do not consider this list of options exhaustive however, and we believe that any regulations put in place should not prohibit the deployment of solutions which may offer better value for the project and the Northern Ireland consumer. It is important that the correct, overall connection solution can be developed.

FFWL partners have a very strong track record in the design and delivery of offshore transmission connections including both offshore and onshore elements, and have been involved in 6 out of the 11 currently installed offshore wind transmission connections in GB, with many more in construction and development. As such we believe that FFWL has the necessary competencies to engineer, procure and construct offshore transmission systems and onshore connections. Therefore this delivery model would be our preference from a purely technical perspective, as it allows a unified and holistic design development approach for the offshore generation and transmission assets.

Our responses to specific issues raised in Chapter 5 are set out below.

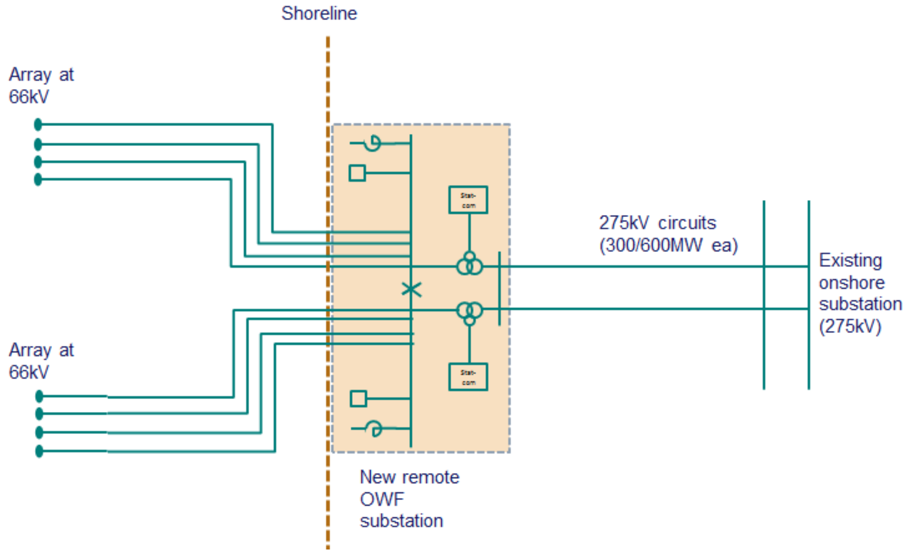
In summary, our views on the points raised in the question box for this chapter are:

- **Preferred transmission connection variation and reasoning**: the regulatory framework should not preclude designs that could be beneficial to the project and the NI consumer, and a more detailed consideration of options (including new technical opportunities) needs to be carried out before a preferred connection design can be identified.
- **Potential offshore substation ownership boundaries**: we note that some connection designs currently under consideration may not include an offshore substation. The optimum point to locate ownership boundaries and metering equipment is the step up transformer LV bushings, and this is consistent with the GB approach.
- **Usage and need for a near shore substation**: this will be dependent upon the design of the offshore connection, with lower voltage connections (particularly those where offshore substations are avoided) favouring the use of a remote substation nearer the shore to enable voltage transformation to take place and minimising the number of onshore cables, and higher voltage connections favouring a direct connection back to the existing network. A near shore substation would also be required if redundancy was to be introduced on the onshore circuits, but not the offshore ones. However, the location of any near shore substation should reflect the high level of designation around the coastline and be set back accordingly to accommodate sensitivities.
- **Procurement and build of the offshore substation and connection to the onshore network**: this is dealt with in detail in Chapter 6.

Connection Design

The consultation identifies several variations for design of an offshore wind farm connection with varying levels of system redundancy (which will be addressed subsequently). All the designs shown include an offshore substation and this is consistent with the majority of offshore wind projects to date. There are cases however, (e.g. Burbo Bank in GB) where projects have been directly connected to shore on long array cables, without the need for an offshore substation. This may or may not be appropriate in the case of the FFWL offshore wind farm, but it is an option that should be explored, particularly considering emerging technologies such as higher voltage arrays. An illustrative schematic of such a system is shown below in Figure 1.

Figure 1: Example illustration of a high voltage array cable design without offshore substation



It is also important to note that in the diagrams in the consultation document it seems that a single offshore substation is shown in all cases. This is one option, but when the geographical size of the offshore wind zone and capacity are considered it may be optimal to construct multiple offshore substations to connect the project and this will have a bearing on the capital cost of any redundancy installed.

It is not clear what the 'preferred' connection option would be until the completion of a detailed analysis of options and confirmation of the technical requirements for the system, and we would anticipate that this would be an iterative and collaborative approach with the transmission owners and operators. Similarly, the need for a near shore substation will be dependent upon the design of the offshore connection. For example, lower voltage connections (particularly those where offshore substations are avoided) would favour the use of a remote substation nearer the shore to enable voltage transformation to take place and to minimise the number of onshore cables, and higher voltage connections favouring a direct connection back to the existing network. A near shore substation would also be required if redundancy was to be introduced on the onshore circuits, but not the offshore ones. However FFWL believes that the term 'near shore' may be a misnomer due to the high level of environmental designation present around the coastline of County Down, leading to the need for the location of the substation to accommodate sensitivities of the area and be set back from the coastline accordingly.

Planning Standards and Redundancy

The consultation identifies that transmission level generation connections in Northern Ireland are designed according to Planning Standard PLM_SP_1. At present, this standard limits the maximum loss of infeed to the system to be no greater than 550MW, and a single circuit is acceptable to connect generation up to and including this figure, provided it does not exceed 20km in length. Beyond 20km, more onerous n-2 'backbone network' standards should be used.

The maximum capacity of a 220kV offshore cable is considered to be approximately 330MW. As such we would anticipate that at least two offshore cables would be required to connect a 600MW offshore wind farm and therefore this would be inherently compliant with this aspect of the standard. However if the 20km limit is to be considered, due to the cable distance offshore and to the existing onshore network, a non-redundant connection would be considered non-compliant.

To date, in all markets, redundant cables have not been deemed economic in the offshore wind industry due to the very large capital costs of such investments. The SQSS in GB consequently defines a separate suite of security requirements for offshore transmission, and this is supported by cost benefit analysis[2].

We believe that it may not be appropriate prescriptively to assign redundancy requirements to offshore wind connections, and provided that maximum loss of infeed limits are respected the most appropriate means to assess the level of redundancy is via a specific cost benefit assessment. This is particularly relevant considering the uniqueness of this project in Northern Ireland. If overarching standards are to be developed, they should mirror the results of such a cost benefit analysis.

Annex 1 provides illustrations of varying levels of onshore redundancy which should be considered (circuit redundancy offshore has not been considered for the reasons stated, FFWL do not consider it to be economically viable to introduce additional circuits offshore for the purposes of redundancy only). We believe it is unlikely that the full n-2 redundant standard would be economic for a project of this nature, and it should be noted that as the maximum loss of infeed is respected in all these cases, none of these options will have an adverse effect on the reserve holding of the Northern Ireland transmission system. It should also be noted that for the fully n-2 redundant option, if double circuit overhead line connections were to be employed, this would necessitate 2xdouble circuit tower routes through County Down with all the consent and delivery risks such large and potentially contentious infrastructure projects could bring.

Ownership boundaries and interfaces

FFWL's preferred ownership structure is discussed in greater detail in our response to Chapter 6. However, here we will address some of the technical considerations and interfaces associated.

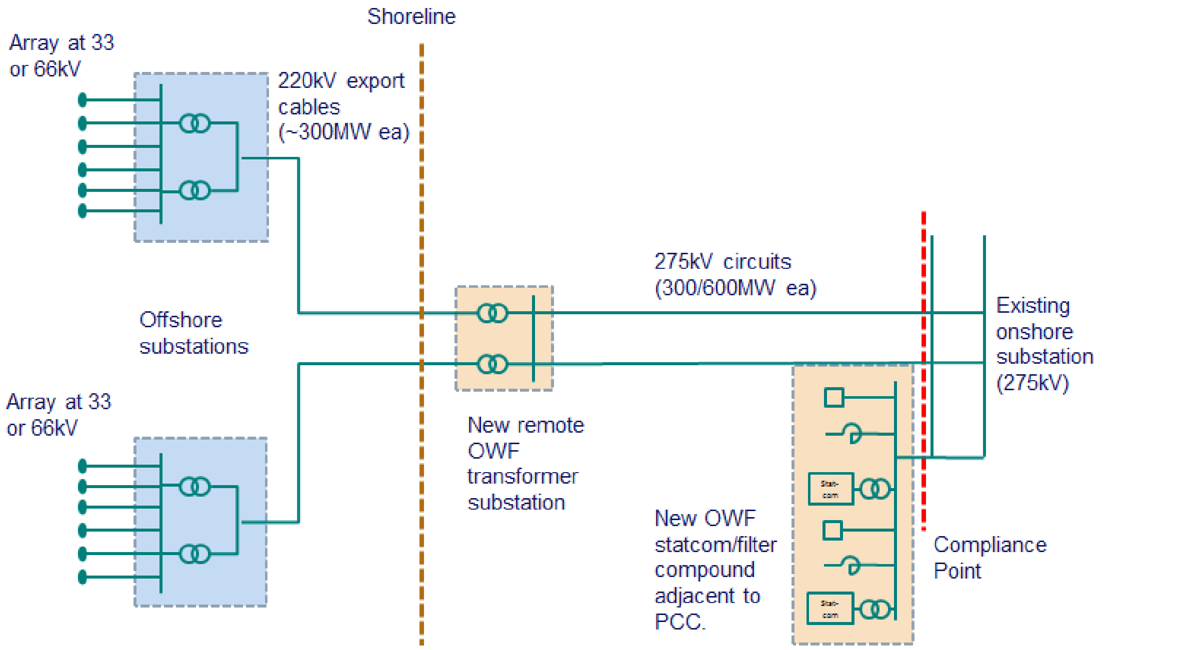
It is generally considered impractical to have boundaries within MV switchboards, as they are supplied as integrated systems. Consequently the step up transformer LV bushings represent the optimum point to locate ownership boundaries and metering equipment in

[2] http://webarchive.nationalarchives.gov.uk/+/http://www.berr.gov.uk/files/file47242.pdf

FFWL's opinion and this is consistent with both the GB and Danish markets. This provides a clear delineation between equipment at transmission voltages thus ensuring absolute compliance with IME3 requirements. An alternative could be to have boundaries located at the MV cable sealing ends, however this means that the point of isolation and disconnection for turbine and string maintenance is at the other side of the boundary, complicating switching strategies and safety rules. In any event, overlapping protection zones and shared intertrip and communications links are unavoidable, and as the offshore substation (if used) will contain both wind farm and transmission assets, shared access and site interface schedules will be required. In GB and the Danish markets it has been preferred to associate the offshore substation with the transmission rather than generation assets.

A further important consideration is the location at which compliance with grid code connection requirements (reactive power, harmonic emissions etc.) is monitored. Typically this is measured at the interface with the existing transmission system (or first onshore substation), which implies a separate suite of requirements for the offshore transmission connection assets. This is appropriate if these are sole-use assets. However this approach must be given careful consideration if these may be shared assets and therefore the performance of one party's system could affect that of another. It should be noted that in the event ownership and metering boundaries are located offshore, a separate compliance monitoring point may be required at the interface with the existing network if there are different requirements for on and offshore assets (as in GB). If a remote/shoreline substation is employed, and depending upon the technology used to connect back to the existing system, it may still be necessary to install reactive compensation and power quality plant at the interface, as well as at the remote substation. Figure 2 illustrates such a system. The cost of these options (and environmental impacts) must be considered in any evaluation of such options.

Figure 2: Example illustration of a remote substation with compliance requirements at interface to existing network.



Chapter 6: Ownership, responsibilities, and licence arrangements

In summary, FFWL's views on the points raised in the question box for this chapter are:

- Our preferred option is for the transmission voltage connection assets to be designed and constructed by the developer, and then divested to a licenced party (preferably NIE). This would ensure compliance with the Third Package unbundling requirements, and would be most aligned with the GB connection ownership arrangements.
- NIE's onshore licence should be allowed to be extended offshore, but with modifications to the onshore process (for example introduction of divestment of assets, and generator payment of "local" TUoS charges to provide a long term revenue to NIE).

As identified in the consultation document, there is no single option for transmission voltage connection asset ownership that is clearly preferred among countries with offshore wind sectors. However, as set out in the report[3] published in 2012 by DECC for its Offshore Transmission Coordination project, countries that have a successful offshore wind market with well-developed policies for offshore transmission connections have tended to opt for either a TO-led (Germany or Denmark) or a market led (GB) approach. In the first version the TO is required to design and deliver the connection assets, and the costs are covered through TNUoS charges levied on demand consumers. In the GB version the preferred option so far has been for generators to design and deliver the assets (include offshore substation and cables, and onshore substation and cables up to the connection point with the main interconnected transmission system), which are subsequently divested to a licenced offshore transmission owner through a competitive tender exercise run by Ofgem. The revenue for the OFTO is recovered from the specific generator through local TNUoS charges over a 20 year period.

This regime, while it removes any control over the transmission assets for the generator, has several financial benefits for GB offshore wind projects:

- The ability for the generator to recycle capital: the requirement to divest the offshore transmission assets frees up capital for the generator which can be deployed to invest in other offshore wind projects. Given the total capital cost of the connection assets, this can have a significant effect on the project's business case. It would not be in the interest of the wider renewables industry for offshore wind generators to have capital tied up in transmission assets.
- Offshore metering point: the ownership boundary is on the offshore substation, meaning that transmission losses are applied in a manner consistent with other transmission connected generators.
- Interest during construction: currently offshore generators in GB are allowed a return of 8.5% on capital spent during the construction period (this rate is periodically reviewed by Ofgem and depends on their assessment of prevailing market conditions).

[3] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/39304/4443-skmcepa-report-1-comparative-assessment-with-key.pdf

As mentioned earlier, for the FFWL project to remain competitive in a CfD allocation process, or remain viable under an administratively set strike price for GB, it is important that the connection costs borne by the project are broadly similar to GB projects.

The FFWL partners have considered all the options set out in the consultation document, and variations thereof, and our initial view is that there are three options of varying attractiveness that should be explored further (Options A, B and C described below in order of preference). The options we discuss in detail below do not include options three and four set out in the consultation document. In light of the likely timescales and cost of implementation, we do not believe it is appropriate to introduce a full OFTO regime (option four in the consultation document), as there is limited scope for additional offshore wind farms in Northern Irish waters. We also do not believe there to be any benefits from placing the ownership responsibility on the SO (option three in the consultation document) as they do not have the relevant experience as transmission owners.

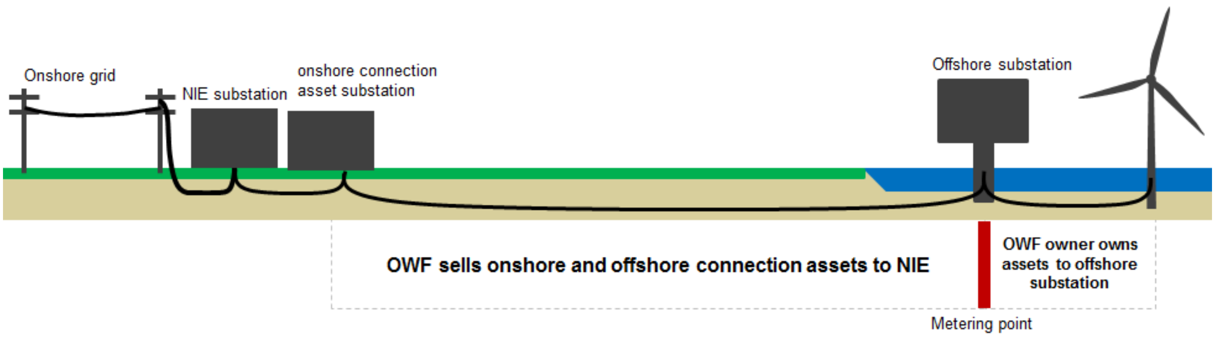
Option A: Divestment of connection assets to NIE (or other licenced party)

This is an alternative option to those listed in the consultation document, and is our preferred option as it would to a large extent mirror the GB Generator Build OFTO regime. This means that the FFWL project would be treated in a non-discriminatory manner relative to other UK offshore wind projects. This option would also unambiguously be in line with the IME3 unbundling requirements.

However, as the scope for further offshore wind projects in Northern Ireland is limited, we do not propose that the regulator should introduce a full competitive tender regime. This would be disproportionately complex, and, most likely not cost effective. The preferred solution is for the connection assets to be divested to NIE as the existing TO, which would avoid the introduction of another licenced transmission owner whose appropriateness and ability to perform would have to be thoroughly assessed.

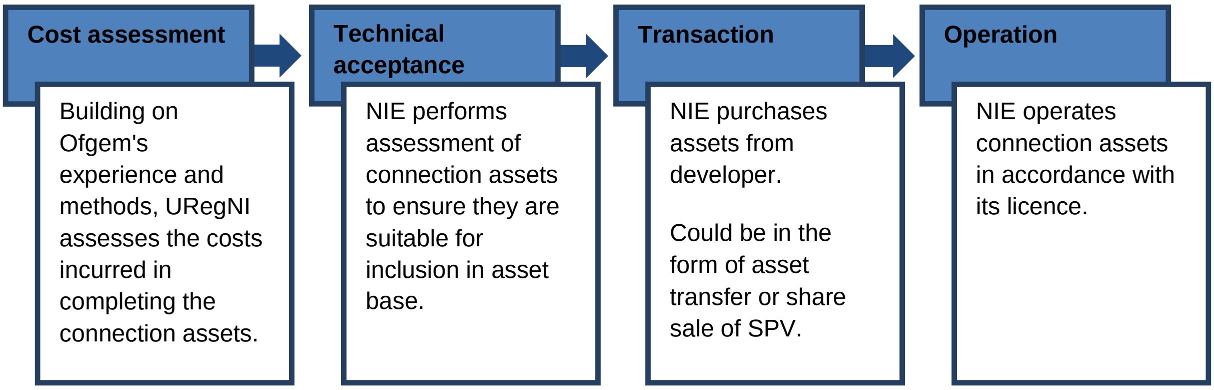
The definition of the specific assets to be included in the divestment process would depend on the design of the connection, in particular on whether the design included an offshore substation or not.

Figure 2: Illustration of Option A with offshore substation



There are several options for how to run a regulated divestment process, but a simplified version building on the experience from the OFTO regime could follow the steps set out below:

Figure 3: High level outline of light-touch regulatory divestment process



Once the divestment process is completed, NIE (or another licenced party, if preferred) would receive a low risk return over a specified licence period through a payment mechanism similar to the GB TNUoS arrangements, with incentives to ensure the availability of the assets is kept at a maximum.

This option has the following advantages:

- It is more closely aligned with the GB offshore transmission policy so more likely that the project will be competitive under a GB set CfD strike price and it avoids NI-specific adjustment with additional costs borne solely by NI consumers.
- If it is known up-front that NIE will be purchasing the assets, they can be engaged in the development and construction phase prior to asset divestment.
- The GB OFTO regime is relatively well established, and there is large scope for learning from Ofgem’s experience, for example from cost assessments carried out to date.
- There is no uncertainty for FFW and its owners on compliance with IME3 unbundling requirements in respect of generation and transmission assets.

This option would require the following regulatory changes:

- Establishing a streamlined divestment process and cost assessment (run by the regulator).
- Extending NIE’s transmission licence to include offshore assets.
- Implementing a revenue recovery mechanism from the generator, for example, through amendments to the TUoS regime.
- Introducing availability requirements and incentives to the offshore TO licence, in line with those in the GB regime.

It is highly unlikely that it would be attractive for the generator to divest the assets to a third party, for the following reasons:

- Risk of invalidating connection agreement (as set out on p. 29 of the consultation) in the absence of a SO-TO regulatory framework akin to the STC in GB.

- Very small pool of potential investors compared to the GB OFTO regime which is well established.
- Inability to guarantee a de-risked long term revenue stream in the absence of a SO-TO regulatory framework.
- Inability to enforce availability targets/incentives in the absence of a SO-TO regulatory framework.

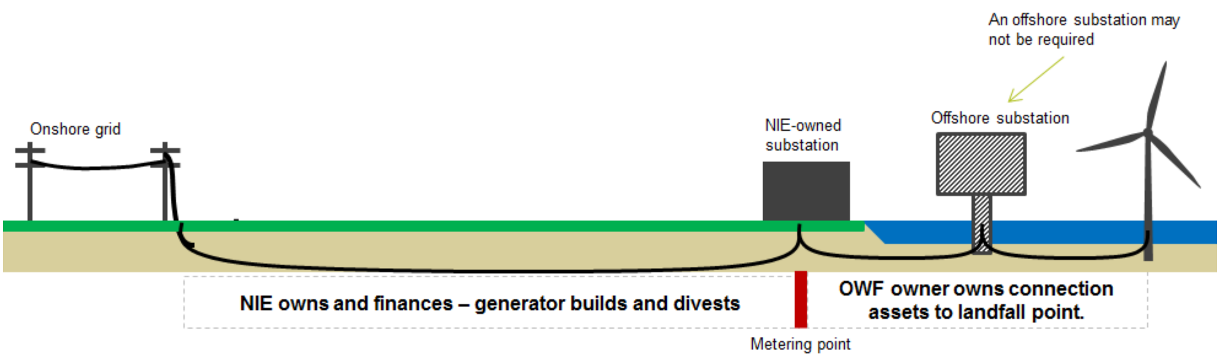
The scope of the assets to be divested and the metering point for the project would depend on the connection design, primarily on whether there is an offshore substation or not and the detail of the changes to be made to the supporting regulatory framework.

Option B: NIE ownership with generator onshore construction and divestment to NIE

This option is a hybrid version of both option two in the consultation document and FFWL's proposed option A. While we prefer option A as set out above because it involves divesting a larger part of the transmission voltage connection assets, option B is the second best option and would be a strong improvement compared to option C (described below).

The geographical location of the Wind Resource Zone and the initial connection design show that the onshore part of the connection will be substantially longer than the offshore part of the connection. The project is currently considering several different connection options, which need to be assessed in terms of cost, technical suitability, and ability to gain planning consent.

Figure 4: Illustration of option B with offshore substation



Irrespective of the final design, this option would split the connection assets into onshore and offshore connection assets, with the responsibility for ownership of the onshore assets falling to the existing onshore TO, NIE. In order to reduce the risk to the developer of delayed delivery of the onshore assets, our preferred option for the construction would be for this to be the responsibility of the generator. The generator's expenditure should then be recovered through a divestment process similar to the option set out in option A. The main difference between options A and B would be the reduced scope of the assets to be divested to NIE.

This option has the following benefits:

- The responsibility of the offshore design and construction would still sit with the developer consortium, which has significant experience in delivering offshore connection infrastructure. Scope exists for cooperation between parties during design, construction and commissioning.

- Reduced revenue risk for the generator if the onshore part of the connection is designed to full redundancy.
- NIE's licence does not have to be extended to cover offshore assets.

The regulatory/licence changes that would be required include:

- Implementation of a regulated asset sale mechanism as set out in option A.
- Implementing a revenue recovery mechanism from the generator, e.g. through the TUoS regime (possibly requiring amendment).
- Introduction of availability target/incentive mechanism to ensure that maintenance outages are coordinated.

We believe the option of allowing the generator to construct and divest the onshore connection assets is preferable to placing this responsibility on NIE, as doing so would introduce additional delivery risk for the project. For the alternative to be acceptable to the project, URegNI would have to introduce a mechanism for delivery guarantees (as seen in Denmark and Germany where the TO delivers the connection assets) to compensate for possible reductions in financial support due to late delivery of projects. In addition, we believe it would be appropriate for URegNI to introduce a mechanism for user commitment as seen in the GB market, whereby the generator provides financial security (e.g. parent company guarantee or letter of credit) to protect the TO from the cost of stranded assets, should the project be cancelled. We believe it would be less onerous for the regulator to introduce a streamlined regulated divestment process and amend the TUoS arrangements as suggested above.

Option C: Developer ownership of the transmission network offshore and onshore

This option is set out as option 1 on p.29-30 in the consultation document. In summary, it requires the generator to develop, own, and maintain all the connection assets up to the interface point with the main transmission system, where the metering point would be.

This would be a significant deviation from the GB regime, and would result in substantially higher costs to the project relative to a project operating within the GB regime. As set out in the introduction to our response, it is important that the economic consequence to a project arising from the regulatory regime in Northern Ireland are broadly consistent with those arising from the GB regime, as this results in NI projects remaining competitive with GB projects (keeping all other factors constant).

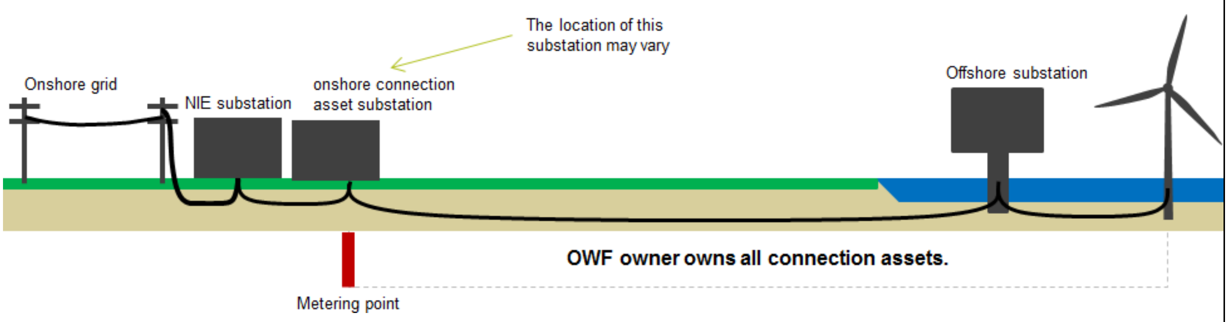
We note that the consultation document mentions Belgium as one country that has chosen an option where the generator is fully responsible for the construction, financing, and ownership of the transmission voltage connection assets. However, even in Belgium the full cost of the offshore connection assets is not attributed to the generator. As set out in the DECC report mentioned earlier[4], the Belgian TSO finances up to one third of offshore cable costs (capped at €25 million), which is in turn recovered through TNUoS. As Belgian generators are not exposed to TNUoS charges, this cost is effectively borne by the Belgian consumer.

We also note that URegNI have taken initial legal advice on the compliance with the IME3 unbundling requirements, and concluded that this option is consistent with this requirement.

[4] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/39304/4443-skmcepa-report-1-comparative-assessment-with-key.pdf

We will have to undertake our own assessment of the legal and regulatory risk of being a long term owner and operator of transmission assets based on the NI regime chosen but moving forward on this basis will only introduce further uncertainty for FFW and its owners that may impact on investment confidence.

Figure 5: Illustration of option C with offshore substation



Even if a NI-specific CfD strike price were set that took account of the higher costs associated with complete ownership of the connection assets as compared to the OFTO regime, this would still result in the reduced ability of the generator to recycle the capital into new offshore wind projects. There is, however, only a limited number of developers willing and able to invest in developing and constructing offshore wind farms which will be required to meet the EU's 2020 renewables target and longer term decarbonisation targets such as the UK's target of 80% reduction of CO_2 emissions by 2050.

Chapter 7: System security, least cost technically acceptable connection design, cost allocation, and charging arrangements

As this chapter has no specific questions, please refer to our responses in Chapters 5 and 6.

Chapter 8: Changes to the connection application process and the NI connection queue.

Connection application timing

The development of a 600MW offshore wind farm is of a different scale and character to most renewable developments in Northern Ireland. The challenges and needs of such a project are also different in terms of development lead times, investment levels and infrastructure necessary to realise connection to the wider transmission system.

One of the issues is the range of options available to connect the FFWL project to the transmission system in terms of location and technical design, which have a considerable impact on the consenting process for the project. Allowing the opportunity to apply for grid connection in advance of planning consent is necessary for the offshore generators as the design of an offshore wind farm (in terms of the location of the offshore platforms, cable corridors and landfalls) and the EIA process (in terms of the above and all the onshore infrastructure) both require a full understanding of the connection arrangements in advance of a planning application being made. If the wind farm was required to have planning permission before applying for its grid connection, it would require the project to consider a wide consenting envelope, spanning many different connection options across a large geographic area and different configurations of offshore platform design.

For this project, current assessment work to date has indicated a wide range of potential connection locations involving different marine routing, landfall and onshore connection options. A consenting envelope incorporating all options would incur significant costs in the EIA process and would require consultees and determining authorities to consider a large range of different options in EIA process. In this regard it should be recognised that this situation does not arise for terrestrial projects that have not to date been required to consider within their EIA works their connection infrastructure. Currently, for such projects, connection works are consented through separate applications, whereas the consenting authorities for the Marine Licence have required that the connection assets (that is, both offshore and onshore assets) are assessed as part of a single EIA as part of the same consents application.

It would therefore be difficult to progress the development of the offshore project without the necessary certainty on grid connection infrastructure provided through the connection application process. We consider that the condition for such early application would be the granting of exclusive development rights from The Crown Estate as announced in October 2012. The receipt of the exclusive development rights marks the start of significant expenditure on surveys, technical design, and environmental assessments. Allowing the developer to apply for a grid connection in advance of applying for planning permission would therefore allow earlier discussion between the developer and the System Operator to identify the optimal connection solution for the project and Northern Ireland, and allow for a single consent application to be submitted for the offshore and onshore electrical infrastructure.

Timing of joining the ITC queue

As set out in the FFWL response to SONI's consultation on FAQ and ITC, we believe it is appropriate that the point of entry to the ITC queue is at the time of the grid connection application. The scale of the offshore wind project means that it can make a significant contribution towards the 2020 renewables target, but also introduces challenges in terms of the timing of the development programme and the developer's ability to commit to what is a significant investment during the development phase. Securing a place on the ITC list and allocation of FAQ for the project provides the necessary confidence to allow the developer to progress the project and make the appropriate preparations required for a significant financial investment decision in the coming years.

FFW does not believe it is possible to split the timing of a connection application, and the point of entry onto the ITC queue. At the time of connection application, assumptions will made upon the basis of the contracted firm background at that point in time. Subsequently, these assumptions could be invalidated as more generation is added to the ITC queue or awarded firm access prior to the project's consent award, and entry of the project to the ITC queue. As a result, there is the risk that when evaluating the works necessary for providing firm access to a project, post consent, SONI/NIE may identify an alternative connection arrangement, different to that provided in a connection offer, which would invalidate a projects consents and all development work to date on securing the grid connection. In short, to split the application date from point of entry to the ITC queue eliminates the advantage of early application and does not provide the certainty necessary to a project. Furthermore, SONI/NIE will be unable to provide connection dates, or a list of necessary connection works, when issuing a connection offer if the final, firm, generation background is not fixed with respect to the project.

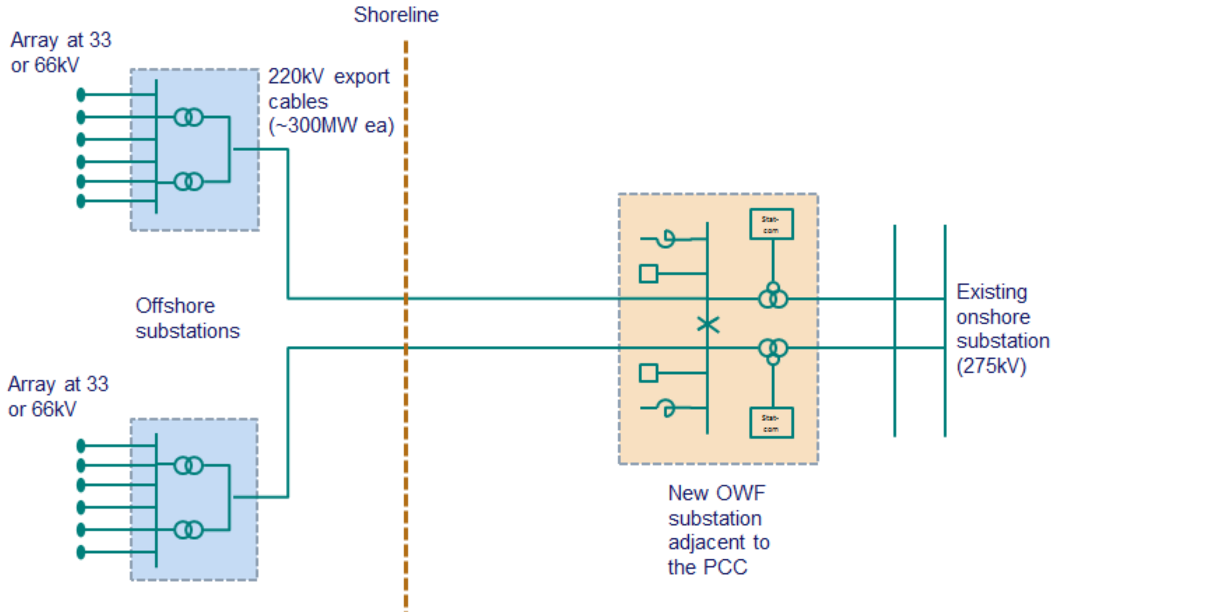
Chapter 9: The need for changes to the grid code

We believe that there will be a requirement to change certain aspects of the grid code. However, the SONI Grid Code is subject to its own governance arrangement and this should be followed in progressing any changes that may be necessary.

Annex 1: variations in connection design and redundancy

This annex set out a comparison of different configurations of offshore transmission connections, with differing levels of onshore redundancy. Note all examples shown include two offshore substations, and this is for the purpose of comparison only. There are also configurations using one offshore substation, or even removing the offshore substations entirely, which may be viable for the project.

Figure A1: Direct connection from offshore wind farm to existing system. No redundancy.



This could be considered a 'traditional' offshore wind connection and this has been the model for the vast majority of offshore wind farms worldwide.

Figure A2: New substation built remote from the existing transmission system. Connection back to the grid via non-redundant circuits.

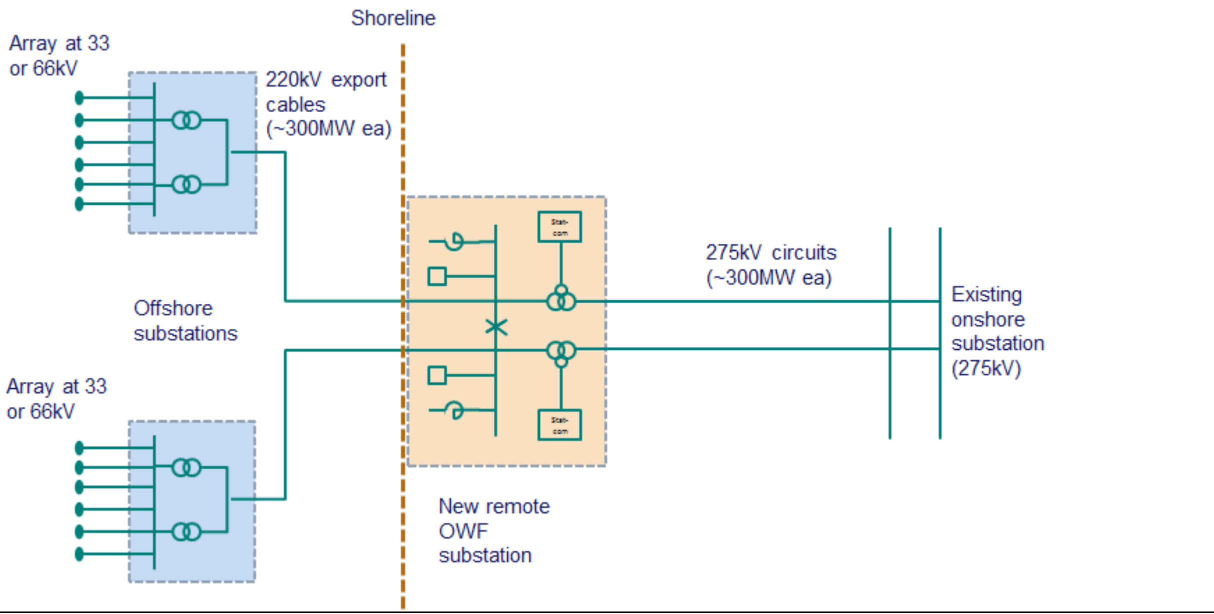


Figure A3: Remote substation, with 2xfully rated export circuits back to the existing system and a HV bussing point, permitting n-1 redundancy.

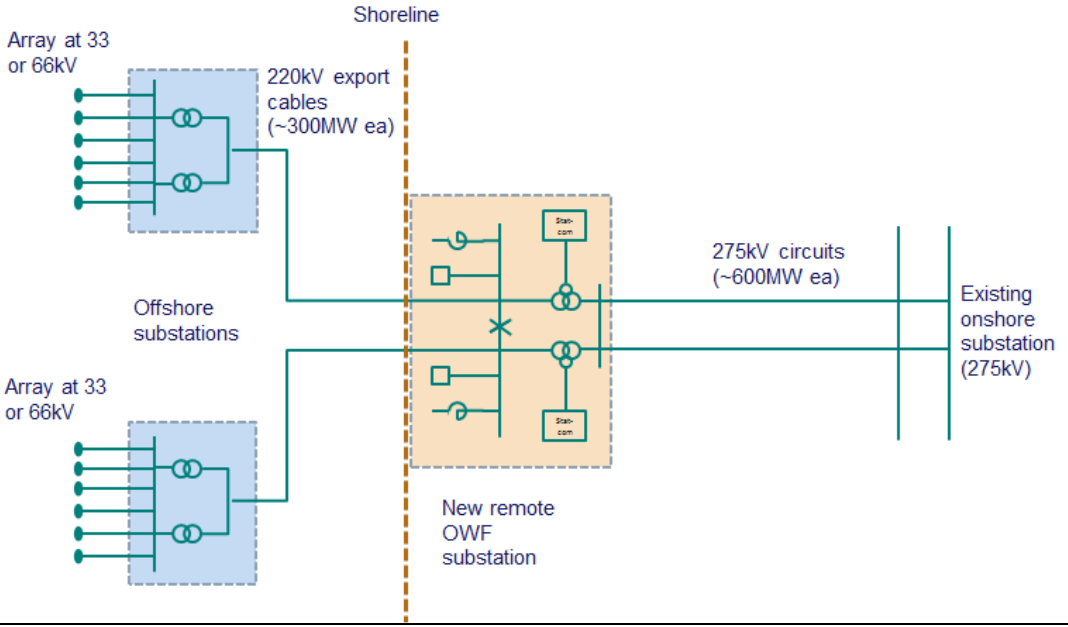
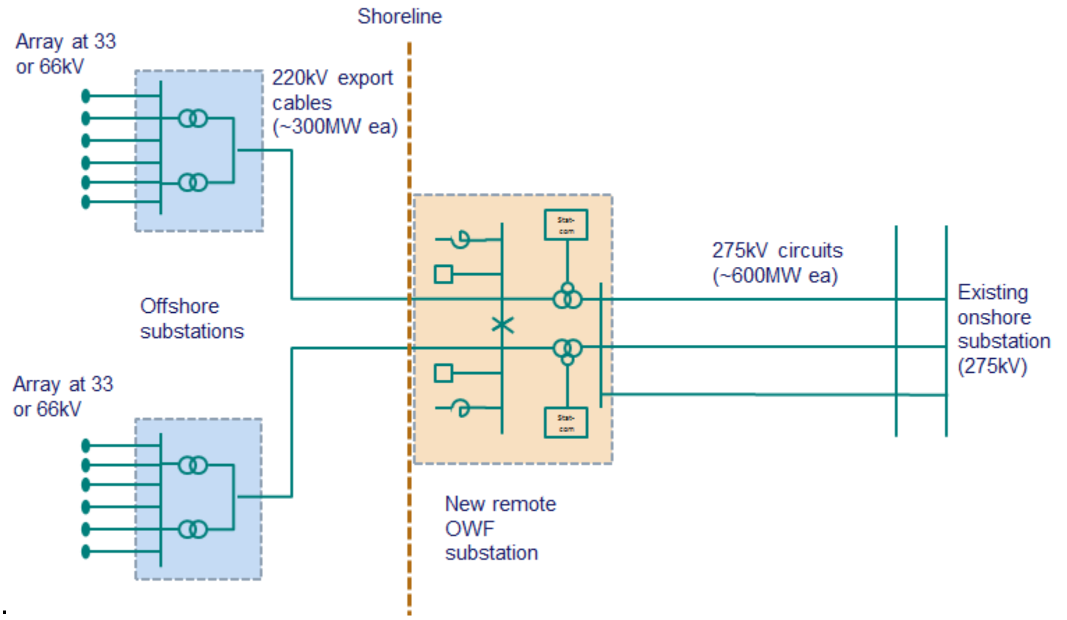


Figure A4: Remote substation with 3xfully rated export circuits back to the existing system and HV bussing point, permitting n-2 redundancy to current full, onshore 'backbone' network standards



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