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Response to DTI / Ofgem's Consultation on Licensing Offshore Electricity Transmission

Introduction:

BEAMA Power Ltd (BPL) is the Trade Association representing principal suppliers of equipment to the UK's Electricity Transmission, Distribution and large Generation sectors.

BEAMA Power Ltd, and their members welcome the opportunity to submit this response to DTI / Ofgem's Consultation Paper on Licensing Offshore Electricity Transmission.
The companies represented by our Association have the global reach to undertake and successfully deliver the size of projects required by Round 2 projects.

The views contained herein are those expressed by Members of the Association and put into a consolidated form.

General:

Project characteristics to date:

Our Members have actively participated in the supply of equipment and services to several of the current Round 1 and prospective Round 2 projects under the current developer driven approach.

The market has been characterised by :-

- Project Delays
- Marginal Financial Returns
- Commercial and Contractual Issues
- Plant Performance Issues

These have resulted in average project delays of 2-3 years and abortive and expensive bidding costs which in some instances have resulted in 3-4 bids being submitted for the same offshore project over a several month period.

For example, these multiple bidding costs coupled with rising raw materials and increased global demand over the 2-3 year period have served to raise the £/MW in the order of 25% in one recently quoted Round 1 development.

Resources:

Increasing demand for energy services and power system infrastructure replacement globally has resulted in production capacity margins being significantly reduced and delivery times for offshore projects being increased.

Coupled with the severe shortage of skilled electrical engineers in the UK being experienced by both suppliers and utilities, resource is now a major factor in the successful economic implementation and achievement of the UK Government renewable energy targets.

We also take this opportunity to express again our view to Ofgem that Contractors capable of delivering these projects currently operate on a global scale and the internal resources of these companies will be directed to those projects that are most likely to proceed, wherever they are in the world, and where there is a realistic opportunity to be successful at contract award.

Tendering Constraints:

Members have consistently expressed considerable concern about the pressure that will be placed on them by the proposal that could lead to multiple tenders on the same project, and the short timescales being proposed will lead to intensive levels of activity

Preparation of competitive tenders for grid connections is an expensive business. Onshore TOs and DNOs usually seek fixed price, design-build offers for substations operating at 132kV and above. Historic UK Treasury and EU procurement rules and the desire to demonstrate a competitive process to Ofgem drive a relatively costly procurement process. Contractors prepare these bids and there is a period of evaluation and negotiation that results in a contract. Main contractors typically incur costs of many tens and often hundreds of thousands of pounds for each project they tender. Sub contractors also incur significant bid costs.
The parties involved can tolerate these bid costs because the market is well established, risks are well understood and uncertainty is manageable. There is also a reasonable chance of winning work. Projects that are tendered usually go ahead. Customer capital programmes are relatively predictable over the medium term (of a price review period) allowing decisions on resource investment.

Offshore projects are significantly more complex. The relative proportion of well defined costs, such as the primary equipment, to those that are unknown at tender stage, such as ground and weather conditions, is much lower. The risk of making a fixed price offer is therefore much greater offshore.

Accuracy of costing depends on significant information and engineering at the tender stage. e.g. a detailed sea bed survey allows foundation design and cable laying to be more accurately assessed. Mathematical modelling of power networks allows cable sizes and equipment ratings to be optimised and reactive compensation to be specified sufficient to meet Grid Code requirements. This level of work can only be provided on a paid basis or where there is a high probability of a full contract, e.g. as a sole preferred contractor.
This reality does not fit well within a time constrained connection offer period. Offers will have to be based on limited information and engineering and therefore cannot be accurate. The TO will run a greater risk than they could accept under price regulation or the developer (and all demand customers) will pay too much.

The alternative, common in the offshore petrochemical industry, is for a paid Front End Engineering Design or FEED study. This is ideally carried out by the potential contractor, who then has an interest in its accuracy and can commit to an outturn cost. More of the work is also reused during the final design than if this is carried out by a third party.
We would support the idea of tender costs being reimbursed, but this should apply to all those in the supply chain who invest significant sums in the tender process. For clarity, contractors such as our Members do not wish to make money from tendering for its own sake. Their tender resources are there to win projects and they would only seek to bid for projects where there is a realistic chance of a contract being awarded.

Our Members welcome competition and agree with Ofgem's view that competition tends, in a healthy market, to stimulate innovation and expedite project execution in the most cost efficient manner.

However, as has been highlighted above significant pressure now exists on all aspects of the supply chain due to global and local demand. Fundamentally any proposed process which is likely to require more supplier / manufacturer resource to provide several bids to different Transmission Owners for what is to essentially the same offshore project, may well not effectively deliver the competition envisaged.

The size and scale of the Round 2 projects, particularly with the higher risk sub sea components and the offshore operational challenges, make the firm pricing of several independent TO bids for such projects within the timescales indicated potentially very difficult. Coupled with the general lack of experience in the engineering profession for such large scale projects and skilled resources, suggest that a multi bidding processes could consume a considerable amount of time and hence result in further escalations in the anticipated £M/MW.

Wider Issues:

There is concern that the wider issues are not sufficiently appreciated in the approach of Ofgem.

Project Risks:
Some construction risks affect both the TO and the generator. Mechanisms for sharing the overall risk would reduce the total combined cost and hence the price paid by electricity customers.

One example is the potential of weather downtime for the installation spread. If the grid connection is considered separately from the generator both have to price for the risk of adverse weather. Statistically this risk is more manageable the longer the duration. i.e. the chance is that bad weather will affect one party, but not all.
The bilateral nature of a connection date puts a constraint on both TO and generator to be ready at the same time. There are clear benefits if the overall programme can be managed jointly and the impact of bad weather on one can be mitigated by accelerating the other's work when better weather returns.
The sharing of vessels can significantly benefit overall cost. A one-off mobilisation of a heavy lift ship to place an offshore substation on a foundation may cost around £2M. If the substation is designed to be installed within the lifting capacity of a vessel already engaged at the site installing wind turbines the additional work is likely to cost a few hundred thousand.
The chosen form of regulation should therefore not force TOs to ring fence their works in such a way that they cannot benefit from sharing risks and resources with developers.

A Licensed Merchant Benchmark

In March 2005 the Government announced its decision to develop a price regulated model for offshore transmission licensing. We accept that decision has been made and are now committed to supporting the development of the best possible form of price regulation.
However, our Members suggest that it is still worthwhile when comparing options for price regulation, to compare their merits with those of a licensed merchant alternative. This is the de-facto situation against which the regulatory impact assessment should be made and it provides a valuable baseline against which the relative merits of the options now being considered may be put into context.
It is worth noting that the class exemption proposed for offshore connections below 132kV effectively defines them all licensed merchant connections.

Differences from onshore

The Government response to the earlier consultation noted that it was necessary to consider the particular aspects of offshore transmission which mean that the general principles of NETA and BETTA should be departed from. These were stated to include:

- The radial nature of offshore connections
- There are no consumers offshore
- Few existing offshore assets
- No incumbent network businesses

The majority of offshore transmission assets will serve only one generator.
This negates the main justification for shallow connection charging and the sharing of most network costs by all customers, i.e. the basis for the BETTA model.
Onshore a shallow connection charging approach operates. The main interconnected transmission system serves all customers and its costs are shared by all customers. The relative costs and benefits of connecting generation to different regions of an existing network are signalled through zonal charging. This mechanism prices

existing capacity or constraints to encourage generation to take account of (and minimise) deep reinforcement costs.

The situation offshore is quite different as there is no pre-existing network and most of the cost relates to assets that are solely for the use of one generator. We suggest that there is no practical basis to regard these assets as a transmission system that serves all. To treat offshore the same as onshore is an artificial concept.

Specific Response to the Key Questions for the Review

CHAPTER: Two

Question 1: Which option do you favour and what are your reasons for doing so? Do you have any views on any aspect of our intended approach under each option?

Each has a significant advantage over the other:

Option 1:-

Is fundamentally more competitive and allows the formation of competing TO-contractor alliances which we believe would bring benefits of collaborative working whilst maintaining competition.

However there is some concern that this option will not fundamentally promote innovation and that severe difficulties maybe encountered in successfully operating this approach. This is mainly based on the limited resource likely to be able to provide firm priced, quality bids to several TOs in the required timescale.

It is believed that this will have significant additional costs both in bidding and the delays likely to result in the tender evaluation and the multiple contractual negotiations that will follow for each of the 10+ projects, which may well all progress from 2008 onwards.

Option 2:-

Better supports the development of a generation project as the developer knows who the host TO will be. It supports budgetary pricing more than Option 1.

Question 2: Do you think that the approaches which have been ruled out should be considered further and are there are any other options or approaches that should be considered?

We recommend that the developer choice option should be further considered. If the developer's costs are reflective of the total cost there will be an incentive to seek the minimum cost option.

If Option 1 is chosen it allows a developer to apply for its own TO license and assemble its own set of contractors.[i] If the developer has choice of TO there would have to be a stage at which this choice was either exercised or suspended to allow a fair bidding process.

We agree that the other two options ruled out are less advantageous than Options 1 or 2 or the developer choice option.

Question 3: Should anything further have been taken into account in assessing the options?

We believe that a strong motivation for developers in their initial preference for a price regulated regime was the desire for costs to be spread across all customers. This is an inefficient mechanism for subsidising offshore renewables. Now that alternatives such as ROC banding are proposed, we believe the preference for price regulation has reduced. The best form of regulation should be chosen to allow the timely development of an appropriate offshore transmission infrastructure. The true cost of dedicated connections should be attributed to each development so that the most efficient are built first. If a subsidy is required, it should be provided by other direct means such as banded ROCs.

In the discussion on the merits of Option 1 in paragraphs 2.35-2.42, we agree with Ofgem's reasoning on all points. We would support the lightest possible regulation which would minimise entry barriers for potential TOs

We feel that the scenario in paragraph 2.51 is highly unlikely. i.e. where a developer of a single generator in a geographic area takes on TO responsibility for several others just to get its own connection built.

CHAPTER: Three

Question 1: Could providing anything further, beyond the comfort already provided by Ofgem, be justified for projects that will be constructed or have secured financial close prior to the award of offshore TO licences?

We would only seek to highlight that the (UK) supply chain is also at risk. We have made investment decisions to meet a potential market that may be further delayed due to the uncertainty of our customers, the developers and their financiers.

Question 2: Would a departure from Ofgem's current approach to the adoption of assets be justified or would different treatment be unduly discriminatory?

No response

Question 3: What are your views on the potential costs to TOs of bidding to build, own and operate offshore assets? Do you have views on how such costs might be minimised?

See discussion above

Question 4: Do you believe there is a risk of a lack of co-ordination that is specific to the non-exclusive approach? If so, how serious a problem do you believe this is? To what extent could the suggested measures or any other measures mitigate such a risk?

See response to Chapter 2 Question 1 above.

Question 5: Is it appropriate to allow generators to bid to provide their own transmission services, in particular in the light of any potential moves towards unbundling at an EU level?

The key question in the whole consultation is whether a dedicated grid connection is properly regarded as a transmission system? It is difficult to see how unbundling a connection from the (only) asset it serves benefits either customers or competition.

Question 6: How can confidence be built that the tender process can be run transparently and fairly and to what extent can the proposals outlined in this chapter ensure this?

No response

Question 7: Is it appropriate to have certain defined re-openers in a fixed-price bidding system?

We support the concept of two-way pre-defined re-openers in principle. This should result in the fairest overall risk allocation and therefore in the lowest overall cost. However, risks and returns are not equal for all parties or at differing stages in the project cycle. They therefore need to be carefully chosen and clearly defined to avoid opportunities for creative legal challenges.

Question 8: How should the geographic extent of exclusive regional licence areas be defined? What is the appropriate balance between obliging exclusive offshore TOs to assume unknown levels of risk and the need for a wider geographic area to ensure a TO is available to connect generators? Is it appropriate to make available three offshore TO licences that cover the three strategic areas and to leave the remainder of the offshore area unlicensed until the need for new licensees arises?

No response

Question 9: On what basis should the competition for offshore exclusive TO licences be run?

No response

Question 10: What is the value and feasibility of benchmarking exclusively licensed offshore TOs and in what way could this be facilitated if desirable?

No response

Question 11: How can suitable incentives be placed on exclusive offshore TOs to ensure that assets are constructed and operated economically and efficiently? Is there an alternative to simply passing through costs which raise the charges paid by consumers and generators? Would it be suitable to use international benchmarks as a means of assessing economy and efficiency?

No response

Question 12: What arrangements would be appropriate for dealing with future build outside of exclusively licensed areas?

No response

Question 13: How can generators can be provided with timely, firm offers within reasonable timescales under the exclusive option?

There is no reason for this to be more of a problem under the exclusive Option 2 than Option 1.
Option 1 gives a greater ability to provide reliable budgetary offers when required in the development cycle.

N Grant
Director

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[i] Para 2.40 *of the consultation document.*