SIEMENS

**Response to DTI/Ofgem Consultation**

# Regulation of Offshore Electricity Transmission

**on behalf of**

# Siemens Transmission and Distribution Ltd

Ofgem Ref: 199/06
DTI Ref: 06/1952
January 2007

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# Siemens in energy

Siemens has been established in the UK since 1843 and has been working in the modern energy and water industries from their birth in the industrial revolution. Today, we serve every aspect of the energy sector, from building and maintaining power stations through to customer data collection. Individually our products and services are designed to deliver premium performance. They create resilience, security of supply and safety, as well as timely, high quality data, all of which must underpin the infrastructure of the energy sector. We have created energy infrastructures in some of the world's most demanding environments and our experience in the UK has given us a deep and detailed understanding of the way the market is developing.

# Siemens Transmission and Distribution Ltd

Siemens Transmission and Distribution Ltd (STDL) is the UK's largest transmission substation contractor. We employ over 700 employees in the UK and are headquartered in Manchester, with principal sites and offices in Hebburn (Tyneside) and Garforth (Leeds) as well as a number of other locations around the UK.

STDL designs and constructs substations at all voltages for UK generation, transmission and distribution companies and industrial customers. In addition we provide services covering all stages of transmission and distribution asset lifecycles including power network studies, operation and maintenance and decommissioning. Siemens also offers a full range of substation equipment including switchgear, transformers and protection for all network voltages.

We are committed to supporting the renewables industry in the UK and have already built or provided equipment to several onshore and offshore wind farm connections. We are currently working on design and build contracts for three offshore wind farm connections:

- Lynn – 3 x 33kV export cables, onshore 33/132kV substation
- Inner Dowsing – same as Lynn
- Thanet – 2 x 132kV export cables, 2 transformer offshore substation

Thanet is the world's first offshore substation with more than one power transformer. It is a prototype for future offshore transmission connections. These projects are being built on a merchant basis, prior to the commencement of offshore transmission licensing.

Siemens is one of only a small number of contractors with the capability and scale to design and build offshore transmission assets and is keen to support the rapid development of a mature and stable offshore transmission industry; hence our participation in the licensing consultation process to date and our response to this consultation.

# This response

The format of this response is to make some general points under the following three headings:

- Price Regulation
- Timing and Project Finance
- Competition and Tendering

We will then answer some of the specific questions asked in the consultation document.

The two main options in the consultation document are compared with each other and, where we believe it is appropriate, with other options ruled out in paragraph 2.17 of the consultation and with a licensed merchant benchmark.

References to Option 1 and Option 2 are as defined in paragraphs 2.1 and 2.2 of the consultation.

# Price Regulation

### A Licensed Merchant Benchmark

In March 2005 the Government announced its decision to develop a price regulated model for offshore transmission licensing. In the preceding consultation STDL was one of a minority of respondents who preferred the licensed merchant alternative. We accept that decision has been made and are now committed to supporting the development of the best possible form of price regulation.

We 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.

We recommend that a further option be added to the partial regulatory impact assessment document; (iv) non-exclusive merchant licenses. Options (ii) and (iii) in section 4 should then be renamed (ii) non-exclusive price regulated licences and (iii) exclusive price regulated licences.

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 first of these is most significant for price regulation. The majority of offshore transmission assets will serve only one generator. This fact of electrical engineering 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 on a regional level 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. 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.

**Cross subsidy**

The form of price control has yet to be developed, but it will have to deal with two conflicting pressures; promoting (subsidising) the connection of offshore generation, (mostly, but not exclusively renewable) whilst not penalising efficient onshore generation (of all types.)

Since there are no customers to protect offshore, the remaining justification for any price regulated approach for offshore transmission can only be that it reduces the cost to the connecting generators of establishing a new offshore infrastructure.

The consultation document proposes that a generator should not pay the full cost of its own connection. This would be mainly borne by demand customers,[i] (as onshore under BETTA.) If the offshore generator is to benefit from a lower connection cost then others onshore must be penalised (or benefit less).

A cross subsidy may be justified in order to overcome the entry barrier for this new technology in the long term public interest. It should, however, be clearly recognised for what it is – a subsidy to offshore generation. The cost effectiveness of this subsidy should be compared with other ways of achieving the same result. We should not create an unnecessarily complex and enduring price regulated regime to deliver a subsidy which could be more efficiently given by other means, e.g. Banded ROCs - the subject of a separate consultation.

There may also be unintended consequences, if the assets which serve individual generators are regarded as a transmission system and their costs are spread across all demand customers. For example, the owner of an offshore gas field can either lay a gas pipe to shore at his own expense and convert the gas to electricity at an onshore power station, or build an offshore power station and ship the electricity ashore over a connection funded by customers.

**Price Regulation and Competition**

Ofgem's principal objective[ii] is to protect the interests of consumers where appropriate by promoting effective competition. This is cited as a reason for Ofgem's preference for Option 1.

We agree with all Ofgem's comments in paragraph 2.27, but would like to take the argument further:

If the price review period for Option 1 is locked for a sufficiently long duration, with pre-defined re-openers, then price regulation becomes conceptually the same as a merchant approach. i.e. There is competition for the creation of the asset and it is paid for over its lifetime under a pre-agreed formula. This could be as easily achieved via a bilateral agreement without price regulation.

In paragraph 2.54 we agree with the Ofgem statement that it is inappropriate to artificially create monopolies where this is not necessary. We would add; 'or price controls where they are not needed.'

## Timing and Project Finance

Offshore renewable generation projects have a long development period. Whether project financed or on balance sheet, the developer invests over a long period before knowing that the project can proceed to construction. Anything that adds to uncertainty, or to its duration, increases the rate of return required to justify the project and therefore the cost of meeting Government renewable generation targets.

The cost and availability of the grid connection is one of the key uncertainties in a project. In comparing alternative regulatory options their impact on the build rate of offshore renewables should outweigh other considerations.

A developer needs confidence that a grid connection will be available in a timely manner and at a predictable cost. Whilst ideally a developer would like certainty of cost and time from an early stage, in practice there will be a series of key decision points during the development where the connection "offer" is refined from an initial budget to a final firm offer over perhaps three to four years.

Experience of on and offshore developers is that the 90day connection offer and then validity period rarely fits the development timetable. It is common for projects to request a connection offer in time to allow consent applications, this first offer is allowed to lapse as the developer is unable to commit until planning and other issues are resolved. The developer then seeks a further offer, hoping that it will be similar. Both offers have to be developed by the TO to the same level of detail, even though one is effectively a budgetary exercise.

Both Option1 and Option 2 would lay down constrained offer periods and hinder efficient project development. Option 1 would have a potential further disadvantage. The best connection offer at financial close of a project may come from a different TO from that preferred at an earlier stage. The two solutions may differ, requiring amendment to planning consents.

## Competition and Tendering

### Competition

Price regulation usually requires that the regulated entity procure capital projects in a demonstratively competitive way. The need to demonstrate competition in every case can result in a more adversarial and expensive procurement outcome. Frameworks or alliances that last for more than one project can bring benefits of repetition and collaborative working.

The skills needed to design and build an offshore grid connection are likely to be spread through several specialist contractors as well as the TO. The projects are therefore better delivered through collaborative approaches, such as alliances.

Option 1 allows potential TOs to ally themselves with a team of contractors who then compete with another TO with a separate alliance. This satisfies the desire for competition, whilst allowing the benefits of collaborative working.

Option 2 creates a regional monopoly TO. If this TO were forced to procure competitively, the potential for alliancing would be limited to lower levels of the supply chain.

The regulation should avoid constraining TOs procurement in a way which inhibits such procurement approaches.

**Tendering**

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 such as Siemens 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 STDL do not wish to make money from tendering for its own sake. Our tender resources are there to win projects. We would only seek to bid for projects where there is a realistic chance of a contract being awarded.

**Sharing wider 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.

Experience of the early Round 1 offshore wind projects is that the sub-contractors took on much of the construction risk and in several well known cases went out of business. More recently tender prices have risen and contractors are more cautious.

The appropriate allocation of risk at the right stages of a project is key to reducing overall outturn cost. Price regulation introduces a glass ceiling in the supply chain between TO and Generator. It also forces the TO to pass risk to its contracting chain as it is unable to accept the risk itself due to its regulated rate of return. This prevents some risks from being taken by the parties best placed to manage them.

## Consultation Questions

**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?**

Neither is strongly preferred, 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.

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.

We recommend a 'war gaming' exercise with representatives of interested parties. By walking through the lifecycle of some typical projects the relative merits could be better appreciated.

If Option 1 is taken to the extreme with the price locked for the generation asset lifetime we would prefer this option more.

**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.[iii] 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?**

The scope for co-ordination in overall network topology is limited, as there will only be marginal spare capacity in any connection.

There is scope for the development of industry standards and best practice, but we would argue that this can be achieved through competitive pressures and trade bodies at least as well as by imposition from TOs.

We therefore do not see the reduced co-ordination from Option 1 as a significant issue.

**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.

Developers who are creating these assets prior to commencement are in any case making provision for their ownership to be separated from the generation company.

**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.

# Conclusions

A case can be made for either Option 1 or 2 being preferred. The relative merits of each are minor when compared with a merchant benchmark.

If Option 1 is taken to the extreme case with the price control locked for the generator lifetime, it becomes closer to our previously favoured licensed merchant approach.

We recommend that both options be "war gamed" with a representative group of parties to highlight the practical issues for their implementation. This may highlight issues which more strongly favour one of the options.

Whilst the focus of regulation is on the regulated TO, consideration is needed for the wider objective of delivering offshore renewable generation. By ring-fencing the TO for regulatory purposes we may create artificial constraints which hinder offshore development as a whole.

Siemens Transmission and Distribution Ltd.

January 2007

*Should you wish to discuss any of these issues in more detail please contact Matthew Knight, Business Development Manager, Renewables Siemens Transmission and Distribution Ltd. Telephone 0161 446 5104*

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[i] "Generators only pay a proportion of network charges, with the majority paid for by demand customers". *Para 2.57 of the consultation document.*

[ii] *Para 2.19 of the consultation document.*

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