Teach Mór Thiar, Inverin,
County Galway,
Republic of Ireland
Tel/fax: +353 (0)91 593236
info@fsteo.com
www.fsteo.com

Submission to

DCCAE

on

Consultation to Inform a Grid Development Policy for Offshore Wind in Ireland

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Non-confidential

Introduction

FST welcomes DCCAE's consultation, aimed at a long-overdue reconsideration of the issues around grid development models, focusing on offshore wind and informed in some detail by the Navigant report. The learnings from this process could prove useful to the wider renewables sector and indeed electricity in general, as Ireland moves inexorably towards a more sustainable system.

FST's Skerd Rocks offshore wind-farm project off the Galway Coast has been designated as a Relevant Project under the Government's Transition Protocol. It has been in development since 2001 & applied for a Foreshore Lease in 2008. FST was a founder member of the National Offshore Wind Association (NOW), and having a strong policy leaning within its team, encouraged NOW Ireland to commission an economic study on grid connection charging policy in 2010[1], which is attached and its relevance will be discussed in the body of this submission.

Grid Connection Aspects

There are 3 distinct aspects to a grid connection:

- Physical: design/allocation of capacity/consenting/construction/operation
- Ownership
- Cost allocation (application & charging policy),

all of which need to be fully considered if a correct choice of model(s) is to be made by Government.

The Navigant report states in section 1.3;

> *"The objective of this report is to provide ample evidence to inform the government decision on the offshore grid delivery model for Ireland,...."*

However, the scope of the report has already been severely hamstrung by 10 assumptions set out on page 8 of the report (also on page 98, as well as page 7 of the consultation document), presumably issued to the authors by the Irish authorities. Three of these assumptions (6 to 8) relate to cost allocation & ownership and read:

> "• *Whoever builds the transmission assets organises financing;*
>
> • *Connection charging policy will follow the onshore model;*
>
> • *EirGrid can seek to transfer grid connection ownership to the TAO in any option where the developer builds the asset; This would need to appropriately balance ownership of risk and cost of risk;"*

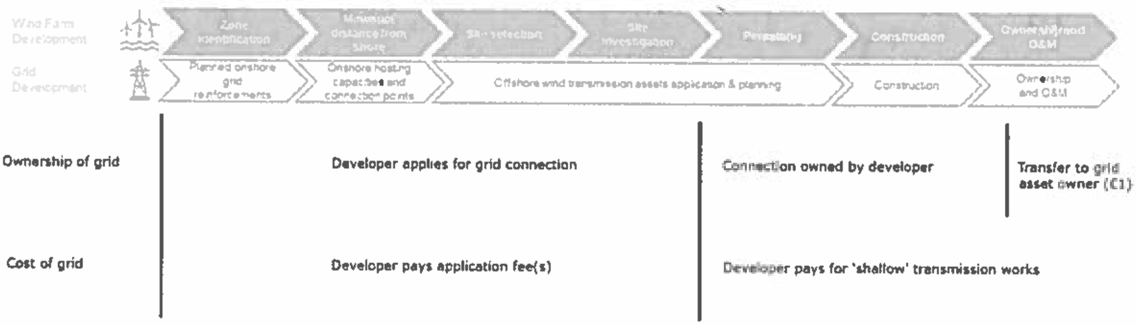
The first seems a practical approach to simplify the construction process and doesn't predetermine who will ultimately own the connection assets or pay their cost. The second concerns the existing onshore charging policy, where the project pays the 'shallow' connection cost in the transmission system (and the 'deep' connection cost in the distribution system). This is the subject of the attached KHSK economic study already mentioned and more on this below. The third is a (potentially) slight softening of current policy where all grid connections are transferred into TAO (or DAO) ownership.

It must also be noted that there are some further potential departures from current connection ownership & charging policies in the reports four options. It is suggested that the offshore connection assets would be owned and paid for by the developer/project in Options 1 to 3, though that does assume the TSO does not require ownership transfer to

[1] Efficient Funding of Transmission Network Connection Costs, for NOW Ireland, KHSK Economic Consultants, January 2010

the TAO[2]; that is not a given because of the likelihood of shared connection assets in the sea. Under Option 4, the TAO would own and pay for the offshore transmission assets to the site, as is the case in several other EU jurisdictions, and that is not in keeping with the existing charging policy (Assumption 7). This opening is to be welcomed.

Because of working within these imposed constraints, it is not surprising that the report pays less attention to ownership & charging aspects of grid connections than it might otherwise do if it were to undertake a truly comprehensive review of the options. The graphical timeline at the head of Fig. 2 (page 7) of the report reflects this by omitting cost altogether and not dealing with ownership at the various stages. So our graphic below expands on the one in the Navigant report, setting out all the above elements in line with current Irish/SEM policy ('onshore').



Furthermore, in section 3, the report sets out four sets of assessment criteria, the first of which is 'Economic & Financial' (though the criteria are not in fact weighted). This seems particularly constrained, since one of the main cost drivers is connection charging policy, which has in effect been taken off the table by virtue of Assumption 7. This we believe is a missed opportunity, since one of the sources of excess cost in all generation is exactly this policy, while it is also a major source of complication and delay.

All in all, the report is rather confused on these key issues, which is not the fault of the authors, but those who set them the task and gave them such a set of assumptions, apparently aimed at limiting the scope for review & for change.

Flawed assessment

Irish grid connection policy currently requires two key things:

- that all grid connections to the project site be ultimately owned by the system asset owner (TAO or DAO), and,
- that the project pays the 'shallow' connection cost in the transmission system, ie everything up to connection to the existing grid, but not the reinforcements required within the existing grid (and the 'deep' connection cost for any connections to the distribution system, meaning the reinforcements in the distribution system must also be paid, though this of course is not directly relevant to offshore wind).

Thus projects must pay for assets they cannot own and indeed are obliged to transfer them to the asset owner for a nominal fee[3] (€1...!). The resulting ownership-payment 'misalignment' gives rise to three significant issues:

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[2] Table 1, pages 9-11, Navigant report

[3] noted in para 4, page 69, Navigant Report

- complication, in particular under group processing with connection assets shared by multiple projects owned by separate parties, amplified by contestability & the requisite legal contracts, as everyone tries to keep track of who is paying for what, who is consenting, who is designing and so on;
- consequent delay, which can be very considerable,
- cost; the financing of what ultimately become public assets at commercial cost of capital and over commercial payback periods, which are much shorter than the asset lifetimes, which incidentally denies the asset owner a return on those assets, (though they do charge the projects maintenance for the assets the projects have just paid for!).

The last point is the subject of the attached KHSK report already referred to. Essentially, instead of a lower State-backed financing cost (spread over the much longer design-life of 30-50 years) being charged to the projects through socialised transmission charges, a much higher financing cost has to be recovered by the project itself, at its commercial cost of capital and normally over its support period (generally 15 years). These higher costs have been absorbed to date in projects costs, on the assumption that fixed price supports (REFIT) and consequent PSO payments were adequate to cover them. However, these excess costs will now influence RESS auction bid prices, thus directly transferring these excess costs to the consumer via the socialised PSO, like a hidden tax. Here we might note that a higher PSO decreases social acceptance (a key driver noted in the report).

If on the other hand, the assets to be owned by the TAO (& DAO) were directly funded by them at much lower cost of capital and over a much longer time period, the reduced cost would be reflected in socialised TuOS (& DuOS) charges to projects, reducing the cost base of all generation projects, and thereby RESS auction bid prices, as well as the ultimate cost to the consumer through the PSO. This is the essential point of the KHSK report and the core message of this submission as well.

By taking this issue off the table through Assumption 7, the authors of the report have been limited in their ability to truly assess the cost of the various options. This issue almost surfaces on page 51 of the Navigant report, which states:

> *"A higher increase in PSO levy would be expected in a developer-led model since it would need to cover investments in offshore wind transmission assets as well as the regular offshore wind farm cost."*

But in the end the underlying fact that those costs will be higher in a developer-led model due to the commercial cost of capital & amortisation periods is unfortunately missed.

Not only that. Such a change would grossly simplify the connection group processing system, as each party would fund what it is due to own, thus avoiding all the complications about who is to pay what share of what cost, compounded by contestability, and all the consequent legal implications from, not to mention the issues of cross-bonding and consumer guarantees where projects fail to materialise. The consultation document and the report reflect concerns about delay and missing 2030 targets, urging haste in adoption of measures, and even have 'timing' as one of the seven key drivers underlying the assessment of the model options (Navigant, Table 3.2), as well having complexity as a consideration in their detailed assessment criteria (Table 3.3). And yet here we have a major complexity & time saving opportunity that has been completely & deliberately omitted from the analysis. Once again the authors of the report almost get to the timing point on page 62, but do not refer to the time saving opportunity presented by a change in charging policy. The Timing discussion on page 94 of the Report doesn't even consider the delay caused by the issues raised herein. And while complexity is discussed on page 76 of the report, the underlying issue here that is causing complexity is completely missed.

In order to understand the full complications and anomalies in the current approach with a view to a better model going forward, it is necessary to examine all of these aspects together. Talk of cost reduction without examining all of the elements that contribute to cost (eg: cost of financing the ultimate payment of grid) is somewhat futile.

Table 1 in both the consultation document and the report suggest that there will be an alignment between ownership and financing of the offshore transmission assets (though based on an assumption that those assets will not be transferred to the TAO). Only in Option 4 is the TAO to own and pay for these assets. This is progress, as misalignment can and does cause a lot of complication and delay, as explained. There are however a number of outstanding issues:

1. there are likely to be shared assets, and even transmission stations, in the sea, so it is hard to see how the TSO is going to manage that when it (or TAO) does not own those assets, suggesting a likely transfer of such assets to the TAO in due course, causing the misalignment referred to herein;
2. The shallow onshore grid components are likely to be owned in all cases by the TAO by default, and yet paid for by the projects, which is the standard misalignment problem we already have today, causing excess cost, complication and delay.

The exclusion of these considerations from the report (by a decision to apparently maintain the existing connection charging policy) is a major missed opportunity to help expedite these offshore wind projects at minimum cost to the consumer.

The essential points being made here are:

1. What becomes a system asset after construction is today financed by the developer at commercial cost of capital over a much shorter period (support time period, generally 15 years), while the asset owner is denied a return on that same asset under regulation. Instead of paying higher socialised TuOS charges arising from recovery of such costs at system cost of capital (over the lifetime of the asset, 30-50 years), a higher cost is paid by the project, so a higher charge will find its way onto the PSO (under the RESS tendering system).
2. The developer that ultimately pays for the asset no longer owns it, which causes complications with deprecation and limits its ability to optimize its recovery of the cost; for example Accelerated Capital Allowances are not permitted.
3. The misalignment between ultimate payment and ownership is one of the main sources of complication and delay in the whole grid connection process, in particular under group processing (which gives rise to shared assets). Layering contestability on top of shared assets gives rise to much further complication. Where instead, the payment by the developer stopped short of the shared assets and matched what the project would ultimately own, while the asset owner paid for what it will own, the whole process would be grossly simplified and speeded up. It is to be carefully noted that Option 4 sets out to do exactly that, and lo and behold, the conclusion is that:

   "Developer perspective: no complexity in grid connection procedure as offshore wind transmission assets are developed by TSO and consents are part of tender award[4]."

One final point. Assumption a) on page 7 of the consultation document suggests separate auctions for developer-led and plan-led developments, which then avoids any differences in conditions distorting the auctions. Indeed, the former are expected to be between the developers of multiple sites, whereas the latter are to be between potential developers tendering for a single site. However, this overlooks the strong likelihood that developer-led projects are either delayed or fail to get support under the developer-led auctions (a certainty, by definition), even if they are viable and are needed to meet Government targets. Are these to be abandoned or to be allowed into some other form of hybrid auction, where enduring projects participate? This suggests that the same connection

[4] Page 77, Navigant report

charging policy needs to apply to all offshore projects. A difference in charging policy would give rise to different cost bases and cause distortions in such auctions. Although Option 4 is likely to give rise to auctions for single sites, Option 3 could well include grid connections paid for by the grid authorities, so that should be the overall connection charging policy for offshore wind. That also serves to make offshore wind more competitive as stated in the report, and as argued here and in the KHSK report, is more economically efficient in any case.

[PS: it is not our understanding that the TSO builds wind farm assets under any arrangement, so it seems that Fig. 2 in the consultation document, which is the same as Fig 4.4 in the Navigant report seems incorrect.]

Conclusions

1. The same grid development model ought not be applied to the Relevant and Enduring projects. We suggest Option 1 or possibly Option 2 (with the distance to shore & RESS criteria removed) in the short run, with a switch to Option 4 in the longer run, with it being developed in parallel given the time it will take to set it up.

2. The existing connection charging policy is an anachronism, having been adopted over two decades ago. By causing a 'misalignment' between the ultimate connection ownership and the ultimate payment for that, it creates untold problems of complexity & delay and is the most expensive way for the ultimate consumer to fund connections, because that cost finds its way to the consumer one way or another. Projects face difficulty on depreciating assets that they have paid for but cannot own, while Accelerated Capital Allowances are simply not available. Option 4 conclusively demonstrates the cost, complexity and timing benefits of its charging approach, and so that should be adopted for all offshore wind, and indeed all renewable generators.

3. It seems almost inevitable that delayed but viable Relevant Projects, or those who inevitably do not (by definition) receive a RESS award in the early developer-led RESS rounds, that are nevertheless essential in meeting Government targets, ought to be able to enter the later auctions, or some form of hybrid auction, in which case any model or models adopted and all offshore projects should be subject to the same basic connection charging policy, ideally along the lines of Option 4.

Consultation questions

1) With respect to key driver **(i), cost levels**, which of models 1,2,3,4, or variant of these, delivers the most satisfactory results? Which features of the model, or variant, are the most influential for your given choice?

> As argued here, a major cost issue has been excluded from proper consideration in this whole process, by virtue of the assumption (number 7, though not fully applied) that connection charging policy remains unchanged. A change in grid connection charging policy to where projects pay for what they own would make a major contribution to reducing cost. As presented, Option 4 is likely to be the most competitive[5], but that could create an issue for any Relevant Projects seeking to enter the same tender as plan-led projects, unless they benefit from the same connection charging policy. Such distortions need to be avoided.

2) With respect to key driver **(ii), environmental impact**, which of models 1,2,3,4, or variant of these, delivers the most satisfactory results? Which features of the model, or variant, are the most influential for your given choice?

> For Relevant projects, Option 2 as presented is a non-starter, given the distance to shore criterion, which has no place at this stage of the development of the offshore wind industry in Ireland, which is entirely fixed base and relatively close to shore. However, a plan-led model should give a much better result in the future.

3) With respect to key driver **(iii), future proofing and technologies**, which of models 1,2,3,4, or variant of these, delivers the most satisfactory results? Which features of the model, or variant, are the most influential for your given choice?

> It is clear that a more plan-led approach can provide spare capacity in shared offshore grid transmission systems.

4) With respect to key driver **(iv), required infrastructure**, which of models 1,2,3,4, or variant of these, delivers the most satisfactory results? Which features of the model, or variant, are the most influential for your given choice?

> Although it appears that only Option 1 is workable in the short run, that will inevitably incorporate a degree of group processing on the East Coast to ensure minimal assets both on and offshore. Option 2 includes pro-active onshore reinforcements, which is very beneficial economicially and time-wise, but seeks to direct the RESS auctions towards firm onshore capacity and that is a mistake (given projects generally connect with non-firm access while firm access is developed with those same reinforcements). So Option 2 could be superior (but with the 'distance to shore aspect' also removed). A plan-led approach for enduring projects will perform the same role.

5) With respect to key driver **(v), compatibility with *Relevant Projects***, which of models 1,2,3,4, or variant of these, delivers the most satisfactory results? Which features of the model, or variant, are the most influential for your given choice?

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[5] Paragraph 4, page 69, Navigant report

Option 2 would in principle be superior given pro-active work on onshore reinforcements, but only with its distance to shore & RESS criteria removed, otherwise Option 1 is the only one that can work for the Relevant Projects.

6) With respect to key driver **(vi), social acceptance**, which of models 1,2,3,4, or variant of these, delivers the most satisfactory results? Which features of the model, or variant, are the most influential for your given choice?

A plan-led option, intended to place floating offshore wind beyond the horizon is likely to be the most socially acceptable approach in the longer run, but that's a long way off given technological developments and it will suffer from increased connection costs. For now, the distance to shore criterion in Option 2 is unworkable, so unless that is removed, we are left with Option 1 for this first phase of the sector's development, with some social acceptability issues inherent in the projects, not the model itself.

7) With respect to key driver **(vii), facilitating the timely development of offshore wind capacity to achieve the 2030 target**, which of models 1,2,3,4, or variant of these, delivers the most satisfactory results? Which features of the model, or variant, are the most influential for your given choice?

If the sector does not get off to a flying start with the Relevant Projects, very little if anything will be achieved by 2030. Thus Option 1 is the model to be adopted now, or Option 2 with the distance to shore & RESS criteria removed, with a view to a plan-led model (but with the same connection charging policy) for the enduring projects.

8) **Rank the key drivers** in order of importance 1-7, which have the greatest impact on the choice of model.

Given 2030 targets, timing is absolutely crucial, so measures such as those discussed in this submission to reduce complexity and increase development speed are going to be very important. At this stage in the development of offshore wind in Ireland, we are entirely dependent on the success of most of the Relevant Projects, so compatibility of the chosen model adopted at this stage seems to require a heavy weighting. There is some low hanging fruit on cost, most especially the change to connection charging policy discussed herein. Social acceptance is going to be a big issue, especially on the East Coast, and needs considerable weighting. Given 'where we are' we are unlikely to be able to optimally develop grid infrastructure and future-proof it, with some consequences on environmental issues, while these drivers will be more relevant to the enduring approach, at which time we can envisage a change to a plan-led model.

So a crude ranking would be: Timing, Relevant Projects, Cost, Social Acceptance, Environment, Infrastructure, Future-proofing.

9) How important is it for Ireland to develop an **indigenous offshore wind energy industry**? How best can an indigenous industry be developed?

Very. Ireland now has a once-off opportunity to re-stimulate its economy (that has been badly affected by the lockdown) with this sector, which will also bring a lot of additional benefits, like mitigating climate change and increasing energy security.

10) How should **onshore and offshore grid connections be optimised**? For example, should consideration be given to common hubs for adjacent projects?

> Yes, these will be essential on the East Coast now and on the other coasts in due course, suggesting Option 4 in the longer run.

11) Are there any further considerations which might **reduce the cost to the consumer**?

> Once again, following the Danish, German and Dutch examples, an Option 4 type-approach to offshore grid, regardless of which model is actually chosen to start with (incorporating a suitably revised grid connection charging policy) is the key point here in reducing cost to the consumer.

12) Currently, developer compensation is not provided for delayed delivery of grid connections to renewable generators connecting to the network. Should **developer compensation arrangements** be provided for delivery of offshore grid connections to renewable projects? Similarly, who is best placed to bear the **outage risks** under the various options?

> It has long been an argument from the renewables sector that the inevitable and pervasive delays in grid delivery should be 'negatively incentivised', as projects are left waiting for months or even years for grid, while the grid authorities have little incentive to perform, and given a lack of full legal unbundling, may indeed have a disincentive. This becomes particularly crucial under RESS, as we will soon see, since failure to deliver grid is THE major issue for meeting RESS build deadlines, and as of now, there are not going to be any mitigating measures. Outage risks lie with the asset owner.

13) Are there any **further drivers** which should be considered when assessing a grid delivery model suitable for offshore wind development in Ireland?

> We consider that there are two additional policy drivers that ought to be considered:
>
> Resource. Renewable energy resources depend on weather conditions, and so vary geographically, so that solar is favoured in Southern Europe and wind is favoured in Western Europe. In Ireland the best wind resource by far is in the West.
>
> Grid capacity allocation. Under an auction model, it is necessary to ensure that grid capacity is not contracted with projects that lose. A Grid Following Funding (GFF) model has been proposed, but that puts the most difficult and slowest stage of the process (grid) after consent and support, which is out of sequence; bidders need precise grid costs and details, and to know that they definitely have grid if they win a tender (otherwise they are at risk and can't meet build deadlines). We prefer either conditional grid offers or grid options.

14) **Overall**, which model, or model variant, is most appropriate as an enduring grid delivery model for offshore wind in the Irish context?

> Option 4 seems the best, but cannot be adopted in the short term for the Relevant Projects, which should be handled under Option 1 (or Option 2 with the distance to

shore & RESS criteria removed), but with the same connection charging policy as will apply under Option 4.

15) It is accepted that a transition towards the chosen enduring grid delivery model will be required to leverage the development of the Relevant Projects in the short term. Taking into account the high level roadmaps set out at Figures 5 and 6 above, **what should this transition look like?**

A key point already mentioned is to provide for the strong possibility that delayed but viable Relevant Projects, or those who inevitably do not (by definition) receive a RESS award in the early developer-led RESS rounds, that are nevertheless essential in meeting Government targets, ought to be able to enter the later auctions or some hybrid version, in which case any models adopted and all offshore projects should be subject to the same basic connection charging policy.

KHSK

ECONOMIC CONSULTANTS

Efficient Funding of Transmission Network

Connection Costs

January 2010

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Executive Summary

1. The National Offshore Wind Energy Association of Ireland (NOW Ireland) has requested KHSK Economic Consultants to examine the impact of certain regulatory issues governing the interaction of the electricity Transmission System Operator (TSO) and independent renewable generators from the point of view of the efficiency of the existing regulations in minimising the cost of electricity to consumers. This issue relates specifically to the funding of transmission system connection infrastructure.

2. Regulations and economic policy interventions always impose costs on the economy and must always be justified on the basis that the expected benefits outweigh these costs. Irish policy statements emphasise the need to ensure that regulations are efficient and minimise the costs imposed on the economy and that the cost of regulations must be assessed to ensure that the approach being followed does not impose excess costs on either producers or consumers.

3. The existing regulations mean that a private generator has the right to connect to the transmission system, but in order to exercise this right it must fund and may construct the required infrastructure in accordance with Eirgrid's specifications, and then transfer these assets to the TSO, at the discretion of Eirgrid, for a nominal payment. As the transmission system is a natural monopoly it is correct that all aspects of the transmission system should be compatible, under single ownership and under single management. Furthermore, it is logical that the TSO should be in a position to specify the ownership boundary.

4. The issue in question therefore is whether the introduction of private financing to the transmission system acts to reduce or increase the cost of supplying electricity to consumers. This is not a question regarding the level of profitability that can be earned by private businesses or the distribution of returns between generators and the TSO. Costs that are incurred must be recouped and the appropriate regulated return is a matter to be determined by the regulator. Therefore, the question to be examined is whether there is reason to expect that the cost of funds might be higher for the private generator than for the TSO? If this is the case, then the current arrangements would mean that efficiency losses would be passed on to the consumer as higher prices.

5. While there are numerous points of difference, international research points to reasons why the cost of public funds would be less than private funds. The Department of Finance in Ireland has been consistent in arguing that publicly funded investment projects in Ireland should be appraised using a discount rate of 4% as this reflects the cost of interest on the national debt. However, investment by commercial state entities should use the cost of capital for that body.

6. The Capital Asset Pricing Model (CAPM) is used to estimate the Weighted Average Cost of Capital (WACC) for investment by private sector operations in offshore wind energy and for the TSO. This follows the methodology adopted by the CER but there are some differences in the parameters used. The

calculation estimates a WACC of 10.2% for the private sector and 5.82% for the TSO.

7. Using an illustrative example of a 100MW offshore wind farm with a transmission connection cost of €15 million, the difference in the total cost of finance between the private firm undertaking the investment and the TSO doing so is estimated at €9.8 million, equivalent to 0.15c per kWh. This is the excess burden of the regulations and is thus the benefit to be realised through reform. In addition the regulations impose a barrier to entry to the sector.

8. Avoiding this excess cost and removing this barrier to entry requires changing the regulations and this should be done unless a conclusive argument is identified that this benefit cannot be realised. If such a conclusive argument is formalised then an alternative mechanism is required, perhaps through a tax efficient structure, to incentivise investment.

1. Context of this Report

1.1 Introduction

Along with considerable growth in demand, the electricity market in Ireland has undergone a number of important changes in recent years, a situation that is likely to persist into the foreseeable future. The most important are the entry of independent generators and the growth of renewable energy. The ESB will remain the dominant player for the foreseeable future and Eirgrid retains a monopoly position in transmission. Given this industry structure and the importance of efficient and reliable energy supply for the sustained recovery of the Irish economy, it is correct that the sector should be closely regulated with an important role for the CER[1].

A starting point for any analysis of this sector must be that energy costs are one area where Ireland is significantly out of line with competitor countries. Electricity costs for business and industry are the second highest in the EU-14 and are 35.5% higher than the Eurozone average[2]. The base price of fossil fuels is outside policy control so attention must focus on identifying the extent to which internal issues such as the structure of regulation or competition, any shortfall in availing of the benefits offered by the EU single electricity market, or the ongoing small proportion of indigenous energy resources in the total, in particular renewable energy, may be contributing to the situation.

KHSK Economic Consultants have been requested by the National Offshore Wind Energy Association of Ireland (NOW Ireland) to examine elements of the interaction between Eirgrid and independent renewable generators from the point of view of the efficiency of the regulations as currently set out in Eirgrid statements authorised by the CER. This relates specifically to the funding of transmission system connection infrastructure i.e. the funding of infrastructure in the vicinity of the ownership boundary between medium to large scale generators and the transmission system.

Following this introduction, Section 2 contains an economic analysis of the issues that arise in relation to whether infrastructure is funded from public or private sources. The central issue is an assessment of the relative cost of capital in each sector. This is based on published literature and research and on the approach that has been taken in Ireland in policy assessments and in published guidelines.

1.2 The Policy Background

Ireland has set a target to get 40% of its electricity from renewables by 2020. To assist in achieving this target, the CER has outlined plans to connect almost 4,000

[1] References to the Commission for Energy Regulation (CER) should be deemed to relate also, where relevant, to the SEM project for the island of Ireland.
[2] National Competitiveness Council (August 2009) *Annual Competitiveness Report* and National Competitiveness Council (October 2009) *Statement on Energy*.

MW of renewable power, mostly from wind, under the Gate 3 process[3]. Renewable power connected to the grid is projected to increase 5-fold, from 1,300MW at the start of 2009 to 6,700MW in 2020. Recent research indicates that the integration of 6,000MW of wind generated electricity into the grid would reduce the cost of Ireland's energy and improve competitiveness[4]. This confirms the results obtained by the CER[5]. However, to achieve these savings, it is important that Ireland is efficiently interconnected and that the regulations concerning the operation of the system are appropriate and are efficiently implemented.

The Regulatory Approach as Currently Stated

The main regulations of relevance are contained in two published statements by ESB National Grid/Eirgrid based on Directives issued by the CER. The first of these identifies a number of high level objectives from which it derives principles that define the policy approach that has been taken in relation to connection to the transmission system[6]. First among these objectives and principles is that:

> *A user connecting to the transmission system will be eligible to pay for the full cost associated with the direct connection of the user to the transmission system.* (page 3)

Thus, full recovery of the cost of connection had been identified as a key objective and principle for the transmission system operator (TSO) even before private firms obtained the right to construct the connection infrastructure. This right, known as contestability, was introduced in 2000.

Contestability meant that the TSO needed to ensure that these new elements of the system were built and maintained in a manner that was consistent and compatible with the rest of the system. Section 37(4) of the Electricity Regulation Act 1999 gave the CER the power to direct the owner of a contestable asset to transfer ownership to Eirgrid, the TSO. Various other guidelines have been issued in this regard with the definitive publication appearing in 2007[7]. Along with providing definitions and guidelines on technical aspects of contestable assets, the statement also identified a number of principles for the treatment of contestable assets among which is the right of the TSO to determine the ownership boundary. The statement also outlines the procedure for the transfer of assets with the result that where assets that have been constructed by private generators are to be transferred, with the approval of the CER, this will be done in return for a nominal fee (e.g. 1 Euro)[8]. In summary, therefore, the situation is that while a private generator has the right to connect to the transmission system, in order to exercise this right it must fund and may construct the required infrastructure in accordance with Eirgrid's specifications and then transfer these assets at the discretion of Eirgrid for a nominal payment. Furthermore, if the infrastructure

[3] CER 'CER announces unprecedented increase in renewable electricity'. Press Release, 13 November 2008

[4] Devitt, C., S. Diffney, J. Fitzgerald, S, Lyons and L. M. Valeri (2009) *The Likely Economic Impact of Increasing Investment in Wind on the Island of Ireland.* Working Paper No. 334. Dublin: ESRI

[5] CER (2009) *Impact of High Levels of Wind Penetration in 2020 on the Single Electricity Market.*

[6] ESB National Grid (2000) *Connection Asset Costs: Guiding Principles* (April)

[7] Eirgrid (2007) *Contestability of Connection Assets* (October)

[8] The statement makes a formal distinction between the TSO and the Transmission Assets Owner (TAO) but this distinction is not important for the analysis in this report.

is instead provided by the TSO then the generator is nevertheless liable for these costs.

Regulation and Competitiveness

Regulations and economic policy interventions always impose costs on the economy and must always be justified on the basis that the expected benefits outweigh these costs. Failure to do so will lead to inefficient regulations and excess costs for either producers or consumers. The need to ensure that regulations do not inhibit the competitiveness of the economy or impose excess burdens has been given increased emphasis in published guidelines for policy formation in Ireland over the past decade[9]. The White Paper on regulation recognises that regulation will impact on competitiveness and states that:

> *Inappropriate regulation can adversely affect the competitiveness of the economy. We must not stifle competition or innovation through regulation that promotes or protects inefficiencies in the economy.* (p.6)

The White Paper also identifies 'Effectiveness' as a key principle for good regulation and states:

> *An associated element of regulatory effectiveness is the need to minimise unintended outcomes. This means avoiding the creation of unnecessary barriers which frustrate and inhibit innovation and stifle economic activity by reducing entry and exit to particular sectors and markets.* (p. 16)

Having set out the importance of, and the principles that underlie, good regulation the White Paper identifies the need to undertake a Regulatory Impact Assessment (RIA) of policies before they are introduced. This recommendation has been codified as a set of guidelines to be followed when undertaking RIA[10].

In summary this approach identifies the need to ensure that regulatory policies are efficient and minimise the costs imposed on the economy as a key requirement of good regulation and that the cost of regulations must be assessed to ensure that the approach being followed does not impose excess costs on either producers or consumers.

The need for regulation of the electricity sector is obvious given the high set-up costs and the natural monopoly that exists in transmission. However, it is similarly necessary to ensure that this regulation complies with the principles of good regulation as set out in the White Paper. An important element of this, given the high infrastructure costs that characterise the sector, is to ensure that the structure of control and ownership of key infrastructure is optimal, that monopoly power is controlled and restricted to the parts of the sector where the case for monopoly is robust, and that the costs of investment in the sector are minimised. This final requirement provides the rationale for this report.

[9] Department of the Taoiseach (2004) *Regulating Better: Government White Paper setting out six principles of Better Regulation*

[10] Department of the Taoiseach (2005) *RIA Guidelines: How to conduct a Regulator Impact Assessment.* (Revised June 2009)

2. The Cost of Public and Private Funds

2.1 Specifying the Issue

The current regulatory situation means that, in practice, private sector generators of electricity from renewable energy wishing to connect to the national grid must finance and may construct the necessary infrastructure according to criteria specified by the publically owned Eirgrid and then transfer ownership, at the discretion of Eirgrid, to this public entity. This raises a number of issues most of which are technical in nature and are not dealt with here. However, two issues arise from the point of view of economic efficiency.

The first relates to the right of Eirgrid to acquire ownership of the assets and specify the physical nature of contestable assets. The arguments in favour of the approach that has been outlined in the CER approved statements discussed above appear conclusive. The transmission system is a natural monopoly since the average cost per unit of transmitting electricity over the grid will fall over all foreseeable levels of usage. In other words, there is no economic gain possible from competition in this sector. Given this, it is conclusive that all aspects of the transmission system should be compatible, under single ownership and under single management. Furthermore, it is logical that the TSO should be in a position to specify the ownership boundary.

The second issue relates to the funding of the infrastructure. The transmission network in Ireland has been financed through public funding. However, the regulations in relation to contestable connection assets means that elements of the transmission system would now be funded by private finance. This raises a question of efficiency: from the point of view of the economy as a whole, is there reason to conclude that the introduction of private financing to the transmission system will reduce the cost of supplying electricity to consumers, or might the reverse be the case? This same question arises in cases where connection assets are provided by the TSO and the cost is to be recovered from the private generator.

It is important to note that this is not a question regarding the level of returns (profitability) that can be earned by private businesses as a result of the introduction of private sector electricity generation. Since it is policy that electricity generation from renewables should be promoted and that competition should be facilitated in electricity generation, then the DCENR must set the feed-in tariff at a level that will make entry to the industry attractive. Thus, if the private sector must finance and then transfer the connection assets, this must be built into the tariff.

Neither is it a question in relation to the distribution of gains between the public sector (the TSO) and the private sector (new entrants) or the regulated level of return to the TSO. If the TSO either builds or 'buys' the connection assets at a price that reflects the cost of supply the assets then this cost must be reflected in its charges and in its regulated return. The approach used in this report cannot be interpreted as an argument that a more efficient system would arise through a different distribution of returns. Instead, the argument is that efficiency can be improved through reducing the cost of providing the assets through a revised approach to funding and that this can be passed through to consumers as lower prices. The implications of this for the appropriate regulated returns is a matter to be determined by the regulator.

The issue of whether the private sector can build the infrastructure at a lower cost than would be incurred by the TSO is not addressed, although it has been frequently argued, and indeed demonstrated, that the private sector has been able to supply infrastructure in a number of sectors at lower cost. Given that the TSO specifies the assets in all cases, there is no *a priori* reason to expect that the cost of providing the assets will differ and further examination of this issue would require a comprehensive examination of specific projects[11]. Therefore, the question to be examined is the cost of providing the finance to fund the construction of infrastructure with a given set cost.

2.2 Public and Private Sector Appraisal

The Cost of Private Funds

Identifying the cost of funds in the private sector, while sometimes complex in practice, is relatively straightforward conceptually. At its simplest, the cost of funds is the relevant rate of interest. Where equity is also involved it is necessary to adjust the calculated cost according to the percentage of equity in total funds. To do so it is necessary to calculate an expected return on equity investment and apply this cost to the non-debt element of the funds. This is the basis of the Capital Asset Pricing Model (CAPM) which provides the Weighted Average Cost of Capital (WACC) for any investment. In practice, identifying the appropriate rate of interest is not a problem but some judgement will be involved in valuing equity investment.

The process of calculating the WACC is used by the CER to provide a BNE price. The methodology is outlined in the Appendix to this report. The appendix also provides an estimate for the WACC in offshore investment. This is estimated to be 10.2%. This is the most appropriate methodology to value the cost of funds for private sector investment in offshore wind energy.

The Cost of Public Funds

Identifying an appropriate cost for public funds used in investment is more difficult and, despite the existence of a huge theoretical and empirical literature on the subject, it is accepted that there is no agreement on the correct approach that should be taken. At its simplest, the risk free rate of interest could be used. Any nominal rate of interest comprises a time preference element, an allowance for inflation and a risk premium. However, while the markets provide a measure of private time preference, the idea of a social time preference (STP) is more controversial. While a multitude of issues are raised in the literature, the difficulties can be summarised in terms of two areas of contention. The first arises from the fact that public funds used in any project have alternative uses. Thus, their true cost is the returns foregone i.e. their

[11] However, the tendency of CER to allow the TSO to recover a contribution to overheads when pricing grid connections may well cause a difference.

opportunity cost. But how should this be measured? The second relates to the appropriate time period to adopt for the returns to provide a net benefit from the project[12].

If the cost of public funds is their opportunity cost then how should this be valued? The simplest approach is to assume that funds used by the public sector from investment can be borrowed so the cost is the rate of interest on public debt i.e. the rate receivable from Government bonds. The implicit assumption is that the alternative use of funds is repayment of the national debt. If this is accepted then the remaining question is whether this should be the average rate payable on the debt or the marginal rate i.e. the rate payable on new debt.

However, this approach is open to question. The fact is that the public sector has an alternative source of funds where the interest rate payable is zero, namely taxes. However, this does not mean that these funds are costless. Rather, the marginal cost of public funds – the cost of raising an additional Euro – is the full cost to the private sector of raising the additional Euro of tax revenue and must include the deadweight loss/excess burden of taxation on the economy. What this means in practice is that a Euro invested by the public sector costs the economy more than a Euro and this must be included in the appraisal, usually by adjusting the value of the initial investment. Estimates of this cost vary but tend to lie in the region of 35% i.e. it costs the private sector €1.35 for every €1 that accrues to the public sector as tax revenues[13]. Recognition of this fact has been one of the driving forces for the move towards the use of private funds in infrastructure projects in many economies over the past few decades. As a result of this issue, it is necessary to decide whether the source of public funds is the national debt or tax revenues.

This discussion leads to the straightforward question: for a given investment, is the cost of funds as estimated by the CAPM above or below the opportunity cost of public funds as estimated by whichever methodology is deemed to be the most appropriate, and used in public appraised as the social discount rate?

The Payback Period

A second issue that has gained renewed recognition in recent years is the period over which an investor can expect to be repaid. This is particularly the case where the investment is in infrastructure with a long useful life – such as a harbour for example – or where the returns accrue slowly over a long period of time as is often the case in appraising investment in environmental projects, for example, non-commercial broadleaf forestry. The private sector will usually not undertake such investments since the payback period may exceed a generation. The problem with applying

[12] This points to a different methodology that is usually adopted in appraising projects where public funds are used compared to financial appraisal in the private sector. In the private sector, the financial model will usually calculate the annual profit based on revenues and debt repayments etc. Public appraisal will usually place the cost of an investment upfront and discount future income to identify if there is a positive net present value in the initial year. One approach is adding interest as a cost, the other is discounting the future income. In a world of perfect markets the two approaches are equivalent – the interest rate is the discount rate. However, the issues discussed in the text mean that this is not the case in practice.

[13] Ruggeri, G. (1999) *The Marginal Cost of Public Funds in Closed and Small Open Economies.* Fiscal Studies, Vol. 20 (1) pp 41-60

discount rates based on interest rates in public sector appraisal is that the project will seldom show a net positive present value. The fact is that the public sector, as the arbitrator of society's objectives, as distinct from the objectives of each individual, should rationally adopt a much longer time horizon for the assessment of benefits. Recent thinking on this issue recommends that the appraisal model should adopt different discount rates depending on the relevant time horizon. A good example of this in practice is the Stern Report on climate change which adopted annual discount rates of as low as 0.1% per annum for actions taken now that have a long term pay-off of a century or more[14]. This assumption, rather than any fundamentally new science on climate change, was the main reason the conclusions of the Stern Report was stronger in support of introducing measures to address the problem than had been the case with most previous economic analysis of the problem[15].

This is an interesting point for consideration in relation to transmission infrastructure. As static fixed infrastructure, commercial appraisal will adopt a write-off period that is much less than the useful lifetime of these assets. This results in a market failure with the result that private investors have a disincentive to invest to the socially optimal level. In other words, private investors will not perceive the returns to be adequate to undertake an investment even though from the point of view of the economy – the point of view that should be adopted when undertaking an appraisal of investment using public funds – the investment would provide a net benefit to the economy.

The simplest way to address this market failure is for the investment to be undertaken using public funds. However, in a regulated market such as electricity supply this can be addressed by ensuring that the feed-in tariff is adequate. This will allow the private investors adopt a commercially optimal payback period while ensuring that actions with a positive long term social return are undertaken. Since this tariff ultimately accrues from the price paid by consumers it is arguable that this is an efficient way to address the problem. The provision of funds in this manner can be viewed as equivalent to a tax, where the funds that are raised are ring fenced to promote the sector, as it provides funds at zero interest but it is a tax that could be expected to have a limited distortionary or deadweight impact on the economy. Thus, its marginal cost is likely to be relatively low.

These considerations mean that investment in these assets by a publicly funded entity will not necessarily be more efficient than investment by the private generator despite their different time horizons, *provided the cost that would be incurred by the generator is recognised in the feed-in tariff set by the Department.* Current policy is in line with this conclusion. However, this is not the basis of the argument that is developed in this report. The main issue examined in the next section is that the cost of funds to the public sector can differ to a meaningful extent from the cost of funds that is experienced by the private sector. This is because the factors that determine the relative cost of funds to the public and private sectors are independent of commercial considerations regarding the payback period and the relative time horizons of the two sectors.

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[14] Stern, N. (2006) *The Economics of Climate Change: The Stern Review*. Cambridge: Cambridge University Press

[15] Dasgupta, P. (2008) 'Discounting Climate Change'. *Journal of Risk and Uncertainty*, Vol. 37, pp 141-169

2.3 Estimates from Research Studies

This discussion means that the question of the most efficient way to fund transmission infrastructure depends on the relative cost of public and private funds. Research indicates that the conceptual basis for estimating the cost of public funds and the discount rates used in relation to the returns from investments using pubic funds have varied between countries and even within countries[16].

Table 1 provides an indication of the rates currently recommended for use in appraisals in a number of countries. This indicates that a real social discount rate of around 4% is typical irrespective of whether it is estimated with reference to the social time preference or the interest rate on public debt[17].

Table 1: Real Discount Rate on Public Investments in Developed Economies

Country	Real discount rate
France	4% since 2005 based on STP with rate decreasing after 30 years
Germany	4% since 2004 based on federal refinancing rate
Italy	5% based on STP
Norway	3.5% based on government borrowing rate
Spain	4% to 6% depending on sector based on STP
UK	3.5% based on STP decreasing after 30 years
US	2.5 to 3% equal to Federal borrowing rate

Source: Spackman (2008)[18]

The issue of using differential rates when appraising public investments depending on the time period involved has further complicated the discussion. For example, one research study in the US recommends that if all the benefits are received within 50 years then 3.5% should be used, 2.5% for benefits accruing after 5- to 100 years, 1.5% for 100 to 200 years and progressively lower thereafter[19].

The emergence of Public Private Partnerships (PPPs) brings the issue of the relative rates applicable to private and public funds explicitly to the fore. However, there has been a lack of agreement on the appropriate discount rate to use in such circumstances and the general practice has been to simply use either the public sector rate or a rate slightly above this level[20]. However, having looked at the basis for this practice,

[16] The cost of funds, if it is assumed that they are fully borrowed, and the discount rate are interchangeable terms in appraisals to aid decisions in relation to investment. To see this, consider that the decisionmaker has a choice: invest in the project or repay (avoid) debt. If the appraisal shows that the discounted returns from the project exceed the investment, this is the same as saying that the returns from the project exceed the returns that would be earned by investing at the rate of interest on public funds i.e. the cost of public funds. If the funds are partly obtained through taxation then the cost of the investment should be adjusted appropriately.

[17] This is not surprising since the interest rate will typically be made up of a time preference element and a premium for risk. The risk premium in developed economies in this period was very low and even though it has risen for some countries in relation to marginal debt in recent years it remains low on average.

[18] Spackman, M. (2008) *Time Preference, the Cost of Capital and PPPs*

[19] Moore, M., A. Boardman, A, Vining, D. Weimar and D. Greenberg (2004) 'Practical Value for the Social Discount Rate'. *Journal of Policy Analysis and Management*, Vol. 23 (4) pp 789-812

[20] Grout, P. (2003) 'Public and Private Sector Discount Rates in Public-Private Partnerships'. *The Economic Journal*, Vol. 113, pp C62-C68

Grout concludes that '*there are powerful arguments for using a higher rate to discount private projects than public sector projects*'. The research leads to the conclusion that failure to do so will mean that '*the present value of private provision will be over-estimated relative to public*'. In other words, the failure to recognise that discount rates in the private sector are higher than in the public sector in projects where there is both a public and a private interest will over-estimate the returns in the private sector and lead to project design where an excessive proportion of the investment is undertaken by the private sector. This recognition weakens the case for PPPs relative to the more traditional model of public provision.

2.4 The Approach Taken in Ireland

Whatever the approach taken to estimate the appropriate rate for the cost of public funds, it is arguable that a key requirement is that a consistent approach is adopted within any economy to ensure that funds are directed towards the most productive projects[21]. This approach has guided thinking in Ireland so that the Department of Finance has tended to adopt a fairly basic approach to what the appropriate rate should be, but that the recommended rate should be used in all cases of appraisal where public funds are invested.

Guidance provided by the Department recommends that all future revenues should be discounted to present values when assessing investments using public funds[22]. Successive publications from the Department have been clear regarding the basis for identifying an appropriate rate and have concluded that the discount rate to be used when appraising public sector investments should be based on the risk free cost of debt to the public sector, i.e. the yield on the appropriate long term Government Bond[23]. This approach does not seem to have been closely argued on any basis other than that repayment of the national debt is the alternative use of funds in the public sector and so the opportunity cost of funds invested by the public sector in any project is the interest rate on public debt. Given that Ireland is a small economy with small borrowing requirements relative to world markets it is reasonable to assume that the supply of credit is infinite so that borrowing is always available as a source of funds[24]. Thus, repayment of debt is the alternative use of funds. This means that it is not recommended that the value of the investment should be adjusted to allow for the marginal social cost of public funds where public funds are invested.

[21] Hahn, R., J. Burnett, Y. Chan, E. Mader and P. Moyle (2000) 'Assessing Regulatory Impact Analysis'. *Harvard Journal of Law and Public Policy*, Vol. 23 (3) pp. 859-885

[22] Department of Finance (2005) *Guidelines for the Appraisal and Management of Capital Expenditure Proposals in the Public Sector*

[23] Department of Finance (2006) *Discount Rate Principles for Public Private Partnership Capital Investment Projects*. Central Guidance Note No. 7, page 5.

[24] It might be argued that this is no longer the case given the fiscal crisis that has emerged and that the social cost of funds approach i.e. the cost of taxes, should be used instead. However, borrowing remains a viable source of funds for the public sector and while Irish debt has attracted a premium rate on international markets in recent times there has never been any indication that funds were constrained. Thus, the implication of the change in the fiscal balance is not that the approach of recent years is no longer appropriate, but that the interest rate on the national debt, and thus the appropriate discount rate, may rise in the future.

The recommended official test discount rate is stipulated by the National Finance Development Agency (NFDA) and is currently identified as 4% for all appraisals of pubic capital projects[25]. This represented a reduction from a well established long term rate of 5%. However, the expected returns from investment in infrastructure to provide a connection to the electricity transmission network will be, in part, dependant on the private sector. The result is that, while not strictly defined as a public private partnership (PPP), investment in this infrastructure, if undertaken by a publically owned entity, would have some characteristics similar to PPPs. For example, not all the decisions regarding the usage of the transmission system connection are under the control of the public sector since generation is undertaken by a private company. As a result, it is considered that there are elements of risk that are similar to those encountered in a PPP. As discussed above, there are reasons to adopt a higher rate. The appropriate discount rates to be used in assessing PPPs are advised by the Department on a case by case basis and have been close to or slightly above 5% in recent years[26].

The Department also advises that, in the case of a commercial State Sponsored Body, the cost of capital should be used as the discount rate. The approach used in the appendix can be adapted to assess what this might be. This calculation is shown in Table 2.

Table 2: Calculation of WACC for Eirgrid

Cost of Debt	
Nominal risk free rate	3.88%
Debt risk premium	2.50%
Inflation	2.00%
Real cost of debt	4.38%
Nominal Cost of Equity	4.00%
Equity beta	1.7
Risk adjusted cost	6.80%
Social Cost of Funds 1:1.35	
Cost of Equity	9.18%
Gearing 70%	
WACC	5.82%

It is assumed that Eirgrid faces a similar nominal risk free rate but that its debt risk premium would be 2.5%, below the 3.5% assumed for the private sector due to the fact that it is state guaranteed. Furthermore, since the state is the single shareholder, the approach to estimating the cost of public funds in Ireland means that the nominal cost of equity is the public sector discount rate of 4%. Applying a similar equity beta of 1.7 – it could be argued that this should be lower given that all of the infrastructure will be onshore and is well understood and tested – gives a risk adjusted cost of equity of 6.8%. However, since the state is investing public (social) funds in a commercial operation, it can be argued that it is necessary to adjust the returns to allow for the

[25] Department of Finance (2007) *Memorandum to Secretaries General* (NFDA, 15th May).

[26] It is notable that published material refers to indicative rates of 5.25% and 5% in illustrative examples. See *Technical Note on the Compilation of a Public Sector Benchmark for a Public Private Partnership Project*, Department of Finance, January 2007.

marginal social cost of public funds i.e. the deadweight and distortionary cost of 35%. This is done giving a cost of equity of 9.18% per annum. However, a state sponsored entity is not as likely to be as constrained in its gearing as the private sector so a 70% gearing is assumed. Thus, the WACC for Eirgrid is estimated at 5.82%.

3. Conclusions

Although there have been numerous policy statements in favour of the development of renewable energy in Ireland, the sector remains under-developed, particularly in relation to off-shore wind energy. The move to feed-in tariffs and the introduction of some tax supports have helped in recent years but connection to the transmission system remains a problematic area. Under the existing regulations, private generators may fund and may construct the connection and then transfer the assets to the TSO, at its discretion.

The analysis in this report shows that this is an inherently inefficient way to proceed. The cost of funding the infrastructure would be reduced if public funds directly injected into the sector were used to finance these assets, or if the infrastructure was financed through the TSO. It is important to note that this is not an argument regarding the distribution of returns in the sector. Instead, it is about the overall cost of generating electricity.

It is recognised that this would require a considerable change to the existing regulatory environment. Should conclusive arguments be put forward as to why these changes should not be made then it is important that initiatives are introduced to reduce the barrier that the current regulations present and to reduce the costs. For example, such initiatives could mean that public funding, acting through the tax system, would contribute part of the funding for the transmission assets thereby reducing the overall cost of these assets as the cost of funds would be reduced.

Appendix: Calculation of WACC for Offshore Wind Energy

The CER has published annual best new entrant (BNE) prices for tariffs for electricity generated from renewable energies. Part of this approach is the calculation of an appropriate weighted average cost of capital (WACC) for the sector. Table A1 shows an example of the CER approach for illustrative purposes[27]. The WACC for investment, on the basis of these estimates, was calculated as 7.52%.

Table A1: Example of Calculation of WACC for Investment in Wind Energy

Cost of Debt			
1	Nominal risk free rate	4.72%	
2	Debt risk premium	2.50%	
3	Inflation	1.90%	
4	Real cost of debt	5.32%	*4=1+2-3*
Cost of Equity			
5	Nominal risk free rate	4.72%	
6	Inflation	1.90%	
7	Real risk free rate	2.82%	*7=5-6*
8	Equity risk premium	5.30%	
9	Expected market rate of return	8.12%	*9=7+8*
10	Equity beta	1.59	
11	Post-tax cost of equity	11.25%	*11=7+(8*10)*
12	Tax rate	12.50%	
13	Pre-tax cost of equity	12.65%	*13=11*(1+12)*
	Gearing 70%		
14	**WACC**	7.52%	*14*=(*4**0.7)+(*13**0.3)

Source: CER (2002)

This has not varied greatly during the period that the CER has published these estimates. For example, the calculations for 2006 and 2007 resulted in an estimated WACC of 7.03% and 7.38% respectively while the most recent estimate is 7.13%[28].

However, while this methodology was accepted as appropriate, independent research indicated that this estimate was too low in the case of offshore wind energy[29]. The main problem was that the CER based their parameters on facilities utilising Combined Cycle Gas Turbine (CCGT) technology, the technology in the 2010 BNE estimate is the Alstrom GT13E2 with a plant output of 190MW. This may be rational given the CER's focus of developing a competitive market but it is inappropriate to use estimates of risk and other metrics based on CCGT to estimate the WACC for the wind energy sector.

[27] Based on CER (2002) *Best New Entrant Price 2003*, page 2

[28] CER and Utility Regulator (2009) Fixed Coast of a Best New Entrant Peaking Plant, Capacity Requirement & Annual Capacity Payment Sum for the Calendar Year 2010. It is noted that while Table 2.2 in this publication used 7.13% as the WACC, this is the UK estimate derived in Table 8.1. The RofI estimate in this table is 6.8%.

[29] Pater Bacon & Associates (2003) *Review of Alternative Models for Calculating the Optimal Price for Wind Energy*

Based on analysis of investments in the sector and consultations with operators, the Bacon report concluded that the offshore sector would experience a lower risk free rate of interest and debt premium and a much higher risk premium for equity than had been allowed by the CER. A higher equity beta for offshore was also deemed to be justified given the relative under-development of the sector. As a result, the report calculated the WACC for offshore generation as shown in Table A2. This shows that the WACC in this case is considerably higher at 9.1%, a rate 21% above the CER estimate[30].

Table A2: WACC for Offshore Projects in 2003

Cost of Debt	
Nominal risk free rate	4.40%
Debt risk premium	1.80%
Inflation	2.10%
Real cost of debt	4.10%
Cost of Equity	
Nominal risk free rate	4.40%
Inflation	2.10%
Real risk free rate	2.30%
Equity risk premium	9.50%
Expected market rate of return	11.80%
Equity beta	1.7
Post-tax cost of equity	18.45%
Tax rate	12.50%
Pre-tax cost of equity	20.76%
Gearing 70%	
WACC	9.10%

Source: Bacon & Associates (2003)

Updating this to the present would require a revision of the debt risk premium and the inflation rate with the result that the real cost of debt and real risk free rate for equity would be higher. The nominal risk free rate of debt can be obtained from recent auctions of Irish Government bonds. The results from these auctions suggest that he risk free rate for longer term periods has fallen since 2003 and that a rate of just below 4% would be appropriate[31]. As has been widely reported, the perception of risk in the economy has also changed considerably in the past few years and so it is appropriate to use the CER's revised estimate of 3.5%.

One issue which poses some difficulty is the inflation rate to be included. Inflation is currently running at an annual rate of -5.7%[32] but is forecast to rise to 0% in 2010[33].

[30] The report found that the CER's estimate was not out of line for onshore investment but this depended on funding with 80% debt.
[31] The NTMA's November auctions provided average yields of 3.072% for the 2014 bond with 4.735% for the 2019 bond, an average of 3.88%.
[32] CSO (2009) *Consumer Price Index*, November
[33] ESRI (2009) *Quarterly Economic Commentary*, Autumn

However, the longer term target of 2% as set by the ECB must be taken into account as inflation is likely to remerge over the next few years . This would possibly push interest rates up slightly above current levels but it is considered that it would be more appropriate to use this inflation rate than the current rate in the calculations. To accommodate this, the 2.0% rate is used. The CER BNE estimate uses a real risk free rate of 1.88% for Ireland suggesting that these values – a nominal 3.88% less 2% – are appropriate.

The CER publication uses an Equity Risk Premium (ERP) of 4.75% and an equity beta of 1.25, giving a post tax cost of equity of 7.81%. This is too low for the offshore wind sector. An ERP of 8% would be more reasonable. Also, the offshore sector remains unproven so there is no reason to use a lower beta than the 1.7 used in the Bacon report. Finally, the CER assumes that gearing of 60% is appropriate given the current financial situation. The calculation of the WACC for offshore investment is shown in Table A3 using these estimates.

Table A3: Updated Calculation of WACC for Offshore Projects

Cost of Debt	
Nominal risk free rate	3.88%
Debt risk premium	3.50%
Inflation	2.00%
Real cost of debt	5.38%
Cost of Equity	
Nominal risk free rate	3.88%
Inflation	2.00%
Real risk free rate	1.88%
Equity risk premium	8.00%
Expected market rate of return	9.88%
Equity beta	1.7
Post-tax cost of equity	15.48%
Tax rate	12.50%
Pre-tax cost of equity	17.42%
Gearing 60%	
WACC	10.20%

This gives a WACC of 10.2% for private sector investment in the offshore sector.

KHSK
ECONOMIC CONSULTANTS

Policy Proposals to Reduce Transmission Network Connection Costs

Policy addendum to Report on the 'Efficient Funding of Transmission Network Connection Costs' prepared for NOW Ireland

January 2010

1. Introduction

At the request of the National Offshore Wind Energy Association of Ireland (NOW Ireland), KHSK Economic Consultants have examined and reported on the inefficiency that arises as a result of existing policy regarding the funding of elements of the transmission connection infrastructure[1].

This note is based on the conclusions of this report. It identifies and briefly examines alternative policy proposals to address this inefficiency so as to reduce the cost of the infrastructure that will ultimately be paid by the consumer. The proposals are designed to minimise the cost of electricity in Ireland and reduce the barriers to entry for businesses wishing to invest in this sector. These policy options are presented as alternatives and would require further detailed examination to identify the optimal approach.

2. Policy Option 1: Public Funding of Connection Assets

If public funds are used to finance the electricity grid including transmission connection assets then the approach used in Ireland would cost those funds at 4% per annum. However, the system inserts a state commercial entity into the system and the recommendation from the Department of Finance is that its cost of funds to this entity should be used. This is estimated in the main report to be 5.82%.

There is some uncertainty concerning what might be a typical transmission connection charge for an offshore wind farm. However, an indicative estimate is that a 100MW facility would incur a cost of €15 million under the current regulations. With a WACC of 10.2%, this is an annual cost of €1.53 million for the full amount.

Assume the cost is borne by the TSO with a WACC of 5.82%. The annual cost of financing this is €873,000 per annum. Thus, there is an additional financing cost of €657,000 per annum assuming no repayment of debt. If financed over 20 years with a constant rate of capital repayment then the difference in the total value of repayments will be €9.8 million.

A 100MW facility with a load factor of 38% will produce 333GWh of electricity per annum, giving 6,660GWh over the 20 years. The additional cost must be paid by the consumer and will amount to 0.15c per kWh. This is approximately 1% of the current domestic price of electricity.

It is clear that this would mean a saving in terms of the cost of generating electricity. Of course, the TSO would need to be compensated for the cost borne in paying for the transmission connection infrastructure but this cost is fully account for in the above calculation. The way in which the necessary transmission charges would be set to compensate the TSO would be a matter for deliberation by the CER. This would only involve a re-distribution of the costs and the gain arises from a more efficient process.

[1] *Efficient Funding of Transmission Network Connection Costs* prepared for NOW Ireland.

3 Policy Option 2: Provide a Tax Efficient Structure for Private Investment

The additional costs imposed through private financing of the system are meaningful and reduce the relative competitiveness of offshore wind generated electricity. Direct public investment in the infrastructure would be the most cost efficient way to facilitate the development of the sector. It is stated Government policy to promote the growth of the renewable sector and companies are able to write off investment against trading profits over 7 years. Should the above option of having the state backed TSO invest in connection assets not be adopted, the state could proxy this approach by providing an incentive to private investors to do so through a tax efficient structure.

Currently, capital allowances can be used only in respect of trading profits within the business. In effect, this means that the marginal tax rate against which the allowances can be used is 12.5%. It is proposed that capital allowances for investment in transmission connection assets should be included within Chapter 1, Part 9 of the Taxes Consolidation Act (TCA) 1997 such that private investors partnering with generating firms would be enabled to offset the investment against taxes at the marginal private rate, currently 41%[2].

This would create considerable value for investors. For example, the investment of €15 million as above if undertaken by the generating firm would result in allowances with a present value of €1.22 million, assuming a private discount rate of 12.5%. However, if an investor can write these allowances off against personal income taxes then the present value rises to just over €4 million. Thus, this would be equivalent to an equity injection of about €3.75 million by the state to provide an incentive for the private sector to undertake the investment.

The scheme would work as follows. A high net worth investor facing a tax liability over the next number of years partners with a company developing the offshore wind farm. For illustrative purposes, assume that the investor would be allowed to join the partnership in return for an equity payment of €3 million. The company also contributes €3 million and borrows the remaining 60% or €9 million. The generating company undertakes to make the agreed payments on this debt. In return the investor can access the allowances worth just over €4 million in present values, worth €6.15 million in current terms. This provides the investor with an attractive IRR of 23%. After 7 years when the allowances have expired the assets are transferred to the TSO and the generating firm assumes the remaining debt. The benefit to the generating firm is that it makes a saving of €3 million on its initial equity investment in return for giving up allowances worth only €1.2 million.

This approach would not fully address the relative inefficiency of private funding of this infrastructure but would leverage existing taxation provisions and would reduce the costs to be borne by generators. As such, this offers the potential to reduce the cost of electricity to consumers and remove a barrier to entry into the offshore wind energy sector[3].

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[2] This approach has been used in the past for investment in productive assets such as hotels.

[3] This potential would not be limited to offshore wind but could be used to promote wave energy, a technology with considerable potential within Ireland. See *Analysis of the Potential Economic Benefits of Developing Ocean Energy In Ireland.* Report by Peter Bacon & Associates and ESB International to Marine Institute and Sustainable Energy Ireland (August 2004).

4 Policy Option 3: Target the Accelerated Allowances Scheme

One of the potential difficulties with the previous option is that the assets are not transferred to the TSO for 7 years. An alternative approach to address this would be to target the capital allowances for energy efficient equipment that were introduced under Section 46 of the Finance Act, 2008 (now Section 285A TCA, 1997) by defining the assets according to their role in the system rather than simply according to their engineering characteristics. The scheme initially applied to electric motors & variable speed drives, lighting, and building energy management systems, but was extended in the Finance Act (No.2) 2008 to cover ICT, heating and electricity provision, air control systems, and electric and alternative fuel vehicles. Under the scheme, a business purchasing these energy efficient items is allowed to write off the full cost against trading taxes in the first year.

It is proposed that this scheme be extended to encompass all costs for equipment and work incurred in constructing the transmission connection assets for a renewable energy generator. This would allow the generating company to partner with an outside investor to construct the infrastructure and, in return for an equity investment to part fund these costs, the partner firm would be entitled to use the capital allowances to off-set its trading profits. After 1 year the transmission assets would be transferred to the TSO.

This approach would be similar in some respects to the previous option although the incentive that would be provided to investment and thus the impact in terms of removing the barrier to entry would be lower, since the allowances would be offset against taxation at the rate of 12.5% only. However, it would fit well with the approach that has been initiated for the sector in recent years since the introduction and extension of the accelerated allowances scheme.

5. Conclusion

Existing policy regulations mean that the cost of funding connection infrastructure would be reduced if public funds directly injected into the sector were used to finance these assets, or if the infrastructure was financed through the TSO. This would require a considerable change to the existing regulatory environment. Should conclusive arguments be put forward as to why these changes should not be made then it is important that initiatives are introduced to reduce the barrier that the current regulations present and to reduce the costs. The proposals above are presented as alternatives to direct public funding, but would require further detailed examination to identify the optimal approach.