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Offshore wind power grid connection—The impact of shallow versus super-shallow charging on the cost-effectiveness of public support

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ABSTRACT

Public support for electricity generation from renewable energy sources is commonly funded by non-voluntary transfers from electricity consumers to producers. Apparently, the cost-effective disposition of funds in terms of induced capacity deployment has to be regarded a key criterion for the success of renewable energy policy.

Grid connection costs are a major cost component in the utilization of offshore wind energy for electricity generation. In this paper, the effect of different attribution mechanisms of these costs on overall cost-effectiveness from consumers' perspective is analyzed.

The major result of this investigation is that an attribution of grid connection costs to grid operators – as against to generators – leads to a smaller producer surplus and, hence, to lower transfer costs for electricity consumers. Applying this approach to the deployment of UK Rounds II and III offshore wind farms could lead to annual savings of social transfers of £1.2b and an equal reduction of producer surplus. This amount would be sufficient to finance the deployment of additional 10% of the capacity under consideration.

1. Introduction

Connection of power plants to electricity grids has not led to disputes concerning the attribution of corresponding costs as long as the value chain of energy service provision had not been unbundled. From the viewpoint of a vertically integrated firm these costs simply added to the long run costs of electricity supply. Since then, particularly the deployment of renewable energy sources for electricity generation (RES-E) has raised the question where exactly to define the boundary of responsibilities between generators and grid operators and whom to attribute the costs of connecting power plants to the grid.

Unbundling of the electricity industry in the member states of the European Union – triggered by the directive 2003/54 of the European Commission on the internal market for electricity – was intended to separate potentially competitive segments of this value chain – generation and supply – from the natural monopoly of electricity grid operation. Implementation of this directive into national regulation has led to a variety of interpretations of the attribution of responsibilities between grid operators and generators. Especially for the attribution of grid connection costs and grid reinforcement costs different practices coexist:

- Super-shallow system integration: this approach limits generation investments to the actual power plant, attributing already the costs for grid connection to the grid operator.
- Shallow system integration: this charging practice attributes grid connection costs to generators, while grid operators bear the costs of necessary grid reinforcements.
- Deep system integration: according to this approach generators are charged for grid reinforcements in addition to the costs for the direct connection line.

Hybrid charging methodologies – subsuming elements of more than one of above mentioned practices – add to the variety of regulations currently implemented in different European electricity markets. Table A.1 in Appendix A presents an overview of currently implemented policies for the attribution of RES-E integration costs in selected European countries. Subsuming this overview, grid connection costs are attributed to producers in most countries, with exceptions for offshore wind, while grid reinforcement costs are attributed to producers and grid operators in half-and-half cases.

In this context, it has to be stressed that reduced expenditures for one party (e.g. wind farm operators) lead to – not necessarily proportional – additional costs for the other party (e.g. grid operators). Eventually, both parties will pass over their costs to consumers. Hence, such configurations have to be found in the attribution of duties, which keep the costs for reaching a certain renewable energy policy target and thus the quantity of public transfers to a minimum. In the presence of public support, this requirement implies a political dimension.

The postulate of maintaining cost-effectiveness in the support of RES-E presumes a normative motivation: the minimization of

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consumers' transfers is given priority over the maximization of the producers' surplus.

2. Background

Integration of power plants into the electricity grid infrastructure is commonly distinguished into grid connection and grid reinforcement.

Grid connection relates to the installation of additional equipment following the switch gears at the voltage level of the generator and before the connection point in the existing grid. Depending on the type and scale of the power plant and the applied transmission technology and transmission distance, grid connection may include converters, transformers, substations, connecting cables or overhead lines as well as power system protection and power quality equipment. According costs of these infrastructure elements can be easily quantified and attributed to a single originator.[1]

Grid connection costs mainly depend on the distance to the connection point and the type of terrain to be crossed as well as on the voltage level of connection, the availability of infrastructure such as transformer stations or substations and on the technical requirements as laid out in national regulations. Consequently, connection costs may account for a marginal share of total investment costs for e.g. building integrated photovoltaic systems or a prominent share for e.g. offshore wind farms (compare Swider et al. (2008) and Fig. 2.1).

Grid reinforcement relates to technical enhancements of the existing grid infrastructure, which are triggered by the integration of additional capacity. Reinforcements may be related to extensions of transformer stations or substations and the upgrade of transmission capacity. The attribution of reinforcement costs to single generators is crucial, as also succeeding plant operators may benefit from network improvements. Above this, if existing transmission bottlenecks are being offset, an even larger group of grid users may profit from positive externalities.

Grid integration costs for wind energy and offshore wind energy in particular are high in comparison to other renewable generation technologies for the reason that these power plants are often situated in remote, sparsely populated areas characterized by weak or even nonexistent grid infrastructure. In terms of absolute installed capacity, wind power is by far the most important renewable technology with the exemption of large hydro. In terms of newly installed capacity, wind power has been the leading power generating technology in Europe in the years 2008 and 2009, accounting for 39% of added capacity (EWEA, 2010a).

In comparison to conventional generation units, the rated power of wind farms is still small[2]; consequently, integration costs are high in specific terms.

The European Commission estimates the offshore wind potential, which is likely to be exploitable by 2020 to account for 33–44 GW (EC, 2008a). This deployment implicates yearly growth rates between 21% and 23%.[3] In line with this estimate, installed offshore wind capacity will increase to 40 GW in 2020 according to EWEA's baseline scenario.

[1] In case that certain grid connection infrastructure elements can be utilized by more than one generator, the first mover may face a disadvantage, when initially all costs are attributed to this generator, as Swider et al. (2008) point out.

[2] Installed capacities of offshore wind farms may reach the scale of conventional power plants in the near future. As of end 2009 the maximum rated power of an offshore wind farm has been reported 209 MW (Horns Rev 2, Denmark) (*Source*: EWEA database of operational wind farms, available at www.ewea.org).

[3] This estimate is referenced to a total installed capacity of 1.1 GW at the end of 2007.

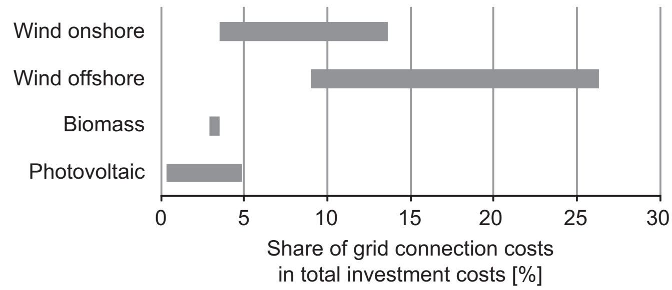

Fig. 2.1. Bandwidth of the share of grid connection costs in total investment costs. *Source*: Swider et al. (2008).

Taking into account these characteristics – particularly high specific grid connection costs and highly ambitious deployment goals – the following analyses will focus on offshore wind power, even if derived results may be applicable to other renewable energy technologies as well.

2.1. Wind power grid integration costs

Disaggregated components of grid and system integration costs of electricity generation from wind power have been quantified in various studies: task 25 of the IEA research cooperation on wind energy analyses the impact of large amounts of wind power on the design and operation of power systems. Members of this task undertake an effort to make results of different wind integration studies comparable. Holttinen et al. (2008) summarize latest findings on the magnitude of additional reserve requirements, balancing costs and transmission reinforcement costs in different electricity markets depending on the penetration level of wind power.

Auer et al. (2007) assess the evolution of grid integration cost components in relation to the deployment ratio of wind energy for single European countries and the EU-27 aggregate based on the GreenNet-Europe simulation model. While costs of balancing and grid reinforcement vary over a broad range due to different power system and infrastructure configurations, costs for direct grid connection can be assessed with higher accuracy on the basis of information on the rated capacity of respective wind farms, distance to the point of connection and the corresponding voltage level of feed-in.

As an input to modeling RES-E grid integration in Europe, Obersteiner et al. (2006) estimate grid connection costs to account for 8% of specific investment costs for onshore wind farms and 10–25% for offshore investments depending on the distance to shore.

Swider et al. (2008) state that grid connection costs for offshore wind farms are highly dependent on the distance to the existing grid and conclude from a case study analysis that specific costs are in the range of €180 and €205/kW for projects in the Netherlands while for German projects under consideration the bandwidth reaches up to €600/kW. In relative terms, 16% of total investment costs is dedicated to the installation of offshore transmission infrastructure including substations. For some German projects situated further offshore, this share can be higher than 25%.

In EWEA's latest review of the economics of wind power, grid connection costs are estimated to account for approximately 9% of total investment costs for onshore installations and are stated to have accounted for 16% for selected offshore wind farms (EWEA, 2009b).

On the basis of a detailed engineering approach, Senergy Econnect and National Grid (2009) find connection costs for the deployment of 26 GW UK Round III offshore wind capacity to

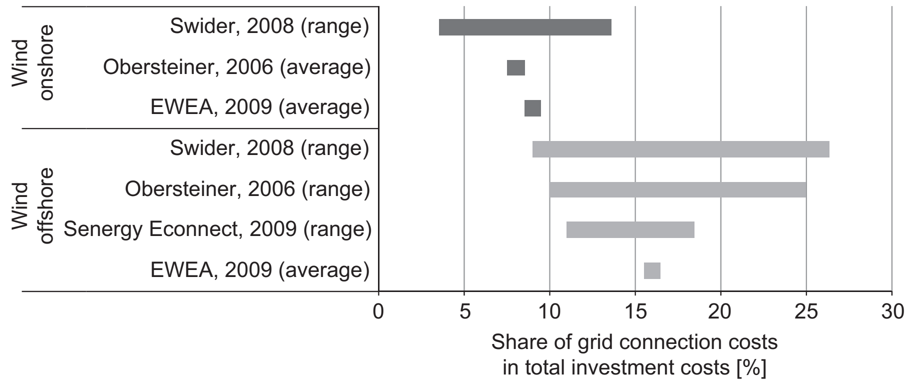

Fig. 2.2. Estimates for wind power grid connection costs as a share of total investment costs.
Source: Swider et al. (2008), Obersteiner et al. (2006), Senergy Econnect and National Grid (2009), and EWEA (2009b).

account for approximately £10b[4] and a relative share of 11–17.5% of overall investment costs.[5]

Fig. 2.2 gives an overview over cited literature sources on the relative share of wind power grid connection costs.

2.2. Attribution of grid integration costs

Critical discussions on the topic of cost attribution mechanisms for DG/RES-E generation units focus mainly on efficient investment signals for the location of power plants in the presence of grid scarcities. Barth et al. (2008) find evidence from an economic analysis that (shallow) grid connection costs as well as (deep) reinforcement costs shall be charged to RES-E producers in the presence of functioning markets reflecting scarcities of available grid capacity.

Modeling interactions of implemented policies for the attribution of system integration costs and the deployment of RES-E in European countries lead Auer et al. (2006) to the conclusion that RES-E installations will be cut down or delayed, if – ceteris paribus – grid connection costs are attributed to generators. The impact of cost attribution is noticeable for onshore wind energy and strong for offshore wind.

Auer et al. (2007) argue that correct unbundling requires the introduction of a super-shallow integration approach: potential discrimination of generators and problems associated with first movers and free-riding can be more easily avoided than in the case of applying a deep integration approach. Auer et al. find evidence that costs can be saved, if the connection of adjacent offshore wind farms is carried out in a coordinated approach and therefore call for grid connection to be provided by grid operators.

Econnect (2005) investigates potential gains in cost-effectiveness in the connection of UK Round 2 offshore wind farms for the case that geographically adjacent wind farms use a common transmission infrastructure in comparison to strictly wind farm-specific connections. As a result, joint connections are found to be cost-effective for approximately 50% of considered projects.

[4] Nominal value of 2008.

[5] On a cost basis of 2008 Senergy Econnect and National Grid estimate average costs of connecting UK Round 3 wind farms to amount to £403.178/MW (weighted average). Taking into account significant cost increases of offshore installations (Ernst&Young, 2009), this number has been inflated at 10% in order to be comparable to estimated overall offshore wind farm investment costs of £3.000.000/MW for the year 2009 (Ernst&Young, 2009; Senergy Econnect and National Grid, 2009).

2.3. Research question

In the presence of public support for electricity production from renewable energy sources the question of cost-effectiveness from consumers' perspective for effectuating a certain deployment of renewable generation arises. The utilization of wind power and offshore wind power in particular requires high specific investments into the connection of these power plants to the existing electricity networks. These costs are eventually socialised among electricity consumers.

On this background, the core question addressed in this paper is as follows:

- What effects do different initial attributions of grid connection costs of offshore wind power to either grid operators or generators impose on the respective costs of support (transfer costs to be finally paid by electricity customers)?

2.4. Approach

After an introduction into the composition of long run electricity generation costs of offshore wind power, the relationship between different attributions of grid connection costs and resulting transfer costs is explored on the basis of a stylized demand and supply curve.

On this basis, the preconditions for cost reductions due to a change of the attribution mechanism for grid connection costs are discussed qualitatively.

Eventually, this formal concept is applied to the deployment of UK Rounds II and III offshore wind projects, for which a simplified cost curve has been developed. Potential transfer cost savings are quantified comparing super-shallow versus shallow charging of grid connection costs.

3. Electricity generation costs of offshore wind power

As long as electricity generation costs from offshore wind power exceed competitive market prices, promotion schemes need to be put in place in order to trigger offshore wind deployment according to international and national renewable energy policies.

It is common to most implemented support schemes that the level of subsidies is equal for single renewable energy technologies or power ranges of these technologies. As a consequence, projects utilizing favorable resources at favorable locations will deliver a higher return for the generator than power plants characterized by low capacity factors or disadvantageous sites.[6] Most of those European countries, which have a promotion scheme in place for offshore wind, do not apply differentiated remunerations of electricity production.[7]

Long run generation costs of electricity from offshore wind power and the expected revenue, which can be achieved from power sales and public support, are the key determinants for generation investment in economic terms. From the viewpoint of policy makers, the level of support needs to be aligned to the long run electricity generation costs of the marginal plant of the considered available potential, which is envisaged to be deployed.

Long run generation costs from offshore wind power – from a static perspective – include specific capital costs[8] and operating costs. Specific capital costs are determined by specific investment costs, the expected lifetime or investment horizon, the cost of capital and the capacity factor of the installation. Specific operating costs include planned maintenance, repair, rental of land, insurance, administration (incl. metering) and electricity consumption (compare Formulas (3.1) and (3.2))

$$LRGC = \frac{CRF\, c_{INV}}{FLH} + c_{\mathrm{O\&M}} \tag{3.1}$$

and

$$CRF = \frac{z(1+z)^t}{(1+z)^t - 1} \tag{3.2}$$

where $LRGC$ is the long run electricity generation costs from offshore wind power [€/MWh]; CRF is the capital recovery factor [1/y]; FLH is the full load hours [h/y]; c_{INV} is the investment costs [€/MW]; $c_{O\&M}$ is the costs for operation and maintenance [€/MWh]; z is the weighted average cost of capital [%]; t is the investment horizon/depreciation time [y].

As laid out in Section 2.2, it is highly disputable to what extent *grid integration costs*, including grid connection costs and grid reinforcement costs, shall be accounted as part of generation costs as well.[9]

In the following economic analysis the focus is put on grid connection costs being part of long run generation costs or not. In principle, the undertaken analysis is applicable to grid reinforcement costs as well but may be less demonstrative.

4. The impact of shallow versus super-shallow charging of offshore wind farm connections on the cost-effectiveness of public support

The implementation of regulatory policies brings about economic effects: this is also the case for energy policies. A valuation of these effects is commonly performed by assessing related changes in economic welfare and thereby testing for allocative efficiency. As a precondition, the demand function of consumers and the supply function of producers need to be known.

In the presence of politically induced RES-E-promotion instruments demand is exogenously triggered and cannot be related to an actual willingness to pay.[10] Consequently, the consumer surplus of deploying renewable sources can hardly be estimated or even measured. Applying a formalistic approach of comparing the demand curve and the actual level of RES-E support, the resulting consumer surplus may be either infinite or zero depending of the mechanisms of support (compare Section 4.1).

Taking into consideration the difficulties of quantifying consumer surplus for supported RES-E generation, benefits to society can be estimated by performing an analysis of external costs. In EWEA (2009a), the value of avoided emissions due to the utilization of wind power is assessed for the EU-27 countries depending on the residual generation mix.[11]

Economic welfare resulting from the surplus of producers also has to be treated with caution in an economic environment of subsidization: as the surplus of generators is resulting from policy intervention, it may not be regarded as equivalently valuable to society in comparison to consumer surplus and its adequacy is a political matter. Excessive rents of the industry, which are effectuated by regulation, are not well accepted by electricity consumers. Instead, rents are demanded to be low.[12]

Taking into account the mentioned difficulties of assessing economic efficiency in the presence of a politically induced demand and, second, taking into account the normative postulate of keeping producer rents originating from non-voluntary transfers from consumers to producers at a reasonably low level, a valuation of the economic success of RES-E support schemes is preferentially carried in the form of a cost-effectiveness analysis instead. Doing so, transfer costs are related to the volume of effectuated RES-E generation. These transfer costs are defined as extra costs incurred by electricity consumers for RES-E generation within a certain support scheme exceeding the respective market value on wholesale markets – not taking into account external costs for society (Ragwitz et al., 2007). The objective of these analyses of transfer costs is to identify successful implementations of support schemes, which are characterized by a situation, where a certain deployment of existing potentials has been achieved at minimum costs for consumers (Held et al., 2006).

4.1. Demand for electricity generation from offshore wind energy

External distortions of the market for RES-E in form of national support policies are leading to a situation, where demand in this market is either totally inelastic in the presence of quantity driven support systems or totally elastic in the presence of price driven support systems. The first mentioned mechanism corresponds to a quota system, where the quota (Q) may be related to the issuance of a technology specific quantity of tradable certificates. The second system corresponds to a feed-in tariff (FIT1,2) (compare Fig. 4.1).

In the following analysis the question of applying different support mechanisms is not considered. It is assumed that in a certain electricity market either a quota system with tradable green certificates or a feed-in tariff system is in place. Both mechanisms provide such support, that they eventually effectuate the deployment of the same offshore wind energy potential. This

[6] Feed-in-tariffs may be differentiated on the basis of full load hours or may be granted for a certain number of full load hours. This practice aims at a certain harmonization of returns.

[7] Price premia in Denmark (as against to e.g. the UK, the Netherlands, Germany, Belgium and Sweden) are differentiated depending on the number of full load hours.

[8] Total investment costs (overnight investment costs plus returns on equity and debt during construction) are often denominated as capital costs. In the context of this paper, capital costs specify (total) investment costs plus opportunity costs of this investment, which denominate a real return over the respective investment horizon.

[9] Also for other components of system integration costs, such as the costs of supplementary reserve capacity or balancing, the problem of attribution to the originator versus socialization is solved differently in different power markets.

[10] Private willingness to pay for green electricity plays a minor role in comparison to regulated support schemes with respect to deployed generation capacities. Additionally, this demand is usually satisfied in a market, which is separated from the politically induced market under consideration.

[11] It can be argued, that external costs of CO_2-emissions are already endogenised in the European electricity markets via the EU-ETS. It will not be discussed at this point, to what extent this argument can be justified—also given the necessity to take a dynamic perspective.

[12] Regulatory authorities tend to value consumer surplus higher than producer surplus. Competition law of the European Union implies a bias towards consumer surplus in the evaluation of welfare effects (EC, 2004).

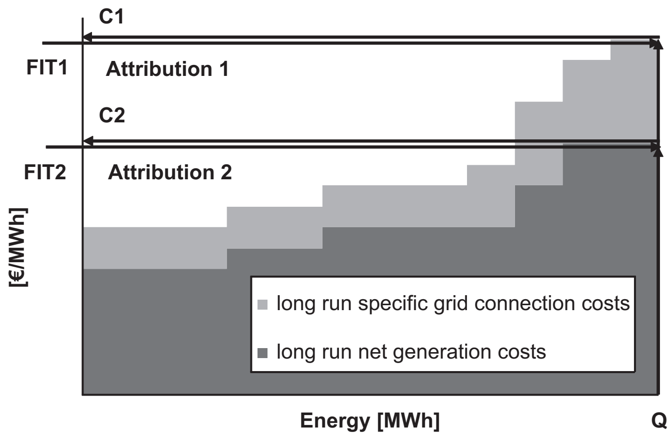

Fig. 4.1. Supply and demand for offshore wind power, long run net generation costs and long run specific grid connection costs (only for better visibility the lines indicating the level of feed-in tariffs and costs do not overlap in the graph). C_1, C_2 is the long run electricity production costs of the marginally deployed wind farm, inclusive (1) or (2) exclusive of the costs for the grid connection [€/MWh]. FIT_1, FIT_2 is the feed-in tariffs, sufficient to achieve demanded deployment [€/MWh]. Q is the quota, equaling the deployment reached through FIT_1/FIT_2 [MWh].

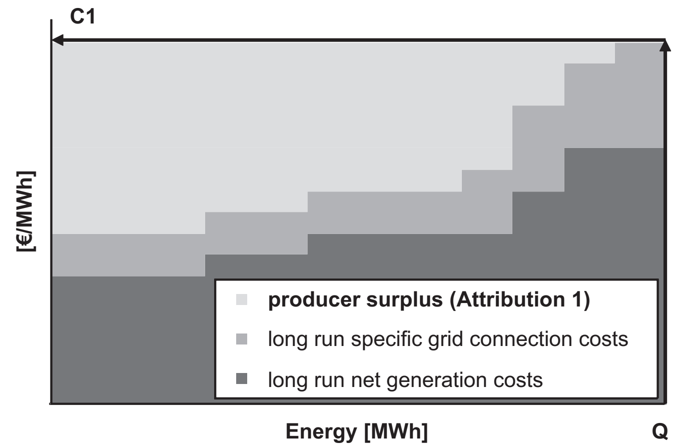

Fig. 4.2. Producer surplus of offshore wind farm operators (grid connection costs attributed to producers—Attribution 1).

implies that the revenue gained from selling both certificates and power at the time, when the marginal power plant has been installed and is generating certificates, equals exactly the feed-in tariff, which is sufficient for the same deployment.[13] This assumption implies that policy makers do have perfect information on the available offshore wind potential and the related electricity generation costs.

This assumption is supported by the fact that especially the deployment of novel technologies is accompanied by strong regulatory intervention. Countries considering offshore wind energy development as part of their renewable energy strategy are determining certain installation roadmaps and are reserving designated offshore deployment zones, be it through spatial planning, as e.g. in Germany, or tendering of development sites, as e.g. in the UK. Eventually, support instruments are adapted in order that these plans materialise.

4.2. Supply curve for offshore wind energy

Long run electricity generation costs from offshore wind power differ widely due to unevenly distributed wind potentials and different installation conditions. If – depending on the regulatory scheme in place – grid connection costs are attributed to plant operators, these differences may even be greater due to the high relative share of these costs on overall costs and their broad range depending on the distance to shore.

To obtain a supply curve for electricity production from offshore wind power, the capacities of available potentials are ranked according to their long run generation costs from most cost-efficient to most costly potentials.

Fig. 4.1 qualitatively depicts the supply functions of offshore wind power for two different cases of grid connection cost attribution.[14] Long run electricity generation costs including infrastructure costs are denoted as C1 for the marginally deployed capacity. Long run generation costs excluding discounted site specific grid connection costs – long run net generation costs – are denoted as C2. The demand (quota) is equal in both cases, whereas different tariffs are resulting if a feed-in tariff system is in place.

In general, the order of deployment of different potentials, which are sufficient to meet a certain demand, may be different depending on the cost attribution scheme applied. Still, in the following analysis of support costs an identical generation portfolio is assumed to be deployed.[15]

The electricity generation potential displayed in the form of a stylized supply curve in Fig. 4.1 is assumed to be eligible for the same level of support. This means that respective power plants of the total capacity Q would generate uniform revenues per output unit. These revenues may result either from the receipt of a certain feed-in tariff or a certain quantity of certificates of a distinct value in addition to the market value of generated electricity.

4.3. Producer surplus of generators

The (long run) producer surplus of offshore wind farm operators determines the aggregate of revenues exceeding (long run) individual production costs. Its magnitude depends on the total deployed capacity, the shape of the supply curve and – in this respect – also on the regulation in place for the attribution of grid connection costs.

In the case of initial attribution to generators (scenario 1), according to Formula (4.1), the producer surplus can be derived from summing up the spreads between long run generation costs of the marginal plant C1 and the respective individual long run production costs. Producer surplus is marked in light-gray in Fig. 4.2

$$PS_1 = \sum_{i=1}^{n} (C_1 - LRGC_i) q_i, \quad Q = \sum_{i=1}^{n} q_i \tag{4.1}$$

PS_1 is the producer surplus of wind farm operators in attribution scenario 1 [€]; $LRGC_1$ long run production costs of individual wind farms [€/MWh]; q_i is the energy yield of individual wind farms [MWh]; n is the number of wind farms installed.

An initial attribution of grid connection costs to grid operators (attribution scenario 2) results in a lower producer surplus,

[13] Higher rates of return, which may be demanded by investors in a quota system due to increased risks of a volatile certificate market, are not being considered.

[14] According to the depiction some potentials are regarded to be distinguished by different grid connection costs only while the net long run production costs are equal.

[15] This assumption will not hold in general for the supply curve of different RES-E technologies. In the context of offshore wind, however, it is plausible, as will be analyzed in detail in Section 5.3.

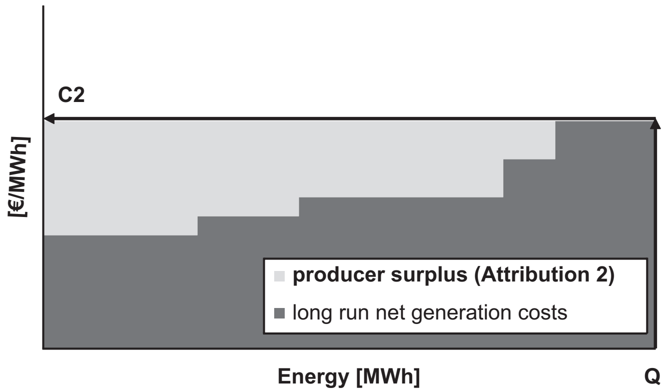

Fig. 4.3. Producer surplus of offshore wind farm operators (grid connection costs attributed to grid operators—Attribution 2).

compare Fig. 4.3 and Formula (4.2)

$$PS_2 = \sum_{i=1}^{n} (C_2 - LRGC_i) q_i, \quad Q = \sum_{i=1}^{n} q_i \tag{4.2}$$

4.4. Transfer costs of electricity consumers

It has been demonstrated in the previous section that depending on the initial attribution of grid connection costs different producer surpluses are resulting. This difference does not equal potential savings from the perspective of consumers for the reason that grid connection costs are being passed over to final energy consumers also in the case of initial attribution to grid operators. Hence, the corresponding effect on transfer costs will be analyzed in the following.

Transfer costs are assumed to be independent from the applied promotion instrument and shall be defined in this context as the additional costs, which have to be borne by consumers for the electricity offtake from offshore wind farms in comparison to the market value of this electricity, if it was sold under a competitive framework e.g. at a power exchange. Simplifying, this competitive threshold is denominated as market price in the following.[16]

Transfer costs are being collected from consumers and distributed to renewable electricity generators through the financial mechanisms of promotion schemes. They shall compensate such generators for higher production costs and infrastructure expenditures in comparison to conventional generation.

Transfer costs in scenario 1 can be calculated as the difference between the long run production costs of the marginally deployed wind farm including its specific capital costs for grid connection and the market price, related to the volume Q, as reflected in Formula (4.3) and depicted in Fig. 4.4.

In order to limit the magnitude of transfer costs, different promotion schemes are designed in a way to simulate a stepped demand curve, where different remuneration levels are reserved for different technologies or different power scales or even different ranges of resource availability—taking account of different production costs. As mentioned in Section 4.2, in this analysis only potentials within one cost/support category are being considered

$$TC_1 = (C_1 - MP) \times Q \tag{4.3}$$

[16] The market value for wind energy is analyzed for the Central European power market by Obersteiner et al. (2009). The market price, at which the feed-in of wind farm operators can be settled on wholesale markets is typically lower than the base load price level in these markets, given that wind power has reached a significant share.

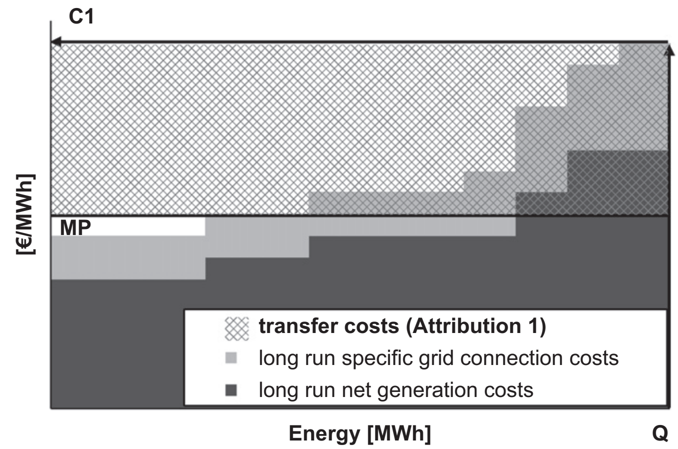

Fig. 4.4. Transfer costs for consumers resulting from offshore wind power deployment (grid connection costs attributed to producers).

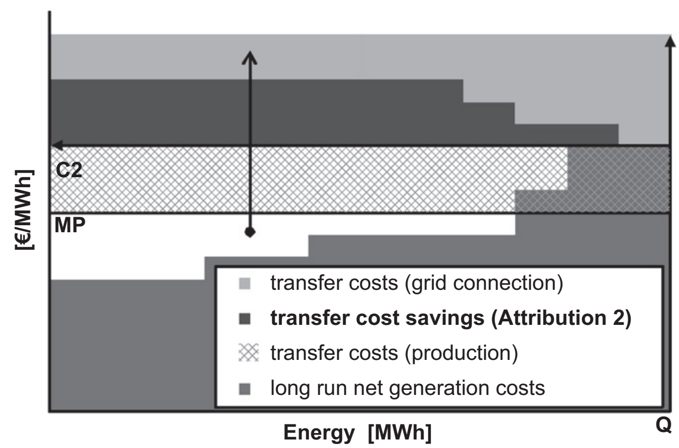

Fig. 4.5. Transfer costs for consumers resulting from offshore wind power deployment (grid connection costs attributed to grid operators). (Only for better visibility transfer costs resulting from grid connection have been shifted towards the upper margin of the graph.)

TC_1 is the transfer costs incurred by consumers in attribution 1 [€]; MP is the market price of wind energy [€/MWh].

In the second scenario grid connection costs are attributed to grid operators and are then passed through into grid tariffs. Therefore, they also need to be considered in the calculation of transfer costs. These include the difference between marginal (net) production costs and the market price – related to the volume Q – and the sum of specific capital costs of individual grid connections, applying a monopolistic grid operator's rate of return (see Formula (4.4) and Fig. 4.5). For the reason of better visibility, approximate regulated specific long run costs of grid connection have been shifted towards the upper margin of the graph

$$TC_2 = (C_2 - MP)Q + \sum_{i=1}^{n} (q_i GC_{i,reg}) \tag{4.4}$$

TC_2 is the transfer costs incurred by consumers in attribution 2 [€]; $GC_{i,reg}$ is the specific capital costs of individual connections (to be borne by grid operators) applying a regulated rate of return [€/MWh].

4.5. Transfer cost savings

As indicated in Fig. 4.5, the second attribution case results in lower total transfer costs for the support of a certain volume of offshore wind power to consumers. These savings are expressed in Formula (4.5) and correspond to the contribution of the marginal transmission infrastructure to the producer surplus of submarginal projects – and hence to transfer costs – in attribution case 1.

$$TCS = (C_1 - C_2)Q - \sum_{i=1}^{n} (q_i GC_{i,reg}) \tag{4.5}$$

These savings are positive, if marginal grid connection costs are increasing with the deployed volume and net production costs are not disproportionally declining. In the case of offshore wind energy, differences in net production costs seem to be mainly caused by different full load hours, water depth and the distance to shore. Grid connection costs are mainly dependent on the distance to a suitable connection point in the existing electricity grid. The qualitative depiction indicates that most economic potentials are assumed to be characterized by low net production costs and low grid connection costs, whereas more costly potentials are characterized by both increasing net production costs and grid connection costs. This assumption implies that potentially higher full load hours at remote wind farm locations do not outweigh higher construction, maintenance and operational costs. In Section 5.3 this relation has been investigated for a set of UK Rounds II and III wind farms and appears to hold.

Therefore, cost savings are expected to be realizable in attribution case 2. Secondly, increasing connection costs are expected to be a major source for these potential savings.

In qualitative terms, potential transfer cost savings as depicted in Fig. 4.5 are underestimated compared to Formula (4.5) for the reason that total costs of grid connection are expected to be lower when all offshore transmission infrastructure investments are carried out by a regulated transmission system operator: lower rates of return on employed capital are assumed to be demanded by grid operators in comparison to unregulated, risk exposed renewable energy project developers. Above this, savings may be realised by joint connection designs (compare also Section 5.4).

5. Assessment of potential transfer cost savings in the deployment of Round II and Round III offshore wind farms in the UK

In the following analysis, the theoretical concept of potential transfer cost savings as described in Section 4.5 of this paper will be applied to the planned deployment of Round II and Round III offshore wind farms in the UK. This example has been chosen for the reason that the UK is the leading country in terms of total installed offshore wind capacity as well as capacity under construction.[17] Above this, the UK regulatory regime foresees generators to bear offshore transmission costs, be it in the form of upfront investments or in the form of regulated use-of-system charges. From this starting point potential transfer cost savings are estimated for the case of changing the applied mechanism of cost attribution towards a super-shallow charging approach.

Estimates on different components of long run electricity generation costs from offshore wind, which are utilized in the following, are subject to high uncertainties. Round III of the UK offshore wind site licensing process is targeted at adding approximately 25 GW capacity to 8 GW of Rounds I and II projects. This deployment goal is highly ambitious against cumulative operating offshore wind capacity at the time of announcement in the year 2007 of around 1.1 GW. Yet, this 33 GW target has been set out by the UK government to be achieved by the year 2020 (BERR, 2007). Offshore wind power is expected to supply the major part of RES-E as a contribution to the UK's overall renewable energy obligation in terms of the binding European 2020 target.

Building up an appropriate supply chain for the installation of the necessary offshore electricity and transport infrastructure is seen as a decisive challenge in pursuing this energy strategy. Substantial reinforcements and extensions of the existing onshore electricity infrastructure are also regarded as a precondition for the deployment of large offshore capacities.

Also from a technological perspective, especially the installation of Round III wind farms is connected to severe challenges due to high distances to shore and great water depths: the distance of planned wind farms to shore reaches up to 200 km in comparison to an average of 30 km and a maximum of 100 km for wind farms under construction in the first quarter of 2010 (EWEA, 2010b). Water depths of several Round III development zones are starting from 30 m and may reach up to 80 m. In comparison, the water depth of offshore wind farms under construction averages 23 m with maximum depths of 40 m.

In addition to this variety of challenges, financing the installation of 33 GW offshore wind capacity remains one of the most crucial ones. The UK Carbon Trust investigates the contribution of offshore wind to a total RES-E share of 40% in 2020 and finds that £75bn will be required to finance the deployment of additional 29 GW capacity within the next decade. This amount is comparable to the observed investment during the peak decade of North Sea oil and gas development (Carbon Trust, 2008).

This paper does not evaluate the mentioned uncertainties and it does not intend to assess the feasibility of the UK offshore wind energy policy to materialise. Instead, the deployment of Rounds II and III offshore wind farms is anticipated and the effect of different attribution options for grid connection costs on the electricity bill of consumers is analyzed. Current cost data for currently available technology is used in the following, even if a shift towards larger turbine sizes, a higher grade of standardization or an improved supply chain might decrease specific costs in the long run. On the other hand, no cost escalations due to raw material or energy price increases have been taken into account.

5.1. *Supply curve for UK Rounds II and III offshore wind farms—core assumptions*

While overnight investment costs for offshore wind turbines are approximately 20% higher than for onshore turbines in specific terms, costs for foundations, installation and grid connection can escalate to a multiple in comparison (showing a broad distribution depending on factors as distance to shore, depth of water, weather conditions and according possible delays of installations (dti, 2007)).

In order to quantify the possible effect of different attribution options of grid connection costs on overall transfer costs, a supply curve of offshore wind projects to be realized in the course of the UK Round II and Round III Crown Estate license is being developed.

Long run generation costs are separated into

(1) costs for connecting the offshore substation to the onshore electricity grid (offshore transmission, onshore transmission, extension of onshore substations). In the following referred to as transmission,
(2) costs for the offshore substation,
(3) all remaining components of investment costs (wind turbine, tower, foundation, intra-wind farm connection, project management, environmental studies, etc.) and operating expenditures.

[17] Installed offshore wind capacity in the UK totaled to 883 MW by the end 2009, while 1592 MW had been under construction in the first quarter of 2010 (EWEA, 2010a).

Table 5.1
Overview over economic parameters of UK offshore wind projects.

			Source
Investment costs			
Investment costs (excl. offshore substation and transmission)	2.550.000	£$_{2009}$/MW	Ernst&Young (2009), BWEA (2009), EWEA (2009b)
Investment costs of offshore connection	90.000–440.000	£$_{2009}$/MW	Senergy Econnect & National Grid (2009)
Investment costs of offshore substation	120.000	£$_{2009}$/MW	dti (2007)
Operating expenditures (OPEX)			
OPEX (incl. decommissioning, excl. transmission, substation)	90.000	£$_{2009}$/MW/yr	Ernst&Young (2009), dti (2005)
OPEX transmission	5.000	£$_{2009}$/MW/yr	Ernst&Young (2009), dti (2005)
OPEX substation	2.500	£$_{2009}$/MW/yr	Ernst&Young (2009), dti (2005)
Economic parameters			
Cost of capital (pre-tax real)	12	%	Ernst&Young (2009)
Load factor (net)	38	%	Ernst&Young (2009)
Project lifetime	20	Years	
Availability	94	%	Ernst&Young (2009)

Information on investment costs of single offshore wind farm projects can be hardly obtained on a comparable basis for various reasons: firstly, non-disclosure policies of affected parties make respective information unavailable on disaggregated level. Secondly, investment costs have been reported to have doubled in real terms within the four-year period 2005–2008 (BWEA, 2009)[18]; early installations have been brought online in a premature market characterized by tight competition between developers as well as suppliers and underestimation of risks and efforts resulting in overall project losses.[19] In contrast, current investment conditions are characterized by supply chain constraints, increased input prices and higher demanded returns for suppliers as well as developers.

For this case study analysis it is assumed that differences in long run electricity generation costs of offshore wind farms are only caused by different distances to shore: higher energy yields under preferential wind conditions further offshore are assumed to be offset by higher transmission losses and higher specific installation and maintenance costs.

Consequently, uniform average specific capital costs of the year 2009 excluding offshore grid connection have been assumed for all wind farms.[20]

Non-distance dependent specific costs for transmission infrastructure, operating expenditures, discount rates, project lifetimes and load factors are assumed to be uniform as well.

The validity of these assumptions and their impact on the following analyses are discussed in Section 5.3.

Eventually, the supply curve is composed of a constant term for capital expenditures and operational expenditures of all wind farm components except the offshore cable plus a project-specific term for the offshore transmission line

$$LRGC = C_{windfarm,spec} + C_{trans,spec} \tag{5.1}$$

LRGC is the long run electricity generation costs of individual wind farms [€/MWh]; $C_{windfarm,\ spec}$ is the specific uniform capital and operating costs of electricity production from offshore wind exclusive of grid connection costs (offshore transmission costs) [€/MWh]; $C_{trans,\ spec}$ is the specific grid connection costs (offshore transmission costs) [€/MWh].

Project-specific connection costs are taken from a *Study on the Development of the Offshore Grid for Connection of the Round Two Wind Farms*, commissioned by the Department of Trade and Industry (Dti), UK (Econnect, 2005), and a respective study for Round III projects (Senergy Econnect and National Grid, 2009). Project-specific distance dependent infrastructure costs have been escalated at a rate of 10% per year until 2009 taking into account observed cost increases (Ernst&Young, 2009), see Table A.5 in Appendix A for a detailed overview over connection costs of considered wind farms.

Current investment costs are stated to amount to approximately £3 m/MW (BWEA, 2009)[21], inclusive of foundation and electrical infrastructure. Up to 19% of this sum are attributed to grid connection including non-distance dependent infrastructure costs (inter-array cabling, offshore substation) (Ernst&Young, 2009).

Recent studies on the economics of offshore wind power estimate a broad range of operating expenditures; while Senergy Econnect and National Grid (2009) state costs of £46 k/MW/a, Ernst&Young (2009) state costs of £79 k/MW/a plus £18 k/MW/a decommissioning costs.

Table 5.1 gives an overview over economic parameters used in this case study for the preparation of a disaggregated supply curve for wind offshore projects in the UK (including data sources). All cost figures are given for the year 2009. In Appendix A, a more detailed extract of data sources for investment costs (Table A.2) and operating expenditures (Table A.3) is provided.

The time-frame for depreciation as well as the cost of capital are identical for both the transmission infrastructure and the actual wind farm. This assumption appears valid in case that the transmission infrastructure is operated by the project developer or a licensed independent offshore transmission operator.[22] Only in case incumbent transmission system operators are obliged to connect offshore wind farms and finance according costs via mark-ups to common transmission charges, as is the case in Germany, longer depreciation periods and lower costs of capital can be presumed. Table 5.2 summarizes different components of long run generation costs of Round II and III offshore wind farms in the UK indexed for the year 2009. These costs have been calculated according to Formula (3.1) and on the basis of the above cited economic data.

[18] Ernst&Young (2009) report a cost increase by 100% in the five-year period from 2004 to 2008.

[19] BWEA (2009) refers to several insolvencies and buy outs of early projects in this context.

[20] Costs for foundation as well as equipment installation are site-specific; still, they are assumed to differ negligibly compared to transmission. When quantifying transfer cost savings, this assumption contributes to an underestimation of potential savings for the reason that more remotelocateinarmenccounoigheostithiespect.

[21] £3.2 m/MW according to Ernst&Young (2009), €2.0–2.2 m/MW according to EWEA (2009b). Van Hem and Kramer (2010) state offshore wind farm costs of €3.8 m/MW for the UK.

[22] DTI (2005) refers to the risk of premature termination of connectees and asset stranding with respect to comparatively high capital costs as well as a potential change of wind technology concerning depreciation time.

Table 5.2
Composition of long run electricity generation costs ($LRGC_{2009}$) of UK Round II and Round III offshore wind projects from different capital expenditures (CAPEX) and operational expenditures (OPEX).

Long run generation costs		
From CAPEX (excl. transmission, substation)	97.73	£/MWh
From OPEX (excl. transmission, substation)	27.04	£/MWh
From CAPEX transmission	3.65–17.90	£/MWh
From OPEX transmission	1.50	£/MWh
From CAPEX array cabling	4.83	£/MWh
From CAPEX substation	4.83	£/MWh
From OPEX substation	0.75	£/MWh
Long Run Generation Costs total	140–155	£/MWh

A graphical representation of this data in the form of a supply curve is given in Fig. 5.1. Single steps of this curve refer to single wind farms. As laid out previously, long run generation costs are assumed to differ only with respect to connection costs.

According to this cost model, approximately £125/MWh of total long run electricity generation costs stem from capital and operational expenditures for the wind turbine inclusive of the foundation and inter-array cabling as well as costs for insurance, lease of the seabed, onshore transmission charges and project management including environmental studies. Around £5.5/MWh can be attributed to the substation. Long run electricity generation costs resulting from the installation and operation of the transmission infrastructure are in a range between £5 and £19/MWh, depending primarily on the distance to shore and the availability of suitable onshore infrastructure.

Total long run generation costs are then in a range between £140 and £155/MWh. As most economic parameters have been adopted from Ernst&Young (2009), this range includes levelised cost of electricity of £144/MWh for the base case scenario of this report. The deviation stems from differentiated offshore transmission costs.[23]

5.2. Quantification of potential transfer cost savings

Potential transfer cost savings resulting from a rearrangement of the cost attribution mechanism in place for the integration of offshore wind power are being quantified following the methodology developed in Section 4.5.

Two attribution scenarios will be differentiated:

(1) Base case: a shallow integration policy is assumed. Project developers need to incur upfront and operational costs of the transmission infrastructure. In this case generators need to be remunerated with the long run generation costs of the marginal project inclusive of connection costs.
Effectively, this policy is assumed to be identical in outcome with the recently implemented UK offshore transmission regulation, which foresees independent offshore transmission operators to finance, construct and operate offshore transmission assets. These firms are granted a regulated revenue stream as a key award criterion of a competitive tender for licenses.[24]

(2) Super-shallow approach: substation and offshore connection including onshore integration are being provided by incumbent transmission grid operators. Additional costs are being recovered via conventional transmission charges, which are collected from suppliers and eventually passed on to electricity consumers.[25] The rate of return is altered to a level of 6.25% real pre-tax (DTI, 2005) for the infrastructure component. The depreciation horizon is kept constant at 20 years, even if a longer utilization could be expected in comparison with project-specific licenses. This scenario is comparable to the "Plug-At-Sea-Concept" of the German offshore transmission regulation.

Transfer cost savings are presumed to arise from pursuing a super-shallow charging approach as against a shallow integration policy. Potential savings amount to £1.2b per year for the outlined case of deploying approximately 33 GW offshore wind capacity in UK Rounds II and III projects in comparison to the base case attribution. This sum would be sufficient to support the installation of additional 3.3 GW offshore wind capacity, underlying highest projected costs in a Round III project[26] and a reference market value of £40/MWh. In relative terms this increase equals 10% of total installed capacity.

5.3. Validity of assumptions on cost parameters

The utilized cost model bases on the assumption that net production costs are uniform for all considered offshore wind farms. This assumption is simplifying and at the same time crucial: it is simplifying, because it does not reflect real world costs in detail, and it is crucial, because the results of the analysis in Section 5.2 are sensitive to the slope of the supply curve of offshore wind energy potentials. As already mentioned in the qualitative analysis, transfer cost savings are potentially realizable, if the ascending slope of net production costs is not outweighed by decreasing long run connection costs. It is assumed implicitly that wind farms, which are close to the shore and to the existing transmission infrastructure and which are therefore characterized by low grid connection costs, benefit from comparatively low construction and maintenance costs. In contrast, remote wind farms characterized by high connection costs are more costly to install and to maintain. At the same time, these cost disadvantages are not (fully) compensated by potentially higher full load hours.

In order to evaluate the overall validity of these assumptions in the case of UK offshore wind farms, the relation of long run generation costs to parameters such as distance to shore, water depth and average wind speeds has been analyzed for a limited set of Round II and Round III offshore wind farms, for which according data could be accessed (see an overview of available data in Table A.4 of Appendix A).

Round II wind farm locations are on average both closer to shore (22 km) and located in more shallow waters (22 m) than Round III wind farms, which will be located at an average distance of 73 km to shore. The average water depth will amount to 30 m for early installations and more than 60 m for later installations. The mean wind speed at round II locations amounts to 9.5 m/s on

[23] Van Hem and Kramer (2010) carry out a comparison of necessary remuneration levels of offshore wind generation in different countries and state, that a total remuneration of €182/MWh would be sufficient to cover long run production costs of UK installations. This number is in line with the assumptions of this paper.

[24] Apart from lower financing efforts, this regulation is not expected to deliver an economic advantage to wind farm operators: offshore transmission charges are expected to equal long run costs of installing and operating respective infrastructure within the projects. Ernst&Young (2009) cite that *many industry participants assume that the new regime will be value neutral to the project until this is proven otherwise*.

[25] The super-shallow approach implies that transmission charges for generators do not or do only partially reflect the long run costs of project-specific grid enhancements. As for the UK, 27% of transmission-network-use-of-system-charges are collected from generators, while 73% are collected from suppliers.

[26] According to a super-shallow cost allocation scenario total costs of the most distant Round III project would amount to £147/MWh in comparison to £155/MWh in the base case allocation.

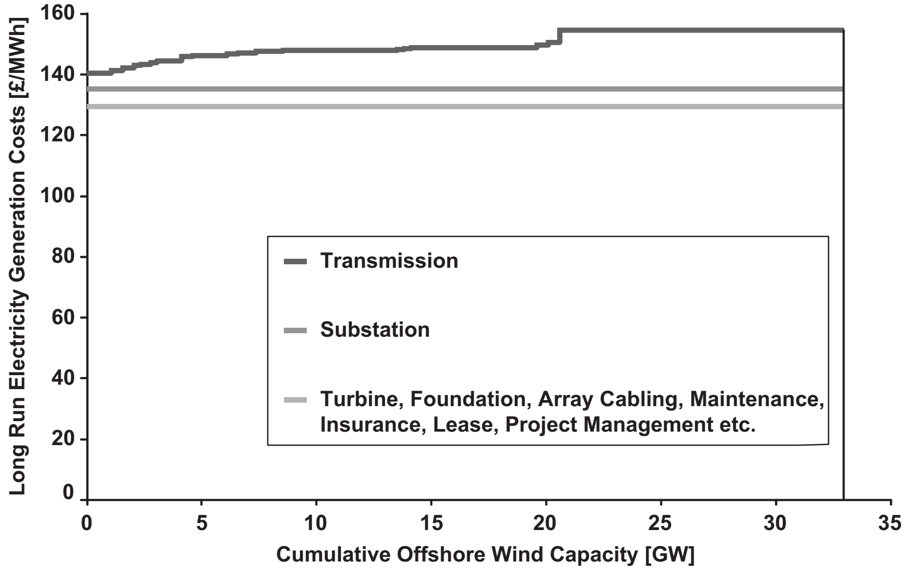

Fig. 5.1. Long run costs of electricity generation from UK Rounds II and III offshore wind farms.

average against 9.8 m/s at round III locations.[27] These wind speeds translate into a load factor of 40% versus 42% for a 2 MW offshore wind turbine.[28]

KPMG finds in a survey on offshore wind farms in Europe (KPMG, 2007) that capital expenditures for offshore turbines (excluding grid connection) show a positive correlation with water depths. The authors state a single correlation coefficient of 0.4.

In a publication by the European Environment Agency (EEA, 2009) the relation between offshore wind farm investment costs and water depth is being explored.[29] Applying this relation to UK offshore wind farms, investment costs (exclusive of grid connection costs) of early Round III projects will be 11% higher in comparison to Round II wind farms. For later Round III projects this value increases to 35%.

These investment cost differences on the one hand and different capacity factors on the other hand have been implemented into the developed cost model. The comparison of resulting long run generation costs shows that higher load factors at Round III locations do not outweigh higher investment costs. Instead, long run net generation costs[30] at early Round III sites are £4/MWh higher than for Round II sites. If 35% higher investment costs for Round III projects in deep waters are assumed, corresponding net generation costs would be already £25/MWh higher than at Round II sites.

This brief evaluation of assumptions does not proof their overall validity. Still, it provides evidence that net production costs and grid connection costs do not show a countervailing trend for the analyzed case of UK Round II and III offshore wind deployment. On the contrary, both cost categories are increasing with the deployed volume. Therefore, avoided aggregate producer surplus from grid connection can lead to overall savings for consumers as laid out in Section 5.2.

5.4. Improvement of cost-effectiveness through joint connection approaches

The establishment and operation of an offshore grid connection infrastructure constitute a natural monopoly: it is less costly if these economic activities are carried out by one firm in comparison to two or more firms (over the full range of market demand). Cost functions fulfilling this criterion are denominated subadditive. In formal terms, subadditivity – a necessary and sufficient condition for the verification of a natural monopoly – is given, if the following equation holds (Baumol, 1977)[31]:

$$C(Q) < C(q^1) + C(q^2) + \cdots + C(q^k) \quad Q = \sum_{i=1}^{k} q^i \tag{5.2}$$

C is the cost function; Q is the market demand; q^i is the potential subsets of output (of individual firms); k is the number of firms.

While the connection of isolated single offshore wind farms may not be characterized by a subadditive cost function, the joint connection of adjacent wind farms may be cost-effective in reality, as demonstrated by Econnect (2005) for UK Round 2 projects. Average unit connection costs will decrease by approximately 10% if cost-effective joint connections are give priority over single connections.

Finally, the installation and operation of an offshore super-grid, as demanded e.g. by the European Wind Energy Association, clearly constitutes a natural monopoly. The purpose of such an infrastructure element is to not only connect offshore wind generation to the existing high voltage networks but to integrate various electricity

[27] Data on the distance to shore, water depths and average wind speeds of offshore wind farm locations have been derived from the following online sources: the website of The Crown Estate (http://www.thecrownestate.co.uk/) and the website of the marine consultancy 4C Offshore (http://www.4coffshore.com/windfarms/).

[28] A calculator provided by the Danish Wind Industry Association has been utilized to transfer average wind speeds measured at 100 m height into energy yields. Following parameter settings have been used: 15 °C air temperature, Weibull shape parameter: 2; roughness class: 0; Turbine: Vestas V66/2000 offshore. See: http://guidedtour.windpower.org/en/tour/wres/pow/.

[29] The relation between investment costs and the distance to shore is explored as well. As a result, increasing grid connection costs are the determining factor here. For the reason that grid connection costs are reflected in the economic model for each wind farm individually, only the impact of water depths is investigated in this analysis of the validity of assumptions.

[30] Long run electricity generation costs calculated according to Formula (3.1) (excluding grid connection) and economic data according to Table 5.1 (changes to this dataset apply for investment costs and the load factor).

[31] The cited equation defines subadditivity for the single-product case. A firm producing more than one product operates as a natural monopolist, if the production of whatever combination of demanded quantities of output by this single firm is less costly in comparison to production by multiple firms (Baumol, 1977).

markets and to aggregate and thereby smoothen geographically widely dispersed variable generation. In order to finance a transnational offshore grid infrastructure, cost sharing mechanisms need to be put in place, which take into account transmission services for offshore wind generation as well as benefits to other market participants. Such benefits may result from lower reserve requirements and welfare gains due to market integration.

6. Conclusions

In an environment of public support for renewable electricity generation technologies, the cost-effective public use of non-voluntary financial transfers from consumers to producers is a topic of highest priority. Therefore the maximization of the ratio between deployed capacities of supported technologies and related expenditures has to constitute a key principle of renewable energy policy.[32]

In this paper it has been investigated to what extent the attribution of responsibilities for providing and operating the electricity transmission infrastructure for offshore wind farms between generators and grid operators influences the resulting transfer costs of electricity consumers—regardless from the support mechanism applied (e.g. a quota-system with tradable green certificates or feed-in-tariffs).

The main conclusion from this analysis is that considerable transfer cost savings are realizable, if the responsibility for grid connection is transferred from offshore wind farm operators to grid operators. These savings can be realised due to the following reasons:

(1) High producer rents emerge, if grid connection costs significantly contribute to the slope of the supply curve of a certain available offshore wind energy potential, for which subsidies are not differentiated. Finally, these rents have to be paid for by electricity consumers.
(2) Capital costs are higher for offshore wind power producers, which are exposed to comparatively high financial risks, in comparison to regulated monopolistic transmission grid operators. Therefore, attribution of connection costs to grid operators leads to a lower financial burden for consumers.

Additional cost advantages may result from a coordinated approach in the connection of adjacent wind farms due to a subadditive cost structure in comparison to competitive separate project developments.

From this perspective, it is suggested to mandate regulated grid operators to provide and operate offshore transmission infrastructure on the basis of common regulated cost recovery mechanisms.

Super-shallow charging – per se – does not provide intrinsic incentives for cost efficient siting of wind farms. For this reason it is necessary to put in place coordinated planning procedures, which result in the identification of preferential or even exclusive, cost-effective offshore wind deployment areas. Corresponding strategies for the reservation of designated offshore deployment zones, be it through spatial planning, as e.g. in Germany, or tendering of development sites, as e.g. in the UK are effective already today.

Cost-effectiveness in the connection of offshore wind farms according to a super-shallow approach will be supported by the fact that regulatory bodies need to approve the return owed to the grid operator for the construction and operation of offshore transmission assets. Only costs, which comply with certain efficiency criteria, are eligible to be passed through into tariffs.

While transfer cost savings, which arise from cutting producer surplus, do not impact economic welfare – this component is simply transferred to consumers – the improvement of cost-effectiveness due to lower capital costs of regulated grid operators in comparison to project developers does have an effect on economic efficiency. According to the Coase-Theorem[33] the two affected parties could agree on an economically efficient use of capital, if they were able to negotiate and share the resulting surplus in whatever way. In reality, regulatory intervention impedes such a bargaining solution. Also in the case of joint versus strictly project-specific offshore wind farm connections it cannot be expected that developers of adjacent wind farms can agree on the installation of a potentially efficient commonly used transmission infrastructure, as inter-temporal aspects and coordination difficulties are likely to impede such solutions.

It has been proven in this paper that a change in the regulatory regime from shallow to super-shallow charging has the potential to reduce the producer surplus generated by wind farms, which are characterized by comparatively low connection costs. An alternative option to capture this surplus to the benefit of the public is to introduce an auctioning process for seabed licenses, which could equal out differences in long run generation costs.

As for the UK, such a mechanisms is not in place and payments of licencees to the Crown Estate comprising of an upfront "option fee" and a yearly "rent" in Rounds II and III are not dependent on costs related to the distance to shore or the nearest appropriate connection point (Crown Estate, 2003). In case the tendering process was organized as an auction, prospective licencees would be expected to be willing to bid the total lifetime discounted producer surplus for any submarginal project. As a consequence, most of the producer surplus would be reallocated to the public sector.[34] In the course of the development of Round III projects The Crown Estate is planning to engage in offshore wind farms as equity investor. Doing so, a proportional share of producer rents can be re-captured by the public sector.

While historically gradual connections of single wind farms to the onshore transmission networks have been observed (Adamowitsch, 2008), European energy policy aims at developing a joint offshore grid in the Nordic and Baltic Sea on the basis of international coordination. Together with the Mediterranean Ring this European super-grid shall connect several different European electricity markets and numerous wind farms at the same time, as demanded in the 2nd Strategic Energy Review of the European Commission (EC, 2008b). It is obvious that the development of a supra-regional common offshore transmission infrastructure is supported by a regulation, which denominates only one party per country responsible for establishing interconnected networks. The latter approach fits to a super-shallow framework of grid integration.

Acknowledgments

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[32] Following this normative postulation it is presumed, that public budgeting is not indifferent to the distribution of benefits and detriments arising to the sponsors versus the recipients of policy-induced transfers. Contrary, cost-effectiveness in the spending of taxes and charges is expected to comprise an overall policy target.

[33] As Ronald Coase laid out in his seminal paper "*The problem of social cost*" (Coase, 1960), the initial allocation of property rights over resources does not affect their efficient use as long as these rights can be traded at no transaction costs.

[34] The Crown Estate's earnings are being transferred to the UK treasury.

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Appendix A

See Tables A.1–A.5.

Table A.1
Overview of current policies for the attributions of RES-E integration costs in selected European countries.
Source: http://res-legal.eu/en.html (visited March 2009), own investigations.

	Grid connection	Grid reinforcement
Austria	Producer	Producer
Belgium	Producer	End user
Denmark	Producer[a]	End user
France	Producer	Producer
Germany	Producer[a]	End user
Greece	Producer	End user
Ireland	Producer	Producer
Italy	Producer	Producer
Portugal	Producer	Producer
Spain	Producer	Producer
United Kingdom	Producer	Producer
Cyprus	Producer	End user
Czech Republic	Producer	Producer
Estonia	Producer	End user
Hungary	End user	End user
Lithuania	Producer	Producer
Malta	Producer	End user
Poland	Producer	Producer
Bulgaria	Producer	End user

[a] Costs for connecting offshore wind are borne by the transmission system operator and passed on to the end user.

Table A.2
Extract of investment cost data.

Offshore wind investment costs (near shore, shallow water)	EWEA (2009)	
	EURO	%
Turbine, transport, erection	1.078.000	49
Foundation	462.000	21
Main cable, substation	352.000	16
Design, project management, environmental analysis, misc.	198.000	9
Internal grid	110.000	5
Total	2.200.000	100
Offshore wind investment costs	Ernst&Young (2009)	
	GBP	%
Turbine, transport, erection	1.504.000	47
Foundation	704.000	22
Main cable, internal grid and substation	608.000	19
Design, project management, environmental analysis, misc.	384.000	12
Total	3.200.000	100
Offshore wind investment costs	BWEA (2009)	
	GBP	%
Turbine, transport, erection	1.550.000	50
Foundation	775.000	25
Main cable, internal grid and substation	465.000	15
Design, project management, environmental analysis, misc.	310.000	10
Total	3.100.000	100
Offshore wind investment costs	***Source***: dti (2007)	
	GBP	%
Turbine, transport, erection	576.000	36
Foundation	400.000	25
Main cable, internal grid, substation	304.000	19
Design, project management, environmental analysis, misc.	256.000	16
Substation	64.000	4
Total	1.600.000	100

Table A.3
Extract of O&M cost data.

Offshore wind operating expenditures	Years 1–5 GBP/MW/yr	%	Years 6–20 GBP/MW/yr	%	**Source**
Turbine O&M	54.000	55	66.000	60	Ernst&Young (2009)
Grid maintenance	5.000	5	5.000	5	Ernst&Young (2009), dti (2005)
Substation maintenance	2.500	3	2.500	2	Ernst&Young (2009), dti (2005)
Insurance	12.000	12	12.000	11	Ernst&Young (2009)
TNUoS onshore	3.000	3	3.000	3	dti (2005)
Lease	3.000	3	3.000	3	dti (2005)
Decommissioning	18.000	18	18.000	16	Ernst&Young (2009)
Total	97.500	100	109.500	100	

Table A.4
Locational parameters of selected UK Rounds II and III offshore wind farms.

	Round	Average wind speed 100 m (m/s)	Water depth (m)	Distance to shore (km)
Zone 1—Moray Firth	3	10.1	57	27.5
Zone 2—Firth of Forth	3	9.7	80	53.6
Zone 3—Dogger Bank	3	9.8	63	197.2
Zone 4—Hornsea	3	9.3	59	99.5
Zone 6—Hastings	3	9.8	63	19.8
Zone 9—Irish Sea	3	9.8	74	37.7
Docking Shoal	2	9.1	14	20.2
Dudgeon East	2	9.2	22	36.6
Greater Gabbard	2	9.9	37	32.5
Gunfleet Sands 2	2	9.9	13	7.4
Gwynt Y Mor*	2	9.8	33	19.4
Humber Gateway	2	9.2	18	10.1
Lincs	2	9.2	12	9.3
London Array	2	9.9	23	27.8
Race Bank	2	9.1	23	33.2
Sheringham Shoal	2	9.2	23	21.4
Thanet	2	10.1	23	17.7
Triton Knoll	2	9.2	28	40.8
Walney	2	9.8	23	19.6
West Duddon	2	9.8	21	20.2

Table A.4 (*continued*)

	Round	Average wind speed 100 m (m/s)	Water depth (m)	Distance to shore (km)
Westermost Rough	2	9.2	22	11.2
Average Round 2	3	9.49	22.3	21.8
Average Round 3	2	9.76	66.0	72.6

Table A.5
Transmission cost data.

UK Rounds II and III offshore wind farm connection costs				
*1 Name of offshore wind farm	*1	*1 Cost/MW (£)	*2 Distance dependent cost/MW (£) (escalated)	*3 Cost/MWh (12%; 20a; LF 0.38) (£)
Thanet	R2	116.667	90.812	3.65
Gwynt Y Mor	R2	120.933	97.058	3.90
West Duddon	R2	135.400	118.239	4.76
Greater Gabbard	R2	147.400	135.808	5.46
Humber Gateway	R2	162.333	157.672	6.34
Walney	R2	170.222	169.222	6.81
Westermost Rough	R2	179.167	182.318	7.33
Gunfleet Sands 2	R2	184.615	190.295	7.65
London Array	R2	186.600	193.201	7.77
Docking Shoal	R2	212.000	230.389	9.27
Bristol Channel	R3	286.667	235.333	9.46
Firth of Forth	R3	300.000	250.000	10.05
Lincs	R2	230.000	256.743	10.33
Race Bank	R2	231.000	258.207	10.38
Triton Knoll	R2	240.583	272.238	10.95
Irish Sea	R3	329.032	281.935	11.34
Dudgeon East	R2	251.667	288.465	11.60
Sheringham Shoal	R2	253.968	291.835	11.74
Norfolk	R3	348.387	303.226	12.20
West Isle of Wight	R3	350.000	305.000	12.27
Hastings	R3	368.000	324.800	13.06
Moray Firth	R3	386.000	344.600	13.86
Dogger Bank + Hornsea	R3	477.383	445.121	17.90

*1 *Source*: Econnect (2005); Senergy Econnect and National Grid (2009).
*2 Round 2 cost escalation: 4 years 10%, according to Ernst&Young (2009); Round 3 cost escalation: 1 years 10%, according to Ernst&Young (2009); non-distance dependent costs: 80.000 [£/MW] DTI (2005); Sinclair Knight Merz (2008).
*3 Levelised cost of offshore grid connection.

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