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Case Studies on conditions and costs for RES-E grid integration

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Deliverable D9 of the project Green*Net*-EU27:

CASE STUDIES ON CONDITIONS AND COSTS FOR RES-E GRID INTEGRATION

EDITORIAL

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The costs of integrating RES-E generation technologies in an existing electricity network can form a significant barrier for their deployment. Thereby, of special importance are the grid connection and extension costs. The costs of grid connection are especially relevant if for example offshore wind is considered. In such a case the next available connection point of the existing grid may be several kilometres away. Hence, additional grid connection costs apply that are generally not necessary, or at least not as high, in case of integrating conventional generation technologies. The costs of grid extension are important if changes in generation and load at one point in the network cause power congestion in another point in the network. Usually, it is not possible to identify a single cause. Thus, the allocation of the resulting costs to a single RES-E generator, for example offshore wind, is at least ambiguous if not impossible.

Two questions to be answered are: (i) what conditions apply for RES-E grid integration and (ii) who has to pay for the additional costs? If a new developer has to pay all the costs of grid connection up-front, then a compromise between the best generation sites and acceptable grid conditions has to be made (here this means that the RES-E developer has a first-mover disadvantage). In such a case the RES-E developer has to include these costs into the long-run marginal generation costs. This may lead to a further increase of these still comparatively high costs. If on the other hand the grid connection costs are covered by the respective distribution or transmission system operator (as the grid forms a natural monopoly these costs are then socialised to the final customers via grid tariffs), then the initial burden does not fall on the first RES-E developer.

Such integration issues are one topic of the EC project *Guiding a least cost grid integration of RES-electricity in an extended Europe* (GreenNet-EU27, Contract No. EIE-04-049-S07.38561, http://www.greennet-europe.org) that focuses on deriving detailed cost figures for renewable energy integration on ex-

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tended European level. This report forms part of this project and aims at analysing the conditions and costs for RES-E grid integration in different European markets, namely: Germany, the Netherlands, the United Kingdom, Sweden, Austria, Lithuania and Slovenia.

The major objective of this report is to present the results of selected country-specific case studies on conditions for RES-E grid integration under different regulatory regimes. This leads to benchmark similar cases (after minor adjustments of constraints in order to guarantee comparability) and to derive best-practice cases. These results then form an input to further work packages dealing with the least-cost grid integration of RES-E in an extended Europe.

The first part of the report deals with the allocation of costs induced by the introduction of RES-E. *Barth et al.* provide general insights on different treatments to distribute the costs of RES-E power integration on individual actors of electricity markets. This leads the authors to derive recommendations for handling the cost distribution based on an economic analysis. *Özdemir et al.* add to this analysis by discussing different methods specifically addressing the allocating of RES-E grid integration costs. Based on a literature review especially the shallow and the deep cost approach are examined. After defining and discussing these approaches the current situation in the EU-15 countries is analysed and policy recommendations are drawn.

The second and main part of the report provides country specific case studies on conditions and costs of RES-E grid integration. All reports are structured by a short description of the electricity system (design of the electricity market, electricity production and demand, past and expected development of RES-E), a discussion of the country specific conditions of RES-E grid integration (integration policies, grid connection and system service requirements, philosophy of allocating grid integration costs) and finally the selected case study results (description, costs). For the different countries the most prospecting RES-E were selected, leading to the case study selection in Table 1. To derive the reported results most importantly literature reviews and stakeholder interviews (in- and outside the consortium) were conducted. Based on these definitions *Özdemir et al.* provide results for Germany, *Beurskens and Jansen* for the Netherlands, *Davidson and Mariyappan* for the United Kingdom, *Pyrko and Abaravicius* for Sweden, *Auer et al.* for Austria, *Skema and Merkevicius* for Lithuania and *Nemac et al.* for Slovenia.

The third part draws some conclusions. *Swider et al.* comparatively discuss the conditions and costs of RES-E grid integration as reported in the case studies. Thereby differences are highlighted and best practice cases are identified.

With these papers this report contributes to the growing literature discussing the various connection charges and their effects on the deployment of RES-E in Europe [1]-[3]. Thereby results on the general problems and options of RES-E grid integration, the respective costs in selected European countries and the available best practice cases are presented.

Tab. 1. Country specific case studies

	Wind onshore	Wind offshore	Biomass	Biogas	Photo-voltaic	Hydro-power
Germany	✓	✓		✓		
The Netherlands	✓	✓	✓		✓	
The United Kingdom	✓				✓	
Sweden	✓					
Austria	✓		✓			
Lithuania	✓					✓
Slovenia			✓		✓	

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DISTRIBUTION OF COSTS INDUCED BY THE INTEGRATION OF RES-E POWER[1]

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Abstract. This paper focuses on the distribution of costs induced by the integration of RES-E power. The treatment to distribute these costs on different market actors is crucial for its development. For this purpose, individual actors of electricity markets and several cost categories are identified. According to the defined cost structure, possible treatments to distribute the individual cost categories on different relevant actors are derived. An economic analysis of the cost distribution treatments is given.

Keywords. RES-E integration, cost distribution, grid connection, grid reinforcement, regulating power

1. Introduction

An increased share of total power production covered by intermitting and not perfectly predictable RES-E power generation leads to a change of the system costs. A detailed discussion of the methods to derivate integration costs and the corresponding determination of integration cost figures can e.g. be found in /Swider et al. 2006/. The approach how these cost changes are distributed on the individual actors taking part in different electricity markets has considerable

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[1] The content of this paper is modified and taken from the report /Barth; Weber 2005/.
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impacts on profitability, investor behavior and finally on the integration of new RES-E capacity, cf. e.g. /Auer et al. 2006/.

The task of this report is to identify different models that exist for distributing additional costs of introducing large amounts of RES-E capacity and to give an economic analysis of identified cost distribution models. Therefore individual groups of actors participating in a liberalized electricity market environment have to be defined. Furthermore a subdivision of the total integration costs into reasonable costs categories is required to determine different distribution treatments corresponding to different elements of an electricity system.

This paper is organized as follows: Relevant actors of electricity markets and categories of costs and benefits induced by the integration of RES-E are discussed in Chapter 2. Treatments for the distribution of the integration costs on the individual market actors are derived according to the cost categories in Chapter 3. A discussion of these cost distribution treatments based on an economic analysis follows in Chapter 4. Finally conclusions are given in Chapter 5.

2. Relevant groups of actors and integration cost categories

This Chapter begins with a definition of groups of actors participating in electricity markets that are relevant concerning the distribution of costs induced by the integration of RES-E power. Subsequently, categories of integration costs are distinguished according to their origin.

2.1. Relevant groups of actors in electricity markets

For the description and analysis of the individual distribution models the following actors in the electricity systems have to be considered:

- RES-E power producers
- Conventional power producers
- Transmission and distribution system operators (TSO and DSO)
- Consumers

RES-E can be one production form in the portfolio of power producers, however in this report power producers are distinguished into RES-E power producers and operators of conventional power plants in order to identify possible impacts of RES-E power producers on the operation of conventional power plants. For the transmission or distribution of the generated electrical power to the consumers within a certain area, a transmission or distribution system operator is responsible, respectively. Possible metering companies are presumed to be part of these system operators. For the individual electricity consumers no subdivision between purchasers of electricity connected to a TSO or a DSO is considered.

2.2. Relevant categories of integration costs and benefits of RES-E

The integration of the often fluctuating and not perfectly predictable RES-E into the electricity system may induce both additional costs and benefits (especially with wind energy)[2]. A detailed discussion on methods to derive figures evaluating these additional costs and benefits can be found in /Weber 2006/, /Söder 2005/. In general, the cost impacts can be separated into capital expenditures (investments) and operational costs or benefits /GreenNet 2004/. Integration costs or benefits related to capital expenditures can further be separated into:

- Grid connection costs
- Grid reinforcement costs
- Investment costs into regulating power plants caused by RES-E power production

The operational aspects mainly consist of:

- Change of operational costs of conventional power plants due to the integration RES-E power plants.

The various sub-categories are discussed in more detail in the following.

2.2.1. *Grid connection costs*

The connection of a RES-E power plant to the existing transmission or distribution grid requires the installation of an additional underground cable or overhead line from the RES-E power plant to the existing transmission or distribution grid and the modification of the existing busbar and transformer. Thereby common requirements defined on EU and national level concerning power quality measures and short circuit levels have to be met. Further requirements are defined by the corresponding grid operator.

The grid connection costs can be principally subdivided into the costs of the local electrical installation (the internal grid) and the connection to the existing power grid. The latter part is the most interesting factor considering cost distribution and mainly depends on the following factors /GreenNet 2004/:

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[2] In fact, also the integration of conventional power plants induces integration costs and benefits.

- The distance of the RES-E power plant to the point of coupling with the grid. This cost factor is essential for off-shore wind power farms.
- The voltage level of the connection line and the connected grid.
- The possibility to apply standardised equipment (cables, busbars, etc.).

Grid connection costs are an important economic constraint for the development of RES-E in many cases where good energy resources are found in remote locations far from load centers. Hence, it is often the case that a compromise between locations with good renewable energy conditions with potentially higher RES-E power production and locations without extremely high grid connection costs has to be found.

The costs of grid connection are mostly included into the total costs during the evaluation process of projected RES-E power plants. For an exemplary wind farm, the grid connection costs are estimated by /GreenNet 2004/ as 12 % of the total investment costs for a on-shore wind farm and 20 % for a off-shore wind farm with 150 MW and situated 20 km from the shore and further 20 km to the nearest high voltage substation. /Dena 2005/ states a total of 544 k€/MW for the North Sea and 349 k€/MW for the Baltic Sea to connect an off-shore wind farm with the German mainland. Further case study results can be found in the part 2 papers of this work package report.

2.2.2. *Grid reinforcement costs*

The integration of large scale RES-E can require additional network capacities in the distribution and transmission grid, depending on the location of the RES-E relative to the load centers and the existing grid structure. For example in Germany, the highest concentration of installed wind power can be found in the North whereas the main consumption area is in the midlands. Thus there are periods with high electricity transits from North to South and from East to West especially at weekends with high wind and low demand, cf. e.g. /Dena 2005/. As the grid was originally planned to supply the relatively low local demand of these regions, it has to be extended to meet the power stability and quality requirements. On the other hand, when RES-E is mainly located near to load centers, the RES-E production can reduce the occurrence of bottlenecks and defer the need of grid reinforcements.

The intermittent feed-in from RES-E must be balanced with regulating conventional power plants that can be located elsewhere in the grid. Also larger control areas that can make use of regulating capacity from outside a country require sufficient transmission capacities. Basically, RES-E will change the power flows in the transmission system and new bottlenecks in the existing transmission or distribution grid may occur.

The more frequent operation of the grid at full capacity due to the transmission of RES-E power to the consumer leads to a higher demand for reactive power in the grid. For example in Germany, additional reactive power sources are already required for the forecasted wind power capacity of the year 2007, cf. /Dena 2005/. Hence, further additional investments into devices for the compensation of reactive power like capacitors, inductors and SVCs (Static Var Compensator) located at corresponding weak points of the grid will become necessary. The locations of these weak points in the transmission or distribution grid have to be derived using complex load flow calculations.

To improve the planning of grid extensions in order to enable an efficient use and connection of generation and demand, the derivation of future RES-E power scenarios is needed. This includes the exchange of information between the TSO or DSO and the investors of RES-E power plants at a very early stage. Thereby detailed information about project plans, time schedules, electrical configuration and exact locations of the connection points is needed /ETSO 2003/.

Generally the need for grid reinforcement and the related costs depends on:

- The connected RES-E power capacity and the present structure of the grid.
- The change of the typical load flow pattern in comparison to the situation with no integration of RES-E power capacity.
- It has to be ensured that the connection of RES-E power plants does not lead to a decrease in power quality and system stability.

2.2.3. *Investment costs into regulating power plants caused by RES-E*

Due to forecast errors and the fluctuations of RES-E power production, the demand for reserve power both for up- and down-regulation will be increased, compared to a situation, where the same energy is delivered by a continuously operating plant. For example in regions with a high wind power penetration and mainly thermal power plants, additional manually activated up-regulating power can be necessary, cf. e.g. /Dany, Haubrich 2000/. In this case power plants running at part-load (spinning reserve) and eventually additional investments in flexible power generation technologies like gas turbines are necessary, cf. e.g. /Swider; Weber 2006/. The possible induced investment costs have to be covered by the trade at regulating power markets, cf. Chapter 3.2. However due to the spatial distribution of wind power plants, the fluctuations of wind power within a short time span like one minute are currently often negligible in comparison to conventional power plant outages and variations of the total load. Thus there is no additional need for power plants providing frequency controlled primary reserve power and only limited need for additional automatic load flow reserve power due to wind power.

Alternatively to the use of regulating power plants to compensate the intermittent RES-E power feed-in, technologies storing electricity like pumped hydro or compressed air energy storages may be used, cf. e.g. /Jaramillo et al. 2004/, /Bueno; Carta 2005/, /Enis et al. 2003/, /Marano et al. 2006/, /Barth et al. 2006/.

2.2.4. *Change of operation costs of conventional power plants and benefits caused by RES-E*

The intermittent RES-E feed-in into the electricity system especially of wind power influences the unit commitment of the conventional power plant operators and increases the use of regulating power to equal the total generation with the demand, cf. /Swider et al. 2006/.

The need for up- and down-regulation can be met by using additional quick start capacity and conventional power plants running at part load (so called spinning reserve). More frequent start-ups of conventional thermal power plants due to drops of RES-E power production lead to additional fuel and maintaining costs. Furthermore it can be assumed that existing conventional power plants are sooner worn out because they have to be run more often in operation modes for which they are not designed. Running conventional thermal power plants at part load reduces the efficiency factor and therefore increases the fuel usage related to the electricity generated. Thus the allocation of providing reserve power between standing and spinning plants is a trade-off between the additional costs of the operation of quick start capacity with typical high marginal costs and the costs of running a spinning power plant with efficiency losses. Whereas in power systems which are dominated by hydro power plants (e.g. the Nordel power system), the needed regulating power can be provided fast and with low variable costs.

Depending on where RES-E power is situated compared to the load centers and the power factor of the used generator type, a possible higher utilization of the grid can increase network losses. Moreover the options for trading electricity over larger distances can be reduced because of the possible more frequent occurrence of bottlenecks in the transmission system.

On the other hand the replacement of thermal electricity production through RES-E power production saves fuel costs. Additionally a conventional power plant producer with further RES-E power plants in its portfolio has the ability to save CO_2-certificates by providing electricity generated with RES-E.

3. Existing methods for cost distribution

The different cost categories, derived in Chapter 2.2, can be allocated to the individual actors of an electricity system by using varying cost distribution methods. In the following potential treatments to distribute additional costs due to the integration of RES-E are identified. Thereby the description of the individual treatments is organized according to the subdivision of integration costs into individual costs categories (cf. Chapter 2.2).

3.1. Principles for the treatment of grid connection and reinforcement costs

The costs of connecting a RES-E power plant to the grid and of possibly needed reinforcements of the grid near to the connection point or at remote locations can be allocated reasonably only to the owner of the RES-E power plant or to the transmission or distribution system operator (TSO or DSO). Furthermore the costs of maintaining the grid have to be distributed between both actors as well. Thereby it is assumed that the TSO or DSO is obliged to connect a RES-E power plant to its grid.

Normally the owner of the RES-E power plant has to bear the connection costs including the installation of cables or lines and the coupling facilities at the connection point with the transmission or distribution grid (e. g. busbar, transformer and meters). Thereby the definition of the connection point has consequences on the connection costs for the RES-E power producer and the TSO or DSO. This is illustrated by the differences of the Danish and German approach to determine the connection point of on-shore wind power farms:

In the Danish approach, the definition of the connection point can lead to share the costs of grid connection between the wind power producer and the TSO or DSO /Pedersen 2003/. This applies only if the wind farm capacity exceeds 1.5 MW. Then an area is assigned by public authorities to the corresponding wind farm and the grid connection costs within this area have to be borne by the wind farm operator, whereas the TSO or DSO pays the construction costs of the connecting line to this area. Thereby the costs of the connection itself (e.g. installation of transformers and meters) are included. Owners of wind power plants located outside of such planning areas, i.e. individual wind power plants with a capacity less than 1.5 MW, have to bear completely the costs of connecting to the grid.

In the German approach the TSO or DSO defines the connection point in the grid (e.g. a busbar) that is capable to link the planned wind farm capacity with the existing grid. Thereby voltage limits, the increase in short circuit levels and power flow issues due to the additional wind power feed-in have to be considered. The wind power producer has to bear the costs of the line or cable from the wind farm to the selected connection point including the costs for the connection itself (e.g. transformers and meters). Hence, the wind power producer will have much higher costs to connect the wind farm to the grid with the German approach in comparison to the Danish one. Furthermore the structure of the local grid and the capacity of the projected wind farm has more influence on the connection costs borne by the wind power producer.

The following procedures are possible for the payment of occurring costs of grid connection and reinforcement borne by the RES-E power producer:

- The occurring costs are paid by the RES-E power producer when the RES-E power plant is installed (up-front or one-off payment). In this case the connection costs are typically assigned to the total construction costs of the RES-E power plant.
- The TSO or DSO installs the connection as well as reinforcements and charges the costs to the RES-E power producer by imposing an annual fee per MW connected or per MWh transmitted. The charges have to be transparent and fixed depending on the present grid structure.

In some countries, the connection charges are set independently of the actual costs by a public regulator, cf. /Ackermann 2004/.

The individual methods to distribute the costs of grid reinforcements between the RES-E power producer and the TSO/DSO can be distinguished as follows. A more detailed discussion of these methods and their consequences can e.g. be found in /Knight et al. 2005/, /Barth; Weber 2005/, /DTI; Ofgem 2000/ and especially in the second paper of part 1 of this work package report.

- Shallow connection method: The treatment in which the RES-E power producer has to pay only for the grid connection and not the grid extension is called the shallow connection method. Thus the possibly needed grid extensions beyond the connection point and at higher voltage levels have to be paid by the corresponding TSO or DSO.
- Deep connection method: By contrast so called deep connection charges attribute to the RES-E power producer also the costs of necessary grid reinforcements induced by the connection of a RES-E power plant. Thus the RES-E power producer has to pay for grid adjustments beyond the point of connection and at higher voltage levels.
- Shallowish connection method: A similar approach to the deep connection charges are the shallowish connection charges. With this method the grid reinforcement costs are split between the RES-E power producer and the TSO or DSO. However, there is no common regulation for the subdivision of costs of grid reinforcements between the RES-E power producer and the TSO or DSO.

The choice of the used distribution method influences the costs of the grid when a significant amount of RES-E power is connected. With the shallow connection method, there is no incentive given to a RES-E power producer for an efficient integration concerning the development of the grid structure. E.g. a wind power producer will only consider the local wind conditions and the occurring connection costs of a potential wind power farm location and not the need for grid reinforcements induced by his wind power farm. Whereas the deep connection method gives clear cost signals for an efficient location of additional RES-E power concerning the structure of the existing grid. However, grid reinforcements deep behind the point of connection have multiple benefits in cases where the new lines are used by others as well. E.g. further power plant capacities could be integrated because of a precedent grid reinforcement and the possibilities for trading electricity would be enhanced. Consequently the costs of such grid extensions cannot be attributed solely to one source /Wilmar 2005/.

3.2. Principles for the distribution of regulating power requirements and costs

The intermittent nature of RES-E power, especially of wind power, increases the use of regulating power or storage devices to balance the total electricity generation with the actual demand. The occurring capital and operational costs of the additional regulating power capacities due to the RES-E power feed-in, cf. Chapter 2.2.3 and 2.2.4, have to be distributed on the individual actors. As the RES-E power producer is the originator of imbalances and the TSO or DSO has in most cases the responsibility to balance the electricity production within its balance area, the costs of regulating power are usually borne by one of these two actors.

If the TSO or DSO has to bear the occurring costs of regulating power, they will be socialized by transmission or distribution system charges. In the case that the RES-E power producer has to bear the costs of regulating power, one possibility is to penalize the RES-E power producer with prices derived from the bids and offers at a regulating power market.

With the so called two-price model, the design of a regulating power market shows two different prices for the up- and down-regulation within a certain hour. This model is applied e.g. in Finland and Sweden /Wilmar 2003/. To give an overview, the different amounts of net income for a RES-E power producer under this two-price model are shown in Figure 1. In the case that the actual RES-E power production delivered at the spot market is lower than the corresponding bid and this extends the total imbalance of the grid, the RES-E power producer has to pay an up-regulating price that is higher than the actual spot market price. In the case that there is an over-production and this extends the total imbalance of the grid, the RES-E power producer is rewarded with a down-regulating price lower than the actual spot market price[3]. If the deviation between the forecasted RES-E power production that has been bidden into the spot market and the actual realized RES-E power production contributes to balancing the total electricity system, i.e. the RES-E power balance is in the opposite direction as the system imbalance, the RES-E power producer will be paid based on the actual spot market price. Hence, the RES-E power producer is penalised only for having its imbalance on the same direction as the total system.

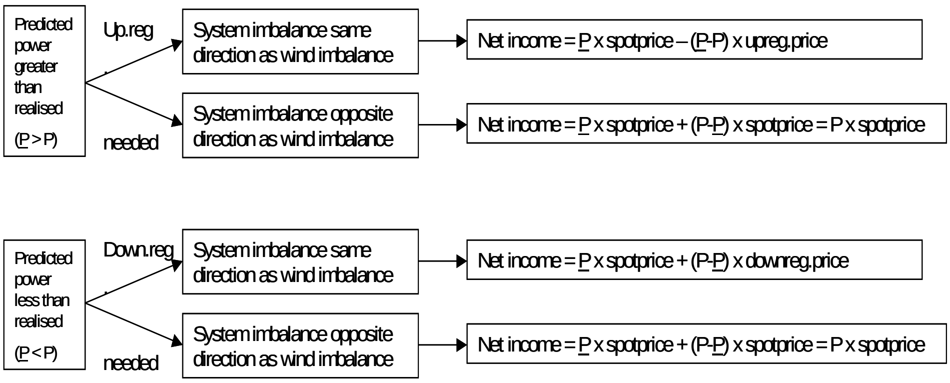

Fig. 1. Net income for the wind power producer with the two-price treatment at the regulating power market /Holttinen 2005/. $\underline{P}$: predicted wind power, P: realised wind power, spot price: power price on preceding spot market

By contrast the one-price model, e. g. applied in Norway /Wilmar 2003/, uses a unique balancing power price paid or charged for any imbalances during an hour[4]. This price depends on the system imbalance based on the cost of the needed regulation, but this price is applicable whether the RES-E power imbalance has the same or opposite sign compared to the system imbalance[5]. During the hours when the RES-E production exceeds the prediction, this excess production is remunerated with the system balancing price, which is generally low, when the system has overall excess production and high when

[3] In theoretical situations with negative down-regulation prices the RES-E power producer would reduce his production to prevent possible negative net incomes.

[4] The same model is applied in Germany, however the RES-E producer are exempted from it.

[5] A further and simplified alternative to this one-price model would be the use of given and fixed penalty fees for under-production and low excess rates for over-production that are not dependent on the actual regulating market prices.

the system is short in power. In the case RES-E production is in short fall compared to previsions, this lack of production has to be paid again at the current system price to the grid operator.

Depending on the used practice, the balancing prices paid by the individual producers differ from the system regulation costs. This is mainly the case in the two-price model. With the one-price model, the payments borne by the RES-E power producer reflect the increase in total system costs caused by RES-E. When the penetration of RES-E power increases, RES-E power is causing more of the imbalances. Hence the correlation between system imbalance and RES-E power imbalance will raise and the effective regulating power cost paid by the RES-E power producer will also increase /Wilmar 2005/.

In the common case that the TSO or DSO has the responsibility to balance the intermittent RES-E power feed-in he can buy regulating power from power producers at different regulating power markets. If the responsibility of balancing the RES-E power production were allocated to the RES-E power producer, the following options for the RES-E power producer to provide the necessary regulating power would be possible:

- The RES-E power producer participates in the regulating power market and has the ability to purchase regulating power like other actors at the regulating power market. Thereby the RES-E power producer has to bear additionally the transaction costs of the markets where he takes part.
- The RES-E power producer holds his own regulating power units or electricity storages. This means that the RES-E power producer has to consider additional investment and operation costs when projecting a new RES-E power plant.
- The RES-E power producer pays conventional power producers or the corresponding TSO or DSO for the supply of the necessary regulating power capacity. This can be done on the base of a power rate per requested MW and/or of an energy price per delivered MWh[6].

Generally the TSO or DSO is responsible for the secure and stable operation of the public grid. The allocation of the responsibility to balance the RES-E power production to the RES-E power producer itself is hence not coherent with the overall system rules. Moreover stability of the overall grid would be more difficult to ensure. This would require to portion the responsibility on the individual power producers and to penalize actions that lead to an instable grid operation by a central institution. However, the correct allocation of imbalances

[6] As the RES-E power producer is in a competitive position with the conventional power producer, the charges for the regulating power capacity set by the conventional power producer will be comparably high /Ackermann 2004/.

to individual power producers and the right penalizing mechanisms would be difficult to establish.

Beside an efficient distribution of regulating power costs induced by the integration of RES-E power, the costs due to the intermittent and not perfect predictable feed-in could be reduced. This can be done most effectively by reducing the gap between closure of the spot market and real-time delivery, by improving the quality of RES-E power production forecasts and by enabling demand side management. Yet a detailed discussion of these issues is beyond the scope of this paper.

4. Economic analysis of cost distribution treatments

In an economic perspective of social welfare maximization, the issue of providing efficient price signals to economic actors is at least as important as the question of cost distribution. To get the prices right in order to have the market providing efficient solutions to the integration of RES-E – this is the key challenge from an economic viewpoint.

Such a line of thinking leads straightforwardly to the introduction of locational pricing as the best remedy to all kind of allocation problems in electric grids, including the distribution of so-called integration costs attributable to RES-E. Given the quasi non-storability of electricity, the locational (nodal) prices should be real-time prices to reflect the actual scarcities of electricity (and ancillary services) in different locations. In a competitive environment, economic agents will then provide the optimal amount of RES-E and other production in the right places by anticipating the future development of the locational prices (or relying on correspondent derivative contracts). This is the essence of the theory, yet its application is complicated by several real-world phenomena:

- The natural monopoly character of the grid: The natural monopoly of the grid has two key consequences: there will be usually one grid operator per region, who has then to be regulated in order to avoid excess monopoly profits. Locational pricing will hence not emerge by itself from competitive forces but will have to be imposed on the grid operator by a regulator. As an exception, it may emerge spontaneously, if the grid operator is state-owned and benevolent, pursuing hence by himself social-welfare maximizing objectives. The second, as important consequence is that a pricing system based on marginal cost will not recover the full cost of operation of the grid. Rather the sub-additive cost function of the grid makes the last (additional) use cheaper than previous uses. When it comes to calculating integration costs, it consequently also matters in which order different functions or users (e.g. trading, renewables) are added to the grid.

- The existence of transaction costs: The existence of transaction costs makes locational real-time pricing not an as attractive alternative as it seems to be at first sight. Especially for smaller scale renewable plants the costs of transmitting real-time information to the plant operator and enabling him to react may exceed the potential benefits from such an approach. The existence of transaction costs may be taken as a justification for the introduction of day-ahead markets, zonal pricing or other simplifications compared to real-time nodal pricing.
- The existence of information asymmetries: The existence of information asymmetries complicates further the emergence of efficient solutions since both grid operators and operators of renewables power plants may withhold information in order to increase their profit. Clear rules on the sharing of operational information and a culture of common information building for strategic decision making may help to overcome these information asymmetries. Yet a careful assessment is needed to weight costs vs. benefits of increased transparency taking also into consideration that high transparency may increase the danger of collusive behaviour in oligopolistic markets like the wholesale electricity market.
- The additional requirement of robustness: The requirement of robustness means that the system should remain stable even if the actors in the system have perceptions of the system dynamics which differ from the reality. Robustness thus goes beyond the classical requirement of system stability. It is however a concept widely used in modern technical control theory and it should also be taken into account at the frontier between technical and economic electricity systems. Given the general trade-off between robustness and efficiency (cf. /Zhou; Doyle 1998/, /Weber 2005/) a certain loss in efficiency is to be expected also if considerations of system stability are taken seriously[7]. Losses in efficiency here mean additional costs compared to the welfare optimal solution without dangers of system misperception.

[7] A detailed analysis of the compatibility respectively divergence of the three concepts of 1) electrotechnical system stability 2) optimal (and/or robust) stable control 3) economic efficiency and robustness is beyond the scope of this paper. This is however a challenging theoretical issue of considerable practical relevance.

4.1. Implications for the treatment of grid connection and grid extension costs

From the previous reasoning, the following implications for the treatment of grid connection and grid reinforcement costs can be drawn:

- Grid connection costs which are clearly attributable to a RES-E power plant installation should be born by this installation. Whether they are charged as one lump-sum payment or as a fixed annual fee is however of minor importance for efficient grid operation - it is an issue of cash flow management.
- Deep grid connection charges are in principle better suited to reflect real-time scarcity than shallow connection charges. Yet they remain a considerable step behind real-time prices, given that they are usually calculated ahead of the investment and do not reflect changes after the construction. They will thus at best provide adequate investment signals but no adequate price signals for operation. And if they are determined based on an incorrect anticipation of later scarcity, they may even provide wrong locational signals at the time of construction.
- The location-dependent benefits or costs of new investments - be it in RES-E power plants or in grid reinforcements – may vary over the lifetime of the investments. Consequently deep connection charges should not be fixed once for ever, but revised regularly according to a transparent mechanism.
- Such a time-varying connection price for RES-E power plant installations with revision periods between one and five years may be a suitable compromise for RES-E power producers. It puts some of the risk of future changes in local scarcity on the investors, but the risk exposure is in a well-designed system smaller as with full real-time locational prices[8]. And obviously the transaction costs tend to be lower.
- Grid extensions deep behind the point of connection usually have multiple benefits, cf. Chapter 3.1. Consequently the costs of such grid extensions cannot be attributed solely to one source.

4.2. Implications for the treatment of regulating power

For the treatment of regulating power and corresponding costs, the following basic considerations have to be taken into account.

[8] However such slowly varying prices do not provide adequate locational signals for physical electricity trading and the conventional power generation behind it.

- Two aspects have to be distinguished conceptually: the creation of market mechanisms, which lead to a minimisation of regulating power costs and the distribution of the resulting costs on the actors concerned. But obviously any market design will have implications both for the cost height and its distribution.
- With typical feed-in tariffs, as currently in place e.g. in Germany, RES-E power producers will not bear directly any costs of the additional regulating power needs they are causing. With most other renewable support schemes, such as tradable renewable obligations, procurement schemes or bonus payments, RES-E power producers participate in the conventional power market and thus also have to bear costs of deviations from schedule – i.e. regulating power costs. Consequently RES-E power producers have no incentives to reduce regulating power under feed in tariffs, whereas they have such signals under other support schemes.
- Zonal pricing with automatic price splitting as currently practised in the NORDEL region is from a theoretical point of view clearly a second-best solution compared to nodal pricing[9]. The key point thereby is that zonal pricing requires transmission capacities between pricing zones to be computed ex-ante, before the trading takes place. In practice however the transmission capacities between two regions are not only a function of the thermal capacity of the lines between these two regions, but also of the location of all the power generators and power sinks in the system[10]. This location may vary from day to day, especially due to trading-induced variable scheduling of power plants. And obviously varying RES-E generation also tends to modify the distribution pattern of generators (and sinks – if demand side management is applied). Under uncertainty about generation location and RES-E generation, the grid operator will tend to set conservative transmission limits, which may constitute unnecessarily high restrictions to trading, leading hence partly to unnecessary market splitting and corresponding efficiency losses. A nodal pricing system avoids these difficulties by determining simultaneously the load flow and the prices[11].

[9] Zonal pricing with explicit auctioning of cross-border capacities as currently practised in the rest of Europe is even less efficient. But here things are evolving, albeit slowly.
[10] This is a direct consequence of the laws of physical load flow in meshed grids.
[11] In a system of full locational pricing, not only active power should be priced but also reactive power. This will then also lead to appropriate locational and operation signals for providers of reactive power. In such a context moreover even a temporal overloading of transmission capacities could be taken into account. Yet in this case, path-dependency in prices is not only induced by the operation restriction of generators but also from the grid.

- Regulating power is in a general sense any power needed to compensate deviations between scheduled power flows at the moment of spot market closure and actual power flows[12]. Clearly the market trading has to close before the actual operation in order to allow the system operator a stable operation, not disturbed by sudden last-minute trading operations. He needs therefore regulating power reserves. However this raises two important issues: how long is the distance between spot market closure and actual delivery? And how are the bids for regulating power coordinated with bids for the spot market?
- From the perspective of a conventional power plant operator, the spot market and the (upward) regulating power market are two alternative sources of revenue. In any market design, which does not preclude from the outset arbitrage between these two markets, power plants will earn at least as much when delivering upward regulating power as when they provide power traded on the spot market. The earnings from the regulating power market will exceed those from the spot market if and only if scarcity is higher for flexible power plants (as needed for regulating power) than for predictable power traded on the spot.
- No simple solution for designing regulating power markets exists. Or more precisely: simple solutions tend to be inefficient and efficient solutions tend to be difficult to implement. This holds especially for the German and other continental European power systems, where flexible power plants are scarce, given that thermal power plants dominate, and where in each regulating market zone (or each pricing node in a nodal system) there exists one dominant firm. A further key issue thereby is that in Germany the amount of automatically activated regulating power is much higher than in the Nordic system, given the UCTE rules[13].

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[12] This general definition of the term regulating power is complicated by the fact that some countries have energy trading taking place after the closure of the spot market on intraday or balancing energy markets (e.g. Denmark and other Scandinavian countries). Then regulating power is only the power activated according to the system net imbalance during the operating hour. In fact, intraday or balancing energy markets are in these cases the “real” spot market, i.e. the market closest to actual delivery. Yet this definition is not commonly shared, notably given the usually limited liquidity of intraday and balancing markets in the countries concerned.

[13] Those foresee an automatically activated secondary reserve, where the activating is done based on the current load-flow across the borders of the grid area under control.

These general considerations lead to the following implications:

- For the distribution of regulating power costs caused by RES-E power production, the basic question is, whether RES-E participates in the conventional power market or not. The decision on the promotion scheme will however depend also on other considerations than the provision of efficient regulating power price signals.
- If RES-E power does not participate in the conventional power market – as is currently notably the case in Germany – the costs related to required regulating power will usually be born by the grid operators and hence ultimately by the grid users. The distribution of these integration costs then depends on the general rules for the sharing of the renewables costs. These can be distributed on a per MWh consumed basis (as currently in Germany) or proportional to the grid charges paid.
- A charge of imbalance costs to RES-E power operators in a system, where they do not participate in the market will always provide some inconsistencies. In particular the use of predefined imbalance tariffs usually does not reflect the real-time scarcity nor does it take into account portfolio effects.
- If the RES-E power participates in the conventional power market (as wind power in Norway, UK and Denmark[14]), RES-E power producers will usually also have to bear the costs of any imbalancing they are causing based on the current balance power price. With a functioning balancing market this provides efficient operational signals to the power producers, if they are charged a uniform real-time price, which reflects the overall system imbalance (and not the individual imbalance) as well as the real-time scarcity of flexible power generation. The use of an asymmetric imbalance tariff (two-price model as currently in place in all Scandinavian countries except Norway) does not provide adequate scarcity signals in that it does not reward imbalances being in the opposite direction of the total system imbalance.
- In this setting, the amount of imbalances to be paid for by RES-E power producers strongly depends on the time span between closure of the spot market and actual delivery. A rather short delay is preferable since then the forecast errors for wind energy are low.

[14] Only newer wind power installations participate directly in the power markets.

- If the time span is longer, the efficiency of the regulating power market is key. If market power is an important issue in the regulating power market (as seems to be the case currently in Germany), RES-E power producers (and consumers) will be charged too high regulating power costs.

5. Conclusion

The objective of this report is to identify different treatments to distribute the costs of RES-E power integration on the individual actors of electricity markets and to derive recommendations for handling the distribution of these integration costs based on an economic analysis.

With regard to grid connection and reinforcement costs, the applied treatment of cost distribution has significant influences on the overall projected costs of the installation of new RES-E power plant capacities. It influences further the structure of the existing transmission or distribution grid and its capability to comply with an growing share of RES-E and increased trading activities. Since grid reinforcements have multiple benefits for the operation of electricity grids and for the trading at electricity markets, these costs should be allocated reasonably to several users of the grid.

The structure of the present markets (e. g. using different price models for the regulating power price fixing or different time spans between the closure of the trading activities and the actual delivery hour) as well as how the RES-E power producers have access to the markets are crucial points for an assessment of treatments for the distribution of occurring regulating power costs due to RES-E power. The resulting plurality makes an harmonisation of possible methods for an efficient cost distribution difficult. To provide efficient operational signals to the individual power producers, it has to be ensured at least that the total of the regulating power costs borne by the individual power producers should equal the total costs of the net imbalance.

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COST ALLOCATION FOR RES-E GRID INTEGRATION

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Abstract. This paper discusses different grid integration cost allocation approaches for RES-E generation facilities. The main question is to determine which actor will carry the grid reinforcement costs needed for RES-E generation. Four approaches of grid integration cost allocation that are available in the literature are examined in this paper, namely: deep, shallow and shallowish (hybrid) cost approaches. The advantages and disadvantages of each approach are analysed with respect to the relevant actors in the electricity market. After defining and discussing the available approaches the current situation in EU-15 countries is analysed. Finally, recommendations for the selection of cost allocation approaches are given in the discussion and conclusion part.

Keywords: grid connection, grid reinforcement cost allocation, renewable energy

1. Introduction

Most of the national electricity markets in Europe have recently been privatized expecting it will bring more competition and efficiency to the sector. There is a general consensus, however, that without unbundling privatization would not work in the desired manner. Developed monopolies in an unbundled electricity sector may prevent competition (Auer, 2006; Hiroux, 2005). Unbundling is

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defined as the separation of electricity transportation from the electricity generation and distribution facilities. Thus, unbundling in an electricity market is needed to allow (non-discriminatory) access of third parties to the sector (Auer, 2006). The relevant actors in an electricity market can be classified as follows:

a) Electricity producers
    i. Conventional producers
    ii. RES-E producers
b) Transmission system operators (TSO)
c) Distribution system operators (DSO)
d) Consumers

The RES-E generation utilities can also be connected to the DSO directly. Therefore, TSO and DSO can be seen as a single entity in terms of grid reinforcement cost allocation approaches, whereas in terms of unbundling and system efficiency it is important that they are separated.

The aim of this paper is to investigate and discuss the different grid integration cost allocation mechanisms for RES-E generation among the previously named actors. Special importance is given to the effects of different mechanisms on RES-E generation development. Thus each mechanism is analysed carefully for relevant actors.

In section possible grid integration cost allocation mechanisms available in the literature are defined and different mechanisms in terms of RES-E generators and TSO/DSO are discussed. Section 3 examines the EU-15 countries with respect to their policies for grid integration. Section 4 concludes the discussion.

2. Allocation of grid integration costs

The grid integration of any electricity producing technology is not for free, whether it is a conventional or a RES-E power plant. The discussion in this paper, however, will be restricted to the RES-E generation. The different grid allocation approaches will affect the RES-E producers much more than the conventional producers, since the RES-E producers are more sensible to additional charges. This is so since the capacity factor (and hence the amount of kWh) is often relatively low while connection costs per MW tend to be higher for smaller generating plants. This, leaves the allocated grid integration cost component relatively important. This holds *a fortiori* if and when distributed generators feeding into DSO networks are discriminated against as compared to large incumbent generators feeding into the transmission network. The methods for estimating the grid integration costs of new power plants (conventional or RES-E) are mentioned in literature explicitly, cf. Söder, 2005; Weber, 2006.

Furthermore, grid integration costs account for a significant percentage of the investment costs for RES-E technologies. Thus, grid integration costs could be a decisive factor in determining the feasibility of an RES-E investment (Auer, 2006).

The integration of a RES-E generation source may incur an additional cost to upgrade the grid upstream of the connection point. This requirement is especially evident in off-shore wind and coastal on-shore wind cases due to relatively weak transportation and distribution lines in the rural coastal areas. The grid connection and grid reinforcement is schematically presented in Fig. 1. In some cases the RES-E generator can also directly connected to transmission lines, which is not shown in the figure below.

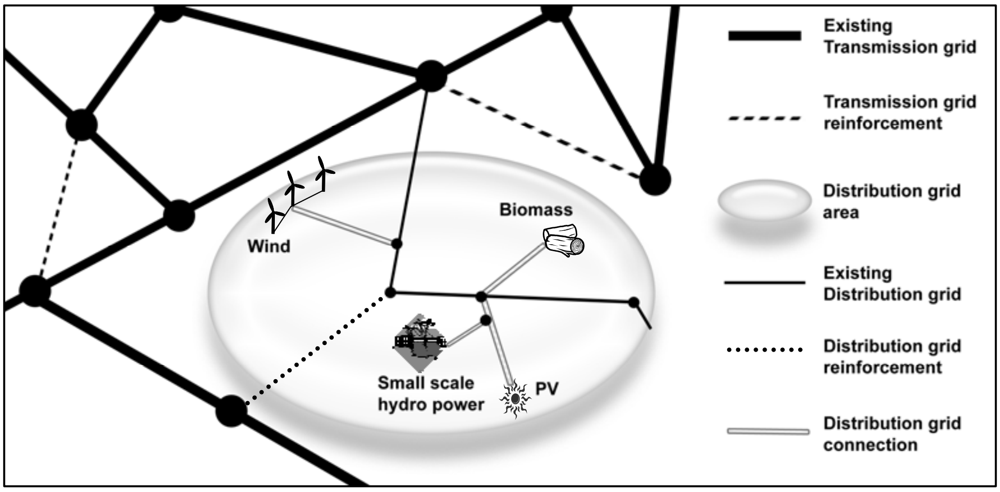

Fig. 1. Grid connection and reinforcement measures on distribution and transmission level caused by large-scale RES-E grid integration (taken from Auer, 2006, original source EEG-Vienna)

It is generally accepted that the RES-E producers should cover the grid connection costs, which is the cost to connect RES-E generation technology to the existing transmission or distribution grid (Barth et al., 2005). However, the definition of a connection point is important here. Different definitions (like in the Danish and German approach) can lead to different cost allocations (Barth et al., 2005). The Danish approach, which is only valid for wind parks with higher than 1.5 MW of capacity, assigns a predetermined area for the corresponding wind farm. The producer is only responsible for the connection costs within that area. The TSO or DSO carries the connection costs from this area to the existing grid including the transformers. This approach can be seen as an incentive to RES-E generation. On the other hand, the producer will carry all the connection costs to the existing grid including the costs of transformers as in the German approach (Barth et al., 2005). The German definition of the connection point is generally adopted in Europe.

In the German approach, new grid connections to the existing grid will probably belong to the RES-E generators as they cover the costs. The situation could get more complicated if later another RES-E generator decides to initiate a project near to an existing one. Obviously, the intention of the newcomer will be to connect the RES-E power plant to the nearest point. So it may be the case that the newcomer will use the connection line of the existing RES-E generator where the newcomer should pay to the existing RES-E generator. An independent regulator is needed for such a situation to determine the fee that the newcomer should pay.

The other discussion is on the coverage of the possible costs of reinforcements (upgrading) of the existing grid. Four different types of grid integration cost allocation approaches are found in the literature, namely deep, shallow and hybrid (shallowish) cost approaches (Knight et al., 2005; Auer, 2006; Hiroux, 2005; Barth et al., 2005). These different approaches determine which actors in the electricity market will carry the burden of the grid improvement costs.

2.1. Deep cost approach

The deep cost approach allocates the grid connection and reinforcement (upgrading) costs only to the electricity producers. Thus, the producer must pay for the adaptations at higher voltage levels beyond the connection point (Barth et al., 2005). This upgrade is needed due to the possible reliability loss of the grid for installing a new generator into it.

This approach is examined in terms of the related actors in the market.

2.1.1. *RES-E producer point of view*

The deep connection cost policy is definitely not in favour of the RES-E producers. The main drawback of this approach for the producers is the increased investment cost of the RES-E project, which is already a capital intensive investment (Hiroux, 2005).

On the other hand, the improved electricity transmission and distribution grids are not only serving the new RES-E generator, but also increasing the reliability of the whole electricity network (Barth et al., 2005). Therefore, it might be unfair to allocate all reinforcement costs to the RES-E generator.

2.1.2. *TSO and DSO point of view*

The network operators (TSO and DSO) have low risk with the deep connection approach. The generators cover the costs at the initial stage of the project. Generally there is a need of regulating rules to assess the needed upgrade in the system. This is generally done by the local TSO or DSO (Barth et al., 2005). A problem that might appear at this point is that the TSO or DSO might allocate higher costs to upgrade the existing grid. As the calculations are not transparent, the RES-E generator might not object to the calculations. Therefore, it might be fair for all the actors in the market that an independent grid regulator may be responsible for calculating these costs.

2.1.3. *Evaluation of deep cost approach*

The main advantage of deep cost approach is that it is "cost reflective". The RES-E producer is expected to optimize the costs so that the efficiency of the network is increased by avoiding the over-investments of reinforced transmission and/or distribution lines (Hiroux, 2005).

On the other side, the main disadvantage of the deep cost allocation system is that it could be a barrier to realize new RES-E projects since this approach increases the investment costs which are already high for RES-E generation.

Secondly, as the reinforcement calculation is not very transparent and as the upgrading also serves for the reliability of the whole network, the costs that electricity producers should carry are arguable. Furthermore, it is important who is deciding the reinforcement costs. It might be inappropriate to let a TSO or DSO to decide on the costs due to previously mentioned reasons. An independent grid regulator is needed for accomplishing these tasks.

Thirdly, this approach may cause such an effect that all RES-E producers will wait for others to implement their projects. Since the first RES-E generator already covers the upgrading costs the second one will benefit from that. Thus, no RES-E producer wants to be the first to implement the project in a specific area. This can also delay or even prevent the increase of RES-E production (Hiroux, 2005).

2.2. Shallow cost approach

The shallow cost approach only allocates the grid connection costs to the RES-E producer. The needed reinforcements in the upstream grid are "socialized" by system and client charges and are in the responsibility of the TSO and/or DSO. Fig. 2 presents the shallow and deep cost approach according to the German approach.

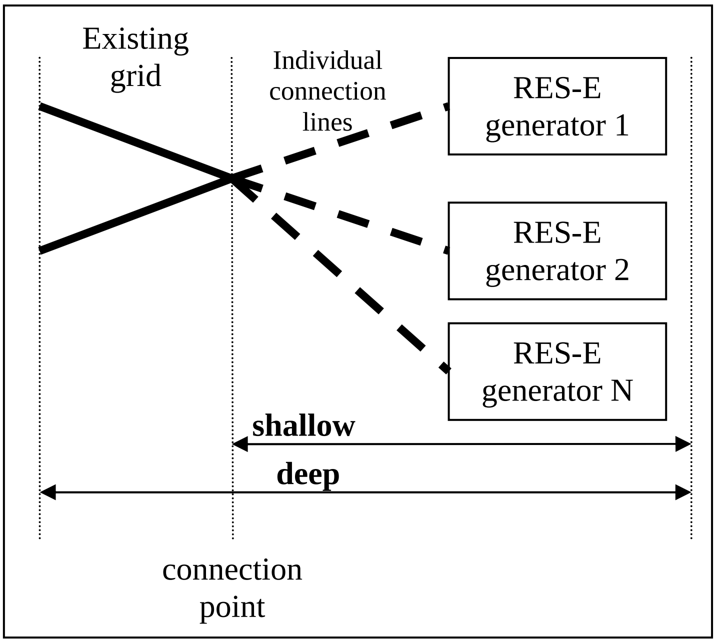

Fig. 2. Definitions of shallow and deep costs according to German approach (taken from Auer, 2006 and modified)

2.2.1. *RES-E producer point of view*

The shallow cost approach could be seen as an incentive for the RES-E development. As the producer only carries the grid connection costs, the overall project costs are lower and more certain for the producer. The lowered investment costs make the project more feasible. As a result of these favourable effects for the producer, it is expected that shallow cost approach will increase the number of RES-E generation projects.

2.2.2. *TSO and DSO point of view*

The TSO or DSO is going to charge the end users (customers) for the use of the system over the lifetime (e.g. 40 years) for the occurred expenses. The reinforcement of the existing grid is a very capital-intensive operation and will significantly increase the capital requirements of the TSO or DSO (Hiroux, 2005). On the other hand, if the TSO or DSO were not short of capital the incentive of TSO or DSO would be to overestimate the total costs of grid reinforcement, since the costs are not carried by themselves (Hiroux, 2005). Hence a regulation of the natural monopoly is necessary.

2.2.3. *Evaluation of shallow cost approach*

The main advantage of the shallow cost approach is that the investment costs of RES-E producers are reduced and can be foreseen. The RES-E producer can select the place of the project without considering the bottlenecks in the existing grid system. The producer should only optimize the grid connection costs.

Furthermore, the actors of production or distribution do not carry the costs of grid reinforcement, but they are socialized by the grid tariffs. Thus the end users carry them. At the end the shallow cost approach can be seen as a support or an incentive for the RES-E production.

The disadvantages of this approach are due to the socialized character of the reinforcement costs. As the producers do not carry the reinforcement costs there is no need for them to minimize these costs. Furthermore, the TSO or DSO does not have the incentive to reduce the reinforcement cost unless they are short of capital. Thus, the electricity network system might be inefficient if the reinforcement costs are not optimised (Hiroux, 2005). One solution to limit the overestimation of reinforcement costs by TSO or DSO could be the regulation of the grid by an independent agent, which will determine the reinforcement costs for each individual case. However, there is no means to force generators to optimise project locations in terms of reinforcement costs with the shallow cost approach. This is the major weakness of the shallow cost approach.

2.3. Hybrid (shallowish) cost approach

The idea behind this approach is to take advantage of both deep and shallow cost approaches and to build a new method that is somehow “between” these two original methods. With the hybrid approach the RES-E producer is charged an extra fee depending on location additional to the grid connection costs. Thus, the RES-E generator caries the grid reinforcement costs to a certain degree and the rest is “socialized” (Hiroux, 2005).

2.3.1. *RES-E producer point of view*

The project costs are lowered with respect to the deep connection cost approach for the RES-E producer. This method is actually developed to reduce the reinforcement costs that are carried by the RES-E producers but also to provide some indication of location information of the project site for the generators. Thus, the producer is forced to optimize the reinforcement costs to some extent by considering the location of the project.

2.3.2. *TSO and DSO point of view*

The share of coverage of the reinforcement costs by the producer determines the closeness of this approach to the deep or shallow cost approach. The extra fee will be determined either by the TSO and DSO or by the regulatory authority. Thus it is very important to decide who will determine the shares in this method.

As the signal of the locality of the project is provided, it is expected that the use of the network will be more efficient than the shallow cost approach. Furthermore, it reduces the maintenance of the network for the TSO or DSO. Thus, hybrid cost approach could be suitable for the TSO or DSO.

2.3.3. *Evaluation of hybrid (shallowish) cost approach*

The advantage of this method is that the producers only pay a fraction of the reinforcement costs relative to the location of the project. That means the producer should also consider the reinforcement costs that reduces the possible inefficiencies in the electricity network system.

Although the hybrid method is a good combination of deep and shallow cost approaches it is still difficult to determine the costs that will be allocated to the producers. The general idea is to charge the RES-E generators so much that the costs will only reflect the reinforcement of the grid that is required for the RES-E project. As mentioned before, it is difficult to calculate the proportion of the grid reinforcement that is needed for an individual RES-E project. Furthermore, it is very important to determine which actor will decide these values. It may be inappropriate if the TSO or DSO determines these costs, since they most probably tend to increase the fees and so this approach gets closer to the deep cost approach. An independent grid regulator may perform this task more objectively.

As a result, the shallowish cost approach reduces the pressure on the RES-E producer by lowering the capital costs but still bares the overall efficiency of the network system in mind. This method might benefit all actors with an appropriate cost calculation method.

3. Grid integration cost allocation approaches used by the EU member states

There is no common ground in the European countries for the choice of the grid integration cost allocation approach. The situation in the EU-15 countries is summarized in Table 1 (Knight et al., 2005). This table indicates that all approaches are represented in the EU-15. However, the deep cost approach is dominating the EU-15 as it is the choice of more than half of the countries.

One interesting point to note is that the countries that accept the shallow cost approach (Belgium, Denmark, Germany and Netherlands) have also a high percentage of RES-E generation (mainly wind) in the country. The only country with a well developed RES-E generation share with the deep connection approach is Spain.

Table 1 indicates that there are very few countries in EU-15 having a high level of system transparency. Furthermore, there are also only a few countries with available literature about the connection cost calculation methods. All the countries with low system transparency are also lacking the publications of cost calculation. It is especially an unjust situation for the RES-E generator, if the level of transparency is low and the deep cost allocation approach is in regulation. Austria, Greece, Italy, Luxembourg, Spain and Sweden are falling into this category, cf. Table 1.

Tab. 1: Grid connection cost parameters for EU-15 countries (taken from Knight et al., 2005)

Country	Cost allocation approach	Level of transparency	Published connection cost calculation methods?
Austria	Deep	Low	No
Belgium	Shallow	High	Yes
Denmark	Shallow	High	Yes
Finland	No Standard	Medium	No
France	Shallowish	Medium	No
Germany	Shallow	Low	No
Greece	Deep	Low	No
Ireland	Deep	High	No
Italy	Deep	Low	No
Luxembourg	Deep	Low	No
Portugal	Deep	Medium	No
Spain	Deep	Low	No
Sweden	Deep	Low	No
The Netherlands	Shallow	High	Yes
United Kingdom	Shallowish	High	Yes

4. Discussion and Conclusion

In this paper, the common cost allocation approaches are defined and discussed. After that the current situation in the EU-15 countries are listed.

It seems like the TSO or DSO is not adversely affected by the choice of the cost allocation method. The costs are carried by the RES-E producer in deep cost approach and they are socialized in the shallow cost approach. Thus, the actual conflict is between RES-E generators and the customers. The question is: Should the grid improvement costs be shared by all the society equally or should they be carried by the generators?

It is mentioned that the deep cost approach can be unjust for RES-E generators where the system transparency is low. Furthermore, as the improvements in the existing grid not only favour the RES-E generators but also the overall system reliability, it is not fair to charge only to the RES-E producers.

Furthermore, reduced investment costs and increased cost calculability would definitely help to develop RES-E further. This can be achieved by changing the cost allocation method from deep connection to either the shallow or to the shallowish one.

The problem with the shallow cost approach could be that it does not take the grid improvement cost into account. This may lead to an inefficient network system. On the other hand, the shallowish approach is also not easy to implement since it should define clearly the costs that will be allocated to the producers.

On the other hand, it seems like an independent grid regulator is needed for all cost allocation approaches. If the tasks of the grid regulator are given to the TSO or DSO it might be unfair for other actors in the electricity market.

To sum up, the shallow or shallowish cost allocation approach should be applied to support the RES-E development and to have a fair system for the RES-E generators. If a country decides to develop RES-E generation quickly the shallow cost approach is preferred. If this approach is not acceptable due to the system efficiency concerns the shallowish approach may be applied. Furthermore, an independent regulator is definitely needed for all cost allocating approaches.

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GERMAN CASE STUDY

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Abstract. The grid integration costs could be significant and decisive for the feasibility of renewable electricity production. Some renewable energy sources for electricity production in Germany are investigated in this paper by looking available case studies in the literature. The focus is on wind parks (off-shore and on-shore) and biomass power plants. One case study for each RES-E is selected and is investigated in detail for electricity generation costs. The main findings are that the grid integration costs are very critical and critical for off-shore and on-shore wind parks respectively. The grid integration does not have a significant effect on electricity generation costs by biomass power plants.

Keywords: Grid integration cost, wind parks, biomass, Germany, case study

1. Description of electricity system

1.1. Design of the electricity market

As in other European countries, the German electricity market has privatized beginning in 1998. Liberalization is achieved in Germany more or less successfully. Although there are more than 900 electricity producers operating, 79% of the market is controlled by four big companies (Brunekreeft et al., 2004; Kempe et al., 2005).

Eurelectric, the Union of the Electric Industry, ascertained a decrease in electricity prices up to 21% in real terms after liberalization due to increased efficiency and competition in the market. However, after 2001 the prices increased again up to 84% of the prices of 1995.

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Precondition to successful liberalization was the unbundling of the electricity market. The unbundling aims to separate electricity production, transmission and distribution (Haas, 2003). The EU Commission argued that although Germany's electricity market is fully privatized there are still obstacles with "unbundling" and "regulation" to achieve a better competition (Commission of the European Communities, 2005).

The European Energy Exchange (EEX) is the energy exchange platform of Germany which has emerged in 2002 from EEX Leipzig Power Exchange and EEX European Energy Exchange Frankfurt. The aim of EEX is to act as a central energy trade platform for central Europe. In future power, gas and other energy carriers shall be traded at EEX (www.eex.de). In EEX both, short term (*spot market*) and long term (*futures market*) trading is possible.

The *spot market* is also known as *a-day-ahead market* since on this market electricity is traded for the 24 hours of the following day. There are two different trading platforms, namely the closed auction trading and the continuous trading (EEX, 2005).

On the *futures market*,the maximum tradable delivery period is six months. The load type is also important in the *futures market* besides the delivery period. The base load must be covered for every day (24 hours), while the peak load coverage includes only the working days between 08:00 a.m. and 08:00 p.m. (CET) (EEX, 2005).

As electricity cannot be stored, the supply and demand within the market must be equalized at all times. A r*egulating power market* (RPM) helps balancing the system. This is achieved by a tendering model for electricity supply. The schematized tendering model of RPM is presented in Fig. 1.

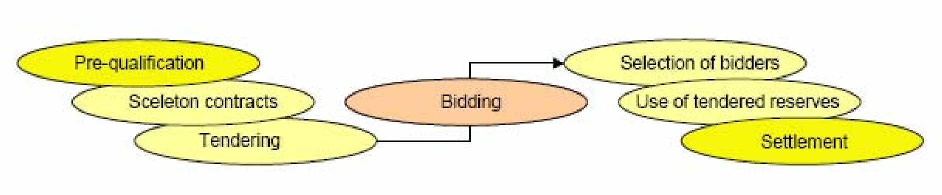

Fig. 1. Schema of the tendering model of RPM

First of all, the supplier should fulfill the pre-qualification criteria, before the first bid skeleton contracts are agreed. Finally, tendering takes place in a secure online portal. In the bidding process the offers are conducted according to the market economy principles. The next step is the selection of bidders. In this step bids are evaluated on commercial and technical criteria. The tendered reserves are used with increasing energy price in order to maintain the balance of the system after the selection of bidders step. Finally, settlement and remuneration take place. For more detailed discussions of the German market for procuring power systems reserve is referred to Swider (2004) and (2006).

1.2. Electricity production and demand

The German electricity production is the biggest in Europe with over 600 TWh (606.5 TWh gross power production) in 2004 (AG Energiebilanzen, 2005). The electricity consumption in Germany has increased about 0.7% between 2003 and 2004. The increase between 1994 and 2004 is about 13% with a minimum and maximum yearly increase of electricity demand between 0.1 and 3.7% (AG Energiebilanzen, 2005). As seen in Fig. 2, the share of electricity consumption in Germany (2004) of industry, households and service sectors are 42%, 28% and 27% respectively.

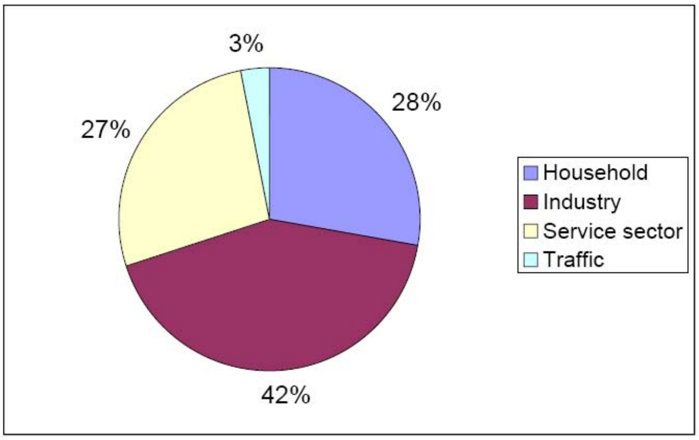

Fig. 2. Share of electricity consumption (2004) in Germany (Source: *AG Energiebilanzen*, 2005)

The distribution of electricity production among different energy sources in 2004 (Fig. 3) shows that nuclear power has the largest proportion (28%) compared to lignite (26%), hard coal (23%) and natural gas (10%). Hydropower and wind as renewable energies are responsible for 4% each of gross electricity production.

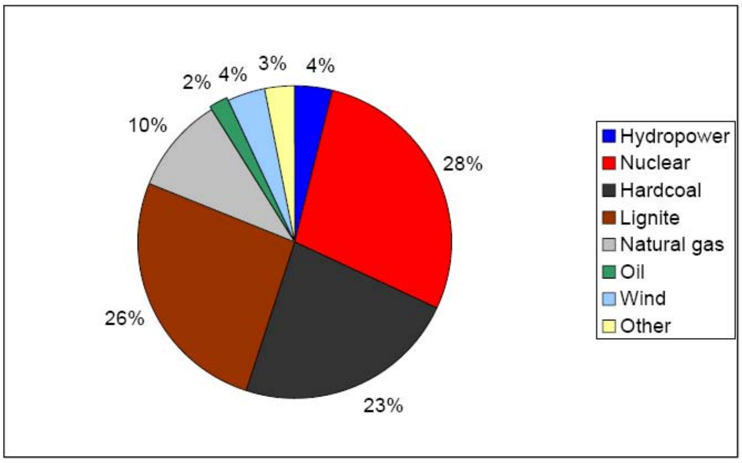

Fig. 3. Share of gross electricity production in Germany according to energy carriers (Source: *AG Energiebilanzen*, 2005)

A share of 60% (67.0 GW) of the total installed capacity for electricity production (111.7 GW) is covered by conventional thermal power plants (Fig. 4). Over 80% of these plants operate with coal (hard coal or lignite), the rest with natural gas or fuel-oil. Nuclear power plants constitute 18.4% of the installed capacity; Hydropower and wind correspond to 19.1%.

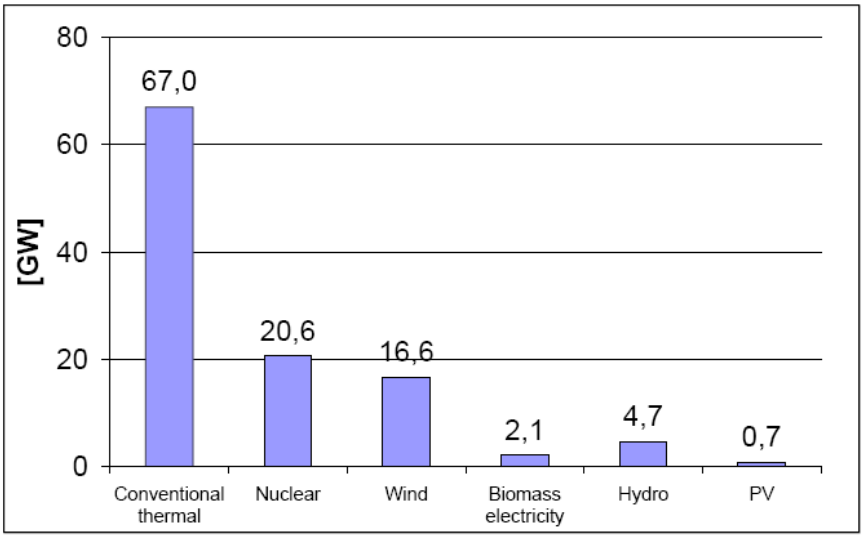

Fig. 4. Installed capacity (in GW) for electricity production in Germany in 2004 *(*Sources*: Verband der Elektrizitätswirtschaft, 2005 and BMU, 2005)*

The distribution of electricity production from renewable energy sources is presented in Fig. 5. The installed wind energy capacity has reached more than 16 GW in Germany in 2004. Electricity generation from wind corresponds to 4.2% (about 25 TWh) of the total electricity demand in Germany in 2004 (BMU, 2005). Electricity generation from hydropower (with 21 TWh/a) represents about 3.5% of the total electricity consumption (Kaltschmitt et al., 2005). The rest of electricity generation (less than 2% of total generation) comes from photovoltaic (PV), biomass, geothermal energy and other sources (BMU, 2005).

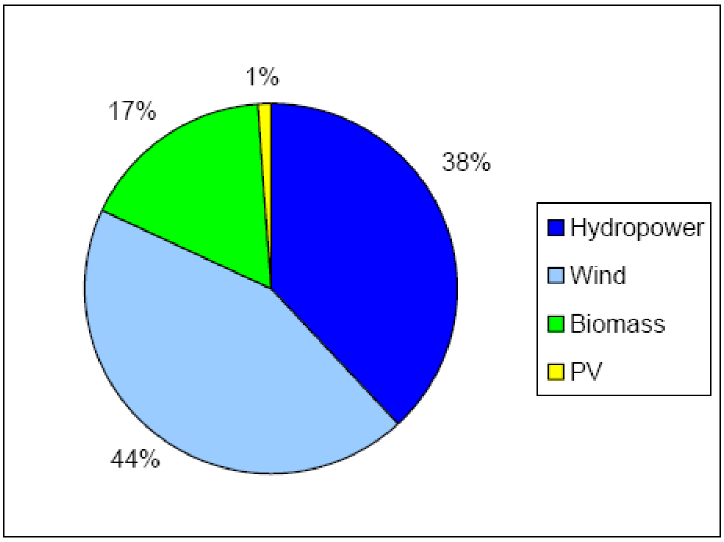

Fig. 5. Share of electricity production with renewable energies *(*Source*: BMU, 2005)*

1.3. Past and expected development of RES-E

The development of installed electrical capacity for renewable energies and the development of renewable electrical energy generation in Germany are shown in figures Fig. 6 and Fig. 7 respectively. Among the renewable energies wind energy provides the highest share of renewable electricity production in 2004. The new trend in wind energy is “repowering”, i.e. the replacement of old wind turbines with new ones with higher capacity and new technology (Fig. 8). The reasons for repowering getting popular are e.g. the depleting sites for wind farm building at land and also the recent technical improvements in the wind turbine technology. Another option for increasing wind electricity generation could be investing in off-shore wind farms which present much higher full load hours and higher wind speeds going along yet with new technical difficulties.

In Germany no off-shore wind farms are in operation at present. However, many projects are in the planning status. DEWI predicts that after 2013 repowering will represent the only market activity for on-shore. After 2016 the investment in off-shore projects will increase significantly. After 2028 the trend also turns to repowering offshore. The peak in yearly installed capacity is expected to be in 2020 with 4.5 GW/a. Hydropower, which was the leading renewable energy source until 2004, is still generating about 3.5% of the total electricity demand. However, 80% of the technical potential of hydropower is already utilized. Thus, it is not expected that the electrical generation capacity of hydropower will increase substantially. It can be seen from Fig. 6 that the total installed capacity of hydropower in the last 15 years has barely altered. The probable reason for the fluctuations in producing electricity from hydropower (Fig. 7) is the different annual precipitation.

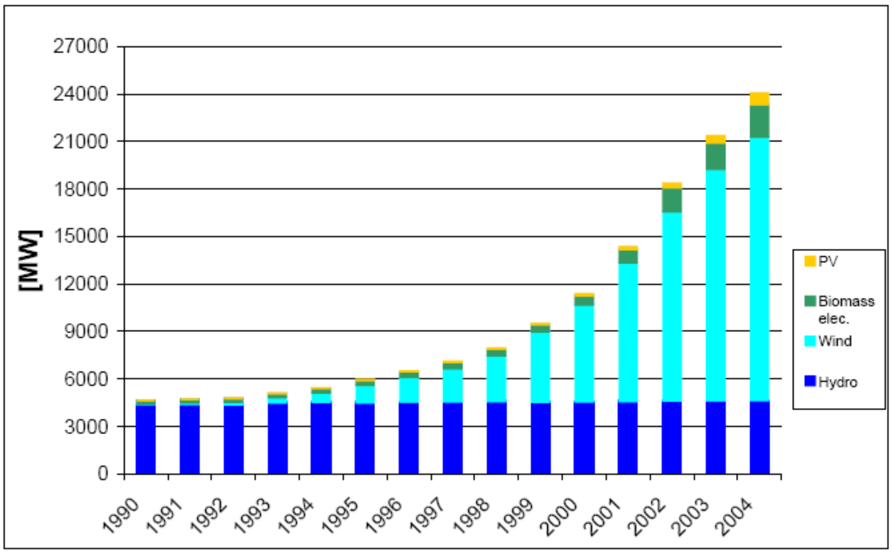

Fig. 6. Installed capacity for electricity production from renewable energies in Germany for 1990-2004 (Source: *BMU, 2005*)

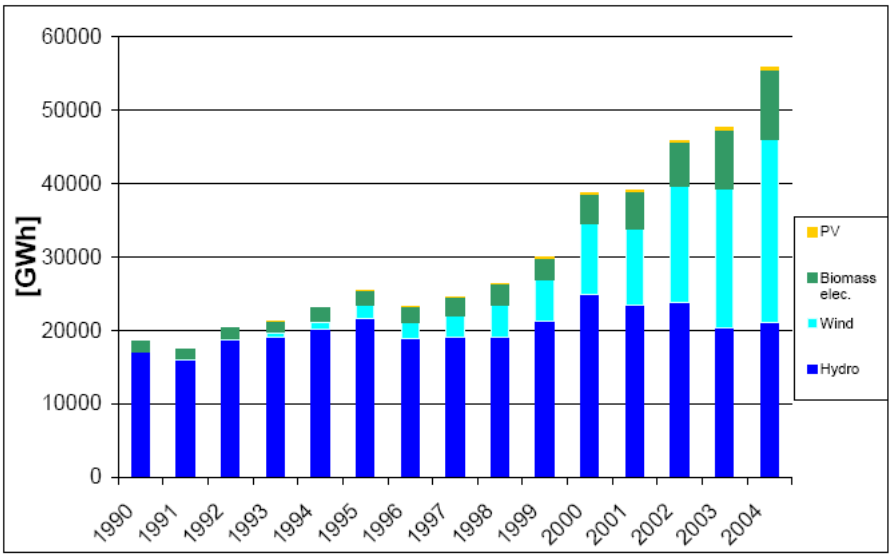

Fig. 7. Electricity production from renewable energies in Germany for 1990-2004 (Source: *BMU, 2005*)

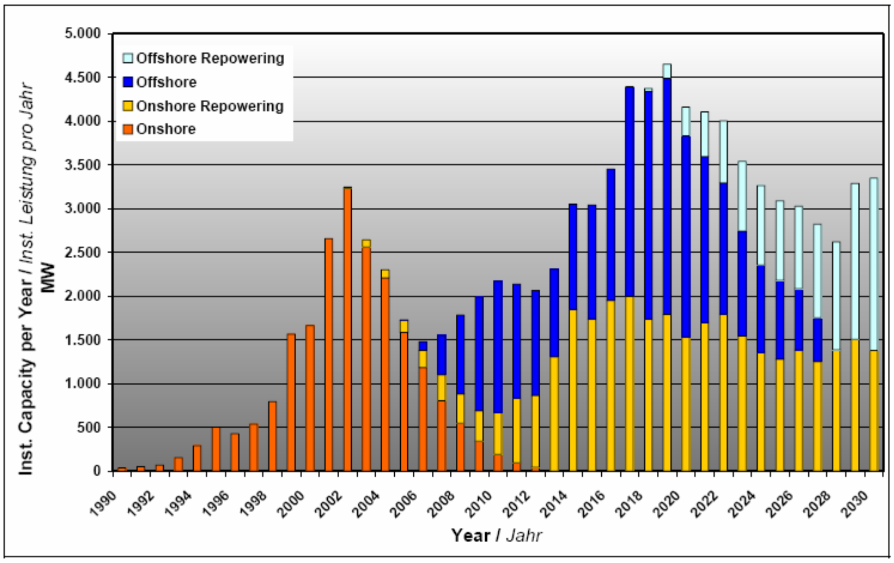

Fig. 8. Development of installed capacity for wind energy converters on- and off-shore and repowering (Source: *DEWI, 2004)*

As another important renewable energy source, biomass plays an increasing role for electricity production with 9.4 TWh/a in 2004, that is 1.6% of the total electricity demand. At present biomass is mainly used for heat production (59.8 TWh/a in 2004) (BMU, 2005).

There are many ways to utilize biomass energy. Firstly, the thermo-chemical path includes carbonization, gasification and pyrolysis. Secondly, the bio-chemical path includes alcohol fermentation, anaerobic digestion and aerobic degradation. Lastly, pressing-extraction and transesterification belong to physical-chemical path. All of these methods (except aerobic degradation) need a combustion phase in order to produce energy. The heat is either used directly or converted to electricity after the combustion. If a cogeneration plant is used then both, heat and electricity is produced which enhances the plant efficiency.

In this study systems that generate electricity are examined only. Direct combustion and biogas production are the two common ways to generate electricity from biomass. Wood is the major fuel for direct combustion. Generally, direct combustion of wood is done without any prior process other than mechanical processes like cutting or pellet production. Energy crops, animal mist and biological wastes are suitable for biogas production. The shares of solid biomass and biogas correspond to 67% and 33% of total biomass electricity production respectively (Fig. 9).

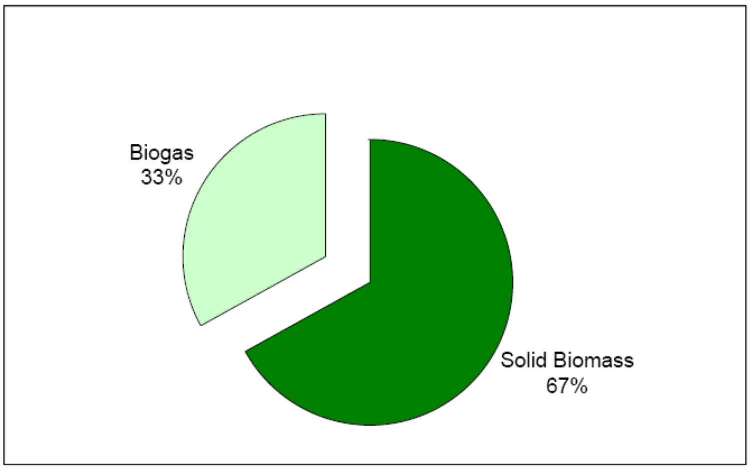

Fig. 9. The shares of solid biomass and biogas of total biomass electricity production in Germany *(*Source*: Scheuermann et al., 2004)*

The increase of installed capacity in 2003 for electrical production from biomass was 17.4% which is higher than for wind energy (13.6%). The potential for bioenergy in Germany in 2050 is expected to be 533.3 TWh/a for a basis scenario and 400 TWh/a for a nature protection scenario (BMU, 2004). This means that still less than 20% of the total theoretical biomass potential is utilized. Therefore, there is a significant opportunity to develop biomass utilization in Germany.

PV, as another source of renewable energy, showed a 73.3% increase in installed capacities in 2003. Although the increase in installed capacity is so high, the level of produced electricity (459 GWh/a) and installed capacity (0.7 GW) in 2004 is very low compared to wind, hydro and biomass electricity production.

Geothermal with 0.4 GWh of yearly electricity production (1 plant in Neustadt-Glewe) in 2004 is almost negligible in the German electricity market. It is not expected that geothermal electrical production will play an important role in Germany in the short run. Thus, at present and at the near future geothermal processes are mainly utilized for heating applications; however, electricity production may increase in the long run.

2. Conditions of RES-E grid integration

2.1. Integration policies

The aim to liberalize the electricity market in Germany was to increase efficiency and competition. However, governmental aid forms the framework for renewable energies with the Renewable Energy Sources Act (Erneuerbare Energien Gesetz, EEG) launched by the German government in April 2000 and renewed in August 2004 (EEG, 2004). One of the goals of the EEG is to achieve a minimum share of renewable electricity production of 12.5% by 2010 and 20.0% by 2020. To achieve this target, a need for regulations to support renewable energy was seen as they are not yet fully competitive against conventional energy sources.

Renewable energies are supported in various ways in Europe such as by feed-in tariffs, tendering, quota obligation, fiscal measures, green pricing and certificates (ETSO, 2003).

The EEG in Germany guarantees fixed tariffs for renewable electricity fed into the grid. Electricity grid operators are obliged to accept renewable electricity on a priority level. Thereby a fixed price for electricity generation from renewable energy sources is set and guaranteed over a certain period of time (in Germany over 20 years). This leads to lower investment risks for the entrepreneurs. The fixed prices in Germany according to the EEG (maximum, minimum and average) are presented in Table 1. There are also tax-exemptions for liquid biofuels and tax-reductions e.g. for cogeneration plants.

Tab. 1. Guaranteed electricity prices according to the EEG (01.08.2004) *(*Source*: BMU, 2005)*

	Hydropower	Biomass	Geothermal	Wind on-shore	Wind off-shore	Solar
Minimum	3,70	3,90	7,16	5,50	6,19	45,70
Average	6,69	10,70	11,08	7,10	7,65	54,05
Maximum	9,67	17,50	15,00	8,70	9,10	62,40

[EURct/kWh]

In general, the network operator who has the best technical and economical connection point to the plant (consequently mostly the nearest connection point) is obliged to purchase the produced EEG-electricity. Except for large wind parks and hydroelectric power plants the electricity is normally fed into distribution networks. The injected EEG-electricity passes from the distribution network operator (DSO) to the transmission network operator (TSO). A clearing concerning the inducted amounts of EEG-electricity takes place between the TSOs, so that each of the four TSO in Germany gets an adequate share from the entire EEG-electricity, that suits to the extend of its respective grid area. Since September 2004 the clearing of wind power is based on an on-line measurement and an extrapolation to determine the active wind power (Zander et al., 2004). Any differences between the expected amount of EEG-electricity and the real inducted amount have to be balanced by the TSO. The resulting costs are transferred to the end costumers. Balancing can be done by short term electricity trades on the spot market or the acquisition of balancing energy. The TSO passes the EEG-electricity in kind of fixed bands to the distributors of the end customer. They are all obligated to use a certain share of EEG-electricity for their delivery of electricity to the end customers. In the whole process the EEG feed-in tariff that is paid to the operator of a plant for the produced electricity, is transferred in each case and in the end is socialized.

2.2. Grid connection and system service requirements

Germany is a member of the Union for the Co-ordination of Transmission of Electricity, UCTE, as with many other EU countries. The primary goal of UCTE is to assure system security. For example, a loss of an element in the system must not cause voltage or frequency fluctuation. Also the power generation plants that operate with renewable energy sources must comply with these regulations. Following the general rules by the UCTE the grid connection and system service requirements in Germany are defined by a distribution code (VDN, 2003a) and a transmission code (VDN, 2003b). These grid codes define general rules by the Association of German Network Operators (Verband der Netzbetreiber, VDN) and are concretised by rules for connecting RES-E (VDN, 2004). These rules form the baseline for the actual grid connection and system service requirements defined by the German distribution system operators (DSO) and transmission system operators (TSO), e. g. EON (2005).

First note that following the liberalization in Germany the use of electricity networks was based on the negotiated third party access regime. This changed due to the new energy act with a newly introduced regulatory authority: the Bundesnetzagentur (EnWG, 2005). Even though the regulator is responsible for the grid connection and system service requirements the rules mentioned before are most likely to retain.

The distribution code defines minimum technical requirements and rules of procedure for access to and use of the distribution (less than 110 kV) networks (VDN, 2003a). The objective is to ensure the technical security and reliability and the technical quality of electric power supply, and the non-discriminatory access to and usage of the distribution systems. However, the DSO has to examine whether the system conditions prevalent at the planned system point of connection are sufficient for operation of the generating unit. Should the system conditions at the system point of connection suffice for operation according to the conditions stated above the DSO submits a verifiable offer as to the network connection scheme. Should the system conditions at the system point of connection not be adequate the DSO furnishes evidence of this inadequacy. In this case, the DSO examines together with the connection holder appropriate modifications, such as network reinforcements, installations for short-circuit current limitation. Generating units connected to the distribution net are usually not utilized for the provision of system services. Therefore, there are no particular requirements placed upon them by the DSO.

The transmission code defines similar minimum technical requirements and rules of procedure for access to and use of the transmission (380/220 kV or 110 kV) networks (VDN, 2003b). One major difference is that generating units connected to the transmission net are usually utilized for the provision of system services. Therefore, there are particular requirements placed upon them by the TSO. Next to others these requirements are on the active power supply (each generating unit must be capable of operation at reduced power output), frequency stability (each generating unit with a nominal capacity greater than 100 MW must be capable of supplying primary control power), reactive power balance (each generating unit must meet specified requirements at the system point of connection), disconnection from the network (each generation unit may, in case of frequency, or shall, in case of stability and system voltage, be disconnected automatically in the event of violation of defined upper or lower limit values) and restoration of supply (each generation unit must be capable of isolated network operation).

In case of RES-E, as defined by the Renewable Energy Sources Act (EEG, 2004), there are deviations from the requirements defined for conventional generation as described above (VDN, 2003b and VDN, 2004). The major reason is that in the case of power injections from RES-E into the network of the TSO operating conditions may occur which can jeopardize system operation. Therefore, upon request of the TSO, it must be possible to reduce the RES-E power supply. This is especially relevant for wind power generation (Erlich and Bachmann, 2005; Erlich et al., 2006). For instance, in exceptional cases the TSO is entitled to perform a temporary restriction of the power output or to cut out the wind farm. Such a restriction of active power will only be performed in extreme grid disturbance situations, so that financial losses are not to be expected (Santjer and Klosse, 2003). Additionally, in the event of network disturbances outside the protection range of the generating unit, the latter must not be disconnected from the network. Wind energy plants are furthermore exempted from the basic requirement of being capable of operation under primary control and the requirement regarding capability of isolated network operation does not need to be satisfied.

2.3. Philosophy of allocating grid integration costs

There are two main approaches to the allocation of grid integration costs: the deep and the shallow costs approach.

In the deep cost approach, the owner of the production plant carries all the costs related to grid integration. In the shallow cost approach, the producer only carries the costs related to the connection i.e. the direct line to connect the plant to the nearest available connection point. Other costs like improvement and upgrading costs are socialized. There are also some hybrid models that attempt to combine both approaches (Hiroux, 2005).

In Germany the shallow cost approach is used. The EEG of 2004 (§13) states that “the plant operator bears the necessary costs of connecting plants which generate electricity based on renewable energy sources, as well as the costs for the appliances necessary to meter incoming and outgoing electricity”. It continues as: “costs for upgrading the grid due to newly connected plants generating electricity from renewable energy sources are borne by the grid operator. He has to present a detailed report on these costs and is allowed to pass them on to the customers when calculating the use of system fees.” Meter, cable and labour are the major cost items in a shallow cost approach where cable and labour costs increase with increasing distance between the plant and available connection point (Knight et al., 2005).

All the case studies found in the literature are based on the shallow cost approach and as the shallow cost approach is in effect in Germany, these case studies are used in this study.

3. Case Study: Wind On-shore

3.1. Description

The total installed wind energy capacity in Germany is currently represented by on-shore wind only, since there are no realized off-shore projects yet. The installed wind capacity was about 16 GW and yearly production was 24 TWh/a in 2004. As indicated before, this is about 4.2% of the electrical energy demand of the country.

With such high installed wind capacities in Germany, nearly all the “good windy” sites are occupied with wind turbines. As a general rule, good wind conditions are in coastal areas, quite in the north of the country. Therefore, the wind farms are mainly concentrated on the coastal areas. As seen in Fig. 8, DEWI predicts that all favorable wind sites are occupied until 2012. After that, in on-shore regions only “repowering” will bring additional installed capacity.

A problem of the high concentration of wind power in the north of Germany is that the produced electricity needs to be distributed and transported to the south as the coastal areas of Germany are not the main electricity demanding areas. This will bring an extra burden on the electricity grid. DENA expects that 850 km of new on-shore transmission line (about 5% of existing) should be built until 2015. The cost for this upgrade of the transmission system is estimated as 1.1 billion €. On the other hand, the investment costs for the off-shore transmission lines are estimated as 5 billion € until 2015 (DENA, 2005).

Furthermore, the alternatives of grid extension, storage extension and the base case without any extension are investigated for Germany for 2020 by Barth et al., 2006. The system operation costs are 107.2, 109.8 and 110.5 Mio. € for grid extension, storage extension and base case respectively. Besides the higher operational costs another disadvantage of the base case is that, as there are some bottlenecks in the system, there might be significant electricity price differences in different regions. Thus, it is reasonable to extend the grid to obtain equal electricity prices and to ensure a stable system (Barth et al., 2006).

Various studies are found in the literature that give cost breakdowns of on-shore wind parks in Germany, cf. Henderson, 2003; Hau, 1996; Neumann et al., 2002; Cler, 2003 (Simonsberg and Paderborn wind parks) and Fichtner-DEWI, 2001. As a case study, a wind park in a “good” coastal area is selected, cf.

Fichtner-DEWI, 2001. The wind park has 45 units of 2 MW turbines forming a total capacity of 90 MW.

3.2. Costs

The full load hours in gross and net production are assumed as 2260 and 2100 hours respectively, cf. Fichtner-DEWI, 2001. All calculations are done in real base for the year 2004. The following distribution of costs is calculated from the available data collected from the source (Fig. 10).

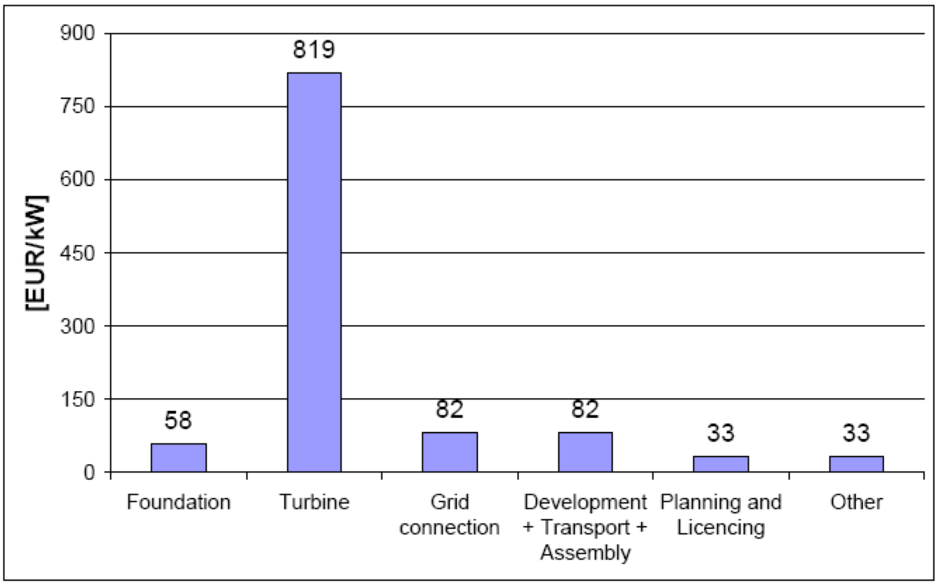

Fig. 10. Specific investment costs (2004) for the on-shore case study in Germany (Sources: *Fichtner-DEWI, 2001 and own calculation*)

The turbine cost constitutes 74% of the total investment cost for the wind park (Fig. 10). This is typical for an on-shore project that turbine cost is the major item. This feature is also evident in Fig 11 where the percentages of the turbine and grid connection costs of the case study are compared with the previously mentioned studies.

As the turbine costs for an on-shore wind park forms the most important cost component, it makes sense to compare the cost of the turbine (818.9 EUR/kW) of the case study with other turbine costs found in the literature (Fig. 12). The selected turbines have different hub heights and have capacities between 1800 kW and 2500 kW, whereas the capacity of the case study is 2000 kW. The case study turbine is closer to the lower band of the price interval. However, it is still in the acceptable range.

The grid integration costs are calculated as 82.2 EUR/kW. Thus, the total specific cost without the grid integration costs will be 1024.3 EUR/kW. The percent of grid integration costs of overall project cost are 7.4%. In other words, the grid integration cost for each turbine in the wind park is 164400 EUR. The specific grid connection costs of the previously mentioned projects are compared with the present case study in Fig. 13.

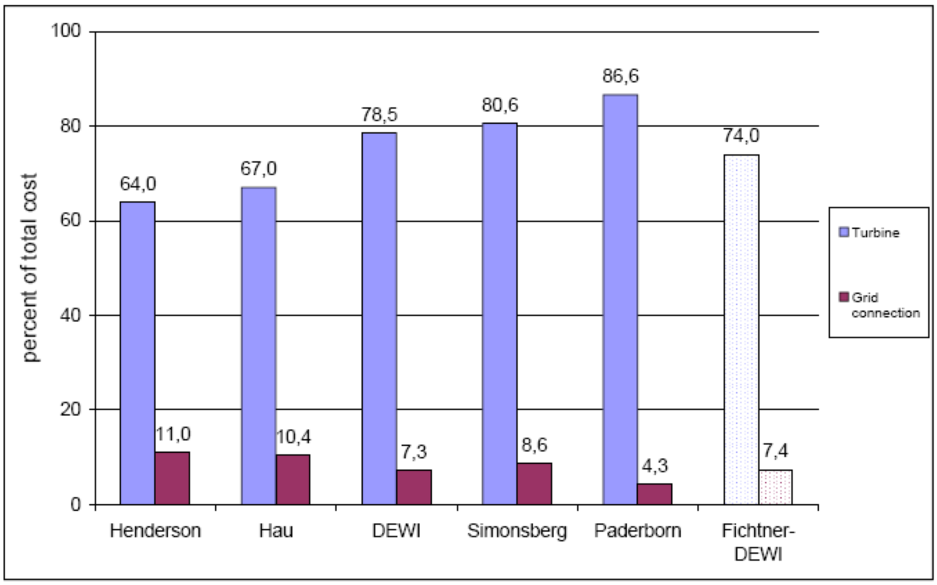

Fig. 11. Comparison of turbine and grid connection costs (in % of total investment costs) for various case studies in Germany on-shore (Sources: *Henderson, 2003; Hau, 1996; Neumann et al., 2002; Cler, 2003 (Simonsberg and Paderborn); Fichtner-DEWI, 2001 and own calculation*)

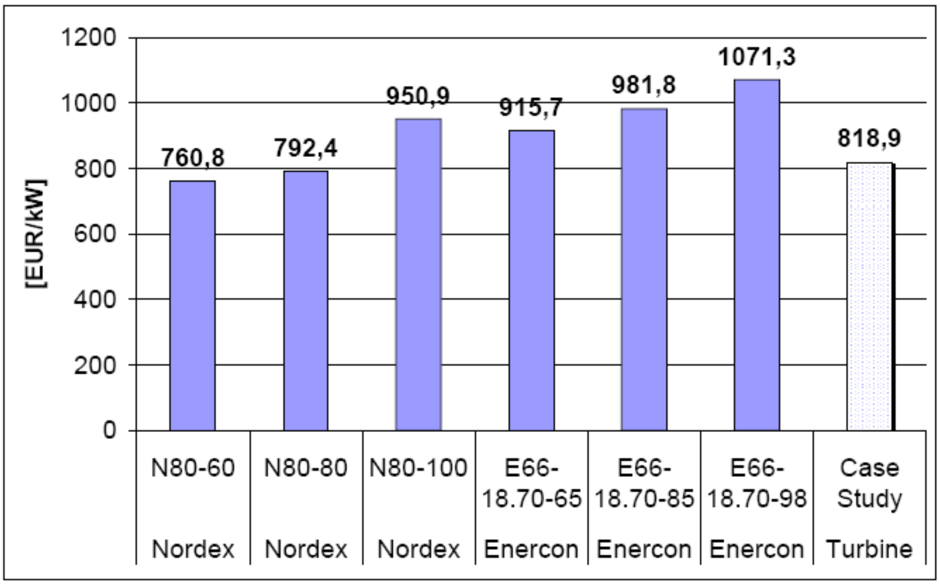

Fig. 12. Comparison of turbine specific costs (2004) for different turbine manufacturers and the case study (Source*: DUWIND et al., 2001)*

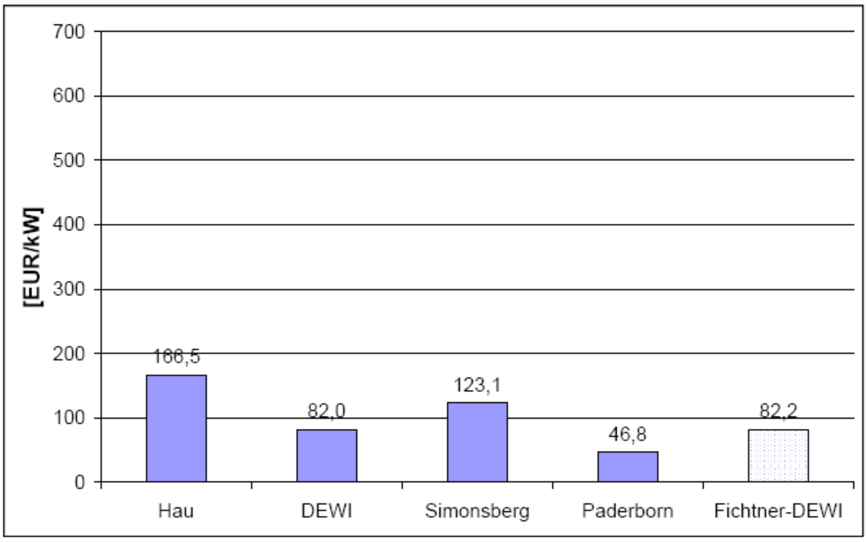

Fig. 13. Specific grid connection investment costs (2004) for on-shore case studies (Sources: *Hau, 1996; Neumann et al., 2002; Cler, 2003; Fichtner-DEWI, 2001 and own calculation*)

The relatively high specific grid connection costs of Hau and Simonsberg are probably due to the fact that these studies are rather old (Hau 1996 and Simonsberg 1993). It is interesting that the low capacity wind park Paderborn (18.2 MW) has lower specific grid connection which may be due to suitable location of the wind farm for grid connection.

The electricity generation costs are presented as a function of full load hours in Fig. 14. As the net full load is assumed as 2100 hours, the production cost lies between 43.1 and 62.7 EUR/MWh. The electricity generation costs without the grid connection costs are in the interval of 39.9 and 58.1 EUR/MWh. Thus, the grid connection costs in this case study constitute 7% of the electricity generation costs. The feed-in tariff for on-shore wind energy is between 55.0 and 87.0 EUR/MWh.

The annuity factor has a significant effect on electricity generation costs. The change of the annuity factor from 0.080 to 0.117 changes the generation costs from 43.1 to 62.7 EUR/MWh which is rather a large interval. For the lower annuity factor the wind park guarantees lower electricity production costs than the feed-in tariff for the entire life time. To guarantee lower generation costs for the highest annuity factor for the entire life time, the full load hours should be at least 2409 i.e. 15% higher than the assumed value.

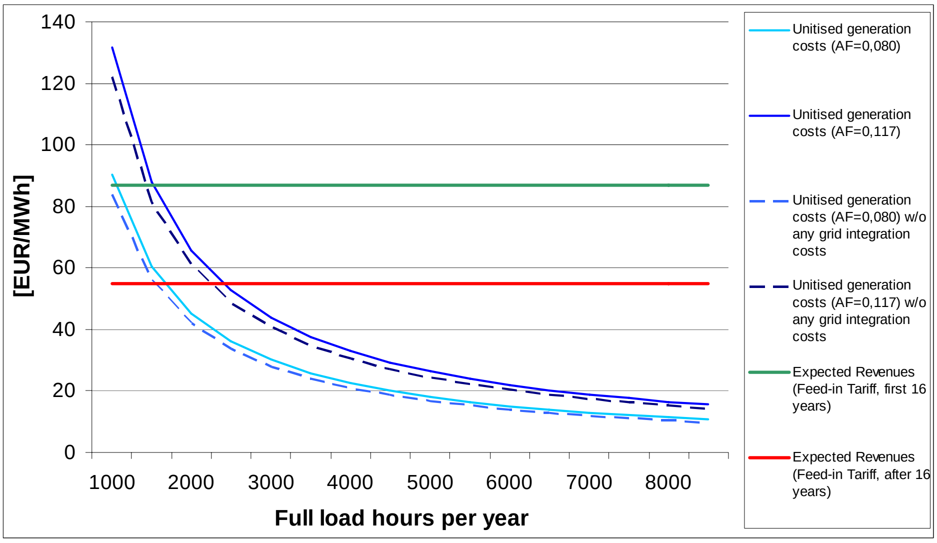

Fig. 14. Electricity production costs (2004) on-shore case study (Source: *Fichtner-DEWI, 2001 and own calculation*) (*AF: Annuity Factor*)

For on-shore wind parks the annuity factor and full load hours play clearly a more important role than the grid integration costs. Higher full load hours are generally achieved in coastal areas in Germany where the wind parks are actually concentrated. However, grid connection costs are not negligible as they constitutes about 7% of the electricity generation costs.

4. Case Study: Wind Off-shore

4.1. Description

As indicated before, there are no off-shore wind parks in Germany that are in operation at present. However, there are many parks that are in the planning phase. As seen from Fig. 8, a rapid growth in off-shore wind energy in Germany is expected until 2020. After that, the trend also turns to “repowering” as in the on-shore case.

There are various studies available in the literature that give cost breakdowns of off-shore wind parks in Germany, cf. Opti-OWECS, 1998, Staiß, 2001; Prüggler, 2005 and Fichtner-DEWI, 2001. Furthermore, there are also detailed studies of off-shore wind park cost breakdown models for other countries like Denmark, UK and Netherlands, cf. Herman, 2003; Opti-OWECS, 1998 and Hartnell et al., 2000.

It is known that the distance to land and the water depth play important roles in off-shore wind park cost calculations. The grid integration costs increase with increasing connection distances. Therefore the analysis is divided into two categories, small and large sized wind parks. This distinction is useful, since the large sized wind parks are generally far-off from the coast and have higher water depths.

As more information is available in the literature for the Baltic Sea, the case studies are selected from that region for both small and large off-shore wind parks. The 90 MW wind park in the Baltic Sea from Fichtner-DEWI report is selected for small off-shore case. The site has 45 units of 2 MW turbines. On the other hand, Kriegers Flak Wind Park (Prüggler, 2005) is taken for the large off-shore case with 350 MW capacity and 84 units (original plan was for 75 units) of wind turbines of 3.5 – 5 MW class. The Kriegers Flak site is located in the Baltic Sea, 110 km away from coast and has a water depth of 20 to 42 meters.

4.2. Costs

The full load hours in gross and net production are assumed to be 3610 and 3160 hours respectively for the small off-shore wind park (Fichtner-DEWI, 2001). Thus, the net load factor corresponds to 36%. For Kriegers Flak, net full load hours are assumed to be 4100 hours which corresponds to a load factor of 47% (Prüggler, 2005). All calculations are done in real base for the year 2004. The following distributions of costs are calculated from the available data collected from the sources for both cases (Fig. 15 and Fig. 16).

Although turbine specific costs are greater in off-shore than in on-shore cases, the percentage of investment costs of the turbine total costs are 47% and 59% (Fig. 15 and Fig. 16) for small and large wind parks respectively which is rather low compared to the on-shore case studies. The reason for the lower percent costs of the turbines is the considerable higher costs in grid connection and foundation for off-shore wind parks. This feature is also seen in Fig. 17 and in Fig. 18, where the percentages of the turbine and grid connection costs of the case study and the previously mentioned studies are separately compared for small and large off-shore cases.

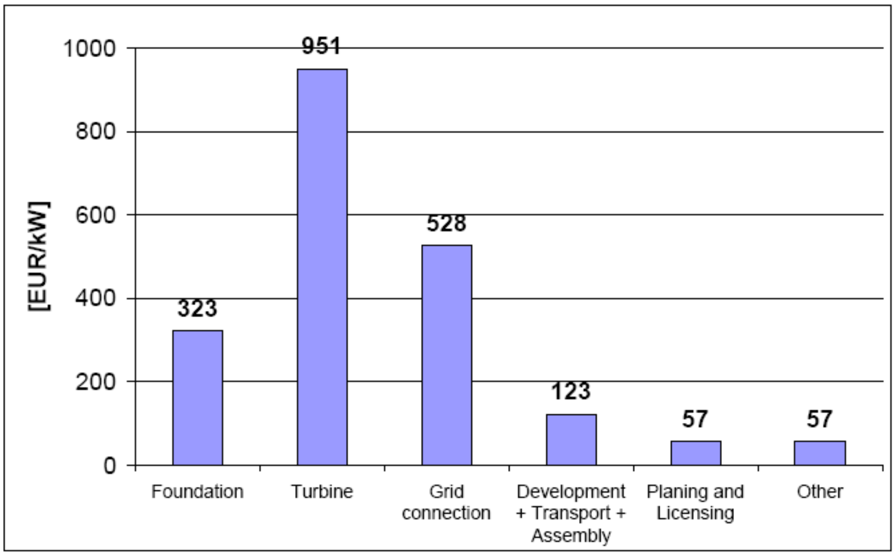

Fig. 15. Specific investment costs (2004) for a 90 MW off-shore case study in the Baltic Sea, Germany (Sources*: Fichtner-DEWI, 2001 and own calculation)*

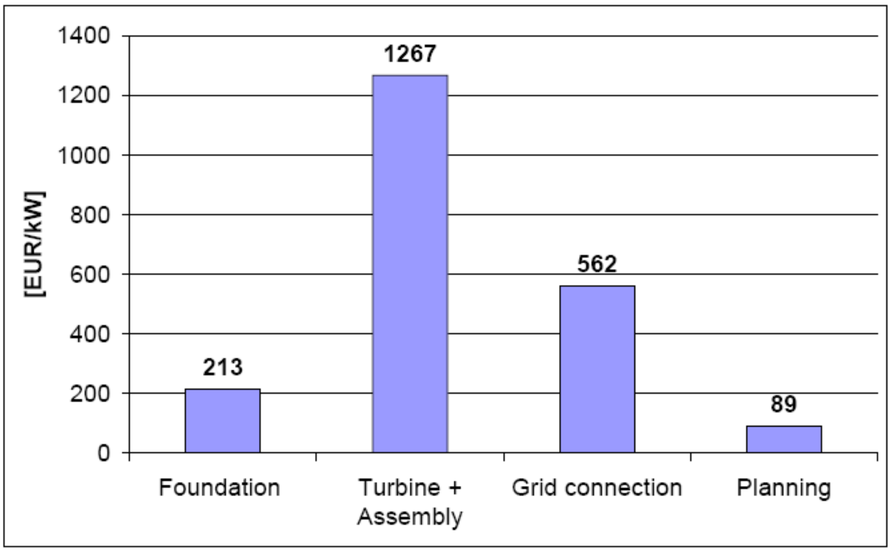

Fig. 16. Specific investment costs (2004) for a 350 MW off-shore case study in the Baltic Sea, Germany *(*Sources*: Prüggler, 2005 and own calculation)*

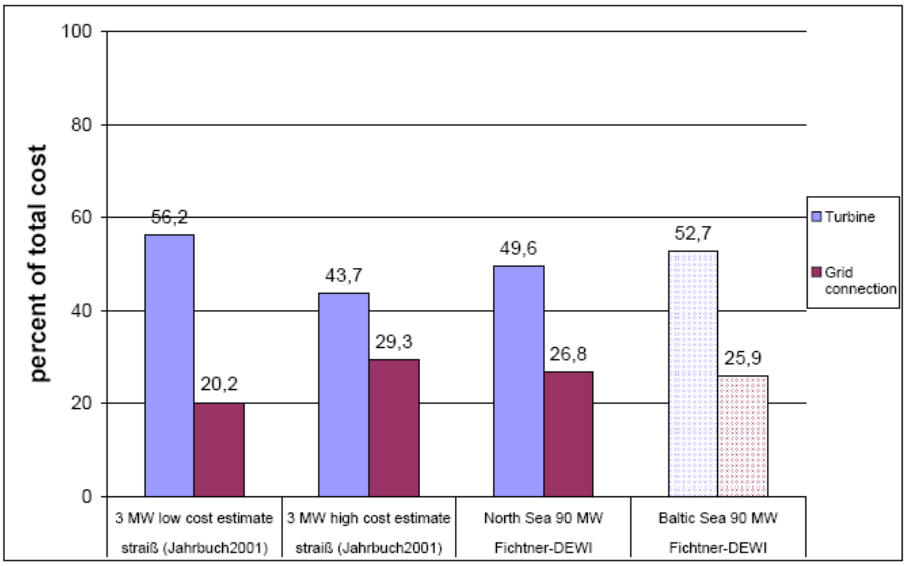

Fig. 17. Comparison of turbine and grid connection costs (in % of total cost) for various “small” off-shore case studies in Germany (Sources: *Staiß, 2001; Fichtner-DEWI, 2001 and own calculation*)

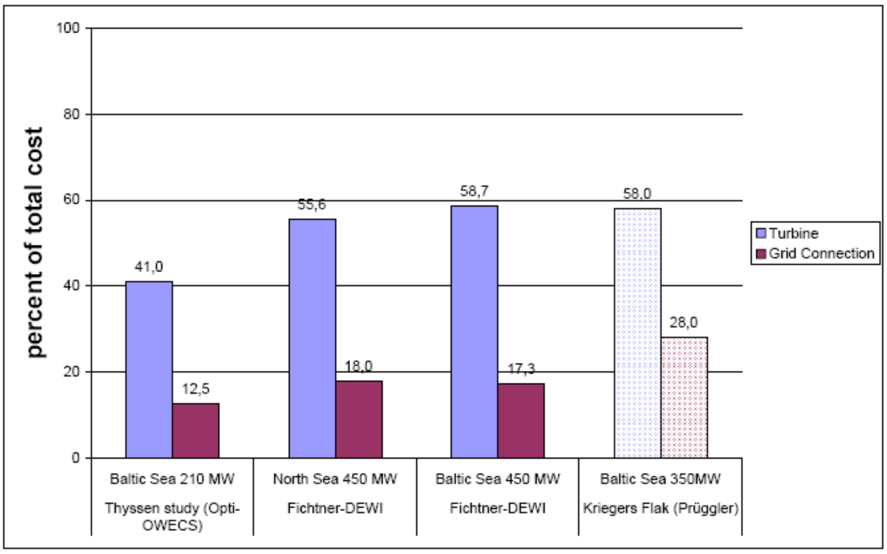

Fig. 18. Comparison of turbine and grid connection percent costs for various “large” off-shore case studies in Germany (Sources: *Opti-OWECS, 1998; Fichtner-DEWI, 2001; Prüggler, 2005 and own calculation*)

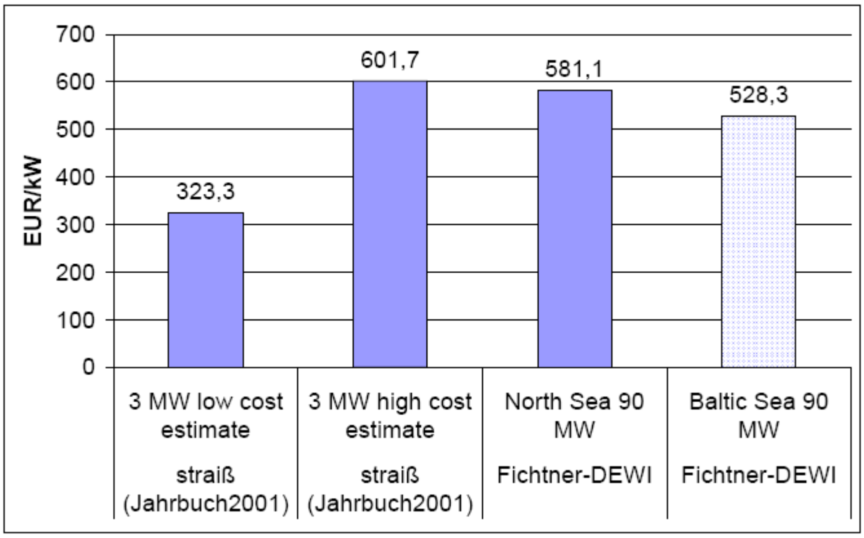

Fig. 19. pecific grid connection costs (2004) for Germany “small” off-shore case studies (Sources: *Staiß, 2001; Fichtner-DEWI, 2001 and own calculation*)

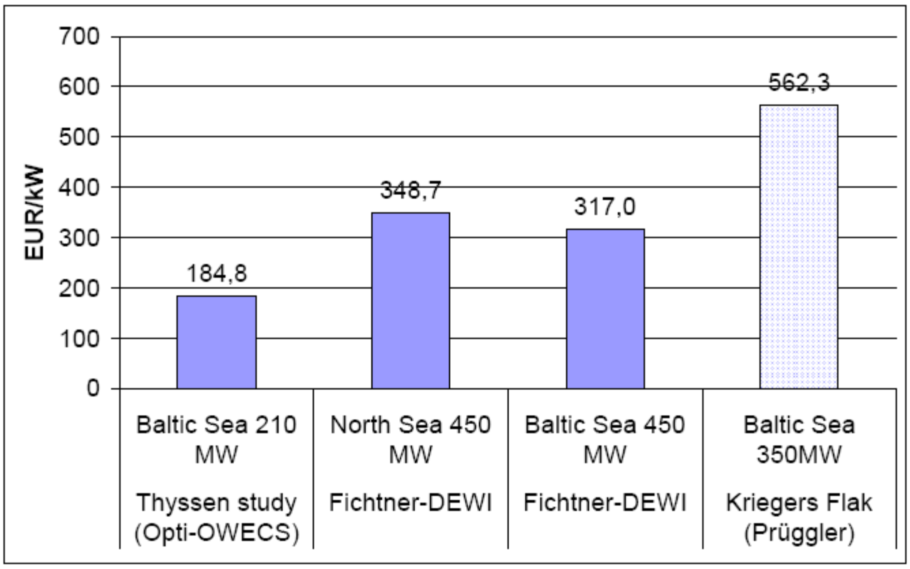

Fig. 20. Specific grid connection costs (2004) for Germany “large” off-shore case studies (Sources: *Opti-OWECS, 1998; Fichtner-DEWI, 2001; Prüggler, 2005 and own calculation*)

The grid connection costs and the specific grid connection costs are lower for the large wind parks, although the transmission line distances to connection points are longer (Fig. 17-20). The specific turbine costs do not change significantly with the size or location of the wind park yet the grid connection costs and foundation costs do. Therefore it could be reasonable to built higher capacity wind parks in order to reduce the specific grid integration costs.

The case study for the small off-shore wind park is representative as both the percent and specific investment costs seem to be acceptable when one compares these values with other case studies (Fig. 17 and Fig. 19).

However, it is interesting to realize that, although the turbine costs of Kriegers Flak case are in well agreement with the other case studies, the specific grid integration costs of Kriegers Flak are more than 1.5 times higher than those other cases. The possible reason for such high grid integration costs may be the relatively long distance to the available connection point (110 km over sea and 11 km on land). A solution for reducing the specific grid integration costs for Kriegers Flak could be building a wind park with even higher capacity than 350 MW.

Another remarkable point in this comparison is that the specific costs of Thyssen study turns out to be very low. Besides the low specific grid integration costs the specific turbine costs are as low as 606 EUR/kW. This price is even lower than the cheapest turbine presented in Fig. 12.

The specific grid integration costs are 528 EUR/kW and 562 EUR/kW for small and large wind parks respectively. These values are more than 6 times of the on-shore case. Such a significant difference is expected, since it is clearly more expensive to install grid connection cables in sea than on land.

The total specific cost without the grid integration costs will be 1512 EUR/kW for small and 1568 for large wind park. Furthermore, the grid integration costs for both cases correspond to 26% of the investment costs. The connection of a single wind turbine costs about 1 Mio. EUR for small and about 2.5 Mio. EUR for a large wind farm.

The electricity generation costs are presented as a function of full load hours in Fig. 21 and Fig. 22. As the net full load is assumed to be 3160 hours, (Fichtner-DEWI, 2001) the production costs lie between 57.2 and 82.1 EUR/MWh for small off-shore wind parks. By the large offshore case with the assumption of 4100 full load hours, the electricity production costs are calculated to be between 64.8 and 84.0 EUR/MWh (cf. Prüggler, 2005). The electricity generation costs without the grid integration costs amounts to the interval of 43.7 to 62.5 EUR/MWh and 53.9 to 68.0 EUR/MWh respectively for small and large offshore cases. The feed-in tariff of wind energy for off-shore wind parks is between 61.9 and 91.0 EUR/MWh.

The grid connection costs constitute to more than 15% of the electricity generation costs in off-shore case studies. It could be even as high as 24% of the generation costs by small off-shore cases. Thus in off-shore cases the grid integration costs have an important effect on the total generation cost. Therefore the grid integration costs should be optimised in order to get the cheapest generation costs especially for off-shore wind parks. They will hence also define if a project is economic or not. Thus the allocation of grid connection cost (generator or grid operator) gets increasingly important.

For small off-shore wind parks the electricity generation cost could be as low as 57.2 EUR/MWh (for annuity factor of 0.08) where it is lower than the feed-in tariff for the entire life time. Even for the highest annuity factor, the electricity generation costs are lower than the feed-in tariff for the first 16 years. To guarantee lower generation costs for the entire life time with the highest annuity factor, the full load hours should be 4208 hours that is 17% higher than the assumed value.

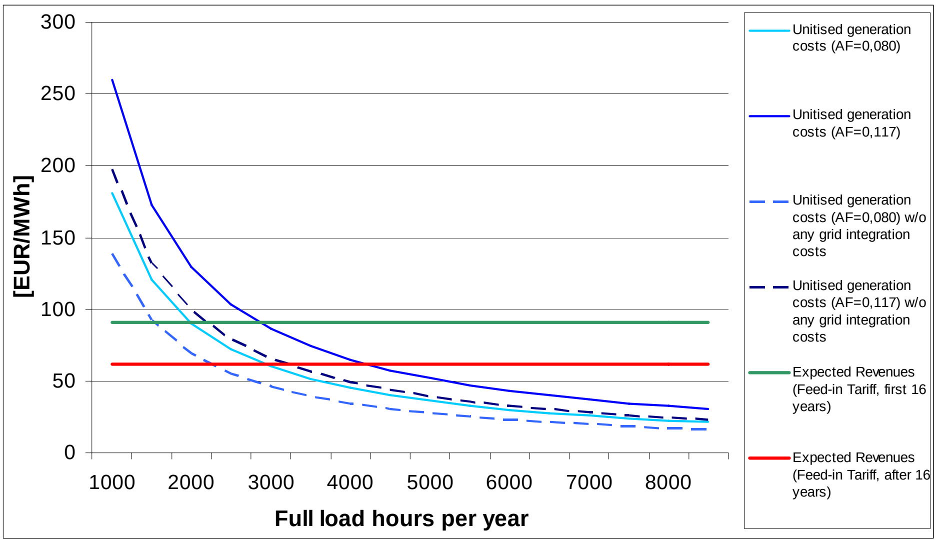

Fig. 21. Electricity generation costs (2004) for 90 MW off-shore case study in Germany Baltic Sea *(*Sources*: Fichtner-DEWI, 2001 and own calculation) (AF: Annuity Factor)*

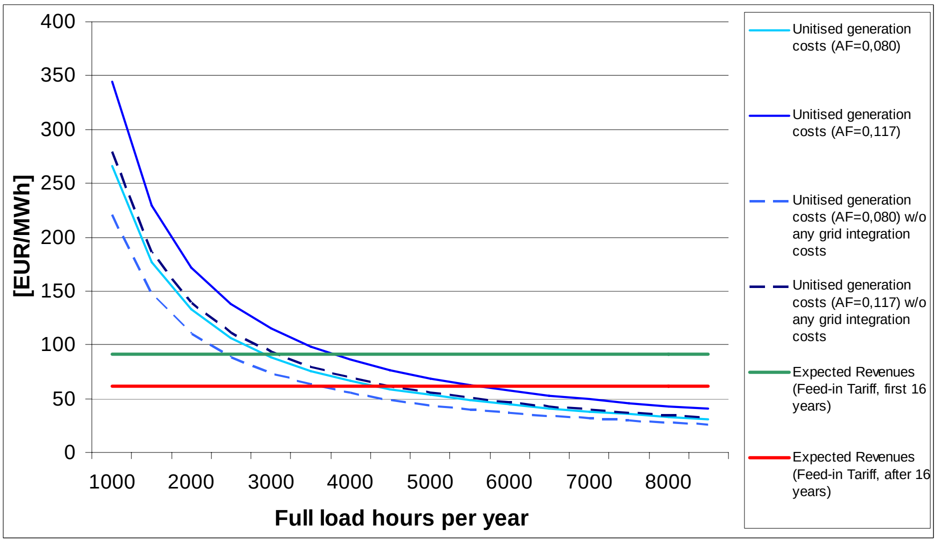

Fig. 22. Electricity generation costs (2004) for Kriegers Flak (Baltic Sea) in Germany *(*Sources*: Prüggler, 2005 and own calculation) (AF: Annuity Factor)*

For large off-shore wind parks the electricity generation cost could be as low as 64.8 EUR/MWh (for annuity factor of 0.08) where it is lower than the feed-in tariff at least for the first 16 years. However, to guarantee lower generation costs than the feed-in tariff after 16 years, the full load hours should be at least 4304 hours. That is 5% higher than the assumed value.

In summary, off-shore wind parks could be economically viable if the following remarks are considered. Firstly, it is important to optimize the grid integration costs since the grid integration constitutes a significant amount of the total investment costs for off-shore wind parks and depend strongly on the wind park location. Secondly, the full load hours have a strong effect on the total electricity generation costs which is also affected by wind park location (Fig. 21 and 22). Thirdly, the total capacity of the wind park should be optimised in order to get lower specific grid integration costs, this again depends on the location. Therefore, the selection of wind park location becomes very important for off-shore wind parks.

5. Case Study: Biogas

5.1. Description

The biogas fund named "Cash Cow II" which is formed by six detached CHPs in Germany (Bayreuth, Hedeper, Holleben, Porep, Salzdahlum and Schrobenhausen) with a total power rating of 2.93 MW (electricity) and 2.57 MW (thermal) is selected as a case study (Aufwind Schmack GmbH, 2005). There are also some other biogas power plants found in the literature in Germany (EE GmbH, 2005; C.A.R.M.E.N., 2003). The electrical and thermal power capacities of the mentioned biogas plants are listed in the Table 2.

Tab. 2. Electrical and thermal power ratings of different biogas plants (Sources*: Aufwind Schmack GmbH, 2005; EE GmbH, 2005; C.A.R.M.E.N., 2003)*

		Pel [kW]	Pth [kW]
	EE GmbH	526	NA
Cash Cow II	Bayreuth	185	223
Cash Cow II	Hedeper	640	247
Cash Cow II	Holleben	640	625
Cash Cow II	Porep	185	223
Cash Cow II	Saludahlum	640	625
Cash Cow II	Schrobenhausen	640	625
Cash Cow II	TOTAL	2930	2568
C.A.R.M.E.N.	Appenfelden	223	337

There are also some solid biomass plants available in the literature (Heinz et al., 2004; Elbe-Ester H. AG, 1998). However, both sources contain insufficient data to perform a detailed analysis. Therefore, the biomass analysis in this paper is restricted only to biogas power plants.

5.2. Costs

The following distributions of investment costs are presented for biogas fund Cash Cow II (Fig. 23).

In the project of “Cash Cow II” the grid and pipeline connection costs have the share of 4.9% of the total investment. There is no data available in this source for the share of electrical grid and pipeline connection separately. Therefore, an assumption for the shares of grid and pipeline connections are made so that the grid connection costs constitutes 2/3 of grid and pipeline connection costs. Thus the grid connection costs are taken as 3.3% of the total investment cost.

The grid connection cost percentage of the case study is compared with the other available sources in the literature (Fig. 24).

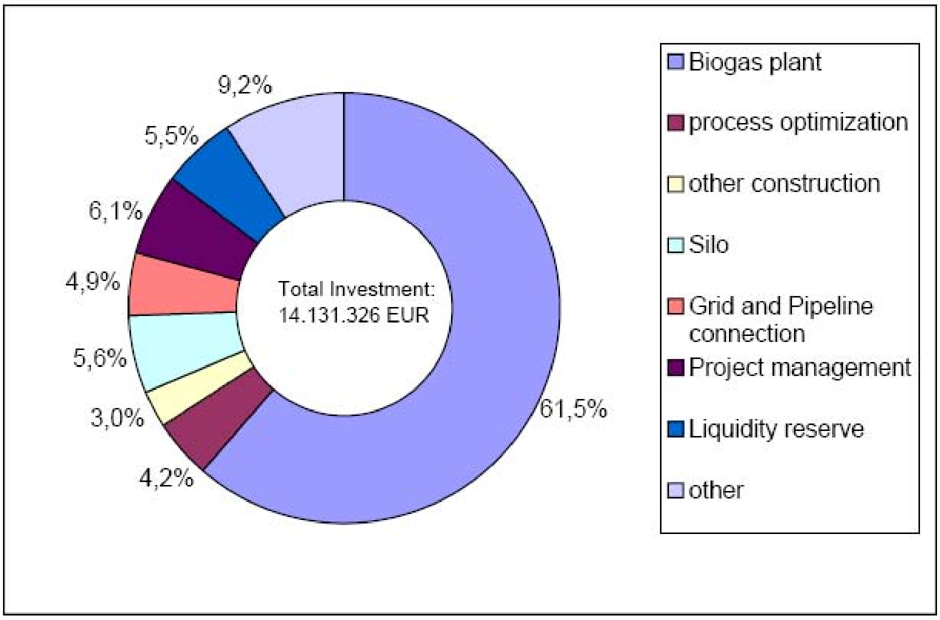

Fig. 23. Investment cost distribution (2004) for Cash Cow II Project (Source*: Aufwind Schmack GmbH, 2005)*

The interval of grid cost percentages of total cost in biogas power plants is between 2.4% and 7.7%. Such a high difference in grid connection costs between Cash Cow II (3.3%) and C.A.R.M.E.N. (7.7%) is interesting, since the capacity of the C.A.R.M.E.N. power plant in Appenfelden is not so different to the individual capacities of Cash Cow II power plants. The total specific investment costs are 2570 and 1434 EUR/kW_{total} respectively. The specific grid integration costs are 235.3 and 415.7 EUR/kW_{el} for Cash Cow II and C.A.R.M.E.N. respectively. Although, the total specific investment costs for C.A.R.M.E.N. are nearly half of those for Cash Cow II, the specific grid integration costs are almost twice as high. One reason for this inconsistency might be that the definition of grid integration costs could be different in these cases. Although the Cash Cow II project clearly defines the grid and pipeline connection costs, what comprises of the connection costs of the C.A.R.M.E.N. Appenfelden power plant has not been clearly specified.

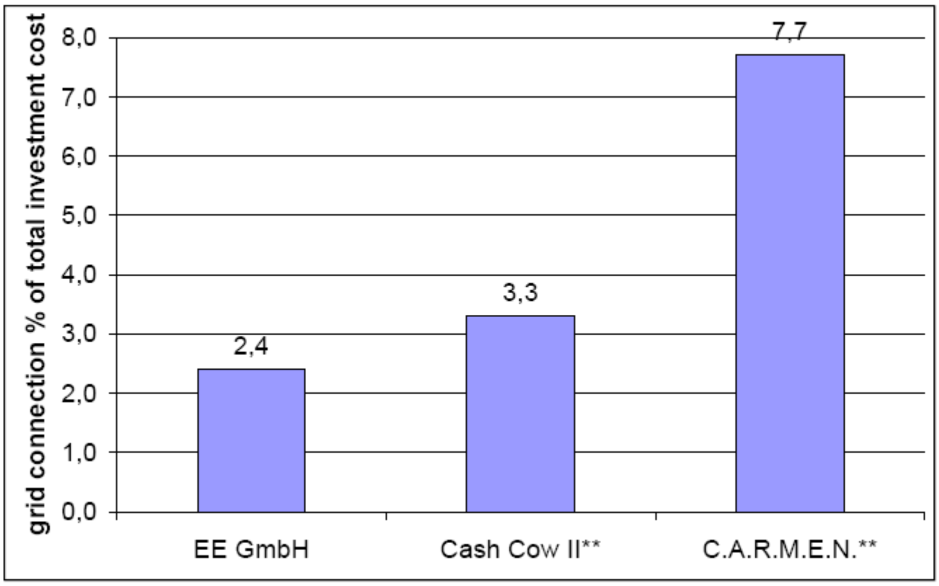

Fig. 24. Grid connection percentages of total investment cost for different biogas power plant case studies (Sources*: Aufwind Schmack GmbH, 2005; EE GmbH, 2005; C.A.R.M.E.N., 2003)* (** assumed that grid connection has 2/3 share of grid and pipeline connection costs for Cash Cow II and C.A.R.M.E.N.)

The electric generation cost for the cogeneration power plant is calculated so that the recoverable heat price is subtracted from the total costs and the remaining cost is allocated to electricity generation. The recoverable heat price is implicitly given in the case study source as 12,1 EUR/MWh_{th}. It could be argued that the heat price is very low since there are some power plants that sell heat at about price of 50 EUR/MWh$_{th}$. However, this difference is due to the availability of customers. In the case study, the main product is the electricity and heat is only a side product that can only be sold at a lower price, which is better than wasting it.

Feed-in tariff for biomass power plants differs according to the capacity of the power plant. A power plant will get 99 EUR/MWh and 89 EUR/MWh for the capacities of 150 to 500 kW and 500 to 5000 kW respectively. Besides, there are also some bonuses that could be added to these values. These are cogeneration, technology and NAWARO bonuses. All of the power plants in Cash Cow II get the cogeneration bonus of 20 EUR/MWh. Except the power plant in Porep, all other plants are eligible for becoming the technology bonus of 20 EUR/MWh. The NAWARO bonus (a bonus for renewable fuels) for energy crops and manure is 60 EUR/MWh and 40 EUR/MWh for capacities 0 to 500kW and 500 to 5000 kW respectively. Four power plant of Cash Cow II have the capacity of 640 kW$_{el}$, whereas the capacity of other two is only 185 kW$_{el}$. The lower values for feed-in tariff are taken for the calculations. Thus, the overall feed-in tariff amounts to 169 EUR/MWh$_{el}$.

The net full load is given as 7.489 hours. The electricity production costs lie between 145.7 and 169.7 EUR/MWh for the Cash Cow II project (Fig. 25). The grid integration costs accounts lower than 2 EUR/MWh, which is lower than 1.5% of the electricity generation costs. The annuity factor and full load hours are playing much important role than grid integration costs. For annuity factor of 0.106 the feed-in tariff is just as high as the generation costs. However, for lower annuity factors the generation costs lie clearly under the feed-in tariff.

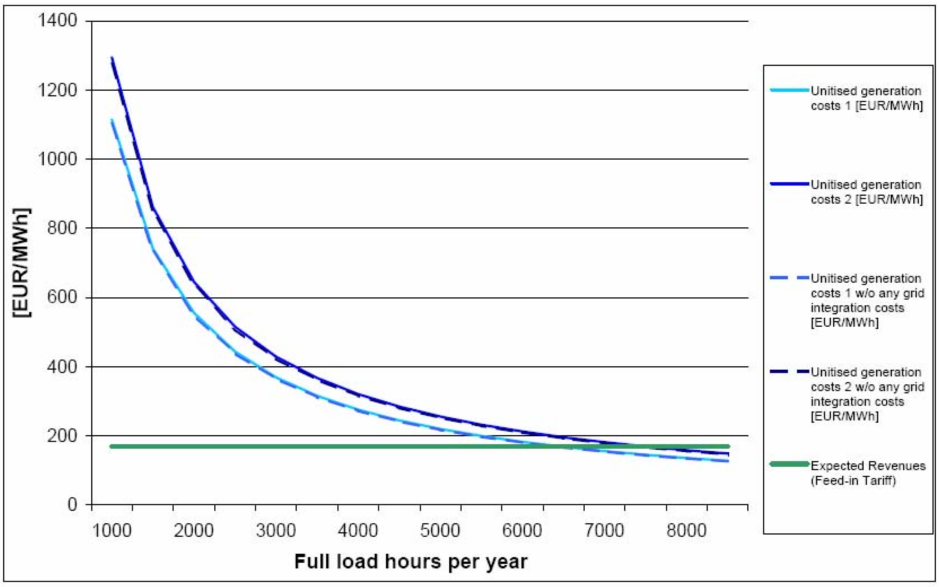

Fig. 25. Electricity generation costs as a function of full load hours for Cash Cow II power plants (biogas CHP) (Sources*: Aufwind Schmack GmbH, 2005; own calculation)*

6. Conclusion

The comparison of several wind parks and biomass power plants showed that the grid integration costs are very critical (15% of generation costs) for off-shore wind parks and are critical (7% of generation costs) for on-shore wind parks. However, in biomass cases the grid integration costs are not that significant since they account only for 1% of the electricity generation costs.

As the grid integration costs are significant in wind park cases, they are also decisive for the feasibility. A reduction in grid integration costs or socialisation of them could make investing in wind parks more attractive. Therefore, it is interesting to make a comparison between different countries and different grid integration cost allocation philosophies.

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DUTCH CASE STUDY

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Abstract. This report focuses in detail on grid connection costs of renewable electricity options (RES-E) in the Netherlands. For four technologies (i.e. wind onshore, wind offshore, solar PV and bio-oil) typical cost ranges are defined, explicitly mentioning the (shallow) costs of electricity grid integration. Also, a general description of the Dutch regulation with respect to grid integration is presented.

Keywords: Grid connection costs, renewable energy, wind, PV, bio-oil

1. Description of electricity system

1.1. The national electricity market

The EU Electricity Market Directive 96/92/EC stipulated that EU member states have to fully liberalise their electricity market by 2007. By then all electricity users should be able to choose their own suppliers, while, at least legal, unbundling of electricity network service providers from generating and/or supply companies should have been implemented. In the Netherlands, all electricity users including small users can choose the supplier of their liking since mid-2004. Furthermore, legal unbundling already exists for quite some time, while complete (ownership) unbundling is expected to be mandatory in the near future.

Access to both the high-voltage grid and the distribution network is regulated on the basis of a regulated Third Party Access (rTPA). Entry to electricity networks should be free and non-discriminatory. A special bureau (Dienst Toezicht en Uitvoering Energie, DTe) has been set-up as the system regulator, which supervises and regulates the implementation of the Dutch Electricity Law of year 1998. DTe is a specific chamber within the Dutch competition authority. DTe is also in charge of supervising the tariffs set by the supplying companies in selling electricity to the captive consumers. A price-cap system has been implemented in order to regulate the transmission system operator (TSO), Tennet, and the distribution system operators (DSOs). DTe has the authority to set the price levels of the network tariffs for the transmission and distribution of electricity.

Currently, Tennet owns the extra high voltage network (150 kV+), while the high voltage (HV), middle voltage (MV) and low voltage (LV) grids (>150 kV and < 0.4 kV) are owned and managed by distribution firms. It is proposed that the high voltage distribution networks (110 kV +) will be transferred to Tennet. In the Netherlands, legal unbundling of distribution networks has been implemented for some years already. Legislation is in a far stage of political adoption to implement complete (ownership) unbundling. In the Netherlands, DSOs are largely owned by municipalities and provincial administrations. They hold a license to serve a specified control area as a regulated "natural" monopolist. During the last decades many mergers among DSOs have taken place. At present (mid-2006) still 10 DSOs are active in the Netherlands. There are large differences regarding the size of these utilities.

Mergers in the generation and supply sector have resulted in a more concentrated industrial structure. At present 4 generating companies owning centralized power plants are active, while three supply companies (Essent, Nuon, and ENECO) cover the lion's share of the retail power market.

1.2. Electricity production and demand

The electricity production in the Netherlands amounted to 100 TWh in the year 2004 (99.8 TWh gross power production, 106.5 TWh electricity consumption). The electricity consumption in the Netherlands has increased with 0.9% between 2003 and 2004 (EnergieNed, 2005). In the Netherlands a very high share of CHP is installed. As shows the table below this share amounts to 30% of the gross production.

Tab. 1. Types of power production in the Netherlands, 2004 (*EnergieNed*, 2005)

	TWh	
Centralised power production	64.9	65%
Cogeneration	29.7	30%
Export	5.2	5%
Total	99.8	100%

Of this power production, almost 60% is generated from natural gas (31 TWh in central power plants and 30 TWh in CHP plants) . Around 26%

originates from coal (26 TWh) and 4% from the only nuclear plant in the Netherlands (400 MW, 3.6 TWh). The remaining share of around 10% is generated from oil and refinery products or other energy carriers (including renewable sources) (data based on annual reports).

Especially the high share of electricity production from natural gas is remarkable compared to other European countries: of all EU-25 states only Luxembourg has a higher contribution. The main reason for this is the availability of important natural gas resources in the Netherlands.

At the end of the year 2004, the total installed capacity of wind power amounted to 1073 MW, a growth of 18% with respect to the capacity in 2003. The electricity production from wind power was 1.9 TWh in the year 2004, which is 1.75% of the electricity consumption. Other important contributors to the renewable power in the Netherlands are co-firing of biomass in coal-fired steam plants (1.5 TWh) and the contribution of municipal solid waste (1.9 TWh, in which the biogenous fraction only has been counted). Small contributions are from hydropower (37 MW and 0.1 TWh) and PV (49 MWp and 0.03 TWh) (CBS, 2005). An overview of the shares of renewable electricity options is presented in the table below: biomass (mainly co-firing in coal plants (52% in 2004) and municipal solid waste (31% in 2004)) and wind power are the main technologies.

Tab. 2. Shares of renewable electricity generation sources in the year 2004 (Source: CBS, 2005)

Wind	38%
Hydropower	2%
Biomass	60%
PV	1%

1.3. Past and expected development of RES-E

The historic development of installed capacities (MW) of renewable electricity sources and the development of electricity generation (GWh) in the Netherlands is shown in the figures below. In the following paragraphs, the specific technologies are discussed in more detail (CBS 2005; van Sambeek 2003).

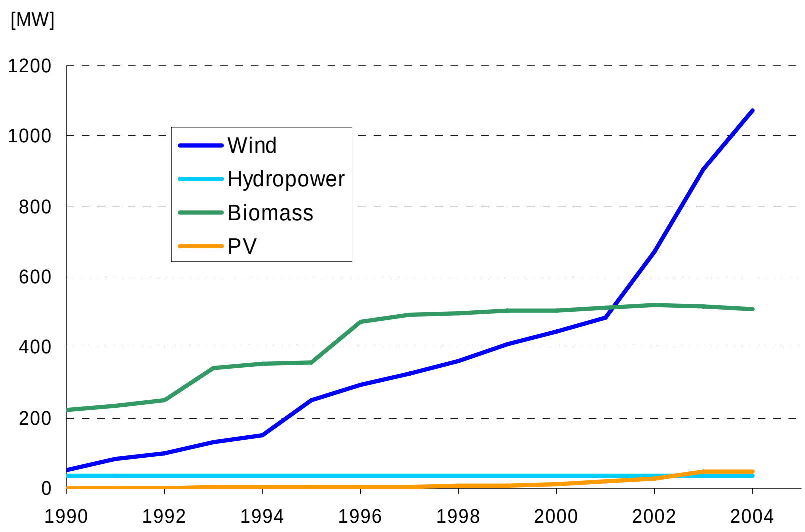

Fig. 1. Installed capacity 1990 – 2004 [MW] for renewable electricity production in the Netherlands excluding imports (Source: *CBS, 2005*)

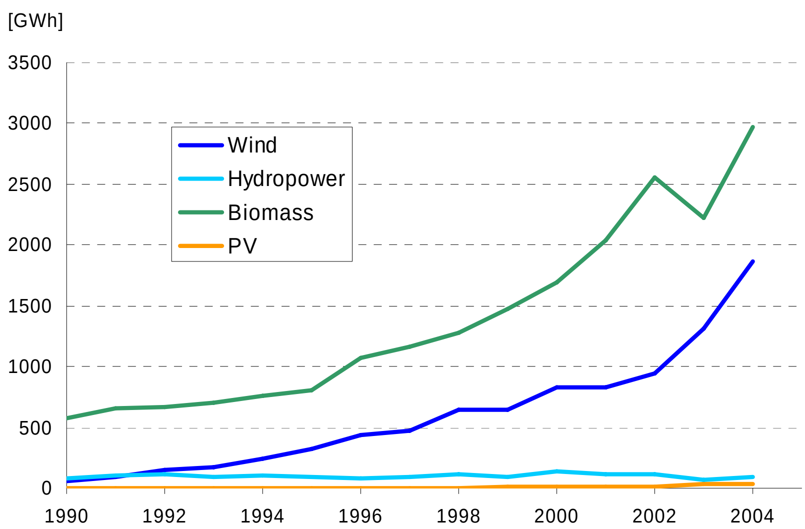

Fig. 2. Electricity production 1990 – 2004 [GWh] from renewable sources in the Netherlands excluding imports (Source: *CBS, 2005*)

Wind power

Beginning in the year 2002, a trend in growth of installed capacity can be observed. Whereas in the period 1995 – 2001 the average annual growth rate is 12%, in the period 2001 – 2004 this rate increases to 30% per year. This increase can be partly attributed to the success of the feed-in premium (MEP), which came into operation in the year 2003. In a covenant that provinces have set up a target of 1500 MW in the year 2010 onshore wind power has been defined. With the current win d power developments in the Netherlands this target seems to be largely met. All data in the graph refer to onshore wind power, although a few wind turbines have been installed in shallow lakes also (19 MW in total). In addition, two offshore wind parks have been planned, of which the first park is currently in the construction phase (NSW park, Egmond aan Zee, 108 MW).

Hydropower

The contribution of hydropower in the Netherlands is relatively low and constant. The installed capacity is 37 MW, which yields an average annual electricity production of 100 GWh. The potential for further developing hydropower is very limited, given the fact that the Netherlands is a country which is very flat: the only hydropower regime possible is the run-of-river type, which is only economically viable at very specific sites of which the number is very limited (possibly two sites could be exploited for MW-size power generation, and a few others for kW-size turbines).

Biomass

This category comprises several types of biomass technologies: co-firing in large coal plants (52% in 2004), municipal solid waste (31% in 2004), small-scale technologies and digestion technologies. The decrease in the year 2003 is caused by the share of co-firing, and is related to changes in support mechanisms on one hand, but to technical problems and environmental permits on the other.

Solar PV

For solar PV an important success factor has been the subsidy scheme (EPR), which ended in the year 2003. In the period 2000 – 2003 the average annual growth was 50%. After the termination of the support scheme, the growth rate was significantly reduced. The installed capacity by the end of 2004 is 49 MW, in which the contribution of grid-connected PV is 90%.

1.4. Future scenarios

For the future development of the Dutch electricity sector reference is made to a report in which a projection is described of energy use, greenhouse gas emissions and air pollution up to the year 2020: (van Dril 2005). The projection is based on assumptions regarding economic, structural, technological and policy developments. Two scenarios have been used: Strong Europe (SE), which is characterized by moderate economic growth and strong public responsibility, and the Global Economy (GE) scenario, which assumes high economic growth and has a strong orientation towards private responsibility.

The projection describes a continuing growth of energy consumption in both scenarios and a declining energy intensity in the GE-scenario. Energy prices for end users are expected to rise, due to increased imports of natural gas and rising costs of electricity generation. The share of renewables in electricity consumption increases considerably due to subsidies for offshore wind and biomass, up to the Dutch target of 9% in 2010.

In the SE scenario the final electricity demand continues to grow in the coming years, to over 122 TWh in 2010 and just under 139 TWh in 2020. Average growth in SE is about 1.5% up to 2010, after which it falls to 1.3% a year. In GE growth is higher, rising to just under 130 TWh and over 157 TWh in 2010 and 2020 respectively, the growth rate in GE is thus 2.1% up to 2010, after which it falls to an average of 2.0% a year. This is shown in the figure below.

Electricity production

The electricity industry consists of central production units, large-scale district heating systems and industrial companies with CHP systems, and other distributed generation. This other capacity includes smaller CHP systems, waste combustion plants and small-scale renewable sources (wind and hydro power etc.). The Netherlands has a large amount of distributed generating capacity, in particular CHP.

Figure 3 shows the proportions of various electricity generation and importation options for the 2000 – 2020 period. At present power is supplied mainly by CHP, coal and gas-fired power plants and imports. Output from coal-fired plants rises to over 30 TWh in 2010 and 2015 (including co-combustion of biomass), thus continuing the rising trend of the past three years.

In the GE scenario (see Figure 3) output from coal-fired plants continues to increase after 2015 as a result of the building of new coal-fired plants during the 2016-2020 period and the oldest coal-fired plants remaining on stream until after 2020. The Borssele nuclear power plant maintains the high output of the last five years, about 3.7 TWh (IAEA 2004).

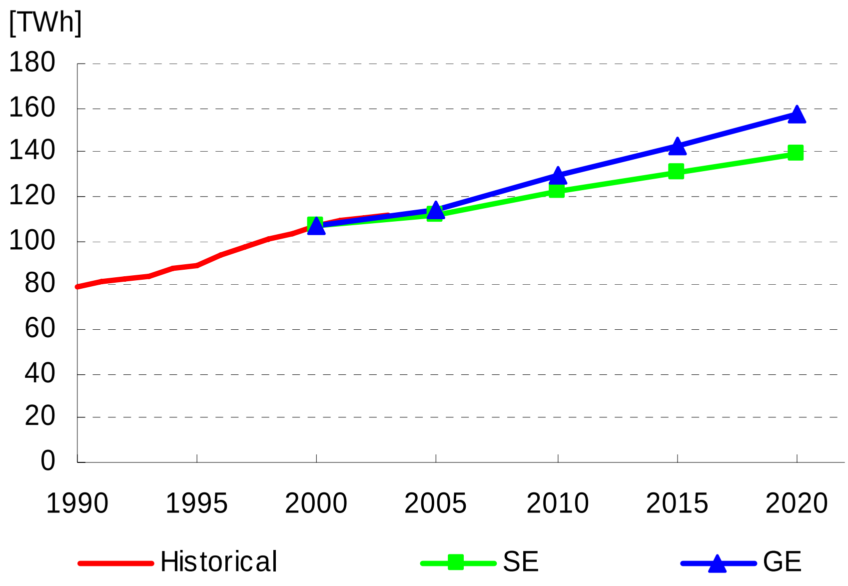

Fig. 3. Total final electricity consumption (history and projection) [TWh]

In the SE scenario the nuclear plant closes after 2013; in GE it remains on stream until after 2020. Imports account for about 15 TWh in 2010, i.e. slightly less than in the 2000 – 2003 period. After that, they fall again to about 6 TWh in 2020 in the SE scenario and 3 TWh in the GE scenario. The share of power from renewable domestic sources increases substantially in both the SE and the GE scenario, from 3.3% in 2003 to about 10% in 2010 in both scenarios; the respective figures for 2020 are 17% (SE) and 24% (GE).

CHP capacity comprises industrial CHP, large-scale district heating and heat distribution units and small-scale CHP, e.g. in horticulture and health service. The total gas-fired CHP capacity in 2003 was 7600 MWe, which generated a total of over 37 TWh of electricity. In industry the chemical industry is by far the largest CHP sector, with just under 2500 MWe. The projected growth of CHP electricity over the 2000-2020 period is about +40%, the largest growth taking place in the chemical industry.

Renewable electricity sources

Based on assumptions regarding the potential for development, cost trends and policies, conclusions are drawn on the expected proportions of national energy consumption and electricity production accounted for by renewable energy under the two scenarios, SE and GE. By comparing the expected

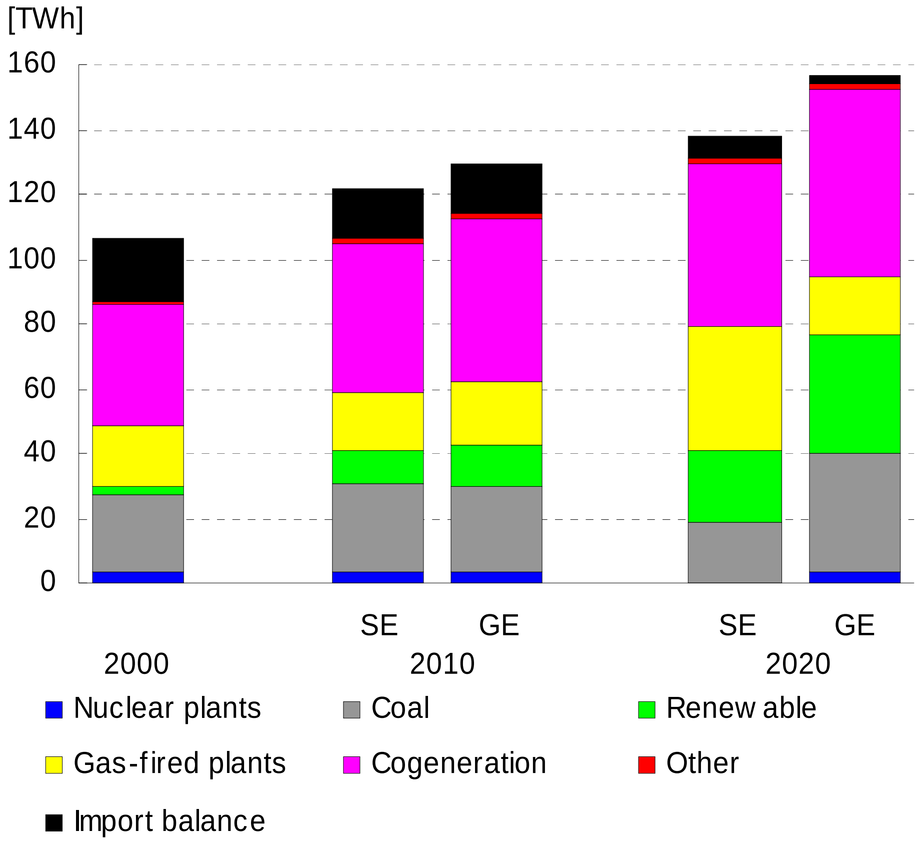

Fig. 4. Net electricity production divided in method of generation, SE and GE scenarios

contribution of renewable energy with total national consumption the proportion of renewable energy is found. The results of this exercise indicates that, according to (van Dril 2005), the 2010 renewable electricity target of 9% is likely to be met. Based on the electricity consumption in the two scenarios, the shares of electricity consumption accounted for by renewably generated electricity in 2020 would be 24% in GE and 16% in SE. This is shown in graphical form in the figure below.

In (van Dril 2005) it is considered that the amount of onshore wind power increases to 2000 MW in 2020 in the SE-scenario, compared to 3000 MW in the GE scenario. Also the offshore wind power growth pattern is expected to increase, but a this point the report has been updated due to new insights. Namely, the capacity of 6000 MW that is reported in the 2005 report in the meantime is not considered politically and financially feasible. A yet unpublished ECN report estimates the 2020 offshore wind penetration to be at maximum 2200 MW.

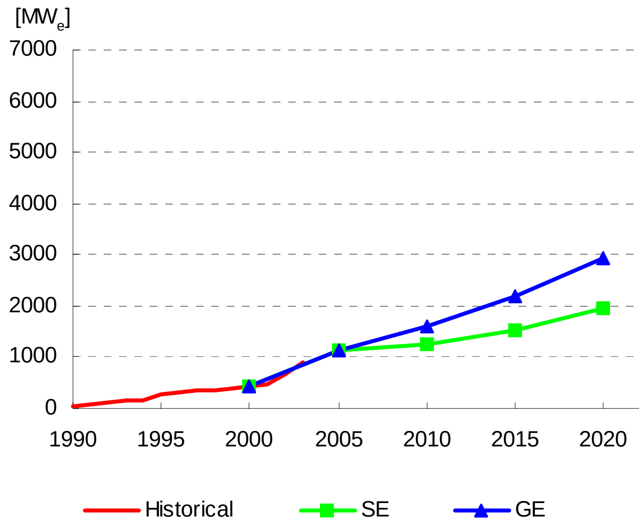

Fig. 5. The projected capacity of onshore wind for the two scenarios

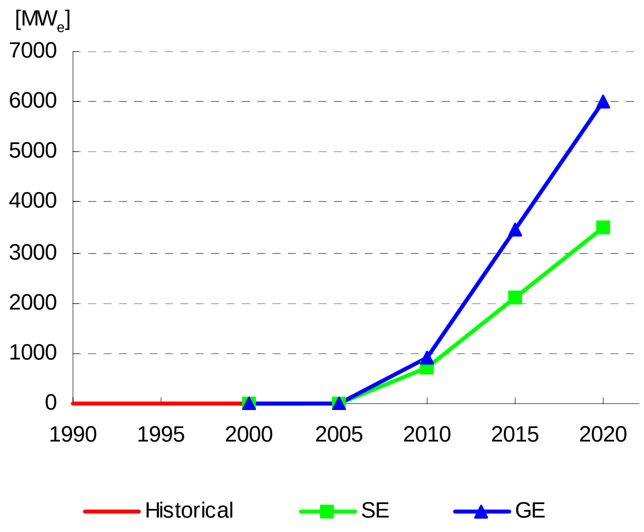

Fig. 6. The projected capacity of onshore wind for the two scenarios. Important: the depicted capacity of 6000 MW currently (mid 2006) is not considered politically and financially feasible anymore. A yet unpublished ECN report estimates the 2020 offshore wind penetration to be at maximum 2200 MW.

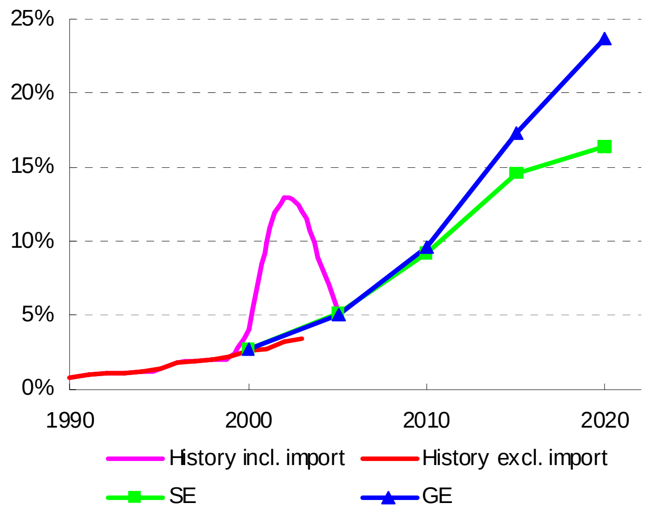

Fig. 7. Shares of the production of renewable energy in final inland electricity consumption

2. Conditions of RES-E grid integration

2.1. Integration policies

As it stands, conditions for RES-E grid integration in the Netherlands are governed by:

- An obligation upon transmission and distribution companies to connect RES-E generators, subject to meeting certain technical and environmental conditions. The technical conditions are specified by the Network Code, the Measurement Code and the System Code specifying the conditions alluded to in Article 31 (paragraphs 1a, 1b, and 1c respectively) of the 1998 Electricity Law. The environmental conditions for obtaining a production permit are determined by procedures specified by the Environmental Management Act (Wet Milieubeheer). Furthermore, siting of most types of generating plants has to comply with spatial planning procedures. In the Netherlands, the competent authority to enforce compliance with the Environmental Management Act and spatial planning procedures are municipal and provincial administrations. Consultation procedures before a licensing decision is reached can be quite time-consuming for certain types of RES-E plants, e.g. typically some 5 years for an on-shore wind park.

Technical grid connection issues will be explained in more detail in section 10.2 below.

- An obligation for generators with 2 MW or larger sized plants to submit at least one day ahead of real time[1] generation plans and to settle balancing energy with a possibility to make adjustments, subject to approval of Tennet, one hour before real time. They can submit their programme either directly with the national TSO, Tennet, (for larger generators who are balance responsible parties themselves) or indirectly with the DSO in whose grid the RES-E generator feeds in his produce or with other aggregators with balance responsibility (for smaller generators).
- Conversely, the Amsterdam-based APX power exchange runs an electronic trading platform for spot wholesale trading with a gate closure time of 24 hours (day-ahead trading). The significant entry barriers and the large gate closure time of the APX discriminate against small RES-E and intermittent RES-E generators.
- A technology-specific “green” electricity market stimulation premium (“MEP” premium) for each MWh fed into the grid by eligible plants[2]. The MEP premiums are set ex ante by the government. In principle, rates are to be based on the projected cost gap of RES-E electricity, compared to the market price of conventional electricity. For most RES-E technologies, the premium is set for a period of 10 years from operational start onward. The premiums for non-intermittent generation technologies tend to allow for incremental balancing cost.[3] To receive the applicable MEP premium, the RES-E generator needs to submit “electronic copies” of Guarantees of Origin (GOs). These are issued by CertiQ, a certification subsidiary of TSO Tennet. Current MEP rates are depicted in Table 3.
- In principle, the RES-E generator can sell his GOs to electricity suppliers who need these for disclosure in compliance with the amended Electricity Market Directive (Directive 2003/54/EC). In the Netherlands, suppliers of “green” electricity have to prove the electricity generation attributes of electricity sold as “green” electricity by way of electronic RE-GOs

[1] Stated more precisely: at least one hour before the start of a balancing mechanism time unit. In the Netherlands, the balancing market is operated with time units of 15 minutes.

[2] Note, that in August 2006 the MEP policy measure has unexpectedly been withdrawn for new projects because the electricity target of 9% was expected to be met (Ministry of Economy, 2006). At the time of writing this report, the continuation of the MEP policy is still unsure.

[3] This is a significant, oft overlooked factor accounting for the tendency for support mechanisms in e.g. the Netherlands and the UK to provide more support on a €/MWh basis than in Germany, where all balancing costs are socialized and passed on the end-user tariffs.

(renewable electricity guarantees of origin). RE-GOs are tracked by a national electronic platform, run by CertiQ. In practice, RE-GOs are mostly transferred by renewable generators to the buyer of his output as part of "bundled" electricity sales contract. As, in practice, typically the MEP premiums are commercially quite attractive, the commercial value of RE-GOs tends to be almost negligible. At present, the commodity price plus the MEP premium broadly covers - at least - fully all generating costs of MEP-eligible electricity. This makes the initial owner of RE-GOs less adamant on commanding a "green" rent premium, whereas from a competition perspective suppliers of green electricity can ill-afford to procure green electricity on the wholesale market at a premium of any significance (exceeding, say, €0.30/MWh). In the current Dutch green electricity market, any green electricity supplier starting to pass on a green premium to their small-scale clients (households) is poised to be faced with a large number defections of green electricity clients to competitor-suppliers.

In the Netherlands, renewable electricity market stimulation policies have been frequently revised over the last six years. Since 2003, the feed-in premium instrument has been the mainstay of renewable electricity market stimulation and, subsequently, discounts on the "REB" energy tax granted to consumers of electricity from renewable generators have been gradually phased out completely. Currently, one other significant RES-E stimulation instrument is in place, i.e. the EIA, a tax credit instrument on investments in eligible generating plants. Since September 2005, certain limits have been put to the eligibility of offshore wind generators and biomass co-firing for feed-in premiums. New measures are considered to curtail the total MEP premium amount to be paid to potential generators wishing to use "too" popular RES-E technologies, that risk to prematurely deplete the available annual MEP fund.[4]

[4] In contrast with e.g. Germany, where system operators are mandated to pass on the cost of grid integration of RES-E in a complicated cost equalisation procedure, in the Netherlands the ex ante projected total annual MEP premium transfers are being financed by an annual MEP fund. The MEP fund is replenished by an annually set fixed surcharge on the electricity bill of each end-user connection. In 2005, the annual surcharge per connection amounted to €58. Evidently, the latter funding approach risks to yield financing problems if MEP-eligible RES-E generation exceeds projections.

Tab. 3. MEP feed-in premium. Data are for the period July 2006 – December 2007 (Source: Enerq, 2006). See also footnote 2.

Technology	MEP feed-in premium (EUR/MWh)
Solar PV, hydropower, tidal, wave, power from clean biomass with a capacity smaller than 50 MWe	97
Wind onshore	65 for new onshore wind 8 for repowering
Wind offshore	97 (but set to 0 to control offshore wind penetration)
Power from bio-oil with a capacity smaller than 50 MWe	60
Power from biomass (not clean) with a capacity smaller than 50 MWe	25
Power from biomass: sewage sludge	0
Landfill gas	13

2.2. Grid connection and system service requirements

The 1998 Electricity Law stipulates *inter alia* that:

- A user of the electricity grid has the right to be connected at the nearest point in the network, be it that a user with a connection of 10 MVA or higher will be connected at the nearest point in the network "where capacity is available" (Art. 27d)
- A user has the right to receipt of a remuneration from the DSO, if at his connection another connection is made on behalf of a third party (Art. 27b)
- Network adaptations associated with new connections should be borne by the DSO concerned (Art. 27e)
- A person wishing a connection up to 10 MVA is entitled to a standard connection (Art. 27f).

Furthermore:

- The TSO and the DSOs have to submit annual proposals for regulation by the DTe of maximum tariffs they charge: electricity transport tariff, tariff for balancing and auxiliary services, tariff for metering of small-scale electricity users with a connection not exceeding 3*80 A (Art. 27 (1))

- The transport tariff relates to consumption of electricity or feeding in of electricity by a network client, irrespective of the location of the network connection (Art. 29 (1)).

The *Network Code* prescribes the rules of conduct between network operators and users in network operations, including the implementation of new connections. It stipulates *inter alia* that connected entities with a contracted and available capacity in excess of 60 MW are required to tender for making available capacity for the next day that the TSO can ramp up or down (generators) or reduce (electricity consumers). Connected parties with a capacity up to 60 MW can tender on a voluntary basis. (Network Code, Art. 5.1.1.1)

The *Measurement Code* specifies the rules of conduct regarding measuring electricity transport volumes and exchange of such measurement data.

The *System Code* stipulates the rules of conduct for network operators regarding the provision of ancillary services.

2.3. Philosophy of allocating grid integration costs

The Dutch Tariff code (Tarievencode 2005) defines tariffs in accordance with Article 36 of the 1998 Electricity Law. The document specifies the elements in the tariff calculation for connecting producers and consumers to the grid and for the transport of electricity.

Transmission and distribution costs

The T&D tariff covers the transmission dependent and independent costs incurred by the network operators. Article 3.2.2 of the Tariff code outlines the costs of the specific issues covered by the T&D tariff. Many are considered in the determination of the x-factor, i.e. the operational expenditures and the capital expenditures.

The transmission-dependent costs includes:

- depreciation charges of the grid infrastructure;
- a reasonable return on the capital;
- the costs of construction and maintenance the grid infrastructure;
- the costs of grid losses, resolving transmission constraints and maintaining the voltage and reactive power balance;
- the cascade costs of grids operating at higher voltage level;
- the operating costs relating to the above;

The transmission independent costs include the costs of meter reading and data management for the benefit of parties having a connection.

Consumers have to pay for the rest of the transmission dependent costs in the EHV and HV grid levels plus the total of the costs in the lower voltage levels, including grid losses. This favours distributed generation, as this type of generation is connected to middle and lower voltage levels grid. In other words, they do not have to pay for any transmission dependent costs.

The cascade principle allocates the transmission dependent costs from higher grid levels to lower grid levels in proportion to the lower voltage grid's share in the total take of energy and/or capacity from the higher voltage grid. Tariffs are transaction based, i.e. based on the invoiced electricity.

Until mid-2004, producers that have connections at EHV and HV grid levels have to pay the National Uniform Producer Tariff (LUP), which accounts for the 25 percent of the sum of the total transmission dependent costs of these grids. As their counterparts in neighbouring countries did not appear to contribute to HV transmission costs, this cost allocation principle has been abolished to shore up the competitiveness of Dutch large generators.

The Network Code allows DSOs to pass through benefits from distributed generation such as reduction of net losses and net investments, nevertheless in practice hardly any DSO used this provision. This gave rise to complaints from various interest groups defending the position of distributed resources (mainly co-generation), such as industries, greenhouse horticulture and energy distribution companies. Prompted by these complaints, DTe organised a round table with DSOs and generators to look for an acceptable compensating mechanism for avoided net losses and net investments. As a result, a provision was brought forward (DTe, 2005b), which indicated that distributed generators connected to the medium voltage (MV) and low voltage (LV) systems, should receive compensation for reducing net losses. The provision has a temporary basis and currently boils down to some 0.37 €/MWh. for every kWh dispatched into the LV and MV grids.

Connection costs

Connection tariffs in the Netherlands depend on the type of connection. Connections until 10 MVA are shallow, regulated and averaged. Shallow is referred to connections charges that only pay for capital and maintenance costs of the connection itself but are not charged directly for other costs incurred by the network operators. In other words, possible adjustments, reinforcements and upgrades beyond the point of connection, which are necessary to facilitate the integration of the generator into the grid, are not paid by the users connecting to the grid. These indirect costs of grid adjustments are passed on to consumers through the use of the system tariff or absorbed by the distribution companies if they are not allowed by regulator DTe to pass these on to the end-users. Furthermore, connection charges are set by the regulator and are not individually calculated but cover a different number of connection profiles.

All users, producers and consumers, pay for the *connection cost* to the grid up the nearest point of connection subject to meeting specified technical requirements. Moreover, connections with a capacity of 10 MVA or higher will only be connected “where capacity is available”. Hence, for larger connections grid operators have more discretion in accepting or refusing a connection application.

Costs the network companies have to incur beyond the connection point, such as network upgrading, have to be borne by themselves. These costs are passed on to end users, to the extent allowed for by the regulator DTe.

Connections larger than 10 MVA are negotiated and deep. Deep is referred to connection charges that cover all costs raised by connecting to the grid. They included the direct costs of connecting to the grid and all indirect costs raised inside the grid. Charges are determined through negotiation processes between users and the DSOs.

Article 2.2 of the Tariff Code outlines the costs covered by the connection tariff, which can be broken down in two components:

- The initial investment costs;
- Maintenance costs.

Deep connection costs can pose a significant barrier to DG projects. As a result, and considering that connection costs discriminate between their size, big DG projects try to keep their connections profiles small enough to fall under the first tariffs. In other words, when connecting to the grid, big DG projects may realise a higher number of small ‘shallow’ connections instead of one big ‘deep’ connection.

Network clients have to accept the cost calculation by the grid operator for network connection. However, some cases exist of technical services companies offering grid connection of onshore wind farms at lower costs than the offering of the DSOs concerned. The DSOs concerned have unsuccessfully tried to legally stop such third party services.

Other costs

Consumers have to pay a yearly commission as well for the *costs of provision of energy balancing and auxiliary services* under responsibility of mainly Tennet and less so DSOs. The most important system service, energy balancing, is delivered by a balancing market organised by Tennet. Large generators and electricity supply companies are balance responsible parties, who directly participate in this market. In principle, RES-E generators can also participate directly or indirectly by using the services of an aggregator. Yet the incumbent large producers have an asymmetric information advantage, as Tennet makes public information on the average market price per balancing market time unit (15 minutes in the Netherlands) with one day delay. Incumbents have a rough insight in the real time market clearing price, as they tend to make bids for each generating plant they own and notice real time which of their plants are called by tennet to ramp up or down. Independent RES-E generators with only one generating facility cannot determine real time in which interval the market clearing price is moving.

System services such as the costs incurred in operating the balancing market are charged in the form of a system tariff. Article 4.2 of the Tariff Code describes the issues covered by the system tariff:

- Costs of reserve and regulating power;
- Costs of black-start facilities;
- Costs connected to the monitoring and maintenance of the robustness function of the 380/220 kVgrid;
- The costs of other duties and activities for the benefit of the system management;
- Internal operating costs in so far as these can be attributed to the system operator of the manager of the national high voltage network.

Reactive power problems are currently not common in the Netherlands, nevertheless Article 3.9 of the Tariff Code includes a reactive energy transmission tariff, part of the transmission dependent tariff. The article outlines the costs covered by this tariff and states that two tariff-categories are applied to the reactive energy for consumers:

- Consumers connected to a voltage level of 1 MV and higher;
- Consumers connected to a voltage level of less than 1 MV.

DSOs in the Netherlands have no incentives to solve the reactive energy problem in the most efficient way, either by optimising their reactive demand on the transmission system or by paying distributed generators to produce or absorb reactive power. In other words, the correct signals are not given to value the services distributed resources can provide.

Tariff setting

Currently connection and transport tariffs are subject to benchmarking exercises without due allowance for integration of distributed generation, comparing cost levels and cost evolutions with other DSOs. Hence, DSOs with less penetration of RES-E generators seem to have a financial advantage in this respect as broadly speaking increased distributed generation has a cost-raising impact on network costs mainly because of the need to reinforce the grid.

2.4. Definitions of grid connection costs

In Section 3 to 6 case studies will be documented on technology parameters for four RES-E technologies in the Netherlands: wind onshore, wind offshore, solar-PV and biomass. The current section elaborates on the definition of grid connection costs, on the method applied for the literature research and on the manner of reporting.

Definitions for grid connection costs

In the GreenNet EU27 project the aim is to compare grid connection costs for several RES-E technologies. It is important to be clear on the definitions used and the system boundaries that have been considered.

As indicated in Figure 7, the case studies in this report distinguish between three cost categories for describing the cost parameters of the RES-E technologies:

1. Technology costs excluding grid connection costs
2. Shallow grid connection costs
3. Deep grid connection costs

Note, that all three categories can have costs related to investments (expenses that occur only once in a project, mostly at the start) and costs that have an annual character (O&M, fees, fuel costs). The three cost categories are described below, taking the case of onshore wind as an example.

Fig. 8. *Cost categories relevant in the case-studies*

Starting with the investment costs excluding grid connection costs, for most components it is clear that they aren't part of the grid connection costs: fundament, tower, nacelle and rotor belong to the investment costs. Not so trivial however is the attribution of electric equipment that is used for realising the grid connection: usually, electric power control and power quality are dealt with by components in the turbine. Nevertheless, in the current report all equipment that is purchased with the wind turbine is considered to be part of the technology costs. This also includes the cable from the turbine to a central point of common coupling at the wind park site: that cable is considered to belong to the turnkey delivery of the turbines.

The point of common coupling however is treated as a component of grid connection costs. All costs related to this central connection point are considered as shallow grid connection costs, including the cables from the point of common coupling to the connection point in the existing grid (thus including any transformers, road or river crossings). These shallow connection costs are influenced strongly by the distance to the nearest grid connection point: for this reason a wide cost range can be found. Other factors determining the cost are the type of connection (AC versus DC, etc.) and the maximum power to be transported. The shallow costs will receive most attention in the case studies, since this component is commonly reported on.

Finally, all expenses in the existing grid related to the connection of the new wind power are considered deep grid connection costs. Especially for the case of wind power, being intermittent by nature, grid reinforcement can have an important financial impact. Note, that depending on the regulatory framework in a country, these costs can be allocated to the RES-E operator or it can be socialised in network charges. The deep connection costs are seldom subject to reporting. For this reason, the case studies in this report focus only on the shallow connection costs and neglect deep connection costs.

Table 4 gives a practical overview of cost components and the cost category they are allocated to. The overview is not meant to be exhaustive, but rather presents the general concept.

Method for data search

First requirement for compiling case studies reporting on costs of RES-E options is the access to relevant data. This can be a problem, since information regarding investment financing is often considered confidential. In addition, relevant stakeholders often don’t see a direct advantage of providing data.

Basically, three approaches can be distinguished: 1) a detailed calculation for a given windfarm based on electrical component price data; 2) literature research; and 3) interviews with relevant stakeholders. The case studies presented in the current report on the Netherlands have all been based on literature research. Both approaches are discussed shortly below, and arguments for the choice of the literature research methodology are presented.

Literature research for finding cost data can be done based on different kinds of reports, each with own complications. General problems of literature surveys are that often grid connection costs are not specified separately. Sometimes it is not clear what costs are considered under ‘grid connection’, and problems exist regarding definitions and system boundaries, which can diverge

Tab. 4. Example of costs allocated to their respective cost category (not exhaustive). In the case studies in sections 4 to 7 only technology costs and shallow grid connection costs are discussed

	Technology costs (excluding grid-related costs)	Shallow grid connection costs	Deep grid connection costs
Investment-related costs	All investment costs related to the purchase of the RES-E-technology (i.e. wind turbine, tower and foundation, PV modules and support construction, biomass conversion technology). All electric equipment required for power control and power quality purchased with the technology (transformers, inverters, switches, control units, including cabling at the site, (connecting individual generators to connection point in case of wind parks, large scale PV plants)). All costs related to planning and personnel during installing of the plant.	Connection point near the RES-E technology, including the cable from connection point at the site to nearest grid (also cable from offshore wind park to shore in case it is owner by RES-E operator). Connection costs of cable to grid (such as personnel costs and rent of equipment). All costs for transformers and other components for the connection to the grid. All costs related to planning and personnel related to grid connection, energy metering.	Costs of adaptations the network operator is obliged to make as a result of connecting the RES-E technology (e.g. for maintaining grid and system stability and reliability or grid extension).
Recurrent costs	All annual costs such as O&M or other recurrent expenses for material or personnel. All fees for land rent and other services (not related to grid connection). Also, costs for back-up power and penalties or fees related to the intermittent origin of RES-E.	Use of system charges, annual network service and maintenance costs, personnel costs and annual fees related to the grid connection.	Annual costs maintaining grid and system stability and reliability related to the connection of the RES-E technology integration into the grid.

between reports (see also Table 3 above). Depending on the targeted audience of a report, the costs can be biased. Reports on a specific project can yield very detailed data, but a problem is that connection costs are always site-specific: they depend on the distance to grid, on the trajectory (i.e. crossing waterways, valleys) and on the voltage level (i.e. 10 kV, 150 kV). In case of reporting on *projected* costs, the *realised* costs might be much different. Some of the problems for reports on specific projects can be overcome by referring to studies that investigated costs for several (i.e. ten or more) projects. Thus averaging the extreme values can yield a general characterisation of a set of projects. Especially when the report respects the variance between projects and documents the data ranges. An additional complication exists when the data concern projects in different countries: this will fade out the regional differences between nations. In the GreenNet-EU27 project, the aim is to characterise national grid connection costs in a representative way. For the case study of the Netherlands, it has been decided to refer to national studies documenting ranges of typical project data.

The use of interviews for finding cost data is also a valuable method, for which however the above-mentioned drawbacks remain, although some aspects can be explored better. Interviews can be held with large project developers, with small private developers and with network operators. Especially the last part is interesting getting to know more about deep connection costs[5]. In the GreenNet-EU project, no interviews have been foreseen on this data-collection task.

For the current Dutch case study reports have been used that were commissioned by the Dutch Ministry of Economic Affairs for estimating feed-in premiums for the years 2006 and 2007. For compiling the base dataset consultation rounds with relevant stakeholders from the Dutch renewable electricity sector have been organised. The data are thus supposed to represent the average situation of the Dutch RES-E market, respecting situations with higher and lower costs. Nonetheless, arguments can be found for questioning the ranges that are presented: the presented values should not be considered fixed, but mainly as indicative. Individual projects might differ largely from what is documented here.

For wind onshore and offshore data have been cited from (van Sambeek 2004), for PV from (Daniëls 2005) and own assumptions, and for bio-oil from (de Vries 2005).

Presentation of cost data

The case studies present the resulting data at the end of each section in the same tables. For each technology, a table exists with 'high' and 'low' cost estimates, following the ranges that have been reported in the cited literature. A third table exists in which the resulting cost and percentage range have been reported. Also, for each technology a figure is given in which the generating costs are presented as a function of the amount of full load hours (both for the high and low estimate).

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[5] In contacts to a Dutch DSO the authors of this report found out that in specific cases (especially when connecting on the 150kV grid) deep RES-E connection costs were confirmed to be zero.

The ranges in the basic data on which the share of grid-related costs are calculated (investment costs, O&M costs, etc.) are reported in paragraphs.

In order to gain better insight in how the data tables have been compiled, two dummy tables are depicted below in which the expressions for calculating the figures are shown.

Tab. 5. Example of table indicating relations between cost breakdown figures (Monetary unit: EUR_{2004}, Source indicated)

Technology data (high estimate)	Investment [EUR/kW]		Recurrent costs [EUR/kW/yr]	
Investment (total)	A	A/A%		
Annual O&M (excluding grid-related)			C	C/G%
Annual grid related O&M			D	D/G%
Fuel costs			E	E/G%
Heat revenues (if applicable)			F	F/G%
Total	A	100%	G = C+D+E+F	100.0%
Grid-related investment cost (value and percentage of total)	B	B/A%		

Calculated electricity data	Unit Generation Cost [EUR/MWh] (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost [EUR/MWh] (discount rate = 10%, lifetime = 15 years)
Investment (total)	H = f(A, annuity, FLH)	H/M%	
Annual O&M	I = f(C, FLH)	I/M%	*same as*
... of which annual grid related O&M	J = f(D, FLH)	J/M%	*indicated*
Fuel costs	K = f(E, FLH)	K/M%	*at the left*
Heat revenues (if applicable)	L = f(F, FLH)	L/M%	
Total	M = H+I+K+L	100% + J/M%	
Grid-related investment cost (value and percentage of total)	N = f(B, annuity, FLH)	N/M%	

Tab. 6. Example of table indicating final data ranges for grid integration costs and relations to table above (Monetary unit: EUR_{2004}, Source indicated)

	Unit Generation Cost (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost (discount rate = 10%, lifetime = 15 years)	
	Cost [EUR/MWh]	Share in MWh cost	Cost [EUR/MWh]	Share in MWh cost
Grid related cost from annual cost	J_{min} - J_{max}	J_{min}/M% - J_{max}/M%		
Grid-related investment cost	N_{min} - N_{max}	N_{min}/M% - N_{max}/M%	*see left*	
Total grid related cost	(J_{min} + N_{min}) - (J_{max} + N_{min})	sum of ranges above		

3. Case Study: Wind On-shore

3.1. Description

The total installed wind energy capacity in the Netherlands currently is represented by onshore wind only, since the first offshore wind power project is currently (mid 2006) still in the construction phase. The installed wind capacity by the end of 2004 was 1073 MW and production in 2004 amounted to 1867 GWh. For the case study, data have been based on the ranges in a report that assesses costs of wind turbine projects in the Netherlands (Sambeek 2004), for technology that is expected to be available in 2006. This will result in a high estimate and a low estimate.

3.2. Costs

Cost data have been obtained from a detailed study on this option in order to calculate a proposal for the Dutch feed-in premium (Sambeek 2004). It documents ranges for the costs of state-of-the-art renewable energy projects in the Netherlands (referring to new projects operational in the year 2006). The data are discussed in the paragraphs below. All costs are in Euro 2004.

Investment costs for onshore wind are considered to be 1100 EUR/kW (including grid connection costs). The reason for this - in international perspective high costs - can be twofold: first, the report states that the grid connection costs are considerable, and that new generations of wind turbines are relatively expensive. The technological progress is said to result in higher energy yields. A second reason could be strategic influencing of policy: the support mechanism in the Netherlands possibly gives an incentive for the market to keep costs high. However, data from real projects confirm this high cost range.

The annual amount of full load hours is considered constant at an amount of 2000 hrs/year. From statistics this appears to be a reliable value. Fix Operation and Maintenance costs range from 30 to 50 EUR/kWe (including annual grid connection costs).

In the investment costs, for grid connection a range of 40 to 150 EUR/kWe is specified. These investments costs related to grid connection can be decomposed as follows:

Tab. 7. Grid-connection related investment cost range (source: van Sambeek 2004)

	Lower value [EUR/kW]	Upper value [EUR/kW]
Connection costs	5	50
Cable to grid	35	100
Total connection costs	40	150

It is confirmed in the report that a very broad range of costs for grid connection can be observed. This probably is due to the large diversification of locations and the distances to the grid.

Another cost component exists: the annual grid connection costs, which are to be paid by the wind project developer each year. These costs are in the range of 1.15 to 1.65 EUR/year for grid connections in the range 0.3 to 3.0 MVA and 7.5 to 14.0 EUR/year for connections in the range 3.0 to 10.0 MVA. For the current case study these costs are assumed to vary between 1.0 and 2.0 EUR/kW/year. These costs follow from regulated tariffs.

3.3. Grid integration costs for onshore wind

These cost ranges result in a share of grid connection investment costs to the total investment costs ranging from 3.6% to 13.6%, and in a share of grid connection operational cost to the total recurrent costs of 2.3% to 3.1%. In the resulting electricity costs this yields a range of (1.9 + 0.5 =) 2.4 EUR/MWh to (9.9 + 1.0 =) 10.9 EUR/MWh (expressed relative to the generating costs (EUR/MWh) a range of 3.3% to 10.5% is found). More detail can be found in the tables and figures below.

Tab. 8. Cost breakdown of electricity generation from onshore wind, commissioning in the year 2006 (High estimate, EUR_{2004}, Source: Sambeek 2004)

Technology data (high estimate)	Investment [EUR/kW]		Recurrent costs [EUR/kW/yr]	
Investment (total)	1100	100%		
Annual O&M (excluding grid-related)			62.0	96.9%
Annual grid related O&M			2.0	3.1%
Fuel costs			0.0	0.0%
Heat revenues (if applicable)			0.0	0.0%
Total	1100	100%	64.0	100.0%
Grid-related investment cost (value and percentage of total)	150	13.6%		

Calculated electricity data	Unit Generation Cost [EUR/MWh] (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost [EUR/MWh] (discount rate = 10%, lifetime = 15 years)	
Investment (total)	53.0	63.1%	72.3	70.0%
Annual O&M	31.0	36.9%	31.0	30.0%
... of which annual grid related O&M	1.0	1.2%	1.0	1.0%
Fuel costs	0.0	0.0%	0.0	0.0%
Heat revenues (if applicable)	0.0	0.0%	0.0	0.0%
Total	84.0	101.2%	103.3	101.0%
Grid-related investment cost (value and percentage of total)	7.2	8.6%	9.9	9.5%

Tab. 9. Cost breakdown of electricity generation from onshore wind, commissioning in the year 2006 (Low estimate, EUR_{2004}, Source: Sambeek 2004)

Technology data (low estimate)	Investment [EUR/kW]		Recurrent costs [EUR/kW/yr]	
Investment (total)	1100	100%		
Annual O&M (excluding grid-related)			42.0	97.7%
Annual grid related O&M			1.0	2.3%
Fuel costs			0.0	0.0%
Heat revenues (if applicable)			0.0	0.0%
Total	1100	100%	43.0	100.0%
Grid-related investment cost (value and percentage of total)	40	3.6%		

Calculated electricity data	Unit Generation Cost [EUR/MWh] (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost [EUR/MWh] (discount rate = 10%, lifetime = 15 years)	
Investment (total)	53.0	71.6%	72.3	77.5%
Annual O&M	21.0	28.4%	21.0	22.5%
... of which annual grid related O&M	0.5	0.7%	0.5	0.5%
Fuel costs	0.0	0.0%	0.0	0.0%
Heat revenues (if applicable)	0.0	0.0%	0.0	0.0%
Total	74.0	100.7%	93.3	100.5%
Grid-related investment cost (value and percentage of total)	1.9	2.6%	2.6	2.8%

Tab. 10. Summary table of grid-related costs in onshore wind unit generation cost (EUR_{2004}, Source: Sambeek 2004)

	Unit Generation Cost (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost (discount rate = 10%, lifetime = 15 years)	
	Cost [EUR/MWh]	Share in MWh cost	Cost [EUR/MWh]	Share in MWh cost
Total generating costs	74.0 - 84.0	100%	93.3 - 103.3	100%
Grid-related investment cost	1.9 - 7.2	2.6% - 8.6%	2.6 - 9.9	2.8% - 9.5%
Annual grid-related cost	0.5 - 1.0	0.7% - 1.2%	0.5 - 1.0	0.5% - 1.0%
Total grid related cost	2.4 - 8.2	3.3% - 9.8%	3.1 - 10.9	3.4% - 10.5%

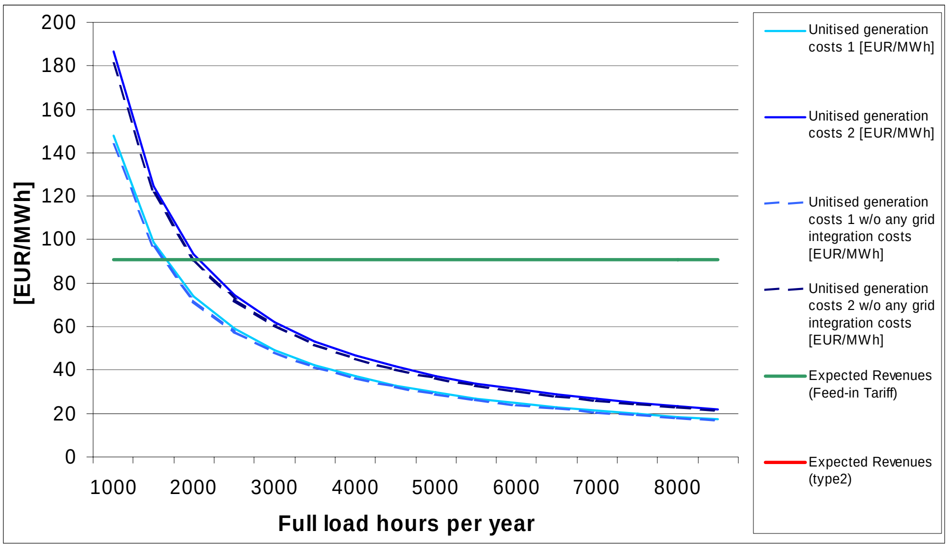

Fig. 9. Resulting cost for electricity production from onshore wind as a function of the amount of full load hours (Low estimate, EUR_{2004}, Source: Sambeek 2004)

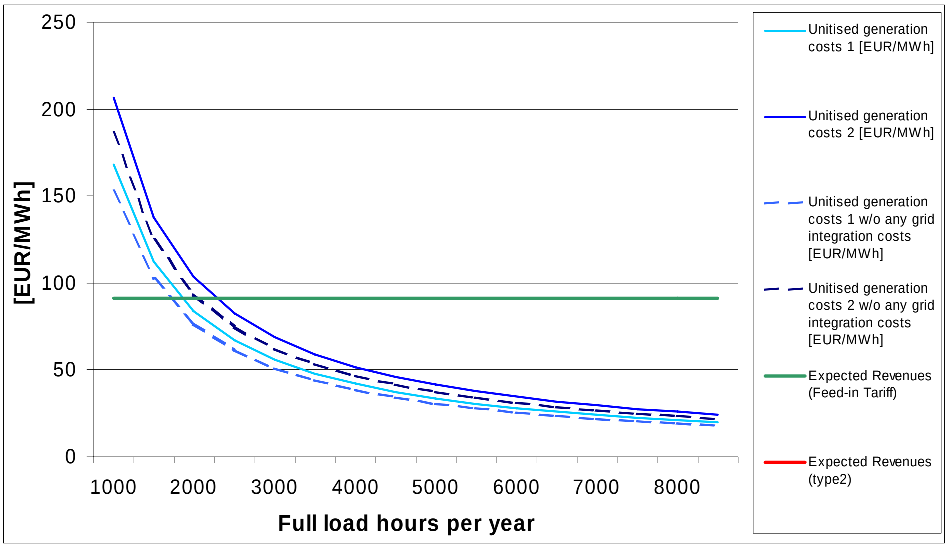

Fig. 10. Resulting cost for electricity production from onshore wind as a function of the amount of full load hours (High estimate, EUR_{2004}, Source: Sambeek 2004)

4. Case Study: Wind Offshore

4.1. Description

An overview of realized projects in the Netherlands is presented in Tab. 11., projected wind farms have been listed in Tab. 12. The two realized projects however cannot be considered as offshore wind farms, since they are located in a lake with very low depths. Most capacity expansion is expected in the North Sea, for which a previous (but now cancelled) government target of 6 GW was in place.

In the Netherlands two projects are currently (mid 2006) in the planning phase. First, the Nearshore Wind Park (NSW) of the Shell/Nuon consortium NoordzeeWind, a demonstration project of 108 MW near Egmond aan Zee (10 km distance to shore) is being constructed, and commissioning is scheduled for 2007. Based on the environmental authorization the NSW has to be entirely dismantled after 20 years of operation.

The second wind farm, the E-concern Q7 wind farm of 120 MW has been projected 23 km offshore of IJmuiden, and commissioning is expected for the beginning of 2008. The name Q7 refers to the name of block Q7 of the Dutch Continental Shelf.

Initially, both new projects were scheduled to begin operating in 2003/2004, but this has been delayed several times. Detailed information for the Dutch wind energy developments (both onshore and offshore) can be found at (WSH, 2006).

Tab. 11. Realised offshore wind projects in the Netherlands (Beurskens 2003)

Project	Location	Power	Commissioning date
Lely	IJsselmeer	2 MW (4 × 500 kW)	1994
Dronten	IJsselmeer	17 MW (28 × 600 kW)	1996
Total realized		19 MW	

Tab. 12. Planned offshore wind projects in the Netherlands (Beurskens 2003, WSH 2006)

Project	Location	Power	Commissioning date
NSW	North Sea	108 MW	2007
Q7	North Sea	120 MW	2008
Total projected		228 MW	

4.2. Costs

Cost data have been obtained from a detailed study on this option for calculating a proposal for the Dutch feed-in premium (Sambeek 2004). It documents ranges for the costs of realised renewable energy projects in the Netherlands. The data are discussed in the paragraphs below. All costs are in Euro 2004 and refer to offshore wind parks starting operation in the year 2006.

Investment costs for offshore wind are considered to range from 2000 to 2250 EUR/kW (including grid connection costs). Note that this is relatively high in an international context. The reasons that are often mentioned for explaining this are the following: the location-specific circumstances at the Dutch shelf of the North Sea (relative deep waters, wave regime) and the large distance to shore (in comparison to other, realised projects).

The annual amount of full load hours is considered to range from 3350 to 3500 hrs/year. Fix Operation and Maintenance costs range from 60 to 90 EUR/kWe (including annual grid connection costs).

In the investment costs the grid connection costs are not made explicit in the report. In (Kooijman 2003) the costs for electric connection are estimated as 9% of the investment costs (based on an offshore wind farm of 50 x 3 MW and a distance to shore equal to 25 km). This results in a range from 180 to 203 EUR/kWe.

Another cost component exists: the annual grid connection costs, which are to be paid by the wind project developer each year. These costs have not been documented in the report. However, although it can be assumed that they are significantly higher than for onshore wind, the assumption here is to set them equal to onshore wind.

4.3. Grid integration costs for offshore wind

These input cost ranges result in a share of grid connection investment costs to the total investment costs of 9% (estimate based on Kooijman 2003), and in a share of grid connection operational cost to the total recurrent costs of 1.2% to 4.3%. In the resulting electricity costs this yields a range of (5.0 + 0.3 =) 5.2 EUR/MWh to (7.9 + 1.5 =) 9.4 EUR/MWh (expressed relative to the generating costs (EUR/MWh) a range of 6.7% to 7.8% is found). More detail can be found in the tables and figures below.

Tab. 13. Cost breakdown of electricity generation from offshore wind, commissioning in the year 2006 (High estimate, EUR_{2004}, Source: Sambeek 2004)

Technology data (high estimate)	Investment [EUR/kW]		Recurrent costs [EUR/kW/yr]	
Investment (total)	2250	100%		
Annual O&M (excluding grid-related)			110.1	95.7%
Annual grid related O&M			5.0	4.3%
Fuel costs			0.0	0.0%
Heat revenues (if applicable)			0.0	0.0%
Total	2250	100%	115.1	100.0%
Grid-related investment cost (value and percentage of total)	203	9.0%		

Calculated electricity data	Unit Generation Cost [EUR/MWh] (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost [EUR/MWh] (discount rate = 10%, lifetime = 15 years)	
Investment (total)	64.7	66.3%	88.3	72.9%
Annual O&M	32.9	33.7%	32.9	27.1%
... of which annual grid related O&M	1.5	1.5%	1.5	1.2%
Fuel costs	0.0	0.0%	0.0	0.0%
Heat revenues (if applicable)	0.0	0.0%	0.0	0.0%
Total	97.6	101.5%	121.2	101.2%
Grid-related investment cost (value and percentage of total)	5.8	6.0%	7.9	6.6%

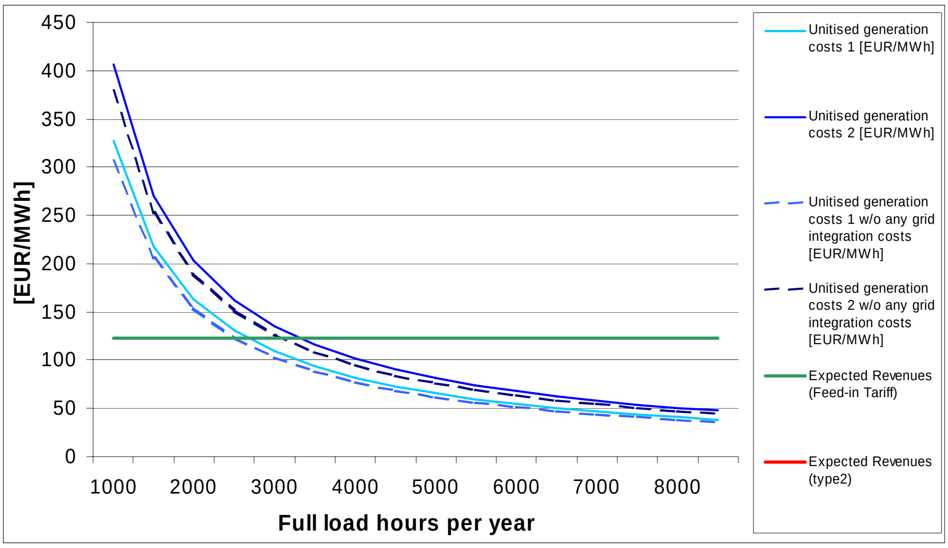

Fig. 11. Resulting cost for electricity production from offshore wind as a function of the amount of full load hours (High estimate, EUR_{2004}, Source: Sambeek 2004)

Tab. 14. Cost breakdown of electricity generation from offshore wind, commissioning in the year 2006 (Low estimate, EUR_{2004}, Source: Sambeek 2004)

Technology data (low estimate)	Investment [EUR/kW]		Recurrent costs [EUR/kW/yr]	
Investment (total)	2000	100%		
Annual O&M (excluding grid-related)			81.0	98.8%
Annual grid related O&M			1.0	1.2%
Fuel costs			0.0	0.0%
Heat revenues (if applicable)			0.0	0.0%
Total	2000	100%	82.0	100.0%
Grid-related investment cost (value and percentage of total)	180	9.0%		

Calculated electricity data	Unit Generation Cost [EUR/MWh] (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost [EUR/MWh] (discount rate = 10%, lifetime = 15 years)	
Investment (total)	55.1	70.4%	75.1	76.4%
Annual O&M	23.1	29.6%	23.1	23.6%
... of which annual grid related O&M	0.3	0.4%	0.3	0.3%
Fuel costs	0.0	0.0%	0.0	0.0%
Heat revenues (if applicable)	0.0	0.0%	0.0	0.0%
Total	78.2	100.4%	98.3	100.3%
Grid-related investment cost (value and percentage of total)	5.0	6.3%	6.8	6.9%

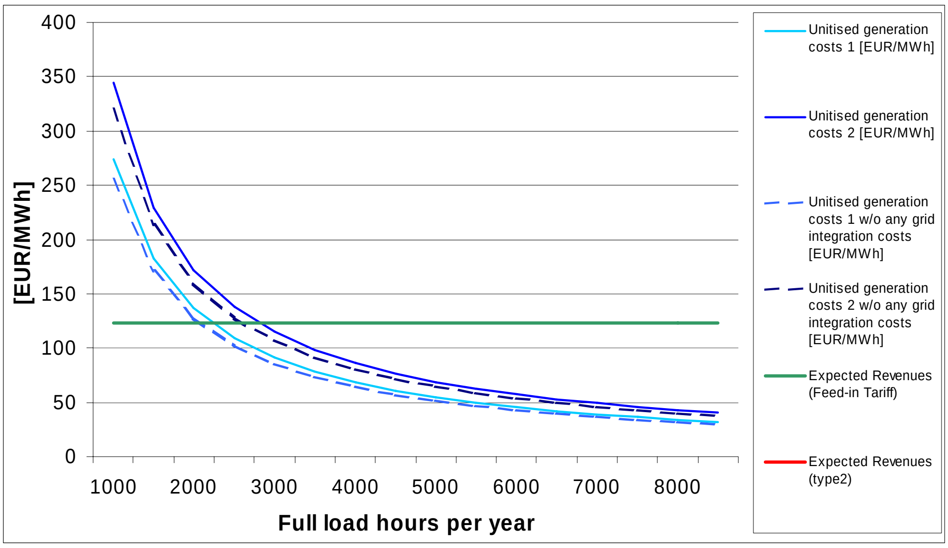

Fig. 12. Resulting cost for electricity production from offshore wind as a function of the amount of full load hours (High estimate, EUR_{2004}, Source: Sambeek 2004)

Tab. 15. Summary table of grid-related costs in offshore wind unit generation cost (EUR_{2004}, Source: Sambeek 2004)

	Unit Generation Cost (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost (discount rate = 10%, lifetime = 15 years)	
	Cost [EUR/MWh]	Share in MWh cost	Cost [EUR/MWh]	Share in MWh cost
Total generating costs	78.2 - 97.6	100%	98.3 - 121.2	100%
Grid-related investment cost	5.0 - 5.8	6.0% - 6.3%	6.8 - 7.9	6.6% - 6.9%
Annual grid-related cost	0.3 - 1.5	0.4% - 1.5%	0.3 - 1.5	0.3% - 1.2%
Total grid related cost	5.2 - 7.3	6.7% - 7.5%	7.0 - 9.4	7.2% - 7.8%

5. Case Study: Photovoltaics

5.1. Description

The level of annual penetration for photovoltaics (PV) in the Netherlands depends strongly on the financial support for this technology. In the period 2001 to 2003 a substantial investment subsidy was available (of over 50% of the total investment costs, by stacking national and local subsidies) which made installed PV capacity to increase rapidly. The installed capacity at the end of 2004 was 49 MWp, with 33 GWh of generated electricity in the year 2004.

With respect to the net integration costs, PV is a special case. Since the installation generally is installed at the consumer’s and behind the metering point, there actually is no grid integration. Especially for small systems (of a capacity less than 4 kWp) the grid integration costs are very low. The only costs that can be considered in such a case are the following:

4. The costs of the cable from the inverter to the 230 V in-house electricity installation (generally less than EUR 10,-);
5. The costs of labour for connecting the PV installation to the electrical installation (generally less that EUR 100,- and in some cases even zero: small PV installations (capacity less than 600 Wp) can be connected by unskilled people by plugging in a grounded 230 V plug);
6. The costs of a metering installation, i.e. to register the electricity produced by the PV installation. It is a question whether these costs are to be attributed to the PV system or that they are part of the normal connection charges of the final user: this may vary throughout the EU. An estimate of the costs of a new electricity meter are EUR 150,-. In the Netherlands, it has been decided that the consumer benefits from ‘smart metering’, which thus has been obliged by the government. So most probably these costs need not to be paid by the owner of an installation.

For the small PV-systems, no literature is available of detailed inventories of integrations costs. Therefore, an estimate is made, based on a 5 kWp system, for which an upper limit of EUR 500,- is assumed, based on the above three components. This is actually the result of an assumption of EUR 250,- with a very high uncertainty (+/- EUR 250,-). This results in investment-related integration costs for PV of 0.1 EUR/Wp (i.e. 100 EUR/kWp) and annual grid-related operational charges of 0 EUR/Wp.

For large PV-systems (installed capacity > 100 kWp) the picture is not much different. In the Netherlands, most existing recent large systems are building-integrated installations, in places with considerable own electricity consumption. In these cases the grid integration costs are absent as well. Higher costs might be found for large isolated ground-based central PV installations, because of the distance to the grid (comparable to those of onshore wind power). This however is not discussed here.

5.2. Costs

The cost assessment for PV is based on a recent ECN-publication (Daniëls 2005) in which (among others) the costs for PV have been assessed. In this document no ranges have been specified, but still the data are rather general. The investment costs for a PV-installation in the Netherlands in the year 2005 are considered 5 EUR/Wp, the annual O&M costs 1.5% of these investment costs, i.e. 7.5 cent/Wp. The amount of full load hours is assumed 790 hours (in the year 2010 actually but here also taken for the year 2005). As explained above, the investment-related integration costs for PV are assumed 0.1 EUR/Wp and annual grid-related operational charges of 0 EUR/Wp. The amortisation period is assumed 15 years (for small consumers however this period could also be 20 years, as a result of a different perception of investment. This however is not discussed here).

5.3. Grid integration costs for PV

These input cost ranges and assumptions result in a share of grid connection investment costs to the total investment costs of 0.0% to 2.0%, and in a share of grid connection operational cost to the total recurrent costs of 0.0%. In the resulting electricity costs this yields a range of 0.0 EUR/MWh to 16.6 EUR/MWh (expressed relative to the generating costs (EUR/MWh) a range of 0% to 1.8% is found). More detail can be found in the tables and figures below.

Tab. 16. Cost breakdown of electricity generation from PV, commissioning in the year 2005 (High estimate, EUR_{2004}, Source: Daniëls 2005)

Technology data (high estimate)	Investment [EUR/kW]		Recurrent costs [EUR/kW/yr]	
Investment (total)	5000	100%		
Annual O&M (excluding grid-related)			75.0	100.0%
Annual grid related O&M			0.0	0.0%
Fuel costs			0.0	0.0%
Heat revenues (if applicable)			0.0	0.0%
Total	5000	100%	75.0	100.0%
Grid-related investment cost (value and percentage of total)	100	2.0%		

Calculated electricity data	Unit Generation Cost [EUR/MWh] (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost [EUR/MWh] (discount rate = 10%, lifetime = 15 years)	
Investment (total)	609.8	86.5%	832.1	89.8%
Annual O&M	94.9	13.5%	94.9	10.2%
... of which annual grid related O&M	0.0	0.0%	0.0	0.0%
Fuel costs	0.0	0.0%	0.0	0.0%
Heat revenues (if applicable)	0.0	0.0%	0.0	0.0%
Total	704.7	100.0%	927.0	100.0%
Grid-related investment cost (value and percentage of total)	12.2	1.7%	16.6	1.8%

Tab. 17. Cost breakdown of electricity generation from PV, commissioning in the year 2005 (Low estimate, EUR_{2004}, Source: Daniëls 2005)

Technology data (low estimate)	Investment [EUR/kW]		Recurrent costs [EUR/kW/yr]	
Investment (total)	5000	100%		
Annual O&M (excluding grid-related)			75.0	100.0%
Annual grid related O&M			0.0	0.0%
Fuel costs			0.0	0.0%
Heat revenues (if applicable)			0.0	0.0%
Total	5000	100%	75.0	100.0%
Grid-related investment cost (value and percentage of total)	0	0.0%		

Calculated electricity data	Unit Generation Cost [EUR/MWh] (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost [EUR/MWh] (discount rate = 10%, lifetime = 15 years)	
Investment (total)	609.8	86.5%	832.1	89.8%
Annual O&M	94.9	13.5%	94.9	10.2%
... of which annual grid related O&M	0.0	0.0%	0.0	0.0%
Fuel costs	0.0	0.0%	0.0	0.0%
Heat revenues (if applicable)	0.0	0.0%	0.0	0.0%
Total	704.7	100.0%	927.0	100.0%
Grid-related investment cost (value and percentage of total)	0.0	0.0%	0.0	0.0%

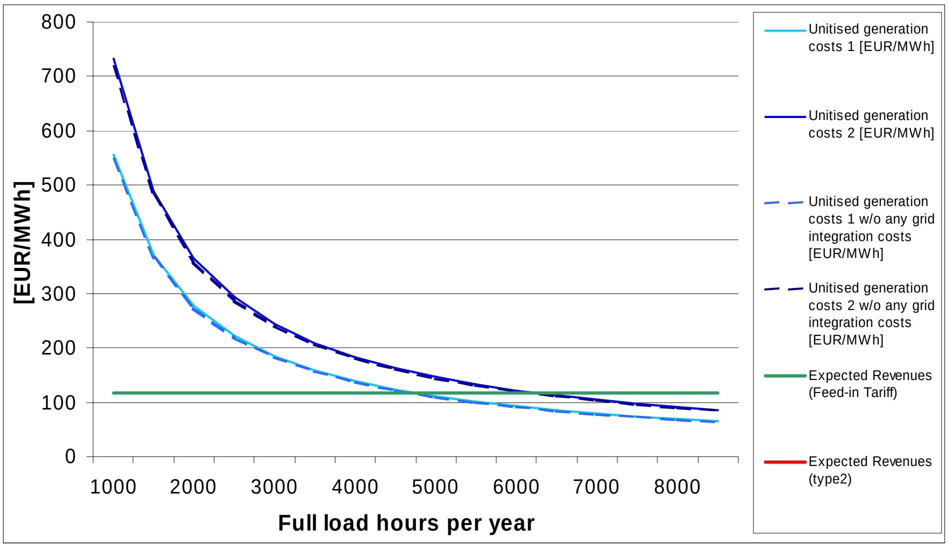

Fig. 13. Resulting cost for electricity production from PV as a function of the amount of full load hours (High and low estimate yield similar results, EUR_{2004}, Source: Daniëls 20005)

Tab. 18. Summary table of grid-related costs in PV unit generation cost (EUR_{2004}, Source: Daniëls 2005)

	Unit Generation Cost (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost (discount rate = 10%, lifetime = 15 years)	
	Cost [EUR/MWh]	Share in MWh cost	Cost [EUR/MWh]	Share in MWh cost
Total generating costs	704.7	100%	927.0	100%
Grid-related investment cost	0.0 - 12.2	0.0% - 1.7%	0.0 - 16.6	0.0% - 1.8%
Annual grid-related cost	0	0%	0	0%
Total grid related cost	0.0 - 12.2	0.0% - 1.7%	0.0 - 16.6	0.0% - 1.8%

6. Case Study: Biomass

6.1. Realised biomass

Biomass is often considered as a traditional renewable energy option. Historically, power generation from municipal solid waste has been most important, with small amounts of digestion options such as landfill gas. By the end of the 1990s, other options start penetrating the market: small scale biomass combustion (typically below 50 MWe) and even large scale biomass co-firing in coal and gas plants. For co-firing in gas plants generally no pre-treatment is required, or sometimes only grinding. In gas-fired plants it is sometimes possible to use bio-oil as a fuel. This depends on the type of installation. See Fig. 14. for more detail.

For the current case study, a small scale electricity option is considered: bio-oil fuelled Diesel engines[6]. By combining several large Diesel engines coupling them with a steam cycle high efficiencies can be attained. Typical power of such a system is just beneath 50 MWe.

[6] The co-firing technology using solid biomass in existing central coal power plants could also have been described, but this is considered not very interesting: the grid connection infrastructure is always already in place, and thus costs are zero.

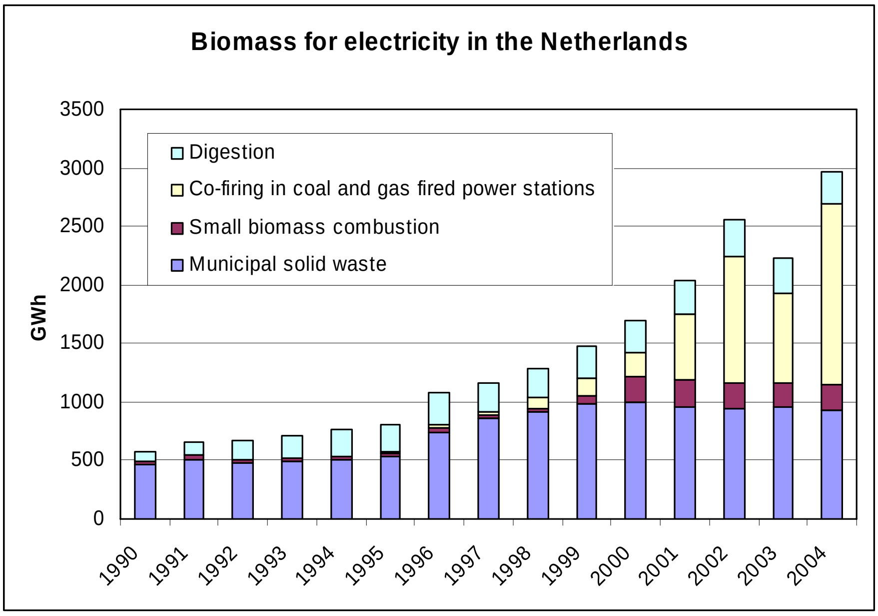

Fig. 14. History of electricity production from biomass in the Netherlands (Source: CBS, 2005)

6.2. Costs

Cost data have been obtained from a detailed study on this option in order to calculate a proposal for the Dutch feed-in premium (de Vries 2005). The report is an update of an earlier version, to which the sector had commented. In the report all market data have been analysed and finally ranges have been proposed. The data are discussed in the paragraphs below (cost have been converted to EUR_{2004}, data refer to plants operational in 2006).

Investment costs range from 1140 to 1239 EUR/kWe. The annual amount of full load hours ranges from 7000 to 8000 hrs/year. Fix Operation and Maintenance costs range from 99 to 157 EUR/kWe. The report assumes the purchase of tradable NO_x-emission permits at a rate of 2.5 to 5.4 EUR/MWhe. Fuel costs (bio-oil such as palm oil) are estimated in a range from 370 to 434 EUR/ton.

The electric efficiency is supposed to range from 45% to 50%. The high efficiency can be reached using a steam cycle. The thermal efficiency of this plant is about 10 to 15%. Important for the calculation of costs however is the importance of the heat credit. This is not described in the report, resulting in a heat credit is of zero. In order to compensate for this an estimate is made, based on the costs of heat production from natural gas. A reference conversion efficiency of 90% is assumed. In order to derive a range, heat transport losses are considered from 0% to 20%. Based on a natural gas price of 5 EUR/GJ this results in a heat credit of 15.9 to 19.8 EUR/MWth. Also, a yearly share of heat sale is to be specified in order to compensate for seasonal variations in heat demand. It is assumed that the installation serves an industrial partner with a constant heat demand. The share of heat sale is put at 80%. Historically, consumers obtained reduction rates for purchasing heat from CHP. This reduction is not considered in the estimate.

In the investment costs, for grid connection an amount of 99 EUR/kWe is comprised. This is supposed to represent a connection to the 150 kV grid including a cable of 4 to 5 kilometres. But in order to be connected, the grid operator requires a fix annual contribution of 1 to 2 EUR/kW/year (see Section 3.2).

6.3. Grid integration costs for bio-oil

These ranges results in a share of grid connection investment costs to the total investment costs of 8.0% to 8.7%, and in a share of grid connection operational cost to the total recurrent costs of 0.2%. In the resulting electricity costs this yields a range of (1.7 + 0.1 =) 1.8 EUR/MWh to (2.2 + 0.3 =) 2.6 EUR/MWh. In relative terms, the range of costs induced by grid connection in the resulting generating costs is 1.5% to 2.6%. More detail can be found in the tables and figures below.

Tab. 19. Cost breakdown of electricity generation from bio-oil, commissioning in the year 2006 (High estimate, EUR_{2004}, Source: de Vries 2005)

Technology data (high estimate)	Investment [EUR/kW]		Recurrent costs [EUR/kW/yr]	
Investment (total)	1239	100%		
Annual O&M (excluding grid-related)			159.0	19.8%
Annual grid related O&M			2.0	0.2%
Fuel costs			662.2	82.4%
Heat revenues (if applicable)			-19.9	-2.5%
Total	1239	100%	803.4	102.5%
Grid-related investment cost (value and percentage of total)	99	8.0%		

Calculated electricity data	Unit Generation Cost [EUR/MWh] (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost [EUR/MWh] (discount rate = 10%, lifetime = 15 years)	
Investment (total)	22.9	16.7%	28.8	20.1%
Annual O&M	22.7	16.5%	22.7	15.9%
... of which annual grid related O&M	0.3	0.2%	0.3	0.2%
Fuel costs	94.6	68.9%	94.6	66.0%
Heat revenues (if applicable)	-2.8	-2.1%	-2.8	-2.0%
Total	137.4	100.2%	143.3	100.2%
Grid-related investment cost (value and percentage of total)	1.8	1.3%	2.3	1.6%

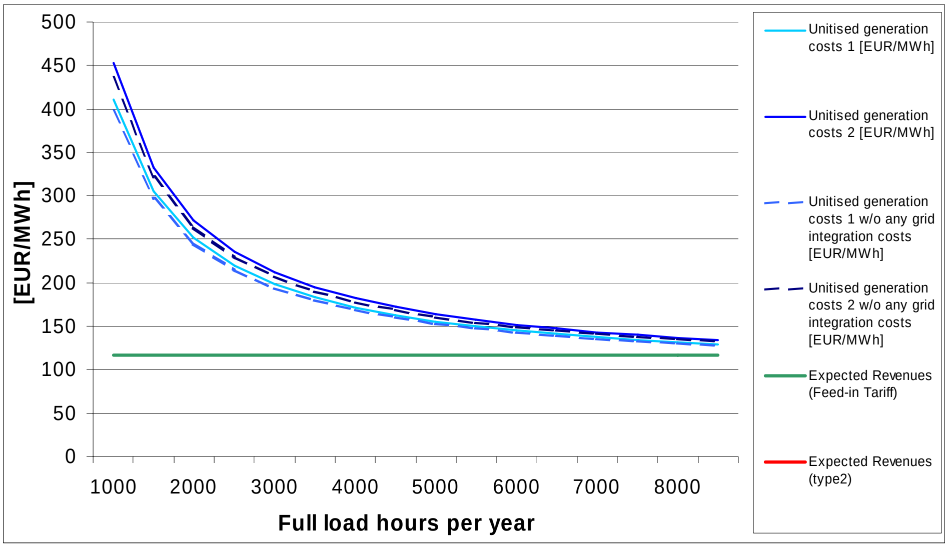

Fig. 15. Resulting cost for electricity production from bio-oil as a function of the amount of full load hours (High estimate, EUR_{2004}, Source: de Vries 2005)

Tab. 20. Cost breakdown of electricity generation from bio-oil, commissioning in the year 2006 (Low estimate, EUR_{2004}, Source: de Vries 2005)

Technology data (low estimate)	Investment [EUR/kW]		Recurrent costs [EUR/kW/yr]	
Investment (total)	1140	100%		
Annual O&M (excluding grid-related)			100.1	15.8%
Annual grid related O&M			1.0	0.2%
Fuel costs			580.1	91.6%
Heat revenues (if applicable)			-48.0	-7.6%
Total	1139.52164	100%	633.2	107.6%
Grid-related investment cost (value and percentage of total)	99	8.7%		

Calculated electricity data	Unit Generation Cost [EUR/MWh] (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost [EUR/MWh] (discount rate = 10%, lifetime = 15 years)	
Investment (total)	18.4	18.9%	23.2	22.7%
Annual O&M	12.5	12.8%	12.5	12.2%
... of which annual grid related O&M	0.1	0.1%	0.1	0.1%
Fuel costs	72.5	74.4%	72.5	70.9%
Heat revenues (if applicable)	-6.0	-6.2%	-6.0	-5.9%
Total	97.5	100.1%	102.2	100.1%
Grid-related investment cost (value and percentage of total)	1.6	1.6%	2.0	2.0%

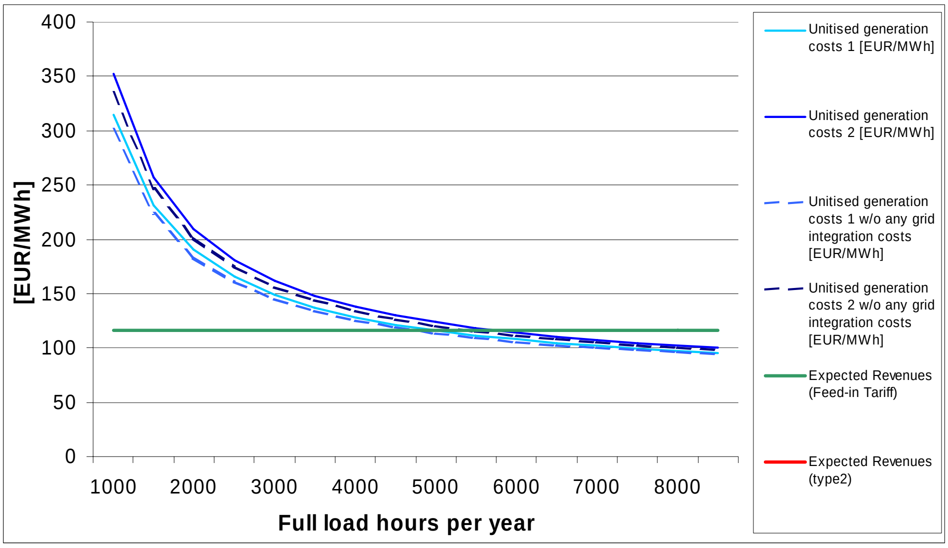

Fig. 16. Resulting cost for electricity production from bio-oil as a function of the amount of full load hours (High estimate, EUR_{2004}, Source: de Vries 2005)

Tab. 21. Summary table of grid-related costs in bio-oil unit generation cost (EUR$_{2004}$, Source: de Vries 2005)

	Unit Generation Cost (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost (discount rate = 10%, lifetime = 15 years)	
	Cost [EUR/MWh]	Share in MWh cost	Cost [EUR/MWh]	Share in MWh cost
Total generating costs	97.5 - 137.4	100%	102.2 - 143.3	100%
Grid-related investment cost	1.7	1.3% - 1.6%	2.2	1.6% - 2.0%
Annual grid-related cost	0.1 - 0.3	0.1% - 0.2%	0.1 - 0.3	0.1% - 0.2%
Total grid related cost	1.7 - 2.1	1.5% - 1.8%	2.1 - 2.6	1.8% - 2.1%

7. Overview of costs resulting from case studies

In the previous sections in this report the contribution of grid-related costs to the total electricity generating costs has been assessed for four RES-E technologies: wind onshore, wind offshore, PV and bio-oil. Each section ended with a summary table. The tables have been merged into one table, see below.

Tab. 22.

		Unit Generation Cost (discount rate = 5%, lifetime = 15 years)		Unit Generation Cost (discount rate = 10%, lifetime = 15 years)	
		Cost [EUR/MWh]	Share in MWh cost	Cost [EUR/MWh]	Share in MWh cost
Wind onshore	Total generating costs	74.0 - 84.0	100%	93.3 - 103.3	100%
	Grid-related investment cost	1.9 - 7.2	2.6% - 8.6%	2.6 - 9.9	2.8% - 9.5%
	Annual grid-related cost	0.5 - 1.0	0.7% - 1.2%	0.5 - 1.0	0.5% - 1.0%
	Total grid related cost	2.4 - 8.2	3.3% - 9.8%	3.1 - 10.9	3.4% - 10.5%
Wind offshore	Total generating costs	78.2 - 97.6	100%	98.3 - 121.2	100%
	Grid-related investment cost	5.0 - 5.8	6.0% - 6.3%	6.8 - 7.9	6.6% - 6.9%
	Annual grid-related cost	0.3 - 1.5	0.4% - 1.5%	0.3 - 1.5	0.3% - 1.2%
	Total grid related cost	5.2 - 7.3	6.7% - 7.5%	7.0 - 9.4	7.2% - 7.8%
PV	Total generating costs	704.7	100%	927.0	100%
	Grid-related investment cost	0.0 - 12.2	0.0% - 1.7%	0.0 - 16.6	0.0% - 1.8%
	Annual grid-related cost	0.0	0%	0.0	0%
	Total grid related cost	0.0 - 12.2	0.0% - 1.7%	0.0 - 16.6	0.0% - 1.8%
Bio-oil	Total generating costs	97.5 - 137.4	100%	102.2 - 143.3	100%
	Grid-related investment cost	1.7	1.3% - 1.6%	2.2	1.6% - 2.0%
	Annual grid-related cost	0.1 - 0.3	0.1% - 0.2%	0.1 - 0.3	0.1% - 0.2%
	Total grid related cost	1.7 - 2.1	1.5% - 1.8%	2.1 - 2.6	1.8% - 2.1%

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UNITED KINGDOM CASE STUDY

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Abstract. This report examines the conditions and costs for grid connection of renewable energy installations in the UK. The grid connection process for distributed generation has represented a significant barrier to new RES E in the UK in terms of the time taken to obtain a connection agreement, the high costs of connection and the application process and uncertainties in the process and costs. It is hoped that recent changes to the grid connection process will address some of these issues and assist developers. Two case studies are presented, one for wind energy and one for photovoltaics. The grid connection of very small scale renewable energy systems i.e. below 100 kW is very simple and represents a very small proportion of the total project cost. This is in contrast to larger systems such as wind farms where grid connection costs make a significant part of the total capital cost of a project.

Keywords: Grid integration cost, wind energy, photovoltaics, UK, case study

List of Abbreviations

AONB	Areas of Outstanding National Beauty
BSC	Balancing and Settlement Code
BMR	Balancing Mechanism Reporting Service
CEGB	Central Electricity Generating Board
BETTA	British Electricity Trading and Transmission Arrangements
NETA	New Electricity Trading Arrangements
DG	Distributed Generation

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DNO	Distribution Network Operators
DPCR	Distribution Price Control Review
DUoS	Distribution Use of System Charges’
DTI	Department of Trade and Industry
ER	Engineering Recommendations
IFI	Innovation Funding Incentive (IFI):
kWp	kilowatt peak
NGC	National Grid Company
NGE	National Grid Electricity Transmission plc
NPPG 6	National Planning Policy Guideline 6, Renewable Energy Developments
Ofgem	The Office of Gas and Electricity Markets
PV	photovoltaics
PPS22	Planning Policy Statement
ROCs	Renewables Obligation Certificates
RES E	Renewable Energy Electricity
RPZ	Registered Power Zone
SSAs	Strategic Search Areas
SBP	System Buy Price
SSP	System Sell Price
TAN	Technical Advice Note

1. Description of UK electricity system

1.1. Design of the electricity market

The UK in the context of electricity generation and supply is made up of three regions: England and Wales; Scotland; and Northern Ireland. The three regions have historically had different structures, both commercially and legislatively, which have to some extent affected the way the electricity market has developed in each. During 2005 a unified set of trading and connection policies were implemented to create a single electricity market for England, Wales and Scotland. Separate arrangements remain for Northern Ireland.

The UK's electricity supply system consists of large, centralised generating plants connected directly to the high voltage transmission system which spans the country. This connects to localised distribution networks, which deliver the electricity to the end-user at a lower voltage using a combination of overhead and underground cables. The UK's electricity system is one of the world's first fully liberalised electricity markets with generating plants, the national grid system, distribution network and supply companies all privately-owned and operated under the regulation of Ofgem (The Office of Gas and Electricity Markets). The national grid is operated by National Grid Company (NGC; a wholly owned subsidiary of National Grid Transco), who are responsible for ensuring the reliability and quality of electricity supply. Strict rules and targets are in place for them to follow and any serious deviation can result in a heavy fine[1].

1.1.1. *British Electricity Trading and Transmission Arrangements (BETTA)*

The British Electricity Trading and Transmission Arrangements (BETTA) were introduced on 1st April 2005. They replaced the previous New Electricity Trading Arrangements (NETA) in England and Wales, and the separate arrangements that existed in Scotland. Under BETTA (and NETA before it), electricity is traded through bilateral contracts between generators, electricity suppliers and customers across a series of markets operating on a rolling half-hourly basis. National Grid Company (NGC), the system operator of the GB electricity transmission system, operates a balancing mechanism to ensure system security at all times.

Under these arrangements generators self despatch their plant rather than being centrally despatched by the System Operator. There are three stages to the new wholesale market, plus a new settlement process. These are illustrated in Figure 1.

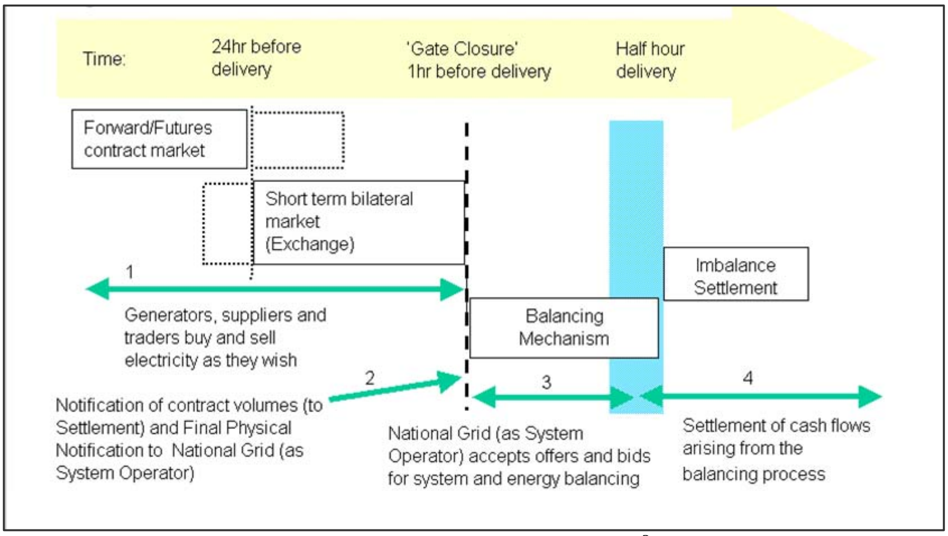

Fig. 1. Overview of UK electricity market structure under BETTA[2].

Participation in the bilateral markets (i.e. the Forward/Futures contract market and the Short-term bilateral markets) and the Balancing Mechanism (i.e. offer/bid submission) is optional. Participation in Settlements is mandatory. In addition, certain categories of generator are required to provide Physical Notifications. The Balancing and Settlement Code (BSC) provides the framework within which participants comply with the Balancing Mechanism and Settlement Process.

Gate Closure is the point in time when market participants notify the System Operator of their intended final physical position and is set at one hour ahead of real time. In addition no further contract notification can be made to the central settlement systems.

1.1.2. *Forwards and Futures Contract Market*

The bilateral contracts markets for firm delivery of electricity operates from a year or more ahead of real time (i.e. the actual point in time at which electricity is generated and consumed) typically up to 24 hours ahead of real time. The markets provide the opportunity for a seller (generator) and buyer (supplier) to enter into contracts to deliver/take delivery, on a specified date, of a given quality of electricity at an agreed price.

The markets are optional with participants having complete freedom to agree contracts of any form. Formal disclosure of price is not required.

The Forwards and Futures Contract Market is intended to reflect electricity trading over extended periods and represents the majority of trading volumes.

Although the market operates typically up to a year ahead of real time, trading is possible up to Gate Closure. Short-term Bilateral Markets (Power Exchanges) operates over similar timescales, although trading tends to be concentrated in the last 24 hours.

The markets are in the form of screen-based exchanges where participants trade a series of standardised blocks of electricity (e.g. the delivery of xMWh over a specified period of the next day). Power Exchanges enable sellers (generators) and buyers (suppliers) to fine-tune their rolling half hour trade contract positions as their own demand and supply forecasts become more accurate as real time is approached. The markets are firm bilateral markets and participation is optional. One or more published reference prices are available to reflect trading in the Power Exchanges.

1.1.3. *Balancing Mechanism*

The Balancing Mechanism operates from Gate Closure through to real time. It exists to ensure that supply and demand can be continuously matched or balanced in real time. The mechanism is operated with the System Operator acting as the sole counterparty to all transactions.

Participation in the Balancing Mechanism, which is optional, involves submitting ‘offers’ (proposed trades to increase generation or decrease demand) and/or ‘bids’ (proposed trades to decrease generation or increase demand). The mechanism operates on a ‘pay as bid’ basis.

The National Grid Company (NGC) purchases offers, bids and other Balancing Services to match supply and demand, resolve transmission constraints and thereby balance the system. Generators and suppliers registered within the Balancing and Settlement Code are bound by the relevant requirements of the Grid Code which includes the arrangements for System Operator to accept Balancing Mechanism bids and offers, for calling off Balancing Services and for dealing with emergencies.

1.1.4. *Imbalances and Settlements*

Power flows are metered in real time to determine the actual quantities of electricity produced and consumed at each location. The magnitude of any imbalance between participants’ contractual positions (as notified at Gate Closure) including accepted offers and bids, and the actual physical flow is then determined. Imbalance volumes are settled at one of the dual imbalance prices; System Buy Price (SBP) and System Sell Price (SSP).

- SBP is the price at which deficits are charged and, when the system is short, reflects the average price at which the system had to buy in order to make good the deficit on behalf of the party (i.e. the average of accepted offers).

- SSP is the price at which surpluses are charged and, when the system is long, reflects the average price at which the system had to sell in order to dispense with the surplus spill energy (i.e. the average of accepted bids).

Imbalance prices are intended to serve as an incentive for market participants to contract sufficiently ahead of Gate Closure to ensure that their physical positions and their contracted positions are balanced. There is therefore a link between imbalance prices and plant margin in that the incentive on a participant to balance determines the level and value of contracting in the forward markets.

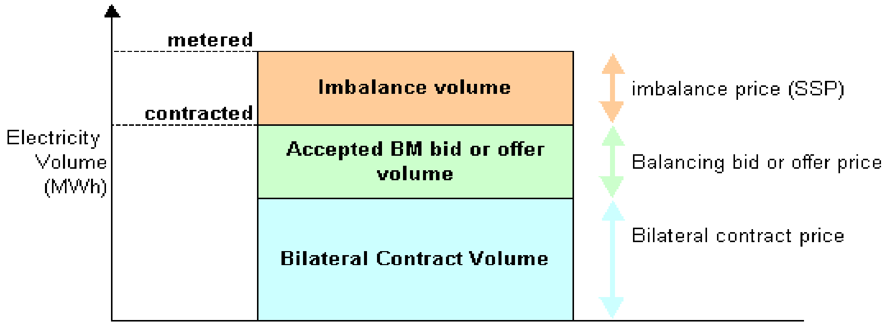

Fig. 2. Energy Imbalance[3].

1.1.5. *Balancing Mechanism Reporting Service (BMRS)*

As part of the BETTA arrangements, market participants have access to information to enable them to trade to balance their positions and self despatch their plant. The Balancing Mechanism Reporting Service (BMRS) is the service for reporting the necessary information that includes:

- Demand forecasts from National Grid;
- Generation availabilities and margins;
- Imbalance forecasts based on participants' Physical Notifications;
- Submitted BM offer and bid volumes and prices; and
- Accepted BM trades and imbalance prices
- A variety of other information related to market operation

Forecast information is primarily made available for the day ahead and on the day. Submitted BM data is made available shortly after Gate Closure. Accepted bids and offers and initial imbalance prices are published shortly after real time.

1.2. Electricity production and demand

1.2.1. *Electricity demand*

The figure below presents daily demand profiles for the days of maximum and minimum demand on the GB Transmission System in 2004/05 and for days of typical winter and summer weekday demand†.

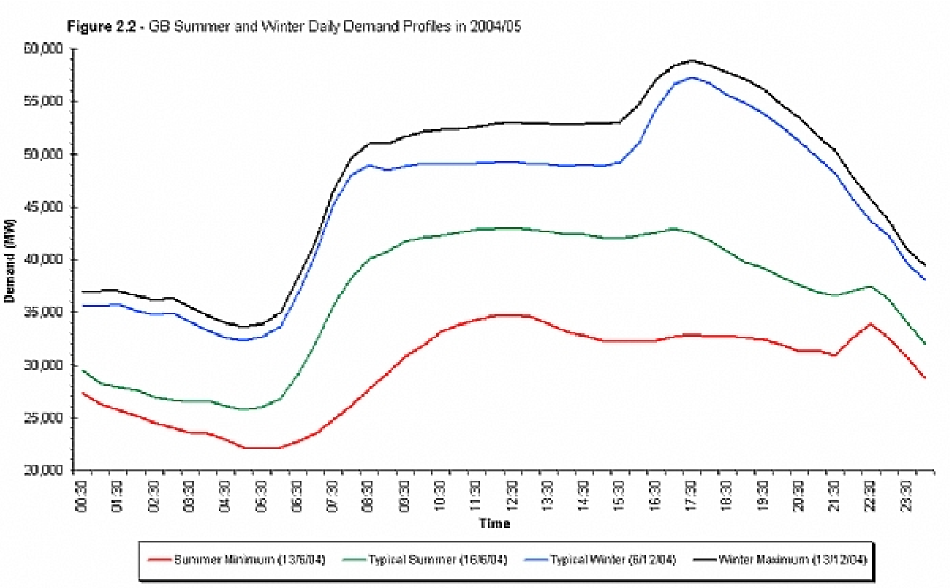

Fig. 3. GB Summer and Winter Daily Demand Profiles in 2004/05[4]

The minimum load in an average year is roughly 20 GW – this would normally be experienced in the very early hours of a warm summer morning. The National Grid Company's 'base' forecast shows annual electricity requirements on the GB Transmission System rising from 355 TWh in 2004/05 to 376 TWh in 2011/12, i.e. average growth of 0.8% pa. Average Cold Spell (ACS) peak demand also increases by 0.8% pa, from 61.5 GW in 2004/05 to 65.0 GW in 2011/12.

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† demands are shown exclusive of station transformer, pumping demand and interconnector exports

1.2.2. *Electricity production*

The capacity of the UK electricity system at the end of 2004 was 80.370 GW, with a peak winter demand during 2004 of 61 GW. The current generation mix is shown in Figure 4. Renewables currently make up 6.8 GW of installed capacity. This figure includes 2.8 GW of pumped storage capacity. The make up of RES-E capacity is shown in Figure 5.

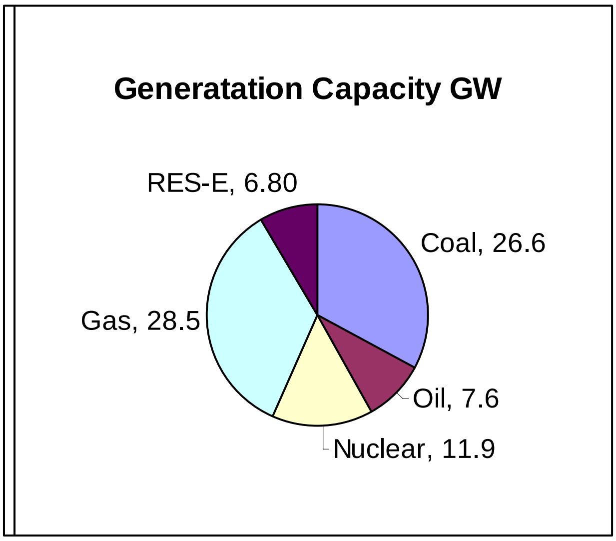

Fig. 4. UK electricity generation capacity (2004)[5]

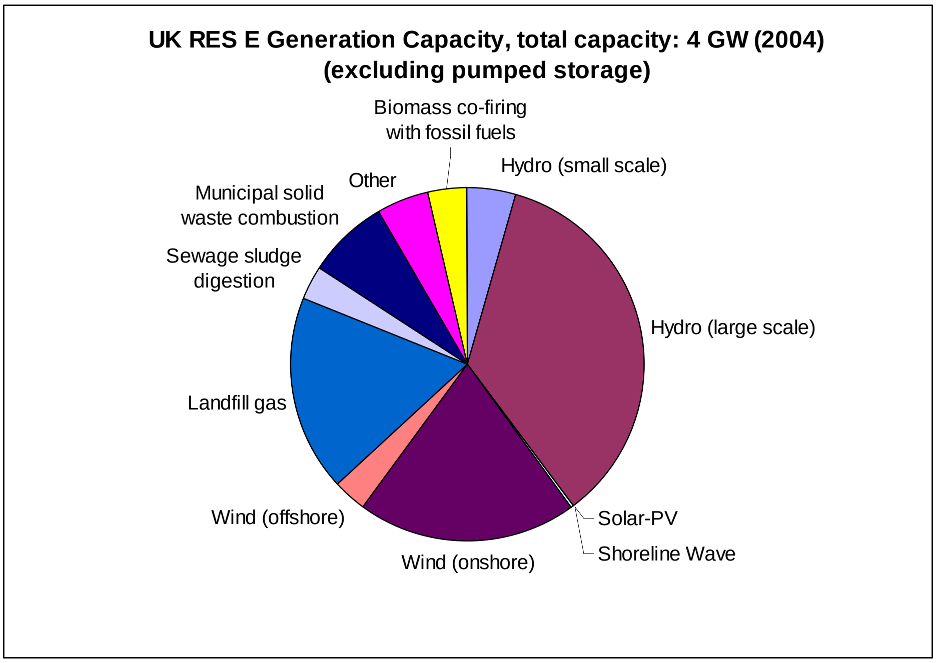

Fig. 5. UK RES E Capacity 2004[5]

In the UK, the Central Electricity Generating Board (CEGB) traditionally adopted a spare capacity margin of 24% in excess of winter peak demand to provide security when planning the need for future installed generation capacity. Under NETA and now BETTA the spare capacity margin is determined solely by the market.

1.3. Past and Expected Development of RES-E

The growth of RES with in the UK is shown in the figure below. Historical figures are taken from Department of Trade and Industry statistics (DUKES) and figures for 2005 onwards are taken from information in a report for the DTI by Oxera 'Results of renewable Energy Modelling' 2004.

Recent growth in RES has largely been due to the expansion of wind energy and also the introduction of co-firing of biomass in conventional coal fired power stations, both of which have benefited from the Renewables Obligation (see section 2.1.2). The growth in wind energy is expected to continue. At the end of 2005 there was 0.7 GW of wind under construction, 2.1 GW of wind consented and awaiting construction and 9.6 GW in the planning system. The future growth of biomass is less certain. The amount of biomass co-firing which

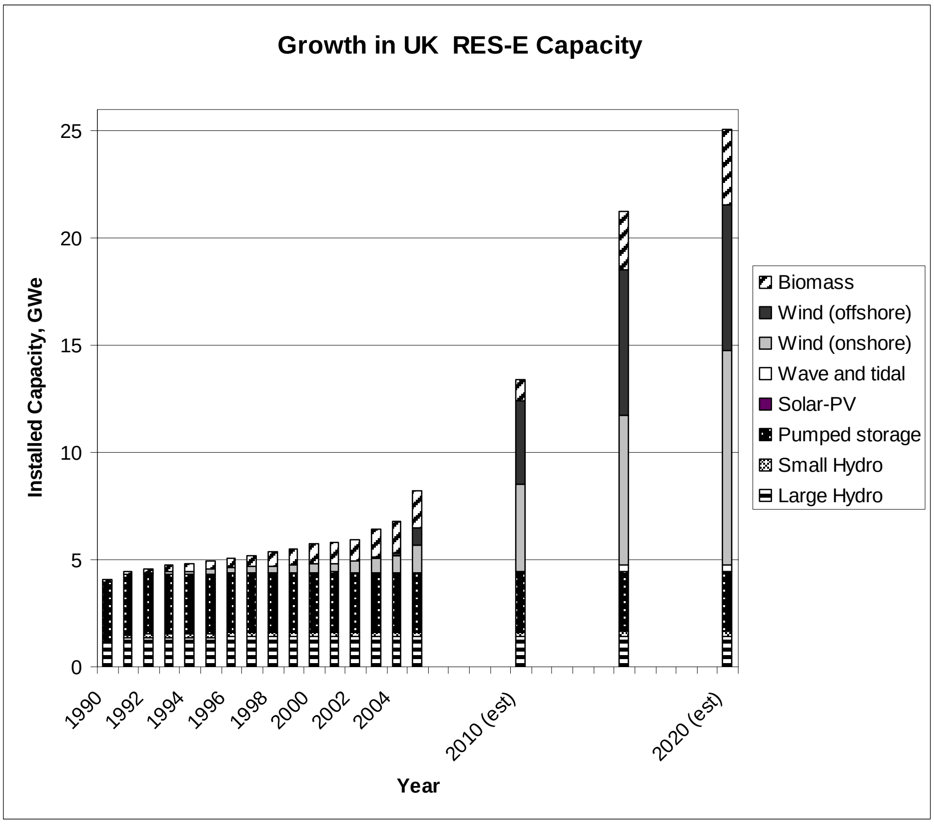

Fig. 6. Growth in UK RES E Capacity6 [5,6]

is eligible for incentives under the Renewable Obligation is being gradually decreased until 2016 when it will no longer be possible to obtain the incentive for co-firing. It is hoped that by this time dedicated biomass power stations will have been constructed however it is uncertain whether this will be achieved, in particular due to design of the current incentives scheme (see section 2.1.2) as well as supply chain issues.

Developments in wave and tidal technologies are expected so that by 2020 they will be making a small contribution to UK electricity demand. These technologies along with PV are considered long term energy solutions but are not expected to make significant contributions in the near term.

2. Conditions of RES-E grid integration

2.1. Integration policies

In England, the Government's Policy on renewable energy is set out in the 2003 Energy White Paper, 'Our energy future – creating a low carbon economy'. The paper confirms the target that, by 2010, 10 per cent of electricity should come from renewable sources. The paper also includes the aspiration that, by 2020, 20 per cent of the UK's electricity supply should be met by renewables. The white paper also requires the individual regions to set targets for renewable energy capacity in the region, derived from assessments of the region's renewable energy resource potential.

In Scotland, The Scottish Climate Change Programme commits Scotland to generating 18 per cent of its electricity from renewable sources by 2010. However, the Scottish Executive has recently agreed that Scotland should aim for 40 per cent of its electricity from renewable sources by 2020. It has announced a series of measures to help reach this target.

In Wales the National Assembly has set out a target to generate 4 tWh per year of energy from renewable sources by 2010, likely to account for 10 per cent of the electricity generated in Wales by that time, and a target to generate 7 tWh per year by 2020.

The Northern Ireland Assembly, as outlined in the Department of Enterprise, Trade and Investment's Strategic Energy Framework 2004, has a development target that, by 2012, 12 per cent of all electricity consumed in Northern Ireland should come from indigenous, renewable energy sources.

2.1.1. *RES Planning Policies*

Planning policy is devolved to national governments, so England, Scotland, Wales and Northern Ireland have separate policies. Policy in relation to renewable energy has recently been updated for England, Scotland and Wales. The underlying aim has been to provide clearer guidelines for the consideration of renewable energy projects and to improve the consistency of decisions. This is in line with wider energy policy and was seen as essential for renewable energy targets to be met.

In England, Planning Policy Statement PPS22 sets out the Government's national planning policies for renewable energy projects in England. PPS22 and its Companion Guide were published in 2004 and are intended to encourage the appropriate development of further renewable energy schemes throughout England. It covers national polices in relation to the sitting of RES generally, and those in close proximity to National Designations e.g. National Parks and Areas of Outstanding National Beauty (AONB). The guide advises planners how to implement PPS22 in their local communities. It explains what makes a ‘good’ renewable energy application, how to assess the impact of plans on the landscape and how to give the community greater involvement. The guide provides advice on the broad range of renewable energy technologies, including biomass, hydro, solar and wind.

In Scotland, National Planning Policy Guideline (NPPG) 6, Renewable Energy Developments sets out the Scottish Executive’s national planning policies for renewable energy projects in Scotland and sets outlined siting considerations for RES at the national level. It states that issues to be considered include visual impact, landscape, birds and habitat. In relation to national designations, it advises that renewable energy projects should only be permitted where it can be demonstrated that the objectives of designation and the overall integrity of the area will not be compromised or any significant adverse effects on the qualities for which the area has been designated are clearly outweighed by social and economic benefits of national importance.

In Wales Technical Advice Note (TAN) 8 outlines the Welsh Assembly Government's aim to secure the right mix of energy provision whilst minimising the impact on the environment and reducing the overall demand for energy. To meet the Assembly's renewable energy target of 4,000 GWh per annum by 2010, the policy aims to achieve 800 MW from strategic onshore wind energy development. The Welsh Assembly Government considers that a few large scale (25 MW+) wind farms could be carefully located to meet the target. TAN 8 identifies seven Strategic Search Areas (SSAs) in Wales which are considered relatively unconstrained. Local planning authorities are encouraged to undertake more detailed mapping and landscape assessment work to formulate local policies for development of large and small scale wind farms in the SSAs and for smaller wind farms outside the SSAs. Community involvement at early stages in the development of policies and proposals is encouraged.

In Northern Ireland regional renewable energy planning policy is currently expressed in the Planning Strategy for Rural Northern Ireland Policy PSU12. It is intended that this will eventually be replaced by a planning policy statement.

2.1.2. *Renewables Obligation*

The main incentive for RES-E production in the UK is the Renewables Obligation, which came into effect in England, Wales and Scotland in April 2002. The Obligation sets a target for electricity suppliers to source at least part of their electricity from renewable generation. The target started at three per cent in 2002-2003 and reaches 10.4 per cent in 2010-2011 and 15.4% in 2015-2016. The target for 2004-2005 is 4.9 per cent. Renewable generators can apply to Ofgem for accreditation to prove that their generation comes from eligible renewable sources. These generators are issued with Renewables Obligation Certificates (ROCs) for their qualifying output. Each ROC represents one megawatt hour of renewable electricity generated. ROCs can be sold by the renewables generator either with, or separately from, the electricity generated. Electricity suppliers can meet their obligation by buying ROCs or by paying a ‘buy out’ penalty (31.39 GBP/MWh for the year 2004-2005). The buy out money is then shared between those who have complied with their obligation in proportion to the amount of ROCs tendered.

A slightly different scheme was introduced in Northern Ireland in April 2005. The Northern Ireland Renewables Obligation has slightly lower obligations levels.

In the year 2004-2005 electricity suppliers met 69% of the total obligation of 15.8 million ROCs. The total amount of electricity supplied under the obligation for this period was 14 315 784 MWh (England and Wales) and 1 445 283 MWh in Scotland. The total payout fund for the period amounted to EUR 19 534 608 (£135 657 001) for England and Wales and EUR 25 348 013 (£17 602 787) for Scotland. One electricity supplier failed to meet their obligation having gone into receivership.

The Renewables Obligation has been effective so far in encouraging wind energy developments and co-firing of biomass in coal fired power stations. The design of the obligation is such that it encourages the most cost effective technologies available on the market now and does not provide assistance to less developed technologies, which will be needed to meet the long term renewable energy aims. Additional support to developing technologies such as biomass power, wave and tidal is therefore required.

2.2. Grid connection and system service requirements

2.2.1. *Grid connection*

There are 12 licensed Distribution Network Operators (DNO) in England and Wales and two in Scotland. These companies each hold a distribution license for the provision of distribution network services. Each DNO owns and operates the local electricity distribution system within its own authorised area. All DNOs have statutory duties to develop and maintain an efficient, co-ordinated and economical system of distribution and facilitate competition in generation and supply. They have a duty to connect any customer who requires a supply. DNOs are obliged to meet minimum standards of performance related to distribution services. New distributed generation wishing to connect to the distribution network must inform the local DNO.

Generating stations that export under 50 MW of electrical power to the grid are not required to have an electricity license to operate. Depending on the size of the generator, installations are expected to comply with Engineering Recommendations G83/1, G59/1 or G75/1:

- ER G83/1[‡] applies to generation under 16 amps per phase, (approximately under 4kW per phase) (although there is a caveat that DNOs can use G83/1 for higher rated installations if deemed more applicable than the Engineering recommendation G59/1 [§]) For single generators, the person responsible for the generator is required to inform the DNO on the day of connection and then provide full details within 30 days. For groups of small scale installations the DNO must be informed prior to connection. The standard aims to ensure the safety of personnel working on the electrical distribution network during maintenance works. The generator must disconnect if there is a grid failure. The generator must be'G83 type tested' which certifies its adherence to specified voltage and frequency limits and anti-islanding protection.
- ER G59/1 applies to generation between 4 kW and 5 MW connected at voltages under 20 kV. The document sets out power quality and anti-islanding protection requirements. A connection agreement must be made with the DNO.
- ER G75/1[**] applies to generation connected above 20 kV or generation with an output greater than 5 MW. G57/1 sets out requirements for design studies to assess the impact of the generator on the network. Other requirements of G75/1 include protection equipment.

The general procedure for connection is as follows:

<u>Stage 1: Feasibility study.</u>

The study is carried out to determine the impact of the proposed generation on the existing network

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[‡] Engineering Recommendation G83/1 Recommendations for the connection of small scale embedded generators (up to 16A per phase) in parallel with public low voltage distribution networks.

[§] Engineering Recommendation G59/1 - Recommendations for the connection of Embedded Generating Plant to the Regional Electricity Companies' Distribution Systems.

[**] Engineering Recommendation G75/1 – Recommendations for the connection of embedded generation plant to public distribution systems above 20 kV or with outputs over 5MW

Stage 2: Formal Connection Offer. Based on successful outcome of stage 1, detailed design work is carried out by the DNO to determine the connection charge and connection offer. Additional technical studies are carried out for large generators (generally over 5MW). These include stability studies.

Stage 3: Project Completion and Commissioning. Following acceptance of the connection offer and completion of other permitting and planning procedures, any necessary work on the electrical network is carried out and the new generator is commissioned.

Obtaining grid connection can cause significant problems to the progress of renewable energy and in particular wind systems both in terms of increasing the cost of getting to the construction stage (due to the internal time taken in discussions/ negotiations with DNOs, etc) and in terms of delaying the project. Negotiating grid connection can take up to 12 months. Grid connection issues which have represented barriers for grid connection of RES-E are listed below. It is hoped that recent developments in planning policies specific to renewable energy, together with changes in grid connection charges and arrangements will help to address these issues and make grid connection of distributed renewable energy easier [7]. These issues include:

- A key issue affecting both the timescales and costs of achieving a connection relates to the process of obtaining Wayleaves[††] for the necessary connection assets.
- Availability and allocation of capacity and issues with queuing systems;
- Lack of clarity in the system which means developers find it hard to plan for grid connections;
- Management and timing of upgrades – in some cases offers have been given but connection dates can be a long way off e.g. 2016;
- Lack of flexibility in terms of when allocations must be taken up and lack of coordination between grid and planning consents;
- The time taken by DNOs to turn around applications, particularly for smaller developers;
- Increased costs of connections.

Table 1 below gives an indication of the cost of connection relating to capital costs on the side of the distribution network. Further details of DNO charging

[††] Permission is required to install electric lines and associated equipment on, over or under private land and to have access for maintenance. Commonly this is done by way of a contractual agreement between the electricity company and the land owner. This is called a wayleave.

and overall likely costs to the generator under a new pricing structure implemented in 2005 are given in section 2.2.2.

Tab. 1. Indicative costs of Connection Works[8]

Works	**Approx. cost**
Cable trenching and reinstatement	
in public highway (tarmac)	EUR 72-144 (£50-100) per metre
in fields or rough ground	EUR 29-58 (£20-40) per metre
11 kV equipment* (up to 5 MW capacity)	
underground cable	EUR 29-72 (£20-50) per metre
overhead line	EUR 14-65 (£10-45) per metre
switching substation (no transformer)	EUR 21600-72000 (£15000-50000)
33 kV equipment* (up to 20 MW capacity)	
underground cable	EUR 29-144 (£20-100) per metre
overhead line	EUR 29-80 (£20-55) per metre
switching substation (no transformer)	EUR 144 000- 360 000 (£100 000-250 000)
*costs include supply, installation, testing and commissioning, but exclude O&M	
132 kV costs vary widely and indicative costs cannot be presented.	

2.2.2. *Philosophy of allocating grid integration costs*

Distribution Network Operators (DNOs) are provided with a revenue stream from demand customers via ‘Distribution Use of System Charges’ (DUoS) that covers the ongoing provision of the distribution network and factors the costs of connection over the long term.

Prior to April 2005 demand and generation customers were charged differently with generators paying connection charges for all works required to connect them to the system (i.e. deep connection charging) and demand customers paying more limited connection charges plus use of system charges (i.e. shallowish connection charging).

The recent distribution price control review (DPCR) brought a series of changes implemented in April 2005 to:

1. simplify the charging structure for connecting distributed generation and bring in shallower charging to generators; and
2. introduce incentives to DNOs to efficiently manage the renewal of network assets and to provide connections for an increasing capacity of distributed generation at all distribution voltage levels

These new arrangements are described in more detail below:

1. Connection charges

From 1 April 2005 a common connection boundary was introduced across generation and demand. New generators (connecting to the distribution network, i.e 132 kV and below) pay shallower connection charges and will begin to pay use of system charges. In addition there is a requirement for DNOs to publish their charging methodologies and justify their approach to setting tariffs in accordance with the license objectives.

As an example, United Utilities' (DNO for the North West of England) charges which came into effect on 1st April 2005 are set out below:

- *Asset annuity charge* – An annuity charge based on 80 per cent of the total cost of the reinforcement works required to connect the generation capacity, over a 15 year life, with a rate of return of 6.9 per cent
- *Capacity Charge* – A standard EUR 2.16 (£1.50) per kW of generation capacity installed (in place of direct recovery of the remaining 20 per cent of the reinforcement assets). An additional EUR 4.32 (£3) per kW of generation capacity installed will be included for distributed generation connected in an RPZ (Registered Power Zone).
- *Operation, Repair and Maintenance Charges* – A standard EUR 1.44 (£1) per kW per annum of generation capacity installed to recover the allowable operation, repair and maintenance on the sole use and reinforcement assets of the connected distributed generator.

Tab. 2. United Utilities Generation Charges as at 1 April 2005[9]

Connection Voltage	**EHV**	**HV or LV**	**LV** (16 Amps per phase, single or multiphase, 230/400 Volt)
Charge to generator Cost per annum per kW of installed generation capacity)	Range: EUR 0- 27.9 (£0.00 - £19.96) Average: EUR 8.3 (£5.77)	EUR 9.26 (£6.43) United Utilities expect to connect generation customers (connected at HV or LV) at an average cost of EUR 86 (£60. /kW)	No charge (United Utilities does not expect to reinforce its electrical network to connect small scale embedded generation during 2005/6)

2. DNO Incentives to Connect DG

The Distributed Generation Incentive allows DNOs to recover their generation connection costs by a combination of pass through (80%) and incentive per kW connected (EUR 2.16 (£1.5) per kW). In addition to the DG incentive Ofgem has introduced the *Innovation Funding Incentive* and *Registered Power Zones* incentive mechanisms.

- **Innovation Funding Incentive (IFI):** The IFI is intended to provide funding for projects focused on the technical development of distribution networks to deliver value (i.e. financial, supply quality, environmental, safety) to end consumers. IFI projects can embrace any aspect of distribution system asset management including connection of distributed generation. A DNO is allowed to spend up to 0.5% of its Combined Distribution Network Revenue on eligible IFI projects and can recover a significant proportion of associated costs from its customers (90% in 2005/2006). DNOs have to openly report their IFI activities on an annual basis.
- **Registered Power Zones (RPZ):** In contrast to the IFI, RPZs are focused specifically on the connection of generation to distribution systems. RPZs are intended to encourage DNOs to develop and demonstrate new, more cost effective ways of connecting and operating generation that will deliver specific benefits to new distributed generators and broader benefits to consumers generally. If a DNO employs genuine innovation in the way that it connects generation it can seek to register the connection scheme as an RPZ. For registered RPZs, the incentive element of the DG Incentive is increased for the first five years of operation by EUR 4.3 (£3) per kW.

Open reporting (i.e. available in the public domain) of IFI and RPZ projects is required. This is intended to stimulate good management and promote sharing of innovation good practice.

2.2.3. *System Service Requirements*

There is a single Distribution Code for Great Britain, which specifies standards for the design and operation of DNO-owned distribution networks (i.e. 33kV and below). To meet these standards, DNOs need to be forewarned about the connection of large loads and generator installations to their networks. The Distribution Code therefore requires users of distribution networks, such as electricity consumers and generators, to provide certain information about new loads and generator installations. It also specifies arrangements for the design of connections to DNO networks, and certains requirements for the control and protection of distributed generators.

The Distribution Code requires that generator installations should be capable of supplying its full declared output regardless of variations in system frequency over the range 49.5 to 50.5Hz. The power output of the installation should not be affected by permitted voltage variations on the network.

The protection systems installed with the generator installation must coordinate properly with the protection systems on the DNO's network. To

ensure that this is achieved, the generator protection must satisfy the following requirements:
(a) It must meet target clearance times specified by the DNO.
(b) Its settings must be agreed between the developer and the DNO.
(c) It must co-ordinate with any auto-reclose policy specified by the DNO.

In addition to the above requirements the Distribution Code also refers to the Engineering Recommendations G83/1, G59/1 or G75/1 which make specific technical requirements for generators depending on their rated size and the voltage at which they are connected to the network.

The GB Grid Code specifies standards of operation of the design and operation of the transmission network. This generally means parts of the network at 132 kV and above although there are differences between regions in the voltage recognised as being part of the transmission network. As well as generators which are directly connected to the transmission network, the Grid Code also covers generators which are connected to the distribution network but which are subject to central dispatch. In addition, where the National Grid Electricity Transmission (NGET) plc considers a generator to have an impact on the transmission system NGET can require the generator to comply with some or all of the Grid Code. The GB Transmission Network Operators have recently set out a proposal that specifies requirements for connecting wind generation equipment to the transmission network. The main capabilities required of wind farms in the proposed GB Grid Code modifications are:

- Reactive power capability
- Active voltage control
- Restricted maximum ramp rates
- Operation over an extended frequency range
- Frequency control capability
- Power system stabiliser function
- Fault ride-through capability

The requirements of the new GB Grid Codes cannot be met by fixed speed induction generator wind turbines without additional equipment to provide fast control reactive power. The national grid company estimates that that the additional costs of meeting the new requirements will be between 1.4%-6% of the turbine capital costs.[10]

2.2.4. *Planning*

Planning consent for new RES generation must be obtained either from the local planning authority (for projects under 50 MW on shore and under 1MW offshore) or by the Department of Trade and Industry (DTI) (for England and Wales) or by the Scottish Executive (for Scotland) for larger projects. The key stages to gaining planning consent are as follows:

- Initial consultation: Developers are encouraged to begin initial consultations with the planning authorities and other statutory bodies at an early stage in the project development.
- Public consultation: Where projects are likely to be contentious, early dialogue and consultation with the general public is encouraged. The aim of such consultation is identify particular public concerns so that these can be addressed in the detailed project proposals.
- Environmental Impact Assessment (EIA) screening: Where the local planning authority believes that a proposed project may have significant effects on the environment it will require the project developer to submit an environmental statement.
- Submission of application.
- Determination: Unless the applicant and the planning authority have agreed a longer period, if no decision has been made after eight weeks, the applicant can appeal on the grounds of non-determination. In the case of applications accompanied by an EIA, the period of time available for determination is four months.
- Planning conditions and planning obligations: Local Planning Authorities have the power to attach conditions to a grant of planning permission and to seek planning obligations from developers, which can enable proposals to go ahead which might otherwise by refused. Planning obligations can be used, for example, to require developers to:
    - undertake off-site highway improvements or
    - undertake habitat enhancements.

Following determination of the application, the time taken to conclude the application is typically 6 months and in some cases up to a year. For onshore projects over 50 MW and 1 MW offshore the planning authority must consider all arguments for and against the proposed development before awarding consent. A local planning enquiry may be held.

There are a number of factors which lead to delays in the planning approval:

- Local authorities are under-resourced and don't have time to deal with planning agreements;
- Local authorities can be resistant to receiving draft planning agreements from developers and want to draft their own agreements which takes time;
- If there are multiple landowners involved in a scheme each landowner will need to sign the planning agreement;
- Some local authorities are unclear about what a planning agreement should contain. This is less of a problem with some authorities in Scotland which are used to dealing with applications. Particular problems are occurring in mid Wales and many local authorities in England who have never dealt with applications of this nature before.

3. Case Study: Onshore wind

3.1. Onshore Wind in the UK

There is currently 1337 MW[11] of wind energy connected to the grid in the UK, generating around 3 500 GWh per year. Figure 7 shows the growth in UK installed wind capacity since 1999. Onshore wind power is currently one of the cheapest forms of renewable energy per kWh in the UK and is expected to represent the majority of new renewables capacity in 2010 and 2020. The UK has some of the best wind resources in Europe in both onshore and offshore locations. The UK's technical wind resource is estimated at 50 000 GWh.[12] The average long term capacity factor of wind power in the UK is 30%.

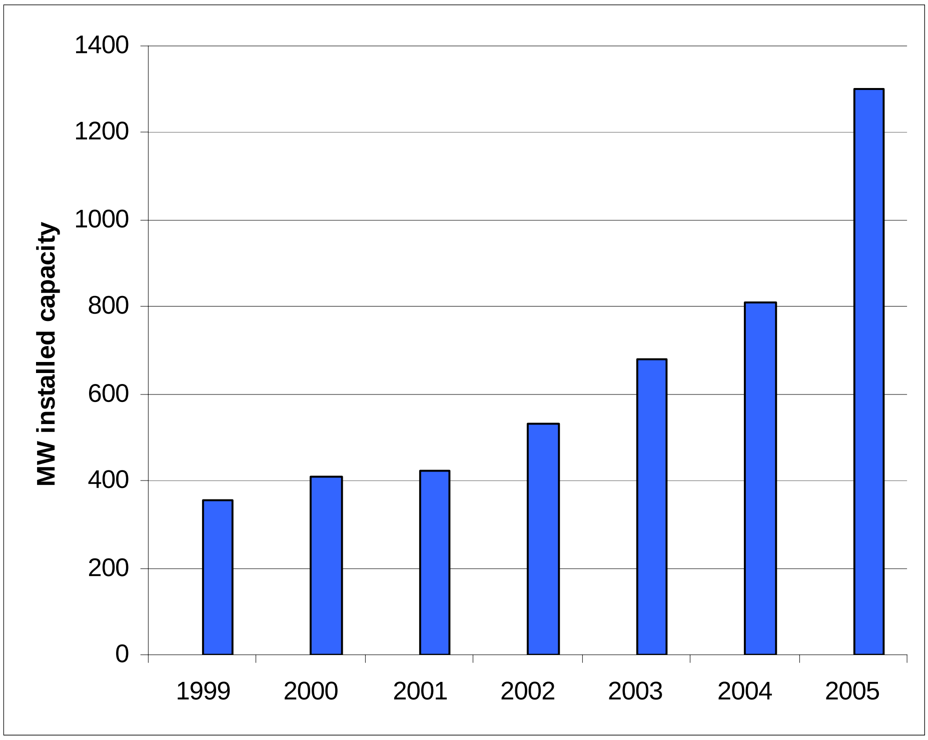

Fig. 7. Growth in UK installed wind capacity[13]

3.2. Tappaghan Mountain, Northern Ireland

Tappaghan Mountain Windfarm has been chosen as an example case study. The wind farm is located on the townland of Glenarn, near Lack in County Fermanagh and on the border with Co Tyrone, made up of the town lands of Glenarn, Stranahone and Stranadarriff. The site is open moorland and is approximately 250 hectares in size.

The wind farm consists of thirteen 1.5 MW GE Wind turbines, totaling 19.5 MW. The wind farm typically produces 51 250 MWh per year, which represents 57% of the domestic electricity needs of the population of Fermanagh District Council.

Fig. 8. Wind turbine at Tappaghan Mountain

3.3. Costs

3.3.1. *Capital costs*

In 2004[‡‡][14], the overall average installed wind plant cost was €980/kW (£670/kW). An analysis of UK projects, only, suggests an average cost of EUR 1109 (£770) per kW. As UK project costs often include provision for operation and maintenance over the first few (typically three) years, this may account for the higher UK figure. Other possible reasons are the cost of securing planning consents and the extra costs of construction in remote hilltop locations. An appropriate range of capital costs is EUR 940/kW to EUR 1300/kW (£650/kW to £900/kW spanning the range one standard deviation either side of the mean). The 2006 Energy Review[15] uses similar capital costs as a basis for its financial modelling.

Total project costs for the Tappaghan Mountain Wind Farm were 25.5 million EUR (17.7 million GBP). The Tappaghan Wind Farm at EUR 1308 (£908/kW) is therefore at the upper limit of the UK cost range. This total project cost does not include any operational costs[16]. The relatively high cost of the project in comparison with other wind farms may be attributed to a

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[‡‡] David Milborrow maintains a database of wind energy project costs, worldwide, drawn from various renewable energy newsletters, manufacturers’ press releases, and journals such as "Windpower Monthly" and "Power UK". The database is used to compile an article comparing wind energy generation costs with those from thermal sources in the January issue of Wind Power Monthly.

combination of challenging ground conditions (peat bog), a lengthy planning process and issues with grid connection.

It was not possible to obtain a detailed cost breakdown but a typical cost breakdown for an onshore wind farm is:

Turbines	72%
Foundations	6%
Electrical connections	2%
Planning	4%
Grid connection	10%
Miscellaneous	6%

It was not possible to obtain details of the cost of grid connection but it is likely that obtaining the grid connection was a lengthy and costly process. In Northern Ireland, an application has to be submitted for overhead wires and Wayleave Rights by the grid operators. The developer can either apply for overhead wires and Wayleave Rights once the windfarm scheme has been approved by the planning authority or submit the planning application for overhead wires and Wayleaves in parallel with the windfarm application. However, this latter route is risky because the developer has to pay the grid operators to submit the application (a cost which can be approximately EUR 28 800 (£20 000)) without having received planning approval.

3.3.2. *Operation and maintenance*

Operation and maintenance costs are estimated by David Milborrow as being in the range EUR 23 (£16) per kW to EUR 29 (£20) per kW plus 1.5% of revenue, reflecting typical royalty payments to landowners.

3.3.3. *Generating costs*

Table 3 summarises the range of cost estimates derived from an analysis carried out by David Milborrow for The Environmental Audit Committee (2005). The analysis was based on the capital and operation and maintenance costs given above and a 15-year capital recovery period, coupled with an 8% “real” test discount rate.

Tab. 3. Onshore wind: current estimates of generating costs (£/MWh)

	Wind speed, m/s		
	7	8	9
Low cost, £650/kW	41.6	32.9	
High cost, £900/kW		44.8	37.0

4. Case Study: Photovoltaics on Social Housing, Kirklees

4.1. Photovoltaics in the UK

The cumulative installed photovoltaic (PV) capacity in the UK at the end of 2005 was 10.9MW. Recent trends in the cumulative installed PV generation capacity are shown in Figure 9. Although the capacity remains very small in comparison to the UK's electricity demand, the annual installed capacity has increased during recent years largely due to the completion of a number of projects under the DTI's grant supported programmes and in particular the Major Demonstration Programme which was introduced in 2002 to provide 50% capital grants. The majority of the new capacity is grid connected.

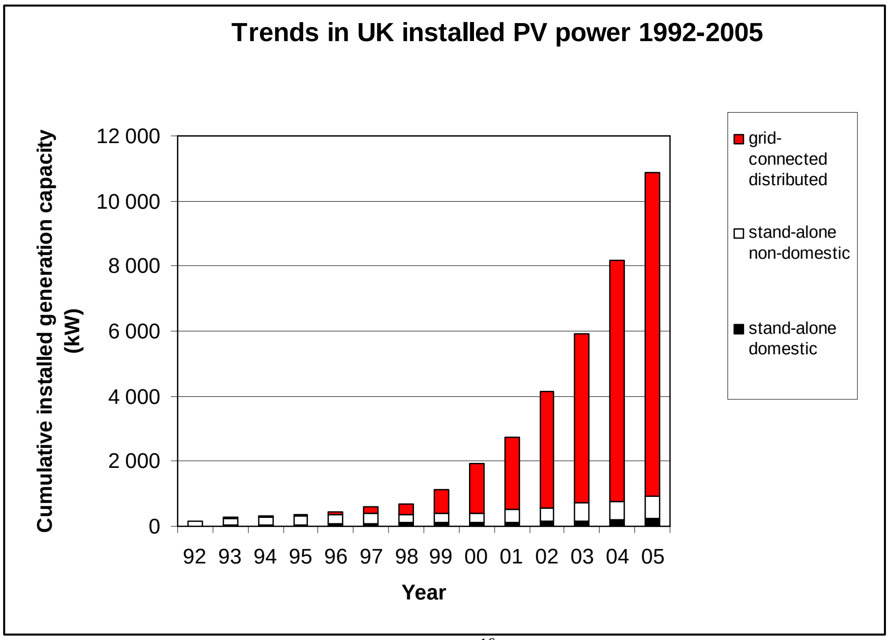

Fig. 9. Trends in UK installed PV power 1992-2005 [16]

Annual generation per kWp PV in the UK varies depending on location. The figure generally used for a typical average system in the UK is 750 kWh / kWp/ annum.

The majority of PV systems in the UK are building mounted on homes, schools and public buildings. There are no centralised PV systems in the UK. Social housing providers are increasingly using PV to reduce the energy bills of tenants. One such example is given in the following case study.

4.2. Description

The installation at the Fernside Estate in Almondbury, Huddersfield, comprises 100 separate photovoltaic (PV) systems on social housing properties owned by the Local Government (Kirklees Metropolitan Council (KMC)). Systems are installed on bungalows and two storey blocks of flats. Completed in 2005, the project is the largest grouped domestic PV installation in the UK.

Each system has a rated power of 1.08 kWp comprising six BP Solar BP7180s mono-crystalline PV modules and a Fronius SunRise inverter. The modules are fixed to the roof using the Conergy Suntop II mounting system. The project was managed and the systems installed by Sustainable Energy Installations, a UK installer of small scale renewable energy systems.

Generation for the site is predicted as 81 000 kWh per year (810 kWh per dwelling). Fuel poverty is an issue with many of the residents at the Fernside Estate and the addition of a PV system is important in reducing the tenants' energy bills.

The systems were individually connected to the low voltage distribution network at 230V, under the UK Engineering Recommendations G83/1 (multiple installations).

Fig. 10. Several of the PV systems installed at the Fernside Estate

4.3. Costs

4.3.1. *Capital costs*

Although the installer was not prepared to provide detailed cost information for this project, detailed data on the cost of PV in the UK is collected as part of IEA PVPS Task 1[17]. Recent trends in prices for small scale domestic PV systems are presented below in Table 4. The range of prices takes into account the significant differences in the projects: the type of technology, the level of standardisation, level of integration etc.

Tab.4: UK trends in system prices (current £) for 1-3 kW roof-mounted system

YEAR	2000	2001	2002	2003	2004
Price /W:	EUR 7.6-10.6	EUR 8.4-12.8	EUR 4.6 - 13.6	EUR 6.4-19.9	EUR 6.0-13.9
	(£5.3 - £7.4)	(£5.8 - £9.0)	(£6.6 - £19.6)	(£4.6 - £13.8)	(£4.2 - £9.7)

The overall price of the Fernside 100 systems project is estimated at EUR 6 000 (£4 600) per kW or EUR 720 000 (£500 000) in total. This is estimated to be broken down as follows (breakdown based on IT Power's experience):

Tab.5: Estimated cost breakdown for the 100 Fernside PV systems

Item	**EUR (2004)**
Equipment	468000
Installation	79200
Civils	43200
Design	2900
Other	2900
Commissioning	11500
Connection costs	5000
VAT	107200
Total	720000
EUR/kWp	6600

Since the systems were connected under Engineering Recommendation G83/1, the amount charged by the DNO for connection were small (of the order of EUR 2880 (£2000) for all 100 systems). An estimated cost breakdown is given below in Table 6.

The cost of grid connection per system is therefore very small, both in terms of actual cost and as a percentage of the total cost. Costs of connecting larger systems which fall under Engineering Recommendation G59 are greater due to increased protection requirements, the cost of the application itself and the fact that the DNO may feel that a larger system is likely to affect the network and may wish to undertake a study to assess any possible impacts.

Tab.6: Estimated grid connection costs for the 100 Fernside PV systems

	Cost per household system (1.08 kWp) (EUR)	**Total Cost for 100 systems (EUR)**
Grid connection (materials, manpower)	22	2160
Transformation		0
Price for contracts and permissions to connect	29	2880
Total	**50 EUR (<1% total system costs)**	**5040 EUR**

For systems which fall just within G59 (i.e. over 16 Amps per phase) and where the DNO requires that Engineering Recommendation G59 is followed strictly, grid connection costs can be much higher. A 4 kWp system connected to a single phase technically falls within G59. This could mean that grid connection costs would be as high as 600 EUR per kWp or 7% of total costs. In practice however DNOs are able to consider installations on a case by case basis and are likely to allow systems that are only just over 16 Amps per phase to be connected under G83.

4.3.2. *Operation and maintenance*

Since the maintenance requirements of PV are minimal the associated costs are small. It is estimated that an annual check of all 100 systems would take approximately 1 week, at a cost of around EUR 1400 (£1000).

5. Conclusions

- The grid connection process for distributed generation has represented a significant barrier to new RES E in the UK in terms of the time taken to obtain a connection agreement, the high costs of connection and the application process and uncertainties in the process and costs.
- It is hoped that recent changes to the grid connection process will address some of these issues and assist developers. Rather than generators paying deep connection charges, from April 2005 new generators pay shallower connection charges and also pay use of system charges. In addition there is a requirement for DNOs to publish their charging methodologies and justify their approach to setting tariffs in accordance with the licence objectives. It

is too early to assess the impact of these changes however these should represent significant improvements for new distributed generators.

- The grid connection of very small scale renewable energy systems i.e. below 16 Amps per phase such as the domestic photovoltaic systems presented in the case study is very simple and represents a very small proportion of the total project cost (< 1%). This is in contrast to larger systems such as wind farms where grid connection costs make a significant part of the total capital cost of a project.
- The British Electricity Trading and Transmission Arrangements (BETTA) were devised to deliver short term low cost power, but emphasis on economic performance penalises renewable energy and small scale generators.
- The UK's main incentive for renewable energy, the Renewables Obligation has been successful in encouraging low cost market ready technologies such as wind energy but it does not encourage the development of new technologies such as biomass, wave and tidal energy.
- A different type of incentive such as technology specific feed in tariffs is required to support new technologies and so meet the long term targets.
- In January 2006 the UK government launched a new energy consultation 'Our Energy Challenge: securing clean, affordable energy for the long term'. The consultation has a broad scope but amongst its key issues for consideration is the reexamination of further nuclear power in the UK, once the current plants come out of operation in the next 10-15 years.

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SWEDISH CASE STUDY

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Abstract. This case study describes Swedish electricity market, liberalised in 1996, and the state of the art of RES-E sources in the grid. Two cases of on-shore wind power are used in purpose to exemplify the development of RES-E in Sweden.

Keywords. Sweden, Swedish electricity market, wind on-shore

1. Description of electricity system

1.1. Design of electricity market

The Swedish electricity market was liberalised in 1996, opening both electricity trading and electricity production to competition. Today, it is largely integrated with electricity markets in the other Nordic countries, with electricity being traded on the common Nord Pool exchange.

The electricity markets in the Nordic countries have undergone major changes since the middle of the 1990s. Norway liberalised its market in 1991, Finland in 1995 and Denmark in 1999 (Swedish Energy Agency, 2005).

With the change in the regulations governing the Swedish electricity market, the Norwegian electricity exchange became a joint Swedish/Norwegian exchange, Nord Pool. In 1998, Nord Pool was expanded to bring in Finland, and in 2000 it was further expanded to include Denmark. Nord Pool is a common market exchange for electricity trading, open to electricity producers, electricity traders and larger electricity users throughout the world (Swedish Energy Agency, 2005).

Svenska Kraftnät (The Swedish National Grid Operator) gives the following short description of the Swedish electricity market operation (Svenska Kraftnät, 2006):

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“Every final electricity customer, from industries to households, must have an agreement with an electricity supplier (power trading company) in order to be able to buy electricity. The power trading company can have several roles; electricity supplier as well as balance provider. Balance responsibility means that the company is financially responsible for the production and consumption of power always being in balance within the company's commitment. If consumption and/or sales exceed generation and/or purchases, the balance provider will have to pay for power (balance power) sufficient to restore the balance. A power trading company can either have the balance responsibility itself or purchase this service from another company. The power trading company can purchase power on Nord Pool - the Nordic power exchange - or directly from an electricity producer or another trading company.

The production plants are owned by the electricity producers. The network owners are responsible for transmitting the electrical energy from the production plants to the consumers. This is achieved via the national grid, the regional networks and the local networks, which are all owned by different network companies. The regional networks transmit power from the grid to the local networks and sometimes to major consumers, for instance industries. The local networks distribute power to the final customers within a certain area. All network owners report their consumption and production measurements to Svenska Kraftnät's settlement system.

Svenska Kraftnät owns the national grid and has the role of system operator. This means ensuring that production/imports correspond to consumption/exports and that the Swedish electricity system's plants work together in an operationally-reliable way”.

Figure 1 gives a schematic overview of the Swedish electricity market:

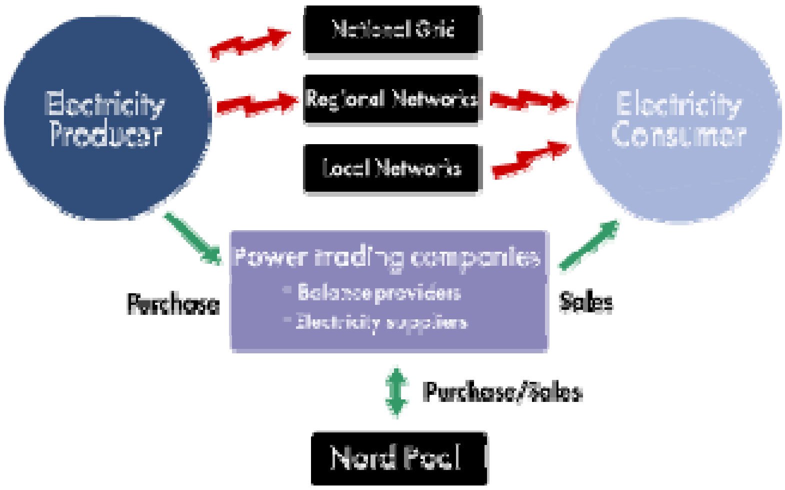

Fig. 1. The Swedish Electricity market (Svenska Kraftnät, 2006)

The national grid consists of 220 kV and 400 kV lines. The regional networks are connected to the national grid, and operate at a lower voltage, usually 70-130 kV. Most of the regional networks are owned by the large electricity producers. The local networks are connected to the regional networks, and supply electricity to domestic users and to most industries. These networks normally operate at 20 kV, with power being transformed down to the normal domestic voltage of 400/230 V. The local networks are owned primarily by the major electricity producers and by local municipalities.

The price of electricity on the competitive Nordic electricity market is determined by supply and demand. The parties involved in the market are electricity producers, electricity traders, network utilities and end users.

The electricity market in Sweden is characterised by vertically integrated companies, i.e. companies that control activities in electricity production, distribution, and electricity trading. Vattenfall, Fortum and E.On (formerly Sydkraft) are major parties in Sweden and the Nordic countries in terms of electricity production, electricity distribution and electricity trading (Swedish Energy Agency, 2005).

1.2. Electricity production and demand

As mentioned previously, the electricity markets in Nordic countries (Sweden, Norway, Denmark and Finland) are closely integrated. Figure 2 gives an overview of the electricity production by source in these countries.

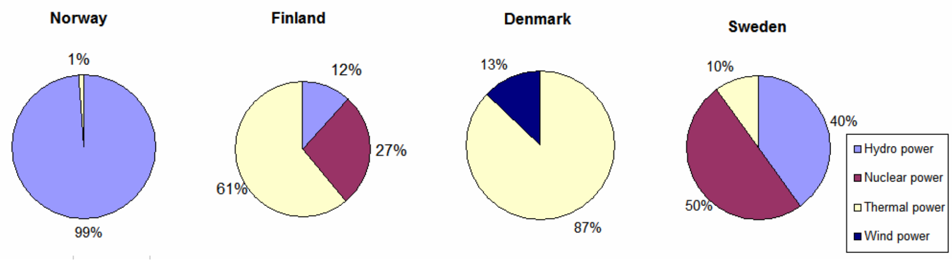

Fig. 2. Electricity production in Nordic countries in 2004 (Swedish Energy Agency, 2005)

1.2.1. *Electricity production in Sweden*

Electricity production in Sweden is based mainly on nuclear power and hydro power. These two power sources provide over 90% of the country's total electricity production, with the remaining 10% being supplied by fossil-fuel and biofuel production and a small quantity of wind power. Total electricity production in 2004 amounted to 148.2 TWh, which was an increase of 15.5 TWh over 2003. Hydro power supplied 59 TWh during 2004, which, although 10% less than in a statistically average year, was 11% higher than in 2003. The eleven Swedish nuclear power reactors produced 75 TWh in 2004, which is the highest annual nuclear production so far in Sweden. Wind power increased by a third from 2003, rising to 0.9 TWh. Conventional thermal power production provided 12.9 TWh. Table 1 shows the details of the Swedish electricity production, broken down by energy source. Electricity production varies in parallel with electricity consumption, which means that production and consumption is higher during the winter than during the summer (Swedish Energy Agency, 2005).

Tab. 1. Net electricity production in Sweden (TWh) (Source: Swedish Energy Agency, 2005)

	1990	1997	1998	1999	2000	2001	2002	2003	2004
Production	141,7	145,3	154,7	151	142	157,7	143,2	132,3	148,2
Hydro power	71,4	68,2	73,8	70,9	77,8	78,4	65,8	52,8	59,5
Wind power	0	0,2	0,3	0,4	0,5	0,5	0,6	0,6	0,8
Nuclear power	65,2	66,9	70,5	70,2	54,8	69,2	65,6	65,5	75
Conv. thermal power	5,1	10	10,1	9,4	8,9	9,6	11,3	13,2	12,9
Industrial CHP	2,6	4,2	4	3,9	4,2	3,9	4,6	4,7	5,4
CHP in district heating systems	2,4	5,6	6	5,6	4,7	5,6	6,3	7,9	7,5
Cold condensing, including gas turbines	0	0,2	0,1	0	0,1	0,1	0,4	0,6	0
Consumption	139,9	142,6	144	143,5	146,6	150,4	148,6	145,1	146,1
Of which distribution losses	9,1	10,7	10,9	10,6	11,1	11,9	11,8	10,6	11,2
Import-export	-1,8	-2,7	-10,7	-7,5	4,7	-7,3	5,4	12,8	-2,1

1.2.2. *Available installed capacity by technology in Sweden*

Figure 3 shows the installed capacity in Sweden in 2004. It has fallen considerably since the deregulation of the market, with most of the reduction occurring in conventional thermal power production capacity. Bearing in mind that, over the same period, electricity production has increased, the reduction in installed capacity means that there is less reserve capacity in the Swedish electricity production system. Since the winter of 2000/2001, available installed capacity in cold condensing power stations and gas turbine power stations has increased as result of Svenska Kraftnät (Swedish National Grid Operator) purchasing standby capacity (Swedish Energy Agency, 2005).

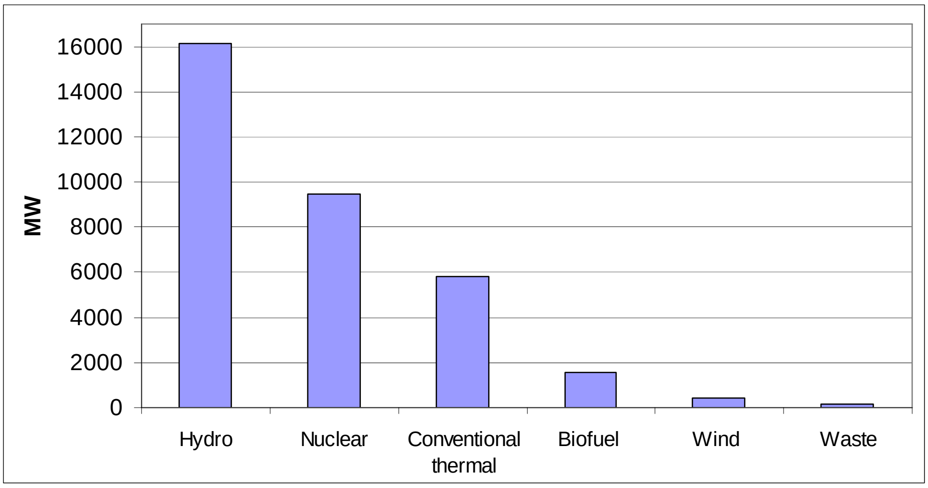

Fig. 3. Installed capacities for electricity production in Sweden in 2004 (Source: Nordel, 2006)

The major renewable energy source in Swedish electricity system is hydropower, covering around 87.3% of the electricity production (16.1 GW installed capacity). In the second place is the bio fuel electricity, covering around 10.2%(1.6 GW installed capacity). It is followed by wind power and waste, 1.3% (0.5 GW) and 1.2% (0.2 GW) respectively.

There are also very little amounts of biogas and PV (20 MW and 3 MW installed capacity respectively).

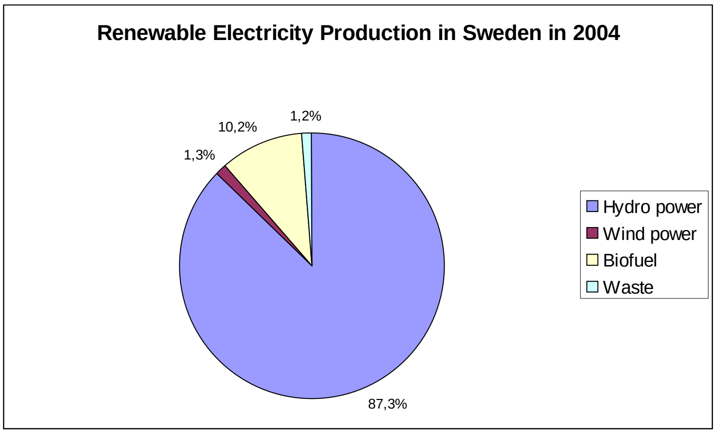

Fig. 4. Renewable electricity production in Sweden in 2004 (Source: Nordel, 2006)

Electricity consumption in Sweden varies with the ambient temperature, as space heating of residential buildings and commercial premises accounts for a considerable proportion of electricity use. In 2004, total electricity consumption in Sweden amounted to 146.1 TWh, with the residential and service sector accounting for about half of this, and industry for about 40%.

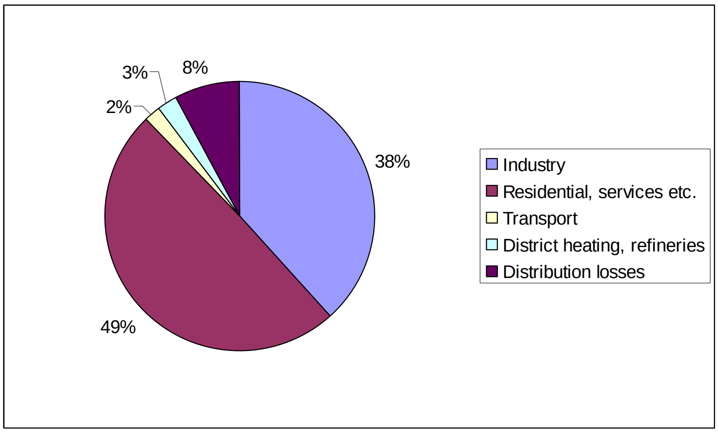

Fig. 5. Electricity consumption in Sweden by sector.

Table 1 shows the changes in the pattern of electricity consumption from 1990. During the 1970s and 1980s, electricity consumption in Sweden increased at a rate of over 4% per year: over the period from 1990 to 2004, this annual increase had fallen to less than 0.5%. After correction for a normal climate year, the annual increase drops still further, to about 0.15%.

1.3. Past and expected development of RES-E

Sweden sets a target for the increase of the amount of RES-E by 10 TWh from 2001 to the year 2010. In the EU Renewables Directive, the indicative target for Sweden has been set at 60% of the electricity consumption in 2010 (including large hydro) (ECN, 2005).

The predominant RES-E production source in Sweden at present is hydropower with the installed capacities of over 16 GW. It has not been changing significantly during last two decades. The major resources are located in the Northern part of the country. Even though there is higher theoretical potential for expansion, the present environmental regulations are not allowing the significant increase in the installed capacities.

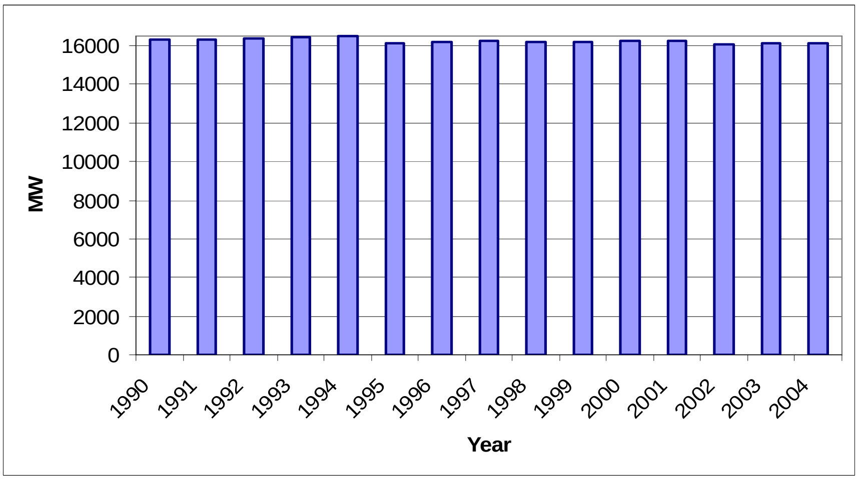

Fig. 6. Historical development of installed hydropower capacities in Sweden (Source: Nordel)

The second largest RES-E source is bio fuel electricity, followed by wind and waste energy. The major bio fuel source in Sweden is wood and wood residues.

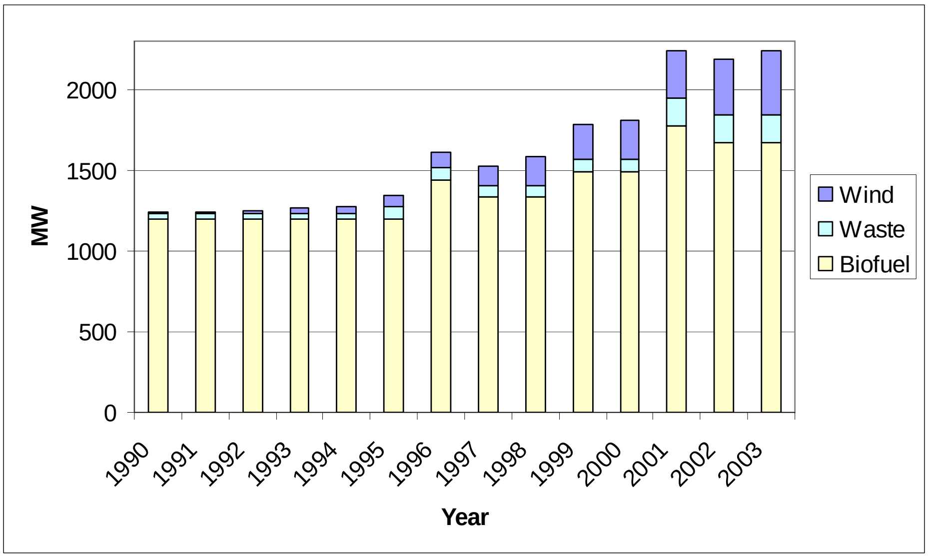

Fig. 7. Historical development of installed RES-E capacities (except hydropower) in Sweden (Sources: Nordel, Swedish Energy Agency, Eurostat)

Wind energy is experiencing a rapid development during last years and is expected to continue or even increase this trend. The development overview is shown on Figure 8.

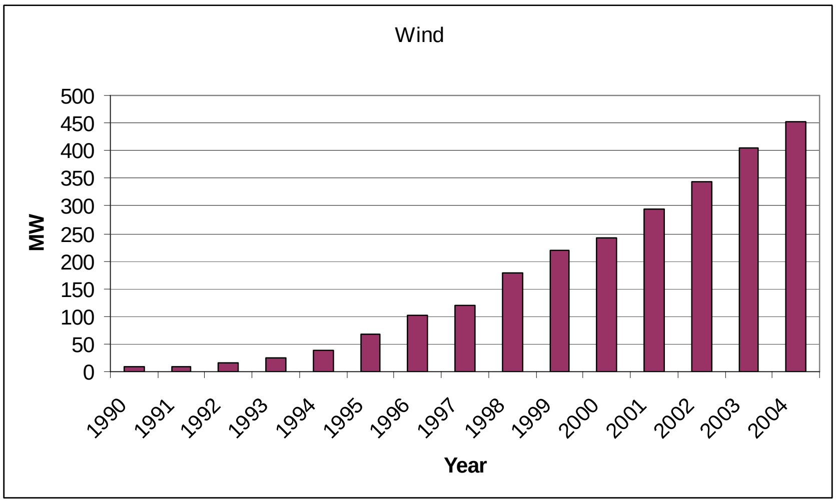

Fig. 8. Wind power development in Sweden (Source: Swedish Energy Agency, 2006)

The total reported wind power production in Sweden in 2004 was 850 GWh, which is 25% increase comparing to the previous year. The present number of registered wind plants is 723. The installed capacity increased by 12% in year 2004.

The Swedish Energy Agency set the target to increase wind power production up to 10 TWh until year 2015. (Swedish Energy Agency, 2005a).

2. Conditions of RES-E grid integration

2.1. Integration policies/renewable energy policies and measures

2.1.1. *Policy instruments*

Sweden, as well as the EU, encourage expansion of electricity production based on renewable energy sources. Swedish Energy Agency (2005) gives a short historic overview of the development of the supporting mechanisms for RES-E:

"Since the 1990s, Sweden has operated several systems for supporting electricity production from renewable energy sources. Investment grants have been provided, for example, for electricity production from biomass, wind power and small-scale hydro power, while production subsidies have been paid for electricity from wind power plants. The country also has a number of

voluntary systems, one of which is the Swedish Society's for Conservation of Nature 'Bra miljöval' ['Good environmental choice'] for electricity, which was introduced after the 1996 electricity market reform. However, the Swedish Energy Agency has established that the voluntary systems have not succeeded in encouraging an expansion of renewable electricity production to the extent that would be desirable".

Taxes and investment subsidies have been the main economic instruments in Swedish energy policy, although the country has started to move towards more market-based systems in recent years, as is well illustrated by the electricity certificate system that was introduced in 2003, and the emission allowances trading system that was introduced in 2005 (Swedish Energy Agency, 2005).

The environmental bonus for wind power production remains, but will be progressively reduced, to be replaced in 2009 by support from the electricity certificate system. In 2005, this subsidy amounted to 9 öre/kWh (1EURct/kWh) of electricity produced in onshore wind power plants, and 16 öre/kWh (1,8 EURct/kWh) of electricity produced in offshore wind power plants. The subsidy is payable to electricity producers selling electricity from wind power plants in Sweden (Swedish Energy Agency, 2005).

The electricity certificate system

Sweden introduced a system of electricity certificates in May 2003. The system works by providing producers of electricity from renewable energy sources with certificates from the State, in proportion to the amount of electricity produced. Under the scheme, generators using solar, wind, biomass geothermal, wave or small hydro (<1.5 MW) are awarded one certificate for each 1 MWh produced, and all consumers are obliged to buy these certificates to cover a set proportion of their use. This requirement started at 7.4% in 2003; in 2005 it was 10.4% and will rise to 16.9% in 2010. Energy-intensive industry is exempt from the requirement. There is a floor and a ceiling set on certificate prices. Should generators find no buyers for their certificates; the government is obliged to buy then. The price was SEK 60/MWh (€ 6.6/MWh) in 2003, with the price falling in future years. For consumers who fail to buy enough certificates, there is a penalty of SEK 175/MWh (€ 19.3/MWh) in 2003 and SEK 240/MWh (€ 26.5/MWh) in 2004 (IEA, 2006).

In 2004, the average price of a certificate was SEK 231. Certificates equivalent to production of 11 TWh from renewable sources were issued in 2004. 8.1 TWh of this quantity was supplied by biofuels, 2 TWh by small-scale hydro power and 0.9 TWh by wind power.

At present, Sweden is the only Nordic country that is operating an electricity certificate system. The Swedish Energy Agency and Svenska Kraftnät are responsible for administration and operation of the Swedish electricity certificate system (Swedish Energy Agency, 2005).

Table 2 below shows a compilation of past and present RES-E support mechanisms (except electricity certificate system) as they are presented in the Global Renewable Energy Policies and Measures Database run by IEA.

Tab. 2. Description of past and present RES-E support mechanisms (except electricity certificate system, presented earlier). [Source: the Global Renewable Energy Policies and Measures Database, IEA]

Title	**A. Feed-in tariffs**	**B. Transitional Regulation for Wind Power**	**C. Measures to Support Wind Power**
Effective from	1998	2003	2000
Description	The liberalisation of the Swedish electricity market provides straightforward access for small independent generators to be connected to the grid. Swedish utilities were obliged to purchase electricity from small generators at agreed prices. Since the end of 1998, biomass and wind power has been sold at the market price plus a temporary support of SEK 0.09/kWh (€ 0.009/kWh) provided by the state.	As part of the green certificates plan, a transitional regulation was introduced in 2003 for wind power plants that had been in operation before 1 January 2003. These plants, until they achieve 25 000 equivalent full-load hours, are granted support for each MWh produced during the initial five-year period: SEK 150/MWh in 2003, SEK 120/MWh in 2004, SEK 90/MWh in 2005, SEK 60/MWh in 2006 and SEK 30/MWh in 2007.	The 2001 budget bill included additional funding of SEK 40 million per year to support wind power installations under the Swedish Energy Policy Programme initiated in 1998.
Policy type	•Guaranteed Prices / Feed in	•Guaranteed prices / Feed in	•Capital grants
Renewable energy	•Bioenergy •Offshore wind •Onshore wind	•Offshore wind •Onshore wind	•Offshore wind •Onshore wind

Tab. 3. (Cont.) Description of past and present RES-E support mechanisms.

Title	**D. Tax Reduction for Wind Power Prolongation**	**E. Investment Subsidy for Plants in Difficult Locations**	**F. Guaranteed Power Purchase Contracts**
Effective from	2002	2003	1997
Description	Tax exemptions for electricity generated from wind power were prolonged to 2009. This "environmental bonus," introduced in 1994, provided the opportunity for deduction of the energy tax due on electricity produced from wind power. In 2004 the incentive is SEK 0.181/kWh.	The Swedish government intends to work together with industry to gaining experience building wind farms in “difficult areas” such as offshore or mountain locations. An amount of SEK 350 million (about € 38.6 million) is planned for this measure.	The guaranteed power purchase contract with local utilities supports small renewable energy projects within the liberalised Swedish electricity market. Local distribution companies must purchase all electricity generated by projects of less than 1 500 kW within their service territories.
Policy type	•Production Tax Credits	•RD&D	•Guaranteed Prices / Feed in •Regulatory and Administrative Rules
Renewable energy	•Offshore wind •Onshore wind	•Offshore wind •Onshore wind	•All technologies simultaneously

3. Case study: Technology 1 (wind on-shore)

3.1. Description

By the end of December 2004 the total installed wind power generation capacity in Sweden was 452 MW (an increase of about 48 MW during year 2004). 22.5 MW of this capacity, was placed off-shore. The total electricity production from wind power in 2004 was 0.9 TWh, about 0.6% of total electricity consumption in Sweden this year (146 TWh). Figure 9 and 10 show the development of wind power generation in Sweden during two decades 1983-2004.

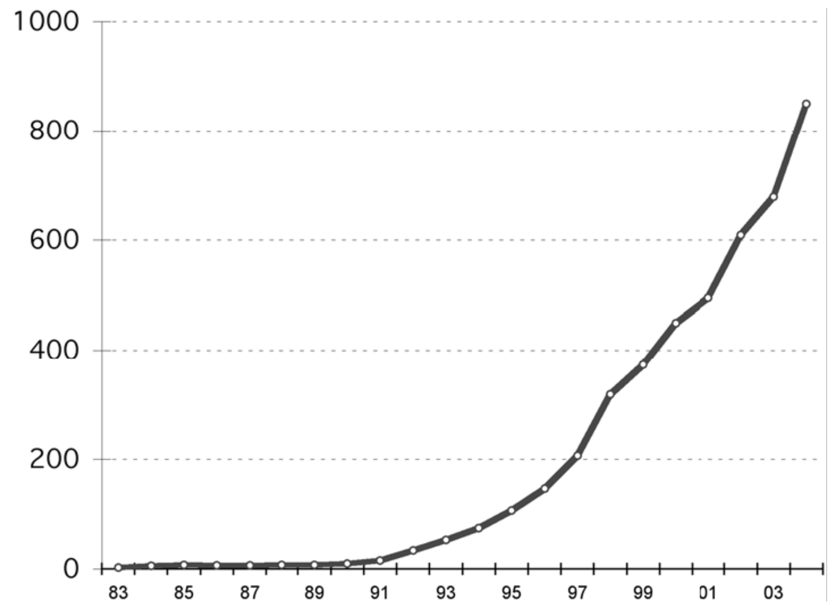

Fig. 9. Wind power generation in Sweden 1983-2004, GWh/a (International Energy Agency, 2004).

According to the plan established by the Swedish Parliament, there is a target for wind power amount of 10 TWh by year 2015.

In our case study on on-shore wind power in Sweden, two 2 MW wind power plants have been chosen: one located in Västraby and another one placed in Jordboen in southern part of Sweden about 60 km from the south coast. Both plants are owned by a company Ekovind AB.

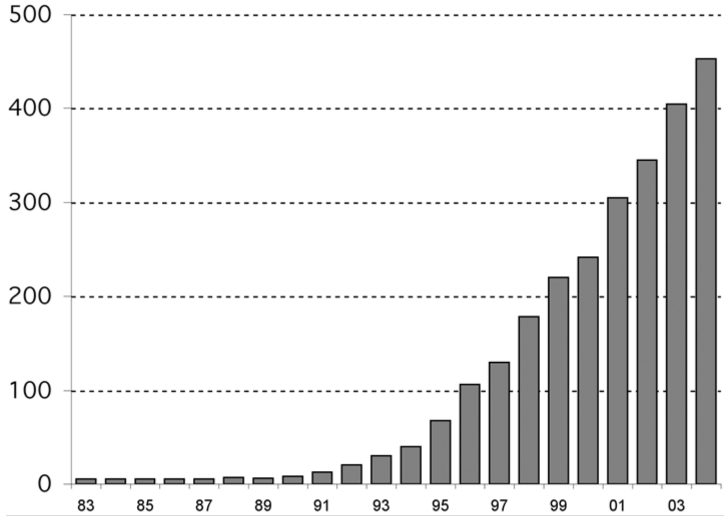

Fig. 10. Wind power capacity in Sweden 1983-2004, MW (IEA, 2004).

3.1.1. *CASE 1A - On-shore wind power plant Västraby*

This plant is a Vestas 2 MW turbine V80 with the following technical specification [2]:

Rotor

Diameter: 80 m; Area swept: 5,027 m^2; Nominal revolutions: 16.7 rpm; Operational interval: 9-19 rpm; Number of blades: 3; Power regulation: Pitch/OptiSpeed®; Air brake: Full blade pitch by three separate hydraulic pitch cylinders

Tower

Hub height (approx.): 60 m, 67 m, 78 m, 85 m, 100 m

Operational data

Cut-in wind speed: 4 m/s; Nominal wind speed (2000 kW): 15 m/s; Cut-out wind speed: 25 m/s

Generator

Type: Asynchronous with OptiSpeed®; Nominal output: 2000 kW; Operational data: 50 Hz/60 Hz; 690 V

Gearbox

Type: Planet/parallel axles

Control

Type: Microprocessor-based control of all the turbine functions with the option of remote monitoring. Output regulation and optimisation is controlled via OptiSpeed® and OptiTip® pitch regulation.
According to our contacts with the owner following data could be collected:
Year of commercial commissioning: 2004

Technical lifetime:	25 years
Efficiency or load factor:	26%
Availability:	98%
Full-load hours:	2350 hours
Capacity credit:	N/A
Length of cable for grid connection:	600 m
Type of grid connection:	medium – 690 V → 10 kV → 130 kV

Figure 11 illustrates power curves for this type of wind turbine.

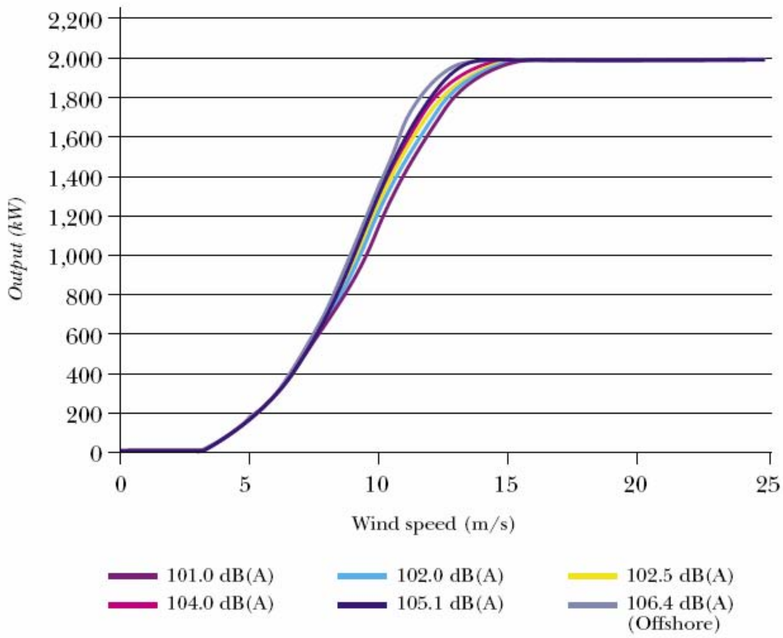

Fig. 11. Power curves (at different sound levels) for the V80-2.0 MW turbine (Vestas, 2005)

3.1.1.a. Costs

Total investment cost is 2 500 000 EUR, which is 1 250 EUR/kW. O&M costs are totally about 142 400 EUR per year divided into the following items:

Administration:	12 174 EUR/a
Site leasing payments:	7 065 EUR/a
Credits:	119 565 EUR/a
Others:	358 7 EUR/a

Shallow grid integration cost is 170 760 EUR (85 EUR/kW). There is no information available on deep integration costs coverage.

3.1.2. *CASE 1B - On-shore wind power plant Jordboen*

This plant is an Enercon 2 MW turbine E70 with the following technical specification [3]:

Turbine concept

Gearless, variable speed, variable pitch control

Rotor

Rotor diameter: 71 m; Type: Upwind rotor with active pitch control; Direction of rotation: Clockwise; Number of blades: 3; Swept area: 3959 m^2; Blade material: Fibreglass (epoxy resin); integrated lightning protection; Rotational speed: Variable, 6–21.5 rpm; Tip speed: 22–80 m/s; Pitch control: ENERCON blade pitch system, one independent pitching, system per rotor blade with allocated emergency supply

Hub

Rigid; height 64 – 113 m;

Main bearings

Dual-row tapered/single-row cylindrical roller bearings;

Generator

ENERCON direct-drive synchronous annular generator;

Grid feeding

ENERCON inverter

Braking systems

3 independent blade pitch systems with emergency supply

Cut-in wind speed

2.5 m/s; Rated wind speed: 13.5 m/s; Cut-out wind speed: 28–34 m/s.

According to our contacts with the owner, following data could be collected:

Year of commercial commissioning:	2004
Technical lifetime:	25 years
Efficiency:	17%
Availability:	98%
Full-load hours:	1700 hours
Capacity credit:	N/A
Length of cable for grid connection:	2000 m

Type of grid connection: medium – 690 V -> 10 kV -> 130 kV

Figure 12 presents power and power coefficient curves for this type of wind turbine.

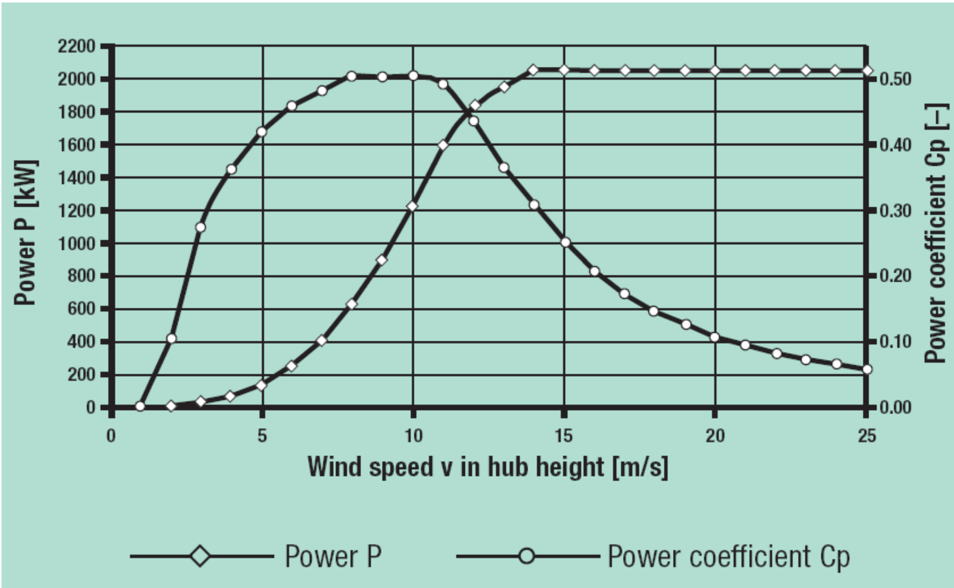

Fig. 12. Power and power coefficient curves for the E70-2 MW wind turbine (Enercon,2005).

3.1.2.a. Costs

Total investment cost for this plant was 1 983 695 EUR, which is about 992 EUR/kW. O&M costs are totally about 113 586 EUR per year divided into the following items:

Administration:	8 695 EUR/a
Insurance:	2 500 EUR/a
Site leasing payments:	7 065 EUR/a
Credits:	95 109 EUR/a
Others:	217 EUR/a

Shallow grid integration cost is 170 760 EUR (85 EUR/kW). There is no information available on deep integration costs coverage.

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AUSTRIAN CASE STUDY

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Abstract - This report focuses on grid connection costs of renewable electricity technologies in Austria. In detail 2 case studies (alpine onshore wind site and large scale biomass fired cogeneration plant) are analysed in terms of grid connection investment shares and electricity generation costs. Furthermore the structure of Austria's energy sector and regulatory framework conditions are presented.

Keywords: Wind and biomass electricity, grid connection costs, regulatory framework conditions

1. Description of electricity system

1.1. The liberalisation of the electricity market

The Austrian eletricity sector was totally liberalised on the 1st October 2001. This took place before the obligation by the EU directives 2003/55/EG and 2003/54/EG (Electricity markets must be fully liberalised within 1st July 2007). Therefore already collateral processes have been realised regarding a 100% opened market structure containing customer switching processes, balance group issues and energy data handling. For this all the unbundling requirements due to national law had to be implemented.

For guidance and supervision of the advancement from a monopoly market to a fully liberalized electricity market (only the natural monopoly of the electricity network is not embedded in market mechanisms) three administrative bodies have been given competence, even on governmental level:

- The Federal Ministry of Economic Affairs and Labour

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- The Electricity Control Commission
- The Electricity-Control Ltd. - "Regulator"

The Federal Ministry of Economic Affairs and Labour as the highest electricity authority has following main responsibilities (Source: E-Control):

- Observing the operations of the regulatory authority
- Administration of the Federal Government's equity interest in Energy Control Ltd.
- Jurisdiction with regard to the activities of Energy Control Ltd., which has to be performed partly by issuing regulations and partly by setting principles
- Issuing and application of regulations as necessary for concluding international contracts such as principles concerning the administration of cross-border trade

The major objective of E-Control is to guarantee some benefit for all market participants in the course of the liberalisation. Regulation will be effected in a transparent way and on a non-discriminatory basis. What is most important to the work of Electricity Control Ltd. is the provision of an efficient electricity sector by adding a new competitive edge.

1.2. Electricity production and demand

In Austria electricity generation is based on a hydro-thermal system. The most important energy source for electricity generation is hydro power. From 1970 to 2000 around 70% of electricity was generated in hydro-power plants. Total hydro capacity installed is around 11.7 GW, approximately 6.4 GW are hydro storage plant (including pump storage). However, hydro generation varies throughout the year. On the one hand, in summer electricity generation from hydro power plants is higher than in winter. On the other hand, electricity demand in winter is higher than in summer. As a result, on-peak electricity demand occurs when water supply is at a minimum. Therefore, in order to meet demand additional electricity either has to be generated by thermal power plants or is imported. In summer, however, excess hydro capacity is available which leads to electricity exports.

The following figures provide an overview on Austria’s electricity sector for the recent years (i.e. 2002 and 2003): In Figure 1 comparison of consumption and generation is given while Figure 2 indicates power exchange with neighbouring countries. As there can be seen, domestic generation stood at 62.7 TWh in 2002 of which 42 TWh have been generated in hydropower plant. In contrary, gross demand accounted for 60.9 TWh. In addition, 2.5 TWh were used for hydro pump-storage plant to be able to cover daily and seasonal peak demand. As a consequence, net import of electricity was in size of 0.7 TWh. This situation changed dramatically in 2003: Hydro generation decreased to 32.2 TWh due to a lack of rainfalls all over the year. The resulting gap had to be covered by an increased thermal generation – 27.4 TWh in total (+34% compared to 2002) – as well as by higher (net) imports – 5.6 TWh (+700% compared to 2002).

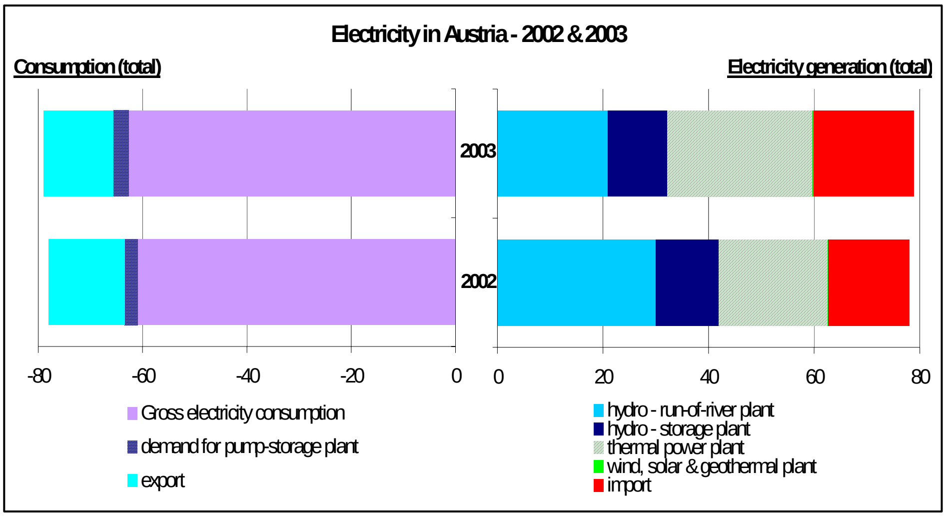

Fig. 1. Electricity generation in Austria in 2002 & 2003. (Source: EEG)

The most intensive power exchange with neighbouring countries took place with Germany and the Czech Republic, see Figure 2 (Compare also Weissensteiner et al (2004)).

As already mentioned, hydro generation varies not only from year to year but also over a year. In this context, Figure 3 represents these fluctuations on an annual basis (left hand-side) as well as on a monthly basis (right hand-side) for run-of-river plant in Austria. Historical time series indicate a variation between 115% and 85% (with the long term average of 100%). That is to say, in the worst case – as actually happened last year (2003) only about 3/4 of the possible maximum is generated. Note, in the years before since the start of electricity market liberalisation in 1999 hydro generation was always well above the average.

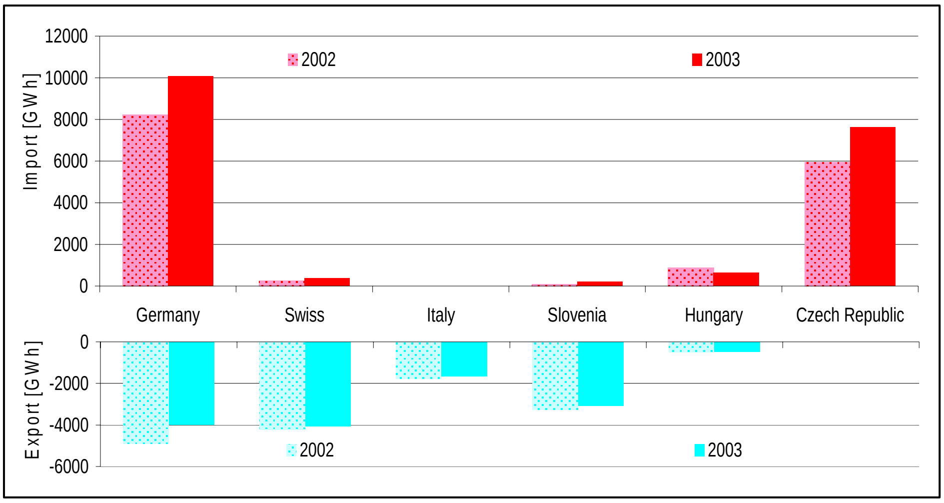

Fig. 2 Imports and exports of electricity in Austria 2002 & 2003. (Source: EEG)

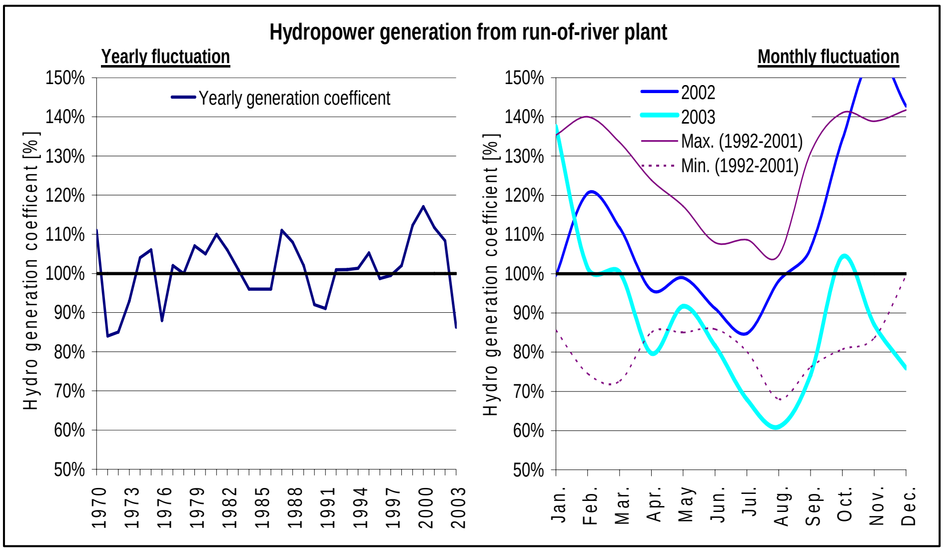

Fig. 3 Yearly and monthly fluctuations of electricity from run-of-river hydropower plant in Austria. (Source: EEG)

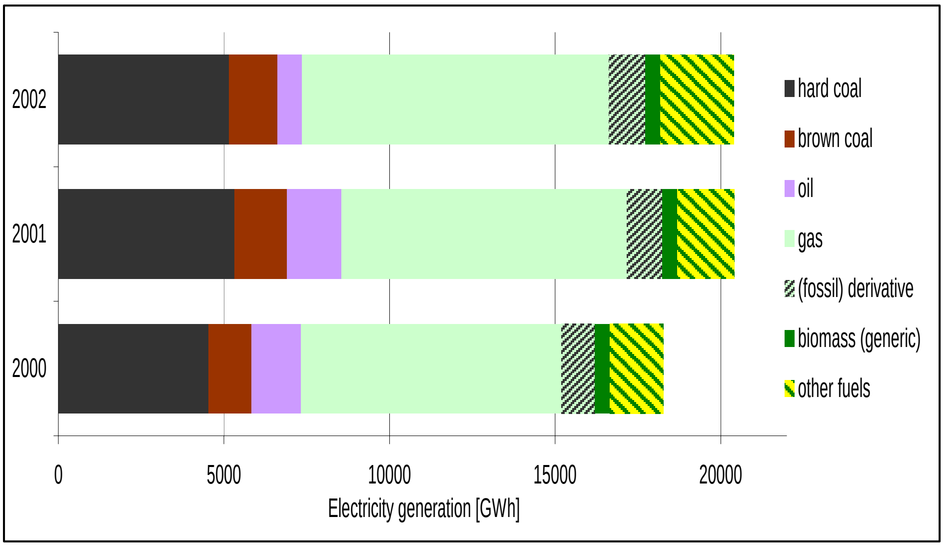

Fig. 4. Electricity generation by fuel category in thermal power plant in Austria in the period 2000 – 2002. (Source: EEG)

In addition, a high capacity of conventional thermal power stations (around 6.4 GW) has been installed. The most important fossil fuel is natural gas which accounted for 9.3 TWh in 2002 (roughly 45% of total thermal generation), followed by 6.6 TWh (in 2002) which were generated from coal (hard and brown coal). In Austria there is no nuclear power station in operation because it is prohibited by law to generate electricity from nuclear power.

'New' RES currently play a minor role in electricity generation but gain more and more importance (e.g. 3180 GWh (Q1-3; 2004) injection volume for small hydro power, followed by wind generation, solid biomass, biogas etc.).

1.3. Past and expected development of RES-E

Supporting the generation of renewable electricity is a challenging objective for Austrian and European energy policies, documented in the European Union's Directive 2001/77/EU, as well as the Austrian Green Electricity Act, which was passed by the Parliament in July 2002 and has been amended several times. This shows a significant trend to environment protection, climate measures, reduction of necessary energy imports as well as promoting the opportunity of domestic electricity production.

"With regard to overall end energy consumption of electricity in Austria, around 70% is generated by hydroelectric plants. In accordance with the Green

Electricity Act, by 2008 at least 9% is to be generated in small-scale hydroelectric plants (< 10 MW) and 4% in other government-subsidised plants (mainly wind power and biomass). Nation-wide feed-in tariffs have already been specified.

According to the Green Electricity Act the three green balancing group representatives – Verbund - APG, TIRAG and VKW - are subject to a purchase and compensation obligation at the set prices (save large scale hydro power). The compensation payments are funded through the support fees to be paid by the end-consumers and the settlement prices to be paid by the electricity traders for the allocated green power" (Source: E-Control). Table 1 shows the green electricity feed-in and compensation volumes in Austria (Q1-3; 2004 compared to Q1-3; 2005)

Tab. 1 Comparison of Renewable Electricity injection volumes and transacted compensation

Renewable electricity injection volumes and compensation Q1-3 2004 in comparison to Q1-3 2005

Energy source	Injection volume in GWh	Net compen-sation in €	% contributions to total renewable electricity injection	% shares of compen-sation	Ave. compensation in cent/kWh	Injection volume in GWh Q1-3 2004	Net compensation in € Q1-3 2004
Small hydro	**3,019**	**138,691,441**	**65.70**	**48.67**	**4.59**	**3,180**	**141,852,174**
"Other" green power	**1,576**	**146,246,794**	**34.30**	**51.33**	**9,28 (9,59)[1]**	**1,004**	**88,087,738**
Wind	952	73,371,435	20.71	25.75	7.71	655	50,252,668
Solid biomass inc. HBF waste	393	40,714,427	8.56	14.29	10,35 (12,16)[1]	203	17,699,247
Biogas	148	19,448,061	3.23	6.83	13.12	66	8,046,506
Liquid biomass	23	3,245,979	0.50	1.14	14.14	13	1,753,175
PV	9	6,063,621	0.20	2.13	65.29	10	6,320,283
Landfill and sewage gas	49	3,307,290	1.07	1.16	6.73	56	3,887,389
Geothermal	1	95,981	0.03	0.03	7.03	2	128,471
Total small hydro and "other" green power	**4,596**	**284,938,235**	**100.00**	**100.00**	**6,20 (6,25)[1]**	**4,184**	**229,939,912**

[1] When large waste incinerators are excluded the figure for average compensation payments increases to that shown in brackets.

[Source: Reports from GPBGRs; preliminary values for November 2005]

Due to the current Austrian support schemes the production of electricity within the renewable energy sector has steadily grown. In the near future there however might be a considerable reduction of the share of green electricity because the Water Framework Directive is implemented and the growth in electricity consumption will not decline.

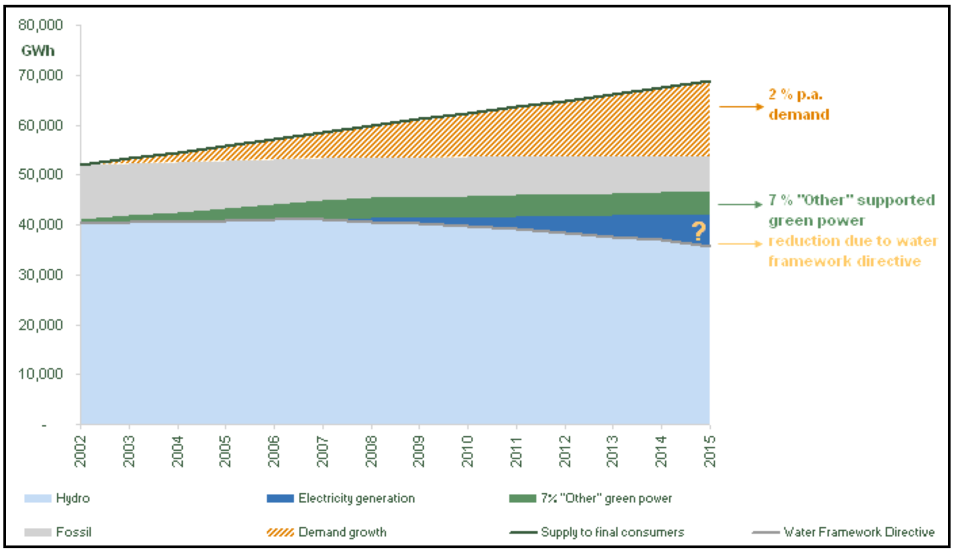

Fig. 5 Scenario of electricity production considering demand growth, green power production, fossil fuels and reductions due to the Water Framework Directive until 2015. (Source: E-Control)

Figure 6 demonstrates the forecast developments in green power expansion on the sole basis of the Injection Tariff Order

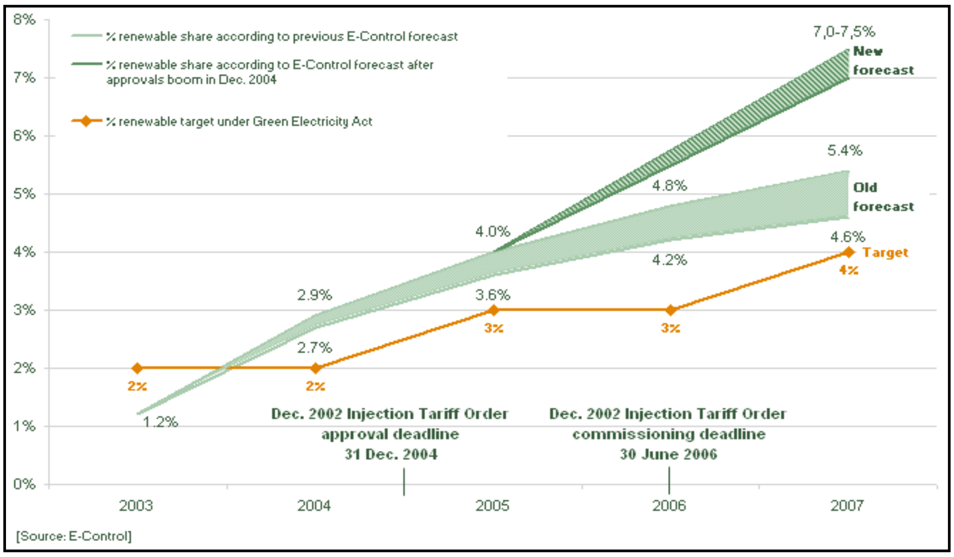

Fig. 6. Green Electricity forecast scenarios (Federal Law Gazette II No. 508/2002 from December 2002; Source: E-Control)

2. Conditions of RES-E grid integration

2.1. Grid connection and system service requirements

Grid connection often is a significant economic barrier for RES-E generation technologies in dispersed locations. If the new RES-E developer has to pay all the costs of grid connection up-front, then a compromise between the best generation sites and acceptable grid conditions has to be made, as is often the case for wind and small-hydro power (see e.g. Resch et al (2003)).[†] To pay for the connection, the RES-E developer includes the costs into the long-run marginal generation costs. However, if the grid connection costs are covered by the grid operator (i.e. the costs are 'socialised' via grid tariffs of 'per unit' charges), then the initial burden does not fall on the first RES-E developer. Obviously, RES-E developers should not have a 'right' to be connected anywhere irrespective of connection costs, so the regulatory authority has to give guidance and adjudicate about disagreements.

The need for reinforcements and extensions of the existing grid infrastructure has a variety of reasons. Changes in generation and load at one point in the network, in principle cause changes throughout the system, which may cause power congestion (bottlenecks). Usually, it is not possible to identify one (new) point of generation as the single cause of such difficulties. Therefore, the allocation of changes of load flows in a system to a single new generator connected to the system (e.g. a new wind farm) is ambiguous, since established conventional generators or changes in demand may cause an equal burden on the grid infrastructure. Therefore, one of the major unbundling issues is to discuss different cost allocation strategies for intermittent RES-E grid integration. According to the textbooks in economic theory it is expected to allocate both grid connection costs and grid reinforcement/extension costs to the grid infrastructure and to spread (socialize) these costs through the transmission and distribution tariffs.[‡] In practice, however, grid connection costs are still allocated to the RES-E power plant in almost all European countries (except e.g. Denmark).

[†] On contrary, grid connection for biomass – in general – is no crucial barrier as the particular location of the plant is even more independent from resource conditions.

[‡] In principle, there exist both options: (i) socialisation within a supply area of a grid operator or (ii) socialisation across the whole country (i.e. covering also several other grid operators).

2.2. Philosophy of allocating grid integration costs

To discuss different philosophies of allocating grid integration costs to market players it might be said that the interface defining the barrier between shallow grid integration and deep grid integration costs influences on the one hand the electricity generation costs of RES-E developers and on the other hand national schemes of cost allocation. These two types of grid integration costs effectuate the two most common charging methods as summarised below:

- Shallow charging method: The RES-E developer has to pay only for the cost appeared by connecting the plant to the grid physically. There is no cost allocation of possible grid reinforcements to the generator.
- Deep charging method: The RES-E developer pays for all costs associated with its connection including any upstream network reinforcement costs due to the connection of the generator and its switchgears.

"The choice of connection charging method relating to DG and RES is a subject of considerable debate as it can profoundly affect the economic viability of a new generation scheme. The main points of contention relate to how the costs of connecting DG and RES schemes should be allocated between the parties involved in such a way that they are considered fair and reasonable by all of these parties. At the current time there appears to be no general consensus in view of the fact that there are many parties involved, each with their own vested interests, and the fact that the costs of connection for a generator is highly dependent on the point of connection and the characteristics of the grid network at the connection point.

A number of papers[§] have been published in recent years discussing the various connection charge approaches and the potential options open to regulators and network operators" (Compare to: ELEP (2005).

To identify best practice strategies for grid related cost allocation, the following case studies should outline the amount and influence on generation costs of the common "Deep" charging method in Austria (for Austria an alpine windpark and a biomass plant have been chosen).

[§] Examples include papers published under the EU projects:
DECENT (http://www.izt.de/decent/),
DGFER (http://www.dgfer.org/),
and SUSTELNET (http://www.electricitymarkets.info/sustelnet/index.html)

3. Case Study 1: Wind Onshore

3.1. Description

The location of the since 2002 operational Tauernwindpark is situated on a mountain ridge in the Austrian Niedere Tauern (near the Klosterneuburger Hütte). It is most suitable for the erection of wind turbines due to the exposure of the site (diagonal to the main wind direction).

The wind park includes 11 wind turbines with a rotor diameter of 66 meters and a power capacity of 1,75 MW each. The produced electricity is transformed from 690 V to 30 kV. The transformers are installed in the lowest segment of the tower and have their own entrance. Each transformer room includes SF6 switch gears so that every individual turbine can be shut down from the grid if necessary. The produced power is transported 20,86 km to the transformer substation Teufenbach using a 30 kV underground cable. In Teufenbach the electricity is transformed to 110 kV and fed into the grid.

Furthermore in autumn 2004 the wind site has been enhanced by two new wind converters. The total investments for this new converters were about 3.500.000 € causing additional 160.000 € of yearly running costs. Because there are no more detailed cost data available the following cost structure reflects the 11 turbines built in 2002 only.

3.2. Costs

The investment costs for this alpine wind site are summarized in figure 7 indicating the relatively high grid connection costs. The turbine costs represent ~71% of total investment for the wind park. Beneath this typical share of converter costs the shallow grid connection costs are high (16.4%) for the case of an alpine wind farm. This is especially due to the cable length of approximately 21 kilometers.

Figure 8 indicates the yearly running costs, which also influence significantly the generation costs. In this onshore case the major running cost factor is caused by repair measures, insurances and personnel. In total the yearly running costs are about 880.000 € which is less than 3.7% of total investment costs.

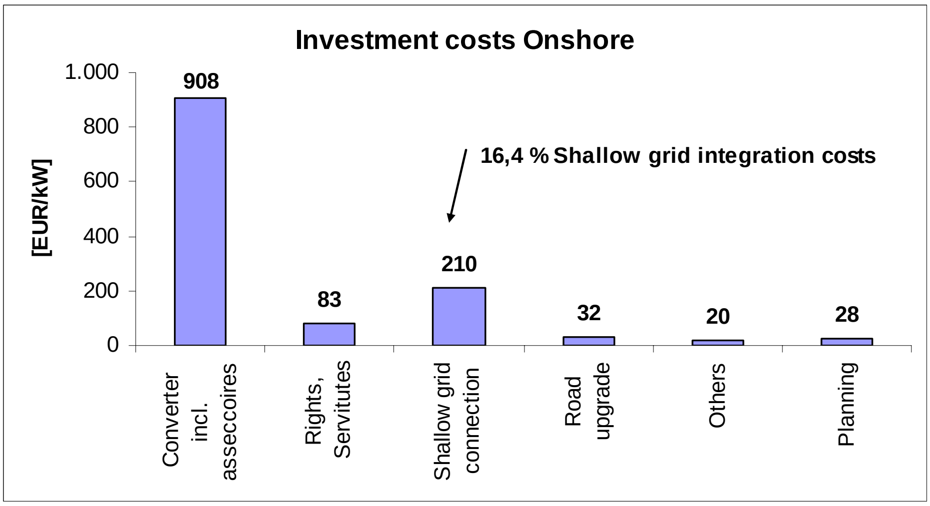

Fig. 7 Specific investment costs (2004) for the onshore case study in Austria (Source: www.tauernwind.com)

Based on these specific investment and running expenditures the electricity generation costs are calculated for different annuity factors in relation to variable yearly full load hours. Furthermore the shallow grid integration costs are on the one hand allocated to the total generation cost and on the other hand excluded (in terms of possible future policy changes). To show economical performance of the project the guaranteed Austrian Feed in Tariff (78 €/MWh) is indicated in Figure 9.

The expectable yearly full load hours for this alpine wind site lie between 2200 and 2360 effecting in generation costs from 91.34 €/MWh to 85.15 €/MWh if the interest rate is 10% and shallow grid connection costs are allocated to the wind park operator. These costs decrease to 80.13 – 74.40 €/MWh if grid connection costs are not taken into account. A further reduction is achieved by an interest rate of 5% causing generation costs of 64.50 €/MWh for 2360 full load hours including grid related costs and to 57.36 €/MWh without grid connection.

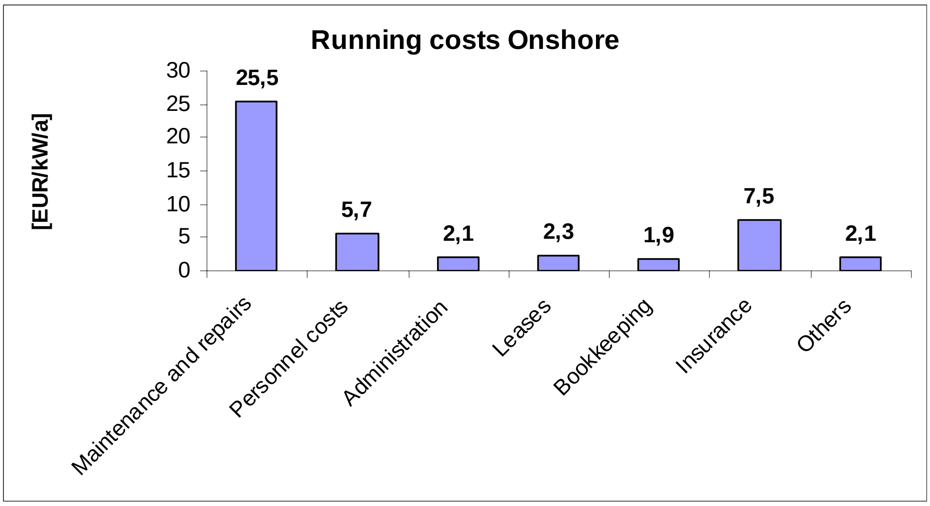

Fig. 8. Yearly running costs covering repair measures, personnel, leases etc. specified in EUR/kW and year (Compare*:* www.tauernwind.com)

Assuming a medium interest rate of 7.5% the generation costs rise to 74.4 €/MWh (incl. grid connection) and to 65.68 €/MWh if grid connection costs are neglected. For this it can be seen, that the Austrian Feed in Tariff covers also overall generation costs, if the grid related costs are allocated to the RES-E generator, at a moderate interest rate.

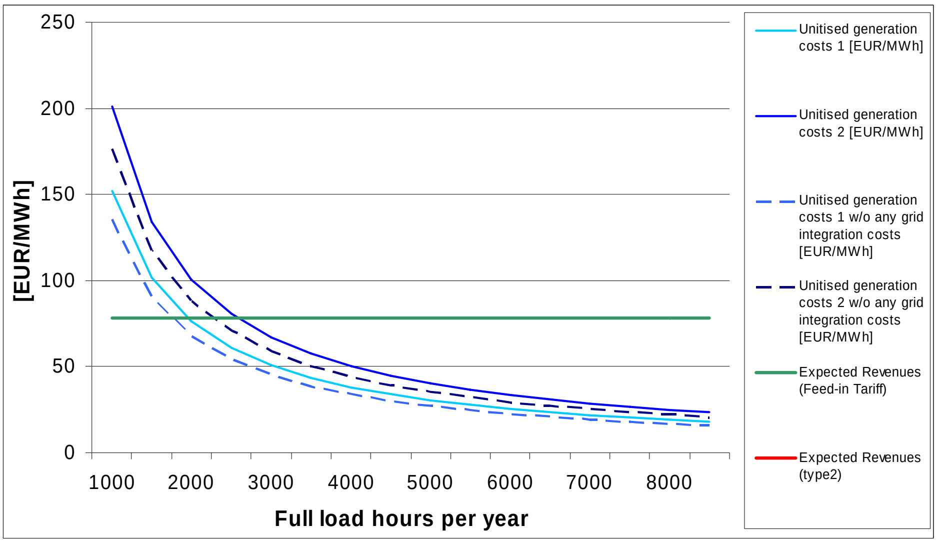

Fig. 9. Electricity generation costs (2004) for the onshore case study (Source: www.tauernwind.com*)*

For onshore wind parks the annuity factor and full load hours play clearly an important role. Beneath them – especially for alpine wind farms - the grid integration costs significantly influence the electricity generation costs. Compared to other onshore sites they are much higher and for that need to be taken into account considerably.

If e.g. in future projects the grid related costs will be allocated to the Distribution Grid Operator – by means of later customers' connection or the possible development of an offshore grid in coastal areas – the feed in tariff has to be reduced. For instance a reduced tariff of about 70 €/MWh for the Tauernwind case would possibly be adequate. The grid connection costs which are then allocated to the Grid Operator should be socialized via grid tariffs, which also may cover possible grid reinforcement costs.

4. Case Study 2: Biomass

4.1. Description

"Wien Energie" the municipal energy utility of Vienna and the "Österreichische Bundesforste AG" the Austrian Federal Forest AG have contracted the operation and design of Austria's largest biomass cogeneration plant (combined-heat-and power production, CHP) in Wien Simmering. The biomass plant will use chips from forest residues as fuel only. This important renewable project for large-scale and environment friendly urban wood fuel use is also meant as a demonstration project, to show Austrian know how in project development and supply logistics.

The new biomass plant will be located at an existing thermal heat and power generation site in Vienna's south-eastern borough of Simmering and will be integrated near two existing fossil-fuelled thermal power production units. By adding the biomass cogeneration unit to this existing power generation site, many economic advantages can be reached by synergy effects due to the use of existing infrastructure (e.g. consisting road and rail connections and access to the district heating or electricity grid), resources for plant operating and maintenance (e.g. skilled manpower). This influences the achievable grid connection and electricity generation costs considerably.

"The foreseen installed total capacity of the plant is 65.7 MW, causing investment costs of some € 52 million. The plant will use about 600,000 m^3 of loose wood chips (mainly from forest residues), and generate electricity sufficient to meet the needs of about 48,000 and heat sufficient to meet the needs of around 12,000 urban dwellings" (see also Madlener et al. (2005)).

Commonly the generation of electricity and heat from biomass - if 100% biomass is used - is on the one hand expensive, mainly due to high logistics costs and a lack of technical efficiency and on the other hand the generated heat rarely can be used over the whole year because of the climatic circumstances in Austria. Wood fuels are geographically dispersed and available only at limited periods of time and in varying quantities and qualities. All these complicating factors demand excellent project planning to achieve minimal investments and as a matter of fact low generation costs. For this the following chapter specifies the most relevant cost factors in regard of the CHP plant.

4.2. Costs

The following shares of investment costs are possibly representative for the "Wien – Simmering" plant (see Figure 10).

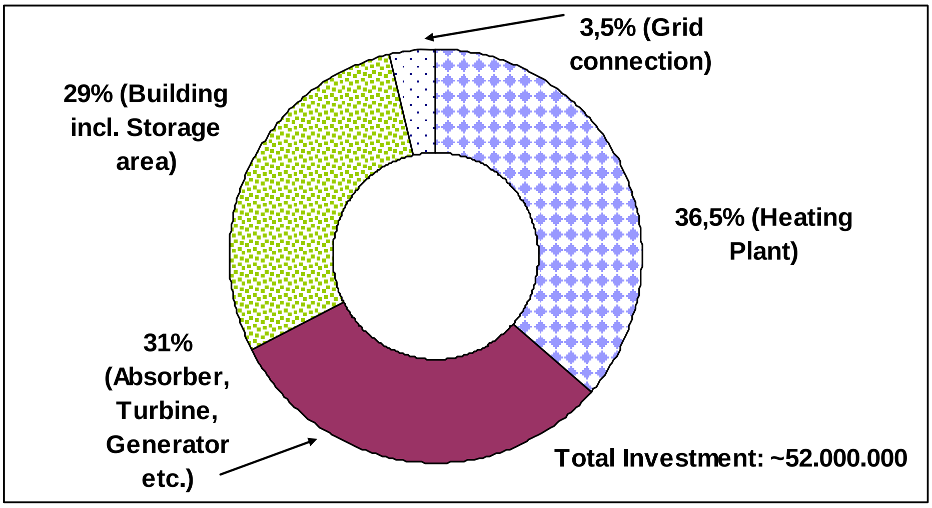

Fig. 10. Investment cost distribution (2004) for Wien - Simmering –solid biomass CHP *(*See also*:* Prüggler (2005))

The grid integration cost constitutes 3.5% of the total investment cost of the wood firing CHP. This grid connection cost percentage is less than all wind park cases seen in the literature. The same trend could be also seen for small scale biomass plants (Compare: Obernberger et al (2005)).

The plant will feature a net electrical capacity of 21.3 MWel during summertime, and 12.9 MWel of electrical capacity and 37 MWth of thermal capacity when operated during winter. For the following scenario it is assumed that about 4700 full load hours for heat sales are achievable throughout the year - this is a share of about 60% - and furthermore that the biomass plant is operated in summer mode because the maximum electricity output is subject of interest for calculating generation costs.

As seen in Figure 11 the grid connection costs will effectuate the electricity generation costs only in a moderate way (scattered lines). As the net full load is assumed 8000 hours (Madlener et al., 2005) the electricity production costs vary between 101.1 and 90.7 EUR/MWh for this power plant. The generation costs decline to 99.7 and 89.7 EUR/MWh with the neglect of grid integration costs which only causes about 1% of cost reduction. Annuity factor and full load hours are playing a much more important role than grid integration costs. The feed-in tariff for plants > 10 MW of electricity capacity is given as 102 EUR/MWh. This power plant operates profitably for even an interest rate of 10% if the full load is about 8000 hours and grid connection costs are included.

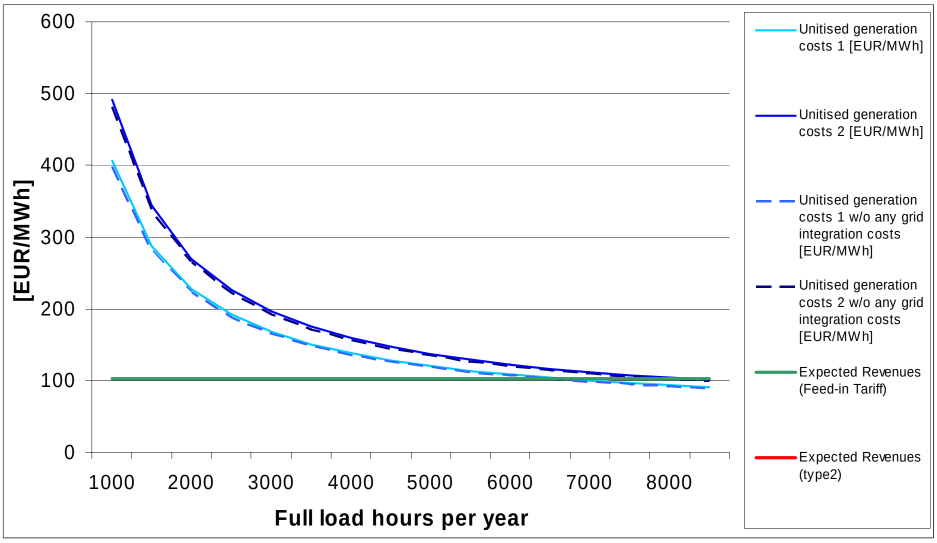

Fig. 11 Electricity generation costs as a function of full load hours for the case study "Wien – Simmering" (solid biomass CHP) in two interest rate scenarios

As mentioned above it is obvious that grid integration costs are less important for biomass power plants than for wind parks, because the primary energy use of biomass plants is not place bound. For this specific case study but even for other biomass projects (e.g. small scale) the guaranteed feed in tariff secures cost coverage and for that there are no adoption needs.

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LITHUANIAN CASE STUDY

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Abstract. This study describes Lithuanian electricity system design, structure of capacity, electricity market, electricity production and demand, past and expected development of Res-e, conditions of RES-E grid integration policy, grid connection and system service requirements, philosophy of allocating grid integration costs. There are described two RES-E case studies in Lithuania: wind on-shore and small hydropower.

Keywords: electricity market, renewable energies, electricity consumption, generation, small hydropower, wind plants.

1. Description of electricity system

1.1 Design of the electricity market

Over the period of centrally planned economy, Lithuania had overdeveloped power generation capacities because the Ignalina NPP, (3000 MW) was built to feed not only Lithuania, but a far larger region, encompassing Belarus, Latvia, and Russia. Electricity network of Baltic countries see in Fig. 1.

In the transition to market period, the energy sector was reshaped, restructured, largely privatised, subjected to competition environment (in certain segments), the activities of energy companies have been unbundled, effective regulation and supervision authorities established. Since 2002, the electricity market environment was established and started in power sector (electricity generation). Current structures of Lithuanian power sector see in the schema in Fig. 2.

The Sector was harmonized with EU energy laws. It was governed by Law on Energy (1995, 2003), Law on Electricity (2000, 2004).

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Fig. 1. Electricity network of Baltic countries *(*Sources*: LEI, R.Skema, A.Markevicius, 2006)*

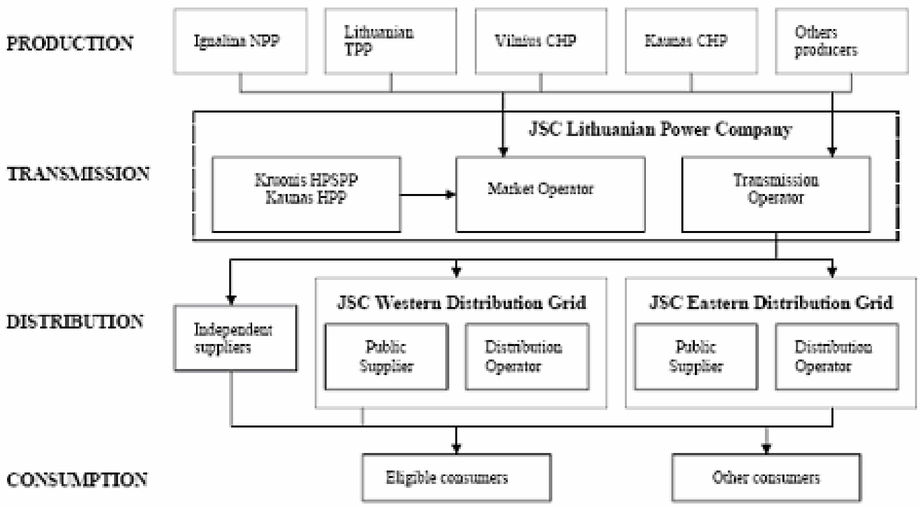

Fig. 2. Schema of current structure of Lithuanian power sector *(*Sources*: LEI, R.Skema, A.Markevicius, 2006)*

Market opening in Lithuania was as follows:

- Year 2002 – 16 % (eligible customers with more than 20 GWh);
- Year 2003 – 26 % (eligible customers with more than 9 GWh);
- Year 2004 – 40 % (eligible customers with more than 3 GWh);
- Year 2003, since July 1 – 70 % (all non-household customers can choose supplier);
- Year 2007 – 100 %.

Electricity market in Lithuania 2004 decompounds:

- Hour-to hour balancing for electricity export;
- Implementation of the automatic energy accounting system;
- SC “Lietuvos Energija” – TNO, MO, exporter/importer;
- 3 public suppliers;
- 8 wholesalers;
- 17 independent suppliers.

The rules for hourly trade have been already approved, far ahead the date of starting the hourly trade (it’s not established).

1.1. Electricity production and demand

In the period of independent state the energy efficiency rose significantly, and national energy intensity strongly declined, the electricity demand dropped to 60 percent of 1991 level, and the huge overcapacities in power sector created a significant barrier for developing RES-E plants.

The shares of electricity production in Lithuania (2003) as follows see in Fig. 3.

The distribution of electricity production among different energy sources in 2004 (Fig. 5.) shows that nuclear power has the largest proportion (45.7 %) compared to Lithuanian TPP (27.4 %), The other items of historical heritage in Lithuanian energy sector include several big objects like Kruonis Hydro pumped power plant (HPSPP 12.2 %) (units commissioned already in post-soviet period, totally 800 MW) and CHP (natural gas 12.9 %). Hydropower energy responsible for 1.8 % of gross electricity production.

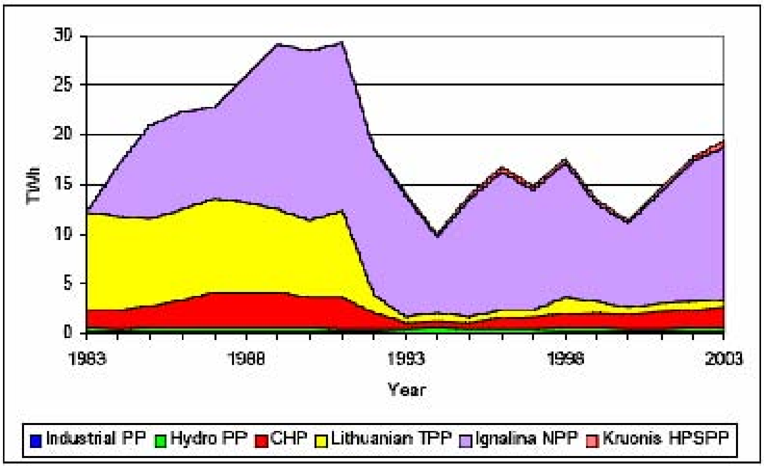

Fig. 3. Electricity production in Lithuania. (Sources*: LEI, R.Skema, A.Markevicius, 2006)*

Internal consumption of electricity see in Fig. 4, part of production comes to export.

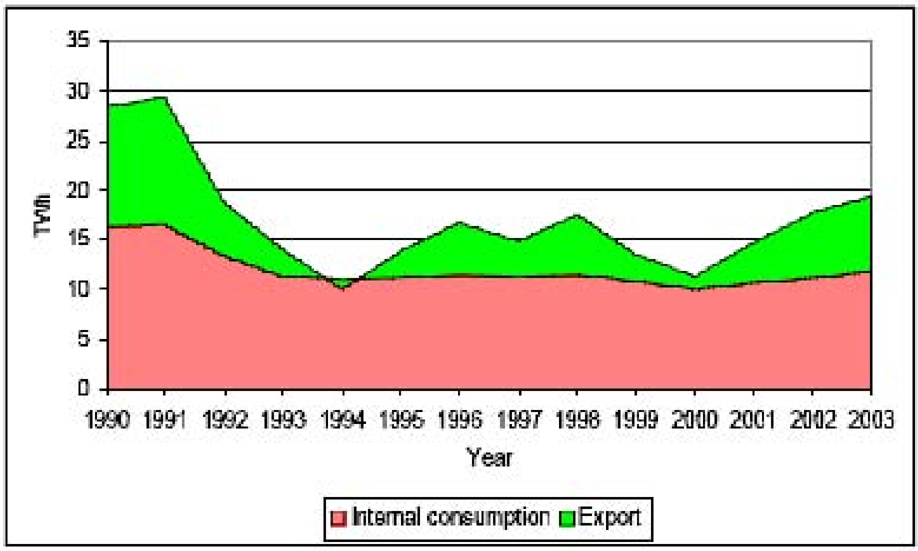

Fig. 4. Electricity consumption in Lithuania (Sources*: LEI, R.Skema, A.Markevicius, 2006)*

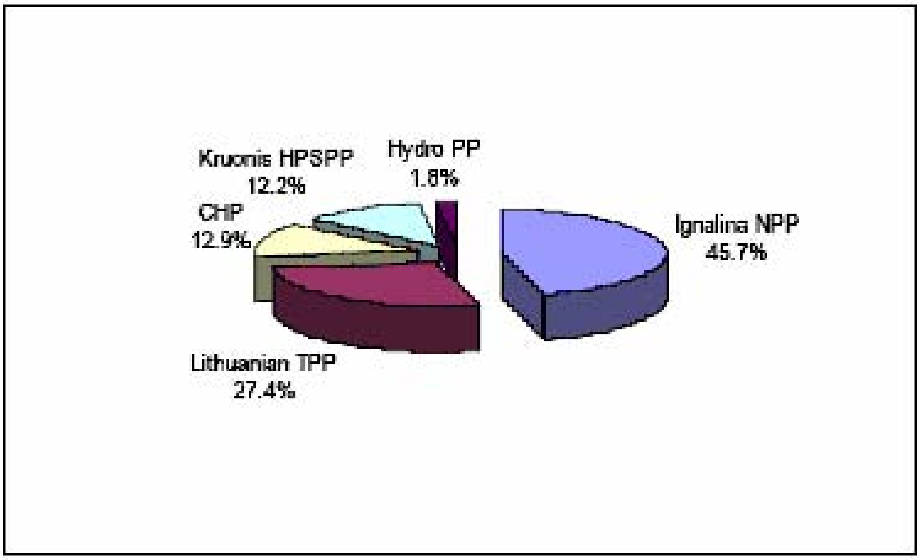

Fig. 5. Structure of capacity in Lithuania *(*Sources*: LEI, R.Skema, A.Markevicius, 2006)*

1.3 Past and expected development of RES-E

In Lithuania electricity production, using RES, mainly determine hydro energy resources. In 2002 electricity production, using RES, comprised approximately 3.51 %, (see Fig. 6) i.e. about half of the pursued standard according to EU directive. The major renewable energy sector was large hydro with the sole plant on Nemunas river (101 MW).

Hydroresources of small rivers are already used, whereas utilization of bigger rivers Nemunas and Neris requires big investments and solution of environmental issues, therefore, the biggest amount of attention, while enlarging electricity production from RES, is given to wind energy.

As another important renewable energy source biomass plays an increasing role for electricity production with 7.4 GWh/a in 2004, that is 0.05 % of the total electricity demand. At present biomass is mainly used for heat production. There are many ways to utilize biomass energy. If cogeneration plant is used then both heat and electricity is produced which enhances the plant efficiency. Generally, direct combustion of wood is done without any prior process other than mechanical processes like cutting or pellet production. Energy crops, animal mist and biological wastes are suitable for biogas production. The shares of solid biomass and biogas correspond to 0.03 % and 0.02 % of total electricity production respectively.

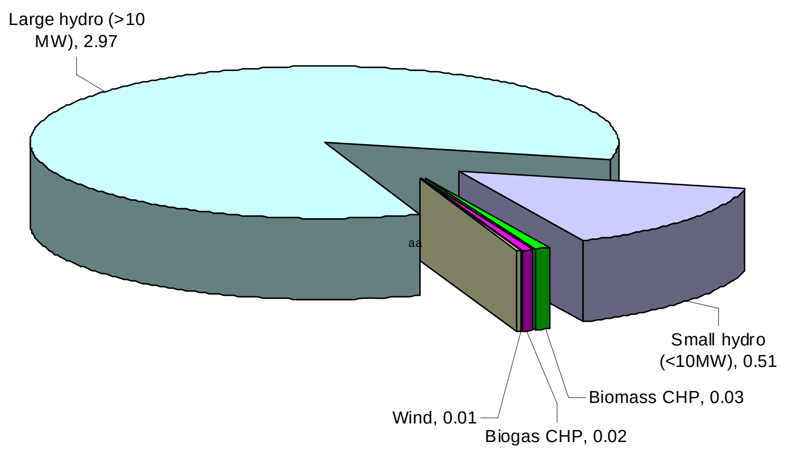

Fig. 6. Share of electricity production with renewable energies *(*Sources*: LEI, R.Skema, A.Markevicius, 2006))*

At present and at the near future geothermal processes are mainly utilized for heating applications, whereas electricity production may increase considerably in the long run. The development of share electrical consumption for renewable energies is shown. in Fig 7.

Before and at present hydropower is a dominant source of energy in RES-E production. Small hydropower is the second largest contributor after large hydro. Past and expected development of renewable electrical energy generation in Lithuania is shown in Figure 8.

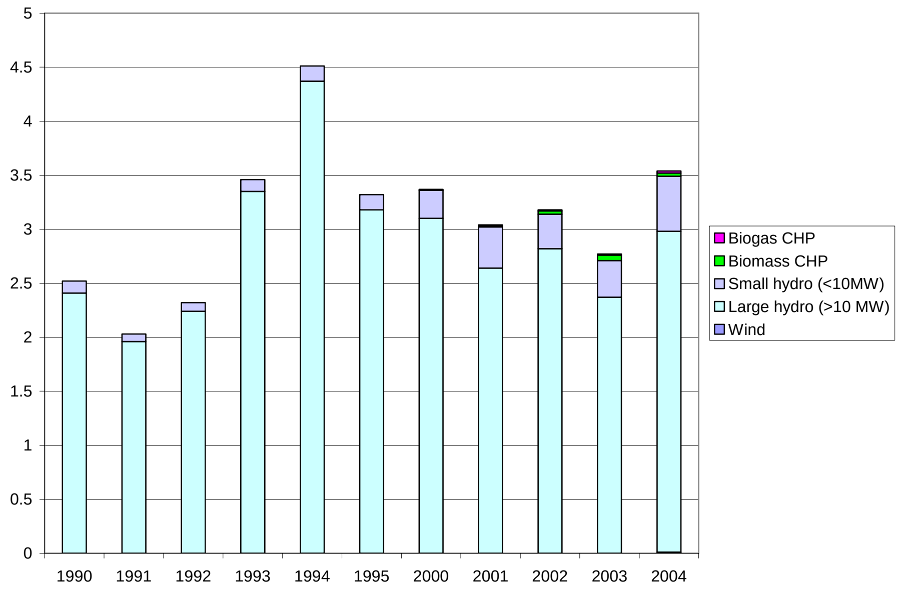

Fig. 7. Past and expected share of RES-E in %, of total electricity consumption (Sources*: LEI, R.Skema, A.Markevicius, 2006)*

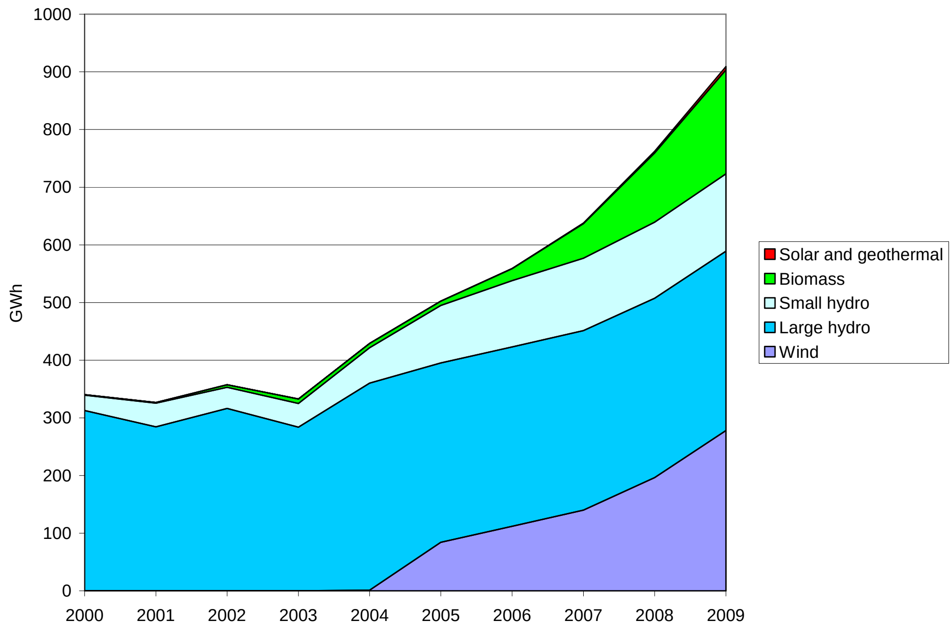

Fig. 8. Past and expected development of electricity generation from RES-E in GWh (Sources*: LEI, R.Skema, A.Markevicius, 2006)*

2. Conditions of RES-E grid integration

2.1. Integration policies

The RES-E sector is incorporated into electricity market as a non-competitive segment of public interests, i.e. under mechanism of public service obligations. The green electricity may not be justified on economic grounds and needs support by special purchase tariff. Such tariffs have been introduced for small hydro, biomass and wind plants. Likewise, the individual electricity purchase tariffs are set for each CHP.

The schedule of introduction of new RES-E capacities in 2004-2009 was laid down by Stimulation procedure for production and purchase of electricity generated from renewable and waste energy sources (approved in 2004 by Minister of Economy). This document implements the Green Electricity Directive and sets a target of 7 % of RES-E in total electricity consumption in 2010.

The grid is easy accessible to new RES-E producers as regards legislation framework, with exception of new large hydro plants. New wind power producers within the limit of yearly capacity quota are provided with purchase tariffs and rebate of 40 % of connection cost under mechanism of public service obligations.

SHP developers are responsible for covering the costs of extensions and of strengthening the grid.

2.2. Grid connection and system service requirements

There is an overall regulation dealing with the technical specifications for the connection to the grid electricity generators.

There are two legal acts defining the connection of RES-E plants to the grid:

Act A. Procedure and conditions for connection of energy objects of power consumers and producers to grids, installations and systems of operating energy companies (approved in 2002 by Minister of Economy);

Act B. Stimulation procedure for production and purchase of electricity generated from renewable and waste energy sources (approved in 2004 by Minister of Economy). This document implements the Green Electricity Directive (D77) and sets a target of 7 % of RES-E in total electricity consumption.

Currently, majority of the candidate RES-E producers are legally privileged against fossil-E producers in connection-to-grid issues. Previously, before 2004, i.e. before the Act B entered into force, RES-E producers were not distinguished between other new producers and, consequently, not encouraged to access a grid, and namely:

- all new generators were connected on their own cost: the connecting links (lines, transformers, etc.) were built by grid operator, but connection cost entirely paid by a new producer;
- if the connection necessitated the extension of the existing grid, these extra cost were covered by an operator. Nevertheless, in case of direct connection to transmission grid (110 kV, 330 kV), the grid extension cost were imposed on a new producer.

According to Act A, two ways were allowed for development of technical project, i.e. connection project:

- an new producer develops the project itself, i.e. undertakes the actions to contract a company competent to produce a project in accordance with technical terms issued by a grid operator;
- an new producer is not willing to develop a project and concludes a contract with a grid operator on project development.

A new producer, in any case, covers the cost of project development. Also, in any case, a producer has to apply to a grid operator for technical terms of a project.

A grid operator is obligated to provide access to grid. Its responsibilities cover issuance of technical terms for connection, organization of development of a project (under request of a new producer) and construction of connecting links.

If extra grid extension is necessary, 2 separate (but associated) projects are developed–grid extension project and technical project.

Starting from 2004, Act B introduced a strong stimulation for connection to grid, but not all categories of RES-E producers were covered. Those who left behind the scope of application of Act B, remained governed by Act A.

The Act B specifies the expected annual capacities of new RES-E plants to be introduced in 2004–2009 and their annual amounts of production. Those capacities and their production are viewed as quotas.

In conclusion, the grid is easy accessible for new RES-E producers as regards legislation framework, with exception of new large hydro plants.

The technical requirements for the connect ion to the grid SHP plants are provided by regional/local grid authorities. The requirements depend on the grid particularities and the power plant local conditions. There has been no discriminatory policy to connect hydropower producer to the grid so far.

2.3. Philosophy of allocating grid integration costs

The new RES-E producers within capacity quotas are supported by the mechanism of public interests and public service obligations (PSO). The mechanism is as follows:

- A producer receives a 40 % rebate from the grid operator for the connection cost. Hence, the connection cost is distributed between a producer and grid operator.
- A 40 % share of grid operator is included into expenses of PSO and reimbursed to the operator in a next year.

This support mechanism shall not be applied for:

- all RES-E plants which a connected beyond the national quotas for 2004–2009;
- wind plants with total capacity above 250 kW;
- large hydro plants (above 10 MW);
- biomass and biogas plants with share of biomass or biogas below 70 %; other kinds RES-E plants with share of RES below 90 %;
- RES-E auto producers (producers that consume what they generate).

As for wind plants, the separate support mechanism is established. It is less benevolent for a new producer as previous mechanism – provides for a less rebate for connection cost. Moreover, it might even turn to additional payment for connection to a grid – connection fee might exceed 100 % of connection cost.

National quota of 200 MW wind plant capacities will be supported. This capacity is planned to be introduced in 2004-2009 in 6 zones in West Lithuania. A candidate-producer is not allowed to access grid simply, but it should win a competition in a specific zone or its part. Candidate-producers submit bids of connection fee, not less than 60 % connection cost. That who submitted the largest percentage shall win against others. Competitions are organised by the Ministry of Economy.

Similarly, as in previous mechanism, the winners receive a rebate from the grid operator equal to 100 % of connection cost minus their bid connection fee and the share of operator is reimbursed from PSO funds in a next year. If a winner’s bid is above 100 % of connection cost, the differences are included in PSO funds for a next year.

All other new RES-E producers not subjected to abovementioned support mechanisms established in Act B, cover 100 % of their connection cost as established by Act A. For exemplar, the line between the powerhouse and the grid has to be built at the expense of SHP producer. But some categories, like large hydro plants, are legally forbidden (from 2005).

3. Case Study 1: Wind On-shore

3.1. Description

The installed wind energy capacity has reached 6.4 MW in Lithuania in 2004. Electricity generation from wind corresponds to 0.01 % (about 1.2 GWh) of the total electricity demand in Lithuania in 2005.

Investigation shows that the Klaipeda region is the most suitable one for the construction of wind turbines, particularly its 10 km wide coastal strip. The threshold, which cannot be passed without capital reconstruction of electricity network, is 500 MW capacities of wind turbines. The wind turbines' annual operation time is 1700-2000 hours; the annual production will be about 0.85-1.0 TWh. In near future in Lithuania 200 MW capacity of wind turbines will be erected.

Tab. 1. Constraints for wind power utilization *(*Sources*: LEI, R.Skema, A.Markevicius, 2006)*

	Inland	**Off shore**
Availability of area	Conflict with air traffic, military, bird habitats etc.	Ship traffic
Availability of grid	Very good	Expensive sea cable connection
Wind resources	Generally low, highly depending on terrain/ distance from coast	Good
Saturation of electricity production	Depends on the type of other generators, feeding the national grid and the connection with neighbouring countries.	

The grid is available all along the coast, so this is not a hindrance for the utilisation of wind power. Offshore sites of wind turbine between Sventoji and Palanga are complicated, due to the coast shipping – especially to Klaipeda Port. Wind turbines may be erected in 20 m deep according to legislation measures.

Primary planning and environment safety assessment have been carried out. Suitable places for wind power plants are identified using maps of wind velocity distribution in Lithuania, which are formed on the basis of measurement data of meteorological stations with wind velocity computer calculation, evaluating local relief and topographical features. There were stated

6 zones (Table 2) of building wind turbines in Lithuania and foreseen power plant connection to power grid, which is technically and commercially justifiable. Chosen places have enough space to equip power plants and they correspond to other specific planning requirements, such as the convenience of coming close to construction place, etc. Environmental and other investigation [9-11] of wind power lead to the conclusion that the Butinge oil terminal zone is the most ideal place for wind power plants to be built with its good access roads and large industry facilities as potential users of power. In this zone about 30 modern wind power farms may be installed, as this zone is not densely populated and is not itself included into the general recreation zone. According to measurement data, wind velocities are large enough to erect from 1000 to 3000 kW wind power turbines here.

In the rest territory of Lithuania average wind velocity is considerably less than in the coastal region, nevertheless, there are areas, where wind velocities are sufficient for building wind power plants. Such is the Žemaičių Hills region and some localities at Laukuva, Raseiniai, Kybartai and others.

Tab. 2. Zones of wind power plants deployment and technical possibilities of wind power plants connection to power grids in the zones *(*Sources*: LEI, R.Skema, A.Markevicius, 2006)*

Zone No	**Connection possibility,MW**	**Title of power line**
1	30	Distribution network
2	40	110 kV transmition line Klaipeda–Pagegiai, Juknaiciai
3	45	110 kV transmition line Klaipeda–Palanga–Sventoji
4	30	110 kV transmition line Sventoji–Zidikai
5	35	110 kV transmition line section Klaipeda–Rietavas
6	20	Transmition network

3.2. Costs

National Control Commission for Prices and Energy determined the purchase price of energy produced in wind power plants, i.e. 6.37 €ct/kWh. After determining electricity purchase price, which is high enough, from wind power plants, favorable conditions will be created for this kind of power in Lithuania.

Since wind energy is periodic and depends on nature conditions, wind power plants may operate only in a complex with one or several reserved sources, which can cover a part of wind power plants' installed capacity. There are several variants for this task.

The first scenario. Wind power plants plus Lithuanian power plant. Complex's advantage is that Lithuanian power plant is already built and does not require investments. The lack is that power plant's units should be kept partially loaded or should be frequently interrupted and run once again. This would increase expenses of such complex. Maintenance of such reserve would be 25,79 €/kW per year (data of SC "Lietuvos energija").

The second scenario. Wind power plants plus Kruonio HAE. Work of this complex is related to energy losses (about 28 %) loading this HAE. Evaluating exploitation costs of HAE itself, purchase price of wind power plants' electricity would increase up to 8.4 €ct/kWh. Other lack – limited mobility of Kruonio HAE. It is expedient to evaluate that in Lithuanian system, when Ignalina NPP operates, Kruonio HAE is fully exploited. Therefore, Lithuanian power plant, using organic fuel, remains as an operative reserve.

Evaluating previously mentioned additional expenses, in year 2010 producing an additional amount of power of wind power plants, calculation data of power price increase is given in Table 3. We can see that power production costs in power system increased from 0.055 to 0.347 €ct/kWh. In the calculation only primary factors are evaluated, no attention was paid to losses in transmission net, nor to the position of wind power plants' produced power in load curves.

Due to this fact, Lithuanian power system annually may have additional expenses 6.6-41.7 mill Euro. It is forecasted that in year 2010 total power production will be 12 TWh. Expenses of this energy purchase besides wind power price is 295.4 mill Euro. Introducing the above mentioned wind power plants' capacities, in Lithuanian power system power production price would increase from 2.25 up to 14 %, depending on the quantity of wind power plants' power. So that power tariff would not increase significantly, it is proposed to introduce wind power plants' capacity not bigger than 170 MW, installing smaller wind power plants' parks of 5 MW and individual wind power plants not smaller than 1 MW.

Preparing Lithuanian wind power development strategy, methods are proposed how to regulate this development so that to defend consumers and state's interests. Determining power tariffs for consumers, expenditure corresponding to public interests is included as well. For year 2003 it is planned that this expenditure will comprise about 68.93 mill €. after building 170 MW wind power plants, which during a year would produce 0.306 TWh of power, an additional "public interests" sum (grant for wind energetic) would comprise 14.16 mill €. Due to wind energetic subsidizing electricity tariffs would increase 0.116 €ct/kWh, therefore, unlimited process of wind power plants.

Tab. 3. Data of power price increase (Sources*: LEI, R.Skema, A.Markevicius, 2006)*

Years	**Technical variants**	**Perspective power, *MW***	**Perspective production, *TWh***	**Increase of power purchase price, *million Euro***		
				Due to enlarged purchase tariff *(3.91 €ct/kWh)*	**Due to 50% reserved power preservation**	**Total**
2003	-	-	-	-	-	-
2010	1	80	0,144	5.630	1.031	6.661
	2	170	0,306	11.960	2.192	14.152
	3	500	0,900	35.190	6.447	41.637

construction besides technical problems may evoke negative social outcomes.

The following distribution of costs is calculated (Fig. 9., turbine type ENERCON E- 40/644,Vydmantai, Palanga).

The turbine cost constitutes 76 % of the total investment cost for the project. This is typical for an on-shore project that turbine cost is the major item.

The grid integration costs per kW are calculated as 34 EUR/kWh. The percent of grid integration costs of overall project cost are 4.1 %. In other words, the grid integration cost for turbine is 34 Thou EURO.

The relatively low grid connection costs of Vydmantai turbine are probably due to the suitable location of the wind turbine for grid connection.

The electricity generation costs are presented as a function of average wind speed in inland zone (distance more than10 km from cost of see) and in costal zone Fig. 10. Load hours as the net full last is assumed as 2.100 hours, the production cost lies between 43.4 and 52.1 EUR/MWh. The guaranteed price of wind energy for on-shore region is 63.7 EUR/MWh.

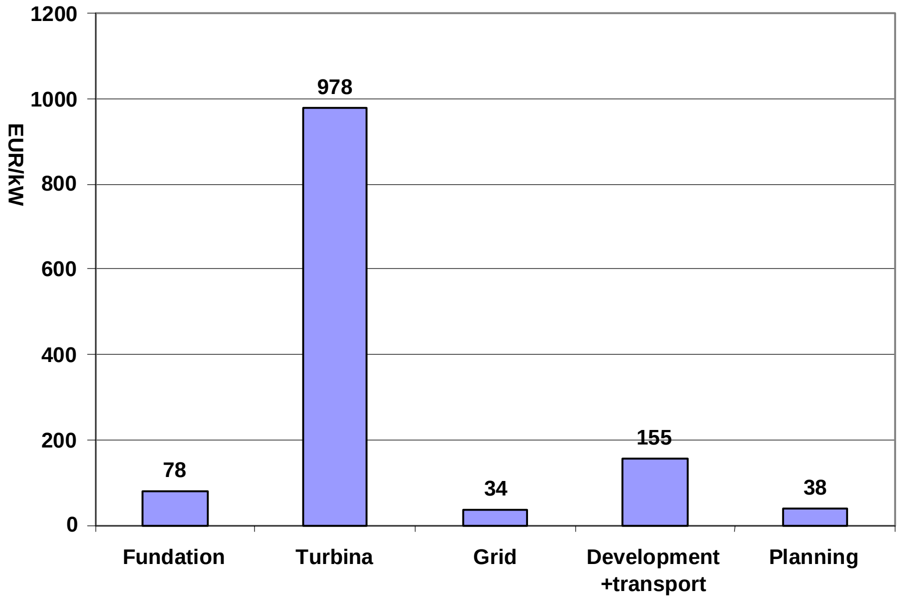

Fig. 9. Specific investment costs (2004) for the on-shore WT in Lithuania (Sources: *LEI, R.Skema, A.Markevicius, own calculation*)

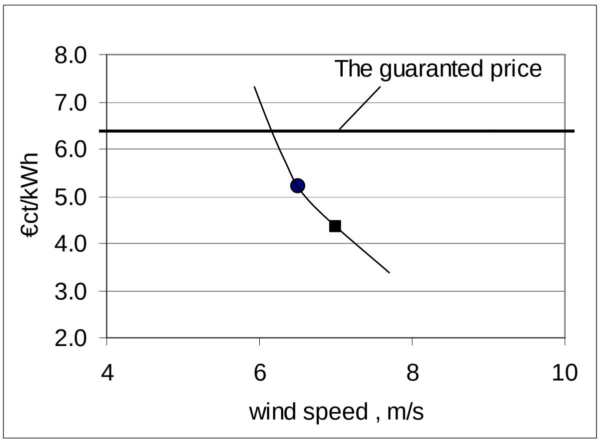

Fig. 10. The electricity generation costs (€ct/kWh) are presented as a function of average wind speed •-wind turbine in land zone, ■-WT in costal zone *(*Sources*: LEI, R.Skema, A.Markevicius, 2006)*

4. Case Study 2: Small hydropower

4.1. Description

For more than 100 years small hydropower has been harnessed in Lithuania. If compared with other not-central generating sources, the following advantages of SHP shall be highlighted:

- savings of fossil fuel, as its price is permanently increasing;
- renewal of energy;
- direct approximate to a consumer, avoiding long power lines;
- long life-period (60 years and even more);
- the equipment manufacturing and building technologies are rather simple;
- simple maintenance, completely automated control;
- no practical damage for environment;
- improvement of river regime due to small heads
- improved resort conditions of the river;
- opportunities to combine HP with other water resource sectors (like ship transport, irrigation, water supply, protection of environment).

On the other hand, the following disadvantages of SHP could be outlined:

- dependency of power production on hydrology conditions;
- high per-unit cost for design services, particularly in case of individual building;
- high per-unit cost for 1 kW;
- limited volume of production, which is insufficient to keep a maintenance personnel.

As we mentioned in above the construction of small hydro power plants (HPPs) is commercial and can be carried out in two stages:

- rebuilding small derelict HPPs and installing new ones near the existing dams. The realistic quantity is about 131 small HPPs;
- building small HPPs on the rivers. It is assessed that the realistic potential of the energy production is up to 1.8 10^6 GJ per year. New small HPPs could be built in the rivers’ zones where their construction is efficient and permissible in terms of the environmental protection. These rivers’ zones should be with the lower water heads and larger flows than near the existing

dams. The constructions should meet all requirements of the environmental protection.

Now SHP plants are almost all privately owned. SHP contribution to the gross electricity generation in Lithuania is very low. Lithuania is country with low SHP turbine manufacturing capabilities. Forecast of SHP installed capacity and electricity generation. in Lithuania is expected to grow in *Lithuania.* There are 78 SHP plants with a total installed capacity of 27 MW (2005) and annual electricity generation of 41 GWh/year (2003) (see table 4). Only conventional techniques have been used in Lithuania during the last decade. The main statistics regarding SHP number, installed capacity, SHP electricity generation during the last 10 years in Lithuania are shown in Table 4. There is clear upward trend for these SHP characteristics over the reference period. More remarkable are the forecasted figures for SHP growth to 2010 and 2015.

Recent SHP sector growth has been impressive: there were only 10 plants in operation in 1990. The same place of SHP development is foreseen for both short and medium terms. Almost all Lithuanian SHP plants can be regarded as young less than 20 years old. Almost all Lithuanian SHP plants can be regarded as recent developments (see Table 5). Low head SHP schemes are prevailing in Lithuania. According to the gross head of SHP plants their percentage is as follows: Low head (up to 5 m) – 51 %; Medium head (5-15 m) – 43 % and High head (more than 15 m) – 6 %. Lithuanian Company “CSC Hidrojėgainė” has produced more than 14 turbines as yet and all of them are performing well.The HP design services are provided by Company “JSC Hidrojėgainė” (in Kaunas and Siauliai) and J.Kavaliauskas personal company. It should be noted that the crucial and basic factor in the design is the availability of accurate hydrological calculations based on measurement data obtained on the site. The calculations provide the assumptions for good quality of design.

Tab. 4. Small hydro power (<10 MW) evolution and forecast in Lithuania *(*Sources*: LEI, R.Skema, A.Markevicius, 2006)*

	1990	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**Forecast* 2010**	**2015**
Total number of SHP	10	15	15	15	19	24	35	42	50	62	70	78	100	130
Capacity, MW	6	6	6	7	8	9	13	14	15	19	21	27	28	36
Generation GWh	18	16	11	17	26	25	27	41	37	41			68	87

** Forecast is based on an extrapolation of the existing trend. The electricity generation for 2010 is almost two times lower than foreseen in the adopted national target to comply with the requirements of the EU RES-E directive (134.2 GWh for 2010).*

Tab. 5. Age structure of SHP plants *(*Sources*: LEI, R.Skema, A.Markevicius, 2006)*

Age	**0-19 years old**	**20-39 years old**	**40-59 years old**	**>60 years old**	**Total**
Number of SHP	37	4	9	0	50

Small hydro contributes 0.51 % to the electricity mix in Lithuania and the total hydro contribution is not significant – about 3 % of total electricity generation. Environmental requirements and various constraints with regard to small hydro are strict. A list of rivers exempted from damming exists. Tables 6 and 7 show the existing resistances to small hydropower development and other environmental restrictions in Lithuania. The most severe impact impeding SHP promotion is fish protection. The EU environmental directives and other regulation related to the river fauna and flora protection are going to adversely affect small hydropower development.

The list of rivers required to protect fish and prevented from damming has been introduced recently in Lithuania (2003). It adversely affects small hydropower potential. Before introducing this list SHP economically feasible potential was estimated at 30 % of natural potential and after introducing this percentage was reduced up to 6 %.

Tab. 6. Resistances to SHP development *(*Sources*: LEI, R.Skema, A.Markevicius, 2006)*

Impact	Degree of gravity (1=no impact, 5=severe impact
Visual impact	2
Fishery	5
Water regulation	2
Competition with other uses of water (irrigation, recreation ect.)	1
Other kinds of resistance*	5

** Requirements of the specific EU environmental legislation, which according to the specialists of environmental protection entirely forbids river damming: NATURA 2000, Water Framework directive, Habitat directive and other conventions protecting the nature of Baltic Sea region.*

The gross theoretical small hydropower potential of Lithuania is 2094 GWh/year (Table 8). The technically and economically feasible potential is 854 and 287 GWh/year, respectively. So far, 14 % of economically feasible potential has been exploited.

Tab. 7. Effect on SHP development and operation of the forbidden rivers, EIA, compensation flow, EU Water Framework Directive and other specific EU environmental regulations. (Sources: *LEI, R.Skema, A.Markevicius, 2006)*

Forbidden rivers for hydropower construction*	**Environmental impact assessment (EIA)**	**Compensation flow (CF)**	**EU WFD and other specific EU environmental regulations**
In 2003 Lithuanian Ministries of Environment and Agriculture together published the list of 147 rivers which have been prevented from hydropower development for ever. Currently this list is under approval by the Government. These forbidden rivers adversely affect SHP economical potential to be exploited.	Lithuania like most industrialized countries has a generalized EIA legislation aimed at all types of development projects. Depending on a particular project size there are two options: mandatory requirement or screening. Hydropower is not directly included in the mandatory list for the EIA. However the screening is needed for hydropower projects larger than 100 kW or alternatively for reservoir volume exceeding 0.2 millions m^3	An officially approved compensation flow (CF) setting methodology exists. CF is set as a mean monthly (30 consecutive days) low flow (return period of 20 years). The losses in SHP electricity production resulting from maintaining CF are negligible (diversions schemes are rare in Lithuania).	WFD is in the course of implementation. Implementation of WFD requirements will result in a prohibition of new SHP construction and complication in authorisation issuing. Referring to the WFD, a project of a list of rivers prevented from being dammed is under consideration of Lithuanian Government.

**Except conventional protected areas – strict nature reservations or protected areas with overall restricted economic regime*

Tab. 8. Small hydropower potential *(*Sources*: LEI, R.Skema, A.Markevicius, 2006)*

Potential	**Generation**		**Capacity**
	GWh/year	**%**	**MW**
Gross theoretical	2094*	100	239
Technically feasible	854	41	195
Economically feasible	287	13.7	65
Economically feasible potential that has been developed	41	14	15
Remaining economically feasible potential	246	86	50
Remaining economically feasible potential taking into account environmental constraints (for example, rivers exempted from damming)	126*	44	29

** The annual energy potentially available in the country if all natural flows were turbined down to sea level or to the water level of the border of the country with 100% efficiency.*
*** Taking into the consequences of the order of the Ministries of Environment and Agriculture (of 16 January 2003 No 27/3D -13) related to the list of forbidden rivers for damming or hydropower development.*

4.2. Costs

The HP building usually needs a huge demand of investment and, on accordance with norms, their pay-back period shall be 10 to 12 years. Once a HP is built on existing dam, this period is shorter. The total cost of dam and pool constitutes 30 to 50 % of HP's capital cost. Hydro turbines, electric power lines, and transformers, with regard to the next future, fish passes incur the rest cost. A 1 km of line costs around 25 000 Euros. The cost of transformer depends on SHP capacity, 50 to100 kW costs about 8 000 Euros, 1 MW about 50 000 Euros. It seems that approximately 15 to 20 % of total capital cost will be assigned for the compliance with environmental requirements obligating to install fish passes on new dams.

The Ministry of Environment has published the list of dams to be provided with dams A guaranteed power purchase price is fixed at 6 €c/kWh. This price is sufficient for HP built on existing dams, however it is not sufficient to cover capital cost in case of a new dam. For such a case, the sufficient purchase price should be set on a twice-higher level, with respect to the same payback period (10 years).

The dominating types of turbines across the Lithuania are those of Kapalan, Banki and Francy. The estimated range of investment costs for new plants is between 2 000 and 2 500 €/kW, with an average generation cost of between 2.5 and 3 €cents/kWh.

The main data of four small HPP Senoji Varene, Jundeliskes, Antanavas and Angiriai are presented in table 9. As seen from data in Table 9 energy production and investment costs are raising dependence on installed capacity, but maintenance price and investment costs per kW decrees

Tab. 9. The main data of four small HPP Senoji Varene, Jundeliskes, Antanavas and Angiriai (Sources*: LEI, R.Skema, A.Markevicius, 2006)*

	Senoji Varene SHPP	**Jundeliskes SHPP**	**Antanavas SHPP**	**Angiriai SHPP**
Type of turbine	Kaplan, type VK-84	Frensis (PO-30-BO-84)	Kaplan, type PR70-BO120	Kaplan, type Z900
Quantity of turbine, unit	1	2	2	2
Installed capacity, kW_{el}	124	200	500	1250
Energy production, MWh/year	600	1100	1400	4000
Flow rate, m^3/h	3	5	11	17
Lift, m	5	6	5,75	14.8
Investment, Thou €	260	230	350	1500
Energy price, €/MWh	71.5	58.0	58.3	58.3
Energy cost, €/MWh		16.0	16.0	
Maintenance price, €/MWh	20.9	17.1	12.4	12.4
Investment costs, €/kW	1969	1158	869	869

Specific investment costs (2006) for the small hydropower in Lithuania are presented in Fig. 11.

SHP developers are responsible for covering the costs of extensions and of strengthening the grid. The line between the powerhouse and the grid has to be built at the expense of SHP producer.

Grid connection costs are approximately 15- 17 % of total investment costs of SHP (see Fig. 12).

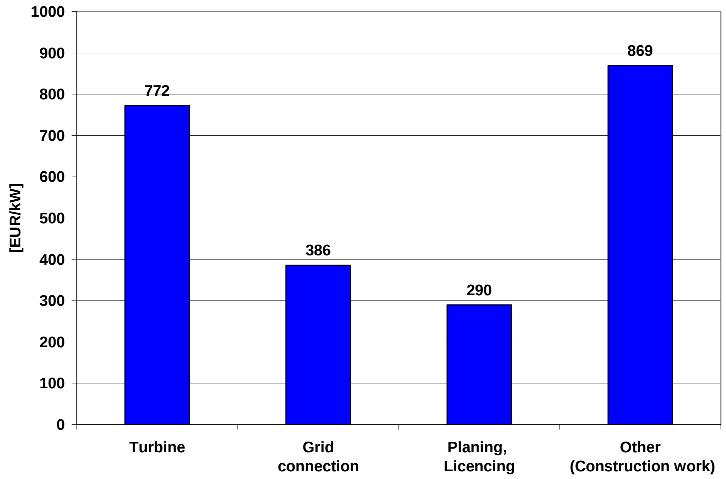

Fig. 11**.** Specific investment costs (2006) for the small hydropower case study in Lithuania *(*Sources*: LEI, R.Skema, A.Markevicius, 2006*

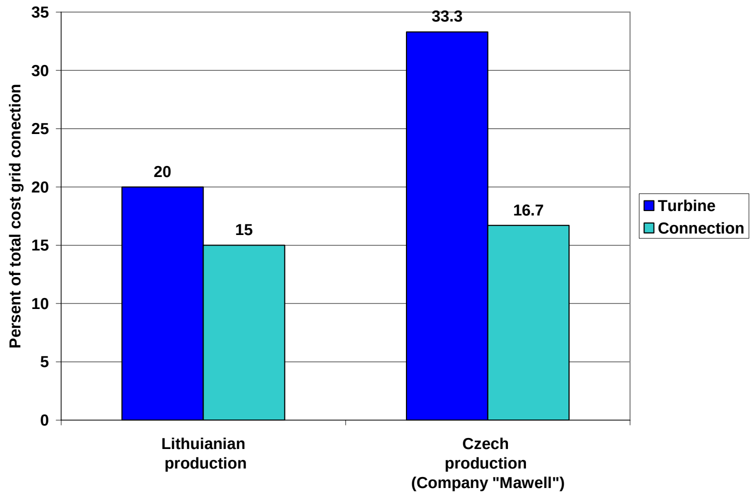

Fig. 1. Comparison of small hydro turbine (capacity – 150 kW) grid connection costs (in % of total investment costs) in Lithuania *(*Sources*: LEI, R.Skema, A.Markevicius, 2006)*

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SLOVENIAN CASE STUDY

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Abstract- The study analyzes the influence of the grid costs to the profitability of the project. The analysis was made within the photovoltaic and CHP on wood biomass technology in Slovenia. Following the model of Germany and Hiroux, 2005 we used shallow grid costs approach. The annuity factor, feed-in tariff and grid costs are important factors for profitability of the PV plant, but solely grid costs represent only a fraction of the influence on profitability. For CHP on wood biomass can be assumed that annuity factor but mostly full load hours play influence the profitability of the project. The direct shallow gird connection costs are not an important factor of the project profitability. Investors do not connect to the grid because of long administrative procedures for connection and therefore can not payback the investment with selling the electricity. So the administrative procedures affect the profitability of the project in higher degree than shallow grid costs.

Keywords: Slovenia, electricity market organization, electricity production and demand, development of RES-E, feed-in tariff, grid connection costs, photovoltaic power plant, CHP.

1. Description of electricity system

1.1. Design of electricity market

The picture below represents present situation of the electricity market in Slovenia after the beginning liberalization and deregulation in year 2001. There

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are four main group suppliers, end users and between those two groups market organizer, regulator and private mediators.

Although the market is liberalized; one company Holding Slovenske Elektrarne controls over 50% of the market share.

Producers are represented below in the table 1. Transmission (on high voltage grid 110 kV, 220 kV in 400 kV) is organized in public utility Elektro Slovenija (ELES), which operates the transmission grid and is also market organizer.

We have five public distribution utilities: Elektro Ljubljana, Elektro Maribor, Elektro Celje, Elektro Gorenjska in Elektro Primorska.

The access to the electricity grid has been arranged through the regulated TPA, which has been also adopted elsewhere in the EU except in Germany. An independent regulator, the Agency for Energy, controls access tariffs for transmission and distribution networks.

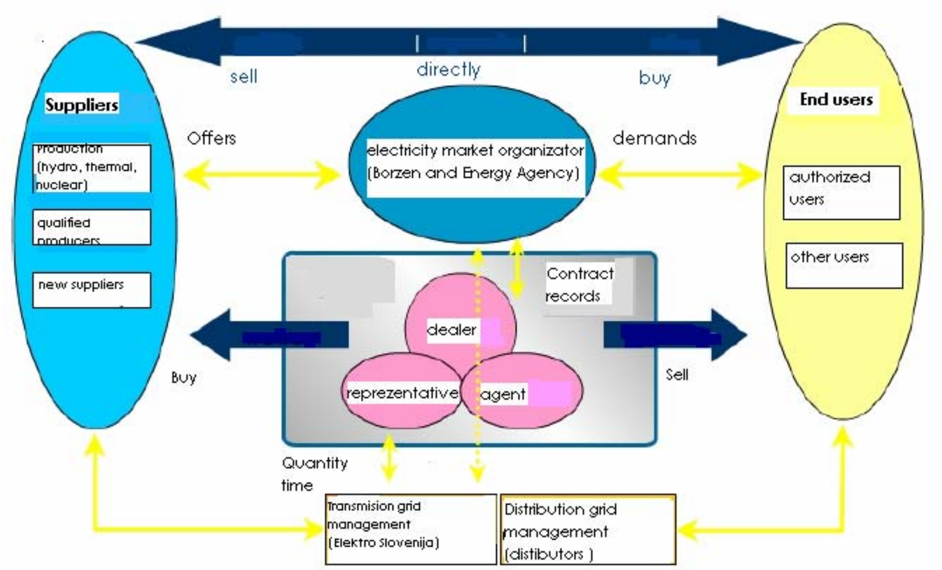

Fig. 1. The organization of the electricity market in Slovenia since deregulation and liberalization. Source: www.elektro-maribor.si.

The electricity market was scheduled for opening up in two stages. On 15 April 2001 the domestic market was opened to competition and in 2003 the market for imports was also opened to competition in generation. Eligible customers are consumers with a connected capacity of more than 41 kW at one location. This represents around 65% of final consumption. Most Slovenian manufacture companies and services are entitled to buy electricity freely with households and some low-voltage customers being captive consumers. On 1st

July 2004 Slovenia has opened its market up to 75% (9500 GWh) of final consumption for all non household end users and it plans to liberalize it up to 100% in year 2007.

Prices for electricity purchased by eligible customers are determined by market forces, while prices for captive customers are subject to control of the Ministry of the Economy till 1st July 2007, when market will be 100% opened.

The estimation of capacities of power plants in Slovenia is presented below.

Tab. 1. Estimate of installed capacity in year 2005

72 public hydro power plants	839 MW
Small hydro power plants (private)	ca 160 MW
4 public thermal power plants	1274 MW
Solar power plants (private)	0,11 MW
1 public nuclear power	676 MW
Biogas (private)	6 MW
Biomass (private)	3 MW
Total power plants	2958,11 MW

1.2. Electricity production and demand

Selected electricity production and demand in Slovenia for the period 1990-2004 is presented in pictures below.

1. ELECTRICITY

1.1 Annual balance of production and consumption of electricity, Slovenia, 1996–2004 GWh

1996	1998	1999	2000	2001	2002	2003	2004	
12 737	**13 705**	**13 261**	**13 624**	**14 466**	**14 600***	**13 821***	**15 272**	**Gross production**
3 668	3 450	3 739	3 834	3 796	3 313*	2 957*	4 095	Hydroelectric power plants[1]
4 507	5 236	4 826	5 029	5 413	5 759	5 657	5 718	Thermal power plants
4 562	5 019	4 696	4 761	5 257	5 528	5 207	5 459	Nuclear power plant
11 972	**12 855**	**12 456**	**12 795**	**13 592**	**13 693***	**12 895***	**14 308**	**Net production**
3 616	3 400	3 683	3 771	3 741	3 265*	2 916*	4 034	Hydroelectric power plants[1]
3 997	4 668	4 288	4 476	4 815	5 120	5 016	5 062	Thermal power plants
4 359	4 787	4 484	4 549	5 036	5 309	4 963	5 212	Nuclear power plant
859	**715**	**601**	**4 232**	**3 154**	**3 794**	**5 975**	**6 314**	**Import**
2 526	**2 609**	**1 934**	**5 553**	**4 926**	**4 928**	**5 811**	**7 094**	**Export**
723	**764**	**691**	**811**	**729**	**737**	**578***	**850**	**Losses in the network**
9 582	**10 197**	**10 432**	**10 664**	**11 091**	**11 823***	**12 481***	**12 679**	**Final consumption**
168	157	161	142	164	128	138	132	Energy sector
4 921	5 055	5 099	5 490	5 648	5 790	6 543	6 710	Manufacturing and constr.
258	268	271	265	256	172[2]	176[2]	189[2]	Transport
2 594	2 658	2 692	2 601	2 675	2 704	3 008	3 012	Households
1 641	2 059	2 151	2 166	2 348	3 023*	2 615*	2 637	Other consumers

1) Estimation of production of small hydro power plants is included in view of distribution's purchase.

2) Only railway and rope-way are included.

ENERGY PRODUCTION

	1990	2000	2003	2004
Electricity¹⁾ (GWh)	13870	12795*	12895*	14308
Hydroelectric power plants¹⁾ (GWh)	2950	3771	2916*	4034
Conventional thermal plants¹⁾ (GWh)	6536	4476	5016	5062
Nuclear power plant¹⁾ (GWh)	4384	4549	4963	5212

ENERGY CONSUMPTION

	1990	2000	2003	2004
Electricity (GWh)	9893	10664	12481*	12679

ENERGY KEY INDICATORS

	1990	2000	2003	2004
Share of electricity from renewable sources in total electricity production (%)	25,5	28,6	22,3*	27,6
Share of electricity from renewable sources in gross consumption of electricity (%)	29,4	31,7	22,1	29,1

Fig. 2. Energy demand and supply and share of RES-E (also large hydro power plants) in Slovenia over past years

Source: Statistical information, 2005.

1.3. Past and expected development of RES-E

Regarding the share of RES in the primary energy balance and electricity production from RES, Slovenia is well placed among the most developed European countries. The largest contribution comes from the hydro power plants (large hydro power plants have more than 10 MW of installed power and produce approx. 24.8% of energy in Slovenia, small hydro power plants have 10 MW or less installed power and produce approx. 4.3% of energy in Slovenia) and biomass (wood and wood residues).

The following table represents the recent level of the renewables and the level expected to be reached in 2010 and 2020. The data are mostly summarized from the Expert Bases for the Resolution of Energy Use and Supply of Slovenia (Ministry of Economy), 1995; some of them are corrected according the latest data and estimations. On general RES level there is no later analysis available, specific data for some of RES are presented further on. New technical and also economical potential is foreseen for wind in the Primorska region, where wind measurements are indicating the possibility for a larger and economical wind exploration.

Tab. 2. Energy potential of the renewable energy sources

	Installed capacity 2000	Contribution 2010	Contribution 2020
1. Hydro Power Plants			
1.1 Large(>10 MW)	750 MW	960 MW	1.200 MW
1.2 Small (<10 MW)	65 MW	100 MW	200 MW
2. Biomass			
2.1 Power production	9 MW	20 MW	40 MW
2.2 Heat-large boilers	350 MW_t	550 MW_t	850 MW_t
2.3 Heat-small boilers	4.000 MW_t	4.400 MW_t	5.000 MW_t
2.4 Biodiesel	0	10.000 TOE	20.000 TOE
3. Wind	0	300 MW	600 MW
4. Photovoltaic	50 kW	3 MW	10
5. Geotermal Energy			
5.1 Power production	0	20 MW	40 MW
5.2 Heat	103 MW_t	330 MW_t	500 MW_t
6. Solar Heat Collectors	100.000 m^2	300.000 m^2	500.000 m^2
7. Heat Pumps	5.000 pc	15.000 pc	30.000
8. Use of Wastes	0	10 MW MW_t	20 MW_t

Source: Expert separate for RES for the Slovenian National Energy Plan, 2002, ApE.

The presented program of the investments in upper table up to 2010 could be compared with the similar programs for RES in EU countries. On the other hand in the period 1995-2000 the government didn’t succeed to introduce any relevant condition to support investing activities that could contribute to increase of RES share in total energy production. Taking into account that the relevant conditions for support RES will be adopted in due time and the proposed amount of the investments will be executed we could expect the shares for the renewables presented on the right picture below.

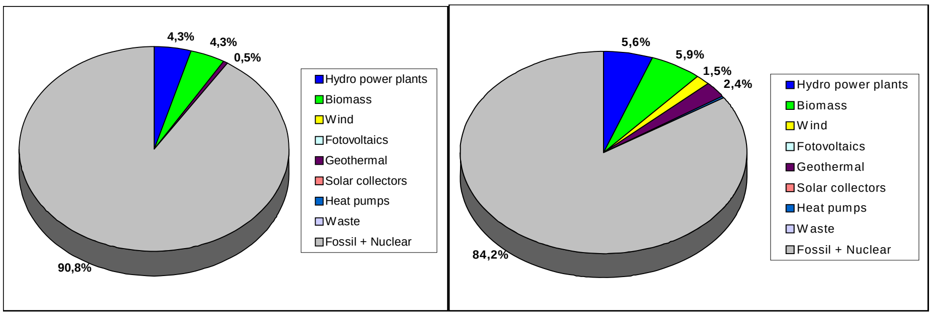

Fig. 3. Share of RES in the primary energy balance of Slovenia in the years 2000 and 2010

Source: Expert separate for RES for the Slovenian National Energy Plan, 2002, ApE.

The forecast for 2010 is only an overview, based on the recent technical conditions and similar forecasts for other countries. The presented forecast for the RES was prepared within the preparation of the National Energy Plan.

2. Conditions of RES-E grid integration

2.1. Integration policies

Slovenia started financial supports for RES in 1990. There were a lot of changes in the organisational approaches and also in the terms of continuity, types and amounts of subsidies. In the last few years the Ministry for Environment and Spatial Planning trough the Sector for Efficient Use and Renewable Energy supports the investments in RES and cogeneration with subsidies for investment projects. The subsidies are foreseen in each year budget, the available amount of money for support is limited and public tenders are issued once a year. As in Germany, Slovenia doesn’t have a special renewable Energy Act. But in National Energy program the goals are:

- 12% share of RES in primary energy balance by 2010
- rise of the share of RES in heat supply from 22% in 2002 to 25% in 2010
- rise of the share of RES in electricity from 32% in 2002 to 33.6% in 2010
- 2% of share of biofules in transport by 2005

To achieve these targets, a need for regulations to support renewable energy was foreseen.

The electricity production with all RES producing electricity listed in the table below, in supported trough the feed-in tariff system. This system is foreseen for independent qualified producers[2], from which distribution companies[3] have to buy electricity at fixed prices over certain period of time in Slovenia is 10 years (Official Gazette RS, no. 25/02) and with Decree on prices and premiums for purchase of electricity from qualified producers (Official Gazette RS, no. 75/06).

Uniform annual prices for the purchase of electricity from qualified producers and uniform annual premiums (when independent qualified producer sells at uniform annual premium, he get paid a sum of adequate premium and market price, which is not necessary higher as uniform annual price) for electricity that the producers are selling individually to the end consumer or via distributor are shown in the table below.

Qualified power producer can own more different qualified power plants from which he can sell electricity at prices mentioned below regarding the type of power plant.

Uniform annual prices and uniform annual premiums do not include VAT. It is foreseen that the prices will change once a year with government decree, taking into account the inflation and other relevant factors.

Environmental development fund of Slovenia is a public fund offering within calls, attractive credits for environmental and RES investments of companies or households. Its main mission is to encourage development in the area of environmental safety.

The government of the Republic of Slovenia passed a regulation on CO_2 emission tax in 1996. The regulation was changed in 2002 (Official Gazette of RS, No 91/2002). The tax is paid on account of the fuel use as well as on the account of the burning of combustible organic substances and it is seen as a state budget income as a whole. Tax is not paid for the use of the biomass, biogas and processed animal albumen and fat. The base for the tax payment represents unit load (UL) and the carbon quantity released with the burning of the particular fuel and combustible organic substance. The government sets the tariff for the unit load (UL) and it currently amounts to 3 SIT/UL.

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[2] Independent qualified producer is a producer which in single object of production produces electrical energy with above average exploitation of cogeneration of heat and power or if he in economically and environmentally adequate way exploits wastes or RES.

[3] Prices of electricity sold to the industrial consumers are set in individuals contracts with them and are market oriented. Prices for household and small consumers are set fixed and set from the government.

Tab. 3. Uniform annual prices and premiums for selling electricity produced in qualified power plants

Type of QPP regarding the primary energy source	Power capacity	Uniform annual price (c€/kWh)	Uniform annual (c€/kWh)
Hydropower QPP	Up to 1 MW inclusive From 1 MW up to 10 MW inclusive	6,16 5,94	2,40 2,18
Biomass QPP	Up to 1 MW inclusive Above 1 MW	9,41 9,12	5,65 5,36
Wind QPP	Up to 1 MW inclusive Above 1 MW	6,07 5,86	2,32 2,11
Geothermal QPP		5,86	2,11
Photovoltaic QPP	Up to 36 kW inclusive and above 36 kW	37,42	33,66
Other QPP[4]		12,09	8,33
Combined QPP using RES[5]		6,70	2,94
QPP or heating plant using communal waste[6]	Up to 1 MW inclusive From 1 MW up to 10 MW inclusive	5,32 4,95	1,56 1,20
Heating plant for district heating	Up to 1 MW inclusive From 1 MW up to 10 MW inclusive	7,30 6,89	3,55 3,13
Industrial heating plant[7]	Up to 1 MW inclusive	7,09	-

Source: Official Gazette of RS, No. 75, 18.7.2006. Exchange rate is 239,64 SIT/€.

Companies, which have to pay the CO_2 emission tax, can get these taxes back if they invest in measures for reducing CO_2 emissions. That means that the companies still pay CO_2 emission tax for the amount of the used fuel, but they can get the tax partly back if they invest in the following projects:

- Introduction of cogeneration of heat and electricity within reconstruction of existing heating power plant.
- Introduction of combined cycle in reconstruction of existing gas turbine.
- Measurements of rational use of energy in existing industrial object.
- Reconstruction of existing devices for heat supply in urban area or other measurements for heat supply.

[4] Power plant using as input other kind of RES, which is not fossil or nuclear. QPP using biogas from animal waste belongs to this group.
[5] Combination of stated RES power plant
[6] QPP and heating plant using communal waste include also QPP using biogas and QPP using gas from communal purifying plant
[7] Average purchase price for industrial heating plant up to 1 MW inclusive is valid for all surpluses of their own consumption that qualified producer dispatches to the public grid. Abbreviations used in the table stand for: QPP-qualified power producer, RES-renewable energy source.

- Exchange of fossil fuels with renewable energy sources in existing heating devices.
- Measurements for reducing heating losses in objects.

2.2. Grid connection and system service requirements

Slovenia is a member of Union for the Co-ordination of Transmission of Electricity, UCTE, whose primary goal is to assure system security. For example, a loss of an element in the system must not cause voltage or frequency fluctuation. Also the power generation plants that operate with renewable energy sources must comply with these regulations.

The producer sells the electricity if the sell and buy contract is signed and the deviations from the supply or buy is arranged. Qualified producers in mikro and small power plants do not make timetable and do not pay prohibited deviations. Costs of those deviations are socialized in the costs of priority dispatch (Of. Gazette of RS, No. 25/2002 and 117/2002).

2.3. Philosophy of allocating grid integration costs

There are two main approaches to the allocation of grid integration costs according to Hiroux, 2005 which are the deep and shallow approaches.

In the deep cost approach, the owner of the production plant would carry all the costs related to grid integration. In the shallow cost approach, the producer only carries the costs related to the connection i.e. the direct line to connect the plant to the nearest available connection point. Other costs like improvement and upgrading costs are socialized.

As in Germany also in Slovenia the shallow cost approach is in effect. The plant operator bears the necessary costs of connecting plants which generate electricity as well as the costs for the appliances necessary to meter incoming and outgoing electricity. Costs for upgrading the grid due to newly connected plants generating electricity are borne by the grid operator and the operator is allowed to socialise them in the costs for use of the grid. Administration costs, meter, cable and labour are the major cost items in a shallow cost approach where cable and labour costs are increasing with increasing distance between the plant and available connection point (Knight et al., 2005). As the shallow cost approach is in effect in Slovenia, it will be used in this study. The study is based on recently collected data and archive of the ApE ltd. No particular study for grid costs of connecting renewables in Slovenia was made.

Feasibility studies are not accessible for public research, so we had to collect data directly from the producers (operator, owners) of power plants. Even from them the data is hard to get.

For wood biomass CHP power plant APE ltd. made the final financial closure report so more accurate data were accessible. For other the data are acquired from telephone interviews and e-mails, so they represent more an estimate, than specific costs.

Grid integration costs for wood biomass cogeneration power plant paid by the owner of the power plant that are included in the shallow grid costs are: acquisition of permits and project documentation, investment into metering, safety requirements and measurements, communication and electrical cables, and installation measurements, that are also included in annual grid connection costs. Labor costs are included in above mentioned costs. Those items are also relevant for other renewable technologies in Slovenia and also considered in this study.

3. Case study: photovoltaics

3.1. Description

At present the interest for investments in photovoltaics (PV) power plants requires a certain level of electricity prices, which gives a reasonable payback period to the investors. The payback period is the main decision factor of PV investments in Slovenia. If the prices do not allow reasonable payback period, we had few investments and implemented only in special off-grid situations or as a result of individual enthusiasm. The Slovenian feed-in regulations from 2003 settled the price for PV plants on 0,28 €/kWh and were increased in 2004 on 0,37 €/kWh. Even with this price for PV, the profitability of the investments is still relatively low. The payback period, without depreciation, is in range of 12-15 years.

In 2002 operated about 30 PV installations with the total power of approximately 50 kW, mostly off grid applications. In last years few PV projects were installed in Slovenia for local electricity supply of mountains huts, which are not connected to the electrical network. These projects were supported also by a Phare program in the period 2000-2002 with the total installed capacity in the range of 10 kW_p. In year 2005 additional 103.785 kW grid connected PV were installed as a result of higher feed-in tariff.

The share of on grid PV power plants in the whole Slovenian electricity system is insignificant, lower than 1%. Up to year 2006 we have approx. 6 PV grid connected power plants with total nominal power of 110 kW and it is expected that the number will continuously rise. For now no upgrade of the transmission and distribution system was made on behalf of grid connecting photovoltaic power plants (the biggest PV grid connected power plant now is 35,64 kWp), so no deep connection costs were made.

Because of the relatively good potential of this energy source here in Slovenia we expect in the near future a higher support of the research work, development and production of equipment by the government and interested institutions.

Weak points of solar power plants are as pointed above: high investment, longer payback period even now when the price for sold electricity from PV is relatively high and complicated process to get all the licenses and permits for selling the electricity as qualified electricity producer. The administrative requirements for connection to the grid represent a serious barrier for potential investors especially for individuals or households. Connection to the grid should be safe, simple and standardized.

3.2. Costs

Slovenia has a large potential for using solar energy to produce electricity, due a sufficient number of sunny days. The global solar radiation of Slovenia is in the range of 1100 kWh/m^2. The expected specific year production of electricity could be more than 1000 kWh/kW$_p$.

End of January 2004 the price for PV systems increased substantially to 37,67 cent €/kWh and in 2006 for all nominal power of the plants the price is now the same. The financial figures and possibilities for investing in small photovoltaic systems up to 36 kW become more realistic.

Tab. 4. A short economical overview of investing into photovoltaic system

Solar Power Plant		
Specific investment	€/kW	6.720
Annual production	h	1.000
Feed-in tariff	Cent €/kWh	37,67
Specific annual income	€/kW	375
Specific annual costs	% of income	5%
Simple payback period	Years	18,8

Source: ApE estimations, 2004.

Investments in solar power plants are very high but the maintenance costs are relatively low. Although high price for electricity produced in such plants is not sufficient for short payback period. Only on remote areas not connected to the grid system such systems are economically reasonable.

Full load hours are assumed as 1000. All calculations are done in real base for the year 2005.

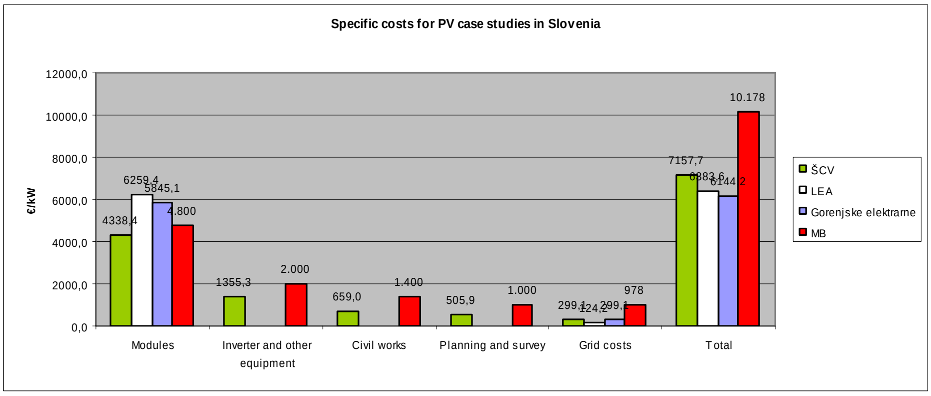

Fig. 4. Specific investment costs for the PV case studies in Slovenia (interviews, own calculations)

We investigated four case studies, three existing (MB, LEA and Gorenjske elektrarne) and feasibility study (ŠCV). Since for all three we weren't able to get specific values for individual investment parameters, we estimated costs for inverter and other equipment, civil works and planning according to feasibility study. But we did get the whole investment and shallow grid costs values.

The MB PV power plant has a specific case, since they invested into the additional measurement technique and into more expensive frame for the plant comparing to the others. Therefore also grid costs represent higher percentage comparative to the other cases.

Of course the biggest share represents the investment into modules and other equipment around 80%. As seen on the figure 3 grid costs are representing smaller percentage of the investment in the range of 2-10%.

The grid integration costs per kW are calculated in the range of 124-987 EUR. Thus, the total specific cost without the grid integration costs will be in the range of 5845-9200 EUR/kW.

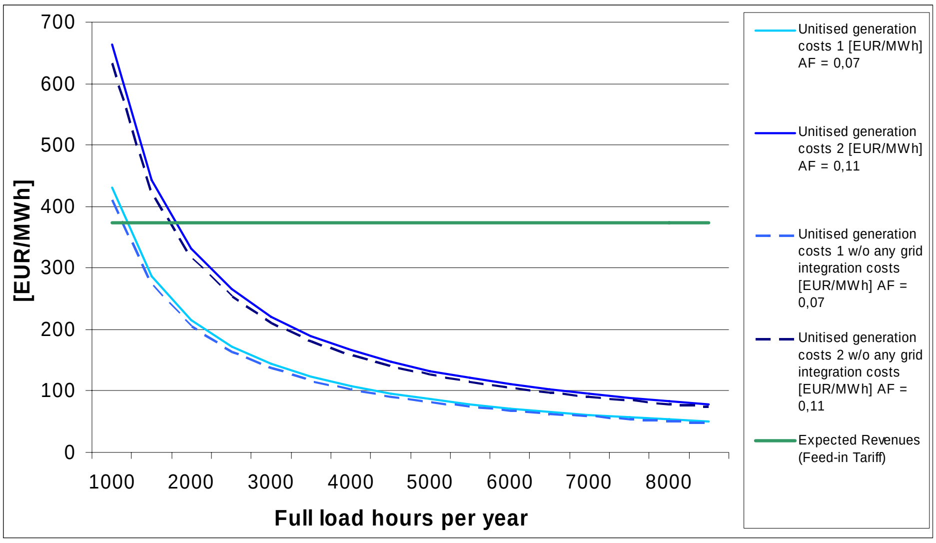

Fig. 5. Electricity production costs, 2004 (Source: interviews and own calculations) AF = annuity factor

The electricity production costs are presented as a function of full load hours in figure 5 for the most representative PV study case Gorenjske elektrarne. As the net full load hours are assumed as 1.000, the production costs lie between 430 and 664 EUR/MWh. If the grid connection costs are neglected the costs reduce to the interval of 409 and 632 EUR/MWh. The guaranteed price of electricity from photovoltaic power plant is 373,86 EUR/MWh. If the grid connection costs in this case are neglected electricity generation costs are reduced for approximately 5%.

The annuity factor is more important, since it changes the generation costs from 430 to 664 EUR/MWh, which is a 35% difference. If the power plant operates more than 1200 hours/a will be profitable, if the contract defines the feed –in tariff for more than 10 years and the low annuity factor is considered with the grid connection costs. If we exclude the grid costs, the plants only needs 1150 full operating hours with the low annuity factor to be profitable which in Slovenia can be achieved in northern and southern parts of the country. With more than 1750 full load hours the plant Gorenjske elektrarne will be profitable taking into account higher annuity factor with the inclusion of the grid costs. If we use classic PV power plant without tracking system and mirrors (those cases were not analysed here) we can not influence full load hours. So the annuity factor, feed-in tariff and grid costs are important factor in the profitability of the plant.

4. Case study: biomass cogeneration

4.1. Description

Forests cover more than 56% of the Slovenian territory. Use of biomass represents the market for agriculture and forestry sector, new working places and decrease in demography problems. Based on achieved experiences use of permanent yearly accretion of bio energy in the coming years, we at the ApE have estimated that an extra 5 PJ of biomass could be added in following 10 years to the current 12 PJ of energetic use. The proposed program is mostly based on wood and wood residues coming from an increased nurturing and cultivation of forest. Additional potential in the range of 0,3 PJ could also represent especially acquiring biogas from agricultural remaining and purification devices. To attain the presented targets a broader investment program should be considered as presented in the next table where for the purpose of this study we included only power plants.

Tab. 5. Investments and support for a 5 PJ bio energy program

Number of biomass devices		Investment per device	Amount of invest. per year	Required subsidy per device	Required subsidies per year
10-years period	Yearly	in €	in €	in €	in €
250 agriculture biogas devices	25	235.294	5.882.353	71.429	1.785.714
100 gasification devices	10	71.429	714.286	23.529	235.294
5 industrial cogenerations	0,5	3.529.412	1.764.706	1.163.866	579.832
Total requirements			8.361.345		2.600.840

Source: Expert separate for RES for the Slovenian National Energy Plan, 2002, ApE.

We have 3 cogeneration power plants on landfill gas (2 small and one middle size) and one on sewage gas. Than we have three on biogas, and five on wood biomass (one middle size others small size power plants). In July 2006 the biggest European collective biogas power plant was opened with 1,8 MW_{el} and 1,6 MW_{th}.

4.2. Costs

Full load hours are assumed as 6.000. All calculations are done in real base for the year 2004. According to these assumptions, the following distribution of costs is calculated. (Fig. 6)

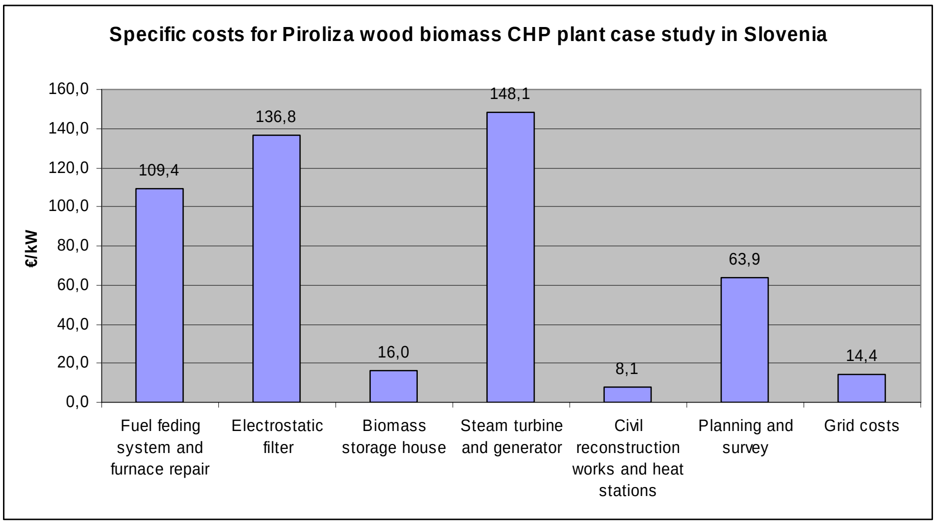

Fig. 6. Specific investment costs for the Piroliza wood biomass CHP power plant case study in Slovenia (Final report, own calculations)

As seen from figure 6 costs for the steam turbine, fuel feeding system and filter constitutes 79% of the total investment cost for the power plant. This percentage is expected for the CHP power plant. Second biggest share of investment costs belongs to planning and survey. Grid costs represent only 3% of the whole investment costs. That costs are only shallow costs, since there is no evident data for deep integration costs. The grid integration costs per kW are calculated as 14.4 EUR. Thus, the total specific cost without the grid integration costs will be 482.3 EUR/kW.

The electricity generation costs are presented as a function of full load hours in figure 7. As the net full last hours are assumed as 6000, the production cost lies between 25.22 and 28.14 EUR/MWh. If the grid connection costs are neglected the costs reduce to the interval of 24.99 and 27.82 EUR/MWh. The guaranteed price of electricity from wood biomass power plant is 94.09 EUR/MWh for power plant above 1 MW of nominal electrical power, and 91.17 EUR/MWh up to 1 MW of nominal electrical power. The neglect of grid connection costs in this case of Piroliza Kamnik brings a reduction of approximately 1% in electricity generation costs.

The annuity factor is more important, since it changes the generation costs from 25.22 to 28.14 EUR/MWh, which is a 10% difference. If the power plant operates more than 2500 hours/a will be profitable, if the contract defines the feed –in tariff for more than 10 years and the low annuity factor is considered. With more than 3000 full load hour the plant Piroliza will be profitable taking into account higher annuity factor. Clearly for power plant on wood biomass

Piroliza Kamnik, and it can be also assumed that this statement can be applied on all 5 existing wood biomass power plants in Slovenia, annuity factor but mostly full load hours play very important role in the profitability of the project.

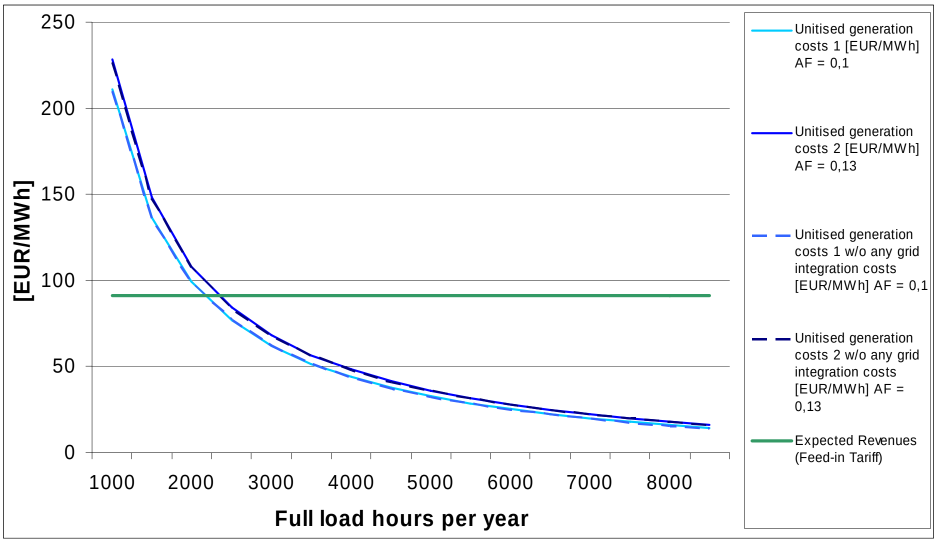

Fig. 7. Electricity production costs, 2004 (Source: Piroliza final report and own calculation) AF = annuity factor

5. Conclusions

In Slovenia about 10 main steps are required to come from the idea to the contract for selling the electricity. The procedure involves a series of different actors. The government should foresee that the investors should settle all what is required at only one institution. The best place would be the electrical distribution companies where the consumers are settling all what is required for the connection of their houses to the electrical grid.

To get the status of QPP, all the renewable energy sources (RES) and the cogeneration power plants with high efficiency are eligible. The process for qualification is rather complicated and time consuming. Such qualification is required even for a 1 kW_p PV power plant and is granted by the minister responsible for energy.

Although explicit costs for connecting to the grid do not represent such a significant share of the investment that could have a large influence on profitability, the implicit costs of time spent to go trough the procedure of the permit acquisition are so big, that the investors are driven away from the investment in the first place. The requirements for connection to the grid are not standardised and known to all involved actors: distribution utilities, designers, installers and investors. In this way the connection represents a serious barrier for potential investors of RES-E power plants, especially for households.

As their normal obligation the distribution companies or their common association should define the standardised connection requirements and technical solutions for different power size capacities. Requirements and standardised connections should be published and easily available to the interested actors.

If the grid connection costs for photovoltaic power plant are neglected electricity generation costs are reduced for approximately 5 %. The annuity factor, feed-in tariff and grid costs are important factor in the profitability of the PV plant since in classic PV system we cannot influence much on full load hours.

Clearly for CHP power plant on wood biomass can be assumed that annuity factor but mostly full load hours play very important role in the profitability of the project. So we can sum up that the direct shallow gird connection costs are not an important factor of the project profitability.

Investors do not connect to the grid because of long administrative procedures for connection and therefore can not payback the investment with selling the electricity. So the administrative procedures affect the profitability of the project.

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COMPARISON OF CONDITIONS AND COSTS FOR RES-E GRID INTEGRATION IN SELECTED EUROPEAN COUNTRIES

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Abstract

This paper compares conditions and costs for RES-E grid integration in selected European countries. These are: Germany, the Netherlands, the United Kingdom, Sweden, Austria, Lithuania and Slovenia. Hence, a wide range of established liberalized electricity markets and recently acceded countries are included. Country specific Case Studies are presented for wind onshore and offshore, biomass and photovoltaic power systems, as based on literature reviews and stakeholder interviews. It is shown that, especially for wind offshore, the allocation of grid integration costs can form a significant barrier for the installation of new RES-E generation if the developer has to bear all such costs (especially the 'deep costs'). If energy policy makers want to reduce the barriers for new large-scale RES-E deployment, then it is concluded that the major part of the grid integration costs should be covered by the respective grid operator. These costs may then be recouped by increasing consumer tariffs for the use of the grid. This, however, is only possible if the grid integration costs are calculated transparently and if effective regulation is in place.

Keywords: Grid integration, wind power, biomass, photovoltaic, case studies, embedded generation, costs.

1. Introduction

Grid connection and extension costs are significant factors for integrating RES-E generation technologies into an existing electricity network. The costs of grid connection are especially relevant if, for example, offshore wind is considered, for which the next suitable grid connection point[†] may be several kilometers away. Hence, additional grid connection costs apply that are generally not required for integrating conventional generation technologies (this is mainly due to the fact that those networks already exist and have been paid for in the past). The costs of grid extension are important if changes in generation and demand at one point in the network cause power congestion in another (deeper) point in the network. Usually, it is not possible to identify a single cause for the change.

[†] This may be a high-voltage transmission grid because of the relatively large capacity of the offshore windfarm.

Thus, the allocation of the resulting costs to a single RES-E generator is at least ambiguous, if not impossible.

Consequently, two questions arise: (i) what conditions apply for RES-E grid integration, and, (ii) who has to pay for additional costs? If a new developer has to pay all the costs of grid integration up-front, then a compromise between the best generation sites and acceptable grid conditions has to be made. This means that RES-E developers may have a first-mover disadvantage by having to include these costs within their long-run marginal generation costs. If, on the other hand, the grid connection costs are covered by the respective distribution or transmission system operator (as the grid forms a natural monopoly, these costs are then 'socialized' to the all customers via grid tariffs); consequently, the initial burden does not fall only on the first RES-E developer.

In order to answer the questions asked above, the major objective of this paper is to present the results of selected country-specific Case Studies on conditions and costs for RES-E grid integration under different regulatory regimes, namely: Germany, the Netherlands, the United Kingdom, Sweden, Austria, Lithuania and Slovenia. For these different countries, prominent RES-E technologies were selected, cf. Table 1. The information came from literature reviews and stakeholder interviews. The overall results may be analysed for best-practice.

Tab. 1. Country specific case studies

Country	Wind power		Biomass	Photovoltaic
	Onshore	Offshore		
Germany	✓	✓		
Netherlands	✓	✓	✓	✓
United Kingdom	✓			✓
Sweden	✓			
Austria	✓		✓	
Lithuania	✓			
Slovenia			✓	✓

The remainder of this paper is structured as follows. A short description of the respective electricity systems is given in section 2. The conditions of RES-E grid integration are discussed in section 3. The costs of RES-E grid integration are analyzed in section 4. This allows best practice cases to be identified in section 5. Finally, conclusions are drawn in section 6.

2. Description of electricity systems

Following the EU Directives 96/92/EC and 2003/54/EC the electricity markets in Europe must be fully liberalized by 1st July 2007. By then (i) all electricity users should be able to choose their own suppliers, and (ii) electricity network service providers must be separated (unbundled) from generating and/or supply companies. Of the considered countries, only Lithuania and Slovenia, which acceded the European Union in 2004, have not yet achieved this target, Table 2.

Another requirement of the EU Directives for each country is for the establishment of an effective regulatory body (i.e. the Regulator), that ex-ante regulates the electricity network. The major reason is that the electricity network forms a natural monopoly and is thus not subject to normal market mechanisms. In most of the countries considered, the access to the transmission and distribution network at liberalisation was based on a regulated third party access. In Germany, however, the access to the network was based on a negotiated third party access, and only after the EU directive 2003/54/EC became effective, was the national energy law revised and a Regulator established.

Note that, following the liberalization in many of the considered countries, mergers in the generation sector have resulted in a more concentrated market structure. In both Germany and the Netherlands, for example, the centralized power plants are owned by just four companies. This results in an oligopoly and raises questions regarding the success of the liberalization, since lack of competition may allow electricity prices on the wholesale markets to increase, so leading to increasing retail electricity prices, especially for small customers.

Tab. 2. Status of liberalization by the end of year 2006

Country	Status of liberalization
Germany	100 %
Netherlands	100 %
United Kingdom	100 %
Sweden	100 %
Austria	100 %
Lithuania	70 %
Slovenia	75 %

The installed capacities for electricity generation and the electricity production in the considered European countries are quite different. Thus Germany has the largest electricity system in Europe (in 2004 production of 607 TWh and installed capacity 112 GW) and Slovenia, one of the smallest electricity systems in Europe (in 2004 production of 15 TWh and installed capacity 3

GW). For this study, however, not only the size of a system is relevant, but also the respective share of RES-E, cf. Table 3, 4 and 5.

Tab. 3. Installed total capacities and share of RES-E (including large-scale hydro power)

Country	Capacity (GW)		Share of RES-E (%)	
	2000	2004	2000	2004
Germany	118	124	13	22
Netherlands	21	22	4	8
United Kingdom	79	80	7	7
Sweden	34	34	58	55
Austria	18	21	65	70
Lithuania	7	6	14	15
Slovenia	3	3	33	33

Tab. 4. Consumption, RES-E production share and 2010 target of the EU Directive 2001/77/EC (including large-scale hydro power, which production is noticeably rainfall dependent by year)

Country	Consumption (TWh)		Share of RES-E (%)		Target (%)
	2000	2004	2000	2004	2010
Germany	572	597	7	10	12.5
Netherlands	109	117	3	5	9
United Kingdom	389	401	3	4	10
Sweden	150	150	55	45	60
Austria	59	65	74	62	78.1
Lithuania	10	12	3	4	-
Slovenia	12	15	31	29	-

Tab. 5. Consumption and RES-E production per capita (excluding large-scale hydro power)

Country	Population (M)	Consumption (TWh/M)		RES-E production (TWh/M)	
	2004	2000	2004	2000	2004
Germany	82	6.97	7.28	0.27	0.55
Netherlands	16	6.78	7.31	0.18	0.33
United Kingdom	60	6.48	6.67	0.08	0.16
Sweden	9	16.88	16.81	0.99	1.28
Austria	8	7.17	7.89	0.74	0.88
Lithuania	4	2.80	3.30	0.01	0.02
Slovenia	2	6.48	7.63	0.19	0.29

The large share of RES-E production in Sweden and Austria, compared with the other countries on Table 3 and 4, is because their electricity supplies are dominated by large-scale hydro-power generation and not, as for the others, by thermal generation. Note that annual rainfall variation causes fluctuation in RES-E production, cf. Table 5. The thermal generation is based on nuclear and coal in Germany and on gas, coal and nuclear in the United Kingdom.

The tables show the change of RES-E capacities and production. The growth in Germany, the Netherlands and the United Kingdom is especially noticeable, mainly due to significant growth rates of onshore wind energy installations. For instance, Germany has the largest installed wind capacity of any country worldwide, with more than 16 GW cumulative by 2004. However, due to the large electricity system, this corresponds to an electricity production share of only 4 %. Nevertheless, the installations in Germany significantly contributed to the impressive worldwide yearly growth rates of installed wind capacities of up to 35 %/y in recent years. However, the rate of deployment is beginning to decrease in Germany, mainly because the available sites for wind farm building onshore are becoming scarce. Hence, investors tend to re-power older onshore wind turbines and to favor offshore installations as a new promising option. A comparable development can be seen in the Netherlands. There the growth rates of new installed wind turbines increased from 12 %/y in the years 1995 to 2001 to 30 %/y in the years 2001 to 2004.

The new installed capacities of other RES-E technologies are not usually as large as for wind power. This is due to either the large long-run marginal generation costs, e.g. for photovoltaic power (nevertheless, the annual growth rates of photovoltaic installed capacity are impressive), or to the limited number of technically and economically prospective sites. The latter is especially so for Germany and the Netherlands regarding the development of hydro-power. However, there are still huge potentials for biomass installations. The proportions of RES-E technologies, based on the respective gross electricity production of the considered countries in 2004, are given in Table 6.

Tab. 6. Share of RES-E in 2004 (% of RES-E production, including large-scale hydro power)

Country	Hydro	Wind	Biomass	PV	Other
Germany	38	44	17	1	0
Netherlands	2	38	60	<1	0
United Kingdom	11	5	84	<1	<1
Sweden	87	<2	10	<1	<2
Austria	90	3	6	0	1
Lithuania	98	<1	2	0	0
Slovenia	99	0	<1	<1	<1

The contribution from photovoltaics remains very small due to the large costs. Also small, obviously, are emerging new renewable energy technologies, such as wave and tidal stream energy. Although the United Kingdom has the greatest potential wind resource in Europe, the relative contribution from wind energy is smaller than in Germany and the Netherlands, mainly due to the differences in the support mechanisms (cf. discussion below).

In the considered acceding countries, i.e. Lithuania and Slovenia, past development of RES-E did not receive much attention. This may be due to the relatively young economies where environmental issues are usually not the biggest concern. Nevertheless, both countries already have a high share of electricity production by RES-E technologies, namely hydro-power. The potentials for new hydro-power installations are however limited, therefore attention is now given to wind and solar energy.

Following the preceding discussion of the seven countries, it can be concluded that the development of RES-E has substantially increased over the past years, especially in Germany. It is expected that the achieved growth *rates* of established technologies will eventually decrease, but new options, like offshore wind, will result in even higher shares of RES-E in the future. However the extent of such cumulative development is highly dependent on the conditions and costs for RES-E grid integration.

3. Conditions for RES-E grid integration

The purpose of liberalized electricity markets in Europe is to increase efficiency by competition, so decreasing electricity prices for the end consumers. However, the EU directive 2001/77/EC partly contradicts this aim. The directive deals with the promotion of RES-E in the European electricity market. Each European country has to set a national indicative target of the share of RES-E on the gross electricity consumption. These national indicative targets should be consistent with the global European Community indicative target of 12 % of gross national energy consumption by 2010 and in particular with the 22.1 % indicative share of RES-E in total Community electricity consumption by 2010. From Table 4 it can be seen that the considered countries are progressing steadily towards these targets.

The introduction of RES-E, especially wind and photovoltaic power, increases generation costs as compared with conventional generation. This is due to their higher long-run marginal generation costs as compared to conventional generation. Hence, the requirement of a defined share of RES-E partly contradicts the aim of liberalization for reduced costs and requires governmental action to achieve the respective national target. Consequently, RES-E technologies are supported by various institutional policy tools, e.g. feed-in tariffs, quota obligations, green certificate trading, fiscal measures, investment grants.

- *Feed-in tariffs* at preferential rates are characterized by a defined unit price that the system operators are obligated to pay to the RES-E generators. The consequent additional costs are passed through to all consumers as a premium on the unit price of purchased electricity. This scheme has the advantages of investment security, the possibility of fine tuning and the promotion of mid- and long-term technologies. Disadvantages include that they may be challenged under internal market principles or may allow over-funding. A variant of the feed-in tariff is to pay a fixed premium above the electricity spot market price to RES-E generators.

- *Quota obligations* are government regulations requiring electricity companies to market specified fractions of their total supply from RES-E and failure to supply leads to fines. The mechanism for such trading may be built upon green-certificates (e.g. Renewable Obligation Certificates). For instance, the Regulator may award RES-E generators with unit-production green-certificates, and the obligated suppliers can then purchase these certificates to fulfill their obligation. This leads to the development of a secondary market where certificates are traded, in addition to the actual electricity. The advantages of such a market-based system are the theoretical potential of ensuring best value for investment and a lower risk of over-funding. The disadvantages include a higher risk for investors and technologies with comparatively high costs not being developed. Pure *tendering* exists alongside such obligated quotas, and is characterized by a series of tenders for the supply of RES-E, which is then supplied on a contract basis at the price resulting from the tender. Principally, the overall administrative costs of a quota system are likely to be higher than a feed-in tariff system.

An overview of the RES-E supporting schemes effective in the considered countries in the year 2006 is given with Table 7. It can be seen that most of the considered countries use the feed-in tariff as their support scheme for the development of RES-E technologies and give additional tax and/or investment incentives. The implementation of the schemes is however slightly different from country to country. For example, in Germany the system operators are mandated to pass the additional costs of the fixed feed-in tariff on in a cost equalization procedure. Thereby a clearing takes place between the transmission system operators, so that each gets an adequate share of the extra costs based on the electricity demand in the respective grid area. The resulting costs are then transferred to the end costumers.

In the Netherlands the government sets ex ante premiums that are based on the projected cost gap of RES-E compared to the market price of conventional electricity. The resulting expenses from the payment of feed-in premium costs are financed through the national budget, so there is no direct link between electricity consumers and RES-E generators. The system of RES-E incentives has experienced several adjustments in the past years, of which the most radical is the unannounced stop of the feed-in premium grants in August 2006 for newly submitted projects (the premium for projects that were already granted are not touched). The reason for this stop was a projection by the Ministry of Economy according to which the electricity target of 9% in the year 2010 was expected to be met based on known projects. The stop was announced as being temporary and is dependent on political priorities. At the time of writing, the continuation of the Ministry of Economy policy is still unsure.

One additional difference concerns the participation of the RES-E generation in the conventional power market. In Germany a RES-E generator does not participate in the latter and hence additional costs, e. g. for regulating power, have to be born by the grid operator and finally by the society. This can be seen as an additional benefit for RES-E generators and is especially important for highly variable and unpredicted wind generation. Thus participation of RES-E in the liberalised electricity markets of the Netherlands and of the United Kingdom is more stringent than in Germany.

Tab. 7. Predominant RES-E supporting schemes in the year 2006

Country	Supporting Scheme		
	Feed-in tariff	Quota	Incentives
Germany	✓		✓
Netherlands	✓		✓
United Kingdom		✓	✓
Sweden		✓	✓
Austria*	✓		✓
Lithuania	✓		
Slovenia	✓		✓

* The supporting scheme is currently under revision. The most important change will be a cap on the financial support for the various RES-E generation technologies.

Other differences are the guaranteed period of paying fixed feed-in tariffs, the reduction of the payment over this defined duration (e.g. due to learning effects) and, last but not least, the bandwidth of the feed-in tariffs. The latter are given for the considered countries with a feed-in tariff in operation and for the year 2006, cf. Table 8. Thereby the bandwidth of minimal and maximal tariffs is primarily based on the installed capacity, the respective availability of the energy carrier (especially relevant if wind and photovoltaic are considered) and the year of installation. Note that the grid integration costs, depending on the respective cost allocation approach (as will be discussed later), have usually been taken into account for the calculation of the feed-in tariffs.

Tab. 8. Bandwidth of feed-in tariffs in the year 2006 (in EUR/MWh)

Country	Wind power				Biomass		Photovoltaic	
	Onshore		Offshore					
	Min	Max	Min	Max	Min	Max	Min	Max
Germany	55	87	62	91	39	175	457	624
Netherlands**	65*		97*		0	97	97*	
Austria***	78*		-	-	30	165	470	600
Lithuania	64*		-	-	58*		-	-
Slovenia	58	60	-	-	91	94	374*	

* One feed-in tariff only.
** Premium on the electricity market price.
*** The feed-in tariffs are currently under revision.

It can be seen that the feed-in tariffs are quite similar for the different countries considered. Slight deviations are mainly due to differences in the supply of the respective energy carrier. For wind and photovoltaics, this corresponds to differences in the expected full-load hours[‡] (for example in 2004, the national average full-load hours were, (i) for photovoltaic plant in Germany, 613 h/y, about 660 h/y in the Netherlands and 750 h/y in Austria; (ii) for wind onshore, 1534 h/y in Germany, about 1810 h/y in Austria and 1739 h/y in the Netherlands). For biomass generation plant, the full-load hours relate mostly to local differences in costs e.g. regarding harvest, transport and quality, of the respective local biomass.

Next to the conditions of the respective RES-E supporting schemes, the conditions of RES-E grid connection and system service requirements are of importance. For example in the United Kingdom, obtaining a grid connection can cause significant problems to the progress of RES-E regarding both increasing the costs and delaying the project, mainly due to the time necessary for negotiations with the connecting entity. Relevant negotiation issues for RES-E grid integration are way-leaves for the necessary connection assets, the lack of coordination between grid and planning consents and the overall lack of clarity in the system of grid integration. This, however, is not only specific to the situation in the United Kingdom. Similar concerns are expressed in other countries, however not with the same intensity.

[‡] 'Full load hours' per year (h/y) = annual production (kWh/y) divided by capacity factor (kW)

In general, the national governments require RES-E technologies to be connected with priority compared to conventional generation. They are usually connected to the next available connection point of the existing grid. This procedure is defined in national grid codes that are often different for the distribution and the transmission network. One major difference is that the power plants connected to the transmission network may be obliged to provide system services, while the power plants connected to the distribution network may not. Such system services are usually requirements on the active power supply, frequency stability, reactive power balance, disconnection from the network and restoration of supply. The specifics of these requirements are, however, not fully harmonized within Europe. Exemptions are allowed to the rules defined by the Union for the Co-ordination of Transmission of Electricity, UCTE, which has the primary aim of assuring overall system security.

The procedure for grid connection is basically as follows. In a feasibility study the network operator examines whether the system conditions prevalent at the planned point of connection are technically sufficient for operation of the generating unit. Should the system conditions suffice for operation according to defined conditions discussed above, the network operator submits a verifiable offer as to the network connection scheme. Should the system conditions at the system point of connection not be adequate, the network operator furnishes evidence of this inadequacy. Then, the network operator, together with the connection holder, examines appropriate modifications, such as network reinforcements and installations for short-circuit current limitation. Following this feasibility study, a formal connection offer is made, and, if accepted, leads to detailed design work to determine the final connection charge and additional requirements. Eventually the project is commissioned.

For RES-E, there are usually deviations from the requirements defined for conventional generation. The major reason is because power injections from RES-E into the grid may jeopardize system operation. For example in Germany, the RES-E generator has to ensure that, upon request, it must be possible to reduce the RES-E power supply. This is especially relevant for wind power generation. For instance, in exceptional cases, the network operator is permitted to instruct a temporary restriction of the power output or the disconnection of a wind farm. Such a restriction of power transfer will only be performed during extreme grid disturbance.

One final aspect to discuss is the method of allocating the respective grid integration costs. In general, the grid integration of any electricity producing technology is not for free, whether conventional or a RES-E power plant. However, the allocation of grid integration costs will affect the RES-E producers much more than the conventional producers, since the RES-E producer’s costs are more sensitive to any increase in the generation costs. Therefore, most importantly, shallow and deep grid integration costs should be distinguished. Both are characterized by the different parts that need to be paid for by the RES-E generator.

- If only *shallow* grid integration costs are required, the RES-E developer pays for only the costs of *connecting* the plant to the grid, and not for grid reinforcement. The major advantage of this approach is that it induces relatively cheap grid integration costs, since any grid reinforcements are paid by the network operator (and ultimately by all the consumers of electricity). The major disadvantage for the consumers of the RES-E developer paying only shallow costs is that the network operator may overestimate the total costs of grid reinforcement, knowing the costs will be socialized. Hence effective regulation and, hopefully, competitive tendering is necessary.

- If *deep* grid integration costs are required, the RES-E developer pays for all costs associated with the connection, including all network reinforcement costs. The main benefit of this approach is that it includes the actual costs of integrating a new generator into the existing network within the generation costs of the RES-E developer. Thereby the RES-E producer is expected to optimize the costs by deciding on the location of the investment so that the efficiency of the network may increase. The main disadvantage of this approach is the increased investment cost of the RES-E developer. Note that the improved network conditions, following any grid extension or reinforcement, serve all present and future network users, not just the new RES-E generator. Therefore, it is usually unfair to allocate all arising costs to a particular RES-E generator. This may also cause a first-mover disadvantage, since RES-E producers may want to wait for others to implement their projects first.

There are two other cost allocation methods. With the first, the RES-E generator bears no costs at all (*super-shallow* approach). Such an approach would definitely favour RES-E generators, since all costs related to the grid integration are covered by the end consumers and do not effect the generation costs. The second is a *hybrid* approach, whereby the RES-E generator has to pay only a *fraction* of any additional grid extension and reinforcement costs. Obviously, the latter constitutes a compromise for the RES-E generator between paying none or all of shallow and deep grid integration costs.

To highlight some distorting effects of the different methods, consider the situation where a RES-E developer has to cover the *shallow* grid integration costs, i.e. he pays for the grid connection. With such an approach, the new build grid connections to the existing grid will probably belong to the RES-E generators, since they pay for them. In general, this method is acceptable to all parties. But what happens if an offshore wind park is considered? Then the situation gets more complicated, especially if later another RES-E generator decides to initiate a project near to an existing wind park. Obviously, the intention of the newcomer will be to connect the RES-E power plant to the nearest point. So the newcomer may want to use the connection line of the existing RES-E generator (this may include extending the existing line). Does the newcomer then need to pay any remuneration to the existing RES-E generator? Or will he need to pay for his own connection so having two connections near each other rather than one shared connection? And can the first RES-E generator then be seen as a network operator, at least concerning the several kilometres of his own grid connection? Keeping these questions in mind, it may be more efficient for overall system operation if the utility network operator pays for, and owns, the whole grid connection, thereby anticipating possible future grid extensions.

From this discussion, it is obvious that the choice of the allocation of grid connection and integration costs is of major importance and can adversely affect the economic viability of new RES-E developers. Thus, the objective is how to allocate the costs fairly between the stakeholders. An overview of the cost allocation procedures presently used by the considered countries is given in Table 9. Note that this overview is an indication of the real situation only, as, in reality, it is not as easy to distinguish the diverse approaches as in theory. There is no consensus, mainly because there are many stakeholders involved, each with their own interests and expectations.

Tab. 9. Overview of cost allocation philosophies in the year 2006

Country	Cost allocation philosophy		
	Shallow	Hybrid	Deep
Germany	✓		
Netherlands	✓		
United Kingdom		✓	
Sweden			✓
Austria			✓
Lithuania		✓	
Slovenia	✓		

Following such a discussion, the German government decided to give developers for offshore wind power an additional incentive to invest (in addition to the feed-in tariff). Thereby a *super-shallow* approach was adopted that commits the German network operators to pay for the grid connection costs. Thus a new offshore grid will be built and owned by the network operators. The costs will be socialized to the consumers and will not be covered by the RES-E developers. The feed-in tariff stays constant. This recent decision can be seen to be a major incentive towards the deployment of offshore wind power in Germany.

It is concluded that the conditions for RES-E grid integration may have substantial influence on the RES-E development in Europe. The difficulties are seldom technical, but predominantly concern the allocation of costs, especially if grid integration costs constitute a significant share of the total investment.

4. Costs for RES-E grid integration

The costs of RES-E grid integration are highly dependent on the point of connection, the characteristics of the network at the connection point and, more generally, on the definitions used and the system boundaries considered. The costs presented below are based on the country specific case studies. Three cost categories are distinguished for describing the costs of the RES-E technologies:

1. Shallow grid integration costs;
2. Deep grid integration costs;
3. Other fixed and variable costs.

Note that all three categories can have costs related to (i) capital investment (costs that occur only once in a project, mostly at the start), and (ii) recurrent costs (e.g. operations and maintenance). The three cost categories are described below, with wind power as the example.

Capital investment costs (excluding grid integration costs) include the turbines, foundations and cable connection up to the site substation. This substation is generally the connection point to the grid. Usually, most aspects of electric power control and quality are dealt with by components housed in each turbine, and otherwise in the site substation. Substations are generally divided between the part accessed by the windfarm operator, and the separately locked part accessed only by the grid operator.

The substation may be treated as a component of the grid integration. All costs related to this substation are considered as shallow grid integration costs, including the power line from the substation to the connection point in the existing grid (thus including any transformers and road or river crossings). These shallow grid integration costs are influenced strongly by the distance to the nearest grid connection point, so giving a wide cost range of specific case studies.

After the grid connection point, all expenses in the existing grid related to the connection of the new wind power plant are considered to be deep grid integration costs. Especially in case of wind power, being intermittent, grid extensions and reinforcements can have an important financial impact. Nevertheless, these deep grid integration costs are seldom reported. Thus the case studies focus on the shallow grid integration costs only and neglect any deep grid integration costs.

The first requirement for compiling case studies on the costs of RES-E options is the access to relevant data. This can be difficult, since information regarding investments is often considered to be confidential. In addition, relevant stakeholders often do not see any benefit in providing such data. Basically, two survey methods have been used: (i) literature research and (ii) interviews with relevant stakeholders. The general difficulties with these methods are that grid integration costs are often not specified separately or, if they are, it is not always clear what costs are actually considered as grid integration costs.

It is furthermore important to note that the analysis of specific case studies obviously leads to the problem that the grid integration costs are site-specific: they depend on the distance to the existing grid, on the trajectory and on the voltage level, to name a few influencing factors. Another difficulty is the difference between projected and realized costs. This is of special importance for offshore wind power, since few projects have yet been realized in the considered countries. To overcome some of the problems mentioned above, several case studies have been analyzed for each technology and country resulting in a bandwidth of RES-E *grid integration* costs, see Table 10.

Tab.10. Bandwidth of RES-E grid integration costs in the year 2004 (in EUR/kW; cost figures have been rounded)

Country	Wind power				Biomass		Photovoltaic	
	Onshore		Offshore					
	Min	Max	Min	Max	Min	Max	Min	Max
Germany	45	170	185	600	-	-	-	-
Netherlands	40	150	180	205	100		0	100
United Kingdom	95	130	-	-	-	-	50	600
Sweden	85*		-	-	-	-	-	-
Austria	210*		-	-	30*		-	-
Lithuania	35*		-	-	-	-	-	-
Slovenia	-	-	-	-	15*		125	985

* One case study only.

Note the wide range of grid integration costs, especially by technology.

- *Onshore wind*. The case studies costs for Austria and Lithuania deviate considerably. For Austria, the large costs are due to the specific case study with an unusual cable length of about 21 kilometres connecting the Alpine wind park to the connection point of the existing network. For Lithuania, the small cost is due to the specific case study near the grid.

- *Offshore wind*. The deviations are mainly due to the considered case studies for the Netherlands being nearer to the shore than the cases considered for Germany (there are no sites near shore) and that all the considered case studies are based on projected costs only.
- *Biomass.* The deviations are due to the case studies being highly site specific and as for each country only one case has been analyzed.
- *Photovoltaics*. The deviations are because the cases partly include inverter costs in the grid integration costs and partly in the other costs. In the Slovenian case additional costs for scientific measurements are included that are usually not necessary for normal operation.

Note that wind onshore is by far the most developed RES-E technology in all the considered countries and hence the results can be seen to be fairly robust. As mentioned above, the costs given for wind offshore should be taken with great care as they are based on projections and not on realized projects. The same care should be given to the costs that are based on one single case study only, where it is generally not possible to derive a robust cost figure. However, these results can give an indication of the actual costs. It can also be seen that the RES-E grid integration costs greatly depend on the respective technology. Hence, as indicated above, the grid integration costs may constitute a major factor for the development of the RES-E deployment depending on the respective cost allocation method applied. This aspect can be analyzed by calculating the share of RES-E grid integration costs on total investment, cf. Figure 1.

Here, the bandwidth of the share of RES-E grid integration costs on total investment is depicted regardless of any country specifics. This is mainly due to the minor deviations between the considered countries as discussed before. It can be seen that the share of the grid integration costs on the total investment is relatively small for biomass and for photovoltaics, generally because of close connection distance. This is completely different for wind power. For wind onshore, the mean share of grid integration costs on total investment of the considered countries and case studies is about 9 % on average and in case of wind offshore as high as 18 % on average. Hence, the grid integration constitutes a major factor on the overall costs. This again highlights the need of a continuing discussion in Europe and worldwide regarding the cost allocation.

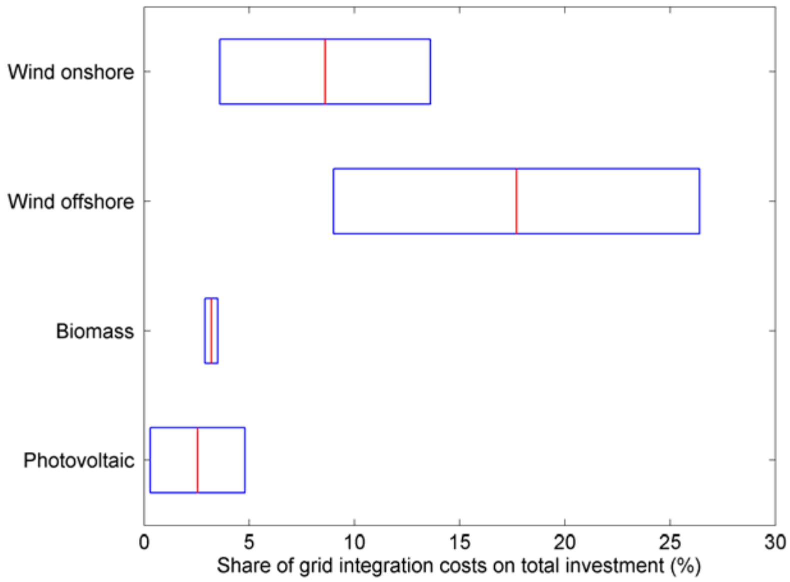

Fig. 1. Bandwidth of the share of RES-E grid integration costs on total investment

Next to the grid integration costs, the *generation costs* are of interest in order to analyze the costs and conditions of RES-E grid integration. The generation costs are considered to be the long-run marginal cost of the generated electricity or, in other words, the unit generation costs over the lifetime of the plant. These costs are equivalent to the average price that would have to be paid by consumers to repay the investor for the capital, operation and maintenance and fuel expenses, with a rate of return equal to the discount rate. In principle the methodology allows the comparison of single units, but may not reflect the full economic impact of a new power plant connected to an existing system. Therefore, it does not substitute for a system cost analysis.

The calculation is as follows:

$$C_g = \frac{\alpha \cdot C_{inv} + C_{run}}{T_{el}} + \frac{C_{fuel}}{\eta_{el}} - p_{heat} \cdot \frac{\eta_{th}}{\eta_{el}} \cdot H_{share}$$

With:	C_g	=	Unit generation cost	(EUR_{2004}/MWh)
	C_{inv}	=	Investment costs	(EUR_{2004}/MW)
	C_{run}	=	Running costs	(EUR_{2004}/MW/y)
	C_{fuel}	=	Fuel costs	(EUR_{2004}/MWh)
	p_{heat}	=	Heat price	(EUR_{2004}/MWh)
	H_{share}	=	Share of heat production scheduled for sale during the year	(%)
	η_{el}	=	Electrical efficiency	(%)
	η_{th}	=	Thermal efficiency	(%)
	T_{el}	=	Electrical Full-load hours	(h/y)
	α	=	Annuity factor	(1/y)

With this definition, the unit generation costs of all considered RES-E technologies can be calculated. Thereby, for anything other than biomass, only the first term of the equation applies. For wind and photovoltaic power, the unit generation costs are dominated by the investment costs because the energy carrier (wind and sunshine) is free of charge. Hence, there are no significant differences between the share of RES-E grid integration costs on the total investment and the generation costs. Note that for variable sources of electricity generation like hydro, wind and solar, additional costs should be included considering adequate standby generation. This has not been considered within this study. In order to determine the generation costs of biomass plants, costs with regard to the production of heat are treated as heat credits and are deducted accordingly. Heat credits are determined by evaluating the heat generation of a reference system with a biomass-fired boiler.

The bandwidth of the calculated RES-E unit generation costs is given in Table 11. To compare results, several parameters influencing the unit generation costs have been harmonized; namely the discount rate defining the annuity factor, the life-time and the respective full-load hours. An accounting discount rate of 10 % is used. The lifetime has been fixed to be 20 years for all the RES-E technologies. The full-load hours are 2100 h/y for wind onshore, 3000 h/y for wind offshore, 6000 h/y for biomass and 800 h/y for photovoltaic. The minimum and the maximum value of the normalized unit generation costs in the table are due to specified ranges for investment costs etc. in the considered case studies.

Tab. 11. Bandwidth of normalized RES-E unit generation costs (in EUR/MWh for 2004; lifetime assumed 20 years; interest rate 10%; full-load hours: 2100 h/y for wind onshore, 3000 h/y for wind offshore, 6000 h/y for biomass and 800 h/y for photovoltaics).

Country	Wind power				Biomass		Photovoltaic	
	Onshore		Offshore					
	Min	Max	Min	Max	Min	Max	Min	Max
Germany	85*		90	120	-	-	-	-
Netherlands	80	90	105	130	105	145	830*	
United Kingdom	95*		-	-	-	-	1005*	
Sweden**	110*		-	-	-	-	-	-
Austria	95*		-	-	115*		-	-
Lithuania**	55*		-	-	-	-	-	-
Slovenia	-	-	-	-	40*		895	920

* One case study only.

** Conditions not entirely normalized.

As already discussed, for the RES-E grid integration costs the resulting deviations between the considered countries are approximately ±30%. One notable deviation is the Slovenian biomass case. Here the costs are comparatively low, as in the considered Case Study. This is because one turbine was already at the location, so the investment costs covered only a new biomass boiler and one other secondhand steam turbine. Hence, this |Case Study result should not be compared to those for the Netherlands and Austria. Other notable deviations regard the Swedish and Lithuanian wind power Case Studies. Here, the calculation procedures have not been normalized and should thus not be compared to the costs for the other countries.

Comparing the different RES-E technologies, however, considerable differences occur. None of the considered technologies (except biomass) comes in the range of recent wholesale electricity prices (for example at the German spot market the average price in the year 2004 was about 29 EUR/MWh and close to 46 EUR/MWh in the year 2005). Especially the normalized unit generation costs of photovoltaics are far-off. One interesting aspect is to compare these unit generation costs with the respective feed-in tariffs as given in Table 8.

- *Onshore wind*. The feed-in tariffs generally seem to be reasonable and give incentives to invest. However, in Austria the feed-in tariff is less than the unit generation costs and hence, only sites with comparatively higher full-load hours or lower grid integration costs form an economically attractive investment. Note that for the Netherlands, the feed-in tariff is a premium on the electricity market price and is thus comparatively larger than for the other countries considered; in the Netherlands it thus forms an attractive incentive for investment. It may be noted that for wind onshore, much more experience is available compared to the other RES-E technologies considered, and hence the feed-in tariff may quantified with confidence.

- *Offshore wind.* The situation is totally different from onshore wind, as currently little 'real world' experiences is available. Here the comparison indicates that the feed-in tariffs are on the lower end of the estimated unit generation costs, especially for Germany (note that in the Netherlands the feed-in tariff is a premium on the market price). This is due to more favorable assumptions regarding the achievable full-load hours as assumed for the case studies, but also to an underestimation of the investment and especially the grid integration costs.
- *Biomass.* The feed-in tariffs seem to be reasonable.
- *Photovoltaic.* The comparison of the Case study results and the feed-in tariffs shows that in the Netherlands and Slovenia the tariff is not sufficient to significantly increase the share of photovoltaics on the electricity generation.

Following the preceding discussion, the main factors effecting RES-E generation costs (apart from the site conditions) are, (i) the costs for RES-E grid integration, and (ii) the respective feed-in tariff or another supporting scheme.

5. Best-practice cases for RES-E grid integration

To derive best-practice cases for RES-E grid integration, it is most important that stakeholder interests are clearly defined. However, the relevant stakeholders in the electricity systems have different interests and expectations. The following stakeholders (actors) can be distinguished:

- Energy policy makers;
- Regulators;
- RES-E generators;
- Conventional generators;
- Network operators;
- Supply companies;
- End consumers.

Generally, for RES-E, the most important and influencing actors are energy policy makers and the associated Regulators. With the high reliability of the system in mind, they follow two partly opposite aims, (i) establishing efficient and cost minimized electricity markets and (ii) introducing a defined share of RES-E generation. The former is based on the need to fulfill the primary aim of the majority of end consumers for paying minimal costs for electricity consumption. The latter is based on several reasons, but most important are climate and environmental issues. These partly opposite aims have already been discussed above. Here it is important to note that these aims require a rational trade-off. Hence, the goal is to achieve a reasonable share of RES-E generation in the system but with least-costs. Note that the introduction of relatively capital-cost intensive RES-E generation may be criticized for having the negative effect of a less efficient electricity market, but there are positive effects. The latter include higher employment rates in the supported sectors, possibilities to export the supported technologies and thus considerable positive effects on the overall economy. Additionally, the integration of RES-E generation in an existing thermally dominated system leads to a higher diversification of the generation portfolio and may thus result in a reduction of fossil fuel price risks.

The RES-E generators obviously aim to receive as much support as possible, ultimately resulting in at least break-even operation and hopefully increased profit. They prefer if any additional costs, like the grid integration costs, are covered by other actors in the market. This would increase the incentives to invest in RES-E technologies and hence leads to a higher share of RES-E on the electricity production. Another important aspect is the RES-E generators' exposure to risks. Any investment depends on the investors expectations on the future development. For example, if a new RES-E investment receives a fixed feed-in tariff for a defined period of time, the exposure to market risks is reduced. If, on the other hand, the new RES-E investment has to compete on the conventional electricity market, then the exposure to market risks is not limited at all, as for most conventional generation technologies.

Established conventional generators do not want to be exposed to the risks of reducing full-load hours for the sake of the system accepting RES-E. This is of special importance if RES-E generation is not subject of the conventional market and is scheduled with priority (i.e. if there exists an obligation to use RES-E at all times, as in Germany). A new conventional generator will want to be treated fairly regarding grid or other integration costs.

Finally, the network operators have the primary responsibility of securing the electricity supply. One desire is to have equal conditions for all network operators. This is of special importance if there is a regulation of the end user tariffs and if the network operators are not equally exposed to new partly variable RES-E generation (as in Germany). The variability of RES-E generation, e.g. wind power, may cause additional difficulties and costs, because the generation is not as firm and predictable as conventional generation. It may thus require improved regulatory power and overall a higher flexibility of the system (e.g. power plants with fast start-up capabilities). However, modern variable-speed wind turbines have considerable capability for power control, including reactive power balancing, and may act as spinning reserve. Note especially that no generation is 100% available, and so all generators are intermittent and require back-up.

Hence, the network operators may request clear incentives to guarantee that such regulatory power is available at all times. For instance, RES-E from hydro power is very controllable and invaluable for network control. The network operators also need clear definitions regarding the connection of new generators. It is important that they have the rights to access the entire network at all times, including grid connections paid for by a new RES-E generator. This requirement is due to the electricity network being very sensitive to failures, which may not only cause problems at the particular site, but also at other points in the network. Such failures may jeopardize the operation of the whole network if not taken care of.

Following this discussion, best cases regarding the conditions and costs for RES-E grid integration in different electricity system configurations can be derived. Regarding the share of RES-E, the situation in Germany seems to be the most favorable of all the considered countries. However, especially for wind offshore, there is a significant barrier for the further deployment if the RES-E developer has to bear even the shallow grid integration costs. It is obviously necessary to think about the definition of shallow grid integration costs in detail if wind offshore shall significantly contribute to the electricity production. This is because the comparative analysis of those costs, above, showed they can be a major fraction of the total investment costs.

On the other hand, the situation in Germany may not constitute a cost efficient electricity system. Even with a large share of RES-E in the system, the efficiency may be increased by replacing the fixed feed-in tariff with more market based instruments. Thereby, the so called ‘locational signals’ are of importance. Locational signals can lead to least-cost grid integration, since the investor can identify particular costs affecting the network and accordingly decides on the cost minimal site for the new installation. In theory, regarding the grid integration, an approach requiring the RES-E developer, or an investor in a new power plant in general, has to pay for the connection according to the location will seem to be more costs efficient as the developer will not decide to place the plant in an area that signals high grid integration costs. Obviously, if the wind offshore case is taken, then the approach is beyond its limits and can form a significant barrier for the further development of the technology. The problem is that such locational signals may cause investors not to invest in offshore technologies at all, because of the high costs of grid integration charged to the RES-E developer. Thus a simpler approach, as discussed before, seems to be a more appropriate solution.

It may also be interesting to consider changing the RES-E supporting scheme by defining a premium on the market prices based on several characteristics, e.g. historic full-load hours or general characteristics of the site. These characteristics should then be subject to revision if the conditions change. The RES-E generator can then participate in the conventional electricity market. This leads to the production not being scheduled with priority compared to conventional generation. Hence, RES-E technologies would then have to compete in a competitive market environment and any additional costs, e.g. for regulatory power, can adequately be assigned to the respective originator. The current RES-E supporting scheme in the Netherlands already leads in this direction.

In the whole of Europe, however, such a change of the RES-E supporting scheme seems to be a possible long-term solution, since RES-E methods cannot be completely changed within a short period of time. Thus an adequate short-term solution has to be found. This solution should at least consider the question of allocating the grid integration costs.

- If the RES-E generator has to cover *shallow* grid integration costs, this has most impact on wind power. For wind, these costs are a large share of the total investment and may therefore constitute a significant barrier to investment. In all other cases, the costs are in a similar range for conventional and RES-E generation technologies. It may thus be a reasonable solution to define a maxim length of the grid connection that has to be paid by the respective generator. This length should be in the typical range of experiences with grid connection in the past. This would still give probable incentives for RES-E deployment, by retaining locational signals leading the potential investor to prefer a site near the next grid connection point. With such an approach, all other grid integration costs, except any costs for regulatory power or similar, would be covered by the network operator and would then be socialized via regulated grid tariffs.

- If the RES-E generator has to cover *both deep and shallow* grid integration costs, this will be a burden regardless of any specific technology, i.e. they can also occur when new conventional generation is integrated; however we note that established pre-liberalization plants never paid such costs. As grid reinforcements and extensions may also serve the needs of other actors in the electricity system, they cannot be easily individualized. If the electricity market does give locational signals (of all the considered countries this is the case in the United Kingdom only) then there seems to be no need at all for additional deep grid integration charges. However, even if the electricity market does give locational signals, the problems regarding the individualization of the occurring costs lead to the solution that it may be more efficient to allocate these costs to the network operator. The resulting costs would then again be socialized via regulated grid tariffs.

As discussed before, the choice of the allocation method for the grid integration costs is a typical question of energy policy. The choice depends much on the desired outcomes for the deployment of RES-E technologies. Following the preceding discussion, it can be concluded that no simple solution exists. Based on the Case Studies, no best-case regarding all of the different aims expressed by the relevant stakeholders can be derived. In general, simple solutions tend to be inefficient and efficient solutions tend to be difficult to implement! The same conclusion can be made about the conditions and costs for all RES-E grid integration.

6. Conclusions

This paper presents a comparison of the conditions and costs for RES-E grid integration in selected European countries. The selected countries are: Germany, the Netherlands, the United Kingdom, Sweden, Austria, Lithuania and Slovenia. Based on literature reviews and stakeholder interviews, Case Studies for wind onshore and offshore, biomass and photovoltaics, it is shown that the allocation of grid integration costs can form a significant barrier for investing in new RES-E installations if the developer has to bear all those costs and, for example, is not remunerated by a sufficient feed-in tariff. If energy policy makers want to reduce the barriers for new large-scale RES-E deployment, the major part of the grid integration costs, especially the so called ‘deep costs’, should be covered by the grid operator Hence, if the major objective is to have accelerated RES-E grid integration with fewer barriers than the status quo, then the strategy should be to socialize all RES-E grid integration costs. This report indicates that more research is necessary, especially regarding the quantification of deep-grid integration costs. The present lack of information and transparency concerning such costs is handicapping RES-E development.

References

See the references within the other documents of this work package report.