Grid Issues for Electricity Production Based on Renewable Energy Sources in Spain, Portugal, Germany, and United Kingdom

Annex to Report of the Grid Connection Inquiry

Stockholm 2008

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Preface

This report is an underlying report to the Inquiry established by the Swedish Government on connection to the grid of electricity production based on renewable energy sources. The aim of this report is to give an insight on how different issues regarding connection to the grid have been regulated in Spain, Portugal, Germany, and the United Kingdom.

This report is based on interviews and legislation. The focus of this report relies on network issues but in order to give an overall insight on the circumstances in which renewable energies are developed in the studied countries even a description of the economical promotion schemes is done.

We would like to thank all those who have contributed to this report:

- In Spain: Asociación Empresarial Eólica – AEE, Comisión Nacional de la energía – CNE, Ministerio de Industria, Turismo y Comercio – MITYC, Instituto para la Diversificación y Ahorro de la Energía – IDAE, Endesa, Iberdrola, and REE – Red Electrica de España.
- In Portugal: REN – Rede Eléctrica Nacional, EDP – Energías de Portugal, APREN – Associação de energias renováveis, DGEG – Direcção Geral de Energia e Geologia, and Centro de Estudos em Economia da Energia, dos Transportes e do Ambiente – CEEETA.
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Stockholm, November 2007

Eva Centeno López Thomas Ackermann

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List of Abbreviations

BEGA	Bilateral Embedded Generation Agreement
BELLA	Bilateral Embedded License Exemptable Large Power Station Agreement
BETTA	British Electricity Trading and Transmission Arrangement
BSUoS	Balancing Services Use of System charges
CNE	Comisión Nacional de la Energía, (Regulator Spain)
CUSC	Connection and Use of System Code
CHP	Combined Heat and Power
DCLF	DC Loadflow
DGGE	Ministry of Economy and Innovation through its Directorate of Energy
LECs	Levy Exemption Certificates
DGE	Dirección General de Energía
DL	Decree Law (Portugal)
DNC	Declared Net Capacity
DNO	Distribution Network Operators
HEDP	Energias de Portugal
GB	Great Britain
IDNO	Independent Distribution Network Operator
NETA	New Electricity Trading Arrangement
NFFO	Non-Fossil Fuel Obligation
NFPA	Non-Fossil Purchasing Agency
Ofgem	The Office of Gas and Electricity Markets
OFTO	Offshore Transmission Owner
PER	Plan de Energías Renovables

PFER	Plan de Fomento de las Energías Renovables
RECs	Regional Electricity Companies
REE	Red Eléctrica de España
REN	Rede Eléctrica (Portugal)
RES Act	Renewable Energy Source Act
RO	Renewable Obligation
ROCs	Renewables Obligation Certificates
SRO	Scottish Renewable Orders
NGET	National Grid Transmission
RD	Royal Decree (Spain)
SPTK	Scottish Power Transmission Limited
SHETL	Scottish Hydro-Electric Transmission Limited
TEC	Transmission Entry Capacity
TIRG	Transmission Investment for Renewable Generation
TO	Transmission Owner
TSO	Transmission System Operator
TNUoS	Transmission Network Use of System Charges
UK	United Kingdom

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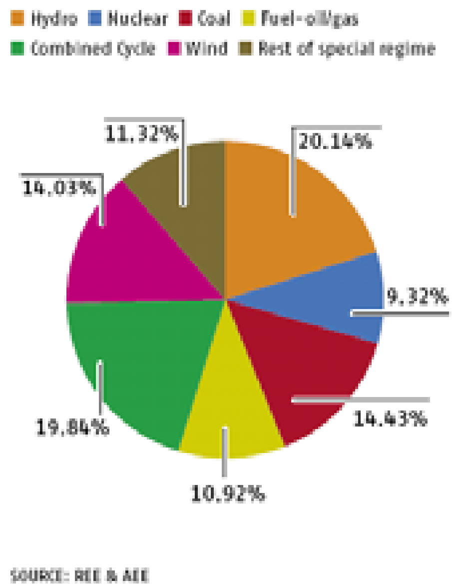
1 Spain

1.1 Introduction

Spain has a total installed capacity in electric power production of 82,336 MWF[1] by the end of 2006. A Breakdown of total installed capacity by technology by the end of 2006 can be seen in Figure 1-1. Spain has very little interconnection capacity with its neighboring countries, France, Portugal, Morocco, and Andorra of about 3%[2] of the installed capacity.

Figure 1-1 Breakdown of total installed capacity for power production by technology by 31/12/2006. Category "Rest of special regime" includes cogeneration and renewables except hydro and wind.

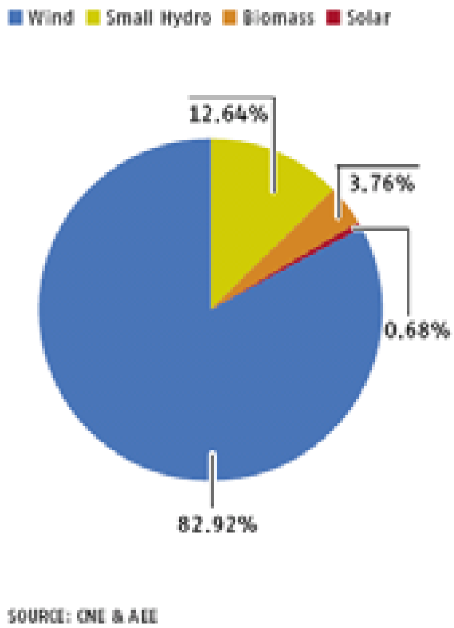


[1] Source: Wind Power 2007, Spanish Wind Power Association, http://www.aeeolica.org/varios/AEE_Anuario_2007_ING.pdf

Source: REE & AEE

The total installed capacity in renewable electricity production excluding large hydropower stations (installed capacity larger than 10 MW) was 13,959 MW by the end of year 2006. Figure 1-2 shows the share of the different renewables technologies to the total installed capacity in renewable electricity production. Wind power is the renewable source that has experienced the largest development in Spain. During the last seven years the installed wind power capacity has grown from 1,585 MW year 1999 to 11,615 MW by the end of year 2006[3]. Wind power production during year 2006 was 23,372 GWh, i.e., approximately 8.5% of the total electricity demand in Spain.

Figure 1-2 Renewable energy breakdown by 31/12/2006



Source: CNE & AEE

Therefore, even though the aim of this chapter is to give an insight on the Spanish renewable sector as a whole, it focuses on the wind power sector. During the last two years it has been an important increase of solar photovoltaic producers and the total installed capa-

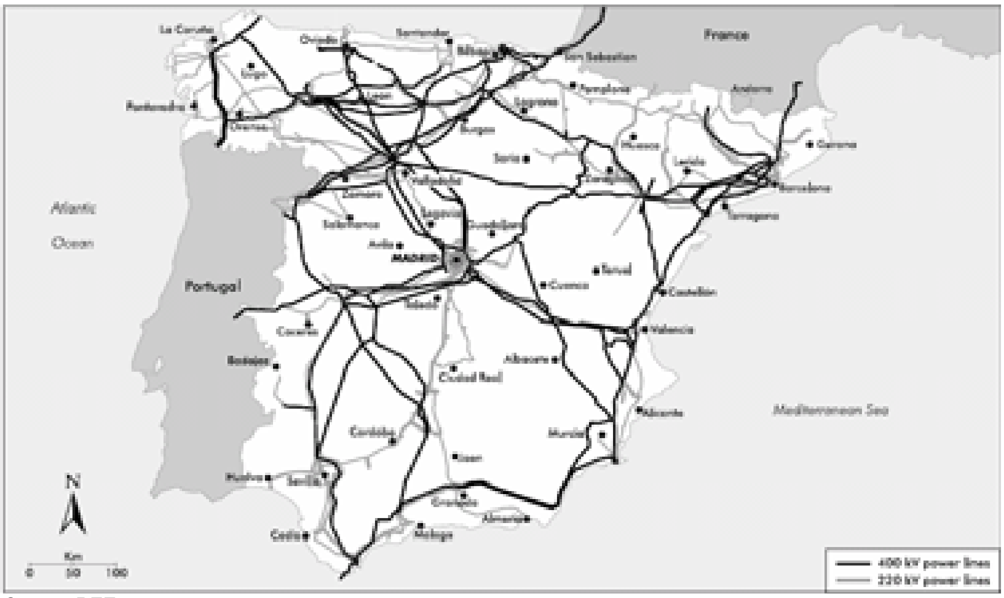
[2] http://www.etso-net.org/NTC_Info/library/e_default.asp
[3] Source: See footnote 1.

city of this technology was by the end of year 2006 equal to 118 MW[4]. Even though the installed capacity of solar photovoltaic installations is not comparable with the installed wind power capacity it might be interesting to get an idea of what is behind the development of solar photovoltaic.

1.1.1 Overview of the Transmission System

The typical voltage levels for the transmission grids in Spain are 400 kV and 220 kV. The international connections are also considered as a part of the transmission system. Red Eléctrica de España, REE, is the Transmission System Operator (TSO) and owns about 99.8% of the 400 kV power lines and 98.5% of the 220 kV power lines[5].

Figure 1-3 The Spanish Electricity Transmission Network



Source: REE

[4] Source: Trends in photovoltaic applications. Survey report of selected IEA countries between 1992 and 2006 http://www.iea-pvps.org/products/download/rep1_16.pdf, page 5.
[5] CNE, Información básica de los sistemas energéticos 2006, Electricidad.

1.1.2 Overview of the Distribution System

The typical voltage levels for the distribution grids in Spain are 132 kV (very high voltage), 66 kV, 45 kV, 30 kV (high voltage), 20 kV, 15 kV, 13.2 kV, 11 kV (medium voltage) and 380 V (400 V in the latest regulation, RD 842/2002, low voltage).

In Spain the main distribution companies are Iberdrola, Endesa, Unión Fenosa, Hidrocantábrico, and Viesgo with a market share of 40%, 39%, 15%, 2.5%, and 2.5% each, which represent 99% of the total distribution activity. During the last years the number of distribution companies has increased considerably even if they have a negligible market share.

1.1.3 Relevant Legislation for Renewable Electricity Production

Electricity producers in Spain are subjected to different legislation depending on the producing technology and energy source used. Producers are classified in two main groups; special regime and ordinary regime. Renewable energy sources are included in the special regime while the ordinary regime consists of conventional power plants such as nuclear power stations and is therefore left out of this study.

The special regime has been regulated by different royal decrees named in the following. Royal Decrees in Spain are legal orders proposed by the government, instead of being proposed by the parliament as in the case of laws, and have a lower range than laws. Royal decrees are named with a number followed by the year they are published.

Royal decrees regulating the special regime are Royal Decree (RD) 2366/1994 which was modified by the RD 2818/1998 in order to adapt the legislation to the Law of the electricity sector 54/1997. The RD 2818/1998 was modified by the RD 436/2004 and recently, May 2007, by the RD 661/2007. Aspects related to the connection of the production installations are regulated in the RD 1955/2000 partially modified by the RD 661/2007, by its annex XI regarding connection and by its "disposición final segunda" regarding deposits for licensing. There is specific legislation, RD 1663/2000, for the connection to the low voltage grid of solar photovoltaic installations with an installed capacity lower than 100 kVA.

There have been some changes in the different royal decrees regarding the groups in which producers in the special regime are divided. The RD 436/2004 established for the first time a division of the solar category into solar photovoltaic and thermal solar and of the wind category into on-shore and off-shore. The RD 661/2007 reduces the number of groups of the special regime from four to three. The three groups are: electricity producers using cogeneration (CHP), renewable energy sources, and waste.

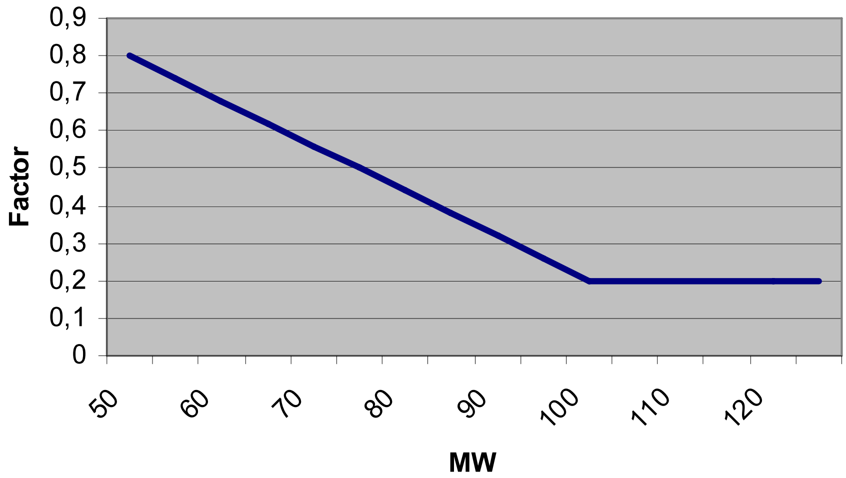
The group with producers using renewable energy sources is called group b and is divided into 8 subgroups[6] as follows:

- b.1: solar energy
- b.2: wind energy
- b.3: waves, geothermic, tides
- b.4: and b.5: hydropower
- b.6, b.7, and b.8: biomass and biogas

Installations with an installed capacity larger than 50 MW are not included in the special regime. However, when these installations use renewable energies, except for hydro power, they receive a premium equal to the premium obtained by a similar installation with a capacity below 50 MW multiplied with a factor. That factor decreases linearly with the installed capacity from 0.8 for 50 MW to 0.2 when the installed capacity is larger than 100 MW, see Figure 1-4. Due to this limitation there are no installations using renewable energies with installed capacity larger than 50 MW.

[6] For more details on which energy sources that are included in each subgroup see RD 661/2007, article 2.

Figure 1-4 Factor for installations using renewable energies with an installed capacity larger than 50 MW.



Currently, most of the producers included in the special regime are regulated by the RD 436/2004 even though there are still some producers regulated by the RD 2818/1998. There are transitory periods established in every Royal Decree in order to switch to a new regulatory frame established by a new Royal Decree. In some cases it is possible for producers to stay in the former legislation and in others there is no transitory period as for example for solar photovoltaic producers that automatically have switched into the new RD 661/2007 by June, 2007.

1.1.4 Regulatory Framework for Network Companies

The income of the distribution activity is established ex-ante in the legislation every year[7] in order to avoid eventual abuse of monopolistic positions. The total income for the distribution activity is based on the previous year income modified by the national average demand increase, the price index, and a certain efficiency factor. Year 2007 a total income of 4,000 M€ was recognized to the distribution activity. To establish the income of each distribution company certain pre-defined shares are used. These shares do not take into account specific demand increase for each distribution company

[7] The income for the different distribution companies for year 2007 was established in the RD 1634/2006 (annex VII).

which means that companies with large demand increase (as for example Iberdrola in the Levante region) get the same incentives to make investment as companies with a stable demand. Not all investment costs are included when calculating the income for each distribution company, it is only those investment costs dedicated to the expansion of the grid to cover the natural increase in demand that are included.

A new model for payment of the distribution activity has been defined in a proposal of Royal Decree made by the Ministry of Industry, Tourism and Trade. One of the major changes to be introduced by the new model is that different rates of the demand growth will be used for different regions. According to the current legislation if the demand growth for the whole country was for instance 4%, then that value was applied to all distribution companies even if there were areas were the demand growth was higher. Reference grids will be used to compare different distribution companies according to the new model which will probably be applied from year 2008.

The costs recognized to the distribution companies are collected by the distribution companies and retailers by means of tariffs and access fees paid by the consumers. Those tariffs and access fees are sent to the regulatory body, Comisión Nacional de la Energía, CNE, who splits them into the different costs associated to the electricity system of which one is the distribution cost. The distribution costs represented year 2005 approximately 74% of the regulated costs. Other regulated costs are for example transmission costs and pemanent costs defined as costs associated to the market operator (OMEL), the transmission system operator (REE) and the regulatory body (CNE) among others.

Besides the state regulation there is a different legislation for each region which can establish different requirements for example regarding quality of supply. This might create economical imbalance since the payment to the distribution companies is determined by the central government and not by the regional authorities.

1.1.5 Development of the Wind Power Sector in Spain

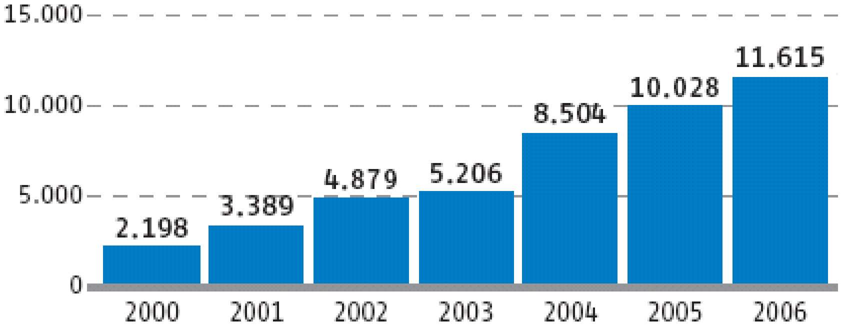
It is important to point out that the development of the wind power sector in Spain has taken place in a very different way than in other countries with large installed wind power capacity such as

Germany and Denmark. In Spain the population density in large areas with good wind resource is much lower than in Germany and Denmark. This has made it possible to build larger wind farms in Spain than in Germany and Denmark. In Germany and Denmark it has been smaller investors who have carried out this development, while in Spain the development has taken place through much larger investors such as electricity and construction companies. In Spain, approximately 60% of the wind power capacity is property of electric power companies. The fact that approximately 40% of the owners are not electrical companies might be a risk since the sector is getting more and more technical with requisites on production management and forecasting for example, therefore the non-electrical companies might sell their installations. Important owners are already (2007) selling their installations and there is taking place a concentration of the sector.

The regulatory measures behind the great development of the wind power sector in Spain during the last seven years, see Figure 1-5, are[8] the payment scheme with feed-in tariffs and the law of the electricity sector 54/1997. The European Commission has published several reports in which it is recognized that the payment scheme of feed-in tariffs is effective in terms of installed capacity[9]. The Law of the electricity sector from 1997 established that in order to cover at least 12% of the primary energy demand with renewable energy sources by 2010 (equivalent to 29% of the electricity demand) a plan had to be elaborated. That Plan had to include political objectives for the different renewable energy sources and related techniques. These political objectives had to be taken into account when calculating the feed-in tariff and premium. The objective of 12% of the primary energy demand took into account the proposed recommendation included in the White Paper on Renewable Energies of the European Union.

[8] According to several interviewed agents of wind power sector in Spain.
[9] The support of electricity from renewable energy sources, Communication from the European Commission, COM (2005) 627 –final, Section 2.3.
http://ec.europa.eu/energy/res/biomass_action_plan/doc/2005_12_07_comm_biomass_electricity_en.pdf

Figure 1-5 Development of the installed wind power capacity (MW) in Spain 2000–2006.



Source: AEE

The plan for renewable energies, "Plan de Fomento de las Energías Renovables"[10] (PFER), was published in December 1999 by the Institute for Energy Diversification and Saving, IDAE. This plan identified a technical potential for wind power in Spain in the range of 7,500–15,000 MW. The plan proposed an increase of 8,140 MW (compare with the capacity installed of 834 MW year 1998) and a wind power production of 19,536 GWh/year to year 2010. The target for the year 2006 was 5,550 MW installed wind power capacity. However, by the end of year 2005 there were 10,028 MW installed wind power capacity, which means double as much as the target of the PFER for 2006.

The PFER was updated with the Plan de Energías Renovables, PER, approved in the year 2005. The PER[11] defines the political targets for the period 2005–2011. The political target for wind power established by the PER is 20,155 MW installed capacity by 2010.

During the years 1993–1994 the cost of capital (interest rate) was very high, about 16–17%, some years later this cost decreased and it happened at the same time as a stable regulatory frame was developed which resulted in a great development of the wind power sector. The feed-in tariffs and premiums have been modified every fourth or fifth year. However, there have not been drastic changes since

[10] www.idae.es
[11] Plan de Energías Renovables en España 2005-2010, IDAE. http://www.mityc.es/NR/rdonlyres/C1594B7B-DED3-4105-96BC-9704420F5E9F/0/ResumenPlanEnergiasRenov.pdf

all political parties have supported the development of renewable energies. The political stability has played a crucial role for the development of the wind power sector in Spain.

In Spain the development of the wind power sector goes in the direction of larger wind farms connected directly to the transmission grid. There are two reasons behind this development. The first reason is the technical development and the second reason is the available capacity in the transmission grid to transport the produced electric power from the connection points. The first wind farms from the year 1997 and 1998 were composed of wind turbines with a capacity of 600 kW connected to the distribution grid. Nowadays, the turbines have an installed capacity of around 2 MW which means that it is possible to connect significantly larger capacity in the same location. By connecting larger capacity, more electric power is expected to be produced and therefore a larger income is expected. This means that larger investments to connect the wind farm to the transmission grid can be made. However, since there is a limitation of 50 MW to get the highest payment (see Section 1.1.3), larger installations are divided into several 50 MW installations.

One reason for investing in larger wind farms is to take advantage of scale economies regarding for example the licensing procedure, since the number of licenses required are almost the same independently of the capacity to be installed.

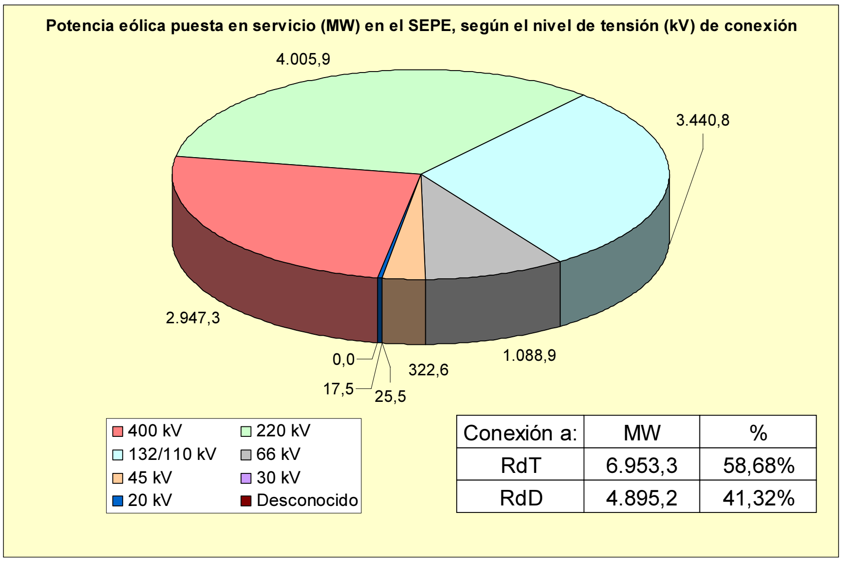
The first wind farms were located at the mountain peaks but the technical improvements led to an increase of the efficiency of the wind turbines that made it possible to also build wind farms in other locations with less wind resource.

In Spain wind power developers have tried to utilize those locations with best wind resource such as mountain chains in the North, Aragón and basins of the Ebro River concentrating the greatest number of wind farms in those areas.

Year 2001 there were about 3,200 MW installed wind power capacity and the proportion of wind farms connected to the transmission and the distribution grid was very different compared to the situation in March 2007. By year 2001, only 10%[12] of all wind farms were connected to the transmission grid while by March 2007, according to Figure 1-6, 58.68% of all wind farms were connected to the transmission grid. Most of the wind farms connected to the distribution grid are connected to the 132 kV level, see Figure 1-6.

[12] Personal communication with REE

Figure 1-6 Voltage levels at which the wind farms in Spain are connected by March 2007.



Source: REE, March 2007

The different regions have developed different policies regarding the development of the wind power sector. The region of Galicia has the largest amount of wind power capacity installed followed by Castilla León and Aragón while Andalucía, Cataluña, and Extremadura remain last in this development. There are regions where the environmental issues have stopped the development of the wind power sector like for example Cataluña. There have been different ways of allocating the connection capacity in the different regions to the different project developers such as tender procedure.

Most of the regions in Spain compete to develop wind projects before the national target of 20,155 MW installed capacity is reached.

The wind power sector has created approximately 35,000[13] job opportunities in Spain. The regions have different requisites relating the creation of employment for giving the administrative licenses, i.e. the licenses for constructing, modifying, or closing wind farms. Wind power production gives increased incomes to the municipality where the installations are located since they have to pay a tax on economical activities of about 1% of the income of the installation.

[13] Eólica 2007, page 87. Asociación empresarial eólica, http://www.aeeolica.org

This might play a role in increasing the local acceptance of wind power.

1.1.6 Possible Barriers for the Future Development of the Wind Power Sector in Spain

According to the interviewed agents of the wind power sector in Spain the target of 20,155 MW installed wind power capacity is most likely to be fulfilled. However, it is more uncertain whether this capacity is going to be build by 2010 as stated in the political target in the PER. The reason behind a possible delay is not the lack of investment but the possible lack of transport capacity in the grid to transport the produced electric power. The construction of the required infrastructure takes long time to complete.

The bottleneck in the development of wind power projects have changed according to a project developer in Spain. In the earlier stage, the bottleneck was the administrative licensing issue while nowadays the bottleneck is the connection issue. In the PFER it was already established a target for wind power of approximately 10,000 MW to year 2010. Some of the reinforcement works in the transmission system, necessary to transport the electricity produced by those 10,000 MW, have been delayed. This means that even if there are investors, some projects cannot be materialized as consequence of the lack of capacity in the grid.

In the region of Castilla León, for example, there are project developers that have started to build wind farms but these will not be able to start producing electric power until the infrastructure between Castilla León and Madrid has been built.

1.2 Payment Scheme for Renewable Electricity Production

After the Royal Decree 2818/1998 was approved electricity producers based on renewable energy sources with a capacity below 50 MW have the possibility to choose between two different payment options since. These options are:

- Fixed regulated feed-in tariff
- Market option (combination of the electricity market price together with a fixed premium).

However, solar producers have only the possibility to receive feed-in tariffs. Producers in the special regime can freely choose payment option but the decision taken is for at least one year.

Up to year 2004, the number of wind power producers choosing the market option was very small[14]. However, the publication of the RD 436/2004 including an incentive for the market option and rising electricity prices led to a huge increase of wind power producers choosing the market option. The high electricity prices resulted in much higher payments than expected for the producers who had chosen the market option. This has led to one of the major changes introduced by the new legislation adopted in June 2007, RD 661/2007, namely the establishment of price caps and price floors for the payment to the producers included in the special regime choosing the market option. Those caps and floors secure a minimum income necessary to recover investment costs and limit the premium to zero when electricity prices exceed the cap value.

In order to illustrate how the market option is constructed let us look at an example of an on-shore wind power producer choosing the market option. Lets assume a market price of 3 c€/kWh, then the sum of the market price and the premium (see Table 1-1) is 3+2.93=5.93 c€/kWh. Since 5.93 is lower than the price floor for wind power which is 7.13, then the wind power producer receives the floor value. If we now assume a market price of 4.5 c€/kWh, then the wind producer receives the sum of the market price and the premium, i.e. 4.5+2.93=7.43 c€/kWh. If a market price of 6 c€/kWh is assumed, then the wind power producer receives the cap value of 8.49 c€/kWh since the sum of the market price and the premium (6+2.93=8.93) is larger than the price cap. Note that in this case the premiums received by the wind producer decreases. If the market price is larger than the cap value, i.e., 8.49 c€/kWh, then the wind power producer does not receive any premium but only the market price.

The retroactivity of the tariffs and premiums has been a very controversial issue. The new Royal Decree 661/2007 defines a transitory period until year 2012 after which installations have to go over to the new payment scheme established in the new legislation.

Electricity production from solar photovoltaic producers is growing rapidly in Spain since year 2005. As mentioned earlier, solar photovoltaic producers have only the possibility to receive feed-in

[14] Eólica 2007, Asociación Empresarial Eólica, Page 82.

tariff. There are three different feed-in tariffs for solar photovoltaic producers depending on the installed capacity as shown in Table 1-1. Unlike in Germany and Portugal there are no different feed-in tariffs depending on whether the solar panels are located on a building or directly on the ground. The highest tariffs are paid to those installations which has an installed capacity under 100 kW. Therefore larger installations are divided in installations under 100 kW each having its own transformer. This makes the limit of 100 kW meaningless.

There is a direct connection between the political targets for each technology and the payment schemes defined in the new Law, RD 661/2007. This Law establishes that when 85% of the political target is reached, then the Secretary General of Energy will establish a period within which registered installations will have the right to receive the feed-in tariff or premium defined for that technology. The period will be of at least one year. Installations registered after the period defined by the Secretary General of Energy will receive, in case of choosing the feed-in tariff option, the final hourly market price[15] or, in case of choosing the market option, the market price and complements of the corresponding markets where the producer participates. Despite that, these installations will be taken into account when defining the capacity targets for the Renewable Energy Plan for 2011–2020.

In the following, Table 1-1 shows the payment scheme for renewable electricity producers defined by the latest legislation published on May 2007.

[15] In the final hourly market price it is included the market price (pool price) together with the prices of all other markets, intra-daily adjustment markets, balancing markets and capacity payment. In July 2007 the final hourly price was 4.498 c€/kWh of which 88% was the pool price, 4 % the intra-daily market prices and balancing markets and 8% capacity payment. See http://www.omel.es/es/pdfs/INFORME_MENSUAL_JUL_2007.pdf

Table 1-1 Payment scheme for renewable electricity production according to RD 661/2007. This payment scheme does not apply for installations registered after the period defined by the General Secretary of Energy after 85% of the political target is reached. Political targets are given for each technology in brackets.

Group	Subgroup	Capacity	Period	Feed-in Tariff c€/kWh	Premium c€/kWh	Cap c€/kWh	Floor c€/kWh
b.1 Solar (871 MW)	Photovoltaic (371 MW)	P≤ 100 kW	First 25 years	44.0381	----	----	----
			Thereafter	35.2305	----	----	----
		100 kW<P≤ 10 MW	First 25 years	41.7500	----	----	----
			Thereafter	33.4000	----	----	----
		10<P≤ 50 MW	First 25 years	22.9764	----	----	----
			Thereafter	18.3811	----	----	----
	Thermal (500 MW)		First 25 years	26.9375	25.4000	34.3976	25.4038
			Thereafter	21.5498	20.3200		
b.2 Wind (20155 MW)	On-shore		First 20 years	7.3228	2.9291	8.4944	7.1275
			Thereafter	6.1200	0.0000	----	----
	Off-shore			----	≤ 8.43	16.40	----
b.3 Waves, tides			First 20 years	6.8900	3.8444	----	----
			Thereafter	6.5100	3.0600		
b.4 Hydro power P≤ 10 MW (2400 MW)			First 25 years	7.8000	2.5044	8.5200	6.5200
			Thereafter	7.0200	1.3444		
b.5 Hydro power10<P≤ 50 MW			First 25 years	=6.60+1.2*((50-P)/40)	2.1044	8.0000	6.1200
			Thereafter	=5.94+1.080*((50-P)/40)	1.3444	----	----
b.6 Biomass	b.6.1 energy crops	P≤ 2 MW	First 15 years	15.8890	11.5294	16.6300	15.4100
			Thereafter	11.7931	0.0000		
		P>2 MW	First 15 years	14.6590	10.0964	15.0900	14.2700
			Thereafter	12.3470	0.0000		
	b.6.2 biomass from residues in the agricultural sector and gardening	P≤ 2 MW	First 15 years	12.5710	8.2114	13.3100	12.0900
			Thereafter	8.4752	0.0000		
		P>2 MW	First 15 years	10.7540	6.1914	11.1900	10.3790
			Thereafter	8.0660	0.0000		

	b.6.3 biomass from residues in forestry sites	P≤ 2 MW	First 15 years	12.5710	8.2114	13.3100	12.0900
			Thereafter	8.4752	0.0000		
		P>2 MW	First 15 years	11.8294	7.2674	12.2600	11.4400
			Thereafter	8.0660	0.0000		
b.7 Biogas	b.7.1 biogas from landfills		First 15 years	7.9920	3.7784	8.9600	7.4400
			Thereafter	6.5100	0.0000		
	b.7.2 biogas generated in digesters	P≤ 500 kW	First 15 years	13.0690	9.7696	15.3300	12.3500
			Thereafter	6.5100	0.0000		
		P>500 kW	First 15 years	9.6800	5.7774	11.0300	9.5500
			Thereafter	6.5100	0.0000		
	b.7.3 animal dung or liquid biofuels		First 15 years	5.3600	3.0844	8.3300	5.1000
			Thereafter	5.3600	0.0000		
b.8 Biomass from the industrial sector	b.8.1 biomass from industrial installations in the agricultural sector	P≤ 2 MW	First 15 years	12.5710	8.2114	13.3100	12.0900
			Thereafter	8.4752	0.0000		
		P>2 MW	First 15 years	10.5740	6.1914	11.1900	10.3790
			Thereafter	8.0660	0.0000		
	b.8.2 biomass from industrial installations in the forestry sector	P≤ 2 MW	First 15 years	9.2800	4.9214	10.0200	8.7900
			Thereafter	6.5100	0.0000		
		P>2 MW	First 15 years	6.5080	1.9454	6.9400	6.1200
			Thereafter	6.5080	0.0000		
	b.8.3 black liquor from paper industry	P≤ 2 MW	First 15 years	9.2800	5.1696	10.0200	8.7900
			Thereafter	6.5100	0.0000		
		P>2 MW	First 15 years	8.0000	3.2199	9.0000	7.5000
			Thereafter	6.5080	0.0000		

The values of the feed-in tariffs, premiums, incentives, caps and floors to be paid to power producers included in the special regime will be actualized annually with the consumer price index, IPC, minus 25 units up to December 2012 and minus 50 units thereafter.

Renewable energy producers receive an incentive for consuming reactive power during low demand periods in which the circulation of reactive power, and therefore the losses in the lines, increases. At the same time they have to pay a penalization if they consume reactive power during peak load hours. The incentive or penalization is calculated as a percentage of a reference value that is updated every year. The RD 661/2007 (article 29) established a reference value of 7.8441 c€/kWh and a percentage (annex V) that goes from -4% (penalization) to +8% (incentive).

Producers using renewable energy sources without storage capabilities such as wind power or solar will no longer receive capacity payment according to the RD 661/2007. Year 2006, the average capacity payment for wind power producers, amounted to 4.81 c€/kWh. Other producers included in the special regime can receive capacity payment but only when choosing the market option.

Below, Table 1-2 shows the payment scheme defined by the RD 436/2004. As mentioned in Section 1.1.3, currently, most of the producers included in the special regime are regulated by the RD 436/2004. However, no later than year 2012 they have to change to the payment scheme defined by the new RD 661/2007, shown in Table 1-1.

Table 1-2 Payment scheme for renewable electricity production according to RD 436/2004. The reference tariff, TRF, for year 2004 was[16] 7.2072 c€/kWh, for year 2005 it was[17] 7.3300 c€/kWh, and for year 2006 it was equal[18] to 7.6588 c€/kWh.

Group	Subgroup	Capacity	Period	Feed-in Tariff c€/kWh	Premium c€/kWh (for all groups in this table except solar and b.8, the formula is 0.40*TRF)	Market-incentive (for all groups 0.10* TRF)
Solar (350 MW)	Photovoltaic (150 MW)	P≤100 kW	First 25 years	5.75*TRF= 41.4414[2004] 42.1475[2005] 44.0381[2006]	----	----
			Thereafter	4.60*TRF= 33.1531[2004] 33.7180[2005] 35.2305[2006]	----	----
		P>100 kW	First 25 years	3.00*TRF= 21.6216[2004] 21.9900[2005] 22.9764[2006]	2.50*TRF= 18.0180[2004] 18.3250[2005] 19.1470[2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
			Thereafter	2.40*TRF= 17.2973[2004] 17.5920[2005] 18.3811[2006]	2.00*TRF= 14.4144[2004] 14.6600[2005] 15.3176[2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
	Thermal (200 MW)		First 25 years	3.00*TRF= 21.6216[2004] 21.9900[2005] 22.9764[2006]	2.50*TRF= 18.0180[2004] 18.3250[2005] 19.1470 2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
			Thereafter	2.40*TRF= 17.2973[2004] 17.5920[2005] 18.3811[2006]	2.00*TRF= 14.4144[2004] 14.6600[2005] 15.3176[2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
Wind (13000 MW)	On-shore	P≤5 MW	First 15 years	0.90*TRF= 6.4865[2004] 6.5970[2005] 6.8929[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
			Thereafter	0.80*TRF= 5.7657[2004] 5.8640[2005] 6.1270[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]

[16] RD 436/2004, disposicion adicional sexta.
[17] RD 2392/2004, article 2.
[18] 1556/2005, article 2.

		P>5 MW	First 5 years	0.90*TRF= 6.4865[2004] 6.5970[2005] 6.8929[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
			From 5 to 15 years	0.85*TRF= 6.1261[2004] 6.2305[2005] 6.5100[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
			Thereafter	0.80*TRF= 5.7657[2004] 5.8640[2005] 6.1270[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
	Off-shore	P≤5 MW	First 15 years	0.90*TRF= 6.4865[2004] 6.5970[2005] 6.8929[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
			Thereafter	0.80*TRF= 5.7657[2004] 5.8640[2005] 6.1270[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
		P>5 MW	First 5 years	0.90*TRF= 6.4865[2004] 6.5970[2005] 6.8929[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
			From 5 to 15 years	0.85*TRF= 6.1261[2004] 6.2305[2005] 6.5100[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
			Thereafter	0.80*TRF= 5.7657[2004] 5.8640[2005] 6.1270[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
Waves, tides			First 20 years	0.90*TRF= 6.4865[2004] 6.5970[2005] 6.8929[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
			Thereafter	0.80*TRF= 5.7657[2004] 5.8640[2005] 6.1270[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]

Hydro power P≤10 MW (2400 MW)			First 25 years	0.90* TRF 6.4865[2004] 6.5970[2005] 6.8929[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004 0.7330 [2005] 0.7659 [2006]
			Thereafter	0.80*TRF= 5.7657[2004] 5.8640[2005] 6.1270[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
Hydro power 10<P≤50 MW		10<P≤25 MW	First 25 years	0.90*TRF= 6.4865[2004] 6.5970[2005] 6.8929[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
			Thereafter	0.80* TRF 5.7657[2004] 5.8640[2005] 6.1270[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
		25<P≤50 MW	First 15 years	0.90*TRF= 6.4865[2004] 6.5970[2005] 6.8929[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
			Thereafter	0.80*TRF= 5.7657[2004] 5.8640[2005] 6.1270[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
Biomass (3200 MW)	b.6 energy crops, biomass from residues in the agricultural sector, gardening, and forestry sites		First 20 years	0.90*TRF= 6.4865[2004] 6.5970[2005] 6.8929[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
			Thereafter	0.80*TRF= 5.7657[2004] 5.8640[2005] 6.1270[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
	b.7 biomass from animal dung, biofuels and biogas		First 20 years	0.90*TRF= 6.4865[2004] 6.5970[2005] 6.8929[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
			Thereafter	0.80*TRF= 5.7657[2004] 5.8640[2005] 6.1270[2006]	2.8829 [2004] 2.9320 [2005] 3.0635 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]
	b.8 biomass from industrial installations in the agricultural and forestry sector			0.80*TRF= 5.7657[2004] 5.8640[2005] 6.1270[2006]	0.3*TRF= 2.1622 [2004] 2.1990[2005] 2.2976 [2006]	0.7207 [2004] 0.7330 [2005] 0.7659 [2006]

Besides the feed-in tariffs, premiums and market incentives in Table 1-2, the RD 436/2004 establishes incentives/penalties for reactive power (annex 5) from 8% incentive to -4% penalty, incentives for fault-ride-through of 5% of the reference tariff (TRF) and capacity payment. The capacity payment applies only to those producers choosing the market option and year 2006 it amounted to 4.81 c€/kWh.

Below, Table 1-3 shows the payment scheme defined by the RD 2818/1998. There are currently very few producers regulated by the RD 2818/1998.

Table 1-3 Payment scheme for renewable electricity production according to RD 2818/1998.

Group	Capacity	Feed-in Tariff c€/kWh	Premium c€/kWh
Solar	P≤5kW (up to 50 MW)	39.6668	36.0607
	P>5kW	21.6364	18.0303
Wind		6.6231	3.1613
Waves, tides		6.7313	3.2755
Hydro power P≤10 MW		6.7313	3.2755
Hydro power 10<P≤50 MW			=3.2755* ((50-P)/40)
Primary* Biomass		6.5090	3.0471
Secondary** Biomass		6.2866	2.8248

*All vegetables with a growing period no longer than one year. Those can be used directly or after a transformation procedure.
**Residues of the transformation of primary biomass such as biogas and biofuels.

Besides the feed-in tariffs or premiums specified in Table 1-3 producers regulated by the RD 2818/1998 receive/pay an incentive/penalty for reactive power (article 26). When the power factor is larger than 0.9 then the producer receives a complement and when it is lower than 0.9 the producer pays a penalty. The amount of the complement/penalty is established in the Royal Decree for tariffs each year.

The feed-in tariffs and premiums defined in the RD 2818/1998 are updated yearly with the variation of the average wholesale electricity price.

1.2.1 Development of payment schemes

By comparing the payment schemes in the last three royal decrees on the special regime the following conclusions can be drawn:

- Solar photovoltaic power production has experienced a great increase regarding payment. Installations with a capacity below 5 kW have almost the same payment as 10 years ago but large installations have got a much higher payment according to the new legislation. A solar photovoltaic installation with an installed capacity of 150 kW received according to the RD 2818/1998 a payment of 21.6 c€/kWh and according to the new royal decree, RD 661/2007 a payment of 41.8 c€/kWh is received.
- Wind power producers choosing the feed-in tariff option receive slightly higher payment than 10 years ago but since 2004 the number of wind power producers choosing the market option has increased tremendously and during 2005 and 2006 they have received very high payments. However, the payment has been limited by the new legislation published on 2007 by a price cap of 8.5 c€/kWh which is 30% higher than the feed-in tariff wind power producers received 10 years ago.
- Electricity production from energy crops and biogas receive much higher payment according to the new legislation. An installation using energy crops with an installed capacity of 1.5 MW earlier received according to the RD 2818/1998 a payment of 6.5 c€/kWh and according to the new legislation, RD 661/2007 will receive a payment of 15.9 c€/kWh.

1.2.2 Agents Opinions on different Payment Schemes for Renewable Electricity Production

According to several interviewed agents in the Spanish wind power sector, payment schemes based on market mechanisms such as green certificates, need price setting mechanisms capable of reflecting real investment costs in order to work as effective payment schemes. This is only possible in a wide and deep market where the participating agents have equal access to the price relevant information. The wind power sector is still emerging and, according to the interviewed, is still not prepared for a payment scheme based only on market mechanisms. However, this kind of market-based payment schemes can be adequate when the sector is more established. There is a risk with those market-based systems to end up paying more for the capacity than what it had been paid with a feed-in tariff system. An example mentioned by some of the interviewed agents in Spain is what has happened in the UK and Italy where the certificates have reached prices of 140–180 €/MWh, which is much higher than the feed-in tariff paid to renewable producers in Germany and Spain of 80–85 €/MWh.

1.3 Application Procedure for Access and Connection to the Grid

The application procedure for the connection to the grid is defined in the Royal Decree 1955/2000 in its Title IV. There are two different procedures depending on whether the production installation is to be connected to the transmission system or to the distribution system. The procedures are outlined below.

Procedure for connection to the transmission system (RD 1955/2000 article 53 and 57)

1. The project developer sends the access application to the transmission system operator, TSO. The application has to include the information defined in the operating procedure 12.1 published by the TSO[19].
2. The TSO sends a report with the eventual anomalies or mistakes to the project developer so that those are corrected.
3. The project developer corrects the anomalies or mistakes within a month from the reception of the report of the TSO.
4. After receiving the correct access application, the TSO has two months to communicate the project developer on the access license depending on whether there is available capacity for the connection or not. If the TSO does not inform the project developer on time, then the project developer can appeal to the regulatory body CNE. If the project developer does not agree with the proposed connection point by the TSO then he can appeal to the CNE who has a period of three months to decide on the conflict. The TSO´s report on available capacity has a validity of six months.

[19] http://www.ree.es/cap03/pdf/po/PO_resol_11feb2005.pdf (only Spanish version available)

5. The project developer sends the basic project and the program of execution to the transmission company in order to get the connection license.
6. The transmission company has to send within a month a report to the TSO[20] regarding the fulfillment of the technical requirements as well as a copy of the basic project and the program of execution.
7. The TSO will write a report within a month.
8. The access and connection licenses can be processed at the same time but to get the connection license the project developer has to have the access license.

Project developers of installations which are to be connected to the transmission grid have to hand in a deposit of 2% of the cost of the whole installation (for example 2% of the cost of the wind farm) to the Ministry, MITYC according to the Law RD 1454/2005 which added a new article to the RD 1955/2000 (article 59 bis). That is a requisite to initiate the procedure for access and connection to the grid. That deposit is given back to the project developer when he/she gets the administrative license for the installation or when, due to reasons beyond his responsibility, the administrative license cannot be obtained.

However, the new legislation, RD 661/2007, modifies the amount of the deposit defined by the former Law, RD 1454/2005, which for the transmission system becomes:

- 500 €/kW for solar photovoltaics
- 20 €/kW for all other producers included in the special regime.

Procedure for connection to the distribution system (RD 1955/2000 article 62, 63 and 66)

1. The project developer sends the access application to the operator of the distribution system, DSO, in the area. Each distribution company has an application model.
2. The DSO sends within 10 days a report with the eventual anomalies or mistakes to the promoter so that those are corrected.
3. The promoter corrects the anomalies or mistakes within 10 days from the reception of the report of the DSO.

[20] As it was described in Section 1.1.1, Red Electrica de España, REE, is the Spanish TSO and the largest but not the only transmission company. Therefore, the transmission company and the TSO are referred to as two different entities even though in most of the cases they are the same entity, REE.

4. After receiving the correct access application, the DSO has 15 days to communicate the project developer on the access license depending on whether there is available capacity for the connection or not. The report of the DSO on available capacity has a validity of six months. If the DSO does not inform the project developer on time, then the project developer can appeal to the Regulatory Body CNE. The DSO has to inform the TSO about access applications for capacities larger than 10 MW (that is a change introduced by the RD 661/2007 in its annex XI. Earlier the limit was 50 MW or a capacity lower than 5% or 10% of the short-circuit capacity of the grid at the connection point for peak and low demand periods respectively). The TSO has to send a report on the capacity within two months. If the project developer does not agree with the proposed connection point by the DSO then he can appeal to the CNE who has a period of three months to decide on the conflict.
5. The project developer sends the basic project and the program of execution to the distribution company in order to get the connection license.
6. The distribution company, in case the connection can affect the transmission system as defined earlier in point 4, has to send within a month a report to the TSO regarding the fulfillment of the technical requirements as well as a copy of the basic project and the program of execution.
7. The TSO will write a report within a month.
8. The access and connection licenses can be processed at the same time but to get the connection license the project developer has to have the access license.

The environmental assessment of the projects is a part of the administrative licensing process and is a requirement to get the administrative license necessary to build the installations. The administrative license can be processed at the same time as the access and connection licenses. The environmental assessment process takes in practice about six or seven months according to one Spanish project developer.

The RD 661/2007 (disposicion final segunda) adds a new article to the RD 1955/2000, called article 66 bis. This new article defines a deposit to be paid by project developers of installations which are to be connected to the distribution grid. The amount of the deposit is:

- 500 €/kW for solar photovoltaics.
- 20 €/kW for all other producers included in the special regime.

It is important to note that solar photovoltaic installations located in residential, commercial, service or industrial premises do not have to hand in the deposit defined in the list above. The payment of the deposit is a requisite to initiate the application procedure of access and connection to the distribution grid. That deposit is given back to the developer when the developer gets the administrative license for the installation or when, due to reasons beyond its responsibility, that administrative license cannot be obtained. Installations which do not need any administrative license for being built will get back the deposit when the installation has been definitively included in the register for special regime.

1.3.1 Definition of the Capacity of a Production Installation

The Law for the special regime establishes a capacity limit of 50 MW to receive the highest payment, see Figure 1-4: Factor for installations using renewable energies with an installed capacity larger than 50 MW. In practice, installations larger than 50 MW are split into several installations each with installed capacity below 50 MW in order to receive the highest payment and make use of the locations with good wind resource. An example of this is the wind farms known as Maranchón I and IV with a capacity of 18 and 48 MW each. To the substations of these wind farms are also other wind farms connected with a total capacity of 130 MW[21]. Since the total capacity is 130 MW, it is also possible to access the transmission grid since it is necessary to have at least 100 MW to connect to the transmission grid (see Section 1.3.2 below). In that case the owners of the different installations make a joint application for the connection to the grid. Each installation gets paid independently. Another advantage is to be able to own the substation and have control over it.

Different generating units are considered, according to the Law RD 2818/1998 (article 3), as one single installation when they inject their energy in the same transformer with a voltage output equal to the voltage of the grid to which they are connected. The capacity of

[21] http://www.biomanantial.com/iberdrola-se-consolida-como-la-primera-empresa-eolica-del-mundo-a-398.html

the installation is the sum of the capacity of the individual generating units. This definition has remained unchanged in posterior legislation. If different generating installations use the same connection installations, then the definition described earlier in this paragraph will be understood relating to the transformer before the one that is used by the different installations. This means for instance that 30 wind turbines of 2 MW each will be considered as a 60 MW wind park if they use the same transformer to connect to the grid. If 15 turbines are connected to one transformer and the other 15 to another transformer, then there will be two installations of 30 MW each.

1.3.2 Permitting Entities

The operating procedure 13.1 published by the TSO[22] establishes minimum capacity limits for the connection of a producing installation to the transmission grid. Those limits are 100 MW for the connection to the 220 kV grid and 250 MW for the connection to the 400 kV grid. These limits were applied even before this operating procedure was approved. The system operator REE has been flexible with the limit of 100 MW for the connection to the 220 kV grid. If for example a wind park with an installed capacity of 50 MW applied for connection to the 220 kV grid and had plans to later enlarge the capacity to 100 MW, then they have got access to the 220 kV grid.

It might sound confusing to combine the limit of 50 MW to get the payment for the special regime as the same time as the minimum capacity is 100 MW to connect to the transmission grid. In practice what is done is that several project developers make a joint application for connection to the transmission grid in order to reach the requisite on minimum capacity for the connection and at the same time receive the highest possible payment. To make the joint application the Law RD 661/2007 establishes the requirement of a node representative that is selected by the regional government or the competitive authority when several project developers ask on access to the transmission grid. It is usually the project developer that has been a longer time at the location or the one developing the largest installation that is selected by the authorities which communicate the decision to the system operator and the transmission company. This speeds up the licensing process.

[22] http://www.ree.es/cap03/pdf/po/PO_resol_22Mar2005.pdf (only Spanish version available)

The administrative licenses, i.e., the licenses for construction, modifying or closing transmission installations are given by the Ministry. Those administrative licenses are public and are published in the State official bulletin, BOE. Administrative licenses for distribution installations are given by the regional authorities. The definition of what is included in the transmission installations and distribution installations can be found in article 5 of the RD 1955/2000. It is important to point out that according to that RD, producing installations, transformers to those installations, and connecting installations such as power lines are included in neither the transmission nor the distribution grid. However, it is quite common for producers which are about to connect to the distribution grid, to give the power line and the position at the substation to the grid company (see Section 1.5).

The administrative license for generating installations with either an installed capacity over 50 MW, located in more than one municipality, or in the sea is a responsibility of the Ministry of Industry, Tourism and Trade through its Dirección General de Energía, DGE. This is established in the Royal Decree 661/2007 article 4.

The administration wants that project developers process the administrative licenses for the wind farm and the connecting line together. It can be a single dossier or several depending on whether the line is to be used by a single producer or by several. According to a Spanish project developer the negotiation with the owners of the land necessary to build a wind farm is usually fast while negotiations with the owners of the land necessary to build a connecting line are more difficult. When no agreement can be reached with the land owners then it is possible to expropriate the land if the installations are declared by the administration as of public usefulness. The administrations use to require the project developers agreement with at least 50% of the involved owners in order to expropriate. Expropriation facilitates considerably the construction of lines since they can be built even if no agreement is reached with all the land owners.

1.4 Obligations of Grid Companies regarding Grid Access

1.4.1 Available capacity

Access and connection to the grid are regulated by the Royal Decree 1955/2000. According to its article 20 the only reason to deny access to the grid is the lack of capacity. The lack of capacity will be justified exclusively according to criteria of security, regularity and quality of the supply.

Moreover the general criteria of security, regularity and quality of the supply, there are also other specific criteria for the producers included in the special regime when deciding on access to the grid. These specific criteria, which are given below, were already defined in the RD 436/2004 and are stated again in the RD 661/2007 (annex 11) with some modifications:

1. The capacity of a generating installation or group of installations included in the special regime connected to one power line of the distribution grid cannot exceed 50% of the capacity of the power line at that point.
2. The capacity of a generating installation or group of installations included in the special regime connected to one substation or transformer cannot exceed 50% of the capacity of the transformers installed for that voltage level.
3. For producers without storage capabilities, such as wind power and solar photovoltaic producers, it is also established that the capacity of the producer or group of producers sharing connection point, will not exceed 1/20 of the grid short-circuit capacity at that point.

In practice, the criteria above are only being restrictive in the connection to the distribution grid and are not actual in the connection to the transmission grid[23]. For the connection to the distribution grid, the limits expressed in criteria 1 and 2 are limiting the capacity to be connected in about 10% of the cases while the limit expressed in criteria 3 is limiting in approximately 90% of the cases when there is not available capacity in the distribution grid. There is still not much experience with the connection to the distribution grid of generating capacity. Therefore it might be wise to be conservative at the beginning and maybe in four or five years loosen those

[23] Personal communication with the Spanish system operator, REE.

limits[24]. The limits above are considered quite conservative by the TSO. For example in Australia, for criterion 3, values of 1/5 instead of 1/20 are being used.

The largest difference between the RD 436/2004 and the RD 661/2007 regarding limits in the capacity to be connected to the grid is that in the first one the limits apply for each individual production installation while in the second one the limits apply for each individual production installation as well as for the total of installations connected at the same point (power line or substation) to the grid. This means that the RD 661/2007 is more restrictive than the RD 436/2004. However, the criteria that the restriction applies not only for each individual production installation but also for groups of installations connected at the same point has been used even before the establishment of the RD 661/2007[25].

The transmission system operator, REE, is allowing the installation of 25% larger capacity from producers based on renewable energy sources without storage capabilities than the grids capacity at the connection point. This is due to the fact that it is very unlikely that all such producers will be producing at full capacity at the same time. Therefore, if the grid capacity at the connection point is X, it is possible to connect 1.25*X capacity from electricity producers based on renewable energy sources without storage capabilities.

The new RD 661/2007 establishes in its annex XI that all access applications to the distribution grids for installations, or group of installations, with a capacity larger than 10 MW have to be sent to the transmission system operator after having got the acceptability by the distribution grid operator. The transmission system operator has to inform on its acceptability. This is a great change since RD 1955/2000 (article 63) established that only access applications for installations with an installed capacity larger than 50 MW or with a capacity larger than 5% of the grid short-circuit capacity at the connection point had to be sent to the system operator. The new RD 661/2007 allows the transmission system operator to deny connection to the distribution grid if that connection can mean lack of capacity in the transmission grid.

There is a significant number of wind farms located between the region of Galicia and Madrid producing below their full capacity since the necessary reinforcements of the transmission grid to transport all energy produced at full capacity have not been materialized

[24] Personal communication with a distribution company.
[25] Personal communication with a distribution company.

yet. This means lower payment than what they could get since they don't receive any compensation for the reduced production.

1.4.2 Priority Access for Renewable Electricity Producers

Since the Spanish Law uses the criterion of non-existence of reserve of capacity, the Law permits over-installation in the connection points. An example of that is what happens in a node called Escombreras where the capacity at that point is 1,800 MW and there are several generating units, belonging to different owners, with a total installed capacity of 3,200 MW. In Spain all generating units have to send their offers to the market operator, OMEL, which makes an economical match between bids and offers and establishes a so called market price. Each generating unit which has offered its production at a price under the market price receives from OMEL the hourly market price for the offered production. However, the economical-based generation program made by OMEL is usually not physically viable. Therefore, the TSO analyzes the viability of the program made by OMEL and elaborate a new program for all generating units where the production of some units has been decreased compared to the economical program and the production of some units has been increased. Those units which have got decreased production compared to the economical program have to pay back to the TSO for the decreased production at the market price; those units which get increased production get paid for the increased production at the price they had offered which can be higher or lower than the market price[26].

In the case of Escombreras, if all generating units have offered a price below the marginal cost to the market operator, OMEL, then they get paid for all offered capacity. Then when the TSO makes the viability study, their production program will be reduced with a prorate scheme since the limit is 1,800 MW, and will have to pay back to OMEL for the decreased production. In this example, all units are conventional power plants which means that they have the same priority order. In the case of having a conventional power plant and a renewable based production plant, then the conventional power

[26] This is described in the operating proceedings 3.2 and 14.4 published by the TSO. Operating proceeding 3.2 "Solving Technical Constraints" available in English version at http://www.ree.es/ingles/i-cap03/pdf/po/PO_resol_24Jun05_ingles.pdf. Operating procedure 14.4 available only in Spanish version at http://www.ree.es/cap03/pdf/po/PO_resol_26 junio2007_14.4.pdf

plant will have to reduce all production if needed to remove the restriction in the grid, and only after the conventional power plants have reduced their production to zero the renewable based power plants will reduce their production since they have higher priority. Within renewable energy sources it is renewable energy sources without storage capability that have the highest priority according to the new Royal Decree 661/2007 published in June 2007. This means that if for example there is a restriction in a node where conventional power plants, hydropower plants with storage capabilities and wind farms are connected, then the conventional plants will decrease their production first; if it is not enough to remove the limitations in the grid then the hydropower plants with storage capabilities will decrease its production. The wind farms will decrease their production only after all other generating units have stopped producing. This means that power plants that have been connected at that point will have to reduce their production when generating units using renewable energy without storage capabilities are connected at the same point and there are limitations in the grid.

1.4.3 Reservation of Transmission Capacity

The Spanish electrical system uses the criterion of non-existence of reserve of capacity. Limitations in the access to the grid will be solved according to what is established in the operating proceedings of the system, see Section 1.4.2. Earlier connection does not mean any preference in the access to the grid.

1.5 Costs Associated to the Connection to the Grid

There is no clear legislation in this issue, on one hand in the RD 436 (disposición transitoria tercera) it is said that costs of the installations required for the connection to the grid will be paid, generally, by the producer. On the other hand, the RD 1955/2000 (article 32) establishes that reinforcement associated to the development of the grid or to the change of equipment will be included in the planning process. Finally, the RD 661/2007 (annex XI) establishes that costs related to reinforcements in the grid are to be paid by the producers unless these reinforcements are not to be used solely by the producer. Current legislation leaves possibilities for different interpretations since it is not closely defined what solely use of the reinforcement of the grid means and, in case of that the reinforcements of the grid are to be used by other producers or the distribution company, how the cost sharing should be carried out. According to the Spanish Wind Power Association, AEE, this is especially problematic with off-shore installations where the required investments for connection to the grid are going to be very large.

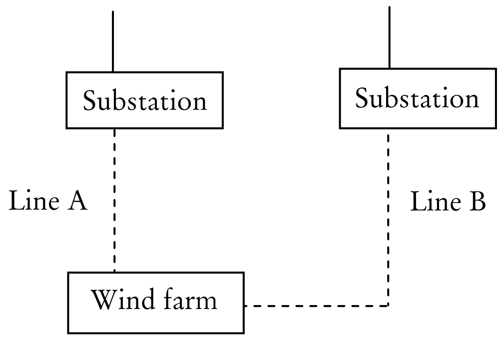
It is not specified in the legislation how the costs due to the reinforcement of the grid should be split between different producers. However, the new Law, RD 661/2007, asks the TSO and the different DSOs to send within a year a description of the mechanisms to follow in order to share costs for connecting installations and necessary reinforcements between different project developers. This requirement is a result of implementing the articles 7.4 and 7.5 of the EU directive 2001/77/CE.

1.5.1 Costs for the Connection Installations

The payment that renewable electricity producers have received until now has been sufficient to finance reinforcement costs that have been necessary for the connection, but the fact that distances from locations with good wind resource to the electrical grid becomes larger makes the required investments also larger and therefore it becomes more difficult for producers to finance reinforcements of the grid. Hence, according to the Spanish Wind Power Association, AEE, it is important to establish a regulatory frame that defines objective criteria to make an equitable assignment of the associated costs to these investments. It is necessary to clearly analyse specific cases to define which costs are specific costs and which are not and to standardize the specific costs.

There are many examples when connecting installations are not to be used solely by the producer. One such example is when more than one connecting power line is built in order to get a more interconnected grid instead for building just one radial power line (see Figure 1-7). In that case, the distribution company pays the difference between the cost for building just one single radial power line (line A) and for building both lines (Line A and Line B). A more interconnected grid benefits both the grid company and the producers who can produce electric power even if one of the connecting power lines has some problem.

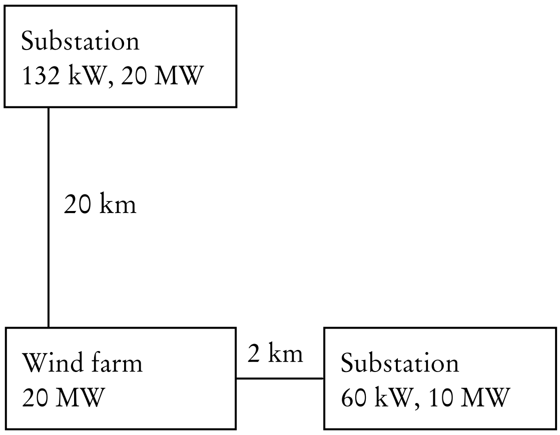
Figure 1-7 Two power lines improve the connection to distribution grid.



According to one of the Spanish DSOs, it is common that for voltages between 45 and 132 kV producers give the connecting power line and even the position at the substation to the distribution company in order to avoid its operation and maintenance and the associated costs.

A common practice is to give provisional access license to the distribution grid so that new producers can begin to produce electricity even though the power lines or necessary reinforcements to transport all the energy produced at full capacity are not built (see Figure 1-8). In this provisional license the production is limited so that the capacity of the grid is not exceeded. It is very common that the grid company obliges the producer to install remote control so that the production can be controlled automatically. The provisional access license allows the owners of the installations to start producing earlier even though they cannot produce at full capacity. This is up to the distribution grid company to give such provisional licenses since the legislation establishes that the lack of capacity is a reason to deny access to the grid.

Figure 1-8 Provisional connection of a wind farm with an installed capacity of 20 MW to a substation of 60 kV with an available capacity of 10 MW until the line to the 132 kV substation with sufficient available capacity is built.



In the RD 1955/2000 (article 32) it is established a time horizon of 5 years within which new producers, using connection installations already paid by another producer or producers, have to pay to those, in proportion to the capacity to be connected.

1.5.2 Costs for Reinforcement of the Transmission Grid

Generally, cost due to reinforcement of the transmission grid, besides the new position at the substation, are socialized while in the distribution grid these costs are paid by the project developers according to the agreements reached with the distribution company. Since costs are socialized when it comes to reinforcements in the transmission grid, problems such as sharing between current and future producers as well as identification of costs applicable to solely one producer are avoided. It is important to note that transmission costs are a small part of the total electricity cost paid by consumers.

According to the RD 1955/2000 article 54 when reinforcements in the transmission grid are necessary in order to connect a new production installation then the promoter has to hand in a deposit to the transmission system operator of 20% of the costs associated to the reinforcement. However, according to the transmission system operator, such deposits have never been handed in since reinforcements in the transmission grid are socialized.

As mentioned earlier costs due to reinforcement of the transmission grid are usually socialized in Spain, i.e., they are financed through the tariff paid by consumers. However, in order to speed up the process, project developers can make agreements with the transmission company according to which the project developer pay the reinforcement costs and the transmission company pays back the same quantity to the project developer when receiving the tariffs paid by the consumers. These kinds of agreements are voluntary and not included in the legislation.

It is the Ministry who decides which costs associated to the construction/expansion of the transmission installations (power lines and transformers among others) are to be socialized.

1.5.3 Costs for Reinforcement of the Distribution Grid

Up to date, costs due to reinforcement of the distribution grid have been paid in some cases by the project developers, in other cases by the project developers and the grid owner and in some other cases they have been socialized. There has not been a clear criterion or a detailed legislation in this matter. Specific problems have been solved through the regional government or by the regulatory body, CNE.

According to the legislation, all costs originated by the connection of a generating installation are to be paid by the owner of the generating installation. However, it might be difficult to identify which costs are originated by a single installation when several installations are connected in the same area. A way to handle this question is what has been done in the region of Castilla la Mancha where recently all connection applications from solar photovoltaic installations have been processed as a group. In this way, the grid companies in the region has been able to identify and optimize the necessary reinforcements of the grid in order to transport all the production from these producers instead of designing a one-by-one solution. The total installed capacity included in this procedure has been 510 MW and the installations will be mainly connected to the 20 kV grid. The costs for these reinforcements will be shared between the different producers according to the connected capacity. In this global treatment the distribution companies have used moreover the criteria expressed in Section 1.4.1, the criterion that the installed capacity of renewable production cannot exceed 50% of the demand in the area in order to avoid voltage variations above what is permitted in the legislation on quality of supply. It has been done by Iberdrola Distribución, Unión Fenosa Distribución (the distribution companies in the region), and the regional government which has welcomed this initiative.

1.6 Costs and Obligations related to measurement

In Spain measurement points are classified in different types and there are different requirements for the different types.

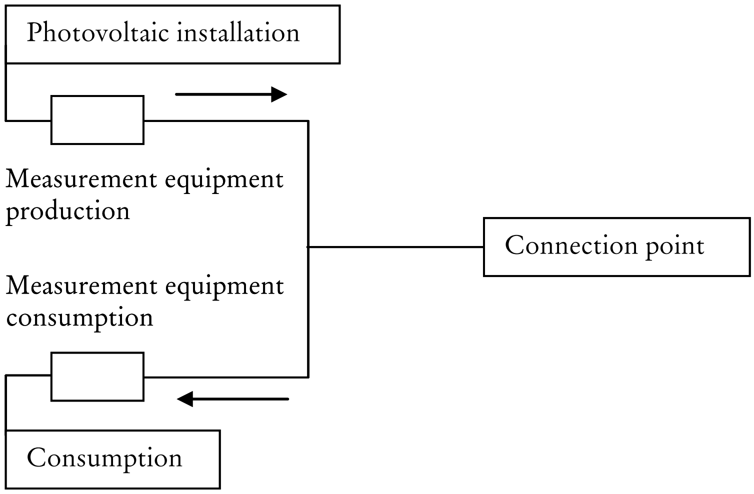
Measurement points of type 1 regarding generation[27] are defined as those points where the energy flow during the year is equal or larger than 5 GWh or where the installed capacity is equal or larger than 12 MVA. For measurement points of type 2 the corresponding limits are 750 MWh and 1,800 kVA. Measurement points of type 4 and 5 are defined as those points with a voltage lower than 1 kV and a production capacity larger respectively lower than 15 kW.

1.6.1 Net-metering

The Law defining the measurement requirements for installations connected to the low voltage grid[28], i.e. measurement points of type 4 and 5, establishes that when a generating installation also consumes electricity, then the installation will be considered as a generating or a consuming installation depending on whether the installed generating capacity is larger than the retailed consuming power or vice versa. In that case net-metering is used. However, it is possible to have two measurement equipments to measure the produced and consumed energy separately. Solar photovoltaic producers typically choose two different measurement equipments (see Figure 1-9) since the tariff they receive for their production, 44 c€/kWh (see Table 1-1), is much higher than what they pay for their consumption, approximately 17 c€/kWh.

[27] Royal Decree 385/2002, http://www.boe.es/boe/dias/2002/05/14/pdfs/A17368-17379.pdf (only Spanish version available)
[28] Royal Decree 1433/2002, http://www.boe.es/boe/dias/2002/12/31/pdfs/A46338-46346.pdf (only Spanish version available)

Figure 1-9 Solar photovoltaic generator with measurement equipment for the delivered energy and for the consumed energy.



1.6.2 Hourly measurement

According to the legislation regulating measurement requirements in the low voltage grid, measurement equipment of producing installations using renewable energy sources has to fulfill <u>at least one</u> of the following characteristics:

For the produced energy:

- A single register for the whole active energy delivered to the grid
- Two registers for the active energy delivered in the low-demand periods and the high-demand periods and one register for the reactive power consumed when delivering active energy to the grid.
- Hourly register of the active power and register for the whole reactive power consumed when delivering active power to the grid

For the consumed energy:

- Equipment according to the contract that can be at the integral tariff or at the market price.

According to the requirements listed above, generating installations connected to the low voltage grid do not need to have hourly measurement; it is enough to have a single register for the delivered active power to the grid.

1.6.3 Measurement costs

The costs for hiring measurement equipment for measurement points of type 5, i.e., connected to the low voltage grid and with an installed capacity lower than 15 kW, are regulated by the legislation and for year 2007[29] go from 0.47 €/month to 2.79 €/month. These prices include maintenance, operation, installation, and verification. The range depends on whether the counter is connected to a one-phase or three-phase circuit and whether the counter can separate the measurement in different time periods such as low-demand periods and peak-load periods or not.

The cost for hiring the measurement equipment for a measurement point of type 4 is, according to one of the Spanish distribution companies, 12 €/month or 144 €/year, i.e., approximately 1,400 SEK/year. It is also possible to own the equipment but in that case verification, maintenance and recalibration of the equipment must be paid separately to an authorized agent. The cost of buying the counter/register machine is about 350 € and the costs of the modem for communication is about 300 €.

For calculating the cost for hiring measurement equipment for other measurement points than of type 4 and 5, network companies should apply a factor of 1.125 per cent to the cost of the counter/register, the communication equipment, maintenance, operation, installation and verification according to the legislation.

A solar photovoltaic installation with an installed capacity of 10 kW receives approximately 9,000 € per year (with a feed-in tariff of 44.0381 c€/kWh) for its power production. This means that the cost for the measurement equipment is negligible.

[29] Royal Decree 1634/2006 (annex II), http://www.boe.es/boe/dias/2006/12/30/pdfs/A46656-46679.pdf (only Spanish version available)

1.7 Grid tariffs

In Spain power producers do not pay grid tariffs to get access to the grid and for using the grid. The Law of the electrical sector, 54/1997, defines grid tariffs and access costs in its article 17 and 18 but only for agents buying electricity. In the Spanish market, understood as the pool, bilateral contracts, and long-term contracts, energy is sold in what is called barras de central, i.e., at the output of the producing installation.

By excluding power producers from paying grid tariffs, no localization signals are given to producers, i.e., there are no incentives to locate production in those points which improve the performance of the whole electricity system by for example reducing losses or minimizing restrictions in certain areas. Such system with grid tariffs giving locational signals is used for example in Sweden where producers in the North have to pay to inject their production to the grid while producers in the South get paid for doing the same. Up to date, in Spain it has been considered that the calculation of location signals is too complex compared to the benefit that they can deliver. However, the regulatory body CNE has to present a proposal to the ministry on such location signals by year 2007.

1.8 Rights and Obligations regarding Real-Time Operation

According to several interviewed agents, Spain is at the forefront of the technical performance of the wind farms as well as of its management. The reason for that is that wind power generation in Spain takes place at large scale since there is a high concentration of wind power in some points of the grid. In approximately 30 or 40 connecting points of the grid 60–70% of the total wind power production is concentrated. The installed wind power capacity at the end of year 2006 amounted to 13% of the total installed generating capacity and to about 8% of the total power production in the country.

The management of the wind energy is necessary to assure the security of the electric power system. Therefore the new Law regulating the special regime in which wind power is included, establishes in its article 18 the obligation for all generating installations based on renewable energy sources with a capacity larger than 10 MW to be connected to an operation centre. Those operation centers make it possible to manage the production from the renewable producers and constitutes an important element in the cooperation between renewable producers and the system operator. These centers help to change the concept of renewable producers as a source of uncertainty for the electricity system into power production which is possible to control. At the same time the operation centers constitutes an important tool for the producer to manage its assets reducing the personal required for maintenance and shortening the reparation times. All costs related to the operation centers have to be paid by the connected renewable power producers themselves.

Renewable electricity producers have priority compared to conventional power producers as it was introduced in Section 1.4.2. This means that when for security reasons the power production has to be decreased, then renewable power producers will be the last to reduce their electricity production. Renewable power producers without storage capabilities such as wind power producers, solar and hydropower producers without dam have the highest priority according to the new Royal Decree 661/2007, published in June 2007. If despite their priority, renewable producers have to decrease their production in real time, i.e. the reduction was not programmed in advance, then they get paid 15% of the market price for the reduced production. If the reduction was programmed then they do not get any payment for the reduced production.

Protection elements in wind farms have to be calibrated to keep the installation connected to the grid as long as the frequency is between 48 and 51 Hz according to the RD 661/2007. These are new values for the calibration of the protections at wind farms compared to the former legislation and are necessary in order to avoid events such as the one that took place November 4, 2006 in Germany. That event led to a frequency decrease below 49 Hz in Spain, making the protections to disconnect wind farms which worsened the problem.

Besides, the RD 661/2007 establishes the obligation for wind farms to stand voltage dips. A calendar to fulfill this requirement has been defined. The machines that can be adapted in order to fulfill this requirement have to do these adaptations before January 1, 2010 and those that cannot be adapted have to communicate this before January 1, 2009. A subsidy of 0.38 c€/kWh will be given to those wind farms that will be adapted and that are registered before January 1, 2008. That subsidy can be obtained after the adaptation works have been accomplished and no longer than during 5 years and in any case no longer than December 31, 2013. The operating procedure 12.3[30] published by the TSO defines the requirements in this respect.

All power producers have to send their offers to the market operator independently of the payment option they choose according to the new RD 661/2007. However, producers choosing the feed-in tariff payment option and that not have hourly measurement requirements, as for example solar photovoltaic installations connected to the low voltage grid (see Section 1.6.2), will not pay for the deviations between the offers sent to the market operator and the real production. Installations without hourly measurement will use the best available data to elaborate their offers to the market operator; however, if there is a lack of such data, hourly profiles will be used. Such hourly profiles are given in the RD 661/2007 (annex XII).

1.9 Conclusions Spain

General renewable Energy Promotion Scheme

- Renewable producers in Spain can choose between two different payment schemes, the feed-in tariff and the market option (market price plus fixed premium). The feed in tariff level for wind power year 2006 was 6.89 c€/kWh and the market option resulted in an average payment for wind power producers of 9.10 c€/kWh.
- There is a strong connection between the political targets defined for each technology and the corresponding promotion scheme by means of feed-in tariffs or premiums, since installations which start producing after a defined period after having reached 85% of the political target established for the corresponding technique, will not get feed-in tariff or premium but just the market price.

[30] http://www.ree.es/cap03/pdf/po/PO_resol_12.3_Respuesta_huecos_eolica.pdf (only Spanish version available)

Key factors for the development of the wind power sector in Spain

- The key factors behind the great development of the wind power sector in Spain have been a stable investment environment by means of fixed regulated feed-in tariffs and political stability regarding the support to renewable power production. Grid issues have become more important as the number of applications for transport capacity has increased and the upgrading of the grid takes several years and slows down the development of the wind power sector.

Are there any size limits in the regulation for renewable electricity production?

- Installations with an installed capacity larger than 50 MW are not included in the special regime and get lower payment than installations with the same technology and energy source but installed capacity lower than 50 MW.
- There are capacity limits for the access to the transmission grid and the distribution grid. To be able to access the transmission grid it is required a minimum capacity of 100 MW for the 220 kV grid and 250 MW for the 400 kV grid. In order to fulfill this requirement several project developers make a joint application to the TSO.
- There are some specific requirements for renewable electricity producers regarding the capacity that they can connect to the grid. For example the capacity of renewable power production without storage capabilities (wind, solar and hydropower stations without dam) to be connected cannot exceed 1/20 of the grid's short-circuit capacity at that point. The capacity of renewable power production at a point cannot be larger than 50% of the capacity of the power line. Those requirements are typically limiting the connection to the distribution grid and not to the transmission grid.

Tariff Structure

- Power producers do not pay any tariffs for using the grid. This has always been like that in Spain and the same applies for conventional power producers and for power producers using renewable energy sources. Therefore, this issue has not been the factor that has triggered the development of the wind power sector in Spain.
- In Spain it is regulated ex-ante by Law how much distribution companies are paid every year. This is financed by the grid tariffs paid by all agents buying electric power to the distribution companies. All tariffs paid the buying agents of the distribution companies are sent to the regulatory body CNE which splits the part of the tariffs that correspond to the distribution activity between the different grid companies. Up to date, five of the distribution companies in Spain accumulate a total share in the distribution activity of 99%.

Network connection costs

- Project developers have to pay for the construction of the power line, transformer and all other necessary installations for the connection to the grid. There is no difference in this matter between conventional power producers and power producers using renewable energy sources.
- There are no well defined Laws regarding deep costs, i.e., costs associated to reinforcement of the grid necessary to connect new producers. However, in practice, costs for reinforcement in the transmission grid are socialized while costs for reinforcement in the distribution grid are mostly paid by the project developer.

Metering

- Power producers connected to the low voltage grid (<1 kV) which also consumes electric power, mainly solar photovoltaic, have the possibility to choose between measuring production and consumption separately and measuring net-production or net-consumption, so called net-metering. These producers typically choose to have two different measurement equipments since the payment for the produced power is almost three times larger than the cost for the consumed power. There is no obligation on hourly measurement for these producers.

Priority access for renewable electricity production

- It is not possible to reserve transmission capacity in the Spanish Grid. It means that conflicts in access are solved according to a priority order defined in the operating procedures published by the TSO. Renewable electricity production without storage capabilities has the highest priority followed by other renewable production, thirdly all other production included in the special regime as combined heat and power production and at last conventional power plants. If producers get their production reduced in advance then they do not get any payment for that reduced production but if the reduction is ordered in real-time operation then they get 15% of the hourly market price.
- According to an operation procedure on the management of electric power produced with renewable energies without storage capabilities, if such a producer is curtailed more than 3 times during a month or ten times during a year then the grid company has to elaborate an investment plan within 6 months.

Network Concessions

- In Spain the power lines within a generating installation and from the installation to the connection point can be built by the producer himself without needing to establish a network company for this purpose. The producer does not have the obligation to connect third-parties to these power lines.

Network Connection Procedures

- Application procedures are very well described in Spain as well as the deadlines associated to different steps of the application procedure. The regulatory body CNE is responsible for deciding in conflicts such as connection points and has also a defined time to resolve on those conflicts.

Technical requirements

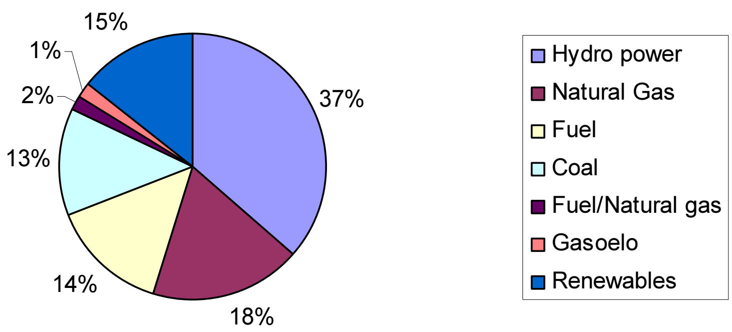
- As the share of wind power has grown in Spain, new technical requirements have been established in the new Law regulating the special regime as for example fault-ride-trough and obligation for all installations with a capacity larger than 10 MW to be connected to control centers.

2 Portugal

2.1 Introduction

The total installed power capacity in Portugal by the end of year 2006 was 13,607[31] MW. A breakdown of the total installed capacity can be seen in Figure 2-1.

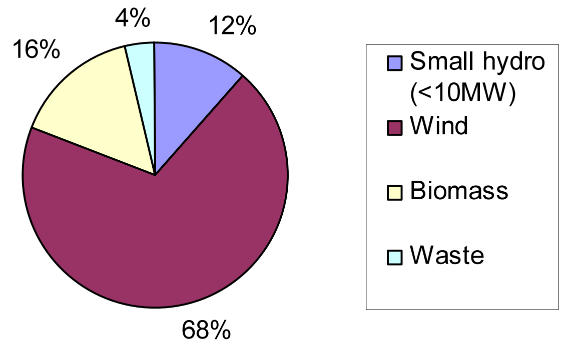
Figure 2-1 Breakdown of total installed capacity in Portugal by the end of year 2006.



The total installed capacity in renewable electricity production excluding large hydropower stations (installed capacity larger than 10 MW) was 2,448[32] MW by the end of year 2006. Figure 2-1 shows the share of the different renewables technologies to the total installed capacity in renewable electricity production.

[31] Source: REN, INFORMAÇÃO MENSAL DEZEMBRO 2006 SISTEMA ELECTROPRODUTOR, http://www.ren.pt/content/587E8DD885674BCB8E8DC317D81625C2.PDF
[32] Estatísticas rápidas, Fevereiro 2007. Direccao Geral de Geologia e Energia.

Figure 2-2 Renewable energy breakdown by 31/12/2006



Wind power is the renewable source that has experienced the largest development in Portugal. During the last four years the installed wind power capacity has grown from 289 MW year 2003 to 1,698 MW by the end of year 2006[33]. Therefore, even though this chapter tries to give an insight on the Portuguese renewable sector as a whole, it focuses on the wind power sector.

The wind resource is larger in the interior and in the North part of the country while the consuming areas are in the south. That means that the transmission grid has to be developed in order to transport the electric power from the producing nodes to the consuming ones through the country even if most wind farms are connected to the distribution grid.

EDP – Energias de Portugal was, twenty years ago, the only production, transmission and distribution company. Nowadays EDP has a share on power production of about 57%, almost the total distribution activity, 99%, and does not participate in the transmission business.

2.1.1 Overview of the Transmission System

In Portugal the transmission grid is composed by all elements at the voltage of 132 kV, 220 kV and 400 kV. There are also some substations with transformers with a low voltage side of 60 kV included in the transmission system. International interconnections are also a part of the transmission system. The capacity of the inter-

[33] Source: IEA Wind 2003 Annual Report and IEA Wind Energy 2006 Annual Report.

national interconnections for commercial purposes during the first quarter of 2007 was 1,333MW.

The transmission system operator is REN – Rede Eléctrica, which holds a 50 year concession to operate the electricity transmission system in Portugal. This concession was originally granted in September 2000 and renewed for a 50 year period commencing in June 2007. Furthermore, REN is the only transmission company in Portugal and is responsible for planning, constructing, operating and maintaining the electricity transmission network and managing the technical aspects of the national electricity system. The state has the majority of the capital in REN. The Portuguese law does not allow REN to operate lines of lower voltage than 130 kV.

About 95% of the required financing of REN consists on a percentage, of about 7%, of the liquid value of the grid defined by the regulatory body ERSE. The rest of REN´s needed financing, i.e., approximately 5%, is related to the operation cost of the transmission grid. REN sends to ERSE every year a plan for the investments to be done but from 2007 the plan is to be sent to the Ministry.

2.1.2 Overview of the Distribution System

The national distribution grid is operated through an exclusive concession granted by the Portuguese State. The national distribution grid consists of low, medium, and high voltage networks. Presently, the exclusive concession for the activity of electricity distribution in medium and high voltage, i.e. for voltage levels between 1 kV and 60 kV, has been awarded to EDP Distribuição. The low voltage distribution grids continue to be operated under concession agreements awarded by municipalities primarily to EDP Distribuição.

Until the 31 December 2006, EDP carried out also retail activity. From January 2007 EDP has created, according to the new legislation, a new company for retail. This new company is called EDP servicio universal, EDPSU, and has the obligation to buy all renewable electricity. Renewable electricity is still a very small part of all the electricity EDPSU has to buy to satisfy the demand paying the ex-ante tariff. EDPSU has to pay EDP for using the distribution grid since EDPSU acts as a consumer to EDP. EDPSU delivers about half the energy consumed in the country since the residential consumers choose to stay in the ex-ante tariff since this is lower than the market prices. This means that tariffs paid by consumers do not cover the payments to power producers.

2.1.3 Relevant Legislation for Renewable Electricity Production

In Portugal, as in Spain, producers are classified in two main groups depending on the energy source and the technology used, the special regime and the ordinary regime. Renewable energy sources are included in the special regime while the ordinary regime consists of conventional power plants and is therefore left out of this study.

The special regime was first established by the Decree Law (DL) 189/88. In the special regime it is included cogeneration, renewable energies and waste. The cogeneration has been regulated by a specific Decree Law 186/95 while the electricity production based on renewable sources and waste has been regulated, since the special regime was established, by several Decrees; the DL 313/95, DL 168/99, 312/2001 (connection issues), 339-C/2001 (feed-in tariffs), 33-A/2005 and recently by the DL 225/2007.

There are no limits regarding installed capacity to belong to the special regime. However, for hydro power installations there was a capacity limit of 10 MW, for each installation, according to the decree law 339-C/2001. This limit of 10 MW was changed by the DL 33-A/2005 to 30 MW which has been maintained in the new decree law published in June 2007.

All producers using renewable energy sources are at the moment paid according to the RD 168/99 with its modification made by the DL 339-C/2001. Only producers using biomass or biogas have chosen to move to the DL 33-A/2005.

2.1.4 Regulatory Framework for Network Companies

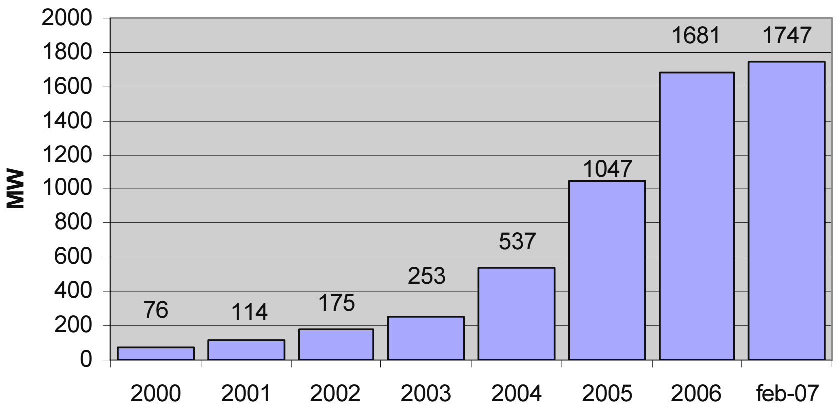
The regulatory body, ERSE, establishes every year the tariffs to be paid by all those agents buying electric power. EDPSU collects the tariffs paid by consumers and pays EDP the corresponding access tariffs.

In the DL 90/2006 it is stated that from year 2007 the additional cost associated to renewable based power production will be paid by consumers in proportion to the number of consumers in each voltage level. Before, the payment of each consumer was proportional to the consumed energy. This makes the cost of renewable supported by consumers with low consumption relatively larger than for consumers with high consumption.

2.1.5 Development of the Wind Power Sector in Portugal

The wind power sector has grown very rapidly under the last seven years in Portugal, especially since the year 2004 as it can be seen in Figure 2-3.

Figure 2-3 Installed wind power capacity in Portugal from year 2000 to February 2007.



Source: Estatísticas rápidas, Fevereiro 2007. Direccao Geral de Geologia e Energia.

On July, 2007 there are 3,750 MW wind power authorized in Portugal, and 1,500 MW that are being allocated through a public tender procedure (see Section 2.4.1). This means a total wind power capacity of 5,250 MW what is above the target of 3,750 MW established in the Resolution of the Council of Ministries RCM 63/2003 for year 2010 and the target of 5,100 MW for year 2013 established in the RCM 169/2005. The political target for wind power in Portugal is comparable with the target in Spain since 5,100 MW with a population of 10.3 million people is about the same as in Spain with an objective of 20,000 MW in 2010 and about 44 million people.

Wind farms in Portugal have an average installed capacity of 12 MW by February 2007[34]. Approximately 75% of all wind farms have an installed capacity between 1 and 25 MW. Wind turbines have an average installed capacity of about 1.6 MW. That is larger than the average in Spain mainly due to the fact that wind turbines in Portugal were installed later than in Spain and a technical development had taken place during that time.

The 60 kV grid is the grid where the main wind power capacity is connected, as it can be seen in Table 2-1.

Table 2-1 Voltage levels at which wind power installations with an installed capacity larger than 10 MW are connected by 31 March, 2007.

Installed wind power with capacity > 10 MW by 31 March 2007						
Voltage level (kV)	**220**	**150**	**60**	**30**	**10**	**Total installed capacity (MW)**
total	154	226	993	46	26	1445
average	39	38	18	8	9	
max	81	114	84	12	14	
min	20	2*	2*	2*	2*	
%	11%	16%	69%	3%	2%	

*In first phase only 2 MW is installed, but the plan is a wind farm larger than 10 MW

Source: REN

In Table 2-1 only connected farms with an installed capacity larger than 10 MW are included. Besides, there is capacity that has been allocated but that is not producing yet. Of those allocated farms 32 will be connected to the 60 kV grid accounting for a total capacity of about 600 MW, 2 to the 150 kV with an installed capacity of 240 MW. This means that the majority of the installed capacity and even the allocated capacity is or will be connected to the 60 kV grid. The allocation of capacity from the tender procedure is not included in the previous analysis. By now, June 2007 there are no wind parks connected to 400 kV and 6 connected to 150 kV. However, new wind farms tend to be connected to the 220 kV grid and in the future it is possible that wind farms will connect to the transmission 400 kV grid.

According to the TSO to fulfill the target of 5,100 MW approximately 60% of the wind power capacity will be connected to the

[34] Estatísticas rápidas, Fevereiro 2007. Direccao Geral de Geologia e Energia.

distribution grid and 40% to the transmission grid. Currently, more than 75% of all wind power capacity is connected to the distribution grid.

Portugal follows a more centralized approach for the development of the wind power sector than for example the Nordic countries since there is one single transmission company and one single distribution company and the Ministry is responsible for allocating the connection capacity both in the transmission grid and in the distribution grid (see Section 2.3.1).

The crucial factor behind the great development of the wind power sector in Portugal is the political desire to create a strong wind power sector materialized in a very attractive payment. The publication of the DL 339-C/2001 increasing considerably the feed-in tariff for wind power producers constitutes a milestone in the development of the wind power sector in Portugal. Applications for about 7,000 MW wind power were made after the publication of that decree. Not all applications were accepted since there was not enough available capacity in the grid to connect all these wind farms and the political target was lower than the capacity of the applications.

Another important factor contributing to the development of the wind power sector in Portugal is, according to the TSO, the connection between the development of the grid infrastructure and the political objective of 5,100 MW wind power installed capacity.

Furthermore, the fact that wind power producers have to pay 2.5% of the incomes from their electricity production to the municipality were the wind farms are located might facilitate the installation of wind farms since they imply an income to the municipality.

In Portugal, it is possible to expropriate land in order to build power lines, substations, and power production installations as long as they are considered as of public usefulness. To build power lines it is not necessary to own the land under it since power lines in Portugal are seen as temporary properties, it is only necessary to buy the land for the support points. In other countries, as for instance Holland, it is necessary to buy even the land under the lines.

2.1.6 Possible Barriers for the Future Development of the Wind Power Sector in Portugal

According to several of the interviewed agents in Portugal, local opposition to visual impact and environmental issues can become barriers for the future development of the wind power sector and for the fulfillment of the political target of 5,100 MW installed capacity wind power by 2013. Up to date, there is no much local opposition but it is growing. According to the interview the lack of investment and technical requirements are not seen as barriers for the development of the wind power sector.

The recently published Decree of Law 225/2007 for electricity production based on renewable sources introduces some changes in order to speed up the process of the environmental impact evaluation. The decree clarifies some procedures and gives time delays for them, however there is no time limit for DGGE (the authority where the process starts) to sent the environmental study to the environment agency (see Section 2.3).

According to the Portuguese Association for Renewable Energies, APREN, project developers see administrative procedures as brakes for the development of the renewable energy sector in Portugal. Time horizons associated to the different procedures and established by Law are not always fulfilled.

2.2 Payment Scheme for Renewable Electricity Production

The payment scheme for producers included in the special regime in Portugal is determined by a quite complex formula that was first introduced year 1988 in the Decree Law 189/88. That formula has been modified by the DL 168/99, DL 339-C/2001, DL 33-A/2005 and recently, May 2007, by the DL 225/2007. The formula defining the payment includes a fixed term which is function of the installed capacity, a variable term which is a function of the produced electric power, and a term to compensate for the environmental impact that is avoided by producers included in the special regime and which depends on the energy source used. Feed-in tariffs are updated every year taking into account the inflation rate.

Besides, producers included in the special regime receive/pay a term for reactive power. Typically, the income/cost due to reactive power is very small, of about 0.01% of the payment producers receive for their production.

As mentioned in Section 2.1.3, all producers using renewable energy sources are at the moment paid according to the RD 168/99 with its modification made by the DL 339-C/2001. Only producers using biomass or biogas have chosen to move to the DL 33-A/2005. Installations which get their licenses for producing electricity after the publication of the 33-A/2005 are paid according to that DL, however, no such wind farms are producing yet. Installations which obtain their licenses from June, 2007 will get paid according to DL 225/2007.

The DL 33-A/2005 modifies the previous legislation on payment schemes for the special regime in some points as for instance, it is established a limit up to which producers can receive the feed-in tariff, the limit is based on produced energy as well as on operating time being the longest 15 years. Beyond that limit, producers in the special regime, according to the DL 33-A/2005, will receive for their electricity production the market price and the price for the green certificates associated to the guarantees of origin. If those certificates are not functioning by the time the limit is reached, then the producers can receive during an additional period of 5 years the feed-in tariff established in the DL 33-A/2005.

According to the Portuguese Association for Renewable Energies, APREN, the comparisons that are made for example by IEA and EUROELECTRIC between conventional power plants and renewable based production regarding production costs and the feed-in tariffs are unfair. For instance, it is not included the fact that emission rights have been donated to a lot of conventional power plants without paying for it, renewable producers have not got such emissions rights. The expectation for electricity prices in the future is that they are going to be higher, that means that conventional electricity producers are going to receive more money while renewable producers are to get the feed-in tariff at an almost constant level. For nuclear power there are many terms that are not included when making such comparisons.

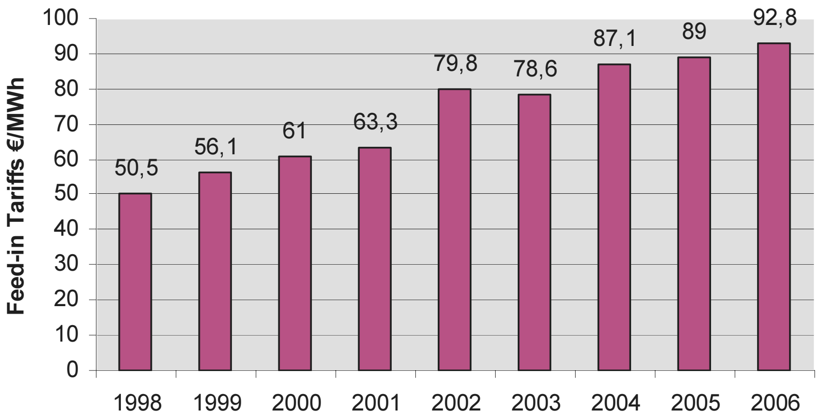
According to APREN it is important to give subsidies to the production and not to the installed capacity since the important thing is that renewable energies cooperate to the production of electricity, there is no meaning of installing wind turbines if they are not efficient or are not producing. In Portugal there were subsidies to installed capacity until year 2005 by means of a program called

PRIME. These subsidies were generally 20% of the total investment cost but no larger than 1.5 million € per project.

2.2.1 Wind Power

The development of the yearly average feed-in tariff paid to wind power producers can be seen in Figure 2-4. Note that the increase of the feed-in tariff for wind power production from year 2002 is a result of the establishment of the DL 339-C/2001 which modifies the DL 168/99. Wind power producers under the DL 168/99 moved to the new feed-in tariff established by the DL 339-C/2001 on January 2002 since the feed-in tariff was significantly higher.

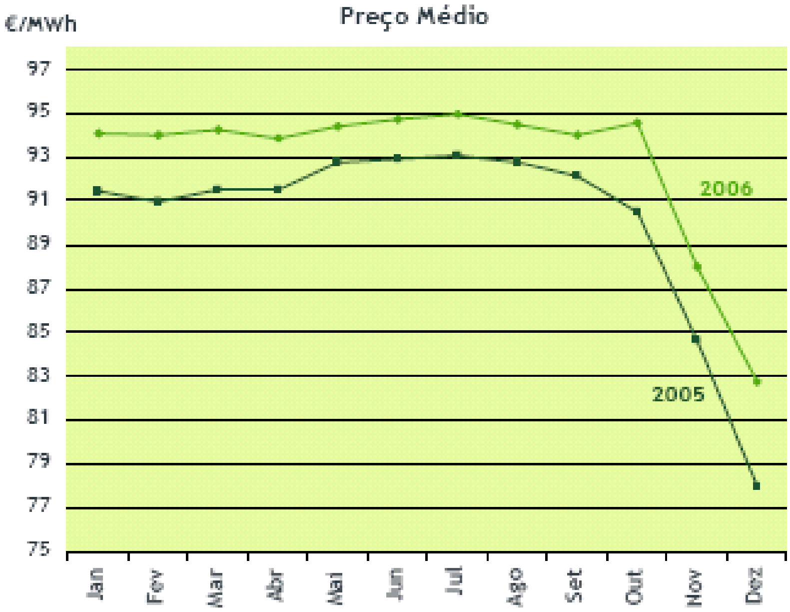
Figure 2-4 Yearly average feed-in tariff paid to wind power producer during the period 1998–2006.



Source: IEA Wind Energy 2006 Annual Report.

The formula defined by the DL 168/99 with the modifications made by the DL 339-C/2001 establishes that the payment for wind power production decreases as the energy production [MWh] per installed megawatt [MW] of the machines increases. Up to 2,000 MWh per MW the payment is at its maximum, between 2,000 and 2,600 the payment decreased to remain at a lowest constant level after 2,600 MWh per MW. That can be seen in Figure 2-5 where the payment for wind power decreases significantly after October each year, when most wind farms have been producing during more than 2,000 MWh per MW.

Figure 2-5 Monthly average payments for wind power production during years 2005 and 2006.



Source: A energia eólica em Portugal 2006, REN.

The Decree Law 33-A/2005 establishes a new feed-in tariff for wind power of about 75 €/MWh, lower than the feed-in tariff established in the DL 339-C/2001. It is the fixed term of the tariff which is reduced in the DL 33-A/2005. Furthermore, the DL 33-A/2005 makes the payment for wind power independent of the energy production per installed megawatt. Note that the lower feed-in tariff introduced by the DL 33-A/2005 cannot be seen in Figure 2-5 since no wind farms are being paid according to that decree yet.

The new Decree Law 225/2007 for the special regime maintains the feed-in tariff for wind power production defined in the DL 33-A/2005, see Table 2-2.

Table 2-2 Feed-in tariffs (c€/kWh) paid to wind power producers according to different legislation.

		DL 339-C/2001	DL 33-A/2005*	DL 225/2007*
Wind power	P≤5 MW	MWh per MW <2,000: 9.1	7.5	7.5
		2,000< MWh per MW <2,200: 8.9		
		2,200< MWh per MW <2,400: 8.7		
		2,400< MWh per MW <2,600: 8.5		
		MWh per MW >2,600: 8.2		
	P>5 MW	MWh per MW <2,000: 8.9	7.3	7.3
		2,000< MWh per MW <2,200: 8.7		
		2,200< MWh per MW <2,400: 8.5		
		2,400< MWh per MW <2,600: 8.3		
		MWh per MW >2,600: 8.1		

*That feed-in tariff will be obtained until a production of 33 GWh per installed MW is reached but no longer than 15 years after the wind farm started producing.
Source: International Energy Agency, Standard Review Portugal 2006 and Portuguese Association for Renewable Energies, APREN.

2.2.2 Solar Power

Before the new Decree 225/2007 was published, no distinction was made between photovoltaic installations on buildings or on the ground. Furthermore, thermal solar installations were not included in the special regime. These were first introduced by the DL 225/2007. According to the DL 339-C/2001 the defined feed-in tariffs will be paid to photovoltaic installations until a total installed capacity of 50 MW is reached in the country. That capacity limit was increased by the DL 33-A/2005 which established a new limit of 150 MW. According to the DL 225/2007 the defined feed-in tariffs will be paid to photovoltaic and thermal installations until the total installed capacity in such installations is below 150 MW. For photovoltaic installations on residential, commercial, services or industrial premises the capacity limit of total installed capacity in the country in order to get the feed-in tariff is 50 MW.

Table 2-3 Feed-in tariffs (c€/kWh) paid to electricity producers based on solar energy according to different legislation.

		DL 339-C/2001	DL 33-A/2005	DL 225/2007
Photovoltaic	P≤5 kW	55.0	44.7*	44.7*
	P>5 kW	31.9	31.6*	31.6*
Photovoltaic located on residential, commercial, services or industrial premises	P≤5 kW	---	---	47.0 **
	5 kW<P≤150 kW	---	---	35.5 **
Thermal solar	P≤5 MW	---	---	27.3
	5 MW<P≤10 MW	---	---	26.8
	P>10 MW	---	---	19.8***

*That feed-in tariff will be obtained until a production of 21 GWh per installed MW is reached but no longer than 15 years after the wind farm started producing.
**That feed-in tariff will be obtained during the first 15 years after the wind farm started producing.
***The government can change this.
Source: Centro de Estudos em Economia da Energia dos Transportes e do Ambiente, CEEETA and Portuguese Association for Renewable Energies, APREN.

2.2.3 Biomass

As it can be seen in Table 2-4 no distinction was made for the different categories of biomass in the legislation from 2001. It was first year 2005 with the DL 33-A/2005 that distinction was made between forestry biomass and animal biomass and landfill gas. This decree of law increased significantly the feed-in tariffs for these energy sources while the feed-in tariff for biogas from digesters was lowered. The recently published decree of law on renewable energy sources, DL 225/2007, distinguishes for the first time biogas generated in digesters and establishes the feed-in tariff for this category double as high as in the former legislation.

According to the DL 33-A/2005 the defined feed-in tariffs will be paid to installations using forestry and animal biomass until the total installed capacity in such installations is below 150 MW. That capacity limit was increased with 100 MW by the DL 225/2007 which establishes a limit of 250 MW. For landfill gas the capacity limit was 50 MW according to the DL 33-A/2005 and has been decreased to 20 MW according to the DL 225/2007. The new decree of law establishes also a capacity limit of 150 MW for biogas generated in digesters.

Table 2-4 Feed-in tariffs (c€/kWh) paid to electricity producers using biomass according to different legislation.

	DL 339-C/2001	DL 33-A/2005	DL 225/2007
Forestry biomass	7.6	11*	10.7***
Animal biomass and landfill biogas	7.6	10.5*	10.2***
Biogas generated in digesters	7.6	5.0**	11.5****

*That feed-in tariff will be obtained during the first 15 years after the installation started producing. That period can be prolonged with 10 more years by the General Direction of Geology and Energy, DGGE. Installations using landfill gas cannot receive feed-in tariff more than 15 years.
**That feed-in tariff will be obtained during the 12 first years after the installation started producing.
***That feed-in tariff will be obtained during the first 25 years after the installation started producing. For installations using landfill gas that period will be 15 years.
****That feed-in tariff will be obtained during the first 15 years after the installation started producing.
Source: Centro de Estudos em Economia da Energia dos Transportes e do Ambiente, CEEETA and Portuguese Association for Renewable Energies, APREN.

2.2.4 Hydropower

Hydropower producers receive according to DL 339-C/2001 a payment of approximately 8.9 c€/kWh. With the legislation adopted in 2005 the feed-in tariffs for hydropower producers with installed capacity between 5 and 10 MW decrease with 15% while hydropower producers with installed capacity larger than 10 MW not exceeding 30 MW can receive a feed-in tariff of 6.4 c€/kWh, see Table 2-5. The new decree law published in 2007 maintains the feed-in tariffs established in the former decree law from 2005 and introduces some changes regarding the period within which hydropower producers can receive feed-in tariffs.

Table 2-5 Feed-in tariffs (c€/kWh) paid to hydropower plants according to different laws.

	DL 339-C/2001	DL 33-A/2005	DL 225/2007
P<5 MW	8.98	8.1*	8.1**
5 MW <P<10 MW	8.80	7.5*	7.5**
P=30 MW	---	6.4*	6.4**

*That feed-in tariff will be obtained until a production of 42.5 GWh per installed MW is reached but no longer than 15 years after the installation started producing. This period can be prolonged by the DGGE for 10 more years.

** That feed-in tariff will be obtained until a production of 52 GWh per installed MW is reached but no longer than 20 years after the installation started producing. This period can be prolonged by the DGGE for 5 more years.
Source: Centro de Estudos em Economia da Energia dos Transportes e do Ambiente, CEEETA and Portuguese Association for Renewable Energies, APREN.

2.3 Application Procedure for Access and Connection to the Grid and Evaluation on Environmental Impact

According to the Association for Renewable Energies, APREN, from the day a project developer for a wind farm sends the first paper to the General Direction of Geology and Energy DGGE, "pre-viability information", until the project developer gets the authorization to start constructing the wind farm, establishment license, it can take between 3 and 7 years (in this period it is included not only the connection procedure but also the environmental impact study and building permission from municipalities). For mini hydropower the same period is between 10 and 18 years. The DL 312/2001 regulates the procedures for connection to the grid. The steps to follow are the following:

1. The project developer sends an application for pre-viability information regarding available capacity of the grid to know whether it is possible to connect the wind farm or not. The content of the application for pre-viability information is defined in annex I in the DL 312/2001.
2. DGGE sends the applications to the TSO (if above 50 MVA) and DSO (if below 50 MVA) who will give a "pre-viability information" (PVI) to DGGE. DGGE has 40 days to give the PVI to the project developer.
3. No later than 70 days after having got favorable pre-viability information, the project developer has to send to DGGE the application on connection point. Wind farms and hydro power stations to be located on sensible environmental areas have a period of a year to send the application on connection point.
4. DGGE has 30 days to answer to the application on connection point. The content of the application for connection point is defined in annex II, Section II in the DL 312/2001. The article 12

in DL 312/2001 establishes the reasons why the application on connection point can be dismissed.

5. The project developer has to make a study of the environmental impact of the wind farm, this study is send to the DGGE who sends it forward to the environmental institute. In practice, from the day the DGGE gets the environmental study until the environmental institute gets it can take between 1 and 6 months.
6. The environmental institute elaborates an evaluation of the environmental impact of the wind farm based on the environmental study and sends to the project developer the so called DIA including a list of restrictions and recommendations.
7. As a response to the DIA the project developer sends the so called RECAP to the environmental institute for its approval.
8. The project developer has to send the application for establishment to the DGGE. According to annex 1 in the DL 168/99, the Ministry of Economy will decide on installations with a capacity larger than 1MW and the Secretary General of Energy will decide when the capacity is below 1 MW.
9. The DGGE gives the authorization for establishment once the environmental institute has written the DIA.
10. With the authorization for establishment and the RECAP approved, the project developer can send to the municipality a request for the authorization of the construction.
11. When the construction of the wind farm is ready then it is time to ask the DGGE for authorization for production. For large farms there are two different authorizations to start producing, the provisional and the definitive. Once the project developer gets the provisional permit it is allowed to start producing. It can take up to several years to get the definitive authorization. According to article 6 in annex 1 in the DL 168/99, authorization for production is evaluated by the regional government when the capacity of the installation is below 10 MW and by the DGGE when the capacity is larger than 10 MW.

As mentioned in Section 2.1.6 the recently published Decree of Law 225/2007 for the special regime introduces some changes in order to speed up the process of the environmental impact evaluation.

There is a special Law for the connection of power installations with a capacity below 150 kW, so called micro-generation, to the low voltage grid (voltage<1kV).

The DL 312/2001 established in its article 23 that project developers have to pay certain deposits and fees associated to the application procedure. The Ministry of Economy defines these deposits and fees through governmental decision, by means of a legal document called Portaria.

The Portaria 62/2002 defines the deposits to be handed in by project developers in the cases established in the DL 312/2001:

- 15 days after having got answer to the pre-viability information application to assure that the developer send the application on connection point, 2,500 €/MW to be paid to the DGGE.
- 15 days after receiving the establishment license to assure that the developer will build the installations, 5,000 €/MW to be paid to the operator of the grid to which the promoter will connect the installation.
- When project developer and grid operator reach an agreement to accelerate the construction of the needed reinforcements of the grid to transport the electricity produced, the amount of the deposit will be agreed between grid operator and project developer. If no agreement is reached then the DGGE will decide but the fee will never exceed half the investment associated to the reinforcement of the grid. The deposit will be paid to the corresponding grid operator.

The deposits will be returned to the project developers no later than 30 days after the condition upon which the deposit was requested is fulfilled or when the obligation cannot be fulfilled by the project developers due to reason beyond its responsibility.

The Portaria 1467-C/2001 defines the fees to be paid by project developers in the cases established in the DL 312/2001. The following fees will be paid to the DGGE of the Ministry of Economy and Innovation:

- Before sending the pre-viability information application, 400 €/MW with a maximum of 8,000 €.
- Before sending the application for allocation of the connection point, 500 €/MW with a maximum of 10,000 €.

2.3.1 Permitting Entities

There is a limit of 50 MW defining which generation plants are to be connected to the transmission grid or the distribution grid. For installed capacity larger than 50 MW the connection is to be done to the transmission grid (150–220 and 400 kV) and for capacity below 50 MW to the distribution grid. There are some exemptions to this rule since there are some parks with installed capacity larger than 50 MW connected to the distribution grid at 60 kV. This criterion is not in the Law but in an agreement between REN and EDP.

It is the Ministry of Economy and Innovation through its General Direction of Geology and Energy (DGGE) who decides on the access to the grid. REN and EDP are technical advisors to the Ministry but it is the Ministry who takes the decision. Both REN and EDP, in the evaluation of available capacity to connect a new producer which they send to the Ministry, can state the lack of capacity as a reason to deny a connection request. The Ministry do not use to question these evaluations. The Laws regulating the connection to the grid are DL 312/2001, DL 68/2002 and DL 172/2006.

The authorization of installations for the production of electric power is, according to annex I in DL 168/99, responsibility of the DGGE. The Ministry of Economy will decide when the installations have an installed capacity larger than 1 MW. Otherwise, the Secretary General will decide.

There is a continuous interaction between DGGE, REN and EDP. They inform each other about available capacity in the grid, new connection points, and applications for capacity. The fact that REN and EDP were a single entity years ago makes the exchange of information between them a natural part in their activity. EDP has more resources available for the evaluation of applications for capacity made by new producers since there are more such applications to the distribution grid than to the transmission grid (see Table 2-1).

2.4 Obligations of Grid companies regarding Grid Access

2.4.1 Available Capacity

The DL 312/2001 removed the previous constraint in the 168/99 and previously in the 189/88 imposed to the maximum installed capacity as 8% of the short-circuit capacity of the network at the connection point. However, EDP maintains the technical criteria, as for instance limits in the capacity to connect, defined in the DL 168/99 for connection to the distribution grid.

After the payment for wind power defined in the DL 168/99 was increased through the DL 339-C/2001, applications for a total capacity of approximately 7,000 MW were sent to the DGGE. Since these applications amounted for a capacity much larger than the political target of 3,750 MW by 2010, the DGGE announced[35] that no more applications for wind power, biomass or photovoltaic were going to be evaluated by the DGGE.

The allocation of capacity is done by the Ministry through the DGGE, not directly by the TSO, REN, or the DSO, EDP. The DGGE takes applications for PVI (see Section 2.3) regarding capacity for the connection to the grid every fourth month getting a certain fee in order to administrate the applications.

It is the DGGE who decides where the different installations for power production are to be connected, that is based on the technical report done by the grid operator. When several project developers want to connect their installations at the same point, it is the DGGE who decides how to allocate the available capacity to the different project developers.

The capacity for the connection of new wind power farms was during the first stage of the wind power development allocated by the so called “prorata” method. This means that if there was a capacity available of 100 MW at the connection point and there were two project developers willing to connect 100 MW each then they got a capacity of 50 MW each.

After the prorata method the Government opened a tender procedure for wind power capacity on February 2005, projects participating in the tender procedure had to be sent to the DGGE by January 2006. The DL 33-A/2005, in its article 8, defines more closely the criteria to apply for the allocation of capacity through the

[35] Despacho 7619-A/2007, http://www.dre.pt/pdf2sdip/2007/04/079000001/0000200002.pdf

tender procedure that was first established in the DL 312/2001 article 14. The detailed selection criteria in the tender procedure were established by the Ministry of Economy and Innovation through its Department of energy[36].

The tender procedure for wind power was divided in two different phases, phase A with a total capacity of 800 MW to be extended to 1,000 MW and with overcapacity of 20% up to 1,200 MW and phase B of 400 MW to be extended to 500 MW and with overcapacity of 20% up to 600 MW. The first phase is concluded and the second phase is being handled at the time, June 2007. Another tender procedure has been done for biomass and it is possible that in the future even a tender procedure for photovoltaic energy is opened.

The tender procedure had four main selection criteria: discount on the feed-in tariff, employment creation, technical requirements, and contribution to the research fond. Project developers could offer a discount to be applied to the feed-in tariff defined in the DL 33-A/2005.

The selection criteria for the tender procedure have been changed since they were published the first time. That due to two main reasons, the first one that some imperfections were identified and the second one that the Government changed just two months after the tender procedure was published.

The selection criteria in the tender procedure are considered by APREN as unfair since the requirements for phase A and phase B are quite different. An example of such difference is that if in the phase A a contribution to the research fond of 35 M€ is expected where the capacity to be allocated is that phase A is 800 MW plus 200 and the requirement for phase B is also 35 M€ even though the capacity to allocated in that phase B is much lower than in phase B, namely of 400 MW plus 100 MW. This means that for phase A, the contribution to the research fond is equivalent to a discount in the feed-in tariff of about 3% while for phase B it implies a reduction of 9%. Those projects which obtain 75 points in the four areas will be selected. Furthermore there is a delay of nine months between phase A and phase B which makes projects in phase B less profitable than projects in phase A since the feed-in tariff decreases with time as described in Section 2.2.1.

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[36] Concurso para atribução de capacidad de injecção de potência na rede do sistema eléctrico de serviço público e pontos de recepção associados para energia eléctrica produzida em centrais eólicas, http://www.dgge.pt/wwwinclude/ficheiro.aspx?tipo=0&id=8557&ambiente=WebSiteMenu

There are some differences in the legislation regulating power production in the ordinary regime and the legislation regulating power production in the special regime. The main difference is that producers in the special regime are treated by the TSO more as a group since they are many more than the number of producers in the ordinary regime. Another difference is that REN can accelerate the construction of for example substations and lines in the case of lack of capacity for the connection of producers in the ordinary regime while this is not done with producers in the special regime since they are so many. However, the main principle that new producers can be connected only when there is capacity at the connection point is the same.

The new decree of law for the special regime DL 225/2007 establishes in its article 3 the possibility for wind power farms with wind turbines able to stand voltage dips to have an overcapacity of 20% at the connection point. The limit in the electric power that can be injected at the connection point is the original capacity limit without taking into account the overcapacity. The Ministry was already applying that criterion even before it was stated in the legislation.

In case of conflicts between the project developer and REN or EDP regarding available capacity in the connection point, it is the DGGE who decides.

2.4.2 Priority Access for Renewable Electricity Producers

In Portugal there is the implicit assumption that installed power plants have priority over newcomers which is rather different than the Spanish approach. By using this pre-emptive approach, the potential for the occurrence of technical restrictions is much smaller in Portugal than in Spain.

During the licensing process for new generation, whether renewable or conventional, to the transmission grid, REN is asked about the ability of the network to transport the energy of the new unit(s). If the installation of a new generator is expected to lead to overloads which would require lowering the production of an existing generator, REN would state that the network cannot accommodate the new entrant and that new investment in the transport infrastructure is needed before the license is granted. If new investments are needed, REN does an assessment of the part of the new investment directly caused by the new generation and the part corresponding to a general improvement of the transport network.

The Portuguese TSO, REN, has not experienced yet (October 2007) the need to restrict wind power production. However, the TSO is concerned about the possibility to have in the future some occasions where the wind power production will be greater than the existing electricity consumption. The restriction in that case will not come from the network but from the system power balance. In the last licensing procedure by means of a tender procedure, see Section 2.4.1, it has been included the possibility for the system operator to require the reduction of wind power during not more than 50 hours per year. Wind power producers will not receive any compensation for these reductions.

Solar power, waves and other renewable electricity production have almost no impact in the Portuguese system. Anyway, they are entitled to produce the licensed power without being interrupted.

2.4.3 Reservation of Transmission Capacity

According to article 12 in DL 312/2001, applications on connection point that cannot be directly approved due to lack of transmission capacity in the grid, can reserve transmission capacity until the construction of the installations included in the plans for the development of the transmission and the distribution grid are carried out. To reserve capacity a deposit has to be handed in by the developer to the DGGE (see Section 2.3).

According to article 7 in DL 312/2001, DGGE can give connection point even when there is not available capacity at the moment if an agreement is reached between the TSO or the DSO and the project developer in order to accelerate the needed reinforcement. In that case the project developer has to pay the additional costs due to the acceleration of the construction of the installations necessary for the reinforcement. When the project developer pays these costs then no deposit is required to reserve that capacity. If no agreement is reached then it is the DGGE who decides the amount of the costs to be paid by the promoter and the TSO or the DSO respectively.

2.5 Costs associated to the Connection to the Grid

In this Section it is described how the different costs associated to the connection to the grid, such as costs for connection installations and upgrades in the distribution or transmission grid are treated in Portugal.

2.5.1 Costs for the Connection Installations

All costs associated to the connecting installations such as line and transformer between the production installation and the connecting point are to be paid by the project developer.

In Portugal the legislation allows the existence of power lines owned by the producer. This is the case with some power lines of 60 kV connecting wind parks to the grid in Portugal. The reason for that is that according to the Law REN cannot operate and maintain any power line with a voltage level below 130 kV. At the same time the distribution company, EDP, does not want to own those lines since there are no customers in the area so the owner of the wind farm has to operate and maintain those power lines. If the power lines were to be owned by the distribution company EDP then they have to maintain the line also.

Regarding cost sharing between different project developers to connect to the transmission grid, there is no law defining the criterion to follow even thought this problem might come up.

According to EDP new producers who take benefit of already existing connecting installations to the distribution grid, should pay proportional to their capacity if they are connected within 5 years after the connecting installations were build.

The installations for connecting the wind farm to the grid are to be paid by the project developers. In the case of lines if there come consumers after the producers have built the line they can be connected to the line and EDP does not pay anything to the producer. In the DL 312/2001 it is written that there is a period of time within which if a new producer connects to the line that other developer has paid then costs for the line have to be shared.

2.5.2 Costs for Reinforcement of the Transmission Grid

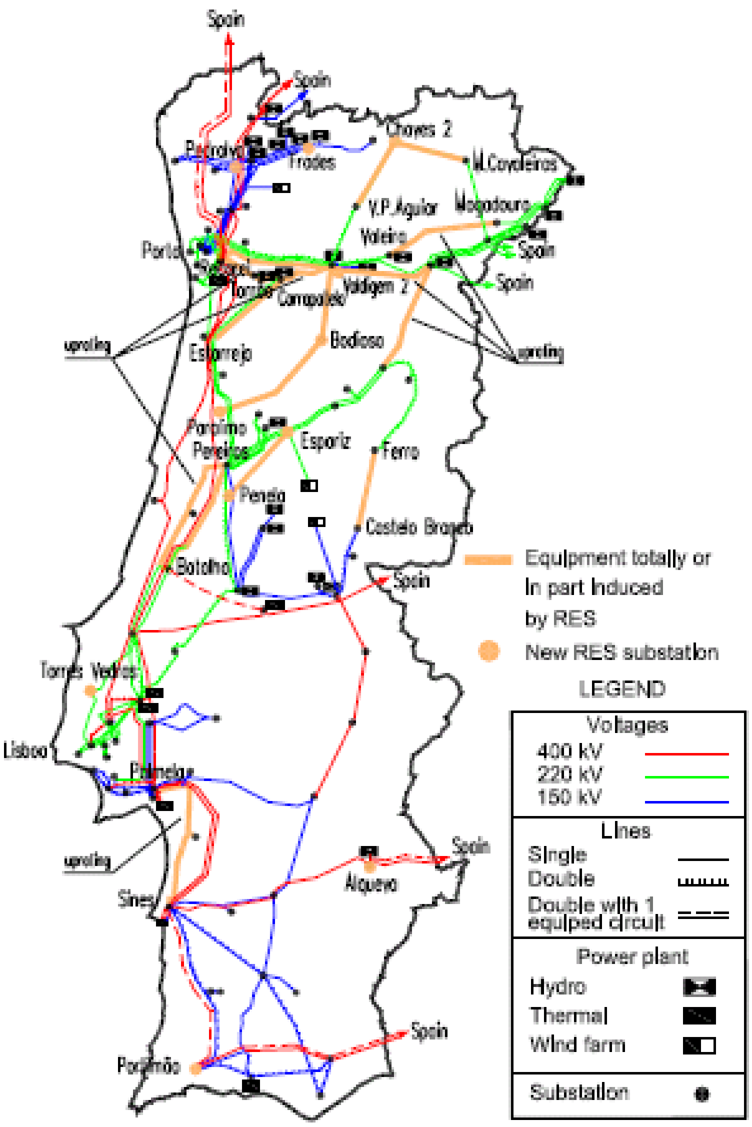
Reinforcement of the transmission grid are socialized and financed through the tariff paid by consumers.

Plans for the development of the transmission grid are developed every second year. The different elements of the transmission grid have different aims. REN estimated in which proportion each element contributes to the different aims such as implementation of renewable production to the system, higher degree of interconnection between the lines and so on. There is no mathematical model used to make the assignation of the different shares.

The last plan for the development of the transmission grid, "Transmission Network Investment Plan for 2006–2011", concluded in November 2005, contains an investment of 190 M€ due to RES generation. In that budget the installation for connecting the parks to the grid are not included since they are to be paid by the project developers.

The main installations to be introduced in the transmission system in order to achieve the political target for wind power in Portugal are shown in Figure 2-6 in orange color.

Figure 2-6 Main investment projects in the Portuguese Transmission grid until 2010, totally or partly induced by the political target for electricity production based on renewable energies (orange color).



Source: REN[37].

[37] Article "National Goals for Renewable Generation in Portugal. An Organizational and Technical Challenge from the point of view of the Transmission System Operator2, Cigré 2006.

2.5.3 Costs for Reinforcement of the Distribution Grid

When connecting to the distribution grid if reinforcements of the grid are needed then the project developer has to pay them even if EDP gets some benefit from the reinforcement. EDP tries to not make agreements with different project developers so that they cannot complain about unfair treatment.

2.6 Costs and Obligations Related to Measurement

Costs associated to measurement for generating units connected to the high voltage grid can be neglected. When it comes to small units connected to the low voltage grid there are no requirements on hourly measurement.

2.7 Grid tariffs

Producers do not pay any tariffs for using neither the distribution grid nor the transmission grid. This has always been like this in Portugal and has nothing to do with the political target of increasing renewable electricity production.

2.8 Rights and Obligations regarding Real-Time Operation

The DL 168/99 establishes in its article 22 that grid companies have the obligation to buy the produced electricity by producers in the special regime. It is EDPSU who buys the electricity from the special regime.
Wind farms installed according to the call for capacity might be disconnected up to 50 hours without being paid. All wind parks might be disconnected when the security of the system is on danger.

At the moment in Portugal there is no obligation for the wind producers to send their planned production to REN. In the tender procedure it was a positive factor but not a requisite. There is however a discussion to make projections obligatory for farms with an installed capacity over 10 MW.

Another very important issue regarding technical requirements is the performance during voltage dips. REN in Portugal and REE in Spain made a study together for 2010 assuming that the targets for installed wind power capacity where to be fulfilled in both countries. Wind turbines are newer in Portugal than in Spain, according to the study in Portugal it was sufficient that new farms had resistance to voltage dips while in Spain it was necessary to modernize 75 % of installed capacity. Those requirements were also based on the assumption that the capacity in the interconnection between Spain and France was increased but since that can take a long time REE and REN decide to impose a common target of 85% of installed capacity with resistance to voltage dips in both countries. This requirement has not been transposed into any Law in Portugal yet. In Spain there are such requirements.

It is important to note that periods with low consumption, good wind conditions and hydro resources are going to be a problem for Spain and Portugal and wind farms are going to need to reduce their production then. That problem would not take place if there was a much larger interconnection capacity with France.

2.9 Conclusions Portugal

General renewable Energy Promotion Scheme

- Renewable electricity producers in Portugal are paid according to a feed-in tariff payment scheme. The feed-in tariff level for wind power year 2006 was 9.28 c€/kWh. However, this payment applies only for wind power producers connected before year 2005. Wind power producers installed after 2005 will receive a feed-in tariff of about 7.5 c€/kWh.

Key factors for the development of the wind power sector in Portugal

- The key factors behind the great development of the wind power sector in Portugal have been a stable investment environment by means of fixed regulated feed-in tariffs, political stability regarding the support to renewable power production, and expansion of the grid in line with the political target for wind power.

Are there any size limits in the regulation for renewable electricity production?

- There are capacity limits for the connection to the transmission grid and the distribution grid. Installations with an installed capacity larger than 50 MW are typically connected to the transmission grid (130–400 kV) while installations with installed capacity below 50 MW are connected to the distribution grid.
- There are some specific requirements for renewable electricity producers regarding the capacity that they can connect to the grid. For example the capacity of installations connected to the low voltage grid cannot exceed 4% of the grids short-circuit capacity at that point and not be larger than 100 kW. For the connection to higher voltage levels the capacity of the installation cannot exceed 8% of the grids short-circuit capacity at that point.

Tariff Structure

- Power producers do not pay any tariffs for using the grid. This has always been like that in Portugal and the same applies for conventional power producers and for power producers using renewable energy sources. Therefore, this issue has not been the factor that has triggered the development of the wind power sector in Portugal.
- In Portugal there is only one distribution company, EDP. It is regulated ex-ante in the legislation the income that EDP receives every year. This is financed by the grid tariffs paid by all agents buying electric power.

Network connection costs

- Project developers have to pay for the construction of the power line, transformer and all other necessary installations for the connection to the grid. There is no difference in this matter between conventional power producers and power producers using renewable energy sources.

- In practice, costs for reinforcement in the transmission grid are socialized and paid by consumers by means of network tariffs while costs for reinforcement in the distribution grid are mostly paid by the project developer.

Priority access for renewable electricity production

- In Portugal there is the implicit assumption that installed power plants have priority over newcomers independently of the energy source used. So far it has not been necessary to curtail wind power production but the last tender procedure for allocating connection capacity allows the Portuguese TSO to curtail wind power producers up to 50 hours without giving them any compensation.

Network Concessions

- In Portugal the power lines within a generating installation and from the installation to the connection point can be built by the producer himself without needing to establish a network company for this purpose. The producer does not have the obligation to connect third-parties to these power lines.

Metering

- There is no obligation on hourly measurement for producers connected to the low voltage grid (<1 kV).

Network Connection Procedures

- Application procedures are well described in Portugal as well as the deadlines associated to different steps of the application procedure. The General Direction of Energy and Geology gives the access permits and is, at the same time, responsible for deciding on conflicts between project developers and grid companies regarding for example connection points.

- Grid capacity for connection to the grid is allocated by the General Direction of Geology and Energy. For wind power two different methods for the allocation have been used. Firstly a pro-rate method (up to 2005) and later (after 2005) a tender procedure. The selection criteria in the tender procedure have been mainly four: discount on the feed-in tariff established in the 2005 legislation (7.5 c€/kWh), employment creation, technical requirements, and contribution to the research fond.

Technical requirements

- There is now legal requirement on fault-ride-through yet for wind turbines in Portugal but this issue is currently being discussed and regulation in this matter is expected.

3 Germany

3.1 Introduction

Germany has a long successful history of developing renewable power generation. A look at the statistics reveals the extent to which the different renewable energy technologies are used in Germany and the dynamic nature of its development, see Table 3-1.

Table 3-1: Development of electricity production from renewable energy as share of total electricity consumption in Germany from 1998 to 2006[38]

1998	1999	2000	2001	2002	2003	2004	2005	2006
4.80%	5.50%	6.30%	6.70%	7.80%	7.90%	9.30%	10.40%	12%

In 2006, 12 % (in total 74 TWh) of the total electricity consumption in Germany was generated by renewable energy. Figure 3-1 shows that in 2006 about 41% (~30 TWh) of the renewable energy generated came from wind power.

[38] "*Erneuerbare Energien in Zahlen – nationale und internationale Entwicklung*", June 2007, Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU), http://www.erneuerbare-energien.de/files/erneuerbare_energien/downloads/application/pdf/broschuere_ee_zahlen.pdf.

Figure 3-1: Renewable energy generation by source, 2006[39]

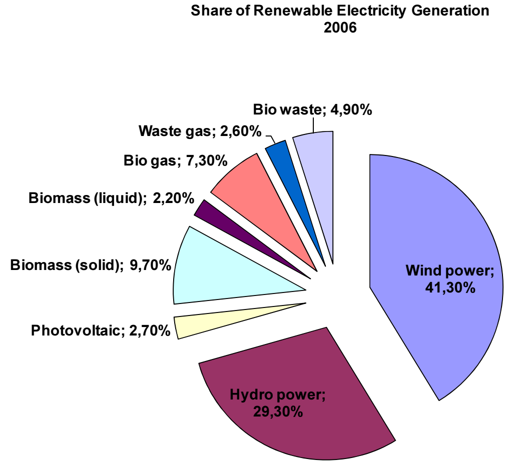


Table 3-2: Development of installed capacity by source from 1990 to 2006. (n.a. = not available)

	Hydro [MW]	Wind [MW]	Biomass [MW]	PV [MW]	Geothermal [MW]	Total [MW]
1990	4,403	56	190	2	0	4,651
1991	4,403	98	n.a	3	0	4,504
1992	4,374	167	227	6	0	4,774
1993	4,520	310	n.a	9	0	4,839
1994	4,529	605	276	12	0	5,422
1995	4,521	1,094	n.a	16	0	5,631
1996	4,563	1,547	358	24	0	6,492
1997	4,578	2,082	400	36	0	7,096
1998	4,601	2,875	409	45	0	7,930
1999	4,547	4,444	604	58	0	9,653
2000	4,572	6,112	664	100	0	11,448
2001	4,600	8,754	790	178	0	14,322
2002	4,620	11,965	952	258	0	17,795
2003	4,640	14,609	1,137	408	0	20,794
2004	4,660	16,629	1,550	1,018	0.2	23,857
2005	4,680	18,428	2,192	1,881	0.2	27,181
2006	4,700	20,622	2,740	2,831	0.2	30,893

[39] ibid.

Table 3-2 and Table 3-3, on the following page, show the rapid development of renewable generation over the past 15 years in more detail. By 2007 Germany has installed the largest amount of wind power world-wide (about 27% of the world capacity) as well as photovoltaic (about 65% of world capacity). Freiburg, a town of 200,000 people in the Black Forest, for instance, has almost as much solar photovoltaic (PV) power installed as the whole of Britain.

Table 3-3: Development of renewable electricity production by source from 1990 to 2006[40]

	Hydro [GWh]	Wind [GWh]	Biomass [GWh]	Biowaste [GWh]	PV [GWh]	Geothermal [GWh]	Total [GWh]
1990	17,000	40	222	1,200	1	0	18,463
1991	15,900	140	250	1,200	2	0	17,492
1992	18,600	230	295	1,250	3	0	20,378
1993	19,000	670	370	1,200	6	0	21,246
1994	20,200	940	570	1,300	8	0	23,018
1995	21,600	1,800	670	1,350	11	0	25,431
1996	18,800	2,200	853	1,350	16	0	23,219
1997	19,000	3,000	1,079	1,400	26	0	24,505
1998	19,000	4,489	1,642	1,750	32	0	26,913
1999	21,300	5,528	1,791	1,850	42	0	30,511
2000	24,936	7,550	2,279	1,850	64	0	36,679
2001	23,383	10,509	3,206	1,859	116	0	39,073
2002	23,824	15,786	4,017	1,945	188	0	45,76
2003	20,350	18,859	6,970	2,162	313	0	48,654
2004	21,000	25,509	8,347	2,116	557	0.2	57,529
2005	21,524	27,229	10,495	3,039	1,282	0.2	63,569
2006	21,636	30,500	16,138	3,600	2,000	0.4	73,874

Similar to the other countries, the German Chapter of this report will concentrate on the issues related to wind power but will also include experience related to network connection/integration learned from other renewable energy technologies.

[40] ibid.

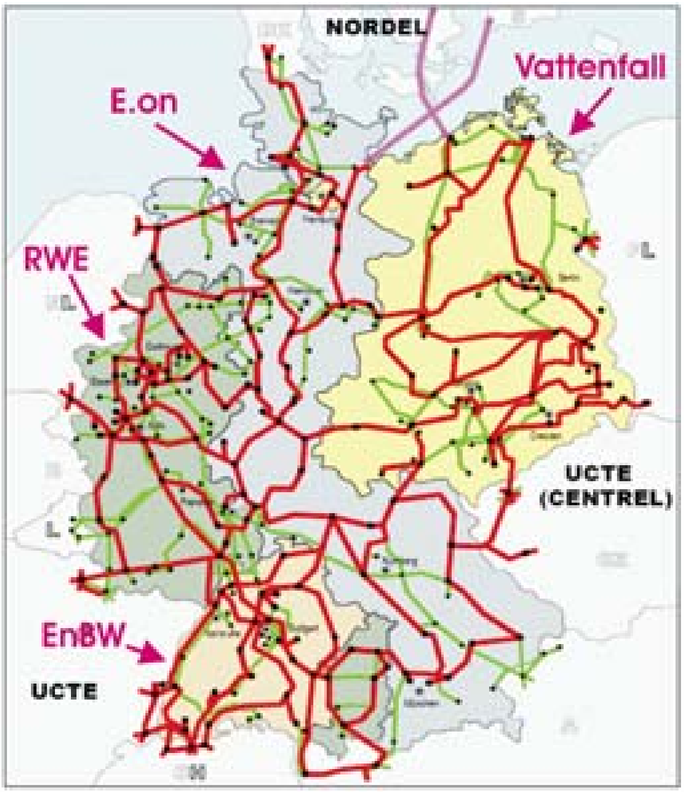
3.1.1 Overview of the Transmission System

Germany presently consists of four transmission system operator (TSOs) which own and operate the high voltage network within their respective regions. The four TSOs are:

- Vattenfall Europe Transmission
- E.on-Netz
- RWE Transportnetz Strom
- EnBW Transportnetze AG

The regional responsibility of each TSO is shown in Figure 3-1. The different renewable technologies are not equally distributed within the German power system. Wind power, for instance, is mainly installed in the windy areas along the coast. Hence, about 48% of the German wind capacity is installed within E.on's region, 37% in Vattenfall's area, 14% in RWE's and only 1% in EnBW's area.

Figure 3-2: The German High Voltage Transmission Network and its TSOs.



3.1.2 Overview of the Distribution Systems

Germany has around 700 operators of distribution networks and 50 operators of regional networks, see Figure 3-3.[41] The companies range from very small network operators for small towns to area network operators covering a number of districts.

Figure 3-3: Schematic geographic representation of German distribution companies. Each small color dot representing a distribution company.

Source: VDN (German Network Association)

[41] http://www.boeckler.de/pdf/wsi_pj_piq_sekstrom.pdf.

The network companies have a mixed ownership, but most of them are municipal companies. They used to have their own power generation (mainly local CHP) and sold the generated power, mainly within the local communities. Nowadays they are unbundled (accounting-wise), so typically a local network company, generator and retailer are still municipal. The deregulation in Germany, however, has increased the number of mergers in the network sector; hence the number of local network companies has decreased from around 900 to around 700 in the past years.

3.1.3 Relevant Legislations for Renewable Energy

The following legislations impact the development of renewable energy in Germany:

- **Renewable Energy Sources Act (2004)**[42]: In April 2000 the first version of the Renewable Energy Sources Act (RES) was put into force by the German parliament, the Bundestag. The Bundestag amended it again on 1 August 2004 with the "Act Revising the Legislation on Renewable Energy Sources in the Electricity Sector". Another update of the RES Act is scheduled for early 2009.

  The Renewable Energy Source Act replaced the Electricity Feed Act,[43] which was in place from 1991 to 2000. In principle the Electricity Feed Act started the development of wind power in Germany by granting priority to wind power by forcing operators of power grids to give priority to electricity fed-in by renewable energies into the grid and to pay a defined, fixed power purchase prices (feed-in tariff) for this. The entry into force of the Renewable Energy Sources Act in the year 2000 has extended this principle to biomass, photovoltaics and geothermal energy.

  The amendment of the Renewable Energy Act (EEG) from 1 August 2004 continued with the basic principle – i.e. compulsory and priority connections of plants generating electricity from renewable energy sources, as well as compulsory and priority purchase and transmission of, and payment for such electricity; but several new articles reinforce consumer protection and aim

[42] Erneuerbare-Energien-Gesetz (EEG), in German: http://bundesrecht.juris.de/bundesrecht/eeg_2004/gesamt.pdf
English: http://www.erneuerbare-energien.de/files/pdfs/allgemein/application/pdf/eeg_en.pdf
[43] Also often translated as Electricity Input Act of 1990 ("Stromeinspeisungsgesetz").

at increasing transparency and reducing the costs inherent to the system. One of these regulations, for example, provides for a public register of plants generating electricity from renewable sources. Also renewable power generation has, in principle, gained the legal right to be connected to the power system, i.e. no separate agreement or contract between a network operator and an operator of a renewable energy plant is required anymore.

- **National Energy Act**: This regulation of the electricity system in Germany prior to start of the liberalization process was based on the National Energy Act of 1935[44]. The central aim of this law was the establishment of a cost-efficient and safe energy distribution.

  In 1998, two years after the EU Directive regarding deregulation was passed, Germany introduced the National Energy Act 1998[45]. The Energy Act defined the legal and regulatory basic principles of the German electricity supply system, hence this Act sets the framework for all non-renewable energy sources. This framework can be summarized as followed:

  - complete liberalization of all segments of the electricity sector.
  - access to the transport network had been regulated by the "negotiated access" through "association agreements between energy producers and industrial consumers" (without a special regulatory agency);
  - unbundling of production and supply segments from the network segment through "separation of accounts".

With the National Electricity Act of 1998 also the regulation of the electricity network was given over to the network companies. The network companies used so called "associations´ agreements" to regulate network access and tariffs. The "associations' agreements", however, caused many legal conflicts concerning the entry to the transmission network for new power producers. In 2003, the Federal Council of Germany demanded an effective control concerning the regulation of the network access, transmission tariffs and demanded a participation of the Federal States in its regulation which was achieved through the National Energy Act of 2005. With the implementation of the regulated access, the

[44] Energiewirtschaftsgesetz von 1935 / EnWG 1935.
[45] Energiewirtschaftsgesetz von 1998.

legal unbundling was fixed and a regulatory agency ("Bundesnetzagentur") was determined.

Since July 2005, the new regulatory agencies have been responsible for regulating and unbundling of the electricity and gas transport segments. One regulatory agency at federal level ("Bundesnetzagentur") is part of the Federal Ministry of Economics and works under its supervision. Additionally, on the level of the Federal States, the respective regulatory agencies are part of the Ministries of Economics of the Federal States ("Landesregulierungsbehörden"). The regulator on Federal State level are responsible for regulating network companies with less than 100,000 electricity or gas customers (incl. end customers), but the Federal States may delegate responsibility to the Bundesnetzagentur.

However, even today questions remain about the detailed tasks of the regulatory agency, i.e. which areas fall within its responsibility. In addition, as the regulatory agency is still in its start-up phase, it currently focuses on certain key tasks and puts very low emphasis on issues related to the Renewable Energy Sources Act such as network upgrade or connection policy related to the RES.

The National Energy Act states that the German government has to develop four additional regulations, which replace issues formerly mainly defined in the "associations´agreements". Three of the four have already been implemented. These are:

- **Electricity Network Access Ordinance**[46]: It defines the general methods of how network companies should measure, document and calculate the actual power flow in the different networks as well as the needed balancing services. This method includes specific regulations of how to include imbalances caused by renewable energies connected to the grid under the RES Act.
- **Electricity Network Charges Ordinance**[47]: It sets the general approach of how to define network charges for transmitting power and how to calculate imbalances between scheduled power delivery and actual delivery.

[46] Verordnung über den Zugang zu Elektrizitätsversorgungsnetzen, or Strom-Netzzugangsverordnung or StromNZV from 25.07.2005, http://www.esw.e-technik.uni-dortmund.de/de/textonly/content/Lehre/Vorlesungen/NEMIII/downloads/StromNZV.pdf

[47] Verordnung über die Entgelte für den Zugang zu Elektrizitätsversorgungsnetzen, or StromNEV from 25.07.2005, see http://www.esw.e-technik.uni-dortmund.de/de/textonly/content/Lehre/Vorlesungen/NEMIII/downloads/StromNEV.pdf (in German).

- **Electricity Network Connection Ordinance**[48]: It defines the legal requirements for network companies to connect customers, i.e. end user, to the distribution network and the corresponding responsibilities such as metering and costs. The ordinance does not apply to generation sources defined in the RES Act.

Finally, the only missing additional regulation is related to the definition of the network tariffs. The German government has suggested to introduce – instead of a cost plus regulation scheme – an incentive regulation scheme starting from January 2009. So far, the German government has only formulated a first draft of this regulation defining the incentive regulation.[49]

Infrastructure Law[50]**:** The law is supposed to speed up infrastructure projects including railway project, motorways and connections to offshore wind farms. It reformulates certain paragraphs in a number of other laws, including the National Energy Act.

In principle the law follows approaches that are similar to those used in Denmark and are under development in the UK, i.e. TSOs are obliged to cover the cost of connecting offshore wind farms to the grid between the offshore substation and the nearest transmission line. This also means that connections to offshore wind farms can be shared by a number of projects, avoiding a situation where each development consortium tries to arrange its own link. Since many farms are planned for a distance of more than 20 kilometres off the coast, grid connection represents a substantial part of their capital cost.

CHP Law[51]**:** The Co-generation Act follows a similar approach as the RES Act, i.e. it guarantees priority grid connection. However, it only provides a bonus payment for the electricity produced, which varies according to the type of CHP-installation and decreases over the years.

The bonus payment is different for different generation and decreased from 1.53 c€/kWh p.a. in 2002 to 0.97 c€/kWh in 2006 for

[48] Verordnung ubre Allgemeine Bedingungen für den Netzanschluss und dessen Nutzung für die Elektrizitätsversorgung in Niederspannung-Niederspannungsanschlussverordung-NAV, 1 November 2006, see http://www.stadtwerke-juelich.de/PDF/TV-N_NAVStrom-NL.pdf (in German).

[49] http://www.bmwi.de/BMWi/Redaktion/PDF/V/verordnung-zum-erlass-und-zur-aenderung-von-rechtsvorschriften-auf-dem-gebiet-der-energieregulierung,property=pdf,bereich=bmwi,sprache=de,rwb=true.pdf

[50] Gesetz zur Beschleunigung von Planungsverfahren für Infrastrukturvorhaben vom 9. Dezember 2006, see http://217.160.60.235/BGBL/bgbl1f/bgbl106s2833.pdf (in German).

[51] Kraft-Wärme-Kopplungsgesetz vom 19. März 2002; see http://bundesrecht.juris.de/bundesrecht/kwkg_2002/gesamt.pdf (in German).

existing CHP-plants, it is 5.11 c€/kWh for new small installations up to 50 kilowatt if continuous operation had started by the end of 2005. Fuel cell plants again have a different bonus payment. See Section 3.2 for comparison to RES Act.

3.1.4 Regulatory Framework for Network Companies

The German regulator, the Bundesnetzagentur, is responsible for regulating and authorizing network companies, including approving network tariffs. Today, the German network companies are regulated on the basis of an ex-ante cost plus approach, i.e. the network companies have to present all relevant costs to the network regulation authorities and suggest a network tariff based on the costs and a certain profit. The regulator must either approve the suggested tariffs or can propose lower tariffs. The procedure is based on an ex-ante system, for instance, the costs that occurred in 2006 are the basis for the network tariffs in 2008. Conflicts between the regulatory agency and the network company regarding tariff setting can go all the way to courts.

Starting in 2009, network tariffs will not be regulated any more on cost basis, but on the basis of an incentive regulation (based on a price-/revenue-cap regulation).

The cost-plus approach means that network upgrading costs, for example due to renewable energy installation, can be fully recovered by the network company as the additional costs will directly result in higher network tariffs. As the development of wind power is mainly concentrated in the costal areas, this potential could result in higher distribution network tariffs in areas with very large amounts of wind energy or other renewable energy.

This point was discussed with the German regulator, VDN (the German network association) and the German wind energy association, and none of these three parties considered this an important issue.[52] The reason for this might be that the required network upgrades are rather limited so far, due to the rather oversized network in former West-Germany. Typically, network upgrades are required in regional networks and hardly in actual distribution networks, so the additional costs are distributed over a large number of customers.

Nevertheless, VDN pointed out that occasionally network companies complain about significant investment costs, resulting in higher

[52] Based on a phone discussion with VDN in June 2007.

network tariffs.[53] However, these are typically individual cases that are not important enough for all network companies to lobby for a different approach. However, with the introduction of an incentive-based regulation approach this will change and VDN already has pointed out that the new regulation approach has to specially include the specifics of network upgrades caused by renewable energy expansion.

In addition, the Bundesnetzagentur commented that higher network tariffs due to network upgrades are not considered an important aspect as public complaints are very limited.[54]

The situation is different for the network connection of offshore wind farms. According to the infrastructure law, the four TSOs are obliged to build and operate the connection between the offshore wind farm and the nearest transmission line onshore. As only the two coastal TSOs are affected by the law, i.e. E.on Netz and Vattenfall Transmission, the additional investment costs would lead to significant differences in network tariffs between those two and the remaining two TSOs. Hence, the infrastructure law (§ 4) requires that the TSOs share the cost proportional to its customers, i.e. each electricity customer in Germany is supposed to pay a similar share of the network connections of the offshore wind farms.

3.1.5 Development of the Wind Power Sector in Germany

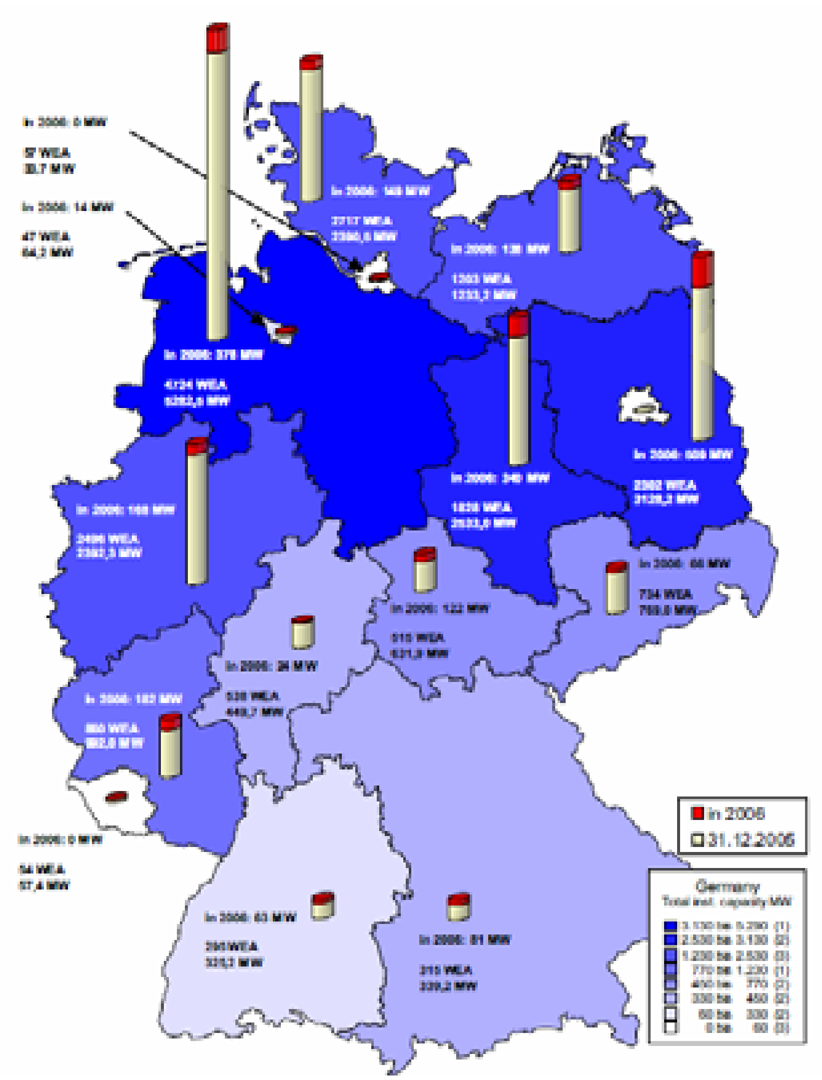
In Germany, the development of wind power started as an independent development of small and medium-sized companies as the large utilities were initially not allowed to own wind power. Even though this was changed later, still today more than 90% of all wind power installed is owned by private individuals, small companies and other independent power producers. Until a few years ago, mainly privat German investors financed wind power projects in Germany; today many wind farms are owned by international investors.

The installation of wind farms took mainly place in form of single wind turbines or clusters of wind turbines, only in the last 2–3 years larger wind farms (up to around 100 MW) have been developed. Hence, almost the entire wind farm capacity installed in Germany is connected to the distribution or regional network.

[53] According to the VDN, those complains focused on Northern Germany in the late 1990, later the impacted network companies were mainly in Eastern Germany and today network companies in South Germany start to complain due to increase number of PV installations.
[54] Based on a phone discussion with, the Bundesnetzagentur in June 2007.

In the beginning of the German wind power development, most of the installations were along the costal lines, later wind power moved more and more inland. Figure 3-4 shows the regional distribution of wind power in Germany in 2006.

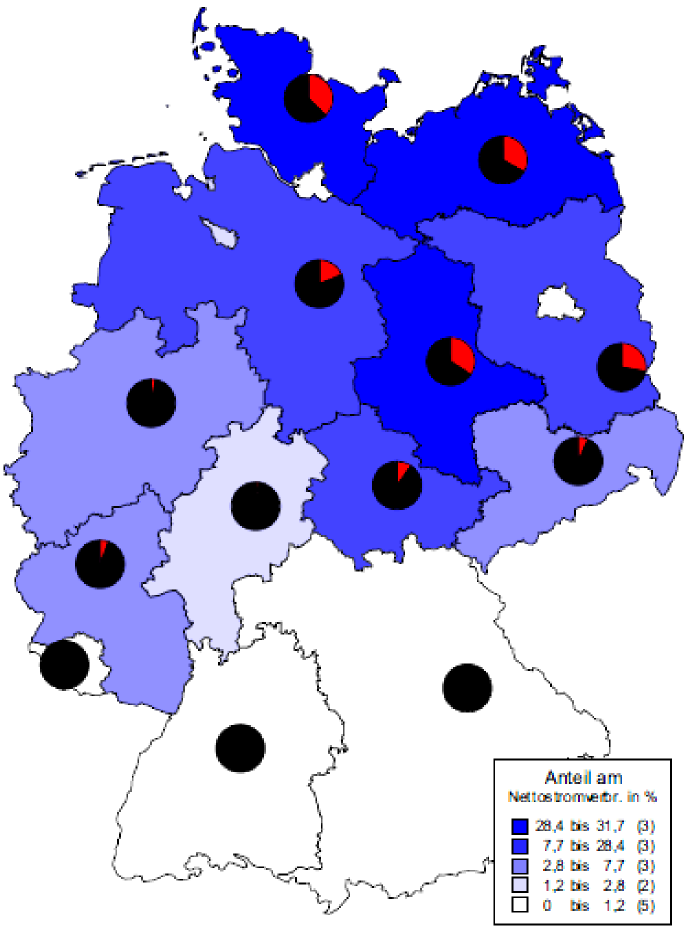
Figure 3-4: Regional distribution of wind power in Germany; in blue total installed capacity; in red capacity added 2006. Status end of 2006[55]



[55] Source: http://www.dewi.de/dewi/fileadmin/pdf/publications/Magazin_30/05.pdf

Figure 3-5 shows the potential regional share of wind power in relation to the net electrical energy consumption of the different States in Germany. It can be seen that wind power plays an important role in the electricity supply, particularly in the coastal areas but also in some inland states.

Figure 3-5: Shares of the potential annual energy yield of the net electrical energy consumption for the Federal States of Germany. Status end of 2006[56]



[56] Source: http://www.dewi.de/dewi/fileadmin/pdf/publications/Magazin_30/05.pdf

Today the wind power industry is an important economic factor in Germany. In 2004, around 64,000 people worked in the German wind sector (57,000 in the bio-energy sector, and another 36,000 in the sectors of solar energy, hydropower, and geothermal energy, so totally 157,000 positions in the renewable energy sector).[57]

About half of all employees are involved in the production and operation of systems and the other half are employed by suppliers or upstream economic sectors like engine construction and electrical device manufacturers, but also including the steel industry as well as company-specific services and the insurance industry.

3.1.6 Future Plans and Possible Barriers for the Further Development of Wind Power

Onshore Wind Power

The annually installed wind power in Germany has dropped from around 3,247 MW in 2002 to about 2,100 MW in 2006. The current predictions for installation of onshore wind power foresee a drop of the annually installed wind power to around 1500 MW. Reasons for this are:[58]

- Limited number of areas that could be used for additional wind power installations;
- The most economic locations are already utilized, it becomes difficult to find economic locations;
- Larger turbine heights, which probably would make some locations economic for wind power installations, are more and more limited by building codes;
- The annual decrease of the feed-in tariff makes it even more difficult to find economic locations; at the same time turbine prices are increasing due to higher raw material costs (e.g. steel) and new requirements outlined in grid codes;
- Network companies have not been able to upgrade the power systems as fast as wind power was growing, hence more and more congestions in the power system slow down the development of wind power. Due to the congestions, curtailment of wind power

[57] Renewable Energy: Employment Effects, Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU), see http://www.erneuerbare-energien.de/files/pdfs/allgemein/application/pdf/employment_effects_061211.pdf

[58] http://www.bmwi.de/BMWi/Redaktion/PDF/Publikationen/Studien/eeg-auswirkungen-der-aenderungen-langfassung,property=pdf,bereich=bmwi,sprache=de,rwb=true.pdf

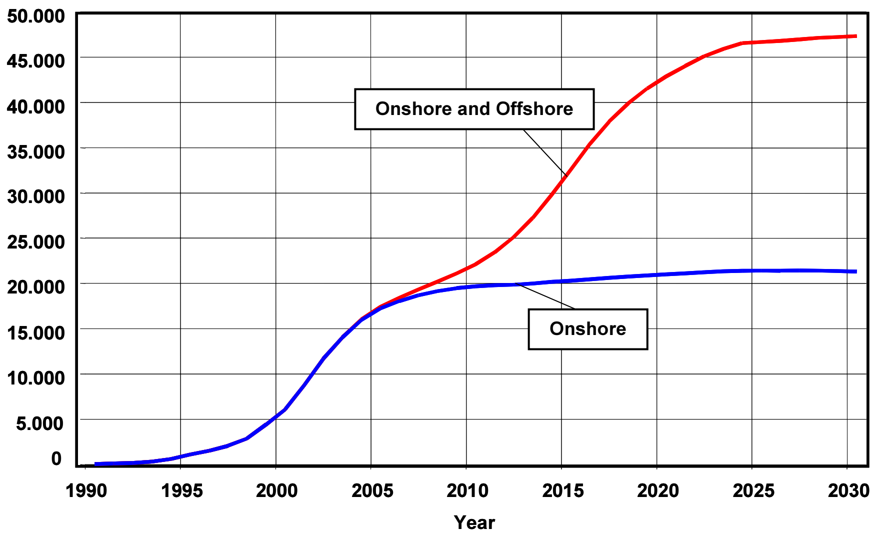
can now be used by network companies to reduce bottlenecks, hence wind farm operators face for the first time the risk of not being able to feed its power generation into the grid, which increases the economic risks for the wind farm operator;

- Repowering, i.e. replacement of old wind turbines with more efficient new wind turbines, often faces similar obstacles i.e. limited network capacity and building codes which limit the possibility to install larger turbines;

Offshore Wind Power

Figure 3-6 shows a forecast by the German Wind Energy Institute of the installed wind power capacity until 2030. The main source of growth here is offshore power generation and that onshore installation will remain quite constant. Which projects will ultimately be implemented is just as vague at the moment as the effects that repowering will have, i.e. the replacement of existing generators by more powerful onshore units.

Figure 3-6: Forecast for the development of wind power in Germany.



Source: Deutsches Windenergie Institut.

Earlier estimates assumed that by 2010 a few thousand MW of offshore wind power will be installed in German water, but so far hardly any project has been built. The first larger offshore project (60 MW) is scheduled for construction in 2008. The early estimates influenced the price setting of the feed-in tariff for offshore wind farms, i.e. the feed-in tariff was set quite high for the years up to 2010 to allow the development of first offshore demonstration projects, see also Table 3-4. After 2010, the offshore wind technology was assumed to be well established, hence the feed-in tariff drops significantly in the following years. As the development of demonstration projects has hardly happened, the German government is discussing to significantly increase the feed-in tariff for offshore wind farms for the years after 2010 for the next update of the RES Act planned for 2008.[59] According to newspaper reports, the first draft of the 2009 version of the RES Act is aiming at a feed-in tariff of 14 c€/kWh for the first years to finally kick-off offshore wind power in Germany. The feed-in tariff will drop to 6.9 c€/kWh after a few years.

The reason for the slow development of offshore wind farms in Germany are:

- Very high initial investment costs due to long distance to shore (~100 km) and large water depth for suitable locations; economics of the projects very uncertain particularly due to rising wind turbine prices;
- Long, complicated and costly permitting process. Nevertheless, so far around 10 projects have been approved for building which would lead to around 3,000 MW (in the first phase). Additional projects currently applying for a building permit could add another 13,000 MW.[60]
- Grid connection issues and responsibility for building a connection to shore was long an open issue. This has changed now with the introduction of the Infrastructure law, see Section 3.1.3.

[59] The first government documents related to 2009 RES Act formulate a renewable energy target in the electricity sector of 27% for 2020 and 45% for 2030.
[60] See also http://www.offshore-wind.de.

3.2 Payment Scheme for Renewable Energy Sources

Since 1991, electricity produced from renewable energy has been reimbursed via a so called fixed feed-in tariffs, i.e. a Government defined nationally fixed minimum purchase price for renewable energy. In April 2000, the Electricity Feed Act, which had been in force since 1991, was replaced by the Renewable Energy Sources Act (RES). The Bundestag amended it again on 1 August 2004 with the "Act Revising the Legislation on Renewable Energy Sources in the Electricity Sector". Another update of the RES Act is scheduled for early 2009.

In the 1990s additional reimbursement, i.e. in addition to Electricity Feed Act payments, could be obtained by joining select projects within the framework of its "250MW of Wind" program. In some cases, the states also granted investment cost subsidies, i.e. using certain wind turbine prototypes in a wind project. This meant that in the early 1990s it was often possible to combine subsidy schemes at the national and state level. The feed-in tariff plus additional subsidies added up to a kilowatt hour reimbursement of 18.31 c€/kWh for wind power in 1991. Considering an average feed-in reimbursement of 7.44 c€/kWh for onshore wind power in 2006, this represents a drop in the reimbursement of wind power of over 59%.[61]

Renewable Energy Sources Act (2004)

For onshore wind power, an initial rate of 8.36 c€/kWh has been set for a minimum of five years for wind turbines which come into operation in 2006. Subsequently, dependent on the specific wind resources on site, the feed-in compensation will be reduced to 5.28 c€/kWh. This reduction will come into effect at sites with very high yields at the end of the fifth operating year whilst the higher price will remain in force at other sites. This means that over the 20 years, dependent on site quality, there will be an average feed-in compensation of between 5.07 and 8.36 c€/kWh. The minimum tariffs decrease, in accordance with the Renewable Energy Sources Act, by a nominal 2% annually for newly operational systems. Thereby a system which becomes operational in 2007 will have an initial

[61] http://www.wind-energie.de/fileadmin/dokumente/Kurzinfos/BWE%20ISET%20Brosch%FCre%20Engl.pdf

rate of 8.19 c€/kWh, which will be reduced to 5.17 c€/kWh after 5 years if they have reached 150% of the reference yield at the planned site. The reference yield is the power production in kWh that a certain wind turbine will produce at a typical inland location with an average wind speed of 5.5 m/s at 30 meters above ground in 5 years. The reference yield is defined for each wind turbine type available in Germany and varying with hub height. The Renewable Energy Sources Act foresees special regulations for re-powering systems and offshore wind power. However, there is no obligation to pay remuneration for wind power systems which do not achieve at least 60% of a defined reference yield at the planned site.

Table 3-4 to Table 3-9 on the following pages list the feed-in tariffs for the different renewable energy technologies based on the RES Act from 2004. It can be seen that a feed-in tariff is defined for almost all renewable energy technologies. One exception exists for hydropower. According to § 6 I RES Act, if the hydropower plant has no spatial connection to a barrage weir with lock or a weir that has entirely or partially already been existing or has been newly built for predominantly other purposes than hydropower generation or contains a full cross lining or if it can be proved that there results an unfavourable ecological state or that the ecological state has not been substantially improved in comparison to the previous situation. According to the regulations of this law, hydropower of more than 5 MW up to incl. 150 MW is only remunerated if the facility has been renewed between 1 August 2004 and 31 December 2012 and if the renewal has resulted in an increase in electrical capacity of a minimum of 15 percent and if after the renewal a proven good ecological state has been achieved or if the ecological state has been substantially improved in comparison to the previous situation.

The feed-in tariff is always paid by the network company to which the renewable generation unit is connected. The network company hands the associated cost over to the corresponding transmission company in the area. The transmission companies pass the costs further on to all retailers in Germany. Each retailer gets a similar share, depending on the number of its customers, and it pays the average feed-in costs of all eligible renewable energy fed into the German power system (calculated on a monthly basis). The idea is that all electricity consumers take a similar share of the renewable energy produced and pay a similar amount of money for it, i.e. the impact of the higher costs for the renewable energy is shared by all consumers. Only certain energy intensive industries receive a special treatment, which means their share of renewable energy is lower.

Table 3-4: Feed-in tariffs for Wind Power based on Renewable Energy Sources Act 2004

Year of Installation	Onshore		Offshore	
	Initial [c€/kWh]	Final* [c€/kWh]	Initial [c€/kWh]	Final** [c€/kWh]
2004	8.70	5.50	9.10	6.19
2005	8.53	5.39	9.10	6.19
2006	8.36	5.28	9.10	6.19
2007	8.19	5.17	9.10	6.19
2008	8.03	5.07	8.92	6.07
2009	7.87	4.97	8.74	5.95
2010	7.71	4.87	8.57	5.83
2011	7.56	4.77	5.71	5.71
2012	7.41	4.67	5.60	5.60
2013	7.26	4.58	5.49	5.49

* Exact time of final reimbursement depends on the reference yield and really achieved yield, at the earliest after five years, though. The initial reimbursement can be extended if the new plant replaces other plants in the same county and at least triples the effect.
** Time of the final reimbursement at the earliest after 12 years and only for plants that have become operative prior to 31 December 2010. An extension of the timeframe depends on the distance to shore and water depth.

Note: Based on the 2000 version of the Renewable Energy Sources Act, the feed-in tariff for the first five years was (after 5 years) 9.10 c€/kWh (6.19 c€/kWh) until end of 2001, for 2002: 9.00 c€/kWh (6.10 c€/kWh) and for 2003: 8.90 c€/kWh (6.00 c€/kWh).

Table 3-5: Feed-in tariffs for Photovoltaic based on Renewable Energy Sources Act 2004

Year of Installation	Installed on or part of a building			Not part of a building			Special Cases
	up to 30 kW [c€/kWh]	> 30 kW to 100 kW [c€/kWh]	> 100 KW [c€/kWh]	up to 30 kW [c€/kWh]	> 30 kW to 100 kW [c€/kWh]	> 100 KW [c€/kWh]	[c€/kWh]
2004	57.40	54.60	54.00	62.40	59.60	59.00	45.70
2005	54.53	51.87	51.30	59.53	56.87	56.30	43.42
2006	51.80	49.28	48.74	56.80	54.28	53.74	40.60
2007	49.21	46.82	46.30	54.21	51.82	51.30	37.96
2008	46.75	44.48	43.99	51.75	49.48	48.99	35.49
2009	44.41	42.26	41.79	49.41	47.26	46.79	33.18
2010	42.19	40.15	39.70	47.19	45.15	44.70	31.02
2011	40.08	38.14	37.72	45.08	43.14	42.72	29.00
2012	38.08	36.23	35.83	43.08	41.23	40.83	27.12
2013	36.18	34.42	34.04	41.18	39.42	39.04	25.36

Note: Based on the 2000 version of the Renewable Energy Sources Act, the feed-in tariff was 50.62 c€/kWh until end of 2001, for 2002: 48.10 c€/kWh and for 2003: 45.70 c€/kWh.

Table 3-6: Feed-in tariffs for Hydro units based on Renewable Energy Sources Act 2004

Year of Installation	For units permited until end of 2007		For existing units that increase its efficency by 15%; payment only for the additional power production due to efficency improvement				
	up to 500 kW [c€/kWh]	> 500 kW to 5 MW [c€/kWh]	up to 500 kW [c€/kWh]	> 500 kW to 10 MW [c€/kWh]	> 10 MW to 20 MW [c€/kWh]	> 20 MW to 50 MW [c€/kWh]	> 50 MW to 150 MW [c€/kWh]
2004	9.67	6.65	7.67	6.65	6.10	4.56	3.70
2005	9.67	6.65	7.59	6.58	6.04	4.51	3.66
2006	9.67	6.65	7.51	6.51	5.98	4.46	3.62
2007	9.67	6.65	7.43	6.44	5.92	4.42	3.58
2008	9.67	6.65	7.36	6.38	5.86	4.38	3.54
2009	9.67	6.65	7.29	6.32	5.80	4.34	3.50
2010	9.67	6.65	7.22	6.26	5.74	4.30	3.47
2011	9.67	6.65	7.15	6.20	5.68	4.26	3.44
2012	9.67	6.65	7.08	6.14	5.62	4.22	3.41
2013	9.67	6.65	-	-	-	-	-

Table 3-7: Feed-in tariffs for Geothermal based on Renewable Energy Sources Act 2004

Year of Installation	up to 5 MW [c€/kWh]	> 5 MW to 10 kW [c€/kWh]	> 10 MW to 20 MW [c€/kWh]	> 20 MW [c€/kWh]
2004	15.00	14.00	8.95	7.16
2005	15.00	14.00	8.95	7.16
2006	15.00	14.00	8.95	7.16
2007	15.00	14.00	8.95	7.16
2008	15.00	14.00	8.95	7.16
2009	15.00	14.00	8.95	7.16
2010	14.85	13.86	8.86	7.09
2011	14.70	13.72	8.77	7.02
2012	14.55	13.58	8.68	6.95
2013	14.40	13.44	8.59	6.88

Note: Based on the 2000 version of the Renewable Energy Sources Act, the feed-in tariff for units up to 20 MW was 8.95 c€/kWh between 2001 and 2004 and for units larger than 20 MW it was 7.16 c€/kWh.

Table 3-8: Feed-in tariffs for Biomass based on RES Act 2004-Part 1

Year of Installation	Biomass excluding the use of wood								Biomass including wood
	up to 150 kW [c€/kWh]	up to 150 kW (CHP) [c€/kWh]	> 150 kW up to 500 kW [c€/kWh]	> 150 kW up to 500 kW (CHP) [c€/kWh]	> 500 kW up to 5 MW [c€/kWh]	> 500 kW up to 5 MW (CHP) [c€/kWh]	> 5 MW up to 20 MW [c€/kWh]	> 5 MW up to 20 MW (CHP) [c€/kWh]	up to 20 MW [c€/kWh]
2004	11.50	2.00	9.90	2.00	8.90	2.00	8.40	2.00	
2005	11.33	2.00	9.75	2.00	8.77	2.00	8.27	2.00	
2006	11.16	2.00	9.60	2.00	8.64	2.00	8.15	2.00	3.78
2007	10.99	2.00	9.46	2.00	8.51	2.00	8.03	2.00	3.72
2008	10.83	2.00	9.32	2.00	8.38	2.00	7.91	2.00	3.66
2009	10.67	2.00	9.18	2.00	8.25	2.00	7.79	2.00	3.61
2010	10.51	2.00	9.04	2.00	8.13	2.00	7.67	2.00	3.56
2011	10.35	2.00	8.90	2.00	8.01	2.00	7.55	2.00	3,51
2012	10.19	2.00	8.77	2.00	7.89	2.00	7.44	2.00	3.46
2013	10.04	2.00	8.64	2.00	7.77	2.00	7.33	2.00	3.41

Note: Based on the 2000 version of the Renewable Energy Sources Act, the feed-in tariff for units up to 500 kW was 10.23 c€/kWh until end of 2001; 10.10 c€/kWh for 2002 and 10.00 c€/kWh for 2003. For units larger than 500 kW and up to 5 MW, the feed-in tariff was 9.21 c€/kWh until end of 2001; 9.10 c€/kWh for 2002 and 9.00 c€/kWh for 2003. For units larger than 5MW and up to

20 MW, the feed-in tariff was 9.21 c€/kWh until end of 2001; 9.10 c€/kWh for 2002 and 9,00 c€/kWh for 2003.

Table 3-9: Feed-in tariffs for Biomass based on RES Act 2004-Part 2

Categories	**a1**	**b**	**a1b**	**a1**	**b**	**a1b**	**a2**	**b**	**a2b**	**a3**	**a3b**
Year of installation	**up to 150 kW**	**up to 150 kW**	**up to 150 kW**	**> 150 kW up to 500 kW**	**> 150 kW up to 500 kW**	**> 150 kW up to 500 kW**	**>150 kW up to 5 MW**	**>150 kW up to 5 MW**	**>150 kW up to 5 MW**	**>150 kW up to 5 MW**	**>150 kW up to 5 MW**
	[c€/ kWh]	**[c€/ kWh]**	**[c€/ kWh]**	**[c€/ kWh]**	**[c€/ kWh]**	**[c€/ kWh]**	**[c€/ kWh]**	**[c€/ kWh]**	**[c€/ kWh]**	**[c€/ kWh]**	**[c€/ kWh]**
2004	17.50	13.50	19.50	15.90	11.90	17.90	12.90	10.90	14.90	11.40	13.40
2005	17.33	13.33	19.33	15.75	11.75	17.75	12.77	10.77	14.77	11.27	13.27
2006	17.16	13.16	19.16	15.60	11.60	17.60	12.64	10.64	14.64	11.14	13.14
2007	16.99	12.99	18.99	15.46	11.46	17.46	12.51	10.51	14.51	11.01	13.01
2008	16.83	12.83	18.83	15.32	11.32	17.32	12.38	10.38	14.38	10.88	12.88
2009	16.67	12.67	18.67	15.18	11.18	17.18	12.25	10.25	14.25	10.75	12.75
2010	16.51	12.51	18.51	15.04	11.04	17.04	12.13	10.13	14.13	10.63	12.63
2011	16.35	12.35	18.35	14.90	10.90	16.90	12.01	10.01	14.01	10.51	12.51
2012	16.19	12.19	18.19	14.77	10.77	16.77	11.89	9.89	13.89	10.39	12.39
2013	16.04	12.04	18.04	14.64	10.64	16.64	11.77	9.77	13.77	10.27	12.27

Categories:

a1: Exclusively biomass from a) plants and parts of plants without processing, b) liquid manure and malt residuum/slop c) substance mix a+b and if the plant is authorized for such substances and if the plant is authorized for such substances and there is no biomass plants of a different variety on the premises for the proportion up to including 500 kW;

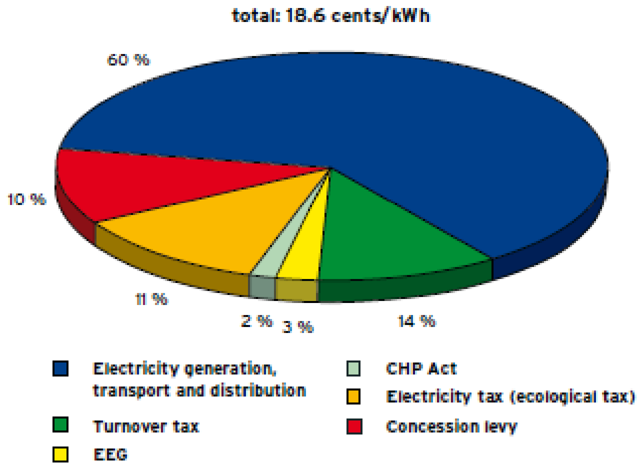
a2: Exclusively biomass from a) plants and parts of plants without processing, b) liquid manure and malt residuum/slop c) substance mix a+b and if the plant is authorized for such substances and if the plant is authorized for such substances and there is no biomass plants of a different variety on the premises for the proportion of 500 kW up to including 5 MW

a3: Use of wood for the proportion of 500 kW up to 5 MW.

b: Exclusively biomass according to biomass regulation without spec. matured timber and plant in CHP operation or biomass production through thermochemical gasification or dry fermentation or if biogas has natural gas quality or if the power is produced through fuel cells, gas turbines, steam engines, organic-cycle plants, multi-substance plants (e.g. Kalina-Cycle plant) or sterling engines.

Figure 3-7 provides an overview of the different cost factors that influence the final electricity price for German consumers. In 2005, the costs of the feed-in tariff added 3% (or 0.56 c€/kWh) to the final power price. In 2006, the costs related to the feed-in tariff increased to 0.7 c€/kWh or about 2.10 € per months for an average household with an annual electricity consumption of 3,500 kWh per year.

Figure 3-7: Composition of the electricity price in the household sector, 2005[62] (EEG = Renewable Energy Source Act).



Average electricity price of a 3-person household with an annual consumption of 3,500 kWh/a in Cent/kWh
CHP Act Combined Heat and Power Act

3.3 Application Procedure for Access and Connection to the Grid

In Germany, non-renewable electricity generators have to individually negotiate access to transmission and distribution grids with the grid operator. A special treatment is defined for renewable energy generators in the Renewable Energy Sources Act § 4. It defines that grid operators shall immediately and as a priority connect plants generating electricity from renewable energy sources and guarantee priority purchase and transmission of all electricity from renewable energy sources.

Due to its importance, the complete Paragraph § 4 of the Renewable Energy Sources Act is included below:[63]

[62] Source: http://www.erneuerbare-energien.de/files/english/renewable_energy/downloads/application/pdf/broschuere_ee_zahlen_en.pdf
[63] Source: http://www.erneuerbare-energien.de/files/pdfs/allgemein/application/pdf/eeg_en.pdf

Article 4
Obligation to purchase and transmit electricity

1) Grid system operators shall immediately and as a priority connect plants generating electricity from renewable energy sources or from mine gas to their systems and guarantee priority purchase and transmission of all electricity from renewable energy sources or from mine gas supplied by such plants. After establishment of a register of installations pursuant to Article 15(3), such obligation for the purchase pursuant to the first sentence above shall apply only if the plant operator has submitted an application for entry into the register. Notwithstanding Article 12(1), plant operators and grid system operators may agree by contract to digress from the priority of purchase, if the plant can thus be better integrated into the grid system. When determining the charges for use of the grid, grid system operators may add any costs incurred in accordance with a contractual agreement pursuant to the third sentence above, provided that such costs are substantiated.

2) The obligation under paragraph (1) first sentence above shall apply to the grid system operator that is most closely located to the plant site and is in possession of a grid technically suitable to receive electricity if there is no other grid with a technically and economically more suitable grid connection point. A grid shall be deemed to be technically suitable even if – notwithstanding the priority established under paragraph (1) first sentence above – feeding in the electricity requires the grid system operator to upgrade its grid at a reasonable economic expense; in this case, the grid system operator shall upgrade its grid without undue delay, if so requested by a party interested in feeding in electricity. If the plant must be licensed in accordance with any other legal provisions, the obligation to upgrade the grid in accordance with the second sentence above shall only apply if the plant operator submits either a license, a partial license or a preliminary decision. The obligation to upgrade the grid shall apply to all technical facilities required for operating the grid and to all connecting installations which are owned by or passed into the ownership of the grid system operator.

3) The obligation for priority connection to the grid system pursuant to paragraph (1) first sentence above shall apply even if the capacity of the grid system or the area serviced by the grid system operator is temporarily entirely taken up by electricity produced from renewable energy sources or mine gas, unless the plant does not have a technical facility for reducing the feed-in in the event of grid overload. The obligation pursuant to paragraph (1) first sentence above for priority purchase of the electricity produced in these plants shall apply only if the capacity of the grid system or the area serviced by the grid system operator is not already used up by electricity produced in other plants generating electricity from renewable energy sources or mine gas which were connected prior to these plants; the obligation to upgrade the grid system without undue delay pursuant to paragraph (2) second sentence above shall remain unaffected. In the event of non-purchase of such

electricity, the grid system operator shall, if so requested by the plant operator, provide proof of fulfillment of the conditions set out in the second sentence above in writing within four weeks and produce verifiable calculations.

4) The relevant data on the grid system and on the electricity generation plants, which are required to test and verify the grid compatibility, shall be presented upon request within eight weeks where this is necessary for the grid system operator or the party interested in feeding in electricity to do their planning and to determine the technical suitability of the grid.

5) The obligation for priority purchase and transmission of electricity in accordance with paragraph (1) first sentence above shall also be applied, if the plant is connected to the grid of a plant operator or a third party who is not a grid system operator within the meaning of Article 3(7) and if the electricity is offered to a grid system in accordance with Article 3(6) via a merely budgeted transit through this grid system.

6) The upstream transmission system operator shall guarantee priority purchase and transmission of the quantity of energy purchased by the grid system operator in accordance with paragraph (1) or (5) above. If there is no domestic transmission system in the area serviced by the grid system operator entitled to sell electricity, the most closely located domestic transmission system operator shall purchase and transmit electricity in accordance with the first sentence above. The first sentence above shall apply *mutatis mutandis* to other grid system operators.

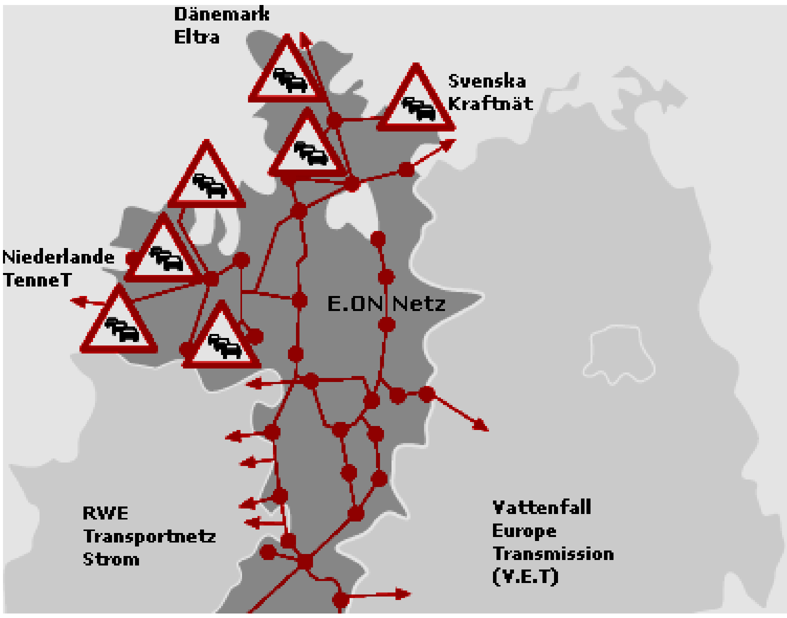
In principle under the Renewable Energy Sources Act a renewable power generation has the legal right to be connected to the power system, i.e. in principle not even a separate agreement or contract should be required anymore between a network operator and an operator of a renewable energy plant. However, based on a recent court decision this legal right applies only to an already installed renewable energy generator, i.e. a renewable energy generator must still negotiate an access agreement if it wants to be sure in advance of how much it can connect and when. This small difference is important, because a network upgrade takes time and no investor will build a wind farm without knowing in advance how much wind power can be connected and when.

From the network operator's perspective the contractual agreement is important because the Renewable Energy Sources Act 2004 (for the first time) allows the network companies to, in principle, curtail renewable energy if this allows more wind farms to be connected to the grid and if both parties agree in advance on this (*RES*

Act: …agree by contract to digress from the priority of purchase, if the plant can thus be better integrated into the grid system.).

Particular E.on Netz, the TSO with the largest share of wind power has defined a number of bottlenecks within its transmission network for times with high wind production and low local load, see Figure 3-8. E.on has signed special contracts with around 1000 MW of wind power since the introduction of the RES Act in 2004 which allows E.on to curtail the wind power in situations with high wind and low load. Of the 1100 MW, about 300 MW are directly connected to E.on's network, the remaining 800 MW are connected to the local distribution network. For the curtailment, E.on sends a signal with the level of power generation allowed to the wind farm operator which then has to confirm receiving the signal and has to act. That means that not E.on actually regulates the wind farm down via remote control, it is the responsibility of the wind farm owner to do so. The curtailment can be used in case of bottlenecks, in case of power system stability risks and during power system maintenance. In 2006, about 1% of the energy production of the participant wind farms was lost due to curtailment. The wind farms are not paid for regulating down their power output.

Figure 3-8: Potential bottlenecks within E.on Netz transmission system.



Source: E.on

Network connection costs, i.e. from the wind farm to the connection point have to be paid by the wind farm operator. The network companies are required to upgrade the network and cover the corresponding costs. This typically results in a conflict regarding the best connection point. According to § 17, paragraph (1) and (2) of the National Energy Act 2005, grid operators are obligated to give access to generation units (and others) as long as *no technical or economic reasons object against it.* This paragraph allows a wide range of interpretation and has caused a large number of court cases. The wind farm lobby argues that in principle even a low voltage system must be upgraded to allow the connection of wind farms, while the network companies typically argue that this is not economically reasonable. The general rule for defining the grid connection point applied for many years was based on the understanding that the total network connection costs, i.e. connection plus upgrade costs, should be minimized independent of who covers which part of the costs.[64]

A new court decision from July 2007 followed the same principle but also defined that a low voltage network must be upgraded to accommodate wind power even if it required the construction of new overhead lines from the connection point to another substation as long as this leads to the lowest overall network connection costs.[65] The argument of the network company was that the new connection is not a network upgrade but part of the network connection, however the court did not accept this argument.

In practice, the network upgrade issue is often solved differently, because the network upgrade based on overhead lines can take years due to very long permit-granting processes. The permit-granting process is typically faster for cabling connections, however they are not considered economically reasonable by the network companies. However, due to declining feed-in tariffs (depending on the year of first connection/operation), time delays have a significant impact on the overall economics of wind farms. Hence, many wind farm operators have decided to take care of the network upgrade issue themselves by building their own cable network to a suitable connection point, often a substation of the next higher voltage level. Some German wind farms have connected different clusters of wind farms to their own cable network to aggregate wind power (up to

[64] Clearingstelle nach §10 Abs.3 Erneuerbare-Energien-Gesetz (EEG), „Vorläufige Handlungsgrundlage“, 08. Mai 2001, http://www.bmu.de

[65] http://juris.bundesgerichtshof.de/cgi-bin/rechtsprechung/document.py?Gericht=bgh&Art=en&az=VIII%20ZR%20288/05

100 MW) and then connect these networks to the high voltage system. Legally, even though some of these connections are 30 to 40 km long, these cable networks are considered part of the wind farm so they are not considered a public grid, i.e. they do not fall under the legal regulations for medium or high voltage networks.

The various laws do not define a clear application process for grid access with timelines or deadlines,[66] but the German Association of network companies has published a guideline for the application and connection of renewable energy systems under the RES Act.[67] The guideline clearly defines which data have to be submitted to the network company and which methods network companies should apply to calculate the possible interconnection capacity for possible interconnection points.

3.3.1 Definition of the Capacity of a Production Installation

While other countries have certain clear definitions what maximum capacity can be connected to which voltage level, such definitions do not exist in Germany. From the technical perspective the VDN guideline[68] regarding network connection is typically used to define the suitable capacity, however, the final decision for a suitable connection point typically depends on the available capacity and the overall costs for network connection and upgrade, see last Section.

The German wind power association, however, points out that often the published data from the network companies are not sufficient to independently verify the technical calculations regarding the available capacity. The regulator points out that in case of complaints, it is the network companies' responsibility to demonstrate how the results where obtained.

[66] A principle timeline is outlined in Artikel 4, paragraph 4, RES Act: "*The relevant data on the grid system and on the electricity generation plants, which are required to test and verify the grid compatibility, shall be presented upon request within eight weeks where this is necessary for the grid system operator or the party interested in feeding in electricity to do their planning and to determine the technical suitability of the grid.*"
[67] http://www.vdn-berlin.de/global/downloads/Publikationen/Fachberichte/RL_EEG_HH_2004-08.pdf
[68] ibid.

3.3.2 Permitting Entities

No generation licence or similar is needed for starting up a renewable energy generation unit. Of course a building permit etc. is needed, but from the power system side only an interconnection agreement is needed (which is – as discussed earlier – legally not really required), which is negotiated with the local network company.

3.4 Obligations of a Grid Company Regarding Grid Access

According to § 19, paragraph (1) of the National Energy Act from 2005 (EnWG 2005) grid operators are obligated to define detailed minimum technical requirements for the grid connection of generation units (both conventional and renewable) and to publish these requirements on the internet. The technical minimum requirements mentioned above differ for each voltage level. At transportation level (110 to 380 kV) the TransmissionCode 2003 and at distribution level (< 110 kV) the DistributionCode sets the requirements.[69]

In addition, according to § 19, paragraph (3), of the same law these requirements must be communicated to the regulatory body (Bundesnetzagentur). According to § 17, paragraph (1) and (2) National Energy Act 2005 grid operators are obligated to give access to generation units (and others) as long as no technical or economic reasons object against it.

On-Site Generation

According to § 18 II National Energy Act, an entity that operates a power generation facility in order to cover its own demand does not fall under the general obligation of a network connection according to Section 1 Clause 1 of National Energy Act. As opposed to this, it results from § 4 V RES Act, that the obligation to purchase and transmit renewable energies even applies if the facility is connected to the network of the facility operator or of a third party that is not a network operator according to § 3 Clause 7 and if the power will

[69] TransmissionCode: http://www.vdn-berlin.de/global/downloads/publikationen/TransmissionCode2003.pdf
DistributionCode: http://www.vdn-berlin.de/global/downloads/publikationen/DistributionCode2003.pdf

be commercially transmitted through this network to a network according to § 3 Clause 6.

In Case of Conflicts

The Bundesnetzagentur, the German regulator, is the arbitrating entity in case of conflicts. According to § 13 I of the National Energy Act individuals and associations of individuals whose interests are substantially affected by the behavior of the operator of a power supply network can request the regulating authority to examine such behavior. The authority has to examine whether the behavior of the operator of power supply networks corresponds to the requirements of the regulations.

Such a claim has to include name, address and signature of the claimant as well as company and headquarters of the respective network operator. Furthermore the behavior of the respective network operator that has to be examined, a list with the individual reasons of why there are serious doubts regarding the legality of the network operator's behavior, and a list with individual reasons of why the claimant is affected by the network operator's behavior. Unless the claim complies with these prerequisites the regulating authority will not admit the claim.

According to § 13 III of the National Energy Act, the regulating authority will make a decision within two months after receiving the complete claim. This period can be extended by another two months after receiving the complete claim. Given the consent of the claimant, this period can be further extended. If – according to Clause 1 – the claim refers to the grid connection of larger new generation facilities, the regulating authority may further extend the period.

3.4.1 Available Capacity

As mentioned before, there are no clear legal rules regarding the definition of available capacity, except the legally non-binding method outlined within a guideline[70] from the network association. Hence, legally network companies are required to upgrade the network for renewable energy sources whenever capacity is not sufficient – as long as *no technical or economic reasons object against it*. Technical

[70] ibid.

limitations are related to § 11 I 1 National Energy Act, which defines that operators of power supply networks are obligated to operate, maintain and – based on demand – extend without discrimination a safe, reliable and efficient power supply network.

3.4.2 Reservation of Transmission Capacity

In principle it is not possible to reserve transmission capacity in the German system. However, renewable energy sources receive a priority treatment, i.e. conventional power plants must reduce their power output or must even shut down in case of network limitation in order to guarantee priority access to renewable power generation. This even applies to large generation plants such as nuclear power stations. This way, renewable energy sources can feed into the power system until the bottleneck is entirely created by renewable energy sources. Hence, earlier connection of conventional power plants does not result in any preference in the access to the grid. A slight conflict occurs between renewable energy sources and CHP sources, which are both guaranteed priority treatment in the relevant laws, however it is not clear which ranks higher in a case where a bottleneck is entirely created by renewable energy sources and CHP.

3.5 Costs Associated with the Connection to the Grid

This is regulated in general in the directive on the access to power supply networks (Strom NEV). According to § 10 I RES Act, also the operators of renewable energy facilities have to bear the grid connection costs themselves. The legal regulations state that the decisive point of reference regarding a decision on who will bear which costs when connecting renewable energy generation facilities is whether it is a grid connection or a grid upgrade.[71] The facility operator has to pay for the grid connection; the distribution as well as the transmission network operator has to pay for a network extension. This rule which is in principle clear is unclear regarding individual cases. Whether an individual case constitutes a network extension or a network connection is not defined by the law and requires an interpretation. Such disputes are typically solved in civil courts. This results from § 102 I National Energy Act, which states that

[71] Different for offshore wind farms, see below.

civil legal disputes resulting from this law fall under the exclusive jurisdiction of the district courts, regardless of the value of the matter of dispute.

§ 4 II 3,4 RES Act also determines that the obligations regarding the network extension include all technical facilities required for network operation as well as connection facilities that are owned by the network operator or that will be transferred to the ownership of the network operator. Also according to § 13 II RES Act, the network operator has to bear the costs required only for network extensions due to newly connected, reactivated, extended or otherwise renewed facilities for power generation from renewable energies or firedamp corresponding to § 4 paragraph 2 on the purchase and transmission of renewable energies.

Currently, network companies can recover the costs for network upgrades via higher network consumer tariffs, see Section 3.1.4. Costs related to network extensions related to offshore wind farms are shared by all transmission companies and recovered via higher network tariffs, see Infrastructure law in Section 3.1.3.

3.6 Costs and Obligations Related to Metering

According to § 21 b I of the National Energy Act the operator of a power supply network is responsible for installing, operating and maintaining the metering equipment as well as for metering the supplied power. However, for renewable energies, the facility operator has, according to § 13 I RES Act, to bear the costs for the metering equipment required for recording the supplied and consumed electric work.[72] The actual metering installation can be done by the network company or any other company.

In principal the metering code 2006[73] of the German network association treats conventional power plants and renewable units similar. The equipment required for installations larger than 500 kW must be capable of providing 15 minute metering. For units smaller than 500 kW the readings will be done once a year. Even for a stand alone renewable energy unit, e.g. a wind farm, the metering equipment must be capable of metering delivered electricity and electricity taken from the grid separately. This also applies for self-generator,

[72] RES Act: ... measuring devices for recording the quantity of electrical energy transmitted and received shall be borne by the plant operator.
[73] http://www.vdn-berlin.de/global/downloads/publikationen//MeteringCode2006.pdf

i.e. residential house with PV equipment; however an aggregated metering (the metering equipment runs backwards in case of delivery of energy into the grid) is in principal possible but requires a special agreement between network company and the operator of the renewable energy unit. Typically, renewable energy operators prefer two separate meterings because the feed-in tariffs are typically higher than the power purchase price for electricity.

3.7 Grid Tariffs

Generators in general are not required to pay network fees or network tariffs in Germany. Until July 2005 there was no legal definition about network tariffs in general in Germany. Until then everyone followed the definition outlined in the associations´ agreement (Verbändevereinbarung II plus)[74] of the German network association that power plants in general are not required to pay any network fee. With the introduction of the National Energy Act of June 2005 and the Electricity Network Charges Ordinance[75], this definition has become legally binding.

3.8 Rights and Obligations Regarding Real Time Operation

This topic is not relevant in Germany because renewable energy operating under the RES Act are not required to consider real time operation, i.e. transmission system operators have to balance renewable energy. The only exception is defined in the grid codes which requires faultride-through of wind turbines in certain situations.

[74] http://www.vdn-berlin.de/global/downloads/Publikationen/vv2plus.pdf
[75] See § 15 Abs. 1 S. 3 StromNEV (Verordnung über die Entgelte für den Zugang zu Elektrizitätsversorgungsnetzen), from 25.07.2005, see http://www.esw.e-technik.uni-dortmund.de/de/textonly/content/Lehre/Vorlesungen/NEMIII/downloads/StromNEV.pdf (in German).

3.9 Conclusions Germany

General Renewable Energy Promotion Scheme

- A special law for renewable energy grants priority access to renewable energy by forcing operators of power grids to give priority to electricity fed-in by renewable energies into the grid and to pay a defined, fixed power purchase prices (feed-in tariff) for this. Based on this law, conventional power plants have to regulate down their production in case of network bottlenecks or access production to guarantee priority production to renewable energy.

Any size limit in the regulations for renewable energy?

- In general, there are no size limitations such as the 1.5 MW regulation in Sweden. However, the feed-in tariff paid to different renewable energy sources can vary depending on the installed capacity. This is particular the case for biomass, geothermal, photovoltaics and hydro power, but not for wind power. Additional size definitions are used in the definitions for meeting requirements.

Tariff Structure

- Generators in general are not required to pay network fees or network tariffs in Germany. This rule was always applied for conventional as well as for renewable power generators, hence grid tariffs played historically no role in the energy policy to promote renewable energy technologies.

Network upgrade costs

- In principal renewable energy generators are required to pay the costs for the grid connection, i.e. all costs from the wind farm to the connection point, and grid companies are required to pay all network upgrading costs. The issue is typically the definition of the best grid connection point. The general rule for defining the grid connection point applied is based on the understanding that the total network connection costs, i.e. connection plus upgrade costs, should be minimized independent of who covers which part of the costs. This could mean that a low voltage network must be upgraded to a high voltage network if this is the most economic solution, but it is also possible that the wind farm operator must build a long line itself to a suitable connection point if this is more economic than upgrading the existing network.

Network concessions

- Network concessions also exist in Germany, however, wind farms can build their own network for the sole purpose of connecting the wind farm to the power system. These wind farm networks are treated as industrial networks, i.e. the rules and regulations of distribution or transmission networks do not apply to these industrial networks.

Network Connection Procedure

- The procedure is not clearly described, but the network association has developed a guideline for the network companies of how to deal with applications. The relevant law defines that *"Grid system operators shall immediately and as a priority connect plants generating electricity from renewable energy sources"*, hence applications can complain to the German regulator in case of delays and the network company then has to explain to the regulator what caused the delays.

Metering

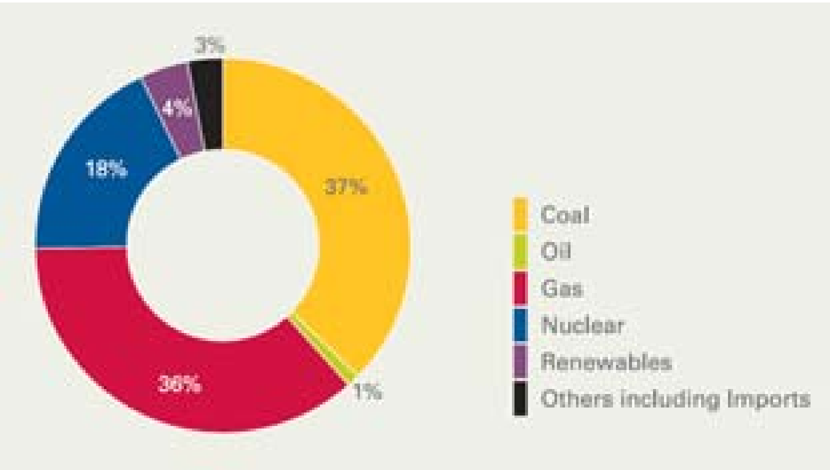
- Renewable generators larger than 500 kW need 15 minute metering systems, metering im/export separately. For small generators only a continuous metering system is required but also measuring im/export separately.

4 United Kingdom

4.1 Introduction

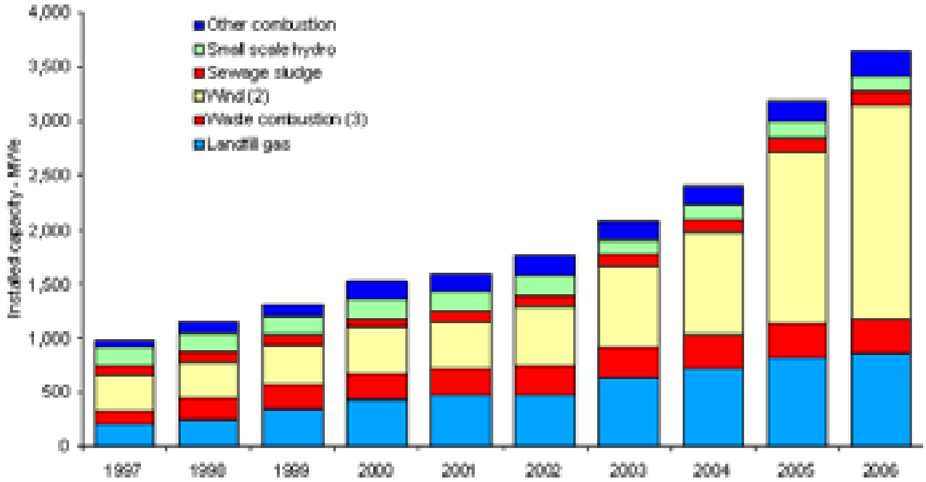
The United Kingdom (UK) has currently around 76 GW of electricity generation capacity to meet an annual consumption of about 350 TWh and winter peak demand of about 63 GW. The UK has also a diverse electricity generation mix. In 2006, 36% was generated by gas-fired power stations, 37% from coal, 18% from nuclear, and 4.5% from renewables, see also Figure 4-1.

Figure 4-1: UK Electric Energy Production in 2006.



Source: http://www.berr.gov.uk/files/file39569.pdf.

Figure 4-2: Electrical Generating Capacity of Renewable Energy from 1997 to 2006 (excluding large scale hydro, which had a capacity of 1,369 MWe in 2006; (2) Wind includes both onshore and off-shore and also includes solar photovoltaics (9.9 MWe in 2006) and shoreline wave (0.5 MWe in 2006); (3) All waste combustion plants are included because both biodegradable and non-bio-degradable wastes are burned together in the same plants.

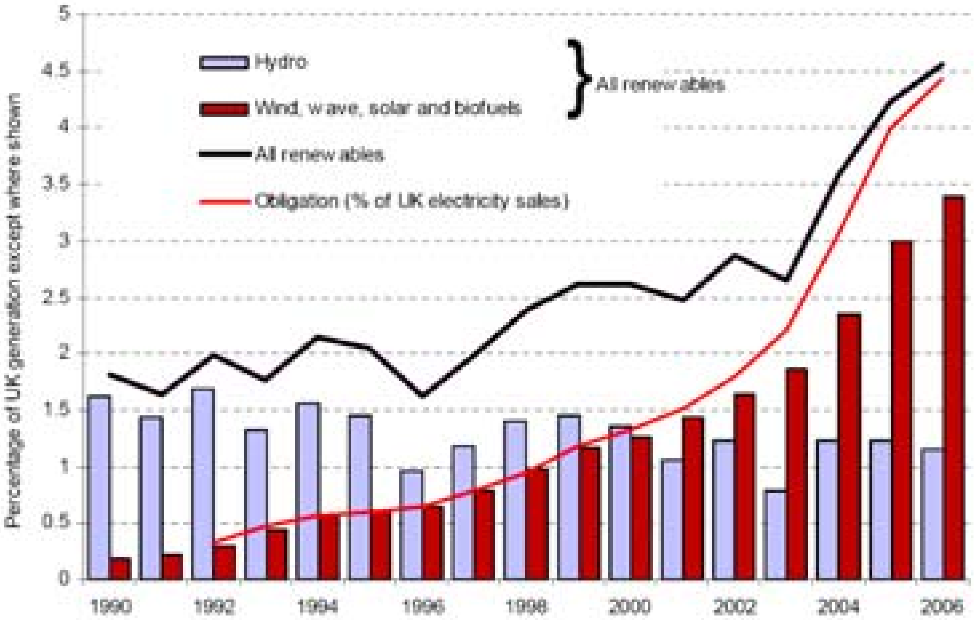


Source: http://www.restats.org.uk/capacity.htm.

Figure 4-2, shows the development of renewable energy installations, excluding large hydro power, from 1997 to 2006. Even though the installed capacity of renewables (excluding large hydro power) increased from 1000 MW in 1997 to more than 3600 MW in 2006, see also Table 4-1, the installed capacity is still small compared to other European countries, e.g. Germany.

In 2006, renewables provided 4.55 per cent of the electricity generated in the UK and total electricity generation from renewables amounted to 18,133 GWh, an increase of 7.5 per cent on 2005. This number includes the electricity generation of large hydro power stations, see also Figure 4-3. Without large hydro stations, the share of renewables was only 3.5%, see also Table 4-2.

Figure 4-3: Growth in Electricity Generation from Renewables since 1990.



Source: http://www.berr.gov.uk/files/file40156.pdf

The main contributors to the 7.5 % increase in renewable energy production between 2005 and 2006 were onshore wind (+43 per cent), offshore wind (+62 per cent), landfill gas (+3 per cent) and municipal solid waste combustion (+12 per cent). There was no increase in co-firing of biomass with fossil fuels and a decrease (-8 per cent) in large scale hydro generation which can be attributed to drier weather. Only 23 per cent of generation from renewables was from large scale hydro in 2006 compared with 26.5 per cent in 2005. Hydro (taking both large and small scale together) remains the most important renewables technology in output terms closely followed by landfill gas and wind (both onshore and offshore), with the co-firing of biomass the next most prominent.

Due to the importance of wind power and similarly to the other countries, the UK Chapter of this report will concentrate on the issues related to wind power but will also include experience related to network connection/integration gathered from other renewable energy technologies.

Table 4-1: Installed capacity of Renewable Energy Sources in the UK from 1998 to 2006.[76]

Installed Capacity (MWe)	1998	1999	2000	2001	2002	2003	2004	2005	2006
Wind:									
Onshore	331.3	357.0	408.0	423.4	530.6	678.4	809.4	1 351.2	1 650.7
Offshore	-	-	3.8	3.8	3.8	63.8	123.8	213.8	303.8
Shoreline wave	-	-	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Solar photovoltaics	0.7	1.1	1.9	2.7	4.1	6.0	8.2	10.9	9.9
Hydro:									
Small scale	171.1	176.7	183.6	188.7	194.2	130.0	142.9	157.9	153.0
Large scale *1)*	1 413.0	1 413.0	1 419.0	1 440.0	1 396.0	1 354.5	1 355.9	1 343.2	1 368.6
Biofuels and wastes:									
Landfill gas	245.1	343.3	425.1	464.7	472.9	619.1	722.2	817.8	856.2
Sewage sludge digestion	89.8	91.3	85.3	85.0	96.0	100.6	119.0	127.9	122.8
Municipal solid waste combustion	204.1	229.6	253.2	260.0	278.9	298.8	307.4	321.4	326.5
Other *2)*	108.0	108.0	157.0	157.0	176.5	183.9	176.3	186.1	221.3
Total biofuels and wastes	647.0	772.2	920.6	966.8	1 024.3	1 202.4	1 324.8	1 453.2	1 526.8
Total	**2 563.1**	**2 720.0**	**2 937.4**	**3 025.9**	**3 153.6**	**3 435.5**	**3 765.4**	**4 530.7**	**5 013.3**
Co-firing *3)*	-	-	-	-	..	92.4	146.2	308.8	310.2

1) Excluding pumped storage stations. Capacities are as at the end of December.
2) Includes the use of farm waste digestion, waste tyres, poultry litter, meat and bone, straw combustion, and short rotation coppice.
3) This is the proportion of fossil fuelled capacity used for co-firing of renewables based on the proportion of generation accounted for by the renewable source.

[76] Source: http://www.dti.gov.uk/energy/statistics/source/renewables/page18513.html

Table 4-2: Electricity generated from Renewable Energy Sources in the UK from 1998 to 2006.[77]

Generation (GWh)	1998	1999	2000	2001	2002	2003	2004	2005	2006
Wind:									
Onshore *1)*	877	850	945	960	1 251	1 276	1 736	2 501r	3 574
Offshore *3)*	-	-	1	5	5	10	199	403	651
Solar photovoltaics	-	1	1	2	3	3	4	8	7
Hydro:									
Small scale *1)*	206	207	214	210	204	150r	283	444r	477
Large scale *2)*	4 911	5 128	4 871	3 845	4 584	2 987r	4 561r	4 478r	4 128
Biofuels:									
Landfill gas	1 185	1 703	2 188	2 507	2 679	3 276	4 004	4 290	4 424
Sewage sludge digestion	386	410	367	363	368	343	379	400	463
Municipal solid waste combustion *4)*	849	856	840	880	907	965	971	964	1 083
Co-firing with fossil fuels	-	-	-	-	286	602	1 022	2 533	2 528
Other *5)*	234	460	487	776	840	937	927	849r	797
Total biofuels	2 654	3 429	3 882	4 526	5 080	6 122	7 302	9 036r	9 295
Total generation	**8 648**	**9 616**	**9 914**	**9 549**	**11 127**	**10 548r**	**14 085r**	**16 870r**	**18 133**
Non-biodegradable wastes *6)*	583	559	519	528	545	579	583	578	651
Load factors (per cent) 7)									
Onshore wind	30.7	28.2	28.2	26.4	29.9	24.1	26.6	26.4r	27.4
Offshore wind (from 2004 only)	..	..	..	..	..	..	24.2	27.2	27.2
Hydro	36.8	38.4	36.4	28.7	34.0	23.3r	37.1r	37.5	34.8
Biofuels and wastes (excluding co-firing)	65.7	64.1	58.6	61.1	61.2	62.5	62.0	58.2	56.8
Total (including wastes)	42.5	44.0	41.9	38.6	42.1	36.5r	43.3r	41.0r	38.9
Load factors on an unchanged configuration basis (per cent)									
Onshore wind	30.9	30.5	29.1r	25.6	28.4r	26.2r	29.2	28.1r	26.7
Offshore wind (from 2006 only)	..	..	..	..	..	..	..	..	27.5

1) Actual generation figures are given where available, but otherwise are estimated using a typical load factor or the design load factor, where known.
2) Excluding pumped storage stations. Capacities are as at the end of December.
3) Latest years include electricity from shoreline wave but this amounts to less than 0.05 GWh.
4) Biodegradable part only.
5) Includes the use of farm waste digestion, poultry litter combustion, meat and bone combustion, straw and energy crops.

[77] Source: http://www.dti.gov.uk/energy/statistics/source/renewables/page18513.html

6) Non-biodegradable part of municipal solid waste plus waste tyres, hospital waste and general industrial waste.
7) Load factors are calculated based on installed capacity at the beginning and the end of the year.

4.1.1 Overview of the Transmission System

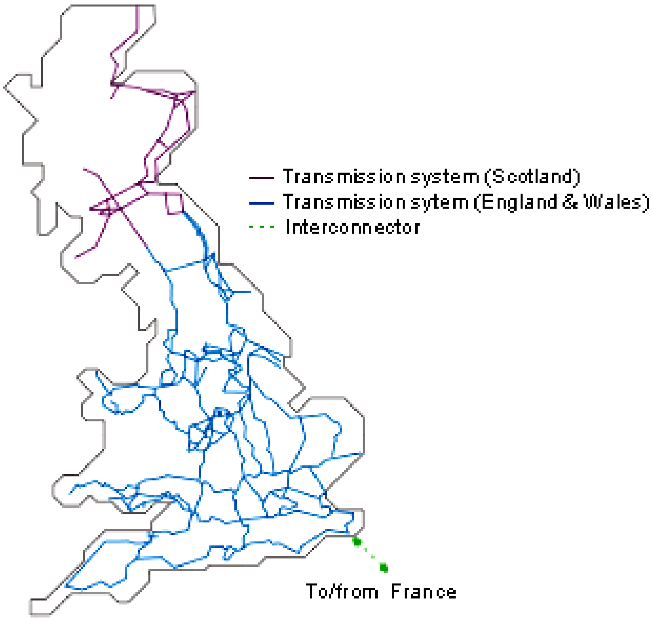
The power system in Great Britain (GB), i.e. England, Wales and Scotland, can be considered almost an island power system, taking into account the rather small connections to Northern Ireland (500 MW HVDC) and to France (2000 MW HVDC) in comparison to the overall installed capacity of 76 GW in GB.

The transmission system in England and Wales is owned by National Grid Transmission (NGET) and the transmission system in Scotland is owned by two companies, Scottish Power Transmission Limited (SPTL) for Southern Scotland, and Scottish Hydro-Electric Transmission Limited (SHETL) for Northern Scotland. Figure 4-4 shows the transmission network owned by National Grid in blue, while the Scottish network owned by SPTL and SHETL is shown in red.

National Grid is the transmission system operator in GB, i.e. National Grid is responsible for managing the operations of its own transmission network in England and Wales as well as, since April 1, 2005 the electricity transmission network in Scotland.

A detailed map of the transmission system in England, Wales and Scotland is shown in Figure 4-5. The map also indicates the distribution areas and the relevant distribution companies (see next Section for details) as well as the main generation sources/locations.

Figure 4-4: The High Voltage Transmission Network in England& Wales and Scotland.



The transmission system operator and each transmission owner operate based on a license from Ofgem (Office of Gas and Electricity markets), the regulatory body in the GB. They are subject to regular price controls, see Section 4.1.4.

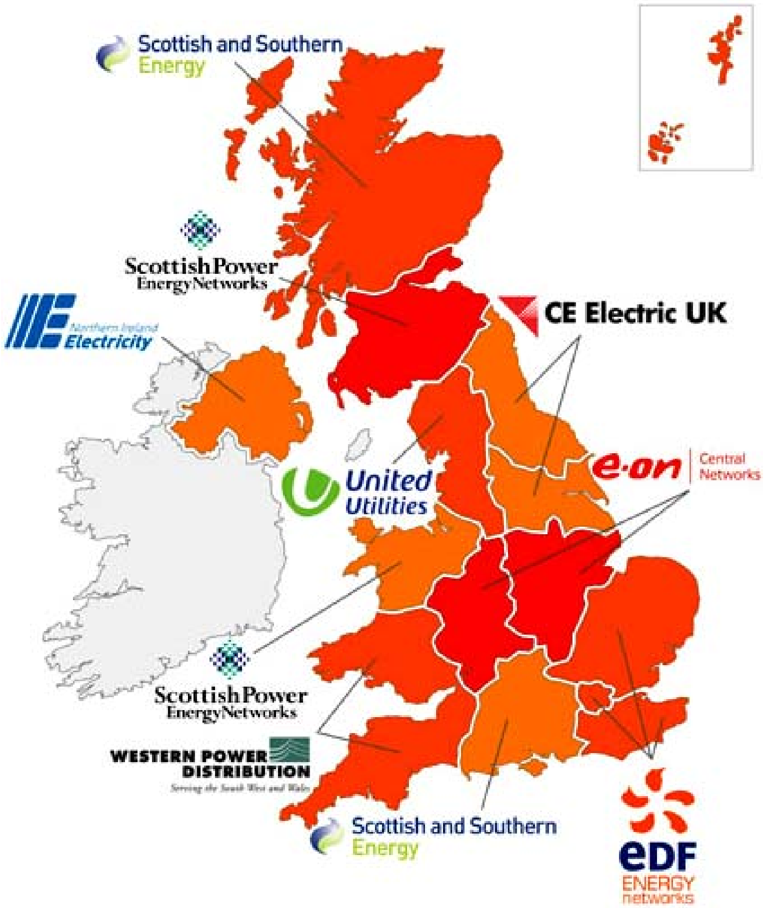
Figure 4-5: The High Voltage Transmission Network in England, Wales and Scotland. The map also indicates the distribution areas and the relevant companies as well as the generation sources/locations.

Source: http://www.berr.gov.uk/files/file32776.pdf

4.1.2 Overview of the Distribution Systems

Ofgem has licensed 13 distribution network operators (DNOs) in GB (14 including Northern Ireland) each responsible for a distribution service area. DNOs came into existence on 1 October 2001, evolving from ex-Public Electricity Suppliers. These companies have distribution service areas corresponding to the areas in which they were formally the incumbent. Within these areas they have certain license obligations, see Section 4.1.4. The 14 DNOs are owned by seven different groups, see Figure 4-6 for details.

Figure 4-6: Schematic representation of distribution companies in Great Britain.



In addition, there are four independent licensed network operators that own and run smaller networks embedded in the DNO networks, called Independent Distribution Network Operators (IDNO). An IDNO is any electricity distributor with a license granted after 1 October 2001. The Utilities Act 2000 amended the Electricity Act 1989 and introduced distribution as a separate activity requiring authorisation. Ofgem is responsible for granting licenses to distribution companies. IDNOs own and operate electricity distribution networks which will predominately be network extensions connected to the existing distribution network, e.g. to serve new housing developments. IDNOs do not have general distribution service areas.

Ofgem has issued four distribution licenses to IDNOs so far:[78]

- Laing O'Rourke Energy Ltd
- Independent Power Networks Limited
- Energetics Electricity Ltd
- The Electricity Network Company Ltd

An alternative arrangement is a private network. This private network allows distributed generation to be connected directly to this network and allows a certain amount of unlicensed generation and supply to take place completely outside the main market. A private network is exempt from the licensing regime when it:[79]

- distributes without any limitation electricity over private wires to business customers, and up to 2.5 MW to domestic customers – exemption from the requirement of a distribution license;
- supplies electricity directly to customers up to a maximum of 5 MW in aggregate of which no more than 2.5 MW can be supplied to domestic customers – exemption from the requirement of a supply license.
- generates no more than 50 MW (or no more than 100 MW with Secretary of State approval) – exemption from the requirement of a generating license;

The benefit of this approach is that the unlicensed operator is able to avoid a number of costs that a licensed energy supplier usually would incur. In particular, the unlicensed operator avoids the costs

[78] Applications from ECG (Distribution) Ltd and UK Utilities (Electricity) Ltd are currently being considered. http://www.ofgem.gov.uk/Networks/ElecDist/Policy/IDNOs/Pages/IDNOs.aspx
[79] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistGen/Documents1/15939-193_06.pdf

related to the Renewables Obligation, the Climate Change Levy, and the Energy Efficiency Commitment.

4.1.3 Relevant Legislations

The United Kingdom consists of four constituent countries: England, Wales, Scotland and Northern Ireland. In the following, only England, Wales and Scotland, i.e. Great Britain – which partly have different legislations related to the electricity sector – will be analyzed. Statistical data may, however, include all four countries.

The deregulation and liberalisation in the UK power industry started with the Electricity Act of 1983 which abolished the legal monopoly by opening up the grid and allowing wholesale wheeling between independent generators and retail customers. However, no competitive market developed. In February 1988, the British government published a White Paper regarding a further increase of competition in the electricity industry. In July 1989, the revised White Paper became law as the Electricity Act of 1989.[80] The new approach focused particularly on the introduction of a mandatory Power Exchange as well as on splitting up and privatizing the power industry.

A. Non-Fossil Fuel Obligation

Part of the Electricity Act of 1989, was the Non-Fossil Fuel Obligation (NFFO)[81], which provided a premium-price, market-enabling mechanism which attempts to encourage renewable-based electricity generation (a similar mechanism was created for Scotland, the Scottish Renewable Orders (SRO)). Under NFFO, potential project developers for renewable energy projects were invited to make offers for building new projects. The developers bid under different technology brands, e.g. wind power, solar, for a feed-in tariff or for the amount of financial incentives to be paid for each kWh fed into the grid by renewable energy systems.

Under the NFFO system, the difference between the premium price paid to ”green” electricity suppliers and the market price has

[80] http://www.uk-legislation.hmso.gov.uk/acts/acts1989/Ukpga_19890029_en_1.htm
[81] http://www.uk-legislation.hmso.gov.uk/acts/acts1989/ukpga_19890029_en_4#pt1-pb7-l1g32

been financed by the Fossil Fuel Levy,[82] a tax paid by licensed electricity suppliers and ultimately passed on to consumers.

In October 1998, the Government published a new White Paper that focused on a new approach to the wholesale electricity market.[83] As a result of this White Paper and further – rather long – discussions, a new regulation approach was developed. Part of the discussion process was carried out by a joint working group for embedded generation[84] (EGWG). The EGWG report concluded that there were a number of obstacles for distributed generation (DG) regarding their participation in the market, but that further investigations were needed to better address the relevant requirements. In addition, the EGWG report concluded that distributed network operators had no economic incentives to connect DG. As a result of the report DTI and Ofgem set up the Distributed Generation Co-ordinating Group (DGCG).[85] The group initiated various studies to investigate the impact of market regulations and network regulations on the development of distributed generation.[86]

B. New Electricity Trading Arrangement

The new overall approach is known as the New Electricity Trading Arrangement (NETA) and finally became operational on 27 March 2001.[87] The NETA approach moved the overall market approach closer to the Scandinavian approach, i.e. the mandatory pool system was removed and buyers and sellers can use a wide range of contracts, e.g. bi- as well as multilateral contracts. Furthermore, a market for the settlement of system imbalance was introduced. The Office of Gas and Electricity Regulation (Ofgem) is currently the main regulatory authority for the electricity and gas sector. The Department of Trade and Industry (DTI) is the responsible organization within the Ministry. DTI's approval is required for key regulatory decisions. The NETA arrangement was initially only applied to England and

[82] http://www.uk-legislation.hmso.gov.uk/acts/acts1989/ukpga_19890029_en_4#pt1-pb7-l1g33
[83] A Fair Deal for Consumers: Modernising the Framework for Utility Regulation: Response by the Director General, Office of Electricity Regulation, June, 1998.
[84] Embedded generation = distributed generation = power generation installed in the distribution network. Many small scale renewable generation is typically connected to the distribution system.
[85] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistGen/disenwg/Pages/Disenrgworgrp.aspx
[86] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistGen/Pages/DistGen.aspx
[87] The New Electricity Trading Arrangements, Office of Gas an Electricity Markets, August 2002.

Wales, but then extended to Scotland and is now known as British Electricity Trading and Transmission Arrangements (BETTA).

C. Renewable Obligations

In parallel to introducing NETA, the renewable energy policy was changed. Since February 2000, the United Kingdom's renewables policy has consisted of four key strands:

- a new Renewable Obligation (RO) on all electricity suppliers in Great Britain to supply a specific proportion of electricity from eligible renewables. The Renewable Obligation and associated Renewables (Scotland) Obligation came into force in April 2002 as part of the Utilities Act (2000)[88]. It requires power suppliers to derive from renewables a specified proportion of the electricity they supply to their customers. This started at 3% in 2003, rising gradually to 10.4% by 2010, and 15.4% by 2015. The cost to consumers will be limited by a price cap and the Obligation is guaranteed in law until 2027. The system is know as certificate system or renewable obligations (ROCs) system with fixed quotas.
- exemption of renewable-generated electricity from the Climate Change Levy, introduced in April 2001;
- an expanded support programme for new and renewable energy including capital grants and an expanded research and development programmes;
- development of a regional strategic approach to the planning of and targets for renewables.

In March 2003, the government's White Paper "Energy future-creating a low carbon economy" was published. It outlines the future energy policy.[89] It formulates the long-term goal of a 60% reduction of CO2 emissions by about 2050. It was outlined in the White Paper that renewable power generation, partly distributed, is expected to play an important role in achieving this goal. In May 2007, the government published another White Paper with the title "Meeting

[88] Utility Act: http://www.uk-legislation.hmso.gov.uk/acts/acts2000/20000027.htm; Renewable Obligations: http://www.uk-legislation.hmso.gov.uk/acts/acts2000/ukpga_20000027_en_8#pt4-pb8-l1g62

[89] Energy White Paper: Our energy future – creating a low carbon economy, Department of Trade and Industry (DTI)- Energy Group, London, UK, March 2003.

the Energy Challenge – A White Paper on Energy".[90] It confirms the original energy policy of a 60% cut of CO2 emissions by about 2050, but it also considers nuclear power an option, in addition to renewable energy. Regarding renewables, it particularly requires a review and update of the current transmission access arrangements, in order to support the timely and cost-effective connection of renewable generation. The work on the review started in August 2007.[91]

As the government has identified distributed generation, which includes distributed renewable energy, as an important part of its environmental agenda, Ofgem – the regulator – has put a lot of emphasis on distributed generation, including Combined Heat and Power (CHP), wind farms, hydro electric power and micro generation technologies. Its main emphasis is on ensuring that the development of distributed generation facilities is not unfairly treated by the way networks are operated and regulated. Ofgem's work in this area is of great importance, because it aims at developing a fair treatment of all generation sources within a deregulated market.[92]

In October 2006, a discussion process was started regarding a Reform of the Renewables Obligation System.[93] The discussion process focuses on two main issues (see also Section 4.1.6):[94]

- brand the RO to provide differentiated levels of support for different technologies;
- introduce a mechanism intended to maintain Renewable Obligation Certificate (ROC) prices in a situation of ROC oversupply.

In addition to these longer term changes, the consultation document contained proposals for a small number of more limited and detailed changes to the Renewable Obligation legislation which have partly been included in a draft 2007 Amendment Order which is still subject to Parliamentary approval.[95] Currently, the main focus of the discussion is around branding the Renewable Obligations (different

[90] http://www.dti.gov.uk/energy/whitepaper/page39534.html
[91] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/070816_Ex_TAR%20Call%20for%20Evidence_FINAL.pdf
[92] For details see http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistGen/Pages/DistGen.aspx
[93] http://www.berr.gov.uk/consultations/page34162.html and http://www.berr.gov.uk/energy/whitepaper/consultations/renewables-obligation/page39555.html
[94] http://www.berr.gov.uk/files/file34470.pdf
[95] http://www.berr.gov.uk/files/file34450.pdf

number of ROCs for different technologies), which is supposed to start in 2009.[96]

D. Offshore Networks

The Government has announced that transmission networks offshore should be licensed on the basis of a competitive approach. Hence, an initial proposal for a licensing and regulatory framework that will apply to offshore electricity transmission networks was developed.[97] The new regulatory arrangements are expected to be in place by 2008.

The key parts of the current proposals are:[98]

- An Offshore Transmission Owner (OFTO) would have the responsibility for designing, building, financing and maintaining the offshore transmission network required to connect an offshore generator. The OFTO would be selected by competitive tender and awarded a transmission license which enables the OFTO to receive a regulated revenue stream from the network user (the offshore wind farms) in return for meeting its license obligations for a predetermined regulatory period (20 years), and would be incentivised to achieve specified performance requirements during this period.
- The proposal for the OFTO tender process suggests a competitive tender process that includes an annual tender application window and which starts all the qualifying tenders simultaneously for coordination purposes. Bidders would not need to be prelicensed to operate in the offshore area before being entitled to bid. Instead, any company meeting the pre-qualification criteria could tender for the right to design, build, finance and maintain an offshore generator connection, in return for pre-defined commercial arrangements. The tender process would be triggered by a generator connection application to the onshore network. Ofgem will manage a tender process and select the successful project,

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[96] http://www.berr.gov.uk/files/file39497.pdf; http://www.berr.gov.uk/files/file39038.pdf and http://www.berr.gov.uk/files/file39039.pdf

[97] http://www.dti.gov.uk/energy/sources/renewables/policy/offshore-transmission/page40532.html and, http://www.ofgem.gov.uk/Networks/Trans/Offshore/Oteg/Documents/Offshore%20Scoping%20Doc%202006.pdf, and http://www.berr.gov.uk/files/file40629.pdf;

[98] http://www.berr.gov.uk/files/file40629.pdf

which results in the award of an offshore transmission license to the winning OFTO.

There is no clarity regarding the future procedure for already existing connections between an offshore generator and an onshore distribution network using a transmission voltage of 132 kV or lower. Currently, 132kV connections between an offshore generator and an onshore distribution system are classed as medium voltage lines. Onshore distribution licenses have been treating offshore generators seeking connections to the onshore distribution system as distributed generator connections. When the new proposed offshore transmission arrangements are introduced, 132kV circuits between offshore generators and onshore distribution systems will be classed as high voltage lines. This would require the owner to hold a transmission license. However, a framework for this issue and the general connection of offshore wind farms to distribution networks is still under development.

E. Independently Owned Transmission Networks

Due to the large demand for grid access of renewable energy installations in Scotland, Ofgem currently reviews options to speed up the installation of new transmission lines.[99] Today the exiting transmission network license holder in the area is the responsible for building new transmission lines.

A new option discussed would be to allow a new party to apply for a license which would allow the party to build, own and operate a section of a line to the main transmission network (similar to the interconnection between England and France). Under this option, no regulated revenues would be provided to finance the connection, the investor would have to enter into negotiations with the user of the line in order to determine the user fee.

Another option would be to tender the rights to build a connection and to obtain a regulated revenue. Under this option the winning party would receive the right to build a transmission line and Ofgem would allow the party to apply transmission network use of system charges for using the line. Ofgem currently favours this approach as it results in the lowest-cost connection solution.

[99] http://www.ofgem.gov.uk/Networks/Trans/ScottishIslands/Documents1/Connecting%20the%20Islands%20of%20Scotland.pdf

4.1.4 Regulatory Framework for Network Companies

The regulator Ofgem is responsible for licensing and regulating the distribution and transmission network companies.

A. Licensing

To qualify for a license, the relevant company must meet the criteria set out in the Guidance Documents.[100] For distribution network companies, the license requires, among others, that the electricity distributors:

- develop and maintain an efficient, co-ordinated and economical system of electricity distribution, and
- facilitate competition in the supply and generation of electricity.

An electricity distributor also has, for the purpose of enabling electricity to be conveyed, a duty to provide a connection between its own distribution system and any premises, when required to do so by:

- the owner or occupier of the premises, or
- an authorised supplier acting with the consent of the owner or occupier of the premises.

B. Price Control

Ofgem regulates the transmission and distribution companies through five-year price control periods.

Distribution network companies are regulated through incentive based RPI – X price control schemes that control prices, not profits, with the retail price index – the rate of inflation – as its benchmark and subtracting X – an efficiency factor – from it.[101] The price control approach provides incentives for

- improving efficiency (reducing losses);
- improving quality of service;

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[100] http://www.ofgem.gov.uk/Licensing/Work/Documents1/9777-Electricity%20distribution%20handbook.pdf

[101] See http://www.ofgem.gov.uk/Markets/RetMkts/Metrng/Metering/Documents1/8944-26504.pdf as well as http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/RevandPrice/Documents1/Revenue%20Rigs%20V3.12(for%20publication).pdf

- responding to the challenge raised by the Government's objectives for renewable energy, for instance, by connecting renewable distributed generation.

Transmission network companies are regulated through revenue cap regulations, i.e. the controls set the maximum amount of revenue which transmission network owners can receive through charges they levy on users of their networks to cover their costs and earn a return in line with agreed expectations. The users in this case could be electricity generators that are connected to the network, retailers or end customers.

For the 2007 to 2012 price control, Ofgem has approved an investment of £5 billion for transmission networks that want to replace ageing assets and for helping to connect renewable generators in northern England and Scotland.[102] In addition, Ofgem has introduced an innovation funding incentive to encourage transmission network companies to invest 0.5 per cent of their revenue in research and development for programs targeted on environmental improvement. This equates to a minimum of £500,000 per year for each company.

In addition, the transmission licenses explicitly include special expenditure allowances for Transmission Investment for Renewable Generation (TIRG), i.e. in order to speed up the process of building transmission lines for renewable energy, the TIRG mechanism provides funding to connect a large volume of renewable generation that was not forecast at the time the relevant price controls were set for the transmission licensees.[103]

C. Offshore Networks

The Offshore Transmission networks are expected to be subject to the same price control approach used for onshore distribution networks.[104]

[102] http://www.ofgem.gov.uk/Networks/Trans/Offshore/Oteg/Documents/FP%20Press%20Release%20Suatainability_56.pdf

[103] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TIRG/Pages/TIRG.aspx

[104] http://www.berr.gov.uk/files/file40629.pdf and http://www.ofgem.gov.uk/Networks/Trans/Offshore/Oteg/Documents/Offshore%20Scoping%20Doc%202006.pdf

D. Private-wire networks

Privately-owned unlicensed networks may operate within existing distribution networks. Advantages include exemption from some license charges and reduced energy loss in transmission. Ports and large industrial users often operate with private wire networks. Studies have shown that private networks incorporating local generation can be used to cut emissions in urban areas. However, there is concern that customers on a private network are vulnerable, since they cannot switch suppliers if prices increase, or complain to a regulator. Government is consulting on how to protect customers and preserve competition if private networks continue to expand.[105]

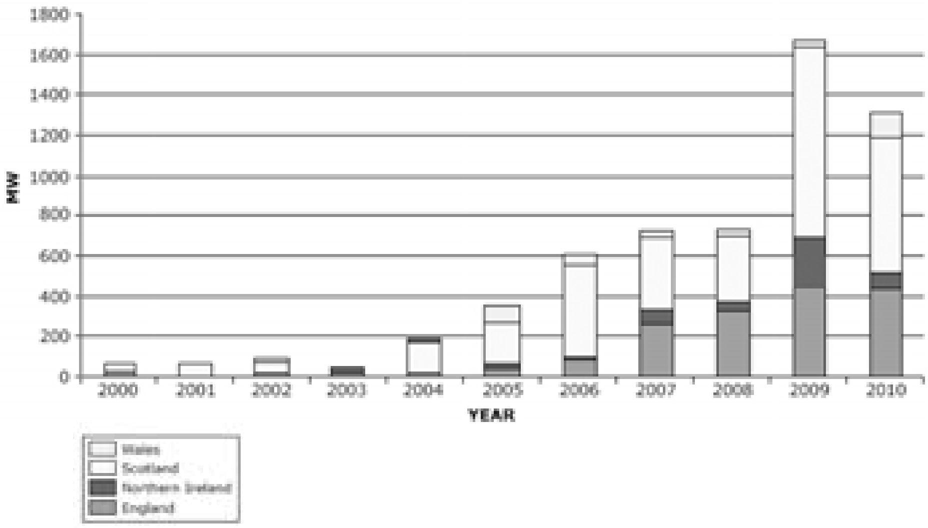
4.1.5 Development of the Wind Power Sector in the UK[106]

The first commercial wind farm in the UK was commissioned at Delabole in Cornwall in 1991, comprising 10 turbines with a project capacity of 4 MW. Throughout the 1990s, there was a slow and steady delivery of 50 new wind farms, and by 1999 the installed operational capacity was 344 MW, averaging 38 MW of new operational capacity per year. During this period the Non-Fossil Fuel Obligation (NFFO) was introduced, which provided premium payments for renewables-generated electricity over a fixed period, with contracts awarded to individual generators. It took a further five years for the UK to reach an installed capacity of 1,000 MW, or 1 GW, of wind power in April 2005; 890 MW of which was from onshore installations (107 projects) and 124 MW was offshore (3 projects), see also Figure 4-7. Figure 4-8, shows the geographical location of the wind farms. It can be seen that most large wind farms are built in Northern England or Scotland.

Following the achievement of the UK's first GW of wind energy in 14 years, the second GW took just 20 months, comprising 1,696 MW onshore and 304 MW offshore developments.

[105] http://www.iop.org/activity/policy/Publications/file_21079.pdf
[106] All data for the UK in this Section include Northern Ireland.

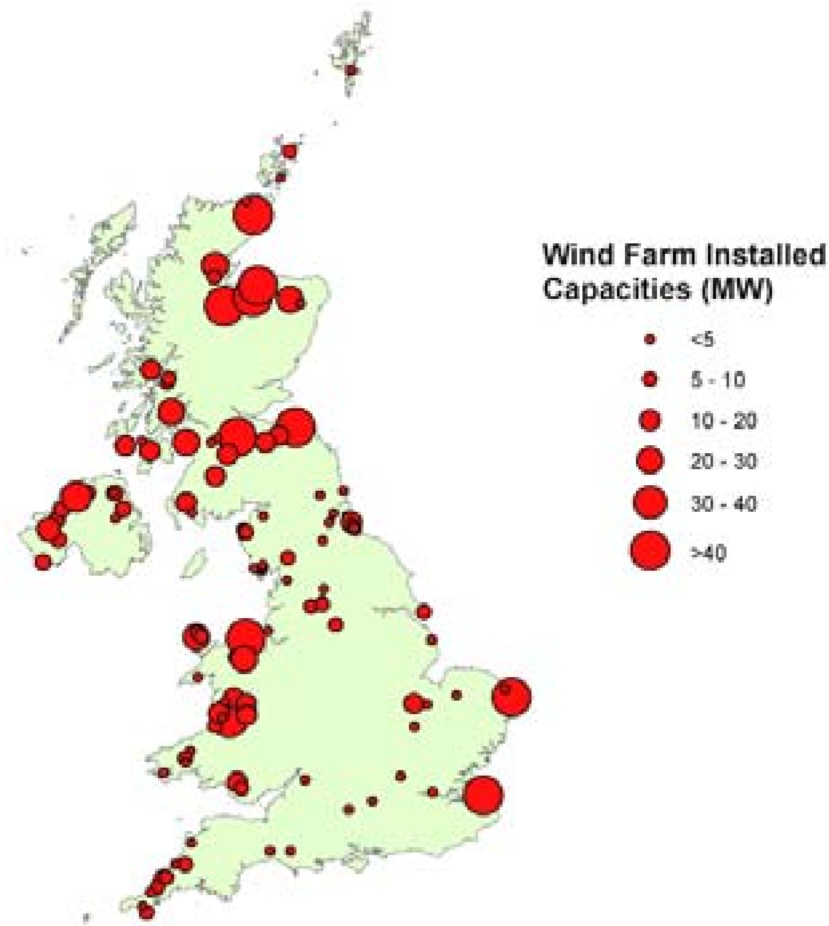
Figure 4-7: Year-on year-existing and forecast onshore wind farms to 2010, by country



Source: http://www.bwea.com/pdf/realpower/rp08onshore.pdf

By July 2007, England had 395 MW wind power installed onshore and 244 MW offshore; Wales had 300 MW onshore and 60 MW offshore and Scotland had 1082 MW onshore. In total, England, Wales and Scotland had 2,081.19 MW wind power capacity installed (2,203 MW including Northern Ireland).

Figure 4-8: Wind Farm Capacities Map (December 2005). Only turbines above 225kW are shown as this is the lower limit of large scale wind.

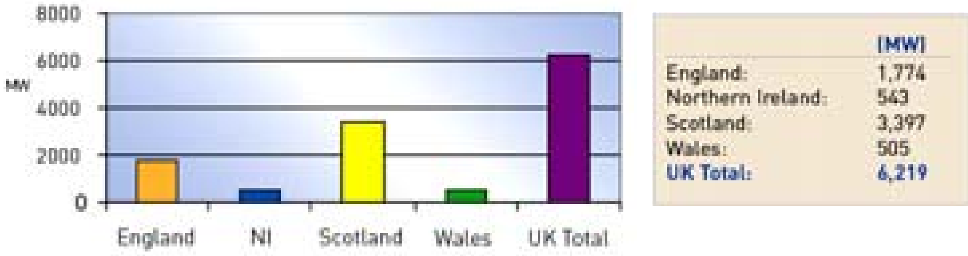


Source: http://www.restats.org.uk/maps.htm.

4.1.6 Future Plans and Possible Barriers for the Further Development of Wind Power

It is anticipated that offshore wind will make a significant contribution of 1,000–1,500 MW equivalent to 1% of UK supply by 2010, gearing up to a potential installed capacity of up to 11,500 MW by 2020. Onshore wind is expected to make the largest single contribution to the 2010 target. In order to deliver a total 6,000 MW to the 2010 target, the British Wind Energy Association estimates that an additional 2,000 MW of wind power is needed to receive building permits before the end of 2007.[107] This additional necessary capacity, plus the already operational or consented capacity, would meet about half of the UK 2010 renewable electricity target (4.5% of UK supply), and would result in the installation of approximately 3,500 turbines in total (about twice the current number installed).

Figure 4-9: Expected onshore wind installation by 2010.



Source: http://www.bwea.com/pdf/OnshoreWindPoweringAheadFull.pdf

A key problem, however, is the rather slow approval rate of building applications as well as limited transmission capacity in parts of the country, in particular between the very windy Scottish locations and the Southern part of the UK. At present nearly 8 GW of capacity are held up in the onshore planning system, equivalent to nearly 6% of potential UK electricity supply. A further 9 GW from offshore projects is awaiting decision or due to be submitted for consent. In 2006 it took local authorities an average of 16 months to decide on wind farm applications – even though the statutory time period for decisions is 16 weeks.

Furthermore, in the past only a few offshore wind farms were installed as they had to deal with low ROCs prices and technical difficulties, hence the realization of offshore wind farms in the rather harsh offshore environment around the UK was very difficult and came almost to a standstill 2 years ago. With increasing ROC prices and more suitable wind turbine technology the interest in offshore wind power picked up again. However, due to the high world-wide demand of wind turbines, on- and offshore, it is rather difficult to find wind turbine suppliers that are interested in delivering wind turbines for large offshore wind projects in the UK.

[107] http://www.britishwindenergy.co.uk/pdf/briefings/ukwindstatusJan07.pdf and http://www.bwea.com/energyreview/ and http://www.bwea.com/pdf/OnshoreWindPoweringAheadFull.pdf

4.1.7 Payment Scheme for Renewable Energy Sources

The following section discusses the old scheme of non-fossil fuel obligations as well as the main current scheme, i.e. renewable obligations and its future development.

A. Non Fossil Fuel Obligations (NFFO)

Before 2002 the renewable energy policy in England and Wales was based on Non-Fossil Fuel Obligations (NFFO).[108] Under NFFO, potential project developers for renewable energy projects were invited to submit offers for building new projects. The developers bid under different technology brands, e.g. wind power or solar, for a feed-in tariff or for the amount of financial incentives to be paid for each kWh fed into the grid by renewable energy systems.

In total five NFFO Orders were made, of which the first in 1990 was set for a total of 102 MW declared net capacity (DNC). This first order resulted in contracts for 75 projects for 152 MW DNC. The second Order, made in late 1991, was set for 457 MW DNC. This resulted in 122 individual contracts (for a total of 472 MW DNC) between the generators and the Non-Fossil Purchasing Agency (NFPA). For landfill gas, sewage gas and waste-derived generation, contracts were awarded at around 6p/kWh, while for wind power a price of 11p/kWh was established. These prices reflected the limited period for the recovery of capital costs.

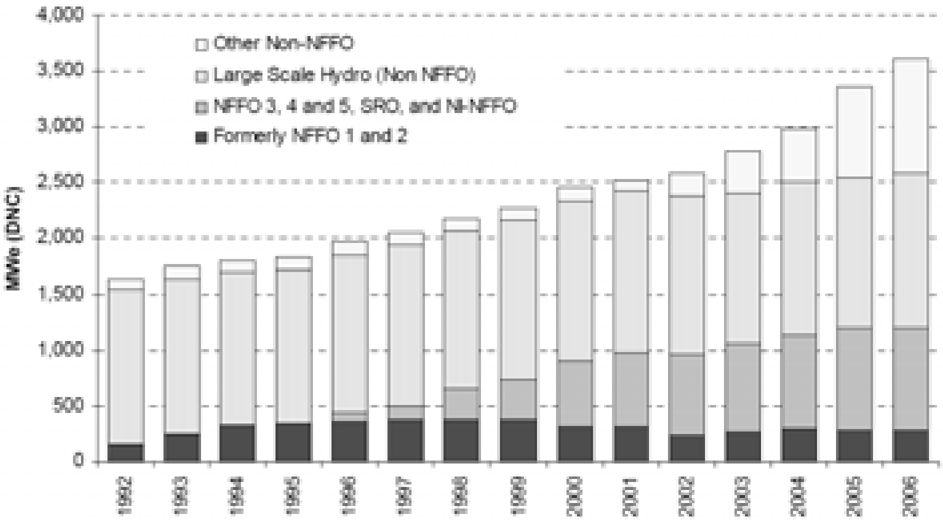
The third Order covers the period 1995 to 2014; this was for 627 MW DNC of contracted capacity at an average price of 4.35 p/kWh. The lower bid prices reflect the longer-term contracts, which are now available together with further developments that have led to improvements in the technologies. Taking into account factors such as denied planning permissions, it is estimated that about 300–400 MW DNC will finally be commissioned.

The fourth Order was announced in February 1997. The contracts comprised 195 projects with a total DNC of 843 MW, at an average price of 3.46 p/kWh. In the fifth and largest Order, which was announced in September 1998, contracts included 261 projects with a total DNC of 1,177.1 MW, at an average price of 2.71 p/kWh.

108 http://www.uk-legislation.hmso.gov.uk/acts/acts1989/ukpga_19890029_en_4#pt1-pb7-l1g32

Table 4-3, on the following page, sets out the technologies and capacities of schemes in all five NFFOs and Figure 4-10 provides an overall overview of the development of NFFO 1 to 5. As at the end of December 2006, 86 projects in the third Order were operational, with a total capacity of 351 MW DNC. There were also 88 projects with a capacity of 241 MW DNC commissioned from the fourth Order projects and 93 projects totalling 188 MW DNC from the fifth Order.

Figure 4-10: Renewable generating capacity from NFFO and former NFFO contracts (including equivalents in Scotland and Northern Ireland) and capacity outside of NFFO.



Souce: http://stats.berr.gov.uk/energystats/dukes07_c7.pdf

Due to the changes in regulations, only the price development between the last three bidding processes can be compared. It is summarised in Table 4-4. Biomass projects have not been included into NFFO5 as none of the successful biomass projects in NFFO3 and NFFO4 was commissioned. Table 4-4 shows that NFFO has lead to significant cost reductions, with the notable exception of biomass. A comparison between the 1997 (NFFO4) and 1998 (NFFO5) average successful bid prices shows a 22 % price reduction (calculated in 1998 prices) in large wind power bidding prices. Surprisingly, the average price of all renewables for NFF05 is 2.71 British pence (p)/ kWh (or 0.038 €/ kWh) while the average price at the England and

Wales spot market was between 3 and 3.5 p/kWh (0.042–0.049 €/KWh) in 1998.

Table 4-3: Overview of Non-Fossil Fuel Obligations in England & Wales and operational capacity 2006.[109]

	Technology band	Contracted projects		Live projects operational at 31 December 2006 *1)*	
		Number	Capacity MW	Number	Capacity MW
England and Wales					
NFFO-1 (1990)	Hydro	26	11.85	13	4.83
	Landfill gas	25	35.50	13	25.09
	Municipal and industrial waste	4	40.63	4	40.63
	Other	4	45.48	3	45.38
	Sewage gas	7	6.45	4	4.08
	Wind	9	12.21	5	8.14
	Total *2)*	**75**	**152.11**	**42**	**128.16**
NFFO-2 (late 1991)	Hydro	12	10.86	9	10.43
	Landfill gas	28	48.45	21	34.64
	Municipal and industrial waste	10	271.48	2	31.50
	Other	4	30.15	1	12.50
	Sewage gas	19	26.86	17	18.56
	Wind	49	84.43	22	51.97
	Total *2)*	**122**	**472.23**	**72**	**159.60**
NFFO-3 (1995)	Energy crops and agricultural and forestry waste – gasification	3	19.06	-	-
	Energy crops and agricultural and forestry waste – other	6	103.81	2	69.50
	Hydro	15	14.48	8	11.74
	Landfill gas	42	82.07	40	79.03
	Municipal and industrial waste	20	241.87	9	126.32
	Wind – large	31	145.92	12	50.50
	Wind – small	24	19.71	15	13.52
	Total *2)*	**141**	**626.90**	**86**	**350.61**

[109] http://stats.berr.gov.uk/energystats/duke6s07_c7.pdf

NFFO-4 (1997)	Hydro	31	13.22	9	2.49
	Landfill gas	70	173.68	62	160.51
	Municipal and industrial waste – CHP	10	115.29	4	33.48
	Municipal and industrial waste – fluidised bed combustion	6	125.93	-	-
	Wind –large	48	330.36	6	38.67
	Wind – small	17	10.33	6	4.03
	Anaerobic digestion of agricultural waste	6	6.58	1	1.43
	Energy crops and forestry waste gasification	7	67.34	-	-
	Total *2)*	**195**	**842.72**	**88**	**240.62**
NFFO-5 (1998)	Hydro	22	8.87	-	-
	Landfill gas	141	313.73	84	180.49
	Municipal and industrial waste	22	415.75	-	-
	Municipal and industrial waste – CHP	7	69.97	-	-
	Wind –large	33	340.16	-	-
	Wind – small	36	28.67	9	7.45
	Total	**261**	**1,177.15**	**93**	**187.94**
NFFO Total		**794**	**3,271.11**	**381**	**1,066.92**

1) Sites that have been closed and sites that are not currently using renewables as fuel have been excluded.

Table 4-4: Successful NFFO bidding prices in British pence/ kWh.[110] Exchange rate August 2007: 1 Euro = 0.7 £

	NFFO3	NFFO4	NFFO5
Large Wind	3.98–5.99	3.11– 4.95	2.43–3.14
Small Wind	-	-	3.40–4.60
Hydro	4.25–4.85	3.80–4.40	3.85–4.35
Landfill Gas	3.29–4.00	2.80–3.20	2.59–2.85
Waste System	3.48–4.00	2.66–2.80	2.34–2.42
Biomass	4.90–5.62	5.49–5.79	-

In Scotland, the first Scottish Renewable Order (SRO) in 1994 included approximately 76 MW DNC of new capacity and comprising 30 projects. At the end of December 2006, 19 schemes were commissioned with a capacity of 40 MW DNC. A second SRO was launched in 1995, and in March 1997, it comprised 114 MW DNC

[110] Source: Fifth Renewable Order for England and Wales; Office of Electricity Regulation, UK, September 1998.

of new capacity within 26 schemes. Under this Order, at the end of 2006 there were 13 commissioned projects with a capacity of 50 MW DNC. A third SRO for 145 MW DNC of new capacity comprising 53 project was submitted to Parliament in February 1999. Under this Order, at the end of 2006 there were 16 commissioned schemes with a capacity of 34 MW DNC. Table 4-5 sets out the technologies and capacities of projects in all three Scottish Orders.

Table 4-5: Overview of Scottish Renewable Orders (SRO) and operational capacity 2006.[111]

	Technology band	Contracted projects		Live projects operational at 31 December 2006 *1)*	
		Number	Capacity MW	Number	Capacity MW
Scotland					
SRO-1 (1994)	Biomass	1	9.80	-	-
	Hydro	15	17.25	10	10.75
	Waste to Energy	2	3.78	2	3.78
	Wind	12	45.60	7	25.13
	Total *2)*	**30**	**76.43**	**19**	**39.66**
SRO-2 (1997)	Biomass	1	2.00	-	-
	Hydro	9	12.36	2	1.46
	Waste to Energy	9	56.05	6	17.65
	Wind	7	43.63	5	31.29
	Total	**26**	**114.04**	**13**	**50.40**
SRO-3 (1999)	Biomass	1	12.90	-	-
	Hydro	5	3.90	-	-
	Waste to Energy	16	49.11	10	22.36
	Wave	3	2.00	1	0.20
	Wind – large	11	63.43	1	8.29
	Wind – small	17	14.06	4	3.43
	Total *2)*	**53**	**145.40**	**16**	**34.28**
SRO Total		**109**	**335.87**	**48**	**124.34**

B. The Non-Fossil Purchasing Agency Limited

The Non-Fossil Purchasing Agency Limited (NFPA) was set up in 1990 by the twelve Regional Electricity Companies (RECs) in England and Wales as their agent for the purpose of purchasing the

[111] http://stats.berr.gov.uk/energystats/dukes07_c7.pdf

output from NFFO generators in England & Wales at the contract price and of selling the electricity suppliers via on-line auctions into the market. Contracts for the first two Orders, 1990 and 1991, have now terminated. Contracts under the remaining three Orders will continue for many years with the last of these contracts not terminating before 2018.

Hence, presently NFPA conducts green power auctions bi-annually. These auctions are for electrical output that will be produced by NFFO generators during a six-months period (starting 1 April or 1 October) following the end of the auction. The auction prices are for electrical output together with – depending on the generation technology – Climate Change Levy Exemption Certificates (LECs) and Renewables Obligation Certificates (ROCs).

The latest on-line auction of green electricity was completed on 27 July 2007. It covered contracts from both NFFO (England & Wales) and SRO (Scotland), amounting to 299 projects with a total of some 861 MW of capacity having been auctioned. The auction began on Tuesday, 24 July 2007 and contracts were finally awarded to a total of 10 successful bidders. The contracts are for electricity produced between 1 October 2007 and 31 March 2008. The results of the latest auction, and the 4 auctions held before, are given in Table 4-6. The average price of the July 2007 auction, at 9.31p/kWh (13.33 c€/KWh), was about 10% lower than the very high levels of the August 2006 auction, which is the equivalent auction covering a winter period and returned an average price of 10.35p/kWh (14.82 c€/KWh). The previous auction covering a winter period was held in February 2007 and produced an average price of 7.20p/kWh (10.31 c€/KWh).

Table 4-6: Overview of NFFO Auction Results. (Exchange rate Sept 2007)

	27 July 2007		21 Feb. 2007		10 Aug. 2006		20 Feb. 2006		22 Aug. 2005	
	p/kWh	c€/kWh	p/kWh	c€/kWh	p/kWh	c€/kWh	p/kWh	c€/kWh	p/kWh	c€/kWh
MIW	4.54	6.50	2.58	3.69	5.48	7.84	4.02	4.02	5.75	6.64
Wind	9.1	13.03	7.36	10.54	10.23	14.65	8.48	8.48	12.14	12.96
Hydro	9.35	13.39	7.47	10.69	9.24	13.23	8.43	8.43	12.07	13.47
Landfill Gas	9.77	13.99	7.47	10.69	10.83	15.51	8.92	8.92	12.77	13.33

Source: http://www.nfpa.co.uk/

C. Renewables Obligation

The first Renewables Obligation Order in England & Wales came into force in April 2002, as did the first Renewables Obligation Order (Scotland).[112] These Orders were subject to review in 2004, 2005 and 2006. These Orders place an obligation on licensed electricity suppliers in England and Wales as well as in Scotland to source an increasing proportion of electricity from renewable sources. In order to provide a stable and long-term market for renewable energy, the Obligation will remain in place until 2027.

Yearly targets have been set up until the 2015/2016 period. In 2002–03 the target was set at 3%, 2005–06 it was 5.5 per cent in England and Wales and Scotland and will increase annually to reach 15.4% by the year 2015/16 and then remain at this level until 2026–2027.[113]

Currently eligible renewable generators receive Renewables Obligation Certificates (ROCs) for each MWh of electricity generated. The Renewable Obligation scheme is currently defined as a technology-neutral instrument, i.e. each generator gets the same number of ROCs for the same amount of energy (MWh) produced. Hence, the scheme is designed to promote the most economic forms of renewable generation.

The eligible generators are:

- wind, wave, tidal stream, PV, landfill gas, sewage gas and biogas from anaerobic digestion unless they were built before 1990;
- Biomass is only eligible as long as the fuel is less than 10% contaminated by fossil fuels (and various other restrictions). The biomass fraction of waste gets ROCs, provided that an ”advanced technology” is used, i.e. gasification or pyrolysis.
- hydro qualifies whatever its size if built after 1990, and if it is refurbished and under 20MW;
- all micro-hydro plants, independent of building date, receives ROCs if they are 1.25MW or less.

The certificates can be sold separately from the electricity to which they relate, i.e. suppliers can purchase these certificates in order to fulfill their obligation. This allows for open trading of certificates.

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[112] http://www.uk-legislation.hmso.gov.uk/acts/acts2000/ukpga_20000027_en_8#pt4-pb8-l1g62

[113] An increase to 20% on a headroom base is discusses, see also http://www.berr.gov.uk/files/file39497.pdf (Chapter 5).

To fulfill their obligation, suppliers can either present enough certificates to cover the required percentage of their output, or they can pay a 'buy-out' price for any shortfall. The Buy-Out price was set at £30.00 per MW/h in 2002/03 and increases each year by the Retail Price Index (RPI). The period 2005/06 had a "buy-out" price of £32.33, the price for 2007/08 is £34.30 per megawatt hour (MWh). All payments are back-channeled to suppliers in proportion to the number of ROCs they present. ROC trading is administered by the Non-Fossil Purchase Agency (NFPA).

The fixed buy-out price is often referred to as floor price for ROCs,[114] however, the buy-out price is not the same as a floor price. A floor price guarantees a minimum price for ROCs in case of oversupply of ROCs, while the buy-out price actually does not guarantee such a minimum price. However, no oversupply of ROCs is expected to occur until 2015 or so, hence in principal it can be assumed that the ROCs price will not drop below the buy-out price until around 2015. For the time after this, the government currently develops a mechanism that is intended to stabilize Renewables Obligation Certificate prices in a situation with ROC oversupply.[115] The government aims at implementing this new approach in the legislations by 2009. The current proposal focuses on the introduction of a 'headroom', i.e. after 2015 the number of ROCs requested by the government should always be 6% higher than the expected production of ROCs for a particular year.

The ROCs have increased the profitability of renewable energy generation as the certificates have an additional value over and above the price of electricity itself. This is especially true for wind power. Furthermore, the renewable obligation scheme has delivered considerably more renewables than the previous support mechanism of the Non-Fossil Fuel Obligation (NFFO).

Table 4-8 shows how suppliers complied with their obligations in England and Wales. It can be seen that due to the redistribution of the collected buy-out price to all parties with ROCs, suppliers had an incentive to pay ROCs prices significantly above the actual buy-out price.

[114] http://www.r-p-a.org.uk/article_faq_list.fcm?section=2&subsite=1
[115] http://www.berr.gov.uk/files/file39497.pdf

Table 4-7: How suppliers complied with their obligations in England & Wales

	2002–03	2003–04	2004–05	2005–06
Total Obligation (MWh)	8,393,972	12,387,720	14,315,784	16,175,906
Total number of ROCs presented	4,973,091	6,914,524	9,971,851	12,232,153
Percentage obligation met by ROCs	59%	56%	70%	76%
Total buy-out paid/ redistributed	£79,251,930	£158,466,502	£136,169,914	£127,167,900
What a ROC was "worth" to a supplier[116]	£45.94	£53.43	£45.05	£42.54

Source: http://www.ofgem.gov.uk/Sustainability/Environmnt/RenewablObl/Documents1/17098-3607.pdf

Table 4-7 lists the detailed prices for ROCs from 2002 to 2007.

[116] When combined with the buy-out price that suppliers effectively avoid paying by presenting ROCs, a ROC produced against the RO was "worth" £42.54 to suppliers in 2005-06.

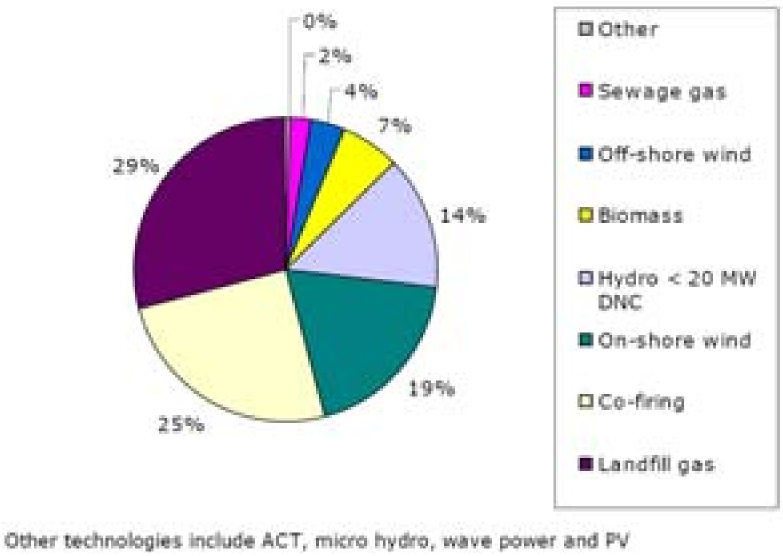
Table 4-8: ROC prices from 2002 to 2007 based on e-Roc auctions. (Exchange rate Sept 2007)

Auction Date	Average ROC Price		Lowest ROC Price		Total Number of ROCs
	£	€	£	€	
17 July 2007	48.12	68.92	47.50	68.03	51,787
24 April 2007	47.51	68.05	47.50	68.03	74,343
22 January 2007	46.17	66.13	46.00	65.88	49,446
24 October 2006	44.81	64.18	44.50	63.74	54,263
20 July 2006	40.62	58.18	40.60	58.15	227,909
20 April 2006	40.65	58.22	40.60	58.15	261,201
19 January 2006	38.42	55.03	37.75	54.07	197,930
20 October 2005	39.16	56.09	35.40	50.70	216,177
20 July 2005	45.72	65.48	45.50	65.17	197,944
20 April 2005	46.07	65.98	45.00	64.45	180,083
20 January 2005	47.18	67.57	46.90	67.17	151,348
26 October 2004	46.12	66.06	45.90	65.74	129,919
21 July 2004	52.07	74.58	51.76	74.13	176,759
20 April 2004	49.11	70.34	48.80	69.89	166,643
20 January 2004	47.46	67.98	47.30	67.75	96,449
21 October 2003	45.93	65.78	44.80	64.17	123,979
16 July 2003	48.21	69.05	47.71	68.33	158,512
15 April 2003	46.76	66.97	46.75	66.96	191,897
16 January 2003	47.46	67.98	45.51	65.18	64,337
17 October 2002	47.12	67.49	47.00	67.32	85,404
				Total	**2,856,330**

Source: http://www.e-roc.co.uk/

Figure 4-11 provides an overview of ROCs issued by technology type in 2006 (England, Wales, Scotland and Northern Ireland). As can bee seen landfill gas generation attracted just under 30% of the total ROCs issued in 2005–06, which is comparable to the share it received in 2004–05 (33%). Co-firing generating stations received 25% of total ROCs with on-shore wind receiving 19%.

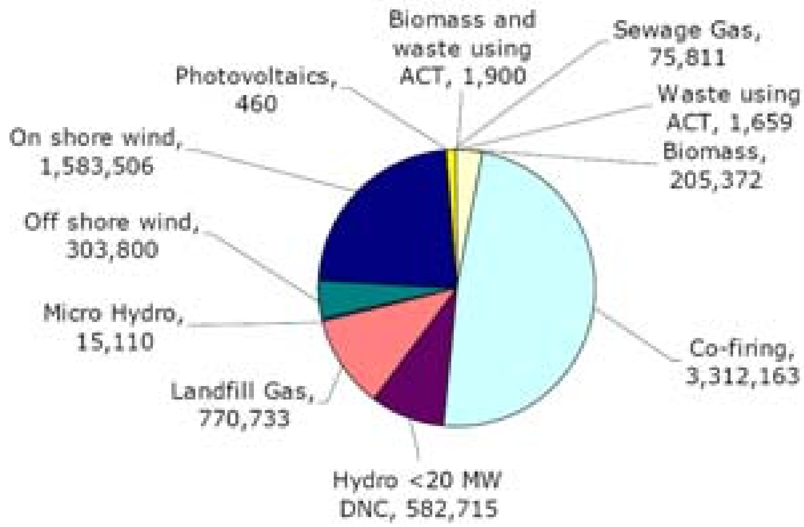
Figure 4-11: Breakdown of ROCs issued by technology type in 2006 (England, Wales, Scotland and Northern Ireland).[117]



When the RO was first introduced, the most prevalent technology type (in terms of the number of accredited generating stations) was landfill gas with 202 projects accredited at 1 April 2002. The most prevalent technology in the 2005–06 obligation period in terms of the number of stations and capacity was on-shore wind with 63 stations (630 MW) being accredited, see also Figure 4-12. Co-firing and on-shore wind stations made up around 70 per cent of the total renewable capacity installed and accredited under the RO in 2005–06 obligation period.

[117] Source: http://www.ofgem.gov.uk/Sustainability/Environmnt/RenewablObl/Documents1/17098-3607.pdf

Figure 4-12: Eligible capacity by technology in kW. (England, Wales, Scotland and Northern Ireland).[118]



D. Renewables Obligation 2008 and Beyond

Subject to Parliamentary approval, further changes will be made to the Renewables Obligation (Scotland) Order to introduce a Marine Supply Obligation (MSO), i.e. a supplier who supplies customers in Scotland will be obliged to meet a certain supply with ROCs issued to generating stations that generate electricity from wave and tidal devices.

Furthermore, some key changes are proposed to be implemented in 2009 (see also Section 4.1.3) such as:[119]

- to brand the RO to provide differentiated levels of support for different technologies;
- to introduce a mechanism intended to maintain Renewables Obligation Certificate (ROC) prices in a situation of ROC oversupply.

[118] Source: http://www.ofgem.gov.uk/Sustainability/Environmnt/RenewablObl/Documents1/17098-3607.pdf
[119] http://www.berr.gov.uk/files/file34470.pdf, also http://www.berr.gov.uk/energy/whitepaper/consultations/renewables-obligation/page39555.html

Table 4-9 provides an overview of the proposed new support levels for different technology bands. Under this proposal established technologies such as landfill gas would only receive 0.25 ROCs per MWh generated while post demonstration projects would receive 1.5 ROCs per MWh and emerging technologies, such as wave or tidal energy, would get 2 ROCs per MWh.

Table 4-9: Overview of proposed bands.

Band	Technologies	Level of support ROCs/MWh
Established	Sewage gas; landfill gas; co-firing of non-energy crop (regular) biomass	0.25
Reference	Onshore wind; hydro; co-firing of energy crops;	1.0
Post-demonstration	Offshore wind; dedicated regular biomass	1.5
Emerging technologies	Wave; tidal stream; advanced conversion technologies (anaerobic digestion, gasification and pyrolysis); dedicated biomass burning energy crops (with or without CHP), dedicated regular biomass with CHP; solar photovoltaics; geothermal	2.0

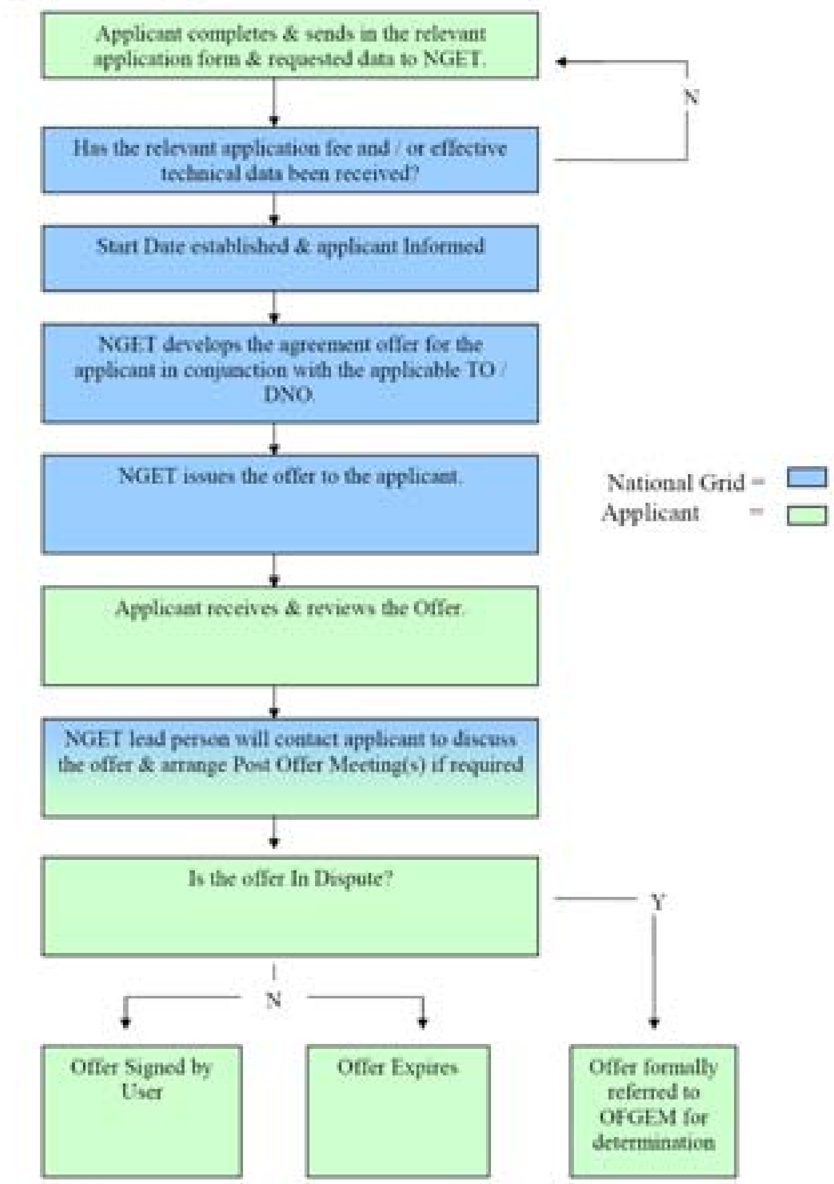
Source: http://www.berr.gov.uk/files/file39497.pdf

4.2 Application Procedure for Access and Connection to the Grid

A. Transmission System

Anyone interested in connecting to the different transmission systems in the UK needs to get in contact with National Grid, the transmission system operator. Figure 4-14 outlines the connections process.

Figure 4-13: Process for connection to the transmission system in the UK.[120]



[120] http://www.nationalgrid.com/NR/rdonlyres/4E10853C-8AEF-4D1B-AAB7-58A33C673114/14355/NationalGridconnectionprocessv10.pdf

All potential applicants, renewable energy generators or conventional generators, are treated equally in the connection process. Any applicant that wishes to connect directly to the transmission system will be offered to enter into a Bilateral Connection Agreement (BCA) with National Grid within 3 months (i.e. in box "NGET issues the offer to the applicant" in Figure 4-13) of application[121]. The BCA Agreement sets out the provisions for generators to comply with the Connection Use of System Code (CUSC), Grid Code and Balancing & Settlement Code as well as defining the terms of the arrangements for connection to the transmission system. The agreement also sets out provisions for any balancing services as customers with this type of agreement will be actively participating in the electricity balancing market.

The relevant application fees are discussed in Section 4.6. Queue management, i.e. handling of large numbers of connection applications is discussed in Section 4.4.

B. Distribution System

Any customer wishing to connect to a distribution system should initially contact the Distribution Network Operator in its area to discuss the proposed connection. For the type of interconnection agreement, the size of the power station and its location is important. The size is dependent on the network area, i.e. in which Transmission Owner's network the site is located, see below:

Transmission Owner - National Grid: (NGET)	Large =>100 MW Medium <100 =>50 MW Small <50 MW
Transmission Owner - Scottish Power: (SPTL)	Large =>30 MW Small <30 MW
Transmission Owner - Scottish Hydro: (SHETL)	Large =>10 MW Small <10 MW

[121] http://www.nationalgrid.com/uk/Electricity/GettingConnected/TransmissionConnected/agreements/ http://www.nationalgrid.com/NR/rdonlyres/538B0362-162B-4CE1-9483-27B3FDADF4C2/16068/GBCCMI3R0FINAL.pdf

Small or medium sized power stations that do not wish to have access rights to the transmission system do not need an agreement with the TSO National Grid to facilitate their connection. Hence all agreements will be with the Distribution Network Operator.

Large generators that want to connect to the distribution system in Scotland can choose between obtaining a Bilateral Embedded Generation Agreement (BEGA) or a Bilateral Embedded License Exemptable Large Power Station Agreement (BELLA). Large generators that want to connect in England and Wales can only apply to National Grid for a BEGA agreement. This is because a BELLA Agreement can only be signed by a customer that is classed as a large power station and exempted from obtaining a generation license. In England & Wales however a large power station is equal to or greater than 100 MW, and only power stations between 50-99.9 MW can apply to the Department of Trade and Industry (DTI) for exemption from holding a Generation license.[122]

The key difference between BEGA and BELLA is that only generators that have signed a BEGA agreement have the right to use the transmission system and have to pay Transmission Use of System charges.

Bilateral Embedded Generation Agreement (BEGA)

The BEGA Agreement sets out the provisions for generators to comply with the Connection Use of System Code (CUSC), Grid Code and Balancing & Settlement Code. This agreement will be offered to customers that have requested access to the GB Transmission System, but that are not directly connected to the GB Transmission system. This type of agreement is therefore applicable to embedded (distributed) generators that wish to export to the GB Transmission system. The BEGA will also provide the customer with Transmission Entry Capacity (TEC), see also Section 4.5. The agreement also sets out provisions for any Balancing Services as the agreement gives the customer rights to operate in the energy balancing market.

[122] The application procedure and deadline is identical to transmission application, see also Figure 4 14.

Bilateral Embedded Licence Exemptable Large Power Station Agreement (BELLA)

The BELLA Agreement sets out the provisions for generators to comply with the CUSC and Grid Code. This agreement does not commit users to adhere to the Balancing and Settlement Code as a BELLA does not give the customer rights to operate in the electricity balancing market, i.e. another party may be responsible for the output under the CUSC and BSC.

According to the distribution network licence requirements, the distribution network company must follow the deadlines for the connection application as outlined in Table 4-10.

Table 4-10: Overview of deadlines for distribution companies related to connection applications.[123]

Service	Standard
Provision of quotations	
Provide a quotation for a new generation connection where the highest voltage of the assets at the point of connection and any associated works is not more than one kilovolt.	within **thirty working days** of receiving the request
Provide a quotation for a new generation connection where the highest voltage of the assets at the point of connection and any associated works is more than one kilovolt but not more than 22 kilovolts.	within **fifty working days** of receiving the request
Provide a quotation for a new connection that is not included within the preceding categories.	within **three months** of receiving the request
Information and design submissions	
Provide the technical information necessary to enable the applicant to identify the proposed location and characteristics of the point of connection of the premises to the licensee's distribution system, where the highest voltage of the assets at that point or any associated works is more than 22 kilovolts but not more than 72 kilovolts	within **thirty working days** of receiving the request
In response to a design submitted for low voltage and high voltage connections by the applicant, outlining a new proposal for connecting premises to the licensee's distribution system, provide a written approval of the proposed design, or a written rejection stating reasons for rejection.	within **ten working days** of receiving the proposed design (unless any part of it would require the use of extra high voltage assets)

[123] http://www.ofgem.gov.uk/Networks/Connectns/CompinConn/Documents1/SLC4F%20searchable%20Licence%20mod.pdf

Service	Standard
In response to a design submitted for an extra high voltage connections by the applicant, outlining a new proposal for connecting premises to the licensee's distribution system, provide a written approval of the proposed design, or a written rejection stating reasons for rejection.	within **twenty working days** of receiving the proposed design
Final works and phased energisation	
Complete the final works for a low voltage connection.	within **ten working days** of receiving the request
Complete the final works for a high voltage connection.	within **twenty working days** of receiving the request
Inform the applicant of the date by which it is proposed to complete the final works for an extra high voltage connection.	within **twenty working days** of receiving the request (and complete the works as soon as reasonably practicable)
Complete low voltage phased energisation works	within **five working days** of receiving the request
Complete high voltage phased energisation works.	within **ten working days** of receiving the request

The relevant applications fees are discussed in Section 4.6.

4.2.1 Definition of the Capacity of a Production Installation

While other countries have certain clear definitions what maximum capacity can be connected to which voltage level, there are no such definitions in the UK. The actual capacity that can be connected to a certain voltage level depends only on the technical feasibility. As seen in the last chapter, regulations in the UK include the option that generation units larger than 100 MW are connected to the distribution system.

4.2.2 Permitting Entities

The Electricity Act of 1989 Section 4(1) introduces a system of licensing for electricity generators, which allows connection to the power system and entry to the electricity generation market. Any generation of electricity without a license is expressly prohibited in the Electricity Act, however Section 5(1) of the Electricity Act provides that the Secretary of State may, by order, grant exemption from Section 4(1)(a). Section 5(2) of the Electricity Act sets out the procedure for making such an order.

On 1 October 2001, the Electricity "Class Exemptions from the Requirement for a License" Order 2001 ("the Class Exemptions Order") came into force.[124] Among other things, this Order exempts small generators that do not at any time provide more electrical power from any one generating station than:

1) 10 megawatts; or
2) 50 megawatts in the case of a generating station with a declared net capacity of less than 100 megawatts
3) as well as offshore generators and on-site (= consumer side of meter) generators.

Generation units between 50 MW – 100 MW, including renewable generation, need a license. However, typically the Secretary of State grants exemption from section 4(1)(a) based on Section 5(1) for renewable generators larger than 50 MW, for instance for wind farms.[125] Hence, it is quite common for the capacity of a distributed generation project to be set at or limited to 99 MW to avoid requiring a license.[126]

The generators that need a license must apply to Ofgem for the license. All generators that wish to become a licensed generator will be required to become parties to the BSC, the Grid Code, the CUSC (for transmission system) and/or the distribution code and must comply with the BSC, the Grid Code and the CUSC and/or distribution code.[127]

It is important to emphasize that unlicensed generators operate in a very different commercial environment to their licensed counterparts. Generation licensing affects both trading arrangements and a distributed generator's relationship with the transmission system. For example, a licensed generator has to be party to the Balancing

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[124] http://www.statutelaw.gov.uk/content.aspx?LegType=All+Legislation&title=The+Electricity+(Class+Exemptions+from+the+Requirement+for+a+License)+Order+2001&searchEnacted=0&extentMatchOnly=0&confersPower=0&blanketAmendment=0&sortAlpha=0&TYPE=QS&PageNumber=1&NavFrom=0&parentActiveTextDocId=2536280&ActiveTextDocId=2536293&filesize=436

[125] See for example http://www.berr.gov.uk/files/file34526.pdf and http://epr.ofgem.gov.uk/document_fetch.php?documentid=9358 as well as http://www.berr.gov.uk/energy/markets/electricity-markets/license-exemp/page34529.html

[126] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistGen/Documents1/15939-193_06.pdf

[127] http://www.ofgem.gov.uk/Licensing/Work/Documents1/5660-Electricity%20Generation%20handbook.pdf

and Settlement Code. This defines and describes the trading arrangements for a generator selling their electricity into the market. Moreover, a licensed generator also has to enter an agreement with the transmission system operator National Grid for using the transmission system. An unlicensed generator avoids the costs and burdens associated with the Code and the need, in most cases, for an agreement with NGET. Unlicensed distributed generators also potentially have access to "embedded benefits". These reflect the fact that distributed generators have a shorter delivery path to consumers. Under current arrangements, an unlicensed generator is effectively treated as negative demand on the system and the electricity they generate is not subject to National Grid's charges relating to the use of the transmission system.

In addition Ofgem is responsible for licensing transmission network operators, distribution network operators and independent distribution network operators.

4.3 Obligations of a Grid Company Regarding Grid Access

The transmission license conditions state the following obligations:[128]

- not to discriminate between any persons or class or classes of persons in providing use of the GB system or in carrying out works for connection;
- to offer terms for connection to and use of the GB system or for the modification of an existing connection within three months of application;
- to offer terms for use of the GB system only within 28 days of application;
- that compliance with the Connection Charging Methodology facilitates effective competition in the generation and supply of electricity and (so far as consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

[128] http://www.nationalgrid.com/NR/rdonlyres/538B0362-162B-4CE1-9483-27B3FDADF4C2/16068/GBCCMI3R0FINAL.pdf

Hence, the transmission system owners have to treat renewable energy and conventional generators equal in regards to connection and have to offer a connection when technically feasible (see also Section 4.4).

Similar conditions are outlined in the DNOs' licenses, i.e. the distribution network operators are required to offer connections to any generation within a set timeframe. The DNOs design these connections to ensure that the distributed generator does not cause the quality of electricity supply to fall below agreed standards, potentially affecting other generators and customers. However, a recent Ofgem document states that "*despite progress in recent years, some argue it is still time-consuming and resource-intensive for distributed generators to obtain a cost-effective connection and that this remains a barrier to the development of distributed generation*".[129]

Finally, private networks do not need a license, hence the regulator cannot put any obligations on these networks.

4.4 Grid Access, Available Capacity and Queue Management

Access Transmission System

The Connection and Use of System Code (CUSC) sets out the standard commercial terms between the TSO and users of the transmission system. This is supplemented by a number of bilateral agreements, including construction agreements, which set out works required to accommodate a user's access rights. The CUSC uses the concepts of Transmission Entry Capacity (TEC). TEC reflects the capability of the wider transmission system and defines the user's access rights to the transmission infrastructure, i.e. a generator cannot export more than its TEC.

Generators can ask the TSO to offer terms for connection to and/or use of the transmission system at any stage of their generation project (provided that sufficient data can be provided to the TSO about the proposed development). The available transmission capacity will be calculated by the TSO (in cooperation with the transmission owners) using certain technical aspects (N-1 criteria, for instance) and will consider all power plants that have already

[129] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistGen/Documents1/15939-193_06.pdf

accepted an offer for connection, i.e. the TSO follows the approach “first come first served”. In case the requested network capacity is not available, the TSO will offer terms for connection based on an ”invest then connect” approach. The TSO will detail in its offer, the works on the transmission system that are required to provide connection to and/or use of the transmission system.

The connection date offered reflects the customer's request but also the time required to complete transmission system works (connection and/or system reinforcement works). In general, connections will not be made until transmission system reinforcement works are complete. However, there have been circumstances where the TSO has been able to agree with customers specific arrangements to facilitate an earlier connection date on a constrained basis (i.e. their access may be limited without compensation).

The key part of the offer from the TSO that includes transmission network upgrades is the construction agreement. The construction agreement sets out the provisions for construction or modification of a direct connection to the GB Transmission system or to facilitate the connection of embedded generation. The construction agreement will primarily set out the responsibilities of each party and the timescales and key milestones in which each party are required to complete each of their areas of work.

Furthermore, the construction agreement provides the necessary financial security that a party must provide to secure against the cost of the appropriate works. Initially, generators that had entered into a contractual agreement with the TSO were required to provide financial security against the transmission system reinforcement works identified in its bilateral agreement. The financial security regime ensures that the TSO and its customers (consumers) are protected from the risk of stranded assets if the project does not go ahead, i.e. the applicant only has to pay for the network upgrade if the project is not going ahead. If the project is going ahead as planned the network upgrade costs are socialized, i.e. recovered via network tariffs paid by all customers.

However, such financial security regime caused a lot of problems particularly for groups of smaller, renewable generators. Hence, the approach was changed and currently applicants must provide a financial security equal to a certain share of the overall investment – typically 2 years of the expected Transmission Network Use of System charge. In addition, they have to prove to the TSO that the project completes certain milestones so that the TSO can be sure that the project is going ahead as planned.

The situation, however, is not considered satisfactory. Therefore Ofgem has started a cross-governance working group named Access Reform Options Development Group (ARODG) for developing other alternatives. ARODG has proposed the following general options regarding transmission network access:[130]

- short term access arrangements;
- access trading arrangements;
- development of a "Spill" product to allow projects to connect and operate without enduring access rights.

These suggestions reflect that intermittent renewable generation (principally on-shore and offshore wind, but also wave and tidal generation), which are often built in locations that currently have little or no transmission network, do not require a constant level of transmission capacity, but need access when their primary fuel (e.g. wind) is available.

A number of selected options developed by ARODG are listed below:

- An Interim TEC product would allow users to use the transmission system in all but a specified number of periods. During these periods, the TSO would be able to curtail a user at zero bid price, or the generator would be required to declare down its output. (This option might already be implemented at the end of 2007);
- ”Deemed Access Rights to the GB Transmission System for Renewable Generators” would allow a renewable generator to export onto the system without wider transmission system reinforcements needing to be in place. Where there is insufficient transmission capacity, it is proposed that other non-renewable generators are constrained off the system first to enable priority access for renewable generators with a new access product, Deemed Transmission Entry Capacity (DTEC). The constraints that would be incurred as a result of taking conventional generators off the system to make way for renewable generators would be funded from Transmission Network Use of System (TNUoS)

[130] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Pages/Traccrw.aspx and http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TransAccess/Pages/TransmissionAccess(ARODG).aspx

charges and not Balancing Services Use of System (BSUoS) charges. (Proposal is currently discussed at the working group stage);

- ”Transmission Entry Capacity with restricted access rights” (TEC-lite) would give only restricted access to the transmission system for new users. TEC-lite would confer different rights to use the transmission system rather than full TEC, and on this basis, those proposing this approach consider that transmission charges would be lower. (Proposal currently at the working group stage);
- TEC Transfer – arrangements to further facilitate the transfer of previously allocated transmission access rights between power stations;
- Extra TEC (ETEC) – the TSO would identify additional transmission access available in operational timescales, which could be purchased before real time and priced ex-ante on a cost-reflective basis.
- Overrun (with ex-post pricing) – this would involve creating arrangements to allow power stations to generate above their TEC, charged on usage and priced ex-post on a cost-reflective basis.
- Shared TEC (subject to discussion) – TEC would be shared between two nodes. The primary party has TEC liability, and the secondary party has rights through a bilateral contract. Charges would be calculated on a cost-reflective basis as a multiple of TEC.

Treatment of Wider Reinforcement

A number of new connection applications can trigger wider reinforcement works (sometimes called ”deep”) on the transmission system, i.e. more than one project can be dependent on a specific set of transmission system reinforcement works. This can result in a 'queue' of projects dependent on major network reinforcements such as most network upgrades between Scotland and England. Due to the costs and number of possible projects involved it is very complicated to include such projects in project-specific construction agreement. Hence, it was decided that certain transmission upgrades are planned and financed via the Transmission Investment for Renewable Generation (TIRG) mechanism.[131]

Queue Management

Due to large numbers of applications for grid access, largely in Scotland, a queue management discussion has emerged in the UK.[132] Over 150, mainly renewable projects, totaling around 12 GW of generating capacity, currently seek connection in Scotland where the network is already constrained. Many of these projects emergerd at an early stage of development in order to take advantage of transitional arrangements under the British Electricity Trading and Transmission Arrangements (BETTA). In all likelihood, only a proportion of the projects currently in the queue will actually connect to the network. The most significant factor is likely to be whether the generator obtains planning consent, but other commercial and technical factors may contribute. The large majority of projects in the queue do not yet have the necessary consents.

The queue management by National Grid focuses on suggesting and discussing new flexible methods with the regulator to deal with the queue, i.e. not necessarily follow the approach "first come first served" but focusing on the progress of the various projects and allowing more generators access to the grid based on suggestions that are similar to the ones developed by the above mentioned TIRG working group. National Grid is particularly focusing on matching progress in the development of generator projects with transmission network upgrades which can only be achieved with regular communication/milestones between applicant and National Grid.[133]

Distribution Network Access

For grid access to the distribution system requiring transmission upgrades, the same method as described above applies regarding the transmission upgrades. In case the connection to the distribution system requires any distribution network upgrades, the applicant must

[131] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/9139-28804.pdf
[132] http://www.nationalgrid.com/uk/Electricity/gb_agreements/gbqueue/
[133] http://www.nationalgrid.com/NR/rdonlyres/47B95865-0225-45C2-B3BE-F753821B1E1B/18039/FinalConclusionpaper.pdf

pay 80% of the costs.[134] These 80%, less any relevant connection charge associated with reinforcement, would be recoverable by the DNO from the applicant over the assumed asset life of 15 years on an annuity basis, starting in the year after the expenditure has been incurred. In addition, the applicant must pay £1/kW/year to cover the on-going operation and maintenance (O&M) costs for the network upgrade and £1.50/kW/yr as additional fee to the network operator related to the DNOs effort to connect the local generation. Ofgem has allowed the additional fee as well as the 80% cost recovery as an incentive for DNOs to connect distributed generation fast and efficiently.[135] A connection is currently only possible after the necessary network upgrades in the distribution and transmission system.

In addition, generators have to pay connection charges – independent of whether the connection has caused any network upgrade – and possible fees related to the transmission system, see also Section 4.8.

4.5 Reservation of Transmission Capacity

Within the Connection and Use of System Code (CUSC), a Transmission Entry Capacity (TEC) is defined which sets the generator's maximum allowed export capacity into the transmission system at any point during the financial year. The TEC is subject to the payment of Transmission Network Use of System (TNUoS) charges calculated in accordance with the Statement of the Use of System Charging Methodology. The TEC is purchased for one year, but procuring TEC in one year gives the User a free option to secure the same level of access in the subsequent charging year.

Hence, as outlined in Section 4.2, distributed generation which has not signed the CUSC also has no TEC and therefore cannot use the transmission system, i.e. they have to sell the power within the distribution network.

If a generator seeks additional TEC or a new generator seeks an initial allocation of TEC this may be done by completing an application and sending it to National Grid. If the TSO considers that

[134] http://www.ofgem.gov.uk/Markets/RetMkts/Metrng/Metering/Documents1/8944-26504.pdf
[135] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistGen/Documents1/15939-193_06.pdf

the additional generator capacity will require network reinforcement for its system to continue to comply with its security standards, National Grid will typically provide a connection offer on an invest-then-connect basis. However, there is also an alternative way, i.e. if somebody holding TEC wishes to sell, parties can negotiate bilaterally the purchase of TEC.[136]

4.6 Costs Associated with the Connection to the Grid

Transmission Connection Charges

Application fees are payable in respect to applications for new connection agreements based on the reasonable costs transmission licensees incur in processing these applications. Users can opt to pay a fixed price application fee (derived from analysis of the historical costs of similar applications) in respect of their application or pay the actual costs incurred. The fixed price fees for applications are detailed in the Statement of Use of System Charges.[137] An example of selected fixed application fees is shown in Table 4-1. If a user chooses not to pay the fixed fee, the application fee will be based on an advance of transmission licensees engineering and out-of pocket expenses and will vary according to the size of the project and the amount of work involved. Where actual expenses exceed the advance, National Grid will issue an invoice for the excess. Conversely, where National Grid does not use the whole of the advance, the balance will be refunded.

Also distributed generators which want to use the transmission system, see Section 4.2, have to pay transmission connection charges.

[136] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/tectrading/
[137] http://www.nationalgrid.com/NR/rdonlyres/65364814-0D47-482A-8B9E-EB32BA5C3259/7871/UoSCI2R1Final4.pdf

Table 4-11: Fixed Prices for New Bilateral Agreements.[138]

		Zone	MW	Fee (£'000)	Agreement Type (as table C)
1	Directly connected generation	NGC South	<100	25 + VAT	Bilateral Connection Agreement
			=>100<300	25 + VAT	
			=>300<500	50 + VAT	
			=>500<1000	50+ VAT	
			=>1000	70 + VAT	
	Directly connected generation	NGC North	<100	55 + VAT	Bilateral Connection Agreement
			=>100<300	55 + VAT	
			=>300<500	110 + VAT	
			=>500<1000	110 + VAT	
			=>1000	160 + VAT	
	Directly connected generation	SPT South	<100	41 + VAT	Bilateral Connection Agreement
			=>100<300	51 + VAT	
			=>300<500	92 + VAT	
			=>500<1000	122 + VAT	
			=>1000	160 + VAT	
	Directly connected generation	SPT North	<100	51 + VAT	Bilateral Connection Agreement
			=>100<300	71 + VAT	
			=>300<500	127 + VAT	
			=>500<1000	172 + VAT	
			=>1000	230 + VAT	
	Directly connected generation	SHETL South	<100	61 + VAT	Bilateral Connection Agreement
			=>100<300	81 + VAT	
			=>300<500	157 + VAT	
			=>500<1000	182 + VAT	
			=>1000	250 + VAT	
	Directly connected generation	SHETL North	<100	61 + VAT	Bilateral Connection Agreement
			=>100<300	81 + VAT	
			=>300<500	157 + VAT	
			=>500<1000	182 + VAT	
			=>1000	250 + VAT	

Distribution Connection Charges

If a generator connects to the distribution system and is not using the transmission system, it only has to pay the reasonable costs that DNOs incur in processing the application. The connection charging methodology can be defined by each DNO but must be approved by Ofgem.[139] If the generator is using the transmission system, the applicant must pay distribution and transmission connection charges.

Annual connection charges are discussed in Section 4.8.

[138] http://www.nationalgrid.com/NR/rdonlyres/65364814-0D47-482A-8B9E-EB32BA5C3259/7871/UoSCI2R1Final4.pdf

[139] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Pages/DistChrgMods.aspx

4.7 Costs and Obligations Related to Metering

Typically any generation asset must have half-hourly import/export metering installed. Microgenerators (<30 kW) are not required to install half-hourly metering, i.e. they are only required to install an import/export meter if they wish to sell their exports to a supplier. Similarly, any generator eligible for Renewable Obligation Certificates (ROCs) and interested to collect ROCs needs half-hourly im/exports metering if the export can be higher than 16 amps/phase.[140] Renewable generators with less than 16 amps/phase export capacity do not need half-hourly im/exports metering but a yearly import/export meter.

If all or part of the electricity that is generated is used on-site by the operator of the generating station, it may be eligible for ROCs. In order to claim ROCs for eligible electricity used on-site, the operator of the generating station needs to measure the power output as described above and sign a declaration (a “Permitted Ways” declaration) and submit this to Ofgem each year. Any electricity consumption of the generator must be deducted from the gross generation.

Net-metering is currently not allowed but some DNOs unofficially accept it. Regulatory changes related to net-metering are under discussion.

4.8 Grid Tariffs

Annual Connection Charges

The annual connection charges are individually calculated for each connected asset. The calculation considers the maintenance and transmission running costs including site-specific maintenance costs and may include costs for upgrading the connection point, but no costs related to transmission network upgrades. The details of the calculation method are outlined in the Statement of the Connection Charging Methodology from April 2007.[141]

[140] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistGen/Documents1/15939-193_06.pdf , http://www.ofgem.gov.uk/Sustainability/Environmnt/RenewablObl/Documents1/April%202007%20Final%20Large.pdf and http://www.ofgem.gov.uk/Sustainability/Environmnt/RenewablObl/Documents1/small%20generator%20guidance_7707.pdf

[141] http://www.nationalgrid.com/NR/rdonlyres/538B0362-162B-4CE1-9483-27B3FDADF4C2/16068/GBCCMI3R0FINAL.pdf

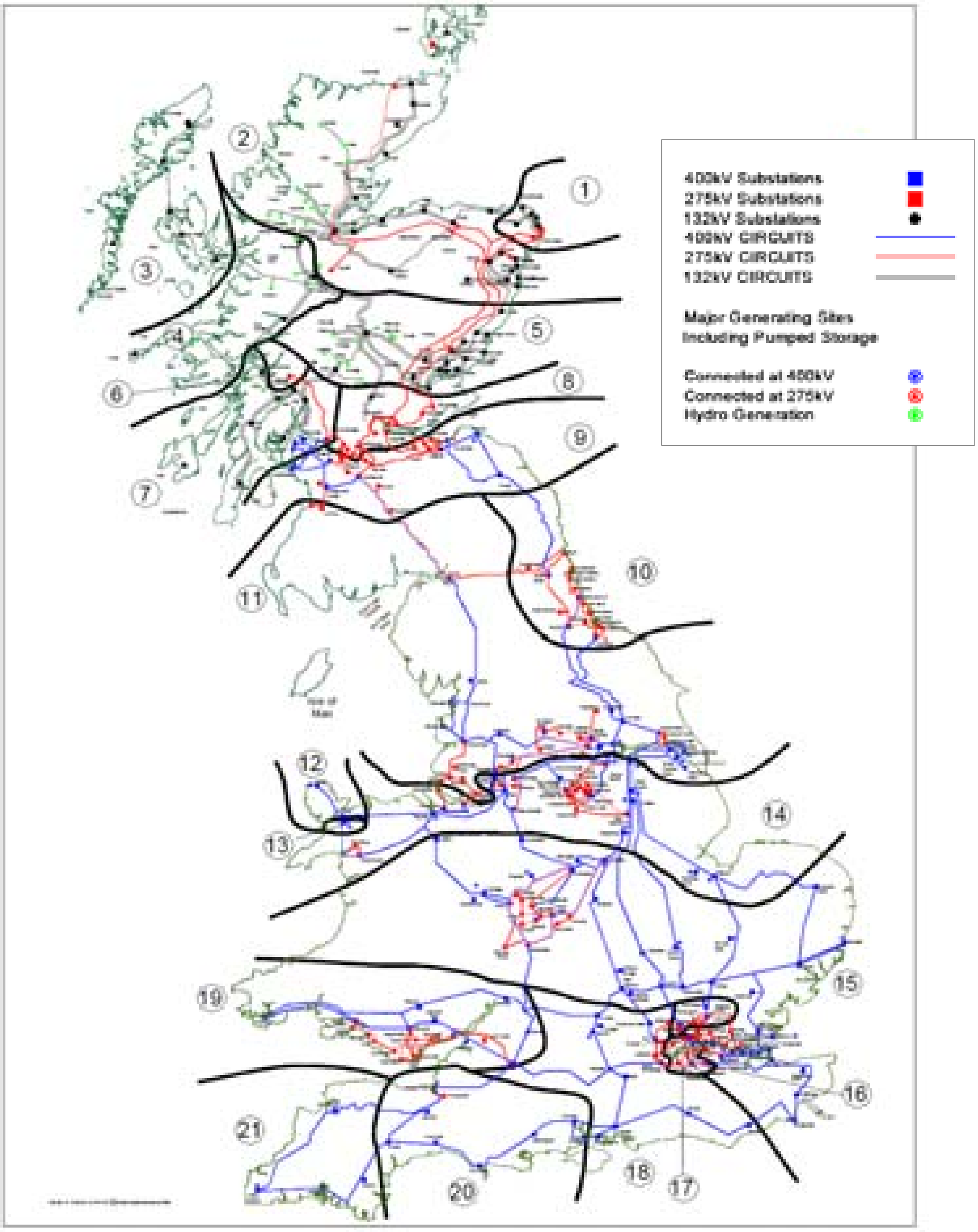
Transmission use of System Charges

Transmission Network Use of System (TNUoS) charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) and must be paid by all users that have signed the Connection and Use of System Code (CUSC), see also Section 4.2. Hence, all generators connected to the transmission system as well as most distributed generators have to pay TNUoS charges.

In April 2004 National Grid introduced a DC Loadflow (DCLF) ICRP based transport model for the England and Wales charging methodology. The DCLF model has been extended to incorporate Scottish network data with existing England and Wales network data to form the GB network in the model. The generation TNUoS depend now on the area in which the generator is connected, see also Figure 4-15. The demand charges depend on a similar zonal approach but the zones are not identical with the zones for generators.

The underlying rationale behind the TNUoS charges is that efficient economic signals are provided to users when services are priced to reflect the incremental costs of supplying them. Therefore, charges reflect the impact that users (generators and consumers) of the transmission system at different locations would have on the transmission owner's costs, if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy.

Figure 4-14: Generation Use of System Tariff Zones as at 1 April 2006 (Geographical).[142]



[142] http://www.nationalgrid.com/NR/rdonlyres/65364814-0D47-482A-8B9E-EB32BA5C3259/7871/UoSCI2R1Final4.pdf, page 8

One special treatment exists for small generators in Scotland which are eligible for a reduction in the listed Generation TNUoS tariffs. This discount has been calculated in accordance with direction from the Authority and equates to 25% of the combined generation and demand residual components of the TNUoS tariffs.

The details of the calculation method for the TNUoS are outlined in "The Statement of the Use of System Charging Methodology"[143] from June 2007 and the current calculation method in the "The Statement of Use of System Charges.[144]

Balancing Services Use of System charges

The TSO recovers the costs of balancing the System through Balancing Services Use of System (BSUoS) charges. The BSUoS charges have to be paid by all parties that have signed the Balancing & Settlement Code, see also Section 4.2.

The Statement of the Use of System Charging Methodology includes a detailed methodology for the calculation of daily BSUoS charges, some working example, and information on BSUoS charge settlement.[145]

Tariffs Related to Distribution Networks

Each DNO licence holder has the obligations to have in place three charging statements:[146]

- the statement of Use of System (UoS) charging methodology,
- the statement of UoS charges and
- the connection charging methodology. The connection charging methodology outlines the method by which connection charges are calculated.

[143] http://www.nationalgrid.com/NR/rdonlyres/33828A47-C4A4-490B-AF7C-25E6E8D7C1DC/17924/UoSCMI3R1FINAL_BSUoSandCAP142_2.pdf
[144] http://www.nationalgrid.com/NR/rdonlyres/65364814-0D47-482A-8B9E-EB32BA5C3259/7871/UoSCI2R1Final4.pdf
[145] http://www.nationalgrid.com/NR/rdonlyres/33828A47-C4A4-490B-AF7C-25E6E8D7C1DC/17924/UoSCMI3R1FINAL_BSUoSandCAP142_2.pdf
[146] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Pages/DistChrgMods.aspx

The proposed methodologies of each DNO will be reviewed and approved by Ofgem. As many charging methods are rather old, Ofgem is pressing the distribution companies to develop charging models that reflect the benefits and costs of distributed generators.[147]

As an example the Use of System Charging Methodology of Northern Electric Distribution is here considered.[148] According to this method, generators connected prior to April 2005 will have to pay no UoS charges as they paid a higher connection charge to directly cover the required deeper connection assets. The situation post-2010 is still under review and no decision has yet been taken.

Generators connected from April 2005 will have paid a lower connection charge to cover the shallower connection assets and hence a separate UoS charge to cover reinforcement costs will be implemented in respect to the electricity that the generator exports to the system. The calculation of the UoS charges includes:

- Annuity pass-through calculation, which is based on a 80% pass-through of the network reinforcements costs caused in the distribution network by the generator (cost recoverable by the DNO from the applicant over the assumed asset life of 15 years on an annuity basis);
- OR&M – based on an allowance for each kW of installed generation capacity (£1/kW/year);
- Revenue Driver – based on an allowance for each kW of installed generation capacity (£1.50/kW/yr)
- NGC Exit charges to the transmission network– a proportionate share of the NGC Exit charges apportioned on an agreed capacity basis.

Hence, distributed generators which did not cause any network upgrades and are not using the transmission system will only be charged the revenue driver (£1.50/kW/yr), which was created by Ofgem as an incentive for DNOs to connect as much distributed generation as possible in an economic and efficient way.

[147] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistGen/Documents1/15939-193_06.pdf

[148] http://www.ce-electricuk.com/lib/liDownload/566/NEDL%20Use%20of%20system%20charging%20methodology%20v1_8.pdf

4.9 Rights and Obligations Regarding Real Time Operation

Renewable energy is treated exactly the same way as conventional generation in the UK, i.e. renewable energy has the same rights and obligations as other forms of generation. Renewable generation can in principal participate in all ancillary service markets if it fulfils the technical requirements outlined for the different ancillary markets by National Grid.[149] However, as renewable energy generation will only receive the ROCs for the actual electricity produced, renewable energy generators typically have little interest to participate in any market that may result in a reduction of power output, such as markets related to frequency control.

4.10 Conclusions United Kingdom

General Renewable Energy Promotion Scheme

- The UK has a Renewable Obligation scheme which came into force in April 2002. It requires power suppliers to derive from renewables a specified proportion of the electricity they supply to their customers. This started at 3% in 2003, rising gradually to 10.4% by 2010, and 15.4% by 2015. The Obligation is guaranteed in law until 2027. The certificates can be sold separately from the electricity to which they relate, i.e. suppliers can purchase these certificates in order to fulfill their obligation. This allows for open trading of certificates. To fulfill their obligation, suppliers can either present enough certificates to cover the required percentage of their output, or they can pay a 'buy-out' price for any shortfall. The Buy-Out price was set at £30.00 per MW/h in 2002/03 and increases each year by the Retail Price Index (RPI). The period 05/06 had a "buy-out" price of £32.33, the price for 07/08 is £34.30 per megawatt hour (MWh). All payments are back-channeled to suppliers in proportion to the number of ROCs they present. The certificates are currently traded at 48.12 £/ MWh (68.92 €/MWh), which results in some of the highest payments for renewables in Europe.

[149] http://www.nationalgrid.com/uk/Electricity/Balancing/services/

Any size limit in the regulations for renewable energy?

- In the UK, there are capacity limits for generators connected to the distribution grid regarding the payment of Transmission Network Use of System charges (TNUoS). These limits vary between different areas in the UK, but in most cases the limit is 50 MW in England and Wales and 30 MW in the Scottish Power transmission area and 10 MW in the Scottish Hydro transmission area. Most generators connected to the distribution network with a capacity below these limits are exempted of TNUoS in recognition of the reduced demand in a zone served by the transmission system. However, generators that have been connected to the distribution network after 1 April 2005 have to pay Distribution Network Use of System charges if their connection required a distribution network upgrade. The Distribution Network Use of System charge should then recover some of the network upgrade costs.

Tariff Structure

- In the UK, generators pay network tariffs (known as Use of System charges) if they are connected to the transmission system. The charges do not distinguish between renewable energy and conventional energy, but they vary based on the location of the connection point. Hence, the connection charges to the transmission grid are high in Scotland, which has low load but many generation sources, and low (in some cases even negative) in South England which has high load and limited local generation sources. In addition, small power stations connected to the distribution network, independent of their technology, do not have to pay Transmission Use of System charges (See above). In principle, power stations are defined as small if they have a total capacity of up to 50 MW in England and Wales, up to 30 MW in the Scottish Power transmission area and up to 10 MW in the Scottish Hydro transmission area. However, generators that have been connected to the distribution network after 1 April 2005 and which have caused reinforcement on the distribution grid have to pay Distribution Network Use of System charges.

Network Upgrade Costs

- In the UK, costs for transmission upgrades are typically socialized. In principle, transmission reinforcements are only performed if sufficient requests for network connections are submitted. However, this approach leads to long delays in cases where 'strategic works' are needed. Recognizing this, the regulator Ofgem recently approved £560 millions for 'Transmission Investment for Renewable Generation'. When it comes to upgrades in the distribution grid, producers in the UK connected to the distribution network after the 1 April 2005, have to pay a Distribution Network Use of System charge (DUoS) which generally reflects the upgrading costs for the exclusive use of the generator. For connections to the distribution grid prior to 1 April 2005, costs for distribution network reinforcement were charged upfront. In the UK, the creation of independent Offshore Transmission Owners (OFTO) are proposed. The OFTO would be selected by competitive tender and awarded a transmission licence which enables it to receive a regulated revenue stream in return for meeting its licence obligations for a predetermined regulatory period (20 years), and would be incentivised to achieve specified performance requirements during this period. OFTO would have the responsibility for designing, building, financing and maintaining the offshore transmission network required to connect an offshore generator.

Network Concessions

- Ofgem has licensed 13 distribution network operators (DNOs) in the UK (14 including Northern Ireland) each responsible for a distribution service area (similar to a concession area). DNOs came into existence on 1 October 2001, evolving from ex-Public Electricity Suppliers. In addition there are four independent licensed network operators that own and run smaller networks embedded in the DNO networks, called Independent Distribution Network Operators (IDNO). An IDNO is any electricity distributor with a license granted after 1 October 2001. IDNOs own and operate electricity distribution networks which will predominately be network extensions connected to the existing distribution network, e.g. to serve new housing developments.

IDNOs do not have general distribution service areas. Finally, privately-owned unlicensed networks may operate within existing distribution networks. Advantages include exemption from some license charges and reduced energy loss in transmission. Ports and large industrial users often operate with private wire networks.

Network Connection Procedure

- All potential applicants, renewable energy generators or conventional generators, are treated equally in the connection process. There are very detailed network connection procedures in the UK, with detailed time lines and definitions of the relevant fees. The procedures were developed by National Grid, the transmission system operator and reviewed and approved by the regulator Ofgem. Any applicant that wishes to connect directly to the transmission system will be offered to enter into a Bilateral Connection Agreement (BCA) with National Grid within 3 months of application. Any customer wishing to connect to a distribution system should initially contact the Distribution Network Operator in its area to discuss the proposed connection. For the type of interconnection agreement, the size of the power station and its location is important.

Metering

- Typically any generation asset must have half-hourly import/export metering installed. Similarly, any generator eligible for Renewable Obligation Certificates (ROCs) and interested to collect ROCs needs half-hourly im/exports metering if the export can be higher than 16 amps/phase. Renewable generators with less than 16 amps/phase export capacity do not need half-hourly im/exports metering but a yearly import/export meter.

5 Summary of Findings

The following sections provide a brief comparison between Sweden, Spain, Portugal, Germany, and United Kingdom regarding issues that are important for Sweden. In the following chapter, we refer to Spain, Portugal, Germany and United Kingdom as the four studied countries.

Each section starts with a table comparing the situation in Sweden and in the four studied countries, followed by a brief analysis of the differences and similarities between the different countries. At the end, we will present the conclusions.

5.1 General Renewable Energy Promotion Scheme

This section focuses on wind power and solar photovoltaics since these energy sources have had a remarkable increase in the four studied countries. For details on other types of renewable energies for the studied countries, please see the country-specific chapters.

Table 5-1: **Comparison of renewable energy regulations and its impact on wind power and solar photovoltaic development**

	Sweden	Spain	Portugal	Germany	UK
Regulation Scheme	Electricity Certificates	Feed-in tariffs & market option (market price + premium)	Feed-in tariffs	Feed-in tariffs	Renewables Obligation Certificates (ROC)
Total Payment Level for wind power 2006 [€/MWh]	=69.12[150] Certificate=21 Energy=48.12	Feed-in tariff: 77.73 Market option: 91.01 (Premium 31 plus energy 48 plus market incentive 7 plus other complements)	92.8	(on-shore) 83.6 for first 5 years, then 52.8	= ~124-130[151] ROCs 59-65 (buy out: 47.9) plus ~65 for energy
Total Installed Generation Capacity end 2006 [MW]	33,819	82,336	13,607	111,000	83,045
Total Installed Wind Capacity end 2006 [MW]	572	11,615	1,716	20,622	1,958
Wind Capacity added in 2006 [MW]	80	1,587	692	2,195	616
Total Payment Level for Solar Photovoltaics 2006 [€/MWh]	=69.12[152]	Feed-in tariff: P<100kW:440 P>100kW:230	Feed-in tariff: P<5kW:447 P>5kW:316	Feed-in tariff: P<30kW:518-568 30kW<P<100kW: 493-543 P>100kW:487-53	= ~124-130
Installed PV Capacity[MW] end 2006	4.8	118	2.3	2,863	9.9
PV added in 2006 [MW]	0.6	60	0	953	1

[150] In addition, wind power producers on-shore with installations on place before the implementation of the electricity certificate system in May 2003 received an environmental bonus equal to 7 €/MWh which corresponds to an average total payment of 76 €/MWh. This system based on environmental bonus is being phased out and will be removed after 2009. Based on Nord Pool information, an exchange rate of 9.2556 SEK/EUR has been used.

[151] Exchange rate of 1£ = 1.4 Euro.

[152] This payment is obtained when selling the production to the grid which is done only by a few installations (less than 5). Commonly in Sweden, solar photovoltaic installations use their electricity production to reduce their own consumption and not to sell it to the grid since the network costs (including compensation for reduction of network losses) to be able to inject electricity to the grid are typically higher than the payment they receive. When reducing their consumption, the payment can be assumed to be equal to the cost of electricity which is about 110 €/MWh for domestic consumers.

It is important to take into account when comparing different promotion schemes for renewable energies that each country has specific national conditions that can be very different. This means that different promotion schemes may be needed to get the same power production. For example, the average wind conditions in Germany are quite low, in 2006 each installed MW wind power generated on average an electric power of 1,560 MWh. In the same year, in Spain each installed MW corresponded to a power production of 2,160 MWh, while in Sweden each installed MW generated 1,850 MWh and in the UK 2,780 MWh on average.

The values shown in Table 5-1 regarding Total Payment Level 2006 for Sweden, UK and Spain (market option) are exceptionally high since electricity market prices in these countries were exceptionally high during 2006. This must be kept in mind when comparing the payment levels between the different countries.

Table 5-1 shows that in 2006 wind power producers in the UK received the highest payments and wind power producers in Sweden received the lowest payments. However, wind power producers in Germany that have been producing for more than five years received lower payments than wind power producers in Sweden. When it comes to solar photovoltaics it is very clear that the feed-in systems in Germany, Portugal and Spain give much higher incentives than the certificate systems in Sweden and the UK. For photovoltaics, Germany is the country with the highest payment among the studied countries and also with the largest installed capacity.

Table 5-1 also shows that the promotion scheme in Germany, Spain and Portugal is based on feed-in tariffs which are defined for the different types of renewable energies. This is a great difference to the electricity certificate system applied in Sweden, for example, where there is a single price for all renewable energies. The most relevant feature of the feed-in tariff scheme is that it secures a certain income during a fixed time horizon while the certificate system gives a more uncertain economical support to the renewable energies since the price can vary significantly over time. The stability in the promotion scheme is the main reason why in Germany there is still a large expansion of the wind power sector even if the remuneration level is not particularly high.

An interesting example of combining a feed-in tariff system and a market-based promotion scheme can be found in Spain where power producers using renewable energies can choose between these two promotion schemes. The income obtained from the market option can be much higher than in the feed-in tariff option but it can also be lower. However, that risk has been minimized by introducing a floor value. At the same time, a cap value has been introduced in Spain in order to limit the State support given to renewable energies. Germany and Portugal have also established different criteria in order to limit the State support to wind power. Germany has defined for each location a reference production model. After 5 years, each installation is compared to the reference model and in case the production has reached more than 150% of the reference production the payment decreases to a 30% lower level. In Portugal wind turbines producing more than 2,000 MWh per installed MW and per year receive lower payments. Wind turbines producing more than 2,600 MWh per year and per installed MW receive a payment per MWh that is 10% lower than that of turbines producing less than 2,000 MWh.

In summary, the countries that have experienced the largest development in the wind power sector, i.e. Germany and Spain, use fixed feed-in tariff promotion schemes. Feed-in tariffs provide a stable investment environment as it sets clear power purchase prices for a defined time horizon. Hence, the regulatory framework regarding payment schemes can be considered the main driver for the development of renewable energy. However, there are some other factors that are relevant for the development of the wind power sector such as the permitting procedure and the connection procedure. In comparison to the four studied countries, wind power producers in Sweden receive the lowest payment, which means that in Sweden all other costs such as connection cost, network upgrades and network tariffs become even more important than in the other studied countries. It must be noted though that in Sweden the electricity certificate system has lead to a significant increase of biomass-based electricity production, but biomass has not been included in the comparison.

5.2 Network Connection Procedure

Table 5-2: Comparison of network connection procedures for producers using renewable energies.

	Sweden	Spain	Portugal	Germany	UK
Procedure Description	Detailed procedure for connection to the transmission grid but not well described for connection to the regional/local grid	Detailed procedure	Detailed procedure	The procedure is not clearly outlined in law, but legally renewable generation has the right to be connected.	Detailed procedure for transmission and distribution connection defined by National Grid, approved by Regulator
Deadlines	Defined deadlines for connection to transmission grid but not for connection to other grids.	Defined deadlines	Defined deadlines	Delays can cause complaints to regulator	Max. 3 months time to deal with application
Fees	None for transmission grid. For other grids it depends on the grid owner.	Yes, both for connection to the transmission and the distribution grid. 500 €/kW for solar photovoltaic[153] and 20 €/kW for other renewables.	Yes, both for connection to the transmission and the distribution grid. 400 €/MW for study on available capacity and 500 €/kW for allocation of connection point.	No	Yes (depend upon size, type and location)

A well-defined network connection procedure reduces the overall costs for the application. It means that the applicant has a clear understanding of what is required from him and what he has to pay and that the network company can develop a method and procedure of how to deal with connection applications. A well-defined procedure includes the information required for the application, the relevant timeline for network companies to reply to the application, and the application-related costs (fees) that are typically caused by network integration studies to be performed by the network company. There are very detailed network connection procedures in the UK, for instance. The procedures were developed by National Grid, the transmission system operator and reviewed and approved by the

[153] Solar photovoltaics installed on residential buildings or industrial premises are exempted of paying such application fees.

regulator Ofgem. Spain and Portugal are also examples of countries with very detailed connection procedures. The procedures are prescribed by law and are not only a conduct code between grid companies and producers' associations.

Countries without clearly defined methods and procedures, including Sweden, frequently report very long response times for network connection applications and communication problems between applicants and network companies.

In Germany, the procedure is not clearly described, but the network association has developed a guideline for the network companies how to deal with applications, but most importantly the relevant law defines that "*Grid system operators shall immediately and as a priority connect plants generating electricity from renewable energy sources*". Hence in case of delays the network companies have to explain to the regulator what caused the delays. That causes additional costs to the network companies if the application is not processed reasonably fast. In Germany, the evaluation methods that determine how much additional generation can be connected at a certain point are not considered to be sufficiently transparent as network data are typically not published. An independent evaluation of the response to an application is therefore rather complicated.

In summary, to ensure that the application procedure is conducted in a clear, unbiased and consistent manner, irrespective of the network company, the renewable energy technology or the applicant, it is necessary to have a clear definition of the connection application procedure with clear requirements of what is needed for the application, a clear timeframe regarding the reply of the network company, and defined basic principals for the interconnection analysis.

Nevertheless, conflicts may arise, hence a clear procedure of how to deal with such conflicts should be developed. Germany, for instance, used to have a specific organisation that helped to settle such interconnection disputes. Today this task is part of the newly started regulator in Germany, similar to the approach in Spain.

Regarding fees for processing connection applications, there are several countries that apply such fees: Spain, Portugal and UK. A reason for such fees is to avoid unserious applications and the work related to them. However, the fees might be a barrier for very small projects such as solar photovoltaics on residential buildings. An option would be to exclude such projects from paying the fees, which is the case in Spain. In Spain, Portugal and the UK, the fees are well defined and do not depend on the owner of the grid to which the installation is connected. This is very important in order to improve transparency and to not discriminate against certain producers. In Sweden, fees depend on the grid owners and are only paid when connecting to the distribution grid, even though the amount of the fees paid is typically discounted from the total connection cost to be paid by the producer.

5.3 Network Investment Costs

Table 5-3: Comparison of network investment costs for producers using renewable energies.

Who pays the costs for…	Sweden	Spain	Portugal	Germany	UK
Connection installations from wind farm on-shore to network connection point	Wind Farm Owner	Wind Farm Owner	Wind Farm Owner	Wind Farm Owner	Wind Farm Owner
Connection installations from wind farm off-shore to network connection point	Wind Farm Owner	Wind Farm Owner	Wind Farm Owner	Transmission Company	Independent Transmission Company (if the connection voltage is 130kV or higher)
Upgrades in the distribution network and regional network	Upgrades that benefit only the wind farm owner are paid by the wind farm owner. When upgrades benefit others then costs are shared.	Mainly paid by new power plant	Mainly paid by new power plant	Network companies	Generator and grid owner share costs
Upgrades in the transmission network	Upgrades that benefit only the wind farm owner are paid by the wind farm owner. When upgrades benefit others (mainly in the 400 kV grid) then SvK pays a part or all costs.	Upgrades are paid by transmission company (socialized)	Upgrades are paid by transmission company (socialized)	Network companies (Costs are socialized between all customers in Germany)	Upgrades are paid by transmission company
Fees or deposits to be paid in relation to upgrade works	No	Yes, but only for upgrades in the transmission grid. 20% of the upgrading costs.	Yes, both for transmission and distribution grid when upgrading costs are accelerated, agreed between grid owner and wind farm owner.	No fees	Deposit equal to 2 year Use of System charge for transmission network upgrades

In all studied four countries, and also in Sweden, project developers have to pay for the construction of the line, transformers and all other necessary installations for the connection to the grid. There is no difference between conventional power producers and power producers using renewable energy sources. However, in 2007 Germany adopted a law which states that grid companies have to pay for power lines connecting off-shore wind projects to their grids. In the UK, the creation of independent Offshore Transmission Owners (OFTO) are proposed. The OFTO would be selected by competitive tender and awarded a transmission licence which enables it to receive a regulated income from offshore wind farms in return for meeting its licence obligations for a predetermined regulatory period (20 years), and would be incentivised to achieve specified performance requirements during this period. OFTO would have the responsibility for designing, building, financing and maintaining the offshore transmission network required to connect an offshore generator.

In the studied countries and in Sweden, there are no laws giving a clear definition of what deep costs, i.e. costs associated to upgrades of the grid necessary to connect new producers, can be considered to benefit just one producer and which can be considered to benefit several producers. This is crucial since this determines who is to pay these upgrades in all studied countries except Germany where upgrades are always paid for by the grid owner. If the upgrades are considered to benefit just one producer, then this producer has to pay the whole cost associated to the upgrade. If they are considered to benefit more than one producer costs are shared between the producer and the grid owner or between the different producers. Spain, for example, follows the criterion that upgrades in the transmission grid benefit more than one producer and are therefore socialized, i.e., paid by all consumers, while, for example, Sweden considers that upgrades in radial power line parts of the transmission grid only benefit one producer and are therefore to be paid for by that producer.

In Germany, grid companies are required to pay all network upgrading costs while in principal renewable energy generators are required to pay the costs for the grid connection, i.e. all costs from the wind farm to the connection point. The main issue is typically to define the best grid connection point. The general rule for defining the grid connection point is based on the understanding that total network connection costs, i.e. connection plus upgrade costs, should be minimized independent of who covers which part of the costs. This could mean that a low-voltage network has to be upgraded to a high-voltage network if this is the most economic solution. But it is also possible that the wind farm operator itself has to build a long line to a suitable connection point if this is more economic than upgrading the existing network.

In the UK, costs for transmission upgrades are typically socialized. In principle, transmission reinforcements are only performed if sufficient requests for network connections are submitted. However, this approach leads to long delays in cases where 'strategic works' are needed. Recognizing this, the regulator Ofgem approved £560 millions for 'Transmission Investment for Renewable Generation' in 2007. When it comes to upgrades in the distribution grid, producers in the UK connected to the distribution network after 1 April 2005, have to pay a Distribution Network Use of System charge (DUoS) which generally reflects the upgrading costs for the exclusive use of the generator. For connections to the distribution grid prior to 1 April 2005, costs for distribution network reinforcement were charged upfront.

Table 5-3 shows that Sweden is the country where project developers have to pay most network investment costs since they have to pay for connections, upgrades in the distribution/regional grid as well as upgrades in the transmission grid in case they are caused exclusively by them. On the other hand, Germany is the country where project developers pay less network investment costs since they only pay for the connection, but not for any network upgrades, neither in the distribution grid nor in the transmission grid.[154] It is interesting to relate this observation to the fact that Sweden is the country where wind power producers receive the lowest payment compared to the four studied countries.

Both in Spain and Portugal, project developers have to pay deposits to transmission companies if upgrade works are necessary to connect them. The reason is to avoid that projects are not realized and the upgrade works are carried out. In Sweden, no such deposits are paid to the transmission company since project developers have to pay network tariffs and upgrade costs (in case the upgrades exclusively benefit the project developer) to the transmission company.

[154] Network upgrade costs in Germany are paid by network companies, which partly causes higher network tariffs for network users, however, these higher network tariffs are currently not considered a major issue by the different stakeholders.

In summary, upgrades in the transmission grid and in the distribution/regional grid are treated differently in the studies countries. Costs related to the upgrade of the transmission grid are generally socialized, i.e. network companies pay for it and can recover the costs via network tariffs. However in Sweden, project developers pay the costs if the upgrade refers to a radial line; while costs are shared between the owner of the production plant and Svenska Kraftnät when the upgrade is done in the meshed grid. Distribution network upgrades have to be paid in most of the studied countries by the company which causes the upgrade, except in Germany where they are socialized as well. In comparison with the studied countries, project developers in Sweden have to pay most network investment costs.

5.4 Capacity Limits in the Regulations for Renewable Energy

Table 5-4: Comparison of capacity limits for producers using renewable energies

	Sweden	Spain	Portugal	Germany	UK
Capacity limits for payment of network tariffs	Yes, 1.5 MW[155]	No	No	No	Not for transmission grid, but for distribution grids ~10-50 MW
Capacity limits for support scheme	No	Feed-in tariff can vary depending on project capacity, projects with capacity >50MW get much lower payment	Feed-in tariff can vary depending on project capacity	Feed-in tariff can vary depending on project capacity	No
Capacity limits for connection to the grid	No	At least 100 MW to connect to 220 kV and 250 MW to connect to 400 kV.	Installations with installed capacity >50 MW connect to the transmission grid, others to the distribution grid	No	Might come for offshore wind farms (new rules regarding the grid connection of offshore wind farms under discussion)

[155] The capacity limit of 1.5 MW in Sweden applies to individual units of an installation. This means that a wind farm with 50 wind turbines of 1 MW each is exempted from paying network tariffs, while a wind farm with 10 wind turbines of 2 MW each has to pay network tariffs.

Only the UK and Sweden have networks tariffs for producers. In all other countries, producers do not pay such network tariffs, see also Section 5.7. Sweden and UK are the only countries of the five included in this report which have limits related to the installed capacity for the payment of network tariffs, see also Table 5-4. In Sweden producers with a capacity below 1.5 MW do not pay any network tariffs, except the fixed metering cost. In the UK there are capacity limits for generators connected to the distribution grid regarding the payment of Transmission Network Use of System charges (TNUoS). These limits vary between different areas in the UK, but in most cases the limit is 50 MW in England and Wales and 30 MW in the Scottish Power transmission area and 10 MW in the Scottish Hydro transmission area. Most generators connected to the distribution network with a capacity below these limits are exempted from TNUoS in recognition of the reduced demand in a zone served by the transmission system. However, generators that have been connected to the distribution network after 1 April 2005 have to pay Distribution Network Use of System charges if their connection required a distribution network upgrade. The Distribution Network Use of System charge should then recover some of the network upgrade costs.

In the countries using promotion schemes based on feed-in tariffs, different limits of installed capacity are defined in order to differentiate the payment within one and the same technology. A clear example is the different payment that solar photovoltaic installations receive depending on the installed capacity; the difference can be about 40%. For wind power, there are certain differences depending on the installed capacity, but they are in the order of 3–5%. The countries using certificate systems do not have any capacity limit since there is only one payment for all kinds of renewable energies.

Regarding the connection to the grid, only Spain and Portugal have defined limits for the connection to the different voltage levels. The reason for setting up such limits has been to simplify the processing of connection applications and to clarify the different responsibilities of the grid owners. The definition of such limits has nothing to do with the promotion scheme chosen. In Spain, for instance, several project developers submit a joint application to the TSO in order to fulfil the minimum capacity requirement for a connection to the transmission grid. Additional size definitions are used in the definitions for metering requirements, see Section 4.

In summary, in most countries, i.e. Germany, Spain and Portugal, there are no capacity limits for the payment of network tariffs similar to those used in Sweden. Capacity limits are either used to define connection voltage levels (Spain and Portugal) or to differentiate the feed-in tariff.

5.5 Network Concessions

Table 5-5: Overview of policy issues related to the construction/ownership of new power lines.

	Sweden	Spain	Portugal	Germany	UK
Can wind power producers build/own the power cables connecting the turbines within a wind farm?	No	Yes	Yes	Yes	Yes
Can wind power producers build the power lines connecting a wind farm to the distribution/ transmission grid?	No	Yes	Yes	Yes	Yes

Network concessions are legal authorizations that are required in some countries in order to build power lines. The origin of these network concessions is the centrally planned electricity system that – with the deregulation – has developed into the current system with several network companies. In Sweden, for instance, there are concessions for an area which allow those that have the concession to build power lines in that area (typically for voltage levels up to 20 kV[156]). In principle no one else can build power lines with a lower or equal voltage level than 20 kV in that area except power lines that are exempted from concessions as, for example, the power lines of industrial networks. To build power lines with a higher voltage level than typically 20 kV, another type of concession called line concession is needed in Sweden. As mentioned before, network concessions give the right to build power lines, but together with the obligation to give access to everyone who wants to connect an installation there. In Sweden, in order to get a network concession the applicant must not work with electricity production or retail of electricity.

[156] There are approximately 330 area concessions in Sweden of which only 10 have a voltage level over 20 kV, all others have a voltage limit of 20 kV.

Producers in Sweden have two possibilities regarding the building of the connecting lines within the wind farm and from the wind farm to the connection point. One, to pay the network company in the area for building those lines and two, to form a network company in order to get line concessions and be able to build the lines themselves. In both cases it is the project developer that pays for the power line but the ownership of the line and the responsibilities associated to it depend on which option is chosen.

A drawback with network concessions is that they increase bureaucracy and makes it more difficult for small project developers to find more economical solutions to build these power lines. This is due to the fact that only in the case of creating a network company the owner of the wind farm can build the lines, otherwise it is only the grid company with the concession for that area that can build power lines. To form a network company has, under current legislation, a lot of consequences for example regarding reporting obligations, which are difficult to meet for small investors.

In all studied four countries, wind power producers can build the lines between the individual wind turbines in the wind farm without needing concession. The main consequence of this is that in these countries grid companies do not have a monopoly over such lines. As opposed to this, it is necessary in Sweden to have a network concession in order to build the lines between the wind turbines of a wind farm.

Regarding the power lines from the wind farm to the connection points in the transmission grid or in the distribution/regional grid, in all the four studied countries wind farm owners do not need any concession for building them. In Spain, wind project developers can build such lines once they are granted the necessary building permits that are the same as the permits required for distribution companies or transmission companies including studies on environmental impact and public consultation. It is common practice that – regarding voltage ranges of between 45 and 132 kV – producers transfer the connecting line and even the position at the substation to the distribution company in order to avoid their operation and maintenance and the associated costs. In Portugal, it is also quite common on the distribution level that project developers transfer the line to the distribution company in order to avoid maintenance and operation of the line. The distribution company has in that case the obligation to give access to consumers and other producers if there is available capacity. By transfering the connecting line to the grid company in

Spain and Portugal, producers avoid operation and maintenance costs for that line since they do not pay any network tariffs (see Section 5.7). However, in Sweden even if the producer transfers the line to the distribution company he will still pay for its operation and maintenance since these costs are included in the network tariffs that producers pay in Sweden.

In summary, in all four studied countries wind farm owners can build the power lines within the wind farm and between the wind farm and the transmission/ distribution grid without needing a concession. Sweden is different since it requires concessions in order to build such lines. The requirement of network concessions increases bureaucracy and makes it more difficult to find more economical solutions to build the power lines since only by creating a network company the owner of the wind farm can build the lines, otherwise it is only the grid company with the concession for that area can build power lines. In the studied countries, lines within a power production installation and from the installation to the distribution/transmission grid are treated differently to lines that are part of the distribution/transmission grid. This applies to all kinds of power producing installations and is not specific for those using renewable energy sources. In the studied countries, sometimes the wind power producer and the grid company of the area enter into special agreements in order to transfer the ownership of the line up to the connection point to the grid company. This way, the producer can avoid operation and maintenance of the lines and the grid company can connect other customers/producers.

5.6 Metering

Table 5-6: Comparison of metering requirements.

	Sweden	Spain	Portugal	Germany	UK
Metering	Requirement of hourly measurement for all production.	No requirement of hourly measurement and possibility to choose between net-metering and im/export metering for small projects[157].	No requirement of hourly measurement for small projects connected to the low voltage grid (<1 kV).	15 min im/export, active/reactive metering for units larger 500 kW; for units smaller 500 kW only yearly energy metering required; net-metering for smaller units possible with agreement.	30 min im/export active/reactive metering; if export less than 16 amps/phase im/export metering required. Net-metering currently not possible, but discussed.

Metering costs can be neglected for large generation plants in the megawatt range; all countries typically have identical metering requirements for conventional power plants and renewable energy plants in the megawatt range. Metering costs, however, become a very important issue for small installations in the kW range, e.g. PV, as the metering costs can have a significant impact on the overall project economics.

For small projects, Germany, Portugal and the UK distinguish between on-site generation, e.g. a PV panel on the roof of a house, and grid-connected generation plant. In case of on-site generation generally no metering is required if the local generation always exceeds local consumption. However, in this case no special payment (feed-in tariff or renewable energy certificates) can be received. In case the local production sometimes exceeds local consumption, customers in Germany and Spain can opt for net-metering. Net-metering means that the power company only bills the net consumption (consumption minus local production). Typically such net-metering is only possible for small installations, e.g. up to 500 kW in Germany.

In addition, power producers in Germany as well as in Spain that are connected to the low-voltage grid – mainly solar photovoltaics – can also choose to have two different measurement equipments, one for the produced power and one for the consumed power since the payment for the produced power is almost three times larger than the cost for the consumed power.

[157] Here, small project means projects that are connected to the low-voltage grid (<1 kV) and with a capacity lower than 100 kW.

Small grid-connected installations, i.e. no on-site installations, often have special rules for metering. For instance, small grid-connected applications up to a certain size (Germany 500 kW, UK 16amps/phase) only have to install simple – cheaper – metering equipment, without 15 or 30 minute metering capabilities.

5.7 Network Tariff Structure

Table 5-7: Comparison of network fees.

	Sweden	Spain	Portugal	Germany	UK
Network Tariff for Power Producer	Yes, but also remuneration from grid owner*	No	No	No	Yes (Use of System charges) if connected to transmission system, but also remuneration from grid owner*

* Network tariffs in Sweden are defined in order to give locational signals which means that producers which reduce network losses receive economic compensation. This can result in negative network tariffs. This system is also used in the UK.

Network fees can be used to allocate certain costs, e.g. network upgrade costs, power system losses, operation and maintenance of power lines, to the power system participants that mainly have caused these costs. In practice, a clear allocation is difficult due to the complexity of clearly identifying who caused what costs in the power system. Hence, some countries such as Spain, Portugal and Germany decided a long time ago that power producers do not need to pay any tariffs for using the power grid. This has always been the case for both conventional power generators and renewable power generators. That means that historically grid tariffs did not play any role in energy policy in order to promote renewable energy technologies.

It is, however, important to emphasize that the network ownership situation in Spain and Portugal differs from that in Sweden. The whole distribution system in Portugal is owned by a single company, and in Spain by five companies[158]. In Spain, distribution companies are regulated ex-ante which means that the Government decides every year on the income for each distribution company and the tariffs they can charge consumers. In both countries the transmission system is almost completely owned by one transmission company. Therefore, it is easier to socialize any costs caused by one generator

[158] There are around 300 small distribution companies in Spain, but their share in the distribution activity is lower than 1%.

in the transmission grid, for instance due to required network upgrades, since these cost will be shared equally by all customers within Spain or Portugal, respectively.

Similar to Sweden, Germany has a large number of distribution and regional network companies (around 900) plus four transmission companies. That means that any costs caused by power generators are not distributed equally among all customers. However, interviews with network companies, customer organisations and the regulator in Germany revealed that this is generally not considered an important issue. Only for the connection of offshore wind farms in Germany, which is the responsibility of the transmission system operators, a special mechanism was developed to equally distribute the costs among all network customers in Germany.

In the UK, generators pay network tariffs (known as Use of System charges) if they are connected to the transmission system. The charges do not distinguish between renewable energy and conventional energy, but they vary based on the location of the connection point. Hence, the connection charges to the transmission grid are high in Scotland, which has low load but many generation sources, and low (in some cases even negative) in South England which has high load and limited local generation sources. In addition, small power stations connected to the distribution network, independent of their technology, do not have to pay Transmission Use of System charges (see also Section 5.4). In principle, power stations are defined as small if they have a total capacity of up to 50 MW in England and Wales, up to 30 MW in the Scottish Power transmission area and up to 5 MW in the Scottish Hydro transmission area. However, generators that have been connected to the distribution network after 1 April 2005 and which have caused reinforcement of the distribution grid have to pay Distribution Network Use of System charges.

In summary, network tariffs for generators are not used in Germany, Spain and Portugal. In the UK, all power plants connected to the transmission system pay a network fee. However, most plants connected to the distribution system pay no Transmission Use of System charge and no Distribution Use of System charge. Hence, many power plants connected to the distribution network can avoid paying any network fee, while in Sweden particularly power plants connected to the distribution network pay rather high fees for using the distribution system. It is important to note that in Sweden network tariffs are defined in order to give locational signals which means that producers which reduce network losses (mainly in the South of Sweden) receive economic compensation. This can result in negative network tariffs. This system is also used in the UK. As opposed to this, in the studied countries where producers do not pay any network tariffs, the producers do not receive any compensation from the grid owner for reduced system losses.

Nevertheless it should be mentioned that network tariffs can provide significant locational signals where to build new generation capacity and therefore could be useful in countries with significant locational mismatch between load and generation.

5.8 Priority Production and Curtailment Policy

Table 5-8: Comparison of curtailment policy.

	Sweden	Spain	Portugal	Germany	UK
When is curtailment possible?	Only via counter buying by SvK when wind farm owner has agreed to principal curtailment in advance	When there are nodes with capacity restrictions and security of the system.	When there are nodes with capacity or security restrictions	Only possible if wind farm owner has agreed to principal curtailment in advance	Only if wind farm has submitted a bid for the regulating market for down regulation
Payment for curtailed energy	Based on market price	For curtailment on real time operation: 15% of the electricity market price. For planned curtailment: no payment.	No payment	No payment	Based on the bid price for down-regulation submitted by the wind farm

Normally any power generation connected to a power system can be curtailed by the system operator during power system emergency situations. This normally also applies to power generation from renewable energy sources. However, the scheduling and curtailment procedure during normal operation is more important. Conventional power generation is typically scheduled based on prices (based on bidding prices in the wholesale market) and bilateral contracts, taking into account local transmission capacity.

In Spain, Portugal and Germany renewable energy is treated differently, i.e. it is defined as priority production. This means conventional power generation must always reduce generation in case of transmission congestions in order for renewable energy generation sources to be able to generate power as long as they do not exceed the existing transmission capacity.

In Germany, network operators are required to upgrade the distribution, regional and transmission network in order to make sure that renewable energy generation is not affected by any network congestions, independent of the actual location of the renewable energy sources. As network upgrades can take years, the additional connection of new renewable energy sources has been put on hold in some areas, because the existing network capacity is not large enough to guarantee priority production of new renewable energy resources. However, renewable energy generators can enter into an agreement with the network operator that they can be curtailed in situations where all transmission capacity is already used up by other renewable energy sources. That means that such an agreement makes it possible to connect new renewable generation systems earlier, however, such new units can be curtailed without any payment.

In Spain such a separate agreement for curtailment is not needed; renewable generation can be curtailed as a last option, i.e. after conventional power plants have been regulated down. In Spain renewable energies without storage capabilities such as wind power, solar energy and hydropower stations without dam, have the highest priority.

In the UK, renewable energy power sources are not treated as priority production. Curtailment is based on bidding prices in a special regulating market which the transmission system operator has set up to determine the generation source that has the lowest curtailment costs. Renewable energy sources can participate in this market, i.e. they will be curtailed in case of transmission congestions if no other cheaper generation technology is willing to be curtailed. However, as renewable energy sources need to generate power to receive the renewable energy certificates (ROCs), they typically require much higher payment for curtailment than conventional generation resources.

In summary, even though the different countries in Europe have different methods to determine which generation source will be curtailed, the outcome is the same, i.e. renewable energy sources are typically the last generation source to be curtailed. As the current Swedish approach for curtailment is similar to the approach in the UK, also in Sweden new renewable energy sources would typically be the last generation source to be curtailed as renewable energy generation would ask for high payments in case of curtailment to offset certificate and energy payments.

5.9 Current Policy Challenges Related to Network Issues

Table 5-9: Comparison of current policy challenges related to network issues.

	Sweden	Spain	Portugal	Germany	UK
Distribution/ Regional Network Upgrades	Related policy under discussion	Policy in place but a better definition of cost-sharing is under discussion	Not an issue	Policy in place for a long time now, but legal details for certain cases still under discussion	Policy was recently adjusted, start to gain experience with new approach
Transmission Network Upgrades	Related policy under discussion	Policy in place but update of policy discussed to better co-ordinate trans-mission and distribution net-work upgrades	Not an issue	Policy in place for a long time, but recently adjusted to speed up the construction of new lines	Policy was recently adjusted; further discussion regard-ing cheapest net-work upgrade (independently owned)
Offshore Connection	Related policy under discussion	Related policy under discussion	Not an issue yet	Recent policy change-> Now responsibility of transmission companies	Policy change proposed-> Tender for independent transmission com-panies proposed
Best Connection Point	Related policy under discussion	Not an issue	Not an issue	Policy in place for a long time now, but legal details for certain cases still under discussion	Policy was recently adjusted, start to gain experience with new approach
Technical Performance/ Grid Code	Grid code implemented	Grid code implemented	Grid code implemented but further needs dis-cussed	Grid code implemented, but updated every 2–3 years	Grid code implemented

The network-related issues emerging with increasing renewable energy penetration are not unique to Sweden, all countries face similar challenges, but have already longer experience with developing the related energy policy, see also Table 5-9 for a brief summary as well as the detailed country chapters for a detailed discussion.

Interestingly enough, all countries continuously adapt and improve their relevant regulations. The changes mainly aim at developing a regulatory environment that allows a development of renewable energy in order to achieve the national targets, and therefore mainly aim at reducing barriers, i.e. connection barriers, and thereby providing an acceptable investment environment. At the same time, however, policy development typically tries to adjust the regulations in a way that additional costs are equally shared by all customers and that renewable energy development does not lead to windfall profits for its developers.

Currently the connection costs related to off-shore wind farms are one of the biggest challenges when it comes to policy-making in the studied countries. However, Germany and the UK have come quite far in this matter and have recently published new laws and regulations.

5.10 Summary and Conclusion

Germany and Spain are the countries that have experienced the largest development in the wind power sector. Both Germany and Spain have used fixed feed-in tariff promotion schemes. However Spain uses also a market-based payment option with a price floor to provide a minimum secure payment level and a price cap to avoid windfall profits. Even Portugal has experienced a remarkable development during the last years also by means of a feed-in tariff system. Feed-in tariffs provide a stable investment environment as it sets clear power purchase prices for a defined time horizon (15-20 years). The UK is the country with most similarities to Sweden when it comes to promotion scheme for renewable based electricity production since they have chosen a certificate system. However, a big difference is that the certificate system in the UK provides a rather high buy-out price. In comparison to the four studied countries, wind power producers in Sweden receive the lowest payment, which means that in Sweden all other costs such as connection cost, network upgrades and network tariffs become even more important than in the other studied countries. It must be noted though that in Sweden the electricity certificate system has lead to a significant increase of biomass-based electricity production, but biomass has not been included in this international comparison.

The four studied countries have well defined application procedures to ensure that the application procedure is conducted in a clear, unbiased and consistent manner, irrespective of the network company, the renewable energy technology or the applicant. In Germany, however, the application procedure is not as clearly defined in a law as in other countries, but the German law gives renewable energy generation the legal right to be connected, which forced the German network association to outline a recommendation for the application procedure for all German network companies.

A well defined procedure is characterized by giving clear requirements of what data is needed for the application, a clear timeframe regarding the reply of the network company, and defined basic principals for the interconnection analysis, costs associated to the processing of the application, and even a clear description of how to deal with potential conflicts. Sweden has, at the moment, no well described application procedure for the connection to the local and regional grid which in some cases lead to longer administrative times.

The four studied countries except Germany apply fees for processing connection applications. In Spain, Portugal and the UK these fees are well defined and do not depend on the grid company. This is very important in order to improve transparency and to not discriminate against certain producers. In Sweden, fees depend on the grid companies and are only paid when connecting to the distribution grid, even though the amount of the fees paid is typically discounted from the total connection cost to be paid by the producer. A reason for using such fees is to avoid unserious applications and the work related to them. However, these fees might be a barrier for very small projects such as solar photovoltaics on residential buildings. An option is to exclude such small projects from paying these fees, as it is done in Spain.

Upgrades in the transmission grid and in the distribution/regional grid are treated differently in the studied countries. Costs related to the upgrade of the transmission grid are generally socialized, i.e. network companies pay for it and can recover the costs via network tariffs. However in Sweden, owners of the installation pay the costs if the upgrade refers to a radial line; while costs are shared between the owner of the production plant and Svenska Kraftnät when the upgrade is done in the meshed grid. Distribution network upgrades have to be paid in most of the studied countries by the company which causes the upgrade, except in Germany where they are socialized as well. In comparison with the studied countries, project developers in Sweden have to pay most network investment costs.

In all studied countries except the UK producers neither pay any network tariffs for using the grid nor get any compensation for reducing network system losses. In the UK, all power plants connected to the transmission system pay a network fee, however, most plants – depending on their capacity – connected to the distribution system pay no Transmission Use of System charge and no Distribution Use of System charge. Hence, many power plants connected to the distribution network can avoid paying any network fee, while in Sweden particularly power plants connected to the distribution network pay rather high fees for using the distribution system. In addition it should be mentioned that renewable based producers in the UK receive currently a comparatively higher payment compared to Sweden.

Network tariffs for generators in general are not very common in the four studied countries. However, network tariffs can provide significant locational signals where to built new generation capacity and therefore could be useful in countries with significant locational mismatch between load and generation.

In Germany, Spain and Portugal there are no capacity limits for the payment of network tariffs similar to those used in Sweden (installation with an installed capacity below 1500 kW do not pay any network tariffs). Capacity limits are either used to define connection voltage levels (Spain and Portugal) or to differentiate the feed-in tariff.

In all four studied countries, wind power producers can build the power lines within the wind farm and between the wind farm and the transmission/ distribution grid. Sweden is different since it requires concessions in order to build such lines and producers cannot get concession. A drawback with the requirement of network concessions is that they increase bureaucracy and make it more difficult for small project developers to find more economical solutions to build these power lines. This is due to the fact that only in the case of creating a network company the owner of the wind farm can build the lines, otherwise only the grid company with the concession for that area can build the power lines. To form a network company has, under current legislation, a lot of consequences for example regarding reporting obligations, which are difficult to meet for small investors. In Spain and Portugal, sometimes the wind power producer and the grid company of the area enter into special agreements in order to transfer the ownership of the line up to the connection point to the grid company. This way, the producer can avoid operation and maintenance costs of the lines, since producers do not pay any tariffs for using the grid to the grid companies, and the grid company can connect other customers/producers.

In all four countries there are no requirements of hourly measurements for small installations. Yearly measurements appear to be perfectly suitable for such installations (up to 500 kW) as they have a very small impact on the actual power flow in the power system. As opposed to this Sweden has the requirement of hourly measurements in order to be able to get payment from the certificate system. In addition, in Germany, Spain and Portugal it is not necessary to measure production independently; i.e. net-metering can be used by small scale installations. However, in practise most producers choose to measure production independently since the payment for the production is much higher than the cost for the consumption.

The four studied countries have different methods to determine which generation source will be curtailed when there are physical restrictions in the grid. However, the outcome is the same, i.e. renewable energy sources are typically the last generation source to be curtailed. As the current Swedish approach for curtailment is similar to the approach in the UK, also in Sweden new renewable energy sources would typically be the last generation source to be curtailed as renewable energy generation would ask for high payments in case of curtailment to offset certificate and energy payments.

Currently the connection costs related to off-shore wind farms are one of the biggest challenges when it comes to policy-making in the studied countries. However, Germany and the UK have come quite far in this matter and have recently published new laws and regulations.

It should be mentioned that some of the studied countries initially had a rather generous payment scheme which made some investments very profitable, but these frameworks were step-by-step adjusted within the different national schemes. Within these adjustments, the different countries made sure that existing power plants were not affected by the changes, which helped to increase the confidence in the national renewable energy policy (stable investment environment), even though the reimbursement was lowered for new installations. Furthermore, it should be mentioned that the national policy makers partly created the initial generous payment schemes on purpose to kick-start the development of renewable energy and to create a new industrial sector. The approach applied to network tariffs, network upgrade costs and curtailment of renewable energy should take into account the overall economic situation for renewable energy.

Finally, it should be mentioned that all four studied countries have shown a flexibility to adjust their energy policy, rules and regulations depending on the technical and economical development in order to create a low-risk environment for renewable energy projects, without allowing windfall profits as it is very difficult to get all relevant regulatory details right at the first attempt. This flexibility and openness to change has been based on a continuous dialogue between policy makers, regulator, network companies and the renewable energy lobby.

Policies that help to reduce the risk for project developers regarding connection procedures, connection costs and upgrade costs will facilitate the development of more renewable energy projects as long as the general payment scheme for renewable generation provides a profitable and low-risk framework.

Statens offentliga utredningar 2008

Kronologisk förteckning

1. Barlastvattenkonventionen – om Sveriges anslutning. N.
2. Immunitet för stater och deras egendom. UD.
3. Skyddet för den personliga integriteten. Bedömningar och förslag. Ju.
4. Omreglering av apoteksmarknaden. S.
5. Könsdiskriminerande reklam. Kränkande utformning av kommersiella meddelanden. N.
6. Fastighetsmäklaren och konsumenten. Ju.
7. Världsklass! Åtgärdsplan för den kliniska forskningen. U.
8. Bidrag på lika villkor. U.
9. Transportinspektionen. En myndighet för all trafik. + Bilagor. N.
10. 21+1➔2. En ny myndighet för tillsyn och effektivitetsgranskning av socialförsäkringen. S.
11. Frihet för studenter – om hur kår- och nationsobligatoriet kan avskaffas. U.
12. Finansiella sektorn bär frukt. Analys av finansiella sektorn ur ett svenskt perspektiv. Fi.
13. Bättre kontakt via nätet – om anslutning av förnybar elproduktion.
    + Annex: Grid issues for electricity production based on renewable energy sources in Spain, Portugal, Germany, and United Kingdom. N

Statens offentliga utredningar 2008

Systematisk förteckning

Justitiedepartementet

Skyddet för den personliga integriteten.
Bedömningar och förslag. [3]

Fastighetsmäklaren och konsumenten. [6]

Utrikesdepartementet

Immunitet för stater och deras egendom. [2]

Socialdepartementet

Omreglering av apoteksmarknaden. [4]

21+1→2. En ny myndighet för tillsyn och effektivitetsgranskning av socialförsäkringen. [10].

Finansdepartementet

Finansiella sektorn bär frukt.
Analys av finansiella sektorn ur ett svenskt perspektiv. [12]

Utbildningsdepartementet

Världsklass! Åtgärdsplan för den kliniska forskningen. [7]

Bidrag på lika villkor. [8]

Frihet för studenter – om hur kår- och nationsobligatoriet kan avskaffas. [11]

Näringsdepartementet

Barlastvattenkonventionen – om Sveriges anslutning. [1]

Könsdiskriminerande reklam.
Kränkande utformning av kommersiella meddelanden. [5]

Transportinspektionen. En myndighet för all trafik. + Bilagor. [9]

Bättre kontakt via nätet – om anslutning av förnybar elproduktion.
+ Annex: Grid issues for electricity production based on renewable energy sources in Spain, Portugal, Germany, and United Kingdom. [13]