Development of interactions between distributed generation and distribution system operators
West Denmark, Germany, the Netherlands, Spain and the United Kingdom

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Project objectives
The IMPROGRES project aims to identify possible improvements in the social optimal outcome of market integration of distributed generation (DG) and electricity production from renewable energy sources (RES-E) in European electricity markets. This will be achieved by:
- Identification of current interactions between DG/RES businesses, distribution system operators (DSOs) and energy markets in coping with increased DG/RES penetration levels.
- Developing DG/RES-E scenarios for the EU energy future up to 2020 and 2030.
- Quantifying the total future network costs of increasing shares of DG/RES for selected network operators according to the DG/RES-E scenarios.
- As a comparison to regular DSO practices, identify cost minimising response alternatives to increasing penetration levels of DG/RES for the same network operators.
- Recommend policy responses and regulatory framework improvements that effectively support the improvements of the socially optimal outcome of market integration of DG/RES in European electricity markets.

Project partners
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1 Executive summary

1.1 Background

Due to increasing shares of electricity from distributed generation (DG) and renewable energy sources (RES) during the last decades, the interactions between DG/RES operators, distribution system operators (DSOs) and the electricity markets have been changing. Electricity production from DG/RES is a key element for the attainment of the three energy policy objectives of the European Union (EU), i.e., sustainability, competitiveness and security of supply. At present, most DG/RES technologies are not economically viable yet and may therefore be entitled to national support schemes. Operational support schemes range from price-based promotion, such as the classic feed-in tariff, to quantity-based support, such as green quotas with tradable green certificate markets. Also, investment support may be applied. The choice and design of support schemes are to the discretion of the individual Member States. The schemes differ in terms of market price exposure, but also in terms of the financial level of support given for the individual technologies across countries. The operations of DG/RES are hence driven by the support mechanism and the electricity market prices (in the case of market-based systems), or by the support mechanism only. At the same time, DG/RES induce costs and benefits for the DSO, which in turn strongly depend on the operations of the DG/RES units. The realization of benefits of DG/RES depends on the provision of the right incentives through network charges. Market prices, support mechanisms and network charges should be arranged in a specific way so that they will not be in conflict with each other, which would otherwise result in perverse incentives for DG/RES operators.

This report constitutes Deliverable D2 of the dissemination activities of Work Package 2 of the IMPROGRES project, dealing with current DG, DSO and market interactions. The D2 Deliverable investigates the development of these interactions in Europe with special emphasis on five case studies: West Denmark, the Netherlands, Germany, Spain and the United Kingdom. Furthermore, it aims at detecting the existing support schemes in these five regions.

1.2 Approach and structure

In order to deal with the aforementioned questions, this report consists of the following parts:

1. An elaboration (Chapter 2-5) on DG/RES in its regulatory and market context, European legal provisions and schemes for their national implementation (support and network regulation).

2. A survey for each of the five country cases on the evolution of support schemes, network regulation and market participation of DG/RES in the respective countries.

3. An in-depth overview of present levels of support differentiated according to technologies for the five country cases as well as network regulation currently applied. The focus of this report is clearly on support; network regulation and charges are dealt with in greater detail in the D3 Deliverable.

4. A final summary of the interactions of support schemes, network regulation and markets.
1.3 Regulatory solutions in the single countries

In the following sections, some basic regulatory concepts will be referred to. They can be separated into support schemes and network regulation. Support schemes can be widely categorised into investment and operating support. The focus of this report is on technologies for which mainly operating support schemes are applied. These are subdivided into quantity-based schemes (where the regulator defines a target of a renewable generation quota that needs to be met) and price-based schemes. The latter one can be implemented as a feed-in tariff where the regulator guarantees a certain income for every generated kilowatt hour (kWh), or as a price premium scheme. In the latter case, a premium on top of market prices is granted.

Network regulation consists of several aspects: Economic network regulation determines the income of DSOs which is necessary due to their natural monopoly characteristics. Competition is increasing from rate-of-return regulation (where a predefined rate of return is given on the bound capital) to incentive regulation. In incentive regulation schemes, efficiency incentives are higher under yardstick regulation than under price and revenue cap regulation (where a time lag in efficiency requirements is introduced). Other parts of network regulation cover network access and network tariffs: It is highly important for a DG/RES operator under which conditions he is allowed to connect to the network and which charges are associated. We distinguish three different kinds of connection charges: shallow, shallowish and deep charges. Shallow charges mean that the DG/RES operator only pays the connection costs to the nearest network point. All further necessary expenses, such as converter stations and grid reinforcements, are borne by the network operators and typically socialized through Use-of-System (UoS) charges. If a deep charging method is applied, the DG/RES operator has to pay for all expenses associated with its grid connection, including upgrades at the transmission level. Shallow charges are a hybrid between these two concepts: the DG/RES operator pays for the connection to the nearest network point and the proportional use of grid infrastructure reinforcements at the distribution level. The type of charging methodology is hence crucial for the allocation of variable and upfront costs incurred by the DG/RES operator.

1.3.1 Denmark

Denmark politically fostered the development and diffusion of wind and CHP units after the oil crises. Thus, the share of DG increased from 1% in 1980 to 35% in 2001. These 35% are composed of distributed CHP, onshore wind mills and industrial CHP.

The very early wind farm development was mainly financed by local wind turbine associations who had a guaranteed feed-in tariff income. The wide diffusion of CHP technology was mainly due to a legal requirement that all gas-fired power plants had to be converted to CHP during the 1990s and the remaining district heating plants use biomass (as far as possible). Both construction and operation of these plants were subsidised, the latter by means of a fixed feed-in tariff with three time-dependent steps. This scheme was replaced by a price premium in 2005. Thus, support follows the supply through the spot market prices, i.e., it provides an incentive to adjust supply when there is excess production or excess demand. The DG/RES support scheme evolved from a feed-in tariff support to price premiums from 1999 onwards. A special feature of the Danish price premiums for new installations until 2008 was that they are not premiums on top of market prices, but guarantee a fixed income as a sum of market prices and the support. This scheme helped integrating especially large amounts of wind power into electricity markets. From 2008 onwards, the support is a pure price premium. However, the controllable CHP generation is fully exposed to price fluctuations since 2005 to give an incentive to adapt to market conditions. With the increasing size of wind farms, the investor structure turned from private persons to
institutions. Nowadays, the Nordic energy exchange Nord Pool offers a special trading regime for small direct participants to facilitate market integration.

There are over 100 DSOs in Denmark. All of them are legally unbundled and subject to a revenue cap incentive regulation whose implementation since 2000 showed some problems. DG/RES have to pay shallow connection charges, but most of the existing capacity is exempt from paying generator Use-of-System charges. However, new wind and CHP facilities can be affected.

1.3.2 Germany

In Germany, the operation support scheme for DG/RES has traditionally been a feed-in tariff (FIT). Until the end of 2008, the Renewable Energy Sources Act of 2004 (EEG 2004) and the Combined Heat and Power Generation Act (KWKG - Kraft-Wärme-Kopplungsgesetz) of 2002 were valid. From 2009 onwards, the FIT of RES have been adapted; main changes constitute a remarkably higher depression for solar energy and higher rates for geothermal and wind power. EU regulations have been adopted with the Energiewirtschaftsgesetz (EnWG, 1998) and its update in 2005. In general, network charges have to be approved by the Federal Network Agency. Only real costs arising from a distinct network structure can be charged. DG/RES units pay shallow connection charges. Use-of-system charges are paid by end consumers only. In current network regulation, there are no provisions that aim at compensating DG/RES-E operators for their possible positive impact on DSO network operations, for example with respect to network losses. However, negative impacts, especially occurring in the transmission grids, are also not penalized. Until now, RES has not participated in the energy markets due to the incentives of the FIT. The new FIT valid from 2009 onwards provides an option for a temporary opt-out of the FIT, which is why spot market integration is expected to increase. With respect to congestion management, CHP units do not contribute as their FIT does not provide an incentive for time-dependent generation. In hours with extremely high wind penetration, wind farms can be curtailed to ensure grid stability.

1.3.3 The Netherlands

The predominant support mechanism for renewable electricity and renewable gas is a feed-in premium on top of the market price. According to a recent revision the premium is no longer a fixed amount per kWh over the project lifetime but rather it is varying with the electricity revenues. The original support scheme started in 2003 and has been suspended since August 2006. Since April 2008 it has been reopened again. Before the year 2000, CHP was supported through priority access, a fixed feed-in tariff and a number of tax measures. From 2000-2005, besides the tax support for new investments, production support was provided in the form of a feed-in premium. Annually, the feed-in tariff level was determined based on forward market prices for gas and electricity. Due to the rise in electricity prices after 2005, the feed-in tariff for CHP was set at zero level. The Netherlands implemented performance-based network regulation in 1998. After the first price control period from 2001-2003, a price cap based on yardsticking was implemented and comprises quality-of-service incentives. In general, different DSOs can experience different cost structures due to differential geographical integration of DG/RES-E units in their networks. Until now, this is not something that is taken into account in the benchmarking procedure. Connection charges are shallow and regulated for units below 10 MVA, and are deep and negotiated between parties for units above 10 MVA. The regulated connection charges are differentiated over voltage levels and are usually distance dependent (i.e. distance between the
existing network and the unit to be connected). Next to connection charges there are also use of system charges. Only consumers pay a use of system charge.

DG/RES units participate to a certain extent directly in energy markets, namely horticulture and industrial CHP units. Wind energy is commonly marketed in a portfolio with other generation technologies.

Due to the strong growth of CHP in some parts of the country, congestion management became necessary. The example of one DSO is stated where a regional market for down-regulation has been established.

1.3.4 Spain

Spain first introduced a FIT (both energy and capacity components) in 1994. In the year 1998, once the general law of the electric sector had been approved, the previous scheme was replaced by another FIT scheme where the level of the tariff was dependent on the average market energy price, which was computed according to a certain methodology. In 2004, a hybrid system of FITs and premiums (both dependent on the average electricity tariff) was applied for the first time. According to regulation, premiums applied were the result of adding up a premium, properly speaking, and some extra incentives. Finally, in 2007 this hybrid system was replaced by another one where FITs and premiums no longer depended on the average tariff. In this system, cap and floor values were introduced for the price earned by RES units.

DSOs are remunerated according to a revenue cap approach based on four year regulatory periods. The revenue cap formula includes specific terms regarding energy losses and continuity of supply (based on number and duration of interruptions). Penalties exist in case of non-compliance with power quality standards. Incremental costs related to the connection and operation of DG in distribution networks should be recognized in the DSO’s allowed revenues. However, this is not taken into account satisfactorily.

At the moment, intermittent energy sources are not able to participate in the Spanish secondary reserve market. Big efforts are being done by wind promoters to research and adapt wind farms so that they can provide load following services. Even though from a technical point of view it seems feasible in the near future, actual premiums over market price do not encourage wind farms to reserve part of their generation capacity to offer it as regulating capacity in the secondary reserve market. [49]

DG pay deep distribution connection charges in Spain, i.e. DG has to pay for any equipment and network reinforcement that is required to meet the technical conditions. The amount of these connection charges is calculated by the corresponding DSO. The rules for this calculation are not simple or transparent, thus discriminatory treatment may arise. DG does not pay UoS charges. As long as UoS charges for DG are not implemented, main network reinforcement costs are socialized among consumers.

1.3.5 United Kingdom

The first support scheme for DG/RES was the Non-Fossil Fuel Obligation (NFFO). It was announced in 1990 as a mechanism that would award competitive orders for building nuclear or renewable based electricity generating capacity [54]. The NFFO system can be qualified as a combination of an obligation and a tendering system. Different NFFO projects competed against each other (within technology categories) for an NFFO award, with the lowest bid winning the award guaranteeing a certain premium price for electricity. The Renewables Obligation (RO) was introduced in April 2002 and requires energy suppliers to source an annually increasing percentage of their sales from renewable sources. The generators of renewable electricity receive a Renewables Obligation Certificate (ROC) per produced MWh (irrespective of time or voltage
level to which the generating unit is connected) that is tradable between suppliers but only valid in one period.

British DSOs are regulated with a revenue cap incentive scheme since 1990. UK regulatory authorities have implemented explicit incentive schemes for DSOs to encourage innovation regarding DG connection issues. These schemes are the Innovation Funding Incentive (IFI) and the Registered Power Zones (RPZ). The IFI is a mechanism to encourage DNOs to invest in appropriate R&D activities that focus on the technical aspects of network design, operation and maintenance. The RPZ is an initiative which provides a financial incentive to distribution companies to develop and implement innovative projects connecting distributed generation to networks where this may not have otherwise been economically feasible. These schemes are brought into the price control mechanism as a cost-plus adder: for specific new DG capacity connected to the network the operating DSO is allowed to receive an additional charge under the price control.

At distribution level, DSO and DG have bilateral connection agreement which allows DG to be curtailed for a relatively short period of time if it leads to significant saving in the cost of upgrading the network to facilitate the connection [49]. This approach can be described as a bilateral market-based congestion management approach.

DSOs negotiate with distributed electricity suppliers on the fair charge to be applied. The connection charge methodology is categorized as shallowish. DG/RES do not pay Use-of-System charges for the transmission grid, but only for the distribution grid.

1.4 Conclusion

Central findings are that a multitude of DG/RES support schemes, network regulation, connection and use of system charging methods are applied in the five analyzed cases. This has contributed to a different penetration of DG/RES across Member States: risk-absorbing support schemes like feed-in tariffs in combination with shallow connection charges and no Use of System charges foster strong DG/RES growth. This happens, however, mostly regardless of arising difficulties for distribution grid operation and only with a limited integration into power markets.
2 DG/RES in its regulatory and market context

The supply of electricity can be split into two subsystems (Figure 1). First, there is the physical subsystem that comprises the generation and transmission of electrical power to the customer. Large power producers feed electricity into the high-voltage transmission network operated by the transmission system operator (TSO). It is then transported at lower voltage levels by the distribution system operator (DSO) in the distribution grid to final customers. This structure has shaped the traditional paradigm of the electricity industry. An alternative is a DG/RES power plant. A multitude of different definitions for DG are in use [1]. In this report, distributed generation comprises plants that are connected directly to the distribution system (Directive 2003/54/EC, Art. 2 (31)) [28], or on the customer site of the meter [1]. This definition also includes non-renewable generation technologies, such as local combined heat and power (CHP) units based on natural gas. The terms ‘distributed generation’ (DG) and ‘renewable energy sources’ (RES) are not equivalent. Renewable energy sources consist of renewable non-fossil energy sources, i.e., wind, solar, geothermal, wave, tidal, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases (Dir. 2001/77/EC, Art. 2a) [26]. The availability of renewable energy sources is typically spread evenly over larger areas, but the bundling of generation units can lead to power plants with a capacity of several hundred megawatts (MW), which are then connected to the transmission grid. For this reason, RES installations connected to the high voltage transmission network, such as offshore wind farms, are not regarded as DG in the scope of this report.

Second, there is the commodity subsystem reflecting the financial flows of the according physical flows in the physical subsystem. Here, power is regarded as a trading good: customers buy their power from a utility. The latter purchases power at the wholesale market (trading) and the transmission service from the distribution company. Wholesale contracts can be concluded either bilaterally (OTC, i.e., over-the-counter, trade) or on an organized market (power exchange). The single sub-markets can be classified according to their time distance to actual physical delivery:

- OTC trade (which is bilateral, but where the electricity exchange can match interested parties) is mostly used for rather long-term baseload contracts.
- The spot market is a day-ahead market\(^1\). Here, market actors can submit bids, typically 12 to 36 hours before physical delivery.
- The intraday market (also referred to as hour-ahead market) covers contracts of the same day up to one hour before physical delivery. Thereby, market actors can balance their production portfolios subsequent to the closure of the day-ahead market.
- The balancing market (also denoted as real-time market) manages participants’ capacity for deviations from planned system conditions, e.g., reserve power. It can be subdivided into several categories and corresponds partially to ancillary services.

The main actors on these financial markets are large power producers as power providers and traders, utilities and large industrial facilities as customers. To a certain extent, the TSO is also involved, e.g., through buying an equivalent amount for transmission losses or trading FIT amounts which it is legally responsible of. With the growing penetration of DG/RES producers,

\(^1\) Note that the term “spot market” is frequently applied synonymously in European markets for “day-ahead market” (as in this report), whereas in the United States the term “spot market” usually refers to the balancing or real-time market.
their integration into these markets is becoming a key issue [66]. Therefore, the design and participation conditions of the markets are crucial: minimum capacity requirements for bids and other determinants can constitute obstacles to their participation in these markets. A utility can deliver power directly via small DG operators or from the wholesale market in order to supply its customers [67].

General conditions for all of these processes are bound by the regulatory and market environment. For the purposes of this report, the regulator is a simplified representation of the relevant legislation. Market design and regulation impact the incentives of the different market actors, i.e., DG operators, large power producers, customers, TSOs and DSOs, and how they are intertwined. For DG/RES, relevant regulation for its integration in the physical and commodity subsystem comprises support schemes, regulation of network access and of network tariffs.

Deliverable D2 analyzes which different combinations of support schemes and network regulation are prevalent in five focus regions: Denmark, Germany, the Netherlands, Spain, and the United Kingdom. This serves as the basis for a further qualitative and analytical investigation of the arising interdependencies and interactions in Deliverable D3. Central importance for the economics of DG/RES operators accrues to support schemes (revenue), connection charges and network tariffs (costs to be paid to the DSO).

The predominant support schemes for DG/RES applied in the five focus regions constitute fixed feed-in tariffs (FIT), price premiums and quota systems. In order to obtain network access, DG/RES operators have to pay connection charges to the DSO in their service area. Connection charges can be subdivided into three main categories of DG/RES cost contribution: shallow, shallowish and deep charges. Shallow charges mean that the DG/RES operator only pays the connection costs to the nearest network point. All further necessary expenses, such as converter stations and grid reinforcements, are borne by the network operators and typically socialized through the Use-of-System (UoS) charges. If a deep charging method is applied, the DG/RES operator has to pay for all expenses associated with its grid connection, including upgrades at the transmission level. Shallowish charges are a hybrid between these two concepts: the DG/RES operator pays for the connection to the nearest network point and the proportional use of grid infrastructure reinforcements at the distribution level. The type of charging methodology is hence crucial for the allocation of variable and upfront costs incurred by the DG/RES operator.

Network tariffs for transport and system services of the distribution network are subject to
national network regulation. In general, competitiveness is increasing from rate-of-return regulation (RoR) to price/revenue cap schemes, and further to yardstick regulation.

Since the regulatory regimes across these three dimensions differ among Member States, it is possible to group the five countries in focus with respect to the combination of support schemes and network regulation applied.

The country matrix (Table 1) depicts a summarizing overview of the type of support schemes and connection charging approach for the respective countries in 2007.

Table 1: Country matrix with combinations of network and support scheme regulation

<table>
<thead>
<tr>
<th></th>
<th>Feed-in tariff</th>
<th>Price premium</th>
<th>Quota system</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Deep connection charges</strong></td>
<td>Spain (revenue cap)</td>
<td>Netherlands (yardstick) (units &gt;10 MVA)</td>
<td></td>
</tr>
<tr>
<td><strong>Shallowish connection charges</strong></td>
<td></td>
<td></td>
<td>United Kingdom (revenue cap)</td>
</tr>
<tr>
<td><strong>Shallow connection charges</strong></td>
<td>Germany (rate-of-return)</td>
<td>Denmark (revenue cap) Nederland (yardstick) (units &lt;10 MVA)</td>
<td></td>
</tr>
</tbody>
</table>

Additionally, it indicates the type of network regulation applied. It can easily be seen that a multitude of different regulatory combinations is practiced, with feed-in tariffs and/or price premiums constituting the predominant support mechanism. The following two chapters will deal with the current state of regulation and application in the individual Member States in greater detail, moving from the European to the national level.
3 Overview of European legal provisions relevant for DG/RES

The large-scale deployment of DG/RES has the potential of substantially contributing to the enhancement of the three primary objectives of European energy policy: competitiveness, sustainability and security of supply [11],[12],[15]. If sited optimally from a power system point of view, DG/RES facilities may induce reductions in line losses, substitute network upgrades at the distribution and transmission level, provide congestion relief and contribute to network reliability and power quality through the provision of ancillary services. Simultaneously, increasing penetration of DG/RES stimulates competition, technological progress and innovation on European as well as on national energy markets while delivering electricity from energy sources with a low or virtually nil emissions impact. These characteristics have been drivers to stimulate the growth of DG [14].

Notwithstanding these potential advantages, an increasing deployment of DG/RES adds to the complexity of tasks of DSOs and TSOs. The way in which the additional costs for system integration are allocated among market actors influences their incentives with respect to DG/RES integration. Therefore, regulation both at the supranational European and at the national level plays a crucial role for the potential benefits of DG/RES integration to materialize. Each benefit of a DG/RES facility tends to be highly technology-, time- and site-specific [48].

The policy on DG/RES integration is characterized by two levels of policy design, i.e., the European level and the national level. At the European level, DG/RES integration is encompassed by various legal provisions, predominantly in the form of Directives. In contrast to Regulations, Directives are not directly applicable but have direct effect: Directives are binding as to the result to be achieved, “but shall leave to the national authorities the choice of form and methods” [2]; that is, Directives are subject to national implementation by the Member States.

<table>
<thead>
<tr>
<th>Directive</th>
<th>Policy Relevance</th>
</tr>
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| Dir. 2003/54/EC: “Electricity Directive” | - Rules for structural organization  
- Procedures for generation capacity  
- Tasks & unbundling of TSOs/DSOs  
- Third party access, market opening  
- Regulatory authorities |
| “Security of Supply Directive” | - Safeguard security of supply |

For DG/RES, four Directives are of particular relevance. Directive 2003/54/EC [16] concerning common rules for the internal market in electricity (the “Electricity Directive”) stipulates the general rules for the structural organization and the opening up of markets in the electricity segment. This includes legal provisions on authorization and tendering procedures for new generation capacity, on the designation, tasks and unbundling requirements for TSOs and DSOs, on third party access, on dates for market opening, and on the establishment of regulatory authorities. The latter are entitled to determine the calculation methods and tariffs for the transmission and distribution of electricity. A Proposal for an amendment to this Directive [16] is currently being discussed. The Proposal comprises reinforcement of unbundling requirements for
TSOs (ownership unbundling or the establishment of an Independent System Operator), the strengthening of the role of and cooperation among regulators, as well as enhanced cooperation among network operators, in particular TSOs.

In terms of support schemes for DG/RES, Directive 2001/77/EC on the promotion of electricity from renewable energy sources [26] and Directive 2004/8/EC on the promotion of cogeneration based on a useful heat demand in the internal energy market [29] are of particular importance. Both Directives encourage Member States to adopt national support schemes in order to promote the deployment of RES-E or CHP, respectively. The choice of support mechanisms for the different technologies is left to the discretion of the Member States. Along with the stipulation of the 2020 targets, the discussion of a new Directive Proposal [19] has been launched to partially replace Dir. 2001/77/EC on the promotion of electricity from renewable energy sources and Dir. 2003/30/EC on the promotion of the use of biofuels or other renewable fuels for transport [27]. Last, there is Directive 2005/89/EC concerning measures to safeguard security of electricity supply and infrastructure investment [30]. In implementing measures to ensure a high level of security of supply, Art. 3(3c) [30] emphasizes the importance of “encouraging energy efficiency and the adoption of new technologies, in particular demand management technologies, renewable energy technologies and distributed generation”.
4 Support schemes

This chapter turns to the actual application of support schemes at the national level by dealing with this area of regulation in three steps: first, the different types of support instruments are described qualitatively in order to provide some insight into their functioning (Section 4.2). Subsequent to the elaboration of regulatory concepts, this chapter proceeds with the current situation in the five country cases, that is, for Denmark, Germany, the Netherlands, Spain and the United Kingdom. This encompasses both the national application of support regimes (state: 2007) and actual DG/RES penetration levels. In the second subsection, a brief summary of the main schemes adopted in the five country cases is given (Section 4.3). Notably, support schemes are typically granted on the basis of technologies, i.e., RES or CHP, and are not based per se on whether an installation is considered DG or not. Therefore, as the third step, a very detailed quantitative overview shows the existing promotion schemes for the five countries, including current DG/RES penetration levels, grouped according to technologies (Section 5).

4.1 Rationale for support

The rationale for the provision of support for CHP and RES-E is based on the inclusion of positive externalities associated with their deployment. An externality arises in a market if the actions of either consumers or producers lead to costs or benefits that are not reflected in the price of the product in that market [4]. Many CHP and RES-E technologies are not yet competitive compared to technologies of conventional thermal generation. However, production based on RES-E and CHP has a low emissions impact and/or contributes to the enhancement of energy efficiency. Simultaneously, the deployment of RES-E reduces the import dependency of the EU on primary energy sources from external suppliers while intensifying competition with the market penetration of new RES-E and CHP producers. The enhancement of the three primary objectives of the EU’s energy policy, i.e., competitiveness, sustainability and security of supply [14], has been a driver to stimulate and promote the growth of these technologies [13].

4.2 Support mechanisms

DG/RES operators may be entitled to support schemes granted at the national level on the basis of technological characteristics. Directive 2001/77/EC (the “RES-E Directive”) contains the legal provisions on the promotion of electricity based on renewable energy sources. Member States may give direct or indirect support to RES-E producers (Art. 4) and may further provide for priority access to the grid system for electricity produced from renewable energy sources (Art. 7 (1)). These support mechanisms are to contribute to the attainment of the national indicative targets in order to reach the indicative share of 22.1% of RES-E produced electricity in total Community electricity consumption by 2010, as stipulated by the RES-E Directive. For 2020, the EU has laid down the binding target of having a 20% share of renewables in overall EU energy consumption [17]. In a similar fashion, for combined heat and power, Directive 2004/8/EC (“CHP Directive”) lays down that direct or indirect support may be provided to producers of cogeneration (Art. 7).

As the application of support schemes is to the discretion of the Member States, the support mechanisms and the levels for support vary across the EU-27 countries. Despite some minor
differences in the detailed design of support schemes at the national level, support mechanisms can be generally divided into investment support and operating support [20].

![Support Schemes in EU](image)

Operating support schemes can further be differentiated into quantity-based and price-based support instruments. Figure 2 provides an overview of the predominantly applied support schemes, which will be dealt with in the following two sub-sections.

### 4.2.1 Investment support

Investment support comprises capital grants, tax exemptions and price reductions on the purchase of goods [20]. Investment support is not related to production [kWh], but serves to facilitate upfront the erection of a production site. This mechanism of promoting renewable energy is mostly used to stimulate investments of energy technologies which are still very far from economic viability. Tax exemptions may have an equal effect for the investor. Capital grants can be used alternatively to or in combination with other support schemes.

### 4.2.2 Operating support

Operating support encompasses price subsidies, green certificates, tender schemes and tax exemptions, or reductions on the production of electricity [20]. Here, a broad distinction can be made into price-based and quantity-based support.

*Feed-in tariff schemes and price premiums constitute the predominantly applied price-based support instruments in the EU-27 [59]. Under a feed-in tariff system, qualified (RES) electricity producers are granted a fixed price per kWh above market rates set by the federal or provincial authorities. This price is guaranteed for a certain period of time, with durations of frequently up to 15 to 20 years. The tariff rates can be differentiated with respect to generation technologies, depending on the latter’s state of maturity and resource conditions in the relevant Member State. This allows technology- and site-specific promotion. Commonly, generators qualifying for feed-in tariff schemes are simultaneously granted priority access to the grid. One of the key features of feed-in tariff schemes is that they provide a high level of investment certainty (investor confidence) and reduced risk exposure to price volatility on power markets. The effectiveness of feed-in tariffs in promoting RES-E penetration has become evident in terms of the wind capacity evolution in Denmark, Germany and Spain. Price premiums are applied as a market-based variant of the feed-in tariff. Under this type of regime, RES-E generators obtain a premium paid*
additionally on top of the wholesale market price, often supplemented by a premium for balancing costs. An important difference between the feed-in tariff and the premium payment is that the latter introduces competition between producers on the electricity market. The exposure of generators to the volatility of the wholesale market price provides incentives to adjust output, following variations in demand and supply of power.

The costs for financing feed-in tariff schemes are typically socialized. Both feed-in tariffs and premiums are mostly structured to encourage specific technology promotion and to induce future cost-reductions by applying dynamic decreasing tariffs/premiums. Besides the level of the tariff, its guaranteed duration period represents an important parameter for an appraisal of the actual financial incentive.

**Quantity-based support schemes** can be subdivided into tendering systems and quota obligations. In a **tendering system**, investors and/or producers compete for getting awarded a contract for a (publicly) funded RES project (e.g., support by means of power purchase agreements). Depending on the contract award mechanism, different selection criteria for the judgment of the bids may be applied. Under the lowest-bid-tendering procedure, all participants solely compete for offering the lowest bidding price. In a competitive bidding system, the proposals of RES operators are ranked in increasing order of cost until the amount to be contracted is reached [52]. Each selected generator obtains a long-term contract to supply electricity at the pay-as-bid price [*ibid*]. Tender as a procurement mechanism allows differentiating between technologies and renewable energy sources so that there will be only competition between, e.g., wind projects or between biomass projects. A tendering-based support scheme used to be in place in France.

In the last few years several countries (e.g., the United Kingdom) adopted renewable obligations, also called **quota obligations**, where minimum shares of renewable energy sources in total electricity generation are imposed on consumers, suppliers or producers. Typically, this system is combined with the issuance of tradable green certificates for the amount of kilowatt hours (kWh) of green electricity produced; the green certificates in turn can be traded on a separate financial market. This means that renewable power producers generate income by means of the wholesale electricity price and additionally by means of the green certificate price when they sell their certificates on the certificate market. In a similar fashion, the instrument of white certificates may be applied to achieve a quantitative target in energy savings. If the imposed obligations are not fulfilled, the producer will have to pay a penalty, which is also set by the government. Various stakeholders (energy producers, traders, suppliers and brokers) have developed ‘the Renewable Energy Certificate Trading System (RECS)’ for Europe for the promotion of a solid policy framework for cross-border trade of renewable energy [60].

**4.2.3 Net metering**

In addition to support schemes, the type of metering is crucial for inducing DG/RES deployment by means of remuneration; this applies in particular to on-site generation. Net metering is a system providing incentives for consumers to invest in renewable energy generation onsite as well: the electric meter runs backwards when their electricity production exceeds their consumption. In the determination of the retail price, their export of excess power to the grid is deducted from the electricity they consume. If less power is generated than required, the electric

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4 Naturally, this necessitates that the RES-E technology does not exhibit natural or technological variability, or is economically storable.
meter runs normally and the unavailable electricity will be taken from the conventional power grid.

4.3 Summary of support schemes

The different EU countries apply a variety of support schemes. During the early stages of DG/RES development with low penetration levels of a DG/RES technology, feed-in tariffs turned out to be most effective [59]. They are nowadays used in Germany and Spain (Table 3).

<table>
<thead>
<tr>
<th>Country</th>
<th>Prevalent support mechanisms</th>
</tr>
</thead>
<tbody>
<tr>
<td>Denmark</td>
<td>Price premium</td>
</tr>
<tr>
<td>Germany</td>
<td>Feed-in tariff</td>
</tr>
<tr>
<td>Netherlands</td>
<td>Price premium</td>
</tr>
<tr>
<td>Spain</td>
<td>Feed-in tariff and price premium</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>Quota system with TGCs (Renewable Obligation)</td>
</tr>
</tbody>
</table>

With increasing levels of DG/RES penetration, feed-in tariffs are not efficient since production is based on the feed-in tariff level and not made accordant to the actual demand for electricity [63]. In particular, as feed-in tariffs are typically coupled with priority dispatch, higher levels of intermittent DG/RES generation impose an increased complexity on the system operator. A transition to a price premium scheme with a premium paid on top of the wholesale market price improves the integration of DG/RES with increasing maturity and diffusion of a technology. In Spain, operators can choose between price premiums and feed-in tariffs, whereas the former are the only prevalent support scheme in Denmark and the Netherlands. Contrarily, the United Kingdom opted for a policy instrument with a stronger focus on productive efficiency of the DG/RES operator: a quota system with tradable green certificates. This is supplemented by a plethora of additional measures.
5 Network regulation

Dealing with support schemes, the previous chapter focused on essential elements of the revenue stream of DG/RES operators. This chapter turns to the costs DG/RES operators incur for the usage of network transport and system services, and thereby to the interface between DG/RES operators and DSOs. As networks constitute essential facilities, they continue to be regulated in liberalised markets. Network regulation hence represents the regulatory boundaries for the costs of DG/RES operators’ network usage and, simultaneously, the DSOs’ income. In analogy to the previous chapter, first a conceptual overview of the different types of network regulation will be provided (Section 5.1) before an aggregate overview of national regulation will be presented based on the survey among project partners (Section 5.2).

5.1 Overview of network regulation

Network regulation can be subdivided into several thematic groups: economic network regulation controlling the costs DSOs can pass on to customers, network access and related access charges as well as the distribution of tariffs to parties connected to the grid. Further aspects, such as the supply of ancillary services, are not within the scope of this report.

5.1.1 Economic network regulation

Due to their characteristics as a natural monopoly, electricity transmission and distribution need to be regulated to avoid monopoly rents and discriminatory access. In theory, perfect regulation of the natural monopoly segment aims at achieving allocative, productive and qualitative efficiency as if the sector was competitive. This intends to approximate the welfare distribution between network operators and customers to a situation under perfect competition. The same applies to resource usage of the operator, and the quality of service level reached.

Directive 2003/54/EC (Art. 20) stipulates that tariffs or methodologies for their calculation are approved ex-ante by the national authority. These need to be designed in a way that they ensure sufficient investment and the viability of the networks (Art. 23(2)). Possible positive effects of demand-side coordination or DG integration need to be taken into account when planning investments (Art. 14(7)). Further details are to the discretion of Member States.

Various regulatory approaches are applied. The predominant types of network regulation are rate-of-return regulation, incentive regulation and yardstick regulation, which will be described shortly in the following [8][64].

Under a rate-of-return (RoR) or cost-plus regulation, the regulator approves a cost base. A fixed interest rate is then given on the bound capital, as reflected by the following formula (based on [44]):

\[ R_{i,j} = OE_{i,j} + D_{i,j} + T_{i,j} + (RAB_i \cdot RoR)_i \]

The required revenue \( R_i \) is composed of the operating expenses \( OE_i \), depreciation expenses \( D_i \), tax expenses \( T_i \), and the product of the regulatory asset base \( RAB_i \) and the allowed rate of return \( RoR_i \).

The common critique to this approach is that there is an incentive to inflate the capital base (Averch-Johnson-effect) to reach a higher total profit, that is, that DSOs may be induced to overinvest in networks.

A nowadays widely practiced way of network incentive regulation is the price or revenue cap: the regulator imposes a maximum price (€/kWh) or maximum revenue (€) on transmission and
distribution companies. If deviations from the expected transmission amount (kWh) are corrected, these two mechanisms are equivalent. In price cap regulation, the regulator defines a price path for the next regulatory period. A regulatory period typically runs for 3 to 5 years, where short time periods are generally applied after the introduction of performance based regulation in order to quickly bring down historic inefficiencies and pass these through to end-consumers. The incentive for the companies is to decrease their own cost in comparison to this predefined price path; the difference constitutes their profit. This can also be combined with stronger requirements for companies that are inefficient in comparison to their peer group (individual X-factor). In summary, the price is determined as follows (on the basis of [44]):

\[ P_t = P_{t-1} \left( 1 + RPI - X_{gen} - X_{ind} \right) \pm Z. \]

The price in the year \( t \), \( P_t \), is calculated from the price of the previous year, \( P_{t-1} \), corrected by the retail price index (\( RPI \)), and general and individual efficiency improvement requirements. The last factor, \( Z \), represents additional bonuses or penalties, e.g., for quality of service.

**Yardstick competition** is an incentive mechanism where a network operator’s allowed expenses depend on the average of the industry peer group for every single year. It is therefore more competitive than price or revenue cap regulation. In practice, various hybrid forms between the aforementioned approaches exist.

The presented mechanisms allot the DSO’s revenue streams. The transition from rate-of-return to incentive regulation aims at incentivising DSOs to operate networks more cost effectively. The detailed design of network regulation, i.e., the incorporation of costs and benefits associated with the connection of new generation facilities and loads, impacts the readiness of DSOs to connect new DG installations as well as their operational strategies for system accommodation. In particular, regulation influences whether DSOs continue to apply a passive operation philosophy (a fit-and-forget approach) or whether they treat DG as an active control element by means of active network management. The latter means that DG is integrated into network control with greater coordination of power system operation, rather than its straightforward connection [50]. A lack of incentive for the DSO, i.e., the non-inclusion of any explicit incentives in national legal regimes for DSOs to incorporate DG in the planning and operation of networks, has been identified as one of the dominating barriers to DG deployment in the DG-GRID project [61]. This implies that many DSOs perceive DG plants as an additional complexity to the network and fear the adverse impact of additional costs arising from their integration. In the DG-GRID project, it was found that except for the United Kingdom, there are no innovation-specific regulatory instruments in network regulation in the EU-15 Member States, the focus being rather on short-term cost reductions than on stimulating network innovations [3]. In the United Kingdom, three parallel instruments are applied: First, the revenue cap rises with 1.5£ per installed kW for 15 years [57]. Second, an Innovation Funding Incentive (IFI) has been adopted which allows DSOs to spend up to 0.5% of its revenue on research and development. Third, Regional Power Zones (RPZ) have been implemented as scheme fostering technical innovations for connections of DG [46]. Quality improvements, by means of a Q-factor, are only incorporated into the regulatory formula of incentive regulation in the Netherlands and in the United Kingdom (ibid).

A thorough investigation of the economic impact of DG penetration in distribution networks on the DSO has been conducted by [47], as part of the DG-GRID project. In their analysis, they take into account a large number of factors, such as network and DG characteristics, and two possible network management philosophies, i.e., passive and active network management. Their analysis
utilises combined a GSP (grid supply point) model and a financial spreadsheet model representing the DSO business.

5.1.2 Network access

It is a crucial topic under which conditions a party will be granted connection to the DSO grid. Access, both for customers and new generators, needs to be non-discriminatory for such third parties. For DG/RES operators, it is not only important if the DSO has to connect them to the grid, but also at what cost level. Connection charges can be divided into three main categories of DG/RES cost contribution: shallow, shallowish and deep charges. Shallow charges mean that the DG/RES operator will only pay the connection costs to the nearest network point. All further necessary expenses, such as converter station and grid reinforcements, are borne by the network operators and typically socialized through the Use-of-System (UoS) charges. Deep charges represent the opposite approach: in this case, the DG/RES operator has to pay for all expenses linked to its grid connection, including upgrades at the transmission and distribution level. Shallowish charges constitute a hybrid between these two concepts. In this case, the DG/RES operator pays for the connection to the nearest network point and the proportional use of grid infrastructure reinforcements at the DSO level.

5.1.3 Network tariffs

A DSO is allowed to recover certain prices or total revenue. If the regulator allows single prices, e.g., differentiated after customers and generators and their connection to voltage levels, there is not much room for interpretation. By contrast, if the DSO can decide himself how to allocate its revenue from customers, there can be major differences whether it is beneficial for DG/RES development. If tariffs are recovered from customers only, it makes a difference if DG/RES is also counted as customers in the few hours when they are net consumers. Contrarily, if tariffs are also recovered from generators, an exemption for DG/RES can be pivotal for their economic operation. Another instrument is payments from the DSO to the DG/RES operator: an amount being paid to DG/RES for avoided usage of the transmission grid (i.e., opportunity cost to the DSO) can be regarded as a negative tariff.

5.2 Summary of network regulation

The central features of network regulation characteristics in the five country cases for the year 2007 are provided by The Netherlands show a different image: Yardstick regulation is applied for network operators and connection charges are differentiated according to connection size. In both Spain and the United Kingdom, DSOs are regulated with revenue cap schemes and can bill deep or shallowish connection charges. Use-of-system charges in the UK depend on the voltage level the generation unit is connected to.

Table 4. Denmark applied a revenue cap incentive regulation in combination with shallow connection charges for DG/RES operators. Most existing DG is also exempt from use-of-system charges. Germany still practised rate-of-return-regulation in 2007, but will shift towards revenue cap incentive regulation from 2009 onwards. Both use-of-system charges and grid reinforcements are borne by final consumers as DG/RES operators pay only shallow connection charges.

The Netherlands show a different image: Yardstick regulation is applied for network operators and connection charges are differentiated according to connection size. In both Spain and the United Kingdom, DSOs are regulated with revenue cap schemes and can bill deep or shallowish connection charges. Use-of-system charges in the UK depend on the voltage level the generation unit is connected to.
Table 4: Network regulation in the five country cases (2007)

<table>
<thead>
<tr>
<th>Country</th>
<th>Network Regulation</th>
<th>Connection charges</th>
<th>Application of use of system charges for generators</th>
</tr>
</thead>
<tbody>
<tr>
<td>Denmark</td>
<td>Revenue cap</td>
<td>Shallow</td>
<td>No, not for most existing DG; new wind and CHP installations can be affected.</td>
</tr>
<tr>
<td>Germany</td>
<td>Rate-of-Return</td>
<td>Shallow</td>
<td>No, only end consumers pay UoS charges.</td>
</tr>
<tr>
<td>Netherlands</td>
<td>Yardstick</td>
<td>Shallow below units of 10 MVA, deep for units above 10 MVA</td>
<td>No, only end consumers pay UoS charges.</td>
</tr>
<tr>
<td>Spain</td>
<td>Distribution: Revenue cap(^5)</td>
<td>Deep</td>
<td>No, only end consumers pay UoS charges.</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>Revenue cap</td>
<td>Shallowish</td>
<td>Yes, DG/RES does not pay TUoS charges; large scale power generation does not pay DUoS charges(^6).</td>
</tr>
</tbody>
</table>

\(^5\) Transmission: Cost of service

\(^6\) In transmission, generation pays shallow connection charges.
6 Country case studies

6.1 Denmark

This country case study is split into the main sections networks, generation, power market and support schemes which are addressed in this order.

6.1.1 Networks

The Danish electricity system is physically split into two areas: the East Danish islands are synchronous with the NORDEL area, whereas West Denmark is part of the UCTE (Union for the Co-ordination of Transmission of Electricity) network. A connection between the two Danish TSO regions is currently being established.

There are over 100 DSOs in Denmark. All DSOs are legally unbundled, and there is no application of the exemption clause from the unbundling requirements for DSOs serving less than 100,000 customers [21]. The fragmented structure stems from the historical background of local electricity supply in the early days of electrification. DSOs are sub-grouped into the categories of regional transmission companies, distribution network operators and so-called transformer unions, which are operators of very small systems. Community ownership is a core feature of all these DSOs; there is a tendency for consumer ownership in West Denmark and for municipality ownership in East Denmark [55]. The East and West Danish TSOs were owned by the respective DSOs until a common state-owned TSO was founded in 2005.

Since 1977, DSOs were subject to price supervision by an Electricity Price Council [55]. The underlying principle was that they should recover their costs through transmission tariffs. Due to the ownership structure, incentives for profits were low as the DSO was directly or indirectly owned by its customers. Expenses for DG/RES connections could under this cost-of-service regime be passed on to customers (which sometimes profited from wind and local CHP production). The course of the revenue cap incentive regulation since 2000 is quite unusual (see [55] for further details). The authors estimate therefore that the impact of this regulatory change is negligible.

6.1.2 Generation

Historically, generation took place locally with rather weak interconnections until the 1950s. The oil crises supported the erection of central power plants, but local CHP generation remained active [65]. From 1981 onwards, the development of wind power was fostered politically. The current regime can be described as a hybrid between central and decentralized generation; in the mid-1980s, an operator of central power plants agreed to install wind and CHP units as a complement for new central power plants. The share of DG increased from 1% in 1980 to 35% in 2001 [65]. The composition of DG generation for 2003 is stated in Table 5; distributed CHP dominates with a share of 51%, followed by wind energy with 34%.

<table>
<thead>
<tr>
<th>Table 5: Main DG technologies in percentage of the total DG production (2003) [63]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distributed CHP</td>
</tr>
<tr>
<td>Industrial CHP</td>
</tr>
<tr>
<td>Onshore wind mills</td>
</tr>
<tr>
<td>Hydro</td>
</tr>
</tbody>
</table>

An overview of the shares in East and West Denmark, separated after controllable and non-controllable DG, is given in Table 6. It is the most up-to-date source where West and East
Denmark are separated and shows that the share of DG is higher in the Western part of the country, which is partially due to the non-controllable wind energy generation.

### Table 6: Characteristics of the Danish system (2003), cited after [63]

<table>
<thead>
<tr>
<th></th>
<th>West Denmark</th>
<th>East Denmark</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Consumption</td>
<td>TWh</td>
<td>19.4</td>
<td>13.2</td>
</tr>
<tr>
<td>DG production, total</td>
<td>TWh</td>
<td>11.1</td>
<td>3.1</td>
</tr>
<tr>
<td>Controllable DG production</td>
<td>TWh</td>
<td>6.8</td>
<td>2.5</td>
</tr>
<tr>
<td>Non-controllable DG production</td>
<td>TWh</td>
<td>4.2</td>
<td>0.6</td>
</tr>
<tr>
<td>Total DG in % of consumption</td>
<td></td>
<td>57%</td>
<td>24%</td>
</tr>
<tr>
<td>Controllable DG in % of consumption</td>
<td></td>
<td>35%</td>
<td>19%</td>
</tr>
<tr>
<td>Non-controllable DG in % of consumption</td>
<td></td>
<td>22%</td>
<td>4%</td>
</tr>
</tbody>
</table>

#### 6.1.3 Power market

The former structure of vertically integrated local electricity monopolies has been fully liberalized by 2003 [33]. East and West Denmark are regions of the Nord Pool electricity exchange for gross trading. Nord Pool manages interconnector usage within the Nordic countries to keep price spreads minimal. This leads to the effect that the operation of conventional power plants in Denmark depends highly on precipitation in Norway and Sweden: these hydro-dominated systems export electricity to Denmark in rather wet periods and import electricity when hydro reservoir levels are low. This pattern leads to strong price differences on power markets depending on annual precipitation, which affects DG/RES participating at the electricity exchange [63]. Electrical capacity for wind accounts for slightly less than 25 percent of installed capacity [37]. In short periods when wind generation exceeds consumption, the excess electricity can be exported to the neighboring countries (within transmission capacity constraints of the interconnectors). The combination of the thermal-wind based Danish system with the hydro-based Norwegian-Swedish system enables the complementary use of renewable resources in electricity generation in the Nordic countries. Nord Pool offers a special trading regime for small direct participants: instead of a high annual fee of 15000 Euro and low variable fees per traded MWh, these can choose to pay a higher variable fee only and waive the high annual fee. This is possible for day-ahead and intraday trading and estimated to be highly advantageous for small DG operators pursuing direct marketing. It is reasonable to assume that directly marketed DG/RES power operators engage in these markets; however, a participation in reserve capacity markets administered by the TSO is not known to the authors.

#### 6.1.4 Support schemes

The Danish state first engaged in influencing the choice of generation technologies after the first oil crisis to reduce oil dependency [65]. Earlier research support for wind energy and experience with decentralized CHP had proven to be helpful for the dissemination of these technologies. In the very beginning, utilities were obliged to “pay 35% of the connection costs and buy surplus power at 85% of the consumer price from wind turbine owners in their supply area” [65]. This made wind farms profitable which were mainly financed by local wind turbine associations. Research subsidies from the state supplemented this operating support.

During the 1990s, all district heating plants with gas network access had to be converted to CHP stations. The remaining district heating plants were urged to convert to biomass as a main fuel. Both construction and operation of these plants were subsidized, the latter by means of a fixed feed-in tariff with three time-dependent steps. Due to problems related to excess production in
some hours, this three-tier tariff was replaced by a price premium in January 2005. This way, support follows the supply through the spot market prices, i.e., it provides an incentive to adjust supply when there is excess production or excess demand [63]. As aforementioned, the operators of central power plants had agreed to erect additional wind and CHP capacity in stakeholder negotiations in the 1980s, which proved beneficial for the further development during the 1990s. The main support element for wind power was feed-in tariffs, accompanied by priority dispatch and the right for priority grid access. Main obstacles in practice, e.g., the delay of grid access, are not known to the authors.

The DG/RES support scheme evolved from a feed-in tariff support to price premiums from 1999 onwards [33]. A special feature of the Danish price premiums for new installations until 2008 was that they are not premiums on top of market prices, but guarantee a fixed income as a sum of market prices and the support. In contrast to a FIT, the DG/RES operator is responsible of marketing the generated electricity himself, but a certain income level is nevertheless ensured. This scheme helped integrating especially large amounts of wind power into electricity markets. From 2008 onwards, the support is a pure price premium. With the increasing size of wind farms, the investor structure turned from private persons to institutions. However, the controllable CHP generation is fully exposed to price fluctuations since 2005 to give an incentive to adapt to market conditions [63].

Offshore wind farms were assigned by tendering mechanisms and operating support is based on individual legislation per project. As for onshore projects, the realization depends highly on the level of the guaranteed income.

6.1.5 Summary

The successful development of DG/RES in Denmark since 1980 is based on a combination of the historical market structure accompanied by certain human capacities and a careful design of the regulatory regime. Different stakeholders agreed in steps to strengthen DG/RES development. A high support level in the 1990s had a very positive impact on the construction of additional capacity. The formerly decentralized structure of electricity supply showed to support this evolution. Today, most DG/RES installations are somewhat integrated into most power markets and still have a guaranteed income.

6.2 Germany

6.2.1 Support mechanisms for DG/RES

In Germany, the operation support scheme for DG/RES has traditionally been a feed-in tariff (FIT). Until the end of 2008, the Renewable Energy Sources Act of 2004 (EEG 2004) and the Combined Heat and Power Generation Act (KWKG - Kraft-Wärme-Kopplungsgesetz) of 2002 were valid. From 2009 onwards, the FIT of RES have been adapted; main changes constitute a remarkably higher degression for solar energy and higher rates for geothermal and wind power. The development for wind power can be split into two main adoptions: On the one hand, higher rates for offshore wind energy aim at supporting the faster utilization of offshore wind resources; on the other hand, additional tariffs for providing system services serve to facilitate large-scale integration into the grid.

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7 mainly based on [62]
The current FIT support levels for the different RES technologies are indicated in Table 7, whereas the RES incentives in the analysis base year 2007 are displayed in the different tables in chapter 7.

Until now, the direct commercialisation of EEG electricity plays a minor role.

Table 7: RES incentives in Germany (2009)

<table>
<thead>
<tr>
<th>RES Category</th>
<th>€cent/kWh</th>
<th>Remark</th>
</tr>
</thead>
<tbody>
<tr>
<td>hydro power - new installation &lt; 5MW</td>
<td>12.67 - 7.65</td>
<td>&lt;500kW - &gt;2MW</td>
</tr>
<tr>
<td>hydro power - upgraded installation &lt; 5MW</td>
<td>11.67 - 8.65</td>
<td>&lt;500kW - &gt;2MW</td>
</tr>
<tr>
<td>hydro power - upgraded installation &gt; 5MW</td>
<td>7.65 - 3.5</td>
<td>for increased power &lt;500kW - &gt;50MW</td>
</tr>
<tr>
<td>land fill gas &lt; 5MW</td>
<td>9.0 - 6.19</td>
<td>&lt;500kW - &gt;500kW</td>
</tr>
<tr>
<td>sewage gas &lt; 5MW</td>
<td>7.11 - 8.16</td>
<td>&lt;500kW - &gt;500kW</td>
</tr>
<tr>
<td>mine gas</td>
<td>7.16 - 4.16</td>
<td>&lt;500kW - &gt;50MW</td>
</tr>
<tr>
<td>biomass - wood-fired, biogas, veg. oil CHP</td>
<td>11.67 - 7.79</td>
<td>&lt;150kW - &gt;5MW</td>
</tr>
<tr>
<td>basic incentive (&lt;20MW)</td>
<td>13 - 2.5</td>
<td>biogas/slurry – wood (vary with el. power) after / before 2009, only for CHP-ratio</td>
</tr>
<tr>
<td>incentive for renewable primary products</td>
<td>3 – 2</td>
<td></td>
</tr>
<tr>
<td>incentive for CHP</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>incentive for technical inovation</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>geothermic – basic incentive</td>
<td>16 - 10,5</td>
<td>&lt;5MW - &gt;20MW</td>
</tr>
<tr>
<td>incentive for CHP</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>incentive for technical inovation</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>wind energy onshore</td>
<td>9.2 - 5.02</td>
<td>5 years* initial fee – 15 years basic fee</td>
</tr>
<tr>
<td>wind energy offshore</td>
<td>13.0 - 3.5</td>
<td>12 years* initial fee – 8 years basic fee</td>
</tr>
<tr>
<td>incentive for system services</td>
<td>0.7 - 0.5</td>
<td></td>
</tr>
<tr>
<td>incentive for repowering</td>
<td>0.5</td>
<td></td>
</tr>
<tr>
<td>solar energy - on roof</td>
<td>43.01 - 33.00</td>
<td>&lt;30kW - &gt;1MW</td>
</tr>
<tr>
<td>solar energy - own consumption &lt; 30kW</td>
<td>25.01</td>
<td></td>
</tr>
<tr>
<td>solar energy - on ground</td>
<td>31.94</td>
<td></td>
</tr>
</tbody>
</table>

*vary with reference location

6.2.2 Network regulation issues for DG/RES
This section is mainly based on information provided by the Bundesnetzagentur (German Federal Network Agency, [9][10]).

In Germany the EU regulations have been adopted with the Energiewirtschaftsgesetz (EnWG, 1998) and its update in 2005. In general, network charges have to be approved by the Bundesnetzagentur. Only real costs arising from a distinct network structure can be charged.

In current network regulation, there are no provisions that aim at compensating DG/RES-E operators for their possible positive impact on DSO network operations, for example with respect to network losses. However, negative impacts, especially occurring in the transmission grids, are also not penalized.

According to § 18 Abs. 2 StromNEV, the DSO estimates the avoided network charges and has to be compensated by the TSO. This applies only if the DG/RES unit is not participating in the aforementioned EEG and KWKG support schemes.

Costs for DG/RES are shared among the TSOs, which are responsible for the support scheme accounting. They charge these costs proportionally to all electricity traders [5]. The later charge these again from their consumers, with an exception rule for large-scale customers.

6.2.3 Participation of DG/RES in energy markets
Until now RES has not participated in the energy markets due to the incentives of the FIT.
But the new EEG 2009 allows direct selling of RES on the markets and gives further incentives for doing so. It can be expected that a minor part of direct sold energy in the next years, but with growing tendencies.

6.2.4 DG/RES providing balancing services
Today DG/RES does not participate in the balancing services due to a missing benefit compared to the FIT.

6.2.5 Grid access
The grid access is defined in the grid code of each TSO. Guidelines for DG/RES at the medium and low voltage are provided by the BDEW (Bundesverband der Energie- und Wasserwirtschaft), the German utilities association. These define terms for the grid access according to grid capacity, grid short circuit currents, frequency, voltage and harmonics. Due to the provision of priority access for DG/RES to the grid, all plants complying with these terms have to be connected to the grid.

From 2009 on, there will be new grid access requirements for DG units, such as wind turbines. According to this new grid access requirement, for wind turbines that are connected to the MV level remuneration will be paid if they are able to ride through a specific voltage dip before access to the network.

6.2.6 Congestion management
Currently, in Germany the feed-in-tariff for micro-CHPs does not give any incentive for CHP operators when it is needed for system balance and congestion management. Therefore, micro-CHPs do not contribute to congestion management and system balancing mechanism in Germany.

In case of congestion on the transmission and distribution grid, curtailment of wind power production for a certain time is an option to ensure grid stability. In Northern Germany, in case of increased congestion on the power grids, wind farm operators have switched off their wind turbines for a short-time in order to ensure the security of the German power grid. Of course, the network operators avoid congestions by curtailing wind power. An incentive for a faster extension of the grid is set by the EEG 2009 because curtailed capacity still has to be remunerated according to the FIT (§12). For that reason, network operators attach importance to developing wind generation management solutions including wind power forecasting and network calculation tools in order to minimize the congestions in the grid.

6.3 The Netherlands

6.3.1 Support mechanisms for CHP
Before the year 2000, CHP was supported through priority access, a fixed feed-in tariff and a number of tax measures. In the framework of their environmental action plans (MAP), the utilities had an active policy to establish co-generation units where clients had sufficient heat demand. Different ownership situations existed. Many industrial installation were privately owned, mainly because of the own use of electricity. In larger (industrial) projects, ownership was combined through Joint Ventures. The smaller installations (often in horticulture) were usually utility-owned. Clients paid for the heat (with some rebate) and the utility reaped the benefits of the electricity.
From 2000-2005, besides the tax support for new investments, production support was provided in the form of a feed-in premium. Annually, the feed-in premium level was determined based on forward market prices for gas and electricity. Due to the rise in electricity prices after 2005, the feed-in premium for CHP was set at zero level.

In absence of a feed-in premium, the investment tax support measures remain, as well as the exempt on paying energy taxes. The higher prices, especially during peak hours, have stimulated a rapid growth in new horticultural CHP installations. There is an increase in night-illumination of greenhouses. During the peak hours these CHP units generate for electricity sales. Heat is often stored in large water storage tanks. The favorable spark spread since 2005 and the increase in night time illumination of greenhouses has led in the past few years to an acceleration of new CHP installations despite the absence of a feed-in premium after 2005 (see figure).

![Figure 3: Development of the total electricity CHP capacity (excluding coal–fueled CHP from 1998 to 2006)](image)

### 6.3.2 Support mechanisms for renewables

The predominant support mechanism for renewable electricity and renewable gas is a feed-in premium on top of the market price. According to a recent revision the premium is no longer a fixed amount per kWh over the project lifetime but rather it is varying with the electricity revenues. The original support scheme started in 2003 and has been suspended since august 2006. Since April 2008 it has been reopened again.

Additionally, some technologies can use tax incentives like (EIA – deduction of corporate tax) and green fund financing (via income tax of individual investors). Guarantees of origin are issued but are used for the voluntary market. The actual premium varies with the realisation of the electricity revenues. The subsidy base is the ex-post financial gap based on average production costs which are fixed for the duration of the project. 2007 levels of the feed-in premium for renewables are presented in the tables in section 7.

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8. This part of the case study originates mainly from [62]

9. Guarantees of origin for the voluntary market concern RES-E already paid for by the government through the support scheme. As such it is double counting, doesn’t help initiate additional projects and has an adverse effect on public support for extending the renewable energy share.
6.3.3 Network regulation

The Netherlands implemented performance-based network regulation with the 1998 Electricity Act [53]. Subsequently, the first price control period ran from 2001 to 2003. In the first period price-cap regulation based on benchmarking was implemented by the Dutch energy regulator that was aimed at reducing historical inefficiencies and creating a level playing field. Thereafter, a price-cap regulation based on yardstick was implemented. In the first period (2001-2003) only an efficiency factor was included (the X-factor) but in later periods a quality factor was included (the Q-factor). In general, different DSOs can experience different cost structures due to differential geographical integration of DG/RES-E units in their networks. Until now, this is not something that is taken into account in the benchmarking procedure.

The Tariff code published by the Dutch regulatory authority specifies the design of network tariffs. It specifies that connection charges are shallow and regulated for units below 10 MVA, and are deep and negotiated between parties for units above 10 MVA. The regulated connection charges are differentiated over voltage levels and are usually distance dependent (i.e. distance between the existing network and the unit to be connected). Next to connection charges there are also use of system charges. Only consumers pay a use of system charge, where large consumers pay a fixed charge plus a capacity dependent charge, and small consumers only pay a fixed use of system charge. In the Netherlands, use of system services are split in system services and transport services, consequently UoS charges consist of (a) system charges and (b) transport charges. DG-operators are obliged to pay a UoS charge for system services, but only for the amount of electricity taken from the network. If net offtake in a year is 'negative', no system charges are levied. The charge is kWh based and should cover the costs for reserve requirements, black-out arrangements, costs related to maintaining the power stability etc. (b) Transport charges are either kW based or both kW and kWh based, dependent of the network level. A DG-operator does not pay transportation costs for the energy supplied to the grid.

In current network regulation there are no provisions aimed at compensating DG/RES-E operators for their possible positive impact on DSO network operations, for example with respect to network losses. In April 2005, the Dutch regulatory authority implemented a provision according to which operators of DG/RES-E units with an annual production capacity of 150 MWh or more received a small compensation payment for avoided energy losses in the transmission network (‘Regeling Uitgespaarde Netverliezen’, known as RUN). This arrangement credited the advantage of DG-units in preventing some energy losses on high voltage levels through the feed-in of energy in a lower voltage level. However, this payment was cancelled by the Trade and Industry Appeals Tribunal in July 2007 due to insufficient legal basis for such a provision in current law. After that, the regulator announced that no new arrangement will be put in place.

6.3.4 Participation of DG/RES in energy markets

The main types of DG/RES in the Netherlands are wind turbines and CHP installations. Depending on the flexibility in the production process and possibilities for thermal storage in case of CHP units, some operators of CHP units sell their excess electricity on electricity markets. A number of aggregators are active which focus on certain market segments, notably horticulture and industrial CHP. Electricity is usually sold on forward markets and the day-ahead market.

Wind power is usually sold to suppliers who integrate it into a portfolio of different generating technologies. Typically, wind producers are confronted with the highest degree of
unpredictability. For the balancing requirements through ‘selling’ their program responsibility to the utility, an amount of around 0.4 to 0.8 ct/kWh is subtracted from the market price.

6.3.5 DG/RES providing balancing services

Deviations from scheduled generation are corrected with an imbalance charge. One of the horticultural aggregators also provides a signal with the sign of the national system imbalance. Operators can use this to predict what will be the financial consequence of producing less (or more) electricity than planned. Whenever they actually change their production, they indirectly affect the national system balance, both in volume as well in the resulting imbalance prices. Although they do not directly participate in the balancing market, they receive more or less similar benefits as if they would have participated in the TSO-organised market for regulation and reserve power. Due to the indirect nature of the effect of CHP operation on national system balancing, the actual size of this contribution is unknown. For provision of other ancillary services, there are still barriers for provision by CHP (communication infrastructure, monitoring devices etc.) and therefore for exploiting the benefits of CHP.

6.3.6 Grid access and congestion management

Getting a grid connection within a reasonable time is the major barrier for DG/RES (and also large conventional power plants) in some regions of the Netherlands where there is insufficient HV transmission capacity. Both the TSO and DSO have an obligation to eventually connect everyone. But, due to recent high electricity prices and the related favorable ‘spark spread’, there is an explosive growth in new CHP installations in parallel to a substantial expansion in conventional large scale generation capacity. But the required re-enforcements of the HV-grid cannot be implemented with the same speed.

For large-scale generators, temporary run-back contracts have been established for almost 5000 MW of new plants that will be commissioned in the period 2009-2012. As an alternative for waiting until a firm connection can be guaranteed, the producer accepts short periods of curtailment of generation in case of congestion, but without any remuneration of lost income.

For DG/RES installations a law is in preparation that will regulate priority access for renewable energy sources in combination with a congestion management scheme for DG/RES. In case of congestion only fossil-fuel based generators will be required to down-regulate their output.

The most urgent situation regarding congestion takes place in the Westland, an agricultural area with a large concentration of greenhouses. CHP capacity has expanded in the previous four years by a factor of 4, from 150 to 600 MW. A covenant between the DNO Westland Infra and the TSO for a temporary and voluntary congestion management scheme has been implemented starting, December 2008. CHP operators have to submit bids for down-regulation, which will be used in case of congestion. This causes an additional administrative burden for lots of entrepreneurs, but on the other hand it more or less guarantees at least the same net benefits from selling electricity as would be the case in a situation without any congestion. These early attempts to have CHPs contribute to congestion management might be interpreted as the first examples of DG/RES contributions to Active Network Management.
6.4 Spain

6.4.1 Incentive schemes for DG/RES-E

Incentives for the production of energy from renewable sources are of two types: Feed in Tariffs (FITs) and price premiums over the market energy price (premiums). The next paragraphs briefly explain the main characteristics of the RES incentives (or subsidies) applied since the first scheme was applied.

Spain first introduced a FIT (both energy and capacity components) in 1994. This scheme was defined in law RD 2366/1994, which was passed, before the general law of the electric sector (law 54/97 passed in the year 1997). According to this scheme, the price earned by RES producers was computed based on electricity tariffs, the capacity and the technology used by the considered power plant. Prices were comprised of a capacity component and an energy one. Besides, there was an extra payment associated with the supply of reactive power and prices differed by time of the day.

In the year 1998, once the general law of the electric sector had been approved, the previous scheme was replaced by another FIT scheme where the level of the tariff was dependent on the average market energy price, which was computed according to a certain methodology. These tariffs were set in the piece of law RD 2818/1998. According to this law, the price of RES energy resulted from adding up the average market energy price, as explained above, and an uplift that was dependent on the technology and the capacity of the RES producer. Despite the fact that RES energy prices indirectly depended on market prices, they did not follow their evolution hour by hour. On the contrary, the reference price was updated periodically based on the application of a certain methodology, as with FITs. An uplift to these prices was computed based on the power factor of producers.

Then, in 2004, a hybrid system of FITs and premiums (both dependent on the average electricity tariff) was applied for the first time. This new mechanism was defined in RD 436/2004. According to regulation, premiums applied were the result of adding up a premium, properly speaking, and some extra incentives. FITs, premiums and incentives were expressed as a fraction of the average tariff that was taken as reference (TMR). The TMR was updated periodically.

Finally, in 2007 this hybrid system was replaced by another one where FITs and premiums no longer depended on the average tariff. These prices were no longer dependent on the TMR and were updated either quarterly, semiannually or yearly depending on the primary energy source. Conditions to be fulfilled by generators in order to be eligible for these charges were added, like the obligation for those larger than 10MW of being connected to a local control centre. Incentives were established to ride-through voltage dips, according to RD 436/2004. Later on, RD 661/2007 stated that those generators installed after the 1st of January 2007 should have voltage dips ride through capability. In this system, cap and floor values were introduced for the price (market price plus premium) earned by wind generators, solar thermal power, small scale hydro and biomass.

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10 This part of the case study originates mainly from [62]. Other sources used for the whole Spanish case study are different questionnaire outputs from the RESPOND and SOLID-DER projects.
6.4.2 Network regulation

Revenues of transmission owners are regulated, i.e. they are guaranteed the recovery of the cost of the investments they undertake once these are approved by the regulator. Therefore, the attitude of transmission owners towards the installation of new generators (both RES and conventional ones) do not depend on whether these generators pay the cost of the reinforcements they cause. If DG/RES generators do not pay the cost of these lines, other network users will.

DSOs are remunerated according to a revenue cap approach based on four year regulatory periods. The revenue cap formula includes specific terms regarding energy losses and continuity of supply (based on number and duration of interruptions). Penalties exist in case of non-compliance with power quality standards. Incremental costs related to the connection and operation of DG in distribution networks should be recognized in the DSO’s allowed revenues. However, this is not taken into account satisfactorily.

Previous regulation established a revenue cap formula to compute the total allowed revenues of all DSOs as a whole. After that, some sharing coefficients computed by the regulator were used to distribute that money among different DSOs. There was not any price control for nearly ten years, therefore actual costs and revenues earned by DSOs were completely decoupled. This situation caused poor new network investments. Moreover, an X-factor of 1% was set for all DSOs as a whole, regardless of the particularities of each one of them.

The new regulation is based on an individual revenue cap formula for each DSO. However, there are two mechanisms to induce efficient investment. Every year, incremental revenues are calculated taking into account the increment of demand and DG connections during the previous year and using a reference network model. In addition, at the end of each regulatory period, DSOs will inform to the regulator of the investments made in the previous regulatory period, and the regulator using a benchmark network reference model will update the starting remuneration base line for the next regulatory period. Therefore, efficient investment is induced by the use of a network reference model. Once again, there is not a clear methodology to compute the X-factor and it is set at the same level for every DSO independently of its efficiency in the development of the system grid. However, the allowed revenues formula has a term dependent on the fulfillment during the previous year of energy losses and continuity of supply requirements.

6.4.3 DG/RES-E ownership issues

In Spain, the Electricity Law 54/97 mandated legal separation between regulated and non-regulated business to be effectively implemented since December 2000. Therefore, distribution businesses have been legal unbundled from generation and retail supply to non-regulated customers. In Spain, distribution companies are now only responsible for network services. Last resource suppliers (retailers that tend to belong to the same holding company as the DSO in the area) provide energy to some customers at regulated tariffs. These consumers are those who have not been able to contract their supply with a retailer or are deemed not to be able to price commercial energy prices.

Ownership unbundling has not been implemented in Spain (although functional unbundling has already been implemented). The incumbent utilities own all type of businesses: generation, distribution, and retail. There are five major utilities that are in this position: Endesa, Iberdrola, Union Fenosa, Hidrocantábrico (EdP group), and Viesgo.
Generation should be unbundled from other activities. Therefore, DSOs can not formally own generation assets, with the exception of small DSOs. However as it was previously commented, the same group can own several different companies to develop different type of electricity businesses. Therefore, it is clear that DSOs may devote a favor treatment for connecting DG/RES when they belong to the same business group. The total DG/RES installed capacity owned by the RES/CHP companies belonging to the same group as main utilities over total DG/RES installed capacity in Spain in 2006 were: Iberdrola 19%, Endesa 10%, Union Fenosa 5%, Hidrocantábrico 3%, and Gas Natural 3%.

6.4.4 The role of DG/RES-E in electricity markets

Reserve markets
Access to reserve markets is also explained in [49]: “In Spain, contributing to the primary regulation service is mandatory for conventional generators, but not for DG/RES (no remuneration considered). The required equipment must be installed at every generation unit. Generating units that don’t comply may contract the service.

Secondary regulation has been established as a competitive market. The service is provided by several regulation zones (sets of generating units belonging to a generating company). The control is automatic and hierarchical: the SO sends signals to each company central dispatch, which in turn sends signals to its own units. The units participating in the service must react to the signals in 5 minutes. Up and down regulating capacity is not separated. The remuneration is comprised of a capacity payment (€/MW) for the total band provided (up and down), and an energy payment (€/MWh) corresponding to the price of the substitution regulation energy. The provision of this service is supervised, and a penalization of 150% of the capacity payment is applied if the units do not comply with the technical requirements of the service.

Tertiary regulation in Spain is also established as a voluntary competitive market. This market is only cleared by the SO if secondary reserve is exhausted. Units that can be on before 15 minutes can participate in the tertiary regulation market. An energy payment (c€/kWh) is defined for this market. Usually, tertiary energy prices are very favourable compared to daily market prices.

At the moment, intermittent energy sources are not able to participate in the Spanish secondary reserve market. Big efforts are being done by wind promoters to research and adapt wind farms so that they can provide load following services. Even though from a technical point of view it seems feasible in the near future, actual premiums over market price do not encourage wind farms to reserve part of their generation capacity to offer it as regulating capacity in the secondary reserve market.”

Ancillary service markets
As [49] explains: “In Spain, RES/DG generators that may access the AS markets are those that sell their output at the energy market or through contracts, are controllable, and have a size of at least 10MW. The maximum wind energy output that the Spanish system can allow under safety conditions is calculated in real time at the TSO control centre for the “Special Regime” (CECRE). If the actual production is higher than this value any unit connected to it can be curtailed. In order to participate in AS markets it is mandatory to be able to follow the orders of

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11 Specifically in this section we have benefited from information collected by Imperial College under the RESPOND project for the UK case [49].
the system operator (controllability). Every generator contracted to provide ancillary services must be connected to a generation control centre which will be in communication with the TSO control centre. All costs derived from this must be paid by the RES/DG unit. There are penalizations associated with deviations with respect to the established programs and, in the case of wind power, for non-compliance with the requirements concerning voltage dips riding.

6.4.5 DG/RES-E and congestion management
Transmission grid congestion in the Spanish system is managed through the application of a re-dispatch algorithm applied to generators and pumped units, and as last resource, to demand as well. Therefore, the market energy price is not affected by the existence of congestion in the grid. An uplift is applied to the final charges paid by consumers in order to recover the cost of re-dispatch.

[49] outlines that “A TSO can also curtail the production of any RES-E to solve grid congestions as a last resource. In the case of the DSO, the contracts signed with the owners of the units are taken in account to establish the priority to curtail production. Wind generators, as any conventional generator, are given 15% of the spot price in case of real time curtailment (they loose the premium for the curtailed energy). This must be regarded as a compensation for the generators, since if the curtailment takes place during the process of constraint’s solution after the daily market, no compensation is given.”

6.4.6 DG/RES-E and active network management
Active network management is not yet implemented in the SP. However, a number of European research projects, such as GAD, have been launched to investigate the AM techniques and the implementability of such methods in the distribution network.

As mentioned above, incentives are there in place for DSOs to reduce losses and improve quality of supply through the use of a revenue cap scheme. However, incentive regulation by itself does not provide enough incentives to undertake a longer term network transformation. Specific mechanisms for this should be implemented. Research projects and tax exemptions should be used to increase DG observability and controllability, on the one hand, and encourage DSOs to implement network management practices on the other.

6.4.7 DG/RES-E and network access
Contrary to consumers, generators only pay transmission connection charges. The connection charge paid by each generator is determined by the TSO on a case by case basis based on the network reinforcements that will have to take place due to the installation and operation of this generator. Given that these reinforcements may be conditioned by the location and operation profile of the generator to be connected to the grid, one could say that the TSO is implicitly taking these factors into account to compute transmission connection charges paid by generators.

DG/RES generators, like any other generator in the system, only have to pay distribution connection charges. They do not pay use of the system charges. Given that DG is connected at distribution level, these generators do not pay transmission connection charges but distribution connection charges. Transmission connection charges paid by RES generation connected to the transmission grid include the cost of all the required network reinforcements (deep connection charges). Generators connecting to the grid may afterwards receive a reimbursement if the lines
built to connect them are also used by another network user connecting to the same line extension within a period of 5 years after the installation of the former.

DG pay deep distribution connection charges in Spain, i.e. DG has to pay for any equipment and network reinforcement that is required to meet the technical conditions. The amount of these connection charges is calculated by the corresponding DSO. The rules for this calculation are not simple or transparent, thus discriminative treatment may arise. DG does not pay UoS charges. As long as UoS charges for DG are not implemented, main network reinforcement costs are socialized among consumers.

6.5 United Kingdom

6.5.1 Incentive schemes for DG/RES-E\textsuperscript{12}

The main current incentive schemes adopted in the UK in order to achieve the renewable target of 10.0% renewable electricity from gross electricity consumption mentioned in the European Commission’s Renewables Directive are: the Renewables Obligation, grant programmes and tax exemptions [42].

The Renewables Obligation (RO) was introduced in April 2002 and requires energy suppliers to source an annually increasing percentage of their sales from renewable sources. The generators of renewable electricity receive a Renewables Obligation Certificate (ROC) per produced MWh (irrespective of time or voltage level to which the generating unit is connected) that is tradable between suppliers but only valid in one period. At the end of the period, energy suppliers need to obtain a sufficient number of ROCs and make up for an insufficient number of ROCs by paying a buy-out price. The buy-out revenues are distributed proportionally to the number of ROCs submitted over the energy suppliers. Hence, there is a clear financial incentive to comply with the RO. Under the RO targets have been set out to 2015 (excluding large hydro): 10.4% in 2010, increasing by 1% per year to 15.4% in 2015. A medium-term target has been specified for 2016 and duration of the scheme is guaranteed until 2027. An aspirational target of 20% RES-E in 2020 has been asserted. In [32], the government mentions an aspiration to get about 20% of total electricity supplies renewable in 2020.

High prices in the first year seemed to give the ROC market a kick-start but compliance ratings were low. In 2004/2005 compliance was 69%, after even lower compliance figures in the previous years. Hence, the effectiveness of this instrument in achieving the set targets in the short run could be questioned. In a review of the RO [31], Dti noted the problem of a very low liquidity on the ROC market. Measures aimed at increasing liquidity were suggested and implemented afterwards resulting in a somewhat higher liquidity in recent years. There are no major changes expected in the support for renewables. In 2007, a consultation was held on possible reforms of the RO containing only limited number of small adaptations [6].

Since 2002 RES-E has been granted a tax exemption: the Climate Change Levy (CCL), which is a tax on electricity consumption (excluding domestic and transport sectors) of £4.30/MWh (6.26 €/MWh), is not levied on renewable electricity consumption.

\textsuperscript{12} This part of the case study originates mainly from [62]
Before the RO another obligation scheme was dominant in the support of renewable electricity generation: the Non-Fossil Fuel Obligation (NFFO). The NFFO was announced in 1990 as a mechanism that would award competitive orders for building nuclear or renewable based electricity generating capacity [54]. The NFFO system can be qualified as a combination of an obligation and a tendering system. Different NFFO projects competed against each other (within technology categories) for an NFFO award, with the lowest bid winning the award guaranteeing a certain premium price for electricity. After realisation of the project public electricity suppliers were obliged to buy all NFFO generated electricity. The difference between the market price and the premium price electricity suppliers had to buy for NFFO electricity was covered by the proceeds of a Fossil Fuel Levy that was levied on all electricity consumers. This mechanism was successful in bringing down the cost of the support for renewables for each technology, but less so in boosting the overall use of renewables in the market [41]. Additional support is also provided through capital grant schemes and enhanced capital allowances (tax incentives) for investments in eligible energy technology plant and equipment.

Electricity generation with DG technologies based on Combined Heat and Power (CHP) production is stimulated by a variety of measures. These include: fiscal Incentives, Climate Change Levy exemption on fuel inputs, eligibility for Enhanced Capital Allowances to stimulate investment; Business Rates exemption for CHP power generation plant and machinery, and reduced VAT on certain grant-funded domestic micro-CHP installations. These measures together should contribute to achieving a target of 10 GW of CHP capacity in 2010 [25].

6.5.2 Network regulation

The UK introduced the price control review, based on performance-based regulation through CPI-X, back in 1990. The first price control period (1990/1991-1994/1995) however is considered quite lenient in the sense that they allowed for price increases above the inflation rate. This explained by the then on-going restructuring process of the UK electricity sector, in particular by the privatisation process. Higher prices were thought to facilitate the sale of assets by public bodies [45]. “The second and third price control reviews for 1995/1996–1999/2000 and for 2000/2001–2004/2005 periods, respectively, significantly reduced real distribution charges and there is ample evidence that they succeeded in achieving significant efficiency improvements and delivering the gains to customers” [45].

The network issues related to distributed generation (DG)\[\text{13}\] came to the front with the publication of a report of the Embedded Generation Working Group, published by DTI in 2001. Among other elements, the report suggests the need for a reassessment of distribution charges, planning and other standards, and the information that is made available to embedded generators. Since then a significant number of consultation documents and reports were published\[\text{14}\] and adaptations to network regulation have followed. For price control reviews this has meant that the impact of DG on Distribution System Operators (DSOs\[\text{15}\]) has been more explicitly addressed in price control reviews. Most importantly, UK regulatory authorities have implemented explicit incentive schemes for DSOs to encourage innovation regarding DG connection issues. These schemes are the Innovation Funding Incentive (IFI) and the Registered Power Zones (RPZ). The IFI is a mechanism to encourage DNOs to invest in appropriate R&D activities that focus on the

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13 Also referred to as embedded generation.
14 See for a listing: [http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistGen/Pages/DistributedGeneration.aspx](http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistGen/Pages/DistributedGeneration.aspx)
15 Known as Distribution Network Operators (DNOs) in the UK.
technical aspects of network design, operation and maintenance. The RPZ is an initiative which provides a financial incentive to distribution companies to develop and implement innovative projects connecting distributed generation to networks where this may not have otherwise been economically feasible. These schemes are brought into the price control mechanism as a cost-plus adder: for specific new DG capacity connected to the network the operating DSO is allowed to receive an additional charge under the price control.

6.5.3 DG/RES-E ownership issues

Network operators are not allowed to operate DG/RES-E units but they are able to enter (long-term) contractual arrangements with DSOs. In these arrangements ancillary services provision, electricity feed-in and other issues can be dealt with.

From the total amount of CHP capacity (5474 MWe in 2007 [43]), 90% is utilised in industrial process. 75% of this capacity is located in the oil, gas and chemical sectors. It is not known which part of this capacity can be considered to be DG. Historically, these units have been owned and operated by the host site. Since the privatisation of the electricity sector in the 1990s however, more and more third-party arrangements via energy supply contracts have become in common. This is driven by the desire to outsource non-core operations, the need to secure professional development and operating expertise, and the lower rates of return that are generally expected by utilities. As a result, many of the major energy supply companies within the UK (E.ONUK, RWE power, EDF, Scottish&Southern Energy and Scottish Power) operate cogeneration business focussing on industrial markets.

Use of CHP in district heating is significantly lower, also compared internationally and accounts only for about 6% of total CHP capacity. The scarce existent district heating schemes are generally developed and operated by independent, not-for-profit companies established by local community councils [43]. CHP use in the commercial and public sector is highly relevant when looking in the number of units: 81% of the CHP units have an electrical capacity of less than 1 MWe. Domestic use of micro-CHP technology has not yet started off: the first commercially available Stirling based micro-CHP unit is expected to enter the market early 2009 [43].

6.5.4 The role of DG/RES-E in electricity markets

Wholesale market

The role of DG/RES-E operators in wholesale markets has recently been described in [49]: “In the UK, any generator which signs up to the Balancing and Settlement Code (BSC – essentially a code of conduct for use of the wholesale and balancing markets and a commitment to pay related charges) can participate in the energy markets directly. Generators under 100MW are not obliged to sign up to the BSC. Generators above 100 MW are registered as Balancing Mechanism Units. Those that do not sign the BSC will typically form a Power Purchase Agreement (PPA) with another larger entity already trading in the energy market. For small generation connected in distribution networks the PPA will be formed with an Energy Supplier. The Energy Supplier will net the total output from distributed generators from their demand requirements in a particular area. The generator will be paid feed-in tariffs. Typically, RES/DG units will choose to take a long term PPA with an Energy Supplier to hedge risk of imbalance in the wholesale markets.” DG/RES-E operators are treated as negative loads and not centrally dispatched by TSO/DSOs.

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16 Specifically in this section we have benefited from information collected by Imperial College under the RESPOND project for the UK case. Information has been published in [49].
Reserve markets
Every generation unit with a capacity higher than 100MW is obliged to take part in the provision of primary reserve. The secondary and tertiary reserve markets are voluntary. RES/DG that are smaller than 100MW are able to offer a few selected reserve / response services as part of an aggregated group (where the minimum group size is 3MW) [49].

Ancillary services market
There are some mandatory requirements for DG/RES-E generators as specified by the Grid Code and Distribution Code regarding the provision of voltage regulating services. These requirements vary according to DG installed capacity and certain type of connections. In practice, aggregated small DG/RES-E units can provide reserves for example. Bilateral Agreements are likely to continue to be used in developing the ancillary service market in the short to medium term. DG/RES-E operators can get payment associated with providing that service to the DSO: “an availability payment will be made for several type of AS, plus an additional payment if the service is called out.” [49]. RES/DG can provide some system services through an aggregator. Whether they are remunerated exactly by time of output and location will be dependent on the contractual agreement with the aggregator and the profit sharing arrangement. No special markets for DSO type ancillary services been organized in the UK yet. A Specific obstacle in the creation of these type of ancillary services markets may include the expected lack of liquidity in the market (the number of generators in the position to offer these services is rather small or all of them belong to the same company).

6.5.5 DG/RES-E and congestion management
In the UK the System Operator (SO) is allowed to modify the scheduled electricity production of DG/RES-E units by buying (selling) the offers (bids) submitted to the balancing market in order to maintain system balance. Both a TSO and DSO can curtail RES-E production is if system security is at risk. Compensation is provided when curtailments are implemented. “At distribution level, DSO and DG have bilateral connection agreement which allows DG to be curtailed for a relatively short period of time if it leads to significant saving in the cost of upgrading the network to facilitate the connection” [49]. This approach can be described as a bilateral market-based congestion management approach.

6.5.6 DG/RES-E and active network management
Active network management is not yet implemented in the UK. However, a number of research projects such as Aura-NMS have been carried out to investigate the AM techniques and the implementability of such methods in distribution network. In general, active network management techniques are targeted to be tested in the so-called Registered Power Zones (RPZs).

6.5.7 DG/RES-E and network access
DSOs negotiate with distributed electricity suppliers on the fair charge to be applied and only incidentally cases are brought to the regulator. The regulator passively encourages DSOs to charge DG operators more cost reflective use of distribution system charges where potential benefits of DG/RES-E operation for network operations are given back to the DG/RES-E operator. DG/RES-E market and network integration is facilitated by a number of license exemptions for certain small units. The ratio for the exemption is the disproportionate administrative and cost burden for small DG/RES-E operators. There do not seem to be significant administrative barriers in the UK regarding network access. However, a possible problem recognized by the regulator is the fact that network charges that potentially do not fully
capture the cost savings from locating generation close to demand, can discourage connection to
the network and create an incentive to bypass existing networks [58]. As mentioned above, the
UK regulatory authority at this point only passively encourages DSOs to adopt more cost-
reflective charges.
7 Overview of penetration and support levels

This section provides a more differentiated and comparative picture of RES penetration and the levels of support schemes in the individual countries. Starting out with RES penetration at the European level, this section then elaborates on the individual technologies. The tables giving an overview of national legislation are based on a survey among IMPROGRES project partners.

7.1 Total RES penetration in the EU-27 Member States

Electricity produced by renewable energy sources in the EU-27 countries amounted to 488.347 TWh in 2006, corresponding to a share of 14.5% of gross electricity consumption\(^{17}\) [22]. The country-specific situation with respect to the achieved as well as the target share of electricity from renewable energy sources is depicted by Figure 4 in more detail.

![Electricity share from renewables](image)

**Figure 4: Actual penetration of RES-E in 2006 and 2003 versus 2010 target for EU-27 [21]**

The share of technology in electricity production by renewable energy sources in the EU-27 in 2006 is dominated by hydropower (63% of total electricity production by RES), followed by biomass (18.4%) and wind (16.8%). Other renewable energy sources, such as geothermal (1.15%) and photovoltaic (0.51%), have a rather marginal contribution to electricity production.

As shown in [59], the potential of different energy sources for the EU-27 for 2020 is country specific. The largest potential in the EU-15 is found in wind energy (43% of total RES electricity production), followed by biomass (31%), and in the new EU Member States in biomass (66%), and wind energy (19%). Both energy sources will heavily influence the future renewable electricity production in Europe. Significant growth is assumed in biomass-based CHP. The estimated maximum potential for the installed capacity of biomass CHP in the EU-27 is up to 42

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\(^{17}\) Does not include pumped storage.
GWₑ by 2020 and 52 GWₑ by 2030, where biomass CHP installations approximately represent two thirds of the total installed capacities of biomass based power plants [18]. Although the potential in photovoltaic is assumed to be at around 3% in 2020, this is a market with high growth rates. The variability of the solar power source has influence on the impact on the grid.

Figure 5: RES-Electricity by technology as a share of the total achieved potential in 2006 for the EU-27 [21]

7.2 Biomass and waste

Electricity generation based on biogenic fuels, such as wood, wood-waste, biogas and based on municipal waste, amounts to 86400 GWh in the EU. The majority of these generation plants are located in North-western European countries, such as Germany (ca. 20000 GWh), Finland, the United Kingdom and Sweden (all exceeding 8900 GWh, cf. Figure 6).

The different national support schemes for biogenic electricity generation are shown in
Table 8. Denmark and the Netherlands apply price premiums whereas Spain uses a price premium or a feed-in tariff (FIT) in the first 15 years. After this period, in Spain no premium is granted or a reduced feed-in tariff. There is a multitude of different approaches in the fine-tuning of the support scheme in terms of co-combustion, fuel types and generation unit capacities. In Germany, there is a differentiation depending on installed capacity and in Spain, in addition to capacity size, also with respect to fuel type. In the Netherlands support is granted up to a capacity size of 50 MW. In the United Kingdom, the main support mechanism for renewables is the Renewables Obligation (RO), which was introduced in April 2002 [42]. The obligation requires energy suppliers to source an annually increasing percentage of their sales from renewable sources. The generators of renewable electricity receive a Renewables Obligation Certificate (ROC). The ROCs are tradable between suppliers. For co-firing, there is no minimum percentage until 31 March 2009. A 25% minimum co-firing of biomass will be imposed from 1st of April 2009 until 31 March 2010; then 50% from 1st of April 2010 until 31st March 2011, and 75% from 1st of April 2011 until 31st of March 2016. Co-firing will no longer be eligible for support after 31 March 2016.

![Electricity generation from biomass](image)
Table 8: Biomass support schemes

<table>
<thead>
<tr>
<th>Type of promotion scheme</th>
<th>Level [€/MWh]</th>
<th>Duration of payment [yrs]</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Denmark</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Price premium</td>
<td>Biogas: total incomes = 80.5 for 10 years and 53.7 for the following 10 years; Biomass combustion: total income = 53.7 for 10 years¹⁸</td>
<td>10/20</td>
</tr>
<tr>
<td><strong>Germany</strong></td>
<td>FIT 80.3 - 109.9¹⁹</td>
<td>20</td>
</tr>
<tr>
<td><strong>Netherlands</strong></td>
<td>Price premium</td>
<td>36 – 97²¹</td>
</tr>
<tr>
<td><strong>Spain</strong></td>
<td>First 15 years: FIT or premium. Afterwards: FIT only</td>
<td>FIT: 107.5-158.9; Premium: 61.9-115.3</td>
</tr>
<tr>
<td><strong>UK</strong></td>
<td>Quota</td>
<td>49.4 (Price observed ex post in 2006/2007)</td>
</tr>
</tbody>
</table>

Table 9: Waste energy support schemes

<table>
<thead>
<tr>
<th>Type of promotion scheme</th>
<th>Level [€/MWh]</th>
<th>Duration of payment [yrs]</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Denmark</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Price premium</td>
<td>9.4 for waste fired industrial CHP started before Jan. 2004²²</td>
<td>6</td>
</tr>
<tr>
<td><strong>Germany</strong></td>
<td>FIT</td>
<td>63.5 - 73.3²³</td>
</tr>
<tr>
<td><strong>NL</strong>²⁴</td>
<td>Price premium</td>
<td>13</td>
</tr>
<tr>
<td><strong>Spain</strong></td>
<td>First 15 years: FIT or premium. Afterwards: FIT only</td>
<td>FIT: 53.6 - 130.6; Premium: 30.8 - 97.7</td>
</tr>
</tbody>
</table>

For waste, the support schemes are applied in analogy to the schemes for biomass, except for the United Kingdom that provides no support for waste. Notably, the support levels are lower than

¹⁸ Different regulations apply for co-combustion.
¹⁹ 39 €/MWh if scrap wood is used; Additions of 40-60 €/MWh for certain fuel categories; plus 20 €/MWh if gas is treated to have natural gas quality or is used in fuel cells, stirling motors etc.
²⁰ New scheme in 2008 under which biomass producers are guaranteed a revenue of 120 €/MWh for 12 years.
²¹ Depending on co-combustion and installed capacity.
²³ Plus 20 €/MWh if gas is treated to have natural gas quality or is used in fuel cells, stirling motors etc.
²⁴ Limited to landfill gas and municipal waste water. New scheme in 2008: Price premium guaranteeing a total revenue ranging from 115 to 137 €/MWh and 58 €/MWh for landfill gas and industrial and municipal waste water for 12 years.
for biomass (Table 9). Again, in Germany and Spain, there is a differentiation with respect to installed capacity size and/or fuel type. In Denmark, the differentiation is based on the voltage level, with a higher premium (13.4 €/MWh) for facilities that are smaller than 3MW and went in operation before 1997.

### 7.3 Combined heat and power generation

Figure 7 displays the electricity stemming from CHP facilities in the different European countries. It does not reflect the actual CHP share as part of the generation mix in the individual Member States. The blue part of the bar indicates the CHP share generated by main activity producers, whereas the red part accounts for auto-producers of CHP. CHP generation takes place in large fossil-fired power plants for district heating, industry process heating or in decentral plants for rather small-scale district heating networks. This technology is considered to be environmentally advantageous because it can reach total efficiencies of above 80% (in comparison to far lower values for separated heating and electricity generation). In Germany, the electricity generation from CHP aggregates to about 80000 GWh; in most other European countries, a production level between 10000 and 30000 GWh is reached.

![Combined heat and power generation](image)

Due to its economic viability CHP received no financial support in the Netherlands in 2008 (Table 10). Formally, there is a support scheme for CHP, but for the year 2008 the support premium was set to zero since an economic analysis based on expected generation costs and electricity prices showed that CHP should be profitable in the absence of support. The range of policy instruments chosen in the other countries is quite large: Denmark opts for one-time payments which are equivalent to the sum of all future price premium payments from 2008 for industrial natural gas fired facilities. Germany and Spain differentiate their support schemes according to installed capacities (and in the case of Spain, also fuel type).
Table 10: CHP support schemes

<table>
<thead>
<tr>
<th>Country</th>
<th>Type of promotion scheme</th>
<th>Level [€/MWh]</th>
<th>Duration of payment [yrs]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Denmark</td>
<td>Price premium</td>
<td>9.4 for natural gas fired industrial CHP started before Jan. 2004(^{25})</td>
<td>6; 8, if &lt;4MW</td>
</tr>
<tr>
<td>Germany</td>
<td>FIT</td>
<td>22.5 - 51.1(^{26})</td>
<td>10</td>
</tr>
<tr>
<td>Netherlands(^{27})</td>
<td>Price premium</td>
<td>20.9 – 22.4</td>
<td>10</td>
</tr>
<tr>
<td>Spain</td>
<td>&lt;1MW: FIT; &gt;1MW: FIT or premium</td>
<td>FIT: 38.3 - 160.1; Price premium: 6.1 - 116.6</td>
<td>No time limit considered</td>
</tr>
<tr>
<td>UK</td>
<td>Large range of support measures, ranging from fiscal incentives to grant supports and promotion of innovation.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

7.4 Hydropower

The energetic yield from hydropower depends highly on usable altitude differences within a Member State. This is also reflected by the electricity generation from hydropower (Figure 8): mountainous countries as France, Sweden, Italy and Austria have an annual production of 37500 to 61500 GWh from this renewable energy source. Most other European countries have smaller hydropower capacity, e.g., run-of-river hydropower plants.

Hydropower is not included in the national RES support schemes in Denmark (Table 11). The remaining FIT and price premium schemes are mainly differentiated with respect to generation capacities (in Germany and Spain). In the United Kingdom, hydropower plants exceeding a capacity size of 20 MW are only eligible to support if they were commissioned after 2002. Note that the support levels are lower in comparison to other RES technologies; this does naturally not apply for the British Renewables Obligations as the latter is dependent on the certificate price.

\(^{25}\) Differentiation depending on voltage level; 10.7 for DG <25MW for up to 8 Mio. MWh or 20 years.
\(^{26}\) For new installations <= 2 MW, depending on installed capacity; partial annual degression; lower 2007 support level of 16.4 for modernised or 12.3 €/MWh for units erected after 1989.
\(^{27}\) For gas motors; no support in 2008.
Table 11: Hydropower support schemes

<table>
<thead>
<tr>
<th>Type of promotion scheme</th>
<th>Level [€/MWh]</th>
<th>Duration of payment [yrs]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Denmark</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Germany</td>
<td>FIT</td>
<td>66.5 - 96.7&lt;sup&gt;28&lt;/sup&gt;</td>
</tr>
<tr>
<td>Netherlands&lt;sup&gt;29&lt;/sup&gt;</td>
<td>FIT</td>
<td>97</td>
</tr>
<tr>
<td>Spain</td>
<td>FIT or premium for small plants (&lt;10 MW). Premium for medium plants (10&lt;P&lt;50 MW)</td>
<td>FIT: 78; Premium: 21 or 25 depending on capacity</td>
</tr>
<tr>
<td>UK</td>
<td>Quota</td>
<td>49.4 (Price observed ex post in 2006/2007)</td>
</tr>
</tbody>
</table>

7.5 Photovoltaics

The European photovoltaic (PV) market is strongly influenced by the development in Germany, which dominates total EU generation with 2220 GWh (corresponding to 89% of EU total). This

<sup>28</sup> Differentiation for new installations smaller than/equal to 5 MW; additional capacity of renovated units >5MW: 35.9 - 74.4 €/MWh for 30 years.

<sup>29</sup> No support in 2008.
outstanding development is due to Germany’s FIT support scheme. The following countries (Spain, Italy, France, the Netherlands and Luxemburg) are characterized by higher solar radiation and/or advantageous support schemes.

![Electricity generation from photovoltaics: 2006](image)

In 2007, approximately 1.54 GWp new photovoltaic capacity has been installed in the EU-27 leading to a total installed capacity of 4.689 GWp [36]. With 3.85 GWp photovoltaic capacity installed, Germany has the highest market share for total capacity of nearly 82%, followed by Spain (11%) and Italy (2.14%). The largest market for photovoltaic in 2007 was still Germany (1.13 GWp new installed capacity), followed by Spain (0.34 GWp). Here, most photovoltaic systems are connected to the grid, with the exception of France, where almost 90% of installed capacity is off-grid application.
Table 12: PV support schemes

<table>
<thead>
<tr>
<th>Country</th>
<th>Type of promotion scheme</th>
<th>Level [€/MWh]</th>
<th>Duration of payment [yrs]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Denmark</td>
<td>Price premium</td>
<td>Total incomes = 80.5 for 10 years and 53.7 for the following 10 years</td>
<td>20</td>
</tr>
<tr>
<td>Germany</td>
<td>FIT</td>
<td>379.5</td>
<td>20</td>
</tr>
<tr>
<td>Netherlands$^{30}$</td>
<td>Price premium</td>
<td>97</td>
<td>10</td>
</tr>
<tr>
<td>Spain</td>
<td>FIT</td>
<td>229.7-440.3 according to generation capacity</td>
<td>After 25 years, income decreases</td>
</tr>
<tr>
<td>UK</td>
<td>Quota</td>
<td>49.4 (Price observed ex post in 2006/2007)</td>
<td>Certificate valid for 1 year</td>
</tr>
</tbody>
</table>

Table 12 provides an overview of the national PV support schemes. Germany and Spain are countries with technology-specific support schemes for PV, which is also reflected in the attained penetration levels (see above). The expected income per kWh is almost 10 times higher than in countries without technology differentiation, as, e.g., the United Kingdom. National legislators support different target operators: in Denmark, only installations with more than 6 kWp are eligible, which means that installations on single-family-homes are not encouraged. The Netherlands practice the contrary approach from 2008 onwards: the eligible kWp margins (0.6 < kWp < 3.5) are set in a way that the PV modules will mostly be erected on single-family homes. Also in Germany, there are higher rates if they are erected on buildings.

7.6 Wind energy

Wind power has experienced a tremendous growth over the last years, and accounted for 3.7% of the EU-27 electricity demand in 2007. The share of wind energy in total installed capacity increased to 7% in 2007. About 30% of all new power capacity installed in EU since 2000 has been wind power, which is over the last eight years the second highest contribution after natural gas (55%) [39].

$^{30}$ New scheme from 2008 onwards: Price premium with a guaranteed revenue of 56 €/MWh for 15 years.
The amount of electricity generated from wind power in 2006 varies strongly across countries (Figure 10). Production in Germany exceeds 30000 GWh, followed by Spain with approximately 23000 GWh. Denmark reaches a level of 6100 GWh, whereas wind power deployment in all other countries is below 5000 GWh, and at a very low level in about 10 countries.

Table 13: Onshore wind power support schemes

<table>
<thead>
<tr>
<th>Type of promotion scheme</th>
<th>Level [€/MWh]</th>
<th>Duration of payment [yrs]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Denmark</td>
<td>13.4 on top of average monthly spot price, plus 3.1 for balancing costs[^31]</td>
<td>20</td>
</tr>
<tr>
<td>Germany</td>
<td>51.8</td>
<td>20</td>
</tr>
<tr>
<td>Netherlands[^32]</td>
<td>65</td>
<td>10</td>
</tr>
<tr>
<td>Spain</td>
<td>FIT 73.2; Premium: 29.3</td>
<td>After 20 years, income decreases</td>
</tr>
<tr>
<td>UK</td>
<td>49.4 (Price observed ex post in 2006/2007)</td>
<td>Certificate valid for 1 year</td>
</tr>
</tbody>
</table>

[^31]: Planned: 33.6 plus 3.1 for balancing costs plus 0.5 for a neighborhood compensation funds.
[^32]: New scheme from 2008 onwards: Price premium with a total income of 110 €/MWh for 15 years.
Table 13 displays the main features of onshore wind power support schemes in the five focus regions and Table 14 for offshore wind power, respectively.

For FIT and price premium schemes, there is a consensus to support wind power for 15 to 20 years, but the level and design of support schemes vary strongly. The monetary value for the United Kingdom is merely indicative, as it depends on every year’s market value for the Renewable Obligation Certificates. As for the mechanism design of price premiums, in Denmark there is a price ceiling for the total amount (wholesale price + premium), onshore wind producers may obtain (e.g., a total income of 48.3 €/MWh plus 3.1 €/MWh for balancing costs). Also, the Spanish system implements upper and lower limits for the support levels, applying both to onshore and offshore wind. In Germany, onshore wind producers may receive an additional 32 €/MWh for up to 5 years if certain productivity targets are met.

Table 14: Offshore wind power support schemes

<table>
<thead>
<tr>
<th>Type of promotion scheme</th>
<th>Level [€/MWh]</th>
<th>Duration of payment [yrs]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Denmark</td>
<td>13.4 on top of average monthly spot price, plus 3.1 for balancing costs</td>
<td>20</td>
</tr>
<tr>
<td>Germany</td>
<td>61.9</td>
<td>20</td>
</tr>
<tr>
<td>Netherlands</td>
<td>97</td>
<td>10</td>
</tr>
<tr>
<td>Spain</td>
<td>Premium &lt;=84.3. Total price earned &lt;=164.0</td>
<td></td>
</tr>
<tr>
<td>UK</td>
<td>49.4 (Price observed ex post in 2006/2007)</td>
<td>Certificate valid for 1 year</td>
</tr>
</tbody>
</table>

---

33 Individual regulations, e.g., total income = 69.5 for Horns Rev.
34 Plus 29.1 €/MWh for 12 years or more if generation is started before 2011 and/or unit is very far from shore.
35 No support in 2008, but new scheme from 2009 onwards.
8 Summary: Interactions of support schemes, network regulation and markets

The regulatory provisions applied by the Member States affect the incentives of market actors, here in particular of the DG/RES operator and of the DSO. In general, there is a tendency among Member States in the field of network regulation of migrating from the traditional cost-of-service (COS)/rate-of-return (ROR) regulation to more incentive-based schemes, such as price/revenue cap or eventually yardstick. This incentivises DSOs to decrease their network cost and increase their efficiency since, under incentive regulation, the difference between cost and allowed revenue accrues to them as profit.

**SUPPORT SCHEMES**

<table>
<thead>
<tr>
<th>Feed-In Tariff</th>
<th>Price Premium</th>
<th>Green Quota</th>
</tr>
</thead>
</table>

**NETWORK REGULATION**

<table>
<thead>
<tr>
<th>COS/ROR</th>
<th>Price/Revenue Cap</th>
<th>Yardstick</th>
</tr>
</thead>
</table>

Figure 11: Support schemes and network regulation – transition to more market based mechanisms

As for support schemes, Figure 11 depicts the transition to more market-based mechanisms from the traditional feed-in tariff scheme to the price premium and, finally, to the green quota with tradable green certificates. In the initial phases of market penetration of a technology characterized by low penetration levels, high cost and high risk, support schemes providing high investment security, such as the fixed feed-in tariff, are typically applied. Along the transition, more market signals are successively incorporated until a technology reaches the commercial phase and becomes competitive to other technologies in the absence of support. This transition in the evolution of predominant support schemes is also reflected by the application of support in the five country cases, as depicted by Figure 12. In Denmark, Germany, the Netherlands and Spain, the promotion schemes move from the classic feed-in tariff scheme (lower left-hand corner) to more market-oriented price premiums over the years. Denmark adopted feed-in tariffs in 1999 and progressed to price premium schemes since the early 2000s: a total income for DG/RES is specified since 2001, but CHP power plants receive a stable premium, i.e., are fully exposed to market price fluctuations. In Germany, feed-in tariffs have been in place since 1991. From 2009 onwards, DG/RES operators can choose to offset their electricity at the market temporarily if they consider this advantageous to remaining in the FIT scheme. Spain first introduced a FIT (both energy and capacity components) in 1994. In the year 1998, this FIT was replaced by another whose level was dependent on the average market energy price, which was computed according to a certain methodology. Then, in 2004, a hybrid system of FITs and premiums (both dependent on the average electricity tariff) was applied for the first time. Finally, in 2007 this hybrid system was replaced by another one where FITs and premiums no longer depend on the average tariff. In this system, cap and floor values were introduced for the price
earned by wind generators. Only the United Kingdom has applied tendering and quota schemes since 1990 (which are subsumed as quota schemes in this case). Note that the figure merely displays the support instruments, but does not refer to their efficacy or efficiency for the promotion of DG/RES.

Combining the dimensions of network regulation regime, connection charging methodology and predominant support scheme, it can easily be seen that a variety of combinations of regulatory regimes is applied as the country matrix presented earlier in Chapter 1 illustrates (Table 1, see below).

Notably, in addition to the impact of the regulatory framework, there are also other country-specific factors that influence DG/RES deployment, such as geographical differences, fuel mixes, prevailing market structure, degree of liberalisation and the historical evolution of the energy sectors [63]. However, the decomposition of the DG/RES operator’s and the DSO’s cost and revenue streams allows some general conclusions on the impact of support schemes, connection charges and network regulation on the incentives of market actors. In the following, a brief elaboration on the impact of the different regulatory dimensions on DG/RES operators and DSOs, respectively, will be provided. This will be treated in further detail in Deliverable D3 of the IMPROGRES project.
Table 1: Country matrix with combinations of network and support scheme regulation

<table>
<thead>
<tr>
<th>Deep connection charges</th>
<th>Feed-in tariff</th>
<th>Price premium</th>
<th>Quota system</th>
</tr>
</thead>
<tbody>
<tr>
<td>Spain (revenue cap)</td>
<td>深连接费用Spain (收入上限)</td>
<td>Netherlands (yardstick) (units &gt;10 MVA)</td>
<td>荷兰(准则)(单位&gt;10 MVA)</td>
</tr>
<tr>
<td>Shallowish connection charges</td>
<td>Shallowish连接费用荷兰 (收入上限)</td>
<td>United Kingdom (revenue cap)</td>
<td>英国(收入上限)</td>
</tr>
<tr>
<td>Shallow connection charges</td>
<td>Germany (rate-of-return)</td>
<td>Denmark (revenue cap) Netherlands (yardstick) (units &lt;10 MVA)</td>
<td></td>
</tr>
</tbody>
</table>

8.1 Impact on the DG/RES operator

The DG/RES operator’s revenue is determined by the national support scheme and possibly through participation in various power markets (see section above). The national support scheme is decisive for the extent to which the DG/RES operator is exposed to price volatility. At one end of the spectrum, under the traditional feed-in tariff scheme, the DG/RES operator’s revenue is fixed for a long duration, irrespective of market forces. In case of a quota system, the DG/RES operator faces price uncertainty both on the power and on the tradable green certificate market. Market participation of DG/RES operators depends on the market rules and design (e.g., minimum capacity requirements for participation, use of aggregators for small-scale generators). Traders can furthermore facilitate market participation in wholesale markets by bundling DG/RES units to virtual power plants. As for the DG/RES operator’s costs, in order to obtain network access (a prerequisite for market access) the connection charging methodology is of high importance. Deep connection charges, in particular, if the method for calculating the network impact of a DG/RES installation is not transparent, can constitute an entry barrier for DG/RES operators. Shallow charges are more favourable since they reduce the capital investments to be made upfront. The country cases show that shallow connection charges in combination with no use of system charges for generators and a less strong economic regulation of DSOs tend to facilitate DG/RES development. By the same token, the design of market participation fees, i.e., annual and variable fees, impact a DG investor’s considerations in terms of future participation on wholesale markets. For small-scale generators high fixed trading fees can constitute another obstacle. Therefore, it is favourable for them if they can waive the fixed annual fee and pay, e.g., a higher variable fee based on their trading volume instead. Finally, the operation philosophy of DSOs (active vs. passive active network management) influences DG integration. The impact of regulatory regimes on the DSO will be treated in the subsequent section.

8.2 Impact on the DSO

The type of network regulation and connection charging regime serves as an instrument on a very aggregate level. The DSO’s revenue is determined by the regulatory regime and its implementation. There are several methodologies in practice how national regulators calculate the DSO’s allowed overall revenues. Both the scheme and the discretionary implementation with respect to the detailed calculation are important for the DSOs. The regulator sets a plethora of incentives the DSOs wish to adapt best to, e.g., for quality of service besides the economic operation of the network. A long-term predictability of the regulatory framework is desirable due to the long investment cycles. Defining the DSO’s total revenue does not consider how it is
recovered among all clients (e.g., actual setting of use of system charges); this means that the detailed composition of the DSO income stays concealed. The level of discretion DSOs can exert with regard to this issue varies across Member States. However, connection charges are mostly regulated today. The connectors pay a different level of the connection’s associated costs across Member States. The remaining expenses are then included in the calculation of the use of system charges.

The DSO’s costs are composed of capital expenditure (CAPEX) and operational expenditure (OPEX). The longevity of network assets can exceed periods of 40 or 50 years, which means that today’s investment decisions have an impact over decades. This applies for the technical operation as well as for the economical recuperation of the investment. The different regulatory schemes consider a DSO’s actual cost at several levels: Rate-of-Return regulation is based on actual costs, whereas the revenue is (partially) decoupled from own costs under the different incentive regulation schemes. An increasing number of DG/RES units can be taken into account by a multitude of approaches within these mechanisms to correct for systematic differences between DSOs. The DSO’s attitude towards DG/RES integration is shaped by the detailed impact on its economics and system operation. The regulation should hence ensure that DG/RES operators are on a level playing field with their alternatives. The DSO should be reaffirmed that it can recover additional costs caused by DG/RES installations through economic advantages (e.g., decrease of network losses), connection charges and use-of-system charges. It could further extend its business activities to more sophisticated metering and possibly participate in the coordination of ancillary services from DG/RES at mid-voltage level. Incentives need to be set in a way that it does not perceive auto-production and generation close to load as a threat to its core business activity.

8.3 Final Remarks

In liberalised energy sectors and with the opening up of markets for competition, DG/RES generators may contribute to the enhancement of sustainability, competitiveness and security of supply, the three objectives of European energy policy. It is the task of regulation to provide signals to market actors, reflecting the costs and benefits inherent to DG/RES facilities, so as to enable the materialization of potential benefits and their effective integration into current electricity networks. DG/RES is encompassed by various EU Directives, despite the lack of a common European policy framework of DG. Amongst others, Member States may adopt technology-based support schemes for the promotion of electricity production from renewable energy sources and combined heat and power. This has led to the evolution of different schemes and support levels across the different countries, as illustrated by the five country cases. Notably, a converging trend to more market-based support can be observed for the countries analyzed. Support schemes constitute a major part of DG/RES operators’ revenue. This implies that they may mitigate other factors detrimental for DG/RES penetration, such as deep or high connection charges or the potential lack of a level playing field in terms of market trading regime as compared to large-scale central generators. In the long run, with the further development of the internal energy market, the question remains how the interaction of network regulation and support schemes will affect the deployment of DG/RES.
9 References


