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This report is a joint deliverable of the SOLID-DER consortium analysing the policy and regulatory framework for Distributed Energy Resources in the enlarged European Union. This report has been drafted by Miroslav Maly (Work Package 1 leader - Enviros), Michael ten Donkelaar & Frits van Oostvoorn (both ECN), Klaus Skytte & Stephanie Ropenus (both Risø) and Pablo Frías & Tomás Gómez (both University Pontificia Comillas).
Finally note that this report is written in 2006 and that by the expression “Candidate countries” we mean Romania and Bulgaria, which are from 1st of January 2007 (new) EU members. For practical purposes in the analysis we use both terms New Member states and Candidate countries, reflecting the situation in 2006, for two group of new Member States from 1st of January in 2007.

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SUMMARY

The SOLID-DER Sixth Framework project has been set up to specifically assess the economic, policy and regulatory drivers and barriers influencing the further integration of Distributed Energy Resources (DER) in the electricity supply system of the new Member States (NMS) and Candidate Countries of Central and Eastern Europe. The SOLID-DER project objectives are the come up with recommendations for the short- and medium-term (directed mainly to policy makers, regulators and stakeholders) and recommendations for RTD actions now needed with a focus on the further long term integration of DER into the electricity supply system of the new Member States and Europe as a whole.

Most electricity markets in the new Member States are not yet fully mature and still in a transition phase. In addition, the new Member States are facing different basic conditions, dependent on their fuel mixes, progress in liberalisation, prevalent market structures, and historical evolution of their electricity sectors. Shares of DER in the new Member States are increasing during the last few years due to the adoption of EU renewable electricity targets and other environmental policy objectives. These targets and objectives have resulted in the adoption of support schemes for renewable electricity sources and CHP in each of the new Member States.

The basic input of this research was derived from a comprehensive "country survey" carried out for countries Bulgaria, Czech Republic, Estonia, Hungary, Latvia, Lithuania, Poland, Romania, Slovakia and Slovenia. This survey included a number of most relevant issues, potential barriers and integration topics that lead to a complete national overview of all relevant DER integration issues in each country. Below a brief summary is given of the most relevant findings per issue.

DER market presence
The overview of the ten new Member States showed that CHP has already a major share in the electricity supply system contributing to about 10 to 20% of electricity production. Renewable electricity is largely limited to large hydro power plants so that shares of renewable energy production are high in those countries with significant large-scale hydropower production (e.g. Latvia, Slovenia, Slovakia and Romania) but below 5% in the other countries. Nevertheless, small-scale RES production has shown a steady increase in production during the last two to three years.

DER policies
All new Member States have adopted support schemes for RES-E production. In eight of the countries this support is provided in the form of feed-in tariffs and in two countries (Poland and Romania) green certificates have been introduced. These support schemes should assist in meeting the country's indicative target for the RES-E directive. Progress per country in reaching the target shows large differences. Countries like Hungary and Latvia have already reached their targets, for other countries meeting the target will be difficult (e.g. Czech Republic, Poland) or nearly impossible (Slovakia) due to the high targets set.

A comparison with support mechanisms in EU15 countries shows that in 9 of the 15 countries feed-in tariffs are in place, while four countries have introduced a quota system with green certificates. Experience with these support schemes shows that a well functioning system with feed-in tariffs creates a certain stability for investors leading to a substantial increase of DER penetration in some countries (e.g. Germany, Spain). A quota system with tradable green certificates can also bring stability for investors as long as targets are agreed for a sufficiently long period. Difference with a feed-in tariff system is that different types of RES-E have to compete with each other. This would lead to more efficient investments in RES-E generation capacity, but might be more advantageous for large energy producers than for small independent power producers.

In countries with less mature RES-E markets, as is the case in most new Member States, a feed-in tariff system may be more suitable to realise a first increase of RES-E capacity. There are two main rea-

sons for that; first, feed-in tariff systems are usually easier to administer and, second, the availability of a feed-in tariff system makes it easier for investors to gain financing for their projects.

Regulatory framework
Major changes can be noted in the network regulatory framework in the new MS. Main developments are the unbundling process of the DSO towards legal unbundling and the increasing access of DER electricity to wholesale markets.

There is no generic strategy towards common framework conditions, in the new as well as in the old Member States, since the framework conditions for DER given by EU legislation are rather broad. This gives substantial scope for variation at the national level regarding economic regulation, market requirements, network regulatory regimes, and support mechanisms for DER.

Many of the present barriers for further integration of DER may be seen as temporary barriers due to the time lag of changing the systems. Nevertheless, a number of major barriers remain towards increased and large-scale integration of DER. Examples are regulatory barriers in the form of complex network access procedures and lengthy spatial planning procedures.

Assessment of costs and benefits
As it happens in the majority of old MS, no systematic evaluation procedures, to assess the impact of DER on costs and benefits, neither explicit regulatory mechanisms, to make market agents participants of such costs and benefits, have been designed and implemented yet.

The situation of NMS regarding the impact of DER on DSO costs and benefits is similar to the EU-15. In most of the countries, DSOs revenues are set under a scheme of incentive regulation, price cap or revenue cap, for a period of several years. In each price control process, the regulator will set tariffs that compensate DSOs for actual increments on capital expenditures and operational and management costs. In most countries, DER connection is considered as another regular DSO activity, with no specific procedures to take into account specific costs or benefits.

DER growth in several EU-15 countries has positively contributed to the development of local and regional industries, along with the generation of new employment. The new MS recognize the potential of DER development on the creation of new industries and employment. However, the estimation of this potential is uncertain today because the current level of DER integration is still very low.

Barriers and recommendations
When comparing the barriers to increasing DER shares into the electricity network in the old and new Member States, we can conclude that they are quite similar. Main barriers identified are:

- Lengthy and complicated administrative procedures, by investors in DER power plants in many countries often considered as the most severe barrier.
- Dominant position of DSOs in negotiating network access in combination with non-transparent connection procedures.
- Unstable support mechanisms making it difficult to plan long-term projects. This is a barrier that is more seriously considered in the new Member States where support for DER has been introduced very recently only.
- Lack of knowledge about advantages of DER generated power leading to opposition of local communities to new DER projects.

Finally we formulate a number of recommendations thereby making a distighion between short/medium term actions mainly by policy makers and regulators and recommendations focusing on penetration of DER in the long term, therefore being more RTD oriented.

Recommendations for short and medium term DER integration
Based on the barriers mentioned above a number of country-specific recommendations can be formulated (mainly aimed at actions by policy makers and energy regulators):

- Complete the unbundling process, not only within the legal framework but also in practise.
- Simplify authorisation procedures for spatial planning and construction permits through a "one-stop shop system" for project authorisation.
- Introduce transparent and non-discriminatory grid connection, grid use conditions as well as cost allocation between DER operators and network operators.
- Market access for DER operators should be ensured through simplified procedures for access to wholesale, balancing and ancillary services markets.
- In the development of support schemes, take into account their cost-effectiveness in the long-term and the stability it has to create for investors.

Recommendations for further DER integration in the long term
A number of long-term recommendations for research and development actions are:
- *Update of RES-E potential for individual countries* - These potentials would be used for setting new RES-E targets after 2010. → Some of the countries (e.g. Slovakia) mention that their RES-E target for 2010 is based on unrealistic assumptions.
- *Analysis of pros and cons of administrative and market oriented systems for promotion of RES-E* - The aim is to analyse pros and cons of various administrative and market oriented systems for promotion of RES-E (e.g. feed-in tariffs vs. green bonuses or green certificates) and prepare recommendations for the EU Commission to support it in its task to adjustments the current system.
- *Identification of major technology innovations in the DER field* - Faster uptake of DER for electricity generation with minimal impact on the environment will require new technologies to be invented and mainly implemented. The aim of the work would be identification of major technology innovations in the DER field needed for the coming 20-30 years.
- *Development of a general guidebook for simplification of the authorisation process for new RES-E projects* - As administrative barriers are still key ones in the authorisation process, aim of the work would be the development of a general guidebook for simplification of the authorisation process for new RES-E projects on country and EU-wide level.
- *Development of a structure of targeted awareness campaigns for various groups and stakeholders* - Lack of awareness on RES-E benefits is still an important barrier to their perception as an important alternative to usual ways of energy supply. The aim of the work would be to prepare EU-wide and regional-wide campaigns for RES-E with recommendations for country specific campaigns.
- *Assessment of biomass fuel chains* - The aim will be to design how to strengthen biomass chains both of waste biomass and planted biomass to get a steady and least cost supply of biomass..
- *Assessment of costs and benefits of different network charging systems for different stakeholders*, such as DER operators, network companies and energy suppliers.
- Improvement of the evaluation methods and *internalisation of environmental externalities*. Despite the fact that several methodologies exist for calculation of environmental externalities, these methodologies are not part of regular evaluation methods for energy planning.
- *Application of innovative network approaches* on distribution and transmission level, so by DSOs and TSOs.

1. INTRODUCTION

1.1 Background

During the last years the integration of different distributed energy resources (DER) in the European electricity supply system has become a key issue for energy producers, policy makers, network operators and the R&D community in Europe. EU policies and targets for a sustainable development of the energy markets, increasing the contribution of RES and low emission generation technologies encourage the growing expectation and penetration of DER in the power supply system. Furthermore, liberalisation of electricity markets resulted in a strongly changing organisation of electricity supply in Europe with subsequently unbundling of the electricity generation, transmission, trade and distribution. This created both new opportunities and barriers to a further DER penetration in Europe.

Work Package 1 of the SOLID-DER project specifically addresses the economic and regulatory drivers[1], barriers and instruments towards the increasing integration of DER in the electricity supply system of the new Member States (NMS) and Candidate Countries of Central and Eastern Europe. DER, including both renewable electricity production (RES-E) and combined heat and power (CHP) has already been available in most of the NMS in the form of CHP, mainly connected to district heating systems. In NMS the intermittent RES-E sources have not yet reached penetration levels that influence the electricity system in terms of load balancing and supply. Due to a number of developments, the integration of DER, and mainly RES-E, into the electricity infrastructure will become an important issue in the coming years for these countries also:

- The adoption of targets for renewable electricity production in the framework of the EU Renewable Electricity Directive (2001/77/EC) has led to the introduction of policy support for renewable electricity production. This mainly concerns small-scale dispersed power generation units that can potentially influence the management of the grid. Recent developments in a number of countries, e.g. Poland, Hungary, show that small-scale renewable energy production is rapidly increasing.
- During the next decades the electricity generation capacity technology mix in the new MS will have to undergo a tremendous modernisation. In the short-term this will already be the case in countries where phase-out some of nuclear power plants takes place (e.g. Bulgaria, Lithuania and Slovakia) and this power production capacity will have to be replaces by new sources. But also in a number of other countries major coal-fired power plants are closely at the end of their lifetimes (e.g. Czech Republic, Poland). Therefore it is of the greatest importance to make the decision makers and business community in the EU but particularly in the business community of the *new Member States aware of the benefits and scope for DER* as a better investment option for replacing today's environmentally polluting electricity generation plants.
- The liberalisation of the electricity market and upcoming network regulation has led to easier access of DER to electricity markets. Nevertheless, the liberalisation process has also led to other developments, such as increasing market power of large power producers that may inhibit the increase of DER in the short- and mid-term future.

1.2 Structure of the report

This report, covering the first phase of Work Package 1 of SOLID-DER will monitor and evaluate the current situation with regards to economic, policy and regulatory constraints and progress for encouraging increased shares of DER integration. It contains a thorough analysis of

[1] This also includes commercial drivers, business operation etc.

DER legislation/regulation and policy support and current market circumstances currently influencing DER integration. This overview should through the course of the project lead to the development of more optimal ways of DER policy and regulation. These results and findings will then facilitate a more co-ordinated and effective dialogue with regulatory bodies, stakeholders and policy makers in presenting them overall analysis of results of EU RTD activities, supported by experts' experience.

In Chapter 2 the report presents an overview of the DER shares in the ten new Member States and Candidate Countries of Central and Eastern Europe. The countries concerned are Bulgaria, Czech Republic, Estonia, Hungary, Latvia, Lithuania, Poland, Romania, Slovakia and Slovenia. Chapter 3 will then provide an overview of the policy support for DER, renewable energy and distributed generation. This is followed by an overview of the regulatory framework related to network access and electricity markets in Chapter 4. Costs and benefits of DER will be analysed in Chapter 5. This report will conclude with an overview of the main barriers to DER integration (Chapter 6) and this will be followed in Chapter 7 by specific country recommendations. Chapter 8 concludes with the main results and several R&D recommendations.

In addition, the research described under Chapter 5 includes specific case studies carried out in several new Member States, analysing the costs and benefits of DER for the electricity supply system. These case studies, for the Baltic States, Bulgaria, the Czech Republic, Hungary, Poland and Slovenia, are included in Annex 1 of this report.

2. COUNTRY REVIEWS

This chapter provides a summary of basic information about the shares of DER, both RES-E and CHP for generation of electricity in each of the ten new Member States and Candidate Countries and the way both RES-E and CHP is supported.

2.1 Bulgaria

The national indicative target for Bulgaria for encouraging the consumption of electricity generated by renewable energy sources for 2010 is 11%. With an existing RES share of about 7-8 % during the past several years, the achieving of the national indicative target presumes an increase of about 50 %, or about 9 % annual increase which is much faster than the recent trend. The total energy generation mix has not been allocated among the different technologies, but it is expected that the biggest share will come from the use of water and wind potential in the country, as well as from the use of biomass.

2.1.1 Share of DER electricity

The current DER share of electricity generation in Bulgaria is shown in Table 2.1. The table shows a steady increase of the RES-E share in national production from 1995 to 2005. Fluctuations during the years are mainly caused by fluctuations in the hydro-power output. Another interesting feature is the increase in small-scale HPP generation and at the same time a decrease of CHP power output.

Table 2.1 DER share in electricity generation in Bulgaria

Production (GWh)	1995	2000	2001	2002	2003	2004	2005e
Total electricity generation	41789	40927	43969	42701	42554	41515	44249
RES- E total	1 751	2 673	1 736	1 656	2 956	3 296	4 761
RES share-E total in el. generation	4.2%	6.5%	3.9%	3.9%	6.9%	7.9%	10.8%
Wind energy	0.0	0.0	0.0	0.0	0.0	1.5	4.6
Small HPP	150	150	352	373	450	528	1 094
RES share- E below 10 MW in el. Generation	0.4%	0.4%	0.8%	0.9%	1.1%	1.3%	2.5%
El. output- public CHP plants	5 574	3 795	4 054	3 610	N/A	N/A	3 818
El. output-auto-producer CHP plants	2 824	1 845	1 711	1 425	N/A	N/A	2 140
Total CHP	8 398	5 640	5 765	5 035	N/A	N/A	5 958
CHP share in el. generation %	20.1	13.8	13.1	11.8	N/A	N/A	N/A
Total RES and CHP generation	10149	8313	7501	6691	N/A	N/A	10719

Sources of data: For RES - calculations of BSREC, for CHP - (IEA 2004c), for electricity generation - (IEA 2004c) and (MEER 2005e) – preliminary data

The total installed power capacity is shown in Table 2.2 . It shows that the only significant RES capacity is based on hydro-power and for more than 80% this concerns large hydro-plants. The total installed power capacity has decreased between 2000 and 2004, which is visible in a decrease of thermal as well as nuclear power capacity.

Table 2.2 Installed power capacity in Bulgaria (in MW)

	1995	2000	2004
Total installed power capacity in the country	12825	13189	12130
Total installed capacity of thermal power stations	5594	6566	5499
Nuclear power stations	3760	3760	2880
Combined heat and power stations:	1040	1053	923

CHP < 1 MW			
CHP ≥1 MW and ≤ 50 MW			
CHP > 50 MW			
Total hydro electric power stations:	2431	2863	2828
Hydro plants < 1 MW	n.a.	n.a.	n.a.
Hydro plants ≥1 MW and ≤ 10 MW	n.a.	n.a.	310
Hydro plants > 10 MW	n.a.	n.a.	2518
Other RES-E plants	Data not available		

2.1.2 DER support

The scheme of financial support in Bulgaria for electricity generated from RES and cogeneration foresees the use of preferential price forming through a feed-in tariff. The feed-in tariff will be valid until 2018 for all existing generators of electricity from RES and high-efficient cogeneration, and for new generators for 12 years after starting electricity generation, put in operation not later than 31.12.2011. This system provides support in the following circumstances:

- Till 2018 for the existing electricity generators using RES, including HPPs < 10 MW;
- During the next 12 years after starting electricity generation (and starting not later than 31.12.2011) for all the new electricity generators using RES, including HPPs < 10 MW;
- Till 2018 for the existing generators of electricity from highly efficient cogeneration of electricity and heat;
- During the next 12 years after starting electricity generation (and starting not later than 31.12.2011) for all the new generators of electricity from highly efficient cogeneration of electricity and heat.

The support scheme for electricity generated from RES has no limitations with respect to technologies and size of installed capacity in the power plant, including for hydro-power plants with a capacity of up to 10 MW. For highly efficient cogeneration of electricity and heat, the support scheme is valid for electricity quantities up to 50 MWh (corresponding to the *DER* definition of SOLID-DER). According to regulations the preferential prices are differentiated by technologies and *not lower than 80% of end sale prices* for the households in the past calendar year.

Having in mind that a feed-in tariff as a scheme provides certainty to investors for supporting the electricity from ***DER***, as well as the national indicative target, no changes are envisaged in the support schemes till 2010 at least. The support scheme is quite simple for administration, however at this stage there is no mechanism for compensation of the additional costs (relative to market price) of DER. The generated electricity is purchased at preferential prices, regardless of the market price, the connection point and other factors, taking into account direct or indirect benefits.

2.2 Czech Republic

2.2.1 Share of DER electricity

The key part of renewable electricity in the Czech Republic is generated in large and small hydro power plants. In 2004 the total RES-E share of gross electricity consumption was 4.1% (including large hydro), of which the large hydro-power share was 1.7%, small hydro share was 1.3% and biomass share was 0.9%. According to data for the year 2004, there was a major increase in wind energy generation. However, the share of wind energy remains negligible so far. Table 2.3 shows the electricity production by RES-E in the Czech Republic. Note that RES-E production fluctuates with large hydro-power output, e.g. between very wet years (2002) and very dry years (2003).

Table 2.3 Electricity production from RES in the Czech Republic

Production (GWh)	1995	2000	2001	2002	2003	2004
Large hydro >10 MW (excl, pumped storage)	2 002	1 255	1 363	1 743	723	1 116
Small hydro <10 MW		503	691	749	660	904
Biogas	103	135	133	127	108	139
Biomass	302	382	381	367	373	593
Wind	-	-	-	1.6	5	10
Solar PV	-	-	-	0	0	0.08
Other *	16	206	199	195	16	10
Electricity production from RES TOTAL	2 423	2 481	2 768	3 183	1 879	2 771
Shares (%)	1995	2000	2001	2002	2003	2004
Large hydro >10 MW (excl. pumped storage)	3,3%	2,0%	2,1%	2,7%	1,1%	1,7%
Small hydro <10 MW		0,8%	1,1%	1,2%	1,0%	1,3%
Biogas	0,2%	0,2%	0,2%	0,2%	0,2%	0,2%
Biomass	0,5%	0,6%	0,6%	0,6%	0,6%	0,9%
Wind				0,002%	0,007%	0,015%
Solar PV	-	-	-	0%	0%	0%
Other *		0,3%	0,3%	0,3%	0,0%	0,0%
Electricity production from RES TOTAL, share in gross consumption	4,0%	3,9%	4,3%	4,9%	2,8%	4,1%

The share of electricity produced by CHP was approx. 14% of total gross electricity production in 2004. The dominant CHP technologies are steam extraction turbines and back-pressure turbines installed in coal power plants and CHP plants (generating 53% and 38% of total CHP electricity respectively). There are also several relatively large gas combined cycle plants (8% of total electricity generated by CHP). The share of electricity production in gas turbines and engines is still rather small although there exists a large number of installations of reciprocating gas engine CHP units using natural gas or biogas/landfill gas.

Table 2.4 Installed power capacity in the Czech Republic (in MW)

	1995	2000	2004
Total installed power capacity in the country	13 803	15 214	17 434
Total installed capacity of thermal power stations	10 644	11 398	11 400
Nuclear power stations	1 760	1 760	3 760
Combined heat and power stations: *	3269	4 541	4 684
Total hydro electric power stations (excl. pumped storage):	± 1008	± 1014	1 014
• Hydro plants < 1 MW	± 100	± 105	120
• Hydro plants ≥1 MW and ≤ 10 MW			142
• Hydro plants > 10 MW	908	909	752
Pumped storage hydro plants > 10 MW	491	1 145	1 145
Wind energy (total)	2,7	3,5	16,5
Geothermal energy	0	0	0
Photovoltaics	0	0	0,1
Solar thermal	± 50000 m^2	± 55000 m^2	± 60000 m^2
Waste:	n/a	2,5	2,5
Wood and wood waste	n/a	n/a	1 227**
Biogas and landfill gas	n/a	n/a	32

Source: Energy Regulatory Office, Ministry of Industry and Trade
** including capacities used for co-firing of biomass

The key target related to RES-electricity production in the Czech Republic is the indicative target of 8% of gross electricity consumption in 2010 adopted in line with the implementation of the RES-E Directive 2001/77/EC. The target has not been split down to specific RES-E sources but major contribution is expected from biomass.

2.2.2 DER support

2.2.2.1 RES-E SUPPORT

In 2006 the system of fixed feed-in tariffs was replaced by a dual system of feed-in tariffs and "green bonuses"[2] introduced by a new Renewable Energy Act No. 180/2005. The feed-in tariffs as well as "green bonuses" are differentiated by type of RES-E, capacity of the source and in the case of biomass, also by parameters of biomass, and their level should guarantee that the simple payback of generic RES-E installations should be less than 15 years. The feed-in tariffs and "green bonuses" are guaranteed to be stable and for at least 15 years for existing installation while in case of new installations they cannot drop by more than 5% against the previous year level. The level of the feed-in tariffs and "green bonuses" is set annually by the Energy Regulatory Office (ERO) and should be set in order that the indicative target of 8% of share of RES-E in 2010 is reached. The green bonuses are also awarded for self-delivered RES electricity.

The level of support under this new support system is relatively high. In case of wind power plants commissioned in 2005 and 2006, the tariffs are higher than in neighbouring countries like the Slovak Republic and Austria. The following tariffs are applied:

- Wind power plants commissioned in 2005: 94 €/MWh, wind power plants commissioned in 2006: 86 €/MWh
- Electricity from biomass: feed-in tariffs range from 80 to 102 €/MWh, green bonuses range from 46 to 68 €/MWh.
- Electricity from landfill gas and sewage gas: 78 €/MWh
- Electricity from biogas: 104 €/MWh
- Tariffs for small hydropower plants:
    - 58 €/MWh for plants commissioned before 2005
    - from 74 to 81 €/MWh for new and reconstructed small hydro power plants - with additional regulations for high- and low-tariff bands.

The producers of electricity from RES may choose between the tariff and the green bonus system. The choice between these two systems, however, does not apply to co-firing of biomass with fossil fuels, where only the green bonus system is applicable.

2.2.2.2 CHP SUPPORT

In case of CHP, a bonus to the market price is provided which is differentiated according to electric capacity and used fuel:

- In case of a small-scale CHP up to 1 MW_e the bonus is 21 €/MWh in general; in case of electricity supply in peak hours, the bonus is approx. 60 €/MWh.
- In case of a CHP plants with a capacity from 1 MW_e to 5 MW_e the bonus is 18 €/MWh and 53 €/MWh in base and peak hours, respectively.
- In case of a CHP plant with a capacity from 5 MW_e to 10 MW_e and use of natural gas the bonus is 5 €/MWh.
- In case of a CHP plant using RES or coal bed methane, the bonus of 1.5 €/MWh is added to general support provided to RES-E.

[2] Feed-in premium, on top of the market price.

2.3 Estonia

2.3.1 Share of DER electricity

Green electricity generation capacities in Estonia have increased in 2004. Total installed capacity of hydro and wind power plants reached up to 27 MW. Annual electricity production by wind and hydro power plants has increased from 19 GWh in 2003 to 33 GWh in 2004. The variations of the share of electricity generated from renewable energy sources in total electricity supply can be seen in Table 2.5. The electricity generation in wind power plants was only 10 GWh in 2004 but the capacity and production of wind power plants is increasing. In 2004 Wind Park in Pakri was established. The annual production of Pakri Wind Park is expected to be 54 GWh. The wind farm will meet 1% of Estonia's net electricity consumption and thus contribute to achieving Estonia's target of RES share in electricity consumption in year 2010. There are two more wind parks already planed in Estonia. The Paldiski Wind Farm will be constructed as phase two of the Pakri Wind Farm. It will contain 22 wind turbines with capacity of 2.3MW each. Another project includes the Turisalu wind farm, 13 turbines, 1.65 MW each. Expected commissioning of both parks is in spring 2006. A target of 100 MW of windpower capacity is proposed by the year 2010 (see case study of Estonia in Annex 1).

Electricity generation in CHP power plants (including 2 blocks of Balti oil shale power plant in CHP mode) was 10.4% from total electricity generation (year 2002). Electricity generation in DER power plants, mainly by small-scale CHP power plants in industrial enterprises and RES-E power plants, was only 0.45% from total electricity generation in 2002.

Table 2.5 Electricity generation, supply and RES-E shares in Estonia

GWh	2000	2001	2002	2003	2004
Electricity generation (total)	8513	8483	8527	10159	10304
• Hydro PP	5.67	7.72	6	13	23.1
• Wind PP	0.33	0.28	1	6	9.6
Imports –Exports	-929	-622	-690	-1906	-1790
Domestic supply:	7584	7861	7837	8253	8514
Share of RES-E, %:	0.08	0.10	0.09	0.23	0.38
RES-E share* (from gross consumption in 2000), %	0.08	0.11	0.09	0.25	0.43
Share of oil-shale, %:	91.1	90.5	90.9	92.5	92.6
Share of natural gas, %:	6.6	6.7	6.1	5	4.7
Share of other fuels, %:	2.3	2.7	2.9	2.3	2.4

* Based on the methodology set forth in Directive 2001/77/EC

By 2010, the proportion of renewable electricity in Estonia will have to increase to 5.1% of the gross consumption (According to the RES-E directive), which is 300-360 GWh. In addition to energy based on bio-fuels produced in combined processes and energy produced in small hydro power stations, the main part of the renewable electricity must come from wind parks. In accordance with the draft Development Plan for the Electricity Sector wind energy should indicatively contribute to meeting a 2.2% share, bio-fuels to 2.5% and other sources to 0.4% of final consumption by the year 2010. This equals to approx. 200 GWh of wind power generated electricity[3].

[3] In the case study selected for Estonia, see Annex 1, devoted to wind power development, the wind potential in Estonia is estimated in 9TWh, without taking into account network constraints, although real targets are about 1.3TWh. Estonia is a country with a high potential of wind power production because the cyclonic activity in the Baltic Sea region is intense. The strongest obstacle for increasing capacity above 150MW of wind generators is the need of higher amounts of running fast reserve generation for compensation in case of wind absence. The National Grid operator must have the right to switch off wind turbines in too windy periods in summer time. On the other hand, current fees and technical requirements for connection of new wind plants into the national grid are too high.

Table 2.6 statistics on installed capacity in Estonia (in MW)

	1995	2000	2004
Total installed power capacity in the country	3 298	3 213	3 051**
Total installed capacity of thermal power stations			
Nuclear power stations	0	0	0
Combined heat and power stations:		298	291
• CHP < 1 MW			2.76*
• CHP ≥1 MW and ≤ 50 MW			98.6*
• CHP > 50 MW			190
Total hydro electric power stations:	1	1.65	4.4
• Hydro plants < 1 MW	1	1.65	4.4
• Hydro plants ≥1 MW and ≤ 10 MW			
• Hydro plants > 10 MW			
Wind energy:	0	0.15	22.8
• Onshore < 50 MW connected to the distribution-grid	0	0.15	22.8
• Offshore and wind parks (>50 MW) onshore			
Other sources		No data available	

* 2002 data, ** 2004 data

2.3.2 DER support

The new Electricity Market Act, from July 1, 2003 sets out an obligation to purchase electricity generated from renewable sources until 2015, including water, wind, solar, wave, tidal and geothermal energy sources, and energy from landfill gas, sewage treatment plant gas, biogases and biomass. The network operator shall purchase electricity generated from renewable energy sources from a producer connected to the network of the network operator, provided that all technical requirements, stipulated in the same Act, are fully met. An amendment to the act in Dec. 2004 (entered into force 01.01.2005) has frozen the price at level of 81 cents/kWh (ca. 5.1 € cents) and limited the purchase obligation to network losses of the grid operator. Earlier the price was linked to the sales price of the two major oil-shale based power plants.

Another amendment of the act has been recently (in September 2005) drafted by the Ministry of Economic Affairs and Communications and it foresees to revise the support scheme to RES-E. Within the support scheme a quantitative limit of 200 GWh to wind power capacity eligible for the support will be established and balance-sharing obligation to wind power plants will be introduced.

In April 2001 Eesti Energia, the major power company, established an alternative way to increase development of renewable energy production in Estonia by issuing green energy certificates for producers and customers. Currently Eesti Energia offers four different categories of certificates according to the level of supply. Green Energy Producer Certificates are issued to all the generators of renewable energy who sell their production to Eesti Energia. Green Energy Customer Certificates are issued to customers of Eesti Energia. Any company, governmental institution and residential customers having a contract with Eesti Energia may purchase electricity produced from renewable energy sources and receive a Green Energy Customer Certificate. The price for this green electricity depends on the amount of purchased power. There are four types of consumer certificates, depending on consumer type and renewable energy consumption. Green Energy Customer Certificates are valid for one year as of the date of issuing. Companies buying green certificates can label products and services with the “Green Energy” label, which demonstrates commitment to the environment, a healthier community and social responsibility.

2.4 Hungary

2.4.1 Share of DER electricity

Gross consumption of RES-E in Hungary in 2005 amounted up to a 4.1% share (the relevant ratio according to the RES-E Directive); 4.9% gross generation and 5.1% net generation. These figures also include electricity from (mainly) wood co-firing (in the proportion of the energy content of the biomass input) at large coal-fired plants. Therefore, the amount of DER RES-E is significantly lower (see table below). All hydro plants in Hungary can also be categorised as DER, the 2 largest hydro plants have a capacity of 28MW and 11MW.

Table 2.7 Shares of RES-E and DER in Hungary in 2005[4]

	Gross generation	Net generation*	Gross consumption
Total generation or consumption	35798	33143	39305
Total RES-E	1838	1612	(1612)**
Total RES-E share	5.1%	4.9%	4.1%
Total DER	4104	3738	(3738)
Natural gas DER CHP	3155	2892	(2892)
DER RES-E	948.9	845.9	(845.9)
Share of DER in total:			
Total DER	11.5%	11.3%	9.5%
Natural gas DER CHP	8.8%	8.7%	7.4%
DER RES-E	2.7%	2.6%	2.2%

*Net generation is gross generation minus self consumption of plants.
**Figures in brackets indicate that net generation quantities were related to gross consumption

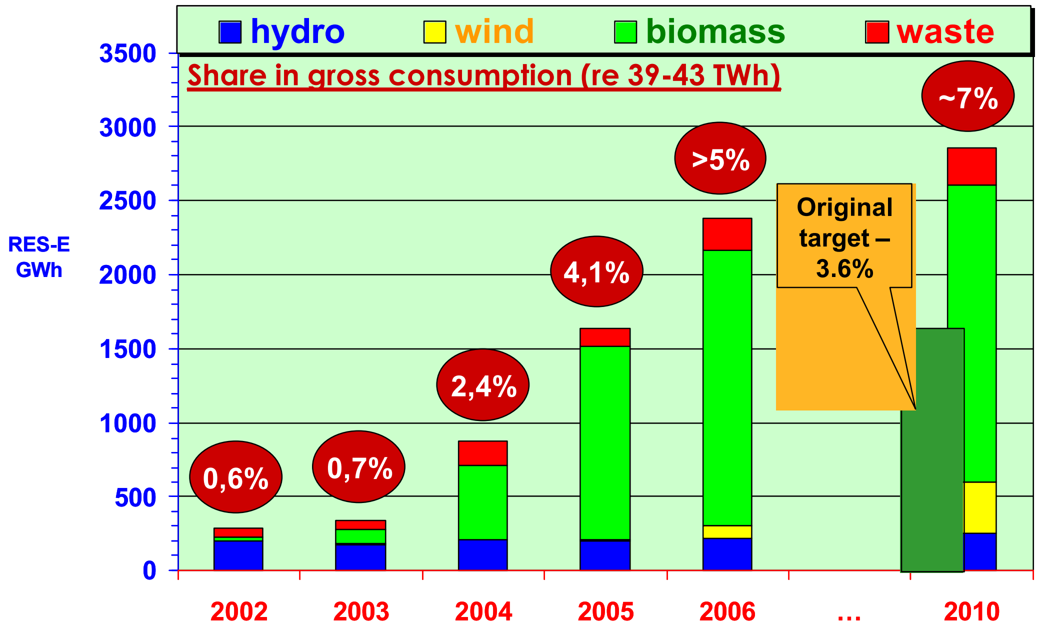


Figure 2.1 Evolution of net RES-E generation re gross consumption in Hungary

Figure 2.1 shows the rapid increase of net RES-E generation in Hungary since 2003. It also shows that the national target for Hungary of 3.6% re gross consumption (no split down) was already fulfilled by the end of 2005 due to rapid development in biomass (wood) based generation (conversion of coal boilers to wood and co-firing wood with coal). When looking at the

[4] Source: MAVIR and MAKK calculations

CHP capacity in Hungary, we can see tat it is increasing, mainly due to the increase of small- and medium scale-CHP.

Table 2.8 shows the installed power capacity in Hungary; apart from the major share of thermal and nuclear power plants a rapid increase is seen in the production of electricity from wind energy and biomass.

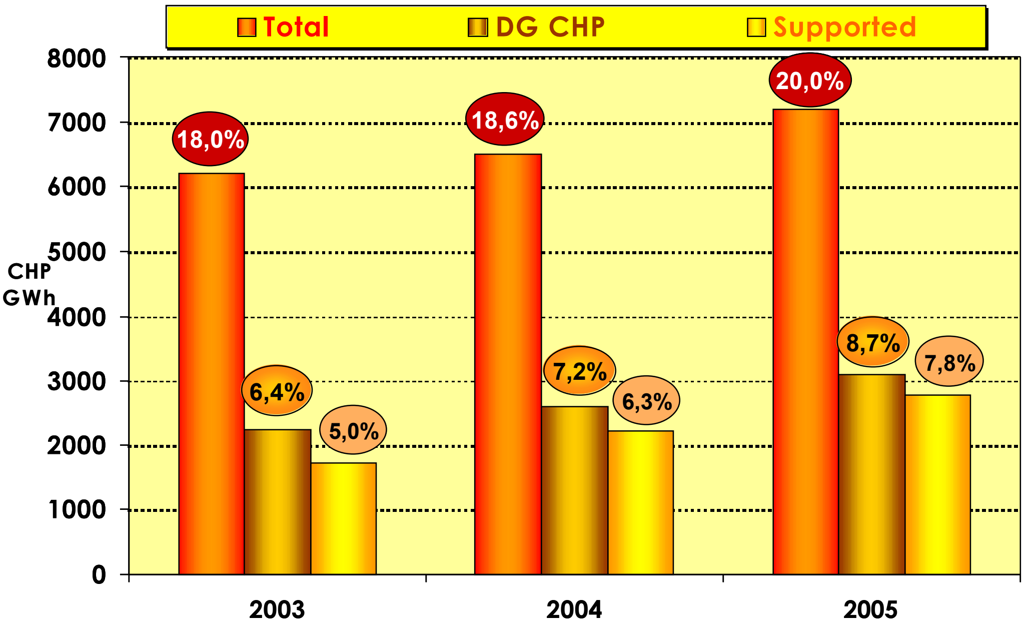


Figure 2.2 CHP generation in Hungary

Table 2.8 Installed capacity in Hungary (in MW)[5]

	1995 net	2000 net	2005 gross / net
Total installed power capacity in the country	6693	7605	8581 / 8067
Total installed capacity of thermal power stations	4974	5787	6648 / 6224
Nuclear power stations	1654	1752	1866 / 1755
Combined heat and power stations:	956 (1998)	n.a.	±1869 / ±1766
• CHP < 1 MW	5	31	37
• CHP ≥1 MW and ≤ 50 MW	n.a.	388	706 / ±663
• CHP > 50 MW	n.a.	n.a.	1126 / ±1067
Total hydro electric power stations:	46	48	51 / ±49
• Hydro plants < 1 MW	n.a.	2	2.4
• Hydro plants ≥1 MW and ≤ 10 MW	8	8	8.8
• Hydro plants > 10 MW	38	38	39.4 / ±37.4
Wind energy:	0	0.25	17
Geothermal energy	0	0	0
Photovoltaics	0	0	0
Solar thermal	0	0	0
Waste:	18	18	24.8 / 20.8
• Municipal solid wastes	18	18	24 / 20
• Industrial waste	0	0	0.8
Wood and wood waste	0	0	85 / 80
Biogas	1	2	5.9 / 5.6

Source: MAVIR (TSO) and MAKK calculations

[5] for earlier years only net capacities were available

2.4.2 DER Support

In Hungary a feed-in system is in place since January 2003 providing a preferential tariff for both RES-E and CHP. It includes all RES-E and waste incineration if selectively collected (organic waste). The main categories are:

1. Renewable electricity (hydro power plants < 5 MW) and electricity produced from selectively collected (organic) waste; if RES is co-fired with fossil fuel, the share of fossil fuel should be below 90%;
2. Hydro power > 5 MW + cogeneration between 6-50 MWe with heat not for district heat + cogeneration > 50 MW with heat for district heat[6];
3. Cogeneration up to 6 MW (non-determined heat purpose) + cogeneration 6-50 MWe with heat for district heating on natural gas basis;
4. Cogeneration up to 6 MW (non-determined heat purpose) + cogeneration 6-50 MWe with heat for district heating *not* on natural gas basis.

The level of support varies depending on technology and zone-time, but on average around 184% (84% premium over the regulated wholesale price in 2006) is provided both for RES-E and CHP. A specific example: support for weather dependent RES-E is about 190% (90% or 40 €//MWh premium). The premium is even larger relative to the average competitive market price (roughly 130%). The premium is financed via a component in the system operation charge.

The total supported amount is fixed in the permit (new regulation as of November 2005) so that benchmark return is yielded, not the number of years. However, after 5 years the Energy Office may revise and alter the amount "fixed" in the permit. This creates regulatory risk for investors. The feed in tariff is annually indexed to inflation. The starting level was prepared based on avoided external damage when replacing fossil fuel generation by RES generation, but political influence also modified it. Actually the decree changed several times since its issuance in December 2002. There is a difference in support of CHP electricity according to the heat being used for district heating or not, where the tariffs for non-DH CHP are lower.

The main problem with the current feed-in-tariff fund is that it causes a larger and larger financial deficit year by year. Also, the transformation of the electricity market model in 2007 (so as to fully accommodate market liberalisation in line with the EU electricity Directive) affects the supplier/DSO. The regulated suppliers´ role is expected to be replaced by a universal supplier for those remaining in the regulated market. As the off-takers of RES-E are regional suppliers, the model should be changed.

As a short-term solution, some off-take quota allocation is expected for traders, and they will pass on their increased costs due to RES-E premiums on consumers. This system seems a hybrid of feed in tariff systems and green certificate system, but without GC being tradable. It resembles a GC system in that for both systems there is a quota RES purchase obligation on traders. But in a tradable GC system instead of buying RES-E, a trader can opt for buying GC. In the Hungarian proposed system the mutual gains of trading cannot be realised, which entails an efficiency loss. For the longer term the feed in tariff system may be replaced by a tradable green certificate system for RES-E. The government has the discretion, but not the obligation on the authorisation of the Electricity Act to introduce the TGC system – after due evaluation of international experiences and national circumstances. However, no date is specified yet.

For compensation of feed-in tariff costs, a feed in component is built in the system control charge. All consumers pay, the TSO collects and then distributes the revenues to the suppliers.

When the CHP producer bids for offering heat supply at procurement tenders, it often offers heat at very low prices, which is made possible by the supported high electricity tariff. It is not

[6] In this category number there is no premium; the support is „only" obligatory purchase at the regulated public utility wholesale price.

classical cross-financing, just a division of revenues for joint products, the cost of which could only be arbitrarily divided. One leg of the revenue is regulation driven (feed in tariff), the other is by market forces (competition in tenders) and local authority consideration.

2.5 Latvia

2.5.1 Share of DER electricity

The share of electricity generated from renewable energy sources in total electricity supply varies from 39.2% in 2002 to 47.7% in 2000. The largest share of the total electricity generated from renewables is produced using hydropower. In 2004, the generated output of such power plants amounted to 3044 GWh, which is 66% of the total generation in Latvia. Taking into consideration that hydropower contributes a substantial share in the total energy output balance, Latvia's capability to produce electricity is largely dependent on meteorological conditions, that is, on the water flow in the Daugava river. Therefore, the annual production of electricity in the Latvian hydropower plants can vary between 1800 GWh and 4500 GWh. Since the beginning of the 1990s an intensive reconstruction of regionally important small hydro power plants (HPP) has started in Latvia. At present Latvia has about 150 small HPP (up to 10 MW) with installed capacity of about 26 MW. The total generated output of these HPP in 2004 amounted to about 65 GWh. The electricity generation in wind power plants makes 0.8% from total consumption in 2004.

Table 2.9 Electricity generation, supply and RES-E shares in Latvia

GWh	2000	2001	2002	2003	2004
Total production:	4136	4280	3966	3887	4595
HPP	2801	2803	2431	2212	3044
CHP	1163	1246	1238	1363.5	1225
Other PP:	172	231	297	311	326
• Small hydro PP	18	37	32	51	65
• Small CHP PP	150	191	253	212	211
• Wind PP	4	3	12.2	48	50
Imports - Exports	1786	1883	2348	2632	2069
Domestic supply:	5922	6163	6314	6519	6664
RES-E share, %	47.7	46.1	39.2	35.5	47.4
RES-E share* (from gross consumption in 2000), %	47.7	48.0	41.8	39.0	53.3
Hydro, %	47.6	46.1	39.0	34.7	46.7
Wind, %	0.07	0.05	0.19	0.74	0.75

* Based on the methodology set forth in Directive 2001/77/EC

Table 2.10 provides actual amounts of electricity generation in CHP power plants, total supply in Latvia, as well as shares of CHP energy sources from total consumption in 2000–2004. There are two large CHP power plants in Latvia: Riga CHP-1 (130 MW) and Riga CHP-2 (390 MW). Apart from these there are more than 26 small CHP power plants implemented in industrial enterprises and heat supply companies with total electric capacity of about 100 MW. The share of electricity generated in CHP power plants varies from 21.5% in 2004 to 24.2% in 2003.

Generation of the power plants according to the given DER criteria (DER is a generator connected to the distribution grid and having a maximum capacity of < 50 MW) is also provided in Table 2.10. The total generation in distributed power plants is provided in line called other power plants. The share of electricity generated in DER power plants (small hydro power plants, wind power plants and some small CHP power plants) varies from 2.9% in 2000 to 4.9% in 2004.

Table 2.10 Electricity generation, supply, shares of DER and CHP in Latvia

GWh	2000	2001	2002	2003	2004
HPP	2801	2803	2431	2212	3044
• Small CHP PP	150	198	253	212	211
CHP	1163	1246	1238	1363.5	1225
Other PP	172	231	297	311	326
Domestic supply	5922	6163	6314	6519	6664
DER share (%)	2.9	3.7	4.7	4.8	4.9
CHP share (%)	22.2	23.4	23.6	24.2	21.5

The indicative target in the framework of the Directive 2001/77/EC for Latvia in 2010 is 49.3% electricity share from renewable energy against 42.4% in 1997 (taking into account the average water flow). According to the *Guidelines to National Energy Program* prepared in 2005 a target for domestic energy production (major part is from renewable sources) is 33% from total primary energy supply.

Table 2.11 Installed capacity of power plants in Latvia (in MW)

	1995	2000	2004
Total installed power capacity in the country	2114	2160	2217
Total installed capacity of thermal power stations			
Nuclear power stations	0	0	0
Combined heat and power stations:	574	608	623
• CHP < 1 MW		1.25	3.29
• CHP ≥1 MW and ≤ 50 MW	54	86.55	99.9
• CHP > 50 MW	520	520	520
Total hydro electric power stations:	1540	1550	1564
• Hydro plants < 1 MW	1.99	15	26.45
• Hydro plants ≥1 MW and ≤ 10 MW	0	N/a	3.45
• Hydro plants > 10 MW	1534	1534	1534
Wind energy		2	27
Other sources		No data available	

2.5.2 DER support

Latvia had a feed-in tariff in place until January 2003, which was double the average electricity price. Now the tariff for small-scale hydro power plants and wind farms is much lower than before and must in some cases be approved and/or negotiated by the Public Utilities Commission (PUC). Currently, the Law on Energy sets mandatory requirements for licensed electricity from:

- Small scale hydro power plants (<2 MW) and wind turbine generators both launched since January 1, 2003, for 8 years, for a price that corresponds to the double average electricity sales tariff. Thereafter, the purchase price will be determined by the PUC;
- Energy facilities that utilize household waste or biogas (<7 MW and launched by January 1, 2008), for 8 years, for a price that corresponds to the average electricity sales tariff;
- Wind turbine generators (erected after January 1, 2003), biomass, including wood and peat, biogas, solar, sea tide and geothermal energy for the market price or the price determined by the PUC.

Since 2002, according to the Latvian legislation a quota system for renewable energy development has been in force. Every year the Cabinet of Ministers issued a regulation defining the total amount of allowed installed capacities for electricity from renewable energy. The quotas defined are typically very small: from 30 MW in 2002 to 2 MW in 2004. The detailed support plan for wind power development is reported in the corresponding case study included in Annex 1[7].

CHP support

The electricity generation in CHP plants, as one of Latvian energy priorities, is integrated in the Energy Law and its amendments. In January 2002 the "Requirements for CHP plants and the procedure of setting the price for the purchase of excess electricity" were issued. These regulations set a higher power purchase price if indigenous energy sources are utilized. In this case it obliges the electricity distributor to purchase all electricity generated in CHP plants at this particular price under the conditions a) the CHP plant supplies at least 75% of the thermal energy produced in the cogeneration cycle to a district heating system and b) uses the cogeneration cycle with fuel efficiency not less than 80%. If these conditions are not met the electricity may be purchased at an agreed price. The price for electricity surplus from CHP plants depends on the fuel (renewable/fossil) and installed capacity:

- CHP with an installed capacity < 0.5 MW_e: the average sales tariff multiplied by 1.12 in case of CHP using RES, for CHP using fossil fuels - average sales tariff multiplied by 0.9.
- CHP with an installed capacity between 0.5 MW_e - 4 MW_e the average sales tariff multiplied by 0.95 in case of CHP using RES, for CHP using fossil fuels the average sales tariff multiplied by 0.75.
- CHP with an installed capacity > 4 MW_e: the tariffs are set by the PUC (both for CHP using RES and fossil fuels)

Based on the Energy Market Law the Cabinet of Ministers has to adopt the new regulation on mandatory procurement of electricity from co-generation plants and its pricing procedures during the first half of 2006. There are no other relevant changes in support mechanisms expected up to 2010.

2.6 Lithuania

2.6.1 Share of DER electricity

Data about actual gross electricity production and consumption, as well as generation from renewable energy sources during the period 2000–2004 is presented in Table 2.12. The share of electricity generated from renewable energy sources in gross electricity consumption (excluding amount used for pumped storage) was 3.52% in 2000 and 4.08% in 2005. According to the amendment of the EU Directive 2001/77/EC the share of electricity produced from renewable sources in 2010 in the new member states will be established on the basis of gross electricity consumption in 2000. Taking into account this amendment the share of RES-E was 3.52% in 2000 and 4.08% in 2005.

Electricity in the Kruonis Hydro Pumped Storage Power Plant (HPSPP) is generated in principle from electricity generated in Ignalina NPP. Therefore it would not be correct to calculate the output of the HPSPP as separate generation. Consequently, the gross electricity consumption in the country is established by deducting the electricity used for pumped storage.

The largest share of the total electricity generated from renewable energy sources was produced by hydro power plants. In 2005, the generated output of these power plants amounted to 453 GWh, which is 98% of the total generation of RES-E energy in Lithuania. The largest producer of electricity from hydro power is the Kaunas Hydro Power Plant (100.8 MW), whose generated output in 2004 was 359 GWh. Generation of electricity in small (up to 10 MW) power plants continues to increase: the total generated output in 2005 amounted to 68.1 GWh, which is 65% more in comparison to the generation in 2003.

[7] The theoretical wind potential in Latvia is from 250 to 1250 GWh. According to the estimates of the Latvian Wind Energy Association, it is possible to install wind generators in Latvia with the total capacity of 600 MW. However, there are not specific targets for windpower development for next years.

Table 2.12 Electricity generation from RES-E in Lithuania

GWh	2000	2001	2002	2003	2004	2005
Kaunas HPP	312.8	284.4	316.5	283.9	359	385
Small HPP	26.6	41.1	36.4	41.2	61.5	68.1
Wind PP	0	0	0	0	1.2	1.8
Biomass PP	0.8	1.2	4.6	7.5	7.4	5.5
Gross production	11425	14737	17721	19488	19274	14785
Gross consumption	10088	10773	11234	11958	12079	11820
Gross consumption without Kruonis HPSPP	9663	10256	10654	11068	11360	11283
RES-E share, %	3.52	3.19	3.36	3.01	3.78	4.08
RES-E share* (from gross consumption in 2000), %	3.37	3.24	3.54	3.30	4.25	4.56

* Based on the methodology set forth in Directive 2001/77/EC

Table 2.13 Electricity generation in DER power plants in Lithuania

GWh	2004
Small HPP	61.5
Wind PP	1.2
Small CHP	529
Gross production	19274
Gross consumption	12079
Gross consumption without Kruonis HPSPP	11360
DER share, %	5.21

The main target of renewable energy policy is an objective set out in the National Energy Strategy of 2002: to strive for a share of renewable energy resources of up to 12% in the total primary energy balance by 2010. With regard to the requirements of the European Parliament and Directive 2001/77/EC the national target established for electricity produced from RES should account for 7% in the overall electricity consumption by 2010.

According to the Procedure for the Promotion of Sales of Electricity Produced from Renewable and Waste Energy Sources, this target is split by different energy sources. The generation of electricity from renewable and waste energy sources in percents from total consumption in Lithuania is provided in the table below.

Table 2.14 Electricity generation in Lithuania from RES from total consumption (%)

Energy source	2006	2007	2008	2009
Wind power plants	0.81	1.50	2.08	2.48
Small hydro power plants	0.90	0.94	0.94	0.95
Other hydro power plants (Kaunas HPP)	2.79	2.71	2.64	2.56
Biomass power plants	0.39	0.73	1.23	1.70
Solar, geothermal and waste energy PP	0.00	0.00	0.01	0.02
Total electricity from RES	4.89	5.88	6.90	7.72

An example of how Lithuania proposes to meet the wind power target using a combination of feed-in tariffs and tenders to build new capacity in selected locations is presented in the case study (Annex 1) [8]. Table 2.14 gives the total capacity of power plants in Lithuania. It shows that the majority of power is produced in nuclear and thermal power plants (including CHP).

[8] Wind power plants in Lithuania whose aggregate installed power of all generators is greater than 250 kW shall be constructed in specific zones. Each zone has a maximum aggregate power limit, and the overall maximum installed capacity of all zones cannot exceed 200 MW according to technical criteria. Producers intending to build such power plants shall obtain permits through the tender procedure. The winner of the tender obtains the right to get the permit to expand electricity generation capacities. The main purpose of division into the zones is to minimize the investments needed to develop electricity networks.

Table 2.15 Installed capacity of power plants in Lithuania (in MW)

	1995	2000	2004
Total installed power capacity in the country	5335.8	6156.6	6233.5
Total installed capacity of thermal power stations	1800	1800	1800
Nuclear power stations	2600	2600	2600
Combined heat and power stations	824	843	811.1
• CHP < 1 MW			4.6
• CHP ≥1 MW and ≤ 50 MW	104	119	116.5
• CHP > 50 MW	724	724	690
Total hydro electric power stations:	107.8	113.4	120.1
• Hydro plants < 1 MW	3.4	8.8	13.9
• Hydro plants ≥1 MW and ≤ 10 MW	2.6	3.8	5.4
• Hydro plants > 10 MW	100.8	100.8	100.8
Kruonis HPSPP	600	800	900
Wind energy			0.8
Wood and wood waste			1.5

2.6.2 DER support

Pursuant to the Regulations, holders of the (public) supply licence are obliged to purchase all electricity generated using renewable energy sources from its producers at the pre-determined prices and sell it to their customers. The government has set the quotas for green electricity purchase until 2009.

As from 2001, feed-in tariffs have been applied for purchase of electricity generated using renewable energy sources. The tariffs are as follows:

- Hydro-power plants (< 10 MW) - 20 LTL cent/kWh (approx. 5.79 €cent/kWh)[9]
- Wind power plants - 22 LTL cent/kWh (approx. 6.37 €cent/kWh)
- Biomass power plants - 20 LTL cent/kWh (approx. 5.79 €cent/kWh)

The Promotion Procedure sets forth that these tariffs will be maintained until 31 December 2020. According to this regulation power generation by wind, biomass, solar power plants and hydro power plants with a capacity of less than 10 MW is promoted. Exceptions to this rule are the following power plants:

- Biomass power plant when biogas and biomass is less than 70% of fuel balance;
- Other types of power plants when renewable or waste energy sources makes less than 90% in fuel balance; and
- Wind power plants which have total capacity of 250 kW and more and are built in not foreseen zones or exceed maximum aggregate power limits specified for the overall zones.

Other measures directed to promotion of electricity produced from renewable sources are:

- *Network connection discount*. Generators whose power plants are using RES for electricity generation are subject to a 40% discount for the connection to the network of operating energy companies.
- *System of green certificates*. The Promotion Procedure sets forth that fixed feed-in tariffs will be applied until 31 December 2020. As from the year 2021, generation of electricity from renewable energy sources will be promoted by a green certificate system.
- *Exemption from the pollution charge*. For the purpose of promotion of electricity generation in bio-fuel power plants, an amendment of the Law on Environmental Pollution Charge was made to which, as from April 2005, physical and legal persons, are exempted from the

[9] 1 EUR – 3.4528 LTL

payment of the pollution charge for emissions of air pollutants which emerge during combustion of bio-fuel.

- *EU Structural Funds***.** EU Structural Funds may provide support for investments into construction of power plants which generate electricity using renewable energy sources. The Lithuanian Environmental Investment Fund provides soft loans for the financing of environmental projects and subsidies for financing of renewable energy projects.

According to a list of public service obligations in the electricity sector approved by the government it is stated that holders of the supply licence and public supply licence are obliged to purchase and to sell to consumers all electricity generated in cogeneration regime in CHP power plants, when they supply heat to the centralized heat supply networks of cities.

2.7 Poland

2.7.1 Share of DER electricity

In Poland most "green" energy comes from hydro-power. Hydropower plants with a capacity over 5 MW are the main suppliers of energy from renewable sources to the national electricity system. In 2004 hydro-power had a 72% share in the "green" energy market.

Presently renewable energy sources using biomass are dynamically developing. The utilization of solid biofuels is the fastest growing branch of the RES-E sector in Poland. Landfill gas utilization technologies, mainly for generation of electric energy or combined heat and power generation, are another fast growing branch of RES-E. In 2000, power plants based on biogas and biomass produced 221 GWh, whereas in 2004 production reached 670 GWh.

During the last three years capacities installed in wind turbines have increased approximately tenfold. In 2000 wind power plants generated 6 GWh of electricity, in 2004 this was already142 GWh (see also Table 2.16). Further investment plans have already been declared, such as projects of wind installations in the Polish territorial waters of the Baltic Sea that are to be assessed. There are reasons to believe that in the coming years a significant increase in installed wind power plant capacity will occur.

Table 2.16 Production of electric energy from RES in Poland (in GWh)

Energy source	2000	2004
Biogas	31	66
Biomass	190	604
Wind	6	142
Hydro	2105	2081
Electric energy production from RES (GWh)	2331	2893
Electric energy consumption in Poland (GWh)	138810	144831
Share of RES-E in electric energy consumption in Poland (%)	1.68%	2.00%

Source: Central Statistical Office

Table 2.17 Shares of CHP in Poland

		1995	2000	2004
Production of electricity from CHP (main activity producers)	GWh	14971	16739	20334
Share on total electricity production	%	11.8	12.5	14.3
Main activity producers share on CHP production	%	74.7	79.9	74.5
Production of electricity from CHP (auto-producers)	GWh	6252	5754	6274
Total energy production from CHP	GWh	21233	22493	26608
Share of CHP in total electricity production	%	15.3	15.5	17.3

Source: Agency of the Energy Market

Table 2.18 Installed capacity in Poland (in MW)

Country	1995	2000	2004
Total installed power capacity in the country	33160	34595	35348
Total installed capacity of thermal power stations	28027	29779	30484
Nuclear power stations	0	0	0
Combined heat and power stations:	no data	no data	no data
Total hydro electric power stations:	2047	2183	2282
• Hydro plants < 1 MW	no data	57	77
• Hydro plants ≥1 MW and ≤ 10 MW	no data	98	184
• Hydro plants > 10 MW	no data	662	615
• Production from pumped storage	1366	1366	1406
Wind energy:			40
Waste:	-	3	3
• Municipal solid wastes	-	-	-
• Industrial waste	-	3	3
Wood and wood waste	-	-	24
Biogas	1	9	22

Source: "IEA/Eurostat/UNECE, ARE

Targets for RES electricity implementation have been laid down in national law. Every 5 years the Minister of Economy presents a report describing targets for the share of energy from renewable sources in national electric energy consumption. The Polish national indicative target for the year 2010 is **7.5%.**

2.7.2 DER support

The obligation to purchase electricity from renewable sources, imposed on undertakings licensed for trade in electricity is the basic mechanism of supporting the "green" electricity. In 2005 the way of energy purchases from renewable sources was modified, in relation to the introduction of certificates of origin which issuance was mandatory for all Member States of the European Union.

The Polish system of green certificates, introduced 1 October 2005, is a two-stage system. The regulator ERO (Energy Regulatory Office) issues the certificates and the Power Exchange handles the remittance procedures. Under the green certificate system all sizes and technologies are supported (hydro, wind, biogas, biomass, PV, and also co-firing of biomass (not DER)) with the exception of pumped-storage. A license is issued by the ERO for all plants. For co-firing a co-firing license is needed plus and authentication by an independent verifying institution.

Within the green certificate system a revenue of up to 233% of the market price can be gained. The market price was approx. 117.49 PLN in 2005 plus up to 133% of market price for GC; in practice GC price varies between 117.49 and 273.75 PLN.

For CHP at present an obligatory purchase system exists up to a limit set in secondary legislation. CHP or "red" certificates are to be introduced in 2007. So far no maximum capacities limit the use. Licenses for CHP will also be issued by the ERO. The expected revenues of the CHP certificates will be approx. 115 % of the "black" electricity average market price of 136.19 PLN (2005 price).

2.8 Romania

2.8.1 Share of DER electricity

The share of electricity production in Romania divided over different sources is show in Table 2.19. This table shows that of the RES-E sources hydro-power provides almost all production. Other sources have minimal shares.

Table 2.19 Electricity production by sources in Romania in 2003

Electricity production	TWh	%
Gross production	57.13	100
Hydro	13.36	23.28
Nuclear	5.51	9.65
Wind	0.00	0.0
Thermal, of which:	38.26	66.97
• Coal	21.64	37.88
• Oil	2.5	4.38
• Gas	14.26	24.95
• Biomass	0.005	0.01

In 2003 no electricity was produced from other renewables than hydro. Due to regulatory measures, in 2004 and 2005 wind electricity generation has started to be used. In 2005, 2 wind turbines were in operation, but producing less than 1 % of national electricity generation. For a standard hydro year we may consider that the share of electricity generation from renewables is 28% (with large hydro) and 0.6% (without large hydro). The indicative RES-E target for Romania for 2010, as recently agreed, is 33%.

In Romania a significant quantity of electricity is produced with cogeneration technology: 1000 MW in back-pressure steam turbines and 4000 MW in condensing steam turbines, fuelled mainly by oil and gas. However, almost all these capacities are old, the majority of which are above 100 MW per unit, and they are grouped in large obsolete thermal power stations. Few real CHP DER units may be considered.

Another concept of DER may regard remote electricity supply, as a large part of the Romanian population is living in rural areas. In total, some 80,000 rural dispersed households in Romania are non-electrified. An off grid energy supply based on small-sized generators may be an alternative solution for these remote households and holiday residences. Due to the large distances to the grid, implying prohibitive costs, in half of the situations, the investment in a off-grid local energy system is equivalent or competitive to the grid connection. Also for remote electrification, very few practical applications were registered.

Table 2.20 Installed generation capacity in Romania (in MW)

	2004
Total installed power capacity in the country	18314
Total installed capacity of thermal power stations	11391
Nuclear power stations	707
Combined heat and power stations:	3885
• CHP < 1 MW	1
• CHP ≥1 MW and ≤ 50 MW	155
• CHP > 50 MW	3729
Total hydro electric power stations:	6328
• Hydro plants < 1 MW	47
• Hydro plants ≥1 MW and ≤ 10 MW	243
• Hydro plants > 10 MW	6038
Wind energy:	1

2.8.2 DER support

Government Decision 1892 of 2004 establishes the support scheme for electricity produced from renewable energy sources. Art.3 of the document states that renewables are to be promoted through a quota-based green certificate system. These green certificates (GC) are traded on a competitive market, distinct from the electricity sales. Large hydro generation is excluded from the green certificate market (above 10 MW of installed power). A certificate represents 1 MWh of green electricity and the certificates are issued monthly by Transelectrica, the Romanian TSO. According to the same Government Decision, a certain amount of quota for Green Certificates (GC) are mandatory to be achieved by the suppliers. These quotas are applied to the electricity sales to end users of each supplier.

For non compliance with the obligation to buy green certificates, the suppliers must pay the missing certificates at a penalty price which is:

- 63€/GC in period 2005-2007
- 84€/GC in period 2008-2012

With the same Government Decision for the period 2005-2012 there were fixed:

- The minimum value of the GC 24 Euro/MWh
- The maximum value of the GC 42 Euro/MWh

In the adopted financial mechanism it is important that a minimum value for GC was established, so that the value of GC was not let entirely on the market. In this way, the minimum value of GC acts like a minimal (guaranteed) feed in tariff. Any business plan and economic estimation may consider now the minimal value as a reference point. The GC can be traded bilaterally through contracts and / or using a centralized market organized by the market operator, Opcom. Monthly auctions have started in October 2005. Romania is one of the few countries that has implemented a green certificate market. A detailed analysis of the Green Certificates mechanism is presented in the case study in Annex 1[10].

[10] Green Certificate market in Romania has been very successful. Romania chose this system instead of the feed in tariffs, to have a better control on the installed capacity in eligible generation units (wind, solar, small hydro, biomass). Green Certificate mechanism is contributing to the stability of the regulatory environment, giving confidence to the investors. Anyway, the Green Certificates market is only one part of the promotion package which consists also of incentives in the investments phase including priority in licensing, no payment for energy imbalances and priority dispatching.

2.9 Slovakia

2.9.1 Share of DER electricity

Currently the major renewable source of energy in theSlovak Republic (SR) is hydro-power. As Table 2.21shows, the installed capacity of the other types of renewable energy sources is also negligible due to limited utilisation of the potential of wind power, geothermal power and biomass. In 2003 the share of small hydro-power plants in total power generation (31,147 GWh) was below 10 MW, which is 0.47%. If the whole hydro-power share in power generation is considered, it reaches 11.5%.

Table 2.21 Electricity production in Slovakia (2003)

Total production, of which	31,147 GWh
• Nuclear power stations	17,864 GWh
• Thermal power stations (incl. industrial power stations)	9,701 GWh
• Hydro power station (including small-scale hydro and other RES-E)	3,582 GWh
• Production from cogeneration plants	4,970 GWh
Production by the dominant producer SE	26,048 GWh
Total gross electricity production in Slovakia	28,892 GWh

The second most widely used RES is biomass, which includes use of forest wood waste in three companies with total installed output of 21.4 MW, and annual power generation of 151 GWh. From agricultural biomass the most used type is biogas produced out of excrements of agricultural animals with a total installed output of 1 MW with annual power generation about 2 GWh.

Table 2.22 Installed generation capacity in Slovakia (in MW)

	1995	2000	2003
Total installed power capacity in the country	7117	8292	8297
Total installed capacity of thermal power stations	2970	3022	3154
Nuclear power stations	1760	2640	2640
Combined heat and power stations:	1101	1180	1307
• CHP < 1 MW		17.7	19.8
• CHP ≥1 MW and ≤ 50 MW	797	640,2	765
• CHP > 50 MW	304	522	522
Total hydro electric power stations:	2386	2498	2505
• Hydro plants < 1 MW	12.5	25.5	29.9
• Hydro plants ≥1 MW and ≤ 10 MW	14.0	28.8	27.8
• Hydro plants > 10 MW	2359	2444	2448
Wind energy:			2.4
Waste			5.4
Wood and wood waste[11]			Ca. 10
Biogas			< 1 MW

According to the Act on conditions of accession of Slovakia to the EU, the country has to meet a relatively high target of the share of RES-E generation in overall gross domestic electricity consumption in 2010 – as high as 31%,

The government approved the Concept of RES Utilisation, which is the basic framework document for RES use. It is shown there, that the RES-E targer is unrealistically high when considering the current situation of RES use. A realistic national indicative and achievable target is 5.85 TWh, which represents 19% share of electricity generated out of RES on the total electricity consumption in 2010. Fulfilment of this lower indicative target (19%) presumes the following

[11] This includes products / waste from agriculture such as straw.

contribution of warious RES: large hydropower plants - 5000 GWh, small hydropower plants - 350 GWh, wind parks - 100 GWh, geothermal energy - 1 GWh, and biogas - 52 GWh.

2.9.2 DER support

There is a system of fixed feed-in tariffs in place in Slovakia, issued in 2005 and valid for 2006 for CHP and RES. Fixed feed-in tariffs are annually determined by URSO, the Slovak regulator for individual units using RES and CHP. The feed-in tariffs for the year 2006 were set as follows:.

- For small hydro power plants between 1900 - 2400 SKK / MWh (50 - 64 €/MWh)[12]
- For solar energy 8000 SKK/MWh (210 €/MWh)
- For wind energy 2500 - 2800 SKK/MWh (66 - 74 €/MWh)
- For geothermal energy 3500 SKK/MWh (93 €/MWh)
- Biomass and biogas between 2000 - 3000 SKK/MWh (53 - 80 €/MWh)

CHP
According to the Energy Act 656/2004 a producer operating CHP units with total installed capacity below 5 MW has a right to preferential access to transmission or distribution if the technical conditions allow for that.

Also for CHP a system of feed-in tariffs exists. The tariffs, annually determined by URSO are differentiated by technology and amount from 1800 to 2500 SKK/MWh for more standard CHP technologies and up to 3000 SKK/MWh for small-scale technologies (micro-turbines, etc.)

Permit to conduct business activities is not required from utilities operating units with total installed output below 5 MW, and utilities generating power from RES with total installed output below 5 MW.

Other support
The “de-minimis scheme” managed by the Ministry of Economy can provide grants up to SKK 4 mln per investment project but the total budget for both RES and energy efficiency projects is limited to SKK 30 mln per year. Also, the Environmental Fund can grant co-funding.

EU Structural Funds can potentially become an important source of co-financing investment projects in the field of renewable energy. Within the operation program “Industry and Services” it would be possible to draw SKK 1,325 bln during 2004-2006

2.10 Slovenia

2.10.1 Share of DER electricity

The gross electricity production from renewable energy sources (RES) in Slovenia in 2004 was 27.7% of the total production. The majority of producers using RES are hydroelectric power stations (97%). The share of the remaining producers refers to the production using waste (municipal, industrial and wood waste) and biogas (see also Table 2.23).

The installed power of combined heat and power stations (CHP) was approx. 212 MW in 2003. The largest share of CHP production is at the Ljubljana Combined Heat-and-Power Station, with installed power output of 103 MW and running on coal. A relatively small proportion of the total production of electricity, less than 3%, is produced by producers connected to the distribution network. The majority of distributed energy resources are small hydropower plants that are spread relatively uniformly across the country.

[12] 100 SKK = €2.67

Table 2.23 Gross production (GWh) by energy sources in Slovenia.

	1996	2000	2004	2004 (%)
Total country gross production	12737	13625	15273	100
Total thermal power stations	4507	5029	5719	37.4
Nuclear power stations	4562	4761	5459	35.7
Combined heat and power stations:	n/a	n/a	n/a	n/a
• CHP < 1 MW	n/a	n/a	n/a	n/a
• CHP ≥1 MW and ≤ 10 MW	n/a	n/a	n/a	n/a
• CHP > 50 MW	n/a	n/a	n/a	n/a
Total hydro electric power stations:	3668	3835	4095	26.8
• Hydro plants < 1 MW	na	169	238	1.6
• Hydro plants ≥1 MW and ≤ 10 MW	na	171	199	1.3
• Hydro plants > 10 MW	na	3495	3658	24.0
Wind energy	0	0	0	0
Geothermal energy	0	0	0	0
Photovoltaics	0	0	0	0
Waste:				
• Municipal solid wastes	n/a	n/a	28	0.2
• Industrial waste	n/a	n/a	5	0
Wood and wood waste	n/a	n/a	93	0.6
Biogas	n/a	n/a	3	0

Table 2.24 Installed net power capacity by energy sources in Slovenia (in MW)

	1996	2000	2004
Total installed power capacity in the country	2563	2631	2965
Total installed capacity of thermal power stations	1098	1115	1335
Nuclear power stations	632	656	656
Combined heat and power stations:	n/a	n/a	212*
• CHP < 1 MW	n/a	n/a	109*
• CHP ≥1 MW and ≤ 10 MW	n/a	n/a	
• CHP > 50 MW	n/a	n/a	103* (coal)
Total hydro electric power stations:	833	860	974
• Hydro plants < 1 MW	n/a	89	106
• Hydro plants ≥1 MW and ≤ 10 MW	n/a	38	37
• Hydro plants > 10 MW	n/a	733	831
Wind energy	0	0	0
Geothermal energy	0	0	0
Photovoltaics	n/a	n/a	0.05
Waste:	n/a	n/a	n/a
Wood and wood waste	n/a	n/a	n/a
Biogas	n/a	n/a	n/a

**2003*

2.10.2 DER support

A system of preferential dispatch aims at supporting electricity production that would not be competitive in an open market. The system allows the producers that are eligible for support to sell their electricity at guaranteed prices (feed-in tariffs), which are higher than the prices at the open market. The system operator of the network to which such production facility is connected has to buy all the electricity produced by the facility that is eligible for support from the system of preferential dispatch. The difference between the guaranteed and the market-based prices is covered by the supplement to the network charge included in the use-of-network price which is determined by the government. The production of electricity in an environmentally friendly way is recognised by awarding the status of qualified producer.

The Energy Act defines the qualified production of electricity as production that generates electricity from renewable resources, waste products, and in power stations using fossil fuels with above-average efficiency; this is mainly achieved by co-generation of heat and electricity. Electricity producers can obtain the status of qualified producer on the basis of the Decree on the requirements to be met for obtaining the status of a qualified electricity producer.

At least once per year, the Government of the Republic of Slovenia determines the purchase prices for all types of qualified producers. When determining the prices for the qualified producers, the government considers the types of production facilities, the use of the primary source and the costs for electricity production. The mode of purchasing electricity is defined by the Decree on the rules for determining prices and purchasing of electricity from qualified electricity producers, and the Decision on the Prices and Premiums for the Purchasing of Electricity from Qualified Producers of Electricity.

All qualified producers, with the exception of producers in hydroelectric power stations with a capacity of more than 10 MW, communal heating stations of more than 10 MW, and industrial heating stations with a capacity of more than 1 MW, are entitled to receive support.

In 2004 the energy prices were around 3.5 € cent/kWh. The guaranteed prices (feed-in tariffs) ranged approximately from 5.2 – 7.0 € cent/kWh:

- Hydro power stations: around 6 € cent/kWh.
- Biomass power stations: 6 - 7 € cent/kWh.
- Wind power stations: around 6 € cent/kWh.
- Solar power stations: 37 € cent/kWh (power < 36 kW), 6.5 € cent/kWh (power > 36 kW).
- CHP: 5 - 7 € cent/kWh.

The Ljubljana Combined Heat-and-Power Station has a special status and is also entitled to support. It has 70 percent efficiency rated out of the input of fossil fuel energy.

In 2004 qualified producers generated 323 GWh of electricity. Among the qualified power stations on the distribution network using RES, the majority are hydroelectric power stations. The share of remaining producers is less than 1.5 percent and refers to the production using biomass and communal waste.

In addition to the support to qualified producers, the system of preferential dispatch also includes the support to the producers that use 15 percent of Slovenian primary energy for the production of electricity (allowed by EU directive 2003/54/EC and the Energy Act). Thus, 563 GWh of electricity is purchased from the Trbovlje Thermoelectric Power Station..

Electricity purchase at guaranteed prices from qualified producers is defined on the basis of 10-year contracts. The guaranteed prices should be determined by the government at least once a year. However, the prices were most recently determined in January 2004 only.

2.11 Developments of DER shares

The country overviews above show a slow but steady increase of RES-E production in most of the ten new Member States during the last few years. In most of the countries small-scale renewable energy shares were at a minimal level before 2000 but started to increase in recent years. The only renewable energy source of significant share already existing is large hydropower, but that cannot be considered as DER. The largest hydro sources can be found in Latvia (46% of electricity production) Slovenia (27%), Romania (23%) and Slovakia (11%).

For CHP we see that all countries have a significant CHP share, between 10 to 20% of electricity production in all countries except Slovenia where the share is lower. Part of these sources can be considered as DER. CHP has a relatively long history in most new Member States. A large number of medium to large-scale CHP plants are in place connected to either district heating systems or large industries. Trends in CHP development differ county by country; most countries show an increase in CHP capacity. A good example is Hungary where the installed CHP capacity almost doubled between 1995 and 2005 (see also Table 2.8). Trends in Estonia and Lithuania show stable CHP share during the last five years and in Bulgaria a decrease could be noted (due to problems with payment of heat bills).

2.11.1 DER shares

When looking specifically at DER sources in comparison to total RES-E and CHP we get the following table.

Table 2.25 DER shares in the new Member States

	RES-E share (% E-prod. in 2004)	RES-E share (excl. large hydro)	CHP share (% E-prod. in 2004)	Small CHP share	DER share (% E-prod. in 2004)
Bulgaria	7.9	1.4	11.8	2.8	4.2
Czech Rep.	4.1	2.4	14.0	5.3	7.7
Estonia	0.4	0.4	10.4	0.1	0.5
Hungary	2.4	2.4	20.0	7.4	9.8
Latvia	47.4	4.9	21.5	3.5	8.4
Lithuania	4.1	0.6	22.4	4.6	5.2
Poland	2.2	0.5	14.3	4.3	4.8
Romania	23.3	1.1	< 20	2.0	3.1
Slovakia	11.5	0.5	16.0	8.6	9.1
Slovenia	27.7	3.7	< 10	3.0	6.7

Table 2.25 shows that the small-scale RES applications, excluding large hydro above 10 MW, make up a small part of renewable capacity in most countries, exceptions are Estonia and Hungary (due to hydrological conditions). This shows again that large hydro-power plants make up the majority in most of the new Member States.

When looking at CHP we can see that production of CHP is for more than half, in most countries more than ¾, based on large-scale CHP (above 50 MW). These are usually installations connected to industrial plants and large district heating systems.

The resulting DER shares are shown in the final column of Table 2.25 and remain below 10% in all ten countries. The largest DER shares (between 7 and 10%) can be found in the Czech Republic, Hungary, Latvia and Slovakia. The lowest shares (below 1%) can be found in Estonia. Also Romania has a relatively low DER share (around 3%).

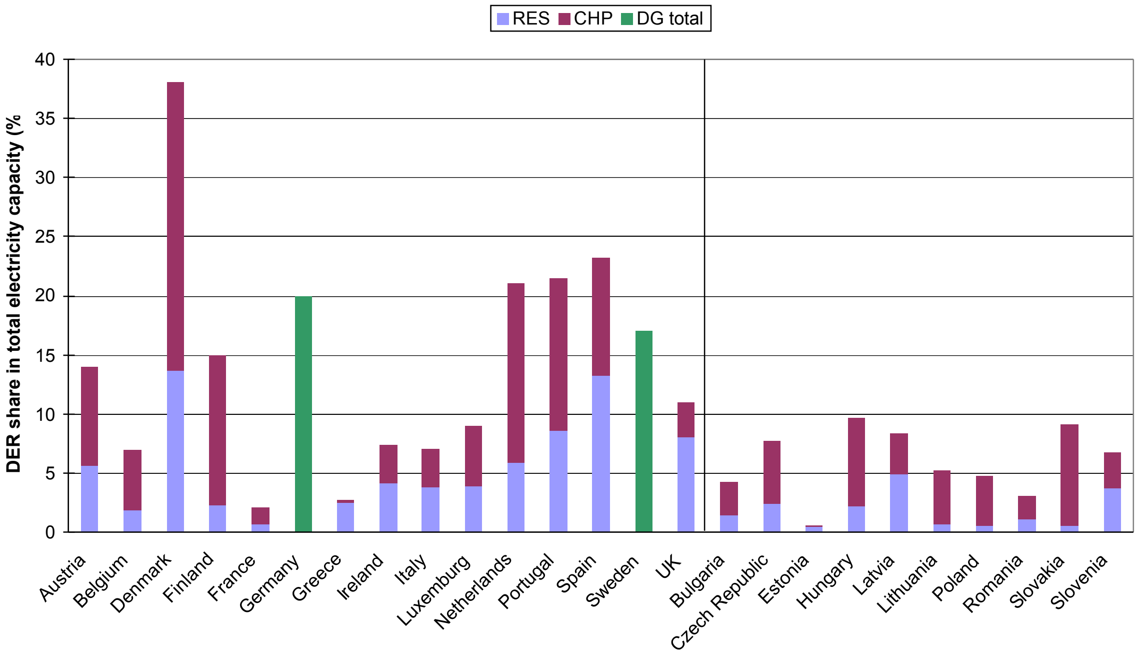


Figure 2.3 DER share in the EU-15 and new MS

Figure 2.3 makes a comparison of DER shares between the EU15 and the new Member States[13]. The figure shows that on average, DER shares are higher in EU15 countries than in the new EU10. Here DER shares are for most countries between 10 and 20%, with Denmark having an extremely high percentage of more than 35% and France and Greece having very low percentages (below 5%). Most new Member States have CHP shares that are comparable to those in the majority of EU15 countries. The large difference in DER shares is mainly caused by the low small-RES capacity in the new Member States. As shown earlier in this chapter, high shares of RES-E in new Member States are mainly consisting of large hydro-power plants.

2.11.2 Recent renewable energy trends

The new Member States were reporting on their progress in meeting the renewables targets for the first time by the end of 2005. These reports conclude that most of the new Member States are moving in the right direction, but only two out of these member states, Hungary and Latvia, appear on course to meet there targets. Poland only in 2005 seemed to get on track, while the situation is unclear in Estonia and Lithuania. Other new Members like Slovakia and the Czech Republic have rather unrealistic targets. The reasons for meeting or not meeting the RES-E targets are different for each country, however. An overview of the recent developments based on their country reports are given below (*Platts Renewable Energy Report, 2006*). For Bulgaria and Romania, who will become EU member by January 1, 2007, no country reports were available.

[13] *Sources are EU-15 data from DG-GRID Project. NMS data elaborated from SOLID-DER national reports*

Table 2.26 RES-E shares and targets of new EU-10 and Candidate countries

	RES-E share 2000 (% consumption)	RES-E share 2004 (% consumption)	RES-E target 2010 (% consumption)
Bulgaria	6.5	7.9	11.0
Czech Republic	3.9	4.1	8.0
Estonia	0.1	0.4	5.1
Hungary	0.6*	2.4	3.6
Latvia	47.7	46.7	49.3
Lithuania	3.4	3.7	7.0
Poland	1.7	2.0	7.5
Romania	n/a	23.3	33.0
Slovakia	n/a	11.5	31.0
Slovenia	28.0	27.7	33.6

* - 2002

Czech Republic

Renewable electricity production is nowadays highly dependent on the amount of hydropower produced which is fluctuating due to subsequent wet and dry years. For example, the share renewable electricity production in 2002 (extremely wet year with floods in part of the country) was 4.9% of the total production. In 2003, due to an extremely dry year and the need of damage repair after the floods in the previous year, renewable electricity production was down to 2.8%. Then there is a significant difference between the RES-E share of production and consumption. In its EC submission, the Czech government said its RES-E share on gross consumption of electricity from renewables in 2004 was 4.1%, but that it accounted for only 3.3% in case of gross power production due to high export of electricity.

Estonia

In its 2005 progress report, the Estonian government reports that in 2004 it generated less than 0.5% of its power from renewables. This portion had risen to 1.2% by the end of 2005, so the country is moving in the right direction, though at the current rate of renewable energy growth Estonia is unlikely to meet its 2010 target. Wind power is seen as having the greatest potential to achieve the goal.

Hungary

The Hungarian target for renewable is modest at 3.6% of all power consumed in 2010, but Hungary is starting from a low base. Hungary's progress report for 2004 shows that renewable energy accounted for 2.4% of all power production (965 GWh) which is three times the level of 2003. By the end of 2005 the share of renewables in total power consumption exceeded the 4% limit (1612 GWh), meaning that already comfortably meets its RES-E target. This large increase has partly been caused by the large increase of the use of biomass, mainly used for co-firing due to very favourable feed-in tariff.

Latvia

In its progress report to the EC, the Latvian government reported that renewable energy met 47% of all power production in 2004, a percentage that has risen steadily from 2000. When looking at consumption, this percentage is even higher (above 50%), meaning that Latvia is firmly on course in meeting its 2010 target. With the vast bulk of its renewable power coming from large hydroelectric power plants, however, Latvia is vulnerable to changes in rainfall levels.

Lithuania

Lithuania has committed to doubling the share of renewables in the balance of consumed electricity from 3.3% in 1999 to 7% by 2010. The share of power produced from renewables in domestic consumption in 2004 reached 3.8% up from 3.0% the previous year, excluding output from the Krunois pumped storage plant (used to store power from non-renewable sources). The country's first wind power plants were built in 2004 (capacity just 900 kW), but the Lithuanian government authorised a further 52 MW in early 2005.

Poland

Poland has a target for renewables share of electricity consumption that rises steadily from 1.9% in 2001 to 7.5% in 2010. With its large agricultural sector, Poland has identified biomass as having the greatest potential, followed by wind and hydropower. Poland's 2005 progress report noted that renewable power production in 2004 was 2.89 TWh, equalling to 2% of power consumption. Initial figures for 2006 put the renewables share at around 2.6%. This means a significant increase but meeting the 2010 target means that the share of renewables has to triple until the end of the decade.

Slovakia

Slovakia's goal is that 31% of all power consumed in 2010 should be met by indigenous renewable power production. Renewable power accounted for 14.4% of total power consumption in 2004, up from 12.4% the previous year[14]. Although making progress, Slovakia must double its output from renewables to meet its target. The Slovak government in its 2005 progress report suggested that its 2010 target may be unrealistic and aims now at a lower target of 19%.

Slovenia

Slovenia signed up to a target of 33.6% of power consumption by 2010 to be produced by renewable sources. RES contribution was 31.7% in 2002, largely from large hydroelectric facilities. At first glance Slovenia would need only to achieve a small expansion of RES-E production. But production from hydropower plants varies depending on rainfall levels, so the amount of power produced from RES can fluctuate quite widely. E.g. renewables met just 22% of power consumption in 2003 - a dry year. The renewables portion was back at 29.4% in 2004, but the percentage contribution is still lower than in 2000 and remains some distance form its 2010 targets. Along with unpredictable rainfall, Slovenia reported it has faced rapid growth in electricity consumption that has outstripped growth in energy production.

[14] The share of RES-E according the IEA energy policy review 2005 was 16.5% in 2003 (or 5.3 TWh)

3. COMPARISON OF SUPPORT SCHEMES

3.1 RES-E support schemes in the new EU Member States

From chapter 2 it became clear that all new Member States and Candidate Countries in Central and Eastern Europe have implemented a support system for renewable energy during the last few years. Meeting the target from the Renewables Directive (2001/77/EC) was the most important reason to implement some form of RES-E support. As shown in Table 3.1, eight of the countries have implemented a feed-in tariff system, two countries (Poland and Romania) have implemented a tradable green certificate system. Additional support is in some countries provided in the form of investment subsidies or soft loans. In the near future investment support is also expected through the use of EU Structural Funds. So far, however, no ex-ante evaluations are known about the use of structural funds for RES-E in the EU15.

Table 3.1 Overview of RES-E support in the new MS

	Support category	Additional support or taxes	Level of support (€/MWh)	% of market price	Years of support provided
Bulgaria	FIT	-	40 - 85	200 - 300	12 yrs
Czech Republic	FIT (fixed tariff or feed-in premium)	Investment subsidies	60 - 100	200 - 300	15 yrs
Estonia	FIT	-	52		7 - 12 yrs (max. until 2015)
Hungary	FIT (feed-in premium)	Investment subsidies	40	190	Until return is yielded[15]
Latvia	FIT (combined with quota obligation)	-		± 200	8 yrs
Lithuania	FIT	Soft loans, exemptions from pollution tax	58 - 64		Until 2020
Poland	TGC	RES exempted from excise tax	Depending on market price	up to 230	No limit
Romania	TGC	-	Min. 24 – max. 42		No limit
Slovakia	FIT	Investment subsidies	60 - 200	110 – 364%	Until 2010
Slovenia	FIT	CO2 taxation non RES	50 - 70	140 - 200	10 yrs

In the countries where tariff information is available (Czech Republic, Hungary, Latvia and Poland) we see that revenues for RES-E are at least 2 times as high as the market price. The highest revenues for DER operators can be gained in the Czech Republic when considering support in absolute numbers. Relatively high support levels are also seen in Slovakia (fixed feed-in tariff) and Hungary (premium on top of market price). In these three countries RES-E support is comparable to feed-in levels in a number of EU15 countries like Austria, Germany or the Netherlands.

The ways the tariffs are differentiated differ per country. The Czech Republic and Slovakia have more than 10 categories and subcategories in place; in Hungary there is one tariff for RES-E and one tariff for CHP. Lithuania has limited its feed-in system to three tariffs, for wind power, small hydropower and biomass.

[15] Revisions of the tariff are possible every 5 years.

When we compare the RES-E support in the new Member States to the EU15 countries we see that the predominant support scheme in the majority of these countries is also a feed-in tariff. An overview of the predominant support scheme is shown in Figure 3.1. Apart from these support systems, a number of EU-15 countries have also additional forms of support in place. E.g. France has a feed-in tariff system, but a tendering system for wind power plants > 12 MW. The UK combines a quota obligation system with fiscal incentives.

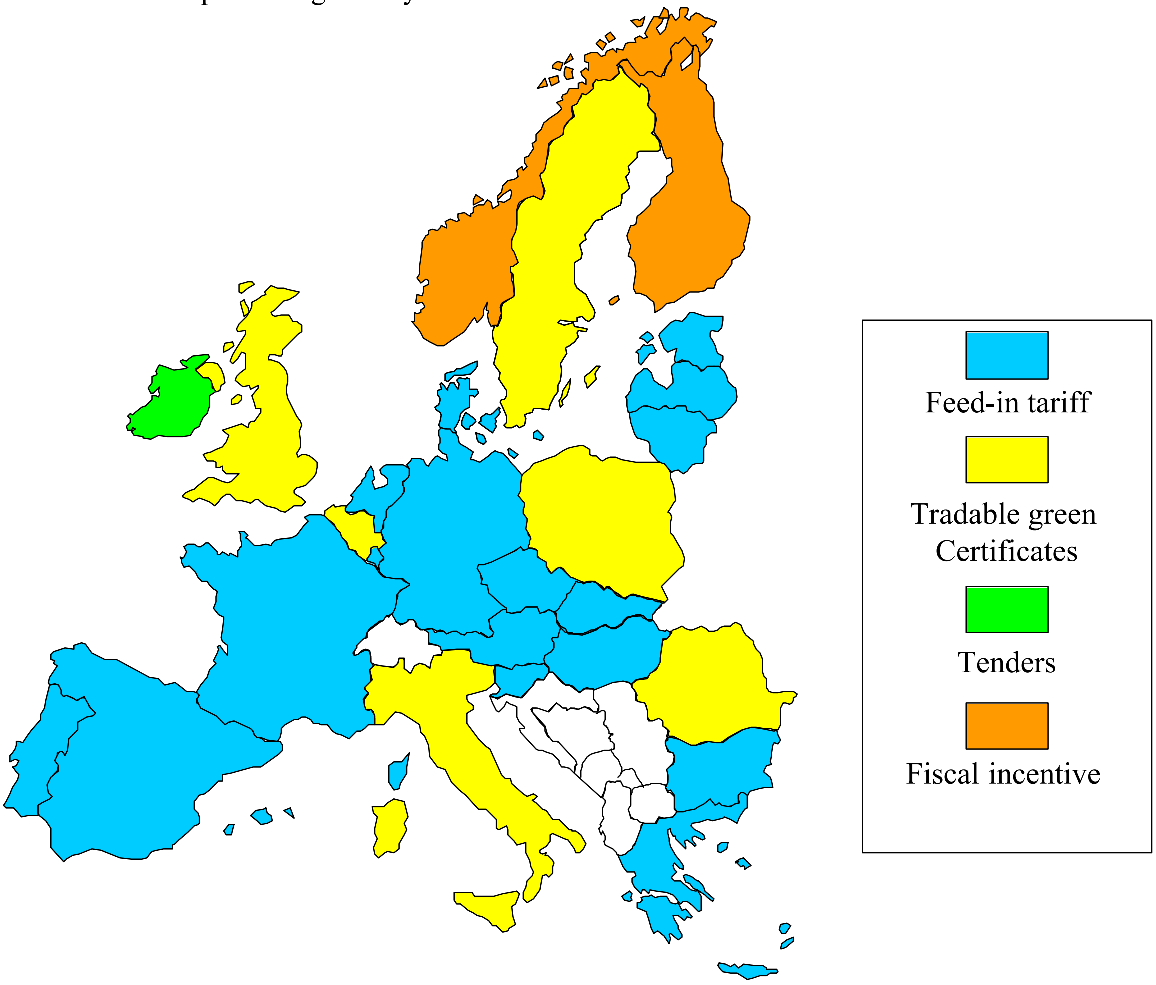


Figure 3.1 Overview of renewable electricity support schemes in the EU25, Norway, Bulgaria and Romania

So far very little can be said about the effectiveness of the support systems as most systems are in place for a very limited number of years (implemented as recently as 2005). As numerous studies carried out in the EU-15 show, however, investors in RES-E usually prefer a system that is stable for a large number of years. When simply looking at the growth of renewable energy in recent years then we could conclude that countries with strong feed-in tariff systems like Germany and Spain experienced enormous growth of RES capacity. Countries like the UK and Ireland with a quota obligation and tendering system respectively, experienced far less growth of renewable energy capacity (Ragwitz *et al*, 2006).

From an investors' point of view a feed-in tariff system provides more security than a green certificate system where the revenues per MWh are dependent on the demand for green certificates. However, a green certificate system could also work well as long as targets for RES-E production or purchase are set high enough to ensure growth of capacity and fines for not meeting obligations are introduced and set high enough to provide an incentive to produce or purchase RES electricity. E.g. the problem with RES-E uptake in Poland was related to the fact that up to 2005 no penalties existed for not meeting the RES-E quotum.

When we look at a stable system, the feed-in tariff system in the Czech Republic could be one of the most attractive for investors. Here relatively high feed-in tariffs or feed-in premiums (choice up to the investor) are combined with a relatively long time of support (15years).

Such a generous system may have its drawbacks, however. An example is Hungary, where the feed-in system is already in place since 2003. Here the RES-E potential has grown significantly since 2003 and Hungary has already met its RES-E target for 2010. The Hungarian feed-in system is already viewed to be expensive nowadays. One of the problems is that large part of the feed in tariff support flows to large plants co-firing biomass. Change of the system may therefore be expected in the coming years. A useful adjustment would be to decrease the support for relatively cheap RES-E production (e.g. co-firing biomass) increasing an interest in RES-E applications that require more support.

3.2 Specific EU15 experiences with RES-E support schemes

This section gives a short overview of support in a selected number of EU15 countries. Of these countries, Austria, Denmark, Germany, the Netherlands and Spain have a feed-in tariff system while Sweden and the United Kingdom have a tradable green certificate system in place.

3.2.1 Austria

Austria has introduced support schemes in the form of green certificate system but after one year switched to feed-in tariffs to support renewable energy sources. The original feed-in tariffs had a duration of 13 years and the level (above 100% of the current electricity market price) had to ensure certainty for investors so that the share of these sources would grow significantly. The level of the feed-in tariffs varied from 3 to 7.8 ct/kWh for the more common sources of RES (Wind, biomass, small hydro) to nearly 60 ct/kWh for PV. For comparison, the electricity market price in Austria (2nd quarter 2004) was about 3.1 ct/kWh. This shows that the support for the different RES per kWh fed into the grid is 100% or more of the market price. These tariffs were valid for installations put into operation before 30.6.2006.
From 2006 onwards feed-in tariffs are available for 10 years and are granted on a first-come, first-serve basis. The 2006 feed-in tariffs are comparable to the ones in the previous years[16]:

3.2.2 Denmark

Denmark has promoted wind turbines and medium and small-scale CHP during at least two decades. In the western part of Denmark this has lead to a wind power capacity of 2155 MW connected to voltage levels of 60 kV and below. Together with the approximately 1600 MW of small-scale CHP, the DER in Western Denmark can produce as much as the peak load of the area, which in 2002 was 3685 MW, while the minimum load of 1189 MW often can be supplied by wind turbines alone.
The production of electricity in Denmark is split between traditional production and ‘prioritised production’, the latter covering mainly renewable electricity based on wind power, biomass and small-scale CHP. Presently, as a result of earlier agreements, the system operators are obliged to purchase the prioritised production at fixed, high billing prices. For renewables, the priority rule is combined with a fixed feed-in tariff, for CHP there is a priority rule and a price premium up above the market price in place. This prioritised production does, however, not have direct access to the wholesale market for electricity.
The main instruments that lead to this increase of renewables and CHP are a feed-in system, political obligations, investment subsidies and tax refunds. Since 1993 a feed-in tariff system exists in Denmark, where utilities were obliged to pay wind turbine owners 85% of the electricity

[16] http://www.eva.ac.at/(en)/enz/einspeis_2006.htm

price for household consumers. New tariffs were adopted in 2001 in anticipation of the start of the green certificate market. The support is now generally lower than in previous policies. For example, for onshore wind energy, the tariff set for electricity from new plants for the first running period is nearly 30% lower than that for existing plants. For plants commissioned in the years 2000, 2001 and 2002, the feed-in tariff is invariable at 5.8 ct/kWh for the first 22,000 hrs of operation and then reduced to 1.3 ct/kWh. Any support is given for a maximum of 20 years.
A Green Certificate Market was planned to replace the existing feed-in system from January 2003. However, the introduction of such a green certificate system has been postponed indefinitely due to concerns from the renewable energy sector about the market for green certificates, especially in the European context. An intermediate scheme has been designed for the period until the introduction of green certificates.

Due to the large increase of DER capacity (both wind power and small-scale CHP) in the power system, costs for the electricity network have increased significantly. This included higher balancing costs (as balancing is only taken care of by centralised power plants). This was one of the reasons for updating the support scheme, taking the costs of DER more into account in the support scheme.

3.2.3 Germany

The German federal government, as well as the state and district government, has put in place a number of measures for promoting renewable sources of energy. The Electricity Feed-in Law (EFL) of 1990 was the first to introduce feed-in tariffs and these tariffs were paid by the utilities. Since April 1st, 2000, Germany introduced a renewable energy sources act (EEG). The grid operators pay the feed-in tariffs under this new law and cover their costs by an additional fee to be paid by all consumers. The law targets wind, PV, geothermal, small hydro (<5 MW) and certain forms of waste biomass plants. The DSO whose grid is closest to the location of the RES installation has the obligation to pay the tariffs. The EEG states that the electricity from renewable energy must be transported and charged to the final consumer.

The prices paid under the EEG are based on a fixed price scheme combined with a decreasing price element. From 2002 on, new installations receive tariffs lowered by a certain percentage each year (1-5%). For every installation the expiry date is 20 years time from the date of operation. The EEG addressed some shortcomings of the EFL as the feed-in tariffs are not longer linked to average consumer prices but based on generation costs of various renewable energy sources. Apart from a decrease of the tariffs for plants put into operation after January 1, 2002, bi-annual revisions of the feed-in tariffs are possible depending on the cost evolution and the degree of market penetration of the RES-E technology concerned. These revisions are based in evaluation reports the responsible ministries have to submit to parliament every two years.

The EFL and the EEG have been very effective in increasing the penetration of wind energy in Germany. Installed capacity increased from 1,100 MW in 1995 to 6,100 MW in the year 2000 and continued to grow to more than 18,000 MW by the end of 2005.

Questions have been raised, however, about the economic efficiency of the system. An increased capacity of wind power (up to approx. 36 MW in 2015) may mean increased costs for grid operators and consumers, as they require major upgrades of distribution and transmission networks. DENA, the German energy agency, has made several calculations of the costs of wind power expansion up to the year 2015 (Dena, 2005). At an increase of wind power (onshore and offshore) to 36 GW à 77 TWh of electricity (approx. 15% of German electricity consumption) by 2015 about 850 km of new 380 kV transmission lines will be required and 400 km of existing transmission lines need strengthening. The upgrades of the transmission and distribution system will mean increased costs, which are estimated at:

- The additional costs of network expansion will be around € 1.1 billion by 2015 (€ 110 million/year). The household costs at these upgrades will be around 0.39-0.49 €ct/kWh. This means at an average annual consumption of 3500 kWh approx. € 13.65 – 17.15 extra costs per year per household.

3.2.4 The Netherlands

Since 2003 a feed-in premium system is in place in the Netherlands, the MEP. The MEP ('environmental quality of electricity production') aims to increase the stability to investors and improve the cost-effectiveness of renewable electricity support. The MEP provides for operating support through a combination of feed-in tariffs and a reduced ecotax exemption. The feed-in tariffs are financed through an annual levy on electricity connections to the network grid. As the future of the exemption is subject of political discussion, the Dutch support scheme is more likely to evolve into a pure feed-in system. Under the MEP the total level of operating support is determined by the sum of the MEP feed-in tariff and the value ecotax exemption. The government guarantees this total level of support for a period of 10 years after entering into operation. For CHP a separate REB tariff exists that is differentiated by the reduction of CO_2 for a given technology.

Other main features of the feed-in tariff system are:

- The RES producer can apply for the MEP feed-in tariff at TenneT (Dutch transmission system operator).
- The level of feed-in tariff is fixed at the level of the tariff in the first year for a duration of max. 10 years (and for wind power max. 20,000 operational hours)
- Tariffs are differentiated according to type of RES technologies (max. feed-in tariff 7 €ct/kWh) and determined annually by the Ministry of Economic Affairs
- Grid operators responsible for metering of electricity from renewable plants delivered into their grids and for the verification of the renewable status of the plant.

An abrupt change occurred in this system only a few months ago, when it was terminated for budgetary reasons. The MEP feed-in premium scheme proved to be a success and the Dutch national indicative target of 9% has come into reach. The costs of the feed-in system, however, became much higher than anticipated initially. This threatened to cause severe budgetary problems resulting in a sudden stop of the support system on August 18, 2006. All projects that already started or applied for the feed-in premium before August 18 continue to be supported for the coming 10 years according to the regulation, but no new projects will be financed.

Due to the success of the system, the Netherlands is already on track to meet its renewables targets for the year 2010 with new the RES-E projects started and in the pipeline.
Now a transition period for certain small-scale (biomass) projects is anticipated. In the meantime the Dutch government is looking for an alternative way to support renewable electricity production combining sustainable growth of the RES-E capacity with cost-effectiveness.

3.2.5 Spain

The Spanish Electric Power Act distinguishes between two electricity production systems: the Ordinary System and the Special System. In the ordinary system the regulatory basis is the free power market or electricity pool where demand and supply bids for electricity are matched prices are set in consequence. In the Special System generation plants below 50 MW belonging to three clearly separated areas (co-generation, renewable energy sources and waste) are given a special status. According to the Act RES-E producers are entitled to feed all their power into the grid system and receive the conventional market price plus a premium.

According to the Royal Decree 436/2004 owners of electric power installations within the Special Regime (registered before 28.03.2004) have the possibility between two options.

1. Sell the electricity to a distribution company, receiving:
    - A fixed price per kWh (adjusted annually by the Government) of 80 to 90% of the average electricity tariff (76.89 €/MWh for 2006)

    - A reactive power service supplement which varies from a penalty of 4% to a bonus of 8% over the average electricity tariff
    - Supplement for continuity of the supply against voltage dips (wind turbines only).
2. Sell the electricity freely on the market (daily sale bids, bilateral contracts). The operators will receive the following remuneration:
    - The price per kWh set in the pool or agreed price in the (bilateral) contract.
    - *Plus* a premium per kWh of the average electricity tariff (reflecting the environmental value of renewable production).
    - An incentive per kWh for participating in the market.
    - A reactive power service supplement.
    - A capacity payment (under same conditions as applied to plants operating within the *Ordinary Regime*).
    - Supplement for continuity of the supply against voltage dips (wind turbines only).

Every year, renewable generators are allowed to choose to follow one or another variant. Currently, due to the high prices in the energy market, most of the Special Regime Generation is under the market option (by the end of 2005, 70% of RES and CHP production was covered under the option of the market price premium).

From 2006, and every four years from then onwards, the Government will carry out a revision of tariffs, premiums and incentives. This revision takes into account the fulfilment of the RES goals, the costs of the different RES technologies, the participation in the coverage of demand and the impact on the technical and economic management of the electrical system. The tariff changes will only be applicable to those installations commissioned later than January 1st of the second year after the year the revision was approved. Apart from this revision, no time limit is placed upon the feed-in system. Support in percentage of average market price varies between 25-40% for CHP, 50% for wind and 50% for biomass.

3.2.6 Sweden

Sweden has introduced a quota obligation system with tradable green certificates in 2003. The system intended to replace previous investment and production subsidies for renewable electricity technology. Production subsidies in the form of feed-in tariffs for land-based wind power will be phased out by 2009. Apart from this targeted support renewable energy projects can receive funding through climate investment programmes. The quota obligation system is the predominant mechanism initiating ongoing and future investments. The overall objective of the scheme is to increase the production of electricity from eligible renewable sources from 6.5% (2002) to 16.9% in 2010. This corresponds to 10 TWh of new RES-E production.

Under the system, all electricity consumers (except energy-intensive industry) are required to buy a share of electricity from RES-E which corresponds to a percentage of their electricity use (8.1% in 2004) and which is raised each year. Electricity suppliers are required to manage the quota obligations of the consumers and hence by certificates from producers. Eligible RES includes existing and new wind, biomass, geothermal, solar and hydropower plants (< 1.5 MW), wave power and peat. All producers of eligible renewable power receive one certificate for each MWh of electricity

The objective was to introduce competition between different RES eligible for certificates. As expected this has resulted in more electricity from biomass-based CHP, whereas the installation of wind power has slowed down.

As the system has operated for a small number of years only not much can be said about its effectiveness. But generally creating competition between RES-E sources means that the cheapest options will be chosen. In case of Sweden these are production increases of existing RES-CHP plants and fuel switches. Small-scale projects such as wind power production seem to be less attractive. This could however change when the cheap RES-E options will be exhausted.

The Swedish certificate system includes one major uncertainty, which is the relatively short time frame. The system will run until 2010 and it is unclear what will happen after that. Considering the time-frame of new RES-E production (around 10-20 years), this mainly brings uncertainty to new entrants into the market that are dependent on external financing (e.g. banks) for their projects (van der Linden *et al.*, 2005).

Therefore, in summary, the Swedish system is cost-effective in that it promotes the cheapest RES-E options but it has not yet created long-term stability in the eyes of market actors.

3.2.7 United Kingdom

The Renewables Obligation (RO) is the key component to promote the generation of RES-E in the United Kingdom. This obligation was implemented on 1st of April 2002 and requires electricity companies to supply an increasing proportion of their production from renewable sources. The proportion of electricity required under the Renewables Obligation will increase between the implementation date and 2010. The obligation accounts for around 3% in the first compliance period that ended 31 March 2003, rising to about 10.4% in the year ending March 2011. Obligation levels after 2010/2011 have now also been set, introducing a target of 15.4% by 2015/2016. The obligation levels are ambitious, and the system design only guarantees high certificate prices if there is a large shortfall compared to the target.

The renewable electricity produced within the UK is rewarded with Renewable Obligations Certificates (ROCs) worth 30 £/MWh A buy-out penalty of 30 £/MWh is set for failure to meet the obligation, thus the non-compliant producer is paying the compliant one the ROC bonus.

The buy-out payment for suppliers who cannot comply with the obligation level was set at 30 £/MWh in 2002/2003, increasing with the retail price index[17]. A defining feature of the UK obligation system is the fact that the buyout payments are "recycled back" to those suppliers who surrendered ROCs. This means that while the cost of the obligation to the end consumer is capped, the value of the certificates may exceed this cap. E.g. in the first year the average trading price of ROCs was £ 47-48/MWh (van der Linden *et al.*, 2005).

From the perspective of the renewable generators, the RO is now considered to be generally effective and the mechanism allows developers to finance new renewable plants. However, while larger companies have been able to use balance sheet in order to invest in new renewable energy capacity, smaller developers have found it more difficult to raise finance from the banking sector. Initially there were major problems with the financial sector being unclear about the system and the government's long-term commitment to it. However, the government has been very clear that it is committed to the obligation as a long-term strategy, and extended and increased the targets until 2015/16. Nevertheless, the fact that the system is still new and liquidity is limited means that the financial sector has been wary to lend money.

3.2.8 General overview

The examples of support for RES-E in the EU15 show remarkable differences in approaches between the countries. Some, like Germany and Spain, provide long-term stability to investors through feed-in tariffs. Others, like Sweden and the United Kingdom have chosen for a market based-approach through renewable energy obligations.

Costs of RES-E feed-in tariffs are often reason of changing or even abolishing a scheme. E.g. in Denmark the system has been adapted as network and balancing costs of RES production have

[17] The buyout was set at 30.51 £/MWh in 2003/2004 and at 31.59 £/MWh for the period 2004/2005

been increasing enormously so that feed-in tariffs have been adapted to time of production. In the Netherlands increasing costs were the main reason for a halt to new projects.

Based on the above examples we can say that there remains a certain risk of over-subsidising DER through feed-in tariffs with negative budgetary consequences. On the other hand, too little support will almost certainly mean that there will be little growth of DER support.

The additional costs for DER support have to be covered somehow, either directly through the government budget or through a specific fee charged to the consumer. As government budgets can be subject to frequent changes a special fee for consumers could be a source for more stable revenues. In case of a special fee, costs are covered by those consuming electricity. This can be in the form of a fixed fee per connection or through a fee per MWh. In the latter case those with the highest consumption pay relatively the most.

A comparable situation occurs when there is a certificate system in place. Usually there is an obligation for suppliers to meet a certain percentage of electricity production or sales through RES-E. The additional costs for RES-E purchase are usually covered within the electricity bill.

This situation with government budgets for RES-E feed-in tariffs increasing beyond its financial possibilities may occur in a number of new MS, but as most of the schemes are only in place for a very limited number of years and most of the new Member States except Hungary and Latvia will still have to put a lot of efforts in reaching their renewable energy target.

The situation may be different when the feed-in tariffs are covered through a charge to the electricity bill. But also here, the costs of supporting RES-E may become higher than is socially or politically acceptable. E.g. autonomous electricity price increase may mean higher costs for households anyway. Introducing a RES-E surcharge on that may be difficult in such circumstances.

Some countries with feed-in tariff schemes, such as Hungary, announced that this system may be replaced by a green certificate system, so far it is not clear when this should take place. This shows that a number of countries still anticipate on a European wide green certificate system to be introduced.

The examples of the green electricity obligations with tradable green certificates in Sweden and the UK show that they come with a number of pros and cons. As the situation in Sweden shows, increase of RES-E takes place there where the costs are the lowest, which is preferable from a long-term point of view. On the other hand, the situation of new and small-scale projects in Sweden is more complicated because of the absence of long-term security (after 2010). The situation in the UK shows that as the government announced to continue with the scheme after 2010 and at least increasing the quota until 2015 means that RES-E investments become more attractive to the private sector, including financial institutions.[18]

3.3 CHP support schemes

Unlike RES-E, CHP is not supported in all the new Member States, but in six of the countries support for (high-efficiency) cogeneration is provided.

- Bulgaria has introduced a separate category within its feed-in tariff system of support for high-efficient CHP
- The Czech Republic has introduced a feed-in premium for CHP plants. In case of RES-E, the relevant RES-E feed-in tariff is combined with the feed-in premium for CHP.

[18] Despite of that UK scientists have recently called for a change of the system to feed-in system due to low performance of the current system.

- Hungary has two separate categories within its feed-in tariff system supporting CHP of capacities up to 6 MW_e. Furthermore, there is an obligatory purchase of electricity of all CHP units between 6 - 50 MW_e and of CHP units above 50 MW_e connected to a district heating system.
- Latvia has a feed-in tariff for CHP electricity. This feed-in tariff is higher when indigenous fuels (such as biomass) are used and also has to be of certain fuel efficiency as well as deliver heat to a district heating system.
- Poland has not yet a support system in place for CHP, but plans to introduce CHP certificates by 2007.
- Slovenia has introduced a separate feed-in tariff category for combined heat and power with above average efficiency.

3.3.1 CHP support in the EU15

CHP is supported in a number of EU15 countries also, but with less preferential financial schemes as is the case of RES-E. A number of schemes to support CHP are currently used in EU Member States (Ten Donkelaar & van Oostvoorn, 2005):

- Guaranteed purchase of qualified CHP electricity, a mechanism to ensure that CHP plants have the option to generate electricity and receive priority dispatch by system operators, exists in the large majority of old EU Member States (11 of 15 countries).
- Tariff support, including fixed tariffs for electricity from qualified CHP plants, fixed bonus on top of the market price for electricity and/or minimum purchase price, are used in the following EU15 countries: Austria, Belgium, Denmark, France, Finland, Germany, Luxembourg, the Netherlands, Portugal and Spain.
- Discounts or exemptions on various taxes such as energy taxes and environmental taxes are used in the following old EU Member States: Denmark, Germany and the United Kingdom. Also Finland and Sweden provide small tax relief for CHP heat.
- Capital incentives are given for certain investments in energy efficient CHP installations in the following old EU Member States: Belgium (Flanders), Denmark, Finland, Greece, Luxembourg, the Netherlands. Sweden and the United Kingdom as a form of grants and subsidies as well as tax discounts.

3.3.2 Specific country examples

3.3.2.1 BELGIUM

A wide range of regional measures exists for the promotion of high-quality CHP. Preferential treatment is given to CHP producers and their customers by awarding them eligibility in liberalised electricity and gas markets sooner than other generators and customers. CHP producers are also free to choose the supplier for any additional electricity they may need, including back-up power and, in the case of industrial CHP producers, power they cannot cover by their own generation.

Another way of supporting CHP introduced in the Belgium regions of Wallonia and Flanders is possible through specific CHP certificates, comparable to RES-E certificates. A certificate system for CHP has been first introduced in Wallonia, and since January 1, 2005 also in Flanders. The number of certificates a CHP plant obtains is dependent on the amount of thermal and electrical energy is saved compared to the situation with separate production of electricity and heat.

The Wallonia decree on electricity market liberalisation makes it possible to use green certificates to promote CHP. This is done by issuing certificates based on CO_2 emissions that are avoided when using CHP compared to the emissions that would have resulted from heat and electricity produced separately by fossil fuel-fired plants. The Flemish green certificate scheme was originally only introduced for renewable energy installations, but since January 1, 2005, (high-quality) CHP has been included.

3.3.2.2 GERMANY

The German Cogeneration Act was enacted in 2002 and developed a framework for the stranded investment arrangements for cogeneration systems threatened by competition. Under the Act, the network operators are required to buy all power produced by energy suppliers in approved CHP facilities inside their territories. The Cogeneration Act determines a fixed surcharge for electricity produced from CHP and fed into the public grid. The surcharge is added to the market price of electricity. These surcharges are reduced annually and completely phased out in ten years. Digressive, time-limited bonus payments (until 2010) to CHP operators for power fed in the grid in addition to the market price to maintain and modernise cogeneration capacity (1.74 – 0.56 ct./kWh), to encourage investment in small units (2.56 – 1.94 ct./kWh) and to aid the commercialisation of fuel cell CHP units (bonus: 5.11 ct./kWh).

In addition to the bonus payments, CHP is promoted by tax exemptions. CHP units with a maximum of 2 MW of electricity generation capacity are exempt from the electricity tax for the auto-producer's own use, and units with a minimum 70% fuel efficiency are exempt from the mineral oil tax.

3.3.2.3 THE NETHERLANDS

CHP policy in the nineties contained a variety of incentives for CHP that caused an enormous growth of the CHP capacity to about 38% of total generation capacity. Most incentives expired with the Electricity Act of 1998. Severe competition with relatively low electricity prices and gas prices has caused a slowdown in the development of CHP, and therefore the Ministry of Economic Affairs announced measures to support CHP. A temporary tax refund was introduced for co-generated power in the Regulatory Energy Tax and an investment subsidy exists for CHP with (minimum efficiency of 65%).

From July 1, 2004, the Dutch Ministry of Economic Affairs has introduced a new support scheme for CHP based on CO_2-free kWh. Under this scheme, CHP plants are compared to separate production of electricity and heat. Compared to these technologies CHP produces an additional amount of electricity with the same amount of fuel, the so-called CO_2-free electricity. These additional kWh are supported with a price premium on top of the regular market price (e.g. in 2005: 2.2 €ct/kWh). This scheme is expected to come to an end by December 2007. For the period afterwards a new scheme will be developed, most likely in the form of an investment subsidy for high efficiency cogeneration.

3.3.3 The CHP directive

The purpose of the European CHP Directive (2004/8/EC) is to create a framework for promotion of cogeneration based on useful heat demand in the internal energy market, in order to overcome still existing barriers, advance its penetration in the liberalised energy markets and help mobilising unused potentials. Implementation of the CHP Directive shall take into account the specific national circumstances, especially concerning climatic and economic conditions.

An important role of the new CHP Directive is to create a level playing field, **regulatory certainty** and, in some cases, **financial support** for cogeneration. In the medium to long-term, the CHP Directive should serve as a means of creating the necessary framework which will ensure that high-efficiency cogeneration, alongside other environmentally friendly supply options, constitutes a key element when decisions on investment in new production capacity are made.

The CHP Directive contains definitions and calculation methods and:

- Defines CHP products (CHP electricity, CHP heat, CHP fuel);
- Defines high efficiency cogeneration as compared to separate production of electricity and heat (energy savings of more than 10% obtained by combined production instead of separate production of heat and electricity);

- Requires member states to enable certification of such high efficiency CHP through a system of guarantees of origin (GO);
- Requires member states to analyse their national potential for high-efficiency CHP;
- Requires member states to outline a strategy to realise this CHP potential.

The CHP Directive does not include new quantitative targets, but instead it urges member states to carry out analyses of their potential for high efficiency cogeneration. These analyses of national potentials should in the end lead to support for high-efficiency cogeneration as far as this type of cogeneration is not able to increase its share in the electricity supply system without support.

3.4 Elements of successful support schemes

Several studies (Ragwitz *et al*, 2006) have shown that most renewable and CHP investments have been realised through a combination of support measures instead of one single instrument. Besides feed-in tariffs and quota obligations based on TGC, which are the basis of many existing renewable electricity support schemes, also capital subsidies, long-term policy support and target setting have all contributed greatly to the creation of a stable investment climate for selected technologies in almost all European markets.

Based on the experiences in several EU15 countries we could say that a feed-in tariff system has created quick results in countries like Germany, Denmark, the Netherlands and Spain. In countries with tradable green certificate (TGC) systems this is less the case, although a stable TGC system might also create a stable growth in the long run as now seems to be the case in the UK. For investors the choice of support system is not the most important, what is important is that a stable system is created for a large number of years during which long-term investments can be planned (Coenraads et al, 2006).

Both feed-in tariff systems as quota obligation systems will have to include a number of elements that ensure a stable investment climate.

- Elements of a successful feed-in tariff scheme include:
    - Tariffs should reflect long-run marginal costs of DER technologies;
    - Tariffs should be technology specific;
    - Tariffs should be stable for a number of years;
    - The scheme should be supported by long-term policy targets;
    - The scheme should be easy to administer.

- Elements of a successful quota obligation scheme
    - Quotas should be based on long-term policy targets;
    - Quotas should be set for a time-scale reflecting the investment cycle of RES projects;
    - Quotas need a system of penalties. These penalties should be well above the level of the green certificates and should also be strictly enforced;
    - The possibility of DER producers to make long-term contracts with consumers should be ensured;
    - The scheme should be easy to administer.

General conclusion / recommendation

A feed-in tariff system seems to be more suitable in countries with less developed green electricity markets such as the new member states. Such a system creates certainty to investors, which is a condition for first projects to be realised. In energy markets with more experience with green electricity a quota-based certificate system can become more suitable. As experience shows however, such a system should include elements that create long-term stability, e.g. willingness of government to maintain the system for a large number of years.

4. COMPARISON OF THE REGULATORY FRAMEWORK

The focus of this chapter is to make a comparison of the regulatory framework on DER in the ten new Member States. The comparison is composed of the following sections:

- Legal and Institutional Framework;
- Unbundling and Economic Regulation;
- DER market access; and
- DER network access.

At first, **the legal and institutional framework** will be presented, outlining the main elements of the EU policy towards DER and briefly explaining how it interacts with national policies on DER deployment and the general market conditions in the new Member States.

The section on **unbundling and economic regulation** deals with two aspects that are crucial for providing sufficient incentives for DER deployment: the *state of unbundling* describes how far national implementation has proceeded to separate the previously vertically integrated electricity undertakings both in legal and functional terms. As DER is mainly concerned with the distribution level, there will be a special focus on DSOs and the possibility for exemption. *Economic regulation* describes the kind of national network regulation in place, which affects the revenues of DSOs and therewith their incentive structure and operation philosophy.

DER market access is about the sale and market conditions for DER in the individual Member States. It focuses in particular on the possibility of getting access to the different markets, the application of notification obligations, and the imposition of sanctions.

DER network access addresses the issues of connection charging approaches, application of Use-of-System charges, and metering requirements.

The comparison in this chapter is based on the use of questionnaires completed by the SOLID-DER project partners. In order to see how and if the situation differs in the new Member States from that in the EU15, in each section short reference is made to the overall state of development in the old Member States.

4.1 Legal and Institutional Framework

4.1.1 EU Policy towards decentralised generation

The European Union (EU) recognizes the various benefits associated with the deployment of decentralised energy sources in a power system. The main drivers for promoting Distributed Generation are the common concerns "to **use primary energy as efficiently as possible**, with the **least** possible **environmental impact** whilst ensuring that **energy supply** is **secure, safe and** supplied at an agreed quality universally and at a **competitive cost**"[19]. Due to its decentralised nature and low environmental impact, distributed generation has the potential to foster the achievement of all the three main objectives of EU energy policy stipulated in the Green Paper 2006 (COM(2006) 105 final), i.e., sustainability, competitiveness, and security of supply.

So far, there has been no common European policy framework on the deployment of decentralised energy resources. DER is rather directly or implicitly included in various legal provisions and policy objectives within European energy legislation. Above all, there is the "***Internal Electricity Market Directive"*** (Directive 2003/54/EC) providing the basis for common rules for the internal market in electricity. This Directive contains essential elements for the creation of a competitive electricity market, such as unbundling provisions, Third Party Access (TPA), market opening, and general rules for the organisation of the sector. In particular, mention of distributed generation is made in Art. 6(3): the authorization procedure shall take into account the

[19] http://ec.europa.eu/research/energy/nn/nn_rt/nn_rt_dg/article_1159_en.htm

limited size and potential impact of small and distributed generation. Art. 14 of the Internal Electricity Market Directive refers to the possibility of priority access and the necessary consideration of DER in network planning.

Furthermore, distributed generation is encompassed by the "***RES-E Directive"*** (Directive 2001/77/EC) and the "***CHP Directive***" (Directive 2004/8/EC). These Directives deal with national support schemes for the promotion of electricity from renewable energy sources or combined heat and power, respectively. These national support schemes are subject to review and evaluation by the Commission. ***Directive*** 2005/89/EC concerning ***measures to safeguard security of electricity supply and infrastructure investment*** relates to distributed generation in Art. 3 (3c): Member States may also take account of "the importance of encouraging energy efficiency and the adoption of new technologies, in particular demand management technologies, renewable energy technologies and distributed generation" in implementing the measures referred to in Art. 3(1) of the same Directive for ensuring a high level of security of electricity supply.

The characteristic of a Directive is that it is "binding, as to the result to be achieved, upon each Member State to which it is addressed, but shall leave to the national authorities the choice of form and methods" (Art. 249, E.C. Treaty). This leaves a degree of freedom to the Member States in that they can choose the means to achieve the result stipulated by a Directive, thereby taking account of particular national circumstances. For example, for achieving their national indicative targets for the contribution of electricity produced from renewable energy sources, Member States may apply different support schemes, e.g., feed-in tariffs or green certificates, as long as they are in line with competition rules and Community legislation.

Finally, DER is included in a number of general EU policies and objectives, such as the meeting of the Kyoto objectives (8 per cent CO_2 reduction between 2008 and 2012 compared to 1990 level), the improvement of energy efficiency, the improvement of the security and diversity of supply, and Towards the Hydrogen energy economy, to name some examples[20]. The EU has been actively promoting research in these areas in its 5th and 6th Framework Programmes.

4.1.2 National policies on DER deployment

As the framework conditions for DER given by EU legislation are rather broad, there is substantial scope for variation at the national level regarding economic regulation, market requirements, network regulation regimes, and support mechanisms employed for DER. In addition, the Member States are facing different basic conditions, dependent on their fuel mixes, progress in liberalisation, prevalent market structures, and historical evolution of their electricity sectors. All these aspects - ***EU legislation***, ***national policies*** and the special ***characteristics of the national electricity sectors*** – are intertwined and influence the current state of DER penetration in the individual Member States.

The difficulty lies in designing the different national regimes in such a manner that they further promote DER deployment in the individual countries while avoiding market distortions and paving the way to a level playing field in the European electricity market in the long run.

In some areas important for DER, certain minimum requirements are set by Directives and EU legislation. An example is the obligation to introduce legal unbundling of DSOs by 1 July 2007[21]. However, many elements having a large impact on DER penetration, such as market access and network regulation regimes, which are at the discretion of the individual Member States. As a consequence, a large spectrum of possible combinations in national regulation approaches on DER exists. Some of them may be very favourable towards DER (e.g. market access for DER, shallow connection charges, and effective support mechanisms) whereas other combinations may have an ambiguous effect or even impede the entry of DER.

[20] http://ec.europa.eu/research/energy/nn/nn_rt/nn_rt_dg/article_1159_en.htm
[21] Yet, even here, there is room for derogation for DSOs serving less than 100,000 customers.

The following sections will elaborate in more detail on the situation in the ten new Member States with regard to unbundling, economic regulation, DER market, and network access.

4.1.3 Market Structure

The market structure at the overall electricity market in a Member State can be crucial for a successful deployment of DER. The Commission identified market structure and a lack of integration as one of the main obstacles to competition (EU COM2004/863) arising from consolidation in the electricity industry. Figure 4.1 illustrates the market share of the largest producer in each of the new Member State.

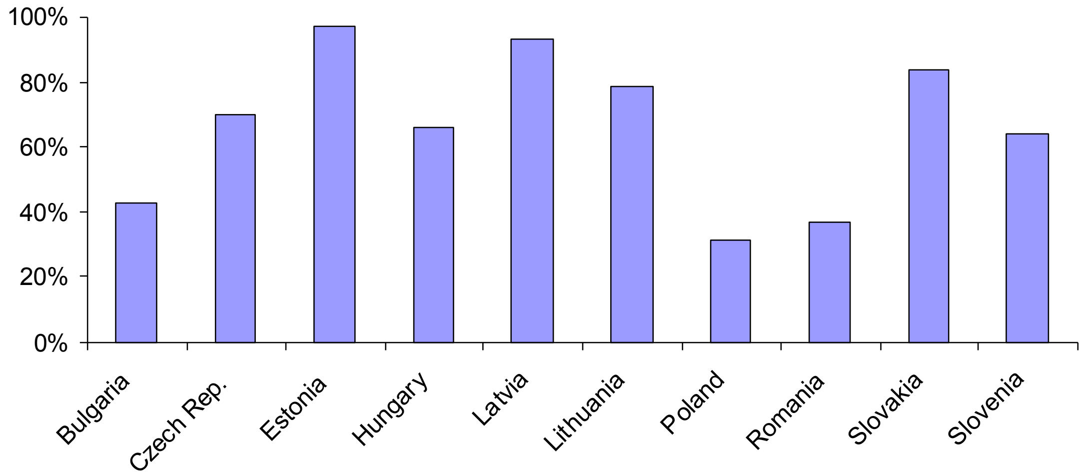


Figure 4.1 Market share of largest producer (% ownership of electricity production)

In most of the new Member States the largest producer controls more than 50% of the total power production. Solely Bulgaria, Poland and Romania, the largest producer controls less than 50%. This is very similar to the market structure of the old EU 15 Member States where solely the Nordic Member States and the UK, the largest producer controls less than 50% (DG-Grid 2005).

The market structure is often historically determined by the size of the Member State as well as by the fuel mix. Small Member States tend to have a larger concentration. Also Member States with large nuclear power stations seems to have a high concentration.

Future decommissioning of nuclear power stations will change the market shares, e.g., this will be the case for Bulgaria, Estonia, and Slovakia, which have planned to shut down some of their old nuclear power stations within the next few years.

The concentration in generation often originates from State controlled power companies. However, simultaneously with the liberalisation of the power markets also consolidations between the energy companies are seen in the individual Member States and intra-Europe.

A high market concentration might imply the use of market power which makes it very difficult for the smaller DER operators to compete on equal terms in price or quantities. Of course, the success of DER deployment also depends on issues like regulation, market and network access. These are discussed below.

4.2 Unbundling and Economic Regulation

Unbundling is the separation of the vertically integrated activities of electricity generation, transmission, distribution, and supply. Its effective implementation is one of the major preconditions to allow for non-discriminatory access to the network and therewith to the market for new market entrants. The unbundling requirements for distribution system operators (DSO) are stipulated in Art. 15 of the Electricity Directive (Directive 2003/54/EC). The new unbundling regime of the revised Electricity Directive[22] consists of four basic elements[23] as follows:

- ***Legal unbundling***: the obligation to create a separate network company;
- ***Functional unbundling***: the independency of the DSO (if it is part of a vertically integrated undertaking) in terms of its organisation and decision making from the other activities not related to distribution; minimum criteria to ensure this are laid down in Art. 15 (2) of the Electricity Directive;
- The possibility for ***exemptions*** from the provisions for both legal and functional unbundling for integrated electricity undertakings serving less than 100,000 connected customers or small isolated systems; and
- ***Accounting unbundling***: the keeping of separate accounts for DSO and TSO activities.

Member States may postpone the implementation of *legal* unbundling until 1 July 2007 (Art. 30 (2), Directive 2003/54/EC).
The possibility for exemption is not limited in time and may be of particular significance for distributed generation. More explicitly, the exemption may present an entry barrier for new DER operators that wish to get access in a network area operated by a vertically integrated undertaking that is not subject to the unbundling obligations. This could be for example the case for DER deployment in rural areas where there are small DSOs serving less than 100,000 customers.

It is in the discretion of the individual Member States to decide whether they apply this exemption or not. The eventual impact of the application of this exemption depends on the number of DSOs with less than 100,000 customers in the particular Member State and the percentage of connections that fall into this category.

Table 4.1 depicts the current state of unbundling (from accounting over management to legal unbundling) as well as the application of the exemption in the ten new Member States.

Three of the new Member States have implemented legal unbundling so far: Lithuania and Estonia fully, and Hungary partially. The remaining of the new Member States have mostly implemented the stage of accounting unbundling at present. No concluding statement can be made at this point in time, though, as most of the new Member States are still in the transition phase and will adopt legal unbundling at the latest by 1 July 2007. It will first be then that the implementation by law and in effect can be evaluated.

Table 4.1 also reveals that the exemption clause has been adopted in most of the new Member States. This implies that most of the new Member States use the full scope of derogations provided by the Electricity Directive both in terms of deadlines for implementation and in terms of exempting DSOs. This is a general observation of the implementation of unbundling at the distribution level which is true for the whole EU (cf. EU COM (2005) 568, p. 12, and Commission of the European Communities (2005), p. 79f.).

[22] Unbundling provisions have been extended in Directive 2003/54/EC compared to the repealed Directive 96/92/EC.
[23] Cf. Note of DG Energy & Transport on Directives 2003/54/EC and 2003/55/EC on the Internal market in Electricity and Natural Gas. The Unbundling Regime. 16.1.2004. pp. 1ff.

Table 4.1 Unbundling and economic regulation of DSO in the new Member States

	Unbundling	Exemption	Economic regulation[24]
Bulgaria	Accounting/Management*	Yes	R / C
Czech Rep.	Accounting*	Yes	R
Estonia	Legal	Yes	P
Hungary	Legal (partially)	No	P
Latvia	Accounting*	Yes	P
Lithuania	Legal	Yes	P
Poland	No Unbundling of DSO*	No	R
Romania	Accounting*	Yes	P
Slovakia	Accounting*	Yes	P
Slovenia	Accounting*	No	P

* Legal unbundling soon to be implemented (between end-2006 and 1 July 2007, dependent on date of national transposition of unbundling provisions).

In the old EU15, around one third of the Member States has not implemented legal unbundling at the distribution level yet (DG-Grid 2005). Furthermore, many of the old Member States still lack the adoption of the requirements of functional unbundling even though these are required to be in place by now (Commission of the European Communities (2005), p. 80). Effective unbundling at the distribution level thus seems to be rather problematic across the whole EU. The overall situation at the distribution level was deemed as rather "less encouraging" by the Commission (ibid). Eight of the old EU15 Member States have already introduced legal unbundling of DSOs (DG-Grid 2005). In six countries there has only been accounting or management unbundling so far. In Greece there has been formal unbundling, but the single national grid operator (=TSO+DSO) is strongly bound to the single national utility PPC.

Interestingly, in the three Member States with the highest shares of distributed generation, namely Denmark, the Netherlands, and Spain, legal unbundling is already in place

One of the major problems in relation to unbundling is its *implementation* by law and in fact. Officially, the majority of the old EU-MS has implemented legal unbundling. In order to analyze the effectiveness of legal and functional unbundling, the European Commission identified six features that should be expected to be in place, such as separate headquarters for the system operator, a separate corporate presentation, unbundled regulatory accounts, audit of unbundled accounts, publication of unbundled accounts, and a separate board of directors (Benchmarking Report 2005, Technical Annex, p. 78f.). The Benchmarking Report reveals that in none of the old MS all these features have been implemented. Furthermore, only two of the old MS, the UK and Belgium, fulfil five of the above-mentioned features. On the whole, the Commission finds the situation of unbundling for distribution "rather less encouraging" (ibid, p. 80).

In some of the old MS, there are even only one or none of the above-mentioned features in place. E.g., Greece has not implemented legal unbundling at the distribution level so far, and the only requirement met is unbundling of accounts (ibid). Despite the legal provision of third party access, formal unbundling of the previously integrated operations, and the creation of an independent TSO, the incumbent PPC still controls electric production, transmission, and distribution. Since PPC lost its legal monopoly, the Greek government has issued licenses for over 2.750 MW of private thermal generating plants, but most private producers have not been able to finance new plants[25]. In April 2006 the Commission sent out letters of formal notice to 17 MS for failure to transpose the Directives on the internal market or for failure to apply them properly. In this connection, legal action has also been taken against Greece in relation to unbun-

[24] P = price cap, R = revenue cap regulation, C = Cost plus regulation.
[25] Cf. Energy Information Administration, Country Analysis Briefs, http://www.eia.doe.gov/emeu/cabs/Greece/Electricity.html

dling: Greece received a letter of formal notice for Directive 2003/54/EC and 2003/55/EC for the absence of or insufficient legal and management unbundling of transmission and distribution system operators in order to guarantee their independence[26]. Of the old MS, legal action for insufficient unbundling at the distribution and/or transmission level in the electricity sector is furthermore taken against Finland, France, Ireland, Italy and Sweden.

Economic regulation

The DSOs provide system and transport services for which they are remunerated via Use-of-System charges, connection charges, energy charges and the like, subject to the national network regulation in place. It is the task of Member States to ensure that the tariffs applied are non-discriminatory and cost-reflective (cf. Art. 14, Art. 20, Directive 2003/54/EC). Several kinds of network regulation approaches can be differentiated: cost-plus regulation, price cap regulation, revenue cap regulation, and yardstick regulation. Price cap and revenue cap fall under the group of incentive-based regulation schemes. Incentive regulation means that "the regulator delegates certain pricing decisions to the firm and that the firm can reap profit increases from cost reductions" (Vogelsang (2002), p.6), thereby making use of the firm's information advantage and profit motive (ibid). The formula for defining the cap typically comprises three elements: a factor for inflation adjustment, an X-factor for productivity/efficiency adjustment of the firm, and special adjustment factors for costs that are passed through (e.g., to the consumer as a tax) (cf. Vogelsang (2002), p.8 and Ackermann (2004), p. 182f.). Yardstick regulation goes further in that the regulator caps the price based on the average cost level of companies with similar demand and cost functions (Ackermann (2004), p. 185). Hence, the latter provides a high inducement for the DSOs to improve their efficiency.

At present, price cap regulation is the scheme mostly used within the new Member States, namely in seven out of the ten Member States. In three countries, revenue cap regulation is applied. An interesting example is the case of Poland, where incentive regulation has been implemented since 2002. The developed legislation allows energy companies to reduce the consumption of fuels and energy by customers through co-financing RES projects. At this moment, no explicit benefits have been reported associated with this mechanism (see Polish case study in Annex 1) [27].

4.3 DER Market Access

Demand for DER and market access are presuppositions for successful deployment of DER. National purchase and support mechanisms aim at fostering market penetration of DER in order to enhance their competitiveness towards conventional and large electricity generators. In most new Member States power from DER is mainly sold on basis of regulated purchase obligation schemes, e.g. feed-in tariffs (Table 4.2). Romania has introduced a green certificate scheme. This is also the case for Poland, but here the green certificate system is combined with regulated purchase obligations.

In spite of the extended use of regulated purchase obligation a relatively high share of the new Member States gives DER access to wholesale markets. One explanation of this is that the regulated purchase obligation includes feed-in premiums in addition to the market price. Though market access is given, in some of the Member States the access is restricted by minimum sales of a certain amount, e.g. minimum of 1 MWh. This limits small DER units' access of the wholesale market.

[26]http://europa.eu.int/rapid/pressReleasesAction.do?reference=MEMO/06/152&format=HTML&aged=0&language=EN&guiLanguage=en

[27] Such possibility given by the law-maker is a guarantee for the energy companies planning development of new technologies to get a refund for their actions towards the RES development. It also gives the opportunity to support the power system through financing polish science. The development of new technologies will surely lead to the smaller investment cost followed by the growth of economic profitability of such investments. It is clear that this mechanism is applied to companies that are responsible for bundled regulated activities such as distribution, retail, and generation.

Access to wholesale markets facilitates a future introduction of market based instruments. In the old EU 15 regulated purchase obligations with fixed prices (e.g. feed-in tariffs) have been very effective in promoting DER. However, there is a trend towards marked based mechanisms, e.g. price premiums, where the support follows the demand for power.

Table 4.2 Sale conditions and access to wholesale markets for DER.

	Sale of DER-E	Access to wholesale market
Bulgaria	RPO	Yes
Czech Republic	RPO	Yes
Estonia	RPO	Yes
Hungary	RPO	No
Latvia	RPO	Yes
Lithuania	RPO	Yes
Poland	GC, RPO	No
Romania	GC	Yes
Slovakia	RPO	Yes
Slovenia	RPO	Yes

RPO = Regulated purchase obligation; GC = green certificates;

An explanation of this trend from regulated purchase obligations towards marked based mechanisms is that the wholesale power market gets too inflexible when a large share of the power production is sold outside the market at fixed tariffs.

Denmark, one of the old MS with a high share of DER, is a good example of a MS that have adjusted their support schemes and access to the wholesale market in accordance with the increasing share of DER. Until 2005, all DER had priority access to the network and were given fixed feed-in tariff per delivered kWh. The decentralised CHP-plants for district heating had a fixed time dependent feed-in tariff with three time steps. Almost all of them have heat tanks with storage facilities, which make the production more or less independent of the fluctuations in the daily heat demand; therefore, they optimised their revenue by producing in the high tariff periods. The share of decentralised CHP is relative large in Denmark, which meant that a relative large of the total power production were made according to the tariff structure. In periods with good windy conditions, the supply from CHP and wind created excess supply situations, which were very costly for the DSO.

Recognising that CHP with heat tanks are controllable technologies that can adjust their short-term supply, the tariff structure in Denmark was changed in 2005 and the CHP were given market access to the wholesale power market. The tariff structure for CHP now follows the supply through the spot market prices by a price premium. This gives the CHP operators incentives to lower the controllable part of their production when there is excess production (low supply market prices) and increase their production when there is excess demand.

This case with market access and change in tariff structure have created a much more functioning DER supply market with less total costs connected to excess supply or demand in Denmark. The non-existence of a common EU support mechanism for DER implies that the economic conditions for DER differ between the Member States. This gives more incentives to deploy DER in Member States with gentle support systems, than to deploy in areas with DER resources or excess demand for power, e.g., if a windmill is deployed in a wind calm area with high support, instead of in a windy area (DG-Grid 2005). This is not efficient for the EU as a whole.

Some DER technologies have more or less uncontrollable production of power, e.g. wind turbines producing according to local wind conditions. This can be a disadvantage for such DER if the market access gives preferential treatment to controllable production. Uncontrollable and unforeseen fluctuations in the power production might cause higher balancing cost in the system in order to remain the overall network balance between supply and demand. In order to adjust the rest of the supply, the system operator might therefore require that DER units notify how much production they are planning to make within the next short period of time.

Table 4.3 summarises the notification obligations and access to balancing markets in the new Member States. In most new Member States DER-operators are not obliged to notify the system operator in advance of how much electricity they will generate. Solely the Czech Republic, Hungary, Lithuania, Poland and Slovakia, planned DER has to be reported. The numbers of hours in advance that the notification has to be given differ a lot. For DER with short-term fluctuations a long notification time can cause large deviations from the planed production which can be very costly if the DER producer is sanctioned for the deviations. Only Polish DER and some Czech DER producers are sanctioned for deviating from the planned production. In Slovenia only DER larger than 1 MW has to participate in the hourly balancing market. These plants can be part of a balancing group (see case study, Annex 1) [28].

Table 4.3 Notification obligation and access to balancing markets

	Notification of DER	**Sanctions**	**Access to balancing market**	**DER active part of generation reserve**
Bulgaria	No	No	Yes	No
Czech Rep.	1 day	Yes	Yes	No
Estonia	No	No	No	No
Hungary	1 day	No	Yes	No
Latvia	No	No	No	No
Lithuania	1 week	No	No	No
Poland	2 days	Yes	No	No
Romania	No	No	No	No
Slovakia	1 day	No	No	No
Slovenia	No	No	Yes	Yes

It might only be some of the DER producers in a Member State that have to notify the system operator and that are sanctioned if they do not deliver the notified amount. An example is the Czech Republic where DER producers with capacity of more than 1 MW (except for small hydro, wind and PV – remaining is biomass, biogas, and small CHP independently of fuel) have notification obligation of the production sum for 1 month (15 days ahead), 1 week as hourly curves (1 week ahead) and detailed and updated 1 day data (1 day ahead). In case that this volume is not available the sanctions are reduction of the remuneration by 20% if deviation is +10% or -15%.

Four of the new Member States give DER-operators direct access to the balancing market, i.e. they can submit bids to the balancing market. However, also at the balancing market, access is often limited to a minimum capacity, which virtually limits the DER use of the markets. In addition, a special case is the one of Hungary, where different time-zone feed-in tariffs have been implemented in order to decrease controllable DER production during valley hours. Feed-in tar-

[28] The task of calculating and charging for balancing the deviations of the supply and consumption of electricity is assigned to the Electricity Market Operator. Deviation amounts and financial calculation of the deviations are established on a monthly basis. The calculating interval is one hour. The parties subject to balancing are joined into balancing groups and sub-groups. A qualified producer can also be a part of a balancing group or a sub-group. Qualified producers that produce energy in micro power plants (installed power less than 36 kW) and small power plants (installed power between 36 kW and 1 MW) do not have to announce their production. They do not pay the sanctions for energy deviations.

iffs in valley hours are lower than the variable cost of some controllable DER technologies. This regulating mechanism allows having an efficient generation dispatch. If this type of mechanism is not implemented, in valley hours there would be surplus of energy production because of the must-run constraints of some base load plants (see case study of Hungary in Annex 1).

Capacity payments or capacity credits and obligations have been implemented in some markets to assess generators contribution to the reliability margin in the system (long-term security of supply). Usually they are proportional to the installed capacity and its availability to supply the peak demand of the system (firm MWs). The capacity payments or capacity credits are usually implemented for centralized generators. None of the new Member States have implemented capacity payments for DER. In the old EU 15 Member States capacity payments for DER are used in several Member States (DG-Grid 2005).

The economics of DER can be improved if they are active in providing ancillary services. However, solely Slovenia, DER-units are active part of the generation reserve when the units are in operation, i.e. generation capacity regulation to the disposal of the system operator. In most of the NMS, as it is reported for Bulgaria in Annex 1[29], DER units are usually not considered by the System Operator as ancillary services providers. The intermittent production and the small size of these units, together with current low penetration levels, justify this practice.

The limited access for DER to wholesale and balancing markets in the new Member States, compared with the old EU 15 Member States, have to be seen in the light that most electricity markets in new Member States are relative young, are still under construction or are in transition. In many of the old EU 15 Member States the markets have existed for decades, which have given these Member States time to adjust their support systems and market access conditions.

This is also reflected in the widespread use of regulated purchase obligations (e.g. feed-in tariffs) in the new Member States. Whereas some of the old EU 15 Member States have had time to adjust their support schemes to more market based systems, e.g. price premiums and quota systems in connection to their wholesale markets.

4.4 DER Network Access

Fair and non-discriminatory network access is one of the main requirements for an increase in distributed generation. New network users have to pay a charge to obtain a connection to the existing network. Three different kinds of ***connection charges*** can be distinguished: shallow, deep and shallowish charges. Shallow connection charges encompass only the direct costs of connecting the DER producer to the nearest point in the distribution network. Additional costs for network reinforcements and upgrades are socialized among the grid users. By contrast, deep connection charges imply that all the costs for network reinforcements both at the transmission and distribution level have to be borne by the DER producer. Shallowish or mixed connection charges constitute a hybrid of the two former approaches: they include direct connection costs and costs for reinforcements at the distribution but not at the transmission level.

The connection charging approach can be of great relevance for DER producers trying to penetrate the market. There is a trade-off between providing incentives for the optimal and cost-reflective siting of new generation capacity (deep connection charges) and facilitating entry for small-sized DER operators (shallow connection charges) for whom these charges may otherwise present substantial capital costs. Shallow connection charges encourage the entry of DER producers, however, may seem less attractive for DSOs. The latter may recover the arising addi-

[29] The Operators prefer to conclude long-term contracts for ancillary services with generators in good technical condition, having larger single installed capacity, higher availability and lower operational costs. The DER generation which cannot be forecast strictly makes these power plants unsuitable for ancillary services participation. At present the participation of non-controllable DER units in the generation system is very slight, but in the future with the increasing of the DER share and availability it will be necessary to include DER units as part of ancillary services. Only after the feed-in tariff system is cancelled and a green certificate trading scheme is introduced, it will be possible for the costs related to DER ancillary services to be clearly identified.

tional costs for network reinforcements, e.g., through Use of System (UoS) charges or by other means, dependent on the kind of network regulation in place. The connection charging approach thus has to be considered in the context of the design of the economic regulation prevalent in the individual Member States.

Table 4.4 Metering and network charges in the new Member States

	Metering required	Connection charges	System charges
Bulgaria	Yes	Shallow	Yes
Czech Republic	Yes	Shallowish	No
Estonia	Yes	Deep	No
Hungary	Yes	Shallow	No
Latvia	Yes	Deep, Shallowish	No
Lithuania	Yes	Deep, Shallowish	No
Poland	Yes	Shallowish	No
Romania	Yes	Deep	No
Slovakia	Yes	Deep	No
Slovenia	Yes	Shallow	No

Table 4.4 shows the most used charges. However, these often depend on the size, technology and source of energy. Therefore, the actual charges can differ within a Member State.

There is a great variation in the connection charging philosophies implemented in the new EU Member States, and no dominant approach can be found. Three Member States have introduced shallow connection charges, two Member States shallowish charges, another two Member States use both deep and shallowish charges, and three Member States apply the deep charging approach.

In the old EU15 Member States, the connection charging methodologies currently in place differ just as much, ranging from deep over shallowish to shallow, regulated charges. However, here around half of the Member States apply Use-of-System charges (DG-Grid 2005) so such component is more common than in the new Member States.

Metering requirements play also an important role for the promotion of DER. In the new Member States; metering requirements have been established in all of the old Member States. The same is true for the old Member States (DG-Grid 2005).

4.5 Final regulatory comments

Most electricity markets in the new Member States are relative young, are still under construction or are in transition. In addition, the Member States are facing different basic conditions, dependent on their fuel mixes, progress in liberalisation, prevalent market structures, and historical evolution of their electricity sectors.

It takes time to change the basic conditions and hence to change the regulatory framework. However, major changes can be noted in the regulatory framework, e.g. the unbundling process of the DSO towards legal unbundling (Table 4.1) and although DER is mainly sold through regulated purchase obligation schemes, access of DER electricity to wholesale markets is already realised in the majority of the countries (Table 4.2).

There is no generic strategy towards common framework conditions, in the new as well as in the old Member States, since the framework conditions for DER given by EU legislation are rather broad. This gives substantial scope for variation at the national level regarding economic regulation, market requirements, network regulation regimes, and support mechanisms employed for DER.

The difference in the national regulatory framework conditions implies that the economic conditions for DER differ between the Member States, e.g. with respect to connection charges (Table 4.4) and sale and balancing conditions (Table 4.3). This gives more incentives to deploy DER in Member States with gentle support and connection systems, than to deploy in areas with DER resources or excess demand for power. At the overall EU level the non-existence of common EU regulatory framework conditions for DER might implies an economic in-efficient deployment.

Many of the present barriers for further integration of DER may be seen as temporary barriers due to the time lag of changing the systems. Nevertheless, a number of major barriers remain towards increased and large-scale integration of DER. Examples are regulatory barriers in the form of complex network access procedures and lengthy spatial planning procedures.

5. COSTS AND BENEFITS OF DER PENETRATION

In this section, several issues regarding potential costs and benefits related with the integration of DER are presented. First, costs and benefits for DSOs are analyzed. Second, some business models examples for DER are presented. And third, socio-economics benefits are classified in terms of: i) creation of employment, ii) GHG emission reductions and other environmental benefits, and iii) other aspects such as energy security, impact on final electricity prices, and R&D and technology development. Results obtained from the national reports are summarized and compared in each one of the previous issues. In addition, comparisons with the EU-15 MS situation are also provided.

5.1 DSO costs and benefits

In general, the integration of DER in distribution networks requires new investments both on new network reinforcements and more sophisticated operational and management procedures. The consequence is that both DSO capital expenditures (CAPEX) and operational costs (OPEX) will increase. There are different impacts of DER on DSO costs (DG-GRID, 2005):

- CAPEX in the short-term will increase in order to accommodate DER connections. New network installations and reinforcement of existing facilities will be needed. In addition, new measurement, control and communication equipments for active supervision and management of DER units will be required.
- CAPEX in the medium and long-term will potentially decrease. Integration of DER in lower voltage levels might lead to benefits associated with postponing network reinforcements in higher voltage levels, subject to certain conditions such as: (i) the probability of DER production at peak load periods, and (ii) the permanence of DER installations in the long-term.
- OPEX due to transaction costs will increase. DSOs have to handle new contracts with DER operators. In addition, extended data management and balance accounting systems will be required.
- OPEX due to more sophisticated management of the network will increase. DSO management is based on simplicity and equipment standardization, to lower as much as possible OPEX. DER integration means higher complexity. DER are new elements connected to the network that impose new network design criteria, and new operating situations.
- Network energy losses can increase or decrease. DSO is responsible to reduce as much as possible network energy losses. Usually, DSOs have economic incentives associated to this objective. Integration of DER impacts on network energy losses. Lower levels of DER penetration may reduce original network energy losses, however higher levels of DER can produce the opposite effect.

Because DSO is mainly a regulated business, it is clear that some explicit incentive mechanisms should be designed to compensate DSO for these additional costs associated with DER integration.

According to a comparison study carried out under the DG-GRID project (DG-GRID, 2005), most of the EU-15 MS do not have implemented explicit regulatory mechanisms to tackle this problem. One important exception is the case of the UK. Explicit economic incentives for connecting DER are recognized to DSOs, mainly expressed as revenue per connected DER capacity unit. In addition, Registered Power Zones (RPZs) is another mechanism intended to encourage DSOs to develop and demonstrate more cost effective ways of connecting and operating DER. Finally, the Innovation Funding Incentive (IFI) is intended to provide funding for DSO projects focused on the technical development of distribution networks.

The situation of NMS regarding the impact of DER on DSO costs and benefits is summarized in Table 5.1. In most NMS, DSOs are compensated for short-term CAPEX increments, including network reinforcements and new investments in measurement and control equipment. This compensation usually comes from connections charges where most of the countries use shallow or shallowish charges, see section 4.4, or through the calculation of new use of system charges in the next control price process. In general, cost increments will be recognized in the following control price process where estimated CAPEX and OPEX will be set by the Regulator for the next regulatory period.

On the other hand, there is no explicit recognition for potential long-term CAPEX benefits. Because current DER penetration levels are very low in most of the countries, it seems that the DER installed capacity is not enough to improve system adequacy and to postpone network investments. Moreover, DSOs feel that DER cannot yet be relied on for network planning.

Increment of operational costs due to higher transaction costs are considered in most NMS when setting tariffs in each price control process. Data management is usually included, as any other administrative cost, when calculating use of system charges.

Explicit incentives for DSOs to promote innovation in new active networks have not been implemented in any NMS.

In general, regulations set DSOs as responsible for losses reduction in their networks. However, explicit compensation mechanisms for losses variations due to DER connections are not implemented in any NMS yet.

Table 5.1 Recognition of DSO CAPEX and OPEX variations due to DER connections in NMS

Country	Recognition of DSO CAPEX variations due to DER			Recognition of DSO OPEX variations due to DER		
	Short term network investments	control & measurement equipment	Long-term network investments	transaction costs	active network innovations	energy losses variations
Bulgaria	Yes	Yes	No	Yes	-	No
Czech Republic	Yes	-	No	Yes	-	No
Estonia	-	-	-	-	-	-
Hungary	Yes	Yes	No	Yes*	No	No
Latvia	-	-	-	-	-	-
Lithuania	Yes	Yes	No	Yes	No	No
Poland	Yes	Yes	No	Yes	No	No
Romania	-	-	-	-	-	-
Slovakia	Yes	Yes	No	Yes	-	No
Slovenia	Yes	Yes	-	Yes	-	-

5.1.1 DER compensations for benefits produced to DSOs

As it has been discussed in the previous section, DSOs may obtain benefits from the connection of new DER, for example, reduction in line losses, or less reinforcement costs. Therefore, it is economically efficient to compensate DER connections when they produce such benefits. According to the conducted survey, only the Czech Republic has implemented a compensation system based on bonus to DER per injected kWh. The bonus is higher for DER connections at low voltage networks, and gradually decreases for DER connections to medium and high voltage networks (see case study of Czech Republic in Annex 1) [30].

5.2 DER Business models

One important issue on DER integration into energy networks is how to make it economically sustainable beyond their research and development stage. This issue has been already studied in other European projects, such as BUSMOD and DISPOWER, and currently under the FENIX project. This section presents two successful experiences on DER business models in EU-15, which can help NMS to improve the integration of DER in their own countries. The objectives of these two pioneer projects were to integrate DER into the energy market. These projects are the PUDDEL project promoted by Energinet in Denmark, and the CORE project developed by Iberdrola in Spain.

5.2.1 The PUDDEL project

The PUDDLE Project has been developed by ENERGINET.DK (PUDDEL, 2005). It is a pilot project for development and demonstration of operation support tools and communication tools for distributed electricity production in a deregulated electricity market.

In the power sector in the western part of Denmark there is a high demand for regulating services due mainly to the increase of wind power generation. Energinet.dk has detected great opportunities in preparing the distributed CHP plants for the supply of regulating power and other system services for the power sector.

The object of the PUDDEL project was to develop operation support tools for balance responsible market players and their portfolio of CHP plants. Moreover, new communication standards/tools and IT systems had to be developed, see Figure 5.1. The project was also aimed to provide an evaluation of the market potential of distributed CHP plants. The PUDDEL project came to include 30 very different distributed CHP plants, and a total of 6 balance responsible market players took part in the project, 5 of which were involved throughout the whole project.

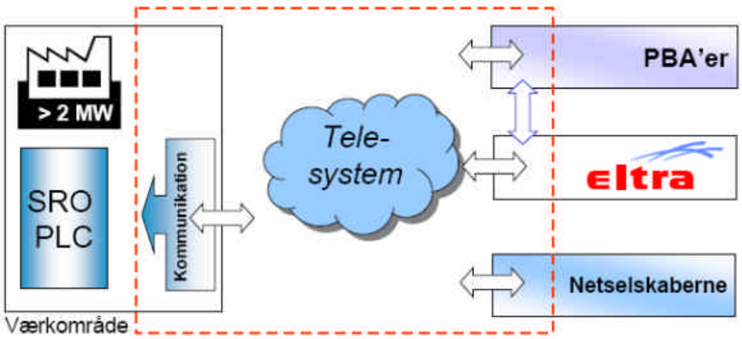


Figure 5.1 PUDDEL Project scheme

[30] The Price Regulation No. 14/2005 sets prices of electricity and relevant services introduced fixed bonus for distributed generation which should be paid by the regional power distribution company. Given bonus are charged in addition to feed-in tariff (in case of RES-E) and/or bonus (RE-E and CHP). The bonus is set as follows:

a) Producer connected to very high voltage distribution network (110 kV) charges regional distribution company according to contract 20 CZK/MWh (€0.65/MWh) per each MWh supplied to the grid based on measured quantity.
b) Producer connected to high voltage distribution network (more than 0.5 kV and less than 110 kV) charges regional distribution company according to contract 27 CZK/MWh (€0.9/MWh) per each MWh supplied to the grid based on measured quantity.
c) Producer connected to low voltage distribution network (0.5 kV and less) charges regional distribution company according to contract 65 CZK/MWh (€2.2/MWh) per each MWh supplied to the grid based on measured quantity.
d) In case of flow of electricity from the local power distribution network to regional distribution network the operator of the local distribution network according to contract charges regional distribution company according to contract bonus as given under a), b) and c) whichever is relevant.

5.2.2 CORE

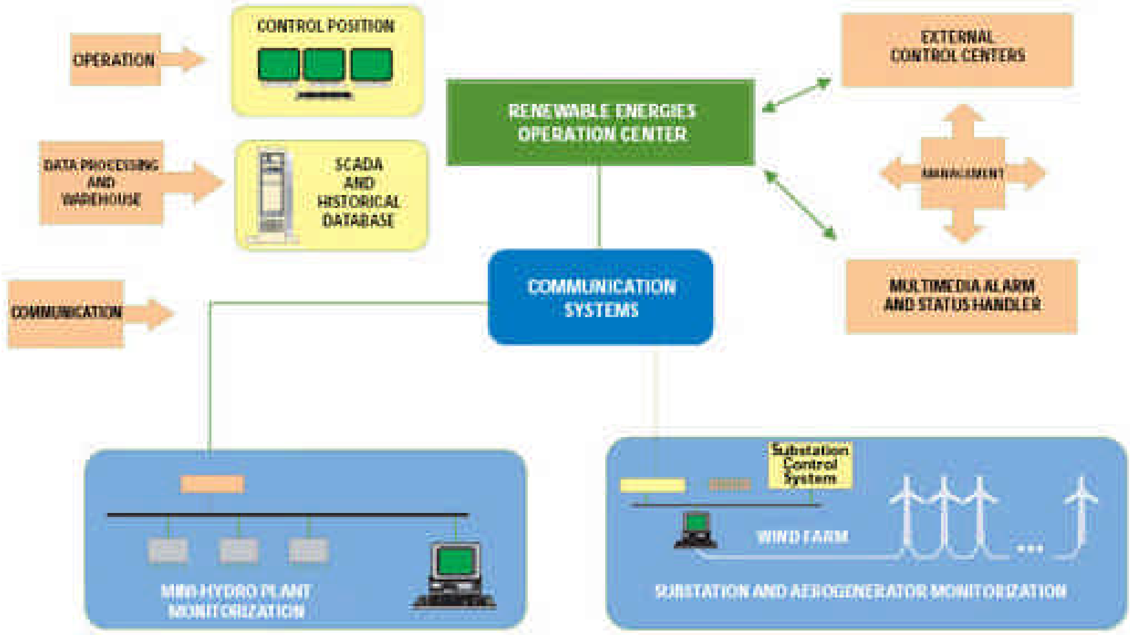
CORE stands for Renewable Energies Operating Centre, which is owned by Iberdrola, a major power company in EU. The centre is located in Toledo, Spain, and it is a pioneer project in the energy industry, both for its state-of-the-art technology and for its operational capacity and scope. CORE remotely monitors the company's renewable energy generation assets, and was designed to optimize the technical management of renewable energy facilities, and improve its economic performance.

Figure 5.2 IBERDROLA's Renewable Energies Operating Centre (CORE)

CORE controls all wind farms, small hydro plants and sub-plants, both those operated by IBERDROLA and by other companies, 24 hours a day, 365 days of the year. Currently the CORE manages wind parks located in Brazil, France and Portugal, and plans to include all its overseas facilities, totalling 304 MW.

The operation system of CORE collects the main operational information from generators and their associated substations from their own controllers (see Figure 5.3). These control systems are connected to the CORE through remote communication channels. One main service from the CORE is that it facilitates maintenance tasks, increasing the availability of the different assets.

Figure 5.3 CORE operation system



The CORE has additional operation and control services, such as: monthly reporting of generated energy, energy invoicing to the distribution utility, and multimedia alarm and status control. Advanced services can also be provided by CORE, including video surveillance of facilities, prediction of energy generation based on weather forecasts, and advanced energy management to improve system stability and energy quality (generation prediction and reactive power control).

5.3 Socio-economic benefits

The development of DER improves security and diversification of energy supply and its environmental impact, and promotes a sustainable socio-economic development of the society.

5.3.1 Employment

Studies on the impact of renewable energy on employment demonstrate that renewable energy technologies have the potential to generate new employment. This is because DER production is more labour-intensive than conventional energy production. During operation, it also uses less imported goods and services since renewable energy sources are mostly local. For example, biomass technologies contribute to stimulate the employment not only on the agriculture sector (planting and harvesting) but also on the regional industry.

An EU-wide study carried out in 1999 estimated that renewable energy has the potential to create over 900,000 new jobs by 2020, including 515,000 jobs in agriculture and biomass fuel supply. Already a number of countries are achieving high employment levels from renewable energy activities, particularly in the wind energy industry. Some examples are Germany and Spain, where 25,000 and 30,000, respectively, new direct and indirect employments have been created (ECOTEC, 2002) (VBPC, 2006). Another example is Austria, where the number of jobs (full time equivalent) created by the manufacture and installation of renewable energy technologies was 13,600. Additionally, 19,100 new jobs were created for the operation of these plants (EEG, 2006).

According to the survey conducted for the NMS, in most of these countries the current contribution of DER to the development of new employment is low. Czech Republic and Hungary estimate that DER will lead to the creation of new jobs, both for engineers and technicians working on development and maintenance of DER installations. First column of Table 5.2 shows the different levels of impact of DER development on the creation of new jobs in the NMS.

Table 5.2 Socio-economic benefits from DER in NMS

Country	DER contribution to new jobs	DER part of CO_2 reduction	Development of JI projects with DER			Other environmental benefits
			JI projects?	Number	CO_2 emissions reduction	
Bulgaria	Low	High	Yes		285kt/year	Meeting SO_2 and NO_X requirements
Czech Republic	Medium	Medium	Yes		220kt/year	Reduction of SO_2 and NOx
Estonia	-	-	Yes	21	100kt/year	-
Hungary	Medium	Medium	Yes	36	1,700kt/year	-
Latvia	-	Low	Yes	27	100kt/year	-
Lithuania	Low	-	Yes	9	69kt/year	-
Poland	Low	-	Yes		-	-
Romania	-	-	Yes		-	-
Slovakia	Low	Medium	Yes		not statistically differentiated	Reduction of SO_2 and NOx
Slovenia	Very low	Medium	No		-	-

5.3.2 Environmental benefits

Fossil fuel based power generation is responsible for the emissions of greenhouse gases, such as CO_2, SO_2, NO_X, CO and dust. In the Kyoto Protocol, industrialized countries agree to reduce their collective emissions of greenhouse gases by 5.2% compared to the year 1990. National targets for emissions range from 8% reductions for the European Union to 10% increase for Iceland (see Table 5.3).

Table 5.3 Countries included in the Annex B to the Kyoto Protocol and their emissions targets

Country	Target (1990-2008/2012)
EU-15, Bulgaria, Czech Republic, Estonia, Latvia, Liechtenstein, Lithuania, Monaco, Romania, Slovakia, Slovenia, Switzerland	-8%
United Stated	-7%
Canada, Hungary, Japan, Poland	-6%
Croatia	-5%
New Zealand, Russian Federation, Ukraine	0
Norway	+1%
Australia	+8%
Iceland	+10%

Source: "A more perfect Energy Union", IEEE Power & Energy Journal, Vol. 4, N. 4, July/August 2006.

The protocol allows those countries with carbon liabilities to acquire carbon credits to help to meet targets through three flexibility mechanisms, i) Joint Implementation (JI) projects, ii) Clean Development Mechanism (CDM), and iii) emission trading.

Joint Implementation allows a country to meet part of its emission reduction target by carrying out a project to reduce greenhouse gas emission in another Annex B country. The clean development mechanism is similar to the joint implementation, but emission reduction projects should be constructed in non-Annex B countries. In 2002, the European Union created a system of emissions trading in an effort to meet these emissions reduction targets. In addition, there exist fines for those member nations that fail to meet their obligations.

DER development based on renewable sources, more energy efficient cogeneration and polygeneration plants, and the conversion of fuel and coal traditional power plants into biomass plants can positively contribute to the reduction of CO_2 emissions.

According to the last report on “Greenhouse gas emission trends and projections in Europe” from 2005 (EEA, 2005) domestic policies and measures up to 2003 were not sufficient for most of EU-15 Member States to be on track to meeting their emission targets. Greenhouse gas emissions in 2003 of most Member States were above their hypothetical target paths from their base-year emissions to their 2010 targets (see Figure 5.4 below and note). On the other hand, nearly all the New Member States and candidate countries are projected to meet with their Kyoto targets by 2010 using existing domestic policies and measures.

As it is shown in the second column of Table 5.2, the current low penetration levels of DER involve just low or moderate CO_2 emission reductions. Part of this reduction is coming from the participation of all NMS, except Slovenia, in different JI projects, together with other partner countries (Sweden, Germany and Netherlands). These projects allow reductions on emissions, which vary from 69kt/year to 3,180kt/year. For example, a reduction of 15.9Mt in 5 years due to JI applications is totalized in Hungary.

Apart from CO_2 emissions reduction, DER development also contributes to the reduction on other greenhouse gases, such as SO_2, NO_X, CO and dust. In Czech Republic and Bulgaria, these reductions have helped to meet the requirements on greenhouse emissions. For example, the Czech Republic estimated a reduction in emissions of SO_2 by 1,800 ton, and NO_X by 1,240 ton by the year 2010 as compared to the base year 2000.

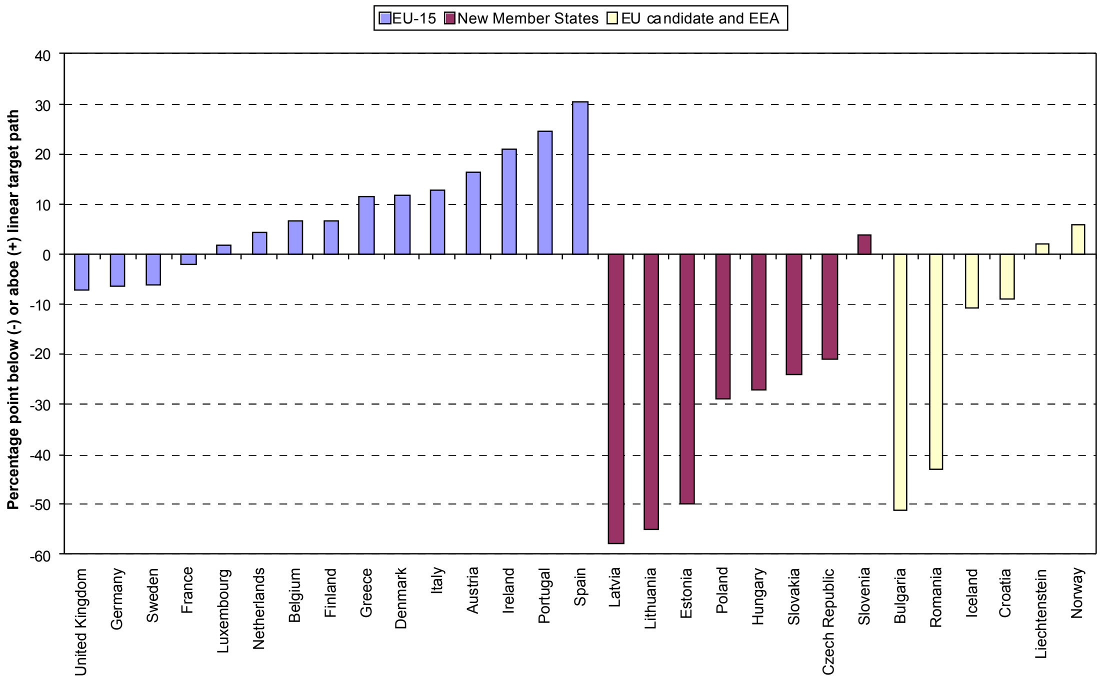


Figure 5.4 Distance-to-target (Kyoto Protocol) for all European countries in 2003[31]

[31] The distance-to-target indicator (DTI) measures the deviation of actual emissions in 2003 from a (hypothetical) linear path between base-year emissions and the burden-sharing target for 2010. A positive value suggests an under-

5.3.3 Economic benefits

Some NMS have implemented the energy and carbon tax in line with the EU energy taxation Directive 2003/87/EC. That is the case of Hungary, Estonia, and Latvia.

Table 5.4 Socio-economic benefits of DER in NMS

	Taxation policy		Energy security		End user price increments due to DER support		Technology policy	
Country	Energy/ carbon tax?	Other tax exemptions	Level of energy dependency	DER contribution to decrease dependency	Past years	Coming years	Own technological developments	R&D programs and funds
Bulgaria	-	-	65%	Very low	<5%	9%	Imported	Active credit lines
Czech Republic	No	Yes	41%	Low	-	6%	Small hydro & PV	Funds
Estonia	No	-	32%	-	-	1€/kW	Imported	-
Hungary	Yes	No	72%	Low	<5%	-	Biogas and biomass	Funds
Latvia	Yes	-	40%	-	-	-	-	-
Lithuania	Yes	Yes	42%	Low	Very low	7%	-	-
Poland	Yes	No	10%	-	-		-	-
Romania	-	-	34%	-	-		Wind power	-
Slovakia	No	No	10%*	Very low	Very low		Biomass	Funds
Slovenia	Yes	-	62%	Low	Very low		-	Funds

* Until 2007 self-sufficient, after 2008 energy dependency around 10%

In a number of countries, namely Hungary, Estonia and Latvia, DER power plants shall be exempted from the payment of pollution charges, leading to major benefits. Some countries have other tax exemptions, for example in Lithuania for companies producing equipment for renewable investments. In the Czech Republic there are tax exemptions for investors in RES-E. The first column of Table 5.4 summarises this situation for the new MS.

DER integration can reduce the energy dependence of a country, because renewable sources are mainly indigenous. In Spain, which imports about 76% of its primary energy consumption, the development of wind power covered 8% of the electric energy demand in 2005, contributing positively to diversify energy supply. Despite many NMS have high energy dependency levels, the contribution of DER to decrease such dependency is still very low (see columns 3 & 4 in Table 5.4).

DER deployment can increase end users electricity prices in NMS. According to the conducted survey, the influence in the past years on electricity tariffs has been very small, below 5% in Bulgaria and Hungary. In the coming years, in order to fulfil the renewable share of RES-E imposed by 2010 targets, it is expected that end user tariffs will increase much more than in the past. The expected price increments are in the range of 6% to 9%, which somehow corresponds to the expected percentage of DER increments (see columns 5 & 6 in Table 5.4).

On the other hand, DER development can positively contribute to the development of regional and local industries, including engineering, design and construction of DER projects. To achieve this objective the industry need government support through research and development programs or funds. Most NMS have a good potential for technological developments in DER, however this technology is mainly imported from other countries, for instance, PV and wind

achievement and a negative value an over-achievement by 2003. The DTI is used as an early indication of progress towards the Kyoto and Member States' burden-sharing targets. It assumes that the Member States meet their targets entirely on the basis of domestic policies and measures.

power technology is imported from Germany. In some countries, like Czech Republic, Hungary and Slovakia, a partly domestic technology has been developed, especially for biomass.

Finally, in Bulgaria, there are credit lines to support DER investment, which provide up to 20% grant for investors. These credit lines exceed the total amount of € 200 million. There are specific R&D funds devoted to DER development in Czech Republic, Hungary, and Slovenia. Table 5.4 summarizes this situation.

5.4 Final comments

As it was shown in Figure 2.3, the current levels of DER penetration in most of the NMS are low in comparison with some of the EU-15 countries. As it happens in the majority of old MS, no systematic evaluation procedures, to assess the impact of DER on costs and benefits, neither explicit regulatory mechanisms, to make market agents participants of such costs and benefits, have been designed and implemented yet.

The situation of NMS regarding the impact of DER on DSO costs and benefits is similar to the EU-15 case analyzed under the DG-GRID project. In most of the countries, DSOs revenues are set under a scheme of incentive regulation, price cap or revenue cap, for a period of several years. In each price control process, the regulator will set tariffs that compensate DSOs for actual increments on capital expenditures and operational and management costs. In most countries, DER connection is considered as another regular DSO activity, with no specific procedures to take into account specific costs or benefits. Usually network reinforcements and new investment in measurement and control equipment to accommodate new DER connections will be considered in the calculation of the new CAPEX. Similarly increments in management and maintenance costs will be added to the calculation of OPEX. What it is missed are real figures on how much these incremental costs represent with respect the total DSO costs. On the other hand, the influence of DER connections on future long-term DSOs costs or savings, derived from active networks management, is not yet considered. An important exception to this general rule is the case of the UK, where new incentive mechanisms to compensate DSOs and to incentive DSO innovation for efficient DER integration have been formulated and implemented.

On the other hand, DER growth in several EU-15 countries has positively contributed to the development of local and regional industries, along with the generation of new employment. The NMS recognize the potential of DER development on the creation of new industries and employment. However, the estimation of this potential is today uncertain because the current level of DER integration is still very low.

The Kyoto Protocol is the common guideline for all the Annex B countries, which includes EU-15 and NMS, for the control of GHG emissions. Most of the NMS are in good position regarding their set emission targets, so DER development in these countries is not motivated for that reason. However, other EU-15 countries are developing JI projects in NMS to meet their targets. Therefore, there is a mutual benefit for both type of situations, EU-15 countries benefit by reducing their GHG emissions, and NMS benefit by increasing renewable generation.

6. BARRIERS AND DRIVERS FOR DER INTEGRATION

6.1 Overview of barriers in the new MS

A large number of barriers to optimal integration of DER into electricity networks prevail in the new Member States. In Table 6.1 a list of major barriers is given identified by the SOLID-DER partners in the new Member States. The barriers are categorised as follows:

- *(Energy) policy barriers* include frequently changing policy priorities, regulations and documents. In general, regulatory uncertainty falls under this category.
- *Network regulatory barriers* include barriers related to network regulation, more specifically to procedures and requirements for connection to the network, setting of connection charges and Use-of-System Charges.
- *General regulatory barriers* - Barriers related to regulation other than network regulation, mainly including administrative barriers.
- *Energy market barriers* - Barriers connected to energy market access, but also problems with market power of large producers
- *Financial barriers* - These barriers are mainly related to financing DER projects
- *Other barriers* - Social barriers (e.g. perception of local communities opposing DER projects) and other technical barriers (e.g. missing gas infrastructure)

In about half of the new Member States regulatory barriers related to spatial planning, environmental permitting and building permissions are seen as a major barrier to new DER projects, especially wind energy projects.

A number of network related barriers could also be mentioned. These problems are more profound in countries where no standardised network access regulations are set and when it comes to negotiation between DER operator and DSO. Procedures become then time-consuming and above all, very costly for small-scale producers.

Another (market related) barrier, mainly experienced in the Baltic States is that a major power producer still dominates the power sector. The major power companies often also have influence on the DSO as legal unbundling of the networks has not yet been completed. The issue of overcapacity of power production was also raised. Overcapacity usually pushes prices down and makes it more difficult for new DER operators to compete.

Financial barriers are usually related to the costs of DER-based power production. In some of the countries studied (e.g. Bulgaria, Hungary, Slovakia), DER support is not very stable, feed-in tariffs are not guaranteed for a long time or are relatively low and do not cover production costs. Due to the differences in support schemes in the countries concerned, this is not a barrier that is of the same importance everywhere.

In this context it is interesting to mention that the type of support provided also influences the possibility to finance a DER project. Potential investors in both the EU15 and NMS have announced that with a feed-in tariff system in place it is far easier to receive a bank loan than with e.g. a quota system with green certificates in place. Feed-in tariff systems are relatively easy to understand and administer and therefore perceived as more stable than green certificate schemes by potential investors (and financial institutions).

Table 6.1 Overview of main barriers to DER integration

	Policy barriers	General regulatory barriers	Network regulatory barriers	Energy market barriers	Financial barriers	Other barriers
Bulgaria	Frequent changes in policy documents and priorities	Strict laws in the field of spatial planning Delays in administrative procedures, too many different institutions involved				Potential costs for network upgrades
Czech Republic		Strict spatial planning and building permission procedures				Public acceptance for some RES-E (e.g. wind power) is low
Estonia		Unbundling of production and distribution is taking place after 2007 only	Complicated connection procedures for new small-scale plants	One major power producer & overcapacity of production keeps prices low	Taxation and pollution charges system limits new CHP capacity	Limited gas supply system
Hungary	Regulatory uncertainty: frequently changing regulations		Dominant position of DSOs in negotiating network connection Uniform UoS charge not beneficial for DSOs investing in upgrades DER not seen as option to postpone/replace network investments DSOs have system operation problems due to CHP/RES purchase obligation	Regulated market segment (including old PPA's)	Feed-in tariff support flows to large plants co-firing biomass Feed-in tariff funds suffer from deficit	
Latvia		Regulatory barriers related to permission procedures	Perception of developers and investors that network charging is discriminatory for small-scale projects Hard to receive permission for grid connection	One dominating power producer, only few IPPs	Preferential support scheme for RES replaced by less preferential one	Lack of experience with new technologies
Lithuania		Special pricing structure	No standard procedures and	Capacity surplus		

		for DER auto-producers enables grid-based electricity consumption only in case of emergency	requirements for grid connection New producers pay all (deep) connection costs	(temporary) in Lithuanian power system		
Poland		Long and complex procedures of administrative procedures (e.g. building permissions)		Domination of large producers on electricity market	Insufficient support schemes (according to investors)	Low public acceptance of RES (fear of higher electricity costs)
Slovakia		Complicated process of RES project approval by Ministry of Environment	Above-standard requirements of DSOs to connect DER		No long-term guarantee of buyout prices for electricity from RES and small CHP units	Insufficient information among population about advantages of RES
Slovenia		Hydro-power plants: long procedures for obtaining water use concessions.	Long and time consuming process for the connection to the network and for obtaining status of qualified producer Requirements for connection are not uniformly defined and determined on case-to-case basis.		All incomes from the sale of electricity are subject to taxation	Opposition of environmental NGOs, local communities to wind energy projects, biogas projects

6.2 Major barriers faced in EU15 countries

Barriers faced by RES-E and CHP operators in EU15 countries have been addressed in a number of European studies such as DG-GRID (Skytte & Ropenus, 2005) and OPTRES (Coenraads et al, 2006). The main barriers to be distinguished are administrative, regulatory, financial and social barriers.

Administrative and regulatory barriers seem to be the most severe compared to other barriers. Examples of these barriers are:

- Involvement of many different authorities in both permitting as well as support related procedures for RES, often showing lack of co-ordination.
- Future development of RES projects is insufficiently taken into account in spatial planning, e.g. no areas are set aside for future RES-E projects in municipal or regional spatial plans.
- Low awareness of benefits of RES at local and regional authorities. An example of this is seen in EIA (Environmental Impact Assessment) procedures where often only the negative impacts of RES-E projects are highlighted.

Grid-related barriers are related to both long-term and short-term issues:

- An important *long-term barrier* is the insufficient grid capacity available and not taking into account future RES projects in grid expansion.
- Short-term grid related barriers are non-transparent procedures for grid connection, including network charging and long lead-times for connection.
- Often objectiveness is not guaranteed in grid connection procedures due to uncompleted unbundling of the network company with the incumbent energy supplier.

Financial barriers, mainly concerning the large upfront investments, are partly overcome by support schemes, but some generic types of barriers remain, regardless of the support in place:

- Investors are hesitating to invest in renewable energy projects. This is especially the case in countries where there has been a lack of long-term framework for renewable energy support.
- Uncertainty about the RES market triggers investment banks to lower their risks by charging high-risk premiums (such as high interest rates), or requiring long-term contracts with consumers as well as by requiring guarantees for minimum prices. This barrier is generally higher in countries with a market-based support system such as quota obligations as with fixed feed-in tariffs. Financial institutions are often unfamiliar with the system, making them hesitant in financing renewable energy projects.
- It is hard to predict at the start of a project-planning period what kind of support will be available for that project and how high the level of support will be.

In general, low predictability of capital subsidies for renewable energy on the one hand, combined with uncertainty in revenues imposes a barrier for the renewable energy project developer to attract investments.

Social barriers remain severe in the form of opposition from local public and local authorities to RES-E projects due to NIMBY (not in my backyard) attitudes. This presents a problem for wind power projects but sometimes also for biomass projects requiring environmental permits. Social barriers are strengthened due to low awareness among consumers of the benefits of RES and invisibility of all costs of electricity from non-RES (external costs).

6.3 General overview

As shown above, similar barriers are faced by DER operators in EU15 countries and new Member States. Permission procedures for spatial planning, environmental permits and grid connection are seen as the main barriers.

Financial barriers are often connected to unstable support schemes and therefore the difficulty to gain financing for projects from third parties (e.g. financial institutions). As most support schemes in the new Member States have been introduced only very recently, gaining financial means for RES-E projects could be a larger obstacle in these countries.

The dominant position of large producers on the power market and the yet uncompleted unbundling is seen as a large barrier in the new Member States. As shown in section 4.2, however, this is an unsolved issue in a number of old Member States also.

7. RECOMMENDATIONS FOR MORE EFFICIENT INTEGRATION OF DER IN POWER SUPPLY IN NEW EU MEMBER STATES

This chapter provides a review of policy, regulatory and institutional recommendations to overcome barriers to DER integration in the electricity supply systems of new Member States and Candidate Countries analysed within the current project. Based on the review presented in section 7.1 a set of general recommendations is proposed in section 7.2.

7.1 Country specific recommendations

7.1.1 Bulgaria

The work for support of increased DER penetration in Bulgaria should be directed towards overcoming the difficulties and obstacles of legal, regulatory and technical character.

Regulatory Trends and procedures
Recommendations of a regulatory character are:

- Improvement of the Bulgarian Energy Law and the regulations and rules arising from it, in order to reduce the risk and to guarantee return on investments. This refers mainly to the structural changes and the allocation of responsibilities of public institutions and market players.
- Amendment of **procedures defining connection to the grid** and the energy purchase after the distribution companies restructuring, which are not clear enough and therefore are subject to contradictive interpretation.
- Clarification of the support framework for DER and possible changes in future years to reduce the investors' uncertainty and suspiciousness.
- The scheme of certain market components introducing certificates of origin and green certificates is about to be elaborated and implemented in compliance with the Bulgarian conditions. As a long-term aspect, regulation for equal access of DER to the market should be developed, as well as **fair allocation of DER benefits** to the respective DSOs.
- The provisions under the Law for Structure of Territories should be mitigated, and the **procedures** under the Earth Law and the Environmental Safety Law **should be shortened**. This will provide a normal investment process for DER construction.

Therefore, there is a need to learn from experiences abroad and to study the introduction and improvement of (network) regulations in other EU countries in compliance with the national conditions.

Administrative procedures
The investors unanimously share the opinion that there are too many administrative procedures, they are too complex and have a long duration, and moreover they are the responsibility of different institutions. This results in delays and unspecified decisions by the state authorities. That problem refers not only to such procedures, but also to the whole administrative system in Bulgaria, which is undergoing improvements. This trend however is quite slow and the institutions responsible for energy policy implementation and regulation should focus their efforts on such improvements.

Technological and technical trends
The preferential energy policy of the EU and other countries is an incentive to provide mass penetration of DER, and this will lead to technology improvement, reduction of production costs and putting this generation in market conditions. On the other hand, this development is

forced due to the lack of reliable methods for evaluation of the harmful impact of conventional technologies on the environment and internalizing their impacts in a detailed cost assessment. On the basis of the analyses made above, the technological trends for studies to support large-scale introduction of DER in the electricity generation practices are as follows:

1. Improvement of the evaluation methods and internalizing the environmental externalities.
2. Improvement and introduction of technical devices enabling regulation of intermittent RES technologies.
3. Modernization of the design and construction of the LV and HV networks in connection with the wide introduction of RES generators in low and middle voltage networks.
4. Study of the RES impact on the environment and the possibilities for its mitigation.
5. Study of the possibilities for sustainable utilization of biomass and planting of energy crops.
6. Search of technological solutions for reliable integration of wind energy into the grid.

7.1.2 Czech Republic

The main recommendations for the Czech Republic are as follows:

- **Analysis of the existing support system to DER** and investigation **on sustainability** in a longer term.
- Simplification of permission for construction of DER and mainly possibility of implementation of one-stop-shop system for authorisation.
- **Streamlining different procedures**, spatial permissions, construction permissions etc.
- Improvement of the evaluation methods and internalisation of environmental externalities.

Technological and technical trends

- R&D activities in the field of development and implementation of new advanced DER generation technologies and processes with better technical performance and lower impact on the environment.
- R&D activities in the field of accumulating technical devices and processes and use of hybrid technologies for mitigation of the limited regulation of some RES technologies.
- R&D activities in the field advanced design, construction and operation of LV and HV networks in connection with the wide penetration of RES generators for low and middle voltage
- Use of biomass in co-firing with other fuels
- Search of technological solutions for reliable integration of the wind energy in the electric power system.

7.1.3 Estonia

The main recommendations for Estonia are as follows:

- A clear long-term policy in the field of DER is needed taking onto account the wider development of DER by small generators that cannot yet compete in the very centralised electricity market in Estonia.
- The full opening of market and legal unbundling between electricity generation, transmission and distribution must be implemented in the short-term future. At present (until 2013) all electricity supply services are concentrated in one company.
- Implementation of technical standards of DER network connection and to minimize interconnection requirements from the grid operators.
- Design of methods how network undertakings could evaluate the value and influence in every network point of DER. To investigate how to assign/calculate/measure the influence of DER to network losses and possible postpone of network reinforcements because of DER.

- Modernization of the design and construction of the existing transmission and distribution grids is required for the wider introduction of DER.
- Because of high investments for new generation technologies, flexible payment policy must be developed in order to mitigate the risk and to guarantee the return of investments.

7.1.4 Hungary

Short-term recommendations for Hungary are as follows:

- Investigate the enhancement of international cooperation to tackle system-balancing problems. For example, examine the possibility, potential and conditions of international trade of tertiary reserves so as to support secure system integration of intermittent (uncontrollable) RES-E (UCTE, 2005).
- Examine the applicability, technical and economic implications of pumped storage power plants to keep up with increasing system-balancing problems due to increasing (intended implementation) of DER.
- Carry out a similar assessment of heat storage to make CHP more flexible and suitable to follow system load characteristics, rather than solely led by local heat demand.
- Examine and assess the different level of technical upgrade requirements and their costs in the distribution network including voltage regulation, DER monitoring, communication and control.
- **Assess more deeply the** Hungarian **RES and DER potential**. Analyse the competitiveness of the different technologies.
- Examine whether the Hungarian RES and DER potential, energy policy (objectives), electricity market model and the applied support scheme are in line with each other, Study foreign DER systems, regulation, incentives, operation, etc. learn and analyse experience.
- **Analyse costs and benefits of DER** specifically in the Hungarian system. Analyse what potential system benefits (e.g. network loss avoidance, reactive power management) of DER could be measured and rewarded, and via what regulatory and market instruments. Analyse how and what locational price signals could motivate DER for (system) beneficial siting.
- Assess the potential and conditions of ancillary service market participation of DER.
- Elaborate regional energy assessments/audits and development programs for decentralised energy production.
- Analyse education options and needs; more specific trainings or courses in higher education (e.g. regional energy manager).

Long-term recommendations for Hungary are as follows:

- Study and develop cooperation between different DER sources (e.g. CHP, biomass, biogas and wind turbine) concerning system operation, voltage and power regulation.
- Possibility or implications of intentional and unintentional islanding with DER.
- Rethink the support scheme (preferring a market-friendly solution), suit the scheme and the support tools to the goals of the national (and European) energy policy,
- Examine how to integrate the niche of DER in “normal” energy markets.
- Carry out a benefit assessment for long-term benefits as well (e.g. reduction in network development needs and equipment lifetime extension subject to statistical availability of numerous DER plants).

7.1.5 Latvia

The main recommendations for Latvia are the following:

- A clear and stable long-term policy in the field of DER is needed.
- Legal unbundling between electricity generation, transmission and distribution must be implemented as soon as possible.

- To perform analysis and improvements to existing RES-E support schemes. The existing feed-in tariff for new hydro and wind power plants is too low to promote the development of these power plants.
- To fix existing support schemes for CHP power plants using RES. At present higher power purchase prices are not applied for small CHP power plants (which do not supply heat to centralized heating system).
- To implement technical standards of DER network connection and to minimize interconnection requirements from the grid operators.
- To shorten procedures for network connection and obtaining building permissions.
- To simplify legal procedures for connections to the network.
- To formulate methods how network undertakings could evaluate the value and influence in every network point of DER. To investigate how to assign/calculate/measure the influence of DER to network losses and possibly postpone network reinforcements because of DER.
- To update the design and construction of the existing transmission and distribution grids for the wider introduction of DER.

7.1.6 Lithuania

In order to reduce barriers for distributed generation in Lithuania it is proposed to implement the following action plan:

Technical recommendations:

- To implement technical standards of DER network connection;
- To implement uniform certification and testing procedures of connection to the network;
- To promote development of DER control technologies and systems.

Market recommendations:

- To implement standard commercial practice for every requested connection;
- To set standard conditions of connection agreements;
- To formulate methods how network undertakings could evaluate the value and influence in every network point of DER.

Regulatory recommendations:

- To formulate new competitive regulation principles in electricity market and in electricity networks taking into account distributed generation;
- To implement adjusting tariffs and incentives for networks suitable to the new distributed generation model;

7.1.7 Poland

Analysis of possible network benefits of DER with respect to distribution system operation. These possible benefits include energy loss reduction, availability of balancing power and provision of ancillary services.

7.1.8 Slovakia

Overcoming regulatory barriers

During the next period, it is necessary to adopt the following legislative measures:

- To introduce a provision on the obligation for distribution companies to preferably purchase electricity generated from RES and CHP to cover losses in the distribution system.
- To establish a long-term guarantee of fixed purchase prices by law; fixed prices are calculated with the assumption of a 12-year investment return; the validity of a fixed price should be guaranteed for such period as well.
- Not require certificates of compliance with the long-term conception of the energy policy in the construction of facilities using RES with installed capacity up to 5MW.

- Grant the right of preferential access and preferential connection to the distribution system of RES electricity producers, provided that they comply with technical conditions.
- The Regulatory Office should determine fixed or minimum prices for individual types of renewable sources, in such a manner that conditions for increasing the share of electricity generated from renewable sources in the total electricity consumption are created, a 12-year (reasonable) period of the investment return is reached, subject to the fulfillment of technical parameters and economic effectiveness.
- The regulatory period for the price regulation of the electricity generation generated from renewable sources should be longer than the current 7 years.

If necessary, formulate a separate Act on the Support of RES Development during coming years and consider the introduction of emission certificates as a flexible mechanism for a re-distribution of economic impact of the purchase of energy from renewable sources on all entities in the energy market.

Information campaigns
Financially support information campaigns through regional agencies, Internet (thematically focused on web sites), training, brochures, and media spots. The program of the support of using RES must be accompanied with a campaign for energy savings.

Education
Introduce teaching of RES into curricula of elementary schools. Support the introduction of new technical courses in secondary specialized schools (photovoltaics, wind energy, etc.). Profile selected technical, economic, and scientific trends to RES applications in universities, as well as energy saving and increase in the energy effectiveness of buildings and facilities.

7.1.9 Slovenia

In order to achieve the goals set in the National Energy Programme regarding the use of RES, support mechanisms should be improved. Especially the prices for electricity produced from RES and CHP should be adapted and more funds should be available for investment support. Also the simplification of the legal procedure for connecting to the network and obtain the status of a qualified producer (that is entitled to receive support) would stimulate the deployment of DER.

7.2 General recommendations for overcoming barriers for wider penetration of DER

Wider penetration of DER and meeting country targets for RES-E and CHP will require overcoming the barriers as identified in Chapter 6. Major recommendations on how to do so are presented below, divided into:
- Optimisation of the support system - both creating stability to investors and be market friendly
- Optimal use of available DER technologies
- Reduction of administrative barriers to new DER projects
- Ensure fair access to grids and energy markets
- Increase of awareness and capacity building

7.2.1 Optimisation of the support system

DER plays an increasing role in the new MS in the form of CHP and recently new RES-E capacity. DER support schemes have been introduced (to meet RES-E and CHP targets) practically in all NMS, mainly in the form of FIT combined with regulated purchase agreements (RPO). Support levels in some countries are comparable to those in the EU15 as their arrangement and support level regards but in some other countries they hardly cover the investment costs. Wider penetration of DER in the mid- to long-term future needs optimisation of the support systems, namely to:

- Increase stability of the support system to avoid the stop-and-go nature of the support thereby reducing investment risks:
    - With feed-in tariffs → sufficient and stable feed-in tariff taking into account long-run marginal costs;
    - Quota obligations/green certificates → setting quota for a sufficiently long period so to ensure a stable demand for green certificates;
- Analyse the sustainability of DER support schemes in individual countries for the long term. This can be done by making a comparison or benchmark of EU10 support systems with those in the EU15;
- Rethink the support scheme (preferring a market-friendly solution), suit the scheme and the support tools to the goals of the national (and European) energy policy,
    - E.g. make use of price premiums so that DER producers will follow market signals;
- Adapt the support level to the long-term marginal costs by monitoring costs and revenues of existing DER projects.

7.2.2 Optimal use of available DER technologies

When purely looking at technical potentials a large number of DER technologies are available to meet energy and environmental objectives. To optimally use this potential it is required to ensure diversity of energy use and at the same time look for the most cost-efficient options.

- Providing support to a wide range of technologies to promote uptake of all prospective technologies available;
- Optimise biomass use with regards to:
    - Co-firing vs. small-scale applications (making a cost assessment of applications of different scales)
    - Fuel availability (making an assessment of different types of fuel use, costs and availability) → also taking into account the growth of biomass crops)
- Encourage employment and local & regional benefits in regions with high DER potentials;
- Support twinning with actions on energy efficiency and demand-side management to benefit from the synergic effect.

7.2.3 Reduction of administrative barriers

Despite general support given to DER, there are still many administrative barriers, which hinder implementation of DER. They could be overcome through implementation of various measures, namely:

- Establishment of a **one-stop shop system** for project authorisation;
- Establishment of clear guidelines for authorisation procedures with a clear attribution of responsibilities of various stakeholders;
- Establishment of pre-planning mechanisms that require regions and municipalities to assign locations for DER (in their spatial plans);
- Simplify authorisation procedures for small-scale projects (e.g. below 5 - 10 MW installed capacity);
- Providing freely accessible information and consultancy with regards to:
    - Project authorisation, national and European environmental policy
    - and national/regional policy in promotion of DER

7.2.4 Ensure fair access to grids and energy markets

Participation of DER in energy markets in NMS is still limited but some countries provide access to the wholesale and balancing markets. DER regulatory framework shows large differences between countries, mainly related to connection charging and balancing conditions (obligations and access). Wider penetration of DER could be ensured through following network-related measures:

- Simplification and streamlining of legal procedures for connection of DER/RES-E to the distribution grid;
- Ensuring transparent and non-discriminatory grid connection, grid use conditions as well as cost allocation between DER operators and network operators;
- Grid infrastructure enforcement and development needs to be planned and developed in advance and take future connection of DER into account;
- Ensure transparent allocation of grid related costs between DER operators and grid operators:
    - Pricing of electricity throughout the network should be fair and transparent and take into account the benefits of distributed generation
- The body responsible for allocating grid capacity (e.g. network operator) should have no links with electricity producers. This means to implement *and* enforce legal unbundling of network operators and electricity producers.

Market access should be ensured to DER through simplified procedures for access to wholesale, balancing and ancillary services markets:

- Less strict notification procedures of DER when offering power to wholesale and balancing markets
- Providing access to the wholesale market of controllable DER sources (e.g. CHP with heat storage)
- Creating market places for ancillary services

7.2.5 Increase of awareness and capacity building

One of the crucial barriers to implementation of DER projects,is still the perception of local communities opposing DER projects, which can be to a large extend due to lack of awareness on cons and pros of such project. The way to overcome such barrier is to:

- Run awareness campaigns to general public on cons and pros of various types of DER projects in media;
- Include education on RES in curricula on various levels of education from primary (elementary) schools to the university education;
- Organise capacity building for civil servants involved related to establishment of one-stop shop system for project authorisation
- Integrate local communities in decision-making of DER projects at the earliest possible stage to create local commitment

8. CONCLUSIONS

This research has specifically addressed the economic, policy and regulatory drivers and barriers towards increasing integration of Distributed Energy Resources (DER) in the electricity supply system of the new Member States (NMS) and Candidate Countries of Central and Eastern Europe.

Due to a number of developments, the integration of DER, and mainly RES-E, into the electricity infrastructure will become an important issue in the coming years:
- The adoption of targets for renewable electricity production in the framework of the EU Renewable Electricity Directive (2001/77/EC) has led to the introduction of policy support for renewable electricity production.
- During the next decades the electricity generation capacity technology mix in the new MS will have to undergo massive replacement and DER sources could play an important role in this field.
- The liberalisation of the electricity market and upcoming network regulation has on one hand led to easier access of DER to electricity markets. On the other hand, the liberalisation process has also led to other developments, such as increasing market power of large power producers that may inhibit the increase of DER in the short- and mid-term future.

Most electricity markets in the new Member States are not yet fully mature and still in a transition phase. In addition, the new Member States are facing different basic conditions, dependent on their fuel mixes, progress in liberalisation, prevalent market structures, and historical evolution of their electricity sectors.

The basic input of this research was formed by a country survey carried out in Bulgaria, Czech Republic, Estonia, Hungary, Latvia, Lithuania, Poland, Romania, Slovakia and Slovenia. This survey included national overviews of:
- Shares of DER in the given country
- National legal and institutional framework, including an overview of the main actors in the electricity supply system
- DER support mechanisms
- DER market access and network access
- DSO costs and benefits (both network related as socio-economic costs and benefits)
- DER barriers and regulatory efforts.
- R&D recommendations in the field of socio-economic research, overcoming barriers to further DER integration.

DER market presence and policies
The overview of the ten new Member States showed the following developments:
- A relatively large share of CHP in the electricity supply system varying between 10 and 22% of electricity production.
- Shares of renewable energy production are high in those countries with significant large-scale hydropower production (e.g. Latvia, Slovenia, Slovakia and Romania) but below 5% in the other countries.
- Small-scale RES production shows a steady increase in production during the last two to three years.
- All countries have adopted support schemes for RES-E production. In eight of the countries this support is provided in the form of feed-in tariffs and in two countries (Poland and Romania) green certificates have been introduced.

- Each country is in a different position with meeting its indicative target for the RES-E directive. Countries like Hungary and Latvia have already reached their targets, for other countries meeting the target will be difficult (e.g. Czech Republic, Poland) or nearly impossible (Slovakia) due to the high targets set.

A comparison with support mechanisms in EU15 countries shows that in 9 of the 15 countries feed-in tariffs are in place, while four countries have introduced a quota system with green certificates. Experience with these support schemes shows that a stable system with feed-in tariffs brings large stability to investors with large increases in some countries (e.g. Germany, Spain). A quota system with tradable green certificates can also bring stability as long as targets are agreed for a sufficiently long period. Difference with a feed-in tariff system is that different types of RES-E have to compete with each other. This could create more efficient investments in RES-E capacity but may be more advantageous for large energy producers than for small independent power producers. Investors seem to be mainly interested in a stable support scheme, whether this is a feed-in tariff scheme or a quota obligation system is not their main concern. In countries with less mature RES-E markets, as is the case in most new Member States, a feed-in tariff system may be more suitable to realise a first increase of RES-E capacity. There are two main reasons for that; first, feed-in tariff systems are usually easier to administer and, second, the availability of a feed-in tariff system makes it easier for investors to gain financing for their projects.

Regulatory framework
Major changes can be noted in the network regulatory framework in the new MS. Main developments are the unbundling process of the DSO towards legal unbundling and the increasing access of DER electricity to wholesale markets.

There is no generic strategy towards common framework conditions, in the new as well as in the old Member States, since the framework conditions for DER given by EU legislation are rather broad. This gives substantial scope for variation at the national level regarding economic regulation, market requirements, network regulatory regimes, and support mechanisms for DER.

The difference in the national regulatory framework conditions implies that the economic conditions for DER differ between the Member States, e.g. with respect to connection charges and sale and balancing conditions. This gives more incentives to deploy DER in Member States with gentle support and connection systems, than to deploy in areas with DER resources or excess demand for power. At the overall EU level the non-existence of common EU regulatory framework conditions for DER might implies an economic in-efficient deployment.

Many of the present barriers for further integration of DER may be seen as temporary barriers due to the time lag of changing the systems. Nevertheless, a number of major barriers remain towards increased and large-scale integration of DER. Examples are regulatory barriers in the form of complex network access procedures and lengthy spatial planning procedures.

Assessment of costs and benefits
As it happens in the majority of old MS, no systematic evaluation procedures, to assess the impact of DER on costs and benefits, neither explicit regulatory mechanisms, to make market agents participants of such costs and benefits, have been designed and implemented yet.

The situation of NMS regarding the impact of DER on DSO costs and benefits is similar to the EU-15. In most of the countries, DSOs revenues are set under a scheme of incentive regulation, price cap or revenue cap, for a period of several years. In each price control process, the regulator will set tariffs that compensate DSOs for actual increments on capital expenditures and operational and management costs. In most countries, DER connection is considered as another regular DSO activity, with no specific procedures to take into account specific costs or benefits.

Usually network reinforcements and new investment in measurement and control equipment to accommodate new DER connections will be considered in the calculation of the new CAPEX. Similarly increments in management and maintenance costs will be added to the calculation of OPEX. Missing are real figures on how much these incremental costs represent with respect to the total DSO costs. On the other hand, the influence of DER connections on future long-term DSOs costs or savings, derived from active networks management, is not yet considered. An important exception to this general rule is the case of the UK, where new incentive mechanisms to compensate DSOs and to incentivise DSO innovation for efficient DER integration have been formulated and implemented.

On the other hand, DER growth in several EU-15 countries has positively contributed to the development of local and regional industries, along with the generation of new employment. The new MS recognize the potential of DER development on the creation of new industries and employment. However, the estimation of this potential is uncertain today because the current level of DER integration is still very low.

Barriers and recommendations
Similar barriers to increasing DER shares into the electricity network can be identified in the old as well as in the new Member States. These are:

- Lengthy and complicated administrative procedures, by investors in DER power plants in many countries often considered as the most severe barrier.
- Dominant position of DSOs in negotiating network access in combination with non-transparent connection procedures.
- Unstable support mechanisms making it difficult to plan long-term projects. This is a barrier that is more seriously considered in the new Member States where support for DER has been introduced very recently only.
- Lack of knowledge about advantages of DER generated power leading to opposition of local communities to new DER projects.

Based on the barriers mentioned above a number of (country)-specific recommendations have been developed:

- In the development of support schemes, take into account their cost-effectiveness in the long-term and the stability it has to create for investors.
- Complete the unbundling process, not only within the legal framework but also in practise.
- Simplify authorisation procedures for spatial planning and construction permits through a "one-stop shop system" for project authorisation.
- Introduce transparent and non-discriminatory grid connection, grid use conditions as well as cost allocation between DER operators and network operators.
- Market access for DER operators should be ensured through simplified procedures for access to wholesale, balancing and ancillary services markets.

9. RECOMMENDATIONS FOR R&D PRIORITIES FOR INTEGRATING MORE DER IN ELECTRICITY SUPPLY

Based on the analysis and findings of the investigations into the economic, policy and regulatory barriers and solutions for integrating more DER in electricity supply a number of recommendations for research and development are formulated. This with a view on the further improving the long term conditions for integration of DER into the electricity supply system in Euope as a whole:

- *Update of RES-E potential for individual countries* - The aim will be to make a detailed and realistic estimate of RES-E potential taking into account also climatic conditions, environmental constraints, technology development, competition among various use of RES. Such potential would be used for setting new RES-E targets after 2010. → Some of the countries (e.g. Slovakia) mention that their RES-E target for 2010 is based on unrealistic assumptions.
- *Analysis of pros and cons of administrative and market oriented systems for promotion of RES-E* - The aim of the work would be to analyse pros and cons of various administrative and market oriented systems for promotion of RES-E (feed-in tariffs, green bonus, green certificates) and prepare recommendations for the EU Commission to support it in its task to adjustments the current system.
- *Assessment of long-term DER costs and benefits* (social, environmental, energy, technical) including specifically long-term network benefits of DER (e.g. reduction of losses, availability of balancing power and provision of ancillary services, reduction of needs for upgrading/extension of grid)). Development of methods for evaluation of the value of the influence of DER on grid. To investigate how to assign/calculate/measure the influence of DER to network losses and possibly to postpone/minimise needs for network reinforcements.
- *Research of the possibilities and needs for cooperation among different DER* sources (e.g. CHP, biomass, biogas and wind turbine) concerning system operation, voltage and power regulation.
- *Identification of major technology innovations in the DER field* - Faster uptake of DER for electricity generation with minimal impact on the environment will require new technologies to be invented and mainly implemented. The aim of the work would be identification of major technology innovations in the DER field needed for the coming 20-30 years. including energy storage
- *Development of a general guidebook for simplification of the authorisation process for new RES-E projects* - As administrative barriers are still key ones in the authorisation process, aim of the work would be the development of a general guidebook for simplification of the authorisation process for new RES-E projects on EU-wide level, which would serve for development of country specific systems and guidebooks.
- *Development of a structure of targeted awareness campaigns for various groups and stakeholders* - Lack of awareness on RES-E benefits is still an important barrier to their perception as an important alternative to usual ways of energy supply. The aim of the work would be to prepare EU-wide and regional-wide campaigns for RES-E with recommendations for country specific campaigns including inclusion of teaching of RES into curricula of (secondary) schools. Support the introduction of new technical courses in secondary specialized schools and universities (photovoltaic's, wind energy, etc.), including teaching selected technical, economic, and scientific trends to RES applications.
- *Assessment of biomass fuel chains* - The aim will be to design how to strengthen biomass chains both of waste biomass and planted biomass to get a steady and least cost supply of biomass. It is also necessary to analyse the ways to optimise the use of biomass for both power and heat production (e.g. use of RES-CHP) as well as biomass use for co-firing vs.

small-scale applications. The work should result with recommendation on an optimal promotion system for a well functioning biomass fuel chain.

- *Assessment of costs and benefits of different network charging systems for different stakeholders*, such as DER operators, network companies and energy suppliers.
- Improvement of the evaluation methods and *internalisation of environmental externalities*. Despite the fact that several methodologies exist for calculation of environmental externalities, these methodologies are not part of regular evaluation methods for energy planning.
- *Application of innovative network approaches* on distribution and transmission level:
    - International cooperation to handle system balancing problems, e.g. trade in tertiary reserves, applicability of pumped storage in international context;
    - Study the possibilities of heat storage to make CHP plants more flexible and suitable to follow system load characteristics;
    - Analyse possibilities of rewarding DER distribution system benefits such as avoiding network loss avoidance, reactive power management.
- Assessment of the potential and conditions of *ancillary service market participation of DER*
    - Carry out costs & benefits analysis to assess the costs for the future power system;
    - Development / use of business models for DER operators and DSOs;
    - Influence of end-user prices on increasing DER shares.

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ANNEX I - COUNTRY CASE STUDIES

Baltic States

Bulgaria

Czech Republic

Hungary

Poland

Slovenia