INOGATE Textbook

RENEWABLE ENERGY REGULATION

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REKK REGIONAL CENTRE FOR ENERGY POLICY RESEARCH

ERRA ENERGY REGULATORS REGIONAL ASSOCIATION

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List of Acronyms

CCGT – combined cycle gas turbine

CCS – carbon capture and storage

CDM – Clean Development Mechanism

CHP – combined heat and power

CER – Certified Emissions Reduction

COP – Conference of the Parties

DG – distributed generation

DSO – distribution system operator

DSM – demand side management

EIA – environmental impact assessment

EIT – economy in transition

ERGEG - European Regulators Group for Electricity and Gas

ERU – Emissions Reduction Unit

ESD – Effort Sharing Directive

ESMA – European Smart Metering Alliance

EUA – European Union Allowance

EU ETS – European Union Emissions Trading Scheme

FIT – feed-in tariff

GHG – greenhouse gas

GC – green certificate

GO – guarantee of origin

GPRS - General Packet Radio Service

GSM - Global System for Mobile Communications, originally Groupe Spécial Mobile

GWP – global warming potential

IEA – International Energy Agency

IPCC – Intergovernmental Panel on Climate Change

ICT – information communication technology

ITC – Inter-TSO Compensation

JI – Joint Implementation

LV – low voltage

MAC – marginal abatement cost

NAP – National Allocation Plan

NREAP – National Renewable Energy Action Plan
OFGEM – Office of Gas and Electricity Markets
PLC – power line communication
PM – particulate matter
PV – photovoltaic
RAB – regulatory asset base
REDD –Reducing Emissions from Deforestation and Forest Degradation
RPS – regulated premium schemes
RES – renewable energy sources
RES-E – electricity produced from renewable sources
SET Plan – Strategic Energy Technology Plan
TSO – transmission system operator
ToU – time of use
UNFCCC – United Nations Framework Convention on Climate Change
UoS – use of system

Environmental policies and regulations - while virtually non-existent in the 1970s - today represent a rapidly growing legislative body bearing considerable public attention. The reason behind public regulation is that environmental amenities such as air, biodiversity, water etc. do not have owners and users usually consider them “free” goods and factors of production. Consequently, they are often used beyond their regenerative capacity and/or become excessively polluted.

Energy generation is a source of pollution. First and foremost substances are emitted into the air, polluting natural water bodies with heat (cooling water from power plants) or depositing nuclear waste into the natural environment. The main air pollutants of the energy sector are: $SO_{2,}$ causing acid rain; NO_x and dust, creating health hazards; and $CO_{2,}$ contributing to climate change.

Key questions in environmental policies are: 1) What are socially optimal pollution levels? and 2) how can this level be reached? Regarding the first question, a comparison of the costs and the benefits of pollution abatement is required. The optimal level of pollution is not zero, but a function of the social costs associated and the cost of pollution abatement. The social cost of pollution consists of costs of all environmental damages, such as health costs and reduced enjoyment of various resources. The answer for the second question (i. e. how can the optimum be reached), policy makers may choose from a range of tools to internalize the cost of pollution.

This textbook focuses on renewable energy generation and also discusses the main economic instrument employed in Europe towards a low carbon economy: emissions trading. Apart from the focus on generation, the textbook devotes special attention to grid issues and the future large scale deployment of distributed renewable electricity generation. This is done from a regulatory point of view, discussing the potential of smart metering and smart grids to reduce electricity use and to coordinate electricity demand with supply.

The textbook is divided into three main chapters. The first is devoted to the understanding of the phenomena called climate change and the international and European policy responses with special focus on the European Emissions Trading Scheme (EU ETS). The second describes the renewable electricity generation technologies, their support schemes and the incentives for distribution and transmission system operators to encourage the large scale uptake of renewable electricity generation. The third section focuses on the notions of smart metering and smart grids and their effect on distributed generation and demand response. The annexes provide additional information and examples complementing the main text.

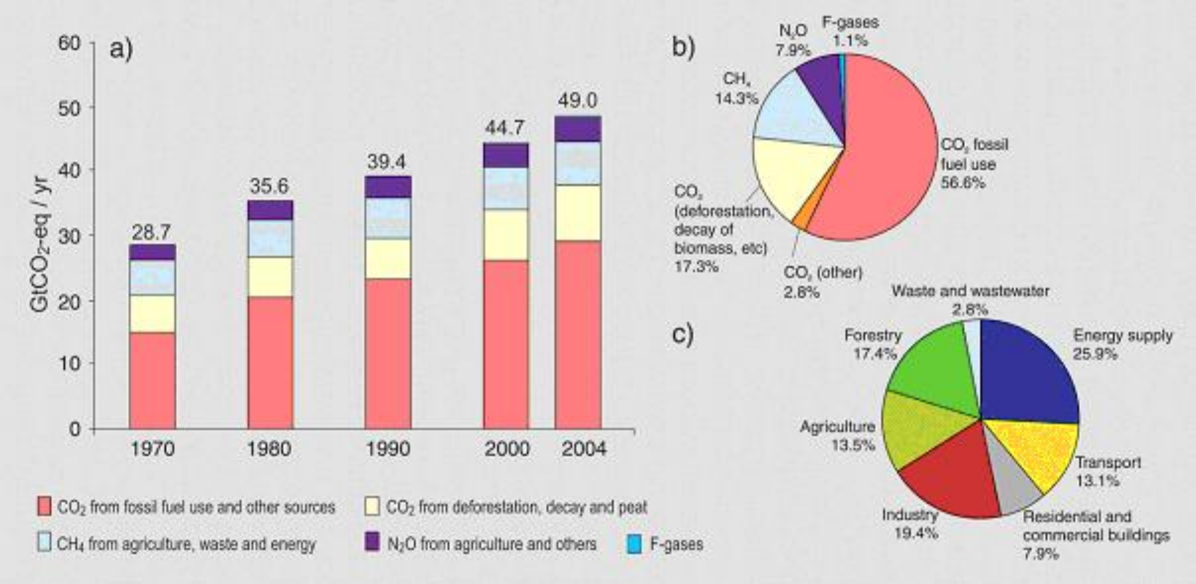
I. GLOBAL AND EUROPEAN CLIMATE POLICIES

This section is devoted to climate change. First, it describes the phenomenon and its causes, then it moves into the greenhouse gas mitigation policies of the European Union. Finally, the economic concept and the actual operation design of the EU ETS is discussed.

I.1. What is climate change?

Some gases, namely atmospheric greenhouse gases (GHGs) through a natural phenomenon trap parts of radiation produced by the Sun. Similarly, the heat radiated back from the Earth surface is trapped, without this radiation the Earth would be far too cold for human life. The problem is this balance has been disturbed by the increase of carbon emissions triggered by industrialization and changes in land use, resulting in an enhanced greenhouse effect. The main greenhouse gases are: carbon dioxide (CO_2), accounting for more than 70% of the enhanced greenhouse effect; methane (CH_4); and nitrous oxide (N_2O) (Figure 1).[1] Water vapour, in spite of being the most important greenhouse substance is quasi-independent of human activities. It is important to note that oceans, forests and soils function as carbon sinks because they absorb carbon dioxide from the atmosphere. Vegetation, especially trees, during their growth period, are net carbon sinks because they remove more carbon dioxide from the atmosphere than they release into it, thus being an important component of the 'carbon exchange' (including the deposition of carbon) - a natural carbon cycle generated through the three major biota: the atmosphere, the oceans and the land.

Figure 1 Global annual emissions of anthropogenic GHGs from 1970 to 2004, (b) Share of different anthropogenic GHGs in total emissions in 2004 in terms of CO_2 equivalent.2 (c) Share of different sectors in total anthropogenic GHG emissions in 2004 in terms of CO_2 equivalent



Source: IPCC 4th Assessment Report

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[1] The 5th Assessment Report is under preparation and likely to be published in 2013/2014.

[2] CO_2 equivalent is a term to quantify the warming potential of various greenhouse gases compared to that of CO_2. It is obtained by multiplying the emissions of a GHG by its Global Warming Potential (GWP) for a given time horizon. The GWP of CH4 is 21, N2O is 310 at a 100 years horizon used in by the UNFCCC and the IPCC Reports.

The phenomena associated with climate change include, an increase in global temperature, sea level rise due to thermal water expansion, melting glaciers and ice caps.[3] Specific impacts of climate change, both in terms of their severity and nature, will vary from region to region. The worst affected regions are likely to suffer negative impacts on agricultural production, human health, psychical infrastructure, water resources and economic activities in general.

The Intergovernmental Panel on Climate Change (IPCC) has indicated that reaching a 2 ºC temperature increase (compared to pre-industrial levels) will mean stabilising greenhouse gas concentrations in the atmosphere at about 445 to 490 ppm CO_2-equivalent, corresponding to about 400 ppm individual CO_2 concentration.[4] This target has been adopted unilaterally by the European Union but not other major industrialised nations.

Climate change is a truly global problem in two senses. First, greenhouse gas emissions are largely generated by energy and land use, both being natural resources at the base of everyday human life; this means all countries and individuals are potential contributors to climate change. Second, all countries and individuals are potential victims too, with the possibility to suffer from the effects of floods, decreased agricultural production, or health deterioration caused by climate change. To make matters even more complicated, there is no direct relationship between the GHG quantities emitted by a country and the consequences it will suffer from climate change. This fact has a serious negative influence on the likelihood of effective collective action. As greenhouse gases get perfectly intermixed in the atmosphere, it makes no difference where they are emitted. The causes and the effects are distributed differently, but not randomly. The smallest GHG contributors, the generally small and poor developing countries are the most vulnerable to climate change impacts. Their emissions per capita are way below that of industrialized countries. At the same time, they are much more dependent on agriculture and have very limited resources to adapt to the changes (e.g. building dams or relocating populations). Per capita emissions of OECD and EIT (economies in transition) countries (denoted as Annex I in the United Nations Framework Convention on Climate Change) are 4 times higher (16.1 t CO2eq/cap) than that of developing (non-Annex I) countries (Figure 2).[5]

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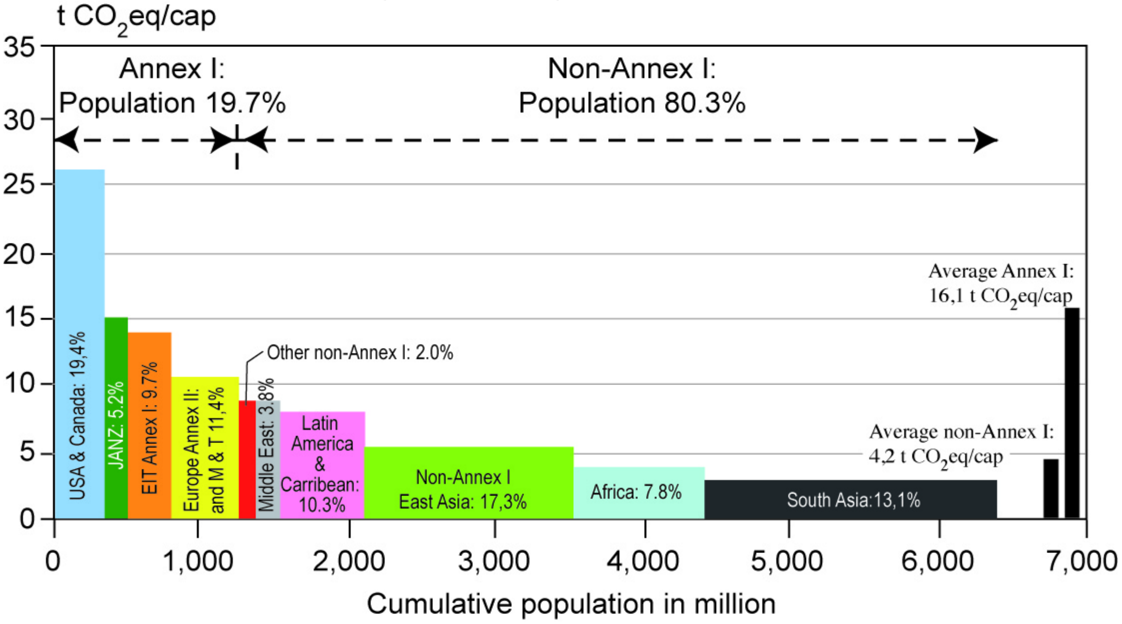
[3] Between 1906 and 2005 the average global temperature has risen by 0.74°C, but interestingly the 11 years between 1995-2006 rank among the twelve warmest years since 1850 (IPCC, 2007).

[4] One part per million (ppm) is equal to a volume of a given gas mixed in a million volumes of air. It is an often used measure for the concentration of a certain gas in the air pollution literature.

[5] For the exact coverage of geographic regions see: http://www.ipcc.ch/publications_and_data/ar4/wg3/en/figure-1-4.html

Figure 2 Regional distribution of emissions by population (Percentages in the bars in both panels indicate a region's share in global GHG emissions, 2004)



Source: IPCC 4th Assessment Report

I.2. Global climate politics

In 1992, international climate policy was born with the adoption of the United Nations Framework Convention on Climate Change (UNFCCC). This was aimed at the "stabilization of greenhouse gas concentration in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system".[6] The UNFCCC was opened for signature in Rio de Janeiro in June 1992 and came into force on 21 March 1994. The Convention currently has 192 parties (states that has signed and ratified it) that hold high-level meetings annually to discuss implementation and future directions of the regime. Developed countries, including EITs, listed in Annex I of the Convention, set the target to jointly return to the emission level of 1990 by 2000. The Convention was not a legally binding document, and therefore reflects a balance of interest between different groups of countries. Developing countries did not commit themselves to quantifiable reductions, in addition, they managed to insert into the document the principle of shared but differentiated responsibility. A principle acknowledging the key responsibility of developed countries in the global mitigation effort due to their strong contribution to past emissions. Moreover, developed countries were willing to take into consideration the developmental needs of the countries in the "South". The group of countries comprised of the less developed, necessitated this approach for moral reasons but also to keep these countries at the negotiation table.

The Kyoto Protocol of the UNFCCC, adopted in 1997, contains legally binding reduction targets for developed countries individually and jointly.[7] Over a first commitment period (2008-2012) industrial countries have to reach an overall 5.2% reduction of greenhouse gases compared to the 1990 emissions level. In addition to the above common target, these

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[6] Art. 2

[7] listed in Annex B of the Protocol (eventually the list is almost identical to Annex I of the Convention)

countries have agreed on differentiated reduction targets as well (Table 1). The Protocol prescribes no obligations for non-Annex I parties to limit their emissions.

Table 1 Kyoto reduction targets

Country	Target (1990 – 2008-12)
EU-15, Bulgaria, Czech Republic, Estonia, Latvia, Liechtenstein, Lithuania, Monaco, Romania, Slovakia, Slovenia, Switzerland	-8%
US	-7%
Canada, Hungary, Japan, Poland	-6%
Croatia	-5%
New Zealand, Russian Federation, Ukraine	0%
Norway	+1%
Australia	+8%
Iceland	+10%

It is to be noted that EITs were free to choose a reference year other than 1990. This possibility prompted these countries to set their emission baselines several years earlier, choosing a year when their emissions peaked (mid 1980s). This approach allowed them to open the gap even wider between their emissions targets and the falling emissions of their economies. Consequently, they can reach their reduction target without actual mitigation measures.[8]

Countries are expected to meet their Kyoto targets mainly by domestically implementing emissions reduction. However, some other instruments are available as to reach the targets. JI allows a country with an emission reduction, or limitation commitment under the Kyoto Protocol (Annex B Party), to earn emission reduction units (ERUs) from an emission-reduction or emission removal project in another Annex B Party and count it towards meeting its Kyoto target. CDM is similar, but the project needs to be in a non-Annex B country (i.e. without emissions limitation commitment). Emissions trading allows countries that have excess emission units (permitted but not used to cover actual emissions) to sell this capacity to countries that are over their targets.[9] In 2001 in Marrakech, the Parties have developed guidelines for the implementation of these flexible mechanisms.

It is important to distinguish between national (or domestic) and international emissions trading. National level trading is carried out between polluting companies acting within a nationally regulated system in order to meet national (or regional) emissions targets. Several states run such schemes and the EU ETS itself is a good example of this instrument. The total number of allowances or credits is controlled by the national governments (or the European Commission). Generally, the national targets set by governments are derived from the Kyoto commitment of a country, but they also take into consideration other policies and measures aimed at the overall amount of the national reduction level. Within the Kyoto Protocol framework, international emissions trading occurs between national governments, when two or more countries agree to trade their surpluses and deficits related to their actual emissions and their emissions targets. Compliance in this case is monitored by the Secretariat of the UNFCCC.

According to the 2007 GHG data, the Kyoto Protocol commitment (5.2% reduction) can be fulfilled as overall emissions of Annex B countries are 16% below the baseline. However, this is only possible due to the massive emissions reduction at the beginning of the 1990s of

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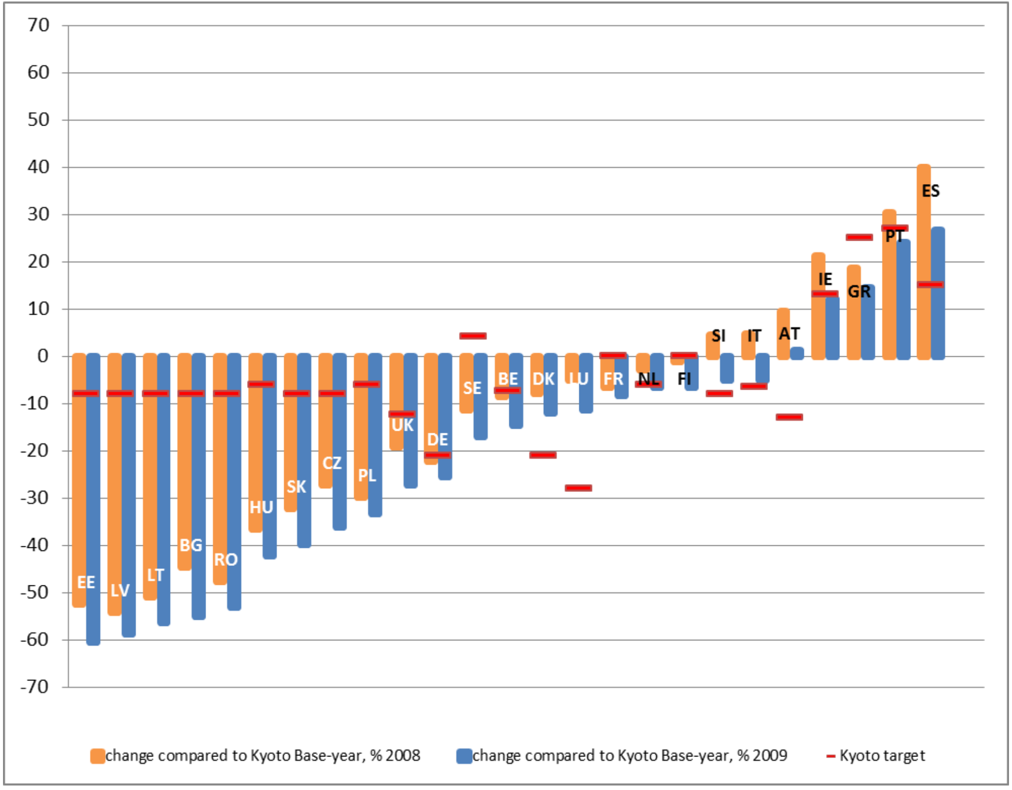
[8] with the exception of Slovenia

[9] CDM projects are supervised by the CDM Executive Board that verifies and certifies emissions reductions (Certified Emission Reduction -CER). The parallel unit for Joint Implementation is called Emissions Reduction Unit (ERU) that is – as a main rule – certified by the state hosting the project. The unit of international emissions trading is Assigned Amount Unit (AAU).

Central and Eastern European countries (including Ukraine and the Russian Federation, the two countries from the INOGATE group which have reduction commitment) caused by their economic collapse. Even if these countries have increased their emissions rapidly since 2000, they are likely to meet their differentiated Kyoto commitments. Apart from them, only Australia seems to be on track to reduce emissions. From the non-EU countries neither Japan, nor New Zealand are likely to meet their national target. So to be in compliance by the end of 2012 they are most likely to need to buy quotas (AAUs) from other countries. The US is not party to the Kyoto Protocol since the US government failed to domestically enforce its promised commitment as a signatory to the Protocol. Within the EU the overall EU commitment is distributed internally among the then 15 Member States. The Cohesion countries (Ireland, Spain, Portugal and Greece) and Sweden are allowed to increase their emissions, the others need to cut up to 28% (Luxembourg). According to 2008 data, a number of countries are likely to miss their commitment by 2012: Spain, Portugal, Ireland, Austria, Italy, Denmark, Luxembourg and Slovenia (Figure 3). With the exception of Slovenia, the Central and Eastern European states are well within their cap. With the economic recession, several countries managed to improve its compliance position as an intended consequence of lower economic output. Data from 2009 shows that only Denmark, Luxembourg, Austria and Spain have to increase its efforts to curb emissions.

Figure 3 Trends of compliance with the Kyoto Protocol (EU27, 2008 and 2009 data)[10]



Source: EEA, 2010 and EEA, 2011

A December 2009 meeting held in Copenhagen was supposed to decide on future governance measures of climate change cooperationfrom 2012, the end year of the Kyoto Protocol mandate. The problem with the Protocol is that its reduction targets fall short of true requirements (i.e. 24-40% reduction in developed countries by 2020) and involves only a limited set of countries leaving the emissions of other countries – notably the rapidly

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[10] Cyprus and Malta do not have reduction targets under the Kyoto Protocol.

industrializing Southern hemisphere countries - unrestricted. The major agenda issues to be solved were and still remain:

- setting ambitious emission reduction targets for developed countries: several countries have already pledged their commitments (EU, Australia, South Korea),
- appropriate national level mitigation actions (ways to reduce emissions) for developing countries and the ways to define it (i.e. per capita or absolute amount etc.),
- scaling up financial and technological support schemes for both adaptation to the consequences of climate change (such as extreme weather events, rising sea level etc.) and mitigation measures,
- inclusion of deforestation in developing countries, international aviation and maritime transport as sectors to be regulated. These GHG sources have been left out in Kyoto but due to their increasing share and in spite of the related special regulatory problems (territorial questions) and current politico-economical privileges (tax free kerosene), they need to be covered.

An effective post-Kyoto agreement needs to include China, India, Brazil and other industrializing Southern countries (contributing an ever increasing share of global emissions) together with the US as a partner of the international regime starting from 2012. Regardless of the political willingness of the President, the so called Byrd-Hagel Resolution forbids the US ratification of any agreement until developing countries are not committed to reduce emissions. Therefore, the US continues rejecting the Kyoto structure and is willing to accept some form of bottom-up agreement only with aggregated country pledges. In contrast, the EU and the developing countries favour a top-down regime with overall reductions established first, followed subsequently by allocation of appropriate shares among participating states according to their respective responsibilities and capabilities.

According to the IPCC, to achieve stabilization of GHG concentration in the atmosphere at 450 ppm CO_2e (resulting in 2° Celsius temperature increase), developed countries should collectively reduce their emissions by 25-40% by 2020, and newly industrializing countries should go 15-30% below their business-as-usual emission level. In contrast, in Copenhagen while the industrialized countries pledged 11-19% reduction altogether, the main developing countries proposed more substantial reductions, that is, approximately 29% by 2020, a reduction being at the high end of their range.

Related to the financing of developing countries' mitigation and adaptation efforts, public pledges were made by several developed countries. Thus the EU proposed 10.8 billion USD per year by 2012, Japan proposed 15 billion USD per year by 2012 and the US proposed 100 billion USD per year by 2020. Even if these are substantial additional resources to the existing funding, the required sum still remains a magnitude higher (Sterk, 2010).

No agreement has yet been reached on the inclusion of aviation and maritime transport into the mechanisms of the regime. The countries could not agree whether potential mitigation measures and targets regarding these two sectors should be global or confined only to industrialized countries. Besides limiting further emissions, inclusion of these sectors could have provided substantial amounts of additional funding for climate policies via taxation and/or auctioning of emission rights.

Developing countries have been keen to include deforestation and forest degradation (*Reducing Emissions from Deforestation and Forest Degradation - REDD*) in the post-Kyoto policy framework. Forest conservation and sustainable forest management could appear as an asset in their emissions account (forests being carbon sinks) thereby the regime would also create an additional incentive for forest preservation.

As presented above, all agenda issues still remaining open, the Copenhagen meeting was unable to deliver legally binding decisions, merely a political declaration ('Copenhagen Accord'). Unfortunately, it was not even supported by all participants.

The negotiations continued and although the next Conference of the Parties (COP) held in Cancún, Mexico at the end of 2010 was considered successful on solving a number of pending question, the Parties could not agree on the key issue: mitigation commitments from 2012. The key point of discussion that directly influences the quantitative target setting is whether developed countries can use their allowances beyond 2012 that were originally meant for the 2008-2012 period. If they can, those countries with substantial surplus emissions allowances (mainly Russian Federation and Ukraine, but also several Eastern EU member states) can sell their excess that would equalize emissions to 'business-as-usual' levels for the developed states as a whole (Chen et al., 2011). The Cancún COP resulted in the further assistance measures for developing countries to reduce their emissions voluntarily. These measures include the establishment of Green Climate Fund and the Technology Mechanism. The Fund is the financial mechanism under the supervision of the COP to support projects and programs of developing countries. The aim of the Mechanism is provide an overview of technology needs and analysis of technical issues and to consider and recommend actions to promote technology transfer to developing states.

I.3. EU policies to reduce GHG emissions

Apart from being at the forefront of the international climate negotiations, the EU has adopted various initiatives to cut its GHG emissions. This section briefly discusses these main policy areas and the related key EU policy targets.

I.3.1. EU Emissions Trading Scheme

The main policy tool of the EU to reach its Kyoto target is the European Union Emissions Trading Scheme (EU ETS) set up by the 2003/87/EC Directive. The Directive regulates more than 12,000 facilities of the 27 Member States responsible for almost half of the total CO_2 emissions within the EU. The EU ETS is the largest emissions market ever. Emissions trading had been successfully implemented before in the USA but covering only several air pollutants like sulphur dioxide, nitrogen oxides, or leaded petrol. Interestingly, the concept was alien to the European environmental policy, having been dominated mainly by command-and-control instruments like technology standards and to some extent pollution taxes. As such, the EU ETS appeared almost unexpectedly when its pilot phase was launched in 2005. The scheme is divided into 3 phases, each successive stage modifying the allocation rules and the scope of the scheme, leaving the fundamental design intact. (For a detailed discussion of EU ETS see later.) By 2020 the cap will be 21% below 2005 emissions level.

I.3.2. Renewable energy utilisation

Mandating the increased use of renewable energy sources, such as wind, solar, hydro and biomass, and biofuels results in lower demand for fossil based electricity and heat, hence reduces GHG emissions and import dependence. The EU (as part of the Climate and Energy Package) has set binding national targets for renewable energy which collectively will lift the average renewable share across the EU to 20% by 2020 (from the 9.2% 2006 level).[11] The national targets range from a renewables share of 10% in Malta to 49% in Sweden. The Member States have a flat rate 10% increase obligation regarding biofuel use. The Renewable

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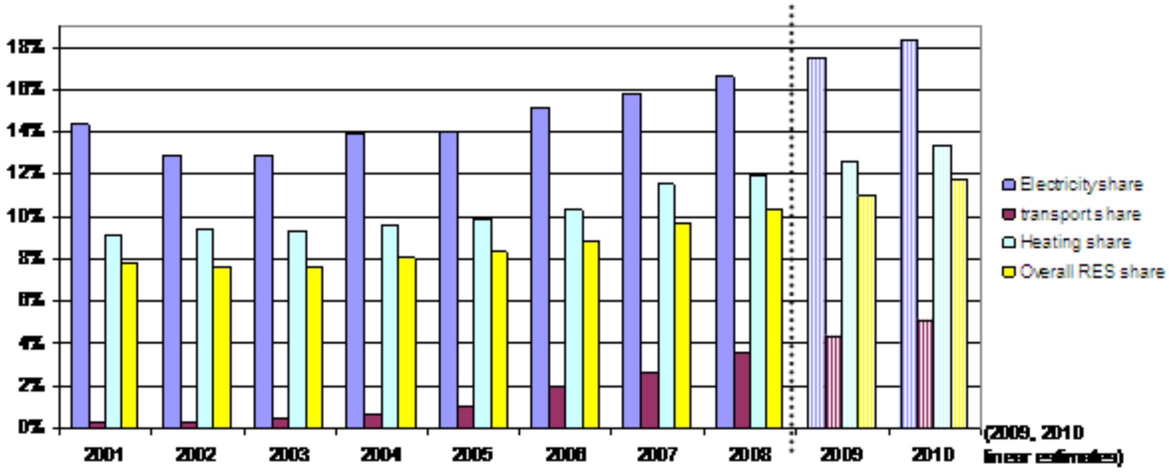
[11] 2009/28/EC

Energy Directive does not set interim targets for 2010. However, two previous directives (Directive 2001/77/EC on renewable electricity and Directive 2003/30/EC on biofuels) – contains indicative targets. The EU as a whole reached just over 18% in case of RES electricity by 2010 as opposed to the 21% target with only 7 member states being in compliance (Figure 4) (*SEC(2011) 130 final*). For transport, the achievement is 5.1% instead of 5.75% and only 9 states are in compliance (COM 2011/31 final). However, if Member States follow the course of action of their National Renewable Action Plan (NREAP) that was submitted in 2010, the 20% EU target will be met by 2020.

Figure 4 Sectoral and overall growth of renewable energy in the EU



Source: COM(2011) 31 final

I.3.3. Energy efficiency improvement

The best way to reduce emissions is to reduce energy use. The EU target for 2020 is to save 20% of its primary energy consumption compared to business-as-usual projections. Since 2006 Member States have an indicative energy savings target of 9% by 2016 that should be reached by the implementation of their national energy efficiency action plan (NEEAP) submitted to the Commission (Directive 2006/32/EC). Another policy stream is to harmonize the labelling of widely used household appliances (refrigerators, freezers, washing machines, dishwashers, ovens, water heaters and hot-water storage appliances, lighting sources and air-conditioning appliances) so as European consumers can base their consumer choices on the efficiency feature of the products (92/75/EEC). A third important piece of legislation regulates the energy efficiency of buildings being responsible for 40% of energy consumption across the EU. Member States must apply minimum requirements as regards the energy performance of new and existing buildings and establish an energy performance certification scheme (2002/91/EC). The recast of this directive requires that as of 2020 new buildings consume 'nearly zero' energy and the energy should mainly from renewable sources (2010/31/EU).

As the EU as a whole is not on track to reach its 20% target on primary energy saving by 2020, the Commission put forward a new directive to reinforce the activity of Member States.[12] The set of proposed measures, which are under serious discussion with the Member States:

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[12] The Commission's estimations suggest that the EU will achieve only half of the 20% target in 2020

- Member States have to set indicative national energy efficiency target by 2020, together with a 10-year heating and cooling plan to promote cogeneration investment and the upgrade of district heating networks,
- ‘energy efficient’ public procurement (products, services & buildings),
- energy efficiency refurbishment of 3% of public buildings annually,
- national energy saving obligation for utilities (1.5% reduction of their energy sales, by volume, of the previous year) achieved among final customers,
- mandatory energy audits for large companies,
- improve the energy management options for consumers via more informative energy bills (easy and free-of-charge access to data on real-time and historical energy consumption), smart meters and appropriate network tariff design, and individual metering for all flats (including multi-apartment buildings), and
- all new electricity generating plants above 20MW should recover waste heat and high-efficient cogeneration should receive priority dispatch.

After finalization of the directive it is likely to be adopted in 2012. The Commission will review progress in 2014 and propose binding national energy efficiency targets if the EU is still not on track to achieve the 20% target.

I.3.4. Non-ETS emissions reduction regime

Whereas the majority of the industrial sector is covered by the EU ETS, other major emission sources (most notably transport, buildings, agriculture and waste) were then left to the mandate of the Member States. In 2009 the EU via its 'Effort Sharing Decision’ introduced binding emissions limits to each Member State that correspond to an overall 10% reduction in the EU compared to 2005 levels as a contribution to the 20% GHG reduction set in the Climate and Energy Package (Decision 406/2009/EC). The national targets range from –20% (Luxembourg, Denmark and Ireland) to 20% (Bulgaria) according to the relative wealth of the Member State.

I.3.5. Carbon capture and storage

Carbon capture and storage (CCS) technology allows for the capture of carbon dioxide emissions of coal fired power plants and their storage in underground geological formations, thus reducing the global warming impact of electricity generation. The CCS, however, is not yet a proven technology in commercial scale. Therefore the EU created favourable aid regulation for CCS and provides direct financial support to demonstration projects with the aim of commercial update by 2020. The main market driver – apart from the direct financial aid for the technology development - to the use of CCS technology is the future price of carbon. The PRIMES model used by the European Commission forecasts 39 €’08/tCO2 in 2030 that would drive CCS investment from 5.4 GW (demonstration plants) in 2020 to 35 GW (EU Energy Trends 2030). The corresponding share of CCS generation in total power generation is 8.7% meaning that 23.6% of CO_2 emissions from power generation are projected to be captured and sequestrated. A CCS Directive establishes a comprehensive legal framework to manage the environmental risks of capture, transport and storage of CO_2 and removes existing legal barriers in EU legislation (2009/31/EC).

(SEC(2011)277).

I.4. Emissions trading

After the overview of the various policy areas that ultimately contribute to the reduction of GHG emissions, we now focus on the most important EU policy tool: emissions trading. The following chapter briefly provides a theoretical background of emissions trading, describes the three regulatory phases of EU ETS and tries to give a tentative assessment with some policy lessons. (For CO_2 emissions trading initiatives in the US see Annex A.)

I.4.1. The concept of emissions trading

Emission trading is a good policy tool when dealing with pollutants that do not cause immediate threat to their environment as it has a buffer capacity that can handle a certain amount of the pollution (e.g. the atmosphere and GHGs). The first regulatory task is to define the boundaries of the emissions trading scheme, namely what kind of entities are involved, which substances need to be regulated, and what is the time period of the regulation. Next, the state/regulator determines the total emissions for a given period of time, the so called "cap". The cap than is divided into allowance units and distributed among the regulated companies. At the end of each year the regulated facilities must issue and present allowances equalling to their annual emissions. Allowances are freely tradable among the regulated facilities.

Emission trading is frequently criticized for simply redistributing pollution instead of reducing it. In fact, before any emission trading is started, the authority establishes the desired extent of emission reduction. It is determined by the number of emission allowances issued. If they are abundant, their price will be low resulting in little reduction. For a most effective clean-up effect, emission trading schemes should constantly generate positive market prices signalling scarcity in the market.

I.4.2. Cost-efficiency of emissions trading

Due to the fact that extra costs are generated for users of natural resources and environmental services, environmental policies have been regularly objected to by both businesses and households. Objections are stronger if a national environmental policy is more stringent than that introduced in other countries or if the costs incurred are excessive. The European climate policy has been, and is, being criticised in two aspects: its costs imposed upon Europeans look rather high and non-EU countries are reluctant to follow. Therefore, in order to meet the targeted emission reductions, it is very important for the European climate policy makers to find the most cost-efficient instruments.

Cost efficiency of emission trading is guaranteed by the polluters' efforts to find the cheapest solution using their freedom to redistribute and/or reallocate the total of predetermined emission rights among themselves. Theoretically, any polluter would use emission allowances trading as long as it is more economical than cutting back emissions. The totality of numerous individual decisions results in such emission allocation patterns that dynamically adjust to technological changes and market prices variations. Let's assume the case when no CO_2 regulation exists and only two companies are operating in the energy sector: company A and company B (Figure 5). Initially they emit Q_a and Q_b amount of CO_2, with their marginal abatement costs (MAC). Shortly an emission trading scheme is set up to fix a total cap of 2Q for the sector, both companies obtaining a Q amount of CO_2 allowance. In absence of emissions trading, company A would have to reduce its emission from Q_a, to Q, company B from Q_b to Q. In this case the area of Q_aQT triangle (Company A) and the area of Q_bQV triangle (Company B) represent the total abatement cost for each of them respectively. This solution however is not cost-efficient because the CO_2 emission reduction to level 2Q is not realized at the least possible cost. This is clearly shown by the marginal clean-up costs encountered: company B having the clean-up cost P_B, while company A as low as P_A.

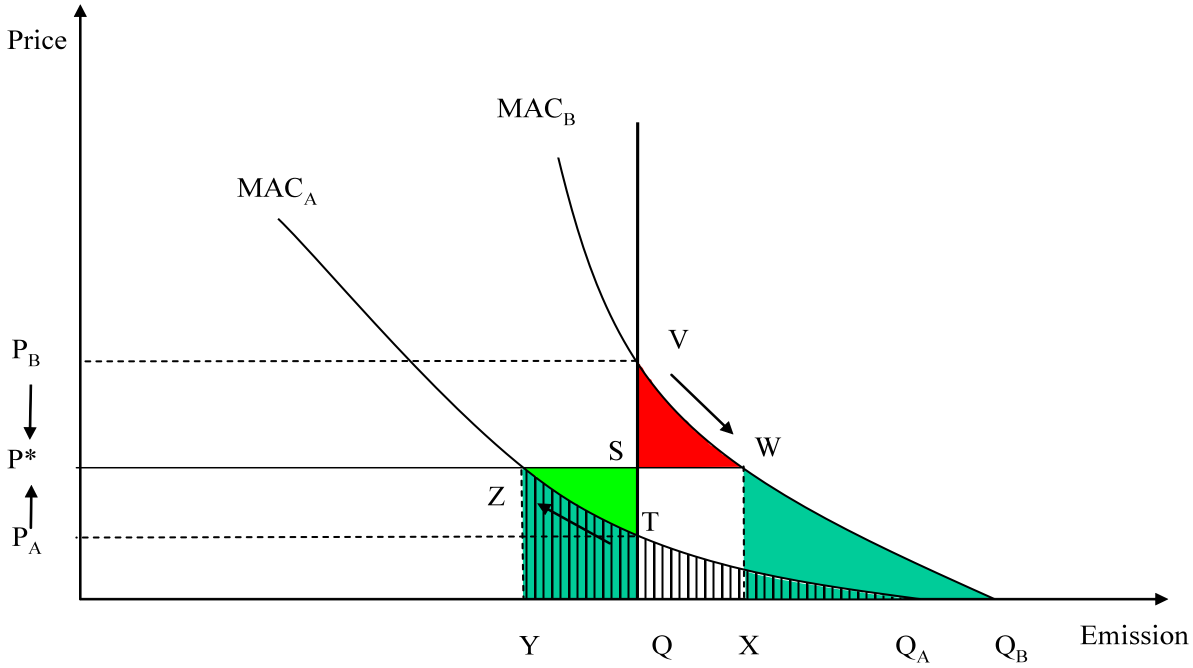
In the case of greenhouse gases being perfectly intermixed global pollutants, the location of their emission point is irrelevant. Therefore, the policies should facilitate a least cost aggregated abatement allocation to emerge. If company A reduces its CO_2 emission not only to the level of Q, but further down to level Y, than company A incurs additional abatement costs represented by the quadrangle area QYZT. But why company A would do this? The answer is very simple: because company A can sell the related emission rights (the amount of Q-Y) to company B. Company A is interested to sell these quotas at a price sufficient to cover at least the additional total abatement cost (QYZS quadrangle area). And why company B would be interested to buy these emission rights? Because due to this purchase, company B would not have to reduce its CO_2 emission to level Q, but just to the level X, saving substantial abatement costs equalling to the QVWX quadrangle area. Since this area is much larger than the additional clean-up cost area QYZT of company A, much room is left to strike a deal and agree on a quota price advantageous for both companies.

Obviously, emission trading makes sense until an incremental emission unit remains cheaper to clean up by company A than by company B, that is, until the marginal abatement costs are equal. (This may be considered as the definition of a cost-efficient allocation of emission allowances). In our example, this situation is achieved when company A owns Y allowances and company B owns X allowances. In that allocation (X-Q) equals with (Q-Y), meaning a total 2Q emission in the energy sector, with a total reduction cost lower than without emissions trading used.

There is a strong incentive to settle the price of emission allowances at P*, a value being equal to the marginal abatement cost found within the regulated industry. Above lines P_A and below P_B quite a wide range of prices exist encouraging both companies to negotiate a date when their emissions are close enough to Q, thus allowing both of them to obtain a better deal than a no trading situation. The closer they get to the most cost-efficient allocation of emissions, the closer the possible prices approach the value P*.

It is important also to observe that the industry (society) saves substantial abatement costs with emissions trading. Because it buys additional allowances instead of spending for clean-up, company B saves considerable amount of abatement cost between Q and X, company A on the other hand incurs much smaller extra abatement expenses between Q and Y resulting in a total cost saving for the society given by the sum STZ + SVW. It is to be noted that funds exchanged (i.e. paid and received) within emissions trading transactions are independent of, and not accounted in social cost-efficiency context.

Figure 5 Cost-efficient emission reduction with tradable CO_2 emission quotas in case of two companies A and B with different abatement cost curves



Source: Lesi-Pál (2005a)

Legend:

MAC_A: marginal abatement cost of company A

MAC_B: marginal abatement cost of company B

Q_A: initial emission level of company A

B_A: initial emission level of company B

Q: emission cap for both companies

P: equilibrium price of allowance*

The cost-efficient allocation of emission allowances is an equilibrium solution regardless of the initial allocation of emissions and emission rights. This means that the optimal level of individual pollution is determined only by the individual reduction costs and the market price of the emission allowances (see Annex B). This equilibrium however has two necessary conditions: at equilibrium marginal abatement costs must be equal and the total emission should also be equal to the approved amount of emission allowances.

I.4.3. The EU Emissions Trading Scheme

According to the European regulation, emitting carbon-dioxide by facilities covered by the ETS without permits is not allowed since 1st January 2005. The directive obliges companies to issue at the end of each year as many EUAs as their annual emissions are. One allowance gives the right to emit one ton of CO_2. Member States are currently required to draw up national allocation plans (NAPs) for each trading period setting out how many allowances each installation will receive each year. Companies that keep their emissions below the level of their pre-determined allowances can sell their excess allowances to other market players at a price determined by supply and demand or bank them for the coming year. Those unable to remain within their allowance limit have to either take measures to reduce their emissions and/or buy extra allowances from the market. Emissions are monitored and reported by installation operators, verified by independent audit companies and supervised by the respective government authority year-by-year. Installations that do not surrender enough allowances to cover their emissions in the previous year are penalized: they have to make up the shortfall in the following year and must pay a fine for each excess ton of CO_2. Allowances are free to be banked within a period but cannot be banked and carried over to subsequent periods.

The EU ETS has been launched gradually in three main phases. The first, trial phase started in 2005 and ended in 2007, the second one, matching the Kyoto period, will end in 2012, while the third phase will cover the years from 2013 to 2020.

Phase 1: 2005-2007

The main achievement of this trial phase was to establish the system for monitoring, reporting and verifying emissions of the approx. 12 000 installations. These installations belong to 5 sectors and are responsible for half of EU's total CO_2 emissions. The scheme covered CO_2 emissions from high-emitting installations in the power and heat generation industry and in selected energy-intensive industrial sectors: combustion plants, oil refineries, coke ovens, iron and steel plants and factories making cement, glass, lime, bricks, ceramics, pulp and paper. The initial allocation of EUAs is based on past emissions (grandfathering) and the NAPs of each Member State had to be approved by the European Commission to ensure thatthe proposed total quantity of allowances is in line with a Member State's Kyoto target. NAPs have been – in most Member States - based on emissions data provided by the installations themselves and in general used inflated projections. The Commission has approved the allocation of about 6.57 billion allowances in total for this trading period. Most allowances (at least 95%) has been allocated free of charge. The national registries holding the allowances in accounts have been set up to allow for the accurate accounting and keeping track of the ownership of each allowance. The fine for non-compliance in this period was 40 EUR/ton CO_2.

Phase 2: 2008-2012

The second phase left the structure and the operation intact but tried to reinforce the scheme by reducing the overall cap (forcing Member States to reduce their cap with the rejection of NAPs), increasing the room for auctioning (from max. 5% to 10%) and raising the fine from 40 to 100 EUR/ton. The Commission corrected for the over-allocation of the Phase 1 by imposing a formula to assess the NAPs submitted by the Member States. An important contributor to this exercise was the knowledge of verified emissions. Additionally, the scheme has been extended to:

- emissions of nitrous oxide from the production of nitric acid (from 2008)
- include Iceland, Liechtenstein and Norway (from 2008)
- CO_2 emissions from civil aviation (from 2012).[13]

Installations are able – within limits - to use credits (ERU and CER) generated under the Kyoto Protocol to fulfil their obligations in the EU scheme. The access to external credits as mandated in the Linking Directive (2003/87/EC) had provided strong impetus for emissions reduction projects in the developing world as European companies could buy CDM cheaper (or by executing the investment themselves) than EUAs (Ellerman and Buchner, 2007).

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[13] All airlines (regardless of their nationalities) need allowances to cover the emissions from their flights to, from or within the EU.

Phase 3: 2013-2020

The role of this longer phase is to serve as the key instrument to reach the 20% GHG reduction target of the EU. Changes in the regulation are threefold. First, a single EU cap replaces the national caps and it is gradually shrinking. The baseline size of the cap will be the average annual number of allowances allocated in the 2008-2012 period that will reduce by 1.74% each year in a linear fashion. This means that by 2020 the cap will be 21% below 2005 emissions level. Second, auctioning is gradually crowding out free of charge allowance allocation. Power generation becomes the subject of full auctioning as it can mostly pass on the extra cost to the consumers. However, the regulation allows for certain Member States to derogate from this rule temporarily and grant up to 70% of allowances for free in 2013 but has to decrease progressively by 2020 (Art. 10c of the revised ETS Directive). For other sectors, the starting auctioning rate, i.e. the share of auctioned allowanced in the total allocated to the industrial sectors is 20% (in 2013) and rising to 70% by 2020. However, certain energy intensive sectors can derogate from this rule on competitiveness claims and hence receive 100% for free. These sectors that are exposed to the risk of carbon leakage (i.e. production and consequently GHG emissions relocation to countries without CO_2 regulation) are defined on the basis of their exposure to competition with non-EU producers. In addition, free allocation to industry will be benchmarked to the 10% most efficient installations of the (sub)sector. This means that installation that meet the benchmark will receive all allowances they need, however those below will have to either invest in abatement or buy allowances from the market. The majority (88%) of auction revenues will be distributed among the Member States on the basis of their 2005 emissions, 10% will be allocate to the poorest states and the remaining 2% among those who reduced this emissions at least 20% below their Kyoto Protocol base year by 2005 (CEE countries). A third change is the further extension of the coverage of ETS.[14] This will extend the coverage from 40% to 43% of EU total GHG emissions.

I.4.4. Drivers of allowance price

EUA is a traded commodity and its price is determined by market demand and supply. The demand side of the markets is determined by the approximately 12,000 firms under the obligation to own an amount of European Union Allowances (EUAs) sufficient to cover their yearly emissions following year 2005. An aggregate demand curve represents the total demand of these 12,000 firms, individual demand curves correspond to the respective company's marginal CO_2 abatement cost (MAC) curve. Thus the total demand for emission allowances is represented by the aggregate marginal abatement cost curve.

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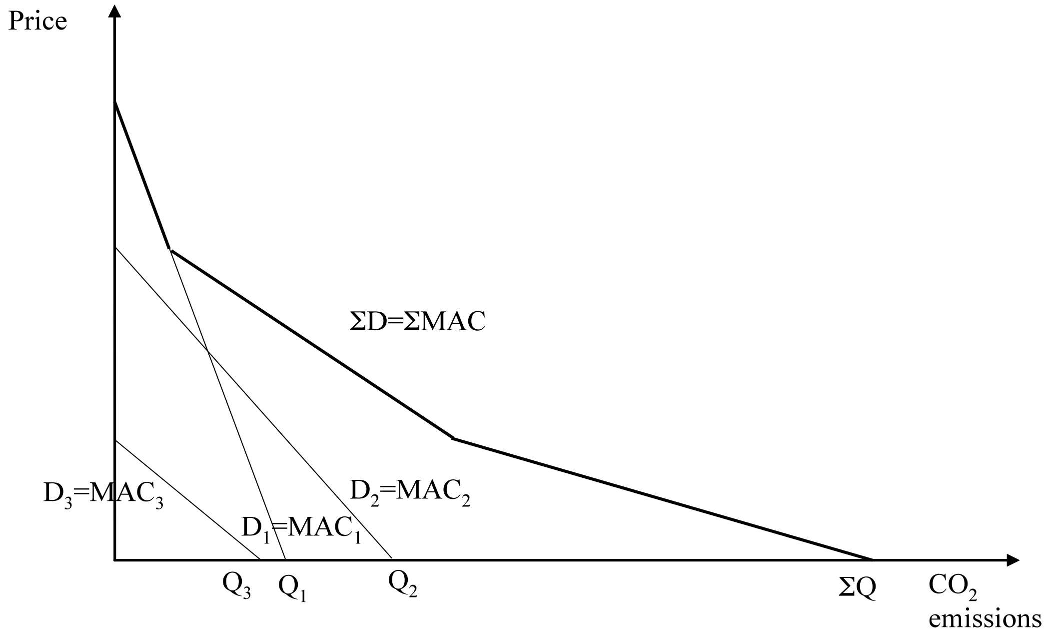
[14] Installations undertaking the capture, transport and geological storage of greenhouse gases; CO_2 emissions from the petrochemicals, ammonia and aluminium sectors; nitrous oxide emissions from the production of nitric, adipic and glyoxylic acid; and perfluorocarbon emissions from aluminium production

Figure 6 The aggregate CO_2 demand curve obtained from the individual MAC curves



Legend:

$MAC_{1,2,3}$: marginal abatement cost of company 1,2 and 3

∑MAC: aggregated marginal abatement cost

Q1,2,3: initial emission levels of company1,2 and 3

∑Q: aggregated emissions

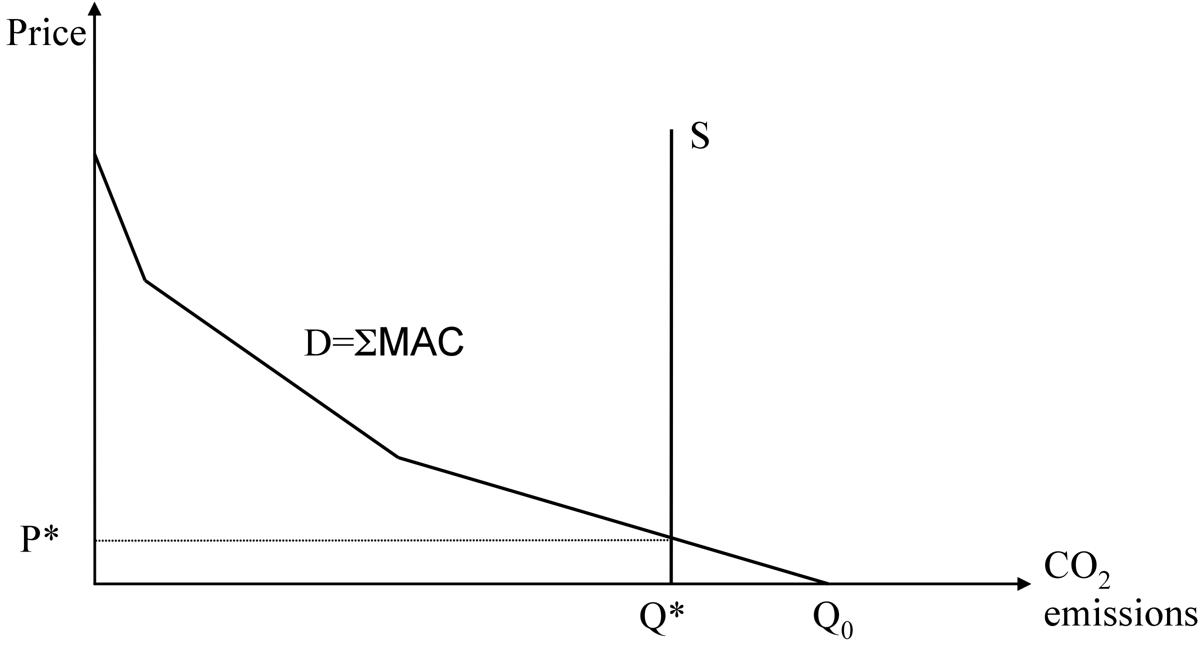
If CO_2 emissions bear no costs then Company 1 emits Q_1, Company 2 emits Q_2, and Company 3 emits Q_3 resulting the total CO_2 emission of ∑Q (Figure 6). When CO_2 emissions are costly, the three companies reduce their emissions to different extents as illustrated with D_1, D_2 and D_3 functions respectively.

Several factors influence the demand for EUA but the majority of them – such as technology development, firm closure and/or new companies - has only minor and gradually appearing influence. Real and speculative demand should be distinguished. The most fundamental factor is the real or long-term demand that is determined by participants using EUAs as a production factor. On the other hand, a large part of EUA transactions is speculative, i.e. actors do use these products strictly to earn profit through their trading. Such trading improves market liquidity and channels information to the actors of the market. As such, speculative trading is essential for sustaining fundamental demand necessary for efficient transactions.

Economic growth and weather have also considerable impact on EUA demand. The economic growth of EU Member States influences EUA markets in two ways: directly through the ETS sector productivity and indirectly by the changing energy demand. Both influences have the same direction: the faster the economy grows the more the demand for EUA increases. As far as the weather is concerned, on one hand, electricity and heat production is largely dependent on temperature: a colder and/or a longer winter increases both heat and electricity production causing more CO_2 emissions by power plants which thus are being forced to increase their demand for EUAs. On the other hand, rainfall too has an impact on EUA price. In case of water abundance hydro power plants can produce above the average, and because hydro power usually enjoys preferential dispatch, fossil fuel plants will produce less. Producing more electricity with hydro plants reduces CO_2 emissions, resulting in diminished EUA demand.

The supply of allowances is not market driven but set by the government. The decision on the overall ‘cap’ is essentially of political nature and reflects the willingness of the society to reduce emissions and commit resources to this end. In case of EU ETS it is prepared by the EU Member States (National Allocation Plans) and approved by the Commission. These documents define national overall caps i.e. the maximum amount to be included in the scheme that firms can emit. Within a regulatory period, firms dispose the same EUA amount for each year. The successive periods are hallmarked by increasingly tight administrative caps. As illustrated in the Figure 7 below, the EUA price is determined by an inelastic supply that is set by the competent authority in advance to the trading period and an aggregate marginal abatement cost of significant elasticity.

Figure 7 Inelastic supply and the aggregate demand in emission markets



Legend:

∑MAC: aggregated marginal abatement cost

D: aggregate demand

S: administrative supply

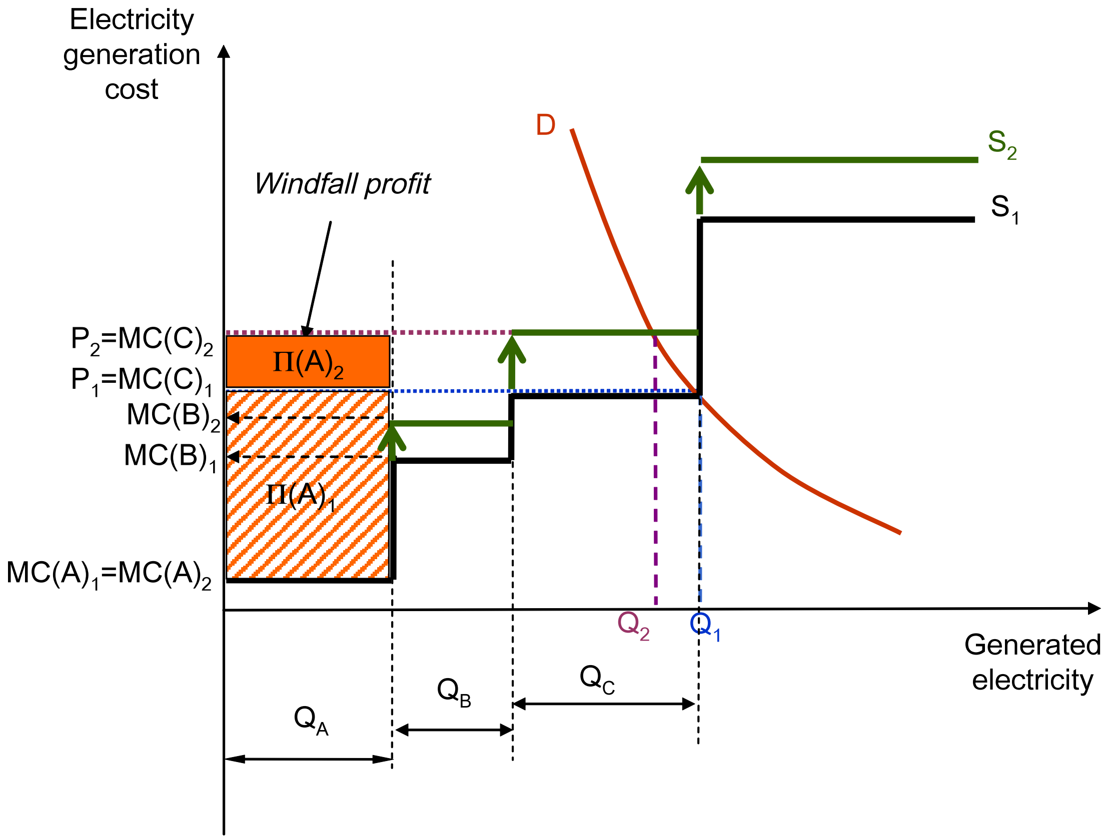
P: allowance price*

The equilibrium price P* is determined by the intersection of aggregate MAC curve of firms (i.e. demand curve) and the total cap line S determined by the National Allocation Plans. The figure shows that a flatter demand curve has similar impact on equilibrium price as a higher supply: lower price. The direct supply includes the amount of EUAs allocated for free and the amount auctioned by the government. These are the elements of supply that market players have to account for.

I.4.5. The impact of EU Emissions Trading Scheme on electricity production

The EU ETS assigns economic value to carbon-dioxide, to a product which was worthless before. Since the ETS was launched, companies have used the carbon-dioxide quotas as a production resource just like fuel or labour. Since its implementation, emissions trading has had a strong influence on several connected markets. Such an effect is shown below in theFigure 8, which illustrates a simplified electricity market.

Figure 8 Effect of the EU-ETS in a sample electricity market



Source: Lesi – Pál (2005b)

Legend:

$MC(A)_1$: marginal generation cost of producer A without carbon regulation

$MC(B)_1$: marginal generation cost of producer B without carbon regulation

$MC(C)_1$: marginal generation cost of producer C without carbon regulation

$MC(A)_2$: marginal generation cost of producer A with carbon regulation

$MC(B)_1$: marginal generation cost of producer B with carbon regulation

$MC(C)_1$: marginal generation cost of producer C with carbon regulation

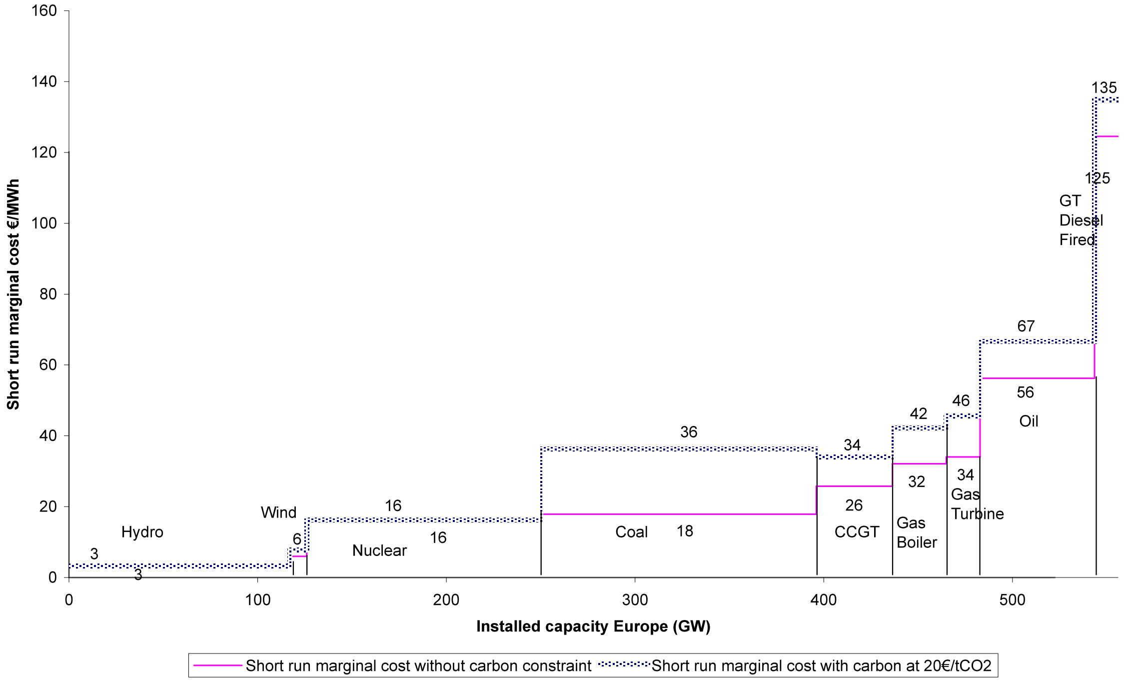
D: electricity demand

Without carbon-dioxide regulation, the supply curve of electricity can be represented by line S_1, the demand for electricity by the curve D. As soon as a positive value is assigned to carbon-dioxide, each electricity producer incurs different cost increases composed of two parts. On one hand additional costs emerge when - due to costly emissions - investing into emission reduction seems to be more profitable, when the investment cost per emission unit is smaller than the corresponding price of the emission quota. The other part of cost increase emerges from the value of allowances that are needed to cover the remaining pollution.

Let's assume three generators: A being a nuclear unit, B an efficient coal power plant and C an old coal-fired thermal unit. Before CO_2 regulation all three of them produce at maximum output. The nuclear power plant produces Q_a amount of electricity, the new coal-fired power plant generates Q_b, while the old one generates Q_c. The equilibrium price of electricity emerges at the point where demand equals to supply, resulting in an equilibrium price of P_1. However, when ETS is implemented, the three different generators incur different cost increases. The nuclear generator (or could be a renewable plant as well) having no CO_2 emission, continues to produce electricity at the same $MC(A)_2 = MC(A)_1$ cost. Marginal cost of the new coal-fired power plant is increased from $MC(B)_1$ to $MC(B)_2$. Naturally, the cost increase for the old coal-fired generator is even higher. Because the supply line shifted up into the position depicted by S_2 and the demand curve D remaining elastic, the equilibrium price of electricity increases to P_2. Another effect of regulation is that electricity consumption decreases to Q_2, a quantity smaller then the initially consumed Q_1. Some producers come out of this situation as winners: e.g. while the electricity price increases, nuclear generators do not incur cost increase, so their profit also increases by $\Pi(A)_2$, an increase frequently referred to as "windfall" profit.

In the following Figure 9, an example is given - using values very close to real-life data -, showing how a CO_2 cost change may modify the European electricity supply curve (CCGT and coal shifting places).

Figure 9 European merit order curve without CO_2 regulation and with 20 €/t CO_2 price



Source: IEA

I.4.6. EU Emissions Trading Scheme: Assessment and policy lessons

Although it is quite difficult to assess such a complex and quite novel policy tool, it might be worthwhile to examine a few central questions: 1) whether abatement has occurred due to the scheme, 2) whether it has accelerated technology development towards low-carbon solutions, 3) what is the impact on electricity prices, and 4) whether it has created economic rents.[15]

Abatement

A number of studies provide evidence that the scheme has induced significant abatement in its first 5 years measured as emissions intensity improvements above historical trends.[16] Estimates range between 2% and 5% of total emissions covered by the scheme. The bulk of abatement happened in the energy sector, driven by switching from coal to gas in which the autonomous effect of then prevailing and expected carbon price has been detected. The evidence of the abatement effect of the new EU carbon market, however, is not fully straightforward as it is very difficult to derive the effect of single explanatory factor while controlling for all the others (e.g. energy prices, regulatory changes etc.).

Technology change

Less controversial is the effect on technological development. The question is whether it can significantly alter the current technology stock so as on the long run and even in the case of missing global carbon market Europe can remain competitive by running on low cost and low carbon technologies. In case the EU would decide to use only carbon price to significantly reshape the current technology stock, it would most likely require much higher carbon price and a regulatory stability beyond the current mandate (until 2020). It does not mean, however, that the current carbon price is without any effect on technology choice: it rewards more efficient installations within the same technology group as with the carbon price factored into investment decisions it biases towards the more fuel efficient options. Much higher carbon price, however, would impose serious competitiveness loss on EU companies in case the rest of the world does not follow suit in placing a price tag on carbon emissions. An implicit acceptance of the limited capacity of ETS to drive innovation, is the technology focused policies of the EU and its Member States, such as the direct support of renewable technologies or CCS, together with the dedicated innovation measured set forth in the Strategic Energy Technology Plan (SET Plan).

Electricity price

The pricing of carbon in the EU ETS raise the price of electricity as the price setting marginal producer includes the carbon cost (see Figure 8 before). In addition, the introduction of carbon price might alter the merit order and hence modify the generation mix. It is important to note that this assumes a competitive wholesale market, and as such does not refer to the EU as whole but only to individual regional electricity markets. The demarcation of countries that constitute a market varies from minute to minute depending on the scarcity of interconnecting lines. The extent of the price increase depends on the carbon intensity of the marginal producer.

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[15] This assessment is partly based on Egenhofer et al. (2011).

[16] The most often cited is Ellerman, Convery and de Perthuis (2010).

Profit

An important point of discussion about the efficiency of EU ETS is the distributional effect of free allowance allocation to the various industrial and energy companies operating under quite different market environments. As we have demonstrated before, the imposition on carbon price creates windfall profit for power generators that suffer lower marginal cost increase with the introduction of emissions trading than the marginal producer. The extra profit is earned as electricity price increases while production cost remains the same or increase but to a smaller extent. This is an intended effect of the regulation. However, once allowances are allocated for free – as in the case of Phase 1 and 2 - companies enjoy further profits depending on their ability to pass the carbon cost to their consumers in the form of higher prices.[17] The energy sector in general has better opportunities in this respect than those industries operating on a competitive commodity market. This profit can be eliminated or reduced either by taxing it (e.g. Spain, UK, Greece) or simply by mandating the auctioning allowances instead of free allocation (as planned for Phase 3) (Copenhagen Economics, 2010). The rent – in case of auctioning – would not accrue to the companies but to the public budget. Various estimates suggest that the overall volume of windfall profit was between 13 and 19 bn € in the 2005-2008 period (Keats and Neuhoff, 2005; Ellermann, Convery and de Perthuis, 2010; De Bruyn et al., 2010; Sijm, 2008).

The EU ETS was successful in creating a European carbon market with all the necessary institutions, creating a price for carbon and a new traded commodity (EUA) and is planned to be the central policy instrument in Europe to mitigate GHG emissions. Its introduction and evolution up to now offer some policy lessons.

Designing a policy instrument on ambiguous data is risky. Phase 1 was characterized by substantial over-allocation. The initial allocation of allowances was based on past installation level production/emissions data provided by the companies. As CO_2 was not regulated before 2005, the companies themselves had no clear information on their own emissions. Naturally, in the national allocation process they pushed the authority towards the upper bound of their own estimates in order to be safe in covering their future emissions. This has led to a situation without scarcity i.e. actual emissions were smaller than the allocated allowances. The average annual cap is 2 152 Mt and the highest yearly emission (2007) was only 2050 Mt.[18] This – together with the banking restriction from Phase 1 to Phase 2 has led to the collapse of EUA price in 2006 (Figure 10). The grey line indicates the Phase 1 EUA price that is different from Phase 2 price due to the banking prohibition. The publication of 2005 verified data and the consequent realization of abundance drove the price down in May 2006 and the two prices started to decouple. Phase 1 allowance has gradually lost its value while Phase 2 EUA price recovered when market actors received signals of future scarcity (Commission rejecting NAPs and pushing for lower national caps).

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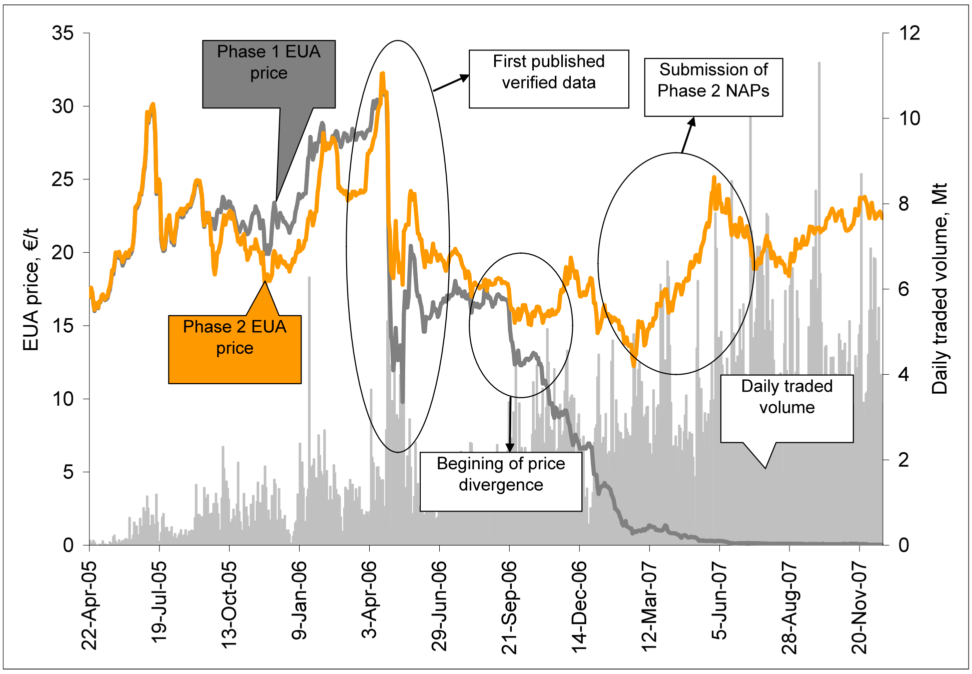
[17] In total, less than 0.2% of all allowances were auctioned in Phase 1 and some 3% in Phase 2 (Ellerman, Convery and de Perthuis, 2010, p. 62).

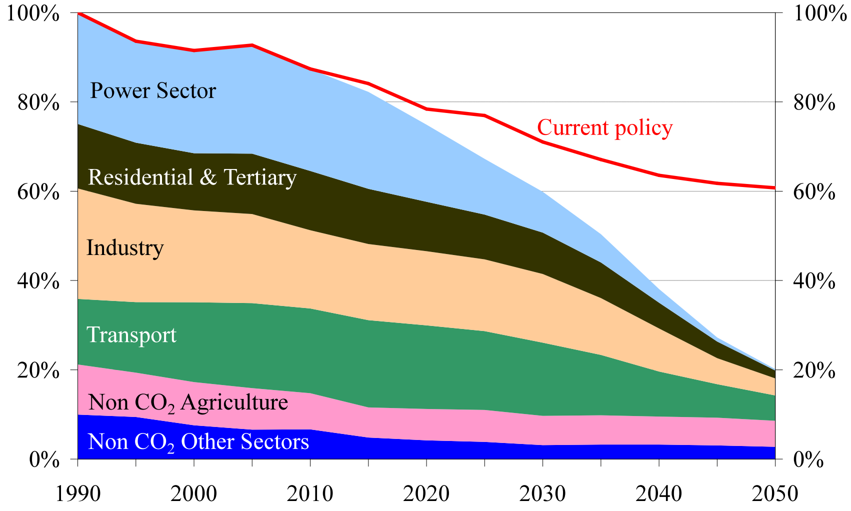
[18] source: Community Independent Transaction Log (CITL)

Figure 10 Phase 1 and Phase 2 EUA price development



Long term targets and the transparency of modalities to fulfil these targets are needed for an effective trading scheme due to the long investment cycles of the energy and the covered industrial sectors. The EU ETS – although born as a tool to fulfil Kyoto obligations – by now is an independent policy that is to remain operational in the medium term. Operational details are fully known until 2020 but the wider policy goals of the EU are set by 2050. The "Roadmap for moving to a competitive low-carbon economy in 2050" sets out a plan to meet the ambitious target of reducing emissions by 80% as agreed by European governments (Figure 11). Long term targets together with inter-phase banking can reduce price volatility and correct for such unexpected events as the current economic downturn that reduced the demand for allowance considerably.

Figure 11 EU GHG emissions towards an 80% domestic reduction (100% =1990)



Source: COM(2011) 112 final

It is important to leave considerable mandate to the Member States when initiating a brand new policy tool even at the expense of efficiency. Allocating allowances on the basis of Member State proposals (NAPs) created inconsistencies in the scheme (different allocation rules for closure, new entrants etc.) but probably was instrumental for the cooperation between the states and the Commission. Free allocation, similarly, was probably crucial in ‘co-opting’ companies that got included in the scheme in 2005.

II. SCALING UP RENEWABLE ENERGY USE

This section describes the major renewable technologies used for grid-connected power production, including their environmental impacts and generation characteristics. Stand-alone systems are not discussed as they are less important from a regulatory point of view.

II.1. Renewable energy technologies

The various types of renewable energy sources can be used in different ways (Table 2). While hydro and wind power are used exclusively for electricity generation, geothermal and solar can generate both electricity and heat.[19] Biofuels (fuels derived from organic matter) such as biodiesel and bioethanol are the main substitutes for petrol and diesel fuels in transportation available on a large scale and usable by ordinary vehicles.

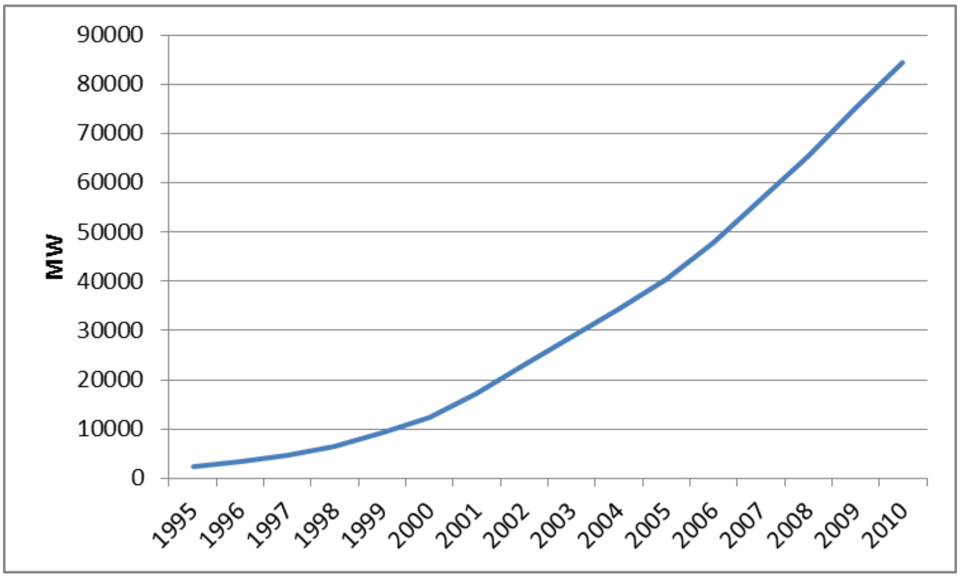
Table 2 Uses of renewable energy

	electricity	**heat**	**Transport**
Bioenergy	√	√	√
Solar	√	√	
Geothermal	√	√	
Wind	√		
Hydro	√		

Wind power

Wind power is one of the most rapidly spreading renewable energy technology. In Europe during the last decade installed wind capacity increased sharply and occupies the third place behind hydro and biomass power (Figure 12).

Figure 12Cumulative installed wind capacity in EU27 (1995-2010, MW)



Source: Enerdata

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[19] Heating in general energy discussion covers cooling as well.

Modern wind turbines extract energy from the wind by transferring the momentum of passing air to rotor blades. The power that can be generated depends on the density of the air, the wind speed and the size of the turbine. The rotors of most wind turbines face into the wind and follow changes in wind direction. Energy is concentrated into a rotating shaft and converted into electricity. The average capacity increases with higher hub height and rotor circular surface. Wind farms are deployed either on land or off-shore. This energy source has relatively low investment cost and very low marginal cost (i.e. only minor maintenance is needed).

Early machines - twenty-five years ago - were fairly small (50-100 kW, 15-20 m blade diameter) but there has been a steady growth in size and output power. Currently, onshore supply is dominated by turbines between 1.5 and 2 MW. The key factor in maintaining design development into the multi-megawatt range has been the development of an offshore market. For offshore applications, optimum overall economics, even at higher cost per kW in the units themselves, require larger turbine units to limit the proportionally higher costs of infrastructure (foundations, electricity collection and sub-sea transmission). The energy yield is improved because the rotor is located higher above the ground able to intercept higher-velocity winds.[20]

The external costs associated with wind energy derive from upstream production processes (system parts, concrete, roads, etc.) and visual intrusion/noise that can be a crucial issue in the permitting process (usually local communities have to approve such developments). Wind turbines have zero emissions during operation.

The electricity produced from wind depends on the weather conditions (wind speed) and as such it is an intermittent energy resource with rather low utilization rate (load factor[21]). A 2010 survey of International Energy Agency (IEA) registered load factors between 21% and 41% for onshore wind turbines, and 34% to 43% for offshore wind farms (IEA, 2010). The optimal integration of wind energy requires a system that can always uptake load generated by wind turbines (no curtailment). No marginal cost places wind always on the beginning of the merit order: the more time it is dispatched, the better. However, once there is no wind, adequate back-up capacities must be in place to guarantee reliable uninterrupted power supply. Consequently, forecasting wind pattern is a crucial task.

Solar energy

The two forms of converting the energy of the Sun into electricity are through photovoltaic systems (PV) and – in a larger scale – by solar thermal power plants. Photovoltaic power generation uses solar cells to convert light directly into electricity. Miniature cells power pocket calculators, in the kW range households as well can be powered by such systems. In stand-alone systems the energy not used instantly has to be stored in batteries. Grid connected systems do not require storage. Stand-alone PV systems are mostly used in remote areas where an extension of a grid is far too expensive. Grid connected PV installations are coupled with two-way meters measuring both incoming electricity from the grid and electricity fed into the grid when generated by the PV system. PV systems are flexible and rather easy to install as they consist of panels (comprising a number of cells filled with semiconductors,

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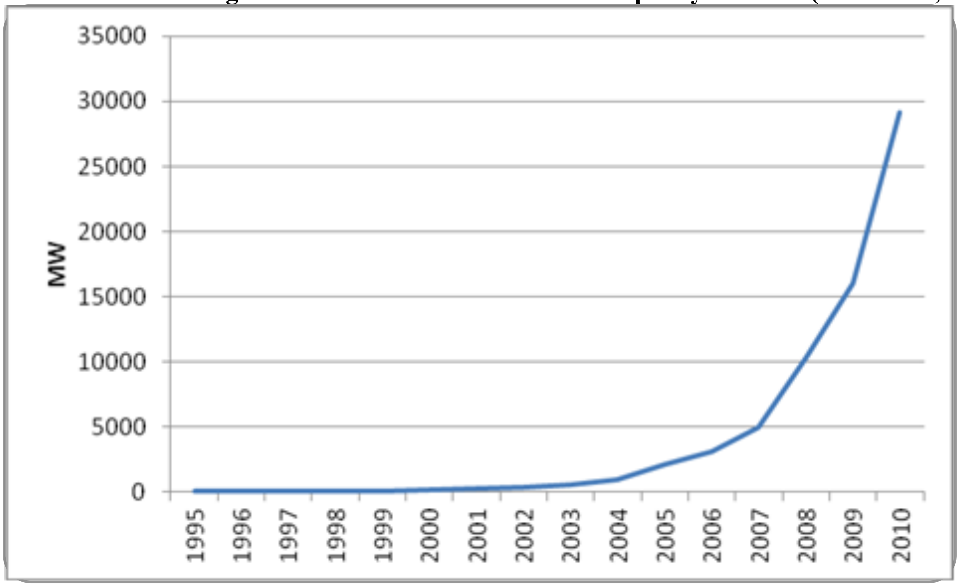
[20] http://www.worldenergy.org/publications/survey_of_energy_resources_2007/wind_energy/744.asp
http://www.wind-energy-the-facts.org/en/part-i-technology/chapter-3-wind-turbine-technology/evolution-of-commercial-wind-turbine-technology/growth-of-wind-turbine-size.html

[21] Load factor: the percentage of hours that a power plant operates at its maximum capability in a given time period.

mainly silicon). They are either ground-mounted or integrated into the roof or the walls of buildings. As the equipment cost is still relatively high, the spread of PV applications is mainly due to generous feed-in-tariffs. Germany is far ahead of other countries even though its endowment with sunlight[22] is worse than many of them. In Europe, in 2010, the growth of PV sector surpassed any other renewable electricity sector in terms of installed capacity with more than 13 GW connected to the grid representing 80% of the new global installed capacity. Most of PV capacity has been installed in Germany (7.4 GW), Italy (2.3 GW), Czech Republic (1.5 GW) and France (0.7 GW).

Figure 13. Cumulative installed PV capacity in EU27 (1995-2010, MW)



Source: Enerdata

Solar thermal plants use the high-temperature heat obtained from concentrating solar collectors to drive conventional engines. Solar power needs to be concentrated as soon as the radiation reaches the earth's surface into a density that is adequate for heating but not for an efficient electricity producing thermodynamic cycle. The capacities of the major solar power plants are within the range of 30-60 MW and are located in Spain, Portugal and Germany.

Solar power systems do not pollute the air. Major environmental impacts are associated indirectly with the production of solar panels, directly with the land use and visual intrusion of the structures.

Hydro power

Hydropower generation is a mature technology that converts the potential and kinetic energy of water into electricity. Storage power plants use the large heights of fall and storage capacity of dams and mountain lakes for electricity generation. Pumped-storage stations use pumps to elevate a mass of water into higher level reservoirs during periods of low grid load to be able to generate electricity as necessary. Run-of-river plants utilize the flow (kinetic) energy of a river or a canal letting water to flow through spin-turbine blades that are connected to generators.

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[22] It is called average solar irradiance and expressed in watts per square meter.

Hydropower is widely used in the world: major hydro-electricity producers are China, Canada, Brazil, the US and Russian Federation.[23] It is far the most important renewable electricity source in Europe as well.

The plant scale for hydropower varies from 5000 MW to 100 kW. Stations under 10 MW (small scale hydro) are usually treated differently by the energy regulation. Micropower usually denotes units under 300 kW as this is about the maximum size for most stand alone hydro systems not connected to a grid, and suitable for "run-of-the-river" operation. The world's largest hydro power plant is the Three Gorges Dam on the third longest river of the world (Yangtze, China). Its 32 turbines adding up to a 21500 MW total installed capacity generated 80 TWh electricity in 2008 (Gleich, 2009).

Hydropower is a very reliable technology free of airborne pollution. However, large plants potentially have serious environmental impacts on surrounding land and wildlife habitat via the changes in the reservoir and/or river water quantity and quality. Redirection of river water into artificial canals reduces the amount of water flow and may cause the drying up of former wetland areas known for their high biological diversity. In some cases, construction of reservoirs requires the destruction of human settlements with the dislocation of the local population.

Large hydro plants are suitable for base load power production but they are also dependent on precipitation patterns. Storage plants can supply both base load and peak load capacity. Pumped-storage power stations are usually constructed to provide peak load support and serve as quick response to failing power supply in a grid.

Biomass combustion

Solid biomass can be a source of electricity by processes including combustion, pyrolysis, hydrolysis or gasification. Major solid biomass fuels are wood and wood residuals, agricultural waste or energy-crops planted for this special purpose. Large scale electricity generation often takes place in conventional coal burning units where biomass and coal are burned together. Gasified solid biomass can power small steam engines and/or combined cycle units as well. Biogas - produced from organic waste through anaerobic fermentation or obtained from landfill gas – may be converted into electricity as well.

A typical biomass power plant capacity range is from 5-7 MWe (producing both electricity and heat) to electricity only plants of 20MWe and above. A special method of biomass based generation is co-firing of biomass and coal in refurbished traditional coal plants. Biomass plants are capable of producing according the production schedule, hence they can be incentivised via the tariff system to align with demand patterns (more in peak hours and less during the night).

Greenhouse gas emissions are significantly reduced by the reutilization of biomass. The carbon dioxide released when burning solid biomass is counterbalanced by the amount it did absorb as source plant in question when it was alive. However, there are always some emissions resulting from processes like cultivation and fuel production, so biomass is not completely carbon-free. Whether combusting it directly or subjected to gasification, biomass resources do generate air polluting emissions. These emissions vary depending upon the precise fuel and technology used. If wood is the primary biomass resource, very little SO_2 is emitted. NO_x emissions vary significantly among combustion facilities depending on their design and controls. They do emit particulate matters (PMs) as well. The most debated

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[23] http://www.eia.doe.gov/emeu/international/electricitygeneration.html

environmental issue about biomass burning is the sustainable use of wood resources. Many fear that – in spite the regulation at wood origin - due to the demand generated by power plants forests are logged beyond their regenerative capacity.

Geothermal energy

Geothermal energy is provided by the heat of the Earth and can be harnessed and utilized in the form of heat directly or transformed into electricity. Today its use has been limited to areas where geological conditions permit the use of a carrier (water in the liquid phase or steam) to transfer the heat from wells in deep hot zones up to the surface. However, a much awaited technological breakthrough ('Hot Dry Rock' or 'Enhanced Geothermal Systems' technology) promises heat recuperation directly from hot underground rocks thus massively extending the geographical availability of geothermal energy.

Geothermal systems can be found in regions with a normal or slightly above normal geothermal gradient (usually under 100°C), especially in regions located around seismic plate contours where geothermal gradients may be significantly higher than average values (100-400°C). The amount and hence the utilization of geothermal energy depends on the temperature of the carrier and the yield of the well. With current technology, electricity generation starts at approximately 90-100 °C. Lower temperature fluids facilitate only the direct use of heat for various purposes.

In Europe only Iceland and Italy have thermal water deposits at moderate depths suitable for electricity generation. Geothermal heat however is widely used for other purposes all over the continent predominantly via heat pumps. This consists of extracting heat from shallow geothermal fluid and transferring it to water or air used in space heating of individual households or district heating.

Although geothermal energy is quite environmentally friendly, it has some adverse effects not only resulting from the construction process but also encountered during plant operation. Geothermal fluids usually contain gases, mainly carbon dioxide, which are inevitably escaping into the atmosphere (roughly one-fifth of fossil power plant emissions). The quality of waste waters discharged by geothermal plants differs substantially according to their location. The discharge of salty wastewater or higher temperature wastewaters to natural freshwaters in general does constitute environmental risk but it is often minimized by legal requirement to re-inject waters into underground reservoir or strata. Additionally, geothermal resources can be considered as renewable only if the extraction of heat and fluids matches the natural recovery rate.

Geothermal power plant provides stable output with high load factor (approx. 95%), so they are suitable for base load production.

II.2. Regulatory tools supporting renewable energy

Most renewable energy technologies are not competitive with traditional non-renewable energy technologies partly because their use is constrained (e.g. low temperature geothermal fluids or high humidity biomass) but mainly because past technical development had a non-renewable focus. Due to the lack of sufficient past experience and innovation, renewables fall behind as less efficient and more costly. However, the spread of these technologies will bring about considerable cost reduction ('learning effect').

Renewable sources have smaller environmental impact and external costs (e.g. various air pollutions) than traditional electricity generation. Without the internalization of these costs, the conventional, fossil-based generators are more competitive and crowd out renewables from in the generation mix. This does not mean, however, that these costs disappear but are spread across the members of the society (i.e. paying tax to operate the national healthcare system to heal lung problems). Furthermore, renewable sources are decentralized and in most cases use local resources, thus helping to reduce transport losses and energy dependency. Finally, and most importantly, renewable energies are inexhaustible.

Assuming that the environment is a valuable asset, we have to rectify the failure of the market to consider all costs (including the external cost) associated with the various energy producing technologies. In real life, the problem is that the external cost of traditional technologies is not factored into the production decisions: dirty technologies are cheaper. To establish a true competitive market, the government has to intervene. The "first-best regulation" is to internalize external costs, the "second-best regulation" is to provides support for clean technologies.

The internalization of external costs can be done either by market based (taxes or pollution markets) or by non-market based instruments (e.g. pollution standards). If the government introduces a pollution tax than equals the external cost of each energy producing plant (lower or zero for renewables and higher for traditional technologies) than the merit order of producers will change: renewables improve their relative position and – depending on the original generation portfolio – can push out the most expensive fossil based generators.

However, environmental regulators tend to charge polluters for only a fraction of the damages they cause (i.e. sub-optimal pollution taxes). Government can correct for this by providing some regulatory support for producers offering the same product with less or no external cost. Such a support for renewable electricity producers is a payment for the avoided external costs, being equal to the difference between the marginal external costs of renewable and non-renewable electricity. It is important to note, however, that although this regulation has similar effect to the 'first-best' regarding the change in the merit order but results in lower equilibrium price and higher equilibrium quantity and because of the non-internalized externalities, in this case power plants do not pay the full (including social) cost of electricity production.

Now that we are familiar with the goals of such government support for renewables, let us see what tools and schemes are available for them.

II.2.1. Renewable energy support schemes

The penetration of renewable energy sources (RES) is usually supported in two forms. The first related to network access, the second pools various financial instruments targeting RES investment and operation. As far as network access is concerned, priority dispatch (or obligatory feed-in) mandates the network operator to take over the electricity produced from renewable sources (RES-E) regardless of its production cost. The only exception to this obligation is if the feed-in poses serious risk to system security. Priority dispatch is sometimes complemented by the appointment of a buyer for RES-E. This buyer can be the network operator or any third party that buys all RES-E, and as such reduces aggregated RES-E balancing cost and settles them against operational subsidies, if any.

Financial support schemes can target either investments in energy systems and/or the operation of energy generation facilities.[24] Additionally, it can target electricity and/or heat production from renewable resources.[25]

Investment support schemes might be direct investment financing programs (refundable or non-refundable), supported investment credits (credit support or credit guarantee) or investment tax support schemes (asset tax, turnover tax, duties, etc.). Financing of supports comes mainly from state budgets, sometimes from international financial institutions and/or development banks.

Production support schemes are focusing on the price or on the quantity of the renewable energy (Figure 14). The two major forms are the feed-in tariff (FIT) and the green certificate (GC) systems.In Fit schemes the RES-E producers receives a pre-set price for electricity that is higher than the market price. Green certificates are tradable commodities that represent the environmental value of RES-E and their demand is driven by an administrative obligation of traders/consumers to buy a prescribed amount of RES-E. The financing source of price support schemes is hardly ever the state budget, rather it is the energy consumer receiving an extra charge included in his/her tariff bill. The financing mode varies across European states (CEER, 2011). Many countries (e.g. Italy, Ireland, France and Spain) finance RES support schemes via specific non-tax levies paid by all consumers. Another common method is to apply a surcharge that is explicitly stated on the electricity bills (e.g. Czech Republic, Germany and Austria). A third way that is characteristic to countries with green certificate systems (e.g. UK, Poland) is to recover the costs of the support system in the form of higher electricity prices. The cost of buying the needed certificates or paying the substitute fee for the difference of acquired and required number of certificates raises the electricity price without explicitly appearing in bills. Estonia includes the RES support cost in the network tariffs, Finland simply covers them from general taxes which means that the individual financial burden is not based on electricity consumption.

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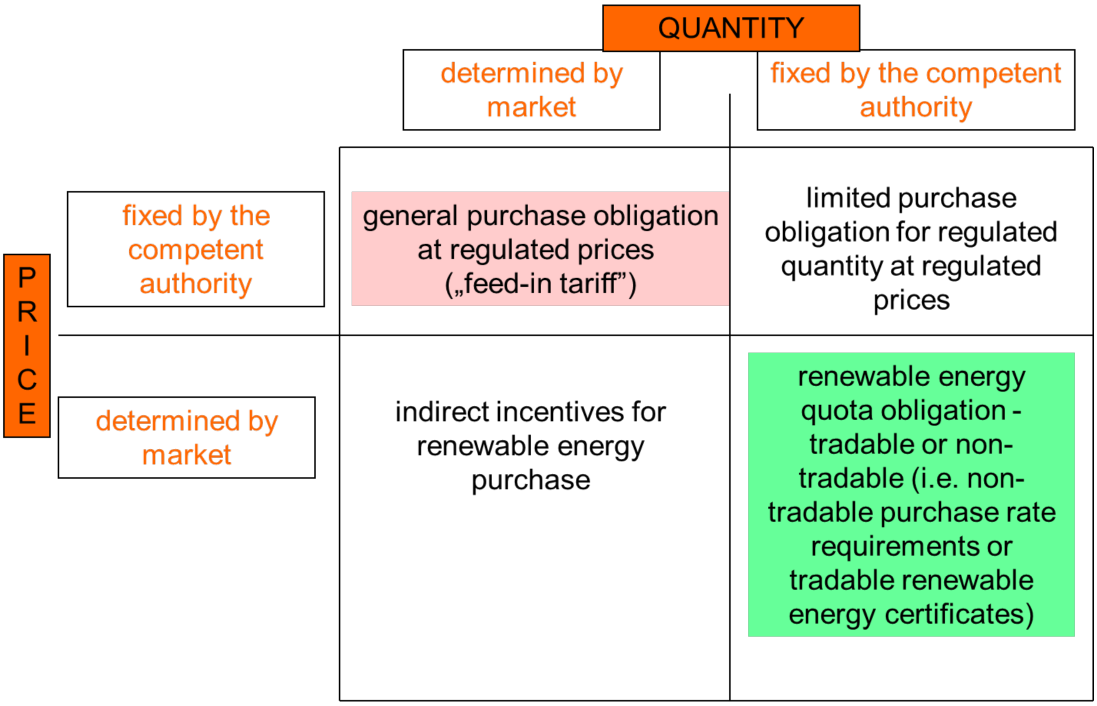
[24] Further difference is whether the support program mainly targets larger, more centralised energy generation systems (power plants, district heating plants or fuel processing industry) or smaller, decentralised energy systems and energy consumers (energy appliances of buildings, consumer appliances or end user or close to end user small scale energy generation systems).

[25] This paper focuses on electricity (RES-E) but the regulatory issues discussed are applicable to heat (RES-H) as well.

Figure 14 Production support schemes of renewable energy



PRICE \ QUANTITY	determined by market	fixed by the competent authority
fixed by the competent authority	general purchase obligation at regulated prices („feed-in tariff")	limited purchase obligation for regulated quantity at regulated prices
determined by market	indirect incentives for renewable energy purchase	renewable energy quota obligation - tradable or non-tradable (i.e. non-tradable purchase rate requirements or tradable renewable energy certificates)

If the feed-in tariffs of electricity generated by renewable sources (price support mechanism) are fixed by the competent authority (either the government or the regulator, or some joint mandate), the production quantities depending on marginal costs of the different types of renewable technologies, are determined by the market. Feed-in obligation schemes can be administered with regulated feed-in-tariffs (FIT) or regulated premiums over the standard electricity market price (RPS – regulated premium schemes).

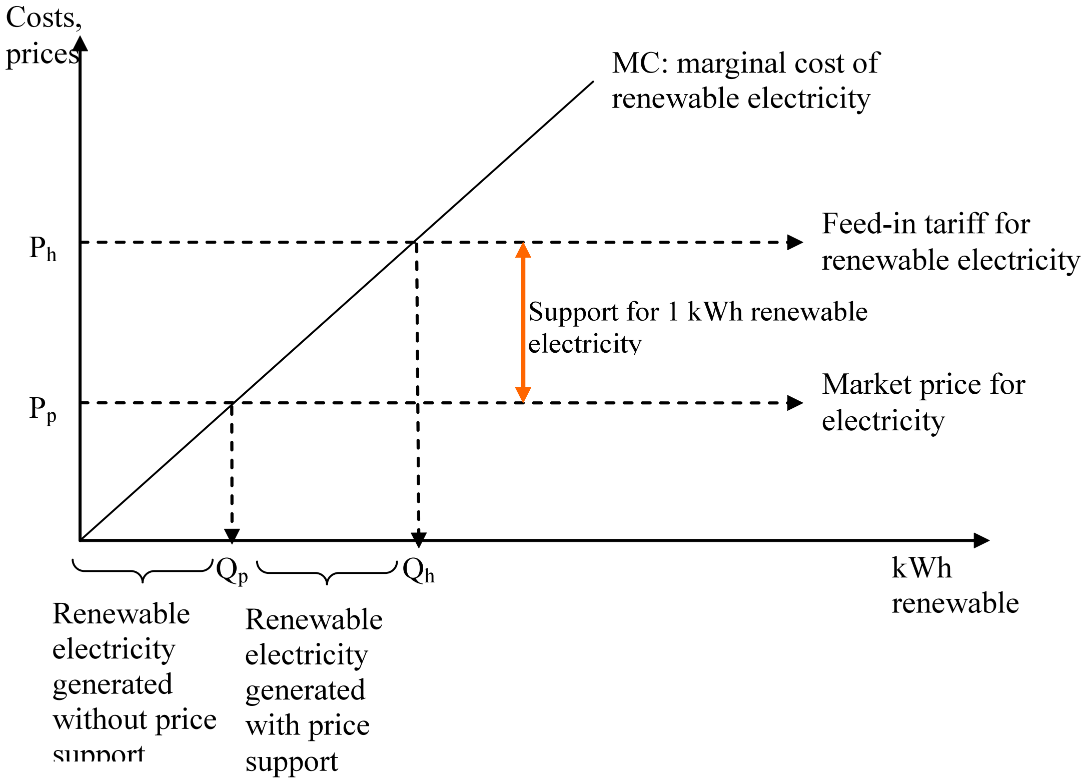
In the production quantity support schemes the quantity of tradable green certificates is determined by the authority through prescribing the total volume of renewable energy to be generated or purchased. This volume requirement can be broken down on volume contributions of the various sources of renewable energy (e.g. wind, solar) or according to the technologies applied (e.g. PV, solar or thermal). If such distribution by the support scheme does not exist, the prescribed volume can be delivered freely by any renewable source. The cost of delivery is logically borne by the market players (traders or consumers) who are obliged to purchase the prescribed amount of renewable energy.

Regulating both price and quantity is not an efficient and not necessarily transparent solution, because renewable production quotas then can be allocated through administrative process only.

II.2.2. Feed-in tariff schemes

Renewable energy feed-in tariff systems support the purchase price of the generated renewable energy. The regulated price (FIT) is set higher than the market price so the generation of renewable energy will become economically more viable. Figure 15 shows the theoretical model of the feed-in tariff concept applied to an electricity generation example.

Figure 15 Model of a renewable electricity feed-in tariff scheme



Legend:

Pp: market price of electricity

Qp: quantity of renewable electric energy when generated at market price

Ph: feed in tariff of renewable electric energy

Qh: quantity of renewable electric energy when generated at feed in tariff

The chart shows that not all the feed-in tariff can be considered as support given to quantity Q_h as this quantity would have been purchased anyhow at a market price. This means that the support for a unit of renewable electric energy is the difference between the feed-in tariff and the market price of electricity. This is the underlying concept behind green bonus regulation being a variation FIT regimes. In the case of green bonuses the producers do not obtain a fix amount of money for every kilowatt-hour but only a premium (green bonus) over the market price. The green bonus scheme is more risky and thus less attractive for investors because future market prices are unknown. For electricity consumers however, the price to be paid for kWh consumed will be less. Operating FIT schemes exhibit considerable design variations.

Differentiation by technology

FIT schemes are often criticised on the ground that they provide “unjustified” high regulated price for producers of relatively low cost renewable energy. If the regulator would have perfect information about the production costs of the licensees, it would set for each renewable energy producer an individually targeted price being only reasonably higher than his/her generation cost. Such a perfectly differentiated feed-in tariff scheme is however only a theoretical option due to the information level and quality available to the regulator.

In reality, regulators often diversify tariffs on the basis of technology to create a more diversified renewable mix. It should be noted, however, that a differentiated FIT scheme is less efficient than a uniform one that maximizes production from a fixed support budget resulting in the cheapest technology spread: only the cheapest technologies will enter the market. Most of the existing FIT schemes in Europe, however, are differentiated by technology, reflecting that the development of a diverse technology portfolio remains an important continental objective. The EU itself has voted for the parallel development of the different RES technologies and demanded that the national RES policy framework needs to respect the full basket of RES technologies as allowed for target compliance (RES Directive, Preamble 14).

Differentiation by size

The promotion of small sale decentralised RES-E generation is a reasonable policy objective (utilisation of local resources, employment etc. and lower network loss of distributed generation - DG) which translates into higher FIT for smaller units, ceteris paribus. The regulator, however, should also consider that the loss derived from scale economies (higher overall cost), network loss increase after a certain DG penetration level. FIT preference for small units can induce the disaggregation of investment at the same location.

Differentiation by time zones

Load following RES-E technologies (mostly biomass, biogas and hydro power station with reservoir) can be motivated by differentiated tariffs to produce in peak periods and go off-line in periods of low electricity demand. This option does not apply to intermittent generators.

Differentiation by commissioning date

New installations often receive a lower tariff that takes into account the technological development resulting in lower production cost. The same goal motivates the application of digressing tariff (pre-schedules, gradually decreasing FIT) for already operating installations.

The most important feature of any FIT regime is the transparent setting of rates (based on cost-plus method and/or benchmarking) and the long-term regulatory (10-15 years) stability regarding the tariff rates, the eligibility for FIT, grid access rules, possible phase-out (conversion to green certificate system) and balancing rules. Additional design tools to reduce the risk of investors are the annual correction of tariffs with inflation or a re-defined exchange rate correction regime (e.g. Ukraine).

II.2.3. Regulatory evolution of support

With the earlier theoretical discussions and the current regulatory practice in mind we can say that at the early stage of technological development (such as the case of the renewable energy industry) and at an early stage of market conditions, a feed-in tariff scheme has many positives: it provides a protective business environment, predictable profit, low investment risks and incentives for expanding production and technical development.

The continuous incentive towards an ever growing production volume sooner or later places excessive pressure on state budgets dedicated to RES support, and consequently, on consumers' electricity bills in the form of higher end-user tariff. This can be controlled either by the tariff system per se (digressing tariffs, lower tariffs for new entrants), the adjustment of the entitlement period (ex post adjustment undermine regulatory credibility) or by the regulator setting production quotas for the different RES technologies. Allocation is usually administrative (e.g. pro-rata) but the cost of the scheme can be reduced by the auctioning of production quotas where producers bid for the discount they are willing to accept on the tariff.

These changes – however – do not always bring about the desired results: the amount of energy supplied/purchased under the changed support scheme might decrease but will seldom cease. As far as availability of information is concerned, the authority always remains in a disadvantaged position compared to players in the regulated energy sector. If too low of a price level (or short entitlement periods) is established, the carefully developed renewable energy sector can easily break down. In addition, the increasingly complicated regulation may too become less predictable and transparent.

This is why the whole FIT support scheme might need to be substituted with e.g. quantity regulation.

II.2.4. Green certificates

Compared to price based support schemes, green certificate (GC) trading is a quantity based support mechanism for renewable electricity generation, when instead of its price, the quantity of RES-E consumption (production) is targeted by the regulation. For example, if a national renewable policy were to set a target of 10% RES-E in the overall electricity consumption for a given year, it would be enough to oblige all suppliers serving end users (and customers purchasing electricity directly from producers) to prove that 10% of their sales (consumption) originates from RES-E generating facilities.

To ensure an effective regulation, authorities need to verify that the prescribed volume of renewable energy consumption has been met. This becomes easier when the consumption of renewable energy is physically measurable, that is, like in the case of bio fuel blending (e.g. % per litre or annual sales volume). In the electricity sector the verification process is somewhat more complicated, because commercial and physical flow of electric power takes place separately of each other. As the consumer does not physically use the purchased volume, the renewable energy consumption requirement cannot be verified physically, only commercially.

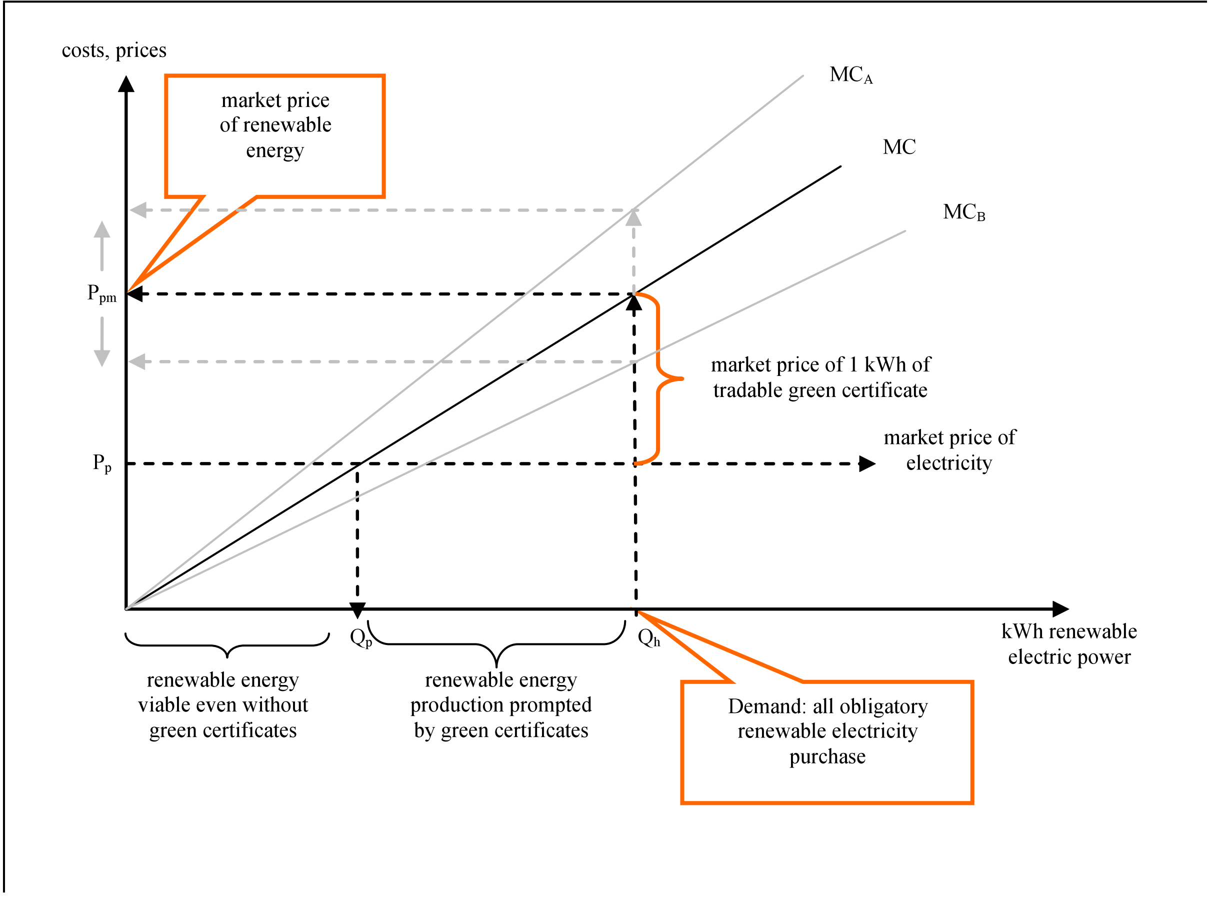
Participants under the obligation to purchase a specific volume of renewable energy can prove to the authorities that they have commercially fulfilled their obligations only by a certificate issued by the renewable energy producer, declaring that a particular quantity of renewable energy has in fact been generated and sold. Certificates should be retained until the end of the regulatory period when they must be submitted to the authorities, usually once a year. Needless to say, the renewable energy sold/purchased is also physically fed into the network and equally fulfils the role of satisfying demand. GCs are transferable independently of the underlying energy.

Under this support scheme the renewable energy producers sell two products: energy and a corresponding amount of green certificates. These two together should generate enough revenue to cover the production costs of RES-E.

The price of green certificates is driven by the market price of electricity and the advancement of renewable energy generating technologies (denoted by its marginal cost) (Figure 16). At a given specific state of technology the price of green certificates will increase when electricity prices fall, but if the electricity price increases – the price of green certificates may fall too; all these occurring due to the fact that a more expensive electricity mix improves the competitiveness of renewables. The Romanian system is described in Annex D.

GCs are often traded in power exchanges resulting in a transparent and uniform price that is beneficial from a regulatory and the investors' point of view as well.

Figure 16 Supporting RES-E with green certificates



Legend:

MC: marginal cost of renewable electricity generation

Ppm: market price of renewable electricity

Qh: minimum level of renewable electricity purchase set by the regulator, total

Pp: market price of electricity

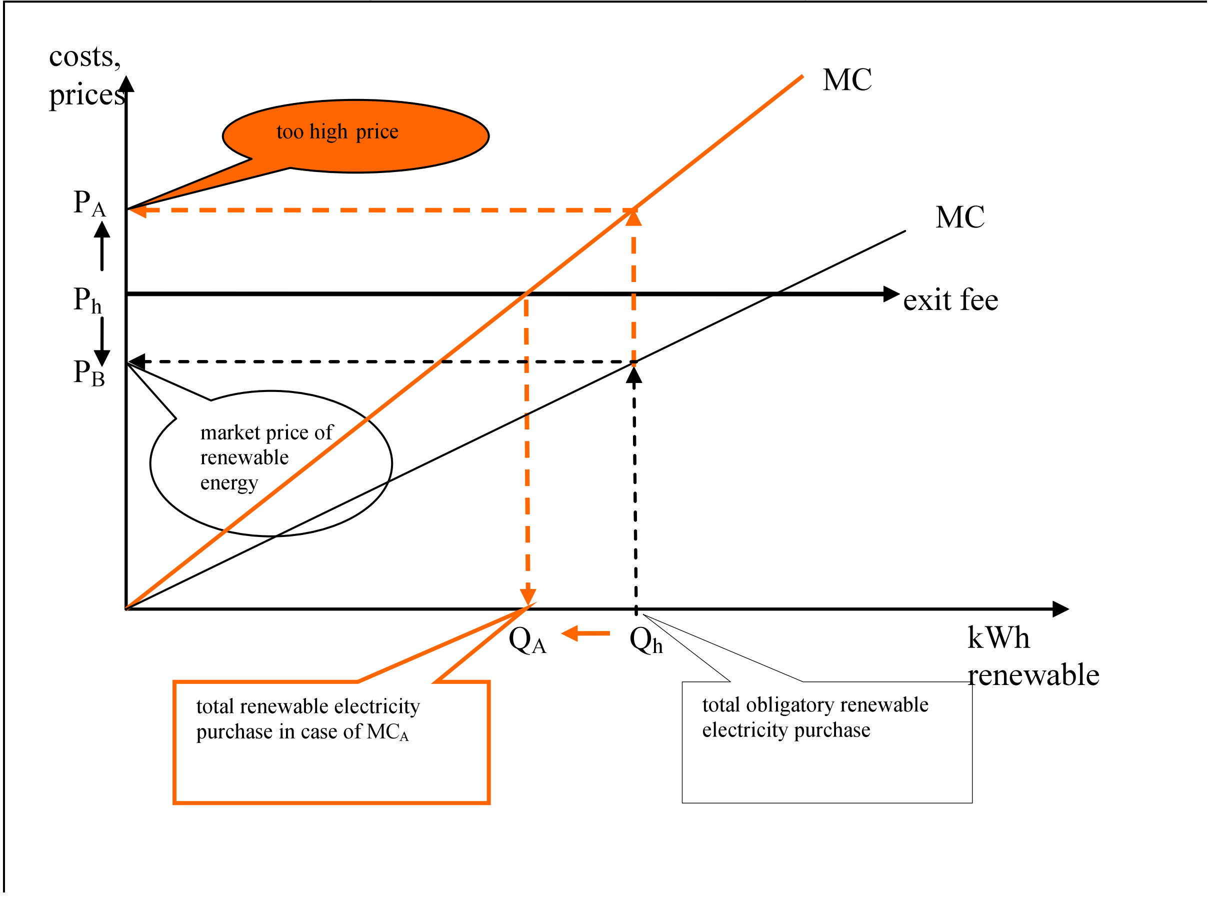
Qp: volume of renewable electricity generation viable even without a purchase obligation

Quantity based support schemes operate with a significant price risk, since they fulfil the desired volume target at – literally – any price. When the marginal cost curve of renewable generation is flatter (MC_B), the price of renewable energy will be lower (more advanced technology: lower costs). Alternatively, at a steeper marginal cost curve (MC_A) the price of renewable energy will become really high (expensive technology, low efficiency: high costs).

There might be significant pressure on the regulator to mitigate this price risk. Pressure comes from consumers wishing to have protection against extraordinarily high prices. Renewable producers, on the other hand, would also like authorities to protect them from excessively low prices, generated by market forces when they substantially reduce the price of renewable energy putting at risk the return on their investments.

When a supplier (consumer) falls 1 MWh short of its renewable electricity purchase obligation, that is, by submitting 1 MWh less certificates to the authority, then it is obliged to pay a commensurate fixed fee specified in advance. This fee is often called exit fee, since by paying it, the service provider exits from the demand side of the certificate market.[26] The exit price acts as price ceiling and the volume of actually purchased renewable energy becomes a function of the exit fee (Figure 17).

Figure 17 The role of exit fee in the GC system



Legend:

MCA, MCB: marginal cost of renewable electricity production

Qh: total minimum renewable electricity purchase set by the regulator

PB: market price of electricity in case of the marginal cost of production is MCB

PA: market price of electricity in case of the marginal cost of production is MCA, and there is no official exit fee

Ph: fine or exit fee imposed by the regulator on non-compliers

QA: the quantity of all renewable electricity purchase in case of an exit fee of Ph and marginal cost of MCA

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[26] Alternatively, this official fee is sometimes referred to as buy-out price, as at this price the service provider may buy himself out of its obligation related to renewable energy consumption.

In case of MC_B the renewable energy purchase requirement set by the regulator can be fulfilled at a relatively low marginal cost, the price of renewable energy remaining lower than the cost-risk driven exit fee. In the case of MC_A however, the required quantity could be bought at a too high of a price, therefore a substantial portion of this quantity will not be purchased, because market participants will opt for paying the exit fee. Thus the price of renewable energy cannot exceed the exit fee.

Green certificate regimes pay for the different technologies equally (uniform price) with no regard to their production costs, thus it provides the highest profit to the cheapest technology. Once the cost of production decreases then - assuming fixed mandatory RES-E supply - it results in lower price hence the gains of technology development ends up with the consumer.

All in all, the conclusion to be drawn is that in early stages of supporting renewables clearly the price support schemes (e.g. feed-in tariffs) are the proper choice, for later stages however, the volume based regimes should be considered. The timing of switching depends mostly on the preferences characterizing the given energy market (consumers, policy makers). The answer will be different in countries with significant cost sensitivity and countries where consumers are strongly environmentally conscious: cost sensitive countries may switch to volume based support relatively early, environmentally conscious countries may maintain the price support schemes for a somewhat longer time period.

II.2.5. Overview of RES regulation in the EU

The European regulatory practice is dominated by the use of FIT, only Sweden, Poland, Romania and Belgium operate green certificate system. Italy, and since 2010, the UK have a mixed scheme based either on the capacity of the installation (under 5 MW FIT applies in the UK) or based on technology (in Italy FIT applies for solar, other technologies can choose between FIT and green certificate). Romania has also legal provisions to apply FIT for installed capacities below 1 MW but the secondary legislation is not yet finalised. RES producers Denmark and Spain receive a 'green bonus' above the market price (premium). In the Czech Republic producers can choose between FIT and premium. In Finland RES producers are supported via the energy tax system (lower tax level). Almost all FIT countries set different tariffs according to the capacity of the power generator and often the tariff gradually decrease over time to account for the maturing of the technology (Table 3). Annex C contains three case studies on the application of FIT.

Table 3 Details of FIT/premium support systems in selected Member States

	Type of support		*Dimensions of tariff differentiation*			*Other important features (1)*		
	FIT	*premium*	*capacity*	*starting date of operation*	*type/location of the resource (2)*	*tariff digression*	*budgetary price support*	*fixed support period (3)*
AT	x		x	x	x	x		x
BG*	x		x	x	x			
CY	x		x			x	x	x
CZ	x (4)	x	x	x	x			
DE	x		x	x	x	x	x	x

DK**	x (5)	x	x	x	x	x	x	x
EE	x		x		x		x	
EL	x		x	x	x			
ES	x (6)(7)	x	x		x	x		x
FR***	x		x	x	x	x	x	x
HU****	x		x					
IR	x		x					x
IT*****	x (6)		x	x	x			
LT	x			x				
LU	x		x		x	x		x
LV	x		x		x			
MT	x						x	
NL	x		x		x	x (8)	x	x
PT	x		x					
SK	x		x	x	x			
SL	x		x		x	x (9)		
UK*****	x (6)		x		x	x	x	x

Source: Infrapont based on EREF (2009)

Notes:

* *wind: tariff based on the number of hours in operation*

** *wind and PV: tariff based on the number of hours in operation*

*** *hydro: seasonal tariffs*

**** *hydro and biomass: intra-day tariff differentiation*

***** *mixed system: FIT/GC*

(1) general features of the scheme (non technology specific)

(2) e.g. type of biomass or biogas, offshore vs. onshore wind

(3) guaranteed by law to all producers (normative regulation)

(4) choice between FIT and premium for all technologies

(5) FIT: hydro, biogas, solar and other; premium: wind, certain biogas and biomass

(6) PV can only receive FIT, all others optional

(7) PV can only receive FIT, thermosolar systems FIT or premium

(8) FIT = fixed base - correction (adjusted annually)

(9) FIT = fixed base (adjustment in max. 5 years) + variable part (adjustment in max. 1 year)

II.3. RES-E licensing, certification and monitoring

There are good reasons to establish and introduce regulatory monitoring and control over RES-E producers. First, these producers generally tend to be supported in some form (e.g. through feed-in tariffs) for some period of their operation, so keeping track of RES-E generation is crucial both for budgetary planning (how much money is spent on RES-E support) and accounting purposes with the individual producers. Second, to be able to establish FIT for these producers, it is essential to collect operation related financial data as well. Finally, to create and modify market rules, able to efficiently promote a massive expansion of RES-E generation, a proper understanding of the behaviour of RES-E generators and their ways of cooperation with grid operators is necessary.

One possible and popular mean to create the basis for regulatory oversight of RES-E producers is licensing. A license includes the specific parameters and criteria, rights and duties pursuant to which an economic enterprise may carry out a regulated activity. Energy production licenses are issued usually by the national energy regulator.

The license requirement of RES-E plants usually is contingent upon capacity size. Below a certain threshold developers do not need to obtain a license from the energy regulatory office: household size RES-E generators, i.e. with connection output < 50 kVA are usually exempt from licensing requirements. It does not mean, however, that small scale plant development is free of administrative procedures (see other licenses). In Hungary e.g. RES-E plants under 0.5 MW do not need a license from the regulator and those between 0.5 and 50 MW has a batch license for the establishment and the operation.

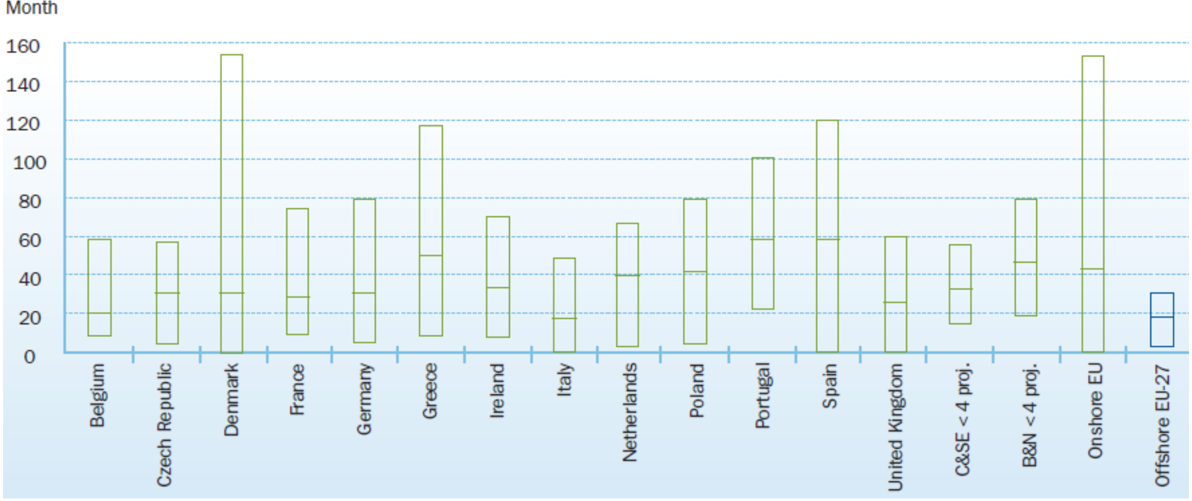
In general, a company to become a RES-E producer has to go through a sometimes rather cumbersome licensing procedure. Although, the rules differ from country to country, it has to obtain at least the following licenses and documents:

- Environmental license, possible based on environmental impact assessment (EIA), issued by the environment regulator
- Building license, issued by local authorities
- Grid connection approval and contract, issued and signed by the network operator
- license for the establishment and operation of its plant (issued by the energy regulator)..

In addition to the basic licenses listed above, investors also should get additional permits from several other authorities, such as a fire department, national health organization, aviation authority, etc. The licensing procedure can differ according to technology as well, considering the various impact of resource use.

The licensing procedure is essentially country specific. However, the length (lead time) and the number of authorities involved in the process are crucial features of any regulatory regime. Cumbersome and long, and more importantly, unforeseeable licensing all act as market entry barriers, as they can endanger the financial viability of the relatively small RES-E projects. This is especially true if the investment is predominantly financed from loans, and the banks approval is contingent upon the actual (and sometimes often changing) FIT regulation. Figure 18 gives an example for the variability of administrative lead time by showing the minimum, maximum and mean length for wind projects.

Figure 18 Administrative lead time for obtaining building license for wind projects



Source: EWEA, 2010, p.26

Note 1: C&SE: Austria, Bulgaria, Hungary and Romania; B&N: Estonia, Finland, Latvia, Lithuania and Sweden

Note 2: The top of the box plot represents the maximum lead time, the middle bar the mean lead time and the bottom of the box plot the minimum lead time according to the survey answers received.

The transparency of licensing is a prerequisite for investors and is affirmed in the Renewable Directive as well: “The procedure used by the administration responsible for supervising the authorisation, certification and licensing of renewable energy plants should be objective, transparent, non-discriminatory and proportionate when applying the rules to specific projects” (2009/28/EC Preamble Art. 40).

The number of authorities involved is a good proxy for the indeterminacy total lead time, and consequentially the cost of license acquirement, especially when these authorities have no compulsory response time or if it is not respected. Estimated typical number of permits required (excl. small-scale systems) is between 1-2 (Germany, Denmark, Italy) and more than six (Bulgaria, Portugal and Romania) but sometimes over 40 (e.g. wind energy in Greece and Cyprus) (ECORYS, 2008). A solution to reduce the administrative complexity of licensing is to establish a single body coordinating all the required licenses for the applicant (‘one-stop-shop’). The Renewables Directive explicitly calls Member States to consider this option for distributed generators.[27]

Another important actor guaranteeing objectivity and non-discrimination on a case-by-case basis is the body of appeal to whom developers can turn with their complaints. This body can either be the energy regulator itself, the responsible ministry or possibly a court.

Apart from the general purposes of the license, it may contain additional provisions required by national regulation. The license issued by the Hungarian regulator e.g. has an extra content for renewable generators: the annual amount of electricity eligible for selling under obligatory feed-in and the period of time up to which the licensee remains eligible for receiving regulated feed-in tariffs (note that the feed-in tariffs are established by the government). The regulator is obliged to set this period of time case by case equal to the estimated payback period of the respective investment project.

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[27] „the relevant authorities should consider the possibility of replacing authorisations by simple notifications to the competent body when installing small decentralised devices for producing energy from renewable sources” (2009/28/EC Preamble Art. 43)

An efficient licensing procedure hence would

- minimize the duration and cost of RES-E licensing,
- be transparent (what licenses are required and from which authority),
- be non-discriminatory (similar projects face the same licensing requirement regardless to the owner/investor),
- include compulsory response deadlines for permitting authorities, and
- designate a body for appeals.

II.3.1. Certification of renewable energy

During the last two decades the massive spread of RES-E generation has largely been promoted by heavy investment and production subsidies provided by national governments worldwide. It is natural that those who provide production subsidies wish to ensure that these subsidies are used only for those eligible kWh-s strictly produced by renewable energy sources. Thus, in parallel to the market penetration of RES-E production, the need to developing a RES-E production monitoring system emerged. The primary tool for monitoring is the certification of RES-E.

Since electrons do not have traceable colour, there is a need for a system capable of tracking certain attributes of electricity from generation to suppliers or final customers. Tracking means the transfer of information about power generation attributes to consumers or other parties (e.g. regulators, governments). The tracking system for disclosure purposes needs to cover the whole electricity market and has two basic forms. De-linked tracking means that the sale of the generated electricity and the certification and administration of the attributes of the same electricity (e.g. fuel used, related CO_2 emissions, etc.) are carried out separately. It may be carried out by an agent/intermediary independent from electricity producers and customers. This is a flexible means of tracking, which does not cause adverse interactions with electricity market transactions. The agent can himself administer the issuance, transfer, registration and redemption of certificates containing the attributes of the electricity generated. Contract-based tracking, on the other hand, involves no separate administration for attribute certificates because certificate transfers are coupled with electricity trading contracts. The role of tracking by certification is manifold.

First and foremost, this certification system serves as the basis for accounting production subsidies to eligible RES-E producers. It is a prerequisite for a transparent support system.

Second, it can fulfil an emerging demand for green electricity among consumers as the environmental attributes of the purchased electricity can now be traced and made visible for the final consumer. For example, in the EU all electricity retailers are obliged to specify on their bills the year based energy mix delivered (Art 3(6) of Directive 2004/54/EC). More precisely, consumers have to be informed not only about the fuel mix, but also about the average CO_2 emission, the nuclear waste and the amount of combined heat and power production associated with the electricity sales portfolio. Naturally, such a disclosure allows for the labelling of 'green' electricity i.e. produced in RES-E generating units.

Third, it is the basis of aggregate RES production data. The introduction of RES-E market share mandates (EU) and/or renewable portfolio standards (USA) creates a need for such certification and registration regimes able to verify whether the RES-E production or consumption targets are met or not. In addition, certification facilitates the accounting of cross-border traded RES-E towards those indicative national targets.

Finally, the quantitative RES-E targets mentioned above did create the opportunity to set up a sophisticated quantity based RES-e support scheme called green certificate trading discussed before. It is important to differentiate between guarantees of origins (certificates in the general sense) and tradable green certificates as means of operational support of RES-E producers. The latter is based on the former but not vice versa.

Exactly these functions are envisaged in the European RES certification legislation which lays down the minimum requirement for the so called Guarantee of Origin systems but leaves the design in the mandate of the Member States (GO defined by 2001/77/EC). The RES Directive (2009/28/EC) requires GO to become an electronic document containing the full life cycle of a certificate, i.e. issuing, transfer and cancellation. It can't be in use longer than 12 months after the related energy production and needs to be cancelled immediately upon use. The issuance of the GO for RES-E is mandatory but for RES heating/cooling it is optional.

II.4. Integrating renewable generation into the electricity network

Besides their relatively high direct production costs, the spread of renewable electricity generation technologies is further hindered by the technical and economic challenges caused by their integration into the electricity network, including both distribution and transmission grids.

II.4.1. Transmission of electricity

The large scale integration of renewable production into the electricity system raises great challenges at the transmission and system operational level.

Distance from source to load- transmission network planning

Ideal conditions for weather-dependent renewable electricity production – such as strong and steady blowing wind, or year-around scorching sunshine – usually exist far away from populated areas. New long distance transmission lines, often in the form of high-voltage direct-current (HVDC) cables are required for bringing the energy generated to the load centers.[28] The method of financing the network extension can have a great impact on spreading renewable production. As an example, distributing the costs of transmission over the entire network can provide a boost to the growth of RES-E, but it also has the potential side effect of masking the true cost of the renewable resource, eventually leading to inefficient investment decisions. For this reason, whenever the cost-causality principle is violated by policy design, it is advisable to combine generation and transmission planning so, to be able to influence (e.g. through licensing) the geographic location of renewable producers. In Europe, where the planned new off-shore wind development is rather far from load centres the network cost-sharing concept is under heavy discussion.

Predictability- real time balancing

Weather-dependent renewable energy generation technologies – such as wind and solar power – are to some extent inherently uncontrollable. Moreover, their production levels cannot be predicted with certainty, not even a few hours ahead of a given time. None of these problems

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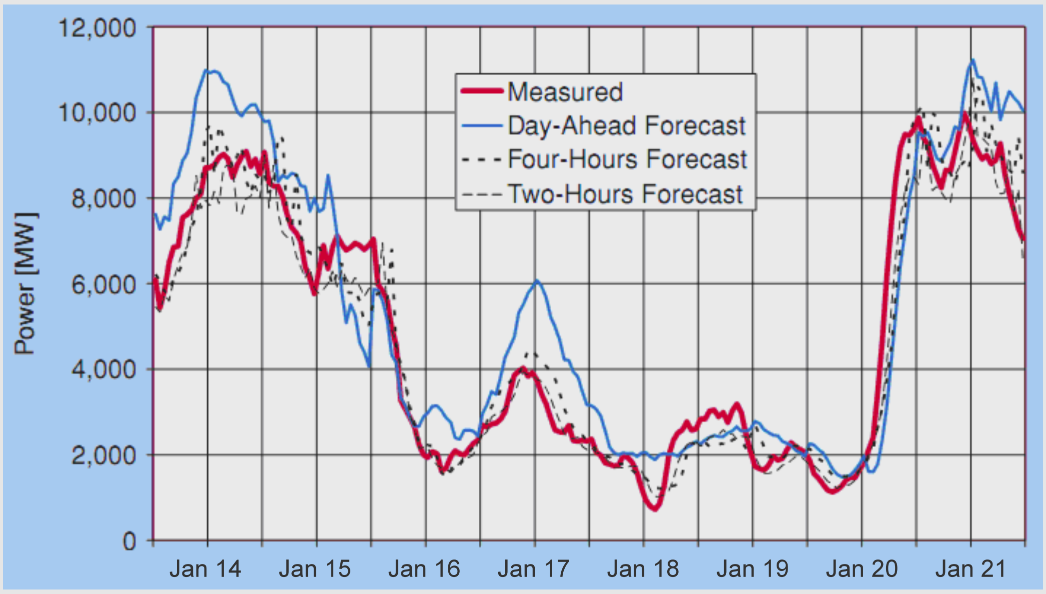
[28] One example of a long-distance renewable power transmission project is the so-called Desertec Concept. It aims to produce electricity by installing Concentrating Solar Power (CSP) plants in Middle East and North African deserts, and transport it to main load centers in Europe or other places.

would matter, of course, if a low-cost, flexible technological option for large-scale storage of electric power would exist. Unfortunately, this technology is not yet available, a continuous real-time balancing of production and consumption in electricity systems is necessary.[29]

In many cases, the prediction challenge is as much a consequence of truly uncertain weather variability as it is of poor data availability and computational methods. While the former is mainly a meteorological problem, which we do not provide any solutions here, the latter can sometimes be remedied by designing better processes and tools.

The forecast horizon of prediction models depends on the purpose of their application. Naturally longer horizons entail larger prediction errors. The figure below shows a time series example of actually measured power output (thick line) depicted against a day-ahead and two shorter horizon forecasts for the same time period.



Source: Ernst et al. (2007)[30]

From the diagram it can be seen that short-run forecasts are considerably more accurate than a longer-run forecast (thin dashed lines are closer to the thick curve than the thin solid line). Aside from the accumulation of prediction errors over time (given identical data), a large part of the difference comes from the updating of hour-ahead forecasts with real-time wind speed and power output measurements, which is not possible with a day-ahead prediction.

However, longer predictions – that is, 2-5 day forecasts – are still needed for power trading purposes in the day-ahead and forward markets, whereas short-run forecasts are useful for system security, reserves activation, and intra-day trading.

The overall accuracy of wind power predictions has been constantly improving over the past years, as more and more experience was accumulated in the industry.

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[29] Pumped storage hydro units may provide a partial solution to the storage problem, but they require special geographical circumstances, which limit their applicability.

[30] Ernst, Bernhard, Brett Oakleaf, Mark L. Ahlstrom, Matthias Lange, Corinna Moehrlen, Bernhard Lange, Ulrich Focken, and Kurt Rohrig (2007), „Predicting the Wind", IEEE Power & Energy Magazine, November-December, pp. 78-89.

In the E.On Netz area in Germany, for example, the root mean squared error, a measure of the day-ahead forecasts average accuracy, has dropped from 10% of installed capacity in 2001 to 6-7% in 2007.

System flexibility- availability of operational reserves

System flexibility, in general, is the ability of a system to withstand sudden shocks and continue operating without any disturbance while serving its consumers. In the case of electricity, system flexibility usually refers to whether the size of available reserves is large enough to accommodate a sudden shift in demand or supply, thereby keeping the probability of forced load-shedding at a tolerably low level.

Technically, power generation and consumption in a control area must balance out exactly in each moment; otherwise the system's frequency starts to drop (in case of excess demand) or increase (in case of excess supply) beyond the band of tolerability relative to its default value, damaging all sorts of equipment within the network. To maintain this balance, the system operator must have a variety of tools and procedures at its disposal.

Among these tools, primary reserves are the first line of defence against frequency fluctuations, materializing in automatically callable production adjustment responses of certain generators, without any human involvement. Such primary response, however, can only deal with smaller disturbances. When a significant disturbance occurs, the system operator must procure additional reserve capacity (secondary and various forms of tertiary reserves) both for upward and for downward regulation with increasingly longer ramp-up intervals (from 30 seconds to several hours).

Naturally, stand-by capacities cannot be used for producing electricity under normal circumstances (e.g. upward regulation reserve during peak hours), or adversely, to run even when it is not economical to do so (e.g. downward night time regulation reserve). The power plants must be compensated both for the energy they produce, and for the reserve capacities they provide. The price of reserves and of the balancing energy produced can be regulated, or alternatively can also be determined in reserve market auctions run by the system operator.

The various types of reserves controlled by the system operator provide the supply side of the balancing market. The demand side, on the other hand, is made up of system users: both consumers and producers, or more commonly, traders and suppliers acting on their behalf. In theory, system users have to provide a production or consumption schedule for each hour of the following day.[31] Should they deviate from that schedule in real time, they are liable to purchase (positive or negative) balancing energy from the system operator. The price of balancing energy is usually determined so as to motivate accurate and unbiased scheduling and to cover the variable costs of the supply side procurement.[32]

The efficiency of balancing markets (whether balancing energy is provided in the most economical way) exerts a strong influence on weather-dependent renewable generators. The inherent uncertainty in weather predictions makes it inevitable that these units will under- or overproduce relative to the reported schedule, so the differences need to be covered with positive or negative balancing energy. A more smoothly operating balancing market leads to a smaller difference between the day-ahead product market price and the price of balancing

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[31] In practice, traders and suppliers usually organize balancing groups and only report their net aggregated schedule towards the system operator.

[32] The cost of reserve capacity is most often included among the system charges and thus not directly borne by those who contribute to system imbalances.

energy, thus mitigating the implicit penalty on scheduling errors. In this case the costs of weather-dependent renewable generation are reduced.

There are many, potentially effective solutions to the increased system flexibility problem, which will be discussed below. Each of them has its own costs and limitations, making the regulator and policy maker to face a particularly interesting problem of finding an efficient combination of them.

Aggregationof small size units

Wind speeds tend to fluctuate often, and in an unpredictable manner, at the local level. Over a larger geographic area however, they average out to reasonably well-forecastable levels. Consequently, it may be worthwhile to mandate a more spread-out pattern of wind installations within a given control area. Such a regulatory restriction on locational choice may decrease generation efficiency, but the increased overall stability of the system can easily make up for this potential disadvantage. An alternative approach to aggregation is the pooling of reserves over several control areas. Introducing a more flexible approach to control area interchanges (such as dropping the requirement that all secondary reserves be procured from a specific control area) can allow cheaper reserves to be called in from neighbouring regions.

Building new generation units

Probably one of the most trivial, but also the most costly solution to the flexibility problem is to simply build more power generation capacity, such as combined cycle gas turbines (CCGTs) or hydro units, able to provide system flexibility. Nevertheless, the importance of market-based signals for new investments in flexible generation must be emphasized.

More frequent scheduling and market operation

The nature of intermittent production is such that forecasts tend to improve dramatically within short time horizons. Therefore, if schedule changes and market operations are updated hourly – or ideally by intervals of 5-15 minutes – it is likely that most of the renewable energy balancing could be taken care by the real-time market itself. This solution will free up most of the reserve capacity thus considerably reducing costs arising from renewable energy integration into a grid.

Incentives through tariffs

Within predictability based reasonable limits, intermittent generation should not be exempt from imbalance charges for shortfalls and/or excesses relative to schedule. If short notice schedule changes are allowed (e.g. one hour ahead), imbalance charges could provide efficient private incentives for encouraging improved on-schedule operation, thus reducing the forecasting burden placed on system operation. In some cases the system operator predicts the operation of whether-dependent generation.

In addition, tariff schemes could be so designed as to motivate some load-following units unable to provide regulation services to have their operations scheduled to enable them to assist in system flexibility. One example could be the discouragement of night time biomass generation, in order to allow operation of sufficient gas-fired and/or hydro units able to provide downward flexibility to the system.

Storage and centralized control

In networks with large amounts of wind generation integrated, the night time downward flexibility becomes a pressing issue on its own. That is, when off-peak hours demand decreases and wind-powered production increases, there is less and less place for load-following units in the system, especially when a large base-load plant (as a nuclear plant) is also present. At higher intermittent capacity levels, not only flexibility is lost, but to prevent overproduction, zero-cost wind turbines must be shut down as well. In this case, energy storage by utilizing compressed air, pumped hydro or thermal storage (e.g. hot water) units becomes indispensable. Alternatively, as a short-term fix, system operators could be given direct control over the wind generation, but only by providing proper compensation to the owners in question.

Demand response

In addition, attention must be paid to the previously overlooked role of large consumers able to provide short term system flexibility, much like generators do. In case of many industrial processes, a few hours interruption of electricity supply can be accepted without significant economic losses. This is often a less costly provision of emergency reserves than having stand-by generation capacity installed. Finally, future upgrading of electricity networks (so-called smart grids) will likely allow an increased use of large scale automated demand-response mechanisms, making possible the integration of more weather-dependent renewable energy sources.

II.4.2. Incentives for Transmission System Operators to integrate large scale renewables production

The fundamental trade-off TSOs are facing in the field of transmission infrastructure development is between minimizing network costs (investing just enough for meeting reliability standards) and making additional investments for facilitating the growing electricity trade and large scale RES integration.

Transmission network development problems are not caused, but simply aggravated, by the foreseen massive RES capacity increase due to the increased amount of electricity transported. The main questions that need to be solved are 1) what would be the ideal network (in terms of actual lines, capacities etc.) and 2) who should finance the necessary investments? An ideal European transmission network connects all actors (including remote RES generators) at least cost. The convergence to this state requires a much more coordinated development planning as the outcome of nationally optimal investments do not necessarily result in a European system level optimum. An important step towards harmonization is that the European Network of Transmissions System Operators for Electricity (ENTSO-E) prepared a 10-year development plan in 2010 based on the mid-term proposals of individual TSOs.[33] The European Commission foresees about EUR 140 billion investment by 2020 in high voltage electricity transmission systems, both onshore and offshore, storage, and smart grid applications at transmission and distribution level (SEC(2011)755). This does not solve,

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[33] The ENTSO-E prepared a 3-year Study Roadmap identifying the necessary work streams to produce an Electricity Highways roadmap to 2050 (The Modular Development Plan on a pan-European Electricity Highways System 2050 – MoDPEHS).

however, the problem that generation investment decisions are not regulated and are independent of network planning. Anticipating transmission infrastructure construction could facilitate new generation development while minimizing social costs. Today, such projects often remain in the pipeline for many years that hinders the generation investments. To this end the Commission in its new infrastructure proposal limits the lengths of the permit granting process of Member States to three years and requires the designation of a single permitting authority for projects of „common interest” i.e. that are of European significance (COM(2011) 658 final).

New developments can be promoted in 2 main business models. *Merchant model* is used for specific interconnector projects run on a fully commercial basis outside the regulatory scheme. An example is the EstLink 1 project linking Estonia and Finland and the related markets. Revenues are determined entirely by a market mechanism. Refinancing of the project is conducted entirely via the income from the congestion rent of the interconnector. The dominant model is the *fully regulated development projects* that are approved by the regulator and become part of the regulatory asset base (RAB). The repayment of investment expenses for these projects is through regulated revenues, i.e. the project costs are directly "socialised" and consumers pay via a share of the energy prices.[34] It is important to note that if TSOs do not have enough financial incentive to invest into congested locations, unregulated investors can be more enticed to build the line and hence prevent the construction of a regulated line. This would not be a problem per se, however studies suggest that it is generally less expensive for the network users as a whole to pay the cost of the line than to pay the congestion rent (CEER, 2004).

Apart from non-negligible social problems of network development (‘Not In My BackYard - NIMBY), the main question of implementation is the distribution of network development cost among the states. The problem is that the benefit of a reliable enhanced network is shared among the states but the distribution of cost does not necessary overlap with the benefits (i.e. French taxpayers financing the transit of solar power electricity generated in Spain and consumed in Austria). Based on the experiences of previous voluntary schemes, the EU initiated mandatory compensation mechanism called Inter-TSO Compensation (ITC) Agreement - that entered into force in March 2011 - with the aim of compensating TSOs for costs associated with hosting transit flows.[35] Hence it aims to incentivize hosting of cross border flows and facilitate the creation of an effectively competitive pan-European electricity market. It includes two elements:

- compensation for transmission losses which depends on flow volumes and electricity price based on the With and Without Transit model. The difference is then compensated at the cost used within national tariffs.
- compensation for the additional infrastructure which can be required to host transit flows via a framework fund (currently 100 mEUR/year) that is distributed among the TSOs based on the levels of transits they cause or host. Perimeter flows (i.e. imports and exports of electricity from and to third countries) shall contribute to the framework fund. The perimeter fee for 2011 has been determined to be €0.8/ MWh.

Beside the ITC mechanism there is a need for sharing the new network development cost among beneficiaries. Identifying the benefits is not easy, the method is not prepared yet.

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[34] Hybrid business model is proposed for interconnectors from the UK to the Netherlands (BritNed) and Belgium (Nemo).

[35] Previous voluntary ITC mechanism resulted in net 200mEUR net money transfer among TSOs.

II.4.3. Distribution of electricity

Compared to traditional power plants, renewable units are often by one or two orders of magnitude smaller in terms of production capacity. Because of their size, instead of transmission grids, they are usually connected to distribution networks. This location choice of renewables creates some problems in the local network, since distribution grids have traditionally been configured to transmit electricity in one direction only, namely from the transmission grid to the end of the line user.

As a result, the network integration of small renewable producers may require the strengthening of the distribution system elsewhere as well, a concept known as “deep connection”. Whether renewable producers entering the market should pay for deep connections, or alternatively the costs incurred may be passed on to all consumers as distribution tariff increases, remains a matter of policy choice.

II.4.4. Incentives for Distribution System Operators to integrate distributed generation

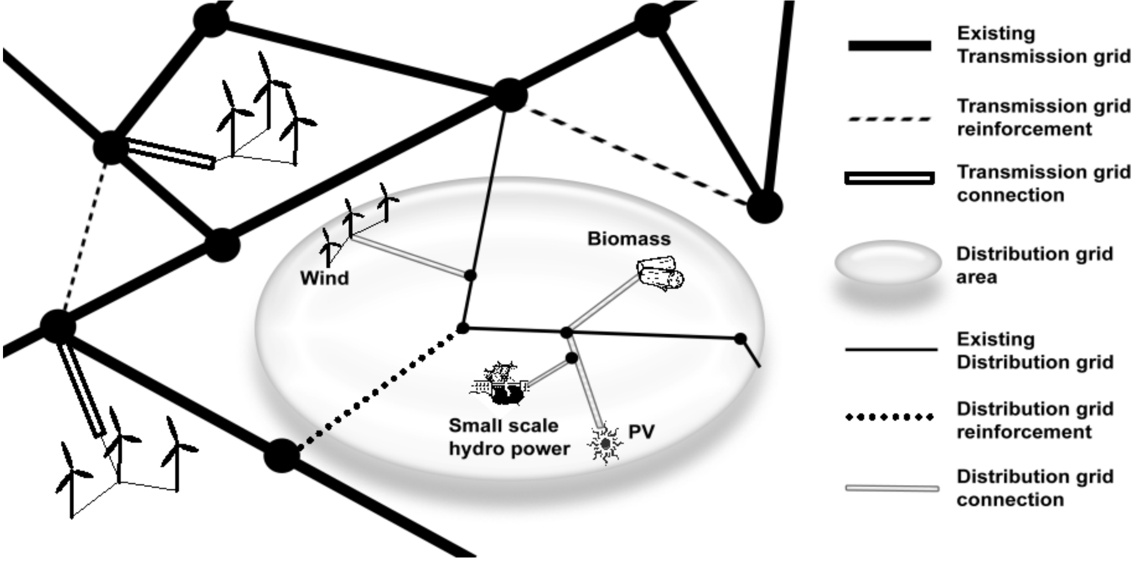
Today’s power system is not confined any more to centralized power production and bulk transport of electricity but includes smaller (most often RES but also micro combined heat and power - CHP) producers that connect to the distribution network, in addition to large scale RES channelled directly to the transmission grid (Figure 19). These producers– according to the EU Electricity Directive – qualify for distributed or “embedded” generation (Table 4).

Table 4 Categorization of RES technologies by size

	RES technology
Large-scale generation	Large hydro (above 10MWe) Off-shore wind Co-firing of biomass in coal power plants Geothermal energy
Medium/small scale generation	Medium and small hydro On-shore wind Tidal energy Biomass and waste incineration PV

Source: GD-GRID, 2006, Final report

Figure 19 Grid connections and grid reinforcements caused by large-scale DG/RES integration



Source: IMPROGRES, 2010

This section discusses the regulatory problems of connecting large scale small generation facilities to the distribution network in the current network paradigm, which does not involve the introduction of smart grids and smart meters required for active network management.

The connection of a single distributed generation (DG) unit has negligible impact on the network. However, the cumulative effect of a multitude of small generators – especially in a smaller geographic area – can have negative effect on network operation. For the DSOs perspective, in addition to the cost of connecting DGs, these actors in the current mainstream regulatory practice (producers do not pay network changes) are not paying customers once they are connected. We should note that DSOs – apart from the network upgrade need - enjoy some benefits of DG as well: if the DG is close to the point of consumption the need for the grid decreases. In addition, up to a point additional DG fulfilling local demand reduces distribution losses but this trend is reversed at a certain penetration level (DG-GRID, 2006).

The regulation of DG connection should strike a balance between guaranteeing the cost recovery of DSOs while maintaining/improving quality of supply and providing easy access for distributed generators to the network.

The cost of the connection of a new RES generator consists of three elements. First, the connection cost that comprises the installation of cables and potential modification of transformer stations, up to the connection point to the power grid. This cost mainly depends on two factors, the distance from the grid and the voltage level of the connection point.[36] The second element is the reinforcement of the grid to be able to accommodate the increased load. The identification of these costs is much more challenging than in the case of connection costs. It depends, in general, on the size of the added capacity, the structure of the grid and consequently the changes of typical load patterns. The third cost element is the investment into regulating power plants that increase system flexibility for the massive RES uptake such as flexible gas-fired generators or various energy storage facilities (e.g. pumped-hydro plants or compressed air storages).[37] These facilities are dominantly connected to the transmission grid but small storage capacities can be connected to the distribution network as well.

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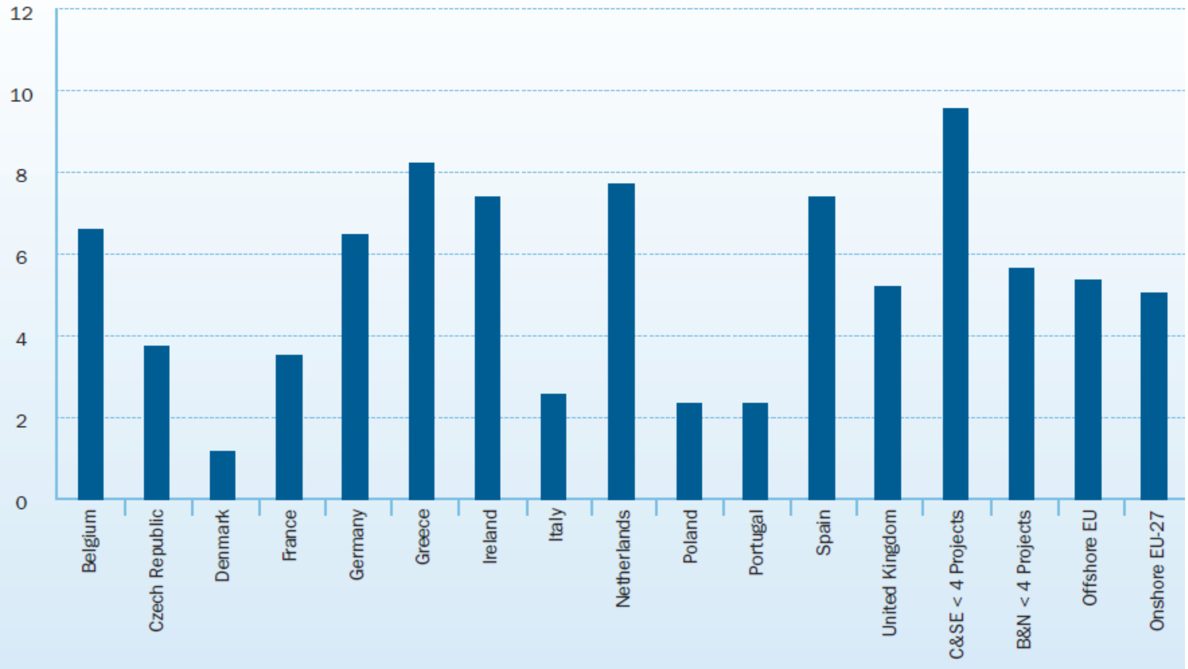
[36] In Hungary the connection cost to medium or high voltage levels is 0.3-0.7 mEUR versus 2-3 mEUR (Infrapont, 2010).

[37] Often further additional cost elements apply such as certain administration fees or the cost of impact study.

The sharing of connection and grid update cost depends on the national regulation. A deep cost allocation means that the renewable energy producer covers both the cost of grid connection and any necessary reinforcements to the grid. Such regulation is applied e.g. in Spain and Croatia (IMPROGRES, 2010). Its major advantage is that it provides locational signal to investors as the exact location in the existing network defines the grid reinforcement cost. Conversely, the major disadvantages are that upfront connection cost can be so high that – especially in times of difficult access to credits – it prohibits entry to this market. The estimation of the network reinforcement cost share of a single investment is highly contingent on other generation decisions and as such is very challenging to estimate. The first mover problem at a specific location is inherent, i.e. whether or not the first entrant shall be charged the full cost and encourage subsequent entrants to rebate some fraction (either by granting the right to the first entrant to charge the followers or the distribution grid operator rebating from them to the first entrant).

A shallow cost allocationrequires the renewable energy producer to pay for the cost of connection only. In this model – used in most European countries - it is the DSO who pays any grid reinforcements. These costs are often passed on to the consumers in their electricity bills. The major advantage is that it does not constitute a high barrier on entry to the renewable generator and - as connection costs are often 6-10% of the whole investment cost – it helps the spreading of this new form of generation (Figure 20). Additionally, connection costs are more transparent and it is easier for the DSOs to develop and apply consistent cost determination rules and guarantee non-discriminatory access to the grid. It, however, does not provide any locational signal to the potential RES investors.

Figure 20. Relative cost of connecting wind parks in various EU countries (mean connection cost as % of total investment cost)



Source: AEE and Fraunhofer IFI in: EWEA, 2010

Several states operate hybrid cost allocation regimes where the actual allocation depends on the agreement of the two parties (e.g. Poland).

The coverage of the total cost (connection and grid enforcement) can take the form of the previously discussed connection cost payment and use of system (UoS) charges. In most EU countries producers are not charged for network use (only the consumers). A trade off exists then between the deepness of connection cost and UoS charges: once deep connection cost applies it can cover system cost, however once DGs pay only for the connection (shallow cost allocation) then it is justifiable to make DGs pay network tariff – either based on capacity or energy use or the mix of the two - and hence pay for the cost they caused. A cost reflective UoS charge system would be differentiated based on location and time and could even be negative if the DG cause network savings.

Currently, in Europe incentive regulation (price or revenue cap) is applied to network operators. It is characterized by the strong focus on short-term cost-efficient network operation. However, it is important to consider long-term efficiency issues like quality of supply and innovation in network regulation. The short regulatory periods of three to five years, offers limited possibilities to realize full long term benefits of innovative – and often more risky - investments; the benefits of such investments are often (partly) captured after three to five years, thus a limited business case for these investments.

Further possible incentives for DSOs are the contractual freedom to include provisions on the volume of electricity fed-in to the network or option to curtail production with (Italy) or without compensation (France). (ECORYS, 2010)

III. REGULATORY ASPECTS OF SMART METERING AND SMART GRID SYSTEMS

III.1. Definitions

III.1.1. Smart metering

Utility metering is going through a radical change where traditional electromechanical meters are being replaced by electrical ones. These are supplemented with communications and processing software to provide a new set of services which will have a profound impact on stakeholders in the whole energy sector. Metering therefore will become a more integrated part of the energy system.

The term, 'smart metering' does not only refer to the meter which can store data on consumption but also to the whole measurement, collection and allocation system, where three main components can be identified: the meter along with other technical devices (e.g. display), the communication network and the data management control centre where meter data is administrated and meters are remotely operated.Smart metering is usually defined by the features it provides. For example ERGEG defines smart metering (ERGEG, 2007) as the entire meter infrastructure that “fulfils or partly fulfils the following main specifications:

- Interval meter data (load profile measurement)
- Remote meter reading, data processing to market players
- Remote meter management (power reduction, disconnection, demand management, etc.)
- Measurement of consumption and generation by distributed units
- Remote meter parameterization such as tariff structures, contractual power, meter interval, etc.
- Remote message transfer from market players to the customer (consumer/generator) as e.g. price signals
- Information displays on the meter and/or communication port for external display
- Main communication port (e.g. GPRS, GSM, PLC, etc).
- Power quality measurement (including continuity of supply and voltage quality)
- Communication port for collection and transmission of other metered data (e.g. gas, heat)”.

III.1.2. Smart grid

Since the emergence of the term, 'smart grid' there have been many definitions created with different views and focus. For example some define the term through the technologies that might be developed, others by the services the grid can offer. At present it seems that within the EU the user centric and output based definition developed by ERGEG (based on the definition of the European Technology Platform) is adopted in most of the countries that have adopted a definition and also by the European Commission in its latest Communication (COM 2011, 202a) (ERGEG, 2009b):

Smart Grid is an electricity network that can cost efficiently integrate the behaviour and actions of all users connected to it – generators, consumers and those that do both – in order to ensure economically efficient, sustainable power system with low losses and high levels of quality and security of supply and safety.

A smart grid employs innovative products and services together with intelligent monitoring, control, communication, and self-healing technologies in order to:

- *Better facilitate the connection and operation of generators of all sizes and technologies; I*
- *Allow consumers to play a part in optimising the operation of the system;*
- *Provide consumers with greater information and options for choice of supply;*
- *Significantly reduce the environmental impact of the whole electricity supply system;*
- *Maintain or even improve the existing high levels of system reliability, quality and security of supply;*
- *Maintain and improve the existing services efficiently;*
- *Foster market integration towards European integrated market.*

Smart grid is basically the upgrading of the distribution network with infocommunication technology that is robust and at the same time flexible in various operational environments. In the early years, utilities most often considered a single (typically private) communications technology. However by now the commonly accepted view is that there is no one-size-fits-all communication technology. Options include private radio frequency (RF) that mesh solutions connecting meters via a concentrator; point-to-point communications with individual meters using public cellular networks (which also provide the backhaul for mesh networks); power line communications (PLC); WiFi; and several others. However, the choice depends on the features considered most critical by the utility e.g. availability, survivability, coverage, latency, security, control, and life cycle. To optimize each factor, utilities might leverage a combination of both public and private networks for the most efficient and reliable operations. (Munday, 2011)

The need for smart grids derives from the changing requirements that electric power grids face. First, electricity grids are ageing and require a significant investment to replace existing infrastructure. Secondly, there is a projected steady increase in electricity demand supported by the possible new power consuming devices such as electric vehicles and heat pumps. Thirdly, energy efficiency targets also highlight the need of decreasing network losses and more efficient use of the grid. And lastly the growing share of renewable generation and distributed generation supported by the environmental targets put the existing grid under increasing pressure. All these require a gradual change from the currently passively managed distribution network to an actively managed grid.

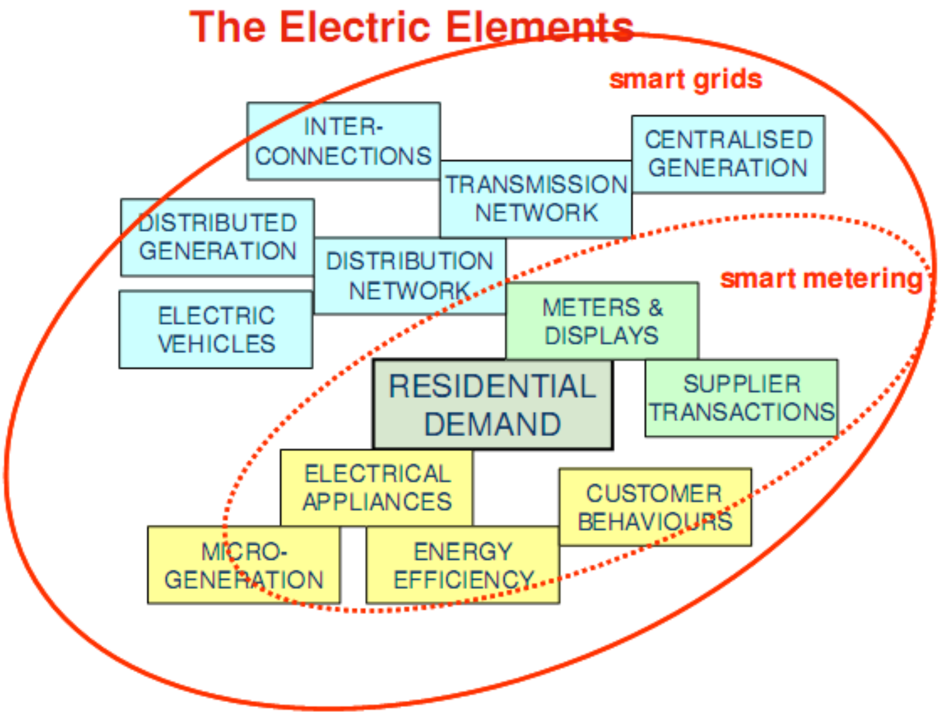
Smart grids are recognized by the European Commission and other European bodies mostly for their important role in achieving the energy and climate goals. The recent EU Council Communication on smart grids states that "smart grids will be the backbone of the future decarbonised power system”. (COM 2011, 202a) And in its Communication on a Roadmap for moving to a competitive low-carbon economy in 2050 it identifies smart grids as a key enabler for a future low-carbon electricity system, facilitating demand-side efficiency, increasing the shares of renewables and distributed generation, and enabling electrification of transport. (COM 2011, 112)

III.1.3. Smart grids and smart metering

Smart grids and smart metering are often confused terms, however ERGEG and other interested associations have the view that smart metering systems should be considered as one major, but not sole part of the smart grid. Moreover a network could be considered as "smart" even if there is no full-scale smart metering in it.

Smart grids and smart metering therefore could be considered separately moreover, in practice the decision making process about their introduction is not synchronized. Usually smart metering has a faster installation pace, however integration of smart grid services and smart grid systems should be assured. Duplications of communication systems and setting up systems with similar functionalities would lead to unnecessary costs. Therefore in the long term it is worthwhile working towards a common infocommunication architecture. In the regulatory issues section therefore we will discuss how to prepare a smart metering system for smart grids.

Figure 21 Elements of smart grid and smart metering



Source: Nabuurs, ERGEG (2009) p. 19.

III.2. Policy drivers of smart metering and smart grids

III.2.1. Energy metering and billing on real consumption – as a requirement

Smart metering provides customers with accurate and detailed information on their real consumption and enables utilities to make the billing based on real usage of energy, rather than the estimations currently used among small and medium consumers. This function is considered as the most important function of smart metering by EU bodies. The argument behind it is that information on actual electricity consumption could trigger changes in customer behaviour, which in the end leads to the reduction of overall energy consumption.

With estimated consumption information, and only very infrequent corrections with real consumption data, currently small and medium size customers are passive actors with very limited incentives to react to prices and market circumstances. Savings due to consumption reductions only materialize when an actual consumption reading takes place, which in most countries is done annually. Until that, bills reflect estimated consumption which do not give any feedback on consumption changes. Without real time information on consumption consumers are not aware of how much they actually consume in a given hour, and how much they could reduce it through simple actions, e.g. turning off the appliances that are used in a stand-by mode. Smart metering can solve this information barrier, thus it is expected to provide more incentives to consumers for end use energy efficiency.

The possibility to be able to achieve energy saving via change in consumer behaviour becomes more and more attractive for policymakers, as it seems that improving the energy efficiency of individual devices might not result at an overall decrease of consumption due to the increased number and use of appliances ('rebound effect'). As approximately 40% of the energy consumption in Europe is attributed to households, the potential of energy efficiency gains is substantial. (ESMA, 2010b)

Real-time consumption measurement and feedback besides overall consumption savings could also result in a more cost-efficient use of the whole energy system by enabling time-of-use tariffs and other demand response schemes that tailor electricity consumption to meet the system needs better. Currently consumers with a uniform tariff do not realize that their consumption during peak periods is much more costly for the system to supply than during the off-peak hours. This results in an inelastic demand that makes the whole energy system more vulnerable to supply shortages and requires higher levels of installed capacities and reserves due to high peak consumption. Smart metering facilitates responsive demand even in a very short term, i.e. within a day, and thus contribute to a more flexible and cheaper system.

Finally, remote energy metering could enhance consumer participation on the energy market by facilitating and accelerating the supplier switching process. With smart metering in place all suppliers will have quick access to metering data, which will be accurate, conflicts on estimated bills and long switching processes due to on-site meter reading could be avoided. Active supplier switching induces increased competition which ultimately leads to lower prices.

With the considerations above EU policymakers started to stress the importance of real time consumption metering and enhanced consumption information to consumers and step-by-step adopted more and more stringent legislations that will outline the mass-scale roll-out of smart metering. The first most significant step was the Energy End Use Efficiency and Energy Services Directive (ESD) published in 2006.[38] In Article 13 the Commission set requirements for the provision of information on actual energy consumption to consumers through meters that accurately reflect actual energy consumption and actual time of use. The ESD states that these interval meters should be placed when it is technically possible, financially reasonable and proportionate in relation to the potential energy saving. It also states that where appropriate, billing should always be based on actual consumption and is presented in understandable terms and it should be frequent enough to enable customers to become more

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[38] Directive 2006/32/EC of 5 April 2006

aware and regulate their own energy consumption. It also outlines which consumption information should be provided to consumers endowed with such meters.[39]

It should be noted that the ESD does not restrict these metering provisions to solely the electricity sector where at present smart metering is considered most seriously but it extends it to the natural gas, district heating and cooling and domestic hot water supplies as well.

The next major step in European legislation towards the mass appearance of smart metering was the third energy package.[40] The new provisions require Member States to “ensure the implementation of intelligent metering system that shall assist the active participation of customers in the electricity/gas supply market”, subject to an economic assessment that determines which form of intelligent metering is economically reasonable and at which timeframe. In electricity, "where roll-out of smart meters is assessed positively, at least 80 % of customers shall be equipped with intelligent metering systems by 2020.” In addition, "Member States, or any competent authority they designate, shall ensure the interoperability and the use of appropriate standards of smart metering systems, having regard to the importance of the development of the internal market in electricity.”

Since the introduction of the Third Energy Package several European initiatives were launched addressing different aspects of smart metering roll out supported by the European Commission. These will be discussed in more detail in section III.3.

III.2.2. Smart grid systems and smart metering supporting distributed energy generation

As we have mentioned above smart grids are considered necessary for large-scale connection of renewable and distributed generation to the grid and therefore to meet the long term environmental goals. The main characteristics of distributed generation that call for a new kind of network system are the following (ESMA, 2010b):

- They are connected to the distribution grid rather than to the transmission grid. This already suggests that managing a large scale of distributed generation requires enhanced system operation that is closer to the system operation performed by today’s TSOs than that of today’s DSO’s.
- The power output of renewable generation is mostly not continuous nor predictable.
- RES-E may get priority over the electricity generated from conventional sources.
- The number of distributed generators is a 1.000 to 1.000.000 factor higher than that of the conventional units.
- They are operated by final customers instead of professional suppliers.

It has to be mentioned that renewables also place challenge to the transmission grid. As renewable resource endowment does not correspond to the spatial distribution of consumption massive amount of renewables will need to be transported from fringe areas of the continent

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[39] Besides ESD there are a set of other European Directives that are less significantly but are also relevant to the provision of smart meters. These are the Energy Performance in Buildings Directive (2002), the Services Directive (2006) and the Measuring Instruments Directive (2006).

[40] Directive 2009/72/EC concerning common rules for the internal market in electricity and Directive 2009/73/EC concerning common rules for the internal market in natural gas

to the major consumption centres. Furthermore the integration of intermittent renewable sources (mainly wind and solar) necessitates the expansion of generation reserves as well.

The European Commission identifies an investment need of €200 billion for energy transmission projects and €400 billion in distribution projects (electricity and gas) of European Interest (excluding national projects and refurbishments of existing grids) in order to meet the EU's 2020 targets. (COM 2010, 677) A current survey of the European Commission shows that already a significant amount of investments have been made in Europe towards smart grid transition: 219 projects were reviewed reaching around €5.5 billion in investment. (JRC, 2011)

One way how a smarter grid can facilitate the large-scale introduction of distributed generation is enabling virtual power plants (VPP). With smart grids distributed generators can be directly controlled through advanced network control programs allowing the aggregation of distributed energy sources into a virtual power plant (VPP). VPPs maximize voltage control capacity with the use of distribution management application which helps determine what measures need to be taken in order to maintain voltage levels. The application can determine the reactive power needed from each generation unit, prompting the VPP to alter the reactive power output of appropriate units. This way – as it is confirmed by the results of pilot projects - the number of distributed generation units that can be connected to the grid could be enhanced.

Smart grids also provide significant contribution to the integration of large share of renewable power generation by enabling the introduction of advanced demand response programs. The discontinuous and less predictable generation of renewables requires a greater flexibility from the power system. Consumption (besides being directed to traditional off-peak periods) could also be tailored to adapt better to the variability to renewable generation. This means the coordination of consumer appliances with real-time levels of energy supply in order to shift demand into periods with high wind and solar power generation. (Smart-A project, 2009)

Furthermore smart grids can facilitate large-scale penetration of distributed generation by enabling new or enhanced ways of storage, which strongly relates to the increased demand side participation it facilitates. Pilot projects investigate the viability of using electric vehicle batteries as storage capacity to help balancing during high renewable feed-ins. Another example is the aggregation of heat pumps which is tested by a Danish pilot project that aggregates 300 heat pumps to absorb electricity generated by wind mills. Other projects aggregate micro-CHP installations in households and store the heat they generate whenever there is no demand for it. While on the other side, when these generate more electricity than what the grid requires they use the batteries of electric vehicles as a form of storage, and then feed it into the grid whenever needed. (JRC, 2011)

III.2.3. Smart metering supporting demand response

The efforts aimed at facilitating the active participation of consumers in the energy markets are summarized by the term demand-side management (DSM). DSM programs consist of planning, implementing, and monitoring activities of electric utilities that are designed to encourage consumers to modify their level and pattern of electricity usage.[41] Within DSM two main groups could be distinguished energy efficiency and demand response. Energy efficiency aims at a reduction in the energy used by specific end-use devices and systems, typically without affecting the services provided. Energy efficiency programs reduce overall

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[41] IEA definition

electricity consumption without explicit consideration for the timing of program-induced savings.[42] On the other hand, demand response is a voluntary temporary adjustment of power demand taken by the end-user as a response to a price signal (market price or tariffs) or taken by a counter-party based on an agreement with the end-user."[43] Accordingly, demand response programs can be categorized into two main groups. Price-based programs rely on the voluntary change of consumption induced by time-varying tariffs, the most commonly used is the time-of-use (TOU) tariff scheme. Incentive-based programs are characterized by a contractual agreement between the consumer and the organizer of the program where in return for discount or credit the consumer reduces its consumption on request. Signing up is voluntary but non-compliance during the program usually entails penalties.

Smart metering is considered as the major facilitator of a radically more active demand side system, done by removing the current major obstacle: absence of real time metering and billing on actual consumption. However, the realisation of the DSM potential of smart metering depends primarily on the reaction of consumers. Therefore, it is very important to understand consumer behaviour in response to the new consumption information and the options provided by new DSM programs. Pilot projects have showed that the success of smart metering often depends on very delicate details. The two most important elements are the way consumption information is presented to final consumers (feedback) and the design features of the DSM programs.

The European Smart Metering Alliance (ESMA) based on a broad sample of experiments and international literature reviews has made the following recommendations regarding the methods and techniques of feedback (ESMA, 2010b, pp 13-25):

- Consumers need to be able to see instantaneously and continuously what is happening to their consumption, without having to switch on an optional in-home feedback device first;
- Direct feedback (i.e. real time feedback either through an in-home display or as a part of a pre payment program or time related pricing structure) seems to be more effective than indirect feedback (e.g. frequent feedback through an interactive webpage, PC, e-mail, SMS or frequent periodic informative billing);[44]
- Feedback seems to be more effective when accompanied with goal setting;
- Historic feedback seems to be more effective than comparative or normative feedback;
- There is more preference for information through an enhanced direct display than through a website.
- Internet promises to provide useful additional feedback through incorporation of further analysis and advice on a longer term basis.

These above findings were affirmed by the Energy Demand Research Project (EDRP) a major project in Great Britain to test consumers' responses to different forms of information about their energy use; involving four energy suppliers with over 60,000 households, including 18,000 with smart meters conducted between 2007 and 2010. The results of EDRP provide further insight on the effectiveness of real-time displays. Customer surveys showed that cost information was used and valued more than unit (kW) information while displays of CO_2 emissions were generally not widely noticed or used or perceived useful. Displays of temperature data were generally rated positively and may have been particularly useful in the

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[42] FERC definition

[43] ETSO definition: ETSO (2007.

[44] See also the results of the In-home display pilot project of Energy Insight in the US.

early stages in responding to advice to reduce thermostat settings. Regarding further technical features the survey found that an audible alarm of high consumption caused no incremental reduction in consumption and was valued negatively by consumers. A “traffic lights” visual sign in contrast was often the most positively rated feature. (Ofgem, 2011)

Finally, it has to be mentioned that even if the smart metering feedback system is designed accurately DSM programs also need to be carefully planned in order to achieve the expected size of consumer reaction. E.g. when designing a TOU tariff the time-zones should be such that consumers can really substitute between the two. For example a TOU tariff scheme designed for households with a peak period between 6 am to 11 pm would not really provide consumers the chance to shift consumption from peak to off-peak period. Also it is very important to have real price differences between the time-zones.

III.3. Regulatory issues and challenges concerning the introduction of smart grid systems and smart metering

In this section we will introduce and discuss the main regulatory issues that emerge regarding smart grid and smart metering roll-out.

III.3.1. Cost-benefit analyses

In most countries the mass roll-out of smart metering is not happening without regulatory support. Market players typically only make an investment if their costs are covered by the future savings the investment yields. In the case of smart metering, however this is rarely the case. While costs are born by the investor that does the metering installation and sets up the data management unit – usually the DSOs - benefits accrue to almost all the stakeholders of the sector. Energy efficiency and savings are typically a benefit to the customers and the society as a whole, but not to energy utilities. Therefore, while overall future benefits might exceed overall costs at the investors’ level the project still could result in a net loss.

Nevertheless there are some pioneering countries where the introduction of interval metering among households and other small-scale consumers is driven by utilities. In Italy, ENEL has equipped small-scale consumers with interval meters without any kind of smart metering regulatory contribution (the Smart Metering Task Force at the regulatory authority was set up later) because it calculated that the reduction in network loss (including thefts) would result in company savings that cover the investment costs (Villa, 2010). In Sweden after a regulatory decision that all meters have to be read at least monthly, utilities found it to be cost effective to replace electromechanical meters with electrical ones.

In most EU countries, however, the mass roll out of smart metering is regulatory driven. Regulators have to carefully consider at what level, how, and at what pace they intend to introduce smart metering for small scale consumers. Since the costs and benefits are partly country specific (e.g. labour cost, level of commercial loss) it is advisable - and EU regulation also requires the Member States - to assess the costs and benefits of different alternatives in the form of pilot projects.

Table 5summarizes the main benefit categories according to the beneficiaries of smart metering. So far we have put the emphasis on smart metering’s effect on energy savings but clearly smart metering has a broader effect on the market. The cost savings by remote management of meters and the savings from reducing network losses (as the cases of Italy and Sweden show) are the most significant benefits, which in some cases, could justify the whole investment, but in other cases usually provide around 70-80% of the utility cost savings. (NRRI, 2008)

Table 5 Benefits of smart metering

Customers	DSOs	Metering companies	Energy retailors	Government / Society
Savings on electricity bills	Remote connections and disconnections	Cost savings by avoiding manual meter reading	Better input data for designing pricing options and energy management services	Overall energy saving and a more cost-efficient sector
Quicker and easier supplier switching	Faster fault location and faster reconnection after outages	More accurate data	Reduction in costs of managing queries regarding bills	Support of embedded generation and the integration of renewables
Increased competition among retailors	More accurate calculation of network losses and reactive power		Reduced theft	
More accurate billing	More accurate monitoring of continuity of supply and voltage quality		Reduced bad debt costs by allowing remote de-enrgisation and pre-payment options	
Prepayment options			Cost sabings on the administration of switching	
Increased level of services			Better planning for balancing	

Source: Revised version of the table in ERRA (2008) p. 36

As for the main cost items, the largest category is the initial investment cost of metering infrastructure. Besides the savings in operational costs, we have mentioned above as the benefits of smart metering, some variable cost items can increase as well (e.g. maintenance and data management costs). In addition a new operating cost item, the variable cost of communication will emerge. Furthermore, smart metering systems are likely to consume more power than traditional metering. And lastly, it is important to note that as smart metering systems are vulnerable to hacking attempts, there will be cost implications of ensuring data privacy and security.

ERGEG in its recently published Final Guidelines of Good Practice on Regulatory Aspects of Smart Metering for Electricity and Gas stated, that the Cost Benefit Analysis should compare the "business as usual" scenario with the new infrastructure scenario with the view on the 20/20/20 targets for climate change and renewables. (ERGEG, 2011) Therefore it should include the extensive value chain. Apart from the customer benefits achieved, a CBA should also take into account the benefits of DSOs, suppliers, metering operators, generators, etc. The CBA should be quantitative as far as possible depending on the national circumstances.

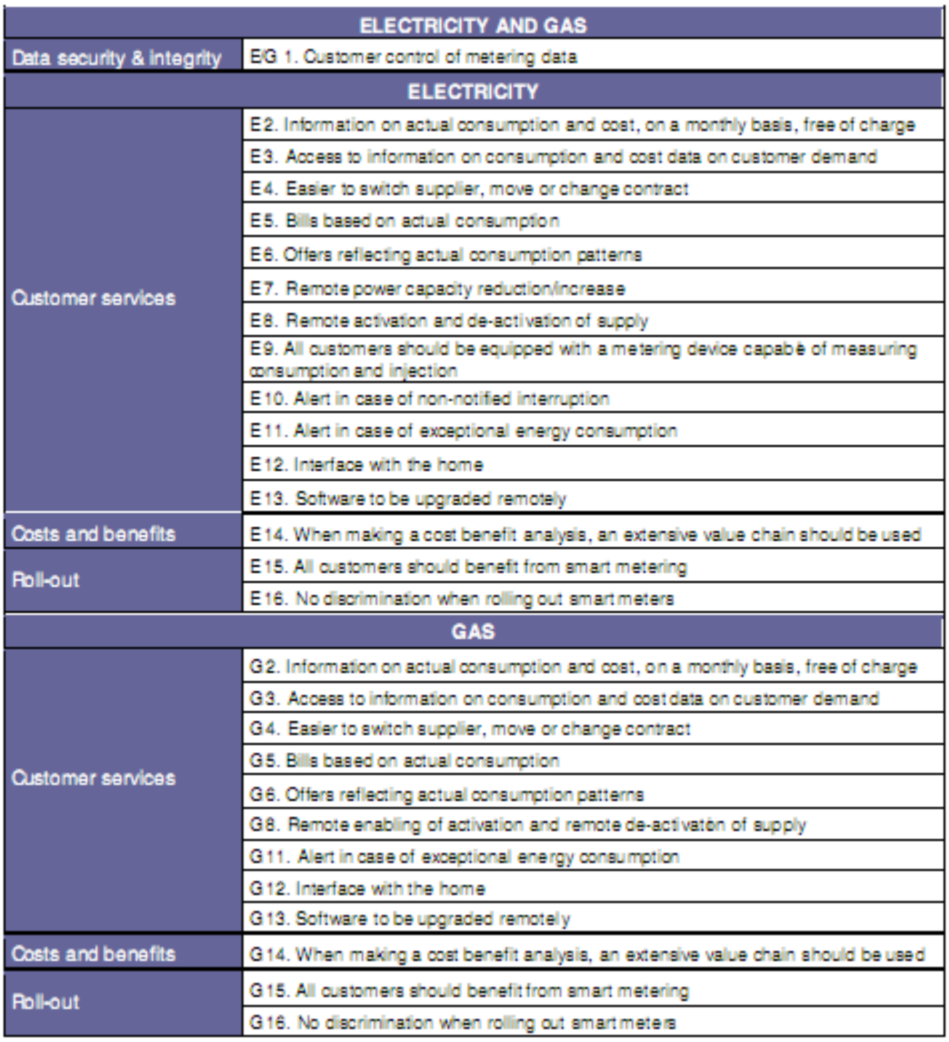
The importance of planning and harmonization

The costs and benefits of the mass scale deployment of smart metering and of smart grids, strongly depend on the services they are designed to provide to consumers. Smart metering systems are comprised of many devices produced by many different manufacturers. These are used by many utilities under different market circumstances and as such further technological development is expected. It is therefore, very important to provide from the start a comprehensive interoperable environment to evade lock-ins and avoidable costs. This requires the setting up of national, but preferably international standards.

To this end, the Commission issued a mandate for the development of an open architecture for utility meters involving communication protocols and functionalities enabling interoperability to the European Standards Organisation (M/441 mandate of 2009).

In addition ERGEG has published its Guidelines for smart metering services for electricity and gas which are aimed to be in line with the functionalities outlined thus far by Mandate M/441(Annex F). The recommendations of ERGEG for the Member States are intended to be a starting point for minimum services rather than an exhaustive list.

Table 6. ERGEG's guidelines of good practice on regulatory aspects of smart metering



ELECTRICITY AND GAS	
Data security & integrity	E/G 1. Customer control of metering data
ELECTRICITY	
Customer services	E2. Information on actual consumption and cost, on a monthly basis, free of charge
	E3. Access to information on consumption and cost data on customer demand
	E4. Easier to switch supplier, move or change contract
	E5. Bills based on actual consumption
	E6. Offers reflecting actual consumption patterns
	E7. Remote power capacity reduction/increase
	E8. Remote activation and de-activation of supply
	E9. All customers should be equipped with a metering device capable of measuring consumption and injection
	E10. Alert in case of non-notified interruption
	E11. Alert in case of exceptional energy consumption
	E12. Interface with the home
	E13. Software to be upgraded remotely
Costs and benefits	E14. When making a cost benefit analysis, an extensive value chain should be used
Roll-out	E15. All customers should benefit from smart metering
	E16. No discrimination when rolling out smart meters
GAS	
Customer services	G2. Information on actual consumption and cost, on a monthly basis, free of charge
	G3. Access to information on consumption and cost data on customer demand
	G4. Easier to switch supplier, move or change contract
	G5. Bills based on actual consumption
	G6. Offers reflecting actual consumption patterns
	G8. Remote enabling of activation and remote de-activation of supply
	G11. Alert in case of exceptional energy consumption
	G12. Interface with the home
	G13. Software to be upgraded remotely
Costs and benefits	G14. When making a cost benefit analysis, an extensive value chain should be used
Roll-out	G15. All customers should benefit from smart metering
	G16. No discrimination when rolling out smart meters

Source: ERGEG (2011), p. 8.

In the beginning of this section we mentioned the case of Sweden where DSOs have started to replace electromechanical meters to provide monthly reading required by the regulator in a more cost-effective way. This early introduction of interval meters, however, was carried out without any common Swedish standard defined by the authorities or the energy business regarding functionality for the smart metering system. Available functionalities therefore differ greatly throughout the more than 100 smart metering systems where only the newer systems might be capable to provide the services outlined in ERGEG's guidelines. Around 10-15% of the meters are not capable for much more than monthly reading. These systems therefore are most likely to be replaced in the near future well before their technical life span. (ESMA, 2010a) This real-life example provides a strong proof for the importance of common standards in providing a sustainable and cost-effective smart metering roll-out.

Services for smart-grids

Just as in the case of smart meters, the costs and benefits of a smart grid depends primarily on the services it provides. When designing the system therefore governments should have a clear view of what services they want from the smart grid. The Commission has published a list of high-level services envisaged and the functionalities these services require (COM 2011, 202b):

- Enabling the network to integrate users with new requirements
  - Guarantee the integration of distributed energy resources
- Enhancing efficiency in day-to-day grid operation
  - Optimise the operation of distribution assets and improve the efficiency of the network through enhanced automation, monitoring, protection and real time operation. Faster fault identification/resolution will help improve continuity of supply levels. Better understanding and management of technical losses, and optimise asset maintenance activities based on detailed operational information.
- Ensuring network security, system control and quality of supply
  - Foster system security through an intelligent and more effective control of distributed energy resources, ancillary back-up reserves and other ancillary services. Maximise the capability of the network to manage intermittent generation, without adversely affecting quality of supply parameters.
- Enabling better planning of future network investment
  - Collection and use of data to enable more accurate modelling of networks especially at LV level, also taking into account new grid users, in order to optimise infrastructure requirements and so reduce their environmental impact. Introduction of new methodologies for more ’active’ distribution, exploiting active and reactive control capabilities of distributed energy resources.
- Improving market functioning and customer service
  - Increase the performance and reliability of current market processes through improved data and data flows between market participants and so enhance customer experience.
- Enabling and encouraging stronger and more direct involvement of consumers in their energy usage and management
  - Foster greater consumption awareness taking advantage of smart metering systems and improved customer information.

Due to the high level interdependency of the two systems, and in order to evade lock-ins, smart metering roll-out should consider future integration into a smart grid system. The list below indicates what precautionary steps should be made (ESMA, 2010b):

- It should be defined which smart grid features the new smart metering system should support, what SM functions are indispensible.
- The ICT architecture of smart metering systems should be designed in such a way that it does not impose barriers in the future introduction of smart grids
- Open communication standards should be used
- Appropriate level of reliability and security of the communication infrastructure should be provided
- Availability of two-way communication with end-customer devices
- Communication system upgrades should be possible

- Where metering service is highly unbundled it should be assured that the DSO has access to the smart metering system
- The communication system should be flexible, supporting sufficient types and number of communication channels and protocols.

Multi-utility smart metering

Although smart metering is discussed usually in relation to electricity it also contains great potentials in the context of natural gas, district heating and cooling, and water metering as well. Since it is expected that in the future smart metering will also be introduced at these utilities it is straightforward to apply the multi-utility approach from the start. Therefore even if smart metering in electricity would be introduced first, within the small-scale consumers, it should be done with a design that later enables the combination of utility measurements into one system.

The clear benefit of a multi-utility system, over the building of parallel individual systems, is the cost savings resulting from the common-optimization of metering installation costs and maintenance costs. A significant part is the reduction of operational reading costs, especially with regards to shared communication systems and customer display. This cost reduction might incentivise utilities - that are otherwise reluctant - to invest in smart metering. A further benefit of multi-utility metering is that it becomes possible to combine individual energy consumption data on a single display, therefore it gives an additional method for consumers to conserve energy.

Smart metering in natural gas, district heating/cooling and water supply generally has the same drivers as in electricity. For example, information and billing on actual consumption provides incentives for a more economical use of resources, while it enables increased monitoring of the networks and therefore better management of the network and reduction of losses. On the other hand, they also have specific aspects compared to electricity. One of the most important is that smart meters all lack a convenient power supply and therefore have to rely on batteries which either have a long duration but are expensive or are cheaper but require more frequent visits for replacement, each method implying major costs. This problem could be overcome by combining the meters with the electricity smart metering system with a low power link to the meter hub.

Needless to say, multi-utility systems pose major challenges regarding data management. These range from the collection of data to its delivery to different retailers. This complexity is further enhanced by data privacy issues, i.e. retailers that are present in more utility segments have to be assured that their competitors will not have a chance to glance at sensitive customer data. The level and seriousness of these problems greatly depends on the initial metering organizational model introduced during the roll out of smart metering. For example, data privacy would be less of a concern if smart metering data management is delivered by an independent metering operator, which does not have any vested interest in these markets.

III.3.2. Metering organizational model

Metering – regardless whether is it smart or not - covers a large set of tasks from the installation, maintenance, meter reading, data validation to data management. In most EU countries all these actions are carried out by DSOs as monopolistic providers of services for a regulated tariff. Often the meter itself is owned by the network company. However this setup is not the only solution. The provision of meter services could also be delivered in a competitive environment, like in the case of UK, where the competing retailers provide the metering services in combination of supply for a price they independently set (liberalised metering market model).[45] But even if we remain within the regulated metering market model, other setups could also be considered, e.g. while installation and maintenance of meters is carried out by the DSOs, meter data collection, management and provision could be serviced by a third party.

The reconsideration of the regulated model might be worthwhile with the smart metering roll-out as new tasks emerge (like the provision of two-way communication) and the complexity of some former tasks will dramatically increase (like meter data management and allocation). Furthermore, the possible future appearance of multi-utility smart metering also has implications on the optimal metering organization design. DSOs might not be the most competent companies for complex data management, and electricity DSOs might not be the most eager actors to deliver these tasks for water utilities in case of multi-utility metering. For the description of the three basic models see Annex G)

III.3.3. Regulatory incentives – output based regulation

As we have already mentioned, smart metering and smart grid deployment is a regulation-driven process: it would not be realised in most countries without the regulatory support in remunerating the investments.

In case of smart metering the method of financing the mass roll-out relates to the organizational model of metering. A liberalized metering model implies that smart meters are provided by traders for a price included in the supply contract and financing period set by the trader. In case of regulated metering, a common solution is to introduce a separate metering charge so that the costs and remuneration of the smart metering roll-out could be handled more fairly and transparently. The timing of the recovery of the initial high investment costs also must be decided. Three models can be distinguished: 1) a smoothed charge that allows the cost recovery through a long period of time, 2) a varying charge that reflects the relation of costs and benefits each year, and 3) a combination of an upfront charge from the customer followed by a lower regular metering charge (ERRA, 2008). All three have their pros and cons with different implications on consumers and the regulated companies.

In case of smart grids the task is to set up a regulatory scheme that incentivizes DSO's transformation into active network managing system operators. Current regulatory practice generally provides incentives for grid operators to improve cost efficiency in the form of decreasing operational costs, rather than upgrading the grid through timely investments; especially those which would result in benefits only in the next regulatory period. Furthermore, the decrease in electricity supply leads directly to a decrease in profits.

Clearly the incentives of grid companies need to be corrected in order to meet the challenges smart grids place: cost increase, revenue decrease, lack of incentives. (Meeus et al, 2010)

Cost increase: the integration of decentralized generation and active demand participation, according to the results of pilot projects, implies increased system operational costs and increased costs for maintaining service quality. In the meantime, the current regulatory framework provides incentives for the reduction of operational costs and for quality of supply improvements.

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[45] The German metering market is also liberalised. Here independent metering operators which could also be the consumers' suppliers provide the metering service, but in case a customer has not chosen an independent metering operator, the DSO provides the service. Source: ERGEG (2009,a)

Revenue decrease: with the integration of decentralized generation and an active demand side, the amount of energy delivered through the grid will be reduced. In the current regulatory environment this however will result in the simultaneous reduction of profits for grid companies.

Lack of incentives: even if the two effects above would be resolved, grid companies would still not be directly incentivized to generate more innovative solutions and smart grid services than the minimum required.

To overcome these challenges, the distortions need to be corrected to provide correct economic signals to facilitate the integration of distributed generation and active demand side management; in addition a deeper revision of the regulatory framework is needed. Cost increase could be counterbalanced with e.g. the introduction of regulated connection charges to avoid bargaining and discrimination. Another tool is the application of more cost reflective use-of-system network charges with differentiation by location and time-of-use. A third possible solution for the cost increase is providing incentives for distributed generators to provide ancillary and/or network services via commercial arrangements (Pérez Arriaga, 2010). Revenue decrease could be alleviated by the decoupling of company profits from the quantity of electricity distributed.

The suggestions for the revision of the regulatory framework include an incentive based regulation aimed at reducing network losses and improving quality of service but now with the consideration of the adverse effects of distributed generation penetration on them, additional revenue drivers to compensate DSOs for the increased costs and the decrease of profits, and specific incentives for innovation. (Pérez Arriaga, 2010)

The upgrading of the remuneration is a complex task that must account for the cost increase and system reliability effects caused by large distributed generation penetration. This will probably require the use of network simulation models. Additional revenue drivers that also introduce new type of incentives are considered in the form of output based regulation. The idea behind output based regulation is that the regulated entity has the best competence, know-how to deliver its service and is better informed of its capabilities than the regulator. Therefore, instead of regulating internal processes and activities regulation should focus on the outcome, i.e. the service of the entity.

Output regulation can be either direct e.g. imposing minimum requirements for certain parameters or performance-based providing penalties and rewards according to certain criteria and performance indicators. Here the task is to find objectively set and measurable indicators that represent the effects and benefits of the ‘smartness’ of the grid. The value of the indicators should preferably be free of exogenous circumstances, depending primarily on the efforts performed by the DSO. Due to national differences, the most adequate indicators can vary from country to country, however an international benchmark of selected performance indicators might be useful. The EU Commission lists potential indicators such as the level of losses in transmission and distribution networks, energy not withdrawn from renewable sources due to congestion and/or security risks, percentage of load demand participating in market-like schemes for demand flexibility (for the complete list see Annex H).

A tight control of performance however could become a barrier to investments as it incentivizes the company to decrease operational costs rather than invest in innovation. Therefore output based incentive regulation should be complemented with regulatory tools that aim at encouraging innovation.

With regards to the latter, regulators should support international cooperation in knowledge sharing – such as the European Electricity Grid Initiative - and efforts put into research and development related to smart solutions and the transition process from R&D projects to final full deployment when it is found to be profitable. Such a regulatory support for DSOs could be the acknowledgement of the uncertainty related to investment in innovation by for example a higher rate of return, and clear rules for the treatment of stranded assets. (ERGEG, 2010)

III.3.4. Data privacy and security

Smart grid technologies raise a number of privacy and data security concerns: there is a potential for intrusion into the private lives of consumers through the use of devices installed in homes while suppliers have concerns over the security of sensitive business data. Therefore, in the case of the broad roll-out of smart metering and smart grids, regulators have to assure data privacy (i.e. ensure that people are not subjected to unwanted targeting, profiling and marketing activity) and safety (i.e. protect smart meters and grids against hackers) for consumers and data security for competing energy businesses. This is recognized at the EU level; the European Task Force on smart grids set up by the Commission has set as key deliverable of Expert Group 2 out of the three expert groups established to "identify the appropriate regulatory scenario and recommendations for data handling, data security and data protection. The aim is to establish a data privacy and data security framework that both protects and enables" (Task force smart grids Expert group 2, 2011, p. 3.).

The task force has opted for the privacy by design approach, meaning that smart grid products and solutions should be designed from the start with appropriate levels of data privacy and security at their core, embedding privacy in the technical design. The expert group in its recommendations has stated that European standard organisations should update, extend or develop new standards covering the security aspects of smart grids. (Task force smart grids Expert group 2, 2011, p. 4-5.) The expert group also recommends that one generic model is adopted by all European countries, for key management, and security and privacy principles, regardless of the communication technology or protocol. With regard to data privacy, it recommends that personal and non-personal data should be distinguished; personal data is considered as a specific type of data and can be traced back to the individual consumer whereas non personal data could be aggregated data, and does not contain references to natural persons. Further recommendations are that there is a clear division of roles and responsibilities regarding ownership, possession and access to data, read and change rights, etc. have to be defined.

The expert group also requested the assistance of the Data Protection Working Party of the EU Commission which published its opinion on smart metering in April 2011. Its aim was to clarify the legal framework applicable to the operation of smart metering technology within the energy sector. It supports the principles of the privacy by design approach and suggests that (Article 29 Data protection working party, 2011):

- Meter readings occur as frequently as is necessary for the operation of the system, or for the provision of a service chosen by the consumer
- Any data collected remains within the household network unless transmitting it elsewhere is necessary, or if the consumer consents to the transmission
- Where personal data are transmitted, any data elements which are not necessary to fulfil the purpose of the transmission are filtered or removed. The overall aim is that the lowest possible data volumes are transmitted
- Access to personal data is allowed only to the extent necessary for the role being performed by the data controller

- Only appropriate recipients of personal data are allowed to access them

The case of the delay in the Dutch smart metering roll-out notably demonstrates that privacy and security concerns should be addressed from the very beginning of the process, or else consumers' cooperation will be lost. In the first roll-out plan, Dutch consumers were obliged to accept a smart meter and that consumption information would be read every 15 minutes. Consumer and privacy organizations criticized the system due to the loss of privacy. For example, the meters could allow employees of utility companies to see when properties were empty or when households had bought expensive new gadgets. The concern from the consumer groups and scientific and political communities led to the withdrawal of the initial roll-out bill. As a result the new version, developed by grid operators in a dialog with all stakeholders, provides consumers the right to refuse the installation of a smart meter and also gives them control over the frequency of the collection of metering data. Also, a set of guidelines to protect privacy and provide security were jointly developed (Task Force Smart Grids Expert Group 2, 2011).

IV. LESSONS AND RECOMMENDATIONS FOR INOGATE COUNTRIES

The scepticism about renewable energy use is often originates from the financial resources the state spends on subsidising RES-E production. It can be especially strong in countries where the utility bills are substantial in the overall income of households and where the access to adequate levels of energy services is curtailed by limited payment ability (energy poverty). Consequently, the consumers' wish to design cost efficient RES-E regulation is justifiable. To this end the regulation should possess some fundamental characteristics:

- as most RES-E production fundamentally depends on subsidies, the stability and transparency of regulation is quintessential: frequently changing tariffs, eligibility requirements and periods directly affects the financial viability of these investments and divert potential future investors away from the sector;
- higher subsidies than the minimum level triggering RES-E investments should be avoided as this is an unnecessary burden on electricity consumers financing the subsidies;
- at the early stage of market development the use of feed-in tariffs (as opposed to green certificates) is probably more adequate as it minimises the market risk of the investor;
- the risk of excessive cost of FIT schemes can be eliminated by setting ex ante production quotas; and
- an adequate support scheme does not automatically generates RES-E investments and production only if coupled with adequate access to the network (often in the form of priority dispatch) and transparent, quick and simple licencing regimes involving as few authorities as possible (easy entry to the market).

Smart grid and its major component, smart metering, are considered to be the backbone of the future decarbonised electricity system, inevitable to implement within the next ten years in the EU. Their realization and mass-scale roll-out is however not a straightforward process, complex regulatory issues arise placing new type of challenges to the regulatory authorities and to all the stakeholders of the sector. Recommendations to this process that can be formulated at this early phase include:

- ♦ Smart metering is indispensible in achieving active consumer participation; however realisation of the DSM potential of smart metering greatly depends on the accompanying conditions, such as how the consumption information is presented to consumers and the design features of the DSM programs. Therefore a through understanding of consumer behaviour is necessary.
- ♦ A cost-benefit analysis that includes the extensive value chain has to precede the mass-roll out of smart metering
- ♦ Since smart metering and smart grid relies on the interaction of many different devices and a constant technological development is expected, a comprehensive interoperable environment is needed from the start. The setting up of national, but preferably international standards is required.
- ♦ Correspondingly, since costs and benefits greatly depend on the features the smart grid and smart metering systems provide a thorough consideration of the minimum services is necessary before the mass-scale implementation.
- ♦ Due to the high level interdependency of the smart metering and smart grid systems and since smart metering implementation is likely to precede that of

smart grids the smart metering roll-out should be done with a consideration of future integration into a smart grid system.

- Smart metering implementation in the electricity sector should also be delivered with a design that later enables its upgrading into a multi-utility measurement system.
- Smart metering and grid technologies raise a number of privacy and data security concerns that need to be addressed by regulators for example by the privacy by design approach.
- The incentives of grid companies need to be corrected in order to meet the challenges smart grids place: cost increase, revenue decrease, lack of incentives.

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V. ANNEX A: EMISSIONS TRADING IN THE US

Although in the run-up for the presidency Barack Obama announced the need for a federal cap and trade program to limit global warming and the consequent bill passed the House of Representatives in 2009, the prospect of such a system being introduced in this presidential term is very remote due to the republican majority in the Senate.[46] The only functioning mandatory regional scheme is the *Regional greenhouse Gas Initiative (RGGI)* involving 10 states and covering CO_2 emissions from fossil-based power plant above 25MW (209 plants as of today) and feeding more than 10% of their electricity to the grid.[47] The target for the first period (2009-2014) is to stabilize historical emissions level and from 2015 onward to reduce by 2.5% annually. The initial 10-state regional CO_2 emissions budget was set based on an analysis of 2000-2004 power plant CO_2 emissions and an anticipated increase in CO_2 emissions prior to the beginning of the program in 2009. This regional CO_2 emissions budget was apportioned among the 10 states. The scheme promotes auctioning more profoundly than EU ETS: the minimum auctioning ratio is 25% but the participants auction approx. 90% of the allowances. The proceeds of the quarterly auctions are devoted to energy efficiency and renewable projects but recently also to cover fiscal deficits in general (Roach, 2011). The compliance periods are 3 years long and non-complying facilities have to surrender three times the missing number of allowances in the next period. The cap proved to be too lax to create scarcity in the CO_2 market. The 2010 verified emissions are 27.1% below the cap (Environment Northeast, 2011). Due to the recession and the low natural gas price the already modest CO_2 prices sunk further and are below 2 USD/short ton.[48] Similarly to the linking of EU ETS to Kyoto project-based credits (ERU and CER), the RGGI allows for the accounting of offset projects but only implemented within the territory of the US. In reality, however this option is not used by the regulated companies due to the low price of CO_2.

Another regional scheme is the *Western Climate Initiative (WCI)* that starts its first commitment period in 2012. It is a collaboration of seven U.S. states and four Canadian provinces with the aim of reducing their aggregate GHG emissions to 15% below 2005 levels by 2020. It is a regional scheme consisting of mutually recognized state cap and trade systems allowing for the trading of allowances in the single market created by the participating jurisdictions. Between 2012 and 2015 (first compliance period) the scheme covers approx. two-thirds of total emissions, from 2015 it will expand to 90%. The WCI regulation requires a minimum auction level of 10% in 2012, increasing to at least 25% by 2020.

The most recent developments in the US are not very encouraging. In 2011 the proposed Midwest Greenhouse Gas Reduction Accord was abandoned; New Hampshire and New Jersey are about to leave RGGI and California announced the delay the start of its GHG market by one year until 2013 (Perdan and Azapagic, 2011). It is important, however, to keep in mind that while the EU ETS is a tool to comply with the Kyoto target of the EU, emissions trading schemes in the US are voluntary in the sense that lack any mandatory reduction requirement.

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[46] American Clean Energy and Security Act (Waxman-Markey)

[47] Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, Vermont, Massachusetts, Maryland and Rhode Island

[48] 1 short ton equals 0.9 metric ton.

VI. ANNEX B: THE ROLE OF INITIAL ALLOCATION

Let us assume a company initially (before CO2 regulation) emitting 100 tons of CO2 and facing two abatement options: to reduce 10 tons of CO2 at a price of € 100 per year, or alternatively to reduce 20 tons at a price of € 500 per year. Under the EU ETS this firms receives 120 tons per year of CO2 quota. What should a good management do with the CO2 quota owned, if the EUA price is € 20? Let's calculate the marginal abatement cost of the two reduction options. Marginal abatement cost of the first option is 10 €/t and 25 €/t for the second one. Although the company's initial emission was 100 tons and 120 tons of EUAs allocated to it, the company's optimal emission is found to be 90 tons. It is worth for the company to abate 10 tons of CO2 at the lower cost of € 100 and to sell 10 tons out of its allowances at a price of € 20 thus raising € 200 revenue, and a net profit of €100. The second reduction option is obviously too costly at 25€/t. In conclusion, while its total abatement cost is € 100, the company can sell the excess EUA allowances of 30 tons (i. e. 120 t – 90 t) at a total price of € 600, obtaining a profit of € 500! How would the optimum change, in the case when the company obtains 60 tons of EUA only? Its optimum would remain the same at a level of 90 tons, having again 10 tons to be abated, but now without any profit made. In this case the total abatement cost is identical (€100), but instead of being able to sell EUAs, the company would have to buy 30 tons costing him € 600, thus its total cost from the regulation is € 700. So, it can be concluded that the emission optimum does not change if the initial allocation changes (as long as the total cap remains), but of course, the profit of the company is altered.

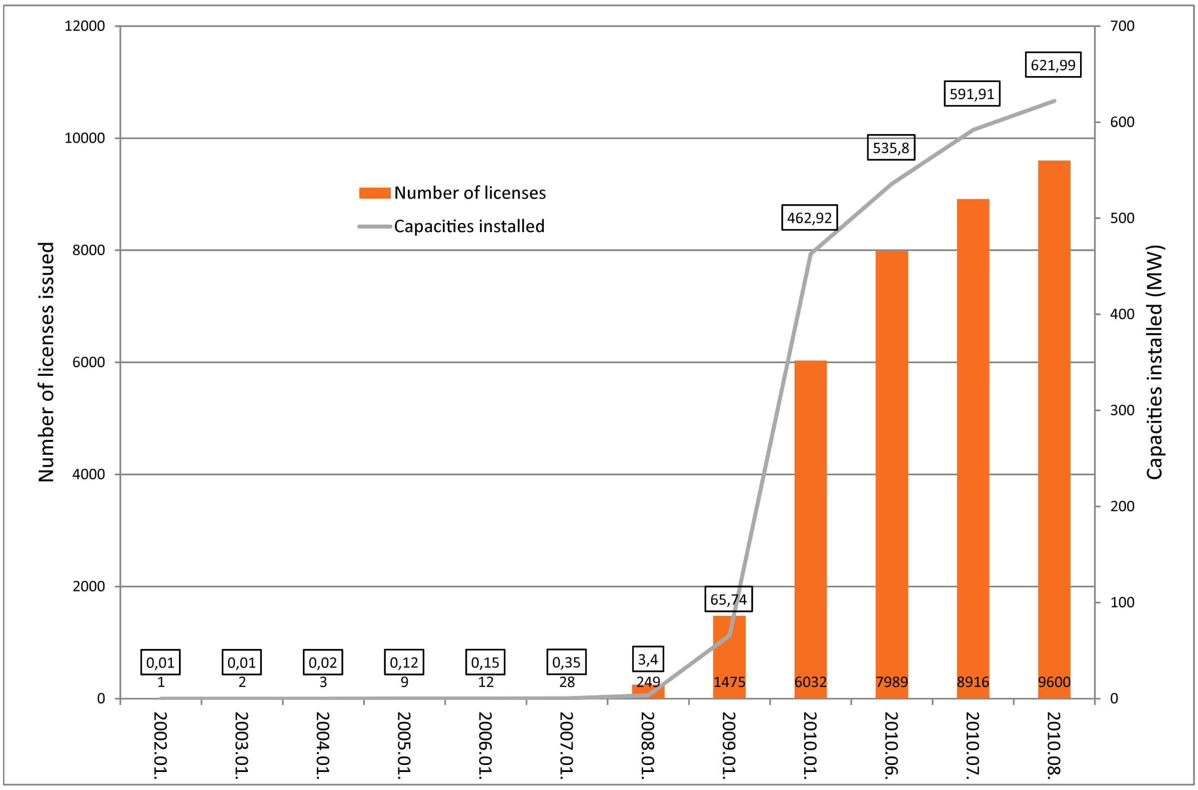
VII. ANNEX C: FIT CASE STUDIES

VII.1. Solar boom in the Czech Republic

The Electric Energy Act introduced a technology-differentiated and obligatory feed-in tariff and bonus system for the support of renewable electricity production in 2002 which were to be renewed annually by the authority. Photovoltaic production received the most attractive tariffs that were 3-4 times higher than other RES technologies. In 2008, for example, the price of 1 kWh of PV generated electricity was at least 54 €cents. DSOs pointed out that solar power receives around 40% of the subsidies but accounts for only 7% of the generation.

Until 2008, PV based electricity production was negligible but in 2009 its share was already 25% of all green electricity, and in 2010 it did already qualify for being the most attractive renewable electricity producer. Between January 2008 and January 2009 the number of licensed PV projects had a six-fold increase. By January 2010 installed capacities passed the 500 MW limit, and at the end of the year amounted to 2000 MW. Production and utilization of the capacities was significantly low (22. Figure).

22. Figure Development of installed PV capacities and production in the Czech Republic, 2002-2010



Source: ERÚ

Investment surge had basically two reasons: attractive tariffs and quick decrease of PV investment costs, the latter amounting to even 40% (!) in 2009. This change was not followed in time by the feed-in tariffs. Thus the support system in a country having lower than the European average solar exposure was able, within a few years, to install considerable PV capacities.

The regulating authority (ERÚ) did warn already in 2007 that without tariff revision, the support system would push consumer prices up. Not surprisingly, the green electricity tariff element in the electricity price quadrupled from 2008 to 2010. The government started the corrections in November 2009 allowing the regulator to reduce tariffs by 5% of those renewable projects which had already realized their returns. PV tariffs were cut back by the legally allowed maximum in 2009. In February 2010 the Czech system operator (CEPS) and the distributors requested in a joint open letter to be allowed to keep the possibility of connecting new renewable projects to the network.

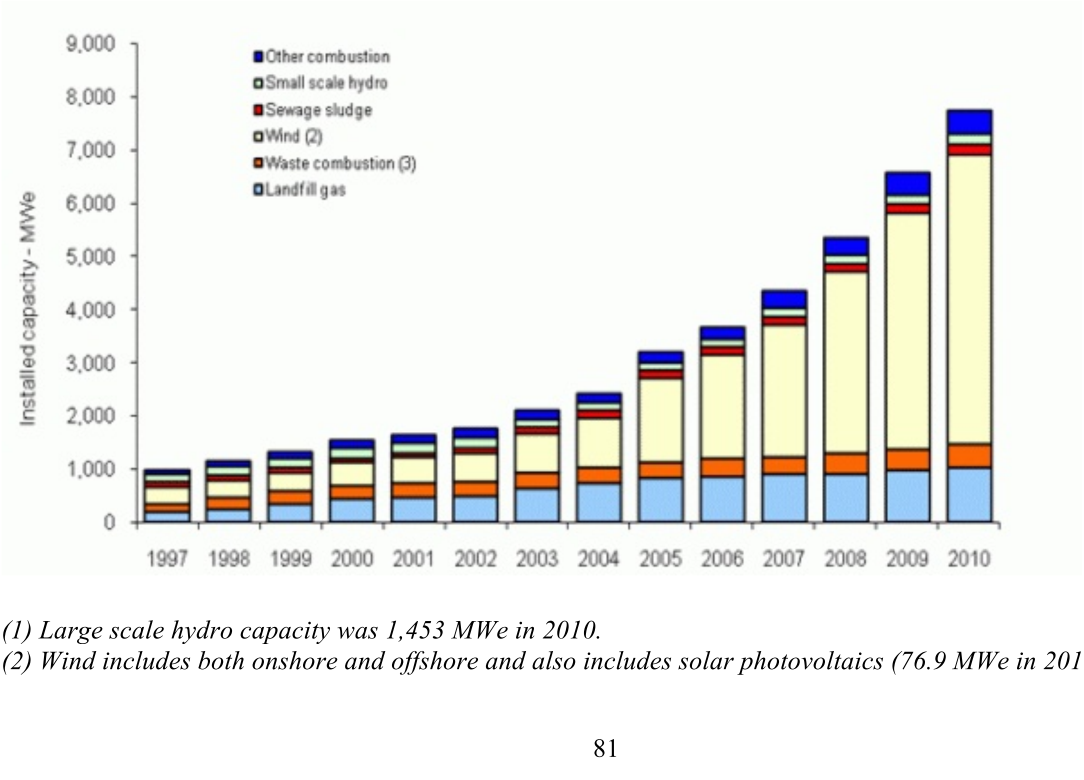
During the past year a number of measures were taken to slow down the expansion of investments. The NREAP prepared in 2010 forecasted 1700 MW PV capacity that was surpassed by actual installed capacities by the end of the year. In September the government cancelled support for PV installations on agricultural land and also lifted the 5 years corporate tax exemption of firms producing solar energy. The growing demand for support was estimated to cause a 12% increase in the public consumer price and 18% for business consumers in 2011. To avoid this, based on a government recommendation, the Lower House of the Parliament adopted several measures. First, those solar electricity producers who built their capacities in 2009 and 2010 should pay an extra tax of 26%. Companies receiving EU ETS allowances in 2011 and 2012 are obliged to pay a 32% special tax and land-use fees of solar power parks located in agricultural land has been raised. Finally, in November ERÚ announced the decrease of 2011 feed-in tariffs by 40% for PV producers below 30 kW and by 51.5% in the case of larger capacities from 2010 levels.

Sources: ERÚ, Platts Energy in Eastern Europe reports

VII.2. UK reversal to FIT for small RES generators

The renewable target of the UK under the RES Directive is 15% of final energy consumption accounted for by energy from renewable sources. The last decade witnesses a steady growth in RES-E capacity, wind being the key driving technology (Figure 23).

Figure 23. The development of RES-E capacity excluding large hydro (MWe)



(1) Large scale hydro capacity was 1,453 MWe in 2010.
(2) Wind includes both onshore and offshore and also includes solar photovoltaics (76.9 MWe in 2010) and

shoreline wave (2.6 MWe in 2010).
(3) All waste combustion plant is included because both biodegradable and non-biodegradable wastes are burned together in the same plant.

Source: RESTAT (National Renewables Statistics, UK)

By the end of 2010 installed generation capacity reached 9,202 MW with a 15% increase from 2009, excludes co-firing in conventional generation stations (a further 390 MW). In capacity terms, wind was the leading technology in 2010 (58%), with hydro second (18%), followed by landfill gas (11%).

The main production support system for RES-E in the UK is a green certificate scheme (Renewables Obligation). Electricity suppliers are to source a specific and annually increasing proportion of electricity from eligible renewable sources or pay a penalty. The regulator (Office for Gas and Electricity Markets - Ofgem) issues Renewables Obligation Certificates to qualifying renewables. These certificates may be sold by generators directly to licensed electricity suppliers or traders. This means that the certificates can be traded separately from the electricity to which they relate. Suppliers present the certificates to Ofgem to demonstrate their compliance. Basically all renewable technologies are eligible with the exception of hydro power from plants exceeding 20 MW and commissioned before 1 April 2002.

At the beginning 1 ROC was awarded for each MWh of renewable electricity generated. In 2009, ‘banding’ was introduced i.e. technologies now receive different numbers of ROCs depending on their costs and potential for large scale deployment. For example offshore wind, wave and tidal, and dedicated energy crops receives 2 ROCs/MWh, while more established technologies receive less support: sewage gas 0.5 ROCs/MWh or landfill gas receives 0.25 ROCs/MWh. Onshore wind continues to receive 1 ROC/MWh. New bands will set from 1 April 2013 (with the exception of offshore wind for which new bands will come in on 1 April 2014).

Feed-in tariffs (FITs) were introduced from April 2010 aimed at small-scale installations up to a maximum capacity of 5 Megawatts (MW). The FITs scheme is intended to encourage deployment of additional small scale, low carbon electricity generation, particularly by individuals, householders, organisations, businesses and communities who would not have traditionally engaged with the energy market. FIT supports new anaerobic digestion (AD), hydro, solar photovoltaic (PV) and wind projects up to that 5MW limit. An additional guaranteed export tariff of 3p per kWh is paid for electricity generated that is not used on site and exported to the grid. The scheme will also support the first 30,000 micro combined heat and power installations with an electrical capacity of 2 kW or less, as a pilot programme.

The tariffs are technology and size differentiated. Additionally, for technologies on a steep learning curve (PV and wind) the tariff decreases with the date of commencement. As a general rule, the eligibility period is 20 years but for PV it is 25 and for microCHP (being a pilot programme it is only 10 years.

Table 7 Feed-in tariffs until 2020 (p/kWh)

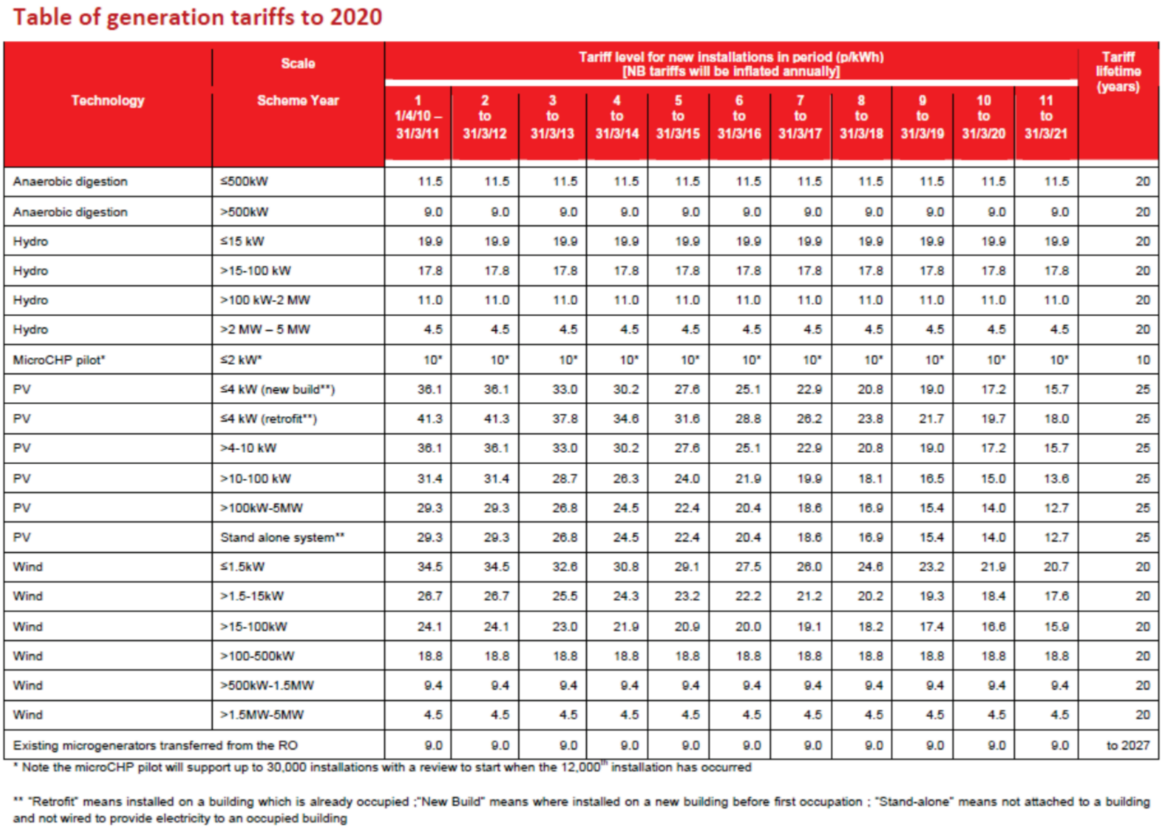


Table of generation tariffs to 2020

Technology	Scale	Tariff level for new installations in period (p/kWh) [NB tariffs will be inflated annually]											Tariff lifetime (years)
	Scheme Year	1 1/4/10 – 31/3/11	2 to 31/3/12	3 to 31/3/13	4 to 31/3/14	5 to 31/3/15	6 to 31/3/16	7 to 31/3/17	8 to 31/3/18	9 to 31/3/19	10 to 31/3/20	11 to 31/3/21	
Anaerobic digestion	≤500kW	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	20
Anaerobic digestion	>500kW	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	20
Hydro	≤15 kW	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	20
Hydro	>15-100 kW	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	20
Hydro	>100 kW-2 MW	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	20
Hydro	>2 MW – 5 MW	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	20
MicroCHP pilot*	≤2 kW*	10*	10*	10*	10*	10*	10*	10*	10*	10*	10*	10*	10
PV	≤4 kW (new build**)	36.1	36.1	33.0	30.2	27.6	25.1	22.9	20.8	19.0	17.2	15.7	25
PV	≤4 kW (retrofit**)	41.3	41.3	37.8	34.6	31.6	28.8	26.2	23.8	21.7	19.7	18.0	25
PV	>4-10 kW	36.1	36.1	33.0	30.2	27.6	25.1	22.9	20.8	19.0	17.2	15.7	25
PV	>10-100 kW	31.4	31.4	28.7	26.3	24.0	21.9	19.9	18.1	16.5	15.0	13.6	25
PV	>100kW-5MW	29.3	29.3	26.8	24.5	22.4	20.4	18.6	16.9	15.4	14.0	12.7	25
PV	Stand alone system**	29.3	29.3	26.8	24.5	22.4	20.4	18.6	16.9	15.4	14.0	12.7	25
Wind	≤1.5kW	34.5	34.5	32.6	30.8	29.1	27.5	26.0	24.6	23.2	21.9	20.7	20
Wind	>1.5-15kW	26.7	26.7	25.5	24.3	23.2	22.2	21.2	20.2	19.3	18.4	17.6	20
Wind	>15-100kW	24.1	24.1	23.0	21.9	20.9	20.0	19.1	18.2	17.4	16.6	15.9	20
Wind	>100-500kW	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	20
Wind	>500kW-1.5MW	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	20
Wind	>1.5MW-5MW	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	20
Existing microgenerators transferred from the RO		9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	to 2027

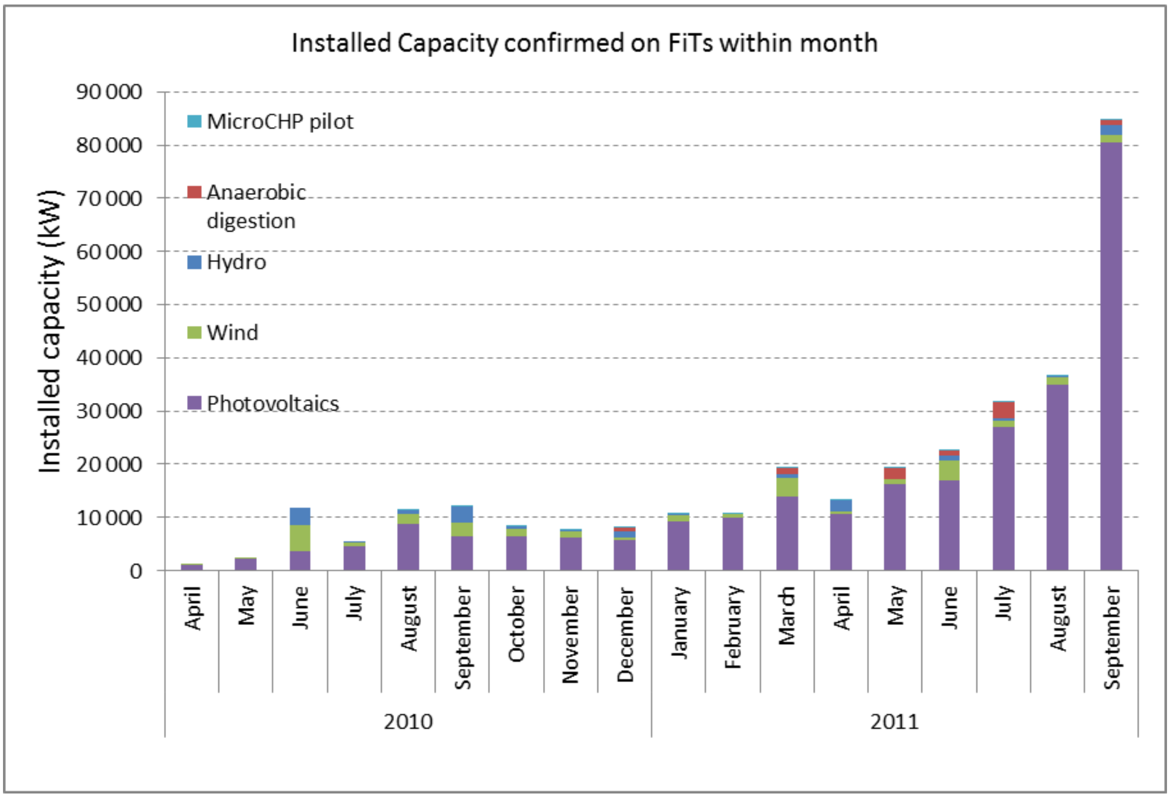
* Note the microCHP pilot will support up to 30,000 installations with a review to start when the 12,000th installation has occurred

** "Retrofit" means installed on a building which is already occupied ;"New Build" means where installed on a new building before first occupation ; "Stand-alone" means not attached to a building and not wired to provide electricity to an occupied building

Source: Department of Energy and Climate Change

Since the introduction of FIT for small installations (April 2010) the uptake has been growing rapidly, PV being the most popular technology (Figure 24).

Figure 24. Installed capacity eligible for FIT (kW)



Source: Department of Energy and Climate Change

VII.3. Ukraine: local content requirement for feed-in tariff and dealing with exchange rate fluctuations

Although the first pieces of legislation on the promotion of RES-E in Ukraine date back to the late 1990s (Decree of CMU of February 3, 1997, No. 137 *On Comprehensive Program for Construction of Wind Power Plants* and Decree of CMU of December 31, 1997, No. 1505 *On the Program of State Support to Development of Non-Conventional and Renewable Energy Sources and Small Hydro and Thermal Energy*), feed-in tariffs were introduced only in 2009.

The FIT is accompanied with the obligation of energy suppliers to connect generators of electricity from non-conventional energy sources to networks (Decree of CMU No. 126 of February 19, 2009, on Specifics of Connection to Power Grid of Power Facilities that Generate Electricity Using Non-Conventional Sources) and the mandatory purchase by the Wholesale Electricity Market Operator. As the reform of the electricity market is discussed, in order to preserve this guarantee the draft law 8575 states that the state guarantees purchase of all electric power produced (apart small hydroelectric power stations!) and not sold by contracts directly to the consumers or energy supply companies. The state guarantees full payments for such electric power within the established limits and under the legally fixed procedure. It means that NERC will decide on the production quotas.

The regulator (NERC):

- issue the licenses for generation

- approves the “green” tariff for electricity generated from non-conventional energy sources
- maintain the registry of non-conventional energy facilities
- publishes annually the information related to cost of connecting non-conventional energy facilities to power networks

The law sets technology and size differentiated feed-in tariffs that are valid until 2030. The tariffs arerevised on a monthly basis to follow changes in UAH/EUR currency exchange rate with a guaranteed “minimum floor” in EUR (Table 8). The tariff is to be reduced by 10, 20 and 30% for the plants commissioned after 2014, 2019 and 2024, respectively. There is a local content eligibility requirement for becoming eligible for FIT. This means that raw materials, materials, fixed assets, works and services must be of Ukrainian origin min. 30% starting 2012 and 50% starting 2014. This also applies to significantly upgraded facilities where it is quite difficult to define the cost of initial investment.

Table 8 Fixed minimal size of feed-in tariff established till 2030 (€/kWh)

ELECTRICITY PRODUCED WITH:		**Formula**	**Retail price for electricity for 2nd class consumers as for January 2009, EUR/KWh**	**Green” tariff level factor**	**Peak time factor**	**TARIFF, EUR/KWh**
			A[1]	**B[2]**	**C[3]**	
Wind energy	up to 600 KW	A*B	0,05385	1,2	not applied	**0,0646**
	600 KW - 2000 KW	A*B	0,05385	1,4	not applied	**0,0754**
	over 2000 KW	A*B	0,05385	2,1	not applied	**0,1131**
Biomass energy[4]		A*B	0,05385	2,3	not applied	**0,1239**
Solar energy	Surface power facilities	A*B*C	0,05385	4,8	1,8	**0,4653**
	Power facilities installed on roofs of houses, buildings and constructions with rated capacity over 100 KW	A*B*C	0,05385	4,6	1,8	**0,4459**
	Power facilities installed on roofs of houses, buildings and constructions with rated capacity below 100 KW and objects installed on the facades houses, buildings and constructions regardless their rated capacity	A*B*C	0,05385	4,4	1,8	**0,4265**
Small hydro power plants		A*B*C	0,05385	0,8	1,8	**0,0775**

[1] *Resolution of the NERC # 1440 dd. 23.12.2008 “On approval for January 2009 of electricity retail tariffs in consideration of tariff level limits by stepwise transfer to establishment of unified retail tariffs for consumers on the territory of Ukraine”*

[2] *The Law of Ukraine # 575/97-BP dd. 16.10.1997 “On Electrical Power Industry” as to stimulation of use of alternative energy sources” with amendments introduced by the Law of Ukraine dd. April 1, 2009 #1220-VI “On Amendments to the Law of Ukraine “On Electrical Power Industry” as to stimulation of use of alternative energy sources” set by 10.86 UAH/EUR exchange rate*

[3] Resolution of the NERC # 1241 dd. 20.12.2001 "On Tariffs Differentiated due to Time Periods"

[4] According to the Law "On Electric Power Industry", the "green tariff" is awarded only for biomass which is fully or partially composed of phytogenious substances.

A planned revision of the FIT scheme contains the inclusion of biogas. The draft Law No 8028 foresees tariff level factors from 2 up to 2,6 depending on installed capacity and type of biogas. In addition the definition of biomass is to be extended to include animal produce as well.

RES-E represented 9.76% of total installed capacity in 2008. This capacity generated 11.31 billion KWh of electricity (6.24% of the total), primarily from hydro (99.62% of the 11.31 bn kWh generated) and wind (0.38%). 157 MW of capacity was added since 2007 and none were retired. Biomass and waste energy grew the most, adding 89 MW of capacity.[49] This show that RES-E market is in an early stage in Ukraine but given the relatively high level of feed-in tariff, it might be an attractive field for investors. The effect of the local content requirement, however, is not known.

Source: interview with Wolfram Rehbock, Senior Partner, Arzinger law firm in Ukraine (http://ukrainian-energy.com/articles/alternative_sources/234/) and presentation of NERC at the 10th ERRA Energy Investment and Regulation Conference (Saint Petersburg, May 2011)

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[49] http://www.energici.com/energy-profiles/by-country/eurasia/ukraine

VIII. ANNEX D: OPERATION OF THE ROMANIAN GREEN CERTIFICATE MARKET

The support scheme for E-RES in Romania is in operation from 2005 and it is based on mandatory electricity mandatory quotas and the trading of Green Certificates. The demand for Green Certificates (GC) is created by a legislation that establishes the share of gross electricity consumption to be produced from renewable energy sources. The legislation introduces a system obliging suppliers of electricity to purchase a number of GC in accordance with the mandatory quota imposed. On the supply side, the Regulatory Authority (ANRE) qualifies each year those eligible producers of electricity who may receive GCs – a document certifying that a certain quantity of electricity was produced by renewable energy sources. According to the legal provisions for each unit of electricity injected into the network (1 MWh) the producers receive a number of GCs. If the legislator wants to promote a certain type of renewable technology, a unit of green electricity produced therewith can receive e.g. 2 units of GCs. GCs can be sold on the Green Certificates Market independently of the quantity of electricity represented by them. The GC market is operated by the Romanian Electricity Exchange (S.C.OPCOM S.A), functioning under the supervision of the regulator. (ANRE Ordinance nr. 22/2006). The price of electricity sold is determined by the electricity market. The price of green certificate is determined by market mechanisms by means of Bilateral Contracts concluded between producers and supplier and on a centralized market organized and administrated by OPCOM.

The price of GCs varies in a certain range [P_{min} - P_{max}] established by Government Decision. The minimum price is imposed for producers' protection, the maximum price is determined for consumers' protection. The electricity is traded separately from the GCs.

At present the support scheme described above will be modified to be in line with the provisions of the Law 220/2008 that made significant changes for the promotion system (especially important increase of the number of GC for each technology), after its approval by the European Commission with regards of state aid rules.

Source: OPCOM

IX. ANNEX E:*DISTRIBUTION SYSTEM OPERATORS'* INCENTIVES FOR DISTRIBUTED GENERATION UPTAKE IN THE UK

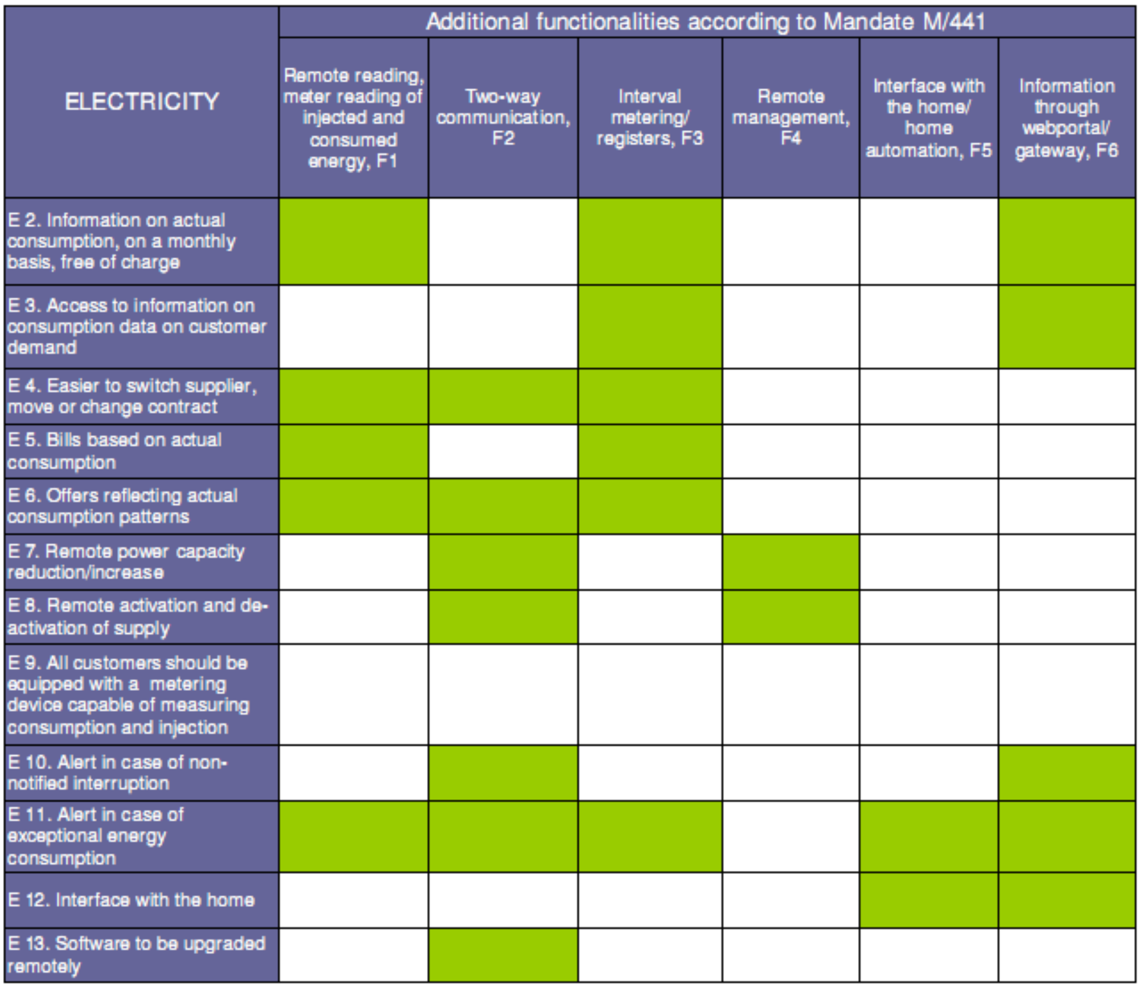
The price-cap regulation introduced in 1995 for DSOs failed to incentivize investment into the grid at the required levels. In 2005, the regulator (OFGEM) amended the grid regulation with the aim of triggering both investments to maintenance of the existing grid and extra investments to facilitate RES integration. The main changes were the substitution of deep connection charges with shallow charges and the inclusion of "ex ante" elements in the price cap regulation, i.e. the DSO can include these extra cost upfront. Specific provisions introduced were:

- both producers and consumers pay shallow connection charges (prior to 2005 producers paid deep, consumers shallow),
- DSOs able to recover their grid related connection and integration cost of RES generation in the UoS tariffs by the combination of pass through (80% of connection cost) and an incentive per $kW_{DG/RES}$ connected (2.16 €/$kW_{DG/RES}$ (singular) and 1.44€/ $kW_{DG/RES}$/yr (annually)),
- DSOs are allowed to use 0.5% of their annual revenue on innovative investment projects (including DG generation connection) and spread a significant share of its cost among consumers (Innovation Funding Incentive), andopportunity for DSOs to claim a higher (4.3 €/$kW_{DG/RES}$) incentive for the first 5 years of operation in the framework of Registered Power Zones (pilot power zones housing innovative network solutions).

Source: DG-GRID, 2007

X. ANNEX F: CORRELATION OF MANDATE M/441 ADDITIONAL FUNCTIONALITIES AND ERGEG ELECTRICITY RECOMMENDATIONS

The following table compares the recommendations of ERGEG with the functionalities set by Mandate M/411.



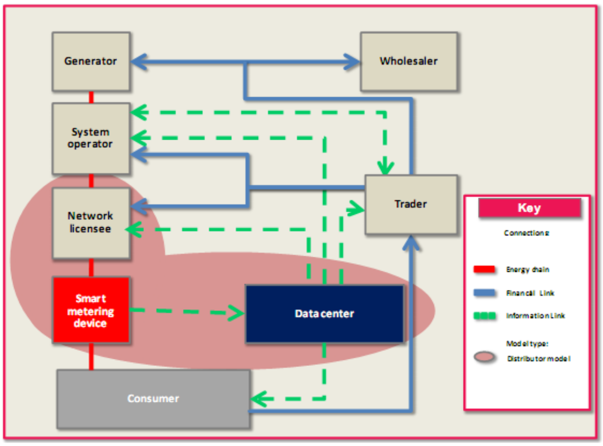
ELECTRICITY	Additional functionalities according to Mandate M/441					
	Remote reading, meter reading of injected and consumed energy, F1	Two-way communication, F2	Interval metering/ registers, F3	Remote management, F4	Interface with the home/ home automation, F5	Information through webportal/ gateway, F6
E 2. Information on actual consumption, on a monthly basis, free of charge	🟩		🟩			🟩
E 3. Access to information on consumption data on customer demand			🟩			🟩
E 4. Easier to switch supplier, move or change contract	🟩	🟩	🟩			
E 5. Bills based on actual consumption	🟩		🟩			
E 6. Offers reflecting actual consumption patterns	🟩	🟩	🟩			
E 7. Remote power capacity reduction/increase		🟩		🟩		
E 8. Remote activation and de-activation of supply		🟩		🟩		
E 9. All customers should be equipped with a metering device capable of measuring consumption and injection						
E 10. Alert in case of non-notified interruption		🟩				🟩
E 11. Alert in case of exceptional energy consumption	🟩	🟩	🟩		🟩	🟩
E 12. Interface with the home					🟩	🟩
E 13. Software to be upgraded remotely		🟩				

Source: ERGEG (2011) p. 36

XI. ANNEX G: ORGANISATIONAL MODELS OF SMART METERING

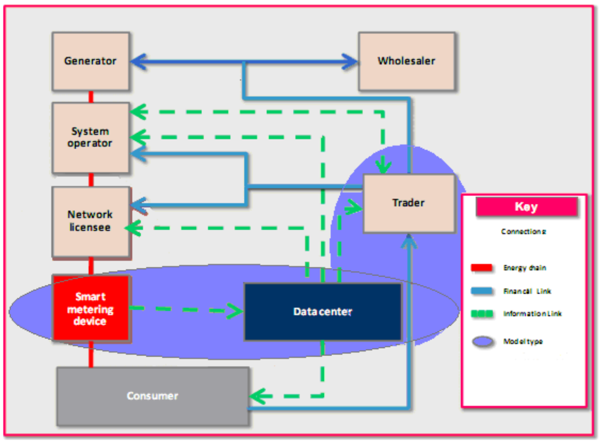
The description below shows as an example the three basic models that were considered in the Hungarian smart metering implementation study.

The DSO model



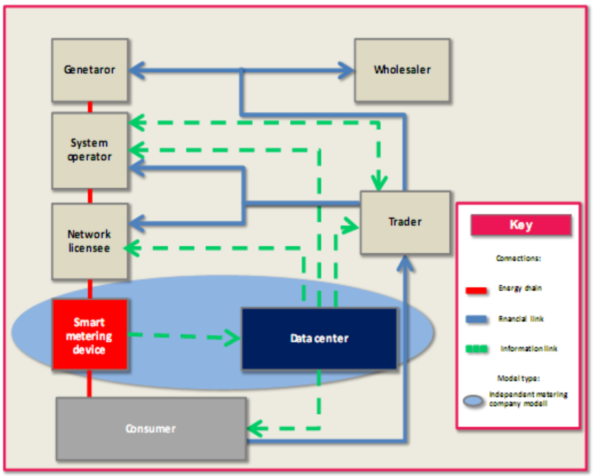
The first is the status quo, the DSO model. Within this model the distribution company owns the smart meter and is responsible for its installation and maintenance. The DSO has a regional monopoly position in metering data collection, transmission to other parties and processing. It provides data to the retailers in a predefined frequency and content. The retailer performs the billing and customer service activities in case of consumers under universal supply, while for the rest of the consumers the DSO provides these services as well.

The trader model



Within this model the meter is owned by the trader, installation and maintenance is the trader's responsibility and the meter is installed on the initiative of the consumer. The trader performs the data collection, transmission and processing in a competitive environment. In case of supplier switching the meter is either disassembled or is left at the consumer following the negotiation between the new and old supplier.

Independent metering operator model



A new player appears in the value chain, the independent metering operator. It owns the meters and has the responsibility for installation and maintenance as well as for the data collection transmission and processing. It provides the data in a predefined frequency and content.

Source: Force Motrice – AT Kearney (2010)

Of course all three models have their advantages and disadvantages compared to the others and there are stakeholders with very strong interests in each model – e.g. DSOs are very much in favour of the DSO model and without their consent any kind of model implementation would be unsuccessful. Therefore the simple question that in the given environment which model provides the largest benefits of smart metering becomes very complex when we start to consider how the models could be implemented in real life. In Hungary for example the decision has not yet been made.

XII. ANNEX H: PERFORMANCE INDICATORS FOR OUTPUT-BASED REGULATION

The EU Commission in its Staff working document related to its recent Communication of smart grids has published a list of potential key performance indicators that could be used in an output-based incentive regulation aimed at reaching the benefits dedicated to smart metering.

Benefit	Potential key performance indicators[50]
(1) Increased sustainability	Quantified reduction of carbon emissions Environmental impact of electricity grid infrastructure Quantified reduction of accidents and risk associated to generation technologies (during mining, production, installations, etc.)
(2) Adequate capacity of transmission and distribution grids for "collecting" and bringing electricity to the consumers	Hosting capacity for distributed energy resources in distribution grids Allowable maximum injection of power without congestion risks in transmission networks Energy not withdrawn from renewable sources due to congestion and/or security risks An optimized use of capital and assets
(3) Adequate grid connection and access for all kind of grid users	Benefit (3) could be partly assessed by: - first connection charges for generators, consumers and those that do both - grid tariffs for generators, consumers and those that do both - methods adopted to calculate charges and tariffs - time to connect a new user - optimization of new equipment design resulting in best cost/benefit - faster speed of successful innovation against clear standards
(4) Satisfactory levels of security and quality of supply	Ratio of reliably available generation capacity and peak demand Share of electrical energy produced by renewable sources Measured satisfaction of grid users with the "grid" services they receive Power system stability Duration and frequency of interruptions per customer Voltage quality performance of electricity grids (e.g. voltage dips, voltage and frequency deviations)
(5) Enhanced efficiency and better service in electricity supply and grid operation	Level of losses in transmission and in distribution networks (absolute or percentage)[51]. Storage induces losses too, but also active flow control increases losses. Ratio between minimum and maximum electricity demand within a defined time period (e.g. one day, one week)[52] Percentage utilisation (i.e. average loading) of electricity grid elements Demand side participation in electricity markets and in energy efficiency measures Availability of network components (related to planned and unplanned maintenance) and its impact on network performances Actual availability of network capacity with respect to its standard value (e.g. net transfer capacity in transmission grids, DER hosting capacity in distribution grids)

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[50] Some of these indicators are already used today in different EU Member States.

[51] In case of comparison, the level of losses should be corrected by structural parameters (e.g. by the presence of distributed generation in distribution grids and its production pattern). Moreover a possibly conflicting character of e.g. aiming at higher network elements' utilization (loading) vs. higher losses, should be considered accordingly.

[52] In case of comparison, a structural difference in the indicator should be taken into account due e.g. to electrical heating and weather conditions, shares of industrial and domestic loads.

(6) Effective support of trans-national electricity markets by load-flow control to alleviate loop-flows and increased interconnection capacities	Ratio between interconnection capacity of one country/region and its electricity demand Exploitation of interconnection capacities (ratio between mono-directional energy transfers and net transfer capacity), particularly related to maximisation of capacities according to the Regulation of electricity cross-border exchanges and the congestion management guidelines Congestion rents across interconnections
(7) Coordinated grid development through common European, regional and local grid planning to optimize transmission grid infrastructure	Benefit (7) could be partly assessed by: - impact of congestion on outcomes and prices of national/regional markets - societal benefit/cost ratio of a proposed infrastructure investment - overall welfare increase, i.e. running always the cheapest generators to supply the actual demand) ☞ this is also an indicator for the benefit (6) above - Time for licensing/authorisation of a new electricity transmission infrastructure. - Time for construction (i.e. after authorisation) of a new electricity transmission infrastructure.
(8) Enhanced consumer awareness and participation in the market by new players	- Demand side participation in electricity markets and in energy efficiency measures - Percentage of consumers on (opt-in) time-of-use / critical peak / real time dynamic pricing - Measured modifications of electricity consumption patterns after new (opt-in) pricing schemes. - Percentage of users available to behave as interruptible load. - Percentage of load demand participating in market-like schemes for demand flexibility. - Percentage participation of users connected to lower voltage levels to ancillary services
(9) Enable consumers to make informed decisions related to their energy to meet the EU Energy Efficiency targets	- Base to peak load ratio Relation between power demand and market price for electricity - Consumers can comprehend their actual energy consumption and receive, understand and act on free information they need / ask for - Consumers are able to access their historic energy consumption information for free in a format that enables them to make like for like comparisons with deals available on the market. - Ability to participate in relevant energy market to purchase and/or sell electricity - Coherent link is established between the energy prices and consumer behaviour -
(10) Create a market mechanism for new energy services such as energy efficiency or energy consulting for customers	'Simple' and/or automated changes to consumers' energy consumption in reply to demand/response signals, are enabled - Data ownership is clearly defined and data processes in place to allow for service providers to be active with customer consent - Physical grid related data are available in an accessible form - Transparency of physical connection authorisation, requirements and charges - Effective consumer complaint handling and redress. This includes clear lines of responsibility should things go wrong
(11)Consumer bills are either reduced or upward pressure on them is mitigated	- Transparent, robust processes to assess whether the benefits of implementation exceed the costs in each area where roll-out is considered are in place, and a commitment to act on the findings is ensured by all involved parties - Regulatory mechanisms exist, that ensure that these benefits are appropriately reflected in consumer bills and do not simply result in windfall profits for the industry - New smart tariffs (energy prices) deliver tangible benefits to consumers or society in a progressive way - Market design is compatible with the way the consumers use the grid

Source: COM(2011) 202b