"Innovative Business Models for Market Uptake of Renewable Electricity unlocking the potential for flexibility in the Industrial Electricity Use"

Regulatory and Market Framework Analysis

A working document assessing the impact of the regulatory and market framework on the IndustRE business models

Deliverable 2.2

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IndustRE

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List of Abbreviations

AAP	Available Active Power
ACER	Agency for the Cooperation of Energy Regulators
AEEG	Autorità per l'energia elettrica il gas e il sistema idrico
ARENH	Accès Régulé à l'Electricité Nucléaire Historique'
BDEW	Bundesverband der Energie- und Wasserwirtschaft e.V
BE	Belgium
belpex	Physical Power Exchange for the Delivery and Off-take of Electricity on the Belgian Hub
BRP	Balancing Responde Party
BSP	Balancing Service Providers
CDCM	Common Distribution Charging Methodology
CECRE	Control Centre of Renewable Energies
CfD	Contracts for Difference
CHP	Combined Heat and Power
CHPC	Combined Heat and Power Certificates
CNMC	Comisión Nacional de los Mercados y La Competencia
CRE	Commission de régulation de l'énergie
CREG	Commission de Régulation de l'Electricité et du Gaz
CSPE	Contribution au service public d'electricite
CTA	Contribution tarifaire d'acheminement
CWAPE	Commission Wallonne pour l'Energie
DE	Germany
DNO	Distribution Network Operators
DSBR	Demand Side Balancing Reserve
DSO	Distribution System Operator
DUoS	Distribution Use of System
EC	European Commission
EDCM	Extra High Voltage Distribution Charging Methodology
EDF	Électricité de France
EEG	German Renewable Energy Act
EEX	European Energy Exchange AG

EMR	Electricity Market Reform
ENDEX	European Energy Derivates Exchange
ENTSOE	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange S.E.
ERGEG	European Regulators Group for Energy and Gas
ES	Spain
FCR	Frequency Containment Reserves
FID	Flexible Industrial Demand
FIP	Feed-in Premium Tariff
FIT	Feed-in Tariff
FR	France
FRR	Frequency Restoration Reserves
GB	Great Britain
GC	Green Certificate
GCC	Grid Control Operation
GSE	Gestore Servici Energetici
GW	Gigawatt
GWh	Gigawatthour
HV	High Voltage
IT	Italy
ktoe	kilo tonne of oil equivalent
kV	kilo Volts
kVArh	kilo-volt amper (reactive) hour
LCCC	Low carbon contract company
LU	Luxemburg
MS	Member State
MV	Medium Voltage
MW	Megawatt
MWh	Megawatthour
NEBEF	Notification d’Echange de Blocs d’Effacement
NRA	National Regulatory Authority
NREAP	National Renewable Energy Action Plan

OMIE	Operador del Mercado Ibérico (OMI)-Polo Español S.A
OTC	Over-the-Counter
PPA	Power Purchase Agreements
PV	Photovoltaic
REE	Red Eléctrica de España
RES	Renewable Energy Systems
RIU	Rete Interna di Utenze
ROC	Renewable Obligation Certificates
RR	Replacement Reserves
SEU	Sistemi Efficienti di Utenza
SME	Small and Medium Enterprise
SNL	Quickly Interruptible Loads
SO	System Operator
SOL	Interruptible Loads
STOR	Short Term Operating Reserve
TCFE	Taxe Intérieure sur la Consummation Finale d'Electricité
TNUoS	Transmission Network Use of System
TO	Transmission Owners
TOU	Time-of-Use
TSO	Transmission System Operator
TW	Terawatt
UK	United Kingdom
UPDM	Peripheral Unit defence and monitoring
VAT	Value Added Tax
VRE	Variable Renewable Energy
VREG	Vlaamse regulator van de energiemarkt
XBID	European Cross-Border Intraday Solution

Executive Summary

This document screens the regulatory and market frameworks of the target countries within the INDUSTRE project (Belgium, France, Germany, Italy, Spain and UK) in the context of possible business models for the exploitation of flexible industrial electricity demand (FID) in relation with variable renewable energy (VRE). This document also defines the starting point for discussion with the stakeholders in order to identify the main barriers to exploitation of business models that lead to win-win situations both for FID and VRE.

The possible business models for FID+VRE have been structured into those that are based on the reduction of the electricity payments (models A), and those concerned with offering services to the power system (models B). To evaluate the feasibility of the business model, a characterization of the regulatory framework in each country has been made, covering the following topics: current and future structure of generation and demand, industrial consumer pricing, and the current participation of FIV+VRE in wholesale energy markets and their responsibilities and options in relation to the provision of network and system services.

The following table summarizes the main findings for the selected countries, where colours indicate from green to red if the proposed business models are viable or not under the current regulatory frameworks. From the table it is clear that there are significant differences among countries (i.e. Belgium vs. UK), and for the same business model different regulations may apply across Europe (i.e. A2.2 or B.1).

Business models	BE	FR	DE	IT	ES	UK
A.1 Time of use tariff or price rates	🟢	🟡	🟢	🟢	🟢	🟡
A2.1 FID shifting consumption in time	🟢	🟡	🟢	🟢	🟢	🟡
A2.2 Supplier owning VRE plants benefits from FID to balance generation portfolio / Direct bilateral sale of energy from VRE to FID	🟢	🟡	🟢	🟡	🟡	🔴
A2.3 On-site VRE and the possibility of netting demand with self-consumption	🟢	🟢	🟢	🟡	🔴	🟢
A.3 FID managing consumption in response to hourly wholesale market prices. With on-site VRE, excess energy sold in the market.	🟢	🟢	🟡	🟢	🟢	🟡
A.4 Reduced network charges by lowering peak demand. With on-site VRE, peak 'net demand' compensated with self generation.	🟡	🟡	🟢	🟡	🟡	🟢
B.1 FID offering reserve capacity, directly or through an aggregator	🟢	🟢	🟡	🔴	🔴	🟡
B.2 FID responding to signals sent by BRP to balance demand-generation portfolio	🟢	🟢	🟡	🟡	🟡	🟢
B.3 Other services to the system (e.g. load interruptibility, services to DSOs)	🟡	🟢	🟢	🟡	🟡	🟡

To clearly understand the reasons for the current situation and the drivers in the near future a set of additional information is provided in a seven annexes. It is clear that further research is needed to clearly understand how these differences appear, and how regulation could be adapted to benefit from the additional flexibility.

1. Introduction

The objective of this document is to screen the regulatory and market frameworks of the target countries of the INDUSTRE project (Belgium, France, Germany, Italy, Spain and UK) within the context of possible business models for the exploitation of flexible industrial electricity demand (FID) in relation with variable renewable energy (VRE), as defined in Task 2.1. Furthermore, the implications of the regulatory conditions and market rules for the feasibility of the proposed business models in each country are examined. This deliverable is aimed to serve as working document for further work in future tasks of the IndustRE project. Therefore, it does not present definite conclusions and recommendations but provides the basis for discussion on the regulatory conditions that could make the business models work effectively in each national environment.

In addition of a brief summary of the business models that is included in this introduction, the remainder of the document is structured as follows:

- In Section 2 an overall picture of the main structural and regulatory aspects that concern the practicability of the business models in the target countries is provided. Further details about the regulatory framework can be found in the Annexes.
- In Section 3 the feasibility of the proposed business models is discussed in light of the described regulatory and market frameworks.
- A series of Annexes contain further information in relation to the topics addressed in Section 2 for each of the target countries.

1.1 Overview of the business models

The business models proposed in T2.1 are defined from the perspective of flexible industrial consumers benefitting from their flexibility, interacting or not with VRE (for further details please refer to Deliverable 2.1). The business models are classified into:

A. *Reduced energy bills by shifting consumption*

In this category are included all business models that involve the flexible industrial consumer managing electricity consumption in response to price signals from the market or the regulated tariffs. The possibility of adjusting consumption by means of netting demand with self generation is considered as well. The structure of the tariffs and the final electricity prices, or the modes of buying electricity (through a retailer or directly in the market), the possibilities of net metering and self consumption and the charges associated to the installation of generation units play a significant role in this type of business models. Also the level of exposure of VRE to the market, which is related to the existing RES support schemes, determines the incentives for VRE operators and owners of selling energy bilaterally or in the market. This category is further classified into the following models:

- ***A.1*** Time of use tariff or price rates, e.g. night rate offered by a supplier.

- ***A.2*** Dynamic pricing signals from the supplier.
    - ***A.2.1*** FID shifting consumption in response to these signals.
    - ***A2.2*** A supplier owning VRE plants benefitting from the FID to balance their generation portfolio. Alternatively, direct bilateral sell of energy from VRE to FID.
    - ***A2.3*** On-site renewable energy and the possibility of netting demand with self-generation, or even net metering.
- ***A.3*** Manage consumption in response to wholesale electricity prices by acceding directly to the market or through a supplier/aggregator. With on-site VRE, excess energy could be sold in the market.
- ***A.4*** Reduced network charges by lowering peak demand. With on-site VRE, peak 'net demand' can be compensated with self-generation.

B. *Offering flexibility services to the power system*

In this category are included all business models that involve the explicit provision of flexibility services to the system by the FID, generally to the TSO or even to the DSO, either directly or through an intermediary. The requirements for qualifying as a balancing service provider are related to the market exposure and balancing responsibilities of VRE operators, and also whether loads are allowed to offer this type of services to TSOs. The existence of a specific interruptibility service for industrial demand or how imbalances are evaluated and priced are crucial factors that determine the feasibility of this type of business models. The following are distinguished:

- ***B.1*** FID offering reserve capacity, either directly or through an aggregator.
- ***B.2*** FID responding to signals sent by the Balancing Responsible Party (BRP), who tries to balance their demand-generation portfolio.
- ***B.3*** Other services to the system, such as:
    - Long-term generation investment deferral (e.g. capacity markets)
    - Network congestion management
    - Reactive power control
    - Distribution system services.

2. Market and regulatory frameworks in the target countries

The aim of this section is to provide the reader with an overview of the main characteristics of the market and regulatory frameworks that are present in each of the target countries. It is specially focused on the topics that more intensely affect the feasibility of the business models for FID in combination with VRE:

- Tariffs and final electricity prices for the industry
- Wholesale energy markets: participation of VRE and FID
- Network and system services: responsibilities and possible services by VRE and FID

In addition, a brief overview of the main technical aspects of the electricity systems in relation to the generation and the demand is provided.

2.1 Structure of generation and demand: the importance of VRE and FID

The structure of the power generation mix and the adequacy of the installed capacity are relevant for identifying the need for flexibility and the potential significance of VRE in the system. The categorization of consumers into different groups of activity, size and connection voltage level is necessary to discover the FID target group in each country. Both elements of the characterization give us a sense of the magnitude of the potential impact of the proposed business models for demand response from FID integrating VRE provided these models were feasible.

The European electricity system is made up of a variety of interconnected regional and national systems, each of which presents its particular generation mix. Even though there are common EU policy guidelines and key directives, the implementation at MS level differs from country to country, leading to a variety of foreseeable investment scenarios especially in view of renewable energy sources and their market development and integration.

The current situation (scenario 2014) is compared in Figure 2.1 and Figure 2.2 to two scenarios (scenario B and scenario Reg.) of potential future developments in new installed capacity for 2020. Scenario B is TSO’s best estimation and scenario Reg. is based on the assumed compliance of the governmental targets set for renewable generating capacities in 2020. The latter is based on EU environmental policy objectives and national targets set in the National Renewable Energy Action Plan (“NREAP”) of each country.

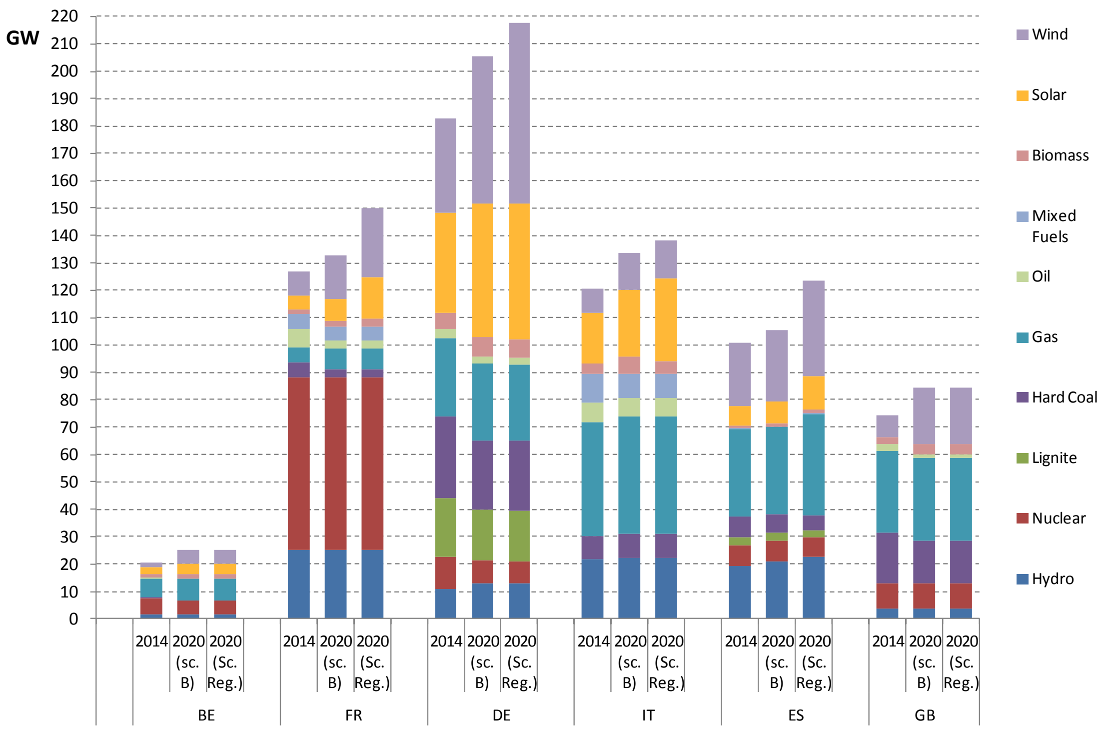

Figure 2.1: Current (2014) and expected (2020) generation mix (GW) of the target countries, according to the TSOs' best estimate (Sc. B) and policy objectives (Sc. Reg.). Source: ENTSO-E.

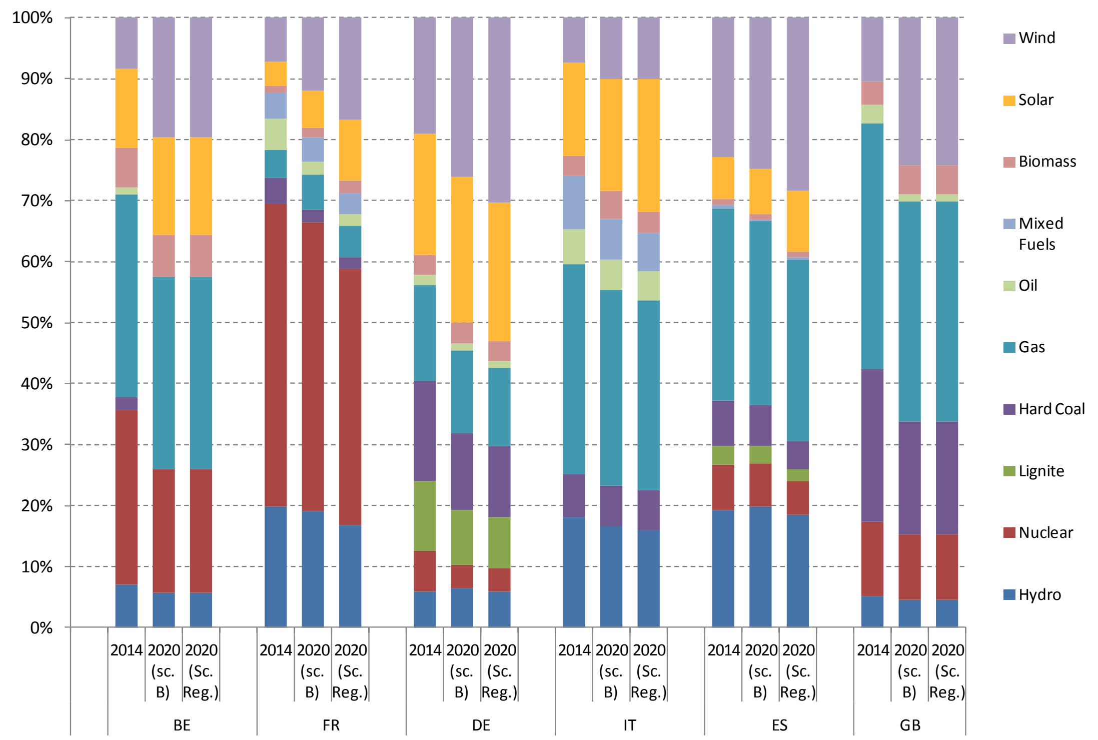

Figure 2.2: Current (2014) and expected (2020) share (%) of each technology in the generation mix of the target countries, according to the TSOs' best estimate (Sc. B) and policy objectives (Sc. Reg.). Source: ENTSO-E.

From what can be seen in the figures, Belgium presents a significant share of VRE in its mix. It can be anticipated that the peak load in Belgium is close to its total firm capacity both in the current situation and in the future scenario. Demand response could therefore be a valuable resource to compensate the lack of secure capacity.

The French power system, the second largest in Europe after Germany, relies heavily on nuclear power and, to a lesser degree, on hydro power. This system presents difficulties to address peak load in spite of its overall average overcapacity. The need for more flexible demand is strengthened by the growing penetration of RES given that nuclear and coal power plants are not very flexible to cope with their variability and unpredictability.

The German power system has the largest amount of installed capacity and is going through a deep transformation of its energy mix, mainly driven by a big support to renewable energy sources and the political decision to phase out all nuclear generating capacity in the next years (by 2022) after the Fukushima nuclear accident.

The Italian power system is mostly made up of conventional thermal generation, hydro and a large share of renewable energy generation, most of it from solar photovoltaic and wind resources. A large volume of conventional fast thermal capacity provides flexibility to the system but the increasing amount of VRE urges for a more relevant role of the demand side.

The Spanish electric power system has gone through a deep technological and regulatory transformation in the past two decades, the former being characterized by a drift towards renewable energy and combined cycles in the generation mix. Overall, the penetration level of VRE is very significant.

The electricity generation mix in United Kingdom is very dependent on fossil fuels (68% generation in 2012) and is increasingly incorporating RES (12%), especially wind energy. In fact, UK has ambitious objectives for 2050 to implement market mechanisms that foster the development of renewable energy resources.

In Figure 2.3, the segmentation of electricity consumption regarding the different large industries is presented for all the target countries at once. They are shown in percentage with respect total electricity consumption by the industry, which in turn is around 30% to 40% of total consumption in all countries.

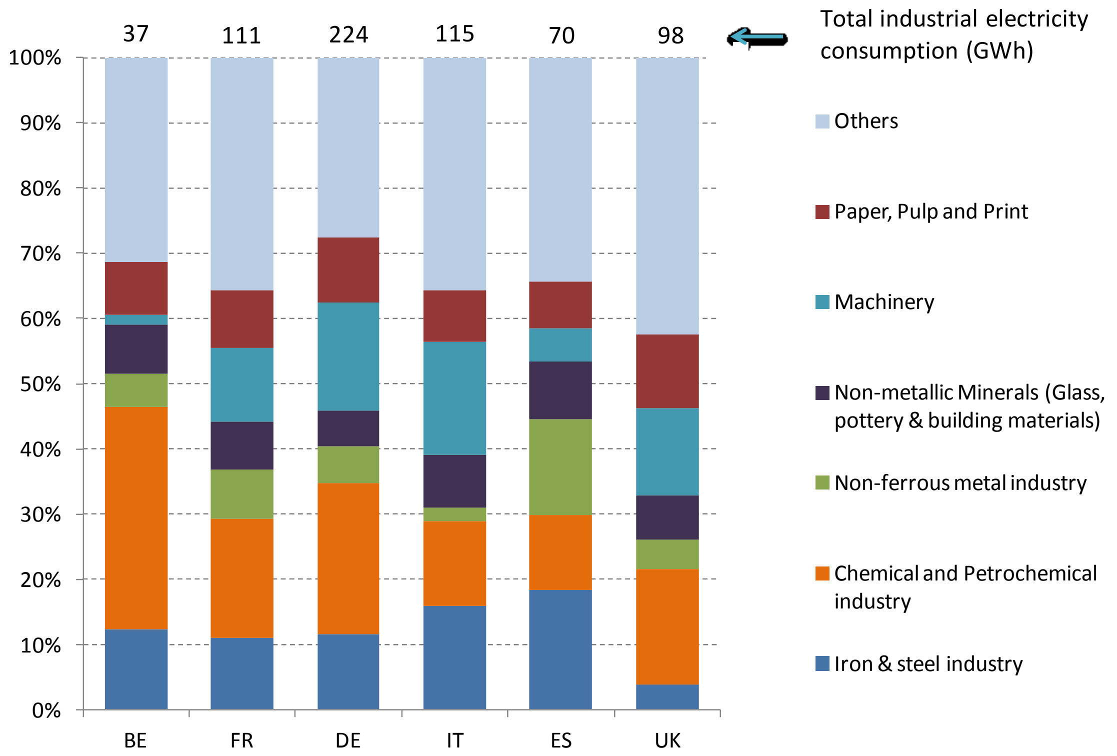

Figure 2.3: Industrial electricity consumption in the target countries, broken down into different sectors. Data provided by Eurostat[1].

The most relevant industries in all target countries are Chemical, Iron and Steel, Machinery, Non-ferrous Metals, Non-metallic minerals and Paper. Water treatment and cold storage present a smaller share and are included among "Others".

2.2 Electricity prices for industrial consumers

The final prices paid by industrial consumers is a key determinant in the applicability of business models of type A., related to the management of flexible demand in response to price signals that incentivize changes in the consumption pattern. These signals can have two sources:

- Variability of the energy price in the market.
- The structure of the network tariffs and other regulated charges.

In this sense, it is equally important to look into the structure of the network tariffs as well as into the relative importance of each of the components of the final price. Sometimes, industrial consumers are charged more complex tariff structures, with time differentiation and incentives to reduce peak demand. Also, industrial consumers are generally charged

[1] http://ec.europa.eu/eurostat/web/energy/data/energy-balances, 2015 Edition, Data for 2013.

lower regulated costs than residential and other small consumers, often through direct allowances or exemptions to the regular tariff. In addition, large industrial consumers are more easily exposed to the real time market prices, or other dynamic structures, through advanced retail contracts. When the energy purchase component has a relevant weight in the final price, the business models A.1 - A.3 will make more sense, while the business model A.4 will be very dependent on the available tariff options and the extent to which the tariff structure sends a sufficiently sound signal that incentivizes peak reductions.

Final electricity price structure for industrial consumers

Figure 2.4 displays the components of the average final electricity prices paid by industrial consumers in 2014 for different consumer sizes in each of the countries under study[2]. Further information on a country-by-country basis can be found in Annex 2. It is generally observed that all components decrease considerably as the consumer size increases. The relevance of different components is variable among countries, even though it can be said that network / regulated charges are generally rather low in comparison to the rest.

Continental systems (France, Germany and Belgium) show the lowest energy costs in contrast to the peripheral Spain, United Kingdom and Italy. These price spreads are due to the fact that the latter present limited interconnection capacities to the interconnected system, even though the Multi-Regional Coupling[3] already integrates these and other 13 countries in the day-ahead timeframe[4].

[2] It must be noted that final electricity prices for households and other small electricity consumers are considerably higher in all cost components, especially those corresponding to regulated charges.

[3] The market coupling mechanism simultaneously determines volumes and prices in all power exchanges and zones, based on the marginal pricing principle and implicitly taking into account the available cross border transmission capacity, therefore optimizing the resulting power flows.

[4] It now covers Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and UK. Also, the European Cross-Border Intraday Solution (XBID), which is aimed at integrating a European intraday cross-zonal market, is expected by 2017.

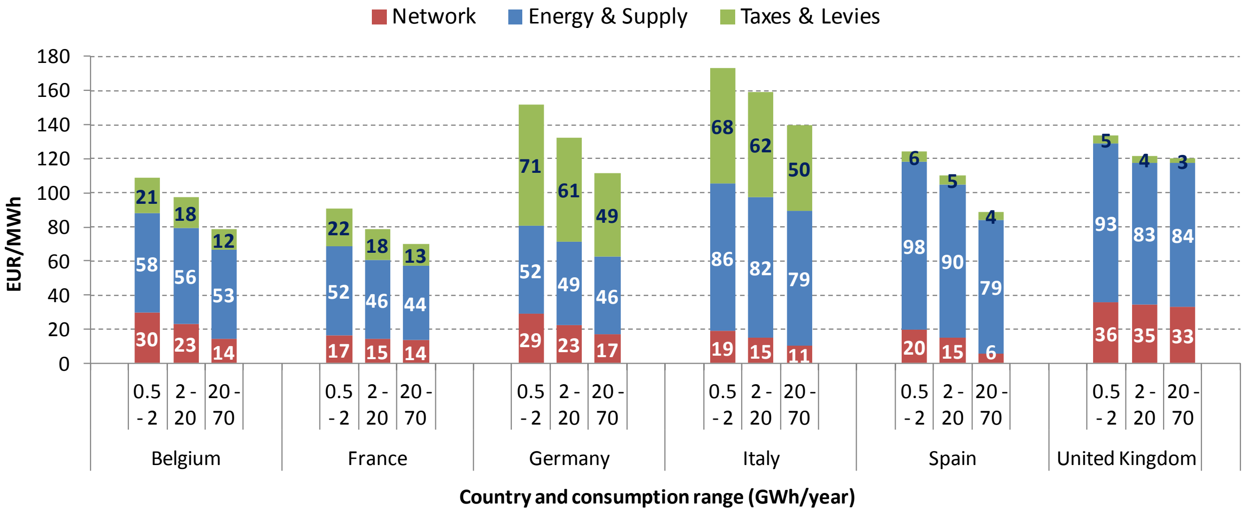

Figure 2.4. Final average electricity prices for industrial consumers of different sizes, in GWh per year: 0.5 GWh < Cons. < 2 GWh, 2 GWh < Cons. < 20 GWh, 20 GWh < Cons. < 70 GWh. Source: Eurostat[5]

The network component, or grid tariff, represents both the allowed revenue for the network activities and other regulated costs[6], which along with the taxes are subject to political decisions or regulatory conditions, and may significantly increase the final price, and therefore reduce the relative significance of the energy price component.

The most extreme case is Germany, which has one of the lowest wholesale electricity prices in Europe but some of the highest final retail prices. Final electricity prices in UK remain among the lowest in Europe even if the wholesale price of electricity is very high, because the VAT is rather low and there are certain additional compensations for industrial consumers. It must be noted that there may be some heterogeneity among the criteria used by the different countries regarding what is referred to as Energy and supply, network and taxes & levies. For instance, in Spain, it seems that the term Energy & Supply may include not only the cost of energy and supply/retail, but also the volumetric component of the network tariff, which in turn includes part of the transmission and distribution costs as well as many other regulated costs that are non-network related. In any case, the figure is illustrative in the sense that it reflects the difference in the average price levels for small-medium industrial consumers and the relevance of regulated costs and taxes in the final

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[5] Electricity prices components for industrial consumers - annual data (from 2007 onwards), nrg_pc_205_c – Eurostat – Data Explorer.

[6] Other regulated costs may include customer management costs incurred by distributors, functioning of the System Operator, the Regulatory Commission or the Market Operator, stranded costs in systems undergoing substantial regulatory changes and subsidies for renewable generation, energy efficiency or specific industries.

electricity price. Further information in relation to prices paid by industrial consumers can be found in Annex 2.

Network tariffs and other regulated costs

Tariffs, network tariffs or access tariffs, are regulated rates charged to network users, mostly consumers, to recover those costs incurred by regulated activities. These include those related to network activities and sometimes other costs not directly related to network activities, depending on the regulatory arrangements in place.

The structure and values of the tariffs paid by industrial consumers (time variability, charging concepts, voltage and power levels, etc.) to recover network and other regulated costs of the system are of great relevance for the potential profitability of the business models that involve price responsiveness, especially A.4 - Reduced network charges by lowering peak demand.

An overview of the basic design elements of network/regulated tariffs in the countries under study is provided in Table 2.1. Further information on a country-by-country basis can be found in Annex 2.

Table 2.1. Settings and structure of network tariffs for consumers in each target country

	Belgium	**France**	**Germany**	**Italy**	**Spain**	**UK (GB)**
Network tariff settings [a]						
DSO	Proposes tariff structure	-	Designs tariff structure	-	-	Uses methodology to calculate tariffs
Government	Defines principles, framework	Defines principles	Sets rules	-	Sets revenues and tariff structure	Defines principles
NRA	Sets revenues, approves DSO proposal	Sets revenues and tariff structure	Sets revenues	Sets revenues and tariff structure	Proposes revenues and tariff structure	Sets rules for allowed revenue
Tariff structure [a, b, c]						
Fixed charge [€]	☑	☑	No	☑	No	☑

	Belgium	France	Germany	Italy	Spain	UK (GB)
Capacity charge [€/kW]	☑	☑	☑	☑ [d]	☑	☑
Energy charge [€/MWh]	☑	☑	☑	☑ [d]	☑	☑
Reactive energy charge [€/kvarh]	☑	☑	Depends on DSO	No	☑	☑
Other charges	-	Exceeding contract. power	-	-	-	Exceeding capacity rate
Time differentiation (seasonal, day, hour, etc.)	Yes (at least three, peak, off-peak and exclusively off-peak , At transmission level also seasonal differences	Summer/ Winter, peak/off-peak, special peaks. 5 time classes for V < 350 kV. HV only usage duration.	Depends on DSO.	No	Up to 6 periods by season, day and hours (6 for high voltage cons.)	Yes (-super red band (Nov-Feb 5pm – 7pm) and normal band (all other times)
Geographical differentiation	No	No	Uneven tariffs across DSO areas.	No	No	Yes nodal
Consumer groups	Depending on grid connection		Depends on DSOs		5 voltage levels (NT0-NT4)	

	Belgium	France	Germany	Italy	Spain	UK (GB)
Other fees	Annual fees by DSOs (metering and contract manag.)	Annual fees by DSOs (metering and contract manag.)	Certain tariff exemptions for large consumer	Measurement and general system costs are charged separately	Rental fee for smart Meter	-

[a] From (Eurelectric, 2013)
[b] From (Fernández et al., 2014)
[c] It is assumed for UK that this is distribution charging only – transmission charges in the UK are on £/kW basis only and have locational variation. UK distribution charging methodology depends on the voltage level – This table is completed assuming Extra High Voltage connections.
[d] Transmission and distribution are structured separately for non-domestic consumers. For high voltage consumers, there is a capacity charge in the transmission tariff, but not a fixed charge, and there is a fixed charge in the distribution tariff, but not a capacity charge. In addition, measurement and general system costs for non-domestic consumers are also charged and structured separately.

It is generally observed that most countries have different types of charges (fixed, capacity based, volumetric). The capacity charge generally incentivizes peak load reduction, but only if overall it accounts for a significant share of the final energy bill. If time differentiation is made for the volumetric, and or capacity, components, consumers are further incentivized to manage consumption to reduce the peak load. Belgium, France, Spain and UK present TOU structure of the tariff, while Italy does not and in Germany it lacks harmonization among the different DSO zones. Exemptions to pay for part of certain regulated charges are conceded to large consumers in Italy and Germany, and tax reductions are applied in Spain. These measures contribute to reduce tariff levels further on, reducing the profitability of business models such as A.4 - Reduced network charges by lowering peak demand.

Incentives to self-consumption: net metering, FID and on-site VRE interaction

The possibility of netting demand with self-consumption or even the subsidies for the surplus energy produced, encourage the combination of business models type A for FID with on-site VRE (business models A2.2 - A supplier owning VRE plants benefitting from the FID and A2.3 - On-site renewable energy and the possibility of netting demand with self-generation, or even net metering).

Belgium

Renewable energy installations with an installed capacity below 10 kW can allow consumers to benefit from a net metering system. This system entails that the amount of electricity produced from the VRE is deducted directly from the general electricity bill of the consumer.

For RE with a capacity over 10 kW, a separate grid connection and production meter is required. From July 2015, in the Flamish region, a tariff for prosumers was launched to make them pay for the distribution network (67 – 106 €/kW installed).

France

Self-consumption is allowed in France (under decree law n° 2008-386 - 23rd April 2008). A convention can be subscribed whereby all electricity produced is consumed on-site. No additional taxes are established on electricity self-consumption. On the other hand, excess generation can be fed into the grid remunerated at feed-in tariff scheme if the user complies with the terms established in the feed-in tariff policy, however net-metering scheme is not explicitly regulated.

Germany

The review of the German Renewable Energy Act (EEG) in 2012 has introduced a limiting factor for grid injection which is favoring direct consumption: with only 90% of the production eligible for a FIT (for systems above 10kWp), the legislation promoted self-consumption over pure production[7]. However, this provision was not kept under the latest review of the EEG in 2014.

Italy

There is a user efficiency system in place, called SEU (*"Sistemi Efficienti di Utenza"*, by which prosumers are charged specific reduced tariffs. This system is made by at least one RES production unit (or high-efficiency CHP) with an upper limit of 20MW and one consumption unit, physically connected among them by a private link with no third-party connection obligation and connected at least at one point to the grid. Supplier and customer can be the same entity; but the generation plants can provide electricity only to one single customer.

Since 2014, under the SEU scheme, industries with on-site generation are exempted from paying 95% of the volumetric part of the general system charges on the electricity self-consumed. SEU can also benefit from net metering, if there is a VRE plant up to 500 kWe. Both aspects encourage industries with on-site generation to self-consume the most part of electricity. There are no additional incentives for industries installing VRE.

There can be benefits also for "close distribution systems", called "RIU" (Rete Interna di Utenze - Internal Users Grid). These are private grids with no third-party connection obligation, connecting one producer and one or more industrial consumers that exchange electricity internally and deliver the net supply (or require net demand) to the High-voltage grid. There are spatial limits to the extension of the RIU and to the identification of the

[7] Information from EPIA (www.epia.org)

subject who manages the RIU (cannot be a TSO/DSO or a dispatcher). RIUs are considered grids and therefore users pay general system charges on all energy purchased from the public grid.

Spain

It is compulsory for renewable generation units of installed capacity above 10 MW to be connected to the network control centre CECRE. Net metering is not allowed; instead separate metering is required for any installed capacity. Regulation of self-consumption is currently under discussion.

United Kingdom

Self consumption is allowed and incentivized due to the tariff structure. Industrial consumers have very strong incentives to try to forecast peak demand periods and manage their injection/withdrawals during those hours (either by using on site generation or by reducing their consumption).

2.3 Wholesale energy markets: which role for VRE and FID?

Energy transactions between generation and load parties are organized in a sequence of successive markets with different time scales, covering from months to years before the trade is to be implemented, day-ahead, intraday, gate closure, real time and post-transaction settlement. A simplified overview of the sequential order of the different consecutive electricity markets as typically found in Europe is provided in Figure 2.5.

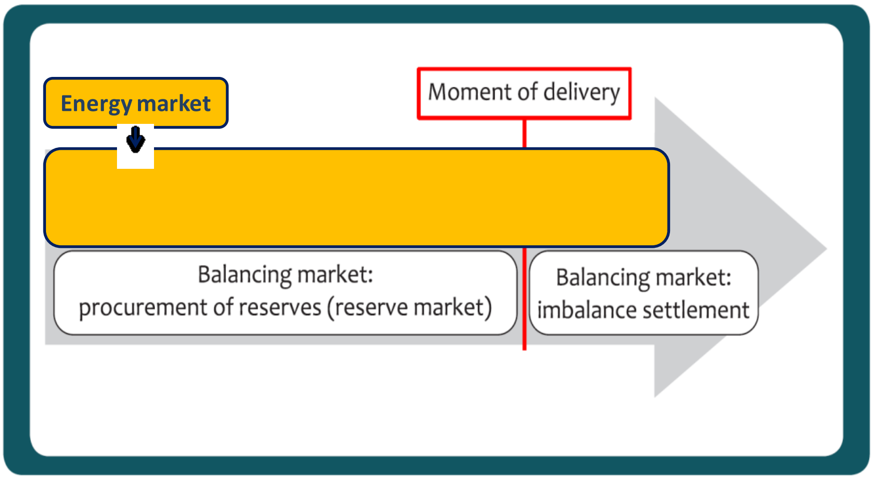

Figure 2.5: Overview of the sequential order of consecutive electricity markets typically found in Europe[8].

[8] "The current electricity market design in Europe", EI-FACT SHEET 2015-01, https://set.kuleuven.be/ei/images/EI_factsheet8_eng.pdf/at_download/file

Generators compete in the wholesale energy market to sell electricity to large consumers and suppliers in different time horizons. Until gate closure, market agents are allowed to balance their positions (of generation or demand) and correct any deviations without the intervention of the Transmission System Operator (TSO) in the day-ahead and intraday markets.

The type of participation of VRE and FID in the wholesale energy market is relevant for the applicability of the business models type A. The role of VRE operators in the market, which is very related to the existing support schemes, will be indicative of their incentives to selling energy bilaterally or in the market. In addition, the form of having access to electricity in the market by FID will be a key determinant in their exposure to real-time market prices.

VRE support schemes and participation in the energy market

The extent to which VRE operators are allowed to participate in the market depends mainly on the current regulation on support schemes for renewable energy. In so far as the expected profitability of VRE is based on regulatory subsidies, VRE operators will be decoupled from actual market conditions and therefore will be less incentivized to be competitive in the market or develop innovative contractual arrangements with FID. Only if certain market mechanism exists for the allocation of subsidies for RES, some incentives for efficient market behaviour in the VRE operators are introduced.

In general, support schemes can be distinguished based on the following criteria:

- Whether the regulatory intervention acts on the price or the remuneration, or on the target installed capacity or generated energy.
- Whether the support is given at the beginning of the investment phase over the installed capacity or later on over the energy that is effectively generated.

Price regulation consists of fixing the value of the subsidy in relation to installed capacity or generated energy, so the final installed capacity is not known ex-ante but led to operators to decide. Alternatively, through quantity regulation, the regulator can prefer to establish a target of installed capacity or energy production, leaving the determination of price or subsidy to a market mechanism. Support schemes based on energy produced, in particular Feed-in tariffs and green certificates, are the most commonly used across Europe, especially for wind power.

A summary of the main support schemes for RES generation in the target countries is presented in Table 2.2, according to this classification. Further information can be found in Annex 5.

Table 2.2 Main categories of RES support schemes.

	Price regulation	Quantity regulation
Capacity-based	Subsidies to investments, tax discounts, e.g. in Italy for solar PV since 2013.	Auction, as the newly introduced system of subsidies for new capacity in Spain. Also recently in Germany for PV.
Generation-based	Fixed tariffs, or Feed-in tariff, FIT (since 2012 in Italy for small units, also in Germany, and soon in UK also for small units). Premiums on top of the wholesale market price, or Feed-in premium, FIP (since 2012 in Italy for P>60 kW, also in Germany). A kind of FIP, CfD, recently in UK.	Compulsory shares (quotas) of RES for generators, e.g. in Belgium, and green certificates (GC), e.g. previously in Italy (will disappear by 2015) and still in UK (ROC's).

Where VRE is subsidized, VRE operators generally go to the market offering null prices to be dispatched. In Spain, due to the recently introduced remuneration based on expected reasonable profitability, VRE operators are encouraged to optimize their strategies of participation in the market and look for bilateral contracts. In Germany, in order to prevent zero prices in the market, the FIP is reduced after more than six hours of zero price, which is occasioned by excessive RES penetration. It is intended to ensure that VRE responds to certain market signals.

FID access to electricity supply and participation in the market

Regulated prices for industrial consumers are generally being phased out so they are forced to go to the free market to purchase their electricity. Additionally, they always have to pay for the use of system or network tariff that corresponds to their level of voltage and power consumed.. In this context, FID connected to the medium or high voltage grid with an average peak demand of some MW and consuming in the range of some GWh per year, as defined in D2.1, has two possibilities to buy electricity:

- Purchasing energy directly through bilateral contracts with generators and from the wholesale market.
- Signing a contract with a supplier in the free retail market with certain price structure conditions (from flat rates to final prices indexed to the real time, going through other forms of TOU dynamic pricing).

A special situation is found in France, where, even though retail competition is now open to large consumers, large industrial consumers with high baseload consumption may benefit from purchasing a share of their electricity consumption under the 'Accès Régulé à l'Electricité Nucléaire Historique' (ARENH). The ARENH is a regulated price, usually below the market price, set by the government for most of the nuclear energy generated by EDF.

In principle, large FID units could have a direct participation even if they may not be incentivized to do so or may not comply with certain requirements. In fact, the different coupled energy platforms across Europe (e.g. APX, Belpex, EPEX Spot, GME, Nord Pool and OMIE) present specific requirements for participation that impose difficulties for certain consumers to have direct access to the market. Some examples are: restraining requirements on the volume of bids, too high fixed charges and full acknowledgement as BRP to participate. An example of such requirements is provided in Annex 3. In the end, most industrial consumers sign contracts with specialized retailers to purchase their electricity who, in turn, may offer different forms of TOU or dynamic pricing products to them.

2.4 Network and system services: which role for VRE and FID?

After market gate closure, the responsibility for generation scheduling and dispatching is transferred to the TSO, who is in charge of maintaining system security and provide an adequate quality of supply.

The TSO is supported in its task of maintaining the balance within its area of control by different grid users. Each TSO acquires ancillary services from network users, mostly contracted ahead of real time from selected grid users that qualify for providing these services. The main elements of ancillary services[9] include active and reactive power reserves for balancing power and voltage control. In particular, active power reserves[10] are used for frequency control and system balancing, i.e. ensuring the instantaneous physical balance between supply and demand, among other system operation needs. These power capacities can be contracted and activated by the TSO with an associate payment for their availability and/or activation, or made available without payment. Closer to real time, operating reserves can be automatically or manually activated, turning these balancing resources into effective Balancing Energy. In addition to the regulation and balancing reserves, and mechanisms to manage congestions in real time, TSO may count on additional emergency services by which, in case of necessity, the TSO could ask for adjustments in the dispatch of generation groups or ask for demand interruptions.

[9] Further elements of ancillary services may include black-start, inertial response, spinning reserve and islanding capability.

[10] Operating power reserves could in principle be provided by generators, storage devices and load response.

Business models belonging to type B. are directly related to the possibilities of FID, alone or in combination with VRE, to provide flexibility services to the system, mostly to the TSO. In this sense, it is necessary to identify the responsibilities and possibilities of participating in the provision of active power reserves and energy for balancing, congestion management and other ancillary services by VRE and FID. They are summarized for each target country below. Further information in this sense can be found in Annexes 6 and 7. In addition, a comparison of the current framework in the design of the balancing mechanisms among the target countries can be found in Annex 4.

VRE services

The balancing responsibilities and possible participation of VRE operators in the provision of ancillary services for TSOs is described in this section.

Belgium

Elia already facilitates the participation of CHP units and wind energy to free bids, a product segment of the tertiary reserves. Elia supports the obligation for RES (e.g. on- and off-shore wind production) to offer downward balancing power. Furthermore, Elia is actively committed to the development of a transparent bidding platform as alternative for the current reserves market.

France

Primary and secondary reserves are compulsory for conventional generators and the provision of this service remunerated. The balancing mechanism (tertiary reserve) in France operated by the French TSO, RTE, takes the form of permanent and transparent calls for tender. It is in principle open to everyone (competitive generators and certain loads) and provides real-time reserve of power that can be used for upward and downward balancing. Renewable energy plant operators are not entitled to offer these services and they do not participate in the wholesale market for energy like conventional generators.

Germany

Renewable energy producers under the market premium support scheme are required to sell their production in the energy market. Such renewable energy producers are not excluded from balancing markets, but can, just as all other installations e.g. enter into respective contracts. Pooling capacities as e.g. in the form of Virtual Power Plants may help offer more interesting products. However, small installations getting support in the form of fixed feed-in tariffs cannot participate in those markets (§39 par. 2 EEG).

Italy

VRE operators are not entitled with balancing responsibilities or allowed to participate in the provision of ancillary services although they are incentivized to improve their generation predictions and minimize their imbalances. They are remunerated or penalized for their imbalances on the basis of the average value of their imbalances in the zone they are located.

Spain

RES operators in Spain are no longer granted priority dispatch in the electricity markets, i.e. prior to electricity from conventional sources, but they generally offer at null prices so they are always dispatched provided the stability and security of the grid infrastructure can be maintained, see (EC, 2012). – Ley 24/2013 art. 26.2. Their revenues are exposed to market outcomes in addition to the specific support scheme, as previously described.

During the validity of the "Régimen Especial", renewable energy plan operators were not entitled to offer balancing reserves. However, the Spanish TSO has recently proposed a set of modifications[11] to the current network codes and operation procedures that regulate the balancing mechanism, which would allow the participation of RES in balancing markets according to EU legislation.

United Kingdom

In the UK, VRE are fully participating in the market and tend to enter long term Power Purchase Agreements (PPA) with integrated utilities, which purchase all the output from VRE at a discount of their subsidized prices, reflecting the cost of balancing plus a profit margin.

FID services

Flexible load is allowed to provide certain active power reserves and balancing energy in some countries (see Annex 4): Belgium, France, Germany and UK. In contrast, Italy and Spain do not allow the demand side to participate in the provision of these services.

Notwithstanding, the major contribution of flexible industrial demand to the operation of the system generally consists of some type of interruptible service by which the TSO procures available capacity for load interruptions for emergency situations, as a form of fast reaction active power reserve. This mechanism exists in all countries with the exception of the UK, as is more deeply described in Annex 7, allowing FID to provide flexibility to the system with a secure remuneration.

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[11] See proposal of 16/03/2015, http://www.esios.ree.es/web-publica/ > Documentación > Propuestas de P.O.: "Propuestas de Adaptación de los Procedimientos de Operación 3.2, 3.3, 3.7, 3.8, 7.2, 14.4 y 14.8 a la Ley24/013 y al Real-Decreto de 26 de junio, por el que se regula la actividad de producción de energía eléctrica a partir de fuentes de energía renovables, cogeneración y residuos".

3. Feasibility of the business models

In this chapter the applicability of each of the different business models is evaluated in the light of the presented regulatory and market frameworks. A country by country analysis in relation to the existing barriers to the development of those business models is presented. Finally, a summary table is provided.

3.1 Evaluation of the feasibility of the business models in each country

As presented in Section 1.1 the list of proposed business models that will be assessed for each country is the following:

- ***Business models type A****: Reduced energy bills by shifting consumption*
    - ***A.1*** Time of use tariff or price rates, e.g. night rate offered by a supplier.
    - ***A.2*** Dynamic pricing signals from the supplier.
        - ***A.2.1*** FID shifting consumption in response to these signals.
        - ***A2.2*** A supplier owning VRE plants benefitting from the FID to balance.
        - ***A2.3*** On-site renewable energy and the possibility of netting demand.
    - ***A.3*** Manage consumption in response to wholesale electricity prices by acceding directly to the market or through a supplier/aggregator.
    - ***A.4*** Reduced network charges by lowering peak demand.
- ***Business models type B****: Offering flexibility services to the power system*
    - ***B.1*** FID offering reserve capacity, either directly or through an aggregator.
    - ***B.2*** FID responding to signals sent by the Balancing Responsible Party (BRP), who tries to balance their demand-generation portfolio.
    - ***B.3*** Other services to the system, such as: investment deferral, congestion management, among others.

Belgium

● ***A.1*** Time of use tariff or price rates, e.g. night rate are in place, e.g. Peak/Off-peak tariffs.

● ***A.2*** Dynamic pricing signals from the supplier are in general feasible.

● ***A.2.1*** FID shifting consumption in response to these signals are common, e.g. based on wholesale market prices or trends.

● ***A2.2*** A supplier owning VRE plants benefitting from the FID to balance their generation portfolio. Alternatively, direct bilateral sell of energy from VRE to FID can be established.

● ***A2.3*** On-site renewable energy and the possibility of netting demand with self-generation, or even net metering, exist. The “direct line” option allows users to avoid distribution and transmission costs and accede to cheaper energy.

● ***A.3*** Manage consumption in response to wholesale electricity prices by acceding directly to the market or through a supplier/aggregator. With on-site VRE, excess energy could be sold in the market. This model is feasible in the current context. Direct access to the market requires the acknowledgement of the FID that owns the VRE plant as BRP; otherwise the only possibility is being exposed to retail prices based on the wholesale market.

● ***A.4*** Reduced network charges by lowering peak demand is possible only for large grid users, given that they have a capacity measurement and a capacity charge. With on-site VRE, peak 'net demand' can be compensated with self-generation.

● ***B.1*** FID offering reserve capacity, either directly or through an aggregator. Demand resources can participate in the balancing markets (R3DP, free bids, etc. See Annex 1 for more details), TSO is working on a more transparent bidding platform to allow more participation of DR.

● ***B.2*** FID responding to signals sent by the Balancing Responsible Party (BRP), who tries to balance their demand-generation portfolio. Aggregators can offer services to BRP via bilateral contract (BRP – Aggregator). For larger grid users a direct contact with the BRP is also possible.

● ***B.3*** Other services to the system: There is an interruptibility service but only for large grid users. Voltage control is mandatory, not remunerated

France

● ***A.1*** Time of use tariff or price rates, e.g. night rate. This option is rather limited for large electro-intensive consumers with a relatively flat demand profile. These consumers will stop being under an integral regulated tariff ("Tarif Vert") by the end of 2015 so they may be offered time varying prices by suppliers. However, they are strongly incentivized to contract energy with suppliers at regulated fixed price for their baseload, benefiting from ARENH ('Accès Régulé à l'Electricité Nucléaire Historique') scheme.

● ***A.2*** Dynamic pricing signals from the supplier are possible but limited.

● ***A.2.1*** FID shifting consumption in response to these signals.

The retail market is being liberalized in France, so industrial consumers could set up dynamic pricing contracts with any supplier. Notwithstanding, this option is not usual in France, for the same reason as A.1.

● ***A2.2*** A supplier owning VRE plants benefitting from the FID to balance their generation portfolio. Alternatively, direct bilateral sell of energy from VRE to FID.

Due to the feed-in tariff support scheme still present in France, suppliers with VRE are encouraged to sell their renewable production in the wholesale market where there is an obligation of purchasing it, instead of arranging a bilateral contract with FID, even though it is possible to establish these bilateral contracts.

- ***A2.3*** On-site renewable energy and the possibility of netting demand with self-generation, or even net metering.

Self-consumption is allowed in France, with no additional taxes. Therefore, a flexible user might be able to adapt their consumption profile to the own on-site RES forecast, thus reducing the energy cost. On the other hand, excess generation can be fed into the grid remunerated at feed-in tariff scheme under certain circumstances.

- ***A.3*** Manage consumption in response to wholesale electricity prices by acceding directly to the market or through a supplier/aggregator. With on-site VRE, excess energy could be sold in the market.

Electro-intensive industries can benefit from the access to electric energy at a regulated price (ARENH) that does not have time variation but incentivizes a flat consumption profile. FID management could be oriented to this objective and the business model could consist of buying the largest possible proportion of overall electricity consumption at the ARENH price.

It seems that netting demand with self-consumption would be possible but the low prices in France may disincentive this option even if it is possible.

- ***A.4*** Reduced network charges by lowering peak demand. With on-site VRE, peak 'net demand' can be compensated with self-generation.

The transmission tariff for HV consumers (TURPE 4 HTB) has a capacity charge and time differentiation for the volumetric charge but it is unlikely that it provides a sound incentive for peak load reduction given that it accounts for a small share of the final electricity price for this consumer group. Small industries may expect more benefits from adapting their consumption profile to reduce their transmission charge.

- ***B.1*** FID offering reserve capacity, either directly or through an aggregator, by shedding load is possible in France and its relevance has been growing significantly in recent years. The TSO procures the balancing services through different calls for tenders, where industrial customers or distributed load shedding submit their capacities offers. The TSO is also carrying out measures to open frequency response reserves, such as FCR and FRR, to demand side.

- ***B.2*** FID responding to signals sent by the Balancing Responsible Party (BRP), who tries to balance their demand-generation portfolio is also possible.

● ***B.3*** Some other services to the system from FID are possible. Load can take part in the capacity market through a certification process contributing to reduce or defer investments in new power plants. Interruptibility programs are implemented by the TSO as well.

Germany

● ***A.1*** Time of use tariff or price rates, e.g. night rate. This model seems to be possible in Germany as the retail market is fully liberalized, so any consumer, including industries, may arrange any type of contract with their supplier, which can take a TOU structure.

● ***A.2*** Dynamic pricing signals from the supplier.

- ● ***A.2.1*** FID shifting consumption in response to these signals. This model seems to be possible for the same reason as A.1.

- ● ***A2.2*** A supplier owning VRE plants benefitting from the FID to balance their generation portfolio. Alternatively, direct bilateral sell of energy from VRE to FID.

- ● ***A2.3*** On-site renewable energy and the possibility of netting demand with self-generation, or even net metering.

● ***A.3*** Manage consumption in response to wholesale electricity prices by acceding directly to the market or through a supplier/aggregator. With on-site VRE, excess energy could be sold in the market.

It is possible to react to real time market prices and benefit from adjusting consumption in this sense.

● ***A.4*** Reduced network charges by lowering peak demand. With on-site VRE, peak 'net demand' can be compensated with self-generation.

There are some adjustments and reductions that network operators can make to network tariffs of large industries according to consumption behaviour. For example, for final customers with a peak load occurring at a different time period than the maximal power in the grid, an individual tariff is offered. The individual tariff must not be lower than 20 % of the published regular tariff.

● ***B.1*** FID offering reserve capacity, either directly or through an aggregator. Demand response and aggregation are allowed in all the German balancing markets. However, the regulation is very strict around balancing group management, which is a clear barrier for new entrants.

● ***B.2*** FID responding to signals sent by the Balancing Responsible Party (BRP), who tries to balance their demand-generation portfolio. Possible but limited for the same reason as B.1.

● ***B.3*** Other services to the system.

The German law allows TSO to take either grid- or market-related measures, whereby the latter may include cutting off installations at peak based on a contractual agreement. DSOs also have the possibility to conclude such contracts with installations connected to their grid, which will normally be awarded reductions in their grid use fees. Possibilities for DSO to invest in other types of demand response are very limited and they currently do not do so, but are currently under discussion.

Italy

● ***A.1*** Time of use (TOU) tariff or price rates, e.g. night rate, are possible and usual in Italy. Consumers, even the large industries, may choose to purchase electricity in the free market, normally through a supplier, or remain with the incumbent supplier under a regulated integral tariff. The regulated integral tariff is a "*tariffa multioraria*" (multi-hour tariff) with three tariff levels according to the time of consumption[12]. For those industrial entities purchasing electricity in the free market, suppliers may offer many different alternatives, including flat tariffs or TOU tariffs. The regulated network tariff is also TOU.

● ***A.2*** Dynamic pricing signals from the supplier are possible in general.

> ● ***A.2.1*** FID shifting consumption in response to these signals. Electricity suppliers can offer dynamic prices to industrial entities, but only on the energy sales component of the electricity bill (excluding taxes and network and general system charges). The price can be indexed to international market (Brent) or national wholesale price (PUN, single national price).
>
> ● ***A2.2*** A supplier owning VRE plants benefitting from the FID to balance their generation portfolio is not likely to happen. Alternatively, direct bilateral sell of energy from VRE to FID is possible but not usual.
>
> In Italy so far the majority of VRE has not been installed by traditional electricity suppliers. Customers in general and industrial entities in particular are given the possibility to purchase electricity certified from VRE, but so far it is very unlikely that a

[12] F1: Monday-Friday (excluding holidays) from 8:00 to 19.00. F2: Monday-Friday (excluding holidays) from 7:00 to 8:00 and from 19:00 to 23:00 and Saturday from 7:00 to 23:00. F3: Monday-Saturday from 23:00 to 7:00; 24h on Sundays and holidays.

supplier integrates FID and VRE to balance the generation portfolio, as there is no incentive/program to do so.

● ***A2.3*** A mechanism for on-site renewable energy and the possibility of netting demand with self-generation exists even though it presents some difficulties of realization.

SEU can benefit of net metering in case of VRE, but only for a capacity of up to 500 kWe. The main barriers that could be found for the development of SEU are a lack of financing from lending institutions and uncertainty on regulation. There also is an increasing pressure to avoid exempting type of customers, such as SEU, from general charges, also because their burden is increasing overtime for end-users.

● ***A.3*** Manage consumption in response to wholesale electricity prices by acceding directly to the market or through a supplier/aggregator. With on-site VRE, excess energy could be sold in the market.

The electricity produced by VRE is in general purchased by the GSE (state entity in charge of buying renewable generation) at regulated price (feed-in tariff or similar). So far, feed-in tariffs have guaranteed higher revenues than wholesale market. There is uncertainty, however, on the amount of future prices guaranteed or delivered by GSE to VRE, given the large amount of RES support schemes and the ending of existing incentivising schemes. Large consumers are formally allowed to participate to the wholesale market to purchase electricity, but in the end only traditional operators are participating.

● ***A.4*** Reduced network charges by lowering peak demand. With on-site VRE, peak 'net demand' can be compensated with self-generation.

Part of the tariff is fixed (on final consumer, with no consideration of total consumption: €/customer/month), a part is variable (€/kWh/month) but there is no charge directly related to installed or contracted capacity. The variable charge is not TOU, so consumers cannot benefit from adjusting consumption and reducing peak demand according to this signal, only to the capacity charge.

Under the SEU scheme, industries with on-site generation may pay the whole amount of regulated charges and taxes, with an exception: they pay the whole amount of the fixed part of general system charges on the electricity they purchase from the grid, but only 5% of the variable part of general system charges on the self-consumed electricity. Until 2014 they did not pay this. SEU can also benefit from net metering, if there is a VRE plant up to 500 kWe. Both net metering and exemption from taxes demonstrate that SEU are encouraged to self-consume the most part of electricity. There are no additional incentives for industries installing VRE.

Both net metering and exemption from taxes demonstrate that SEU are encouraged to self-consume the most part of electricity.

● ***B.1*** FID offering reserve capacity, either directly or through an aggregator.

Frequency variations control can be provided only by generation units, or by pumping units. VRE so far cannot provide these services. The Italian TSO (Terna) purchases the resources (congestion management, balancing and reserve capacity) to operate safely the system mainly on the MSD (Mercato Servizi per il Dispacciamento, Market for Dispatch Services). Only generation units able to provide these services (according to their performances and location) can participate to MSD.

With the exception of interruptibility services, large industries are not remunerated for FID. However, a new system of capacity remuneration mechanism will be put in place from next year in which DSM is allowed to participate, at least in principle. Therefore, FID could benefit from it, even though at present the demand side participation characteristics have not been specified yet.

● ***B.2*** FID responding to signals sent by the Balancing Responsible Party (BRP), who tries to balance their demand-generation portfolio.

Each BRP must respond for imbalances in their portfolio, being able to compensate imbalances of generation and demand separately. FID could help BRP to reduce demand imbalances, but not in interaction with generation imbalances. VRE are obliged to provide their best estimations of electricity they are going to produce, to guarantee safety and security of the system: thresholds for maximum electricity considered for imbalances are established according to each single type of renewable energy. There is an optional system by which VRE plants that outperform on average with respect to the forecast of similar VRE in their zone and of the same type of plant are incentivized to opt out the scheme. However, they are not made fully responsible of their imbalances.

● ***B.3*** Other services to the system.

With the exception of interruptibility services, consumption patterns or FID are not remunerated to provide flexibility services. The amount of interruptibility services needed by the system is defined annually by the Ministry of Economic Development and is subject to annual or multiannual auctions. Industries involved can define an annual and monthly cap for unavailability.

Spain

● ***A.1*** Time of use tariff or price rates, e.g. night rate, are a feasible business models. The so-called “access tariffs”, which recover both network and other regulated costs, has Time of Use (TOU) differentiation of up to 6 periods for HV consumers. The retail market is fully liberalized for large consumers and suppliers may offer time of use contracts which may follow the same TOU structure or a different one.

● ***A.2*** Dynamic pricing signals from the supplier are in general, feasible, with some constraints mostly related to the integration with on-site VRE:

● ***A.2.1*** FID shifting consumption in response to these signals is possible, given that large consumers can arrange dynamic pricing contracts with suppliers.

● ***A2.2*** A supplier owning VRE plants benefitting from the FID to balance their generation portfolio is not possible, due to the fact that offers/bids in the wholesale energy market and the balancing markets are separate for generation and consumption.

Alternatively, direct bilateral sell of energy from VRE to FID are possible but not usual.

● ***A2.3*** On-site renewable energy is possible but the possibility of netting demand with self-generation is not allowed. In principle, injections and consumption are metered and rewarded, or charged, separately. The regulation of self generation and consumption is under discussion.

● ***A.3*** Manage consumption in response to wholesale electricity prices by acceding directly to the market or through a supplier/aggregator is possible. Specialized suppliers for large consumers may directly pass through the market price plus a fixed or market-indexed component to recover imbalances and management costs. With on-site VRE, "excess" energy being sold in the market is not directly applicable because all (not only the excess) injected energy would be measured separately from consumption and would be subject to the renewable energy remuneration scheme.

● ***A.4*** Reduced network charges by lowering peak demand. With on-site VRE, peak 'net demand' can be compensated with self-generation. This model is only partially possible. The access tariff is TOU and includes a capacity charge but its value is relatively low for industrial consumers. In addition, even if contracted power can be lowered to reduce the capacity charge, it cannot be done with self-consumption from own VRE.

● ***B.1*** FID offering reserve capacity, either directly or through an aggregator is not possible. Consumers are not allowed to provide any kind of balancing services.

● ***B.2*** FID responding to signals sent by the Balancing Responsible Party (BRP), who tries to balance their demand-generation portfolio. Each BRP must respond for imbalances in their portfolio, being able to compensate imbalances of conventional generation, Special Regime (inc. VRE) generation and demand separately, for there is a dual imbalance pricing system. The recently suggested amendments to the Operating Procedures of the TSO will not differentiate between conventional generation and VRE but still generation will be differentiated from demand. FID could help BRP to reduce demand imbalances, but not in interaction with generation imbalances.

- ***B.3*** Other services to the system. Large consumers can provide the Interruptibility Service to TSO for emergency situations. No specific markets for other services to TSOs or DSOs have been established where consumers can participate.

United Kingdom

- ***A.1*** Time of use tariff or price rates, e.g. night rate. This model is very limited because around 80% of trading activity occurs in the bilateral market (OTC and forward trades).

- ***A.2*** Dynamic pricing signals from the supplier are in general rather limited in relation to the purchase of electricity in the market but there seems to be room for savings in relation to the network tariffs.

  - ***A.2.1*** FID shifting consumption in response to these signals. This model is very limited for the same reason as A.1.

  - ***A2.2*** A supplier owning VRE plants benefitting from the FID to balance their generation portfolio. Alternatively, direct bilateral sell of energy from VRE to FID. This model is very unlikely since VRE require long-term PPAs from credit-worthy parties.

  - ***A2.3*** On-site renewable energy and the possibility of netting demand with self-generation, or even net metering. It is possible but limited because separate metering is required.

- ***A.3*** Manage consumption in response to wholesale electricity prices by acceding directly to the market or through a supplier/aggregator. With on-site VRE, excess energy could be sold in the market. Even if it is possible, there is little experience on this.

- ***A.4*** Reduced network charges by lowering peak demand. With on-site VRE, peak 'net demand' can be compensated with self-generation. This model seems to be feasible in the British context because of the high value of avoided transmission costs if peak demand is reduced, which is reflected in the locational part of the transmission network use of system (TNUoS) tariffs. The capacity that is used to calculate transmission charges (for injection or withdrawal) is based on each parties position during peak demand period (in reality the average of the three highest demand periods is used). Consequently, parties and especially industrial consumers have very strong incentives to try to forecast peak demand periods and manage their injection/withdrawals during those hours (either by using on site generation or by reducing their consumption).

- ***B.1*** FID offering reserve capacity, either directly or through an aggregator. This model is partly possible because some services can be offered by FID to the TSO, as indicated in Annex 1.

● ***B.2*** FID responding to signals sent by the Balancing Responsible Party (BRP), who tries to balance their demand-generation portfolio. This is possible when the supplier is distribution connected, assuming the role of BRP. FID might have balancing responsibility if transmission connected.

● ***B.3*** Other services to the system. No specific markets for other services to DSOs have been established were consumers can participate but intensive industrial demand can participate in the capacity market (even though in practice this has been very limited and already committed for a long period of time), provide supplementary balancing reserves and may be exempted from green levies.

3.2 Summary of the applicability of the business models in each country

The following table summarizes per country the viability of each business models in each target country. A colour is assigned to each model with the following meaning: red if significant barriers exist that do not enable the business model; yellow if the present circumstances limit the full realization of the business model or make it unattractive; and green if the business model is compatible with the current regulatory and market framework.

	BE	FR	DE	IT	ES	UK
A. Reduced energy bills by shifting consumption						
A.1 Time of use tariff or price rates	green	yellow	green	green	green	yellow
A.2 Dynamic pricing signals from supplier						
A2.1 FID shifting consumption in time	green	yellow	green	green	green	yellow
A2.2 Supplier owning VRE plants benefits from FID to balance generation portfolio / Direct bilateral sale of energy from VRE to FID	green	yellow	green	yellow	yellow	red
A2.3 On-site VRE and the possibility of netting demand with self-consumption	green	green	green	yellow	red	green
A.3 FID managing consumption in response to hourly wholesale market prices. With on-site VRE, excess energy sold in the market.	green	green	yellow	green	green	yellow
A.4 Reduced network charges by lowering peak demand. With on-site VRE, peak 'net demand' compensated with self generation.	yellow	yellow	green	yellow	yellow	green
B. Offering flexibility services to the power system						
B.1 FID offering reserve capacity, directly or through an aggregator	green	green	yellow	red	red	yellow
B.2 FID responding to signals sent by BRP to balance demand-generation portfolio	green	green	yellow	yellow	yellow	green
B.3 Other services to the system (e.g. load interruptibility, services to DSOs)	yellow	green	green	yellow	yellow	yellow

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Rebours, Y.G., Kirschen, D.S., Trotignon, M., Rossignol, S., 2007b. A Survey of Frequency and Voltage Control Ancillary Services mdash;Part II: Economic Features. IEEE Trans. Power Syst. 22, 358–366. doi:10.1109/TPWRS.2006.888965

5. Revision history

Table 5.1. Revision history

Version	Date	Authors	Notes
0.1	18/05/2015	Mercedes Vallés, Pablo Frías and Tomás Gómez (IIT – Comillas)	First draft – to receive inputs from task partners by 5th June
0.2	22/06/2015	IIT –Comillas and all partners	Update with the contributions from all partners. First complete version for feedback and discussion in the 24th-25th meeting,
1.0	09/07/2015	IIT-Comillas and all partners	Final draft version
2.0	24/07/2015	IIT-Comillas and all partners	Final submission

1. Annex - Characterization of electricity generation and demand

The purpose of this description is to serve as a technical support for the rest of the document. Each country specific environment is analyzed in relation to:

- The current structure of the generation mix of each electric power system, with a special focus on the current penetration of VRES, and future expectations.
- The segmentation of electricity consumption, especially regarding the different large industries.

The data used for the comparison of the different generation mixes is based on the Scenario Outlook & Adequacy Forecast (SO&AF) 2014-2030, an annual publication made by ENTSO-E for the Ten-Year Network Development Plan[13]. Further information about each country's energy position has been taken from the Communication from the European Commission (EC) COM(2014) 634 about the progress in the completion of the Internal Energy Market and its accompanying documents (EC, 2014a, 2014b, 2014c).

The current situation (scenario 2014) is compared to the best estimation of potential future developments in new installed capacity for 2020 according to TSOs (scenario B) and the estimation based on the assumed compliance the governmental targets set for renewable generating capacities in 2020, according to EU environmental policy objectives and national targets set in the National Renewable Energy Action Plan ("NREAP") of each country (scenario Reg.).

The data used for the characterization of electricity demand is based on national information sources.

.Belgium

The power generation mix in Belgium is largely dominated by nuclear power and fossil fuels, most of which is based on natural gas, as can be seen in the Figure 1.1. It can be anticipated that the peak load is close to its total firm capacity both in the current situation and in the future scenario that is anticipated by its TSO, S.A. Elia System Operator (Elia). Looking at the actual production, nuclear power plants produced approximately 32.1 TWh of electricity in 2014, being the lowest level of production of the past 8 years. Nevertheless, the share of nuclear power in the actual production still amounts to 53.9%.

[13] https://www.entsoe.eu/publications/system-development-reports/adequacy-forecasts/Pages/default.aspx

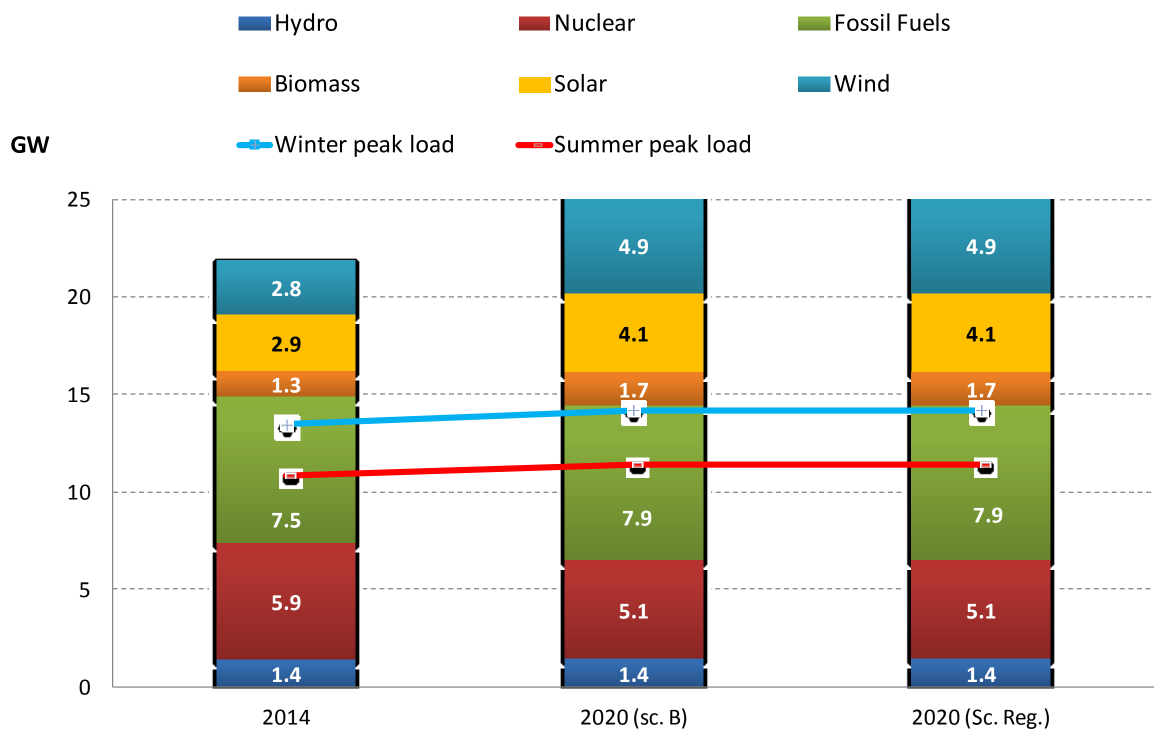


Figure 1.1. Current (2014) and expected (2020) generation mix in Belgium, according to the TSO's best estimate (Sc. B) and policy objectives (Sc. Reg.). Data provided by ENTSO-E.

The electricity consumption in Belgium reached 80.4 TWh in 2014 (26.8 TWh and 53.6 TWh of electricity consumption respectively connected to the transmission and distribution grid), which is a decrease of 2.1% in comparison to 2013. The maximum peak power demanded in 2014 was 12.7 GW, while the minimum level of power demanded amounted to 5.9 GW. The Belgian energy flows for 2014 are depicted in Figure 1.2.

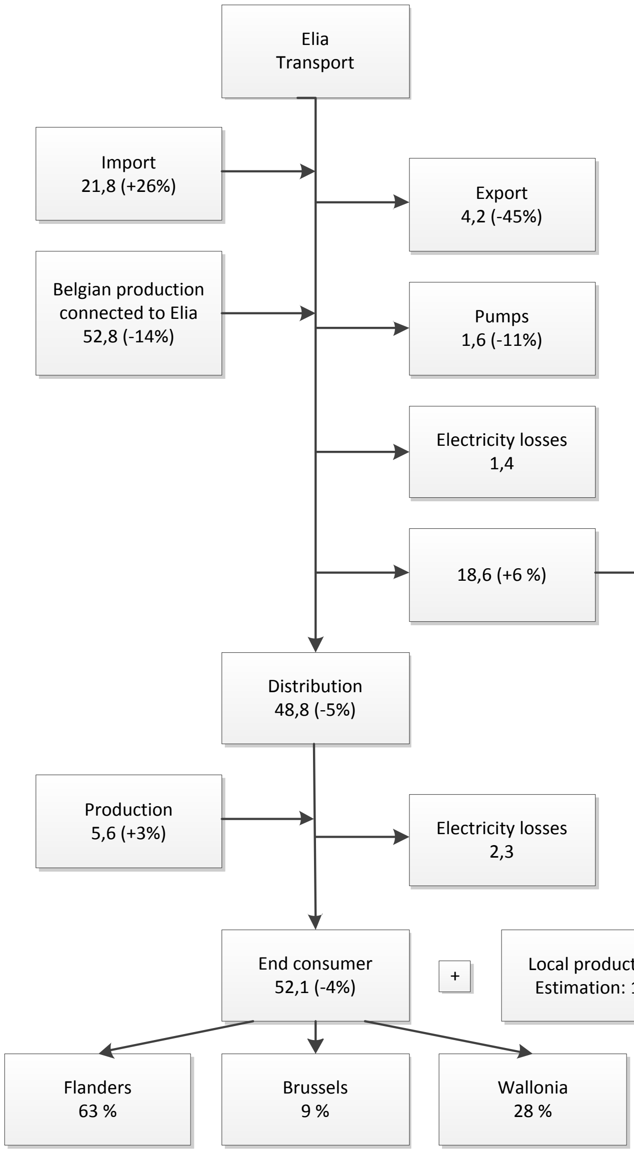


Figure 1.2: Belgian electricity flows 2014 (Source: Synergrid).

The order of magnitude of the electricity consumption by the industrial sector can be perceived in Figure 1.3. The industrial electricity consumption amounted to 37.23 TWh in 2013, representing 45.89 % of the total electricity consumption.

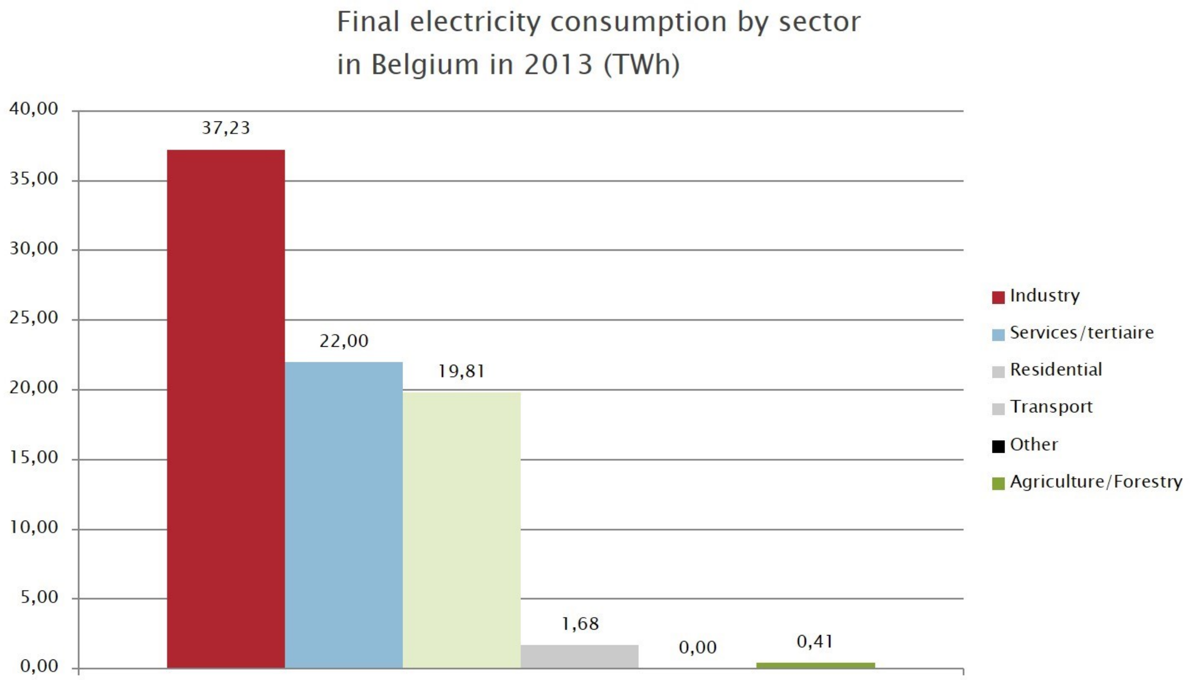


Figure 1.3: Final electricity consumption by sector in Belgium in 2013 (TWh) (Source: Febeg)

More detail on the relevant electricity consumption by the different industrial sectors for Belgium can be found in Table 1.1. The table provides an overview of the energy consumption, subdivided by energy source, for different sectors (i.e. industry, transport and others) for 2013, expressed in kilo tonnes of Oil Equivalent (ktoe). Figure 1.4 gives an overview of the segmentation of the Belgian industrial electricity demand in 2013, expressed in GWh.

Table 1.1: Final Belgian energy consumption by sector in 2013 (ktoe) (Source: Eurostat)

Belgium 2013 (ktoe)	Total all products	Solid fossil fuels	Crude oil & petroleum products	Gas	Renewable energy	Non-renewable wastes	Electricity	Derived heat
Final energy consumption	34.802	1.539	13.917	9.956	1.729	143	6.963	554
+ Industry	10.460	1.422	444	4.079	685	143	3.201	485
+ Iron and Steel	2.376	1.175	14	790	0		396	

Belgium 2013 (ktoe)	Total all products	Solid fossil fuels	Crude oil & petroleum products	Gas	Renewable energy	Non-renewable wastes	Electricity	Derived heat
Final energy consumption	34.802	1.539	13.917	9.956	1.729	143	6.963	554
+ Chemical and Petrochemical	2.775		22	1.243	12		1.093	406
+ Non-ferrous metals	303		6	116			162	
+ Non-metallic minerals	1.301	232	115	487	117	19	240	
+ Transport eEquipment	376		5	184		111	186	
+ Machinery	127		22	52	2		50	
+ Mining and Quarrying	37						37	
+ Food, Beverages and Tabacco	1.332		13	760	68		451	40
+ Paper, Pulp and Printing	737		21	114	292	13	257	39
+ Wood and Wood products	243			20	192		31	
+ Construction	198		63	58			77	
+ Textile and Leather	196		1	98	1		95	1
+ Not elsewhere specified (Industry)	460	16	162	155	1		126	

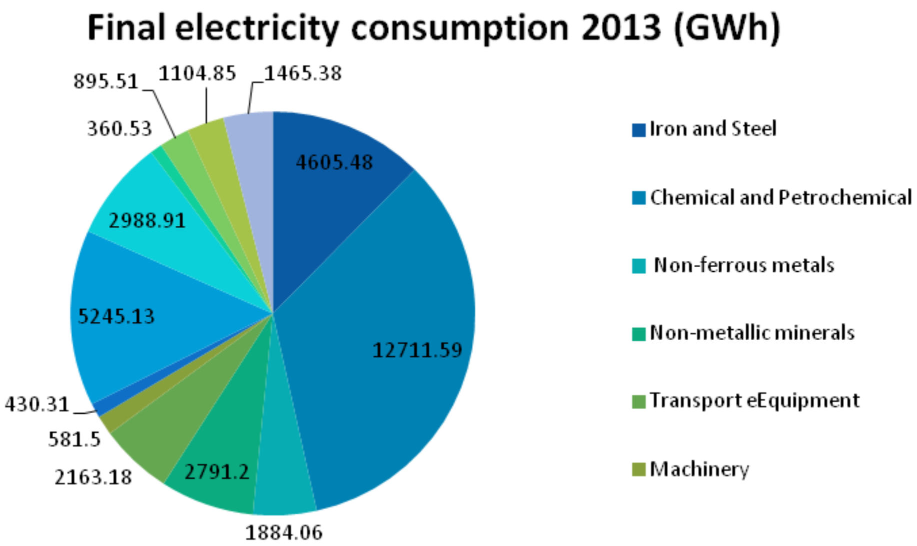


Figure 1.4: Segmentation of industrial electricity consumption in Belgium in 2013, expressed in GWh, based on information provided by Eurostat.

Security of supply may be endangered in the future years in the Belgian electric power system due to various reasons, which include the limited interconnection capacity, unforeseen shutdown of nuclear power plants, the actual closure of traditional gas power plants as well as the announcement of new closures in the future. Demand response could therefore be a valuable resource to compensate the lack of secure capacity.

Belgium's national renewable energy target is 13% share of generation by 2020, according to the National Reform Programme of 2013, and it looks like the country is on track to achieve this objective. It must be noted that the current share of renewable energy production is around 7% and its installed capacity accounts for approximately 27%.

Different grid projects are in the pipeline aiming at expanding Belgium's interconnection capacity. Within the Nemo project the interconnection between Belgium and the UK is foreseen. The commissioning of the interconnector is planned for 2018. Furthermore, the Creos grid project envisions the realization of an interconnection between Luxembourg and Belgium allowing to increase the transfer capability between LU, DE, BE and FR and contributing to the security of supply of both countries. The final completion of the interconnector is planned for 2020. The interconnection capacity with Germany is expected to be reinforced by 2019 via the ALEGRO project.

Belgium's political structure in relation to energy policy and regulation is complex because competences are shared between the federal and the regional governments (Flanders, Wallonia and Brussels capital). The federal government enacts at transmission system level (>70 kV) and focuses on inter alia: large production, nuclear power production and consumer rights. At the regional level the authority extends to the fields of electricity distribution (=< 70 kV), decentralised production and renewable energy. Accordingly, Belgium has different regulators assigned to the different political regions (i.e. CREG at federal level and VREG, CWAPE and Brugel at regional level).

.France

The French power system, the second largest in Europe after Germany, relies heavily on nuclear power and, to a lesser degree, on hydro power. Nuclear power accounts for 75% of the electricity production while hydro represents 14% (according to data of 2013 from the French Energy Regulatory Commission, CRE[14]). Renewable electricity generation accounts for 19%, most of which is renewable hydro, and only 3% and 1% of total electricity production come from wind and solar energy resources, respectively.

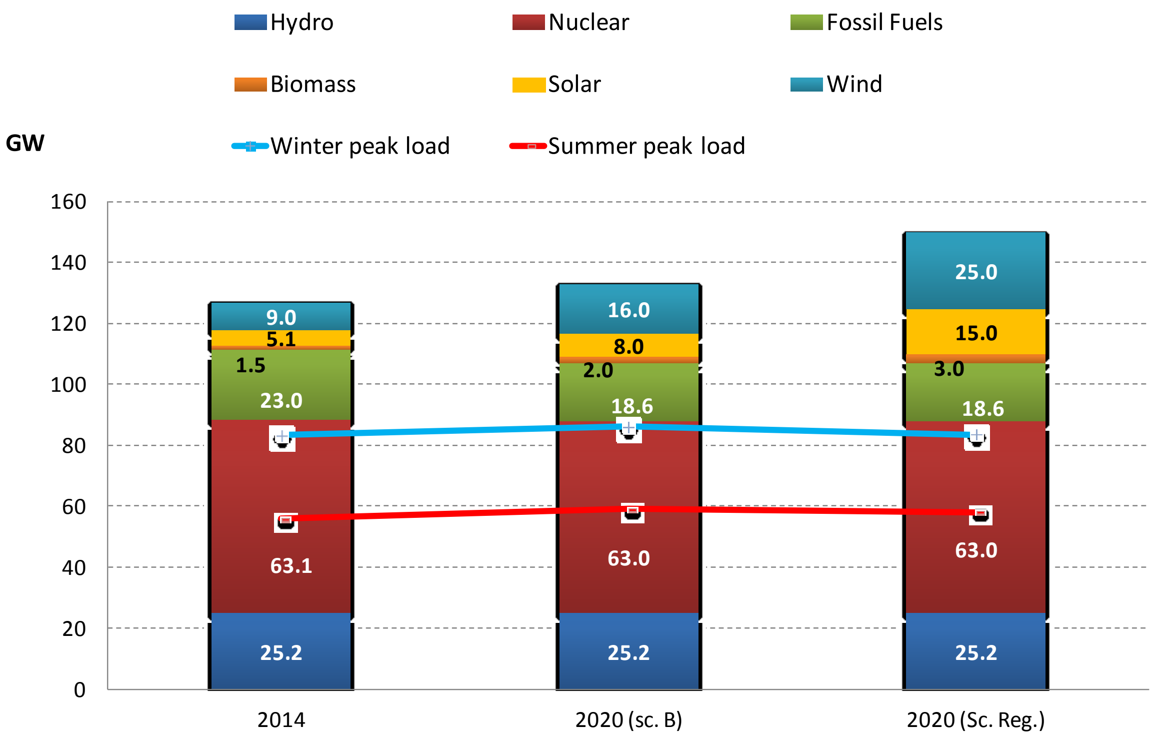


Figure 1.5: Current (2014) and expected (2020) generation mix in France, according to the TSO's best estimate (Sc. B) and policy objectives (Sc. Reg.). Data provided by ENTSO-E.

This system presents difficulties to address peak load in spite of its overall average overcapacity. It can be seen in Figure 1.5 that the winter peak load, which presents high variability and is very dependent on the temperature, is close to the limits of installed firm capacity. The CRE[14] recognizes that new investments will be needed in the near future in

[14] http://www.cre.fr/en/documents/publications/annual-reports/activity-report-2013/

order to maintain security of supply, whether these are allocated to production means to satisfy an increasing peak demand or to mechanisms to better exploit flexible demand response. The need for more flexible demand is strengthened by the growing penetration of RES given that nuclear and coal power plants are not very flexible to cope with their variability and unpredictability.

It is expected that support for renewable energy increases from now to 2020 but there is great uncertainty whether the future investments in RES will allow France to comply with its regulatory objectives. On 26 May 2015, the Energy Transition Law was finally approved by the *Assemblée Nationale*[15], by which France has set itself a RES target of 23% share of overall energy consumption by 2020, and 32% by 2030, and set limits to the share of nuclear power production from 75% to 50% of total electricity production by 2025.

The total consumption of large, medium and small industries in France is shown in Figure 1.6; the industrial demand has been divided in different sectors. These industries may be connected to the transmission and distribution networks.

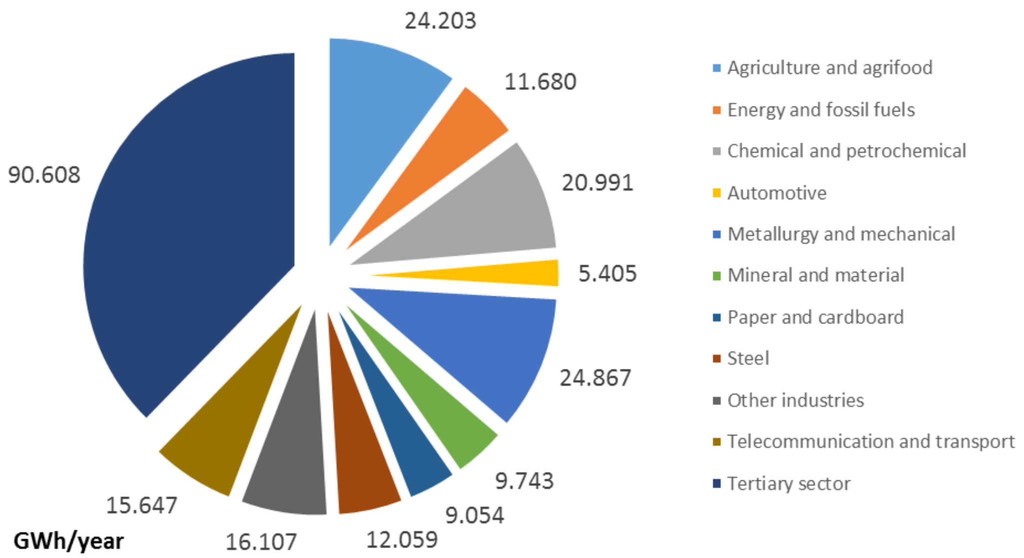


Figure 1.6. Total consumption of large, medium and small industry in France (2013), based on information from Réseau de transport d'eléctricité[16].

Figure 1.7 represents the annual consumption per industry that is directly connected to transmission network, i.e. not including those consumers connected to the distribution network.

[15] http://www.assemblee-nationale.fr/14/ta/ta0519.asp

[16] RTE, Statistiques Production Consommation Echanges 2013

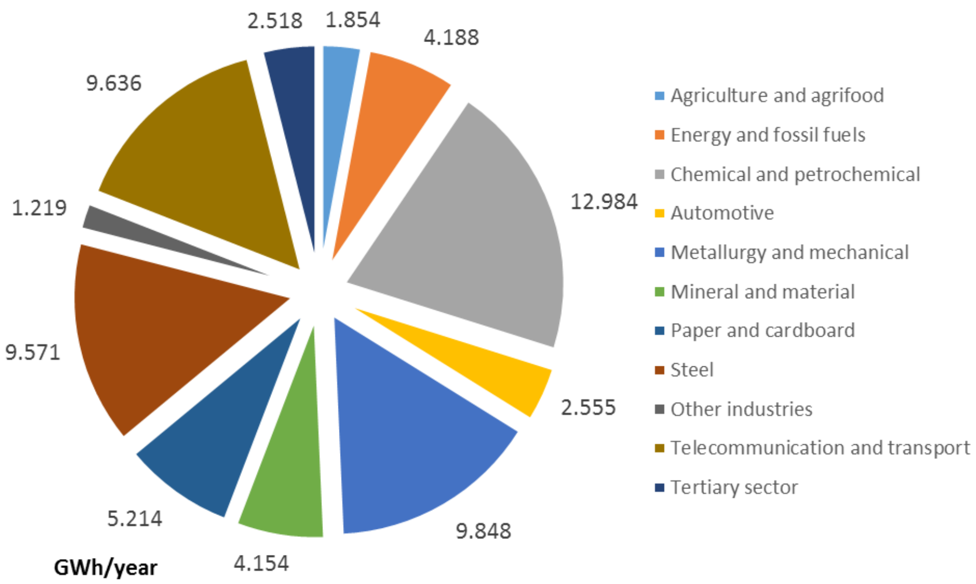


Figure 1.7. Total consumption of industries in France that are directly connected to the transmission network.

In addition, the same data related to these industries is classified in Table 1.2 according to the voltage level; for each voltage level the annual consumption is specified.

Table 1.2: Energy consumption of large industries connected to the transmission network.

Volatge level			Total energy (GWh)
HTA	1 kV < U ≤ 50 kV	45 kV	1.414
HTB1	50 kV < U ≤ 130 kV	63 kV	23.260
		90 kV	9.447
HTB2	130 kV < U ≤ 350 kV	150 kV	56
		225 kV	28.157
HTB3	350 kV < U ≤ 500 kV	400 kV	1.406
Total			**63.739**

.Germany

The European power system with the largest amount of installed capacity is going through a deep transformation of its energy mix, mainly driven by a big support to renewable energy sources and the political decision to phase out all nuclear generating capacity in the next years (by 2022) after the Fukushima nuclear accident. Figure 1.8 shows the current situation and future expectations. The main source used for electricity production nowadays is coal (44%), followed by RES (29%) and nuclear energy (15%).

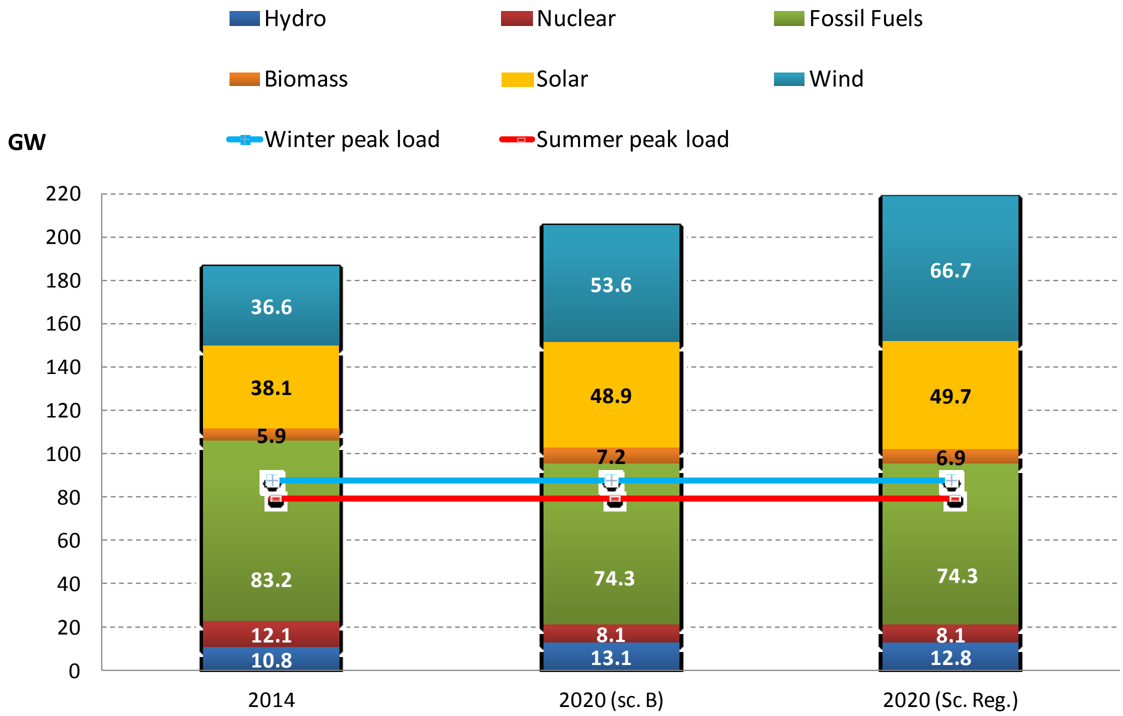


Figure 1.8: Current (2014) and expected (2020) generation mix in Germany, according to the TSO's best estimate (Sc. B) and policy objectives (Sc. Reg.). Data provided by ENTSO-E.

The nuclear phase-out has not changed Germany's national targets in renewable energy and environmental policy. According to this, the share of RES in electricity generation should increase up to 35% by 2020, which is accompanied by various regulatory, policy and technical measures, both in relation to the design of adequate renewable energy support policies and to the improvement of the mechanisms that balance the increased volatility and unpredictability of generation from VRE without incurring in excessive costs. Moreover this the phasing out of coal power plants besides the phasing out of Nuclear is a further challenging topic. The German government recently published a Green Paper on its future energy market design. The Green Paper focuses on how to develop a future market design and regulatory framework for the electricity sector that ensures that the power supply is secure, cost-efficient and environmentally friendly.[17]

[17] Bundesministerium für Wirtschaft und Energie, Ein Strommarkt für die Energiewende, http://www.bmwi.de/BMWi/Redaktion/PDF/G/gruenbuch-gesamt,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf

.Italy

The Italian power system is mostly made up of conventional thermal generation (56%), hydro (18%) and a large share of renewable energy, most of it from solar photovoltaic (15%) and wind (7%) resources, as can be observed in Figure 1.9. Due to the composition of the generation mix, the absence of large baseload plants such as Nuclear Power ones (and the limited amount of energy produced by coal, which amounted to 12% in 2013) and the interconnection limitations, electricity prices in Italy are some of the largest in Europe.

Support to renewable energy in Italy is higly significant. In 2014 renewable energy production, including hydro, was 101 TWh (38% of total net energy production, 267TWh), while solar and wind alone accounted for 38 TWh (16% of total)[18]. Import accounted for 15% of total energy consumption. The objective for 2020 is to achieve a 17% of gross final energy consumption, a target that is already close to actual figures.

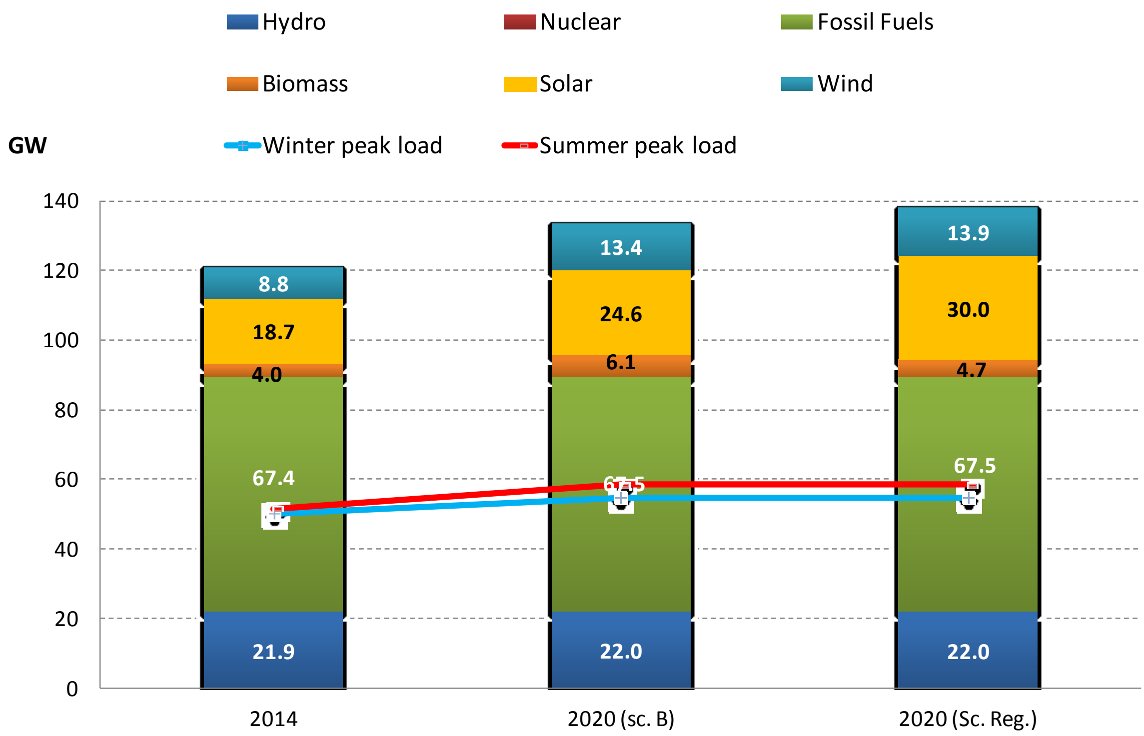
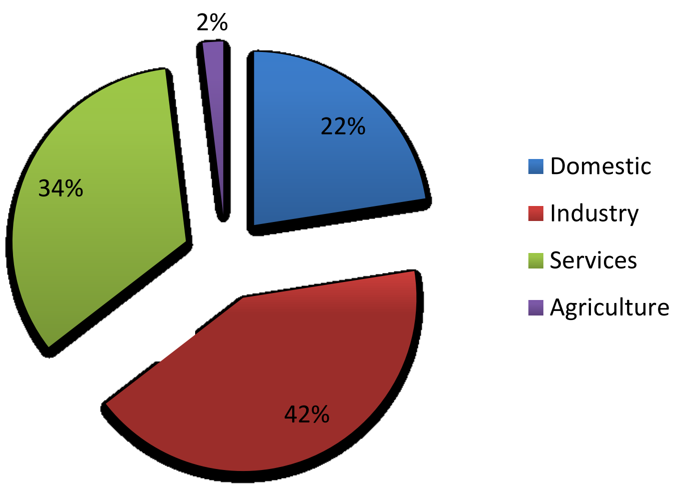


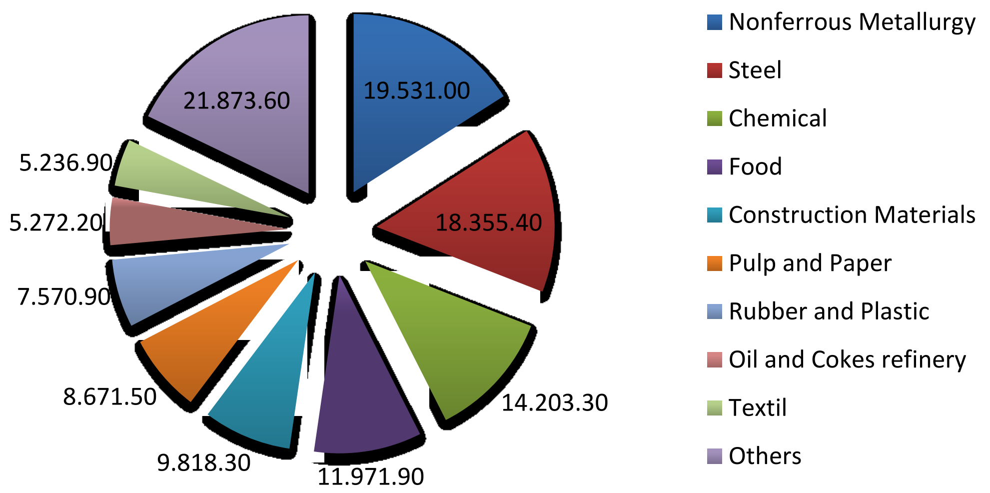
Figure 1.9: Current (2014) and expected (2020) generation mix in Italy, according to the TSO's best estimate (Sc. B) and policy objectives (Sc. Reg.). Data provided by ENTSO-E.

The total electricity consumption is represented in the following graph, segmented for each sector. [18]

[18] Terna, Dati statistici sull'energia elettrica in Italia" 2013



The total electricity consumption can be further divided for the different sectors of the industry. The most important ones are shown in the following graph.



It is not only interesting to analyse the use of the electricity, but also at which level the consumers are connected. As the flexible consumers are mainly connected to the high voltage grid, it is important to know what their share is in the total electricity demand. The next table shows the division for the electricity demand for each voltage level.

Electricity Consumption for different voltage levels		
	Volume (in MWh)	Number of connections
Domestic		
Low Voltage	59 111	29 355 000
P<1,5 kW	256	572
1,5 kW < P < 3 kW	49 654	26 283
3 kW < P	9 202	2 500
Non Domestic		
Low Voltage	74 290	7 343 000
Medium Voltage	95 211	108 427
High Voltage	39 392	1 689

.Spain

The Spanish electric power system has gone through a deep technological and regulatory transformation in the past two decades, the former being characterized by a drift towards renewable energy and combined cycles in the generation mix. Currently, RES (including hydro) account for more than half of the installed capacity and the total produced energy in Spain.

Among the national policy targets for Spain is to cover 20.8% of final energy consumption with RES. Spain was supposed to be on track to reach this objective but recent changes in the support schemes for renewable energy could significantly limit the future investments in new capacity until 2020, as can be seen in the Figure 1.10.

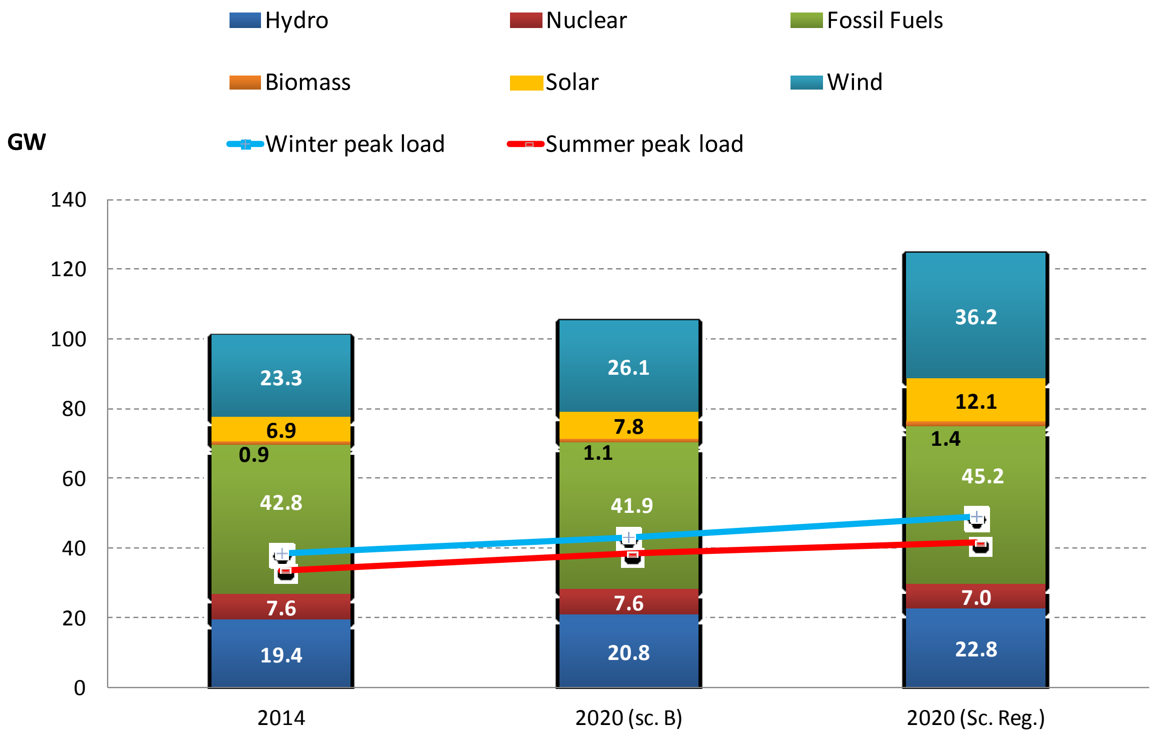


Figure 1.10: Current (2014) and expected (2020) generation mix in Spain, according to the the TSO's best estimate (Sc. B) and policy objectives (Sc. Reg.). Data provided by ENTSO-E.

The overall electricity consumption is segmented into different activities as presented in Figure 1.11, according to information provided by the Spanish Ministry of Industry, Energy and Tourism[19].

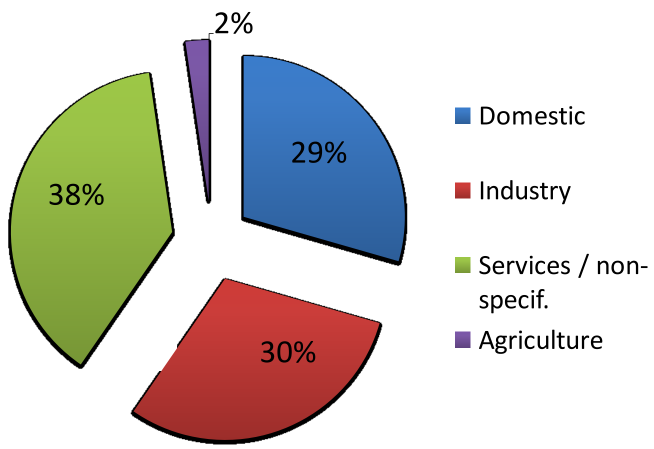


Figure 1.11: Segmentation of electricity consumption into different activities in Spain, for 2012.

19 http://www.minetur.gob.es/energia/balances/Publicaciones/ElectricasAnuales/Paginas/ElectricasAnuales.aspx

Electricity consumption for industrial usage is further broken down into specific categories, among which the most relevant are shown in Figure 1.12.

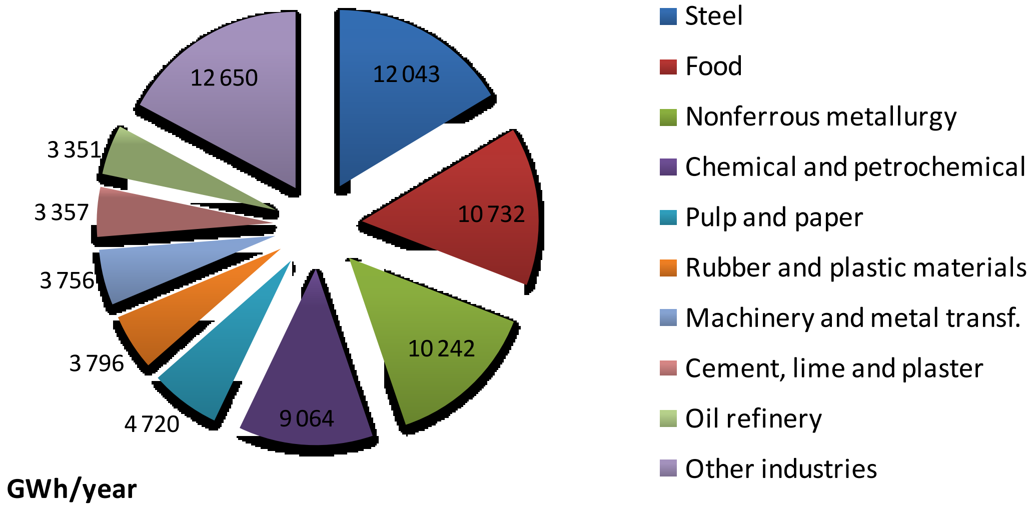


Figure 1.12: Segmentation of industrial electricity consumption in Spain in 2012, based on information from the Spanish Ministry of Industry, Energy and Tourism[19]*.*

Electricity consumers can alternatively be classified according to the tariff group they belong to, which differentiates between voltage levels, as shown in Table 1.3. The flexible large industrial consumers are presumably within those connected to highest voltage levels, as noticed by the resulting average consumer size, highlighted in green in the table. Large industrial consumers in Spain are very often connected to the HV network, frequently at 66 kV, although in some regions they are also connected to MV levels (e.g. 30-36 kV) and the largest ones are always connected to highest voltages.

Table 1.3 Electricity consumption segmentation into different tariff groups in Spain in 2012, based on information from the Spanish Ministry of Industry, Energy and Tourism[19]

		Tariff group	Number of consumers	Contracted Power (MW)	Consumption (TWh)	Average contracted power (kW/cons)	Average consumption (MWh/cons)	eq. h/year
	LV consumers V < 1 kV		**28 491 421**	**150 886**	**114**	**5**	**4**	**756**
LV	P < 10 kW	2.0	26 830 055	114 936	69	4	3	603
	10 kW < P < 15 kW	2.1	888 563	11 273	9	13	11	841
	P > 15 kW	3.0	772 803	24 677	35	32	46	1 428
	MV-HV consumers V ≥ 1 kV		**108 698**	**32 586**	**120**	**300**	**1 104**	**3 682**
MV	1 kV ≤ V < 36 kV; P ≤ 450 kW	3.1.A	86 134	7 351	16	85	180	2 111
	1 kV ≤ V < 36 kV; P > 450 kW	6.1	19 974	15 826	55	792	2 764	3 488
HV	36 kV ≤ V < 72 kV	6.2	1 609	3 412	16	2 121	10 193	4 807
	72 kV ≤ V < 145 kV	6.3	435	1 787	9	4 108	21 170	5 153
	V ≥ 145 kV	6.4	546	4 210	24	7 711	43 353	5 623

.United Kingdom

The electricity generation mix in United Kingdom is very dependent on fossil fuels (68% generation in 2012) and is increasingly incorporating RES (12%), especially wind energy.

Figure 1.13 shows the energy mix of Great Britain, to which Northern Ireland must be added to complete the picture of United Kingdom.

UK has ambitious objectives for 2050 willing to implement market mechanisms that foster the development of renewable energy resources, some of them contained in the Electricity Market Reform (EMR)[20].

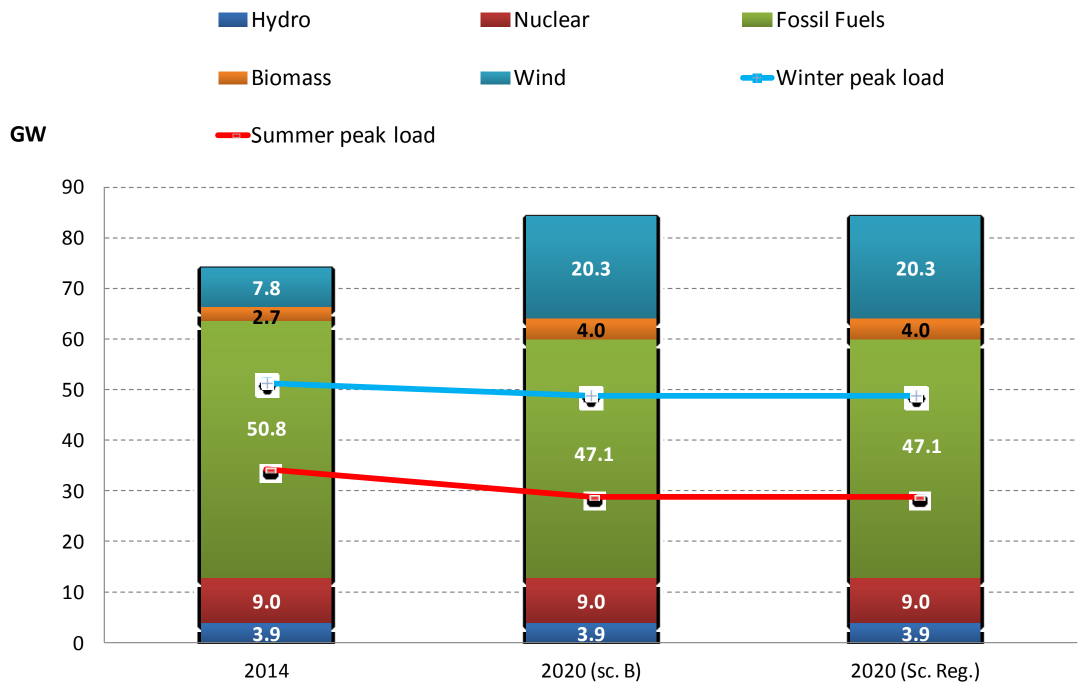


Figure 1.13: Current (2014) and expected (2020) generation mix in Great Britain, according to the TSO's best estimate (Sc. B) and policy objectives (Sc. Reg). Data provided by ENTSO-E.

Industrial electricity demand accounts for 26% of total electricity consumption, of which the largest share goes to Iron and steel, paper, food, chemical and engineering industries, as can be observed in Figure 1.14.

20 https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform

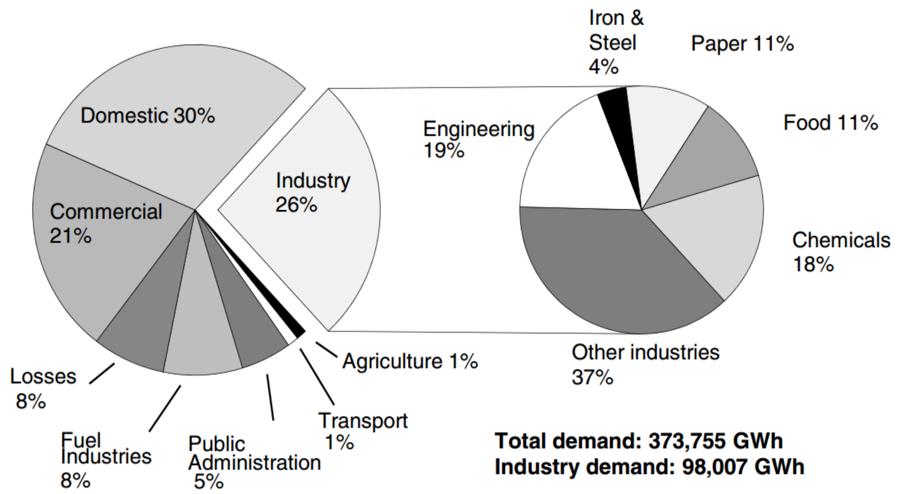


Figure 1.14. Electricity demand segmentation in United Kingdom. Source: DUKES, DECC.

2. Annex - Electricity prices and tariffs for industrial consumers

The objective of this section is to provide further information for the better understanding of the design and the characteristics of network tariffs and the final price composition for the industrial customers.

.Belgium

The transmission network tariffs are defined by the federal regulator (CREG). Until recently, CREG also established the distribution network tariffs. Following a constitutional reformation of 1 July 2014, the regional regulators are authorized to define the distribution network tariffs. Thus, for the period from 1 January 2015 till December 31, 2015, VREG, CWAPE and Brugel have approved the distribution tariffs for electricity and natural gas for Flanders, Wallonia and Brussels Capital Region respectively.

Consumer groups are divided depending on their grid connection. Within this context the voltage level prescribes the network tariffs to be paid.

Table 2.1: Overview of consumer groups within the Belgian electricity market

HS:	Professional consumers directly connected to HV (>26 kV)
TransHS:	Professional consumers connected to a HV substation (>26 kV)
26-1 kV:	Professional consumers connected to MV (26 – 1kV)
TransLS:	Professional consumers connected to LV substation
LS:	Professional and residential consumers connected to LV

For grid users with peak measurements a capacity charge is included in the distribution tariff. This network compensation is based on the subscribed capacity, the capacity made available, which is determined on the basis of the maximum power quarter-hourly recorded, consumed over the last 12 months, including the billing month. For grid users without a peak measurement, i.e. standard electricity meter, the grid tariffs are based on the actual consumption and the applicable tariffs (i.e. dual or single tariff).

Table 2.2: overview of network charges for the different consumer groups

	Consumer group				
	HS	TransHS	26-1 kV	TransLS	LS
Grid user with peak measurement	Yearly subscription of capacity	Capacity charge x EUR/kW	Capacity charge + proportional	Capacity charge + proportional	Capacity charge x EUR/kW

	Consumer group				
	HS	TransHS	26-1 kV	TransLS	LS
	x EUR/kW Monthly subscription of capacity* x EUR/kW * Seasonal and off-peak difference		term x EUR/kW + x EUR/kWhnu (peak hours) + x EUR/kWhsu (off-peak hours)	term x EUR/kW + x EUR/kWhnu (peak hours) + x EUR/kWhsu (off-peak hours)	
Grid user without peak measurement	/	/	Basic tariff (peak tariff) x EUR/kWh	Basic tariff (peak tariff) x EUR/kWh	Basic tariff (peak tariff) x EUR/kWh
			Dual tariff x EUR/kWhnu (day) + x EUR/kWhsu (night)	Dual tariff x EUR/kWhnu (day) + x EUR/kWhsu (night)	Dual tariff x EUR/kWhnu (day) + x EUR/kWhsu (night)
			Exclusively night tariff x EUR/kWhsu (night)	Exclusively night tariff x EUR/kWhsu (night)	Exclusively night tariff x EUR/kWhsu (night)

In Belgium, locational differences can occur with regard to the network tariffs. In particular, the actual network tariffs for each consumer group are defined by the relevant distribution network operator one is connected to. The differences in distribution tariff are due to:

- Parameters specific to the grid area: city versus countryside
- the size of the public service obligations
- the investment policy of the network operators

The aspects included in the distribution tariff are:

- the use of the distribution network:
    - the subscribed and additional capacity
    - system services
    - measuring activities
- the public service obligations imposed on the DSO:
    - free electricity
    - public lighting
    - Subsidy scheme for energy efficiency
    - Social suppliers and placement of budget meter
    - buyout green power and CHP certificates
- support services for:
    - the compensation of grid losses
    - the regulation of voltage and reactive power
- surcharges

Tariff offers for large industrial customers are, in contrast to tariff offers for residential customers and SMEs, not advertised. An industrial customer will receive a tariff quotation upon request from the chosen supplier. Before a supply contract is concluded, there is a negotiation phase, on the basis of the tenders received. The scope of these negotiations includes all components on which the supplier has a margin. This not only includes the price of the electron but also the "renewable contribution" which the supplier asks to offset the costs incurred in order for the supplier to meet his regional obligation towards CHP and / or green certificates.

According to CREG estimates approximately 10% of the large industrial consumers[21] have a fixed, contractually-agreed tariff. Again 10% of the large consumers have a contract with a fluctuating price based on quotations of the BELPEX daily market. The remaining 80% of larger customers have a contract with a price determined on the basis of "clicks" on the forward quotations of ENDEX and, in some cases, on the BELPEX daily market.

Energy prices which were invoiced in 2013 to large industrial customers seem to be situated within the range of € 15 /MWh and € 94 /MWh, see Figure 2.1. This significant price difference can be explained mainly by the specific characteristics of each industrial customer, but also by the timing that industrial customers have chosen to conclude their contract and the "clicks" on the wholesale market they perform.

[21] Large industrial consumer: each customer with a billed consumption of at least 10 GWh/year

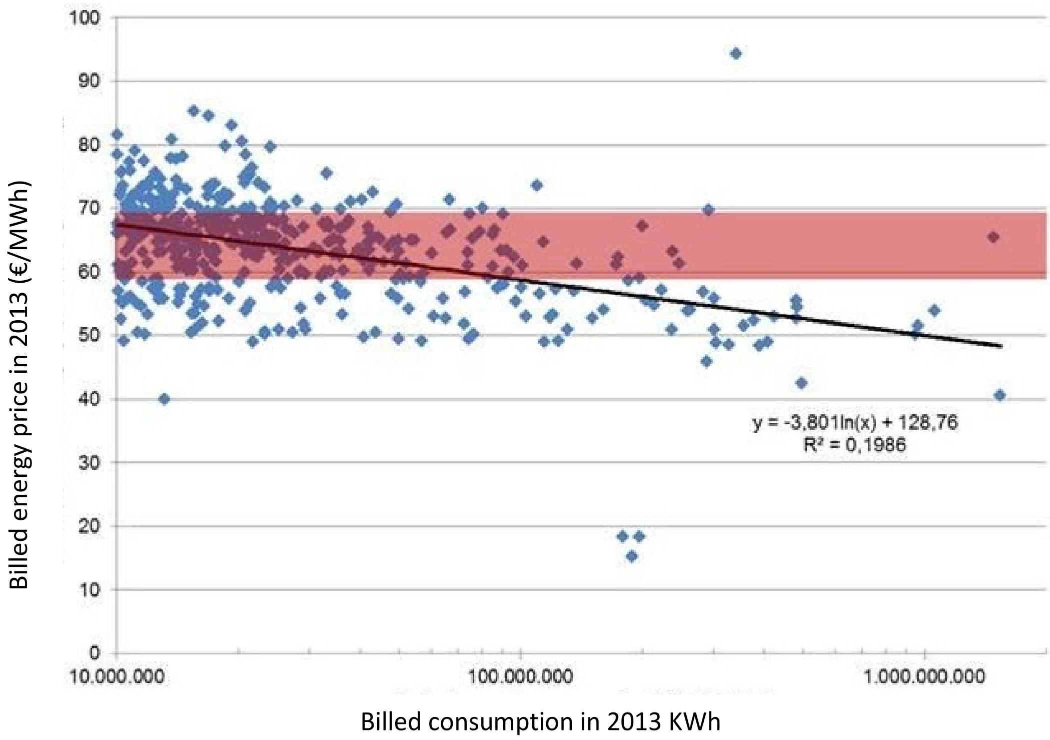


Figure 2.1.: price in function of energy consumption for 2013 contracts (Source: CREG)

.France

France has a long tradition of integral regulated tariffs for all types of most consumers. Since the 1st July 2007, the electricity retail market in France is opened to competition. However, the transition from a fully vertical integrated market to a competitive market is not fully achieved, and two pricing systems are available:

- Consumers have a contract with the historical operator (EDF or local companies) and the government sets the regulated price.
- Consumers may choose their supplier, who settles the price according to the market prices.

According to CRE (Activity Report 2014), 91% of consumers are supplied under regulated tariffs, which accounts for 91% and 58% in terms of total electricity consumption from residential and non-residential consumers, respectively.

Three types of regulated tariffs have been in place for different consumer categories (see Figure 2.3):

- **Blue tariff ("Tarif Bleu")** : P< 36 kVA
- **Yellow tariff ("Tarif Jeune")**: 36 kVA < P < 250 kVA
- **Green tariff ("Tarif Vert")**: P> 250 kVA

The regulated tariff is composed of the following charges:

- Production costs (≈31%)
- Transmission & Distribution costs (≈30%)
- Commercialization costs (≈8%)
- Taxes: (≈31%)
    - Contribution to the electricity public service (CSPE). The "*Contribution au service public d'electricité*" (CSPE) is aimed to defray the renewable subsidies and social tariffs.
    - Tax on final consumption (TCFE). the "*taxe intérieure sur la consummation finale d'electricité*" (TCFE) is a tax on the final electricity consumption. In 2014, this tax was 0,5€/MWh. Exemptions are presented in this tax if the industrial customer is a metallurgy, electrolysis, non-metal minerals or chemical sector; moreover, if the electricity cost is equal 50% of the added value produced by the company, release of this tax is also possible.
    - Transport (Delivery) Contribution (CTA). The "*Contribution tarifaire d'acheminement*" (CTA) is a charge for energy sector pensions. It is fixed at 10,14% of the fixed part of transmission tariff.
    - Value added Tax (VAT)

By the end of 2015, the Green and Yellow tariffs, for consumers > 36 kW, will be completely phased out, so most non-residential consumers will be obliged to go to the free retail market to purchase electricity. The type of consumers included in this group can be seen in Figure 2.3.

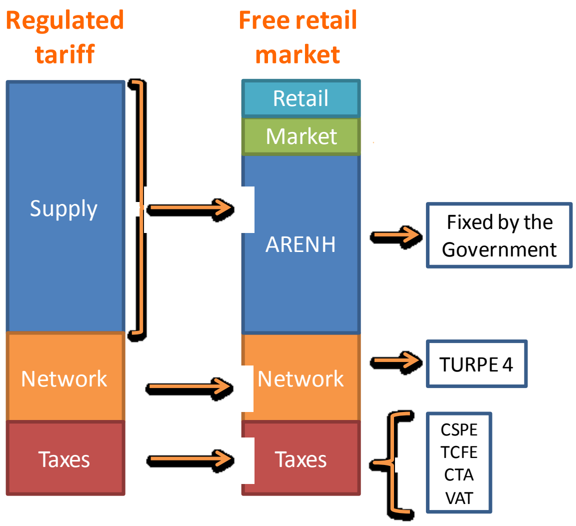


Figure 2.2. Final price or tariff structure for a typical industrial consumer before and after the phase out of regulated tariff

Type de site	Type de tarif	Puissance compteur (kW)	
Résidentiel, Petit pros	Tarifs bleus	3 - 36	
Professionnels	Tarifs jaune	36 - 250	
Entreprises	Tarif vert A5	250 - 10 000	250 - 3000
Entreprises - Très grands sites	Tarif vert A8		3000 - 10 000
	Tarif vert B	10 000 - 40 000	
	Tarif vert C	> 40 000	

Figure 2.3. Structure of the traditional regulated tariffs in France. Inside the orange frame are the regulated tariffs that will be phased out by the end of 2015.

Large industrial consumers in the free retail market face an additional competitive advantage that is worth mentioning: the possibility of purchasing part of their energy under the ARENH mechanism. The ARENH (*Accès régulé à l'électricité nucléaire historique*) is a regulated price, usually below the market price, set by the government for baseload nuclear electricity generated by EDF and sold to alternative suppliers (only up to 100TWh to be allocated between the suppliers). Large consumers with high baseload consumption may benefit from purchasing a share of their electricity consumption to these suppliers under the ARENH scheme, and the residual consumption under a market price.

The tariff relating to the highest voltage levels (HTB, V ≥ 50 kV), or the public electricity transmission user tariff, TURPE 4 HTB, came into force on 1st August 2013 and is applicable for a period of 4 years[22]. This tariff has a particular structure and definition than that of TURPE 4 for medium and low voltage levels (HTA and BT).

The structure of the tariff changes with the introduction of time of use differentiation for the time of day or season for tariffs for all voltage ranges, not only HTB3 (350 kV ≤ V < 500 kV), but also HTB1 (50 kV ≤ V < 130 kV) and HTB2 (130 kV ≤ V < 350 kV) voltage ranges.

TURPE charges represent the costs for the transmission network utilisation and comprise the following concepts[23]:

- Management costs.
- Metering costs.

[22] https://clients.rte-france.com/lang/an/clients_producteurs/services_clients/tarif.jsp

[23] https://clients.rte-france.com/htm/fr/mediatheque/telecharge/Comprendre_le_tarif_01_08_2014.pdf

- Withdrawal tariff: it includes a fee for reserved load capacity – single annual fee - , a fee for load capacity according to 5 time periods and the fee for consumption based also in 5 time periods. Periods are defined according to types of season and time of the day. In addition, three contract options are available: medium, long and very long utilisation.
- Other fees that include a fee regarding the exceeding of power capacity, a fee for regrouping of connection or a transformation fee.

An analysis regarding the final electricity price paid by industrial consumers is performed below[24]. Three different examples of industrial consumers have been assumed for comparison. Table 2.3 summarizes the main features of these customers.

Table 2.3. Features of different industrial consumers for the estimation of the final prices in the French case.

Profile	Profile 1	Profile 2	Profile 3
Consumption (GWh)	25	25	250
Hours/year	2.527	2.527	8.760
Voltage level (kV)	30-70	≥150	≥150
Capacity at peak (MW)	9,89	9,89	28,54

Profile 1 and 2 correspond to medium industries that function on working days; the only difference between them is the connection voltage level. An electricity intensive industry is represented in Profile 3. The different components that define the final price are broken down in Figure 2.4.

[24] Based on information from the report "*PWC: A European comparison of electricity and gas prices for large industrial consumers*".

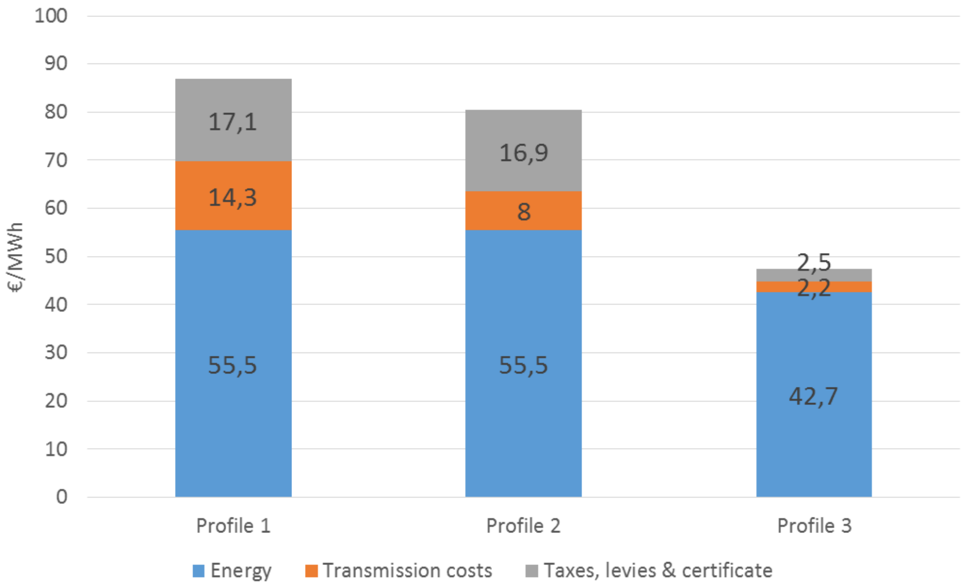


Figure 2.4: Final price components for large industrial consumers in France.

It is noticeable that the price is lower for electro-intensive industry as around 95% of their total consumption is baseload and can be supplied with nuclear power under the regulated price (ARENH). The higher energy price for Profile 1 and 2 is due to their exposure to the market as they have a more spiky demand profile. Regulated costs for the network usage, i.e. transmission costs, are reduced as the voltage level connection increases. In addition, the French government introduced a reduction of 50% in transmission costs for those consumers whose energy rate was larger than 10 GW/h and their consumption overtakes the 7000 hours/year. Finally, taxes and other levies are lower for electro-intensive industry (Profile 3) because of the exemptions applied to this type of large consumers.

.Germany

In Germany, consumer electricity prices are comprised as follows.

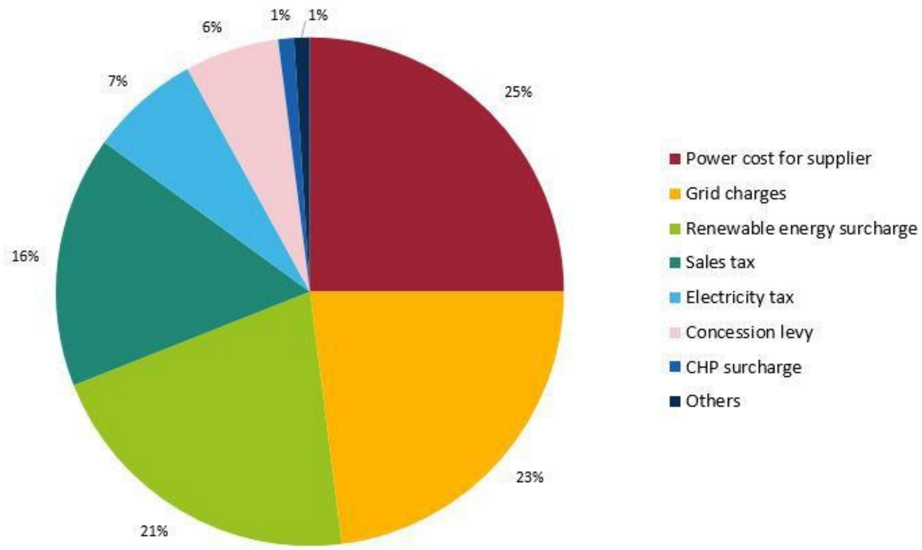


Figure 2.5: Composition of power prices for households. Source: BDEW, 2015.

- About 25% production costs
- About 23% grid charges
- About 21% surcharge for the financing of the support to renewable energy ("EEG-surcharge")
- Value added tax of 16% (19% on the pre-tax price, thus 16% of the after-tax price)
- Electricity tax of 7%
- Concession levy of about 6%
- Levy for the financing of the development of the offshore grid
- About 1% surcharge for the financing of the support to cogeneration
- About 1% surcharge for the financing of the partial reduction of grid charges for energy-intensive users.

However, for industrial users, different mechanisms allow for some reduction of the energy bill.

First, certain energy-intensive consumers can apply for a reduction in the contribution to the financing of the support for renewable energy under the EEG[25].

To be eligible, the following cumulative criteria apply:

- Minimum consumption of 1 GWh;
- Active in a sector listed in Annex 4 of the EEG, whereby:

[25] Gesetz für den Ausbau erneuerbarer Energien (Erneuerbare-Energien-Gesetz –EEG 2014), BGBl.I.S.1066, last amendment 22.12.2014 (BGBl.I.S.2406).

- For undertakings in sectors on list 1, they need to show an electricity-intensity exceeding 16% (17% starting from 2016);
- For undertakings in sectors on list 2, an electricity-intensity of 20% is required;
- Existence of an energy management system or equivalent in the undertaking.

The reduction then means that while the full "EEG-surcharge" has to be paid for the first 1 GWh. For all electricity beyond that first 1 GWh the surcharge will be reduced by normally 15%. However, two restrictions apply to this rule:

- First, the maximum reduction an undertaking can get is limited to 0.5 % of the gross added value, where the electricity-intensity exceeds 20%, and to 4% where this is not the case.
- Second, the reduction may not lead to a situation in which the undertaking in question pays less than 0,1ct EEG-surcharge per 1 GWh (O,05ct for certain listed industries); while the for the first 1 GWh the full surcharge has to be paid anyways. [26]

The TSOs are obliged to reimburse downstream distribution grid settle these payments through a specific settlement mechanism. Lost revenue can be passed on to end consumers as a special surcharge on their electricity bill.

Since the last reform of the EEG, even self-consumers (i.e. consumers which produce electricity for own consumption) may under certain circumstances be charged with the EEG-surcharge. Under the previous legal framework, the production for self-consumption had been exempted from the EEG-surcharge, which constituted a rather relevant possibility to reduce their electricity bills, in particular for industrial consumers. Under the EEG 2014, still, if it is a renewable energy plant, the production may qualify for a reduction, and the law still provides for some exemptions altogether, in particular where

- the electricity is used for the own consumption of the plant itself; or
- the self-consumer is neither directly nor indirectly to the grid; or
- The self-consumer fully supplies itself with renewable electricity and does not get support for the electricity it does not consume itself
- Or where the plant is smaller than 10kW, for 10 MWh electricity per year, for a duration of 20 years. [27]

As regards the electricity tax, certain exemptions from or reductions may be available as well.

As regards the grid use tariffs, while they are regulated, they are not harmonized among all grid operators and there are large differences between the natures and thus also between

[26] Compare § 64 EEG

[27] Compare § 61 EEG

the costs of the distribution grids in particular. In Germany, though, only consumers and thus not producers, currently pay grid use tariffs.

As mentioned above, different models exist for consumers to reduce their grid use tariffs.

However, in addition to that, under the relevant rules, there are possibilities for certain undertakings (with more than 7.000 hours of consumption and at least 10 GWh consumed per year) to get reduced (or individual) grid use tariffs which take into account their consumption behaviour[28]. Reduction is staggered, and undertakings with 7.000 consumption hours can get a maximum reduction to 20% of the published grid use tariffs, undertakings with 7.500 consumption hours 15%, and for undertakings with more than 8.000 consumption hours 10%.

Final customers with temporary high power consumption and a significantly lower or no power consumption in the remaining time may also apply for reduced grid use charges. Here individual tariff may not be lower than 20 % of the published regular tariff.

In relation to final prices, according to Analysis of German Electricity Prices published by the Federal Association of the Energy and Water Industry (BDEW) in June 2014, regulated costs account for 52% of the electricity bills of household customers and 49% for industrial customers.

.Italy

Consumers below 16.5 kW may choose to purchase electricity in the free retail market or remain with the incumbent supplier under a regulated integral tariff. The regulated integral tariff is a "*tariffa multioraria*" (multi-hour tariff) with two or three tariff levels according to the time of consumption[29]. In turn, large consumers go to the free market, normally through a supplier, and agree on an energy purchase contract which may be based on flat rates, TOU or more dynamic offers.

The regulated costs of the system are charged to all consumers in the following categories[30]:

- **Network services**: transport, distribution and metering (*servizi di rete*)
- **General system charges** (*oneri generali di sistema*)
- **Taxes**: VAT and others

[28] Compare § 19 Stromnetzentgeltverordnung; StromNEV

[29] F1: Monday-Friday (excluding holidays) from 8:00 to 19.00. F2: Monday-Friday (excluding holidays) from 7:00 to 8:00 and from 19:00 to 23:00 and Saturday from 7:00 to 23:00. F3: Monday-Saturday from 23:00 to 7:00; 24h on Sundays and holidays. Alternatively, only P (Peak), from 8:00 to 21:00 in the week days and O (Off-peak), the rest of the time.

[30] The integral regulated tariff also comprises the energy supply category, called "Servizi di vendita".

Network service and general system charges are made up of some or all the following different components: fixed charge (€/year), a capacity charge (€/kW/year) and a volumetric one (€/kWh). The values of these charges differ between consumer groups but do not have time differentiation. A summary of the values of network service charges for high voltage consumers is provided in Table 2.4.

Table 2.4: Network services charges (distribution, transmission, measurement) for MV and HV consumers in the Italian electricity system.

		Medium voltage (1 kV ≤ V < 35 kV)			High voltage	Very high voltage	
		P ≤ 100 kW	100 kW < P ≤ 500 kW	P > 500 kW	35 kV ≤ V < 150 kV	V < 380 kV	V ≥ 380 kV
		MTA1	MTA2	MTA3	ALTA	AAT1	AAT2
Distribution charges	Fixed €/year	477	429	415	20 987	20 987	20 987
	Capacity €/kW/year	37	33	29	-	-	-
	Energy €/MWh	0.63	0.57	0.49	0.21	-	-
Transmission charges	Capacity €/kW/year	-			18.34	18.34	18.34
	Energy €/MWh	6.44			1.05	1.04	1.04
Measurement charges	Fixed €/year	258.5			143.1	143.1	143.1

General system charges have a different structure[31] for each of the following concepts:

- A2 *Oneri per il finanziamento delle attività nucleari residue* (charges for maintenance and decommissioning of old nuclear plants)
- A3 *Fonti rinnovabili e assimilate* (incentives for renewable energy production)
- A4 *Regimi tariffari speciali ferrovie* (supporting tariffs for railways)
- A5 *Finanziamento della ricerca* (supporting research on electricity system)
- A6 Stranded Costs
- AE *Agevolazioni imprese energi*vore (benefits for energy-intensive industries)
- AS *Bonus sociale* (supporting social tariffs)
- UC4 *Imprese elettriche minori* (supporting small local utilities, for example in the islands)
- MCT *Misure di compensazione territoriale* (local compensations, usually where large generation plants/infrastructures are built)
- UC3: balancing costs on transmission and distribution
- UC6: balancing quality costs
- UC7 *Efficienza energetica negli usi finali* (supporting energy efficiency)

Some benefits are proposed for large energy-intensive industries ("type A" components of general system charges are 0 for consumptions higher than 8 GWh (MV) and 12 GWh (HV)) and the government approved a Decree to decrease by 10% the electricity bill for Small and Medium Enterprises in 2014.

[31] The specific values for each tariff group and charge can be found in http://www.autorita.energia.it/it/elettricita/auc.htm

Table 2.5: Average final electricity prices for non-domestic consumers in the Italian electricity system in 2012. Source: AEEG – SI.

LV	112.5 €/MWh
MV	95.1 €/MWh
HV and VHV	81.5 €/MWh

.Spain

The latest methodology to calculate the transmission and distribution tariffs in Spain defined by the NRA and approved by the government dates from 2014[32]. According to this methodology, theoretically, network tariffs have to be calculated in order to allocate the costs of transmission and distribution only, and have to be differentiated from those charges that are aimed at recovering other regulated costs. Notwithstanding, currently the so-called "access tariffs", which recover both network and other regulated costs, are still defined by the government, and published without differentiating both types of charges, and without much clarity about the methodology used to calculate them.

Consumer tariff groups are distinguished by voltage level and power demand in different time frames, while generator tariffs only depend on the volume of energy injected to the grid, regardless of other factors. All tariffs (consumers and generators) are similar across the whole country, with no geographical differentiation.

Five voltage levels are differentiated for the design of tariffs:

- NT0, for voltage levels below 1 kV (low voltage)
- NT1, for voltage levels from 1 kV to 36 kV
- NT2, for voltage levels from 36 kV to 72.5 kV
- NT3, for voltage levels from 72.5 kV to 145 kV
- NT4, for voltage levels higher than 145 kV

All hours in one year with similar characteristics are classified into tariff periods. For tariffs charged to consumers that are connected to high voltage (NT1-NT4), six periods are defined (P1-P6), based on combinations of "electric season" of the year (high, medium and low), four types of days of the week and groups of hours of the day.

[32] http://www.boe.es/boe/dias/2014/07/19/pdfs/BOE-A-2014-7658.pdf

The specific values of the access tariffs for each year are calculated based on the annual allowed revenue of transmission and distribution activities plus the addition of other regulated costs. Those for 2015 are established in the Order IET/2444/2014, of 19th December[33]. Transmission costs are assigned to voltage level NT4 (V > 145 kV), while distribution costs are allocated among voltage levels NT0-NT3, based on the information received from distribution companies and using a simplified network model. Consumers are not allocated costs of voltage levels downstream of their connection level.

The final access tariff is made up of three types of charges: a capacity charge, an energy charge and a reactive energy charge. The values for the energy and the capacity charges for 2015[34] are shown in Figure 2.6 and Figure 2.7, respectively.

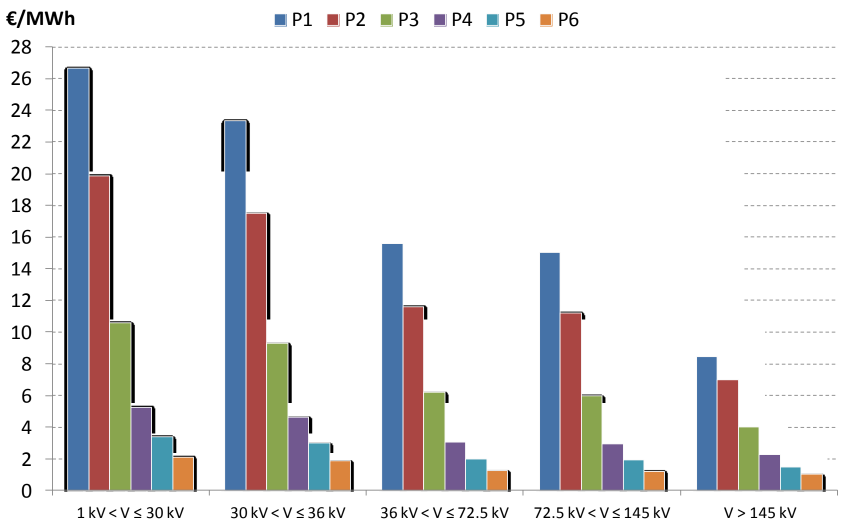


Figure 2.6: Energy charges of the network tariff for different high voltage consumers and tariff periods in Spain, for 2015 [34]

[33] http://www.boe.es/diario_boe/txt.php?id=BOE-A-2014-13475

[34] These values are presented in a friendly format in https://www.iberdrola.es/02sica/gc/prod/es_ES/hogares/docs/Triptico_tarifas2015.pdf

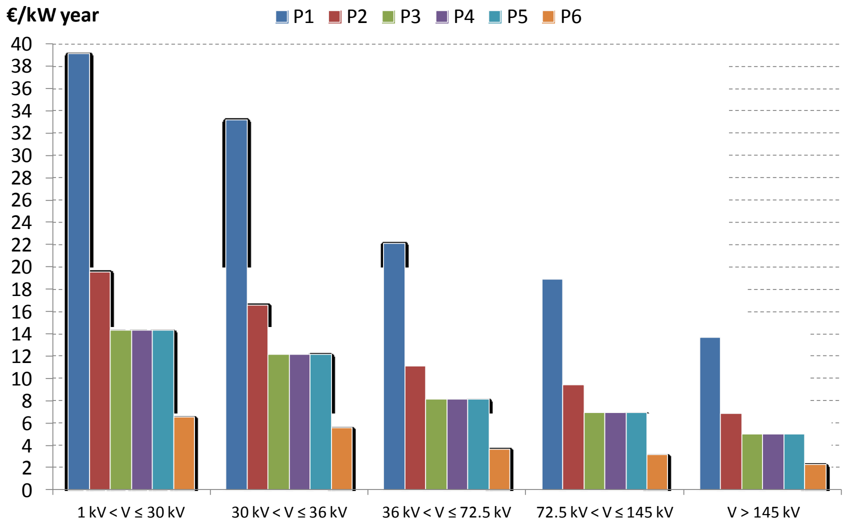


Figure 2.7: Capacity charges of the network tariff for different high voltage consumers and tariff periods in Spain, for 2015 [34]

Access tariffs have a very high impact on the final price of small electricity consumers but not so much on the final price for industrial consumers. Figure 2.8 presents an estimation of the final average price of electricity and its components in €/MWh for the different categories of large consumers in Spain. The final electricity bill is composed of:

- **Energy market price**, which is composed of the pool price, i.e. is the resulting day-ahead and intraday market price, plus the technical constraints and ancillary services costs. All these costs are charged through the market operator OMIE. Capacity payments and demand interruptibility payments are charged through this component as well.
- Capacity and energy charges of the **access tariff**.
- **Energy losses**, which are calculated as a percentage of total energy consumption. These percentages are predetermined by the Ministry along with the access tariffs, for different tariff periods. For HV consumer loss coefficients are defined in Order IET 107/2014, as shown in Table 2.6.

Table 2.6. Loss coefficients to be charged to large consumes connected to high voltages with TOU differentiation in the access tariff of 6 periods (expressed in % of consumed energy)

Voltage	Allocated energy losses (% of consumed energy)					
	P1	P2	P3	P4	P5	P6
NT1	6.8	6.6	6.5	6.3	6.3	5.4
NT2	4.9	4.7	4.6	4.4	4.4	3.8
NT3	3.4	3.3	3.2	3.1	3.1	2.7

Voltage	Allocated energy losses (% of consumed energy)					
	P1	P2	P3	P4	P5	P6
NT4	1.8	1.7	1.7	1.7	1.7	1.4

- **Smart meter rental fee**. This amount is around 1 to 2 €/month for small consumers (SM Type 5), but can reach 98 €/month for HV consumers (SM Types 1 and 2)[35].
- **VAT and other taxes**:
  - Municipal tax, applied only on the component related to the cost of electricity in the market and energy losses
  - Special tax on electricity, applied on top of the energy market price, the energy losses, and the components of the access tariff plus the municipal tax. This tax is included among the special taxes, which are regulated by law 38/1992, ever since 1997 (Law 66/1997). It is imposed on electricity consumption and its value is discretionally specified by law (since 1st January 2015 it amounts to 5.1127% of the total electricity bill, before VAT). Law 28/2014 of 27th November on Special Taxes allows industrial consumers whose electricity consumption purchases exceed 5% of their production value, or those whose electricity costs account for more than 50% of the overall cost of a product, to have their tax base for the Special Tax on Electricity reduced by 85%.
  - A VAT of 21% is applied on top of all price components and previous taxes.

[35] http://mifactura.es/nuestro-blog/65-el-contador-o-la-gran-caja-negra-del-sector-electrico

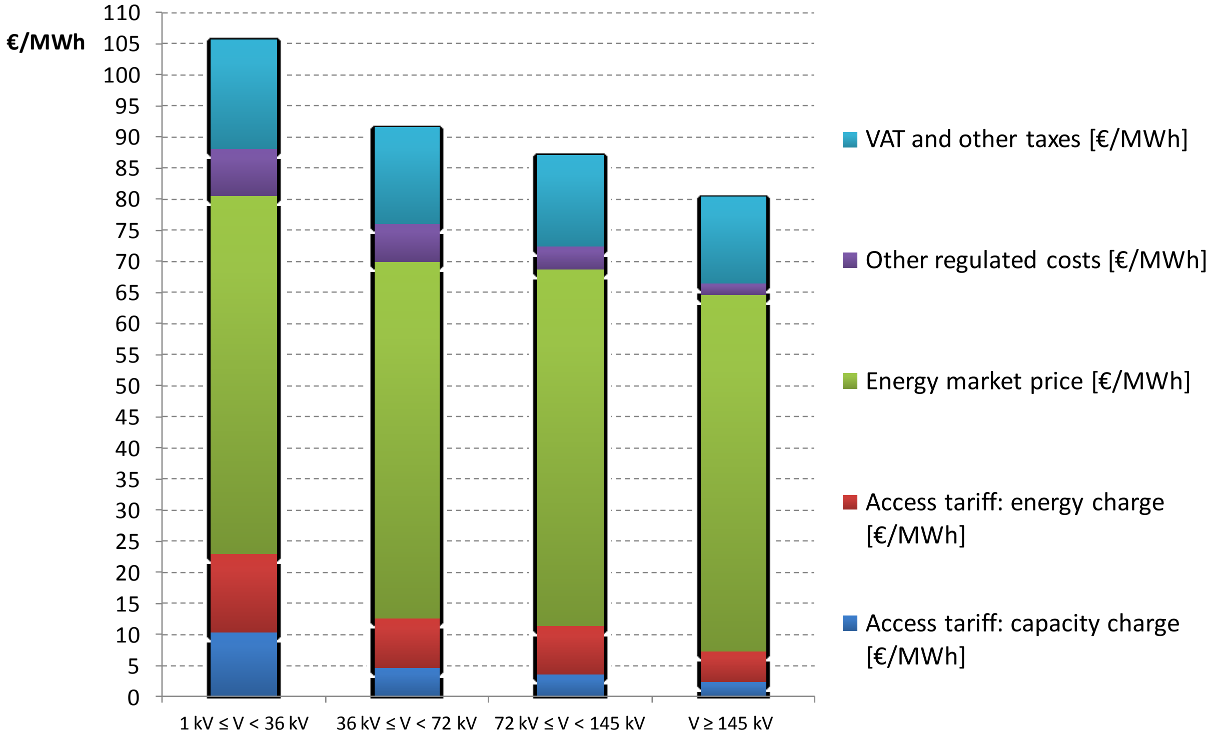


Figure 2.8. Final average electricity price breakdown for industrial consumers in Spain. Own elaboration based on information from OMIE (http://www.omie.es), CNMC (http://www.cnmc.es) and the Ministry of Industry, Energy and Tourism(http://www.minetur.gob.es/). Note: other regulated costs comprises the SM rental fee and the energy losses.

It can be noticed that the larger consumers, usually connected to higher voltage levels, apparently stand a better chance of getting lower prices because they have an easier and more direct access to the wholesale electricity market. The share of the regulated cost is lower and therefore, the opportunity of benefitting from energy market price variation is higher. In turn, there is a lower incentive for adjusting contracted power or time of consumption in relation to the access tariff.

.United Kingdom (Great Britain)

Network charging methodologies in Great Britain are completely different for transmission and for distribution connected parties.

The British wholesale market is characterized by a single national wholesale price which reflects the marginal cost that would prevail in a system without network congestion/constraints. Although there is non-locationally specific pricing, infrastructure costs are recovered through network tariffs called Transmission Network Use of System charges (TNUoS) that includes a location specific component. Given the dominant North to South power flows, network charges for generators vary from around £25/kW/yr in Northern Scotland to -£5/kW/yr in South West England, while network charges for demand customers, based on their peak demand, vary from £23/kW/Yr in North Scotland to £45/kW/yr in South West England.

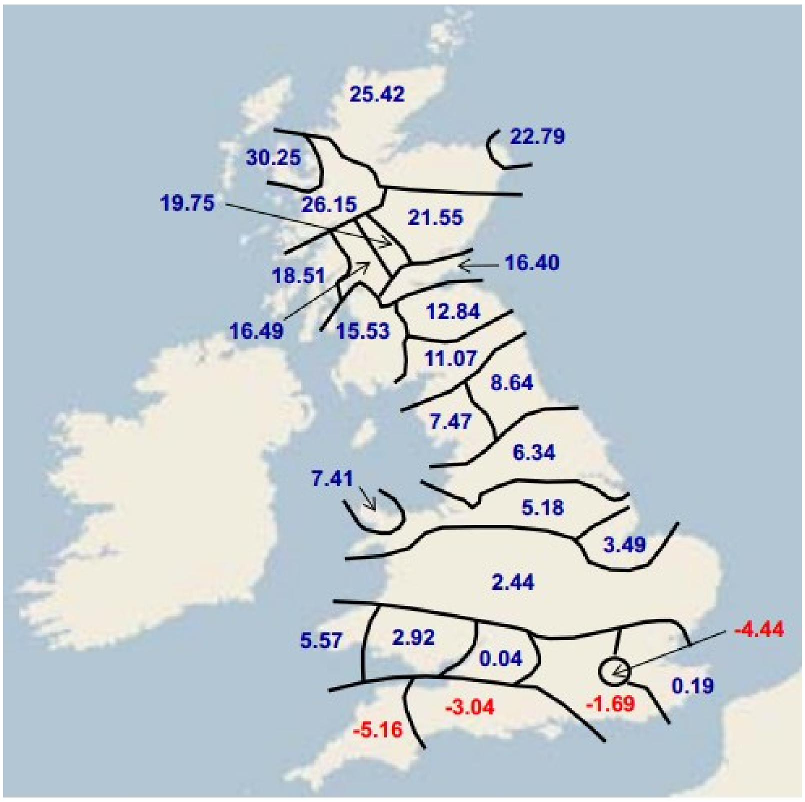


Figure 2.9. GB generation transmission tariffs £/kW/yr

For 2015/16 the total revenue collected will be £2,637m and it is expected to almost double by 2030. The cost is split 27/73 (the exact split is currently under review with proposals to review it annually or change the split to 15/85) between generation and demand and currently, the majority of transmission network costs (c. 75%) are collected through non-location specific flat charges (called residual charge) implying a high level of cost socialization. The locational part of the TNUoS tariffs is computed using a methodology, which intends to reflect the long run marginal costs of transmission investment. This part of the transmission tariff was recently reviewed through a regulatory project called TransmiT.

The capacity that is used to calculate transmission charges (for injection or withdrawal) is based on each parties position during peak demand period (in reality the average of the three highest demand periods is used). Consequently, parties and especially industrial consumers have very strong incentives to try to forecast peak demand periods and manage their injection/withdrawals during those hours (either by using on site generation or by reducing their consumption).

The Distribution Use of System (DUoS) tariffs are calculated using a combination of two charging methodologies. The first methodology is called the Common Distribution Charging

Methodology (CDCM) and it is used to calculate charges to users who are connected to the LV and HV levels of the network. The second methodology is the EHV Distribution Charging Methodology (EDCM) and it is used to calculate site specific charges to users who are connected to the EHV levels of the network.

Both the CDCM and EDCM are common charging methodologies that are used across Great Britain by all DNOs. The methodologies were developed through joint collaboration between DNOs and the regulator and industry stakeholders. While the methodologies are identical across all DNOs the inputs to the methodologies reflect the characteristics of the network and the number and characteristics of consumers in each DNO area.

3. Annex – Further details regarding wholesale energy markets

Wholesale price differences among coupled European power exchanges are particularly relevant in peripheral systems with limited interconnection capacities, such as Italy, Great Britain and Spain, in contrast to the continental interconnected systems, such as France, Belgium and Germany, as can be observed in Figure 3.1.

Figure 3.1: Comparison of average wholesale electricity baseload prices, first semester of 2014. Source: (EC, 2015).

Table 3.1 presents exemplary requirements for participation in different Belgian power exchanges.

Table 3.1 Exemplary requirements and charges in some European power exchanges

	Minimum volume	Charges
Belpex	0,1 MWh	12.500 € (subscr.) 12.500 €/y 0,20 €/MWh
Endex	1 MW	63 €/m 0,025 €/MWh

APX (NL)	0,1 MWh	5.000 € (subscr.) 28.500 €/y 0,02 – 0,08 €/MWh

Figure 3.2 and Figure 3.3 compare average wholesale electricity baseload prices in different regional markets in Europe.

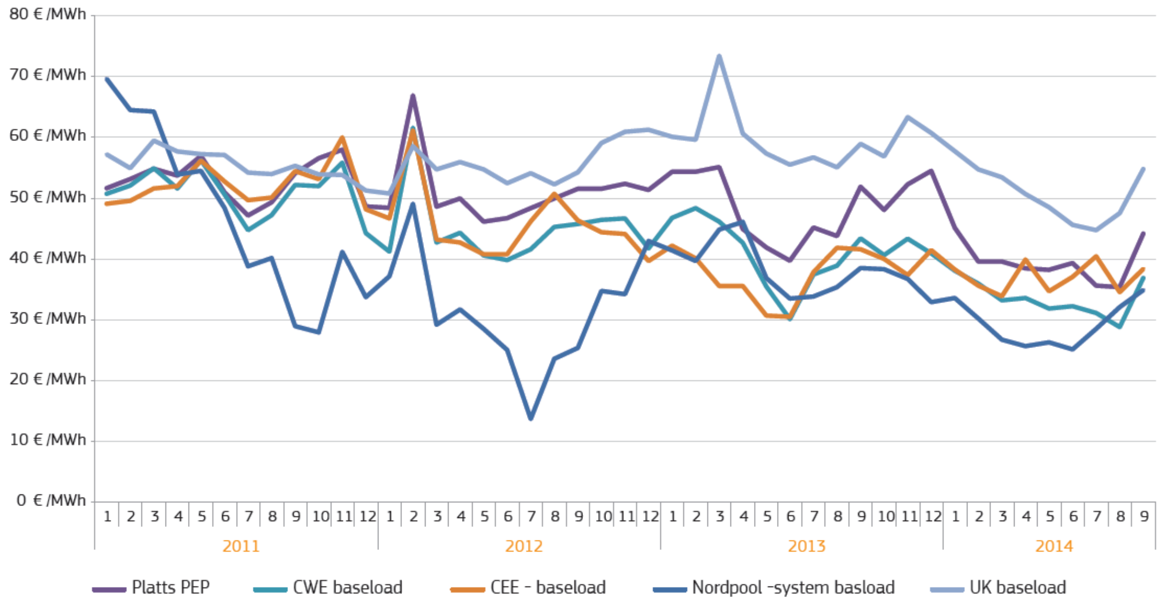


Figure 3.2: Comparison of average monthly wholesale electricity baseload prices in different regional markets in Europe (CWE, CEE, Nordpool and the UK). Source: (EC, 2015).

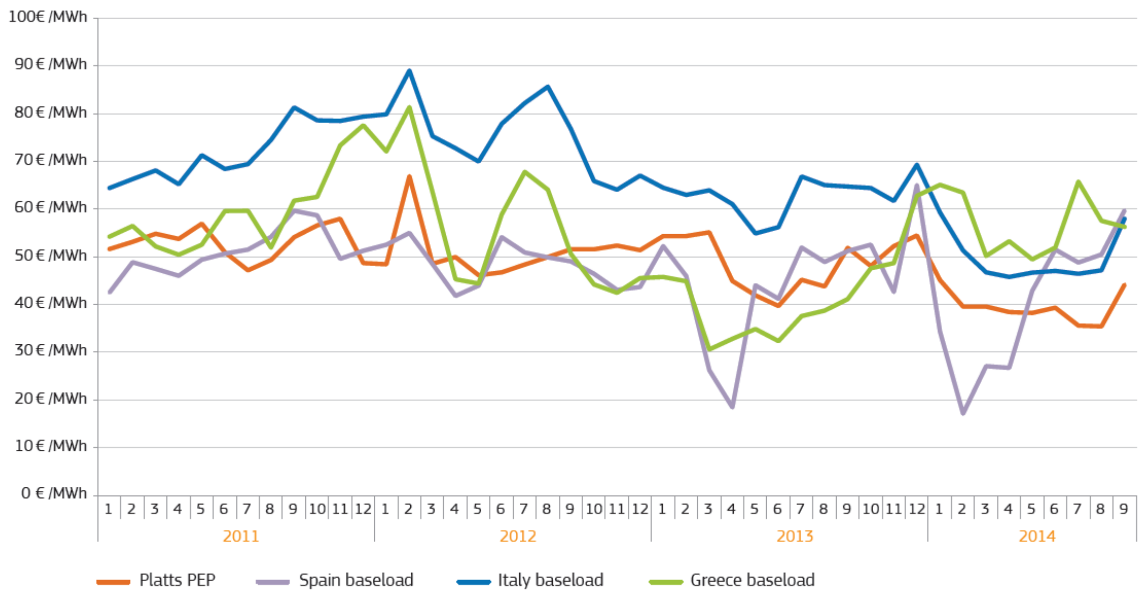


Figure 3.3: Comparison of average monthly wholesale electricity baseload prices in different regional markets in Europe (Italy, Spain and Greece). Source: (EC, 2015).

The following figures present average monthly traded volumes and prices that have occurred in the different power exchanges of the target countries.

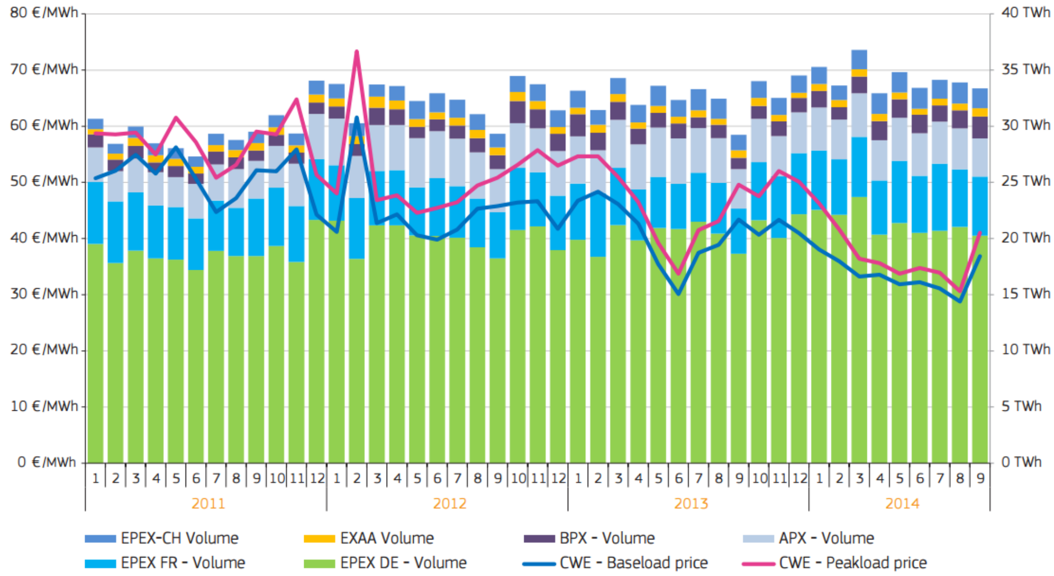


Figure 3.4. Monthly traded volumes and prices in Central Western Europe. Source: (EC, 2015).

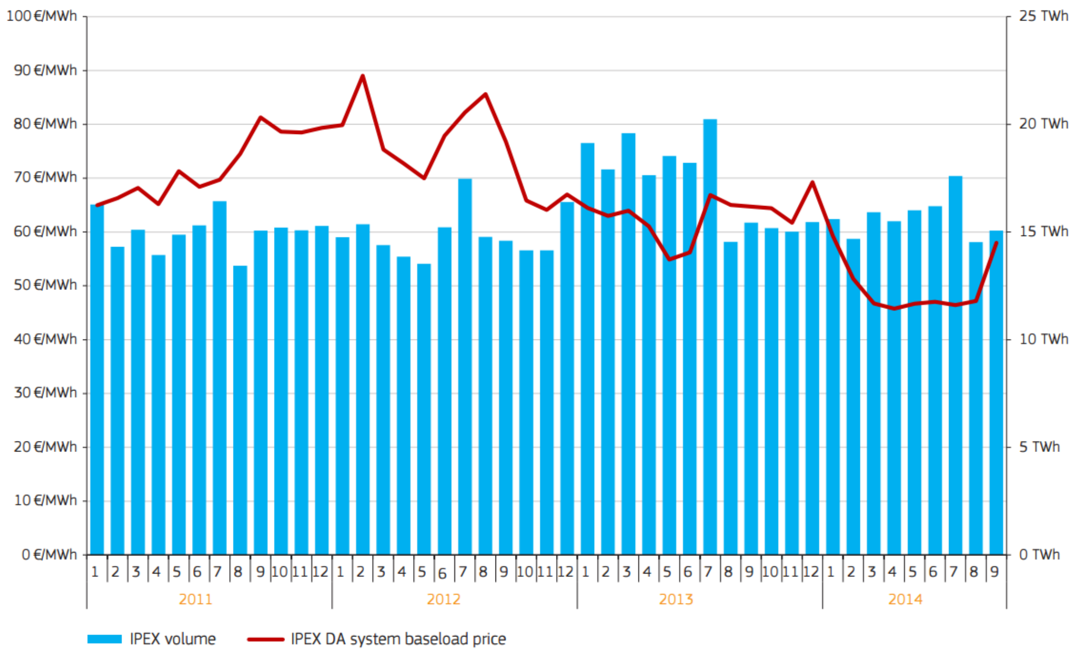


Figure 3.5. Monthly traded volumes and prices in Italy. Source: (EC, 2015).

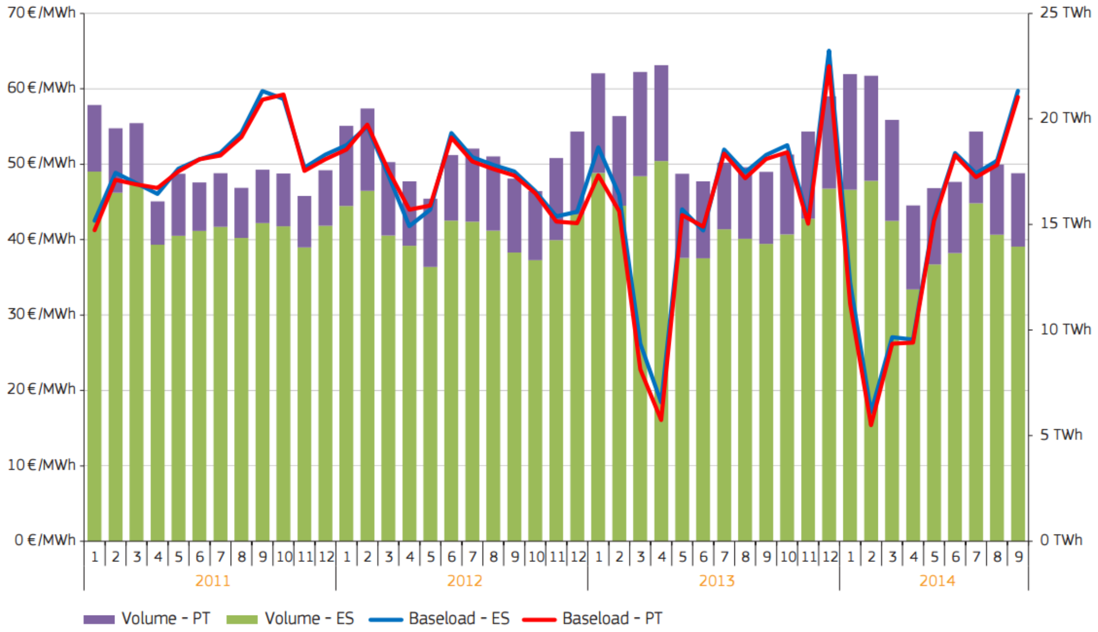


Figure 3.6. Monthly traded volumes and prices in the Iberian Peninsula. Source: (EC, 2015).

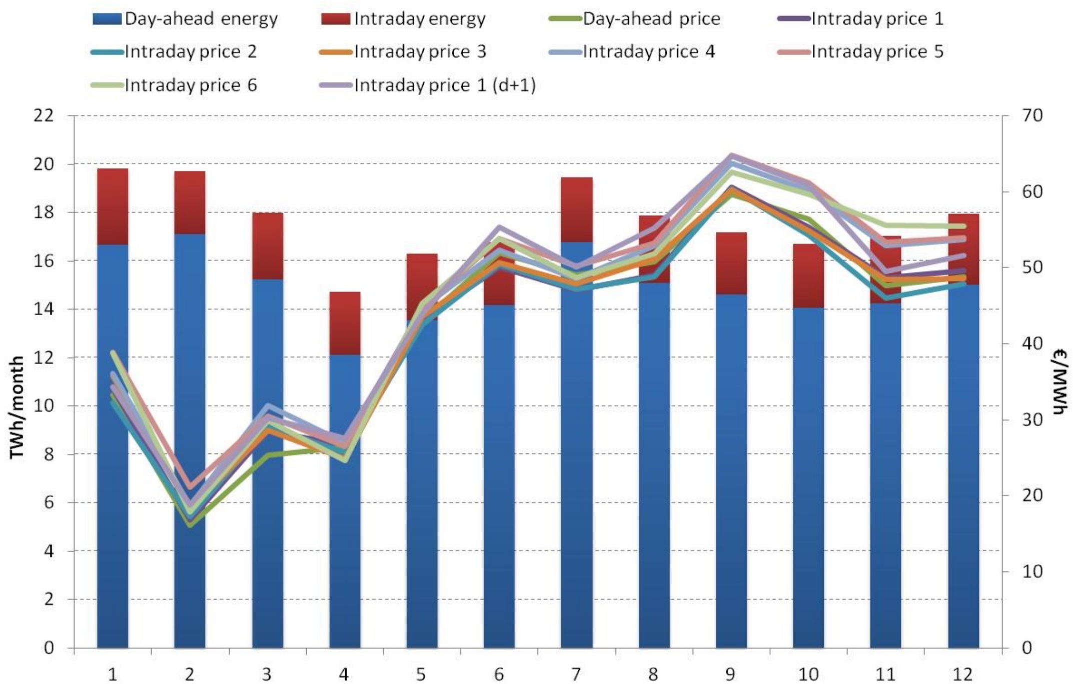


Figure 3.7. Average prices and yearly traded volumes in different intraday sessions and the day-ahead market in the Spanish-Portuguese market (OMIE). Source: http://www.omie.es.

4. Annex – Comparison of the basic characteristics of the balancing mechanism in different target countries

There are a number of different processes pursued by the TSO in order to ensure that it has sufficient resources to call upon to deliver Balancing Energy in real time. Notwithstanding, under certain market designs, balancing energy consists not only in energy activated under ancillary services (reserves) contracts but also energy provided directly to a specific Balancing Market or Balancing Mechanism.

The balancing market can be considered as that part of the overall electricity market that provides balancing services. A balancing market therefore consists of two important parts:

- All processes utilized by the TSO to procure Balancing Energy or reserving capacity (from which balancing energy could be activated), i.e. balancing services procurement, which defines the features of the procurement processes, e.g. the way of bidding, constraints/requirements on the balancing market participants, way of payment to the bidders, constraints on the TSOs, who makes the merit order and how it is constructed, etc.
- Imbalance settlement scheme[36], which allows costs borne by a TSO to be passed on to Balance Responsible Parties. A Balance Responsible Party is therefore responsible for the financial settlement of its imbalances.

Electricity balancing services comprise the procurement and settlement of the following operating reserves of active power, as defined by ENTSO-E and ACER (ACER, 2011; ENTSO-E, 2014): Frequency Containment Reserves, Frequency Restoration Reserves and Replacement Reserves. The definitions of FCR, FRR and RR should allow us to differentiate balancing services on the basis of activation time, time to full activation and the duration of the service. Figure 4.1 illustrates the main parameters that define the time for the activation of certain type of reserve capacity.

[36] The imbalance settlement does not balance the system but is an ex-post mechanism for defraying the costs of balancing and at the same time incentivizing good contracting and short term planning behavior on the part of Balance Responsible parties.

Therefore, imbalance settlement is an element apart from the balancing market and does not interfere with it. It can be seen as part of the wider trading arrangements rather than a part of the Balancing Market.

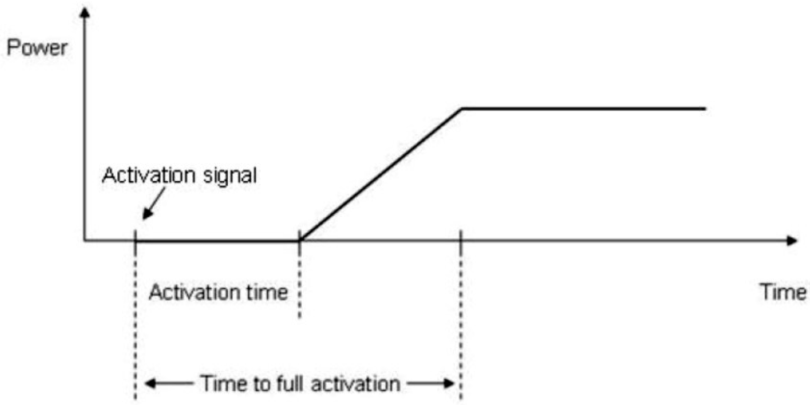


Figure 4.1. Parameters that characterize the timeframe of the operating reserve

• **Frequency Containment Reserves (FCR)** are operating reserves for constant containment of frequency deviations, or fluctuations, from nominal value in order to constantly maintain the power balance in the whole synchronously interconnected system. The activation of these reserves, which generally is automatic and local[37], results in a restored power balance at a frequency deviating from nominal value. The activation time is up to 30 seconds after the incident that initially caused the imbalance. This category of reserves was previously known as Primary Control Reserve, as in (Rebours et al., 2007a).

• **Frequency Restoration Reserves (FRR)** are used to restore frequency to the nominal value and power balance to the scheduled value after sudden system imbalance occurrence. This category includes operational reserves with an activation time from 30 seconds up to 15 minutes, depending on the specific requirements of the synchronous area. The activation of this category of reserves is done centrally. It is identified with the previously called Secondary Reserves, but it can be activated manually or automatically, in contrast to Secondary Reserves, which only included automatically-activated reserves.

• **Replacement Reserves (RR)** are used to restore the required level of operational reserves to be prepared for a further system imbalance. This category includes operational reserves with activation time from 15 minutes up to hours. It was previously described as Tertiary Control Reserves. This operating reserve generally makes it possible for TSOs to cope with significant and systematic imbalances in the control area and to resolve major congestion problems. It is the core of the balancing mechanism.

In some countries, **FRR** and **RR** may need to be broken down into a number of separate categories such as occurs in Iceland, Ireland or UK (slow and fast products, the slow one further differentiated into manual and automatic activation). Also a variety of RR products differentiated both by time to activate, duration of service and mode of activation.

[37] Traditionally provided by the fast and automatic response of governors built into generators.

Markets for ancillary services for reserves in most European countries trade capacity and energy, i.e. capacity availability and energy are remunerated separately. Under such schemes, the TSO is pre-contracting and paying for the availability of the reserves while the energy is remunerated upon utilization in real time.

In this context, the figure of the Balance Responsible Party (BRP) is very relevant. As defined in (Eurelectric, 2014), a BRP is any market participant that is responsible for the imbalances of a certain metering point. In principle, every network user connected to the grid is responsible for his individual balance. Depending on the market design, market agents may directly be balance responsible or they may outsource this task to a third-party BRP, so every network connection must fall under the portfolio of a BRP.

A variety of approaches are followed across Europe, as described in (Rebours et al., 2007b) and (ENTSO-E, 2015). The main design elements of balancing markets are:

• ***Procurement scheme***: different options depending on the product (energy or capacity), such as mandatory provision, organized markets or bilateral contracts.

• ***Product procured***: balancing capacity and/or balancing energy.

• ***Minimum bid size (in MW)*** that is allowed to participate in the mechanism.

• ***Product resolution (time)***: maximum resolution for which a product can be bid (e.g. 1 h in the case of 24 auctions day-ahead market for reserve provision).

• ***Gate-closure***: time at which bids are no longer accepted.

• ***Product differentiation (up/down)***: separate products for upward and downward or joint upward and downward ("band"), i.e. symmetric.

• ***Provider***: generators only or also pump storage units and/or load.

• ***Activation rule***: priority order for reserve activation.

• ***Activation time***: the minimum notice needed by a Balancing Market participant to deliver the power of its balance offer. It is the elapse time between automatic activation signal or manual order emission and the beginning of the energy delivery (ERGEG). It is different from the full activation or the total amount of balancing power, see Figure 4.1.

• ***Settlement rule***: remuneration rule applied to Balancing Service Providers (BSPs) for service provision, pricing rules for the settlement – marginal pricing, pay as bid, regulated price.

• ***Cost Recovery Scheme***: from whom the costs are recovered. It could be either a) Balancing responsible party or its chosen representative responsible for its imbalances or b) the grid user, the natural or legal person supplying to, or being supplied with active power by the TSO.

• ***Monitoring***: the type of monitoring in place by the system operator to ensure performance of the plant, which could be ex-post check, real time monitoring or a hybrid of both.

The purpose of this sub-chapter is to focus on the balancing mechanism and ancillary services mechanisms for the provision of active power reserves and the activation of those reserves under the framework of the balancing mechanism that exists in the countries under study. Of great relevance are the preconditions for the provision of balancing services, which have a relevant impact on the feasibility of those business models that rely on the participation of the demand side in the balancing mechanism.

A survey that can be found in (ENTSO-E, 2015) complies information about the different approaches to ancillary services procurement and Balancing market design across Europe and monitors the implementation of the Network code on Electricity Balancing (NC EB), as updated in November 2014. Further information is available from the corresponding TSOs, as indicated below:

• There are four TSOs in Germany for different control zones: Tennet, Amprion, 50hertz and TransnetBW. Some information related to balancing is gathered in https://www.regelleistung.net/ip/action/static/prequal

• RTE is the only TSO in France, see http://www.rte-france.com/en/article/balancing-mechanism

• Terna is the Italian TSO, see http://www.terna.it/default/home_en/electric_system/transparency_report_en/balancing.aspx

• Elia is the TSO in Belgium, see http://www.elia.be/en/products-and-services/balance/balancing-mechanism

• In the UK there are three Transmission Owners (TOs) and one of them, National Grid also acts as the System Operator for the whole Great Britain and is responsible for ancillary services procurement as well as administering the balancing mechanism, see http://www2.nationalgrid.com/uk/services/balancing-services/

• Red Eléctrica de España (REE) is the TSO in Spain, see http://www.ree.es/es/actividades/balance-diario

In the first place, the general approach used for the balancing process can be, according to (ENTSO-E, 2014):

• ***Central dispatch***: dispatch arrangement in a Relevant Area where the TSO determines the commitment and output of a majority of generation or demand and issues instructions directly to them. This type of scheme is present in Italy.

• ***Self-dispatch – portfolio based***: a portfolio of units or generators (or other plant types) follow an aggregated schedule of actions to start/stop/increase output/decrease output in real time. This type of scheme is present in Germany.

• ***Self-dispatch – unit based***: generators (or other plant types) following their own schedules of actions to start/stop/increase output/decrease output in real time. This type of scheme is present in Spain, France, UK and Belgium.

The following tables present a comparison of the main features of the balancing mechanism of the IndustRE target countries, focusing on the provision and the activation of the different types of operating reserves that have already been described.

Table 4.1. Characteristics of the provision and use of Frequency Containment Reserves (FCR)

	Belgium	**France**	**Germany**	**Italy**	**Spain**	**UK**
Procurement scheme	Organized market + mandatory provision	Mandatory provision	Organized market	Mandatory provision without capacity reservation	Mandatory provision	Pre-contracted and mandatory offers
Procured product	Capacity	Capacity	Capacity	Energy	Capacity	Capacity
Minimum bid size (MW)	-	1 MW	2 MW	2 MW	10 MW	10 MW for generation and 3MW for demand management
Product resolution (in time)	Monthly	-	Weeks	-	-	Monthly tender
Gate closure	Monthly	-	Days	-	-	Weeks
Product differentiation (up/down)	Separated products	Symmetrical	Symmetrical	Symmetrical	Symmetrical	Separated products
Provider	Generators + pumping storage units + load	Generators + pumping storage units + load	Generators + pumping storage units + load	-	Generators	Generators + pumping storage units + load

	Belgium	**France**	**Germany**	**Italy**	**Spain**	**UK**
Activation rule	Automatic	Automatic		Automatic	Automatic	Automatic
Activation time	<30 s	<30 s	<30 s	<30 s	<30 s	<30s for generation and <2s for load
Capacity Settlement rule	Pay as bid	Regulated price	Pay as bid	Not remunerated	Not remunerated	Pay as bid
Cost recovery scheme	BRP + grid users	100% grid users	100% grid users	NA	NA	100% BRP
Monitoring	Ex-post check	Hybrid	Real time monitoring	Ex-post check	Ex-post check	Hybrid

Table 4.2. Characteristics of the provision and activation of Frequency Restoration Reserves (FRR)

	Belgium	**France**	**Germany**	**Italy**	**Spain**	**UK**
Procurement scheme	Organized market	Mandatory provision	Organized market	Mandatory offer (energy)	Organized market	Tender
Product procured	Capacity & Energy separately or both	Capacity & energy	Capacity (bids for energy prices)	Energy	Capacity	Availability, holding and utilization
Possible providers	Generators + pumping storage units	Generators + pumping storage units + load	Generators + pumping storage units + load	Generators only	Generators only	Generators + pumping storage units
Product differentiation (up/down)	Separated products (cap. & en.)	No (Symmetric)	Separated products		No (Symmetric)	Separated products
Gate closure for capacity bids	Month ahead		Last day of M-1		D-1 (<4pm)	Monthly
Capacity product resolution (time)	Monthly tendering		Month (monthly auction)		1 h (daily auction)	Half hour
Capacity minimum bid size (MW)	1 MW	1 MW	5 MW	10 MW	10 MW	50MW

	Belgium	**France**	**Germany**	**Italy**	**Spain**	**UK**
Capacity settlement rule	Pay as bid (capacity market)	Regulated price	Pay as bid (capacity price)		Marginal Price	Pay as bid
Gate closure for energy bids	D-1 (<6pm)		Same as capacity (price bids only)		-	1hour
Energy Product resolution (time)	15 min	30 min	Same as capacity	15 min	Same as capacity	30 min
Energy minimum bid size (MW)	<= 1 MW	<= 1 MW	5 M	<= 1 MW	No minimum bid size	1 MW<= x <= 5 MW
Activation rule	Pro-rata	Pro-rata	Merit order - Energy price bid	Pro-rata	Pro-rata	15 min
Activation time	30s, maximum volume at 7.5 min	<= 1 min	5 min full load; at least 1 MW in 30 s	h-1	30 s	<= 2min
Energy settlement rule	Based on day ahead offered prices with a price cap	Regulated price	Pay as bid (energy price)	Pay as bid	Marginal Price from RR bid ladder	Pay as bid
Cost recovery scheme	BRP +grid users	Grid users	Grid users (capacity), BRP (energy)	End consumers (Italy)	End consumers (capacity), BRP (energy)	BRP

	Belgium	**France**	**Germany**	**Italy**	**Spain**	**UK**
Monitoring	Ex-post	Hybrid	Real time	Real time	Real time	Hybrid

Table 4.3. Characteristics of the provision and activation of Replacement Reserves (RR)

	Belgium [a]	France	Germany	Italy	Spain	UK
Procurement scheme	Organized market	Bilateral contracts	Organized market		Mandatory offer	Organized market and bilateral
Product procured	Capacity & Energy separately or both		Capacity (bids for energy prices)		Energy	Capacity and Energy separately
Possible providers	(emergency) generators + load connected at TS and at DS level + turbo-jets + non-spinning units + power plants (>25 MW) + large wind farms + APP	Generators + pumping storage + load			Generators	All units including embedded generation and demand
Product differentiation (up/down)	Separated products (cap. & en.)		Separated products		Separated products	Same
Gate closure for capacity bids	Previous year, D-1		D-1 (<10 am)		D-1 (<11 pm)	3 annual tenders
Capacity product resolution (time)	Year (yearly auction), daily auction		4 h (daily auction)		-	3 annual tenders

	Belgium [a]	**France**	**Germany**	**Italy**	**Spain**	**UK**
Capacity minimum bid size (MW)	1 MW				-	3MW
Capacity settlement rule	Pay as bid (capacity market)		Pay-as bid (capacity market)		-	Pay-as bid (capacity market)
Gate closure for energy bids	D-1 (<14h)		Same as capacity		D-1 (<11 pm), updates until h-1	t-1h
Energy Product resolution (time)	15 min		Same as capacity		1 h	30min
Energy minimum bid size (MW)	1 MW	10 MW	5 MW	10 MW	10 MW	3MW
Activation rule	Energy price bid. Techno-economic merit order: Free bids (daily auction) R3 production (increase of generation) R3 DP (flexibility at distribution level) ICH (decrease of offtake)		Energy price bid		Energy price bid	Energy price bid
Activation time	15 min	15 min	15 min	15 min	15 min	20<t<240min
Energy settlement rule	Pay-as bid		Pay as bid		Marginal price	Pay-as bid

	Belgium [a]	France	Germany	Italy	Spain	UK
	(energy market)		(energy price)			(balancing mechanism)
Cost recovery scheme	BRP + grid users	BRP (capacity)			Grid users and BRP	BRP (capacity)
Monitoring		Hybrid			Ex-post	Hybrid

[a] For Belgium the TSO is designing a completely new bidding platform to restructure the tertiary reserves market. Within this market, totally different products will become available. At the time of writing this report, the date of implementation is not decide.

Other details: United Kingdom

A summary of the different types of balancing and ancillary services that can be provided by the demand side in the UK is provided below:

Frequency Control by Demand Management

- Minimum of 3MW but aggregation possible
- Available continuously for declared periods
- Demand reduction must take place within 2 seconds and be sustained for a minimum of 30 minutes

Short-Term Operating Reserve (STOR) - Reserve

- Offer a minimum of 3MW generation or steady demand reduction (aggregation is possible)
- Maximum response time of 240 minutes (typical contract for 20 minutes or less)
- Ability to deliver for a minimum of 120 minutes
- Have a recovery period after provision of reserve of not more than 1200 minutes
- Able to deliver at least 3 times per week (around 2800MW capacity contracted)

STOR Runaway - Reserve

- STOR for 2015/16 for which only demand side can participate (200MW) so as to incentivise new market participants

Demand Side Balancing Reserve

- Under DSBR large energy consumers will be paid to reduce their demand during winter weekday evenings (between 4pm and 8pm) in response to instructions from the SO. Half-hourly metered site
- Ability to reduce load at two hours' notice and to sustain load reduction for a minimum of two hours between 4pm and 8pm, non-holiday weekdays between November and February
- Capacity must be provided in 1MW tranches or smaller aggregated units.

Other details: Belgium

The variety of products in the Belgian context is further specified in the following tables.

Table 4.4. Characteristics of the balancing mechanisms for Belgium: provision of FCR (R1 and R2)

	Frequency Containment Reserves – R1	**Frequency Restoration Reserves – R2**
Procurement scheme	Organized market + mandatory provision	Organized market
Product	Capacity	Capacity and energy
Possible providers	Load + generators + pumping storage units	Generators + pumping storage units
Product resolution	Monthly tendering	Capacity: monthly tendering Energy: free bids day ahead

Activation time	Max reaction for complete activation: < 30 sec. Min activation time: 15 min	Max reaction time from 0MW to maximum up or down: 7,5 min.

Table 4.5. Characteristics of the balancing mechanisms for Belgium: provision of FRR (R3)

	ICH **Interruptible load**	**R3DP** **Dynamic profile**	**SR** **Strategic reserves**	**R3 Prod**	**CIPU free bids**
Reaction time	3 min	15 min	1,5 h	15 min	15 min
Duration + number activations	2 / 4 / 8 h 12 / 4 / 4 times	2 h 40 times	4 / 12 h 40 / 20 times	No limit	Depending on nomination
Product	Capacity and energy	Capacity	Capacity and energy	Capacity and energy	Energy
Possible providers	TSO connected load	DSO connected load/generation	TSO connected load/generation	Non-spinning units	Generators + large wind farms
Product resolution	Yearly tendering	Yearly tendering	Yearly tendering	Yearly tendering	Free bids day ahead
Volume	261 MW	100 MW	850 MW	300 MW	

5. Annex – Regulation of renewable energy generation

The aim of this chapter is to examine the regulatory treatment of variable renewable energy (VRE) generation in each country, in relation to:

- Support schemes
- Grid issues (connection schemes, net metering, charges, etc.).

The purpose of this analysis is to understand the available options and the incentives for carrying out investments in VRE generation that could be useful for industrial consumers or VRE operators to jointly manage flexible consumption and variable generation, either on-site or separately. It is also important to evaluate whether VRE operators would deem it necessary to count on additional sources of profitability other than the existing support scheme, which could pave the way for the need for new business models possibly involving FID. In this sense, the conditions for connecting to the grid (bearing reinforcement costs, need for remote controllability, etc.), the existing support schemes to capacity or energy from VRE, the possibilities of netting demand ('behind the meter') are relevant aspects to explore.

5.1 VRE support schemes

In general, support schemes can be distinguished based on the following criteria:

- Whether the regulatory intervention acts on the price or the remuneration, or on the target installed capacity or generated energy.
- Whether the support is given at the beginning of the investment phase over the installed capacity or later on over the energy that is effectively generated.

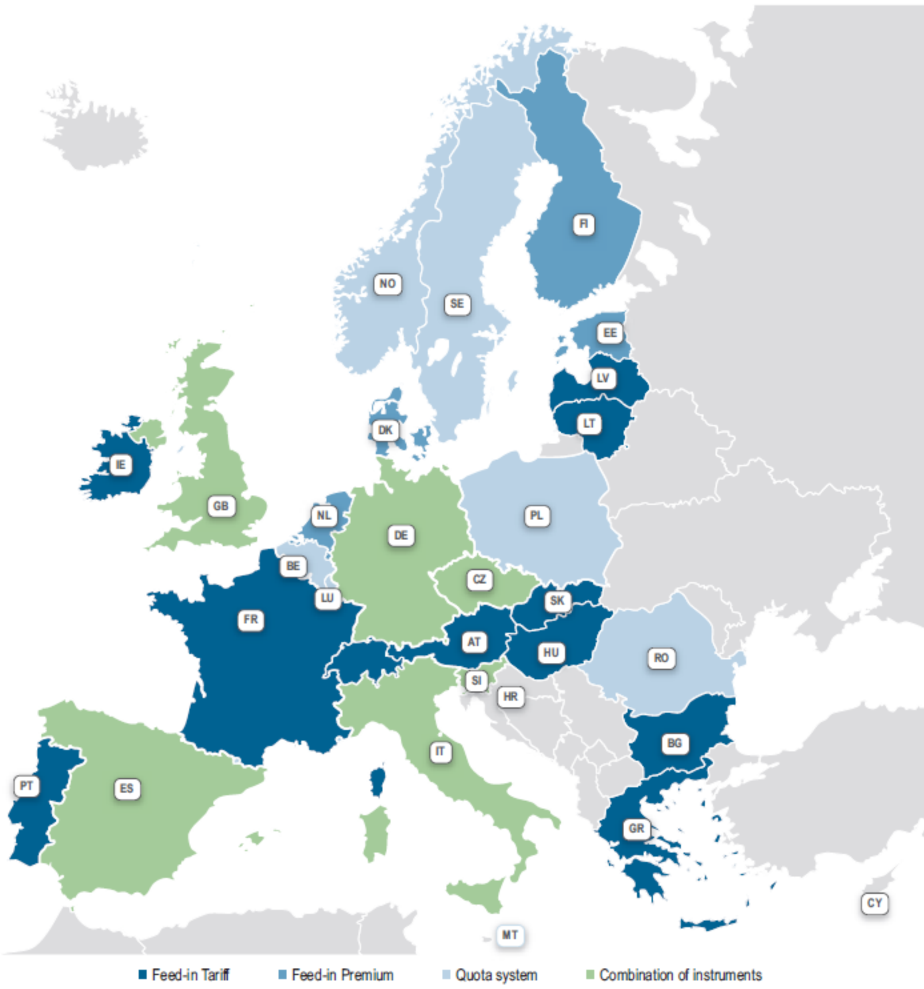
This way support schemes could be grouped in two categories, as shown in Table 5.1: price regulation and quantity regulation. Price regulation consists of fixing the value of the subsidy in relation to installed capacity or generated energy, so the final installed capacity is not known ex-ante but led to operators to decide. Alternatively, through quantity regulation, the regulator can prefer to establish a target of installed capacity or energy production, leaving the determination of price or subsidy to a market mechanism.

Support schemes based on energy produced, in particular Feed-in tariffs and green certificates, are the most commonly used across Europe, especially for wind power.

FIT for wind power: Spain (currently derogated) and France.

Green certificates for wind energy: UK, and Belgium.

Combination of instruments: Germany and Italy.



Source: RES Legal (2014), available on: http://www.res-legal.eu

Note: The map shows the main support instrument in each member state based on three general categories and a combination of these three. Tax incentives, loans and other forms of support measures are not included in the map.

Figure 5.1: Overview of the main RES support schemes across Europe, from (ACER/CEER, 2014).

Table 5.1 Main categories of RES support schemes.

	Price regulation	Quantity regulation
Capacity-based	Subsidies to investments, tax discounts	Auction
Generation-based	Fixed tariffs or premiums on top of the wholesale market price (Feed-in-tariff – FIT – and feed-in-premium – FIP, respectively)	Compulsory shares (quotas) of RES for generators and green certificates (GC)

.Belgium

In Belgium, electricity from renewable sources is promoted mainly through a quota system based on the trade of certificates. At both federal level and the levels of the three Belgian regions (Brussels-Capital Region, Flanders and Wallonia) support schemes for RES have been developed requiring transmission and distribution system operators to purchase green energy certificates or Combined Heat and Power Certificates (CHPCs) at a guaranteed minimum price.

At the federal level the Royal Decree of 21 December 2012 on the mechanisms to promote RE generation prescribes that Elia is required to buy back green certificates from generators of renewable energy connected to the transmission grid in Belgium. Offshore wind farms, photovoltaic facilities commissioned before 1 August 2012 and facilities that use water or tidal energy to generate electricity are entitled to receive this support. This federal support mechanism is valid for 10 years after the facility is commissioned, and green certificates are issued by CREG or the regional regulators.

Within the Flemish region, on a generators request Grid operators must buy the green certificates from generators connected to their grid or to the closed distribution systems connected to their grid. The Flemish support scheme for RES experienced a systematic reduction of support. The minimum support that is laid down depends on the energy source and generation technology that are used and the date of commissioning. The date of commissioning also determines how long this support is provided for. See the following tables for further details. Currently, for RE installations commissioned from July 1, 2014, the minimum support is a green certificate of 93 euro, valid for 15 years. For one green certificate at least 1000 kWh of electricity must be generated.

Table 5.2: RE installations with a capacity of up to 250 kW

Date commissioning	Minimum support	Duration
2006-2009	450 euro	20 years
2010	350 euro	20 years
Jan. – June 2011	330 euro	20 years
July – Sept. 2011	300 euro	20 years
Oct. – Dec. 2011	270 euro	20 years
Jan – March 2012	250 euro	20 years
April – June 2012	230 euro	20 years

July 2012	210 euro	20 years
Aug. – Dec. 2012	90 euro	10 years

Table 5.3: RE installations with a capacity over 250 kW

Date commissioning	Minimum support	Duration
2006-2009	450 euro	20 years
2010	350 euro	20 years
Jan. – June 2011	330 euro	20 years
July – Sept. 2011	240 euro	20 years
Oct. – Dec. 2011	150 euro	20 years
Jan – July 2012	90 euro	20 years
Aug. – Dec. 2012	90 euro	10 years

(Source: VREG, http://www.vreg.be/nl/bedrag-minimumsteun-voor-2013)

For the Walloon region, following Article 40 of the Decree on the Organisation of the Electricity Market and Article 24 quinquies of the Decree of the Walloon Government of 30 November 2006 on Support for Renewable Energy and Combined Heat and Power Generation, each renewable-energy or combined heat and power (CHP) generator can sell to the operator of the local transmission system, directly at a guaranteed minimum price, some or all of the green certificates awarded to them. The price of the green certificates which the local transmission system operator is required to buy is set at €65 (Decree of the Walloon Government of 20 December 2007, Article 35).

The support scheme issued in the Brussels Capital Region is similar to Wallonia, but of course the legal basis is different.

.France

Electricity from RES is promoted through a feed-in tariff scheme. Each technology has a different remuneration amount depending on the investment and the operation costs. Entities that are eligible for this remuneration scheme are renewable energy installations that have a maximum installed capacity of 12 MW or are located in a wind development area. CHP plants with a capacity larger than 2 MW can also benefit from this scheme.

Furthermore, tax regulation mechanisms such as tax incentives or VAT reduction in PV installations on building are implemented in order to encourage investments in renewable energy generation. In addition, plant operators may receive a premium, which depends on the amount of electricity exported and is intended to reflect the degree to which this electricity helped achieve the national energy targets (art. 5 and 10 Loi n°2000-108).

The allocation of the costs that arise from this support scheme falls on the end consumers, who defray the feed-in tariff for RES generation. End consumers are obligated to pay the "Contribution au service public de l'electricité" (CSPE) in the energy bill, which covers the additional costs of the renewable subsidies.

.Germany

In Germany, the EEG 2014 now combines several instruments. With the market-premium, i.e. a technology-specific premium paid to renewable energy producers on top of an average market price, a generation-based price-regulation is in place[38]For small installations, feed-in tariffs are still available, though.[39]

However, Germany also started auctions for PV free field installations, which are capacity-based and shall deliver a certain amount of new capacity over a certain time frame[40].

Further, and as German law provides that electricity supported by the EEG cannot be sold as renewable electricity but only as grey electricity of unknown origin, the EEG allows producers not to participate in the support scheme but directly sell their electricity as renewable electricity at those prices which electricity suppliers are willing to pay[41] . In this scenario, guarantees of origin can be used to proof the renewable quality of the product sold.

In addition, certain investment subsidies or tax reductions may apply under different funding programs both on federal as on Länder level may be available.

.Italy

Incentives for production from RES-E differ in Italy between solar and wind, and within each category, on the basis of the year of first production and size of plants. In summary: for solar plants, from 2005 to end of 2012, five different feed-in premium programs for solar plants have followed one another, while since 2013 the FIP has been replaced by a system of feed-

[38] Compare § 34 EEG.

[39] § 37 EEG.

[40] § 55 EEG; PV-Freiflächenverordnung

[41] § 20 EEG, § 80 EEG

in tariffs plus a premium on the amount of energy that is self-consumed. The regulation that has established such a change (DM 06 July 2012) set up a cap for total amount of incentives beyond which no further incentives were allowed (6.7 Billion Euros), that was reached in July 2013. Therefore, no new incentives are foreseen for solar plants.

From 2005 to 2012 Wind and other renewable plants (such as biomass) have been supported by Green certificates. The decree of 06 July 2012 has established also new another regulation for wind and other renewable energy sources except solar ones. In particular it introduced auction downward for wind plants over a defined threshold (5 MW for wind), registration and feed in tariff to a limited power supported per year for medium size plants (between 60 kW and 5 MW for wind), and free access to fixed feed in Tariff for smaller plants (under 60 kW for Wind).

As green certificates will disappear after 2015, plant operators that already were under the previous support scheme (green certificates) will receive, from 2016 on, a feed in premium of about 78% of previous incentive mechanism, till the end of plant's incentive period.

However in the same regulation DM 6 July 2012 the Italian Government has fixed an overall cap of 5.8 Billion Euros per Year which cannot be overpasses by the sum of all incentives for all Renewable energy plants, solar excluded.

In June 2015, GSE (which monitors incentives in Italy) have declared that 5.7 Billion Euros have been reached, being very close to the limit. Therefore is urgent a new regulation from the Italian Ministries (at present under discussion) to avoid a stop of new investments in the renewable sector.

A further instrument adopted to promote VRE especially in the cases where it is connected in the same area with private consumption units is a subsidy regime called "Scambio sul posto" (Exchange of energy on site) adopted with the deliberation AEEGSI 570/2012. With this regime the owner of a VRE plant and a consumption unit receives a compensation for the difference between the value of energy produced and fed into the network and the value of energy withdrawn from the network and consumed in a different period following production. "Scambio sul posto" is not compatible with other forms of incentives.

Moreover, Italy has adopted the 2006/32/CE European directive with DL 115/08, Law 99/09, and finally Law 116/2014 regarding efficiency in final uses of energy. The AEEG (Italian Regulatory Authority) with the deliberation 578/2013 has defined rules for connection of "SEU" (User's Efficient System) to the national grid referring to cases of production and consumption in the same area. Those systems that meet the criteria of SEU can benefit of reduced taxes on some components of the energy tariffs included in the energy bill. The SEU is compatible with the "scambio sul posto" mechanism.

.Spain

The main support scheme for energy sources classified as the former so-called "*Régimen Especial*" (Special Regime), among which renewable energy plants were included, was a price-regulation system. The choice could be made between a FIT and a FIP. This scheme was in force until the end of 2011, when it was suspended. It fostered a fast deployment of a vast amount of installed capacity of renewable energy plants, contributing to endanger the financial sustainability of the system due to the impossibility of recovering the costs incurred by the State from the support scheme through the access tariff as it was designed.

The price regulation system was phased out through Real Decreto-Ley 9/2013 with the aim of containing the public expenditure. Real Decreto-Ley 9/2013 provided for the exceptional existence of a specific remuneration scheme for generation from renewable, cogeneration and waste resources, which has been later defined in RD 413/2014, of 6th June 2014. This "Specific Scheme" is not technically defined as a support scheme but as a complementary remuneration to allow renewable technologies to compete with traditional technologies in the market. Renewable energy plant operators will be compensated on the basis of their installed capacity and the type of generation technology if the revenues from their expected participation in the market do not fulfil a reasonable profitability level. This reasonable profitability is estimated on the basis of the expected performance of standard well-managed installations, so as to provide RES operators with an equitable standard rate of return. On the basis of this, a plant receives the amount that its correspondent well-managed theoretical standard installation would receive (EC, 2012). Such standard remuneration parameters[42] are approved in Order IET/1045/2014[43].

Inscription in a benefit registry must be requested by plant operators and approved by the General Direction of Energy Policy. Plant operators that already were under the previous support scheme are automatically included in the registry for this remuneration scheme. Plants will continue benefitting from this scheme for the full of their "useful regulatory period", as defined for each type of installation in RD 413/2014. New plants will be able to enter this scheme through a competitive procedure.

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[42] Such parameters are independent of the technology and include: Return on investment, Return on operation, Incentive for investment due to the increase of the generation costs, Regulatory useful life, Minimum number of operating hours, Operation threshold, Maximum numbers of operating hours for the purpose of receiving the return on operation; Top and bottom limits of market prices, Average yearly price of daily and intra-daily markets.

[43] http://www.boe.es/boe/dias/2014/06/20/pdfs/BOE-A-2014-6495.pdf

.United Kingdom

In the UK, there are three support schemes for VREs. The first is the so called Renewable Obligation Certificates (ROCs) scheme, which was the main support scheme the past few years.

A ROC is the green certificate issued for eligible renewable electricity generated within the United Kingdom and supplied to customers in the United Kingdom by a licensed supplier. ROCs are issued by the regulator to accredited renewable generators.

The default is that one ROC is issued for each MWh of eligible renewable output. Some technologies get more, some less. For instance, offshore wind installations receive 2 ROCs per MWh onshore wind installations receive 0.9 ROCs per MWh and sewage gas-fired plants receive half a ROC per MWh.

Generators sell the ROCs to suppliers, which are required to meet a certain percentage of their total supply through the purchase of RES. ROCs are intended to create a market, and be traded at market prices that differ from the official buy-out price. If there is an excess of renewable production, beyond the supplier obligation, the price of ROCs would fall below the buy-out price. The price of ROCs could approach zero if renewable and non-renewable generation costs became similar, when there would be little or no subsidy for renewable generation. If there is less renewable production than the obligation, the price of ROCs would increase above the buy-out price, as purchasers anticipate later payments from the buy-out fund on each ROC. Obligation periods run for one year, beginning on 1 April and running to 31 March. Supply companies have until the 31 August following the period to submit sufficient ROCs to cover their obligation, or to submit sufficient payment to the buy-out fund to cover the shortfall. The cost of ROCs is effectively paid by electricity consumers of supply companies that fail to present sufficient ROCs, whilst reducing the cost to consumers of supply companies who submit large numbers of ROCs, assuming that all costs and savings are passed on to consumers.

As such, VREs under the ROC scheme receive the equivalent ROCs for their generation plus the energy price.

Obligation period	% of Supply	Buy Out Price (£/MWh)	Effective Price per Unit (p/kWh)
1 April 2002 to 31 March 2003	3.0	£30.00	0.09
1 April 2003 to 31 March 2004	4.3	£30.51	0.13
1 April 2004 to 31 March 2005	4.9	£31.39	0.15
1 April 2005 to 31 March 2006	5.5	£32.33	0.18

Obligation period	% of Supply	Buy Out Price (£/MWh)	Effective Price per Unit (p/kWh)
1 April 2006 to 31 March 2007	6.7	£33.24	0.22
1 April 2007 to 31 March 2008	7.9	£34.30	0.29
1 April 2008 to 31 March 2009	9.1	£35.76	0.33
1 April 2009 to 31 March 2010	9.7	£37.19	0.36
1 April 2010 to 31 March 2011	11.1	£36.99	0.41
1 April 2011 to 31 March 2012	12.4	£38.69	0.48
1 April 2012 to 31 March 2013	15.8	£40.71	0.64
1 April 2013 to 31 March 2014	20.6	£42.02	0.87
1 April 2014 to 31 March 2015	24.4	£43.30	1.06

The UK government has introduced wide-ranging reforms to the UK electricity market which will eventually see feed-in tariffs with contracts for difference (CfD) replace the Renewables Obligation as the main renewable generation support mechanism. Unlike ROCs, CfDs will also be available to generators of nuclear electricity. The Renewables Obligation will remain open to new generation until 31 March 2017, allowing new renewable generation that came online between 2014 (when the CfDs started) and 2017 to choose between CfDs and ROCs. After that date, the government intends to close the Renewables Obligation to new generation and 'vintage' existing ROCs, meaning that levels and length of support for existing participants in the Renewable Obligation will be maintained.

This implies that going forward the main support scheme for large scale VREs in the UK with be the CfDs, which are explained below.

A CfD is a private law contract between a low carbon electricity generator and a company, wholly owned by the UK Government. A new company has been incorporated to take on this role called the Low Carbon Contracts Company (LCCC). The LCCC is often referred to as the CfD Counterparty.

Under the CfD, a generator is entitled to be paid the difference between the strike price (a price for electricity reflecting the cost of investing in a particular generation technology) and a national electricity market Reference Price. The generator therefore receives revenue from two sources: from the sale of electricity in the market and from difference payments under the CfD. Support is available under a CfD for 15 years. The cost of CfDs will ultimately be met by consumers via a levy on electricity suppliers.

VREs are grouped in three technology groups for the purposes of CfDs; established, non-established and biomass conversion. The purpose of technology groups is that the strike prices are determined through technology group auctions, where VREs compete with each other by bidding different strike prices.

Established Technologies / Group 1	Less established Technologies / Group 2	Biomass conversion / Group 3
Onshore Wind (>5 MW)	Offshore Wind	Biomass conversion A separate group is needed as the scale of these projects may distort competition in Groups 1 and 2. This technology group will be subject to immediate competition.
Solar Photovoltaic (PV) (>5 MW	Wave	
Energy from Waste with CHP	Tidal Stream	
Hydro (>5 MW and <50 MW)	Advanced Conversion Technologies	
Landfill Gas	Anaerobic Digestion	
Sewage Gas	Dedicated biomass with combined heat and power	
	Geothermal	
	Scottish Island onshore wind projects (subject to state aid approval)	

The third type of support schemes for VREs in the UK is the small scale FiT, which is targeted to domestic installations and is administered by suppliers, by paying a fixed amount per MWh of domestic VREs production.

5.2 Grid issues

.Belgium

In Belgium, access of electricity from renewable energy sources is basically regulated by the general legislation on energy. Electricity from renewable energy sources is given priority in both connection to and use of the grid. Distribution grid operators are obliged to finance grid expansion. Renewable energy installations with an installed capacity below 10 kW can benefit from a net metering system. This system entails that the power generated by the green power plant is deducted from the electricity consumption. The amount of electricity produced is deducted directly from the general electricity bill. For RE with a capacity over 10 kW, a separate grid connection and production meter is required.

From July 2015 all grid users within the Flemish region, including owners of renewable energy installations where net metering is applicable, are required to pay a fair and reasonable compensation for the services provided by the distribution system. Therefore, a tariff for prosumers (consumers who generate their own power) was launched. This tariff differs depending on the relevant distribution network operator and the installed capacity. The greater the capacity, the greater the remuneration for the use of the distribution network. The tariff varies between 67 – 106 euro per kW installed capacity.

Owners of renewable energy installations with a capacity larger than 10 kW are not entitled to a net metering system. They are required to request a separate access point with the relevant DSO and must install a separate electricity meter for the purchase of electricity on the one hand and injection of electricity to the grid on the other hand. Furthermore, they are required to sign a contract with a balance responsible for their access point of injection.

.France

The use of the grid by RES is subject to the general legislation on energy. There are no special provisions for electricity from RES.

In relation to the connection to the grid, plant operators are obliged to bear all costs directly related to the connection of electricity generation plants (including renewable energy plants) (art 18 Loi 2000-108). The grid operator is obliged to grant access to the grid without discriminating against certain plant operators (art. L121-4 Code de l'énergie). Electricity from RES is not given priority of use.

RES generators may be shut down by request of the distribution grid operator under circumstances of full load or overload. The connection agreements specify the information on the shutdown of electricity units.

.Germany

Renewable energy producers have guaranteed rights to get connected to the grid and access the grid[44]. In case this should require grid expansion or improvement, the grid operator has to pay for such, while the renewable energy producers only pay for the mere

[44] §8 EEG

connection costs[45]. In case the relevant grid operator does not provide for the expansion or improvement, renewable energy producers may even be entitled to compensation[46].

In addition to this, renewable energy shall be granted priority take-off and dispatch, wherever this is technically feasible[47].

.Italy

Renewable energy plant operators have priority access, connection to and use of the grid.

If the connection of a renewable energy plant to the grid requires certain investments to improve security of Grid management (for instance adopting UPDM "Peripheral Unit Defence and Monitoring", or other monitoring systems, etc.), the operator of the plant is obliged to bear those costs.

A structural grid issue especially in South Italy is congestion of high voltage lines and insufficient network capacity that bring the TSO, TERNA, to apply significant curtailments to the power that renewable energy plants can feed into the Grid. While in the period between 2010 and 2013, the TSO has reduced those curtailments, in the last two year them have increased again.

The Italian regulation in case of curtailments defines that GSE evaluates expected power in those limited hours and pays the plant operator with day ahead zonal energy price, while green certificates associated to the missed production are not recognized.

VRE plants and in particular Wind energy plants are not asked nor paid by TSO to provide ancillary services in the Italian energy market.

.Spain

Renewable energy plant operators have priority access, connection to and use of the grid. The suspension and phase out of the support schemes for "*Régimen Especial*" in general, and RES in particular, does not interfere with the right and priority of access to the grid.

If the connection of a renewable energy plant to the grid requires certain investments to reinforce and extend the network, the operator of the plant is obliged to bear both costs (connection and possible expansion), i.e. to pay for "deep" connection charges.

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[45] Compare § 16 EEG; § 17 EEG

[46] §13 EEG

[47] §11 EEG

It is compulsory for renewable generation units of installed capacity above 10 MW to be connected to the network control centre CECRE. Net metering is not allowed; instead separate metering is required. Regulation of self-consumption is under discussion.

DSOs are not allowed to arrange commercial agreements with generators. TSOs can do so through the procurement of ancillary services.

RES generators may be curtailed by the TSO only after conventional generators have been curtailed wherever possible (art. 56, 65, 52 – 66bis RD 1995/2000). It is noticeable that at TSO level, some curtailments of VRE have been produced in the last years due to insufficient network capacity and congestions. In practice, wind farms are curtailed more often than other RES installations. Conventional energy has been re-dispatched to compensate for these curtailments, significantly increasing system operation costs. In addition to this, installed capacity has also been limited on certain occasions due to limited network capacity.

.United Kingdom

There is no priority access to the grid in the UK for VREs, however since all generators that pay their transmission charges have fully firm connections, this implies that VREs in case of congestion are compensated, through their participation in the balancing mechanism. Nonetheless, one might argue that there are significant reputational risks that VREs face when they are constrained off since this is perceived as being paid for not producing.

6. Annex - Participation and responsibilities of VRE in the energy markets and in the provision of balancing services

.Belgium

Elia already facilitates the participation of CHP units and wind energy to free bids, a product segment of the tertiary reserves. The fact that the granting of the GC's remains strictly bound to the actual energy produced, causes these bids to be placed at a negative price which takes into account inter alia the opportunity cost of lost GC's. Elia supports the obligation for RES (e.g. on- and off-shore wind production) to offer downward balancing power.

Furthermore, Elia is actively committed to the development of a transparent bidding platform as alternative for the current reserves market. The criteria for the submission of bids (e.g. Ramping rates and duration) will facilitate the participation of RES such as wind, biomass, CHP systems in offering flexibility. The Belgian TSO, Elia is involved in a technical pilot project aiming at integrating wind power in the portfolio of downward secondary reserves (R2) sources. As it is still in the testing phase, there is no commercial product yet. The pilot project concerns a wind farm with 11 wind turbines of 7,5 MW. The main challenges are the loss of green certificates, which is for the moment compensated by Elia, and the determination of the production of the wind turbine without curtailment.

An approved method is required to prove the delivery of control reserve. Within this respect the available active power (AAP) of wind farms plays an important role. A method for the exact estimation of the AAP is essential. First results of Elia's method to estimate in real-time the Available Active Power to deliver R2 are relatively positive.

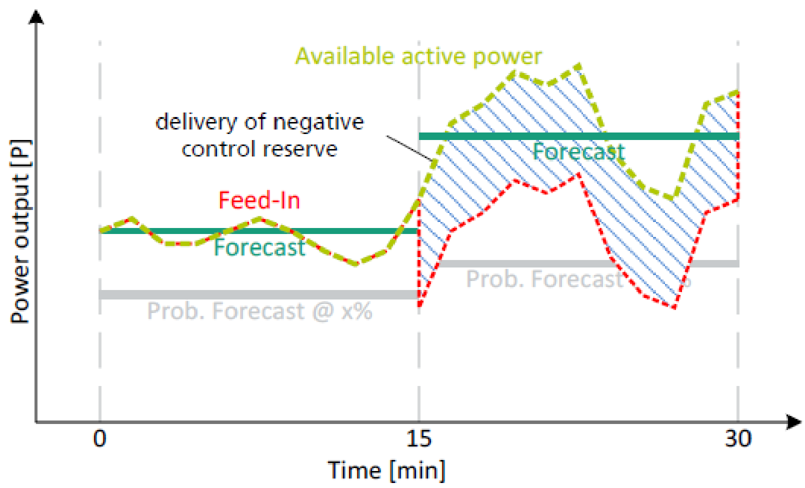


Figure 6.1: principle of available active power for wind power (source: PPT Elia task force balancing 20/11/2014)

The next steps in this process would be continuous testing under different scenarios to confirm preliminary results and start reflections on integration of wind farms in the current R2 market.

.France

Primary and secondary reserves are compulsory for conventional generators and the provision of this service remunerated. The balancing mechanism (tertiary reserve) in France operated by the French TSO, RTE, takes the form of permanent and transparent calls for tender. It is in principle open to everyone (competitive generators and certain loads) and provides real-time reserve of power that can be used for upward and downward balancing. Renewable energy plant operators are not entitled to offer these services and they do not participate in the wholesale market for energy like conventional generators.

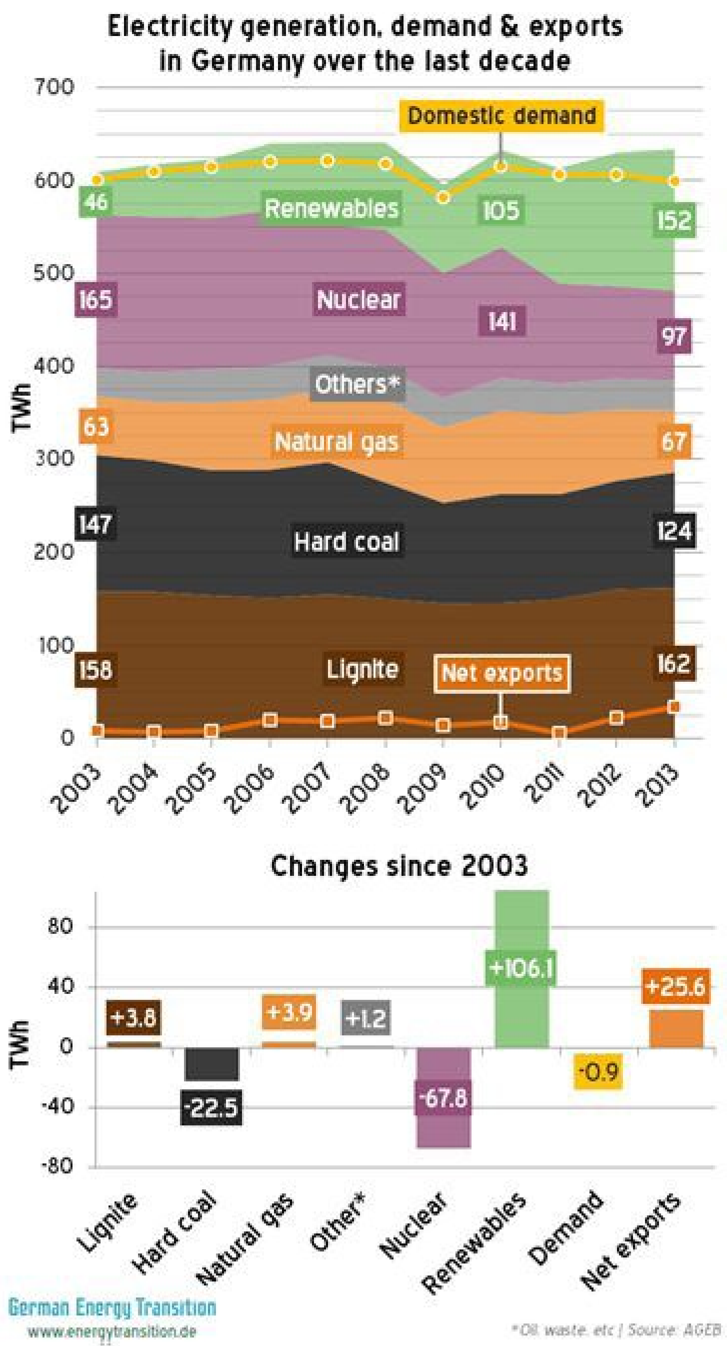
.Germany

The German electricity market is first of all marked by a fairly large number of power production units in comparison with other EU countries. As of 1st of June 2015, the German Power unit list ("Kraftwerksliste") of the Federal Grid Agency tabled production units with a net nominal power of in total 197.2 GW (excluding fully phased out units). From this amount 91,4 GW are from VRE and in total 86.8 GW are within the framework of application of the EEG .[48]

Those installations which have been phased out since 2011 are still registered in this list and amount to currently 7,2 GW.

The electricity market is organized via the wholesale level at the exchange, meaning for spot and future markets at the European Energy Exchange AG (EEX) respectively the European Power Exchange S.E. (EPEX), or off exchange via so-called "Over-the-Counter"-business (OTC). The price level at the exchange constitutes in principle the reference price for the OTC market. The fine tuning of output of the production units is used to optimize the results at the spot market exchange.

[48] See Inventory of German Electricity power plants by Federal Grid Agency: http://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/kraftwerksliste-node.html



As a rule only those production units are used whose marginal costs are below market price.

Under the market premium support scheme the renewable energy producers are - required to sell their production on the market[49] .

The new EEG 2014 tries to tackle the increasing occurrences of negative prices due to increased VRE in the system. From the 1.st of January 2016 on the EEG 2014 foresees in this § 24 EEG a reduction of support down to zero, if this renewable electricity was produced in a time frame, in which the prices on the spot market showed for six or more consecutive hours negative values. With such reduction in way of a “zero premium” the law intends to encourage the renewable operator, to stop their production in those time intervals.[50]

Such renewable energy producers are not excluded from balancing markets, but can, just as all other installations enter into respective contracts with the grid operators. Pooling capacities as e.g. in the form of Virtual Power Plants may help offer more interesting products.

However, small installations getting support in the form of fixed feed-in tariffs cannot participate in those markets[51].

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[49] Compare § 34

[50] For a first analysis on the effect of this new mechanism, see Energy Brainpool: Zukünftige Auswirkungen der Sechs-Stunden-Regelung gemäß § 24 EEG 2014-Kurzstudie im Auftrag des Bundesverbands WindEnergie e.V.,https://www.wind-energie.de/sites/default/files/download/publication/zukuenftige-auswirkungen-der-sechs-stunden-regelung-gemaess-ss-24-eeg-2014/2014-12-11_bwe_sechsstunden-regelung_energybrainpool.pdf

[51] § 39 par. 2 EEG

Further, for solar power plants with an installed capacity between 10kW and 1.000kW, an incentive to directly market their production or self-consume the electricity produced was introduced already in 2012: They will be paid the full support only for 90% of their production, for the rest, in case not marketed directly or self-consumed, they will get only a reference market value for solar power[52]. This model was however not kept in the new EEG 2014 and thus does not apply to new solar power plants.

In addition, renewable energy is always and as a rule granted priority take-off and dispatch, where this is technically feasible[53].

In Germany, every sixth company now generates its own electricity, roughly 50% more than in 2013. They range from rural family-owned companies to Dow Chemical Co, BASF, Bayer Leverkusen, automotive companies and so forth. About 16% of German companies were producing their own power by the middle 2014, according to the German Chamber of Commerce—up from about 10% a year earlier. A further 23% of companies are considering to shift to auto generation[54]

.Italy

The Italian energy market is divided in 22 market zones (of which 6 are “real” zones, called “geographic”, while the other are “virtual” zones, i.e., interconnection points with Foreign zones, main single production centres and external coupling zones); Wind energy plants are mainly concentrated in zones SUD and Sicilia.

Energy from VRE enters in the Italian energy market at price zero, therefore if the hourly energy demand in a specific region is fully covered by renewable energy the income for those hours is zero. In south Italy this scenario happened many times along the year and an increasing trend have been discovered since 2010 on going.

Imbalances produced by VRE plants in Italy are presently regulated under deliverable 522/2014 on the Italian authority AEEG. According to this deliberation, market agents are obliged to provide the best estimations of electric energy to be produced, even in the case of non-programmable plants, to guarantee safety and security of the system.

As a general principle, VRE are grouped in the category of plants that are not able to provide balancing services (called “unqualified plants”). The imbalances generated by these plants is penalized or rewarded on the basis of the principle that imbalances can provide a negative or a positive externality to the electric system by increasing or reducing the imbalance of

[52] § 33 EEG 2012

[53] § 11 EEG

[54] According to German Chamber of Commerce and Industry.

the zone in which they are producing. If, for instance, a “unqualified plants”, being it a VRE or not, generated in a given hour and zone an imbalance of opposite sign with respect to the net imbalance of its zone (for instance, the zone was short of energy and the VRE was overproducing), the production unit would receive a remuneration for its “service” depending on the average imbalance price (as determined in the balance market). If on the contrary the sign of the imbalance was the same of the zone (e.g., overproducing and a zone long of energy), it would have to pay the average imbalance price (for the whole energy it has imbalanced).

The new regulation allows VRE producers to choose (every year) whether to choose such a scheme for all their production or select a system of exemption threshold, differentiated according to the type of renewable energy, as follows:

- 49% for dispatching from wind plants;
- 31% for dispatching from PV;
- 8% for dispatching from run-away hydro;
- 8% from small plants;
- 1,5% from other sources (geothermal).

These are the thresholds (for each production unit in each zone and hour) below which the VRE would not be responsible for its own imbalance, paying (or receiving) the imbalance price, but just a reduced figure, which correspond to the net value of imbalances averaged out across all producers and technologies in that zone (and hour). In other words, under such a scheme VRE are made responsible only for the aggregated imbalances in their zone, regardless of the units and the technology that have made it. By distributing the cost of imbalances across all production units that have produced them, such a scheme disregards the fact that for instance Wind farms, due to wind variations, have great unpredictability especially at unit time as small as one hour.

.Spain

RES operators in Spain are no longer granted priority dispatch in the electricity markets, i.e. prior to electricity from conventional sources, but they generally offer at null prices so they are always dispatched provided the stability and security of the grid infrastructure can be maintained, see (EC, 2012). – Ley 24/2013 art. 26.2. Their revenues are exposed to market outcomes in addition to the specific support scheme, as described in Chapter 5.

During the validity of the “Régimen Especial”, renewable energy plan operators were not entitled to offer balancing reserves. However, the Spanish TSO has recently proposed a set of modifications[55] to the current network codes and operation procedures that regulate the balancing mechanism, which allow the participation of RES in balancing markets according to EU legislation.

Among other modifications, this proposed adaptation would end with the differentiation between renewable and other Special Regime generation from conventional generation. For instance, imbalances in different regulation areas would not be differentiated according to the origin (renewable and conventional).

Another amendment is the suppression of the requirement for RES offering operating reserves of a minimum sum of bids of 5 MW (it is kept at 10 MW). From the approval of these amendments on, VRE operators willing to offer ancillary services for balancing would have to pass a technical test, which is currently being defined and discussed by regulators and the TSO, to qualify to provide the service

In addition to this, in the event of bidding blocks of similar price, priority would be given to renewable energy generation in the direction that the volume of renewable energy increases (or is not reduced).

.United Kingdom

Grid connected VREs are fully participating in the energy market and have full balancing responsibility and thus facing imbalance charges under both the ROC and CfD FiT subsidy schemes. For this reason, independent VREs tend to enter long term Power Purchase Agreements (PPAs) with integrated utilities, which purchase all the output of VREs at a discount to their subsidized prices, reflecting the cost of balancing (plus a profit margin) that VREs are taking on.

Participation in balancing and ancillary services markets is also possible, however due to the intermittent nature of VREs it is usually not possible to meet the technical specifications of ancillary services on a stand-alone basis, but might be possible as part of a portfolio of a utility.

[55] See proposal of 16/03/2015, http://www.esios.ree.es/web-publica/ > Documentación > Propuestas de P.O.: "Propuestas de Adaptación de los Procedimientos de Operación 3.2, 3.3, 3.7, 3.8, 7.2, 14.4 y 14.8 a la Ley24/013 y al Real-Decreto de 26 de junio, por el que se regula la actividad de producción de energía eléctrica a partir de fuentes de energía renovables, cogeneración y residuos".

7. Annex - Congestion management and emergency services for TSO with explicit participation of the demand side

Flexible load is allowed to provide certain active power reserves and balancing energy in some countries (see Annex 1). Notwithstanding, the major contribution of flexible industrial demand to the operation of the system generally consists of some type of interruptible service by which the TSO procures available capacity for load interruptions for emergency situations, as a form of fast reaction active power reserve.

This section describes some of those mechanisms that currently exist in the target countries with direct and explicit participation of the demand side in the operation of the transmission system, mostly involving energy intensive consumers such as large industries.

.Belgium

In case of congestion problems on the high-voltage grid the interruptibility service is called upon by Elia, the Belgian TSO. The interruptibility contracts comprise one of the two facets of the Belgian tertiary reserves. In order to participate, a transmission grid user must agree to interrupt part of his off take. The reduction of the amount drawn from the transmission grid must reach a contractually agreed level. This contractual limit is called the 'shedding limit'.

A grid user providing the interruptibility service offers the TSO, Elia, an average annual power reserve, in the contract referred to as the 'reference power reserve'. The power reserve really made available by the grid user is determined by evaluating the difference, if positive between the reference power of the industrial unit subject to interruptibility and the shedding limit stipulated in the contract. In other words, all power not taken off and consumed by the grid user is made available to Elia. There is a stipulated minimum volume for the reserve power: it must be at least 5 MW per tariff period, otherwise the grid user cannot offer this service.

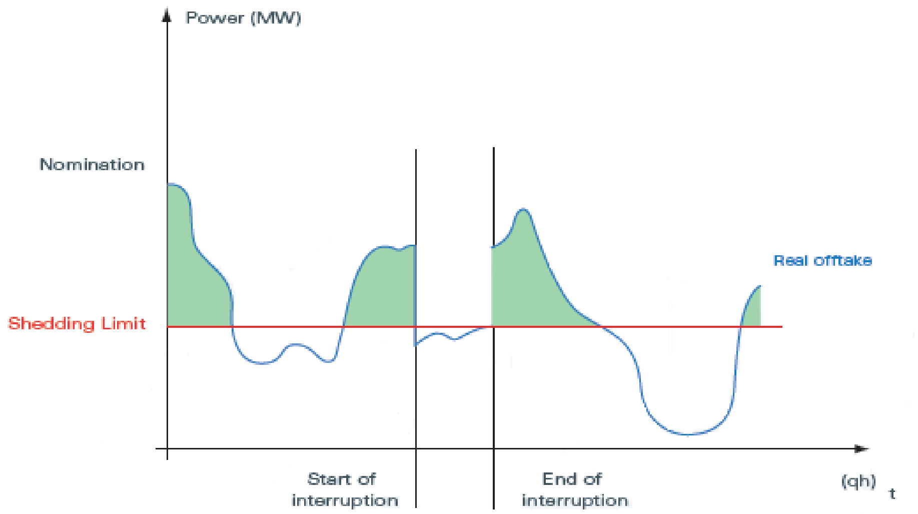

Figure 7.1: Principles of the interrupltibility contracts by Elia (Source: Elia product sheets)

When Elia decides the interruptibility service must be activated, a device located in the grid user's process is remotely controlled activated. When this signal is received, the grid user's offtake must drop below the shedding limit within 3 minutes of Elia's request.

The interruptibility service is subject to certain conditions:

- Elia may activate the interruptibility service no more than four times per year;
- there must be at least 24 hours between two interruptions;
- the total duration of periods of unavailability, i.e. the length of time during which the grid user cannot provide this service, is specified in the contract.

There are two different versions of the interruptibility service: the A4 service in which the maximum duration of interruption requested by Elia is 4 hours, and the total duration of interruption over the contractual period is limited to 16 hours, and the A8 service in which the maximum duration of interruption requested by Elia is 8 hours, and the total duration of interruptions over the contractual period is limited to 24 hours. Note that there is never any prior warning before Elia activates the interruptibility service.

Elia pays two kinds of remuneration to grid users who provide the interruptibility service. At first a payment is foreseen for providing the reserve. Even if Elia does not request the activation of the interruptibility service, it still pays those grid users with whom it has signed an interruptibility contract. However, payment for provision of reserve only covers those periods during which the service is actually available to Elia. Elia has defined distinct tariff periods (e.g. peak, off peak and weekend hours). The Payment for provision of reserve is made via a system of monthly advances. Elia settles up at the end of the contract.

Secondly, the payment due for activating the interruptibility service is based upon the quarter-hourly activation price and the quarter-hourly values measuring the interruption. The activation price is linked to the bid prices for upward activation selected by Elia. The minimum payment for activation amounts to €75 per MWh. The assessment of the volume of interrupted energy during each quarter hour is based upon the nomination and the actual power taken from the grid.

.France

Since 2003, load shedding capacity can participate in the balancing mechanism. The load shedding mechanism consists of cancelling or postponing consumption according to a signal. Industrial and aggregation of load distributed load shedding can participate in this mechanism. The TSO procures the balancing services through different calls for tenders, where industrial customers or distributed load shedding submit their capacities offers. Providers of this service commit to offer their flexibility and shed or shift loads if TSO requires it, and being remunerated for it. For instance, in 2014, the available capacity provided through load shedding was up to 1200 MW.

Different programs are available related to demand side participation. The "Appel d'offres effacement"[56] mechanism allows the French TSO to dispose demand capacity within two hours. Interruptibility programs for large consumers (above 60MW) are implemented to decrease electricity demand thereof within 5 seconds.

Moreover, the NEBEF ("Notification d'Echange de Blocs d'Effacement") mechanism establishes demand reduction from end consumers or third parties on the day-ahead market. The TSO is carrying out measures to open up the provision of balncing services to the demand-side.

.Germany

Balancing is done by the grid operators in Germany, both on distribution and transmission grid level. Each grid operator is thereby in charge of the respective own territory and responsibility. Since there are four transmission grid operators in Germany, some coordination is needed.

Since 2001, the four TSOs have been procuring their required primary control reserve, secondary control reserve as well as minute reserve on an open, transparent and non-discriminatory market for control reserve according to the guidelines of the Federal Cartel Office (Bundeskartellamt - BKartA).

Until 30th November 2007, the procurement of primary and secondary control reserve was carried out independently by each TSO every six months.

[56] http://www.cre.fr/documents/deliberations/approbation/capacites-d-effacement-2015/consulter-la-deliberation

Since 1st December 2006, the minute reserve required by the four TSOs has been procured via a joint tender. For this purpose, the TSOs' common Internet platform www.regelleistung.net provides with the details. Prior to the start of the joint procurement, each TSO already individually procured its minute reserve via daily tenders. In order to process these daily tenders, the German TSOs had developed IT-based procurement platforms along with suitably defined, market-based control reserve products able to support the stable operation of the grid.

A joint tender for the procurement of primary and secondary control reserve was introduced one year later on 1st December 2007 and is also processed via www.regelleistung.net.

The procurement is carried out as a tender auction on the German Control Reserve Market with participation of numerous bidders. It is not only open to plant operators, including renewable energy plant operators, but also to electricity customers. By pooling technical units (generation facilities and controllable consumer loads) it is also possible for small bidders to take part in the tender.

However, under the respective legal framework[57]), the four transmission grid operators need to keep a core portion of the control reserve to be provided from within their control area.

The four TSOs cooperate at operational level through the coordinated use of control reserve in the grid control cooperation (GCC), which is similar to the establishment of a single control area, as the reserves are held jointly.

German law allows TSO to take either grid- or market-related measures, whereby the latter may include cutting off installations at peak based on a contractual agreement[58]. On TSO level, there are now monthly tenders for interruptible load organized, wherein immediately interruptible loads (SOL) and quickly interruptible loads (SNL) are being auctioned. SOL are automatically controlled, SNL within 15 minutes. The lot size for each bid may vary between 50 and 200 MW, but smaller bidders can pool to meet those sizes. Various different offer options are available:

- at least 15 minutes at any given time, several times a day at different intervals for a duration of up to one hour per day, at least four times a week
- continuously for at least four hours at any given time, once every seven days
- continuously for at least eight hours at any given time, once every 14 days

[57] Compare §6 Stromnetzzugangs-Verordnung

[58] Compare § 13 par. 1 Energiewirtschaftsgesetz; EnWG

However, even outside any contractual agreement, the TSO can take management measures where the stability of the grid requires[59]. In such case, the TSO has to inform the relevant DSO and electricity suppliers.

The DSO also has in principle the possibility to conclude interruptible load or other balancing contracts in general with installations connected to their grid, which will normally be awarded reductions in their grid use fees[60]. However, here no common market exists.

.Italy

Interruptibility services have traditionally been regulated by contracts between TERNA and the service providers, that were auctioned monthly and every two/three months per each triennial regulatory period. The overall amount of capacity contracted (end of 2012) was 4300MW. Resolution of 20 June 2014, 301/2014/R/eel from the NRA established a new discipline for interruptibility services starting from 1 January 2015. According to this mechanism:

- 75% of the maximum quantity of interruptibility services defined by the Ministry of Economic Development is purchased through pluriannual auctions.
- 25% of the maximum quantity of interruptibility services defined by the Ministry of Economic Development is purchased through annual auctions.
- Industries can define an annual and monthly cap for unavailability.
- Each industry has the possibility to buy back (permanently or only for a pre-defined period) the interruptible capacity from Terna (italian TSO), only after one third of the total duration of the contract has already passed; the buyback must be remunerated to Terna.

.Spain

In Spain, the TSO carries out a congestion management procedure just after the gate closure for the day-ahead market and right before the markets for regulation and balancing reserves, in order to solve infeasibilities of the scheduled dispatch, especially due to network congestions. This procedure consists of a re-dispatch of generation units that is based on technical and economic criteria.

In real time, the TSO counts on emergency services to cope with critical situations in which the security of the system is threatened (voltage collapse, serious constraints, etc.). Among these we should highlight the demand interruptibility service, which can be provided by

[59] Compare § 13 par. 2 EnWG

[60] Compare § 14a and § 14b EnWG

large industrial consumers. The TSO activates this service by ordering the provider (industrial consumer) to lower its active power demand to a predefined value.

The interruptibility service is an auction-based system regulated by Orden IET/2013/2013[61]. The main conditions for participation are:

- Consumers offering this service commit themselves to consumer more than 50% of their annual consumption during valley hours.
- These consumers need to have an automatic load shedding device installed for infrequent occasions when the system frequency drops under some limits established by the TSO.
- The service is remunerated for available capacity, according to the results of the auction, and energy effectively interrupted, based on the reference price calculated every trimester and published by the Directorate General of Energy Policy of the Ministry of Energy.
- The assignation of this service is done through annual auctions of 9 blocks of product of 90 MW, of high availability, and 238 blocks of product of 5 MW, i.e. 2000 MW in total. These blocks can be called upon up to 240 hours per year (5 MW product), with a maximum of 40 hours per week, and 360 hours per year (90 MW product), with a maximum of 60 hours per week.
- The service is activated upon request in different modes (instantaneous, rapid and hourly), with different notice times. By activating the service, the TSO demands the consumer to keep consuming certain value of active power during a period of time. The maximum duration of the service is one hour each time.

According to the results of the latest auction in November 2014, the 2000 MW for 2015 were sold to the Spanish TSO, REE, for M€ 352, i.e. for 176 339 €/MW on average[62]. The total amount of industrial consumers that were assigned to provide this service is 113, among which all but 19 were business groups. The reference price for the settlement associated to a power reduction order in this service to be applicable in the first trimester of 2015 is calculated as the average wholesale electricity prices in the day-ahead market during the last trimester of 2014 and the forward market operated by OMIP for the first trimester of 2015, resulting in 48.20 €/MWh[63].

[61] http://www.boe.es/boe/dias/2013/11/01/pdfs/BOE-A-2013-11461.pdf

[62] http://www.esios.ree.es/web-publica/, *Servicio de Interrumpibilidad > Resultados*

[63] http://www.boe.es/boe/dias/2015/02/09/pdfs/BOE-A-2015-1221.pdf

.United Kingdom

The demand side can participate in a series of balancing and ancillary services, as detailed in Annex 1.

The Demand Side Balancing Reserve (DSBR) is a specific mechanism that resembles demand interruptible services. Under DSBR large energy consumers will be paid to reduce their demand during winter weekday evenings (between 4pm and 8pm) in response to instructions from the SO.

The ability to reduce load at two hours’ notice and to sustain load reduction for a minimum of two hours between 4pm and 8pm, non-holiday weekdays between November and February is required. Capacity must be provided in 1MW tranches or smaller aggregated units.