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Market Design for Large Scale Integration of Intermittent Renewable Energy Sources

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MARKET DESIGN FOR LARGE SCALE INTEGRATION OF INTERMITTENT RENEWABLE ENERGY SOURCES

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Executive summary

Power systems are increasingly challenged by the large-scale development of intermittent renewable sources. There are already national power systems coping with a large share of intermittent renewables, most often wind. In some European countries where targets have been imposed by the Directive on the promotion of the use of energy from renewable sources, capacity penetration by renewables could be close to 100% of peak demand in 2020. Similar initiatives to support renewables exist in non-European countries as well.

The purpose of this technical brochure is not to discuss the relevance of such targets. It focuses instead on the tools used by power systems to manage an increasingly important share of intermittent renewable energy sources (i-RES). The technologies currently used feature technical and economic characteristics that make more complex the short-term and long-term management of power systems. A review of these challenges is provided in the first section of this brochure.

To hasten the development of i-RES technologies, incentive mechanisms have been put in place in many nations. These mechanisms have often been designed to ensure an effective and efficient development of i-RES. Many different schemes have been employed, market-based or not, centralised or not, and some of them have been a qualified success. However these schemes have not only influenced the development rate of i-RES, but also the way risks and responsibilities are shared between i-RES plants and the System Operator. Political choices have sometimes been made to free i-RES developers from market risks to promote faster renewable development. Yet such priorities can be questioned as the share of i-RES into the system becomes significant. The second section provides an analysis of this trade-off and presents the main existing schemes.

More flexibility will be needed in power systems. In a liberalised electricity market, the incentives to develop and operate plants in a flexible way should be delivered by market signals. The design of wholesale electricity markets will therefore play a key-role. Negative prices can signal a surplus of electricity better than a zero-price, while low price-caps will give fewer incentives to players to operate when most needed. Moreover, as forecasts improve significantly when calculated closer to the generation horizon, market participants should be given an opportunity to manage their bids closer to real-time. Intraday markets could reduce the costs of balancing and help the integration of i-RES. These considerations are the subject of the third section of this report.

The fourth section focuses on Ancillary Services. The need for reserves will be significantly impacted by i-RES. Solutions could for example include a more dynamic management of these reserves, but in any case it will be more important than ever to price these reserves in a cost-reflective way in order to ensure a cost-efficient behaviour from market participants. A complementary solution could be to integrate i-RES into the provision of reserves and other ancillary services such as reactive power provision and the brochure discusses these possibilities with regards to the technical limits of i-RES.

A significant share of intermittent resources will have major consequences for electricity generation plants and also on the transmission network. I-RES often face a trade-off between causing high transmission costs or being built in areas with less generation potential. The design of connection charges is especially relevant to solving this problem and is studied in the fifth section.

Finally, a range of technical tools and complementary measures can be employed to reduce constraints on the power system. The brochure provides a review of these tools such as better forecasts and coordination, development of demand-side management, investments in storage capacities or capacity market / capacity remuneration, forming the basis of the sixth and last section.

From our analysis, there is often a trade-off between greater cost-reflectivity versus fewer barriers to investment for i-RES technologies. Approaches favouring cost-reflectivity include exposure to electricity prices, charging imbalances, paying deep connection costs. By contrast, Feed-in Tariffs and shallow connection costs tend to isolate i-RES from the costs they generate. The large variety of schemes and rules in place in power systems worldwide partly reflect these preferences.

Strikingly, systems featuring the highest shares of i-RES (Spain, Germany and Portugal) present significant differences in the way they manage i-RES. Their approaches also tend to differ significantly from theory. This phenomenon reveals that it is difficult to analyse power system operation on an individual rule-by-rule basis. Rather, the entire package of rules in place in a power system must be considered as a whole. It is also tricky to apply a general theory to power systems widely differing in terms of infrastructures and available resources. As recently underlined by the Council of European Energy Regulators (CEER) in its report Implications of Non-harmonised Renewable Support Schemes, what investors need is a stable set of rules rather than a perfect, harmonised scheme to support renewables. Discrepancies in rules between national power systems might hamper competition but they also allow for different national characteristics and ambitions. While power systems could benefit from examination of foreign experiences, this study highlighted that very different approaches were appropriate in very different power systems, which must be kept in mind when applying lessons from abroad.

These analyses are complemented by case studies of a number of national power systems: Australia, Brazil, China, Spain, Germany and France.

Foreword

This technical brochure was completed in May 2013. It is partly based on questionnaires answered by Working Group C5-11 members in 2010. Respondents are listed in Appendix 7, the authors would like to thank them for their valuable contribution.

Context: the growing share of i-RES in power systems

Power systems tend to feature an increasingly significant share of electricity generated by renewables. This development results from a wide range of preoccupations including Climate Change mitigation, reducing dependency on fossil fuel imports, or creating a national industry. There are already national power systems coping with a large share of intermittent renewables, most often wind. In some European countries, where targets have been imposed by the Directive on the promotion of the use of energy from renewable sources[1], capacity penetration of renewables could be close to 100% of peak demand by 2020 (Figure 1). Similar initiatives to support renewables exist also in non-European countries, such as Renewable Portfolio Standards in the US and the Renewable Energy Target in the Australian National Electricity Market (NEM). The survey conducted by CIGRE WG C5-11 in 2010 shows that the most ambitious targets are set in Europe.

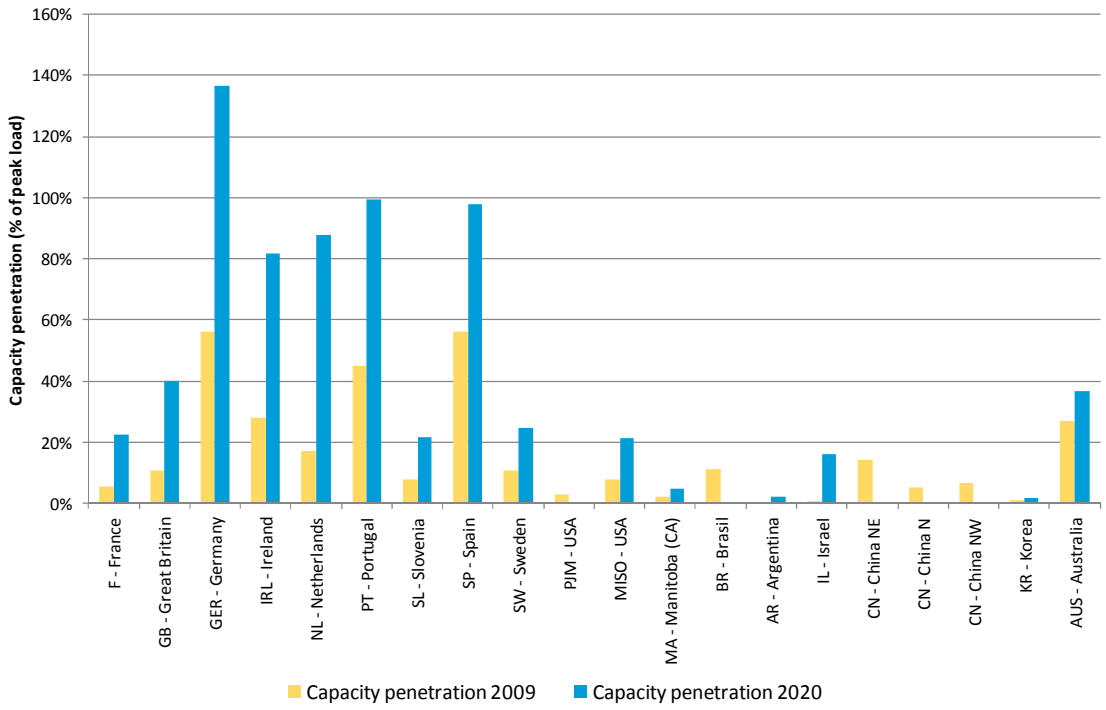

Figure 1: capacity penetration of intermittent RES (Source: CIGRE WG C5-11, 2010)

The purpose of this technical brochure is not to discuss the relevance of such targets. We will focus instead on the tools used by power systems to manage an increasingly important share of intermittent renewable energy sources (i-RES).

[1] Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009

1. Intermittent Renewables features

Before getting into details, it is important to point out that "intermittency[2]" is not specific to renewables. Existing generation units are subject to unexpected forced outages and none are able to operate 100% of the year or with an absolute certainty of delivering when committed. Power systems are also used to cope with the variability and uncertainty of the demand side. However, the output of the bulk of traditional generation is controllable with relatively low failure rates and demand fluctuations are reasonably predictable and change relatively slowly. Despite not being a new phenomenon, the variability and uncertainty introduced by i-RES into power systems creates additional challenges due to the size and the difficulty in predicting changes. The magnitude of change can be akin to a common mode failure as wind and solar radiation can be the common fuel across significant geographic areas, albeit with some diversity – this is discussed further in the next section. As wind power and solar power will probably constitute a significant share of the future electricity mix in Europe, we will focus on these two sources of energy. The figures might be different for other technologies but the nature of the problem will remain identical.

1.1. Technical features

In this section we focus on three technical characteristics of i-RES which are relevant to the integration of large-scale RES: output variability, the difficulties in forecasting this output accurately, and the fact that RES output often depends on local resources ("site-specificity").

1.1.1. Variability

Wind doesn't always blow, sun doesn't always shine. As a result wind power and solar power fluctuate over time. Fluctuations are seasonal, daily, hourly or minute-by-minute and affect power systems in different ways.

[2] The term "variable" is sometimes considered as more appropriate than "intermittent" (See for instance the 2010 NREL paper by Milligan and Kirby). Intermittent implies something that rapidly cuts in and out of availability, whereas solar and wind generation generally vary more gradually over longer timescales. "Variable" captures the nature of this behaviour more accurately. However, the term "intermittent" has become common and will be used in this paper.

			10-15 minutes		1 hour		4 hours		12 hours	
Region	**Region size**	**Nr of sites**	**Max decrease**	**Max increase**	**Max decrease**	**Max increase**	**Max decrease**	**Max increase**	**Max decrease**	**Max increase**
Denmark	300×300 km^2	>100			-23%	+20%	-62%	+53%	-74%	+79%
- West Denmark	200×200 km^2	>100			-26%	+20%	-70%	+57%	-74%	+84%
- East Denmark	200×200 km^2	>100			-25%	+36%	-65%	+72%	-74%	+72%
Ireland	280×480 km^2	11	-12%	+12%	-30%	+30%	-50%	+50%	-70%	+70%
Portugal	300×800 km^2	29	-12%	+12%	-16%	+13%	-34%	+23%	-52%	+43%
Germany	400×400 km^2	>100	-6%	+6%	-17%	+12%	-40%	+27%		
Finland	400×900 km^2	30			-16%	+16%	-41%	+40%	-66%	+59%
Sweden	400×900 km^2	56			-17%	+19%	-40%	+40%		
US Midwest	200×200 km^2	3	-34%	+30%	-39%	+35%	-58%	+60%	-78%	+81%
US Midwest+ Oklahoma	1200×1200 km^2	4	-26%	+27%	-31%	+28%	-48%	+52%	-73%	+75%

Table 1: Extreme variations of large scale regional wind power as % of installed capacity (Holtinnen 2009)

Short-term variability

Fast fluctuations can occur within seconds or within minutes. Several studies have demonstrated that these fast fluctuations do not constitute a significant burden for the system operator and can be handled by traditional methods used to manage load fast variability (Frunt, 2011). Moreover, very short-term variations (within seconds) tend to statistically average out when i-RES penetration increases.

Longer-scale variations occur over a period of several minutes to several hours. The range of these variations can be quite high as illustrated in Table 1. Yet it can be noticed in this table that even at times of extreme weather events wind production never switches completely or instantaneously. However, balancing requirements will increase for high levels of i-RES penetration depending on the technological and geographical spread of i-RES, as well as on the quality of local wind and solar resources. For instance, the region of Australia with the highest penetration of wind is approaching the situation where the measured drop in wind output within a 5 minute dispatch period is equivalent to loss of the largest thermal unit. We will mention the adaptation of Ancillary services to i-RES in section 4.

Some modern wind turbines are designed to curtail production when wind speeds exceed a certain threshold, in order to protect the wind turbines. This leads to a situation where the production of individual turbines suddenly switches from peak production to zero (see Figure 2).

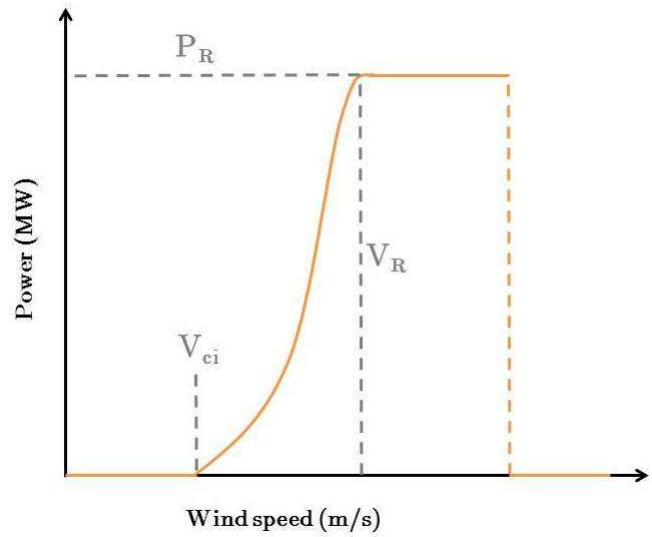

Figure 2: Typical transfer function of a wind turbine. V_{ci} is the cut-in wind speed; for wind speed higher than V_R the wind is spilled by feathering the blades (Söder, 2002) .

However this effect will be distributed in time across a wind farm (the entire wind farm will not instantaneously switch from peak to zero), and across a region. This means that it will occur more slowly than the sudden forced outage of a large thermal unit (for example), and will likely be more predictable (via wind forecasts).

Long-term variability

There are also climatic seasonal effects affecting i-RES. The output from solar photovoltaic panels will typically be lower during the winter while average wind farm output may also vary with season. This phenomenon is less challenging from a system security point of view but it means additional plants may be needed to cope with these effects, especially if periods of low generation coincide with periods of high demand. It therefore can constitute a challenge for generation adequacy.

Smoothing factors

For a given technology, *geographical spread* can result in much lower variability on a system-scale. The more units and the less correlated their production, the less variable the total output, as illustrated in Figure 3. Even in small systems such as Denmark, significant stability gains are achieved when comparing the system as a whole to each wind farm independently. Extreme weather events nevertheless occur on significant geographical scales (> 1000 km) that can therefore affect entire large systems at the same time.

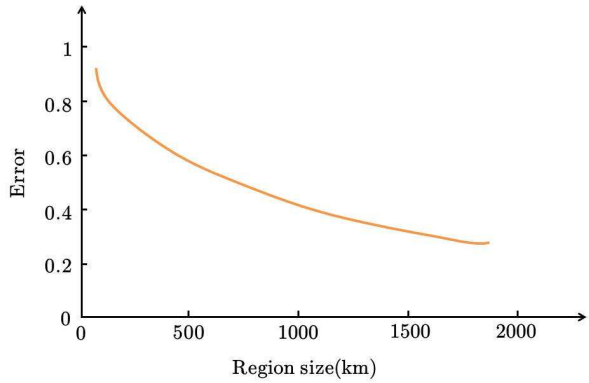

Figure 3: Decrease of forecast error for aggregated wind power prediction, based on data from 40 wind farms in Germany (Holttinen et al., 2009)

Significant gains can also be obtained from *technological spread*. NERC provided an example of a situation when PV output and wind farm output were negatively correlated, resulting in a much more steady output (Figure 4). The correlation between demand and i-RES variability is also an important factor. On a long-term basis, power systems typically feature a seasonal peak during the winter (due to heating) or during the summer (due to air-conditioners). This seasonal peak demand may or may not correspond to the peaks of i-RES output previously mentioned. Such effects can also occur on shorter time-scales: demand is for example often low at night when solar PVs are not generating. Situations can occur when load and i-RES generation vary in the same or opposite directions.

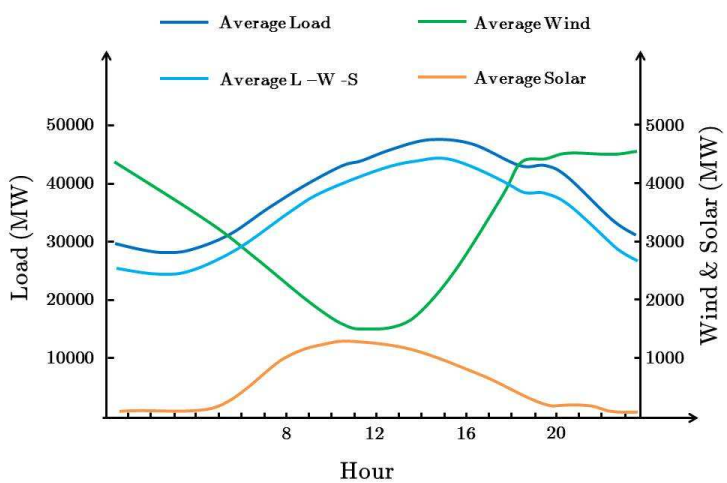

Figure 4: California average wind and solar output, along with net demand, July 2003 (NERC, 2009)

Using both technological spread and geographical spread, it could be possible for a given power-system to smooth variations by adopting a risk-portfolio approach such as that proposed by Roques, Hiroux, and Saguan (2010).

1.1.2. Low-predictability

Electric systems need to forecast the conditions of real-time balancing to minimize the risk of black-outs (real-time imbalances). Depending on dynamic constraints of technologies, most thermal plants plan their production in advance as they have limited flexibility whereas some others get the capability to start/stop very quickly. The i-RES technologies, wind being the typical example, depend on very complex physical phenomenon. It is therefore difficult to accurately forecast what will be the exact contribution of these plants in real-time. Hence imbalances between the forecasted and actual production can occur at the system-scale which can lead to global imbalances and the need to use flexible and reliable dispatchable plants (mostly thermal units and large hydro) to ensure the real-time balancing of supply and demand.

At this stage it is worthwhile to well-distinguish the global system's requirements, whose goal is to ensure the real-time balancing of supply and demand, and the producers' market behaviour whose goal is to maximise their profit (diminishing their balancing costs, and therefore the differences between the D-1 and RT markets). TSOs are responsible for managing the global real-time imbalances, wherever they come from. TSOs have several tools to do it, from reserves to balancing markets. The i-RES producers, if they have access to the market, can maximize their profit with the adequate strategic behaviours. Consequently, the forecasts made by TSOs should be used to ensure the real-time balancing of supply and demand whereas the forecasts made by each i-RES producer are supposed to help maximising their profit and, hence, minimising the balancing cost with the adequate strategic behaviour.

System Operators are used to managing uncertainties in power systems, as load is also not perfectly predictable. Maupas (2008) estimated that the Mean Square Error (MSE) of load in France would be roughly the same as that resulting from 15 GW of installed wind power. However he also argued that errors in consumption were much more regular and therefore easier to correct. This is partly due to phase errors specific to wind forecasts (as illustrated in Figure 5) leading to forecast errors with opposite signs. The experience with demand forecasting is also quite extensive.

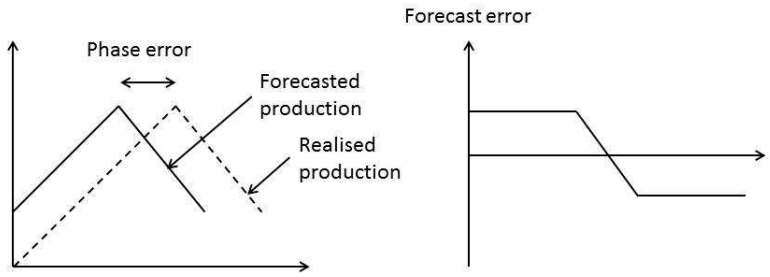

Figure 5: Impact of a phase error on forecast error (Maupas (2008))

Wind forecast tools keep improving over time as experience increases. They are generally based on physical models and meteorological data mixed with statistical models. However while they tend to do well for short-term projections (i.e. a few hours) they still face difficulties in providing accurate estimates for the day-ahead as illustrated for Germany in Figure 6. For comparison, the day-ahead Mean Square Error for the French system load during winter 2006 and 2007 was about 1% of peak

consumption (Maupas, 2008). A possible solution for integrating wind energy in electricity markets is therefore to allow trading closer to gate-closure (see Borggrefe and Neuhoff (2011)).

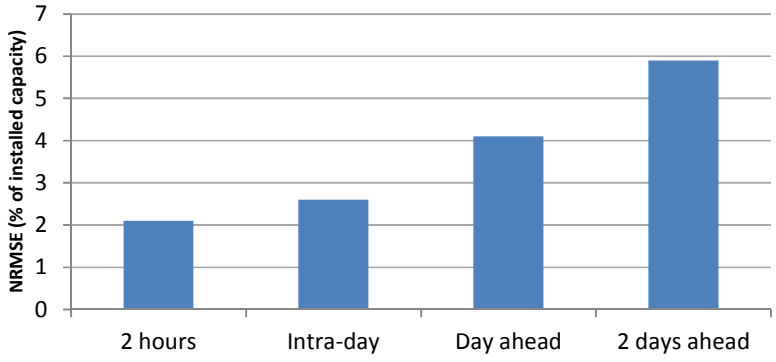

Figure 6: Wind power forecast error with increasing forecast horizon (2009 average value in Germany, from Tambke as quoted by EWEA (2010))

As for variability, the forecast errors of several wind farms can self-compensate and the average error is lower for larger systems or large portfolios. Aggregation of wind farms is therefore useful for managing short-term uncertainty.

1.1.3. Site specificity

Wind properties vary a lot geographically, including at a national scale. Solar resource quality also depends a great deal on latitude. The best resources are generally geographically concentrated and sometimes far from the existing grid. In the UK the best wind resources are located in Scotland; to access these resources the network must connect these areas to consumption centres in the south of England. The pattern is similar in Germany. Furthermore, intermittent renewables are often land-intensive. As a result, the higher land prices closer to load centres are another constraint to be taken into account.

A trade-off is hence to be faced between building at the best generation sites and minimising transmission costs. This is exacerbated by the fact that the load factor of a wind farm is typically low, meaning that it will often be inefficient to build enough transmission capacity to carry the full installed capacity of the wind farm. It is necessary to handle these dilemmas in a cost-efficient way, which can be made easier by appropriate connection tariffs and procedures (see section 05).

Finally, the variability of i-RES output can result in significant variations in network flows. These flows can impact neighbouring power systems; for example, electricity generated in the North of Germany results in parallel flows through Poland and the Czech Republic.

1.2. Economical features

In a perfectly competitive liberalised electricity market featuring marginal pricing, the optimal strategy for generators is to bid their marginal cost (Stoft, 2002). The generators offering the cheapest options will then be selected first until demand is met. These generators should recover

their fixed costs when more expensive units are called, since all generators are paid at the price bid by the last dispatched unit. In general, the peaking units featuring the highest marginal costs only earn revenue at times of scarcity. This means that regulatory interventions such as price-caps designed to prevent market-power abuse can result in a "missing-money problem" if set inappropriately low, as demonstrated by Joskow (2008). This is not a new problem and Joskow calculated empirically that in PJM, between 1999 and 2004, scarcity rents would have covered only 40% of the fixed costs of a new peaking unit.

I-RES typically feature a very low marginal cost, roughly zero in the case of wind or PV. They are also often isolated from spot market prices when they benefit from specific support mechanisms such as the feed-in tariffs.

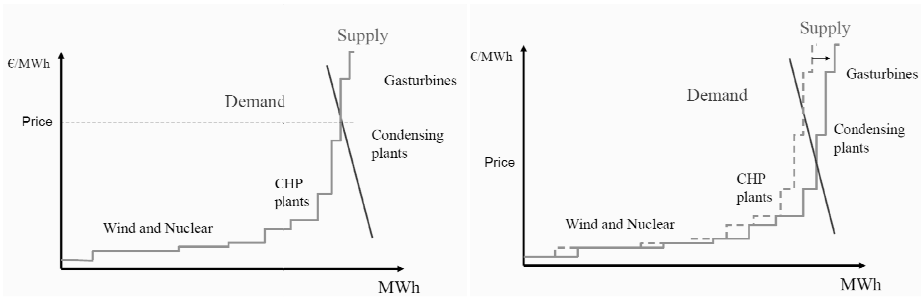

Figure 7: Merit-Order and Prices in a generic electricity market, with low wind output (left figure) compared to high wind output (right figure). Source: Morthorst (2008)

This means that they will typically be dispatched first, and the marginal cost structure of the electricity market will vary depending on i-RES availability (see Figure 7). If wind power generation is high and demand is low, prices will be close to zero. In Spain 2010 spot prices were equal to zero for 300 hours. However when the wind stops blowing, dispatchable plants must be called to maintain reliable supply. Some of these back-up units will only run a few hours a year and must be able to recover their fixed costs at that time. Base-load units and mid-peak units will also be affected by this "merit-order effect"; for example, in Spain CCGT plants were dispatched for only half as many hours in 2010 compared to 2004 (Eurelectric, 2010). The missing money problem could therefore be exacerbated by increasing i-RES penetration. Market participants will also be exposed to more volatile prices.

However, before addressing the "missing-money" problem, its existence has to be verified. Hence, it must be taken into account that additional remuneration is often provided to generators who deliver reserves and other ancillary services. These additional sources of revenue outside of the spot-market can mitigate (and sometimes compensate) the missing-money problem.

In an energy-only market, a solution to solve the missing-money problem would be to adjust market price caps on an on-going basis as renewable penetration increases. Alternatively, a capacity remuneration mechanism can be implemented, as mentioned in section 6.4.2.

2. *Incentive mechanisms dedicated to Intermittent Renewables*

Incentive mechanisms dedicated to i-RES are motivated by a range of economic and political reasons. They can be justified by the positive environmental externalities of such generators, a desire to develop a mass market to reduce costs, or the prospect of developing a national industry instead of importing fossil fuels. In this section we will not discuss these objectives but will rather review the tools employed by governments to reach a given target of i-RES penetration. This is relevant in our analysis as the interaction of i-RES with the market is impacted by these tools.

There is a wide range of tools used either to push technologies or to pull the demand for generation from these technologies. Each of these instruments plays a key-role at different stages of technology maturity – from demonstration projects to integration to the market of mature technologies –, as illustrated in Figure 8. In this document we review challenges linked to the large-scale deployment of relatively mature technologies. The on-going analysis will therefore focus on the production-based instruments, which aim at pulling the demand for that kind of production into the system such as the FIT, FIP and green certificates.

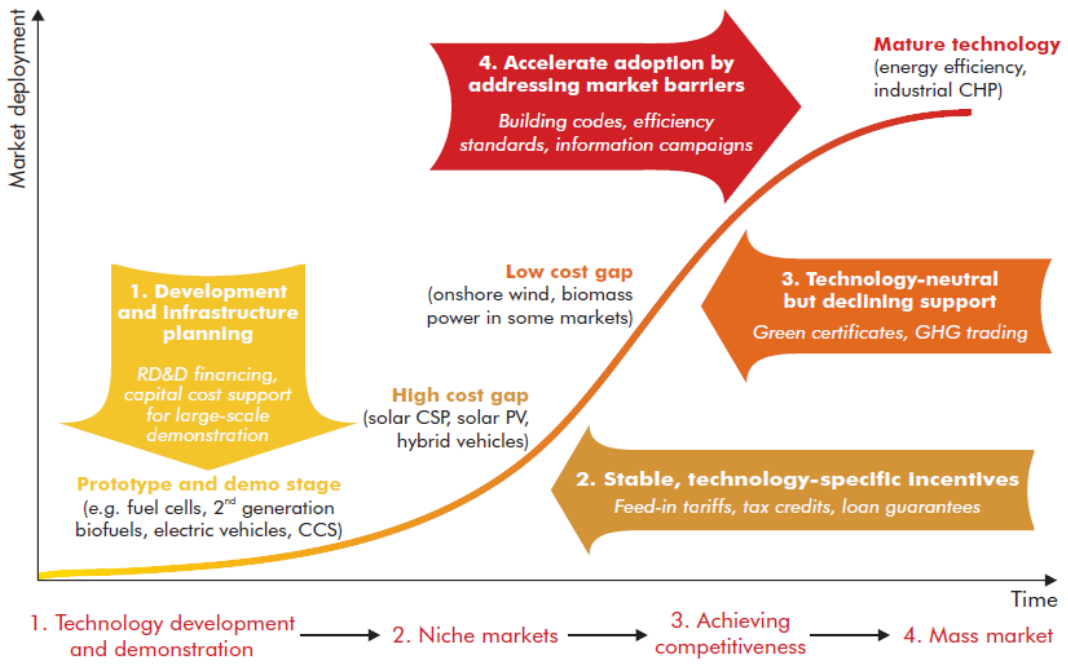

Figure 8: Policies for supporting the development of low-carbon technologies (Source: (IEA, 2010))

Note that a good incentives scheme should promote efficient system operation by all involved parties. The devil is always in the details and a mechanism should not purely focus on fostering i-RES, but at fostering i-RES and at the same time guaranteeing a proper integration in the overall system.

2.1. Available instruments

We define in this section the main categories of instruments employed by governments to support i-RES. It is important to distinguish the nature of the mechanism from its detailed design. Here we distinguish the price-setting and volume-setting instruments. That's what we call the nature of the

instrument. Within the price-setting instruments, as well as within the volume-setting tools, the detailed design can change the incentives structures. For example, technologies can be differentiated or not, premiums can be uniform or vary geographically, tendering auctions can be binding or not. The efficiency or impacts of a given policy cannot be assessed without keeping this in mind. In this report we apply a relatively high level analysis which is sufficient to understand the interaction between incentive mechanisms and market integration, but we caution the reader that a deeper analysis, more impact-assessment-based, would be required to fully explore the implications of the range of incentive mechanisms used.

"Indirect" instruments are also employed by national authorities. As for instance, some detailed schemes can exempt I-RES from paying imbalance charges (see section 3.2.3) or connection charges (see section 5). Those elements deeply modify the incentives given to i-RES producers, but also the signals sent to other stakeholders (market players, TSOs, etc). This report highlights this point, but focuses only on the main impacts of the large-scale integration of intermittent electricity.

2.1.1. Regulatory price-setting instruments

This first category of tools features a fixed premium generators receive at times of investment (i.e. per MW installed) or at times of generation (i.e. per MWh produced). While the government cannot be sure that development targets will be reached if the price is wrong, these schemes have the advantage of providing developers with revenue certainty.

Feed-in Tariffs (FITs)

Feed-in tariffs are generation-based instruments. I-RES producers receive from an entity (utility, supplier or grid operator) a fixed price for each unit of electricity generated, for a set length of time. These costs can be recovered from consumers or taxpayers. FITs have historically been the driving force behind very effective policies in Denmark, Germany or Spain and are still in place in many countries. Under this scheme, generator revenue is isolated from the electricity market and revenue-risks are therefore limited as long as the scheme remains in place.

FITs are often claimed to be more effective for achieving large-scale development targets. They have proven to be extremely effective policies in Germany, Denmark and Spain. FITs are simple to understand, even by extremely small investors. They don't require an analysis of the market or current investment trends. This is especially important as i-RES typically feature significant upfront investments associated with low operating costs and are therefore highly exposed to discount rates. Moreover it is difficult to control the production of a wind farm and in many cases it is always worth generating: in a system with a small penetration of i-RES exposing developers to electricity prices provides little benefit. It is also seen as less costly, since developers exposed to higher market risks (especially in the case of Green Certificates when producers are also exposed to a risk on premium prices) require a higher rate of return.

Tariffs must be continuously updated to follow technology cost reductions in order to avoid windfall profits and provide an incentive to reduce costs. However the fixed premiums are sometimes adjusted too slowly compared with cost changes, which can result in a massive oversupply in the market. Therefore the efficiency of such a scheme relies mainly on the necessary tight control of

public authorities. Adjustments can then be dramatic: in France a 3-month moratorium has been applied in December 2010 to adjust the regulatory scheme for the PV FIT (see appendix).

FITs are generally technology-differentiated, as the premiums are adapted to specific technology costs. They can also be size-differentiated; small generators usually receive a higher premium than large generators.

Feed-in Premiums (FIPs)

Feed-in premium are similar to FITs, but the generators receive the premium in addition to their revenue in the electricity market. The total revenue they earn for a unit of electricity generated can be in some cases capped and floored.

Grants

While FITs and FIPs are generation-based, rewarding the output of supported units, grants are investment incentives received at the time of building the plant and proportional to the installed capacity. They can also be location and technology differentiated.

2.1.2. Regulatory quantity-setting instruments

Price-setting and quantity-setting instruments should in theory lead to the same results. Yet, one of the main drawbacks of price-setting instruments is that they require governments to accurately estimate the optimal premium. If the government estimate is inaccurate the quantity targets will be missed. This is particularly problematic if prices are too high, leading to massive development of i-RES and significant costs for consumers and/or taxpayers.

Green Certificates (GCs)

Under this generation-based support scheme targets are set by the government for a given share of generation from i-RES. Obligations are imposed on generators or suppliers to fulfil these quotas or in some cases to pay an administratively determined buy-out penalty (providing the basis for the maximum-price of a certificate). Generating electricity from i-RES produces a right to create a pre-defined number of credits that can then be traded. The price of these credits is established based on market supply and demand. I-RES generators receive these extra revenues in addition to electricity market prices. It is possible to weight certificates from different sources to provide specific technologies with higher revenues (for example, to discriminate emerging technologies from more mature ones); this is the case under banded ROCs[3] in the UK.

Tendering

Tendering schemes can be either generation-based or investment-based. A fixed amount of i-RES to be installed is requested by the government and developers competitively tender for either investment grants, a feed-in tariff or a generation premium. The Non Fossil Fuel Obligations that were in place in the UK in the 90's belonged to this category and offshore-wind recently benefited

[3] See box 1 (section 2.2) for further explanation.

from such a scheme in France. An innovative variant referred to as the Large-scale Solar Auction is currently being implemented in Australia.

2.1.3. Additional instruments

Tax incentives

There are two ways in which i-RES can benefit from tax mechanisms: they can indirectly benefit from the pricing of negative externalities to which they do not contribute (such as a sulphur tax or carbon tax), or benefit from a tax-refund such as a lower VAT. Note that in the first case (sulphur-tax, carbon-tax) RES will indirectly receive additional revenue through higher electricity prices caused by taxes on conventional generation, while in the second case (tax-refund) the mechanism can be considered as a source of negative costs. The impact on electricity prices will therefore be quite different under each approach. In countries where energy taxes are high, such a scheme can be sufficient to support the development of renewables.

Green marketing

By comparison to the regulatory tools presented so far, green marketing functions on a voluntary basis. It is based on consumers' willingness to pay a higher price for their electricity when it is generated by i-RES. It remains quite a marginal tool.

Access to capital

Loan guarantees or direct access to capital can also be offered to support i-RES projects. Such measures allow developers to gain access to capital at a lower-cost. Examples include the Clean Energy Finance Corporation in Australia, the Loan Programs Office in the USA or the Green Investment Bank in the UK.

Carbon trading

Emissions trading is not an instrument directly dedicated to RES implementation, but it provides an incentive to build lower emissions generation. This mechanism is a way to incite an electricity company either to reduce the pollution from existing conventional plants, or to build less or zero emitting plants. Each company from a given range of sectors (electricity generation, cement industry, chemistry etc...) receives an annual emissions quota. The initial quota can be allocated for free, or through auctions. By the end of each year, if the company has emitted more than their quota they are required to purchase allowances which are traded on the market (conversely, a company which emitted less than their quota can sell certificates into the market). An emission trading scheme of this nature has been implemented in Europe (European Emission Trading scheme (ETS)), and is scheduled to commence in Australia in 2015 (see appendix).

Grants to Research and Development programs

An indirect way to promote the development of renewables is to fund R&D programs in order to improve i-RES performance and lower their costs.

2.2. Exposure to market signals in electricity markets

As discussed above, support instruments can be price-setting or quantity-setting, technology-specific or not, and mandatory or voluntary. These characteristics will have a major impact on the nature and the quantity of technologies installed in the market. We focus in this section on an additional feature relevant to market integration: exposure to electricity prices and market signals.

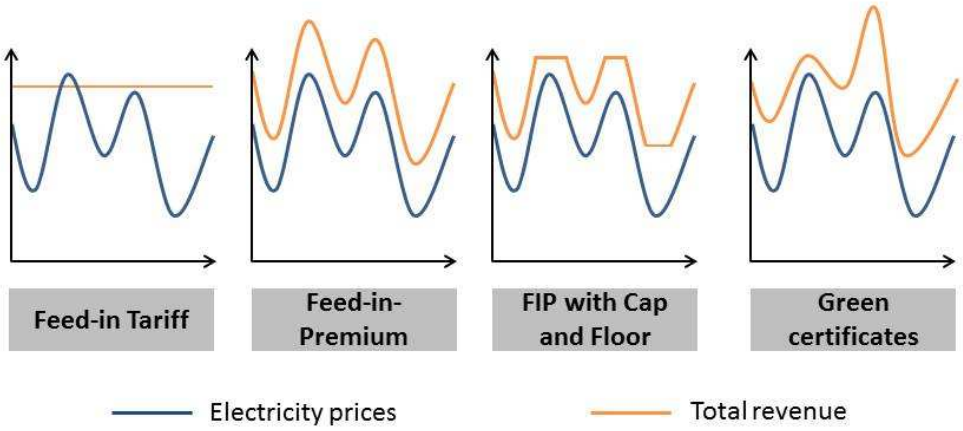

Figure 9: Role of market prices in different support schemes

As illustrated in Figure 9, FITs, FIPs or GCs expose generators to different risks. While FITs completely protect generators against electricity price risk, both GCs and FIPs include remuneration from electricity markets as a part of the generators revenue. In some cases, where there is no cap and floor on total revenue and negative prices are allowed in the market, this market exposure can provide an incentive to the generator to curtail its production. Generally speaking players receive more incentives to efficiently manage their production when they are exposed to market signals. Market signals lead to price and volume risks. Policy makers hence typically face a trade-off between exposure to market signals and a risk minimisation approach (Klessmann, Nabe, & Burges, 2008).

At times of large-scale integration, there is a need for a smooth transition from a low-risk approach to a more risky support scheme. Note that, as described in Hiroux and Saguan (2010), support schemes cannot be analysed without taking the other components of the market design into account. The microstructure of the incentive schemes also plays a key-role in the signals received by generating units.

The high penetration of i-RES, particularly when they are isolated from the market, leads to a change of the paradigm of system operation. Indeed, there are situations when it would be less costly for the system as a whole to curtail generators with zero-marginal cost, for instance to avoid costs of shutting down and starting-up thermal units, or respect ramping constraints.

In this context, it is necessary to distinguish the market player level and the system level: if the wind power producer receives one signal (negative prices) it can choose either to pay to produce or to stop its plant (market player's behaviour); whereas the TSO curtails wind power producers because of a global system imbalance. If only variable cost were to be considered, there would be no

incentives to first curtail wind and PV since they have zero-marginal cost. But if the TSO takes into account the complete cost of curtailment (cost of shutting down, ramping rate, etc...) it will be more efficient to cut for some hours wind and PV rather than to curtail other conventional units.

Thermal generators are currently providing the needed flexibility to the system, but by operating in a system with a growing share or i-RES they are exposed to higher costs and reduced efficiency. Furthermore, in a system featuring a significant share of i-RES there will be cases when the generation by i-RES is greater than demand. Exposing generators to electricity prices is a first step in providing incentives to i-RES to contribute to the safe operation of power systems. In Spain for example a smooth transition took place from FITs to FIPs as detailed in box 1. Another approach could be to maintain FITs for small projects to limit transaction costs whilst applying a more market-

Box 1: Two contrasting policy evolutions: Spain and the UK

1) SPAIN: progressive market integration of wind farms (*Source: Abbad (2010)*)

In Spain 1998, Royal Decree 2818/1998 introduced **pure FITs** with no technical obligation.

Royal Decree 436/2004 added an economic alternative (**FIPs**) on a voluntary basis, providing a more volatile but higher return to investors. Several technical obligations such as mandatory output forecasts, and incentives to modulate reactive power generation and fault-ride through capacity were also introduced. 90% of generators switched to the FIP scheme.

Finally, Royal Decree 661/2007 introduced **cap-and-floored FIPs** to limit windfall profits when electricity prices were high.

Even generators opting for FITs have to pay balancing costs and therefore are not completely isolated from markets.

2) The UK: lowering risks after an attempt at more market-based policies?

In 1998, a technology-differentiated **tendering mechanism** called *Non Fossil Fuel Obligations* was put into place. It has only met a qualified success due to the extremely low prices reached during the auctions.

In April 2002, a **non technology-specific Green Certificate** scheme was introduced: the *Renewables Obligation*. There was a clear willingness from the government to not pick any winners and adopt the most market-based possible approach to support i-RES. Suppliers are given the possibility to pay an administrative-set penalty, and the revenues from this "buy-out fund" are redistributed to complying suppliers.

However, in 2010, "banded ROCs" were put into place. Under this **technology-differentiated** scheme, emerging technologies received more credits. Small projects were also entitled to **FITs**.

Finally, in December 2010, the proposal for an Electricity Market Reform issued by the Department of Energy and Climate Change (DECC) featured **FITs with Contracts for Difference.** In practice these function as a variable FIP with incentives to optimise dispatch.

based approach for large projects, as it is currently the case in the UK.

Finally, industries benefiting from FITs are still exposed to political risks. Recent cases in Spain, France and Germany revealed being 100% dependent on a regulated tariff is not a risk-free situation. As the penetration of renewables increases governments can become concerned by the amount of subsidies delivered to i-RES and can be tempted to reduce these payments. While these cuts usually do not impact already existing plants, they affect installers and component manufacturers and might prevent the emergence of an industry.

3. Wholesale electricity market design

Due to its low storability electricity is a unique commodity. As generation must always be equal to demand, managing power systems is a complex task that requires a system operator to centralise information and responses. In many power systems electricity markets have been liberalised and the set of services from generation to distribution that used to be provided by vertically integrated utilities has been unbundled. Most wholesale electricity markets were designed to attempt to solve the traditional unit-commitment problem: how to provide electricity when required at the lowest possible cost whilst respecting technical constraints. The resulting organisational structure is presented in 3.1. The traditional architecture of many wholesale electricity markets will be challenged by increased volatility and uncertainty. A set of possible solutions is presented in section 3.2.

3.1. Organisation of the electricity markets

The design of electricity markets is not an exact science. The degree of centralisation in each market and the nature of the traded products vary. Some power systems feature a pool while others feature a power exchange[4]. In some systems nodal pricing is applied while in others a single-price is applied across the whole power system. Most markets feature a common spine composed of four elements shown in Figure 10 and described below: forward markets, day-ahead markets, intraday (real-time) markets and a final phase of imbalance settlement. These various markets are used by participants to manage their portfolio across a range of different time scales.

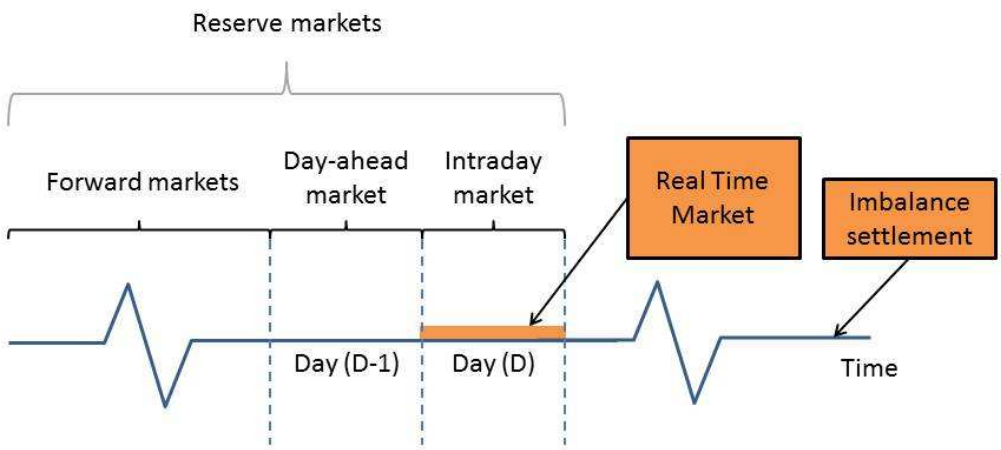

Figure 10: Sequence of wholesale electricity markets (from Vandezande (2011))
GC =Gate Closure, DA = day-ahead, ID= Intraday

[4] There is no unique definition of a pool and a power exchange (PX). Boisseleau (2004) used the two criteria of initiative and participation. Pools are the result of a public initiative and participation is mandatory, whereas PXs are the result of a private initiative and participation is voluntary. Stoft argue that the two models differ because pools feature side-payments whereas PXs do not.
These terms can therefore sometimes be misleading: for example, the Scandinavian "Nord Pool" is a non-mandatory power exchange pool.

Forward markets are usually bilateral, or "Over the Counter", markets. Many power exchanges also allow participants to trade forward products (for example, the EEX for German and French products). Participants can use these financial markets to hedge their physical position from years to days in advance. While they often constitute the forum where most exchanges take place, prices are based on expectations of spot market prices.

The Day-ahead market gives market participants the opportunity to fine-tune their portfolios for a number of time periods (for example, hours or each 15 minutes). It allows the system operator to collect generation and consumption forecasts at "gate-closure time" to check the feasibility of the power flow. Different products can be traded: simple price-quantity pairs for a single time unit, or more complex combinations sometimes called "block bids".

Many power systems now also feature intraday markets where participants can adjust their positions taken in the day-ahead markets. The intraday markets' gate-closure is then the opportunity for market participants to balance their positions. The influence of this parameter is discussed in Borggrefe and Neuhoff (2011).

After the last gate-closure participants can no longer modify their positions and must pay the imbalances with actual generation or consumption in real-time[5]. The Transmission System Operator (TSO) is responsible for procuring the services necessary to manage imbalances, by purchasing electricity in the day-ahead market or in real-time. Systems differ in the way TSOs charge imbalances, as described by Vandezande (2011). Under a one-price system the same imbalance price is applied (with a different sign) to long and short positions. Under a two-price system a penalty is applied to imbalances going in the same direction as the system imbalance. We discuss in 3.2.3 the consequences of applying two-price mechanisms.

3.2. Large scale integration of intermittent renewables in wholesale markets

As mentioned in section 2, the investment and operation of generating units are determined by the interactions between the different incentives and market signals they receive. Support schemes only constitute a part of these signals. As i-RES become more largely integrated into power systems, they cannot be kept isolated from the market.

Moreover, the response of thermal generators to the new needs created by the large-scale development of i-RES will be based on price-signals received from the market. It is therefore required that the market is designed in such a way that the adequate signals can be provided.

[5] In some countries however (for example Germany), participants may adjust schedules after the last gate closure. More details on what is called "ex-post nominations" can be found in section 3.2.2.

3.2.1. Appropriate price signals in the day-ahead market

Negative prices

Electricity markets naturally feature non-convexities: thermal plants feature start-up costs, ramping constraints and minimum load constraints. Flexibility has a cost and even when prices are low some generators will be prepared to face losses in order to avoid shut down: thermal units could be expected to bid negative price for their minimum output to ensure that this is dispatched, even with strong wind generation. A study of the German electricity market by Nicolosi (2010) revealed that even when the prices were as low as -500€/MWh there was still 46% of the available capacity generating, including 83% of nuclear power plants and 71% of lignite power plants.

Spot markets without any negative prices	Spot markets featuring negative prices with a floor	Spot markets featuring negative prices without any floor
- Argentina	- Australia NEM	- Great-Britain
- Brasil	- Belgium	- Norway
- Korea	- Germany	- PJM-USA
- Portugal	- France	- Slovenia
- Spain	- Ireland	- Sweden
	- MISO-USA	- Switzerland
	- Netherlands	
	- Belgium	

Table 2: Presence of negative prices in the set of studied countries (Source: CIGRE WG C5-11, 2010)

As the share of i-RES increases, extreme events with zero or negative prices will occur more often. I-RES have very low marginal-costs and may receive additional generation support, and are therefore likely to be dispatched first as described in section 1.2. Furthermore as the load factor of i-RES is low the installed capacity will typically be several times greater than the average available capacity. There will then be times when the production from i-RES and nonflexible conventional generation[6] will be higher than demand and prices should be lower or equal to zero. In Spain prices were equal to zero for 300 hours in 2010. When electricity becomes a “bad” instead of a good, adequate (negative) pricing is necessary. However negative pricing is not implemented in all power markets and when it is implemented a floor is often in place. The value of this floor price varies significantly from -3000 €/MWh in Germany, France, Belgium, and the Netherlands (i.e. in the CWE region), -200 €/MWh in Denmark, and -1000 Australian $/MWh in the Australia NEM[7] (Australian Energy Regulator, 2011; Barquin, Rouco, & Rivero, 2011). To illustrate the variety of design, Table 2 presents answers of participants to the CIGRE questionnaire.

[6] « nonflexible » means that conventional generation features ramping rate, starting costs, long building time…
[7] On 25 April 2013, 1000 Australian dollars was worth around 790 Euros and 1030 US dollars

Support mechanisms make negative prices occur more often: generators benefiting from FiTs are immune to market prices since they receive the FiT whatever the system and market conditions. FiPs are more market oriented but, if negative prices are used to deliver incentives to i-RES to curtail generation, they should be set at least as low as the expected marginal costs of generating during this hour minus the premium. In the case where the marginal cost of generation is equal to zero and i-RES generators receive an expected premium X, they get an incentive to produce, even when the market prices are negative (until the negative price = - X). Therefore the floor for negative prices should be lower than – X. For higher floor prices, signals will be muted and i-RES generators will not be willing to curtail generation. Therefore such support mechanism make i-RES non flexible, whereas it could be more interesting to curtail them since they feature lower ramping and opportunity costs than thermal generation. Note that this reasoning will be modified in case i-RES are exposed to balancing charges: if they lose in average Y due to imbalances, they will have an incentive to produce until prices reach (-X+Y).

Finally, it can be considered that negative prices reflect the lack of flexibility of current electric systems, which are mainly based on the ability of generation to follow inelastic demand. They highlight the need to evolve towards a new paradigm where generation and demand are able to fit to each other (see section 6.2)

Price caps

In a liberalised electricity market and in the absence of additional incentives, generators' remuneration is provided by revenues from the energy market. The peaking units with the highest marginal costs can only cover their fixed costs at times of scarcity. As it is difficult at times of scarcity to distinguish scarcity rents from market power abuse, price caps have been put in place in most electricity markets. While economic theory indicates that price caps should be set at the Value of Lost Load (VOLL) this is difficult to estimate in practice, and price caps are usually set at much lower values[8], except in the Australian NEM (see box 2 and section 6.2). The lower the price cap, the more severe will be the 'missing money' problem described in section 1.2. Moreover, incentives for demand response and storage units will be reduced when the range of prices is low. While it might be argued that a wider spectrum of prices would lead to higher risks for participants, there are ways to hedge against such volatility. Price volatility is needed to deliver the incentives required to manage generation volatility. Price spikes provide incentives to reduce consumption (when consumers have the ability to process price information) and to invest in new generation units. Reducing the amplitude and the frequency of spikes will challenge generation adequacy unless complementary sources of revenue are introduced in the market. In section 6.4 we will introduce some of these solutions.

[8] In Spain OMEL has a cap of €180.30/MWh, in Denmark ELSPOT has a cap of €2000/MWh, German and French Day-ahead market have a cap of €3000/MWh. A literature survey of estimates for VOLL was conducted by Cramton (2000) who determined that estimates ranged from $2,000/MWh to $20,000/MWh. A 2011 survey has estimated VOLL at €26,000/MWh in France.

Box 2: Price caps in the Australian National Electricity Market

Price caps schemes can be sophisticated. In the Australian NEM, in addition to a standard A$12,900/MWh price cap, a Cumulative Price Threshold is also applied. This mechanism is designed to reach a compromise between the risk of financial damages of market participants exposed to spot prices and the minimum revenue necessary to cover the fixed costs and operating costs of the peaking plants used during only a few hours per year.

The cumulative price is calculated using a 7-day rolling window. As soon as the cumulative half-hourly spot price over this window exceeds A$193,900 a much lower administered price-cap of 300 A$/MWh is applied until the cumulative price falls back below A$193 900. This corresponds to an average spot price of A$577/MWh over 7 days or 7.5 hours of A$12 900 prices.

This situation occurred in January 2009 in South Australia and Victoria, for example.

3.2.2. Adequate time units

Getting closer to real-time

As explained in section 1.1.2, i-RES production is difficult to forecast on a day-ahead basis. If generators are not given the opportunity to adjust their positions during the last 24 hours before real-time they will be exposed to significant imbalance costs. Forecast error is significantly reduced closer to real-time, as illustrated in Figure 6. To integrate i-RES generators in electricity markets it is hence necessary to provide them with the opportunity to trade closer to real-time. Even in the case when i-RES are price-takers, the SO can then use the updated information about physical production to reduce the gap between forecast and actual generation by taking part in the market. Intraday markets have become a common feature of most surveyed electricity markets. They can be *Over-The-Counter* (OTC) as in Switzerland (transactions are then concluded directly between two traders or through a dealer network, without any centralisation). Alternatively, centralised options include *continuous power exchanges* when transactions are conducted on a first come first serve basis (as in Germany, Belgium and France or Nordpool), or *discrete auctions* which take place at a given time as is the case in Spain[9] (Barquin et al., 2011).

When intraday markets exist in a power system, the last gate-closure determines the last opportunity for participants to correct their positions. It is commonly assumed the closer this gate closure is to real-time, the less uncertainty faced by i-RES producers. There is a limitation to this reasoning: intraday markets must be sufficiently liquid. Liquidity is often low in intraday markets[10]. If i-RES generators cannot trust prices reached in the ID market due to poor liquidity the benefits of

[9] In Spain there are 6 intra-day auctions, which allow parties to adjust positions close to real time, when forecasts of generation and demand are more certain.

[10] In 2009, exchanges in the Spanish ID market represented 10% to 16% of exchanges in the Spot market; in Germany they represented 4.2% of exchanges, and they accounted for 0.5% in Denmark (Barquín, 2011). These three countries feature a significant share of renewables.

these intraday markets will remain limited. Due to oscillating predictions[11], i-RES producers might prefer not to trade in intraday markets and simply pay imbalances in real-time (Maupas, 2008).

The system operator requires a short delay to manage the system in a safe and efficient way so the minimum gate-closure time is therefore technically limited. However the time needed by the SO has been considerably reduced thanks to breakthroughs in information technologies: in the NEM (Australia) and PJM (USA) markets, gate-closure occurs every five minutes.

In a few power markets, it is even possible for two parties to exchange energy until the day following the physical trade. This scheme allowing ex-post nomination is applied in Germany: Balancing responsible parties (BRPs) may submit re-nominations and adjust schedules for electricity provision within the same control area up several hours after the delivery time. Ex-post nominations can be used for two purposes: 1. To nominate any transactions that were agreed before delivery but not nominated; 2. To enable the exchange of imbalances between two balance groups. At the end of the day-after process, each TSO performs a final verification of all internal exchanges. All nominations that have already been confirmed by an intermediate confirmation report are finally confirmed, whilst inconsistent nominations may either be rejected or corrected by the TSO according to some pre-defined principles. However, such an arrangement requires market participants to find a counterpart with the opposite imbalance. It does not address the forecasting issue of i-RES but provides an alternative financial method for addressing imbalances.

Reducing time-units

Shorter gate-closure times assist producers in managing the lower predictability of i-RES. However, electricity markets will also need be adapted to manage the variability introduced by i-RES. Reducing time units provides one way to transfer more balancing responsibility to market participants and to reward flexibility, as shown in Figure 11.

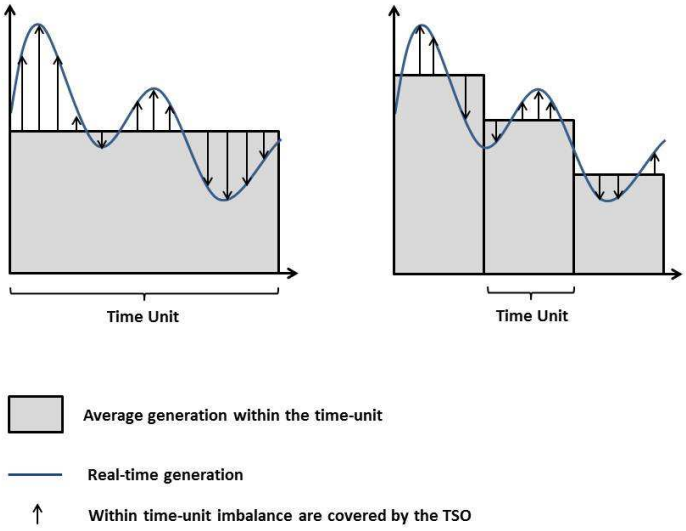

Figure 11: Responsibilities of the TSO for different time units

[11] The term "oscillating predictions" refers in this document to the situation when successive wind power forecasts for the same generation time alternatively overestimate and underestimate the real output.

When an hourly product is traded, imbalances are generally measured as the difference between actual and forecast average production over the full hour. The SO is then physically responsible for imbalances within the hour, as described by Frunt (2011), and the corresponding costs are socialised among participants. This scheme has been successfully applied to uncorrelated and relatively non-variable production units, but it might not provide the resolution necessary to handle i-RES variability. By reducing the time unit it is possible to shift responsibilities from the system operator to producers. It also allows a more accurate and therefore fairer remuneration for energy generation and delivers better incentives to reduce demand when most needed.

3.2.3. Pricing imbalances

The definition of imbalances can vary from market to market. In some power markets (such as France, and Germany), *gross settlement* is applied; imbalances are defined as the difference between injections and withdrawals within a perimeter. However in most power systems a *net settlement* is applied, where metered energy produced in real-time is compared to financial positions taken in the day-ahead and intraday markets. In case of difference, the term *negative imbalance* is used when production is lower than expected while the term *positive imbalance* is used when production is higher than expected.

This is a particularly significant problem for i-RES due to the challenges inherent in forecasting generation. Most power systems feature one or two pricing systems to charge imbalances. In *single-price systems* settlements are made at the same price whether imbalances are helping the system or not. Under a *dual-price system* a different imbalance price is applied for positive and negative imbalances. Typically, imbalances contributing to the system imbalance must pay a penalty while imbalances going in the opposite direction are settled on the basis of wholesale prices.

The rationale for dual-price systems is to give participants stronger incentives to manage their production and thus to reduce the occurrence of situations when the SO must cope with significant imbalances. High penalties create a significant advantage for generators operated as a part of a larger portfolio as demonstrated by Vandezande, Meeus, Belmans, Saguan, and Glachant (2010). These generators tend to manage imbalances within their own portfolio and often do not declare their full capacity, which creates a source of inefficiencies. Therefore, dual-price systems allow the system operator to reduce the risk of significant imbalances but this comes at a cost for generators and hence consumers.

		Conventional generators subject to:	
		Single-price system	**Dual-price system**
i-RES generators subject to:	**No imbalance charges**	- Brazil - Germany - Portugal - Switzerland	- France - Ireland
	Single-price system	- NEM[12] (Australia) - Korea - MISO (USA) - Netherlands - PJM (USA)	- Norway - Sweden
	Dual-price system		- Great Britain - Slovenia - Spain

Table 3: Imbalance-pricing systems in place in the surveyed countries (CIGRE WG C5-11, 2010)

As illustrated in Table 3, in many power systems i-RES are subject to a different regime or may even entirely avoid exposure to imbalance costs: Germany, Ireland and Portugal handle a significant penetration of i-RES without charging i-RES for imbalances. In France, i-RES imbalances are included in the incumbent's (EDF) perimeter: producers themselves are not responsible for imbalances. The rationale for this has been to minimise risk for i-RES developers, and it should be recognised that it constitutes an indirect support to renewables. It has also been argued that since i-RES are not able to control their output there is no point in providing them with incentives to do so. Nevertheless it is possible for these producers to improve their forecasting tools or to pool their offer with other uncorrelated power producers to minimise uncertainty. If i-RES producers are to be exposed to the costs they create in power systems charging them for imbalances must be considered.

[12] In some power systems such as the Australian NEM, the concept of imbalances is not really defined: generators are paid for what they produce at the pool price on a five minute basis. However in the context of our analysis this can be described as a single-price system, as featured in this table.

4. Ancillary services adaptation to RES

Power itself is only one of the goods provided by generators in a power system. A complementary set of ancillary services (AS) is needed to ensure the reliability and the quality of the power delivered. The impact of i-RES on these services is two-fold. Firstly, due to their characteristics described in section 1.1 including low-predictability, a large penetration of i-RES will impact upon the need for these services. Secondly, i-RES may be unable to provide some of these services, which has implications for the secure operation of high penetration i-RES systems. We review in this section the related additional challenges and possible solutions.

4.1. Impact of intermittent RES on AS

4.1.1. Classification of AS

There is a lack of consensus on the definition of Ancillary Services. Stoft (2002) for instance included economic dispatch, trade enforcement and transmission security in the list he established. In our analysis we apply the classification proposed by the CIGRE working group C5-6 (see Table 4). While some of the services described do not exist in every power system, this set of definitions is sufficiently accurate to allow a first-order analysis.

Ancillary Service Type		Operation	Application	Timeframe	CIGRE categorisation
Primary Frequency Control		Not directed by TSO	Instantaneous & Continuous Control	< 1-2 min	**AS-1**
Secondary Frequency Control	Load Frequency Control	Directed by TSO	Continuous	5-30 min	**AS-2**
	Contingency Reserves Spinning		Event-driven		**AS-3**
	Contingency Reserves Non Spinning				**AS-4**
Tertiary Network Control	Replacement reserves	Directed by TSO	Event-driven	30-120 min	**AS-5**
Voltage Control			Event-driven		**AS-6**
Black Start			Event-driven		**AS-7**

Table 4: Classification of Ancillary Services (source: CIGRE WG C5-6, 2010)

Primary frequency control: AS-1

In case of an imbalance between electricity generation and demand, the frequency of the grid will deviate from its standard value. The AS-1 service is designed to halt frequency change following a disturbance. It is generally provided continuously using turbine speed governors, and the reaction is instantaneous.

Secondary frequency control: AS-2, AS-3, and AS-4

Once the primary frequency control has stabilised the frequency to a steady but lower or higher level away from the standard value, secondary services are used to bring frequency back to its

standard value. AS-2 is provided continuously in response to a control signal, while AS-3 and AS-4 are both event-driven. AS-3 is provided by spinning reserves (i.e. unloaded generation synchronised with the grid and ready to be used) while AS-4 is not.

Tertiary frequency control: AS-5

Following the deployment of secondary control, tertiary control is used to free up fast-reacting units by replacing them with slower ones in preparation for another disturbance. The sequencing of reserves activation is shown in Figure 12.

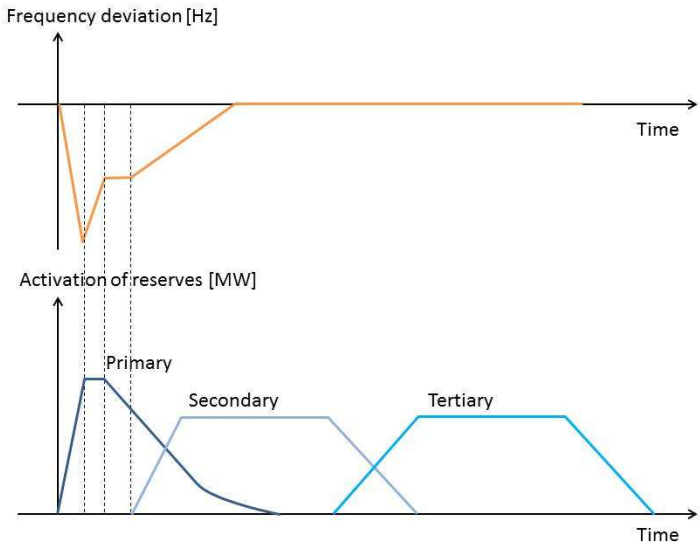

Figure 12: Frequency deviation and subsequent activation of reserves (Source: ENTSOE Operation handbook)

Voltage control: AS-6

Generally, voltage tends to drop as power flows from generators to load. Variations in voltage can lead appliances to underperform and to age more rapidly. To compensate for voltage drops, reactive power provision by generators and condensers is needed.

Blackstart service: AS-7

In case of severe event, a large part of the generation could be shut down. To be re-started, most generators require power from the grid. Restoring the power grid therefore requires generators able to provide a “blackstart” service (i.e. able to start without power from the grid).

4.1.2. Impact of Intermittent RES

Impact on primary frequency control

The impact of i-RES on need for primary frequency control will be limited. As calculated by Frunt (2011), on time scales of seconds to a few minutes the quick fluctuations of wind production will generally compensate for each other on an aggregate basis and remain small compared to load

variations. Moreover, the allocation of primary reserves in a power system is generally driven by the need to cope with outages of large generators. Large wind or solar power variations are generally much slower meaning that these primary reserves should remain sufficient.

The increased penetration of i-RES could result in a lower system inertia as described in a study by Fox et al. (2007). The inertia provided by the stored mechanical energy in a system plays a key-role in case of major disturbance: the higher the inertia, the lower the dynamic impact of the loss of a generation unit. In a conventional power system a significant share of system inertia is provided by thermal generators turbine, meaning that their displacement by i-RES could reduce system inertia and therefore make the system less resilient. DC technology, often used to connect distant offshore wind farms, decouples the stored energy of the wind turbines from the grid. Furthermore, variable-speed wind turbines and PV plant do not provide any inertial response, as discussed by Fox et al. (2007).

High system inertia does not decrease the need for primary reserves but rather allows them to react more slowly. Furthermore, lower system inertia also allows the system to recover more rapidly. There is significant on-going research that would allow i-RES to emulate inertia (See for instance Eirgrid and Soni (2009)).

Impact on secondary and tertiary frequency control

Due to uncertainty related to production forecasts, generation units might not be committed when needed, or committed when not needed. Calculations by Frunt (2011) showed this would lead to higher requirements, mostly for tertiary reserves. Additional reserve requirements are related to the system characteristics and estimations of the additional reserve requirements with increasing i-RES penetration vary greatly depending on the methodology employed. The study conducted by Holttinen et al. (2009) provided estimations for different power systems: for a wind penetration level of 20%, additional reserve requirements in a sample of international power systems ranged from 4% to 18% of installed wind capacity.

It is important to point out that additional reserve requirements do not mean more investments are needed: as emphasised by Perez-Arriaga (2012), the increased requirement rather means that a larger quantity of plant will need to be operated in a manner providing more ‘readiness’. Furthermore, in general reserves will be most needed when generation by i-RES is significant and hence when conventional units have spare capacity available.

The questionnaire conducted by CIGRE in the context of this report revealed current levels of reserves were considered adequate by all the respondents. It also showed that the level of reserves and the penetration by intermittent renewables were poorly correlated (see Figure 13).

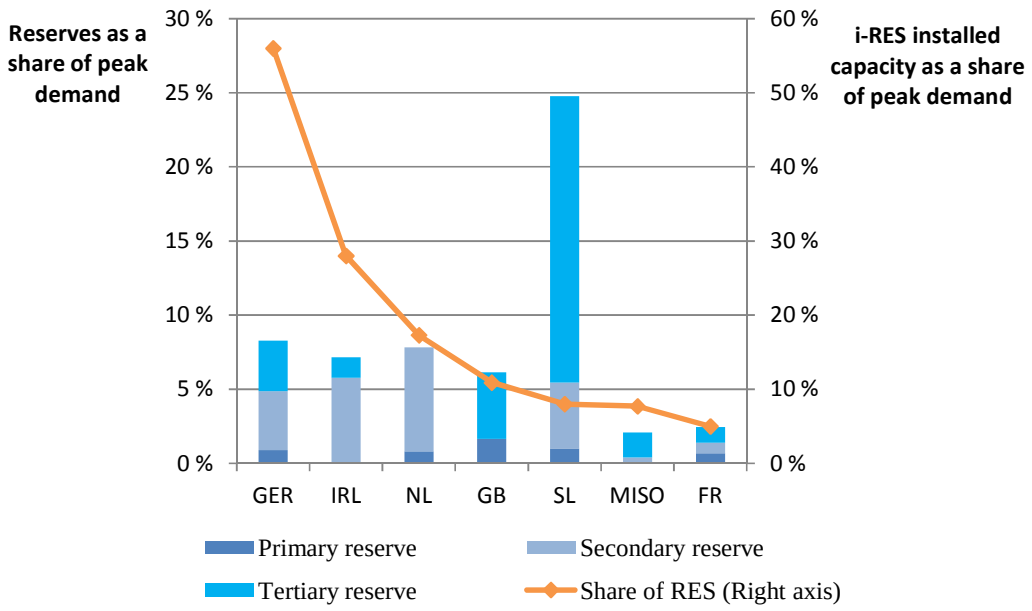

Figure 13: Level of reserves and installed i-RES capacity as a share of peak demand (source: CIGRE WG C5-11, 2010)

Other significant drivers of the requirement for reserves were found to include the size of the system and of the largest in-feed, and the flexibility of the generators in this system. In Slovenia (SL) for instance, the main driver for the size of reserves is the size of the largest generating unit (Krško Nuclear Power Plant). As this unit is quite large compared to the peak demand, the level of tertiary reserves required is also quite high.

The number of balancing zones and interconnection capacities also plays a key-role. When a system featuring low provision of reserve is closely interconnected with one with a high availability of reserve, the combined system generally has a lower aggregate requirement than the sum of the two systems alone. This has been the driver for merging balancing zones in Germany and is a strong point in favour of cross-border allocation of reserves (see section 6).

Provision of voltage control and blackstart services

There is no reason why i-RES should lead to an increased need for these services. However as they will displace the conventional generators that used to provide them, the burden will be transferred to the remaining units and to i-RES generator themselves. We study this possibility in section 4.2.1.

4.2. Managing new challenges

4.2.1. Integrating RES into ancillary services?

Traditionally, i-RES generators have not been required to deliver ancillary services. I-RES generators feature several characteristics that might prevent them from providing these services. For example, it would be difficult to rely on i-RES to provide blackstart services as by definition these resources might be unavailable when needed.

However, as i-RES generators increasingly displace thermal generators, the remaining thermal units might not be able to provide the full quantity of AS required. Fortunately, modern pitch-regulated[13] and variable speed turbines are able to provide real-time active and reactive power control, if the corresponding incentives are put into place.

In order to provide frequency control, a generator must be both flexible enough and available when needed. Wind turbines are for example flexible enough to provide frequency control and technologies are available to control their output as required (for example, variable-speed wind turbines and pitch-regulated turbines). While thermal generators typically ramp slowly and need a long lead-time to shut down, i-RES can usually switch-off immediately[14]. Technical requirements requiring these capabilities are already in place in many power systems. Worldwide, i-RES in France, the UK, Ireland, the Netherlands, Portugal, MISO (USA), Brazil, and Korea must be able to follow P/Q curves.

Yet, even when technical requirements are the same for conventional and i-RES generators, these requirements usually only specify an obligation regarding the technical capacity to provide ancillary services. There is no guarantee regarding the actual provision of these services. In Germany, a system featuring a high share of i-RES, there is no obligation to meet technical requirements but there is a financial incentive to do so: generators complying with technical specifications receive an add-on on top of the Feed-in-Tariff for five years.

Box 3: Provision of reactive power by wind farms: the Spanish case (*Source: Abbad (2010)*)

In Spain, the first Royal Decree regarding support to renewables 2818/1998 did not include any technical obligation.

Royal Decree 436/2004 introduced an economic incentive (and penalty) associated with the provision of reactive energy. The difference between the best incentive and the worst penalty amounted to 12% of the average total system cost.

Finally, Royal Decree 661/2007 made it mandatory for any facility bigger than 10 MW to be connected to a dispatch centre. When needed, the dispatch centre can dictate a particular set point to this facility.

As they have very low marginal costs, i-RES are often generating at their full potential[15]. In order to provide upwards regulation, generation by these units would need to be kept at a level below their potential, which would result in higher fuel consumptions and carbon emissions by other plants. Technically, i-RES could easily participate into downward reserve markets. Yet, due to their low marginal costs, i-RES generators will pay higher opportunity costs when voluntarily reducing output

[13] Pitch control aims at controlling the angle of attack that the blades of a wind mill present to the wind steam.
[14] Fox, Flynn et al. mentioned the case of Denmark, where wind turbines must be able to reduce the input power below 20 % of turbine rating within two seconds.
[15] When we reach higher penetration of i-RES, there are likely to be periods when i-RES units are curtailed anyway and therefore could provide upward regulation services essentially “for free”.

(by comparison to flexible thermal units with significant variable costs). I-RES will therefore require a higher price to provide some reserves.

4.2.2. Dynamic management of reserves

The level of reserves needed to cope with i-RES uncertainty will be strongly correlated to the expected share of generation provided by i-RES. Adjusting the level of secondary and tertiary reserves daily will allow a more accurate management of these reserves. Day-ahead sizing of reserves is already in place in most countries.

Since forecasts improve substantially closer to the production horizon, the level of required reserves could be usefully adjusted on an intra-day basis. Borggrefe and Neuhoff (2011) underlined the benefits of an intraday market for reserves: as the wind feed-in increases, the thermal power plants that have recently reduced their output would be able to provide positive balancing power at a low cost. Yet, in the absence of an intraday market for reserves these thermal players are not able to provide this service, and upwards balancing is provided by flexible units with high variable costs.

Therefore rather than simply increasing the level of reserves as i-RES penetration increases, a more dynamic approach could allow a swifter management and reduced balancing costs. However, intraday management of reserves exists in only a few power systems such as the Australian NEM, where frequency control reserves are adjusted continuously based upon the time-error in each dispatch interval.

5. Connection of intermittent renewables to the network

In this section we review how the rules for connecting renewable generators and the design of network tariffs influence the development of intermittent renewables. It is worth here to highlight the necessary temporal adequacy between the construction of i-RES units and the related upgrades of the networks (connection and reinforcements). While it takes between 24 and 36 months to build the new i-RES units, it can take up to 10 years for a new transmission line. Therefore there is a huge need for coordination, and for coordination signals, for the connection of new i-RES technologies.

5.1. Design for connection charges

When a new generator is to be installed, it must be connected to the grid. In addition, reinforcements of the network may be necessary. A wide range of schemes can be applied to recover these connection costs, each having consequences for the development of the generation sector.

5.1.1. Main existing policies

Deep connection policy

Under this scheme, both grid connection and network reinforcement costs are paid for by the generator. Therefore, it is intended to be fully cost-reflective and deliver strong locational signals to developers. Moreover, existing generators are not impacted by new developments, which is important in a competitive environment.

However the deep connection cost mechanism is seldom applied. Due to the nature of the electricity physical flows, it can be complicated to allocate the costs of augmentation to a given market participant. The electricity network has public good properties and the first-mover in the market might pay for capacities that will benefit other participants. A second reason that deep connection charging is rarely applied is that it creates significant additional upfront costs which can form a barrier to investment in new generation capacity.

Shallow connection policy

Under this scheme, the generator will only pay the grid connection costs. The complementary network reinforcement costs are covered by network charges. It is then cheaper and easier, for developers to install new generation. Moreover shallow connection charging avoids difficult and sometimes arbitrary decisions on the allocation of costs. The main drawback of shallow connection charging is the absence of cost-reflectivity and strong locational signals. Participants do not receive any incentives to invest in locations minimising the needs for investment in the network, which can produce inefficient outcomes and increase costs for consumers.

Hybrid approach

The shallow connection policy and the deep connection policy constitute two extreme solutions. In some systems, a hybrid approach has been applied, by adding a locational signal to shallow connection costs.

5.1.2. Which design for i-RES

When choosing a scheme for allocating connection costs, a trade-off is made between higher cost-reflectivity (deep connection costs) and easier development (shallow connection costs). The choice in-between the different connection charge allocation schemes depends also on the nature of transmission assets as a public good, knowing that the reinforcements/upgrades made on the network basically benefit to all stakeholders by improving the secure security of supply, even if they are due to one producer in particular.

However RES feature several characteristics that expose them to connection costs in a unique way.

Firstly, as described in section 1.1.3, RES are often located further away from load centres and have less flexibility in the selection of generation sites. In addition, i-RES usually have a relatively low capacity factor. Therefore, paying for network reinforcements sufficient to handle their full installed capacity will usually prove to be extremely expensive.

Deep connection charging policies will also be more difficult to put into place when i-RES constitute a large share of the electricity generated, due to the significant fluctuations of the power flows. The cost-allocation of network investments is already a difficult problem in a system without a significant share of i-RES, yet it will be even more problematic in a system with a high penetration of i-RES.

For these reasons, shallow costs are likely to contribute to a faster development of i-RES. In France, a deep costs policy was applied before 2002, but the rule was changed to shallow costs in November 2002 to allow i-RES integration, as described by Hiroux (2005). From the survey conducted by CIGRE (2010) it appears that shallow costs are applied in most countries both for i-RES and other generators (e.g. in Australian NEM, Belgium, Germany, Portugal, Spain and Sweden). In the UK, a hybrid approach is applied: site-specific connection charges (proportional to unit capacity) are implemented in addition to shallow connection costs. Deep connection costs are sometimes employed in North America (such as in the MISO system in the USA). In this case, any generator, including i-RES, is required to pay the deep connection costs. In France, Regional patterns for grid connection of i-RES, allowing a pooling of some network costs, is currently implemented (see appendix).

It is important to point out that the nature of the connection costs is not the only parameter impacting the development of i-RES, as underlined in an official report by the Swedish government (2008). It is argued in this report that the development of the wind power sector in Spain was slowed down by the significant delays needed to upgrade the grid. To cope with such difficulties, the European Union has given priority connection to renewables[16]. Such priority schemes are also in place in other countries (such as Korea).

Note that an open question is whether it is always optimal to connect i-RES at their full installed capacity to the grid, given that the full output will only be reached during a limited number of hours. Alternatively, more flexible connection arrangements could be designed allowing i-RES to be curtailed under certain conditions thereby limiting the need for extensive grid upgrades.

[16] Directive 2009/28/EC of the European Parliament

5.2. Network tariffs

Network costs are typically recovered via a transmission tariff that can be paid by consumers or generators. This study did not find evidence of any power systems using network tariffs to specifically support renewables. Rather, tariffs are usually designed such that they do not hinder the development of renewables. The survey conducted by the CIGRE (2010) revealed that RES generators are never exempt from injection tariffs when dispatchable generators are subject to this tariff.

There is however one characteristic that could be crucial for i-RES integration: whether charges are proportional to the energy consumed, or to the maximum capacity. Charges based on maximum capacity are for instance in place in Great-Britain, Ireland, Sweden and Brazil. Charges based on energy are in place in France, Norway and Israel. Due to their low capacity factor, i-RES are affected negatively by charges based on maximum capacity. Stoft, Webber, Wiser, and Division (1997) showed that charges based on maximum capacity would reduce the amount of intermittent capacity compared to the least-cost technology mix.

5.3. Network codes

According to ENTSO-E[17] definition, network codes are set of rules that apply to one or more parts of the energy sector. In this section we focus on requirements for generators, i.e. specific rules that all generators (potentially including i-RES) must comply with to be connected to the network. These rules are designed to ensure that generators contribute to stabilise the system frequency (frequency and voltage range under normal circumstances) and respond to faults (voltage ride through and reactive power injection at times of disturbances). As large-scale development of i-RES takes place, network codes must be adapted: on the one hand, compatibility of previous codes with new issues must be ensured; on the other hand, i-RES can no longer remain passive as their share in the generation mix increases (MIT Energy initiative, 2012).

A key-question for large-scale integration of i-RES is therefore to know to what extent these units can cope with the same requirements as thermal generators. Recent studies indicate that modern wind turbines are for instance able to cope with the same requirements as conventional generators (NERC, 2009). Recent grid codes developments indicate that standards are indeed evolving towards active contribution of i-RES (See for instance the review of grid codes provided by Altın et al. (2010)). Our surveys also revealed that there was no specific grid code for i-RES in a large majority of the participating countries. Exceptions at that time included Australia, Brazil, Ireland and Portugal. A majority of respondents also mentioned the obligation or the existence of economic incentives for i-RES to follow a set P/Q curve (more details can be found in section 4.2.1).

Recently, discussions have been taking place in the ENTSO-E area, where new grid codes are being drafted. Analyses by ENTSO-E revealed that current requirements on conventional power plants were appropriate to ensure the stability of the electricity network. However, the increasingly significant role played by i-RES would require re-allocating these requirements between future generators on a level playing field (including i-RES generators). The key issues identified included Fault Ride Through capacity, frequency and voltage stability, and remote control capability. Note

[17] ENTSO-E is the European Network of Transmission System Operators for Electricity.

that during the public consultation, doubts have been raised by wind power producer associations on the ability of i-RES units to deliver the same services as conventional generators without hindering investments in the sector.

6. Developing Complementary tools

6.1. Technical tools

6.1.1. Improving forecasting

The most obvious way to reduce the impact of i-RES low predictability on power systems is to improve the accuracy of forecasts. Forecasts for generation by i-RES are conducted using a wide set of tools, from Computational Fluid Dynamics meteorological models to statistical models. The quality of wind forecasts has improved considerably during the last decades yet these forecasts remain far from being perfect, as discussed in section 1.1.2.

Box 4: Incentives and responsible parties for the provision of accurate forecasts

1) Indirect incentives for producers in Spain: increasing exposure to imbalances

In Spain i-RES generators have been increasingly exposed to imbalances since the first Royal Decree RD 2818/1998 when they had no obligations regarding the accuracy of forecasts.

Under Royal decree RD 436/2004 large installations (larger than 10 MW) were to provide an output forecast to the distribution companies they were connected to. Furthermore, hourly forecast errors exceeding 20% were subject to penalties.

Since RD 661/2007, i-RES pay their full deviation costs.

2) Direct incentive for TSOs in Italy

Under article 5 of *deliberazione 351/07* established by the Italian regulator, the TSO Terna receives a performance-based incentive to accurately forecast the output of wind power plants. Depending on the evolution of the average hourly forecast error, the TSO will either receive a premium or pay a penalty.

3) Indirect incentive for TSOs and direct inventive to producers in Germany

In Germany, TSOs used to be responsible for selling 100 % of the energy from i-RES on the day-ahead market and to pay a penalty in the case of deviations. Under this regime the potential charges must be approved by the regulator before being passed through to consumers and TSOs can be held responsible in case of poor decisions. This is the main reason why TSOs have a strong incentive to use accurate forecasts (Ernst et al. (2010)).

Since January 2012, wind power producers can choose another option: the “direct marketing” of their production. In case of an inaccurate forecast they incur a penalty, which provides an incentive to invest in high quality forecasts technologies and introduces competition into the market for forecasts.

While better accuracy can be achieved via technological breakthroughs, it is important to point out that market design can play a key-role in improving the quality of forecasts.

Adequate market design can give participants an incentive to improve their forecasts. This incentive can be either direct (such as via a premium to participants for high accuracy forecasts or a penalty for poor accuracy forecasts) or indirect (such as via exposure to imbalances). Depending on the party responsible for the forecast provision, these incentives can also be directed towards the System Operator or the balancing responsible parties. The main issue concerns the identity of who would have the responsibility of the forecasts, and if this forecast responsible party is the most efficient to bear that charge. In other words, the forecast responsible party should receive the accurate signals and incentives to (i) optimize the forecast tools and (ii) to minimize the impacts of such forecasting errors. Once again it is important here to distinguish the need for the system real-time balancing and the need for market participants. Box 4 provides examples of incentives and responsible parties for the provision of accurate forecasts.

Good forecasts require good data. A study by MIT (2011) illustrated that the provision of accurate data by i-RES generators was critical for the production of accurate forecasts. This study also underlined that limited access to wind data at wind turbine-hub height constitutes a significant barrier to wind power forecast improvement in the USA. Furthermore, wind generation forecasts also require other elements such as maintenance schedules and the availability of individual turbines. The analysis of real time and historical data can also improve forecast accuracy.

6.1.2. Improving coordination

As the amount of power delivered by smaller distributed generating units increases, the participation of these units to the security of the network becomes necessary. However, even in case when adequate incentives would be in place, transaction costs might be too high for a single unit willing to participate very actively in electricity markets. By pooling a set of units under the control of an intermediary (aggregator, TSO…) it could be possible to unlock the technical potential of these units, increasing the economic value of these units and lowering the total costs for the system. Note that significant issues remain to be solved when it comes to determining control rights and allocating risks and revenues between the different producers. A heterogeneous set of experiences are already in place in different countries, from private initiatives and pilot R&D projects (e.g. research project Kombikraftwerk 2 in Germany), to mandatory schemes (See Box 5).

I-RES can also be pooled with DSM resources or other distributed controllable units such as micro-CHP plants. The resulting “Virtual Power Plants” can then participate as a single unit in wholesale electricity markets, or commit to provide reserves to the system operator. If connected to different points of the network, these units would still be required to dispatch separately to allow appropriate management of network congestion.

Box 5: Case of the CECRE in Spain

The Control Centre for Renewable Energies (CECRE) introduced in 2006 by Red Electrica de España is an operation unit integrated into the Electrical Control Centre (CECOEL). It is used to manage and control i-RES producers, including all wind farms with an installed capacity greater than 10 MW.

Wind farms are connected to authorised generation control centres connected to the CECOEL through the CECRE. The information needed to ensure real time operation (such as active and reactive power, voltage, temperature and wind speed) is provided to the CECRE every 12 seconds.

Once this information has been analysed and calculations made, the results are sent to the generation centres that must follow the instructions delivered.

This two-way communication allows optimisation of the integration of i-RES under secure conditions.

6.2. Demand-side management

As discussed in the previous sections of this document, flexible generation resources will be required to manage the variability of i-RES. However, flexibility can also be provided by the demand-side of the electricity market. Many believe that Demand-Side Management (DSM) could deliver many important power system services (See Table 5).

Service provided	Description
Peak Clipping	Reducing the utility load primarily during periods of peak demand.
Valley-Filling	Improving the system load factor (increasing load in off-peak periods).
Load Shifting	Reducing utility load during periods of peak demand, while at the same time increasing load in off-peak periods.
Conservation	Reducing utility loads, more or less equally, during all or most hours of the day.
Flexible Utility Load Shape	Setting-up utility options to alter customer energy consumption on an as-needed basis.

Table 5: Services provided by Demand Side Management

DSM resources are already able to react rapidly enough to cope with the operational challenges created by i-RES. For example, in the PJM market, DSM resources bidding in the capacity market are

required to be dispatchable by the system operator within 30 minutes. However, technical potential constitutes only one of the prerequisites. In order to provide a demand-response service consumers need to be informed when they should curtail their consumption, and they need an incentive to do so.

Information can be provided through the use of smart-meters. 100% of the households in Sweden and Italy are already equipped with smart-meters while plans of deployment or experimental programs are taking place in France, Belgium, Portugal, and Brazil. Rollouts of smart meters have also started in two regions within the Australian NEM, and large-scale plans have also been developed in the PJM in the USA.

Incentives must also be provided by mechanisms such as dynamic retail rates. Retail tariffs without time-differentiation (regulated or not) do not deliver any incentives to consumers to reduce their consumption when needed. In the context of competitive retail electricity markets, retailers have an additional incentive to differentiate the products they offer to consumers by providing a menu of flexible contracts. If DSM is to play a role in electricity markets, good price signals are necessary: price-caps (positive and negative) limiting the incentives to invest in flexible generators will also reduce the incentives for DSM. In addition, since DSM programs typically feature high upfront investment costs (requiring, for example, the installation of smart-meters) they will be extremely sensitive to uncertainty regarding the regulation of electricity prices.

Box 6: Examples of DSM programs

1) France: Load-shedding on peak-days

In France, the historical supplier EDF introduced in 1982 the scheme "Effacement Jours de Pointe". Households and industrials benefit from a lower average tariff if they agree to pay a significantly higher price (up to 10 times higher) during 22 days from 1st November to 31st March each winter. Customers electing this option receive a signal on D-1, either via a red light on their meter or by a text-message, indicating when peak pricing periods are occurring. This creates a strong incentive to reduce their consumption during those periods.

2) Participation in ancillary services in PJM

In PJM, eligible DSM resources can participate on a voluntary basis in three Ancillary Services markets:

- Synchronized Reserves (Reducing consumption within 10 minutes of PJM dispatch)
- Day Ahead Scheduling Reserves (Reducing consumption within 30 minutes of PJM dispatch)
- Regulation (Following PJM's regulation and frequency response signal).

It is also important to recognise that DSM resources can have reliability issues. Therefore it is sometimes assumed that it is not possible to rely on consumers to supply DSM in the critical periods. Therefore, the critical investments for quality of supply must be supplied via other means: this is generally the task of System Operators, mostly distributors (CIGRE 2010). Moreover, while it is

possible for DSM resources to shift load from one hour to another, it could prove more difficult to provide long-term (up to one week) generation dips experienced in power systems featuring a high i-RES penetration during anticyclones. Aggregation of consumers into an active pool is a possible solution to this problem, symmetric to the benefits of aggregation of i-RES described in section 6.1.2. Aggregators providing this service already exist in NEM (Australia), PJM (USA), France, Germany or Norway. Some of these aggregators are now targeting the integration of i-RES through the use of DSM.

Note that a link can sometimes be established between the market price cap and DSM. For example, in the Australian NEM the market price cap (A$12,900/MWh) is the maximum price scheduled generators (and any scheduled loads) may bid for dispatch and is also the price set if involuntary load shedding is initiated by the system operator. As a result the spot price:

- may go to the market price cap if supply is very short, the last scheduled units are dispatched and they have bid at the cap;
- will be set under the rules to the cap if involuntary shedding is initiated by the system operator – this makes the cap price a default demand side bid price.

6.3. Storage

The ability of storage technologies to accumulate energy for later release provides an alternative worth consideration to manage the technical challenges described in section 1.1, such as low predictability and variability.

Two main options are possible, as described by Denholm, Ela, Kirby, and Milligan (2010). Storage technologies can be integrated at the level of individual i-RES plant to support operation or integrated at a system scale to support system operation. Operational support to i-RES plants can include Transmission Curtailment, Time Shifting, Forecast Hedging, Frequency Support and Fluctuation Suppression as described in Table 6.

Service provided	Description
Transmission curtailment	Mitigation of constraints imposed by insufficient transmission capacity at times of exceptionally high output.
Time shifting	Storing energy at times of low-demand to discharge at high-demand.
Forecast hedging	Mitigating the exposure to imbalances penalties.
Frequency support	Maintaining grid frequency following a system disturbance.
Fluctuation Suppression	Stabilizing wind farm generation frequency.

Table 6: Services provided by storage units at a RES-operation level (Source: Electric Power Research Institute (2004))

As the benefits of aggregation are lost when a local storage unit is employed to smooth the output of an individual unit, it is often more efficient to operate storage units at a system level. Therefore, in most power systems storage capacities are not directly used by individual wind farm operators. There are nevertheless some exceptions when the benefits of sharing expensive components at a single location are sufficient; typical examples include concentrated solar power plants (CSP) featuring thermal storage, as developed in Spain or in the USA.

While most of the installed storage capacity in the world is pumped-hydro, storage units include a wide variety of technologies with significantly different characteristics (such as storage capacity and ramping speed). As a result the range of services they can deliver is also large (see Ruester, He, Vasconcelos, and Glachant (2012) for a complete description of these services). Most of these services will be delivered (when cost-effective) by investors as long as sufficiently strong and reliable price-signals are in place in electricity markets (see discussion in section 3.2.1).

Rather than designing complex targets for storage development, a simpler approach could consist of ensuring storage units are allowed to compete in electricity markets as standard generators. In the USA for instance, FERC orders 890 and 719 required ISOs to modify their tariffs and market rules to ensure that energy storage units could participate freely in electricity markets (Electric Power Research Institute, 2010).

When storage facilities participate in electricity markets, their profitability depends on the spread between peak and offpeak prices. Therefore this profitability will be impacted if the spread gets lower as a result of large-scale development of renewables. More generally speaking, any regulatory measure affecting this spread (such as price-caps and floors) will lower the profitability of storage.

The question of grid tariffs applied to electricity storage can be crucial for incentivising the development of this technology. In some countries, specific tariffs are applied to storage (e.g. Switzerland, Austria). In some cases, certain storage technologies may be exempt from grid tariffs as it is the case in Germany for new electricity storage facilities until 2020 (See Ruester et al. (2012)).

6.4. Investments in flexible generation units

6.4.1. The need for flexible generation

Flexible generation units are one of the tools for managing i-RES variability and low predictability from the supply-side. Currently, a large share of the flexibility of power systems is delivered by such generation units.

The flexibility of a power plant is determined by a set of technical characteristics such as start-up time, start-up costs, ramp rate and minimum stable generation (IEA, 2012). While natural gas, coal and nuclear-fired generation plants are all able to vary their output, gas-fired power plants endowed with low investment costs and high flexibility are able to most cost effectively contribute a significant share of these resources.

When a power plant is made to function in a more flexible way (e.g. ramping up and down more frequently) it is exposed to cycling costs including lower fuel-efficiency, shorter life-time and higher maintenance costs. Therefore it is essential that the generator receives the value of this additional

flexibility for the System Operator. While part of this remuneration should be provided through fluctuating price signals in well-designed electricity markets, regulatory tools such as price-caps and floors often distort the signals received by investors.

Some of these flexible units will only be needed to generate a few hours a year. The high uncertainty on revenues could repel potential investors. Even in less extreme cases, the reduced load factor resulting from higher i- RES penetration could depress revenues of conventional units. In Spain, for example, thermal generating plants have seen a significant reduction of their load-factor (See Figure 14).

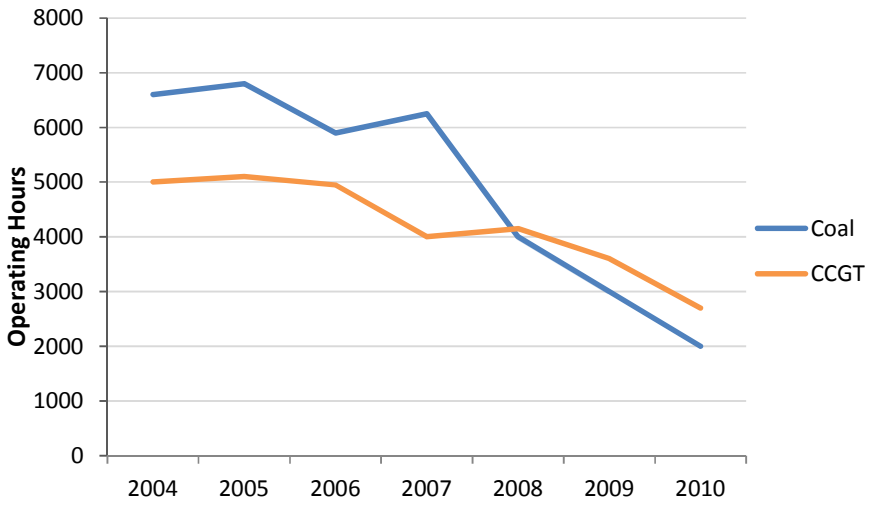

Figure 14: Operating hours (full capacity) of CCGT and coal plants in Spain (Source: Eurelectric)

6.4.2. Capacity remuneration mechanisms

As mentioned in the previous section, flexible generation units might encounter challenges in recovering their fixed costs in an energy-only market unless market prices can rise to very high levels. This phenomenon is not new and has been the subject of much debate in a range of markets. While some countries have decided to rely on an energy market only (such as the NEM in Australia), others have implemented capacity markets or capacity payments, as it is the case in Ireland and PJM.

The discussion has been renewed in recent times due to the increasing penetration of i-RES, increasing the risk to financial viability. Discussion includes the possible need for development of capacity remuneration mechanisms in order to ensure an adequate level of investment.

Some countries experiencing high i-RES generation, like Germany, are thinking of introducing a capacity market to deal with new generation investment, in response to lack of market signals to build peak and reserve capacity (EWI 2012). If such mechanisms are put into place, it will be necessary to ensure that they remunerate flexibility and not simply capacity.

The potential for these mechanisms to become a new subsidy scheme in addition to subsidies for the renewable sector should be avoided. A capacity market mechanism can take years to implement, during which the conditions of the electricity system can change dramatically. Finally, there is no complete consensus on the best way to address the “missing money” problem.

It has been suggested that introducing capacity remuneration mechanisms in addition to energy payments would be a way to support the development of storage capacity by providing them with another source of revenue. A non-discriminatory approach should be applied if capacity remuneration mechanisms were to be introduced for standard generators. It is indeed important that such capacity remuneration mechanisms should be carefully designed to avoid any distortions, for instance between supply-side response and demand-side response (Gottstein & Skillings, 2012), or between interconnected neighbouring markets.

A possible alternative to support the deployment of storage resources is to design special reserve products more adapted to the technical characteristics of storage resources. For example, the Midwest ISO in the US recently developed such a product; *Stored Energy Resources* are able to supply operating reserves and are only required to deliver 100% of their capacity for a duration of five minutes (instead of the 60 minutes imposed on other resources).

The topic of capacity markets and capacity payments has been the subject of extensive research (see for example CIGRE TF C5-7.1 Technical Brochure “The impact of electricity market design on infrastructure investment”, 2012), further analysis is outside of the scope of this report.

7. Conclusion

The large-scale development of i-RES is progressing worldwide, mostly driven by a set of political and regulatory decisions. A significant penetration of intermittent renewables will constitute a challenge for the safe and economical operation of power systems.

Intermittent-RES are often relatively passive participants in electricity markets. In some cases, incentives schemes introduced to support renewables could isolate them from important market signals or even distort the market prices when i-RES capacity grows.

One could argue that the existing rules in electricity markets were not tailored for units featuring a variable and poorly predictable output. If i-RES are to form a significant proportion of electricity systems, they must play an active role in electricity markets. This is especially the case for Ancillary services. Any support mechanism should be designed in such way that it not only fosters i-RES but that it also addresses system integration concerns.

Intermittent RES must be connected to the grid, and their development might require additional investments to reinforce networks. This creates challenges regarding the way connection costs should be charged.

From our analysis, there is often a trade-off between greater cost-reflectivity versus fewer barriers to investment for i-RES technologies. Approaches favouring cost-reflectivity include exposure to electricity prices, charging imbalances, paying deep connection costs. By contrast, Feed-in Tariffs and shallow connection costs tend to isolate i-RES from the costs they generate. The large variety of schemes and rules in place in power systems worldwide partly reflect these preferences.

Strikingly, systems featuring the highest shares of i-RES (Spain, Germany and Portugal) present significant differences in the way they manage i-RES. Their approaches also tend to differ significantly from theory. This phenomenon reveals that it is difficult to analyse power system operation on an individual rule-by-rule basis. Rather, the entire package of rules in place in a power system must be considered as a whole. It is also tricky to apply a general theory to power systems widely differing in terms of infrastructures and available resources. As recently underlined by the Council of European Energy Regulators (CEER) in its report Implications of Non-harmonised Renewable Support Schemes, what investors need is a stable set of rules rather than a perfect, harmonised scheme to support renewables. Discrepancies in rules between national power systems might hamper competition but they also allow for different national characteristics and ambitions. While power systems could benefit from examination of foreign experiences, this study highlighted that very different approaches were appropriate in very different power systems, which must be kept in mind when applying lessons from abroad.

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Appendix 1: Market Design for the integration of i-RES in Australia

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1. Introduction to Australian Electricity Markets

There are two significant electricity markets in Australia: the National Electricity Market (NEM), which spans the eastern states, and the South-West Interconnected System (SWIS), located in Western Australia. These are illustrated in Figure 15. There are also small stand-alone systems in the Darwin-Katherine, Alice Springs (Northern Territory), and Mt Isa (western Queensland) areas, fed by a combination of gas turbines, steam turbines and reciprocating gas/diesel generators. The rest of Australia is very sparsely populated and served by small local systems (generally diesel generation).

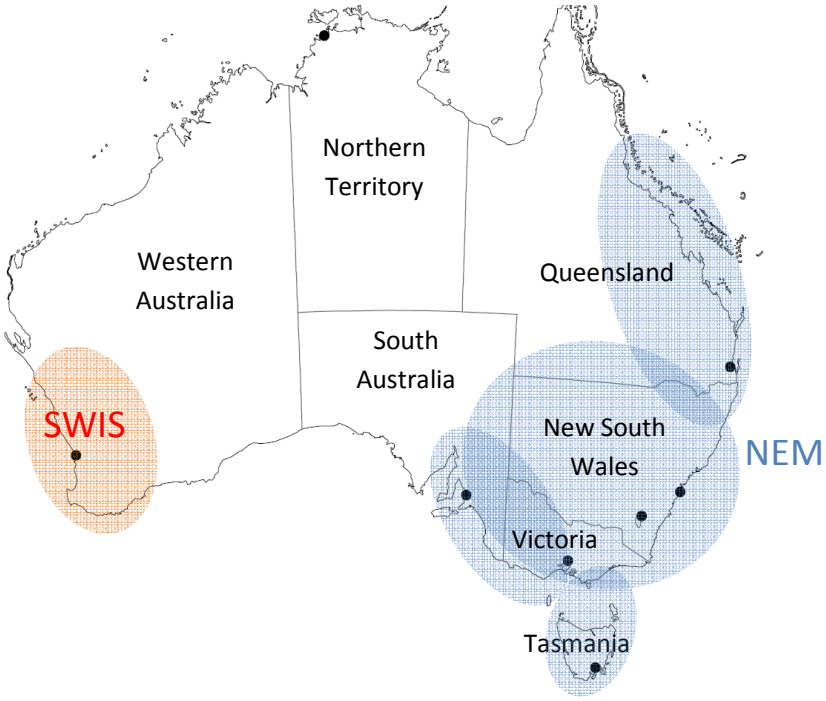

Figure 15: Australia's electricity markets

The NEM serves around 80% of the electrical load in Australia, with an annual energy consumption of 200 TWh and a peak demand of 35 GW (Australian Energy Market Operator (AEMO), 2011; Australian Government, Department of Resources, Energy and Tourism, Bureau of Resources and Energy Economics, 2012). The SWIS is a much smaller system with a peak demand of 3.8 GW and energy consumption of 18 TWh pa (Independent Market Operator of Western Australia (IMO WA), 2011), supplying around 7% of the electricity in Australia. The maximum demand for both the NEM and the SWIS occurs in summer (associated with hot weather). The sole exception to this is the Tasmanian region, where heating loads drive a maximum demand in winter. Tasmania is connected

to the mainland grid via a DC undersea link called Basslink (nominal maximum capacity of 500 MW on a continuous basis).

Both the NEM and the SWIS are completely isolated from each other and from surrounding grids. Connection of the SWIS to the NEM would require the installation of more than 2000 km of high voltage transmission network, which is likely to be prohibitively expensive in the near future.

1.1. Strong demand growth

By contrast with many European countries, Australia exhibits strong economic growth, which is reflected in a growing demand for electricity. The projected annual growth rate in peak demand is 2.6% in the NEM (Australian Energy Market Operator (AEMO), 2011) and 3.7% in the SWIS (Independent Market Operator of Western Australia (IMO WA), 2011). However, energy supplied by the NEM market has fallen over the last three years due to slower than expected recovery from the global financial crisis, milder than expected summers, increased penetration of embedded generation (mainly rooftop PV), and possibly a contribution from increasing customer awareness and investment in energy efficiency (Australian Energy Market Operator (AEMO), 2011). This trend is not expected to continue, with energy consumption projected to grow at an average of 2.3% per annum over the coming decade in the NEM (Australian Energy Market Operator (AEMO), 2011) and 2.9% in the SWIS (Independent Market Operator of Western Australia (IMO WA), 2011).

1.2. High reliance upon coal-fired generation

Around 75-80% of NEM electricity is supplied by coal-fired generation, with an additional 15% from gas-fired generation (Australian Government, Department of Resources, Energy and Tourism, Bureau of Resources and Energy Economics, 2012). At present, renewable technologies only supply around 6-8% of NEM electricity, with the majority coming from hydro resources (5-6%). Wind currently supplies approximately 3% of NEM energy (Australian Energy Market Operator (AEMO), 2012). Despite the present high reliance upon coal-fired generation, more than half of the proposed new capacity is in renewable technologies, mostly in wind generation. The majority of other proposed new plant is gas-fired (Australian Energy Market Operator (AEMO), 2011). Although significant low cost coal resources remain, the recent introduction of carbon pricing in Australia makes investment in new coal-fired generation high risk.

The SWIS has a higher reliance upon gas-fired generation; 40-50% of electricity is supplied by gas-fired generation with coal providing the bulk of the remaining energy (Electricity Supply Association of Australia (ESAA), 2009). At present, renewables supply 6-7% of energy in the SWIS, almost entirely from wind generation (85-90%) plus landfill gas.

Western Australia (WA) and Queensland (QLD) have substantial natural gas resources, which has led to the development of a Liquid Natural Gas (LNG) export industry in WA, and a rapidly developing LNG industry in QLD. The imminent expiry of major domestic contracts has put significant upward pressure on domestic gas prices in WA. A policy for domestic reservation of 15% of volume has had only limited impact on prices (Department of the Premier and Cabinet, Government of Western Australia, 2006). Similar outcomes are possible in the QLD market in the near future.

2. *Renewable resources in Australia*

2.1. Wind resources

As illustrated in Figure 16, wind resources are high in the southern states of the NEM and in the SWIS. This is driving wind generation development supported by the national Renewable Energy Target scheme (outlined below) to locate in these areas. Many existing wind farms achieve capacity factors in the range 35-45% (Australian Energy Market Operator (AEMO), 2012; Office of the Renewable Energy Regulator (ORER), Australian Government, 2012). Significant land areas remain available for wind development, so offshore wind development is not considered likely in the immediate future.

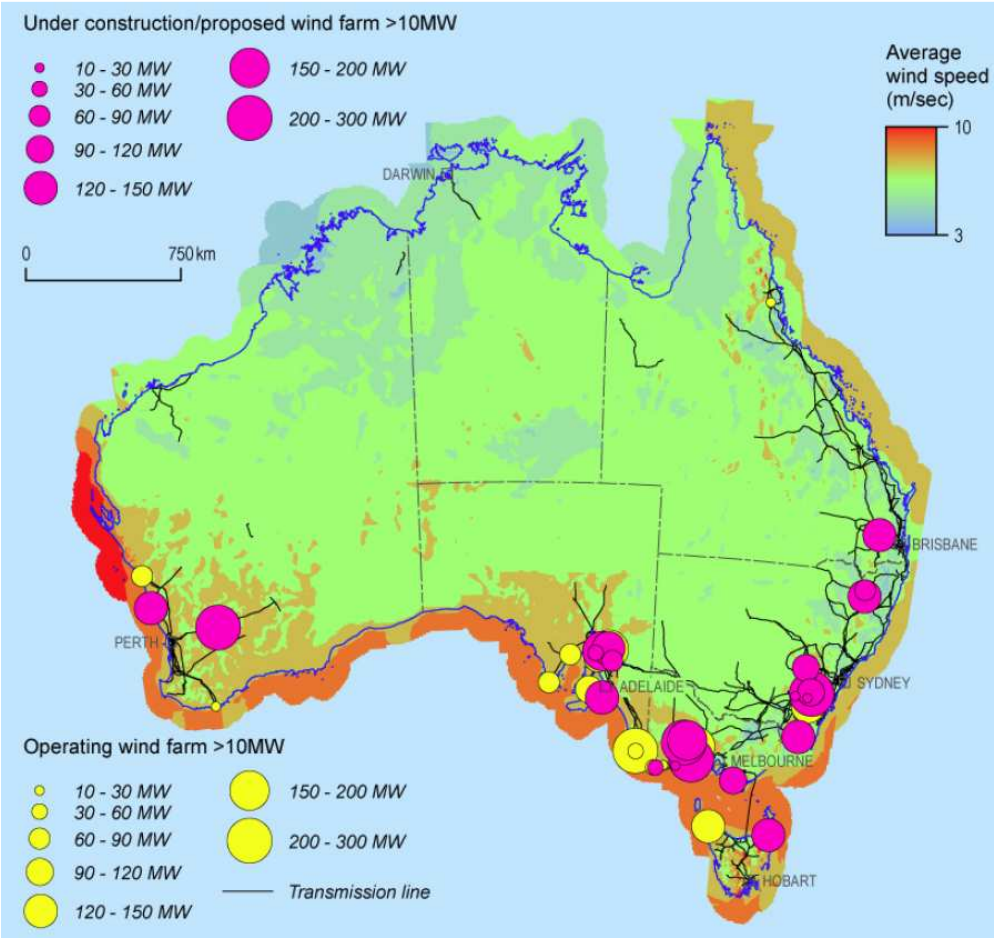

Figure 16: Wind resource in Australia (Australian Government, Department of Resources, Energy and Tourism, Geoscience Australia, 2010)

Unlike some other nations, wind resources in Australia do not demonstrate a strong correlation with season. Time of day wind trends vary site to site and are not generally consistent. Most wind farms do not demonstrate a strong correlation with demand, except for a slight reduction in average generation during the highest peak demand periods (Cutler, Boerema, MacGill, & Outhred, 2011).

The majority of NEM wind development to date has occurred in the South Australian region, which features a relatively small load. This means South Australia wind penetration is 20-23% by energy (Australian Energy Market Operator (AEMO), 2012), with 1204 MW of wind capacity installed (Australian Energy Market Operator (AEMO), 2012). This has resulted in depressed South Australia wholesale pool price (Cutler, Boerema, MacGill, & Outhred, 2011), with zero and negative prices now occurring for 42-85 hours each year (mostly when significant wind generation is operating) (Australian Energy Market Operator (AEMO), 2012). For this reason, minimal new wind development in this region is anticipated unless the transmission network connecting South Australia to Victoria is significantly strengthened.

Wind developers in Australia realise significant economies of scale for two reasons:

1. Wind developers widely agree that the acquisition of a suitable Power Purchase Agreement (PPA) is essential for securing project financing, and the retail sector in Australia is oligopolistic, with only three major retailers. This makes negotiation of PPAs challenging, regardless of the size of the project.
2. Negotiation of grid connection in the NEM is widely viewed as challenging and laborious, regardless of project size. Automatic access standards are demanding to meet, and sometimes impossible to achieve due to conflicting requirements.

This has meant that most wind developments in Australia are more than 50 MW in size. This further reduces the geographical diversity of wind generation in the system. This is a particular issue in the SWIS, where the scale of wind developments is particularly large relative to the system size. For example, the 206 MW Collgar wind farm commissioned recently increases SWIS wind penetration from 4-5% level to 7-8% by energy, in a single wind farm (Collgar Wind Farm, 2012). Large development increments create challenges for system operators.

2.2. Solar resources

Australia features excellent solar resources, with an annual global horizontal insolation of 2000-2300 kWh/m^2, up to twice that of Germany (European Commission). A typical large-scale, grid connected, fixed flat panel photovoltaic (PV) system is projected to achieve capacity factors around 21-23% (Bureau of Meteorology (BoM), Accessed July 2011).

As in other global locations, solar resources are generally higher during summer, coinciding well with peak demands. Queensland is an exception to this, with the summer monsoon season decreasing average solar irradiance levels.

Thus far, solar development in Australia has been solely at the residential scale, due to favourable subsidies (discussed below). As of March 2012, there was more than 1430 MW of residential scale solar PV installed in Australia, with growth around 20-40 MW per month[18]. More than 840 MW was installed in 2011 (Clean Energy Regulator, 2012). This means residential scale solar now provides around 0.6% of NEM energy (Australian Energy Market Operator (AEMO), 2012).

[18] It is unclear whether this growth rate will continue given the recent reduction of subsidies for residential scale solar.

Australia's first large-scale solar project is currently under development: a 10 MW solar farm in the SWIS, supported by a state government grant (Verve Energy, 2012). Further large-scale solar development may eventuate in the near future, supported by the Solar Flagships scheme (outlined in more detail below).

2.3. Other renewable resources

Although Australia currently sources some energy from hydro resources, minimal further development of hydro power in Australia is anticipated; remaining watercourses are of high environmental value, and the anticipated prevalence of drought limits the accessible value in developing these sites.

Some further development of biomass resources may be possible in Australia, utilising, for example, waste fibrous material from the north Queensland coastal sugar cane industry (bagasse). However, development of these resources for large-scale electricity generation has been limited to date, likely due to challenges in collecting and storing the bulky material for year-round operation, reliance on commodity cycles, and other non-economic barriers.

Australia also features significant geothermal resources, although at a depth that has proved difficult to reach and located at sites remote from the existing grid. Commercial development is not expected to be wide-spread until 2030 or later.

3. Incentive mechanisms in Australia

3.1. 20% Renewable Energy Target (RET)

The most significant mechanism supporting renewable development in Australia at present is the Renewable Energy Target (RET). At inception, this scheme aimed to reach 20% of energy supplied from renewable sources by 2020. In practice, the percentage may be greater as the target was translated to specified energy targets but demand is now forecast to be less than expected. It is a green certificate scheme, with eligible generators creating Renewable Energy Certificates (RECs) for each MWh of energy produced. Retailers have an annual liability to surrender certificates to the Clean Energy Regulator, defined by the Renewable Power Percentage (RPP) applying in each year. The price of certificates is therefore determined by the market supply-demand balance.

The scheme has two parts: the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).

The LRET aims to procure 41,000 GWh of energy from large-scale renewable generation by 2020. Certificates created by large-scale renewable generators are called Large-scale Generation Certificates (LGCs). The RPP for the LRET (which dictates the annual liability of retailers) is determined from legislated targets (in GWh) applying in each year. The price of LGCs is market

determined and capped by a shortfall charge of $65/MWh (nominal)[19]. Given taxation considerations this shortfall charge equates to an LGC price cap of around $92/MWh (nominal).

The SRES provides a subsidy for small-scale renewable technologies (including residential rooftop photovoltaics and residential solar water heating). Certificates for the entire life of the unit are created (deemed) when it is installed. The RPP for the Small-scale Renewable Energy Scheme (SRES) is determined based upon the number of certificates created each year, such that demand matches supply. The price of STCs is capped at $40/MWh (nominal).

Figure 17 illustrates the RET targets applying in each year. The 20% by 2020 target includes contributions from renewable generation installed prior to 1997 (mostly hydro generation) which may create certificates when they operate above their historical baselines. During high precipitation years the number of certificates created has been significantly boosted without requiring the installation of further renewable generation.

The LRET was preceded by the MRET (the Mandatory Renewable Energy Target), which began in 2001. This earlier certificate scheme successfully increased the quantity of renewable generation installed, closely in line with the annual targets (as illustrated in Figure 17).

In 2009, global prices of solar photovoltaic modules decreased by 13% in response to a worldwide oversupply of modules, caused by the economic slowdown and a change of government policy in Spain. Simultaneously, the Australian dollar appreciated significantly, which in combination caused a 40% reduction in Australian module prices (AECOM, 2010). This coincided with the introduction of several extremely favourable domestic policies to support residential photovoltaic installation, including attractive feed-in tariffs and a “solar multiplier” which allowed small-scale technologies to produce five certificates for each MWh of generation produced (compared with one certificate per MWh for large-scale technologies). The combination of these factors resulted in a massive oversupply of the REC market in 2009, 2010 and 2011, as illustrated in Figure 17.

[19] All prices in this case study are in Australian dollars, unless otherwise indicated.

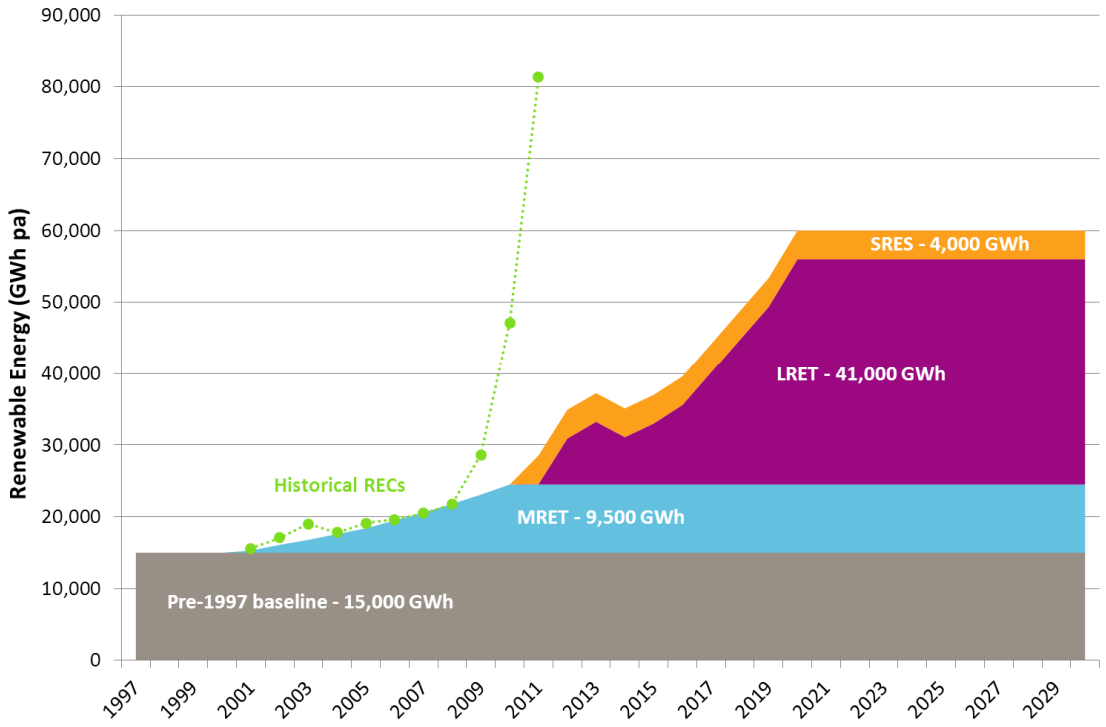

Figure 17: Renewable Energy Targets in Australia (Office of the Renewable Energy Regulator (ORER), Australian Government, 2012)

At the time when the oversupply occurred, there was no distinction between large- and small-scale certificates; the division of the two schemes (LRET and SRES) was a result of this event. Since there was no distinction, the oversupply in small-scale certificates resulted in an oversupplied market, which reduced the price of certificates below the economic level required to support new wind development. This stalled the renewable energy market in Australia since 2009.

Now that the LRET and SRES have been split, analysis indicates that the oversupply in certificates in the LRET (which carried over from the previous scheme) will end in 2015-16 (Office of the Renewable Energy Regulator (ORER), Australian Government, 2012). Given commissioning timelines, this suggests retailers will seek power purchase agreements for renewable energy supply from late 2012 onwards.

Almost all large-scale Australian renewable developments sell the majority of their energy via pre-agreed power purchase agreements (PPAs) with retailers. These agreements specify a constant price (for example, $100/MWh) at which energy will be purchased. This price includes “black” electricity, as well as green certificates, and therefore provides a natural hedge for both parties against changes in electricity price (caused by the introduction of a carbon price, for example). Securing a suitable PPA which transfers a significant proportion of project risk to retailers is widely viewed in the Australian renewable industry as essential for procuring project financing.

3.2. Feed-in Tariffs (small-scale technologies)

In 2010 all regions of Australia offered feed-in tariff schemes to support the development of small-scale renewable technologies, particularly rooftop photovoltaics (Productivity Commission, 2011, p. 84). These schemes have been extremely popular and created significant demand for solar photovoltaics. Generous feed-in tariffs became fully subscribed in a short period, with most reaching capacity caps far earlier than anticipated (Office of the Renewable Energy Regulator (ORER), Australian Government, 2012). This resulted in rapid policy changes. All such schemes are now closed to new connections, or have significantly reduced the payment rates (Alternative Technology Association, 2012).

3.3. Solar Flagships

The Solar Flagships scheme aims to support the commercial demonstration of large-scale solar projects in Australia with the installation of 1 GW of solar capacity by 2020. Half of the funding is targeted at photovoltaics, and half at solar thermal technologies.

Solar Flagships is a capital grant scheme, requiring proponents to supply detailed project designs and cost estimates to the Federal Government for a short-listing process, and finally selection of four projects to receive capital grants. The capital grants only partially cover project costs, with proponents being required to finance a significant proportion of the project themselves. Unfortunately, the timeline for the Solar Flagships process coincided with the oversupply in the RECs market, meaning that none of the three large retailers in Australia (AGL, Origin and TRUenergy) were willing to negotiate PPAs at a level sufficient to support these projects. This led to stalling of the Solar Flagships program, but extended deadlines has seen two AGL receive funding for two solar PV projects with a combined capacity of 159 MW and supported by an internal PPA.

3.4. Australian Capital Territory Solar Auction

The Australian Capital Territory (located within New South Wales) has recently introduced a Large-scale Solar Auction scheme. Development of up to 210 MW of large-scale solar capacity is targeted with 40 MW to be allocated in the first round. Projects will be supported by feed-in tariffs, with price determined by a reverse auction process.

The scheme has been immensely popular, with 49 proposals submitted, and 22 shortlisted. Shortlisted candidates have now been invited to submit Stage 2 proposals. Since some research indicates that well designed (dynamic) FiT schemes deliver renewable energy more effectively and at lower cost due to the reduction in project risk (Haas, Panzer, Resch, Ragwtz, Reece, & Held, 2011), this incentive mechanism shows significant promise.

3.5. Carbon pricing

Carbon pricing was introduced in Australia on 1 July 2012, under the Clean Energy Future legislation. The carbon price is fixed for the first three years of the scheme, beginning at \$23/tCO_2-e. From 2015, emissions trading will begin with the carbon price being set by the market supply-demand balance. Carbon targets applying in 2020 will be in the range -5% to -25% below 2000 levels. Modelling indicates this will result in carbon prices in the range \$30 to \$60/tCO_2-e (in 2020, in real 2010 dollars) (Treasury, Australian Government, 2011).

Coal-fired and gas-fired generators in Australia will be liable for the surrender of carbon permits under this scheme[20]. This cost is expected to be passed on to consumers, with an increase in the average electricity price of around $1/MWh for each $1/t$CO_2$-e anticipated (due to the average NEM emissions intensity of 1tCO_2/MWh, and borne out by extensive detailed modelling). Despite this, electricity prices are not expected to reach levels sufficient to support renewable investment in the absence of the RET scheme until post 2030 (ROAM Consulting, 2012).

Politically, the Federal opposition continues to be strongly opposed to the carbon pricing scheme, with a policy to repeal the relevant legislation if successful at the next Federal election (anticipated in late 2013). In practice, repeal will be complex. However, continued debate at the Federal level over the scheme perpetuates investment uncertainty.

3.6. State-based policies

The energy markets are also affected by state-based policies, including policies aimed at promoting transition to cleaner energy technologies and through the planning and approvals process (Australian Government, Department of Resources, Energy and Tourism, Bureau of Resources and Energy Economics, 2012). For example, favourable planning processes have been a contributing factor to significant wind development in South Australia to date. South Australia has a stated commitment to achieving 33% renewable energy by 2020 (Clean Energy Council, 2011) (up from the current 20-25%). This is mostly to be achieved by simplifying access to Federal schemes via streamlining of regulatory frameworks and provision of local information (Government of South Australia, RenewablesSA, 2011).

The recently elected Victorian (2010) government introduced State planning rules for wind farms that enforce a minimum two kilometre distance between commercial scale wind turbines and residences (VIC Dep of Planning and Community Development). Wind farm developers will have to apply for new planning permits under these stricter planning guidelines if they have failed to start construction before 15 March 2012. NSW (2011) has announced a similar intention. These restrictions may push wind farm development to more remote locations or to other regions, at higher cost (Clean Energy Council, 2012).

4. National Electricity Market (NEM)

4.1. Wholesale electricity market design

The NEM is a regional (or zonal), mandatory, gross, energy-only, 5 minute security constrained optimal dispatch, marginal pricing market (in each interval, all generators are paid at price of the highest dispatched bid).

Dispatch in the NEM is managed by the Australian Energy Market Operator (AEMO). Generators submit bids to AEMO for each interval, offering to supply the market with specific amounts of

[20] Peaking gas-fired units may fall under the annual emissions threshold, and would then be covered upstream by an increase in fuel costs from their gas supplier (who carries the carbon liability). Gas-fired generators may elect to acquire their carbon liability directly via the use of an Obligation Transfer Number (OTN).

capacity at particular prices. AEMO then optimises dispatch to minimise cost of production and provides instructions accordingly to generators (Australian Energy Market Operator (AEMO), 2010).

The spot price is determined in each of the five NEM regions, being the marginal cost of supplying energy to the regional reference node (located at the capital city load centres of each region, illustrated with black dots in Figure 15). As the NEM does not feature capacity payments, all revenue to support generation investment must come through the spot price. A Market Price Cap (MPC) of $12,900/MWh limits the maximum pool price in any interval (Australian Energy Market Commission (AEMC), 2012), and a Market Floor Price of -$1,000/MWh is similarly applied (Australian Energy Market Operator (AEMO), 2010). The market also features a Cumulative Price Threshold (CPT) of $193,900/MWh; if this threshold is exceeded over a rolling seven day period an administered price cap of $300/MWh (and a market floor price of -$300/MWh) is imposed.

Market participants generally enter contracts to hedge the spot price using a range of financial products. Around 70 -90% of demand is generally hedged in this way.

4.2. System adequacy

AEMO publishes a "Statement of Opportunities" annually (Australian Energy Market Operator (AEMO), 2011), which outlines demand forecasts, new generation proposals and calculates the resulting forecast supply-demand balance. The primary measure of reliability is the level of unserved energy (amount of energy demanded but unable to be supplied in a region expressed as a percentage of total energy demanded in that region over a specified period such as a year). Market settings are designed to limit unserved energy to no more than 0.002% of unrestricted energy demand over the long term. This limit is operationalized through Minimum Reserve Levels (MRLs). The year in which reserve levels are anticipated to fall below the MRL is presented in the Statement of Opportunity as investor information.

The Australian Energy Market Commission (AEMC) is responsible for making market rules and also for setting market parameters related to meeting the reliability standard. This includes assessing the appropriate level of the MPC, the market floor price and the CPT. Typically, extensive market simulations utilising carefully collected generator outage data is used to determine the MPC (and other parameter values) which will result in profitability for the marginal peaking generator required as installed capacity to meet the reliability standard. In the most recent Reliability Standard and Reliability Settings Review the MPC was increased from $10,000/MWh to $12,500/MWh (Australian Energy Market Commission (AEMC), 2010) (rising with inflation to $12,900 from July 2012 (Australian Energy Market Commission (AEMC), 2012)).

The NEM also features a reserve safety net. When there is sufficient notice of an upcoming reserve shortfall that threatens to compromise MRLs, AEMO may tender for reserve contracts from generators or demand side sources beyond those factored into AEMO's usual forecasting processes. At these times, emergency generators and other generators connected directly to the distribution network may enter contracts to boost NEM supply. Similarly, electricity consumers may offer for a financial consideration to decrease their demand at times of supply shortfall (Australian Energy Market Operator (AEMO), 2010).

4.2.1. Capacity valuation of i-RES

Since the NEM does not feature a capacity market, the capacity valuation of wind farms and other i-RES (intermittent Renewable Energy Sources) does not affect their revenues. However, their contribution to reliability must be assessed in order to conduct system adequacy assessments. At present, seasonal contribution factors for each region are determined based upon the minimum level of output available at least 85% of the time during the top 10% of the seasonal demands in a region. This results in summer contribution factors for wind generation ranging from 1% to 9.2% of installed capacity (Australian Energy Market Operator (AEMO), 2011). However, there is a significant body of evidence that suggests that wind actually contributes far more than this to system reliability (Milligan & Porter, 2008). This indicates that the approach applied in the NEM at present to wind capacity valuation could be considered overly conservative, and is likely to remain under continuing review as wind penetration in the NEM increases.

4.3. Very fast market (five minute dispatch)

The NEM features a five minute dispatch interval (whereby the market is re-dispatched by AEMO every five minutes). Generators are paid based upon half hourly trading intervals, where the price in each trading interval is the simple average of the six five minute dispatch intervals.. Short dispatch intervals allow AEMO to frequently and cost effectively adjust the whole system via an efficient dispatch optimisation to manage unanticipated variations in demand or generation (particularly from i-RES generators). Variations within each five minute dispatch interval are managed via regulation ancillary services.

Furthermore, although generator bids are provided for each trading day daily at 12.30pm, generators can adjust the capacity in each of 10 bid price bands at any time up until five minutes prior to dispatch. Generators are responsible for managing their own unit commitment via the bids they offer in each five minute dispatch interval.

Contracts in the market are purely financial (cash settled) and are not considered in dispatch.

Together, these factors mean that an imbalance market is not required in the NEM. Deviations from the dispatched level are typically small because they rely on a forecast made five minutes prior to dispatch and overall accuracy is not reliant on contract partners generating and consuming what they said they would. Furthermore, any deviation from the dispatch level can be corrected in the following five minute dispatch interval.

In addition to minimising forecast errors and allowing efficient frequent whole-of-system re-dispatch, the very fast market in the NEM provides an incentive for new flexible, fast-start generators to enter the market. Although prices can be low (or even negative) when supply is high relative to demand, prices can also rise quickly when wind output falls and other generation needs to ramp up or start generating. When prices rise rapidly in this manner there is significant incentive for flexible investments capable of capturing this value (Cochran, Bird, heeter, & Arent, 2012).

Five minute dispatch has worked effectively since NEM start in 1998. Although the NEM was not originally designed with i-RES in mind its features greatly facilitate integration of i-RES into the market..

4.4. Semi-scheduled classification

Prior to 2008, i-RES generators were classified as Non-Scheduled because they could not practically comply with some Rule requirements for Scheduled Generators (such as following a dispatch target). In 2008 it was recognised wind generators were beginning to have material impacts on power system security, so a new generator classification of "Semi-Scheduled" was introduced to apply to any new intermittent generator larger than 30 MW. I-RES generators under this classification are required to participate in central dispatch, including submitting offers and limiting their output to below a certain dispatch level whenever dictated by the central dispatch process (such as when unrestricted operation might violate secure network limits) (Australian Energy Market Commission (AEMC), 2008). When AEMO has not declared a network security issue involving the wind farm, they do not need to operate at AEMO's dispatch level. However, Semi-Scheduled Generators are still subject to Frequency Control Ancillary Service (FCAS) Causer Pays provisions. As for other generator types, these incentivise a Semi-Scheduled Generator to ramp its actual generation at a uniform rate. Any deviations from a uniform rate of change that contribute to frequency deviation add to the FCAS Regulation Causer Pays factors for that generating unit, and will thus lift the proportion of FCAS Regulation costs attributable to that generating unit (Australian Energy Market Commission (AEMC), 2008).

Individual wind farms are not responsible for preparing generation forecasts, but instead provide information such as plant availability to AEMO, who is then responsible for preparing an unconstrained intermittent generation forecast (UIGF) for each semi-scheduled generating unit. This reduces barriers to entry for small wind developers with minimal cost for AEMO.

4.5. Contractual arrangements

Given the very high NEM market price cap, wholesale market volatility can be significant, and is typically managed via financial hedges. Historically, this has taken the form of over the counter (OTC) swaps, caps or other structured products. Increasingly, however, participants are trading standardised futures and options products through the Australian Securities Exchange (ASX). This provides greater transparency and reduced credit risks. In 2010-11, trades amounted to 285% of the underlying electricity consumption, with an annual turnover of $549m and $315m for ASX and OTC trades respectively (Australian Financial Markets Association (AFMA), 2011).

Some businesses in the NEM also utilise vertical integration to manage wholesale market volatility. The three major retailers in Australia (AGL, Origin and TRUenergy) also own and operate significant generation assets ("gentailers"). This has led some renewable developers to register as retailers (typically targeting large industrial users) thus providing a direct path to market via their own vertical integration and removing the need to negotiate PPAs with "the big three".

4.6. Exposure of i-RES to negative price events

The use of a certificate scheme to support renewable development in Australia is typically thought to allow i-RES generation to remain exposed to spot market prices, and particularly to maintain incentives to curtail during negative spot price events. However, as outlined earlier, most i-RES developments in Australia are supported by a PPA that provides a guaranteed level of revenue for each MWh produced over a long timeframe (15-25 years). An interesting consequence of the

widespread use of PPAs in this way is that it may remove the incentives for i-RES to curtail generation during negative price events in a similar manner to under a FiT arrangement.

Negative price events occur in the South Australian region in particular, due to the significant penetration of wind generation there and with most wind farms (on PPAs) submitting negative bids to avoid curtailment. There is only one non-contracted wind farm in South Australia; this wind farm is observed to regularly curtail its output in response to pricing events by submitting positive bids to the market and hence setting the price in some periods. Historically, payments from wind farms due to generating during negative price periods have been $2,000 to $10,000/MW per annum; these payments would be recovered from their PPA counterparties. However, several of the wind farms are operated by a major gentailer which has a major retail presence in the region and is therefore hedged against negative price events.

In future, as wind penetration increases and negative pricing events become more common it is possible that PPAs will incorporate clauses that restore incentives to curtail generation during negative price events. This would allow retailers to capture the benefits of these events. However, since wind farms are often a significant contributor to creating negative pricing events, retailers may prefer to perpetuate negative pricing by maintaining wind operation during these periods. Gentailers may seek to manage their portfolio to achieve the outcome that maximizes their profits, depending upon whether they are over-hedged on their generation assets or demand liabilities.

4.7. Ancillary services

Ancillary services in the NEM are outlined in detail in an appendix of an earlier CIGRE Working Group paper (CIGRE Working Group C5.06, 2010). In summary, AEMO operates eight separate real-time spot markets for the delivery of Frequency Control Ancillary Services (FCAS). These include raise and lower regulation services, and three different raise and lower contingency services (six seconds, 60 seconds and five minutes). Generators offer bids to provide each FCAS service in conjunction with their energy bids. FCAS offers are co-optimised with dispatch of energy by AEMO. The costs of each service are therefore dependent upon the amount of service required at any particular time, and on the market bids to provide each service by market participants.

AEMO also purchases Network Control Ancillary Services (NCAS) and System Restart Ancillary Services (SRAS) under agreements with service providers.

The regulation requirement is the most likely to be affected by i-RES generation, as the system is required to respond to increased variability within each dispatch interval. In the NEM, the regulation requirement is determined dynamically based upon the time error, within a pre-determined range. If the time error is within the +/- 1.5 second band, the regulation is set to 130/120 MW (raise/lower). If the time error is outside this band an extra 60 MW of regulation per one second deviation outside the band is added, with an upper limit of 250 MW. The Tasmanian region is a special case; since it is connected to the mainland grid via a single DC link, its regulation requirement is set nominally to 50 MW (Australian Energy Market Operator (AEMO), System Operations, 2012). The dynamic setting of the regulation requirement in this manner, combined with procurement of FCAS via a co-optimised market should minimise the integration costs of i-RES in the NEM.

Payment recovery for regulation services is based on a Causer Pays principle. The response of generators and loads to frequency deviations is monitored and used to determine a series of "contribution factors". Participants whose responses assist in correcting frequency deviations are assigned a positive contribution factor (which is set to zero). Participants whose responses exacerbate frequency deviations are assigned a negative contribution factor; the higher the contribution to frequency deviation, the higher the factor. For each trading interval, total regulation payments are recovered from participants on the basis of these causer pays factors, being assigned to Market Participants who cause the need for FCAS (Australian Energy Market Operator (AEMO), Electricity System Operations Planning and Performance, 2008). The Causer Pays methodology means wind farms and other i-RES generators are likely to receive accurate signals about the cost that they add to the system in terms of increase regulation requirements.

4.8. Networks

4.8.1. Connection of i-RES

A shallow connection charging policy is employed in the NEM. Generally, generators are responsible only for their own connection costs (he exact boundary between the connection of the individual generator and infrastructure related to broader network investment is negotiated on a case by case basis). However, there is no requirement for network service providers to reinforce constrained generation connection points. Additional network reinforcement that reduces total system costs or is needed to ensure security of supply is implemented as part of the annual planning process and is covered by network charges levied on customers.

Despite the application of a shallow connection policy, there are significant incentives for generators to connect at strong network points. Because the NEM is a regional market (with a single wholesale price applying across each region), network losses within regions are accounted for through Marginal Loss Factors (MLFs) (Australian Energy Market Operator (AEMO), Legal Department, 2009). These are static numbers close to one for each NEM connection point that scale generator revenues (and costs for loads). MLFs are calculated annually, based upon the volume weighted losses in the transmission network associated with generation at a given connection point. Locations that are remote from loads and on a weak part of the grid are likely to be associated with high losses, and therefore an MLF significantly below one. Generators can access MLFs greater than one if they are sited in locations that have an excess of demand, such that the operation of the generator reduces network losses (by supplying load locally). Locations that are in strong parts of the grid, or close to load centres will have an MLF very close to one.

MLFs create significant incentive for generation to locate at strong network points, or close to load centres, and to match generation size to local load and network size. These incentives are particularly significant for renewable generators, since the volume weighting of the MLF calculation emphasises high network losses that may occur when an i-RES generator is operating at high levels.

Furthermore, the NEM does not offer firm transmission rights, and no compensation is paid to generators for energy lost due to transmission congestion or curtailment due to transmission constraints.

Unfortunately, i-RES generators may have limited ability to respond to market signals since renewable resources and land availability are often restricted to remote locations. Developers must weigh all of these factors in deciding where to locate a new generator.

The network connection process is often cited as one of the most challenging parts of bringing a new NEM generator to market. Unlike many international systems, the NEM does not mandate fixed performance standards; instead the performance requirements are negotiated (with defined minimum and maximum capabilities) in each case depending upon the specific needs of the system at a particular location.

Automatic Access Standards are defined in the Rules, and define the highest technical level of performance that can be required of a generator. These standards specify requirements around contingency performance and fault ride through, active power management and frequency control, reactive power and voltage control, and provision of a validated dynamic model (Ecar Energy, 2011). In order to achieve automatic network access, the generator must meet the automatic access standard across all criteria, which is often technically difficult due to conflicting requirements. A minimum access standard is also defined, which is the minimum technical level of performance allowed. Typically, generators connect on a negotiated access standard, which is a level in between the automatic and minimum access standards. This must be negotiated and agreed with the connecting network service provider (NSP) and AEMO. The generator should demonstrate that the negotiated access standard is as close as reasonably practicable to the automatic access standard, and must demonstrate that it will not have a detrimental impact on power system security and quality of supply to other network users (Australian Energy Market Operator (AEMO), Transmision Services, 2011). Developers typically refer to this negotiation process as lengthy and laborious, and cite it as one of the most significant barriers to rapid deployment of i-RES in the NEM.

4.8.2. Network development

In the NEM, networks are divided into two categories: transmission networks (typically 110kV and higher voltages) and distribution networks (typically 66kV or lower voltages). Although the market rules permit multiple Transmission Network Service Providers (TNSPs), typically one TNSP serves each region for historical reasons– although in one region the role is split between a planner and an asset owner. Multiple Distribution Network Service Providers (DNSPs) own and operate the distribution networks within each region.

As natural monopolies, the revenue of TNSPs and DNSPs is determined via regulatory process. Regulated electricity network businesses must periodically apply to the Australian Energy Regulator (AER) to assess their revenue requirements (typically, every five years). The AER sets a ceiling on the revenues or prices that a network can earn or charge during a regulatory period.

Currently NEM transmission network planning is primarily undertaken by jurisdictional planning bodies in each region and AEMO. The planning bodies prepare Annual Planning Reports that describe network development plans for their respective regions. More recently, AEMO has prepared the National Transmission Network Development Plan (NTNDP) that aims to enhance coordination between regions and provide long-term vision for NEM transmission network development (Australian Energy Market Commission (AEMC), 2011).

Before a network augmentation can be undertaken, the associated TNSP must apply the Regulatory Investment Test for Transmission (RIT-T) to identify network development options that provide the most market benefit. The RIT-T is an economic framework for identifying efficient transmission investment options that promote reliable supply and deliver market benefits, such as improved generator competition (Australian Energy Market Commission (AEMC), 2008). A similar process is employed for distribution network expansion (the Regulatory Investment Test for Distribution, RIT-D) (Australian Energy Market Commission (AEMC), 2009).

The network development framework has come under scrutiny recently due to the anticipated development of i-RES under the 20% Renewable Energy Target (RET) scheme (Australian Energy Market Commission (AEMC), 2011). It has been recognised some of the lowest cost renewable sources are located remote from existing networks, and much of the new generation likely to seek connection is relatively small compared to the "lumpy" network investment required to connect it. Despite potential long term savings, it is unlikely the initial connecting party would be willing to pay for an expanded network connection in anticipation of future generation growth given the high cost of transmission. This could lead to the unnecessary duplication of connection assets and delays in connection as each new generator connects to the network (Australian Energy Market Commission (AEMC), 2011).

This issue has been addressed in a recent rule change that requires transmission businesses to undertake, on request, specific locational studies to reveal to the market potential efficiency opportunities from coordinated connection of new generators in a particular area. Once a study is published, the decisions to fund, construct, operate, and connect to a scale-efficient network expansion (SENE) will be made by market participants and investors within the existing framework for connections in the Rules (Australian Energy Market Commission (AEMC), 2011). Although private investment in network assets has been very limited in the NEM to date, it is possible this will be assisted via the initiation of the new Clean Energy Finance Corporation (CEFC), which aims to provide low cost financing and financial "de-risking" of projects that facilitate low emissions development. The initial recommendations for the CEFC include transmission projects under scope for consideration, where they can demonstrate financial barriers to their development exist (Commonwealth of Australia, 2012).

4.9. Operation under high i-RES penetration

It is of interest to consider how the NEM might operate with very high penetration of i-RES. Since most i-RES have very low or zero short run marginal costs, it could be anticipated that under the marginal pricing NEM they would be incentivised to bid the majority of their capacity at close to $0/MWh. This would mean the wholesale market price would fall to zero except in periods of supply shortfall (when insufficient i-RES is operating). During these rare periods, the price would be either at the Market Price Cap (MPC), or determined by peaking generation such as hydro resources or demand side participation. The MPC would presumably need to be set to a very high level to ensure peaking generators remain commercially viable. This creates an increasingly volatile market, where financial hedges will become increasingly vital.

It is as yet unclear whether a stable market could operate under these conditions.

5. South-West Interconnected System (SWIS)

The South-West Interconnected System (SWIS) supplies electricity to the south-west of Western Australia, via the Wholesale Electricity Market (WEM). The WEM features a day-ahead net pool energy market settled on a marginal basis, an imbalance market, and a capacity market to manage investment signals (discussed further below).

Key entities in this market include:

- ***Independent Market Operator (IMO)*** – operates the WEM and is responsible for maintaining and developing rules and market related procedures that govern operation of WEM
- ***Western Power*** – owns, operates and maintains transmission and distribution networks within the SWIS
- ***System Management*** – a ring-fenced business unit within Western Power responsible for dispatching the system in real time. It also conducts short and medium term (up to three years) system planning, including outage planning
- ***Verve Energy*** – A government owned corporation that owns and operates generation assets in the SWIS. Verve assumes additional responsibilities in the market (in excess of the responsibilities of IPPs), including being the default provider of ancillary services and balancing. (From July 2012 these services may also be provided from other participants.)
- ***Independent Power Producers (IPPs)*** – privately owned and operated generation assets in the SWIS
- ***Economic Regulation Authority*** – performs a regulatory and market surveillance role, including regulating Western Power revenue.

5.1. Wholesale electricity market design

The market rules applying in the SWIS have recently undergone significant changes (commenced 1 July 2012), with introduction of competitive balancing and load following ancillary service (LFAS) markets (Independent Market Operator (IMO), 2012). The following discussion outlines the new market design.

5.1.1. Bilateral contracts

Most energy in the SWIS is traded via bilateral contracts. Generators and loads enter into bilateral agreements to supply and purchase energy. The details of these bilateral trades are confidential.

5.1.2. Short Term Energy Market (STEM)

Bilateral energy positions can be modified on a daily basis through trading in the Short Term Energy Market (STEM) (Independent Market Operator (IMO), 2006). If market participants wish to purchase or sell energy outside of their bilateral contracts, they make a STEM Submission with the desired price-quantity pairs in each 30 minute Trading Interval. STEM submissions are made by 9:50am the day ahead. Based upon these bids and offers, the STEM clearing price is determined for each Trading Interval by matching supply with demand whilst supplying the maximum possible quantity of energy at the lowest possible price. All offers to sell with lower offer prices and all bids to buy with

higher bid prices are deemed scheduled. All settlements are transacted at the STEM clearing price. The STEM auction is completed by 10.30am daily, on the day prior to dispatch.

The STEM features a cap and a floor. At present, the Maximum STEM Price is $314/MWh, adjusted annually based upon an assessment of relevant costs (Independent Market Operator (IMO), 2012). Liquid fuelled generation can be offered up to the Alternative Maximum STEM Price, which is $570/MWh at present, adjusted monthly with oil prices. The STEM price may be negative, down to a market floor of the Minimum STEM Price, which is the negative of the Maximum STEM price (-$314/MWh).

5.1.3. Balancing

The net bilateral position and STEM position of each market participant describes their net contract position. The day prior to dispatch, IPPs provide schedules called Resource Plans to the IMO, indicating their desired level of generation in each Trading Interval, reflecting their net contract positions. Verve does not submit Resource Plans (except for any facilities they choose to operate on a facility basis), but instead System Management develops a dispatch plan for the Verve portfolio, scheduling Verve plant around the IPP Resource Plans to meet the forecast day ahead load. Verve's initial dispatch plan is announced by 4pm daily on the day prior to dispatch.

Verve and each IPP must supply Balancing Submissions for their entire available capacity. Balancing Submissions contain price-quantity pairs for the full available capacity of each facility in each Trading Interval, and the expected ramp rate limits applicable.

Initial Balancing Submissions must be provided by 6pm on the day prior to dispatch, but they can be reviewed up until two hours prior to the commencement of six hour balancing windows. i-RES generators only supply a price for balancing down (since they can only control reduction in output). A Balancing Merit Order is determined based upon the Balancing Submissions, taking account of accepted Ancillary Service offers (outlined in more detail below).

System Management dispatch all plant according to the submitted Resource Plans and Verve's dispatch plan (determined the day prior to dispatch); adjustments to manage forecast errors are made in accordance with the Final Balancing Merit Order, so that supply matches demand in each 30 minute Trading Interval.

The balancing price is set at the price of the marginal tranche dispatched in the Final Balancing Merit Order, with all balancing market transactions paid at the balancing price (Independent Market Operator (IMO), 2012). Parties providing balancing up are *paid* the balancing price, and parties balancing down *pay* the balancing price. The balancing price may be positive or negative depending upon the balancing requirement and the bids provided by market participants to provide the service.

The gate closure times for each part of the process are summarised in Table 7.

Time period		Action	Periodicity
Scheduling Day	8.50am	Revisions to **Bilateral Submissions** close (provided by Market Participants to IMO)	Daily
	9.50am	**STEM submissions** close	
	10.30am	**STEM auction** ends	
	12.50pm	**Resource Plans** submitted by IPPs (reflect Net Contract Position, including bilateral trades and STEM outcomes)	
	4.00pm	**Verve initial dispatch plan** released	
	6.00pm	**Initial Balancing Submissions** from Market Participants to IMO	
	3.00am	**LFAS Gate Closure** (5hrs prior to dispatch window commencement)	Six hour "fixed" windows
	4.00am	**Verve** re-submission of **Portfolio Supply Curve** (price-quantity pairs for balancing) (4hrs prior to dispatch window commencement)	
	6.00am	**IPPs Balancing Submissions** Gate Closure (2hrs prior to dispatch window commencement)	
Trading Day	8.00am	**Trading Day commences**	

Table 7: SWIS energy market gate closure times (Independent Market Operator (IMO), 2006; Independent Market Operator (IMO), 2012)

5.2. Ancillary services

A range of ancillary services are defined in the SWIS, including Load Following, Spinning Reserve, Load Rejection Reserve, Dispatch Support, and System Restart. The most relevant of these to i-RES integration is likely to be the Load Following Ancillary Service (LFAS).

IPPs which are deemed technically capable of providing LFAS are eligible to submit offers into the LFAS market. Verve is required to offer into the LFAS market based upon the assumption that it will provide the entire requirement. Offers into the LFAS market consist of price-quantity pairs for the provision of upwards and downwards LFAS.

LFAS duties are assigned to facilities with the lowest enablement fees, and the Balancing Merit Order is adjusted to remove that capacity (provision of LFAS and balancing is considered mutually exclusive). Payment to all assigned LFAS providers is on the basis of the highest enablement price accepted, plus a balancing payment (at the balancing price) for increase or decrease in energy output for LFAS operation. Two LFAS enablement prices are set for each interval (the LFAS Marginal Price Upwards and the LFAS Marginal Price Downwards), both in $/MW (Independent Market Operator, 2011).

5.2.1. Determination of the LFAS requirement

The LFAS reserve quantity is specified in the market rules as "the capacity sufficient to cover 99.9% of the short term fluctuations in load and output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average" (Independent Market Operator (IMO), 2012). It is determined by System Management on an annual basis, although the rules allow it to vary by the type and time of day and across the year (allowing some level of flexibility). The recent

commissioning of Collgar wind farm increased the LFAS reserve requirement from ±60 MW to ±90 MW, with a monthly gradual increase in capacity as the farm was commissioned (Western Power, 2011). Given that the LFAS reserve quantity is driven almost entirely by the installed wind generation, and the wind resource does not appear to exhibit any strong trends by time of day or season, it seems unlikely that a pre-determined LFAS reserve by time of day or season will vary significantly. However, under the present rules it may be possible for System Management to vary the LFAS reserve dynamically depending upon system conditions. For example, the variability of wind plant output has been shown to be a function of wind production level, with low variability at high and low output levels and high variability at moderate output levels (due the shape of the wind turbine power curve) (King, Kirby, Milligan, & Beuning, 2011). Through analysis, an equation can be developed for the standard deviation of variability as a function of the production level, allowing a simple but effective metric for dynamically optimising the LFAS reserve.

5.2.2. Allocation of LFAS costs

At present, the costs of LFAS provision are allocated amongst i-RES generators and non-dispatchable loads according to their metered schedules (MWh of energy generated or consumed) (Independent Market Operator (IMO), 2012). This methodology allocates the majority of LFAS costs to loads (since there is a much larger quantity of system load consumed than is generated by i-RES). However, i-RES generators are found to be much larger contributors to the LFAS requirement; analysis of fluctuations in the SWIS suggests that system loads could be adequately served by a LFAS reserve of ±30 MW, whilst i-RES generators alone would require a LFAS reserve of ±60 MW (Western Power, 2010). This suggests that there are not accurate cost signals to new i-RES developments, with loads providing an indirect subsidy. Rule changes to address this issue are anticipated imminently.

5.2.3. LFAS cost projections

It is projected that with the anticipated significant increase in i-RES capacity installed in the SWIS, LFAS costs could become extremely high (ROAM Consulting, 2010). This is as a result of a combination of factors:

1. ***Highly concentrated wind development*** – The nature of the incentive schemes offered in Australia create significant economies of scale, favouring large (>100 MW) wind developments. This means opportunities for smoothing via geographical diversity are minimally realised.
2. ***Small system size*** – The SWIS is a relatively small system, meaning that cost-effective individual wind developments constitute a significant proportion of the system (8-10% of peak demand), and there is a reduced number of generating assets available to provide LFAS.
3. ***Rising gas prices*** – Western Australia recently developed a significant Liquid Natural Gas (LNG) industry, causing gas prices to rise to international parity. Since LFAS are typically provided by gas-fired plant, this directly and significantly increases the cost of LFAS provision.
4. ***Rising carbon prices*** – A carbon price began on 1st July 2012. This further increases the cost of gas-fired generation (providing LFAS).

5. ***Static reserve setting*** – The LFAS reserve capacity in the SWIS is determined annually at present.

5.3. System adequacy

System adequacy in the SWIS is managed via a capacity market termed the Reserve Capacity Mechanism (Independent Market Operator (IMO), 2006). Each market customer (retailer) is required to hold sufficient "Capacity Credits" to cover their share of the total system requirement in each year. Capacity Credits are assigned to generators and demand side management providers by the IMO, with the requirement that generators receiving these credits make their capacity available to the market, and participate in centralized outage planning.

Capacity Credits can be traded bilaterally with retailers, or offered to the IMO for auction. Market customers who do not procure sufficient Capacity Credits bilaterally are required to fund capacity procured by the IMO. If system capacity is over supplied, the cost of the excess capacity is shared across all market customers. The Reserve Capacity Price is set at the highest capacity bid scheduled in the auction or, if sufficient capacity is available and no auction is held, based on the cost of a new entrant open cycle gas turbine plant, and is received by all capacity offered in the auction.

5.3.1. Capacity contribution of i-RES

Until recently, i-RES received a capacity valuation similar to their average generation (capacity factor multiplied by their installed capacity). A rule change was recently implemented (from 1 January 2012) to change the methodology for valuing i-RES capacity (Independent Market Operator (IMO), 2011). The new methodology requires determination of three quantities: the 95% probability of exceedence level of contribution by the whole i-RES fleet over the 12 highest load periods in each of the eight previous years (the "Fleet Capacity Value"), the average output of each individual i-RES generator in the 250 highest load periods in each of the three previous years (the "Facility Performance Level") and the sum of all the Facility Performance Levels (the "Fleet Performance Level"). The capacity valuation of each i-RES generator is then given by (Facility Performance Level)/(Fleet Performance Level) x Fleet Capacity Value (Independent Market Operator (IMO), 2011). Analysis of historical data suggests that this methodology leads to a capacity valuation of wind farms of around 15%, ranging from 9-18% for individual installations (represented as a percentage of nameplate capacity) (Sapere research group, Dr Richard Tooth, 2011). Solar generation is likely to receive a higher valuation due to their bias for operating during peak (daytime) periods.

6. Summary

Table 8 summarises and compares the market attributes of the NEM and SWIS that are relevant for the integration of i-RES.

Market Attributes	NEM	SWIS
Capacity payment	No	Yes
Market Price Cap	$12,900 /MWh	$314 /MWh
Market Price Floor	-$1,000 /MWh	- $314 /MWh
Dispatch Interval	5 minutes	30 minutes
Proximity of gate closure to dispatch	5 minutes	Day ahead
Balancing market	No	Yes
Determination of Regulation Ancillary Service requirement	Dynamic	Annual
Regulation reserve capacity as a proportion of peak demand	0.3% - 0.7%	2.4%
Typical wind farm size as a proportion of maximum demand	0.3%	2.7%
Procurement of Regulation Ancillary Service	Market (co-optimised with energy market)	Market

Table 8: Comparison of the attributes of the NEM and SWIS

The NEM design appears to be successfully indifferent to generation technology, adapting relatively easily to the integration of wind power and other i-RES technologies. The very short (five minute) trading intervals and gate closure before dispatch mean that an imbalance market is not required, even with significant i-RES penetration. Large forecast errors do not arise in the five minutes since gate closure, and co-optimised re-dispatch of the whole system every five minutes allows the most efficient response to any rapid changes in i-RES output. The dynamic setting of regulation ancillary services based upon the observed time error, and the procurement of this service via a co-optimised market also make the provision of this service extremely efficient and low cost. The main question facing the NEM is how the energy-only Marginal Pricing design will evolve as the penetration of very low short run marginal cost generation increases; a capacity market is at times discussed to ensure a sufficient signal for investment to meet the reliability standard.

The SWIS design suits inflexible, firm thermal assets that can provide high certainty over their level of dispatch, but require long lead times for unit commitment and de-commitment. It allows assets of this type a high degree of certainty about their future operation, timing of generation changes and ability to meet contractual positions, reducing the risk of operating in this market. However, the SWIS is less well suited to significant penetration of i-RES, due to the fact that it is a small and isolated system facing highly concentrated wind development, and therefore likely to face technical challenges relatively early. The efficient integration of i-RES could be facilitated by reducing the length of the Trading Interval. Increased participation in the new balancing and LFAS markets may also lead to more efficient market operation.

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Appendix 2: Integration of Renewable Sources in Brazil

Maria Paula B. M. Salvador – ONS, Brazil
Dalton O. C. do Brasil – ONS, Brazil

1. Introduction

Throughout the world the use of renewable energy sources has been considered important for the reduction of emissions of greenhouse gases and for each country's energy security. Policies to encourage the use of these sources for power generation are relatively new and have evolved gradually in recent years. The use of alternative renewable energy sources is a developing industry, and one of the major challenges for its consolidation is based on the creation of policies that are able to make it economically competitive.

In Brazil, following a global trend, the effects of global warming, as well as the benefits of using these energy sources, stimulated the development of programs that would encourage the production of energy through wind and solar sources, as well as biomass and water through small hydro plants. With the increasing participation of these sources in Brazilian market, one gains security in the diversification of the country's energy mix, profiting from inputs available in its territory and reducing impacts on the environment, as well as reducing dependence on fossil fuels, such as oil and coal. With all this alternative potential along with the great hydraulic available and yet to be explored, it is expected to ensure the energy supply for future demand.

This work has as main goal to present an overview on the insertion of alternative renewable sources in Brazil, since the beginning of Proinfa - Programa de Incentivo às Fontes Alternativas de Energia Elétrica (Incentive Program for Alternative Sources of Electric Power), a pioneer in the search for diversification of energy sources, to the present day, in which some of these sources already have considerable levels of attractiveness for investors.

2. The Brazilian Electric Mix

The Brazilian electric mix, unlike most in the world, is composed mostly of large hydroelectric dams, with complement of thermal plants, which together represent 98.9% of the installed capacity, ensuring the security of the Brazilian Interconnected Power System - BIPS and low tariffs, i.e. the payment of fair rate for energy services by the consumers (Figure 18).

In Brazil hydro generation should represent the majority of the expansion of electricity supply (Table 9), thus ensuring the future supply of energy, while the other sources, including alternative renewable, play a complementary role.

The current trend of the Brazilian energy planning is the prioritization of the participation and feasibility of alternative renewable energy sources, as has been shown in regulated auctions of power purchase, in which these sources already present quite competitive power generation costs.

Solar energy is not included inTable 9, but according to the report of EPE - Energy Research Company - "Analysis of Solar Generation insertion of the Brazilian Energy Matrix"- May 2012, currently all of

the installed capacity of solar photovoltaic generation in Brazil is aimed at serving isolated and remote systems.

Table 9 - Evolution of Electric Power Installed Capacity in Brazil

Source (BIPS - Brazilian Interconnected Power System)	Installed Capacity 2011 (GW)	Installed Capacity 2020 (GW)	Average Annual Growth 2011/2020
Wind	1	12	24%
Biomass	5	9	6%
Hydroelectric + SHPs (Small Hydroelectric Plants)	89	122	3%
Nuclear	2	3	5%
Thermal Generation	18	26	4%

Source: PDE 2020 – Report Ten Year Plan for Energy Expansion Ministry of Mines and Energy and Energy Research Company, 2011

3. Legal and Regulatory History of the Power Sector

The Brazilian power sector has been increasing dynamically, which is justified by the objective of ensuring the supply of electric power and seeking low tariffs for the optimum operation of the Brazilian Interconnected Power System - BIPS.

The Constitution of 05.10.1998 began a new era in Brazilian history, with less participation of the State in infrastructure sectors, due to a new institutional model with a forecast of active participation by private entrepreneurs.

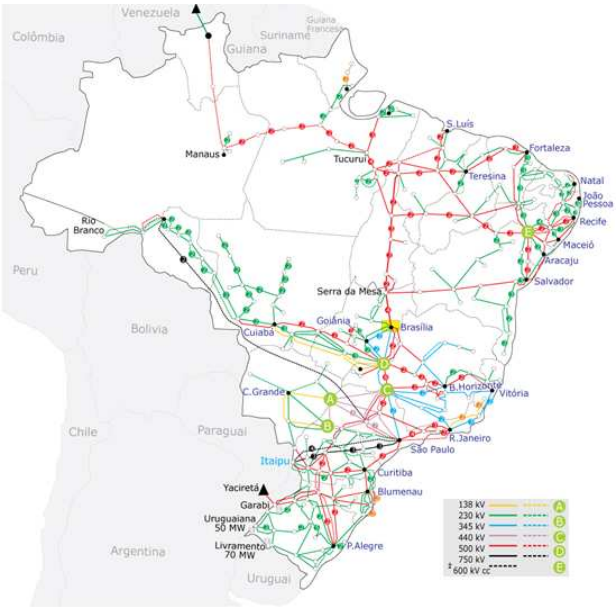

Figure 18 – Brazilian Interconnected Transmission Power System

Source: ONS - Brazilian Interconnected Power System Operator

Especially in the Brazilian power sector, for several decades, regarding investments, the State used its own funds and others from international funding institutions and banks. It was the State who

determined the energy tariffs, considering the general needs of the national economy. With this design, attracting investments and system efficiency depended directly on public management, with great political influence.

From the 90s, with the growing indebtedness of the State, the model was admittedly depleted and the need for private resources to meet industry demand became increasingly evident. Institutionally, the State reform in Brazil began to be designed with the approval of the Concession Law of Public Services, Law no. 8,987 of 02.13.1995. To allow the entry of private resources in the increase of the electric power supply, there was a need for specific legislation. Shortly afterwards, Law no. 9,074 of 07.07.1995 regulated the previous legislation regarding the energy market, allowing private entities to produce and trade electricity. The same law provides open access to transmission systems and distribution of electricity and creates the concept of free consumer, who may choose from which producers they will purchase power. Thus, an extensive process of privatization of the Brazilian power sector was initiated, starting with electric power distributors and generators. One of the main objectives of the privatization process was to establish differentiated treatment per activity: generation, transmission, distribution and commercialization, according to the market structure of each.

By Law no. 9,427 of 12.26.1996, ANEEL, the Brazilian Electricity Regulatory Agency, was created to regulate the Brazilian power sector. In 1998 through the Federal Law no. 9,648, MAE, the Wholesale Energy Market, was implemented aiming at creating the environment in which the transactions of electricity purchases and sales in the interconnected power system would be conducted. The same law defines the rules for the organization of the Brazilian Interconnected Power System Operator-ONS. On 07.31.1998, through ANEEL Resolution no. 245, the concept of Basic Grid was created, defined as the transmission system formed by facilities with voltage equal or higher than 230 kV.

After the power rationing that occurred in 2001 and 2002, through Laws no. 10,847 and 10,848 of 2004 and Decree no. 5,163, the federal government set the foundations for a new model for the Brazilian Electric Sector. Its main objectives were to ensure the security of electricity supply, the stability of the regulatory framework, and to promote low tariffs and social inclusion in the sector. From that moment, two new institutional agents were created, the Energy Research Company - EPE, responsible for planning the expansion of the electrical system, and the Electric Power Commercialization Chamber - CCEE, aiming at the commercialization of electric power in the interconnected system. CCEE was created to be the institution that would give continuity to the activities of the old Wholesale Energy Market - MAE. Both institutions have become part of the Power Sector Monitoring Committee - CMSE, with the duty to constantly evaluate the security of power supply.

Law no. 10,848 established a new regulatory framework to the sector, significantly changing the rules for energy commercialization. The distributors could only buy electricity through public auctions, in the "Regulated Contracting Environment".

In 2002, ANEEL Resolution no. 666 of 11.26.2002, partially ratified by Resolution 166 of 2005, introduced new concepts for charging free consumers, such as: Energy Rate (TE), Distribution System Usage Rate (TUSD) and Transmission system Usage Rate (TUST).

3.1. Legal Incentives for Renewable Alternative Sources

The use of renewable alternative energy sources reduces the impacts to the environment, and diversifies the energy mix, ensuring greater security of energy supply to the population. In Brazil,

these sources also enable the economic and social development of less privileged regions, inducing the use of local resources, since such supplies allow greater flexibility in the installation of plants, whether close to consumer centers or in rural areas.

The transformations that occurred in the Brazilian electric sector were enabled through incentives for renewable energy alternatives. The Ministry of Mines and Energy - MME, the Brazilian Electricity Regulatory Agency - ANEEL and sectorial legislation (government, states and municipalities) are encouraging the use of these energy sources by means of concessions of tariff discounts, exemptions and subsidies that promote the development and deployment of technologies that enable their consolidation. Some initiatives that support the development and consolidation of this type of energy in the Brazilian energy mix are illustrated below:

I. **Law no. 9,648 of 04.27.1998**
   Exempted the payment of "financial compensation" for the exploitation of water resources for the purpose of electricity generation by SHP - Small Hydroelectric Plants and granted to SHPs the right to 50% discount on tariffs for use of the distribution and transmission system.
II. **Law no. 9,991 of 04.27.2000**
   Established the Fossil Fuel Consumption Account – CCC, firstly aiming at reimbursing part of the generation cost of energy generation in isolated systems. Currently, these resources are used to subsidize power plants electricity generation, or other alternative sources: wind, solar and biomass.
III. **Law no. 10,438 of 04.26.2002**
   Created the Energy Development Account - CDE, where part of the funds can be used to increase the competitiveness of energy produced by small hydropower plants and wind farms, biomass and solar plants and authorized the use of resources from GER - Global Reversion Reserve for installation of small hydropower plants and wind farms, biomass and solar plants.
IV. **Law no. 10,762 of 11.11.2003**
   Extended the benefits of Law no. 9,648 for wind farms, biomass and solar plants, whose power injected capacity into the electrical system is less than or equal to 30 MW and can benefit from a 50% reduction in tariffs for the use of distribution or transmission systems.
V. **Law no. 10,438 of 04.26.2002 - created Proinfa**
   Incentive Program for Alternative Sources of Electric Energy, aiming at increasing the share of electricity produced by these sources in the Brazilian energy mix.
VI. **Decree no. 6,048 of 02.27.2007**
   Ensured distributors fully pass the energy cost from renewable alternative sources to consumers' prices.
VII. **ANEEL Resolution no. 481 of 04.17.2012**
   Provides tariff reduction for solar plants up to 30MW (80% discount on TUST - Rate of Use of Transmission System and TUSD - Rate of Use of the Distribution System) within ten (10) first years and 50% on subsequent years.
VIII. **ANEEL Resolution no. 482 of 04.17.2012**
   Defines the general conditions that allow consumers to install small micro generators up to 100 kW, and mini-generation from 101 kW up to 1 MW, and inject the surplus into the distribution network, receiving credits to be deducted from energy bills.

4. Power Generation Market – Renewable Alternative Sources

The model currently prevailing in the Brazilian electricity sector provides that the trading of electricity can be accomplished in two market environments: Free Contracting Environment - ACL and Regulated Contracting Environment – ACR (Figure 19).

This model aims mainly at ensuring the expansion of energy offer and maintaining market balance. Therein, it is expected that the entire market (load) should be 100% contracted, and that all generation must be covered by the physical guarantee of projects, per production capacity. It is also foreseen that the contracting of energy should be conducted through offer auctions at the lowest average cost (USD / MWh), serving the market at the lowest cost, and ensuring low tariffs. In this model, the market expansion makes generation expansion possible.

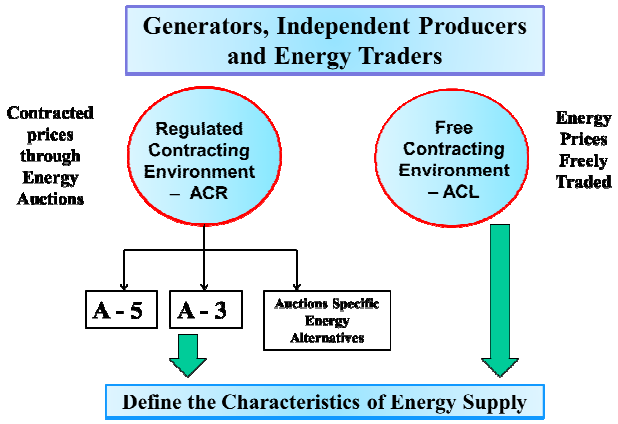

Figure 19 – Contracting Environments

4.1. Free Contracting Environment – ACL

The Free Contracting Environment is a trading environment where "free" consumers can buy energy from producers, as an alternative of supply from the local utility.

In this contracting environment of electricity, the consumer negotiates energy price directly with generators and traders, choosing his energy supplier. The contracting of electricity is made through bilateral contracts.

4.2. Regulated Contracting Environment – ACR

In the Regulated Contracting Environment - ACR, distribution agents, through public auctions regulated by the Brazilian Electricity Regulatory Agency - ANEEL and operated by the Electric Power Commercialization Chamber - CCEE, acquire electricity to meet their market, so-called captive consumers.

The market forecast of each distributor is the main factor in determining the amount of energy to be contracted by the system.

Contracting in the ACR is formalized by means of regulated bilateral contracts, denominated Electricity Commercialization Contracts in the Regulated Environment - CCEAR, which are concluded between selling agents (generation agents, trading agents or importers authorized for this purpose) and the distributors who participate in auctions to buy and sell electricity.

In this contracting model, power purchases are made through two types of contracts: power availability contracts and energy amount contracts.

4.2.1. Contracting by Availability

In this power contract model the seller agrees to the availability of production capacity. The generator is committed to providing a certain amount of energy and assumes the risk that if this power supply is affected by adverse conditions that may interrupt its energy supply; it is forced to purchase power from another source to meet its supply commitment.

4.2.2. Contracting by Amount

In this type of contract, the seller agrees to the delivery of the energy contracted. The monthly settlement of the difference between the energy contracted and the energy produced is made by the Settlement Price of Short Term Market - PLD. The generator agrees to provide a specific volume of its capacity to the ACR. In this case, the revenue from the generator is guaranteed and possible risks are imposed on the distributors, who pass some of these costs to consumers.

4.3. Energy Auctions in the ACR

The Brazilian Electricity Commercialization Model provides:

4.3.1. Existing Energy Auctions (A-1)

Comprises energy sales from fully amortized generation assets. This type of auction is usually classified as type "A-1". Auctions arranged with anticipation of a year from physical delivery of energy "A", which should always be provided from the first day of the contracted year. Auctions for Contracting "Existing Energy":

- Organized by the Government;
- Coverage of the existing market;
- Auction with anticipation of a year, long enough to give predictability to production agents and distributors.

4.3.2. New Energy Auctions

According to the Decree of President of the Republic of Brazil no. 5,163, of 07.30.2004, the distribution agents are required to meet 100% of the demand of their consumer market, which should be contracted through new energy auctions promoted by ANEEL.

Auctions for Contracting "New Energy"

- Organized by the Government;
- Must supply electrical market expansion (consumption);
- Auctions with anticipation of five (5) years to meet the expected growth of the market and three (3) years to meet market growth beyond what was expected.
- "Special" Auctions for Contracting Backup Energy;
- The government defines the market demand to be contracted and organizes the contracting process;
- Additional contracting to the market demand in order to increase security of electricity supply in the BIPS – the Brazilian Interconnected Power System;

- The costs of such contracting is shared between all end users of electricity in the BIPS, including free and special consumers and auto-producers with respect to the share of energy due to the interconnection with the BIPS;
- The backup energy is accounted and settled exclusively on short-term market of the Electric Power Commercialization Chamber - CCEE and its contracting is formalized through the signing of a Backup Energy Contract - CER among seller agents in auctions.

The auction mechanism in the ACR is called "Anglo-Dutch Auction", which occurs in two steps:

Step 1 – Uniform Rounds:

The auction is descending and occurs in an iterative process in which the auctioneer announces prices, one for each item being sold. Competitors subsequently indicate the quantity of each item wanted at the current price. This process is repeated until there are no more items with excess demand.

Step 2 – Simultaneously Discriminatory Round:

Bidders have the opportunity to offer a new final bid, which is the price that buyers are willing to provide. This phase is discriminatory, and then the winning bidders will receive the equivalent of their price bids (pay-as-bid).

New Energy Auctions A-3 and A-5

The purpose of these auctions is to provide distributors the possibility of energy advance contracting to fully meet their estimated demand considering a three to five year horizon ahead. These types are known as "A-5" and "A-3", i.e. with lead times of five or three years from physical delivery of energy "A".

In the new model of the Brazilian electric sector, the distributors are authorized by ANEEL to transfer to energy tariffs the amount of generation contracted up to the limit of 103% of their foreseen load, increasing the security of the Brazilian interconnected system and ensuring that the contracted amount of energy is as close as possible to the actual future load. In this case, distribution agents always prefer to contract more energy, where there is a tolerance for automatic transfer to tariffs. However, if contracting less energy than necessary to meet total load, distributors have to buy power on the spot market, where energy cost is higher.

This way, the distributors can cover most of their demand for contracting new energy 5 (five) years in advance, buying energy at an auction where the price is theoretically lower; since it is expected a higher concentration of hydro energy in auctions "A-5". Subsequently, in auctions "A-3", distributors make a finer adjustment of their contractual demands, considering that the auctions "A-3" will have a more accurate estimate of demands compared to the auctions conducted for "A -5 ".

The forecast of demand from distributors in the BIPS is responsible for the decision of where to make power generation investments over the years, in addition to the minimum amount of investments in thermal generation sources and sources that come from alternative energy (solar, wind, among others).

Backup Energy Auctions

The backup auction aims at increasing security and the guarantee of electricity supply to the BIPS. This is held by contracting beyond the total of energy demanded by distributors.

The backup energy is defined in Law no. 10,848, of 03.15.2004, where it is mentioned that the granting authority (government) can set the contracting of generation capacity backup, where contracting costs shall be passed as Backup Energy Charge - EER to all BIPS' electricity consumers , including special and free consumers and auto-producers.

The Presidential Decree no. 6,353, of 01.16.2008, regulates the contracting of backup energy. In this decree, it is emphasized that backup energy should be contracted through energy auctions targeting specific sources, as was the case of the Backup Energy Auctions - LER/2008 - biomass, LER/2009 - wind farms, LER/2010 - small hydro plants, wind farms and biomass and LER/2011 wind farms and biomass. Backup energy is accounted and settled at CCEE's short-term market. Contracts are signed with the Electric Power Commercialization Chamber as the representative of consumption agents: distributors, auto-producers and free consumers, and the revenues are used to discount the cost of contracting.

In Backup Auctions, the investor offers an amount of energy limited to the physical assurance that reflects its expected production; in the case of SHPs - Small hydroelectric plants - this limit is based on historical flows (minimum 30 years), biomass on monthly power availability declared by the agent and in the case of wind energy on the production certified by historic measurements of winds. If the actual generation of the enterprise is different from stated expectations, the entrepreneur will suffer penalties.

Main Features of Backup Auctions

- Contracts in the modality of amount of energy;
- Increases system security;
- Delivery of energy from own production (contracts of energy purchase from other generators are prohibited);
- Contract signed exclusively with CCEE;
- Physical Guarantee can only be sold at auctions;
- Quadrennial reconciliation - the contracted amount is revised to the annual average value effectively generated from the beginning to the end of the supply in the quadrennium, and the average value of contractual obligations may not exceed the amount contracted;
- The anticipation of the entry into commercial operation enables that all energy generated is purchased by CCEE at the selling price of the auction;
- Aiming at reducing contractual exposure and avoiding penalties, the agent may expand its plant to reduce such risks.

Alternative Sources Auctions

Energy alternative sources auctions are aimed at meeting the consumer market of distribution companies through sale of electricity from new generation projects that use this type of energy. The maximum energy prices are set by the granting authority according to the source of generation, hydro or biomass and wind. The value of energy contracted for each seller agent is the same of its final bid (pay as bid).

Main Features of Alternative Sources Auctions

- "Energy availability" contracts for wind and biomass sources;
- Delivery of energy from own production (contracts of energy purchase from other generators are prohibited);

- Quadrennial reconciliation - at the end of each quadrennial, in case it doesn't reach the energy contracted, the seller must reimburse buyers for the maximum value between the fixed income and the average PLD - Differences Settlement Prices of the entire period;
- Contracts signed with all distributors;
- Delay in entry into commercial operation entails concluding contracts for replacement;
- The anticipation of the entry into commercial operation enables the sale on the spot market;
- Possibility of expansion of wind farms to reduce the probability of contractual exposure;
- Bilateral contracts for replacement.

Overview of Energy Sources Auctions

Table 10 - Results of Energy Auctions with Renewable Sources

Auction	Source	Winners		Avg. Price U$/MWh
		Unites	MW Installed	
Proinfa/2002	Wind, Biomass and SHP	54	1423	140,8
LER-2008	Biomass	31	2379	29,5
LER-2009	Wind	71	1806	65,6
LER-2010	Wind, Biomass and SHP	33	1207	63,6
LFA-2010	Wind, Biomass and SHP	56	1686	67,5
LER-2011	Wind, Biomass and SHP	41	1218	49,8
A-3/2011	Wind, Biomass and SHP	49	1716	50,0
A-5/2011	Wind, Biomass and SHP	42	1212	52,4

Source: EPE - Energy Research Company

4.4. Mechanisms of Regulated Energy Auctions

At first, distributors record the amount of energy they need to cover, i.e. before the auction for electricity. The demands of each distributor are grouped together forming a power buyer "pool". All distributors are represented by this "pool" of energy that will acquire at auction a sum of energy demands requested by all these distributors. The costs of purchasing electricity at auction are represented by an average cost which is unique for each participant in the pool. Thus, the distributors will pay the amount equivalent to the amount of energy required, multiplied by the average purchase price of the power pool.

To minimize the problem of distributors who failed contracting all the demand requested in the auction, there are adjustment auctions that enable non-contracted distributors to buy the missing energy. However, the maximum allowable contracting per distributor in adjustment auctions is limited to 1% of its effective load and the right to transfer the cost to energy tariffs is limited to the lowest of the contracting costs related to "A-5" and "A-3" auctions.

For power generators, new energy auctions provide the opportunity of power guaranteed purchase, ensured by long term contracts, made even before the plants start to be built. Thus, there is a reduction of risks and uncertainties associated with the project and a contribution to the reduction of costs of power generation; since investors require a lower internal rate of return – TIR for the project construction. That’s why new energy auctions are organized in advance.

5. General Aspects of Renewable Energy in Brazil

Electricity generated from wind power, solar and biomass has the potential to soon occupy a greater share in the Brazilian energy mix, as shown on Table 9. The conditions are favourable: the country has begun to master these technologies, especially regarding wind power and, in a lower degree, solar power; such demand exists; investments are being made and the prices are more competitive. The production of energy from these sources is complementary to the hydroelectric plants, which accounts for over three quarters of the energy in Brazil.

Wind power energy potential in Brazil was preliminary evaluated in 2001 and the results showed on shore power generation potential of 143 GW, with measurements made for towers up to fifty meters high, as shown on Figure 20. Currently, in more recent studies, it is estimated a capacity of over 300 GW of power potential by this kind of source. It is noteworthy that this amount is more than twice the total current installed generation capacity in Brazil, which is 119 GW, considering all generating sources.

Another source with high potential in Brazil - but poorly utilesed - is biomass, mainly derived from sugar cane bagasse fired. The capacity of electricity generation estimated for this source is 9 GW in 2020.

Solar energy still has a long way to go in Brazil. Its greater representativeness is in Heliothermic systems (water heating) and in power generation with photovoltaic plates - PV in isolated systems. However, Brazil has a huge potential for this kind of renewable energy, considering the characteristics necessary to its development.

5.1. Overview of Wind Energy in Brazil

As already mentioned, it is currently estimated a wind power capacity potential of over 300 GW in Brazil, pointing to a large growth potential of this source.

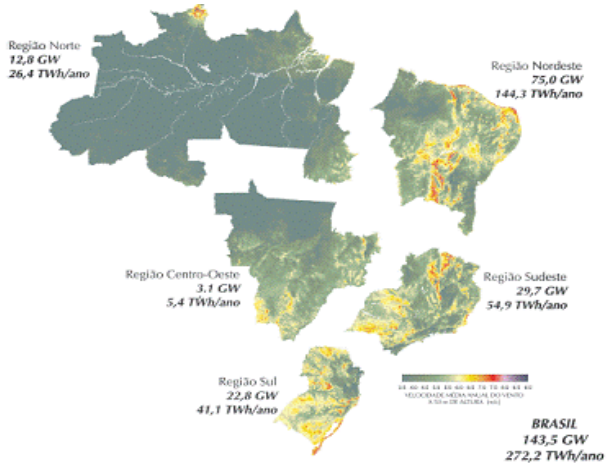

Figure 20 – Electricity production in Brazil in 2001

Source: CEPEL - Research Center of Electrical Energy

Initially this kind of technology has benefited from tax incentives and has been sponsored by the government within the program called Proinfa - Incentive Program for Alternative Sources of Energy, where wind farms have been commercialized with average prices of USD156 per MWh.

The wind source from 2005 to 2008 was considered "uneconomic." With the global crisis, manufacturers' holders of wind technology had to look for new potential markets in order to sell their products, and Brazil seemed to be quite interesting in this respect. In 2009 an auction was held for that particular source type, characterized as backup auction. In that auction wind energy was commercialized for an average value of USD 84 per MWh, i.e., a reduction of 54% over the average values sold on Proinfa Program. Later, with the cost reduction of equipment and deployment, technological improvements, such as increasing towers of wind turbines to one hundred (100) feet in height, and the improvement in quality of measurement of winds, with smaller errors in the capacity factors of these plants led them to gain more prominence in the energy market, making this kind of Energy attractive and competitive in Brazil. In Energy auctions in 2011, this source came to commercialize energy at values of USD 49.8 per MWh, becoming an integral and competitive part in new energy auctions, which are held to serve the consumer market of the distribution utilities, where all the sources participate with obligations, penalties and liabilities. Currently this energy represents only about 1% of the installed capacity in Brazil, but in 2016, with the results currently obtained in the auctions in 2010 and 2011, this capacity should increase to 5.5%.

Main Advantages of Wind Energy

- Clean, renewable and inexhaustible energy, low environmental impact, does not emit polluting gases and reduces the emission of greenhouse gases;
- Easy integration with hydro: modulation capacity of reservoirs;
- Rapid deployment of wind energy enterprise, with reduced environmental impact;
- Regional Complementarity: South and Northeast;
- Significant presence in energy auctions: 13 enrolled GW in 2009, 10.5 GW in 2010, 11 GW by 2011 and 16 GW so far to auctions planned for 2012;
- Harmonic coexistence with other activities;
- Income generation in the localities and land regularization.

Challenges faced

- Intermittency, i.e. the wind does not always blow when electricity is required, making it difficult to integrate their products into the daily dispatch operation program. With this feature the system needs to create a backup of power to serve the consumers in the case of no wind farms available;
- Connection to the transmission system, delays in the implementation of transmission lines and obtaining environmental permits;
- Impact on local birds;
- Noise impact.

5.2. Overview of Photovoltaic Solar Energy in Brazil

The map of solar radiation in Brazil (Figure 21) shows great potential for the exploitation of solar energy, with daily solar radiation ranging from 4.1 to 6.5 kWh/m2. For reference, the average energy received in Europe is 1.2 kWh/m2 (Source: EPIA – European Photovoltaic Industry Association).

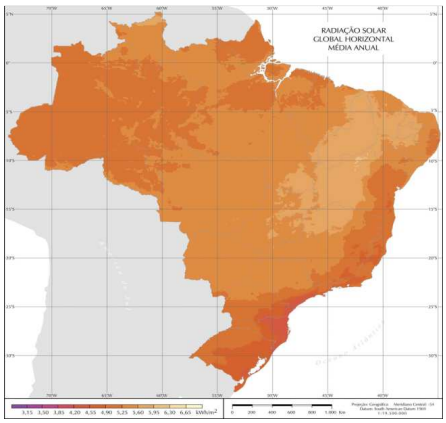

Figure 21 - Brazilian Atlas of Solar Energy - INPE/2006

In recent years, photovoltaic energy has been considered as a very promising technology. Brazil has a number of favorable natural characteristics, such as high levels of insolation and large reserves of quartz components, which can generate important competitive advantage for the production of silicon with high degree of purity, cells and solar modules, products of high value. These factors enhance the attraction of investors and the development of an internal market, making it possible to envision an important role in the energy mix for this kind of technology.

Currently, governments and public services utilities are the main investors, using photovoltaic panels on road signs, street lighting, telecommunications and others. The federal project 'Energy for All', which aims at bringing electricity to disadvantaged and isolated communities, also uses photovoltaics. However, PV systems on-grid are still a novelty: the cost of purchase and installation of the panels and the lack of subsidy policies to boost this alternative energy source remain the two main obstacles.

Several campaigns are being held to arouse the attention for photovoltaic generation - PV in Brazil. First, the idea of deploying solar panels in football stadiums for the 2014 World Cup was introduced, and later eighteen (18) projects of R & D by ANEEL focused on PV generation were approved.

ANEEL Resolution no. 481 of 04.17.2012 approved rules that encourage the installation of solar photovoltaic interconnected to the power grid. The Compensation Energy System was created - SCE, which allows the consumer to install power generators at home and exchange Energy with the distribution grid. Thus, the consumer produces the energy that he consumes and the surplus is transferred to the power grid system, which rewards the consumer with energy credits for consumption to discount in the coming months. The advantages are lower costs of bills and encouraging the use of a clean and renewable source and preliminary also avoiding high taxes.

Through these projects it is expected to help developing solar energy production, reducing costs, encouraging competition and enabling research institutions for this kind of technology.

Main Advantages of Solar Energy

-Clean and non-polluting source;

-Abundant in Brazil, high levels of radiation;

- Brazil has one of the largest reserves of silicon in the world, which can develop on solar cell production in the industry;

-Used in isolated systems, replacing the cost of power generation by diesel;

- Used for water heating in homes, can help on reducing the peak hours of the system caused by showers with direct electric resistance.

Challenges Faced

- Costs are still very high if compared to other renewable sources already used in Brazilian energy mix;
- Incipient legislation and need for a deeper knowledge of the technology;
- Uncertainties regarding the competitiveness of this energy source with other renewable sources used in the Brazilian energy mix;
- Questions from distributors regarding the implementation of Distributed Generation - GD.

5.3. Overview of Biomass Energy in Brazil

The production of electricity, mainly in alcohol and sugar mills in the system of co-generation, having as fuel the bagasse and straw from sugar cane is a very common practice in Brazil. Since the 80s, plants have evolved to a position of almost self-sufficiency in electricity production, indicating great potential to produce surplus electricity that can be incorporated into the national energy mix (Figure 22).

Biomass, mainly consisting of leftovers from sugar cane, is an effective alternative to sustain the growth of electricity consumption, mainly due to its characteristic of complementarity with hydro plants (see Figure 23). The period of sugar cane harvest takes place between the months of May and November, coinciding with the dry period of the electrical system, when reservoirs are quite depleted.

For a sustainable development of bioelectricity, investments in more efficient boiler installations to process the additional sugar cane bagasse and straw must be considered, as well as the automation of existing processes and equipment. Also, the government must promote and maintain public and economic policies that enable the construction of new plants and the commercialization of energy.

The production of bioelectricity with sugar cane bagasse is available mainly at the greater consumption area of the country, the state of São Paulo, which accounts for 62% of national production of sugar cane.

In addition to the bagasse of sugar cane, it is possible to find in Brazilian energy mix power plants that generate bioelectricity using other types of inputs, such as rice husk and sliver of wood, among others.

Advantages of Biomass Energy

- 100% renewable energy, low environmental impact;
- Inflexible generation: energy available with renewable fuel provided;
- Predictability;
- Small / medium projects : rapid deployment;
- Location: BIPS' load center, lowest cost of connection and operational risk;
- Regional power complementarity: Southeast and Midwest hydrology coincides with the sugar cane harvest;
- Environmental Licensing: time, cost and less complexity in the approval;
- Reducing CO2: clean and low-pollution source, entitled to receive carbon credits.

Challenges Faced

- Deforestation and destruction of animal habitat;

- It has lower calorific power, especially the bagasse from sugar cane, compared with other fuels;
- Difficulties in the transport and storage of solid biomass.

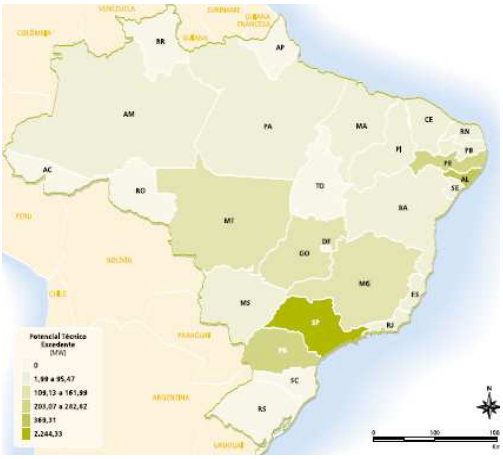

Figure 22 - Potential of Electric Power Generation in Sugar and Alcohol Industry

Source: CEMBIO – National Reference Center on Biomass

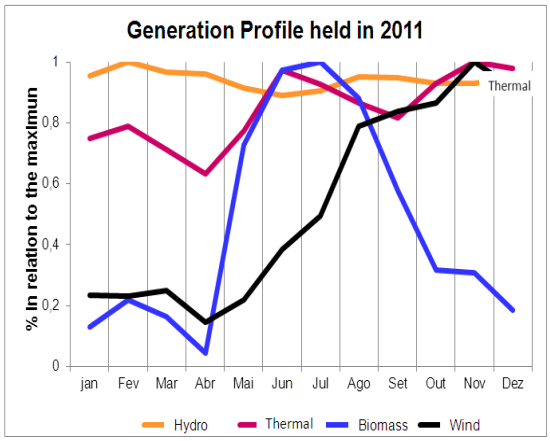

Figure 23 - Complementarity of Renewable Energy Alternatives

6. Connection to Transmission Systems

6.1. Access and Connection to the BIPS

Generally speaking, the shallow cost principle is applied in Brazil. The generator pays for the assets of its exclusive use, necessary for its connection. The reinforcements in the Basic Grid are paid by all users.

Free access is established by Law no.9,074 of 07.07.1995 and Law no. 9,648, of 05.27.1998. It is entitled to any agent or free consumer to connect and make use of the electric system through reimbursement of the costs involved, regardless of energy trading, being a basic instrument to effective competition in the generation and sale of electricity.

It is up to ONS – the Brazilian Interconnected Power System Operator, by means of Law no. 9,648, Decree no. 2,655, of 07.02.1998 and by ANEEL Resolution no. 281 of 10.01.1999, to define the conditions of access to the Basic Grid and contracting of its use.

6.2. Process of Access to the BIPS

In Module 3 of ONS' Grid Procedures - Access to Transmission Systems, the instructions and procedures for the access to the Basic Grid, including connection to it and its use, are established. For the case of accesses in DITs - Other Transmission Facilities, the technical requirements are those ones the transmitter to be accessed. The process of accessing the BIPS consists of two basic steps: the access request and the issue of the access report.

The access request is the requirement that, accompanied by data, preliminary studies of access and information about the enterprise object of the access, shall be submitted by the party accessing to ONS or to the transmission utility, if the connection intended is to the Basic Grid.

The document that consolidates and establishes the conditions of access is the access report, in which are consolidated the assessments of technical feasibility of the requested accesses to the BIPS. It is an integral part of the Contract of Use of Transmission System - CUST that the accessing party signs with ONS for the realization of its access.

The main purpose of the report is to establish conditions of access, analysing the available capacity of the system to meet the accessing party and maintain service to other agents within the requirements of security, quality and reliability, as defined in the Grid Procedures. It also has as role anticipating relevant issues of regulatory and operational nature or aspects affecting the quality of service offered by the transmission systems, when necessary. Briefly, the report included general data of the access and the accessing party, legal issues, feasibility of electric service to the accessing party, need for extensions or reinforcements in the electrical system, among others.

It should be noted that in this process the agent is in charge of building and connecting the facilities and equipment for its own use, i.e., from its power plant up to the connection to the Brazilian Interconnected Power System. The necessary adjustment in the transmissions system is planned and conducted by EPE and ONS.

6.3. ICG - Transmission Facilities of Exclusive Interest to Central Generation

The purpose of creation of Transmission Facilities of Exclusive Interest of Generation Centers for Shared Connection - ICG by ANEEL was facilitating the access of generators in locations where the electrical system is not well developed and planning the power grid to access generators that participate in auctions in an integrated way, considering the minimum overall cost.

ICGs are classified as transmission facilities in voltage level below 230 kV, not part of the Basic Grid, designed to access power generation on a shared mode, defined by public call to be held by ANEEL and bid together with facilities of the Basic Grid for two or more generating plants. ICGs comprise busbars, transmission lines, power transformers, including those with higher voltage winding in the level of the Basic Grid voltage (230 kV and higher) and the lower voltage winding with a level below 230 kV, as well as all other substation equipment not classified as Basic Grid facilities (Figure 24).

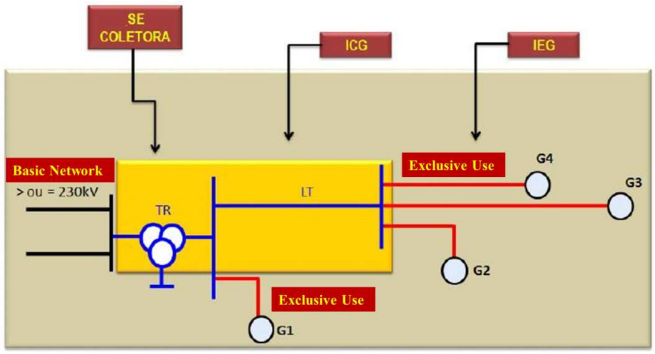

Figure 24 – Generation Shared Facility – ICG

Source: ONS – Brazilian Interconnected Power System Operator

On June 10, 2008, ANEEL Normative Resolution no. 320 established the criteria for the classification of ICGs. These facilities are designed to provide access of wind farms, biomass and small hydro to the

Basic Grid. The transmission company that wins the bid will have the granting of such facilities and will be remunerated through connection charges paid by power plants that share these facilities, prorated according to the power injected. After the end of the concession period, defined during the bidding, the ICG will be transferred at no cost to the local distributor, except for the border transformer that will be transferred to the transmitter owner of the Basic Grid facility. The plants connected to these facilities shall pay, in addition to connection charges, charges for the use of transmission and the electrical losses in the proportion of electricity generated.

6.4. Contractual Relations in Transmission

Contracting and administration of electric power transmission services and the respective access conditions as well as of ancillary services are part of ONS' missions.

The transmission facilities that comprise the Basic Grid are made available - through Contract for Provision of Transmission Services - CPST- to the Brazilian Interconnected Power System Operator - ONS, which coordinates and operates the BIPS under operating rules approved by ANEEL and consolidated in the Grid Procedures. The current regulation requires that the contracting of transmission services has to be done via transmission contracts: Contracts for Provision of Transmission Service - CPST, Contracts for Use of the Transmission System - CUST and Connection Contracts, in addition to Contracts for Ancillary Services.

CPST is signed between ONS and companies owners of transmission assets of the Basic Grid that make them available to their accessing parties under ONS administration and coordination.

The Contract for Use of the Transmission System - CUST is signed between ONS and the user of the transmission system and establishes the conditions for use of the transmission system, and the remuneration of transmission agents.

The Contract for Connection of the Transmission System - CCT is signed between the transmission company and the agent, having ONS as intervener.

7. Technical Requirements for Connection

The agents who access the power transmission system should meet the technical requirements for their connection. When connected to the BIPS Basic Grid, the minimum technical requirements described in Submodule 3.6 of Module 3 of ONS grid procedures must be implemented, which aims to preserve higher performance standards for the transmission systems. In the case of connection to DITs, the technical requirements should be followed too.

The Main Requirements for Connection of wind generators to the Basic Grid are:

- Operating with power factor within the range of 0.95 capacitive to 0.95 inductive at the point of connection with the transmission system for any level of active power generated;
- Dynamic behavior of the generating units in case of disturbances in the transmission system - the need to keep the power plant connected during external disturbances ("Ride Through the Fault"), as shown in Figure 25;
- Modelling of generators for electrical studies - providing detailed information from manufacturers (type of machine and control system);
- Assess the impact of the access user facility in voltage quality (phenomena of harmonic distortion and voltage fluctuation), checked at the connection point in the transmission system.

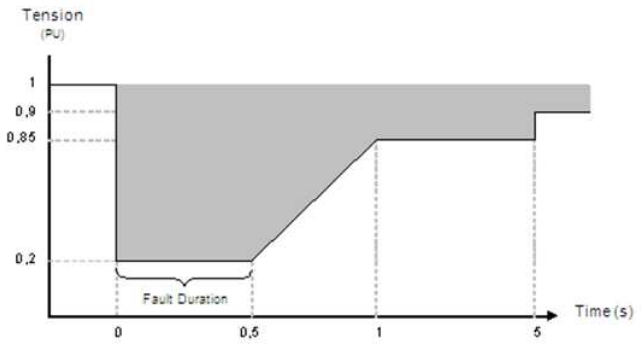

Figure 25 – Voltage on the terminals of wind turbines

Source: ONS – Brazilian Interconnected Power System Operator

8. Conclusion

An analysis of the world scene shows that there are indicators of a future focused on energy diversification with a significant increase in the use of clean energy for electricity generation and growth in energy efficiency of processes.

In recent years, both in Brazil and in the world, the great interest in the expansion and consolidation of the use of renewable energy sources in the energy mix are based on the reduction of dependence on fossil fuels like oil and coal, and the environmental issues such as global warming and the goals of reducing emissions of greenhouse gases set in the Kyoto protocol. In Brazil, where the majority of its energy mix is renewable energy, 77% of the installed capacity comes from hydroelectric plants. Investments in the integration of these sources also aim to reduce the need for the use of thermal and nuclear plants as alternatives to periods of low production of hydroelectricity, and these new sources are important to complemented national power generation.

The increase in the diversification of the Brazilian energy mix with the inclusion of alternative sources and the construction of run of rivers hydroelectric power plants, i.e. without reservoirs, are factors that currently challenge the Brazilian electrical system. The incorporation of these sources will require changes in the way the Brazilian power system is planned and operated, thus maintaining the reliability, security of supply and low tariffs, which are the foundations of the Brazilian model. With this new scenario, a reduction of the share of hydropower in the total of the installed capacity in Brazil is expected, and the increased participation of renewable alternatives, where only wind will increase from 1% in 2011 to 5.5% in 2016.

Currently wind energy deserves mentioning for being a source with low environmental impact and having enjoyed a great technological progress in recent years, having been presenting decreases in its costs of implementation and operation, becoming more competitive in relation to other types of alternative energy sources such as small hydro and biomass. Solar energy, primarily using photovoltaic panels, still faces many obstacles, but faced with its large potential in Brazil, it started to gain a little more popularity in small residential and commercial projects, especially with the expectations of the implementation of distributed generation.

Appendix 3: Wind Development in China

Ma Li – China Three Gorges Corporation
With contribution of Dr Jenny Riesz – AECOM, Australia

China is one of the most significant developers of renewable energy in the world. By the end of 2011, more than 45 GW of wind power was installed in China, accounting for 4.36% of total installed generation capacity and 1.56% of nationwide total generation. The nationwide installed capacity of wind generation doubled in the period 2006 to 2010, and China is now driving the most rapid growth in wind generation of any country in the world(Li et al., 2012; State Electricity Regulatory Commission, 2012).

88% of the installed wind generation capacity is located in the "Three North" regions (Northeast, North and Northwest of China), with the proportions illustrated in Figure 26 and listed in Table 11 (SERC, 2012). The highest penetration of wind is being experienced in the Northeast region, with 6.47% of energy being sourced from wind generation in 2011.

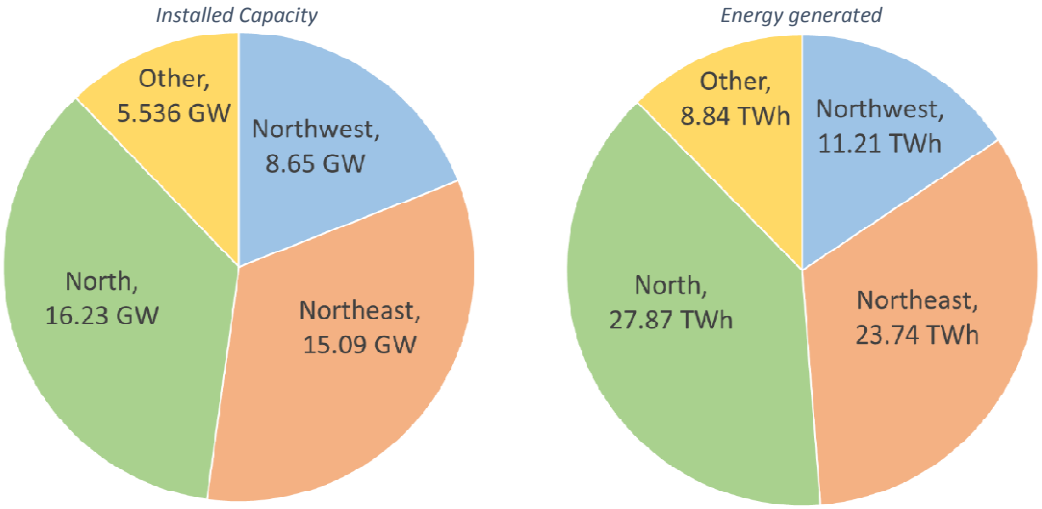

Figure 26 - Wind generation in China in 2011

Region	Capacity (GW)			Energy (TWh pa)		
	Wind	Total	Percentage wind	Wind	Total	Percentage wind
North China	**16.23**	**222.25**	**7.30%**	**27.87**	**1038.10**	**2.68%**
Beijing	0.11	6.3	1.75%	0.31	26.57	1.17%
Tianjing	0.13	10.97	1.19%	0.14	61.35	0.23%
Hebei	4.32	44.31	9.75%	8.77	222.46	3.94%
Shanxi	0.9	49.87	1.80%	1.32	234.43	0.56%
Shandong	2.42	68.44	3.54%	4.11	318.06	1.29%
West of Inner Mongolia	8.35	42.36	19.71%	13.23	175.23	7.55%
Northeast of China	**15.09**	**97.99**	**15.40%**	**23.74**	**366.83**	**6.47%**
Liaoning	4.02	34.01	11.82%	6.61	142.34	4.64%
Jilin	2.85	23.06	12.36%	3.99	70.66	5.64%
Heilongjiang	2.55	20.88	12.21%	4.39	83.44	5.27%
East of Inner Mongolia	5.67	20.04	28.29%	8.75	70.38	12.43%
Eastern China	**3.13**	**217.22**	**1.44%**	**6.09**	**1098.59**	**0.55%**
Shanghai	0.21	19.5	1.08%	0.4	102.08	0.39%
Jiangsu	1.58	68.88	2.29%	2.68	393.5	0.68%
Zhejiang	0.32	60.6	0.53%	0.56	279.08	0.20%
Anhui	0.2	31.75	0.63%	0.25	166.13	0.15%
Fujian	0.82	36.49	2.25%	2.2	157.8	1.39%
Central China	**0.47**	**214.43**	**0.22%**	**0.66**	**898.77**	**0.07%**
Henan	0.11	52.24	0.21%	0.17	259.5	0.07%
Hubei	0.1	52.62	0.19%	0.15	207.33	0.07%
Hunan	0.06	30.93	0.19%	0.05	119.5	0.04%
Jiangxi	0.13	18.01	0.72%	0.18	73.85	0.24%
Chongqing	0.05	12.98	0.39%	0.11	54.34	0.19%
Sichuan	0.02	47.65	0.04%	0.02	184.25	0.01%
Southern China	**1.94**	**185.41**	**1.05%**	**2.88**	**785.04**	**0.37%**
Guangdong	0.85	76.31	1.11%	1.5	371.35	0.40%
Guangxi	0.05	26.9	0.19%	0.01	105.74	0.01%
Hainan	0.25	4.25	5.88%	0.49	18.75	2.63%
Guizhou	0.04	37.36	0.11%	0.06	135.17	0.04%
Yunnan	0.75	40.59	1.85%	0.82	154.03	0.53%
Northwest of China	**8.65**	**107.43**	**8.05%**	**11.21**	**464.31**	**2.41%**
Sanxi	0.10	24.60	0.41%	0.09	117.92	0.07%
Gansu	5.46	27.27	20.02%	7.09	107.22	6.61%
Qinghai	0.02	14.43	0.14%	0.00	49.62	0.01%
Ningxia	1.42	18.44	7.70%	1.14	99.69	1.14%
Xinjiang	1.65	21.72	7.60%	2.90	87.60	3.30%
Tibet		0.97	0.00%		2.27	0.00%
The whole nation	**45.51**	**1044.73**	**4.36%**	**72.49**	**4651.64**	**1.55%**

Table 11 - Installed wind power capacity and energy generated by wind in 2011

1. Drivers of Renewable Deployment in China

China introduced a new Renewable Energy Law which came into force in February 2005, which has driven significant deployment of wind generation in China since that date. Under this program, the Plan of National Wind Power Development from 2011 to 2015 aims to achieve over 100 GW of installed wind generation by 2015.

A range of stakeholders have taken action under this initiative, including(SERC, 2011; State Electricity Regulatory Commission, 2012):

- ***Governments*** – Governments have promoted the development of wind generation via direct financial support, allocated via a bidding process in the early days, but now allocated by choosing large power generation enterprises. Five rounds of bidding for the development of on-shore wind projects have successively occurred since 2003, and the first off-shore wind project bid was completed in 2010. Also, local governments have established regional green development strategies and policies on wind development, including the implementation of a range of supporting policies and rules.
- ***Network companies*** – Network companies are responsible for ensuring adequate transmission access for wind developments. The State Grid Corporation of China has conducted studies projecting the likely transmission requirements for wind integration, and is at various stages of planning and construction of transmission access to eight wind power "bases" each of around 1GW in scale.
- ***Generation companies*** – Generation companies are responsible for designing, constructing and operating wind projects in China. They are also responsible for providing various grid services, such as low voltage ride through capability and power quality management. At present, they are also responsible for the provision of wind power forecasts. Generation companies have been working to improve automation and communication systems associated with wind generation, and are investing in training of employees to undertake the required maintenance of wind assets. Generation companies also work with network companies to assist in the network planning process, facilitating coordinated wind development.
- ***Regulatory bodies*** – The State Electricity Regulatory Commission of China (SERC) and the National Energy Administration of China (NEAC) have explored a range of regulatory adjustments to support the integration of wind generation into China's power system. For example, in July 2011 NEAC introduced policies defining potential sites for wind development and the approval requirements for the development of those sites, standards for construction, operation and management of wind farms, and requiring that the relevant Energy Department in each province investigate and evaluate the potential for the development of distributed wind generation.

2. Investment in integration of variable renewable generation

China has invested significant funding into the development of transmission networks to support wind deployment. By the end of 2011, the State Grid Corporation had invested 44 billion RMB (around 7 billion USD) in transmission projects related to wind generation. This was used to construct 24,000 km of transmission lines at voltages between 35kV and 750kV and twenty-five 37,700 MVA substations.

The State Grid Corporation is also responsible for ensuring the security and reliability of the grid. The development of standard systems for wind construction has assisted in maintaining security and reliability throughout the connection process, and during routine maintenance processes. Monitoring systems have also been installed in key regions, allowing more informed grid planning based upon improved wind and load forecasts.

Network companies in China have also explored innovative methodologies to optimise scheduling of wind and conventional power sources, and ensuring effective utilisation of storage potential. At the end of 2011 a national wind and photovoltaic storage demonstration project was commissioned in Zhangbei. The aim of this project is to explore the use of storage to smooth output from wind and photovoltaic generation. The project also explores the use of demand management techniques, such as utilisation of surplus renewable generation for local urban heating.

3. On-going challenges

Despite significant investment in the integration of variable renewable technologies, challenges have been encountered. In the Three North regions at present more than 13% of wind power generated is curtailed, while in the Gansu province and the east of Inner Mongolia, more than one quarter of the wind power generated is curtailed due to transmission constraints. Most wind farms in China are located at the extremities of the power grid which means that significant wind development can rapidly exceed the thermal limits on the existing transmission lines. New network investment has struggled to keep pace with the rapid rate of wind development.

Insufficient fault-ride through capability of the wind farms installed has also been an issue, in some cases causing cascading grid disturbances. Unlike many international grids, China has not implemented mandatory requirements for features such as reactive power adjustment and low voltage fault ride through. Since these features increase the cost of manufacturing turbines, they have not been included at many locations. Issues of this nature have been encountered at the Jiancaitang Wind Farm of Gansu Province and the Qingyuan Wind Farm of Henan Province. At these sites, other loads on the grid (related to the electric railway and the metallurgical industry) caused an imbalance of the three-phase voltage which caused the protection controls at these at these wind farms to trip. This caused loss of power supply.

Challenges have also been encountered in the coordination of the development of power sources of other types. In general, conventional power stations developed in parallel with wind generation have not been designed with the integration of wind generation in mind, and therefore often are not optimised for rapid ramping, fast start capability and low minimum loads. These features will increasingly be required as more wind generation is installed.

4. Conclusions and recommendations

China has installed a significant capacity of wind generation over recent years. To address the challenges and issues that have been encountered a range of actions could be implemented, such as:

- Development of national standards for the technical specifications of installed wind farms, including fault ride through capability, active power regulation and reactive power regulation;

- Introduction of national standards for wind forecasting, dispatch and operation;
- Development of standardised testing procedures for new wind farm connections;
- Implementation of national standards for wind turbine manufacture;
- Establishment of research into wind power technologies and their integration into grids at state-level research institutions;
- Where reasonable, retrofit of existing wind farms with suitable technologies to support power quality and grid stability;
- Improved coordination of the development of new generation and the planning of the transmission grid, with an aim towards establishing an ultra-high voltage backbone and optimal resource allocation at all voltage levels; and
- Improved coordination of the development of conventional power stations, including an appreciation of the grid services that are likely to be required of these units with an increased penetration of wind generation (including fast ramping and fast start capability).

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Appendix 4: Market design for large scale integration of intermittent renewable energy sources: the Spanish case

Eng. Luis Imaz, Eng. José Carlos Fernández, Eng. Javier Revuelta
– Red Eléctrica de España, Spain

1. Introduction to the Spanish Electricity Market

The Spanish peninsular power system is characterized by an annual demand of 254.8 TWh and a peak demand of 43.9 MW (REE, 2011). Its generation mix is regarded as broadly diversified, with nuclear, coal, gas combined cycle, hydro and wind technologies supplying more than 10-15% each of the annual demand.

The transmission grid in Spain is highly meshed. The network is interconnected with Portugal, Morocco, Andorra and France. However, the Spanish electricity system is considered an electricity island because its commercial exchange capacity with France represents only 3% of the installed power in Spain, a figure which is well below the 10% agreed by the European Union (Barcelona European Council, 2002).

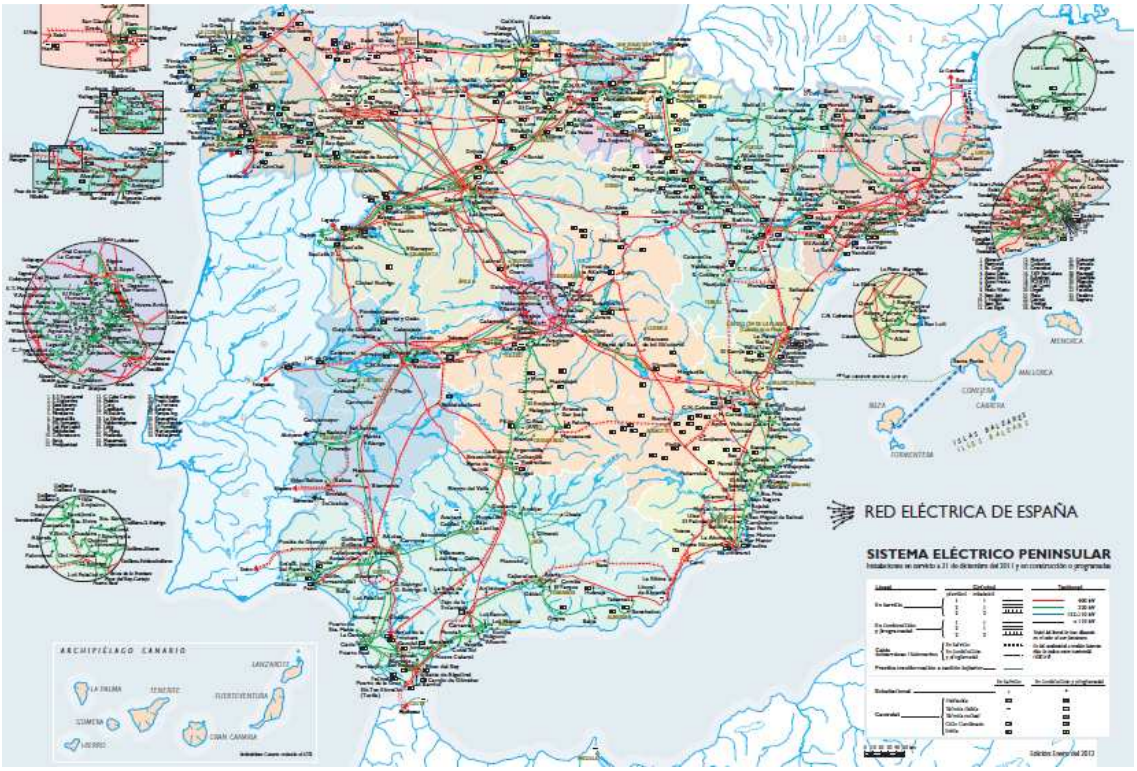


Figure 27. The Spanish power system as of December 31, 2011. Source: Red Eléctrica de España

The Spanish and Portuguese wholesale electricity markets are integrated within the Iberian Electricity Market (MIBEL). Since 1st July 2007, there is a single day-ahead market and 6 intraday markets for the whole Iberian system, which provide a single Iberian price. Only in case of congestion, "market splitting" is applied and prices in both markets differ. The organized day-ahead and intraday markets are managed by OMIE[21]. Intraday markets enable market players to adjust their previously committed schedules (in the daily market or in previous intraday markets).

MIBEL also includes an OTC (over-the-counter) market, where trading is allowed in parallel with the organized markets, and an organized forward market. The latter encompass (i) the organized long-term energy market, managed by OMIP[22]; and (ii) the CESUR auctions, managed by OMIE, which are auctions for the supply of consumers under the so-called 'last resort tariff'[23].

Apart from the MIBEL marketplace, the Spanish power production market also embraces the system adjustment services. They are managed by Red Eléctrica de España, the sole Transmission owner and System Operator (TSO) in Spain. These services, which are aimed at guaranteeing continuity and security of supply through the coordination of the production plants and the transmission system, are the following:

- Security of supply service: it consists of a re-dispatch process so as to ensure a minimum production from plants using Spanish coal as energy source;
- Resolution of technical constraints identified in the final programs derived from either physical bilateral contracts or the organized markets (day-ahead and intraday) as well as all those technical constraints that can appear in real time operation;
- Ancillary services, which comprise: (a) 'd-1' additional upward power reserve market; (b) services associated with load-frequency regulation (primary regulation, secondary regulation and tertiary regulation); (c) Voltage control of the transmission network; and (d) Black start;
- Deviation management: this service, slower than tertiary regulation, is essential to counteract expected deviations between production and demand, covering the gap in between the intraday market sessions.

The security of supply service and the resolution of technical constraints are carried out taking into account the merit order of the relevant market. Primary regulation is mandatory for all generating units without any remuneration while voltage control is also mandatory for generators over 30 MW, consumers over 15 MW, DSOs and the TSO. The additional upward power reserve, the Secondary and Tertiary regulation, and the deviation management service, are all provided through market mechanisms. Figure 28 shows an overview of the short-term electricity market in Spain (from day-

[21] OMIE is the acronym of the Iberian Energy Market Operator (*Operador del Mercado Ibérico de Energía MIBEL* – Spanish Pole).

[22] OMIP is the acronym of the Iberian Energy Market Operator (Operador del Mercado Ibérico de Energía MIBEL – Portuguese Pole).

[23] These auctions are managed by OMIE. The auctioned products are cleared by differences (financial clearance), and the resulting price of these auctions is used as a reference for setting the last resort tariff.

ahead onwards), and how the system adjustment services interact with the day-ahead and intraday markets.

With regard to the Spanish retail market, it is fully liberalized since January 1, 2003. Any consumer is free to choose its supplier. There is, however, a regulated tariff called 'last resort tariff' which is applicable to low-voltage electricity consumers with contracted power of up to 10 kW who do not have a contract with a power supplier. This regulated tariff is deemed to incentive consumers to contract with the more competitive supplier while safeguards the rights of those who do not want to move to the liberalized market. Distributors cannot supply electricity to consumers and consequently their activity is restricted to the network business.

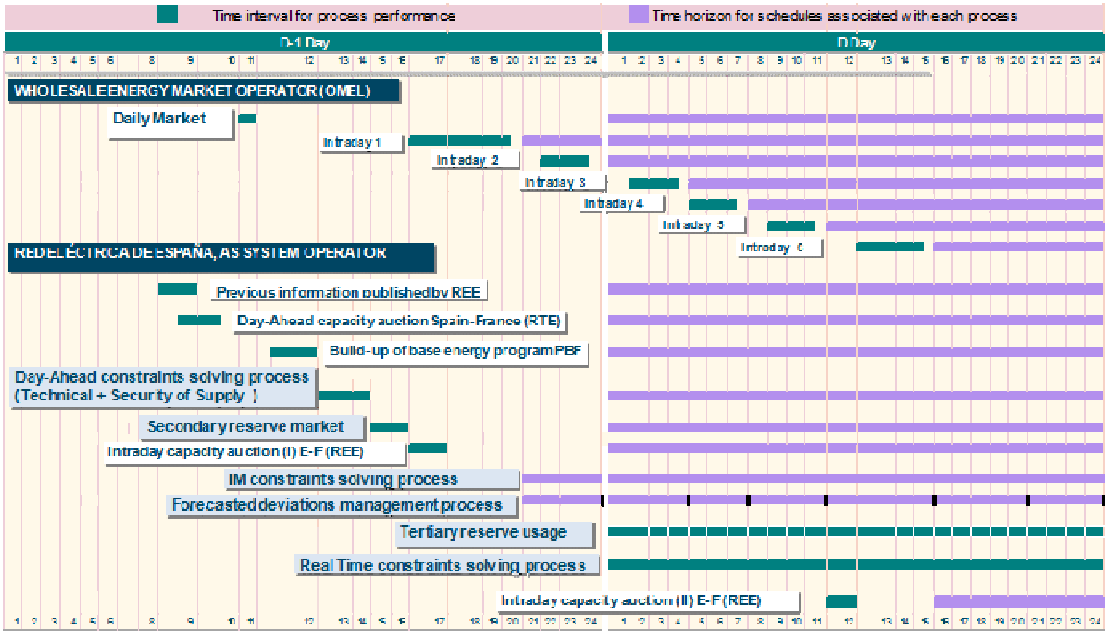


Figure 28. Short-term electricity markets and system adjustment services in Spain

2. *Renewable resources in Spain*

The high contribution of renewable energy sources (RES) to the supply of electricity demand is one of the most remarkable features of the Spanish power system. Spain is today a worldwide leader in the integration of electricity production from RES into the electricity market. On the basis of a sustained support from energy policy, favourable weather conditions, continuous effort in R&D and permanent involvement and cooperation amongst market players, the TSO (Red Eléctrica de España) and the National Regulatory Energy Agency (CNE), the share of RES generation in the Spanish Power System has been steadily increasing since the late 1990s.

Present figures of the Spanish power system illustrate the importance of RES technologies in the Spanish generation mix. As of the end of 2011, Spain´s net generating capacity in the peninsular system was roughly 98,000 MW (see Figure 29). This total included more than 21,000 MW of wind power capacity (the second largest wind energy capacity in Europe and the fourth largest worldwide (ENTSO-E, 2012; World Wind Energy Association, 2011); around 4,000 MW of solar photovoltaic

capacity (the third largest photovoltaic capacity in Europe and the fourth largest in the world (European Photovoltaic Industry Association, 2012)); and approximately 1,000 MW of solar thermal capacity (the highest worldwide capacity) (Protermosolar, 2012).

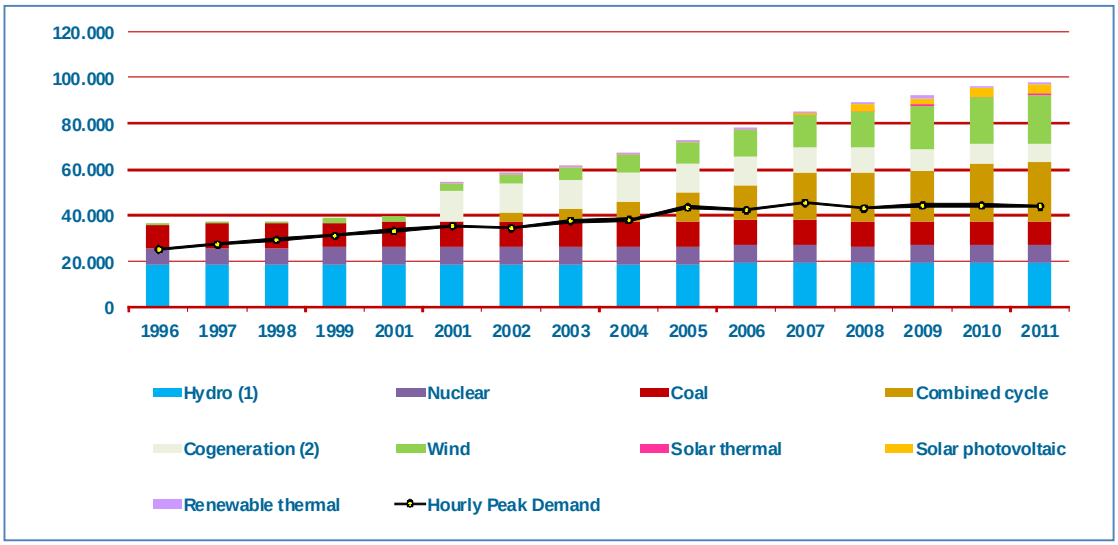
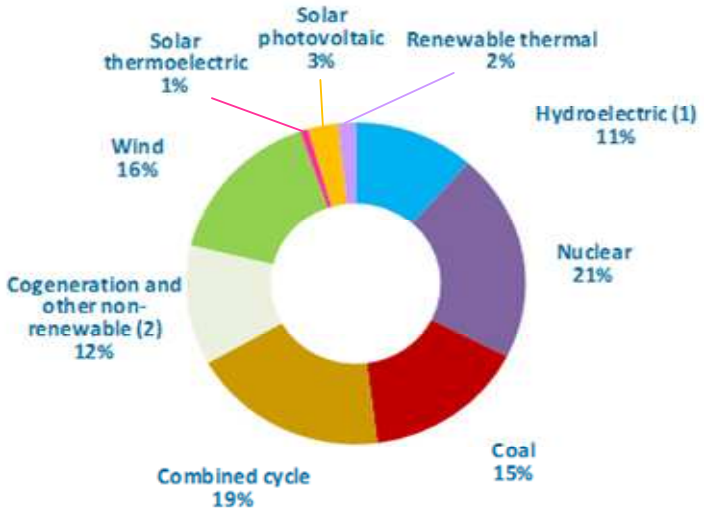


Figure 29. Net installed power in the Spanish peninsular power system. Annual evolution.
Source: Red Eléctrica de España

The enormous increase in RES capacity has had a significant impact on the Spanish energy mix. In 2011, renewable energy sources provided 33% of the electricity produced in Spain, with significant contributions from wind (16%) and solar (4%) technologies (see Figure 30). In terms of primary energy consumption in the same year, 11.6% out of the total primary energy consumed in Spain (129.3 Mtoe) was provided by renewable energy sources (2.8% wind, 1.2% solar, 3.9% biomass, 2% hydro, and 1.7% others)(IDEA, 2012; REE, 2011).



(1) **Includes pure pumped power.**
(2) Includes non-renewable thermal and fuel-gas.

Figure 30. Net production structure in the Spanish peninsular power system. 2011. Percentages out of a total of 262 TWh of net annual production
Source: Red Eléctrica de España

Finally, it is relevant to mention that the contribution of RES has achieved very significant figures not only in terms of energy but also with regard to power. The last record of wind production was achieved on 24th October, 2012, at 3:03 am, when 13,285 MW out of the 20,677 MW of electricity demand in the Spanish peninsular system at that time were supplied by wind power, which means a percentage of 64.05% of total demand being supplied with wind energy.

Looking further into the future, the integration of RES generation is likely to remain as one of the major challenges for the Spanish power system in the coming decades. Firstly, Spain is highly dependent on hydrocarbons, particularly oil and gas, so the deployment of RES technologies can be seen as a domestic energy resource that reduces its traditional dependence on foreign fuels, thus increasing security of supply. Secondly, the renewable energy goal is a headline target at EU level. The EU Directive on the promotion of renewable energies (Commission, 2009) sets a target of at least a 20% share of energy from renewable sources in the EU's gross final consumption of energy in 2020, and specifies national targets to be fulfilled by each Member State. This EU objective implies that in 2020 approximately 40% of the Spanish electricity production should come from RES, including large hydro. In 2010 and 2011, renewable production in Spain surpassed its expected production according to the annual path envisaged in the National Renewable Energy Action Plan (NREAP) in order to achieve the abovementioned national objective in 2020 (Ministerio de Industria Energía y Turismo, 2010).

3. Incentive mechanisms for intermittent renewables

3.1. The renewable policy in Spain

One of the main drivers for Spain to become a world leader in renewable energy, particularly wind and solar, has been the support mechanisms put in place along the years. The first support scheme dates back from 1994, when a feed-in tariff was introduced in order to support electricity produced from renewables and cogeneration. In 1998, the support mechanism was complemented with an option for renewable energy producers to participate in the wholesale market and receive the market price plus a premium. Since then, this 'two-options' approach has been maintained, though the requirements and conditions for the support have experienced several changes.

The last Spanish regulatory framework for renewables support was given by the Royal Decree 661/2007 and several later modifications (Spanish Government, 2007). In January 2012, this support mechanism was abolished for new investments (Spanish Government, 2009), mainly on the grounds of (i) the success in achieving the objectives in wind and solar installed power for the 2010 horizon; (ii) the comfortable leeway to cope with the 2020 renewable objectives; and (iii) the complex economic and financial context.

Therefore, Spain has presently no support mechanism in place for new renewable energy. It is worth to mention, however, that the former regulatory regime still applies for those installations in

operation or pre-qualified[24] as of the date of entry into force of the abolition (January 28, 2012). Such regulatory regime given by the Royal Decree 661/2007 is explained below.

3.2. The Royal Decree 661/2007

For those installations for which it is still applicable, the Royal Decree 661/2007 (along with subsequent minor modifications), sets forth the support mechanisms for electricity production from cogeneration, renewables and waste in Spain. Two options are possible for the participation of these technologies in the energy market[25]:

- Under the 'feed-in tariff option', they can sell all their production through the distribution or the transmission grid at a regulated tariff with no hourly discrimination. For example, the general full tariff for onshore win fixed in 2007 was set at 73 €/MWh during 20 years, and 61 €/MWh onward;
- Under the 'market option', they can sell their energy in the wholesale electricity market. This energy will be paid at the market price and, in addition, will receive a premium over that price. As an example, the premium for on-shore wind was initially (2007) 29 €/MWh during 20 years, and then 0 onward (which means that they will only receive the market price). This option, which was already in place since 1998, was modulated in the Royal Decree 661/2007 by fixing a cap and a floor for the total "hourly market price + premium" paid to the majority of the renewable technologies[26]. For wind energy, the floor was initially (2007) set at 71.2 €/MWh and the cap at 84.9 €/MWh. Under this mechanism, wind promoters are protected against very low market prices, that can eventually go down to 0€/MWh[27]. Symmetrically, end consumers are protected against expensive payments when market prices happen to be very high.

Both the feed-in tariff and the premium, as well as the cap and floor values, are updated on a yearly basis (quarterly for some technologies), on the basis of the consumer price index (CPI) and an adjustment factor that can be fixed or related with fuel costs indexes, depending on the technology.

To date, the expected higher income under the 'market option', following the promoters' expectations on the power pool prices, has incentivised a very large majority of the wind energy promoters to choose this alternative. Only a very small percentage (~3%) remains under the 'feed-in tariff option'.

4. Integration of intermittent renewables in the Spanish Wholesale Market

After years of experience and modulation of the regulation, in general terms renewable producers participate today in the Spanish electricity market as any other conventional producer. Renewable

[24] Installations already included in an official Register were allowed to keep the former support mechanism under several specific requirements, even if they were to be built after the abolishment. The Register was cancelled by the same regulation that abolished the support mechanism (Royal Decree-Law 1/2012).
[25] Generators may change from one option to the other only after being for a minimum of one year under the same option.
[26] The cap&floor system does not apply to solar PV (which has only a FIT regime), geothermal and other technologies.
[27] In fact, this has already happened several times.

producers under the 'feed-in tariff option' are obliged to bid their forecasted hourly production in the power pool at an instrumental price of 0€/MWh. Similarly, producers under the 'market option' participate in the market with their own sale bids, in the same manner as conventional generators. The marginal price fixes the hourly price for all generators, including renewable producers in the 'market option'. The feed-in tariffs and premiums accrued to RES producers are settled by the regulator, the "National Energy Commission" (CNE).

Renewable producers re-adjust their schedules in the power market according to their best information at the time of the gate closure of each intra-day session[28]. This is the last moment for such adjustment. If significant imbalances are foreseen by the system operator between the last relevant intra-day session and real time, additional 'Deviations Management Market' sessions are called by the TSO where only controllable generators can participate and submit sale or purchase bids for final adjustments before real time.

During the operating hour, the system operator uses the market-driven secondary and tertiary reserves in order to balance generation, demand and international exchange programs in the different time horizons. Such balance, which is needed so as to compensate deviations from the market schedule, upwards or downwards, needs the use of balancing generators, and therefore has a cost. The cost of such balancing is shared by all market participants causing the deviation, no matter if they are on the consumer or the producer side, including renewable generators. The settlement rules for the use of upward and downward reserves incentivize the renewable producers (just like all other generators) to always provide their best forecast: if they deviate downwards, they purchase the needed upward reserve at least at the price of energy that they received in the daily session (but maybe higher, depending on reserve bids). On the contrary, if they deviate upwards, they receive for their energy a maximum price equal to that of the previous daily session (but maybe lower, depending on downward reserve bids). Thus, there is an economic incentive for renewable plants to keep enhancing their forecasting tools.

As of June 2012, there are over 800 wind farms installed in Spain. In fact, they do not participate in the market individually but in groups, through representative market participants. There are different possible schemes for market representatives, which submit bids on behalf of all their represented RES promoters. Under such a scheme, aggregated deviations and penalties are minimized.

5. Ancillary services and intermittent renewables

5.1. Ancillary services adaptation to intermittent renewables

The differences between the forecast of renewable production, the scheduled RES generation and the real production from these units was one of the main reasons why in 2008 and 2009 upward power reserve became a scarce resource in the Spanish power system in a significant number of hours. This situation led to the introduction in 2012 of the upward power reserve market, which is intended to procure upward power reserve, in addition to the available reserve which arises from previous (d-1) constraint solving process.

[28] The gate closure is at least 3 hours and 15 minutes before delivery. It is higher for some specific hours.

None of the other ancillary services has been modified as a consequence of the increase in RES generation in Spain.

5.2. Provision of Ancillary services by intermittent renewables

Primary reserve is mandatory for all production plants, so renewable plants which are not technically able to provide this service must contract this service with other generators.

As regards their contribution to voltage control, renewable units contribute to the reactive power service independently of whether they are connected to the transmission network or not, and whether they participate under the 'feed-in tariff option' or the 'market option'. RES plants are obliged to maintain their power factor in a range between 0.98 capacitive and 0.98 inductive. In 2007, a table of bonuses and penalties was established in the Royal Decree 661/2007, with incentives if stricter power factors were achieved and penalties in case of failure to remain within the range limits. This bonus/malus mechanism was abolished early in 2012, and today only the penalties remain applicable: RES energy delivered with a power factor out of the binding limits is penalized with a 3% charge applied over a regulated price of 82.954 €/MWh. A new operation procedure is currently in the process of approval (new P.O. 7.5) with the aim of promoting a more active participation of renewable production units in voltage control by encouraging voltage set-points regulation rather than power factor regulation. It is expected that, for more ambitious levels of wind penetration, a dynamic voltage control may be required in the near future.

Lastly, Spanish renewable generation is allowed to participate in the provision of market-driven ancillary services -the additional upward power reserve market, and the Secondary and Tertiary regulation- only as long as the renewable plant is 'controllable'. This condition is fulfilled when, among other conditions, the renewable unit is able to deliver production forecasts with an error below the specifications and to undertake active power set points (Red Eléctrica de España, 2012). To date, only solar thermal plants are likely to be considered as controllable RES production for the purpose of providing ancillary services.

6. Connection of intermittent renewables to the Spanish network

In Spain, renewable energy systems have priority of access and connection to the grid. Connection costs have to be paid by the RES plant owner. For non-controllable RES units, their installed capacity connected to a node of the network cannot surpass 1/20 of the short circuit power of the network at that node (Spanish Government, 2007).

With regard to the use of the network, RES production is granted priority of dispatch in the electricity market, provided stability and security requirements of the system are fulfilled. Non-controllable units have precedence over controllable RES. In addition, RES technologies contributing to a larger extent to security and quality of the power system are given priority over other RES technologies.

7. Complementary tools in the Spanish power system

The successful integration of intermittent renewable energy into the Spanish Power System can be seen as the result of many different actions that have been developed along the last two decades.

The different tools that have contributed to some extent to the deployment of renewable energies without jeopardizing system security can be summarized in the following 'complementary tools':

7.1. RES-driven transmission network development plans

RES integration has been one of the main drivers for network expansion in the last years. Transmission network (220 and 400 kV) has been increased from less than 30,000 km of circuit in 1994 (when the first support mechanism entered into force) up to more than 38,000 km in 2011.

7.2. Strict technical requirements

In Spain it is mandatory for all RES technologies above 1 MW in size, to send real time measurements of their production to Red Eléctrica's control centre CECRE (see below). This is generally performed through a few authorized RES control centers (below 30 in June 2012) owned by different market players. Additionally, wind producers must provide proof of their capability to meet a maximum output set point within 15 minutes, under request of the system operator. These instructions are issued in situations of risks for system security, when all other measures on controllable production have been exhausted. And RES generators are compensated for their 'curtailed energy' with 15% of the market price (typically reaching 0€/MWh during this type of events).

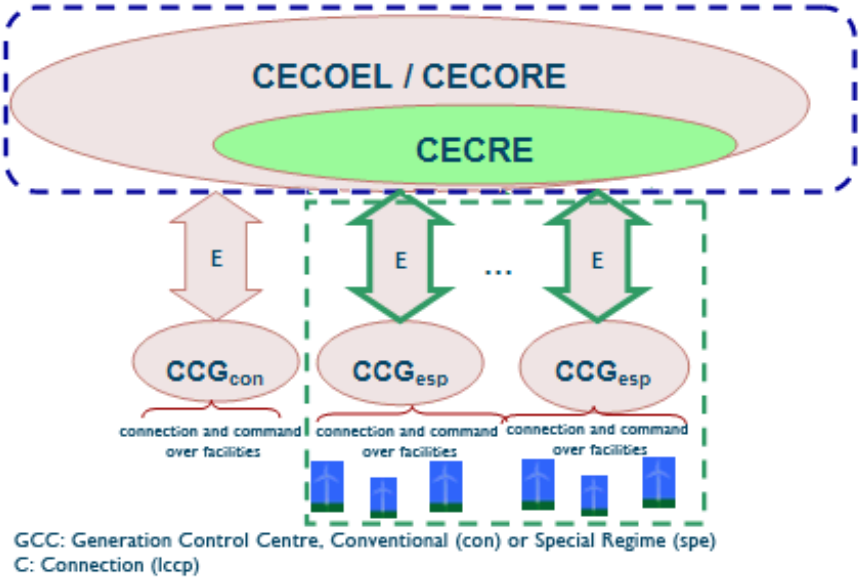
Most technical requirements are mandatory for authorization of installation, such as the capability to "ride through faults", that is, to remain connected to the grid during voltage dips in the distribution or transmission network. This requirement was not compulsory until 2008, which put the system at risk under increasing penetrations of wind power. Once this requirement entered into force, all new plants satisfied this obligation while plants in service before that date were retrofitted.

7.3. Monitoring and control: The CECRE

The extraordinary growth of renewable generation, especially wind power, in Spain has led these energy sources to take on a significant role in the coverage of the power demand (see section 2). Moreover, the high number of renewable generators in the Spanish electrical system (there are more than 500 wind farms) made the information exchange in real time between them and Red Eléctrica increasingly difficult. These facts, together with the unique properties associated with intermittent renewable generation encouraged Red Eléctrica (the Spanish Transmission System Operator) to create a Control Centre for Renewable Energies (CECRE) in 2006.

The CECRE, which is an operation unit integrated into the Power Control Centre (CECOEL), is a worldwide pioneering initiative to monitor and control renewable energies in the Spanish peninsular power system. CECRE is the sole interlocutor in real time between CECOEL and each one of the authorised generation control centres (GCC) to which renewable units are connected (see Figure 31). The GCCs must not only have sufficient capacity of control, command and monitoring over the generators assigned to them but also a suitable connection with Red Eléctrica's CECRE 24 hours a day and 365 days a year. The functioning of CECRE is basically as follows:

- The information is collected from production units. Measurements such as active and reactive power, voltage, connectivity, temperature and wind-speed are taken from wind farm s every 12 seconds;
- Based on this information, renewable production that is feasible to integrate into the power system is calculated per individual wind farm and per transmission node;
- The calculation is sent to the GCCs, which in turn communicate to their associated producers the instructions for the modification of their production orders, if needed.



- **Figure 31. The CECRE (in green) as the key instrument for the Control of Renewable Energies production by the Spanish Transmission System Operator, Red Eléctrica de España**

- Source: Red Eléctrica de España

Thus, CECRE helps Red Eléctrica to guarantee the security of the system, by means of providing real-time communication with the renewable generating stations. By knowing at all times their conditions and variables of operation, Red Eléctrica can issue the necessary instructions so as to maintain the system within security and quality standards. In this manner, CECRE allows the maximum amount of production from renewable energy sources, especially wind energy, to be integrated into the power system.

7.4. Prediction tools

Since the early times of RES deployment in Spain, the need to perform wind production forecasts was recognized as a crucial instrument for the success integration of this technology. As a consequence, Red Eléctrica de España developed a forecast tool called SIPREOLICO, which enables centralized and zonal wind prognosis.

Continuous improvements of the tool and methodologies have been implemented, allowing lower forecast errors and more accurate estimations of the system state and, therefore, more efficient decisions for the dispatch. More than 10 years of experience in wind power forecasting have permitted the attainment of typical mean absolute error of wind forecast lower than 15% with

respect to the mean production (this error, with respect to the installed total wind capacity is lower than 4% at this horizon) in the 24 hours ahead. Work to improve wind prognosis is ongoing and is considered essential by Red Eléctrica de España among the tasks to ensure the safe and efficient integration of wind power in the Spanish system.

8. Challenges for the future

8.1. Adjustments to cope with the affectation to non-RES generators

Installing large-scale RES in a system affects the behaviour of the system, and thus impacts on market prices. Generally, a much higher flexibility is required from conventional generators in order to meet a more volatile net load. Besides the lower yearly production of conventional generators displaced, their operation has been progressively modified: steeper ramp rates, higher use of the "constraints market", more start-ups, shorter times of connection to the grid, operation at lower partial load etc. These higher operational costs should be recovered through market power prices (either in the power exchange or through bilateral contracting). No specific adjustments have been revised concerning this issue. However, two regulatory adjustments for conventional generators in the past years can be mentioned:

- the capacity payments external to the power market are divided into two separate payments: the "availability term" (assigned to specific technologies) and the "investment incentive term" (only for those plants in service after 1998 and for a timeframe of ten years).
- a reserve market was recently put into operation, in order to allow for additional payments, besides the sales of energy into the market, to specific plants disconnected from the grid but capable of providing fast reserves to the system.

Further adjustments for both the conventional controllable generators and the RES uncontrollable generators are expected in the future if higher penetrations of RES are desired in the Spanish system. The market rules will need to ensure not only the installation of RES generators allowing to meet the national energy objectives, but also to attract the adequate investments of back-up/flexible capacity ensuring security of supply.

8.2. Dealing with RES spillages

According to studies performed by Red Eléctrica de España the situations in which not all the renewable resources can be integrated into the production dispatch are expected to increase in the coming years. The main reason is that during off-peak hours there will not be enough leeway for renewable production, because of the power from conventional thermal units that is needed to guarantee a feasible operational programme. The estimation carried out by Red Eléctrica de España on the average spillage of renewable energy sources for 2020 is around 2.3 TWh of RES spillages per year, and volume which is equivalent to 3.1% of the yearly wind production[29].

[29] This estimation is based on a central demand scenario and a generation scenario consisting of 34.8 GW of wind power, 3.8 GW of solar thermal power and 6.25 GW of photovoltaic power.

The need for additional storage plants, more interconnection capacity with neighbouring countries (especially France) and the implementation of further incentives for an efficient demand response are amongst the instruments that will have to be considered in the coming years in order to further integrate RES energy without incurring in inefficient RES spillages.

9. Conclusions

The Spanish success on the integration of large-scale intermittent renewables has been based on a progressive learning from the experience. The transmission network has evolved in the last years so as to cope with the increase in RES production. Efficient control, monitoring and forecasting tools and schemes have been developed in order to integrate RES without jeopardizing security or quality of supply. Technical conditions have been gradually imposed as long as RES technologies evolved. The energy policy and the collaborative approach of market players, industry, DSOs and the TSO, as well as the regulator, have been the complimentary ingredients for achieving the expected results.

For the coming years, several challenges appear if the 2020 EU energy policy targets are to be fulfilled in Spain. Higher flexibility will be required from the power system in order to integrate large volumes of intermittent RES production while minimizing inefficient RES curtailments. Some of the issues to further analyze are the controllability of RES production and its forecast, the deployment of storage facilities, the regulatory regime of flexible conventional generation, the increase of the interconnections with the European system and the improve in demand-side management tools.

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Appendix 5: Market Design for the integration of i-RES in Germany

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Arhur Henriot, EUI, Italy

1. Renewable resources in Germany

As part of the German government's Energy concept, ambitious targets have been set, aiming at a share of electricity consumption generated by renewables of 35% by 2020, 50% by 2030, and up to 80% by 2050.

In 2011, a total of 123.5 GWh were generated from RES in Germany, which constituted about 20.3% of gross electricity consumption. Wind contributed with 48.9 GWh (about 8.12% of total generation) and solar PV with 19.3 GWh (3.20%), the rest mainly being provided by biomass and hydropower.

In 2011, the installed capacity was equal to 29.1 GW for wind energy and 25.0 GW for solar photovoltaic, both being close to the minimum load and representing together about 70% of the peak load.

2. Incentive mechanisms in Germany

Two economic options are available to RES producers in Germany when it comes to selling their production:

- fixed feed-in tariffs and reimbursement by the TSO,
- direct marketing by the generators or any other intermediary (aggregator or trader).

Note that it is possible to split the generation capacity of an installation between the two different schemes.

2.1. Feed-in tariffs

The key tool employed to support renewables in Germany has historically been a scheme of feed-in tariffs, associated to regulation and coordination of the RES production by the four German TSOs. Under this scheme, illustrated in Figure 32:

- RES producers would receive a fixed remuneration from the network operators they were connected to (mainly DSOs).
- Costs would be reimbursed by the TSOs to the DSO. The share of energy from RES to be managed by each TSO would correspond to the share of final electricity consumption in its control area ("horizontal equalisation").
- Wholesale market integration of RES generation would be realised by the TSOs acting as sales agent (selling the electricity on the wholesale market (D-1, intraday)).
- Net costs for TSOs (i.e. total feed-in tariff payment to RES-producers minus market integration revenues) would then be recovered from supply companies in the form of specific surcharge on the electricity price, which would be paid in proportion to each supplier's delivery to final end

consumers (except for energy-intensive consumers). In other words, the surcharge is paid by consumers as part of their electricity bill and handed over by suppliers to the TSO.

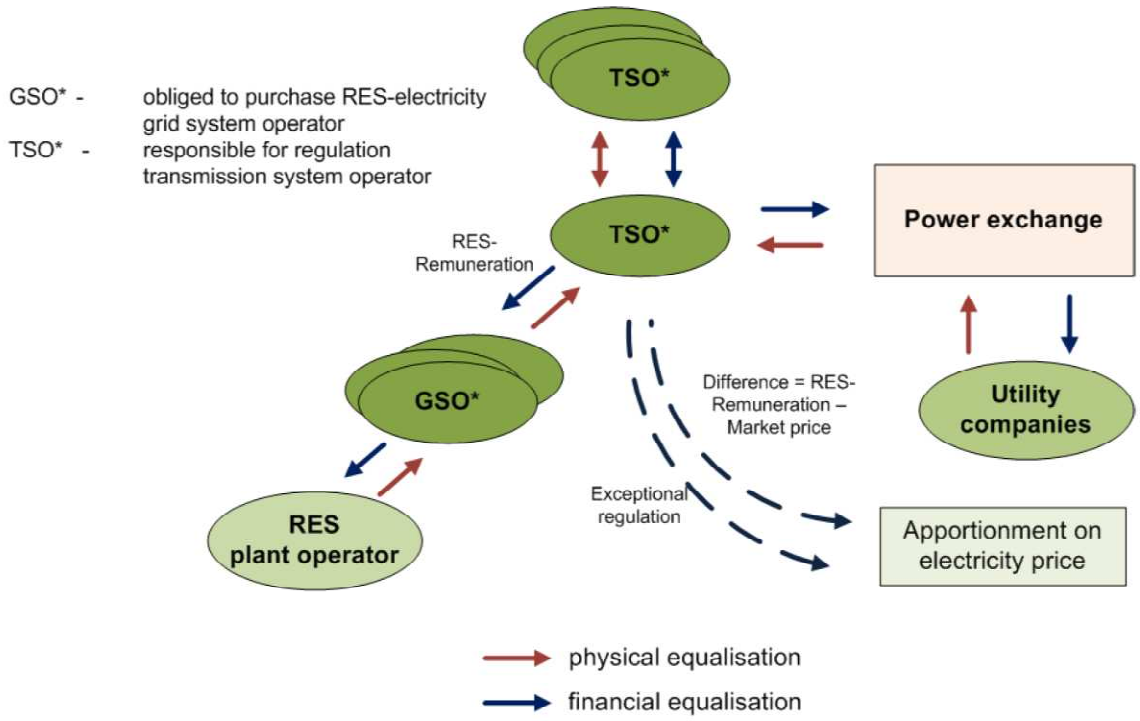

Figure 32: The German national equalisation scheme from 01/01/2010 (Source: Algeier,2011)

2.2. Direct marketing

Since January 2012 an alternative for RES plants operators is to opt-out of the Feed-in tariffs regime and directly market part of their production (Gawel and Purkus 2013). After selling this energy on the wholesale market, they receive a premium corresponding to the difference between the FIT and the market price. In addition, the producers receive a "management premium" that is designed to cover the costs related to transaction costs and imbalances. In 2012, this fee was equal to 12 €/MWh for wind power, falling gradually to 7 €/MWh by 2015. Further reductions were introduced after the Management Premium Ordinance (MAPrV 2012). There have also been talks of making direct marketing mandatory for new plants built after 1 August 2013 (existing plants could still be free to opt for feed-in tariffs).

This scheme has met a considerable success: by the end of February, about 78% of the offshore wind production was sold through this model. This might indicate that the management premium has been set at a relatively high value. However it is not guaranteed this scheme will remain attractive after the programmed fall of the management premium.

3. *Wholesale electricity market design*

3.1. Organisation of the electricity market

The German Day-Ahead electricity market, operated by EPEX Spot closes daily at 12:00 PM. Trading is then possible in the intraday market, also operated by EPEX Spot. By opposition to the day-ahead market, the intraday market is a continuous market: compatible buy and sell orders are matched as soon as possible.

The tradable products include single-contract orders for an individual hour or a 15-minute period[30], as well as block-orders combining several expiries on the same delivery day. A block-order cannot contain both hourly and quarter-hourly bids.

The order book is open 24 hours a day throughout the year. Hourly contracts for the next day can be traded from 03:00 PM and until 45 minutes before delivery. Quarter-hourly contracts can be traded from 04:00 PM and until 45 minutes before delivery[31].

In addition, bilateral contracts between participants are possible until the day after, either to nominate any transactions that were agreed before delivery but not nominated, or to enable the exchange of imbalances between two balance groups.

Imbalance settlement is based on difference between measured injection and off-take as well as scheduled exchanged (national and cross-border). Balancing responsible parties are subject to single-price imbalance pricing, the price being equal to the marginal costs of system balancing in each 15-minute settlement interval.

Since 01/01/2011 there is no special reserve product in place for managing RES. A summary of the existing products can be found in Table 12.

	Frequency of volume updates	Volume (Average value for 2012)
Primary regulation	Weekly	590 MW/h
Secondary regulation	Weekly	Upward: 2080 MW/h Downward: 2110 MW/h
Minute reserve	Daily	Upward: 2300MW/h Downward: 2000 MW/h

Table 12: Reserve products defined in Germany

TSOs are also encouraged by the regulator to contract additional “cold reserve” generation capacity. This is due to congestion on North-South transmission corridors and resulting risks for local mismatch of generation capacity, especially at certain situations with various factors at the same time (RES generation, load, congestion, cold weather). Also local voltage management capability shall be ensured. TSOs have therefore increasingly contracted cold reserve, e.g. at Austrian power generators or German generators intended to be mothballed.

[30] Quarter hourly contracts have been introduced on the German intraday market on the 14th of December 2011 and are mainly used by TSOs optimising their activities of selling RES generation.
[31] The lead-time period has been shortened from 75 to 45 minutes on the 29th of March 2011.

As of 2013, TSOs now must contract up to 3500MW of dispatchable load from industry consumers connected to 110kV grids or higher. This gives additional market-based flexibility and is a test-balloon for further development of demand-side management.

3.2. RES management

In the case when the producers decide to receive a FIT, a TSO is in charge of selling the energy generated in wholesale markets. The TSO must bid the resulting amounts of energy on the day-ahead and intraday markets[32]. Note that there might be some restrictions on bids by the TSOs. In case market prices are below -150 €/MWh in the day-ahead market, a second auction must be organised in which TSOs can only offer renewable energy at a price above -350 €/MWh, whereas the standard price-floor is -3000 €/MWh in the day-ahead market and -9999€/MWh in the Intraday market. The costs resulting from preventive (before real-time) and corrective (at real time) balancing management are integrated into a specific RES charge which comes on top of the final consumer electricity price.

In principle, TSOs are obliged to host any RES generation. However, the legal provisions on RES feed-in tariffs provide the possibility that network operators and RES producers agree on partial/total curtailment of generation during exceptional system conditions. In this case restrictions to RES generation are subject to the contractual agreements between parties.

In the case when activation of all market-based or contract-based instruments is not sufficient, redispatch may be enforced by TSO on all generators without compensation. Yet, the TSOs must curtail the production of conventional power plants before reducing RES generation.

TSOs serve as sales agent but pass resulting cost to final consumers; incentives have therefore been put into place to incentivise TSOs to manage efficiently the RES production. The Ordinance on the Accomplishment of the Federal Balancing Mechanism (for Renewable Sources), abbreviated Ausgleichsmechanismus-Ausführungsverordnung / AusglMechAV, sets rules for the marketing of renewables sources by the TSOs which have been remunerated by the feed-in tariff. It stipulates that "the day ahead and intraday generation forecast of renewable sources eligible for the feed in tariff have to be carried out according to the [latest] state of the scientific and technical knowledge."

In practice, the distribution network operators (ca. 900) forecast power generation by technology and category (size) on the basis of monthly data from RES producers and pass this information to the corresponding TSO. TSOs combine the information from DSOs and suppliers for the purpose of day-ahead and intraday forecast; they use also external forecast service providers both for one-year and short term (day-ahead and intraday) forecasting.

RES producers opting for direct marketing are responsible for selling their own production and also for imbalances. They hence have direct financial incentives for good forecasting quality as they assume economic consequences from resulting differences between forecasted and actual generation.

[32] § Abs.2 of the Regulation of the further development of the nationwide compensation mechanism (*Verordnung zur Weiterentwicklung des bundesweiten Ausgleichsmechanismus*) introduced by the Federal Cabinet on 27 May 2009,

4. Connection to the network

Generators (RES as non-RES) do not pay any injection tariffs in Germany. First-connection costs are allocated on a shallow cost basis, RES are not exempt but they benefit from priority for connection. The costs of reinforcing the network are covered by the network operators and included in the transmission and distribution tariffs paid by network users.

There are technical restrictions regarding the connection of RES installations. Depending on their size, RES units must be equipped with remote control and live power measurement devices. PV installations for instance had to be retrofitted with flexible inverters providing for frequency-dependent active power control.

Additional technical equipment to new and existing wind power installations for achieving better controllability and capability to provide reserve products are remunerated with a specific bonus.

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Appendix 6: Support schemes for renewables in France

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1. Introduction

Four mechanisms are currently implemented in France to support renewable generation:

- Purchase obligation with feed-in tariffs,
- Calls for tenders,
- Green certificates,
- Tax credits.

These mechanisms supplement the European tradable emissions permits scheme resulting from the Kyoto Protocol.

Moreover, a scheme concerning connections to the grid allows a sharing of the grid costs among renewable producers.

Section 2 of this document outlines the political context of renewable energy in France. Section 3 surveys the four support mechanisms, focusing on photovoltaic generation, and explains how incumbents are compensated for the resulting charges. Section 4 details the connection scheme.

2. Political context

In 2007, several political meetings were organised in France in order to take long term decisions concerning the environment and sustainable development. As part of "Grenelle de l'Environnement"[33], two acts have been passed: Grenelle I (3 August 2009) and Grenelle II (12 July 2010) (French Ministry of Ecology Sustainable Development and Energy) .

In its national plan for renewable energies, consistent with the Dec 2008 EU "Energy-climate" package, France has set an objective of a 23% share of renewable energy in its total energy consumption in 2020.

According to Electricity Act of 10 February 2000 (updated with the Ordinance no 2011-504 of 9 May 2011, hereby defined as "2011 Energy code") (French Government, 2011c), the minister of energy is in charge of elaborating the Multi-Year Planning of Investments concerning electricity generation, heat, and gas (*Programmation Pluriannuelle des Investissements* hereby defined as PPI). The order of 15 December 2009 (French Government, 2009), related to the PPI, sets objectives for the development of electricity generation capacities, including renewable energy, according to the commitments of the "Grenelle de l'Environnement".

[33] Since the May 1968 agreement between government and unions signed in Grenelle Street in Paris, every large meeting gathering stakeholders and government is named "Grenelle of…"

3. Overview of support mechanisms in France

3.1. Purchase obligation with feed-in tariffs

This price-based mechanism concerns biogas, wind energy, photovoltaic energy, geothermal energy, hydroelectricity, and biomass.

The economic rationale is set by the Electricity act of 10 February 2000: purchase contracts must take into account:

- capital and operating costs avoided by EDF[34] and the local distributors (which have the duty to purchase the renewable energy). They correspond to the costs these operators would have incurred to generate or procure the energy in the absence of purchase obligation. Following a public consultation in 2001, the French regulator decided to adopt a calculation method based on electricity market prices;
- to which can be added a premium taking into account the contribution of renewable producers to achieve the objectives of the energy policy. The level of this premium cannot lead to a remuneration of the fixed capital of renewable generation assets that would exceed a normal return on capital, considering the risk associated with these activities and the guarantee enjoyed by these facilities to sell their entire generation at a predetermined rate.

3.2. Case of photovoltaic generation:

The risk of such a policy has recently been illustrated by the photovoltaic sector. The order of 15 December 2009 related to the PPI sets an objective of 5400 MW of installed PV capacity in 2020. The feed-in tariff, in its latest revision (31 August 2010), ranged from €280/MWh for ground plants to €580/MWh for panels installed on house roof. The significant decline of solar panel prices in the period 2009-2010 led to a very high profitability of such investments.

This resulted in a very high and uncontrolled number of applications: at the end of 2010, the installed capacity was around 900 MW, but 6400 MW were in the waiting list for connection to the grid.

As a consequence, the support mechanism was suspended by a decree of 9 December 2010, and negotiations were organised with stakeholders to implement a more balanced scheme.

The regulator (CRE) was asked for advice on the new tariffs. In its deliberation of 3 March 2011 (French Government, 2011a), it compared the post tax Internal Rate of Return (IRR) of the capital invested to an average WACC of 5.1% (average cost of capital of companies from the renewable energy sector). Its conclusions were that for most installations, the proposed tariffs provided a maximum IRR that is comparable or slightly higher than the reference WACC, and could reach up to 11 % for the housing sector. It therefore concluded that those tariffs were compliant with the 2000 Electricity law. The CRE estimated that the evolution of roof installations was likely to be around 200 MW of additional capacity per year, including consideration of a decrease of the feed-in tariffs

[34] Electricité de France, the French incumbent

of 10 % every year (indexation excluded). In this case, the public service charges resulting from the support of PV should amount to € 390 to 420 million per year in 2020.

The new tariffs represent a maximum of €460/MWh. They shall be reviewed every quarter, depending on, among other things, the cumulative capacity of plants which have requested a connection during the preceding quarter, according to a formula published in the order of 4 March 2011 (French Government, 2011b).

This demonstrates one possible way to hybridise a quantity mechanism with a price based mechanism.

Table 13 represents the evolution of the PV feed-in tariffs before and after the moratorium.

	€ before tax / kWh	2006	2007	2008	2009	01/01/10 to 15/01/10	16/01/10 to 02/09/10	03/09/10 to 01/12/10	Morato-rium	10/03/11 to 30/06/11	01/07/11 to 30/09/11	01/10/11 to 31/12/11	01/01/12 to 30/06/12	01/04/12 to 30/06/12	01/07/12 to 30/09/12	01/10/12 to 31/12/12
T1	Residential rooftop ≤ 3kWp (*)	55,00	55,96	57,19	60,18	57,75	57,75	58,00	58,00	46,00	42,55	40,63	38,80	37,06	35,39	34,15
T2	Education or health services rooftop ≤ 36kWp	55,00	55,96	57,19	60,18	57,75	57,75	51,00		40,60	37,23	33,25	30,09	27,23	24,64	22,79
T3	All buildings rooftop ≤ 36kWp	55,00	55,96	57,19	60,18	57,75	42,00	37,00		30,35	27,46	24,85	22,49	20,35	18,42	17,04
T4	All buildings rooftop from 36 to 100kWp	55,00	55,96	57,19	60,18	57,75	42,00	37,00		28,83	26,09	23,61	21,37	19,34	17,50	16,19
T5	Ground based installations	30,00	30,53	31,19	32,82	31,50	31,40	27,60		12,00	11,68	11,38	11,08	10,79	10,51	10,24

kWp : kW peak

Table 13: evolution of FiT for PV generation

For large ground-based projects (exceeding 100 kW), calls for tenders have to be organised to manage the evolution of installed capacity, with annual objectives of 120 MW for installations on buildings between 100 and 250 kW, and 180 MW for ground-based installations and installations on buildings exceeding 250 kW.

This new policy has caused significant job losses in France: the photovoltaic sector accounted for 32,500 employees in 2010 but only 18,000 in 2012. Therefore, at the beginning of 2013, the Ministry of Ecology, Sustainable Development and Energy decided upon urgent measures to boost the French photovoltaic sector, and to reduce the large trade deficit of the sector estimated at €1.35 bn. Annual objectives for new solar projects will be set to 1,000 MW instead of the previous 500 MW. New calls for tenders will be launched in 2013 for large installations, partly focused on innovative technologies, and taking into account the whole carbon footprint of components. Small installations shall receive a bonus of up to 10 % if they are “made in Europe” (French Government, 2013).

3.3. Calls for tenders

The 2011 Energy Code states that when the production capacity does not meet the objectives of the PPI, the Minister for Energy may use the tender procedure.

The electricity generated by a tendered project is sold to EDF or the local distributor, who are obliged to sign a contract with the winners at the price resulting from the call for tenders.

The regulator organises the calls for tenders launched by the State; it writes the specifications, analyses the bids received, proposes to the government a ranking of bids, and provides advice published in the Official Journal.

One advantage of this mechanism is that the price is not determined ex-ante by the government, but rather by the operator himself. Therefore it is not necessary to repeatedly update the feed-in tariff to adapt to productivity improvements and avoid speculative bubbles (like that experienced in the PV sector). In order to ensure competitiveness in the tender process, one can expect that the bidder in the tender will propose a price taking into account the latest cost of technology available.

However, calls for tenders generate significant transaction costs (from sources such as the preliminary consultation on the General Conditions, writing of specifications, multiplicity of players, proceeding spread over several quarters and so on). They can also be unsuccessful if the economic or legal conditions do not allow the emergence of any application satisfying the specifications (for example, if the prices offered by the bidders are considered too high). Furthermore, once selected, projects can experience a significant lead time before commissioning of the full quantity selected is complete. Administrative burdens and local opposition leading to systematic judicial challenges can contribute to the delay of project implementation.

To date, 11 calls for tender have been launched for RES plants since 2004:

- 4 for biomass and biogas (2004, 2007, 2009, 2010),
- 2 for offshore wind (2004, 2011),
- 2 for onshore wind (2004, 2010),
- 3 for solar energy – photovoltaic and thermal (2009, 2011, 2011).

According to the data available on the regulator's website at the beginning of 2013 (CRE, 2013), Table 14 identifies the calls for tenders conducted.

According to the French government, new tenders for offshore wind and solar generation will be launched in 2013, and the conditions defined in the 2011 call for tenders will be modified for the remaining periods.

Launch of the call for tender	Technology	MW	MW selected	Price €/MWh
2004	Biomass	200	232.4	Not disclosed
	Biogas	50	0	Not disclosed
2004	Offshore wind	500	105	Not disclosed
2004	Onshore wind	500	278.35	Not disclosed
2007	Biomass 5-9 MW	80	84.6	128.10
	Biomass > 9 MW	220	229.8	
2009	Biomass	250	266.1	145.00
2009	Solar (PV in mainland, PV or thermal + storage in islands)	300	Not disclosed	Not disclosed
2010	Biomass	200	Not disclosed	Not disclosed
2010	Onshore wind + storage in islands	95	Not disclosed	Not disclosed
2011	Offshore wind	3000	1928	226.50
2011 (7 periods from 01/08/2011 to 30/06/2013)	Solar PV	300	1st period: 45	229
2011	Solar PV + thermal	450	Not disclosed	Not disclosed

Table 14: synthesis of current calls for tenders (source: CRE, RTE analysis)

3.4. Green marketing: guarantees of origin

A guarantee of origin is a document that aims to prove that the electricity supplied stems from a renewable source. It can be required by producers which do not otherwise benefit from a purchase obligation. For energy under purchase obligation regime, the buyer (EDF or local distributors) may require the issuance of the guarantee. Guarantees can be transferred from one holder to another.

Until 1st May 2013, guarantees of origin are issued by RTE, in compliance with the Decree no. 2006-1118 of 5th September 2006. Companies can apply for guarantees of origin for the electricity they generate if they are a generator without a feed-in tariff agreement, they generate from renewable sources or CHP, and if their facility has a meter described in a binding contract between the electricity generating facility and its grid operator.

As of the end of 2012, the quantities issued by RTE and used by market participants are shown in Figure 33 and Figure 34. The decrease in issued volumes can be explained by inaccuracies in the 2006 decree, the impossibility of exporting guarantees, and the lack of business opportunities (few customers are willing to voluntarily pay more for "green" electricity). Only 53 % of issued volumes have been used.

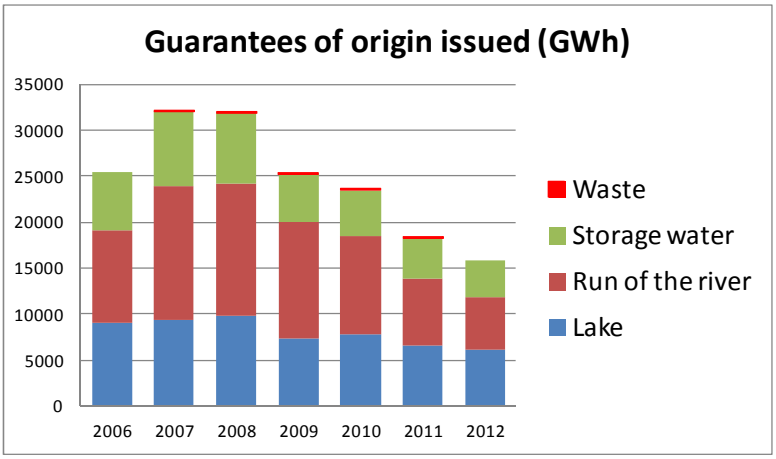

Figure 33: guarantees of origin issued by RTE (source: RTE)

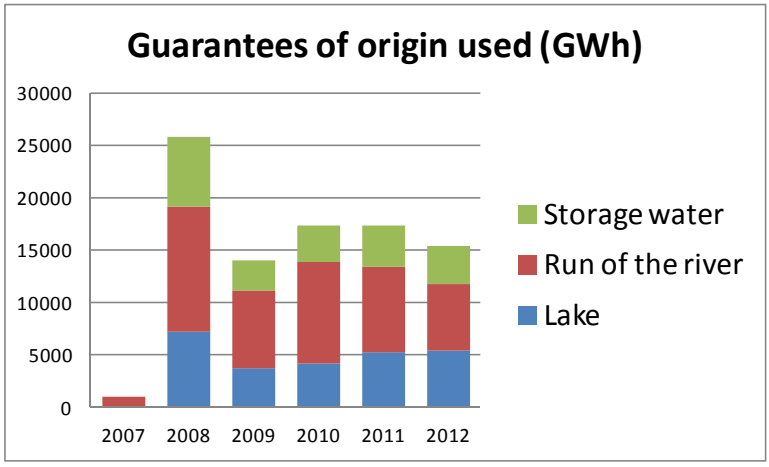

Figure 34: guarantees of origin used by users (source: RTE)

The European Directive 2009/28/CE regarding the promotion of the use of energy produced by renewable sources aims to normalize and standardize the guarantees of origin that existed in various forms in European countries. It has been transposed into French law by the Ordinance of 14 September 2011 (French Government, 2011d).

Following a call for tender from the French Ministry of Ecology, Sustainable Development and Energy conducted in March 2012, an order of 19th December 2012 (French Government, 2012b) appointed Powernext[35] as the National issuing body for electricity guarantees of origin in France from 1st May

[35] Powernext operates electronic trading platforms for spot and derivatives markets in the European energy sector

2013 for a five-year term. The French Registry, which will be implemented in compliance with Decree n°2012-62 published on 20th January 2012 (French Government, 2012a), will allow its users to issue guarantees of origin to certify their generation, to transfer guarantees to other users, and to use guarantees as a proof of the renewable origin of the electricity supplied to their end-use customers. The registry's account holders will be able to import and export guarantees of origin in Europe as Powernext will be compliant with the AIB's (Association of Issuing Bodies) European protocol shortly after the registry becomes operational (Powernext, 2013).

The order of 19th December 2012 indicates the tariffs (excluding taxes) to be charged by Powernext:

- Fixed part:
  - € 2000 per year and per user
  - € 450 per installation per period of 3 years
- Variable part:
  - € 0.03/MWh for issuance of a guarantee of origin
  - € 0.01/MWh for transfer, export, import or cancellation of a guarantee of origin.

Guarantees of origin will have a period of validity of one year after the first day of the guaranteed period.

After transferring its register to Powernext, RTE will continue to perform some marginal functions concerning guarantees of origin: upon Powernext's request RTE will check data concerning the issuers, including the characteristics of the installation, the references of the grid access contract, and the fact that the unit has generated at least the energy to be guaranteed.

3.5. Tax credits

Households can benefit from tax credits if they undertake works to improve the insulation in their homes, install efficient heating systems, or install equipment for producing electricity from sun, wind or water.

In 2011, the tax reduction was defined as 45 % of the price of the equipment for electricity generation from wind, hydro and biomass, and 22 % from PV panels. In 2012, they have been lowered to 32 % and 11 % respectively.

This mechanism is a type of subsidy. It has the advantage of being proportional to the investment cost, and therefore automatically incorporating cost changes.

It supplements the feed-in tariffs. In its deliberation of 3 March 2011 related to PV feed-in tariffs (see section 3.2), the CRE estimated that the maximum IRR would be lowered from 11 % to 8 % if the 22 % tax credit was removed.

3.6. Funding of the support mechanisms

- Guarantees of origin, being a voluntary scheme, require no specific funding besides the price operators are requested to pay to have their guarantee issued, and the price consumers are prepared to pay for the "green" electricity brand.
- Tax credits impact the budget of the State; therefore every taxpayer contributes.

- Feed-in tariffs resulting from purchase obligation and calls for tender require specific funding. This is achieved via the "CSPE" mechanism.

Established by the Law No. 2003-8 of 3 January 2003, the Contribution to Public Service of Electricity (CSPE) aims at compensating operators[36] for various costs they have to bear, including the additional costs resulting from the support mechanisms for renewable energy. (The CSPE also includes financing of cogeneration, tariff equalization across France's mainland and islands, social measures and so on). The CSPE is paid by the final consumer. It is collected by the TSO/DNO or the supplier, who then transfers it to the "Caisse des Dépôts et Consignations" (Deposit and Consignment Office, owned by the French State), which in turn transfers it to the operators who supported these public service charges.

Therefore, in this case the cost of the mechanism supporting RES is paid by the electricity consumer, as a distinct charge included on their invoice.

The energy regulator (CRE) must propose every year to the minister in charge of energy the amount of public service charges and the unitary contribution (in €/MWh).

In its deliberation of 13 October 2011 (CRE, 2011), the CRE stated that the total charges (RES + cogeneration + tariff equalization + social measures) allocated to 2012 will be € 4,253.7 million. With adjustment calculations related to previous years, the charges to be collected in 2012 will be € 5,207.7 million.

Concerning the renewable energy sources component, the increase is significant, principally due to the development of wind and photovoltaic power: € 14.1 million in 2008, € 2,216.4 million in 2012.

In its deliberation the CRE stated that the CSPE should be raised to € 13.7 /MWh. This is based upon a total cost of € 5,207.7 million divided by a consumption of 380.9 TWh. Some customers are eligible for an exemption[37], which means that the consumption subject to CSPE is lower than the total French annual consumption which is estimated at 475.7 TWh.

However, the government has set the level to € 9/MWh until 30 June 2012 and to € 10.5/MWh until 31 December 2012, which should result in a loss of € 1.3 bn for EDF in 2012. Mid-2012, according to information published by EDF, the cumulative deficit of EDF since the implementation of CSPE has amounted to € 4.5bn.

In its deliberation of 9 October 2012 (CRE, 2012), the CRE stated that the CSPE should be raised to € 18.8 /MWh. The renewable energy sources component should increase to € 3,014.7 million. However, the 2011 Energy Code limits the increase of CSPE to € 3/MWh per year. The rate will thus be € 13.5/MWh, which should result in a loss of € 2 bn for EDF in 2013.

[36] Mainly the incumbent EDF, and local distributors

[37] The amount of CSPE to be paid by a consumption site is capped to a level updated annually by RPI (€ 569,418 in 2013)

4. Regional plans for grid connection ("S3REnR")

The "Grenelle II" law (no 2010-788 of 12 July 2010) established two types of "plans" to facilitate the connection of renewable energies:

- ***Regional Plans for Climate, Air and Energy ("SRCAE"):*** approved by the regional authority, the Regional Plans for Climate, Air and Energy set qualitative and quantitative targets for the development of renewable energy sources by year 2020.
- ***Regional plans for grid connection of renewable energy sources ("S3REnR"):*** based on the SRCAE, the Regional plans for grid connection of renewable energy sources are established by grid operators (DSO and TSO). They mainly consist of:
  - Development works (detailed by asset), discriminating between new construction and reinforcement of the existing network,
  - Capacity forecast of the plan (global and detailed by substation),
  - Projected cost (detailed by asset).

The projected cost of the regional assets to be constructed is borne by the generators which will benefit from the new capacity and reserved to transport renewable energy. Payments are calculated as a "quota share" determined pro rata based upon installed capacity. The components of the calculation of the quota share are defined ex ante and approved by the regional authority. They may not be revised ex post.

A regional "pool funding" arrangement collects all quota shares from regional renewable generators, and aims to finance all regional transmission and distribution grid assets that need to be constructed.

The cost of reinforcement works is not borne by producers, but rather remains charged to the users of the network via the grid access tariff.

The cost of connection assets (providing connection of an individual generator to the grid) remains borne by each generator.

The generators pay their quota share to the grid operator to which they are connected. A TSO/DSO agreement reallocates the share between the parties (between TSO and DSO assets to be financed).

Investment costs (creation and reinforcement) are included in the System Operator's Regulated Asset Base (RAB). The quota share paid by the renewable generator is treated as an investment subsidy which reduces the RAB.

As an example, in the Picardie region (for which the Regional Plan was published in December 2012), a global capacity of 975 MW will be reserved for future renewable generators. Works to be conducted by RTE consist of € 6.8 million of reinforcements (financed via the transmission grid access tariff) and €18.8 million of assets creations (such as new links, substations, transformers and so on, to be financed by new renewable generators through quota shares). For distributors, creation of assets represents €38.4 million. The quota share is thus calculated as $(18.8 + 38.4)*10^6/975$ = €58,600/MW (RTE, 2013).

5. Conclusion

Policy support for renewable energies has produced some success in France, as illustrated in Figure 35. Photovoltaic installed capacity has grown from 4 MW in 2006 to 3,515 MW in 2012. Wind capacity accounted for only 94 MW in 2001, and has reached 7,449 MW in 2012. In 2012, French generation produced by renewable sources (excluding hydro) accounted for 24.8 TWh, which represents 4.6 % of French generation, composed of 2.8 % from wind, 0.7 % from PV and 1.1 % from waste, biomass and biogas. All renewable sources (including hydro generation) provided 16.4 % of French generation.

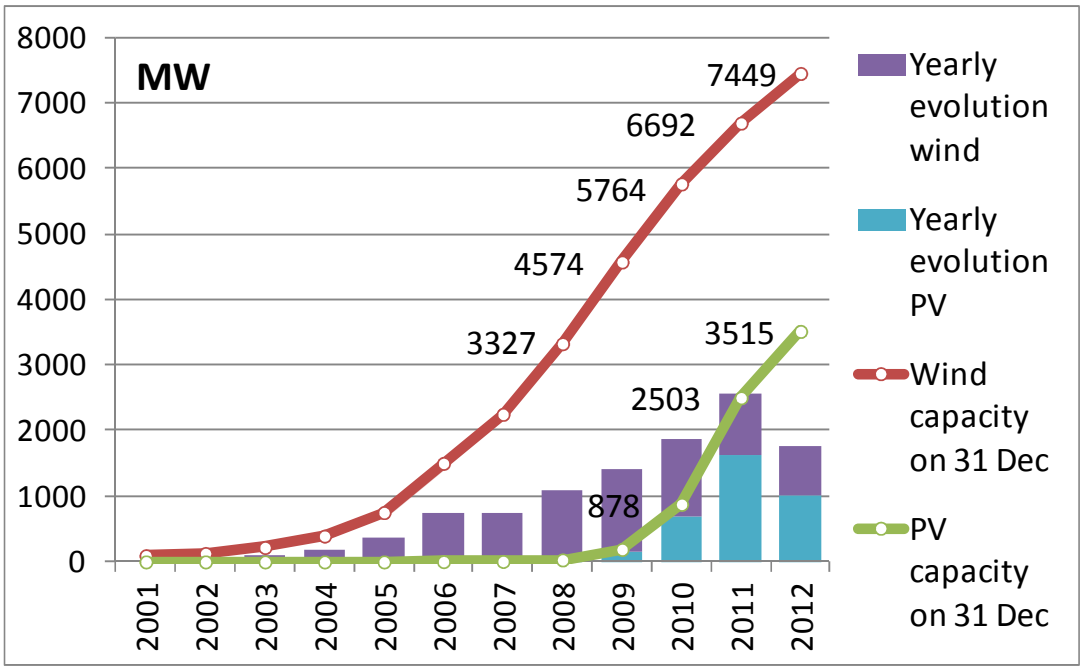

Figure 35: Evolution of wind and photovoltaic installed capacity in France (source: RTE)

However, a decline of annual growth has been observed since 2011 for wind and 2012 for solar, and France remains below the trend necessary to reach its objective for 2020. The French support scheme remains uncertain, and local opposition is sometimes strong, which does not provide investors with the stable framework they need to invest in long term assets.

As an example, feed-in tariffs for wind are currently subject to an appeal before the French Council (the highest administrative court in France) lodged by anti-wind power associations, arguing that support for wind farms constitutes illegal state aid because it had not been notified in advance by the French State to the European Commission. The State Council transferred the case to the European Court of Justice, which will decide whether or not feed-in tariffs constitute a state subsidy and if they are compatible with European market rules. According to some experts there is a risk that wind generators will be required to reimburse the grants received.

The construction of power plants has to be conducted in alignment with numerous administrative rules and local consultation requirements. The implementation of the offshore wind park awarded

following the 2004 call for tender is still blocked by an administrative decision driven by local residents.

The French State has to reconcile often conflicting objectives. Most significantly, they must achieve the stated renewable energies targets, while minimizing price increases for the end consumer. This can lead to "stop and go" policies, such as that observed in the photovoltaic sector. This illustrates the risks of price mechanisms and the potential benefits of introducing quantity mechanisms. The intention to limit prices increases is understandable, but the mechanism as applied has at least two drawbacks: firstly it does not transfer the appropriate price signal to the final consumers, secondly it generates a € 5 bn deficit for the incumbent.

Finally, as renewable energies are often situated remote from consumption centres and from existing grids, connection to the grid can remain a burden, which should be eased by the regional plans currently being implemented.

At the end of 2012, the French government launched a public debate on energy transition. A new energy policy is expected in 2013.

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Appendix 7: CIGRE WG C5-11 QUESTIONNAIRES RESPONDENTS

The technical brochure is partly based on questionnaires answered in 2010 by:

Roberto Giunti	Argentina
Marcelo De Freijo	Argentina
Juan Luchilo	Argentina
David Swift	Australia
Greg Thorpe	Australia
Dalton O C Brasil	Brazil
Chuck Steele	Canada
Xiaomeng Lei	China
François Regairaz	France
Holger Ziegler	Germany
Alex Haffner	Great Britain
David Stevens	Ireland
Yakov Hain	Israel
Yang Sung Bae	Korea
Paul Boonekamp	Netherland
Hans Olav Ween	Norway
Ricardo Pereira	Portugal
Milos Pantos	Slovenia
Jose Arceluz Ogando	Spain
Jan Sundell	Sweden
Marek Zima	Switzerland
William Phillips	USA
Albert DiCaprio	USA