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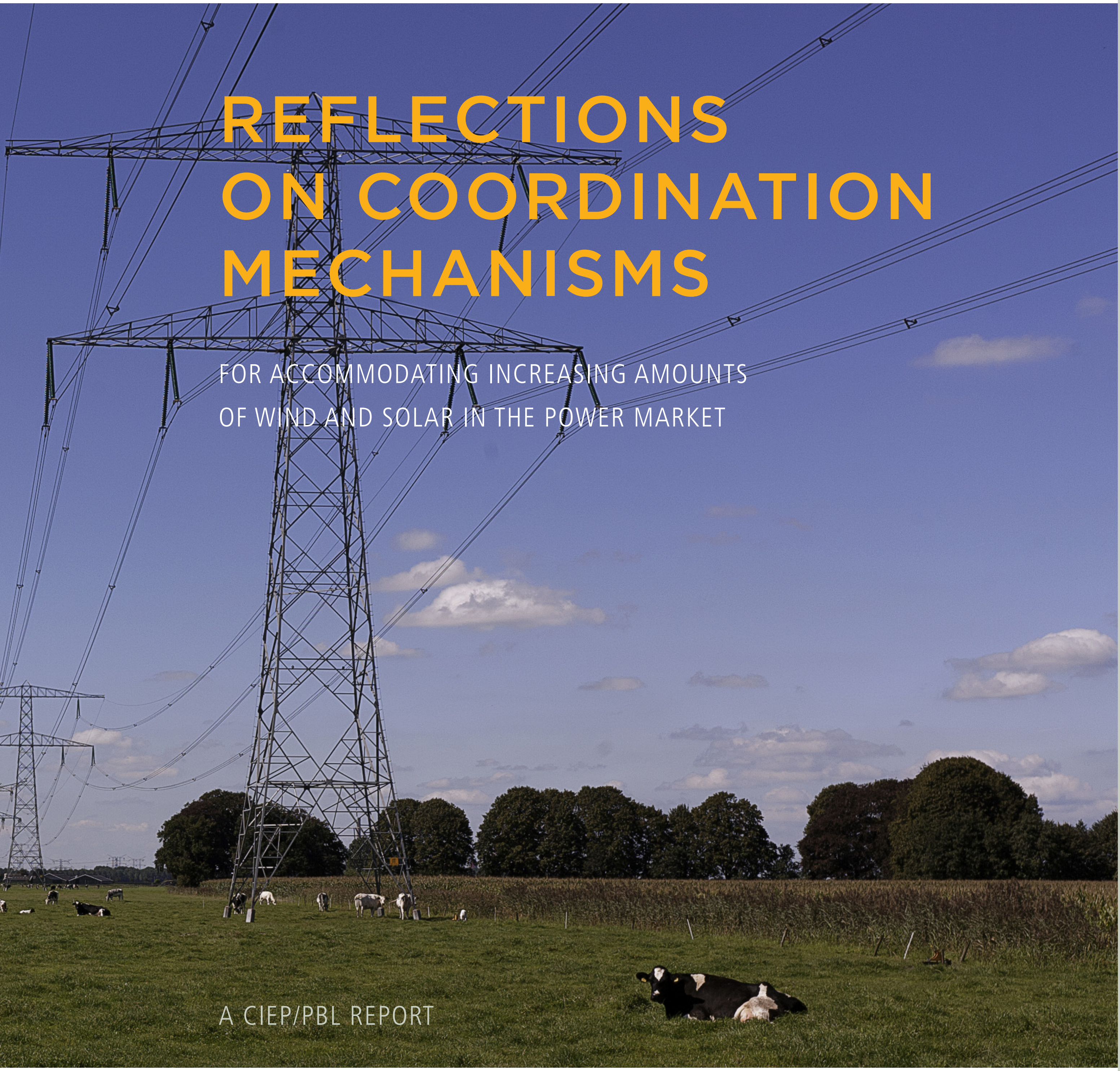

REFLECTIONS ON COORDINATION MECHANISMS

FOR ACCOMMODATING INCREASING AMOUNTS OF WIND AND SOLAR IN THE POWER MARKET

A CIEP/PBL REPORT

CIEP PAPER 2014 | 05

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EXECUTIVE SUMMARY

European power markets are being confronted with an unprecedented transition process toward a low-carbon power system. The speed and complexity of this shift are raising serious challenges and operational difficulties. The successful increase in the deployment of variable renewable electricity technologies is bringing the EU objective of raising the share of these technologies in its energy mix to 20% by 2020 closer to an attainable reality. But there are deep concerns about the continuing impacts of this transition, especially as it is further expanded to include a substantially larger share of renewables by 2050. Concerns centre on the increasing costs for consumers and tax payers, on how to manage operation when there are large degrees of variability within the energy mix, and on the uncertainty of supply security due to generation and system adequacy risks. More generally, this transition demands a more fundamental rethinking of the role of the state and the role of the market, with due regard for the still prevailing paradigm of an internal EU electricity market with increasing cross-border flows and market integration.

In exploring the emerging challenges and opportunities, this essay offers a number of reflections: on how to enhance investor confidence in a continuing market-based context with effective long-term oriented coordination mechanisms; on how to apply and implement support schemes for investing in new low-carbon generation technologies; on understanding market dynamics in the interaction between generation and the networks and in its day-to-day system operation, with the need for deploying effective regulatory adaptations in a pragmatic way; and on maintaining the necessary operational back-up capacities and longer-term-oriented generation adequacy. It must be recognized in all these reflections that the power system in the EU is still largely based and optimized on centralized approaches in a strongly internationally interconnected system. But this will change as well. Generators, network operators, investors, consumers, local citizen groups, traders and suppliers are all in search of their roles and opportunities in this transition process.

The issues are being discussed at many levels: nationally and locally, at EU levels and in a more regionally-oriented context. The issues are urgent, but there is still time to consider different approaches and look for robust solutions. Market forces will continue to be the guiding mechanisms for prices and investments, and market parties at all levels will remain the ultimate decision makers. Governments and government agencies will have to actively and effectively facilitate these decisions in a stable but adaptive way. This essay addresses these issues and interactions, starting with three observations: a substantial increase of VRE (Variable Renewable Electricity) will not cause subsidies for new investments in certain types of renewable energy to end, as wholesale prices have decreased faster than production costs and may decrease further, especially at times of VRE generation; second, network costs will increase, depending on many aspects like the degree of curtailment that will be accepted or the degree of demand-side management that could be achieved; and third, long-term adequacy may only be available at much higher total costs. These observations require further analysis and discussion, but would need already now some new approaches. As the actual power system has not been developed to deal with a large share of VRE, it is being confronted with challenging transitional problems. It is not the large share of VRE as such that is causing problems, but its occurrence in a power system that has been gradually developed and optimized under completely different circumstances.

To a large extent the transitional problems can be solved within the prevailing market-based context. One needs to realize, however, that markets are always dynamic and complex, and often even impossible, to predict. It also means that in the quest to find an effective and efficient mix of policy and regulation, one has to develop new avenues as well, resulting in new policies, instruments and regulations. This process will have to be one of learning by doing, where sometimes policies and instruments that are not delivering will have to be abandoned. Learning by doing can be successful if the long-term ambition remains unambiguous and if it is accepted that national approaches alone will not be sufficient, meaning that European approaches will be required, while also understanding and accepting that within the EU many structural and physical differences will necessarily remain. All-EU solutions will not always be possible or even desirable. Hence a more regionally oriented model, such as the one of the developing NW-EU energy market, could be more successful.

INVESTMENTS IN GENERATION

In order to decarbonize the power sector by 2050, the overall EU approach will have to change fundamentally before 2030-35. In rethinking how to stimulate investments in new generation in the prevailing market-based context, the most important existing policy instruments are investigated, both the general ones (the Emissions Trading Scheme, ETS, and Contracts for Difference, CfDs) and those which are more VRE-specific (feed-in tariffs, FiTs, and feed-in premiums, FiPs, as well as auctions and supplier obligation schemes). In addition, three others that are under discussion in policy debates are looked at: Emissions Performance Standards (EPS), Capacity Remuneration Mechanisms (CRMs) and the Regulated Asset Base (RAB) methodology. The essay also includes some thoughts about long-term arrangements and on facilitating investor confidence in planning and licensing procedures.

No single policy instrument will be sufficient to allow policy makers to achieve their policy goals. A mix probably will be needed. Choices will be based on the particular market situations and the weight policy makers attach to their different national preferences. The first option would be to improve ETS, which, despite the actual shortcomings, is still the only market-based EU policy instrument. A strengthened ETS has to be supported by additional instruments for a longer time than is often realized. The subsidy schemes should therefore have a clear preference for the more market-based approaches such as FiPs. Regulation such as EPS is something worth exploring more actively. Quantitative supplier obligations for renewable energy could also be an option. More radical interventions with CRMs, perhaps in connection with a RAB, may be useful as well if other approaches are less successful.

A more extended and deliberate transition period than currently is envisioned might be advisable as well, as temporization in large-scale investments combined with learning from technology and policy innovations could decrease costs. In all cases, one has to accept that the power system will become more expensive. Attaining the low-carbon aim is a difficult and, at least in the next decade, costly endeavour.

NETWORKS

In the transition towards a mix with high shares of VRE, the operational and regulatory designs will have to be adapted to fit the physical characteristics of the networks and their economic implications. Energy networks are capital-intensive and have long lifetimes and a monopolistic nature. Investments in these networks take time; more VRE requires additional investments in grid extensions and a substantial intensification of the management of the electro-technical balance.

We recommend a rethinking of the grid-generation paradigm, placing more emphasis on the role and operation of the infrastructures, including applying technology neutrality and considering a more energy system-integrated orientation. Reconsidering this 'grid-follows-generation' paradigm could also lead to higher social-economic benefits. A more precise cost allocation for grid users, more innovative demand-response mechanisms and the introduction of (cross-border) market mechanisms (including ones for operating reserves) could further decrease additional network costs in a market-based way. Enhancing operational efficiency requires technology neutrality in balancing, with an extension of the 'flexibility space' (focusing particularly on the role of gas and its regulatory conditions), and with a cross-border expansion of balancing zones in which system operation and network usage are guided by market-based arrangements. Decentralized generation and/or new demand-side orientations will increase their shares in the balancing market. TSO/DSO interactions will become increasingly important, and more specific roles for the DSOs and other Distributed Energy System (DSEs) providers could lead to a rethinking of their regulatory space. All of this would require regulatory innovation, perhaps including experimentation with regulatory exemptions.

ADEQUACY

System and generation adequacy are, together with supply security, high on today's policy agendas. Adequacy of the system can no longer be guaranteed, however, as existing flexible generation is closing and new investments in back-up are not being made. Concerns are being expressed about the investment climate and the low rewards for investing in new capacity, questioning the role of the prevailing Energy-Only Market (EOM). Options for capacity payments, whether in a market-based context or not, are therefore emerging. Many options have been more extensively discussed elsewhere, but the specific questions in the context of our reflections focus on the long-term coordination requirements. Flexibility of prices and additional room for demand-side integration, the certainty that no price cap will be used, the further development of market coupling, intraday and balancing markets and markets for ancillary services diminish the eventual need for dedicated mechanisms to stimulate back-up capacity. It would be unwise to abandon the Energy-Only Market before all options to increase its effectiveness have been explored. The academic literature draws no final conclusions about whether separate capacity rewards are needed, as the possible improvement of adequacy has to be weighed against costs. Furthermore, uncertainty will increase, as nobody knows how long the policy debate on CRM will last or how future politicians will implement the rules. However, politicians and regulators don't like to take any risk with real or perceived in-adequacy. When they would consider the introduction of a CRM, the least they could do is to do this jointly in a regional context. The same is true for any another option to improve adequacy, i.e., developing adequate storage capacity (especially long-term).

REGIONAL APPROACH

All of the issues discussed in this essay will require a European approach. A number of them could be tackled with national policies, but with cross-border interactions EU rules are applicable. One has to realize that policy implementation will become too complicated if 'all-EU' solutions are attempted. Hence, regional approaches, such as the Pentalateral Energy Forum, which includes the Benelux, France, Germany and now others, should be the goal. The Netherlands could take more initiative in bringing a number of the policy issues to the Penta agenda: issues such as assessing generation adequacy, VRE integration in the grids, expanding market-based balancing options and zones, coordinating VRE support schemes, enhancing joint cooperation between the TSOs, and even more ambitiously, a more general approach to the fuel mix policies, including the role of gas. Wherever possible, these issues could be supported by an enhanced German-Dutch bilateral cooperation, and where appropriate by a Belgian-Dutch approach.

THE STATE AND THE MARKET

In all, this essay does not suggest that the energy market has to move one-dimensionally back to the state. Instead, it suggests that the state must be aware of being part of a process in which it stimulates and facilitates investments of clean energy in general and VRE in particular. A state trying to implement effective and efficient policies is well advised to investigate how markets can perform better and how private entities can play their role. The energy market has two different coordinating functions, i.e. the daily operation and facilitating new investments in the medium and longer term. This distinction has to be accepted and therefore requires some mix of new or improved policy instruments on the road towards a more carbon-neutral power system that incorporates VREs by 2030/35: policy instruments that have a clear impact on the market and on the investment decisions required. There is no other alternative for the investment function than that the state continues to be involved. But market forces for intraday balancing can be developed more than they are today, both on the demand side and on the side of the operating reserve. This is the operational part. Markets could also be obliged to operate faster by allowing them to work (very) closely to real time before balancing. Improving these markets will decrease the additional costs of a power system with larger shares of VRE. A better interaction between the grid and generation will further diminish the additional costs. As local cooperatives and local initiatives by well-informed citizens, asking for more involvement and promoting local strength, are becoming more and more visible and apparent, and as the energy industry is starting to re-invent itself by developing new business models and approaches, the uncertainty of the outcome has to be accepted. It goes without saying that government and its regulatory agencies are part of this process and should reflect in this dynamic policy environment in more effective and adaptive decision-making procedures.

The future is open, but not completely formless. Some of the options are easier to implement than others or are already being explored in individual countries. More flexibility of the system could start with the direct implementation of the recent EU Guidelines on State Aid. A further policy package could be developed quickly with improved ETS, adaptation of feed-in tariffs into premiums, programme responsibility for all generation sources (except the smaller ones), more demand-side integration and an increased role of balancing and intraday markets. A new way of dealing with the generation-network interaction and an introduction of EPS could bring about system improvements, but this needs further consideration. Capacity Remuneration Mechanisms, maybe in combination with a broader introduction of a Regulatory Asset Base, could be necessary, but other flexibility options have larger net benefits and could be introduced much more quickly. Finally, the state should act judiciously, allowing markets to perform their tasks wherever possible.

1 INTRODUCTION

The emergence of wind turbines in the countryside and PV collectors on rooftops over the past decade visualizes the physical impact of energy and climate policies guiding European economies towards an environmentally sustainable future with an acceptable degree of climate change. It is a clear indication of a successful take-off in many of the EU countries towards meeting their ambitious 20/20/20 targets. Now that we are moving past the initial phases, it is time to take a closer look at the economic impacts of these policies.

Germany is beginning to realize that its subsidy schemes for renewable electricity are becoming more and more costly.[1] Germany's neighbouring countries are confronted with the cross-border impacts of the increasing amounts of generated green electricity. Last year a number of large European energy companies stated that present EU and member state energy and climate policies make the EU 'un-investable'. It is not per se necessary that these particular companies invest, but someone has to finance the large investments that are needed to attain a low-carbon power system. It is a reminder that economic sustainability[2] is a prerequisite for environmental sustainability in the EU, where markets have been chosen as the coordinating mechanisms for production and consumption. Given the ambitions of EU governments to continue their efforts to decarbonize the energy systems, new coordinating mechanisms are needed to realize a clean, reliable and affordable power system.

Many technological options for decarbonizing power systems already exist. Some are dispatchable and therefore fit well in the present system, such as hydropower, nuclear power, biomass and fossil fuels with carbon capture and storage (CCS). Each of these has specific drawbacks in terms of costs and social acceptance, making the case for an energy mix with large degrees of wind and solar power generation the generally preferred way forward. This essay focuses on variable renewable electricity (VRE) sources as being one of the backbones of the future power system. These sources pose some specific challenges as well that need to be tackled in order to

1 Germany decided in the course of 2014 to reform its Renewable Energy Act with a break through the cost dynamics and to limit rising costs for electricity consumers.

2 The term *sustainability* is used here to denote the capability of everlasting functionality. At the same time it refers to the broader meaning of the term, with its ecological, social and economic dimensions, to convey that systems generally last a long time when they provide for a broad variety of demands.

realize a successful transition to a low-carbon power system. To get a clear picture of the implications, we look beyond topical issues and focus the analysis on a future situation in which VRE generation occupies a substantial share (30-50%) in the European power system. The spatial scale of this analysis is the EU, with a focus on the Netherlands in the NW-European market.

To make a low-carbon power system with 30-50% VRE technically and economically feasible and durable, major technical changes are needed in power generation facilities, in power networks and in balancing and systems operations. There is much debate about the suitability of present market models for attracting investors for these new facilities. Some say that minor changes to the present 'Energy-Only Market' will suffice to deal with investors' needs (Neuhoff 2013), while others expect extensive government involvement to guarantee the profitability of new investments (Helm 2013). A position in between these extremes is clearly possible. In the following chapters reflections will be made on various propositions presented in the literature to improve existing coordination mechanisms in electricity markets.

Before doing that, Chapter 2 intends to give a clear picture of the nature of the problems related to VRE expansion. As noted, this study does not reflect on current problems as such, but looks retrospectively from a situation in which the share of wind and solar power has increased substantially and reflects on pathways that can be chosen to enable this situation in a cost-effective and reliable way. Large shares of wind and solar power are to be expected and may even be considered necessary. Their further introduction raises transitional problems, which can be overcome, but not without interventions in regulation and policy. In the next chapter three issues will be considered: the impact of rising shares of wind and solar power on the wholesale market price and subsidies, their impact on reliability, and the impact on system costs if no policy measures are taken.

2 PROBLEM ANALYSIS

2.1 CONFLICTING SOCIAL OBJECTIVES FOR POWER SYSTEMS

The social objectives of energy policy are generally phrased as providing sufficient energy and electricity and that it is reliable, affordable and clean. But once this general objective is translated into operational terms, the conflicts between reliability, affordability and decarbonization become apparent. Generally speaking, policies to decarbonize the power system tend to increase system costs and will reduce its affordability. If decarbonization is achieved by means of a large share of variable or intermittent forms of power generation, this would also impact the reliability of the power system. To maintain its reliability, costs will go up and affordability will go down. So, clean, reliable power will be more expensive than the power produced today unless technological and operational innovation can manage to reduce production costs.

At present, each of these objectives faces serious headwind, as can be read in many recently published reports from think tanks, consultants and research groups. For decarbonization to become socially acceptable, it will need to come at an affordable price and its perceived benefits will need to surpass its costs. This means that policy options which successfully reduce the private and social costs of reliable low-carbon power delivery will contribute most to the social objectives of energy policy. Adopting this type of policy would therefore increase the opportunities for policy makers to balance between the three objectives.

2.1.1 Decarbonizing power production with VRE

EU leaders have endorsed the objective of reducing Europe's greenhouse gas emissions by 80-95% by 2050 as compared to 1990 levels. The 'Roadmap for Moving to a Low-Carbon Economy' (EC, 2011a) shows how the effort of reducing greenhouse gas emissions could be divided cost-effectively between different economic sectors. If all sectors contribute according to their technological and economic potential, the power sector should be able to switch to an almost carbon-free production system (meaning a 93-99% reduction in emissions between 1990 and 2050), keeping fossil fuels in the power sector only when CCS technology is used. One cannot expect Northwest Europe to invest substantially in new nuclear energy in the next decade, and CCS is still stagnating in an early demonstration phase. Substantially increasing the shares of VREs therefore seems unavoidable, or is an option to be promoted vigorously, depending on one's position in this debate. The EU Commission mentioned in its 2011 Impact Assessment of its Energy Roadmap 2050 that 'renewables will become the largest source of electricity, seeing its share increase from 15% of electricity production in 2005 to around 50 to 55% in 2050' (EC 2011b). The main reference forecast of the German government expects 26% wind and 9% solar power in 2030, and 45% wind and 12% solar power in 2050 (DENA 2012). Many studies have examined the technical options to produce carbon-free power by 2050 (Knopf, 2013). All of them conclude that VRE (solar and wind) will need to cover a substantial part of the expected electricity production, varying from 20-37%, see Table 1.

TABLE 1: ESTIMATED COSTS OF GHG REDUCTION AND SHARES OF VRE IN EUROPE

	Baseline scenario		40% GHG reduction		80% GHG reduction	
	2030	2050	2030	2050	2030	2050
% GDP-loss			<0.7	0.4-1.8	<0.7	1-10
% solar	0-3	0-4	0-4	4-8	0-5	4-10
% wind	4-10	6-15	11-18	13-21	13-22	16-27

SOURCE: DERIVED FROM FIGURES 7 AND 11 IN KNOPF, 2013. FIGURES BASED ON 13 MODELS (MARGINS OF 50% CONFIDENCE INTERVAL FOR % SOLAR AND WIND). NOTE THAT GDP LOSS RESULTS FROM ALL MEASURES (BOTH WITHIN AND OUTSIDE THE POWER SYSTEM) TO REDUCE GHG EMISSIONS.

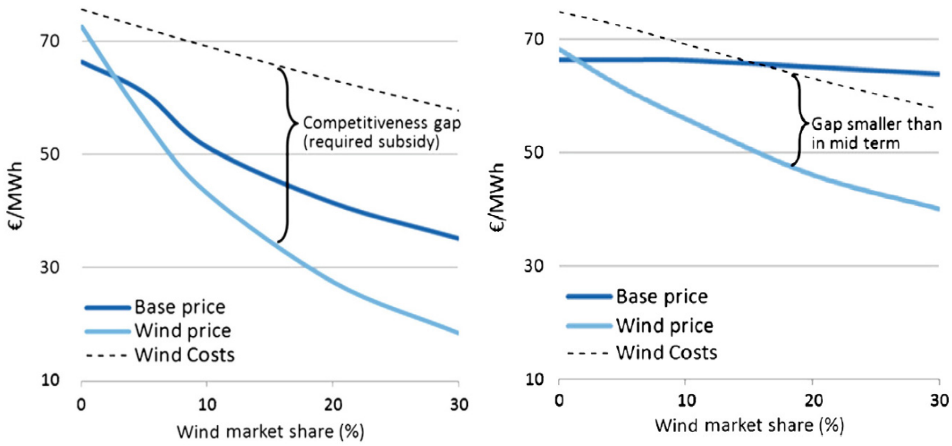
As illustrated in Table 1, it is to be expected that the share of wind energy production will remain substantially larger than that of solar power, especially Northwest Europe. Wind generators will try to increase their load factors. With interconnection they are expected to attain 30%, and even 40% or more for offshore wind. Solar-PV in our region will not easily surpass 850-1000 full load hours, a load factor of 10 percent. It could be expected for Northwest Europe that a system with wind energy combined with a flexible backup of e.g. gas generation will become the backbone of the power system, whereas solar will remain merely an additional source. This implies that the regulatory approaches for these generation options require different accents as well.

VRE deployment in a well-supplied market reduces wholesale power prices

Once wind and solar power have matured, they will have the potential to supply electricity at very low costs. Following the logic of the learning curve, maturity increases with deployment. Subsidy schemes were designed to get these technologies 'through the valley of death' and to close the competitive gap, creating a situation in which they could easily compete with fossil power. Power prices were even assumed to develop irrespectively of the type of power production. But this perspective ignored important features of present day power markets. The variable cost of the marginal plant in the market is a strong determinant for the electricity price at any given moment. Incentivizing investments in new RES capacity in an already well-supplied market creates overcapacity. If the resulting capacity mix is then increasingly characterized by low marginal cost technologies (new RES and existing nuclear and/or lignite), further price decreases will result. This so-called merit order effect of increasing RES additions then adds to downward pressures in an already well-supplied system. Market forces would then start to prevent further capacity expansions. But with continuing support schemes, further downward price pressures will result, with continuing calls for support mechanisms for existing non-RES generation capacity based on higher marginal (fuel) costs. If support schemes continue and (temporary) closures are postponed, such price-depressed periods could continue for a long time.

This wholesale price reduction is more severe in some points in time than at others. Because VRE plants produce when weather conditions are favourable, irrespective of market conditions, they create even larger price reductions. This results in revenues (wind price in Figure 1) that are less than the average wholesale prices (base price in Figure 1). This is especially relevant if large amounts of wind energy depress prices and when large amounts of solar PV run during sunny noontime periods, affecting the gas plants in NW Europe which normally service the markets in these periods. Yet as always, this needs to be seen in the context of the total generation mix, including the degree to which VRE feeds into the wholesale market (Wind energy) or into the retail market (solar PV) The impact of this 'correlation effect' may diminish in the long run, when the flexibility of the power system is further enhanced, see Section 2.1.2. However, if support schemes continue to be more important than market forces, a market with structurally depressed power prices will remain. This impact of increasing VRE deployment on power prices in an already well-supplied power market is a fundamental feature of the present market design that has long been ignored but which could potentially jeopardize decarbonization goals and the reliability of the power system if not dealt with appropriately. In the long run a race between cost reductions of VRE and a depressing effect on the wholesale price could continue. Of course, other factors like a possible capacity shortage or prices of coal, gas and carbon influence the outcome of this race as well.

FIGURE 1: IMPACT OF EXPANDING WIND MARKET SHARE ON MID-TERM (LEFT) AND LONG-TERM (RIGHT) WIND PRICE AND BASE PRICE; COMPARED TO WIND COSTS FOLLOWING A LEARNING RATE OF 5%

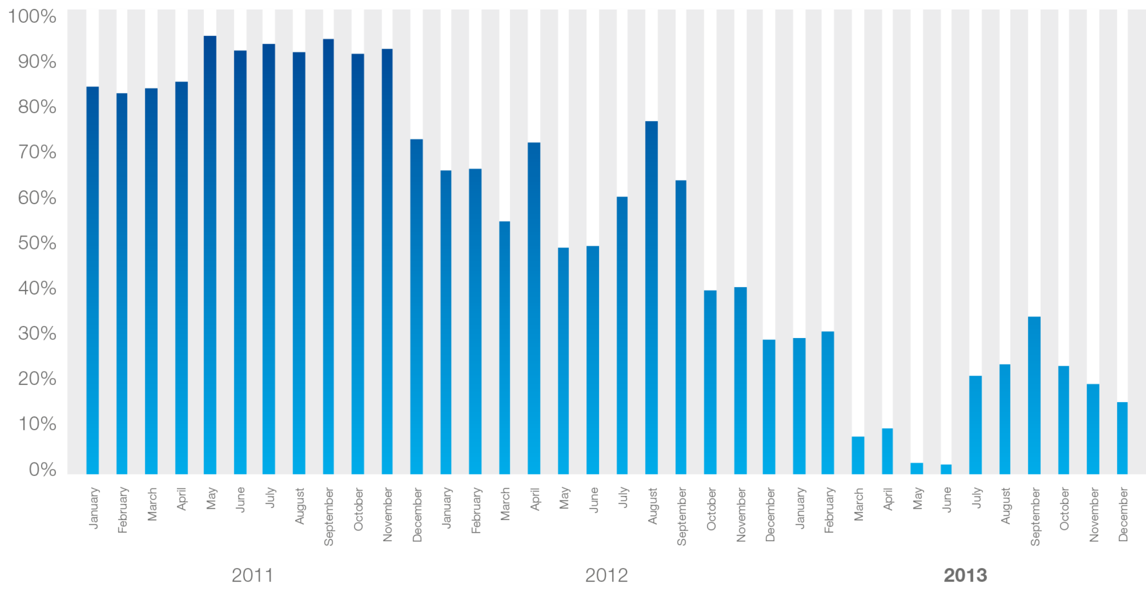


SOURCE: HIRTH, 2013. BASE PRICE REFERS TO THE AVERAGE WHOLESALE POWER PRICE; WIND PRICE REFERS TO THE AVERAGE VALUE OF WIND ENERGY ON THE POWER MARKET.

Cross-border impacts of VRE deployment

Another aspect to be mentioned is the cross-border impacts of the increasing amounts of VREs in the electricity system. This is especially apparent in the context of the NW European energy market with its designs of market coupling in the region. Market coupling in electricity was introduced in 2007 between the Benelux and the French power markets, gradually expanding further to other parts of the region. The particular market model has been accepted as the EU Target Model for the whole of the EU internal electricity market and is today largely a reality. The main purpose of the coupling design was to enhance cross-border trade to a level at which prices on both sides of the border were largely aligned most of the time. This was increasingly the case up to around 2011. In its 2013 Market Review (TenneT 2014), TenneT, the Dutch/German TSO, reported on these developments and concluded that for the Benelux/German region in particular, electricity prices in the wholesale market are again becoming increasingly unaligned due to the impacts of differing energy policies. Figure 2 provides an indication of these developments.

FIGURE 2: PRICE CONVERGENCE BETWEEN GERMANY AND THE NETHERLANDS (IN % OF HOURS)



SOURCE: TENNET MARKET REVIEW 2013

A related aspect is that cross-border flows between the Netherlands and Germany are increasingly moving from East to West, which is remarkable, as the cost of electricity in Germany is higher than in the Netherlands. TenneT calculates in its report that in 2013 the *cost* of 100 German TWh produced was about €7 billion, whereas the same amount of Dutch TWh would only cost about €5 billion. In the current market system, where import and export flows are based on wholesale *prices*, this gives rise to the paradoxical situation that electricity is exported from high *cost* Germany to low *cost* Netherlands. It has nothing to do with the differences in fuel mix policies in the two countries or the way in which the costs of the system are allocated. This is only one of the examples of the cross-border interactions that have surfaced in the recent EU electricity market developments.

VRE subsidies grow instead of decline

Most VRE subsidy schemes cover the difference between average production costs and realized power revenues. Since production costs were expected to decline with growing deployment of VRE, subsidies (per kWh) were also expected to decline. However, when revenues decline faster than costs, subsidies per kWh have to rise. Simulations of the impacts of expanding wind power supply to 30% in the German power system (see Figure 1) show an ever-expanding gap between average production costs and revenue, up to 4 ct/kWh, even with optimistic assumptions about learning rates. Assuming more flexibility in the power system, this gap would still expand but would be only half as large as without flexibility. Simulations of the Dutch power system show similar results for Germany (Hirth 2013) and the Netherlands (Nieuwenhoudt & Brand 2011).

When subsidies per kWh grow, existing budgets will generate less VRE than expected. Even when subsidies are financed outside government budgets through levies above and beyond consumer bills, this mechanism remains unfavourable to the expansion of VRE deployment and could become unaffordable for many consumers.

Commercial investors shy away from VRE

As long as VRE expansion leads to reduced revenues for producers, VRE investments will remain dependent on subsidies and thus subject to regulatory risk (the same is true for nuclear energy). While public support for rooftop PV panels seems to be persuasive, wind turbines prove to provoke all sorts of resentment that turn critical citizens into strong opponents. Taken together, these developments justify serious concern about the timely operation of sufficient VRE capacity in 2035. While decarbonization targets urge the speeding up of VRE deployment, economic considerations suggest the opposite. It could be economically prudent to expand VRE deployment robustly but to keep this expansion more in line with demand growth and the decommissioning of existing power plants. To expand more quickly would mean incurring extra costs of early depreciation of existing power plants and an erosion of the financial capacity of power companies to invest in decarbonization measures.

Decentralized private VRE generation is stimulated

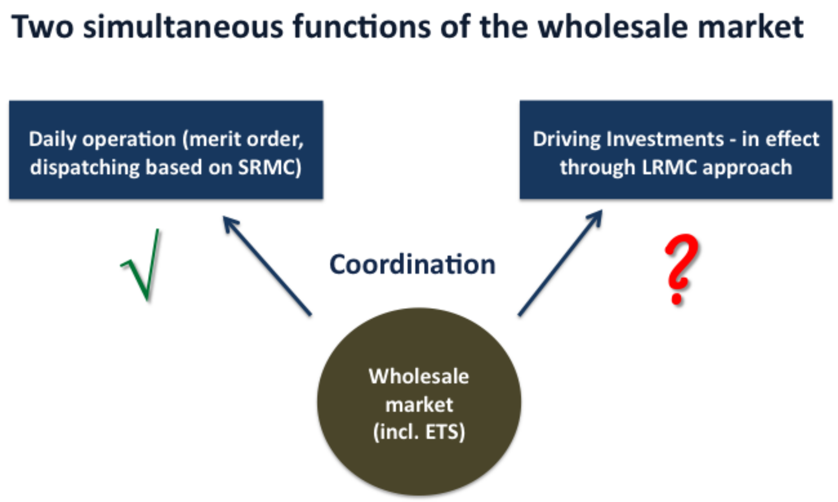
When private households consider investing in solar panels, they compare production costs to retail prices (not to wholesale prices, as commercial investors do). Retail prices include energy taxes and extra levies to finance government subsidy schemes for VREs. The larger the difference between costs and retail price, the greater the advantage of installing solar panels. Since the difference grows when subsidies increase, leading to cost reductions as well, and when commercial consumers also see the merits of investing in VREs due to growing feed-in tariffs or premiums, we could have a self-propelling mechanism that increases the opportunities for self generators. If self generators don't pay levies for VRE support, they transfer these charges to other consumers, indirectly raising retail prices and increasing the advantage of self-consumption even further. This may seem favourable for decarbonization, but it does not lead to a fair allocation of costs and benefits. Due to their low load factors in Northwest Europe, solar-PV will remain a purely local option for a long time. This implies that in case of a local surplus for solar-PV, one has to first search for local solutions – both technical and regulatory.

2.1.2 Securing a reliable power supply with VRE generation

Security of the energy system is generally enhanced by diversifying its resource base. As such, substituting fossil sources with renewable sources adds to supply security. But in the power sector reliability is also related to the absence of blackouts and a constant quality of power supply in terms of voltage and frequency. VRE's advantage of low CO_2 emissions comes with the disadvantage of poor dispatchability of its power supply due to the inherent variability of wind force and solar radiation. This means that VRE deployment reduces the reliability of the energy system. In economic terms, it exerts a negative external effect on the public good of reliability. Since society values reliability highly, it needs to be restored, preferably by internalizing it to VRE producers.

With small shares of VRE in the system, its fluctuating output can be leveled out with existing non-VRE capacity. But when VRE shares reach more than 20-25%, it will be difficult to run back-up capacity profitably for a (sometimes very) limited amount of time, unless prices are allowed to peak. This changes the risk profile of non-VRE capacity, exacerbated by fears that (very) high prices in the wholesale market will be capped by regulators. The role of the wholesale market is being challenged, and its function of driving investments in generation capacity is becoming less significant in relation to the increasing roles of the various support schemes. This may also impact the ability to maintain system adequacies in a cost-effective and reliable way, requiring a further rethinking of how to manage power systems with increasing share of VREs. Although a simplification, it is useful to distinguish two different functions of the wholesale power market. One works reasonably well, while the other is under pressure (Figure 3). The wholesale market has a strong and effective role in coordinating daily operations, in which the dispatching of generators is based upon short-term marginal costs. However, investment in new generation capacity is increasingly driven by other mechanisms than the wholesale market, such as RES support schemes in a number of countries and CRMs elsewhere. Should we expect this to be a temporary phenomenon, or will it turn out to become more structural?

FIGURE 3



These developments are an important driver of the present discussions and concerns about generation adequacy. As non-VRE generation is increasingly becoming less and less profitable with the diminishing number of running hours and the prevailing prices in the wholesale market, the energy industry is being confronted with the risks of stranded assets, especially in gas plants. This is not only a financial burden for the industry, where the ten largest EU energy utilities faced a total write-down of some €6 billion on their gas-plants in 2013 (Caldecott & McDaniels 2014); it also puts at risk the investment climate for back-up capacity in particular and new generating capacity in general. An additional element in that debate could come from further questions about the role of gas in the transition process.

2.1.3 Keeping reliable clean power affordable

Affordability relates the cost of a good or service to the purchasing power of its consumer. Energy poverty in Europe is estimated to affect 50 to 125 million people. The rise in retail electricity prices and the economic crisis have led to a significant increase of energy poverty over the past few years (CGSP 20-13). Since future developments of purchasing power and electricity costs are loosely coupled, the power sector could serve affordability best by keeping future costs of low-carbon electricity as low as possible. Correcting cost allocation is typically the role of governments.

Future costs of power delivery depend on numerous factors, such as fuel prices, carbon permits and capital, and learning rates of technologies for power generation, transmission, distribution and systems operation. Scenario studies can show the impact of uncertainties in these developments. An example is ECF's study 'Roadmap

2050' (ECF 2010), which shows that the levelized cost of electricity (LCoE) in a baseline scenario is roughly the same as in scenarios with 40, 60 or 80% RES in 2050, as a weighted average over the period between 2010 and 2050. This cost estimate seems very optimistic compared to an extensive study of the Energy Modeling Forum (EMF28), which compares the results of 13 modeling groups on the costs of reducing GHG emissions in Europe (Knopf 2013). It found that GDP reduction (compared to a baseline scenario, as a proxy for costs) is likely to rise sharply after 2030, depending on the degree of GHG reduction (see Table 1) and on model assumptions and characteristics. Of course, this says nothing about real costs, as the negative external effects in the baseline scenario (such as air pollution, climate change and, to some extent, import dependency) might be much larger than the financial cost of clean power. Despite the complexities of these models, they generally fail to capture the technical complexities of the power system in any great detail and underestimate or neglect the system integration costs of intermittent renewable energy.

Other detailed power market studies indicate that additional system costs rise quickly with growing shares of wind and solar power generation, rising to more than €24-65/MWh for VRE shares of more than 25%, see Table 2. Comparing these figures with the cost of onshore wind generation in Germany (estimated at €60/MWh by 2020) and of solar PV generation of €130/MWh or less, one may conclude that system costs start taking a substantial share in total power delivery costs when VRE generation roughly exceeds 15% of power generation. This means that the present efforts to reduce VRE generation costs need to be supplemented with efforts to reduce additional system costs. Careful planning and optimization could keep additional system costs of 45% VRE penetration down to 10-15% of total system costs, as illustrated by a recent IEA model study. But adding VRE without adapting the rest of the system could increase costs by 40% or more (IEA 2014).

TABLE 2: ESTIMATED ADDITIONAL SYSTEM COSTS OF EXPANDING SOLAR AND WIND ELECTRICITY IN FRANCE, THE UK AND THE NETHERLANDS, IN EUR/MWH, ORDER OF MAGNITUDE

			Wind			Solar
VRE-share	10-15%	15-25%	>25%	10-15%	15-25%	>25%
Adequacy	3-6	3-6	4-15	5-15	10-15	10-20
Balancing	1-5	1-5	>5	1-5	1-5	>5
Network	4	7-15	15-25	10	10-15	15-40
Total	**8-15**	**11-26**	**>24-45**	**16-30**	**21-35**	**>30-65**

COMPUTED FROM CRASSOUS AND ROQUES 2013; GROSS ET AL. 2006; NEA, 2012, SIJM 2014

Today, VRE generation is still more expensive than non-VRE generation. VRE deployment support schemes are designed to reduce the costs of low-carbon generation technologies. According to the German Fraunhofer Institute, the cost of onshore wind power (LCoE) will reach parity with that of power generated with brown coal, hard coal and CCGT (gas) within the decade. Solar PV will likely reach parity (become competitive) by 2030, provided that fossil fuel and carbon credit prices increase according to expectations (Kost 2013). It should be noted that this cost comparison is partial, since it does not account for additional system costs of VRE expansion. Another important note is that this projected increase of fossil fuel and carbon prices is not guaranteed, as we have seen with falling coal and carbon credit prices in recent years. Still, many scenario studies assume that these prices will rise in the long run. To the extent that this is not going to happen, the social costs of decarbonization will be relatively higher.

Whether the additional financial costs of decarbonizing a reliable power supply are acceptable remains a political question. Much will depend on the level of these costs, i.e., on the ability to materialize least cost solutions and on the allocation of these additional costs among power consumer groups and tax payers. Continuing to exempt large industrial users in order to protect their competitive position, as is done in Germany, will place the fairness of cost allocation schemes at risk and may therefore undermine public support for this decarbonization endeavour. Cost allocation within consumer groups, in terms of network and system costs, as in the levies and taxes paid as part of the electricity price, is relevant for the incentive structures for power market participants. An allocation with perverse incentives may easily lead to inefficiencies, both in generation capacity and in networks. In this paper we focus on the coordination mechanisms needed to enable economic agents to implement least-cost solutions for VRE integration.

2.2 CLASSIFYING PROBLEMS WITH EXPANDING VRE OUTPUT

The previous analysis showed that expansion of VRE production (on its own) affects wholesale prices, most notably in an already oversupplied market, and has consequences for the reliability of the power supply system. Adverse effects of VRE expansion originate from the variable nature of its output (dependent on changing weather conditions), the cost structure of its technology (near-zero marginal costs), and the present market design (dispatching based on marginal costs). These impacts cause problems for all stakeholders involved, i.e., the VRE sector and the non-VRE sector and perhaps even more so for the system operators. The introduction of more VRE in the power system may also turn out to be very costly if no forward-looking approach is taken. Therefore, expansion of VRE production requires a rethinking of existing coordinating mechanisms throughout the whole value chain, including their market and regulatory (support) schemes. In the following chapters we will reflect on adaptations of existing coordination mechanisms for the three broad groups of problems we have analysed, i.e., maintaining stimuli for low-carbon investments, managing the grid-generation interactions, and maintaining system and generation adequacy.

TABLE 3: PROBLEM CLASSIFICATION DUE TO THE EXPANSION OF VRE OUTPUT

	Capacity	Flexibility & Adequacy
Generating Plant	Chapter 3: Adding 30-50% VRE to the power system	Chapter 5: Maintaining systems reliability with back-up, storage, etc.
Networks	Chapter 4: Connecting wind and solar systems to the grid	Chapter 4: Flexible systems operations and demand-side management

Chapter 3 addresses the problem of the high financial risks of investing in VRE expansion in a prolonged situation of diminishing wholesale prices and continued dependency on government support schemes. In Chapter 4 the possibilities of managing the integration of VRE generation in the power grid in a cost-effective way are explored. These costs will rise sharply when VRE shares exceed 15-25% of power supply. Although this may take another 10 years for the EU as a whole, countries like Germany have already reached that level and are experiencing severe network problems. In Chapter 5 options are discussed for maintaining system reliability and security of power supply with large shares of VRE in the system in a cost-effective and competitive manner. Present market designs will generate insufficient income for fossil fuel plants to be able to guarantee operation (back-up) in times of low VRE output, which is already an immediate concern in some NW European countries. New coordinating schemes are considered, including ones with respect to payments for capacity that can only be operational for short periods. After the reflections on a number of the options to solve the problems analysed, Chapter 6 then reflects on possible agendas for ongoing international discussion, focusing on the NW European market. Finally, the essay ends with some more holistic remarks on the ongoing balance between 'markets' and 'governments'.

3 STIMULATING LOW-CARBON INVESTMENTS, WITH A FOCUS ON VRE

3.1 INTRODUCTION

Chapter 2 explored how the electricity market no longer provides efficient incentives for investments in generation capacity as the share of VRE increases. Only a small number of actual investments are now being made. The subject of this chapter is to identify what policy interventions could be useful in stimulating low-carbon investments and, in particular, wind and solar electricity in the context of the Northwest European power market.

Is a lack of investment a problem? One could argue that a lack of investment by market parties in the case of overcapacity is a fully understandable reaction, with no considerable negative external effects. As the European Commission recently communicated in its Guidelines (EC 2014a), it is generally accepted that competitive markets tend to bring about efficient results in terms of prices, output and the use of resources. However, this is not necessarily the case in the presence of market failures. Under certain conditions, state interventions may correct market failures. To assess whether this would be the case in a given situation, the problem that needs to be addressed must be diagnosed and defined (EC 2014a). But next, investors are also confronted with regulatory risks: rules are uncertain and the inter-linkages between them are imperfect, which also leads to uncertainty about changes. In some instances, market failures and regulatory failures reinforce each other, resulting in a lack of investments. As discussed in Chapter 2, the causes of insufficient investments have to be analysed carefully, as new policy instruments are not always the most effective answer.

Some policies aimed at addressing market imperfections are already in place, such as sector regulation, mandatory pollution standards, price mechanisms such as the EU Emissions Trading System (ETS) and carbon taxes (EC 2014a). The European Commission argues that additional measures should only be directed at the residual market failure, i.e., the market failure that remains unaddressed by these interventions. In some cases (such as in the UK and Belgium) the lack of adequacy in generating capacity is considered to be a rather urgent issue, while in other countries (like the Netherlands) it is much less so. The risk of regulatory failure implies that 'more of the same' is not always the best solution.

3.2 OPTIONS CONSIDERED

In this chapter we investigate what additional policy interventions might be necessary to achieve the 2030 Framework and beyond, addressing the 2050 climate ambitions in the power sector. In doing so, we necessarily look at policy instruments that activate investments in low-carbon power in general and variable renewable electricity (VRE) in particular. We analyse the most important policy instruments currently being implemented: those that aim at decarbonization in general (Emissions Trading, Contracts for Difference) and those focusing on (variable) renewable energy in particular (feed-in tariffs and premiums). Further, we look at three policy instruments which are under discussion in some European countries or have been suggested in the policy debate. In all, we investigate several policy instruments from the perspective of whether and how they are capable of stimulating low-carbon investments:

- The policy instrument of Emissions Trading (ETS), which does already exist but has to be improved in order to foster clean investments (3.2.1).
- Policy instruments like market tariffs and premiums (3.2.2), Contracts for Difference (3.2.3) or supplier obligations (3.2.4), which could continue to contribute to revenue streams instead of being merely temporary policy instruments that are perceived as needing to be abolished as quickly as possible.

Additionally, three policy interventions could be looked at which are analysed less often in this context:

- Specific regulation as has been suggested recently with different intentions either as a way to close old carbon-intensive power generation (IEA 2014) and therewith increase wholesale prices, which would decrease the need for additional revenues for new low-carbon generation; or as a way to terminate new investments in carbon-intensive generation, thereby improving the relative position of clean power investment (ECF 2014). Emissions Performance Standards (EPS) are discussed in Section 3.2.5.
- Capacity Remuneration Mechanisms which have mainly been proposed as a way to deal with a shortage of adequacy, but which could also be used to stimulate clean investment in a more general way (3.2.6).
- Recent proposals in academic literature that reconsider the structure of the power market more fundamentally (Helm 2014) and investigate whether an approach like Regulated Asset Base interventions in the overall power generation could be a cost-effective improvement of the market structure (3.2.7).

Finally, we also consider additional options that would enhance investor confidence in large energy projects (see Section 3.3). One is to have a close look at long-term contracts between market parties. The cost of less potential competitiveness in this case would weigh less heavily than the revenue of long-term finance enabling investments.

Note that we work the other way around than the European Commission in its recent Guidelines. The Commission assesses that regulation and market-based instruments are the most important tools for achieving environmental and energy objectives. It has developed guidelines for additional interventions to achieve the 2020 targets, which should also help lay the groundwork for achieving the objectives set in the 2030 Framework (European Commission, 2014). We, on the other hand, take a back-casting approach, meaning that we start with the long-term trajectory and investigate which policy options that could contribute to a future market model need to be taken into account now.

In all cases we consider whether the policy instrument options are considered to be:

- effective, meaning that they stimulate investment in clean power in general and VRE in particular by generating investor confidence;
- cost-effective, i.e., incurring the lowest costs for society;
- simple, meaning as administratively uncomplicated as possible for investors and agencies involved;
- applicable in parts of the EU, the regional context, in case not all EU member states are prepared to introduce them;
- an improvement of the power system into which VRE is integrated;
- able to foster innovation;
- helpful for governments in guiding the market in specific ways, including the interaction between the grids and generation (Chapter 4).

The analysis will not investigate whether single policy instruments are 'better' or 'worse' than others, as this cannot be answered without taking all aspects of the relevant policy context into account. In reality, policy instruments do not operate in an isolated way, but interact. However, reflections on the weaknesses and strengths from a system perspective of the power market can be made. This system perspective implies that all of them can only be effective in a long-term framework. A long-term ambition, with adaptive implementation changes if needed, is a prerequisite for effective policy.

3.2.1 Emissions trading

Doubts have been raised about whether the EU ETS provides a proper price signal for investment in low-carbon technologies. Several options have been proposed to improve this situation. A permanent setting aside of 900 million allowances in the actual third trading period will only marginally influence the emission price. Nevertheless, because the emissions cap is decreasing annually, the price of emissions permits will undoubtedly continue to rise over time. The PBL Reference pathway with existing supply and demand patterns expects the CO_2 price to increase from €7 in 2014 to €10 by 2020 and €17.80 by 2030. These expectations more or less correspond with the IEA's Current Policy Scenario (2013) (€12 by 2020 and €19 by 2030) but are a far cry from its effective climate policy scenario €27 by 2020 and €74 by 2030).

In January 2014, the European Commission proposed two reform amendments to the ETS Directive: (a) a strengthening of the annual linear reduction factor from 1.74% (2013-20) to 2.2% from 2021 to 2030; (b) the creation of a 12% 'automatically set-aside' reserve mechanism of annual emissions permits in the 2021-30 period, in which the number of permits to be auctioned is influenced by the total excess. Implementing this reform, the long-run prices would marginally increase to €13.50 by 2020 and €24.10 by 2030 (Brink, 2014). If one realizes that with existing gas and coal prices a CO_2 price of €40-70 (depending on all other factors) would be needed to switch existing power plants from coal to gas, it is difficult to imagine how improvements of the ETS alone can cause a change in investment patterns in the coming decade or become a stimulus to innovation.

The UK has already introduced a carbon price floor, which came into effect in April 2013, aiming to ensure that power producers pay £30/t CO_2 by 2020. It was decided in March 2014 that this tax would rise to £9.55/t as of April 1 2014 and to £18.08/t starting in April 2015, but it will remain at that level until the end of the decade, despite the government's previous plan to further increase it quickly. Action by one member state alone does not influence the EU cap and potentially leads to more emissions elsewhere (waterbed effect). This is also known by the British government but is considered to be less relevant, as the aim of the tax, aside from collecting revenues, is to foster national low-carbon investments.

To create a more predictable investment climate, a guaranteed minimum (and eventually maximum) price is an attractive option. An auction reserve price would imply that no allowances would be auctioned below a pre-defined floor price; a variant that has been analysed by PBL (2013) also includes a price ceiling. This would change the current cap-and-trade instrument into a tailored combination of a quantity and price instrument. In theory, the option would reduce uncertainty regarding emissions prices while maintaining the advantage of a trading system and would introduce a more robust investment signal. On the other hand, the policy system would become more and more complicated, becoming an administrative burden and regulatory risk rather than a well-functioning market instrument. The introduction of a price floor – or floor and ceiling – would build upon the existing monitoring by the Commission and include market interventions in prescribed ways. PBL (2013) investigated the effect of an auction reserve price increase, from €15/t in 2013 to €25/t in 2020 and €50/t in 2030. In combination with a price ceiling, this would shape a 'price tunnel'. A secondary effect of this price path is that it would decrease the estimated renewable energy subsidies. It depends on the assumptions with regard to economic growth, the pathway of increasing renewable electricity generation and the necessary subsidies as to how large this impact could be, but a rough estimate by PBL indicates that the combination of a strengthened annual CO_2 reduction to 2.46% starting in 2016 and, as mentioned, a price floor, could reduce the necessary renewable energy subsidies by roughly three-quarters.

These policy changes cannot be expected to be sufficient to incentivize investments in VRE soon after 2020, as the difference between the CO_2 price and cost of energy for most VREs will remain too large for a long time. Therefore, we have to analyse additional instruments as well. Another feature of the possible impact of ETS on investments is not often mentioned. When the greenhouse reductions become large, which is the aim by 2050, the volume of the remaining GHG gets smaller, the market becomes less liquid and the price will start to fluctuate more and more and become irregular. This issue is not urgent, but it might eventually negatively impact investments and is an additional argument in favour of a 'price tunnel'.

3.2.2 Feed-in tariffs and premiums

A next step could be to consider *continuing* the use of subsidies. This would be a change of the current political philosophy. The reasoning has always been that subsidies and consumer charges are a *temporary* step towards the full competitiveness of clean energy options. However, as was illustrated in Chapter 2, only in optimal locations could onshore wind become competitive with gas and coal-fired power plants by 2020, but not with lignite; solar, offshore wind and nuclear will probably not even reach this goal by 2030 (Fraunhofer, 2014). Due to the merit order effect, especially wind and solar energy will continue to depress wholesale prices and receive increasingly less income, also because most wind turbines produce simultaneously, further depressing the rewards received (Hirth 2013). This would imply that even with decreasing costs of renewable energy, subsidies have to continue much longer than expected, as the wholesale prices will continue to decrease as well.

Feed-in tariffs have great merits. They guarantee certainty for the investor and thereby decrease financing costs. Some years ago, most observers argued that feed-in tariffs were the most cost-effective policy instrument to incentivize clean investment (IEA, 2009), and recently Fabra et al. (2014) still endorsed this argument. However, feed-in tariffs also have an important negative aspect, namely that they do not stimulate full involvement of generation in the market. Therefore, premium systems are often advocated to ensure that (renewable) energy producers take responsibility for selling their power themselves instead of passing this function on to a public counterpart like the TSO. In the situation of increasing needs for flexibility, this argument gains weight. Therefore, the Commission (EC 2014a) has formulated three conditions for aid for electricity from renewable energy sources: (a) it should be granted as a premium in addition to the market prices; (b) beneficiaries (except the smallest ones) should be subject to standard balancing responsibilities, unless no liquid intra-day markets exist; and (c) generators should have no incentive to generate electricity under negative prices.

Fabra et al. argue that a feed-in tariff still makes sense because the world of wholesale power markets and wind forecasting is quickly evolving and all parties involved could receive the same revenue from selling the power. This could be true, but it could also be an argument not to oblige the counter party to play this role. The additional higher capital costs are a real aspect to take into account. If the shares of intermittent energy get large and the system needs all options to increase flexibility to prohibit increasing system costs, a change from a fixed feed-in tariff to a more flexible premium as obliged by the European Commission seems a necessary option. A merit of feed-in tariffs premiums is that innovation can be taken into account, either by announcing long-term cost reductions in advance, as is done in Germany, or by making auctions dependent on attaining long-term cost aims as with Dutch offshore wind.

3.2.3 Contracts for Difference

Recently, the United Kingdom introduced Contracts for Difference (CfDs) to stimulate clean investments. 'Feed-in Tariffs with Contracts for Difference' (the official name) are intended to provide stable and predictable incentives for companies to invest in low-carbon generation. Generators will receive the price they achieve in the electricity market plus a 'top up' to the market price up to an agreed level (the 'strike price') for a long period. When the market price is higher than the agreed level, the generator has to pay back. The Contracts for Difference for the new nuclear power plant in Hinkley B has a comparable long-term horizon. The CfD guarantees stable revenue – even more stable than that of the feed-in premium. Details differ, however. The premium is financed either by the government budget or by an explicitly visible part of the energy tariff. The CfD is not explicitly visible in the energy bill, as it is part of a broader sum of supplier costs. CfDs are not intended for very small generation, as the transaction costs would be too high; in the UK a separate feed-in tariff for this group remains.

An important difference between the CfD or auctions and market premiums is that CfDs offer the possibility for governments to act as a central buyer. Governments may consider beforehand what type of generation and in what volume they want to contract. It depends on investor interest and the prices offered as to whether contracts will be concluded, but at least government may try to thoroughly formulate its preferences. The same is valid for auctions, but not exactly for feed-in premiums in which the financing party only offers the available incentives.

3.2.4 Supplier obligation systems

The United Kingdom, Sweden-Norway and Flanders are Northwest European countries and regions that use various forms of obligations for the supply of renewable energy. In these systems, (licensed) energy suppliers are obliged to generate or buy a certain share of renewable energy. These systems make use of certificates. Generators receive renewable energy certificates, which can be sold to suppliers that need to use them to comply with their obligation. These certificates have a certain price, depending on supply and demand, but often with certain minimum levels. As the costs of different types of renewable energy differ considerably, different technologies often receive more or fewer certificates per unit of generation. The United Kingdom recently decided to abandon this system and replace it with CfDs. Sweden and Norway, with mainly hydropower and biomass, are quite happy with the obligation. In the Netherlands long discussions have been held as to whether this system is an improvement over the FiPs. The conclusion was drawn that the risk of high windfall profits for low-cost renewable generation, and the uncertainty and thereby high-risk premium for investors, weighed more heavily than the theoretical advantage that obligations will stimulate low-cost generation. In combination with the recent UK decision, it does not make sense to consider quota as a feasible option for Northwest Europe in the near future. However, in the long run, if markets become even better connected and further ideas on how to diminish windfall profits are developed, it could make sense to have a second look at this issue.

3.2.5 Emissions Performance Standards

Regulation plays a role only indirectly in the European power market, mainly by regulating air quality, spatial planning, nature, etc. It is not the intention in the actual European power market to enforce specific clean investments by regulation, as this would contradict the idea of a market and particularly the idea of emissions trading. A contradiction between market instruments and regulation is not self-evident, however. In the US, some states plan to combine Emissions Performance Standards (EPS) with regional emissions trading systems, as the EPA (the federal environmental regulator) has introduced an EPS for new installations. The UK, too, has decided to apply EPS for new generation in combination with the ETS.

The UK EPS will act as a regulatory backstop on the amount of CO_2 emissions from *new* coal-fired power plants (DECC 2013). The EPS will support the existing planning policy requirement (not existent in e.g. Germany or the Netherlands) that any new coal-fired power station must have at least 300 MW of generating capacity equipped with CCS demonstration as a condition of its consent. The statutory limit on annual CO_2 emissions due to the EPS is 450g/kWh at base load. A plant is allocated a total tonnage of CO_2 within which it has to remain each year. In this way it does not limit back-up capacity. The EPS implies that the plant must either have considerable co-firing of biomass (up to 40-50%), capture some 40% of the CO_2 emissions or generate only in times of peak load. If the consent has been given, this is 'grandfathered in' until 2045. This implies that a change of the EPS level in future will not apply retrospectively. The EPS is set at a level that will not impact gas generation. The UK Energy Bill provides flexibility to lower the EPS level in future. The EPS for new plants will be reviewed every three years. EPS also applies to existing plants that upgrade boilers to extend plant life.

Another approach could be the result of a suggestion by the IEA, e.g. in its in-depth review on energy policy of the Netherlands (IEA 2014a), namely to consider regulation as a way to enforce the closing of *old* coal-fired power plants. This could be done by an EPS or in other ways, as has been done recently in the Netherlands. A closure of five old coal-fired plants (see next paragraph) could not be implemented voluntarily, due to the application of competition rules by the regulator ACM, and had to be enforced by the government in a combination of air quality regulation and the national coal tax (Ministry of Economic Affairs, 2014). Because existing plants have a permit to produce, it will not be easy to implement an EPS for existing plants quickly. However, if announced in a timely way and connected to the timing of revisions which are necessary once in a while and implemented technology-neutrally, or if implemented differently, it is a policy measure worth considering as a 'backstop' of the EU ETS.

The fundamental issue of interaction with ETS will be an issue in the public debate. Indeed, CO_2 emissions have already been capped by the ETS. The role of an EPS could be additional, and in the coming period the impact of this regulatory approach has to be taken into account in the periodical ETS assessments of expected emissions decreases. Indirectly, the wholesale price would slightly increase, as some capacity would have to be withdrawn. In the Dutch case, the closure of five old coal-fired plants (2.6 GW, 10% of national capacity) as part of the National Energy Agreement would lead to an increase of the wholesale price by roughly 1 percent (ACM 2013). What could be the benefit of an EPS, and why might it be easier to implement this policy instrument as compared with the 'first best' option of improving ETS?

- An EPS can be introduced in a smaller region (such as the UK alone).
- It is possible to introduce different standards for both new and old plants in different member states, to convince those countries that have the largest problems with higher climate policy ambitions about the gradual phase-out of coal and lignite. For example, as a first step NW Europe could introduce a standard of 450g CO_2/kWh (comparable to the UK standard) for new plants, but Poland could be allowed to start with 600g for new plants.
- An EPS does not have the 'carbon leakage problems' ETS has. The fiercest opponents of a strengthening of ETS are some heavy industry spokesmen, which is understandable, as they feel competitive disadvantages with other continents. This problem does not fully arise in the power sector, although a number of energy-intensive industries have to pay a high electricity bill. Another option to solve this problem is to divide ETS into two parts, one for the power sector and one for heavy industry.

However, to introduce EPS or other regulation without taking the (negative) effects on the CO_2 price of ETS into account would seem to be counter-productive. If 450g CO_2/kWh for new plants would suffice, this effect would depend on the number of coal-fired power plants that would have been installed with ETS alone and cannot be built because of the EPS. This probably will be small. An EPS for existing plants does not seem to be feasible before 2020 due to legal restrictions, but could eventually have substantial impact. Other regulation could be introduced more quickly, depending on national circumstances.

Observers will continue to ask what relation could exist between an EPS and ETS.

- In theory, EPS is unnecessary with a well-functioning ETS, yet it is doubtful whether this will be feasible in the near future;
- It cannot be expected that the chances of EPS preventing new coal-fired and lignite plants by 2020 will be large: EPS would mainly have symbolic value;

- This would be slightly different if EPS were valid as of 2015 and if it would look at all substantial refurbishment as well;
- Whether EPS is a valid option only for new coal or lignite, or whether it is a first step to phase out all fossil fuel without CCS (if one has accepted an EPS of 450g CO_2/kWh, it is relatively easy to change the figure to 300 and even beyond) depends on the interaction one foresees with ETS. As long as an improvement of ETS is the first policy option and EPS is only a bridge towards a higher CO_2 price, it does yet not make sense to consider a further strengthening of EPS. Therefore, the incentive for innovation will be small;
- The introduction of EPS seems to be feasible in the European legal context.

3.2.6 Capacity Remuneration Mechanisms

Several Northwest European countries have worries about the adequacy of generation capacity in the near future: do markets offer adequate forward signals? This concern will be addressed in Chapter 5. However, the issue is not the only reason to consider a CRM. The combination of high CAPEX, low OPEX and the merit order effect of intermittent variable renewable energy leads to low VRE revenues, which probably are inadequate to compensate for long-run marginal costs, inclusive of all capital costs. Of course, high CAPEX alone is no reason to search for new market models. Refineries and steel factories have comparable cost structures. In those sectors, security of supply is a relatively less pressing issue, as storage and global trading are possible. In addition, more innovative long-term arrangements may be possible to enhance investor confidence in new capacities, where others could argue that electricity markets as such are not producing the longer-term confidence base that investors require.

Forward pricing in electricity usually covers no more than 5-7 years at most, even in mature and liquid electricity markets, whereas investors need some kind of coverage for a period of up to 10-15 years, hence requiring a more profitable return rate instead. Applying CRMs that deal with this kind of problem in a longer-term context could be worked out if the regulator were to define a total demand for needed capacity, which then could be auctioned in either a general or selective way (in the latter case, using different types of auction for types of capacity). It would only make sense if the capacity payment were long enough, at least 15 years. Latin American countries have experience with this policy instrument. It is a matter of weighing the pros and cons as to whether other improvements as sketched in this chapter are considered to be sufficient, or whether an additional CRM would be necessary.

3.2.7 Regulated asset base

Recently, the option of extending the regulated asset base (RAB) was proposed (Helm, 2013). The merit of this option is easy to understand. As mentioned in Chapter 2, the economic feature of low-carbon investments is the high up-front and low operating costs, which will put downward pressure on the marginal costs and, under the current market framework, will lead to low average prices with a high level of irregularity. Combined with high regulatory uncertainties, investors ask for 8-12 percent revenue of capital costs, which is much higher than the average costs national Western European governments ask for and that regulated network companies take into account.

The RAB model has two steps. First, a network company invests on issues that have been accepted by the regulator and receives a revenue-based tariff based on a benchmark. At the price-setting periodic reviews, the regulator determines whether the capital expenditure in the previous period has been efficiently conducted. Next, it transfers the efficient numbers into an asset base, the RAB. The RAB is fixed and sunk, and the regulator guarantees that customers will pay, including a fixed return. It is the customers, not investors, who bear the equity risk (Helm, 2013). This makes the RAB a very attractive way of financing low-carbon investments. It would be worthwhile to investigate how the RAB option could be combined with the necessity to increase the flexibility of the power market design. In principle, this is possible. The actual difference on the power market between incentivizing daily operation and fostering investments would be deepened, moving towards two more separate policy instruments for two aspects of the market. Introducing the RAB is an extreme change of the actual European market model and cannot be implemented in one country alone. However, it would be worthwhile to investigate the idea of experimenting with this option in a regional context, especially if a CRM is considered to be inevitable.

3.3 ADDITIONAL OPTIONS AND SPECIFIC LONG-TERM COORDINATION ARRANGEMENTS

It is useful to discuss some other options that would enhance investor confidence in new large energy projects. Both in building generation plants, be it VRE or non-VRE, and in developing energy infrastructure, there is usually an extensive period of uncertainty involved in the preparatory, planning and licensing phases. And once the license has been granted, appeals and court cases could add to further uncertainties as well. If large capital investments are required, usually combined with substantial upfront commitments, such uncertainties and long lead times are additional risk factors which might impede not only investor appetite, but also that of their financiers. The responsible authorities could play a role in diminishing these risks. At the EU level, for instance, the new Infrastructure Regulation requires a timely and even 'one-stop shop' type of licensing process for the so-called PCIs, the Projects of Common Interest. This approach was inspired by the Dutch RCR-arrangement, the *Rijks Coördinatie Regeling*. It would help if similar types of arrangements could be established for new generating plants as well.

But more could be done. Arrangements could be considered in which the responsible authority gives a clear indication of the time-frame involved once a formal licensing request is initiated. Of course there could be all sorts of uncertainties around such a time frame, especially when hearings, information requests and objections are at stake. If that is the case, some kind of best-effort commitment could be considered by the respective authorities, to be extended further in some kind of an insurance scheme to cover the cost overruns when the committed time frames for the licensing procedures are not met. This could be seen as a similar public insurance, as is available when it comes to export credit risks. Based on their experiences, insurance companies could develop financial instruments to cover these risks, if necessary combined with some kind of a government guarantee system. Such an approach would fall under the often-heard 'regulatory innovation' mantra.

Long-term contractual arrangements are an established way to share risks and benefits in volumes and prices between suppliers and buyers regarding the financing of large investments. In the gas sector such arrangements have been effective for decades and have enabled investments in new production and field and infrastructure development via consortia in which all stakeholders (e.g. producers, infrastructure companies, traders, consumers and banks) have been able to find a place. Comparable arrangements were made in the power sector, usually establishing long-term import and export contracts requiring the building of cross-border infrastructure capacities. An essential part of such arrangements was a set of conditions that were not always perceived to be quite in line with competition law and policy, especially when used to secure various forms of market power. Therefore, during the market liberalization process that was agreed upon at EU levels, such arrangements had to be redrafted or even abolished. More and more short-term trading with more and more flexibility and regulatory interventions in allocating infrastructure capacities were the result. It also became apparent that existing field (gas) or power production facilities were able to sell additional quantities on the basis of such short-term arrangements.

However, when the need to make major new investments in production and infrastructures became more pronounced, it became apparent as well that long-term coordination throughout the (new) value chains had to be re-established. We indicated earlier in this chapter the VRE support schemes that brought such longer-term arrangements and investor assurances. Another example is the recent agreement regarding the Shah-Deniz production in the Caspian Sea and the necessary new pipeline infrastructure to bring that gas to European markets. In power generation we could also note the Finnish case of a consortium of large electricity consumers, power companies and banks financing a nuclear plant. The new EdF Flamanville NPP seems to have followed a similar course. The Netherlands tried to arrange a comparable scheme some years ago to finance a new coal plant, where the output was largely sold in advance to a consortium of large electricity consumers, but this failed for other reasons.

Although one could state that in general terms the trend in the gas and power sectors is to move away from the usual type of long-term contracts, especially when it comes to more spot market-oriented flexible pricing, we could note on the other hand that innovative long-term coordination mechanisms in specific cases are being re-established.

3.4 ASSESSING THE OPTIONS

To summarize our reflections in this chapter, we very briefly sketch some of the pros and cons of the different policy instruments in a qualitative way. The specific long-term coordination arrangements or additional options as mentioned in 3.3 are worth considering in any way.

All policy instruments could be effective, although in practice CfDs have not yet been proven in Europe. In theory, the cost effectiveness of ETS could be the best, as it leaves the most freedom to the investors themselves. EPS mainly prevents 'dirty' investments and does not directly incentivize the 'clean' ones. As both Feed-in Tariffs (FiT) and Feed-in Premiums (FiP) stimulate more expensive renewables, we rank them lower on cost-effectiveness, although one could argue that this is exactly what they are supposed to do. FiTs have led to lower risks and therewith banking costs, and FiPs have shown to deliver flexibility in incentivizing low-cost renewable energy, so we rank them equally. Quota systems work well in Sweden-Norway but have been abandoned in the UK, as there CfDs are considered to be more cost-effective. As mentioned, there has been no experience to date with CfDs, but it is to be expected that they will rank more or less equally with FiTs and FiPs in this respect. The RAB theoretically has both advantages and disadvantages with regard to cost effectiveness. It could hamper direct competition in generation but would secure for the investor a long-term rate of return. CRMs have been proposed in different ways and will be dealt with in Chapter 5, as they are mainly meant to improve adequacy of generation. However, seen from the angle of clean investments in VRE, some variants of CRM have proven to be cost effective in Latin America.

ETS, FiTs and FiPs have shown that they can be managed in an administratively relatively simple manner. For an EPS this is less certain, but it could build on existing examples. The first experience with CfDs shows administratively complicated procedures. The RAB is a proven instrument in network regulation, and CRMs are already being applied in different forms in some countries. Most of the policy instruments can be introduced in one country or a group of countries, except ETS. It is also doubtful whether the RAB could be introduced anywhere in the EU, as it does not match the current European legal framework. With the new EU Guidelines on State Aid, the possibility of new FiTs is less certain as well. All options other than FiTs can function in the context of larger shares of VRE and will probably not complicate the interaction of demand and supply on prices. However, as FiPs and CfDs explicitly stimulate specific technologies, they still have impact on these interactions. If governments want to ‘guide’ the market as a ‘single buyer’, CfDs and auctions are probably the best way to do this. ETS and FiPs offer the fewest possibilities to guide the market in a direct way. Carefully designed EPS and FiTs, a RAB and selective CRMs probably could. Finally, FiTs and FiPs have a proven track record in potentially fostering innovation by means of their clear paths towards cost reduction. The RAB and CRMs do not even aim at innovation. CfDs and ETS could, in theory, but have no track record in this regard to date.

Concluding, no single policy instrument will be able to guide policy makers towards a low-carbon future. Most likely, a mix will be needed. Choices could be made depending on the weight policy makers attach to the different criteria. If Europe is to take the aim of decreasing greenhouse gas emissions by 80-95% by 2050 seriously, the power sector will have to change fundamentally before 2030-35. A word of caution is that the policy instruments mainly stimulate large-scale investments. Small-scale investments, such as rooftop solar-PV by citizens, require other types of incentives. Circumstances in respective countries differ considerably in this respect. In Germany 40-50% of solar and wind capacity is owned by individuals or cooperatives, whereas in the Netherlands and UK this share is much lower. Therefore, effective incentives to stimulate small-scale investments will differ from country to country.

The first option is always to improve ETS, which despite the actual shortcomings in stimulating clean investment is still the only European policy instrument we have. As the success of this endeavour is not guaranteed, it is a good idea to continue improving other existing policy instruments and experiment with new ones in order to learn more about their (cost-) effectiveness and other features in case they really become necessary. Without vigorous application of additional policy instruments, the 2050 ambition will not be attained. A strengthened ETS has to be supported by additional policies – subsidies, regulation, quota or other – for a longer time than is often realized. In all cases, one has to accept that the power system will become more expensive. Attaining the low-carbon aim will be a difficult and, at least in the next decade, costly endeavour. Finally, most instruments will stimulate new, additional financial flows and limit the actual 'double function' of the market. In Chapter 7 we return to this difficult balance between the state and the market.

4 MANAGING THE GRID-GENERATION INTERACTION

4.1 INTRODUCTION

In the transition process of changing the generation technology mix into one with high shares of wind and solar (VRE) power, the physical characteristics of the networks and their economic and regulatory implications will have to be adapted. Energy networks are very capital-intensive, usually have very long lifetimes of more than one consumer generation and have a monopolistic nature. Expanding wind and solar power to 30-50% of power generation will require large additional investments in grid extensions. Once VREs are connected to the grid, their variable nature will require a substantial intensification of activities to maintain at all times the electro-technical balance in the system in which the electric flows follow physical laws, independent of national borders. In this chapter we will reflect on possible coordination mechanisms to manage this new challenge of increasing shares of VREs in the fuel mix for electricity generation.

First, this chapter deals with future network cost increases related to grid expansion (Section 4.2). Especially the costs of network improvements will rise sharply when VRE production rises, as was explained in Chapter 2 (see Table 3). Here we suggest that the present 'grid-follows-generation' paradigm could merit reconsideration. Second, we will explore ways to improve the flexibility of system operations to deal with the variable (intermittent) nature of VRE output in a cost-effective way (see Section 4.3). Third, in Section 4.4, we will reflect on adaptations in coordination mechanisms to support cost reductions and system operations. These will cover the interactions between market mechanisms and regulatory interventions for both problem areas because solutions to each of the problems often interact and involve the roles and structures of the TSOs and DSOs in their implementation.

4.2 The G-G paradigm

In many areas, regions and countries, the electricity supply system is shaped around decisions on the optimal location of generating plants. Siting criteria of generation capacity were, and to some extent still are, based on economic generating efficiency, for instance in relation to technology choices, fuel supplies, cooling availabilities, etc. The decision on the location had to be accommodated by building infrastructures to transmit the power to the consumers. This 'grid-follows-generation' (or G-G) paradigm has in practice resulted in a number of principles for connecting generators and consumers and for allocating costs and benefits. Everybody, be it consumer or generator, has the right to be connected to the grid in a non-discriminatory way, with shallow connection and deep connection rules and cost allocations. TSOs and DSOs are obliged to offer all network capacity that is needed and to invest in new capacity wherever and whenever possible. However, grid planning procedures tend to take more time than planning new generation and are therefore becoming less and less in line with building new generation and load. This is resulting in increasing financial risks and liabilities and could lead to a reconsideration of the interaction between planning, financing and licensing between new networks and generation facilities.

Connecting VRE generation sites to the grid stretches the tensions created by the G-G paradigm, since the optimal location of solar systems of wind turbines may be far from the locations where their output is consumed. This is especially the case for off-shore wind, but also for CSP installations. These long distances imply long cables and thus high additional grid costs. It might be worthwhile to consider locating VRE generation facilities at sub-optimal sites, where the disadvantage of lower output is outweighed by the advantage of lower grid connection costs. In a recent study (E3G 2014) this was further elaborated for the North Sea Grid with the ambitious plans for developing large-scale off-shore wind-parks. Box 1 presents some further examples of the impacts of siting decisions and their cost effects. It may also be relevant to make a distinction between building a new cable for connecting a particular plant and the alternative of allowing a nearby existing back-up gas plant.

BOX 1: Examples of siting effects

(1) A new wind park to be built on location A at a cost of 100, based on the allowed physical planning rules, to be connected to the network with an investment of 60. The TSO has to make additional deep connection costs on an annual basis in order to maintain system integrity at a capitalized cost of 30, adding up to a total cost of 190. However, when overall system costs are considered, it turns out that alternatively locating the park at the more expensive location B (cost 120) could lead to connection cost savings of 30, leading to a total cost of 180. What would prevail: the lowest (private) location cost of A or the lowest total (social) cost of B? It could also make sense for the cost savings to be shared between the park's investor and the system operator.

(2) A new gas-fired power station to be built in the Northeast part of the Netherlands, close to the major natural gas import stations. The construction of this power station would result in a new power line from the Northeast part of the Netherlands to the main consumption area in the West of the Netherlands. It would make sense to study the alternative of building this power station close to the main consumption area in the West of the Netherlands. This would avoid the new power line. Instead of power, the (imported) natural gas would have to be transported from the Northeast part of the Netherlands to this power station. This option might be very attractive, since gas transport is typically much cheaper and easier (quicker) to build than power transmission.

Reconsidering the paradigm in terms of siting assessments also includes issues about cost allocations and the division between costs to be socialized and the cost to be paid by the agents that create costs for the network operators. Network costs increase when new investments in grid expansion have to be made and when they accommodate new VRE capacity. The existing paradigm is that the investor in a new plant pays for the (shallow) connection costs, whereas the additional (deep) connection costs are socialized. These reconsiderations may lead to a re-assessment by the regulators of the risk/reward balance. Allocating the deep connection costs in social terms without changing the connection rights might come up. Tariff structures could then be redesigned in such a way that both consumers and generators pay their shares of the network costs based on the 'cost-causing principles', allowing stringent locational signals and incentivizing siting decisions. Considering more system-integrating solutions might also impact the existing network unbundling paradigm, in that the balance between the regulated monopoly and the market sector would be challenged. A more ambitious approach for the networks to be able to enhance total cost efficiency could even include tariff structures that create incentives for a more cost-efficient use of the networks, which will be further discussed in Section 4.4.1.

Electricity production, transmission, distribution and supply may also benefit when relations with comparable gas- and heat chains are considered. This may become more apparent in a decentralized context, where distributed generation (VRE or otherwise) and demand side management, together with heat and/or gas supply options, are assessed in an integrated way. This could lead to win-win situations from a network perspective, and it would therefore be useful to deploy these technologies in a way that would allow network development to be the determinant factor. This could also play a role when storage options are considered, for instance in relation to geo-thermal options or specific power-to-gas technology options.[3] Considering such approaches could be especially useful in greenfield and industrial park situations.

4.3 SMART OPERATION OF THE GRIDS

Balancing supply and demand of the electrons in the system is an essential element of grid operations. This is the primary task of the Transmission System Operator, the TSO. This balancing task has resulted in a wide set of rules and procedures, reflected in (EU) Network Codes and related (national) documents. Both the generators and the consumers will have to carry obligations allowing the System Operator (SO) to guarantee the appropriate balance in the system at all times. The introduction of VREs and the expected further increase of these sources have brought, and will increasingly bring, new challenges for the SO, resulting in increasing complexities and costs of the system.

VREs are intermittent sources, and it is more difficult to direct their outputs in line with the needs of their consumers than it is for the more traditional energy sources. This results an increasing need for balancing, both daily and over the year, depending on the season. A fair and efficient system of balancing obligations and requirements should not discriminate between the sources. This means that non-discriminatory mechanisms should be established for all generating technologies, including the so-called programme responsibilities that they should take on in their role of contributing to balancing the grid. This is in line with the conditions set by the European Commission in its recent State Aid Guidelines. In addition, there will be an increasing need for ramp-up and ramp-down systems and procedures in assuring the necessary flexibility, also both daily and over the year. Studies such as ECF 2012 have indicated, for instance, that the number of start-ups in conventional mid-merit CCGTs will increase dramatically from the currently less than 50 times per year to at least five times as much in a 2030 forecast with 50% VREs. This forecast is already supported by the number of interventions by TenneT Deutschland, growing from some 2 interventions on two days in 2003 to around 1000 over 300 days in 2011.

This increasing need for developing an efficient ‘flexibility space’, with adequate, reliable and efficient management of increasing volatility in available generating and storage technologies, calls for a rethinking of present balancing rules and procedures, including the further deployment of market-based mechanisms (see also section 4.4.1.). It should be stressed that effective demand response mechanisms, with their

3 These options are included in the Dutch System Integration proposals as part of the TKI programme.

large unexploited resources, should be a critical element in this process. In reflecting on the various options that exist, we make a distinction between the short-term options (within the day) and the medium/long-term options (over the year). Such a rethinking should also include the relation between the regulated and market domains, as the supply of flexibility services will lead to new business models servicing a market that is largely bound by regulatory conditions.

Managing the balance within the day could be much further improved by a number of options. Developing designs and incentives for improving the predictability of VREs is already underway but could be further enhanced if business models could be used as needed to virtually manage small-scale facilities as a single VPP. This could be further developed by assuming full programme responsibility as well. In addition, non-VREs [4] will continue to play their roles as back-ups, in line with their reaction possibilities to ramp up and ramp down. Due to the flexibility of modern gas-based CCGTs (combined cycles), it is expected that they could deliver efficient flexibility services, especially with new business models. A further optimization of the roles of non-VREs could be explored by adapting the rules for balancing and programme responsibility. A word of caution should be added: these rules discriminate on the basis of carbon emissions, and some of the most flexible (old-fashioned) conventional generation is the most carbon-intensive. However, running those plants would rarely be necessary, so their net contribution to carbon emissions would be negligible.

Some further words on the role of gas are to be made, as gas is considered by many to be the most appropriate non-VRE source for providing this flexibility service. At present there is a concern within the EU that the required back-up capacities in gas for providing flexibility services and for meeting peak-load demand may no longer be sufficient, as the present market situation is not making these plants profitable. This is also causing concern as to maintaining system- and generating adequacy, leading to calls from industry and policy makers to set up Capacity Remuneration Mechanisms (CRMs). We will come back to that in Chapter 5.

Expanding the case for G2P (gas-to-power) could be also strengthened by facilitating the flexible use of gas plants by means of diminishing regulatory barriers in the network. Where currently largely fixed gas network tariffs exists for power plants, a larger part for variable components could be considered, maybe on a case-by-case basis. Regarding pipeline capacity products, capacity bundling at co-located multiple exit-points would improve incentives, including more flexibility on capacity products

4 This term covers all conventional fuels (gas, coal, lignite), as well as nuclear and hydro. They all can play their roles, sometimes depending on their specific technical conditions, and perhaps sometimes more on a mid-term basis.

on a daily basis (Frontier 2014). However, it is not quite clear if this new opportunity for the gas industry could already be efficiently used in the present business models and regulatory designs. Providing flexibility means supplying on a short notice, even within the hour. Supply arrangements should be able to meet these needs, with sufficient flexibility options. This means not only devising arrangements that would allow short-term transport or storage intervals, but also nominating their use in these short-term periods. The same would be needed for the necessary infrastructures, as short-term shipping may increase.

Gas TSOs and therefore their Ten-Year EU Network Plans, together with the Network Codes for gas, should facilitate this option in a way that is consistent with the flexibility and balancing needs for electricity, as called for by Eurelectric in a recent paper (Eurelectric 2014). More coordination between the respective ENTSOs is needed, all the more so as doubts are rising as to what extent ongoing developments in the EU Network Code process under the Third Package have brought to sufficient coordination between gas and electricity. A clear coordination, such as the one between the rules for investment and operation and those for network access and capacity allocation, would facilitate an efficient role of gas in the power system. Issues such as the re-nomination times for gas (prohibiting the short-term ramp-up of gas plants within the hour) and, according to some, the differences between the gas day and the electricity day (06.00 versus 00.00) might be barriers. Power plant operators may need such flexibility, but the use of the present gas balancing regime does not provide a commercially viable option. ‘Block’ auctions for balancing power (i.e., for a month or 7 days) would also create a market situation that is not attractive for gas-fired plants, as they would then need to commit to running for at least 7 days. This last point could be covered by introducing short-term blocks (day or half day) for balancing power procurement (Eurelectric 2014).

Demand-Side Integration (DSI), also sometimes known as demand response mechanisms or demand-side management, is a flexibility option in the balancing requirements that is emerging more and more on the radar screens of policy-makers and market-participants. DSI could, for instance, play various roles, such as coordinating an action plan that would address the more general need to encourage consumers to reduce peak demand. DSI is employed on the basis of price incentives and could be organized publicly (state, DSO/TSO) or privately (aggregators). Aggregators are a relatively new phenomenon in the (so far mainly US) market, enabling individual customers to take part in the wholesale market. To give aggregators access to the wholesale market, regulation is necessary, for instance by requiring that 'unnecessary barriers to demand response participation in energy and capacity service markets shall be eliminated', and more precisely that 'aggregators that bundle reductions of individual residential and commercial customers and bid them into the wholesale markets must be paid the same market price as generators'.[5] An important qualifier is that aggregators are only compensated when it is cost effective to do so. It should be noted that this regulatory approach is still in an experimental phase, but it could be very interesting to learn from its ‘learning by doing’.

In order to indicate current expectations, some studies mention that only a marginal portion of the flexibility need is likely to be alleviated by DSI (CE 2012), whereas other studies picture a more optimistic and proactive view (ECF 2014). It must be emphasized, however, that the impact assessments are based primarily on the assumption of a vertical demand curve, representing the perceived reality that electricity demand is inelastic to price signals. Cost and technology limitations have formed the basis of these perceptions, but further innovative concepts are emerging, leading to the possibility of more sloped demand curves. US system operators in the Northeast of the US, such as in the PJM and NY power markets, have introduced sloped demand curves as a more accurate representation of customer valuation of reliability and resource adequacy.[6] Applying the VOLL principle (the Value of Lost Load), as a more application-specific pricing signal for consumers, would give additional options for the efficient and effective balancing of the system during specific intervals within the day (RAP 2013). Box 2 presents some further ideas. We should add, however, that price elasticity will continue to be less effective when prices fluctuate only marginally. Prices should therefore be allowed to fluctuate more widely.

It makes sense to promote these options for all consumer groups whenever possible, learning lessons from other power markets, such as in New England and Texas in the US, where already today some 25% of all frequency regulation is done via DSI. This does not mean to say that the US experience could be copied one-to-one in European markets, as the institutional and regulatory conditions differ significantly. But in a transition to a low-carbon energy system, there is much to gain from a full integration of the demand side into the electricity market systems. Balancing rules would probably need some adaptation, and regulators could give System Operators incentives to facilitate DSI, especially when new business models such as demand aggregation applied by new and existing market players are emerging. Special attention is to be given to what this would mean for the retail sector and for distribution system operators (DSOs), raising regulatory and competition issues.

5 US Energy Policy Act 2005 and FERC order 745

6 http://www.pjm.com/markets-and-operations/demand-response.aspx

BOX 2: DSI examples

DSI programmes could use sensors on large residential appliances such as air conditioners or electric water heaters. If properly priced, the willingness to pay in order to avoid interruption of electricity supply, even for many hours, would be very low if there were sufficient tank capacity. The alternative would be the case for lightning during the evening hours, where willingness to pay would probably be much higher. Similar considerations could be applied to clothes dryers or refrigerators; these could be provided with sensors that would switch them off during times when prices are high. When prices reach high levels (which can be set in system programming) a signal could be sent to cut back the electricity consumption of controlled devices or turn them off completely. Consumers would be compensated for their participation and would also benefit from lower prices through consuming at cheaper moments. The technology is there in principle and, again, when properly priced and organized in an efficient way, DSI could become a much more effective resource in adequately balancing electricity markets.

An already existing example of 'smart organization' is the Smart Grid Project in The Hague via the Powermatcher system, which combines heat pumps with balancing VRE. A new apartment complex with 300kW heat pumps and sub-stations based on on VPP uses imbalance trading of flexible load, compensation of intermittent VRE generation and control of the maximum load capacity of the grid substation to guarantee customer comfort.

The *Financial Times* reported on 24 June 2014 that US global demand response capacity will grow from 30.8 GW in 2014 to some 200GW in 2023, representing a market value of some $10bn. PJM, the world's largest competitive electricity market, procured 11GW in May of 2014, compared to 167GW procured in generation. Domestic consumers in the US are paid $20-25 for summertime interruptions to airco applications controlled by time-out switches and facilitated by aggregators such as EnerNOC and Comverge. In the UK, the National Grid will tender up to 330MW of demand-side balancing reserves in the coming winter. ERCOT (Texas) has indefinitely postponed capacity payments because of the success of DSI schemes.

DSI, pilots, business models, supplier contracting and aggregators should be further considered, perhaps also in line with questions regarding forms of reliability pricing and fixed connection forfeits for final consumers. A future for DSI will also require long-term arrangements, especially to accommodate larger consumers if they want to take an active role in this market and make the necessary investments. Investments may also be required regarding back-ups and heat buffering in large installations. To ensure that DSI will gain market maturity, clear rules will have to be developed in relation to cost allocation principles. In this context, mention should also be made of options that DSOs may have, such as installing innovative battery modules in their grids and providing some short-term storage when VREs produce more power than the system can manage. These technologies could influence peak load patterns and lead to diminishing system costs. This might create some form of line pack, as is known in the gas grids, and could give rise to issues about the specific tasks and roles the DSO should be allowed to play. The business case for such storage technologies in electricity will be very different from the one in gas and may be very much dependent on the degree to which costs are socialized. Finally, storage within the day (or night) via electric vehicles is often mentioned as well. This option may require further study, but is usually considered irrelevant for the next 5-10 years. Many issues are still pending, including ones related to technology, but also ones about relevant responsibilities, including those of the DSOs.

Again, regarding DSI, the specific interactions between electricity consumption and industrial and/or residential heat supply systems could be a new avenue for innovative conceptual approaches. Integrated energy concepts in specific situations, where primary and secondary energy sources are considered in their centralized and de-centralized interactions, may be worth pursuing. This would also be in line with the paradigm remarks made in Section 4.2. Innovation and R&D for both new and existing technology approaches, as well as assessment of the relevant regulatory and business models for developing and/or promoting the (short-term) flexibility options, are therefore strongly recommended.

The need for flexibility is not limited to the situations within the day, but also beyond the day, even beyond the week or month. This will especially be the case when surplus power is produced in the summer period and shortages may develop in the winter, calling for some longer-term (seasonal) storage. Large-scale hydro-facilities (where the geography allows) and smaller-scale pumped underground storages are the most recognized options. The technology exists, and large-scale deployment is taking place. These longer-term needs for storage have more implications for the discussion on system adequacies than for shorter-term flexibility needs, so we will come back to the storage issues in Chapter 5.

4.4 COORDINATING MECHANISMS

4.4.1 Market mechanisms

Grid balancing, discussed in the previous sections, is one thing. Combining this dispatching function with market forces is another. Both of these elements will have cross-border impacts and could lead to further regional operations and applications. Making markets 'faster' by allowing market forces to act as much as possible, even minutes before gate closure times when the system operator steps in, would enhance economic efficiency. In addition, extending balancing zones could also lead to the more effective and efficient deployment of VRE technologies. Such interactions between balancing zones and bidding (or pricing) zones have to be assessed in relation to the physical flow realities and the network topology.

Making markets faster by more frequent rescheduling at short-term intervals, dispatching resources in smaller increments when net demand is ramping up or down, even at 5-minute intervals, is already applied in advanced energy market systems in the US and elsewhere (RAP 2014). By making the value of resource flexibility more visible, such as from interruptible services or emergency demand response mechanisms, the true short-run cost could be reflected in market clearing prices. The rapid developments in IT, in addition to the DSI-aggregating options mentioned in Section 4.3, would facilitate these applications. Markets in New England and Texas are moving in this direction and the UK's Ofgem has recently adopted similar arrangements as part of its Electricity Balancing Code Review. European TSO's (ENTSO-E) have already recently added their voices to enhance the role of DSI (ENTSO-E 2014). All these developments could also emerge into a full Operating Reserve Demand Curve, establishing a value for balancing reserves based on the VOLL principle in the resource adequacy process. This would create an open real-time market for balancing services and would greatly expand the possibilities for system operators to manage all sorts of short-term volatilities in supply and demand in an efficient, market-based way. Regulatory authorities should look into these issues together with market stakeholders and explore the possibilities of adapting regulatory designs in these directions.

On-the-day cross-border trading, or even continuous trading until minutes before gate closures, would bring about further market integration. However, in assessing bidding- and balancing zone configurations, a number of impacts will have to be taken into account, such as, according to ACER 2014, the efficient use of the networks, liquidity and hedging concerns, market power and investment incentives. Regulators and policy makers, together with the TSOs and market parties, will have to be part of this assessment process, and it could make sense, for instance, to start such a process in a regional set-up, or even between already (partly) integrated markets such as the German-Austrian or Dutch-German markets. It is to be noted as well that such approaches probably will have to be further extended to policy coordination in a more general sense.

Market mechanisms are not limited to the trade of the electric commodity as such but could also be made to play a role in the pricing of transmission services. Efficient use of the networks could be improved by adding user incentives to pricing systems. Locational signals, for instance, could be made a stronger part of the siting decisions for new generation and load. Locational signals are only partly used in the 'copper plate' model used in the EU context. A transmission pricing system that gives a more innovative signal reflecting scarcity and congestion in the system is the one based on Locational Marginal Pricing (LMP)[7], or nodal pricing, as applied by PJM, the Independent System Operator active in the Northeast of the US.[8]

It could be useful to reflect somewhat on the US experience in the EU context. Allocation of transmission capacity via market mechanisms in an auctioning system is already applied to interconnectors, especially when there is physical congestion in the system. Such yearly and monthly auctions of transmission rights are used in the NW EU context. This explicit auctioning on a daily basis has evolved into more implicit auctioning systems, leading to market-coupling and even price-coupling devices, and has become the target model for the whole of the EU electricity market. Applying such models in a national context within the EU market would encourage network users and system operators even further to act in a fully market-conform way, diminishing where necessary their (social) risk exposures. It goes without saying that such an approach could also be part of a rethinking of the grid generation paradigm as discussed in previous paragraphs, requiring a change of TSO structures and a major overhaul of existing regulatory designs.

4.4.2 TSOs and DSOs

The roles and mandates of the organizational structure of the networks may have to change, as they will be confronted with two different trends. First, there is the development of further cross-border expansion of trades and markets, and second, the more decentralized development of VRE-technologies and demand response

7 This reflects the sum of the System Energy Price (the cost of energy ignoring constraints and losses, uniform across all nodes in the system), the Congestion Price (the cost of congestion in the presence of binding constraints) and the Loss Price (cost of marginal losses by location).

8 PJM is the Interconnect System in the Pennsylvania/New Jersey/Maryland electricity system in the US and a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia, making it the largest single electricity market in the world. See www.pjm.com

systems. In line with the changing grid generation paradigm, the improved interaction between the transmission system and the distribution system could be a critical condition for an efficient transition towards a low-carbon energy system.

The function of operating a transmission system will only become more complicated and more critical. System operation is becoming more important than 'simply' building, owning and maintaining a transmission infrastructure. Cross-border impacts and issues add to the operational roles. This could become a reason to separate the two functions, i.e., transmission and system operation, the latter remaining basically a monopolistic and therefore regulated activity. Building and maintaining transmission lines could then develop into a more industrial activity within the necessary regulatory conditions. Such a development would be in line with EU rules, as the Third Package already allows this model and it is already applied in some special cases. On the other hand, it must be emphasized that the operation of the system and the transmission of the flows via the networks are very much interlinked, and this interaction should not be easily abandoned.

Local initiatives, individual and in cooperatives, are getting stronger. Distribution systems will become more important due to the increase in local or sub-regional generation and demand response options. DSOs in many countries could act as a leading partner in the development of these 'distributed generation' options, and in some cases they are already doing so. Smarter operation of their grids, together with the drive towards smart(er) metering will add to these roles. Game changers such as smart ICT deployments and the development of the variety among distributed energy resources (including generation, storage and demand response) will allow the creation and proliferation of new Distributed Energy Systems (DESs), from micro-grids and virtual power plants to remote aggregation of controllable loads and smart charging systems for electric vehicle fleets. Various international and multi-disciplinary studies are underway to further explore the 'Utility of the Future' (MIT 2014); a recent study by CIEP (Stapersma 2014) already sketches some of the models that present new opportunities for the industry.

It goes without saying that such DES developments at regional or local scales will lead to a rethinking of the whole value chain, in particular the TSO-DSO interaction. DSOs may develop into DESs, posing questions about remuneration of the distribution grids and cost allocations, with the redesigning of network tariffs as a consequence. Further interactions with other network operators will have to be considered, particularly those with the system operators, including the option of (regional) balancing at DSO levels. The interaction between the TSO and the DSO with regard to balancing, however, is a complex phenomenon and needs to be carefully considered, especially since it may have wider implications for the network configuration beyond the local or regional level. As Battle (2012) underlined, in order to make the most of both DSI and DES, a strong coordination between the TSO and the DSO is very necessary, in which each of the respective 'jurisdictions' is respected, the purchasing of balancing services is coordinated (such as via joint auctioning) and duplications are avoided.

It may therefore be necessary to redefine the roles and responsibilities of the DSOs, among others in terms of national and European rules and regulations. In the Dutch context proposals are already being developed to allow specific exemptions for decentralized VRE generation and in support of network functions.[9] Experiments will be allowed for systems with up to 10,000 consumers that deploy local balancing of supply and demand and project-based networks. These networks will be subject to specific rules for unbundling and network tariff methodologies for a period of up to 4 years. Such network planning approaches at local levels might further enhance possibilities for integrated power/gas/heating approaches, including cable/pipeline interactions. These Dutch experiments are embedded in a larger modernization and simplification of the whole legal framework of the Dutch gas and electricity markets, without questioning the overall EU legal basis.[10]

4.4.3 Regulatory innovation

Stable regulatory designs are crucial for network owners, -operators, -users and -investors. However, market and policy dynamics cannot be neglected, and their regulation will need timely periodic redesigning. Most of the issues mentioned in our reflections will require some degree of regulatory rethinking, including changes to the legal basis and regarding mandates and procedures. New investments in networks will be required, and it is very likely that the current regulatory paradigm, 'asset sweating' of the existing network stock, will lose its dominance. New projects may require a case-by-case approach with specific cost determinations (such as LRIC[11]) and cost recovery approaches, including fair cost-benefit allocations and a fair sharing of risks and benefits. Especially when wider cross-border issues and impacts may be involved, innovative thinking is needed, including on allowing regulation in the weighted cost of capital (WACC). These WACC rates differ between the NW EU countries, varying from 6.6% in Belgium to 11.7% in the UK, and are therefore not in line with the required level playing field for attracting investment capital (Glachant et al. 2013a). The WACC rates should therefore be part of such regulatory reconsiderations.

9 *Besluit experimenten decentrale duurzame elektriciteitsopwekking*, Ministry of Economic Affairs, June 2014.
10 The so-called 'Wetgevingsagenda Stroom'.
11 Long Run Incremental Cost

Innovation may be needed, not only in redesigning transmission tariff systems or when balancing and pricing zones are at stake, but also with regulatory pilots. These innovations may become relevant in specific large-scale greenfield situations where larger-scale VREs are applied, such as the work in the context of NSCOGI,[12] but also in the application and review process of specific interconnectors and their exemption options. This may be the case when these new lines have a special, beneficial cross-border context. Regional institutional arrangements might be needed as well, including expanding the role of ACER, the EU Agency for the Cooperation of Energy Regulators. This would result in another challenge for National Regulatory Authorities.

12 The North Sea Countries Offshore Grid Initiative

5 MAINTAINING SYSTEM AND GENERATING ADEQUACY

5.1 INTRODUCTION

In the preceding chapters we discussed the issues involved in supporting investments in low-carbon (VRE) generation and the need for the effective and efficient management of the interactions between generation and the grids. It is appropriate to now reflect further on the adequacy issues, or as sometimes mentioned in a somewhat broader context, the issue of maintaining or even guaranteeing energy supply security. In that context, we express our concerns about the investment climate, about the rewards for investing in generation capacity in general, and particularly about meeting back-up needs for shorter demand periods, in which we question the role of the prevailing Energy-Only Market (EOM). We also bring up options for capacity payments, whether or not in a market-based context. Options to be considered are discussed more extensively in another paper by CIEP (CIEP 2012), so we focus here on the specific questions in the context of our reflections on the long-term coordination requirements.

Adequacy issues demand a more detailed understanding of what is assumed to be at stake, what the real concern is, and what the issues and possible remedies are. Echoing the recent EU Guidelines on State Aid (EC2014a), before discussing remedies, a clear assessment is needed about the generation or system adequacy risks. What is the time frame, is it the short-term flexibility and balancing issue that is at stake, or is there a longer-term issue regarding supply security in generation capacity due to a shortage in new investment projects? Such assessments not only have a national component, but also a cross-border one due to the many existing interconnections. And therefore, adequacy assessments need to be based on a common methodology by the connected TSOs. Remedies could then be found, in which mutual assistance mechanisms are applied and further developed whenever possible.

At the national level, solutions might easily be found if the TSO secures the necessary stand-by capacity through the approaches discussed in Sections 4.3 and 4.4 or, more structurally, via long-term contracts with the respective generators and perhaps also with large industrial electricity consumers. In the latter case, the contracts could be part of the connection agreements, including the option of short-term supply-interruptions. Such arrangements could be considered to be among the operating reserve options from the perspective of the TSO. In addition to the generation side, arrangements could be applied on the retail supply side, especially regarding the supply to household consumers. When such suppliers are regulated via licensing, as is done in the Netherlands and in many other EU countries, the licensee could be obliged to send an indication of its supply plan to the competent national authority on a (multi-) annual basis. Such a supply plan could include the firm's own generation or could come from its purchasing policy on the wholesale market. Such a plan could then be a more indirect way of enhancing security of delivery and therefore contribute to supply security and generation adequacy.

Allowing TSOs to be more involved in the generation market and/or the supply market to large consumers and obliging suppliers to household consumers to be licensed could, however, frustrate market-efficiencies, depending on the market structure. Adequate market monitoring by the Regulatory Authority or the Competition Authority could then be a *conditio sine qua non*. Such monitoring mechanisms are advisable anyway, also in the more structural remedies discussed in this chapter. We make some further observations on this issue at the end of this chapter.

5.2 ARE CAPACITY REMUNERATION MECHANISMS AN OPTION?

A number of Northwest European countries have expressed their concerns about the adequacy of generation capacity in the near future. The increasing shares of VREs in the region, the changing needs within non-VRE electricity generation, the impacts of VRE on electricity prices in the wholesale markets, the policy-based closures of existing nuclear power plants and the prevailing depressed economic situation in the region have all added to the concerns about maintaining system and generation adequacy. Belgium, the UK and France are introducing or preparing different sorts of Capacity Remuneration Mechanisms (CRMs) and in Germany the pros and cons of such mechanisms are being assessed. At least for the time being, Germany has introduced a specific procedure in which non-VRE plants proposed for lay-offs must be assessed by the regulator (BnetzA) on their system adequacy impacts and may be forced to stay in stand-by operation with a specific capacity reward. Concerns are also expressed by neighbouring countries, such as the Netherlands, about the cross-border impacts of these CRMs, and more specifically about their compliance with the fundamentals of the internal energy market. The European Commission has therefore included in its State Aid Guidelines (EU 2014) the steps member states will need to take in their assessment procedures before forming the conclusion that generating adequacy is at stake and that, as a last resort, the introduction of a CRM is the option to follow.

More generally, the issue of capacity payments has stepped up the academic debate about the EOM and its role in incentivizing new investments in generation capacities. It has also intensified analysis of the various options to consider, such as elaborated by CIEP (2012). The academic literature draws no final conclusions about the usefulness of CRMs, as any possible improvement of adequacy has to be weighed against costs. In general, the possible need for CRMs is diminished by the flexibility of prices and the certainty that no price cap will be used, the development of market coupling, intraday and balancing markets, and markets for ancillary services. It is possible that economists will argue against the need to introduce a CRM as instrument to incentivize back-up capacity, whereas politicians or regulators don't like to take any risk with adequacy, whether real or perceived. It is therefore understandable that the European Commission is urging member states to clearly demonstrate the reasons why the market cannot be expected to deliver adequate capacity in the absence of intervention. Indeed, costs could increase substantially in a rather un-transparent way. As mentioned in Sections 4.3 and 4.4, a wide variety of market-based options to ensure system adequacy are either available or in a process of innovative application and implementation. If some kind of a capacity mechanism were to be needed after all, the introduction of a strategic reserve, organized by the TSO and to be called upon under clearly defined conditions, could still be the most cost-effective. It makes sense to monitor these developments carefully and investigate whether the most cost effective solutions are being implemented.

As always, whether other improvements as sketched in this chapter are considered to be sufficient is a matter of weighing the pros and cons. If, after assessing the adequacy needs and the alternative options, including the ones about demand side integration, the final conclusion that comes to the table to introduce a CRM, it would still need to be very carefully designed. It would be logical to give the TSO a central role in the analysis (as is foreseen in the UK model), also allowing a more specific local or even regional approach. Almost certainly then, the CRM would be presented as a temporary instrument when it comes to maintaining enough short-term back-up capacity, but it is difficult to imagine how investors would invest in the market if all they know is that some waiting would reward them in capacity payments. One can therefore question whether a CRM could provide such longer-term assurance. Alternatives for CRMs, such as the proposed tradable call options for flexible back-up capacities, as suggested by Pöyry (2014) and others, could have some further impacts but seem to also be lacking the longer-term assurances.

5.3 THE RAB AS A POSSIBILITY

Another way of approaching the short- to medium-term adequacy needs could come from applying the Regulated Asset Base (RAB) methodology, as indicated in Chapter 3. In the discussion about giving incentives for new investments in high Capex/low Opex technologies, one could consider using this rather innovative approach of determining the value of the asset on an *ex ante* basis, for instance by using the LRIC paradigm, and then adapting it to use as the basis for some kind of a long-term WACC in determining the specific reward on a case-by-case basis. It could also be considered innovative to apply this methodology with the specific aim of securing new back-up capacity for maintaining system adequacy. As was analysed in Chapter 2, the increasing amounts of VREs in the system will need back-up generating capacity that will only be called upon during short periods of time. The determination of that capacity could be much more focused than the general way discussed in Chapter 3. It would also be applicable for new capacity only and could be very much specifically determined by the relevant TSO. The determined WACC could then be financed as part of the system tariff, whereas the coverage of the running costs could be part of the overall balancing market in the relevant area. Of course, it may run into unfair competition with other (existing) back-up capacity or even DSI mechanisms, but again, the EU State Aid Guidelines would have to be applied.

This RAB methodology could also be used when discussing other back-up possibilities. Expanding interconnector capacity could be among them, as specific back-ups could also come from neighbouring systems across the border. This would of course also be seen in the context of allowing cross-border capacities to participate in possible national CRMs. More structurally, the role of storage capacity will have to be seen in this context as well.

5.4 STORAGE OPTIONS

Maintaining system adequacy is not only about (short-term) back-up generation and flexibility needs, but also about developing seasonal storage capacity. As mentioned in Section 4.3, large-scale hydro facilities and smaller-scale pumped underground storages are solutions that are being deployed. However, extension of these facilities may be reaching its limits, especially at the NW EU scale.

In this context we should also mention power-to-heat. With this technology, electricity can be stored and very low or even negative power prices can be avoided. In this technology, natural gas, e.g. to generate steam, is replaced by immediate power usage. The value of power is then almost equal to that of natural gas, at €20-25/

MWh. The heating market is much larger than the power market, so there is ample opportunity for power-to-heat conversion. The power-to-heat technology is well known and inexpensive. It can be expected that consumers will start to invest in it, as soon as very low (<€20-25/MWh) power prices start to occur regularly in the power market. So far, these very low prices occur only occasionally. The effect of the power-to-heat technology will be that a limit to the decrease of power prices develops, at a level of €20-25/MWh. In other words, the decrease in power price with increasing wind penetration, as depicted in Figure 1 in Chapter 2, will not continue indefinitely. The result is that subsidies for wind and solar-PV can be reduced a bit and that power production in conventional power stations with very low variable costs (those using nuclear and lignite) will be slightly more profitable. The penetration of the power-to-heat technology will not alter the investment climate in (flexible) gas and coal power stations. If market circumstances are such that power-to-heat is attractive, power stations with relatively high variable costs will not run.

But also new storage options are being considered, such as the ones that would transform electric energy into gaseous formations (Power-to-Gas, P2G[13]). This could support the decarbonization of other parts of the energy system (i.e., the heating sector, the transport sector through gas in transport, etc.). To consider P2G primarily in a context of providing (medium- to longer-term) storage services may result in by far the most expensive solution. Granted, other options as discussed in the previous chapters could be much more cost effective. But considering a broader and more integrated system approach, including applications in industrial sectors other than the power sector, where process steam flows, heat, feedstock and power are used in an integrated setting, the story may become a different one. Deploying such technology options at larger and industrial scales would seem to make sense only if this were done in the context of large industrialized areas, such as the Eems Delta in the North of the Netherlands and expanding into NW Germany or, maybe even more appealing, in the context of the wider ARA system (Amsterdam-Rotterdam-Antwerp). From the Dutch perspective, this could present new opportunities for Dutch-German or Dutch-Belgian cooperation, further building on the already existing industrial bases in energy infrastructures between the countries. It would also be in line with a further extension of the Dutch Gas Roundabout concept into a wider Energy Roundabout one.

These storage options are also related to longer-term arrangements, in which capacity itself may be more relevant than providing capacity service. Capacity will have to be available when needed, and the needs are not always directly visible or

13 It is important to note that when P2G is mentioned, it will usually mean conversion into hydrogen.

attributable. Here again, investor confidence for building new capacities is critical, and to some extent governments will have to step in to bolster this. The market as such does not care about long-term supply security or maintaining system adequacies. This could also be seen as a further reflection on remunerating capacities for storage, capacities that have to exist without being immediately used.

5.5 THE ENERGY ONLY MARKET?

The market price of electricity is mainly determined by the merit order of electricity generators, reflected in the wholesale market. Generally speaking, in the NW EU region, electricity prices today are lower than those of a few years ago. This seems logical, as demand has decreased due to the economic crisis and new generation (fossil and renewables) has come on stream, creating overcapacity in some regions. Coal prices have decreased and carbon prices have fallen as well, adding further to lowering price pressures. The present generation overcapacity will have to vanish gradually. Nuclear plants will be closed in Germany and are at risk in Belgium, old coal-fired plants will close in the Netherlands and elsewhere, and a significant number of gas-fired plants have been (or will be) mothballed. The continued growth in VRE generation capacity will result in a further reduction of running hours for the non-VRE stations, so, even more capacity may follow.

However, the question is whether the current low electricity prices are primarily caused by a boom-bust cycle in the power market, as we see more in other capital-intensive production cycles, or by government interventions with generous subsidy schemes for VRE generation. In both cases, one might expect that sooner or later investments in new non-VRE generating capacity will become necessary again, to serve as back-ups for VRE generation or due to market fundamentals in supply and demand. In the academic literature this is referred to as the ‘missing money problem’ (Joskow, 2007). This is becoming increasingly challenging under policies that promote rapid and large-scale decarbonization. Investors in new plants will have to earn back their money by selling electricity at prices at an ‘investor margin’ above variable costs. However, with a limited number of running hours, this margin must become a significant one. While a margin of about €40/MWh may be sufficient for a new base-load CCGT with 6000 hours per year, this margin needs to increase to some €240/MWh in order to produce a comparable result for a new back-up CCGT with about 1000 hours per year. Similar margins may be necessary for new Open Cycle Gas Turbines (IEA 2010).

High peak prices for many hours per year are then needed to justify investments in back-up options in generation and demand curtailment. If such prices do not occur, investments in back-up facilities and arrangements will not take place and the reliability of the electricity system may be at serious risk. In other words, a reliable electricity system with high shares of VRE will need an Energy-Only Market with high peak prices. Economic theory would indicate that when scarcity occurs or is anticipated, there are at least two arguments to accept the occurrence of high peak prices.

Scarcity in the power market, including on the basis of an Operating Reserve Demand Curve, will give market stakeholders in the various generation options the opportunity to bid in the market at prices significantly above their variable costs, thus improving their margins. Such a high price (in the order of some €250/MWh or more) puts pressures on public authorities to intervene in order to enforce a price cap for consumers in order to maintain affordability and competitiveness. Public authorities could also be called to act on the basis of perceived (tacit) collusions and start a competition enquiry, such as regularly takes place in the UK. This regulatory risk could then create a significant hurdle, deteriorating investor confidence to invest in options for back-up capacity.

Scarcity of electricity in the market may also lead to the development of the various innovative IT-based options for consumers to preserve their electricity use, stretching the merit order curve and sloping the demand curve. These consumers, be they large industries or demand aggregators, could sell options to reduce their electricity demand at a price which is higher than their VOLL (Value of Lost Load), competing also with the variable costs of back-up generators. The challenge would no doubt be great, as it would require another business model that integrates buying and selling electricity and producing or withholding production in a rather short-term time frame. Such a burden would be placed on the regulatory designs and operating procedures of regulators and TSOs, but the results might be very rewarding, as ongoing developments in some US electricity markets tend to indicate.

More flexibility in the market and better standards and procedures such as discussed in this paper are options to reflect on and introduce. Furthermore, it takes time for the market to gain experience with managing and coping with high peak prices. This is all the more so because society is hesitant to accept such learning curves and the related risks of temporary failures and (very) high power prices. Although some further stretching of old and depreciated generating capacity as back-up might be a time-buying option, there still may not be sufficient capacity left in the NW EU context to fully manage the need for balancing an electricity system with large shares of VRE generation.

Therefore, we tend to prudently conclude that the Energy-Only Market has not yet exhausted its possibilities but that it still runs the risk of not being able to present adequate longer-term-oriented investment signals, particularly for new capacity in back-up and more generally for the high Capex/low Opex technology. A Capacity Remuneration Scheme in a very clearly defined and conditioned set-up could then be considered as a safety-net (IEA 2013a), especially when it is designed as a strategic reserve. In any case, it would be recommendable to closely monitor market developments, not only in an *ex post* context but, even more importantly, in a forward-looking way.

6 AN AGENDA FOR THE (NW) EU DISCUSSION

6.1 INTRODUCTION

It seems to be generally accepted that the issues discussed in this paper will require some kind of a European approach. Establishing sufficient investor confidence in new low-carbon generation technologies and developing the necessary energy infrastructures all have to take place in a European market environment. Many of the issues could be tackled via national policies, but when cross-border interactions take place, EU rules are applicable. This is the case when support schemes are applied, when interconnectors are regulated and when market integration and the rules of the internal market set the boundary conditions. System adequacy and supply security considerations, however, together with fuel-mix policies, are very much at stake, and they all are basically national issues which may have further national sovereignty dimensions.

Recently, the European Commission (EC 2014) acknowledged that renewable energy integration into the EU's electricity market will require new and innovative governance approaches. Implicitly, this is also an acknowledgment that different member state preferences as to the level and speed of integration have made it impossible to realize the roll-over of the existing 2020 framework with an EU target, broken down into national, legally binding targets. Such cracks have also appeared around the discussions on the new EU State Aid Guidelines (EC 2014a). The new Energy Security Strategy (EC 2014b) further highlights these acknowledgments when it states explicitly that 'all fundamental political decisions on energy should be discussed with neighbouring countries'.

Little is known what the European Commission has in mind with 'governance', except that it should be different from the 'European semester' (the annual procedure of checking and assessing national budgets) and that it should strengthen regional (cross-border) cooperation. A logical place to start this approach would be with regional coordination or regional approaches to energy co-operation. There are at least three advantages to this. First, they already exist (such as the Regional Initiatives, the Pentalateral Forum, the North Sea Countries Offshore Grid Initiative, the Nordic Cooperation and the Visegrad-4 projects). Second, it is at the regional level where the problems occur and also where they can be solved, if properly defined and if physical and economic connections are concentrated.[14] Third, such regional approaches, if properly designed and managed, are our best hope to complete the EU's internal energy market, as the EU's sustainability goals with its low-carbon technology drives require new and stronger inter-related policy actions with sometimes very specific devices that cannot be reached at full EU-28 levels. It should be noted, however, that the regional approach is not the only model for the 'new governance'; a more topical approach is imaginable as well. This could make sense in cases where geographical and physical factors are less dominant and could be applied in cases of best-practice exchanges of specific policy instruments such as VRE support schemes.

Because those who hope for a national way out often argue that a real EU energy policy is lacking, one should not forget that a clear and global EU energy policy framework basically does exist. The European Council agreed already in the spring of 2007 on such a framework, and the resulting three implementing packages in 2008 and 2009 brought the policy further in legal terms and approaches. However, the coordinating EU machinery failed to develop and assure the necessary consistencies between the various policy packages, and this then resulted in quite some flaws and failures (De Jong et al. 2010). It also made visible the difficulties to come up with a full-fledged single and all-EU answer to the challenges that the energy and climate concerns are bringing. It further fed the more general discussions on more or less EU policy, bringing additional tensions to the subsidiary paradigms.

It must be understood, however, that when supply security and industrial interests are at stake, as is more the case today than it was in 2007, a black-and-white approach between either 'Brussels' or the national member state does not work anymore. The ongoing concerns about gas security and, more generally, energy security, are also exerting pressure on the debate in terms of how much EU is needed or acceptable in energy policy. The recent actions of the European Council in its March and June meetings (EU 2014) seem to bring the whole debate on the EU 2030 framework into a wider energy security context. It may turn out in a further struggle not only about how much 'EU versus national capitals' there should be, but also how much 'government versus the market' would be acceptable. Instead of pursuing the elusive internal energy market, a better way to create a more unified and effective Europe would be to seriously embark on regional energy approaches. The European Council made this already explicit by recognizing that the completion of the internal energy market should be done through regional approaches. This

14 In the Pentalateral Energy forum (Germany, France, Benelux and Austria, also with participation from Switzerland), recent action has started on developing regional generation adequacy assessments (Penta-plus).

could offer a third way, namely devising 'unthinkable' solutions for effective energy policy-making on the basis of a common set of guiding principles with 'go's and no-go's' in order to maintain the paradigm of the three EU energy policy objectives of competitiveness, supply security and sustainability (De Jong, Egenhofer, 2014).

6.2 THE REGIONAL DIMENSION

Referring to a project done by CIEP and partner institutes (De Jong 2014) analysing the potential of 'regional co-operation approaches in energy', it is useful to explore the ongoing decarbonization agenda in that context. Regional or 'Schengen-like' energy-policy making (Glachant 2012), especially if developing bottom-up, has generally been viewed with caution or even suspicion by the European Commission. The notable exception has been the top-down approaches initiated by European Energy Regulators in their so-called Regional Initiatives. Unfortunately, these top-down attempts have not had the expected impact on policy development and implementation (Glachant and Ahner 2012, Kaderjak et al. 2013), but the recent governance suggestions from the Commission in its 2030 Framework paper opens a new avenue for further enhancing regional cooperation approaches.

The so-called Penta market integration approach was initiated by the governments of NW Europe, where the Benelux countries and France, later joined by Germany, developed models for market coupling and price alignments. This was possible also by directly involving the TSOs, the Power Exchanges and the Regulatory Authorities. It turned out to become an Electricity Target Model for the whole of the EU. Ongoing developments of energy policy instruments in the Pentalateral Forum are taking place (De Jong and Groot, 2013), and another CIEP paper (Meulman et al. 2010) discusses in some detail a number of possible approaches to enhance further policy cooperation in the Penta-context. These range from rather informal information-sharing devices to a much more focused harmonization of the various policy instruments and can serve as a check list of opportunities.

6.3 THE PENTA AGENDA?

If we reflect further on the possibilities to enhance the coordinating mechanisms in the low-carbon power market, the Penta-plus framework would seem a suitable way out to start the discussions between stakeholders, policy makers, regulators, TSOs and market parties. It goes without saying, however, that such an approach would have to be based on the principles of the EU Internal Market and would greatly be facilitated if the European Commission could give some further guidance as to its suggested 'new energy governance'. We therefore modestly suggest some of the issues, reflections and ideas of our paper as an agenda for the Penta process.

Some of them are already on the agenda of the Florence Forum, as recently underlined in their May 2014 conclusions:

- *Generation adequacy*. As the Penta ministers have agreed in 2012 to refocus the Penta work on adequacy assessments and common methodologies, it would be advisable to expand that work into a true Penta-wide assessment of the adequacy of generation capacity under a number of scenarios and explore policy options when system adequacy and supply security could be at stake. Such an approach would also be fully in line with the new EU State Aid Guidelines (EC 2014a). It could also be further expanded in the application of Capacity Remuneration Mechanisms (CRMs) whenever found necessary and feasible in a cross-border context. It could then be very effective to discuss the modalities of such a scheme and to apply them in cross-border installations as well.
- *VRE integration in the grids*. When we explored the challenges that TSOs would have to face with regard to an expanded role of VREs in the system, it was found that cross-border cooperation could improve the efficiency and system adequacy of that development. Discussions could focus on the rules for connecting the VREs and dispatching them in the system. Exploring options for improving weather forecasts beyond borders and coordinating criteria and exchanging data to assess the impacts on wind and solar generation would add to this activity.
- *Expanding balancing options, balancing zones and balancing markets*. As balancing and flexibility is expected to become more critical, options to improve least-cost-effectiveness should be further explored in the regional context. Learning best practices is one element, but further coordinating operational approaches and possibly further integrating zones and market mechanisms across national borders could enhance the benefits. It would likely be useful to start a process of studying, exploring, assessing and discussing relevant options and operational devices.
- *Reassessing the generation grid paradigm.* As discussed in Chapter 4, this would cover a number of more general features of grid operation and grid planning. These features might be a relevant item as well when the role of the grids in their cross-border context is considered. The previously mentioned E3G study on the North Sea Grid is another example.
- *Coordinating and/or combining VRE-support schemes.* On this more policy-oriented and politically sensitive subject, mutual reflections on the boundary conditions set by the European Commission in its recent State Aid Guidelines could be a starting point. In such a reflection, issues could be explored surrounding the conditions for and timing of the various VRE support schemes and the way in which specific cross-border deployments could be enhanced and coordinated. A mutual information arrangement could be set up about the

implementing rules and developments, allowing some gradual exploration of areas for enhancing mutual cooperation and coordination. This could even move in the direction of exploring possible trajectories for expanding VRE capacities, maybe even with regional targets and a regional siting plan.

- *Enhancing joint cooperation between TSOs*. Most, if not all, of the issues that could be discussed in the Penta-setting require the intensive involvement of the TSOs. There are already a number of mutual cross-border operations and joint ventures in which TSOs are working together. The two TSOs of Belgium and the Netherlands (Elia and TenneT) are already directly involved in the German markets, and it would therefore be a logical and organic process for more policy cooperation in the Penta framework to be developed and expanded in the direction of further cross-border TSO cooperation. This might especially be the case when system operation is at stake, where a number of the Penta TSOs are already developing joint projects and activities with regard to system security and cross-border management of their interconnectors. At some later stage, even various types of further unbundling of the SO function might be considered but it must also be emphasized that many EU practices have a large tradition and experience with the grid operation interactions. At some future point, however, the ISO model might be useful in a greenfield situation, such as is now happening in the NSCOGI project, where the countries bordering the North Sea bordering are working on off-shore grid concepts (E3G2014).
- *The role of gas in the future power system*. In our paper we have made a number of references to the role of gas in the low-carbon system. Developing this role might also be an important issue in the Penta context, especially since the Penta mandate includes gas as well. Coordinating the consistencies between the gas and power sectors definitely has a cross-border impact when it comes to balancing and nominating for transmission capacities. One might also consider joint approaches or even joint projects on the P2G technology, especially if it is approached in a wider system-oriented setting.
- *The wider fuel mix policy issues.* At some stage it will become logical and rational for the policy-related items mentioned in this listing to be discussed and to have a more general debate on a 'regional fuel mix policy'. When markets are further integrated, when economic agents are active in these integrated markets, when the TSOs and DSOs are following that course, as we see already beginning today, when VRE support schemes are more coordinated, and maybe even under a non-discrimination heading, it would be hypocritical if the wider energy policy umbrella were neglected. It should be noted that already today, after the experience of some years of market coupling and price alignments in the Penta region, the past two years have marked a return to price differentials on the

various sides of the borders. This is despite the success of market coupling, as the underlying factors of these differences stem from the market developments in the respective fuels, notably more because of cheap (brown) coal and expensive gas then as a result of low electricity prices due to near-zero marginal costs of the VREs (TenneT 2013).

6.4 THE BILATERAL APPROACH

It is furthermore useful to explore if a more focused bilateral FRG-NL approach could give added value. One reason for this idea is the fact that the Dutch market is becoming more and more associated and even increasingly intertwined with the German market (TenneT 2014). Within the NW EU market, for instance, the largest amount of net cross-border flows in 2013 took place between Germany and the Netherlands. Another reason is the already existing cross-ownership in transmission, in which TenneT has become directly involved in the German transmission developments, resulting in increased interest on the part of the Dutch government as well. Further strengthening this claim is the recent suggestion from the financial sector that mutual interest is important when considering cross-shareholder participation, as this makes financing possibilities more robust (ING 2014).

A comparable approach could be useful regarding the Dutch-Belgian relationship. Issues to be discussed could be similar to the ones mentioned in Section 6.3. Both governments are already exploring their bilateral relations at the policy level, including that on energy. However, it would be useful to explore the option of a more informal dialogue at expert levels, where opinion makers, academics and think tanks are involved, feeding the policy and political process both in the bilateral and the Penta context.

6.5 SPECIFICALLY DUTCH INTERESTS

In this essay we have reviewed a number of issues regarding the developments in the electricity markets. These issues are not limited to national markets and national policy environments, but have a wider European perspective as well. The important National Energy Agreement that was settled in 2013 in the Netherlands refers to this wider policy context, implicitly underlining that a ‘national energy market’ no longer exists in today’s European context. We also made the case that it might be very appropriate to discuss the issues beyond those of national markets in a NW EU market context, i.e., the Penta system. However, this will open up a two-way-street, on the one hand reflecting and considering what the specifically Dutch interests are, and on the other hand looking at what the impacts might be for the Dutch energy market structure and regulatory frameworks as a consequence of this wider policy orientation.

This paper does not aspire to explore these issues in depth, but it is worth mentioning some of the underlying ideas. We mention the three that are perhaps most important:

- The Netherlands has an advantageous geographical location. In energy terms, this is usually known as the 'Dutch Roundabout', in particular for gas and gas infrastructures. Yet electricity is relevant as well, including the relation with other energy sources and carriers.
- Both nationally and in Europe on the whole, a clear vision about the role (Dutch) gas can or should play in the transition towards a low-carbon energy system is lacking. It is, without a doubt, in the Dutch interest to reflect on developing such a coherent vision and to use this as a basis for national and European policy making.
- In the industrial structure, the publicly owned Dutch TSOs in electricity and gas both have a cross-national dimension and ambition. But the (publicly owned) DSOs and their important roles and drivers for the energy transition and cross-border ambitions also deserve mentioning. At some stage stakeholders and shareholders will have to be more clear and precise as to how they see the position of the networks, especially, as we discussed, in terms of reconsidering the paradigms in the relations between the grids and the other components of the energy cycle.

As touched upon, Dutch interests cannot be viewed without taking due account of the wider European policy-making environment in general and the more direct NW EU framework in particular. Within that latter context the Dutch position is not the only one; our regional neighbours and partners have their own national political and industrial considerations as well. It is clear that in the Penta family the two largest economies, Germany and France, are playing a leading role. Their more concrete concerns today are in dealing with the generation adequacy issue and the policy options of introducing capacity payment mechanisms. Bilateral discussions between the two countries are therefore priority items on their international agendas, where the modalities of any arrangement include, to our understanding, cross-border participation in the possible national CRMs. This also takes into account the boundary conditions set by the European Commission in its State Aid Guidelines. Although the Dutch perspective on adequacy concerns is different, it would be recommendable for Dutch policy makers not to shy away from these CRM discussions. This the more so as our southern neighbour (Belgium) is about to introduce a specific CRM due to its perceived specific generation adequacy concerns.

It is even more advisable to think more openly and to consider bringing new initiatives from the Dutch side into the next Penta agenda setting. Of the suggestions made in this section, a number of them could well be eligible from the German context. Win-wins could come from further discussions on VRE integration and the role of the flexibility space. Integrating VRE using different models for managing balancing responsibilities, balancing zones and pricing zones, together with options for locational pricing for transmission services, could be part of this. At some point in the future, ideas could be developed about adopting a regional approach to market monitoring and perhaps also to carbon market developments and/or carbon regulation. On a more structural basis, explorations could be made about the TSO/ DSO interactions and the challenges and prospects of the changing DSO roles.

7 SUMMARY AND FINAL REMARKS

This essay started with three observations: with a substantial increase of variable renewable electricity (wind and solar), one cannot expect the subsidies for new investments to end, as wholesale prices will probably decrease faster than production costs; system costs will increase, especially in networks; and adequacy will not remain guaranteed *per se*. Next we reflected on three possible solutions.

First, network investments take time, and with investments in generation, additional network costs are probably the largest part of increasing system costs due to a large share of VRE. Reconsidering the paradigm that the network follows decisions with regard to generation could lead to a more optimal approach from the point of view of society. A further look at who causes costs and has to pay, along with introducing more flexibility in the grids (including demand-side integration) could decrease additional costs. More market elements could be introduced, such as on-the-day cross-border and intraday trading, innovative demand response schemes and an Operating Reserve Demand Curve. Efficient use of networks could be further improved by transmission pricing signals with stronger locational signals. The power network cannot be fruitfully analysed independent from the gas grid. All these changes would imply different types of regulatory innovation.

Second, investments in low-carbon power generation can be incentivized in different ways. No policy instrument is a silver bullet, and interactions between policy interventions are faced with the risk that market failures could be replaced by regulatory risks. Strengthening the European Emissions Trading System seems to be an option and has several advantages. However, this may not be sufficient to stimulate options such as offshore wind. Continuing of feed-in premiums or Contracts for Difference may thus seem indispensable for the time being. One could also consider more radical changes by introducing Capacity Remuneration Mechanisms, possibly in combination with a Regulatory Asset Base. This certainly is not without problems, but could have merits as well. Finally, a 'bridge' towards a situation with substantially higher CO_2 prices could be constructed with specific regulation, either aiming at closing old ordinary coal-fired power plants or prohibiting new ones from being built. It could make sense, however, in all cases to reflect on the time frames of developing the necessary low-carbon generation. A more gradual development of the large-scale investments, combined with learning by means of technology and policy innovation, could decrease costs.

Third, adequacy of the system is becoming more complicated and can no longer be guaranteed per definition, as existing flexible generation is closing down and new investments in back-up are at risk. The academic literature draws no final conclusions about whether separate remuneration for capacity is needed, as a possible improvement of adequacy has to be weighed against costs. Flexibility of prices, the certainty that no price cap will be used, the further development of market coupling, intraday and balancing markets, markets for ancillary services and demand-side integration (including operating demand reserves) do offer ample new chances but in the end may not diminish the eventual need for dedicated mechanisms to stimulate back-up capacity. Before considering additional capacity remuneration, it makes more sense to improve these aspects of daily market operation. Furthermore, if capacity remuneration is introduced, uncertainty will increase, as nobody knows how future politicians will implement the rules. However, politicians or regulators don't like to take any risk with adequacy (real or perceived). When considering the next steps, the least they could do is to do this jointly in a regional context.

'The state is back with all the inefficiencies that this may bring, and the upcoming new designs are becoming less and less different from the old times of the vertically integrated monopolies such as the CEGB', concluded Dieter Helm (2013, 2014) in some recent articles. The state never left. But indeed, it must be recognized that since the initial waves of liberalization since the 1990s, European governments have been very active in setting targets, drafting regulations and implementing subsidies. The reflections in this essay imply a continuation of this trend. Not because this is something to be preferred *ex ante*, but setting long-term targets for an energy system and pricing negative external effects is a political reality in the EU and no institution other than the state is in the position to do this. National governments are (again) largely determining their national fuel mix, among others because they still legally have the national sovereignty to do so, making a more coordinated EU approach, even at regional levels, difficult to achieve. The security concerns in combination with the climate and competitiveness concerns are leading factors in today's energy policy agenda. This has to be accepted and will probably even deepen as the impacts of the search for a low-carbon power fuel mix get clearer. Governments may deny their influence and may not wish it, but that does not change the facts. At the same time, the 'energetic society' in all its layers and levels is taking its own initiatives – not only to combat climate change, but also to promote local strength, or in a wish to be locally more energy-independent.

Making a distinction between the state and the market is not always productive. A state that is considering effective and efficient policies would be well advised to take market mechanisms into account and to analyse how markets could be used to meet the policy objectives, such as moving towards a more carbon-neutral energy mix with a substantial share of VREs by 2030/35. The wholesale market for electricity, for instance, has two different coordinating functions: one for the daily operation of the system and one for incentivizing investments for future generation. Understanding these two functions could be helpful when a new policy mix is deemed necessary, as this may have large impacts on the market. This is relevant for the investment function. But for the operational part, intraday and balancing markets, for instance, could be extended much further than they are today. Improving these markets in the operation of the networks would decrease the additional costs of a power system when there are increasing shares of VRE. When the interaction between the grid and generation is further improved the cost savings could be even greater.

Helm is also right in pointing out the potential inefficiencies of more state intervention. Indeed, as much as market failures have to be analysed, one must also acknowledge the regulatory failures. Decreasing the number of market failures could lead to an increase in regulatory failures. The issue of capacity remuneration is a vivid illustration. One needs to accept that the future simply cannot be predicted. John Kay once remarked: 'Markets are not a well- oiled physical machinery, they are a constantly changing, adaptive biological system. Pluralism is their motive force, their essence chaotic, and their development inherently uncertain. If we could predict the evolution of markets, we would not need markets in the first place' (Kay, 2010). Market regulation is not something with a well-defined beginning and end, but an ongoing process (WRR 2012).

This is even more so if the roles of citizens, citizens groups and the changing roles of enterprises are included in the analysis. Some 50 percent of renewable energy capacity in Germany is owned by citizens. Energy companies are reinventing themselves, trying to become 'the holistic energy manager of the future' (Peter Terium, CEO of RWE in *Energy Post*, 2014). Indeed, the responsibility of energy companies to society tends to increase and society itself is becoming more energetic. Nobody expected this development ten years ago, and nobody knows what will happen in the next ten years. But citizens and citizens groups need to know what the long-term ambitions and policy instruments of governments are, and which proposals energy companies will make; otherwise it is almost impossible to attain something that can become larger than grassroots initiatives only.

Different regulatory and policy adaptations have been explored in this essay. A clear and stable long-term ambition on the objectives that have to be attained is a prerequisite for an effective and adaptive policy mix. Some adjustments are easier to implement than others and are already being explored, either nationally or collectively, in the Northwest European countries. Table 5 gives a brief summary. Improving ETS and implementing the recent EU Guidelines on State Aid by changing feed-in tariffs to feed-in premiums would be a logical starting point. Introducing programme responsibility for all VREs, except maybe the smallest ones, seems inevitable to be able to deal with a larger share of VRE. A larger role for balancing and intraday markets would be a next step. Introducing and using the opportunities for demand-side integration, such as allowing larger price fluctuations is another. All these options can be implemented within the existing regulatory EU framework. Introducing EPS for both old and new coal-fired plants is then an important fall-back option when adequate carbon price levels are not reached. A serious reconsideration of the generation grid paradigm will have large potential benefits as well, but this cannot be implemented overnight. Studies and demonstrations can be started immediately, however. Finally, capacity payments could still become necessary, but other flexibility and adequacy options will have (much) larger net benefits. Therefore, CRMs are more an option for last resort and for further consideration than for fast introduction.

TABLE 4 POLICY OPTIONS WHICH CAN BE INTRODUCED RELATIVELY QUICKLY (BASIC PACKAGE) OR NEED FURTHER CONSIDERATION IN PREPARING A LARGER SHARE OF VRE

Basic package	To be further considered
– Improvement of ETS – Giving feed-in tariffs priority – Programme responsibility for all – Balancing and intraday markets – Room for demand-side integration	*Quickly* – Generation network paradigm – EPS *Later, if needed* – Capacity Remuneration (eventually with a Regulatory Asset Base)

Accepting the reality that governments continue to have a strong role in the fuel mix and that markets could expand their contributions to the actual implementation of their policies, it would be counterproductive if this searching for effective and efficient solutions remain a national approach. The Northwest European energy market is by far the most integrated part of the EU energy system, and its market coupling has led to an improved utilization of the interconnections. The Pentalateral Forum has recently renewed its policy agenda. Germany is at the forefront of searching for new approaches for a system with a significant share of VRE. The Netherlands has joined with its recent Energy Agreement, and France has also recently defined its targets for diminishing the role of nuclear energy and expanding that of VREs. These countries are very well positioned to join forces. Possible topics to explore in a more in-depth cooperation include generation adequacy, VRE integration in the grids, expanding balancing options, coordinating and/or combining VRE support schemes, enhancing joint cooperation between TSOs and the role of gas in the future power system. Also, intensive bilateral contact could add to the process of learning-by-doing, and in some later stage it would be useful to include the UK as well.

In all, this essay does not suggest that the energy market has to move one-dimensionally back to the state. Instead, it suggests that the state has to be aware of being part of a process in which it stimulates and facilitates investments in clean energy in general and in VRE in particular. This awareness will need to take into account that markets are always dynamic and that policy adaptation is a critical element. An effectively operating state should organize its policies in such a way that ambitions, targets and implementing guidelines are robustly defined as part of a long-term orientation for at least some 10-15 years. Adaptive implementation in terms of specific policy measures and regulatory details will need shorter-term decision-making procedures, allowing market dynamics and involving active stakeholder participation. Regulatory authorities should then be allowed and instructed to follow suit and to safeguard effective and transparent consultations and procedures. This will place an additional challenge on decision making at EU levels, again reinforcing the argument of using regional approaches.

The future is open, but it not a blank. At the same time, the role of the market could and should be increased to enhance further flexibility within the market. As citizen groups increase their presence and active participation, and as energy companies start to re-invent themselves, market dynamics and uncertainties have to be accepted.

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