Securing Power during the Transition

Generation Investment and Operation Issues in Electricity Markets with Low-Carbon Policies

Manuel Baritaud

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Foreword

At the October 2011 Governing Board Meeting at Ministerial Level, IEA member countries endorsed the IEA Electricity Security Action Plan (ESAP). The proposed electricity security work program reflects the challenge of maintaining electricity security while also seeking to rapidly reduce carbon dioxide emissions of the power systems. In particular, the large-scale deployment of renewables needed to meet low-carbon goals is technically feasible. However, it will lead to more volatile, real-time power flows, which will create new challenges for maintaining electricity security.

Well-functioning electricity markets will be needed to stimulate the sufficient, timely investment needed to achieve low carbon and electricity security goals at least cost. Governments have a crucial role to play. Better integrated and more effective policies, regulation and support programs will be needed to complement and reinforce incentives for market-based flexibility to help deliver cost-effective electricity security and decarbonisation.

The Electricity Security Action Plan consists of five work streams:

1. Generation Operation and Investment. This work stream examines the operational and investment challenges facing electricity generation in the context of decarbonisation.
2. Network Operation and Investment. This work stream examines the operational and investment challenges affecting electricity transmission and distribution networks as they respond to the new and more dynamic real-time demands created by liberalisation and large-scale deployment of variable renewable generation.
3. Market Integration. This work stream identifies and examines the key issues affecting electricity market integration, including policy/legal, regulatory, system operation/security, spot/financial market and upstream fuel market dimensions. It draws from the other work streams as appropriate, and from regional market development experience in member countries.
4. Demand Response. This work stream examines key issues and challenges associated with increasing demand response, reflecting its considerable potential to improve electricity sector efficiency, flexibility and reliability.
5. Emergency Preparedness. This work stream develops a framework for integrating electricity security assessment into the IEA's key peer review programs – Emergency Response Reviews and In-depth Reviews – to improve knowledge and information sharing on electricity security matters among IEA member countries, with a view to helping strengthen power system security and emergency preparedness.

"Securing Power during the Transition" is an issue paper on generation operation and investment in liberalised electricity markets with low carbon policies. After a brief overview of the fundamentals of liberalised electricity markets, it presents the policy context of the transition to a low-carbon economy and reviews the current and foreseen operating challenges and the investment issues. It considers ways to strengthen policy and regulatory arrangements to encourage more flexible and responsive operation and more timely and efficient investment. It is part of a series on electricity published in conjunction with the overall Electricity Security Action Plan.

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Executive summary

Will electricity markets deliver electricity security during the transition to a low-carbon economy?

Electricity security has been a priority of energy policy for decades due to the dependence of modern society on reliable electricity supply. Only a few years ago there was confidence that liberalised electricity markets in IEA member countries could also deliver sufficient and timely generation investments needed to ensure security of supply. Most of the liberalised power markets experienced significant investments in new efficient combined cycle gas power plants on a merchant basis. *Lessons Learned from Liberalized Electricity Markets* (IEA, 2005) concluded that "electricity market liberalisation has delivered considerable economic benefits" and that *"minimising regulatory uncertainty is key to creating a framework for timely and adequate investment"*.

However, policies to decarbonise electricity systems have served to magnify investment risk and uncertainty at a time when the capital stock is ageing and slowing demand growth is discouraging investment in many IEA power markets. Some new low-carbon sources (mainly wind and solar photovoltaics) have unique technical characteristics that accentuate real-time power system volatility, creating additional challenges for system operations. The combination of these developments is increasingly perceived to pose a challenge to maintaining electricity security in many IEA power systems.

Ensuring security of electricity supply is not just about avoiding blackouts at any cost; it is also about the functioning of electricity markets. Clearly, a basic requirement of any effective market and regulatory framework is to ensure a reliable and secure supply of electricity. An efficient *r*egulatory and market framework would also seek to deliver reliable electricity services that meet end-use requirements at least cost. Ultimately this can only be achieved over time if the market stimulates adequate investment in new generation capacity at the right time, in the right place, and using the most cost-effective technologies.

In several OECD countries most incremental power production is driven by government policies rather than markets – based on feed-in tariffs or quota systems. New nuclear investment also extensively relies on public policy support. This has led to a situation where some pioneers in electricity market reform are beginning to express concern about the capacity of energy-only wholesale markets to provide sufficient incentives to deliver the investment needed to facilitate decarbonisation while continuing to deliver reliable supply of electricity.

"*Securing Power during the Transition*" assesses the threats and identifies options for competitive electricity markets embarking on the transition towards a low-carbon generation. The analysis provides an integrated analysis of issues, covering the impact of the global economic and financial situation, energy policy context and the implications for electricity market design. Its objective is to identify opportunities to improve regulatory and market designs to create a framework for timely and adequate investments, in particular in conventional power plants.

Key findings

Energy markets have the potential to ensure electricity of supply provided that a number of policy measures are pursued. These measures constitute a basic package that will bring benefits, not only in terms of security of supply, but also in terms of overall efficiency during the transition to a low carbon economy. They include:

- providing more certainty concerning climate policies;
- enhancing low carbon support instruments in order to ensure more effective integration of variable renewable generation into electricity markets, in particular, the participation of variable renewables to ensure system security;
- incrementally improving wholesale energy market design in order to accommodate increasing shares of variable renewables at least cost; and
- enhancing technical standards and procedures, to more clearly define and enforce reliability criteria, adequacy forecasts and controllability requirements of renewable generators.

Nonetheless, several reasons may explain why governments have introduced or are considering the introduction of capacity mechanisms. First the degree of uncertainty concerning climate policies and the pace of deployment of renewables may magnify risk to such an extent that markets alone are unlikely to deliver efficient and timely investment responses. Second, regulations that restrict efficient electricity price formation, such as unduly low prices caps, can undermine market-based signals for efficiently timed and located investment responses. Third, the reduction in spot prices and lower and less predictable periods of operation resulting from increasing volumes of variable renewable generation, increases cash flow uncertainty for conventional generation, with the potential to encourage the closure of existing conventional capacity and discourage timely investment in new capacity. Where these risks are material, there may be a case for, capacity arrangements that can create a safety net in order to ensure sufficient and timely investments. Possible capacity mechanisms include:

- Targeted contracting of capacity, which can provide a temporary fix but may introduce distortions between technologies.
- Market-wide capacity mechanisms can be effective to create a safety net if well-designed but tend to be costly and complex and can introduce other forms of market distortion, such as the risk of over-investment or under-investment and market manipulation.

Capacity mechanisms would constitute a shift toward heavy-handed regulatory intervention, in which a central entity – not the market – has to plan how much generation capacity is needed. Added to the policy-driven deployment of renewables, such mechanisms have the potential to jeopardise the competition benefits from electricity market liberalisation.

Competitive electricity markets must be supported by tough regulation

Even if competitive electricity markets are still relatively recent, there is clear empirical evidence that well-designed competitive markets does work and can bring economic benefits. That has not been an easy conclusion; given the unique features of electricity in terms of real time balancing needs and lack of demand response to prices, market rules must be well designed to ensure reliable supply. The experience of several IEA member countries over more than ten years demonstrates how it has worked in practice.

Parallel to the process of developing competition, many OECD governments have adopted policies in order to decarbonise electricity generation in the coming decades. To meet the greenhouse gas reduction objectives and mitigate global warming, governments are actively pursuing low-carbon policies. Defining high level principles for the electricity market is simple: set a high carbon price, add some technology-specific support and create a competitive market platform to bring in new technologies and innovative solutions. This will create the foundation for decarbonising the electricity sector at least cost and delivering adequate generation capacity to maintain electricity security of supply. This being said, existing carbon pricing mechanisms such as the European Emissions Trading Scheme (ETS) seem sufficient to influence dispatching decisions and investment choices between readily available technologies such as coal and gas, but do not create sufficient incentive for the large-scale commercial deployment of new low-carbon technologies.

Uncertainty about climate and renewables policies impacts future investment needs

Policies have been introduced or are being considered to reduce greenhouse gas emissions. But defining appropriate policies during the transition is necessarily an incremental development process. The global climate negotiations have proved to be challenging and most stakeholders do not expect a new global agreement to enter into force before 2020 at the earliest. Regional carbon markets introduced to date have resulted in prices that are to too low and too uncertain to trigger low-carbon investments. Given that any carbon market is driven by policy decisions and is subject to uncertain economic and technological developments, carbon price volatility is to be expected. Facing this situation, some countries have introduced a carbon price floor(s) (the United Kingdom) while others are considering introducing sectoral measures restricted to electricity generation (the United States) rather than economy-wide carbon markets.

Renewables support schemes have proven effective at facilitating deployment. They pursue multiple objectives, including promoting long-term industrial policies, and economic stimulation. They have delivered substantial and sometimes unanticipated levels of deployment of some technologies. But most of these technologies are promising but not yet fully cost-competitive and renewable deployment has come with a cost. In many cases, they pose an increasing burden on the price of electricity for domestic and, in certain countries, industrial consumers. The pace of their deployment is dependent on the level of government subsidy and recent policy decisions have served to raise the degree of uncertainty associated with the pace of their deployment.

The growing challenges of designing a stable regulatory framework and well-functioning markets

Stable and predictable climate and low-carbon policies would have the potential to mitigate some of the problems associated with investment incentives. Examples of such policies include providing more certainty for carbon pricing, defining attainable policy goals, developing predictable policies for renewables and energy efficiency, and avoiding sudden decisions that can erode certainty and confidence among market participants. Governments should aim to provide as much certainty and predictability as possible, recognizing that the uncertain economic environment and technological developments will demand a degree of flexibility.

Delivering cost-effective energy efficiency improvements is a critical component of electricity security. If this potential is left untapped, greater investment will be needed in new generation. Well-functioning markets create incentives to deliver innovative and cost-effective demand response and energy efficiency. Policies should seek to complement and build on these incentives. However it is important that there is as much certainty as possible that energy efficiency policies will deliver their targets, both to ensure that costs are minimised and so that they do not introduce undue uncertainty in demand trends that would make investment in supply more challenging.

Increasing shares of variable renewables exacerbate the issues with investments in peak power plants. The variability of electricity demand and the need to meet peak demand has always been a concern for system operators. During a few hours of peak demand, efficient electricity wholesale hourly prices are volatile and much higher than the yearly average wholesale price: efficient peak prices reflect the costs of the plants needed to meet peak demand. With high shares of wind and solar power, new investment in capacity, including generation plants, demand response, storage capacity will be needed. However, attracting sufficient and timely investment in peak capacity and incentivizing demand response has proven to be a problem for several OECD electricity markets.

Removing restrictions on wholesale peak prices during scarcity conditions is important to ensure well-functioning electricity markets. Wholesale peak prices during scarcity conditions are not intrinsically bad, since in periods of scarcity, high prices act to incentivise demand response. More sophisticated structural and behavioural remedies should be pursued to address concerns about market power, rather than poorly targeted price controls. Ultimately a more flexible demand side would contribute to mitigating market power and price volatility, and ought to be pursued to enhance market efficiency and flexibility.

Increasing shares of variable renewables will decrease load factors of base-load plants and mid-merit plants, add to the variability of revenues and can lead to very low wholesale prices during hours of high renewable generation with zero fuel cost. Variable renewable resources will reduce conventional base-load capacity needs over time. Yearly variability of weather conditions may further increase the variability of revenues. Compounded with uncertain carbon prices, this will further deter market-based investment in low-carbon base-load technologies. Attracting financing with more volatile and variable cash flows will become an increasing challenge, exacerbated by the current financial context.

Variable renewables will need to provide flexibility services in order to secure system operations

At significant penetration levels, generation using variable renewable energy magnifies the volatility of real-time electricity balancing, increasing the challenge to maintain reliable and secure power system operations. Challenges include:

- the low contribution of variable renewables to meet peak demand with a reasonably high probability,
- longer and steeper ramp-rates of residual demand, and
- the limited predictability of renewables and higher balancing needs during hours of high renewable generation.

The flexibility of the electricity system can be increased by flexible conventional generation, interconnections, storage and demand response. But variable renewables such as wind and solar photo-voltaic (PV) can and should have a role to play, which necessitate that their output be controllable.

With high shares of variable renewable resources, these will also have to contribute to the balancing of the system. The experience in many countries to date indicates that beyond a certain level (20 to 30% of energy, depending on the features of the electricity systems), the variable renewable output must be controlled during periods of exceptionally high output in order to ensure secure and reliable system operations. This means that in practice, some wind turbines or solar power plants must be curtailed, as is already the case in Spain, Texas and Ireland. Investment in other flexibility options helps mitigate curtailment for security reasons.

Efficient participation of renewables in the markets requires both renewable support and adaptation of the design of markets. Some renewable technologies including hydro, biogas and concentrated solar power with heat storage are already capable of flexible operations and a provision of system services. Other large-scale variable renewable facilities could also participate in the energy market by providing a dollar per MWh bid, below which they are no longer willing to generate. This implies an adaptation of the design of renewable support instruments.

A market platform for flexible services can be based on existing balancing and reserve markets and creates a level playing field for all technologies. Defining flexibility products such as ramping up and down, fast response ramping, minimum load balancing, etc. can reveal a price for each flexibility service. These services are being supplied by the same assets, and their availability depends on short-term arbitrages between different markets. All technologies should be able to participate in these markets, including variable renewable and conventional generation, demand response and storage. Participation of renewables in balancing markets would orient investment within renewables towards a more flexible portfolio and provide longer-term signals to invest in capacity with the right capabilities.

Capacity arrangements can create a safety net to cope with uncertainties

While in theory, well designed, energy-only electricity markets could ensure adequate investments, this is becoming increasingly challenging under policies that promote rapid and large-scale decarbonisation. Our analysis also indicates that current policy and regulatory risks may act as a deterrent for the investments in generation needed to ensure security of supply. Existing or foreseen restrictions on power peak prices, lack of credibility of carbon policy, the uncertain pace of development of renewable and nuclear policies, as well as energy efficiency policy targets, all induce a degree of policy risk. Private investors are not in the best position to handle these kinds of risk.

Improved climate, energy and renewable policies and better energy markets are needed to address these challenges. Following the economic crisis, many OECD countries are currently experiencing a situation of excess capacity, and thus have a window of opportunity in which to address these issues before considering other more interventionist arrangements. This should be a priority as they will deliver economic benefits in terms of lower dispatching costs and better price signals and have the potential to substantially reduce the transitional costs associated with of decarbonisation. This includes improving renewable policies, removing restrictions on peak prices, creating more transparent and efficient market platforms for flexibility services, developing efficient locational pricing and integration of the day ahead, intra-day, balancing and reserve markets. Obviously, this is easier said than done and in particular improving climate policy depends on a range of wider issues including progress with international negotiations and will take time. If a situation of excessive uncertainty persists, there may be a material risk that competitive electricity markets may not provide timely and sufficient investment to maintain security of supply.

Capacity mechanisms, including targeted contracts and market wide capacity arrangements, are a second-best solution to ensure security of supply and generation adequacy. The objective of such mechanisms should be not to increase the profitability of existing assets hit by the economic crisis, but rather to provide certainty that there will be enough capacity available, either with existing old plants or new assets if needed.

Targeted contracts can help countries facing short-term and transitory adequacy or reliability issues during the transition period. Such contracts are quick to implement and unwind once policy and regulatory uncertainty has been reduced and market design improved. Therefore, targeted contracts have the potential to promote security of supply without necessarily jeopardizing the the economic benefits from well-functioning energy-only markets in the longer run. However, expectations of such contracts can distort market prices and might lead to strategic behavior as companies withhold investment and wait for their introduction. Moreover, experience in certain countries indicates that it could be difficult to stop them.

Market-wide capacity mechanisms can be effective to ensure generation adequacy but tend to be complex, costly and subject to regulatory risk. By creating an explicit market for capacity, they can be effective to ensure adequate capacity. They can be used to promote flexibility, investment in capacity and in particular, demand response. They also have the potential to address the growing discrepancy between the ongoing need for flexible conventional generation capacity and its declining utilisation, which is a salient feature of systems with high variable renewable shares. They have the potential to encourage competition between different technologies, while reducing the risk of over-investing in particular technologies associated with targeted contracts.

However, capacity markets tend to have high transaction costs and put a burden on regulatory institutions. They might have unintended consequences in introducing secondary incentives and, depending on their design, may create excess capacity and lower demand response during scarcity conditions. In addition, while regional integration of electricity markets is an important source of flexibility and efficiency gains, national capacity markets tend to reinforce national rather than market-wide assessments of generation adequacy, thereby introducing distortions between different countries or jurisdictions. Before introducing capacity mechanisms, governments should carefully consider the timing of their introduction, their impact on incentives and define common rules for regional markets spanning multiple jurisdictions.

Searching for a target model of low-carbon investments

This work mainly focuses on issues regarding timely and efficient investments in conventional power plants during the transition towards a low-carbon economy. During the transition, governments will probably continue to incentivise most non-hydro renewable and other low-carbon investments. Looking forward, a major challenge facing electricity markets will be to deliver investments in low-carbon technologies, which should represent the bulk of new investment if decarbonisation of the power sector is to be achieved in the medium-term. What will the market wholesale power prices be with high variable renewables? What share of low-carbon electricity can be expected from market-based investments in electricity markets with a high price of carbon? Will this be enough to achieve the decarbonisation objectives while maintaining security of electricity supply? Designing a wholesale electricity market to reach the least-cost dispatch and deliver the desired level of low-carbon investment is a challenge that will require further research. If a revised market design is needed in the next decade to help cost-effectively and efficiently manage very high shares of low-carbon generation, work on this model should begin now. The prospect of another change in market settings could cause further investment uncertainty and lead to delayed investment, so the sooner there is clarity around this long term direction the better.

1. The general framework for efficient electricity markets[1]

An effective electricity sector has to deliver low-cost, secure and sustainable energy. In many economies competitive forces are seen as the most efficient means to achieve this outcome. But "markets do not design themselves'' and in virtually all markets for goods and services, governments use policies to correct for some level of market failure, and in this respect, power markets are no exception. Effective policy in the electricity sector should allow consumers to capture the bulk of the benefits that flow from competition, whilst also delivering solutions to pressing environmental challenges.

This chapter seeks to introduce the role of competitive markets in electricity generation. First, several unique features of electricity are identified that are relevant to the role of competition in power markets. Second, two approaches of electricity provision are presented, one based on monopoly provision and the other on competition. Some benefits and shortcomings of these two approaches are outlined. Lastly, three areas are presented where regulators intervene to address problems of market failure, while maintaining the benefits of competitive activity in the power sector. These areas are supply reliability, reductions in carbon emissions and technology spillovers. The section concludes with a brief discussion of the capacity of electricity markets to deliver the long-term decarbonisation objectives.

Electricity: a service with unique characteristics

Electricity has a number of characteristics that affect the way competitive forces are used in electricity production and supply. Three are outlined below.

Real time supply

Since electricity cannot be stored cost-effectively in bulk quantities, supply and demand must be balanced in real time, using complex systems of dispatch among multiple providers. Supply and demand imbalances in one location on an electrical supply network have the potential to upset the balance across the entire interconnected network. As such, a system operator must ensure that demand is balanced across the network at all times so as to maintain frequency for all network users. A platform is used to allow all those providing electricity supplies to communicate in real time with the system operator. In a competitive electricity market this central platform must also be a market platform, to allow for the matching of demand and supply, so that the cheapest energy bids can be identified and dispatched to meet demand.

Networks with monopoly characteristics

Electricity is distributed through a network of generators, loads and wires. In a given geographical area it is economical to build only one network, and a single network is most cheaply provided by a single supplier. When one supplier is best placed to provide a service, this is a service with 'natural monopoly characteristics', meaning competition between multiple providers cannot operate to reduce costs of supply. As a result, networks services are provided commercially by single parties and the revenues from these services must be regulated, to ensure the provider does not abuse their monopoly position. In economies with competitive markets for electricity

[1] The principal author of this section is Steve Macmillan.

supply, network activities are split from competitive activities in the generation and marketing of electricity.

A lack of demand response

Consumers have traditionally had limited opportunities to respond to short term changes in the cost of power supply, as their rates do not react to short term changes in overall demand. This means that the retail price and end customer pays for electricity does not increase when the wholesale price for electricity is highest, even though the cost of that electricity may change substantially. The differences in the cost of supply are generally averaged and spread across all users, so price signals do not communicate information about the scarcity of electricity at particular times. As a result, customers are unable to ration supply in response to the value they place on it and will continue to demand electricity even when its underlying cost is at peak levels.

Technological developments are addressing this lack of demand response, by measuring when customers use their electricity and using this information to develop more cost-reflective tariffs. However, in the medium term the lack of demand response in electricity markets continues to have important implications for policies designed to influence consumer behaviour.

Two approaches for providing electricity

Two approaches exist for providing electricity in modern economies. The first is an integrated monopoly provider and the second is a competitive market. In practice, a multitude of variations exist that integrate elements of both approaches.

In virtually all energy markets worldwide, provision via a monopoly was the primary model for industrial organisation. Under this scheme, a single agency or company is tasked with managing the entire energy supply chain for customers in a defined area. Typically, these utilities were government owned and fully vertically integrated, meaning they owned all the assets required to generate, distribute and retail electricity.

In a competitive market approach, competition is introduced to segments of electricity supply. While approaches differ widely, competition is most frequently introduced in generation and marketing (also known as retail). Competition in distribution is limited for the reasons outlined above.

Vertically integrated regulated monopolies

Under a model of monopoly provision the vertically integrated utility enjoys an exclusive mandate over the demand of customers in a given area, meaning it does not have to compete for customers based on price or the quality of its service. As such, government agencies are tasked with ensuring that the quality meets community expectations and prices are kept at acceptable levels.

Where a single entity provides all electricity for customers in a defined area, governments and regulators have a role in determining the appropriate level of investment in supply. If investment is inadequate to meet demand then customers will experience electricity shortage and rationing of electricity. Conversely, if investment is in excess of levels required to meet demand then the cost of electricity must eventually rise significantly to fund investments in infrastructure that is rarely used. When a regulator approves an investment under a monopoly model, the utility passes on the cost of this investment to all its customers. Since no customer will willingly forego electricity altogether, the regulators' decision effectively ensures that end customers will fund any investment that has been approved.

Publicly-owned utilities are sometimes also tasked with meeting a broader range of public policy goals than merely the efficient and effective provision of electricity. These could include keeping the price of retail energy at lower levels that do not reflect cost (for example, through cross subsidies), maintaining employment, or preferring a certain generating fuel.

Benefits

The benefits of monopoly provision are generally considered to be simplicity and certainty. A single integrated utility does not require complex systems to dispatch multiple providers at the wholesale level, or retail market platforms that allow for switching of customers between different retail providers, or an elaborate access regime to ensure multiple parties can access monopoly network infrastructure on equal terms.

A single provider can theoretically integrate all the information it has on customer usage into nuanced view of developments in demand. Where fresh investment is required to meet demand, a government can direct a utility to invest at a given time and this ensures that capacity will be adequate to meet reliability standards.

Moreover, regulated monopolies have also been able to deliver investments in capital intensive and innovative technologies. For instance, this rendered possible the large-scale deployment of nuclear fleets in France from the 1970s to 1980s, contributing to controlling costs and mitigating risks.

Drawbacks

The drawbacks of the monopoly model are that the utility arguably has weak incentives to reduce costs, to improve its service offerings, innovate in new services or invest in new generation technologies. Once a regulator has approved a given level of investment, the utility is virtually guaranteed to collect the approved revenues, regardless of how it performs. In practice, regulators of monopoly providers frequently seek to introduce incentives similar to those associated with competitive markets, to promote efficient outcomes that meet acceptable levels of service.

A further drawback is that like any observer the regulator will face limitations in its understanding of the dynamics of supply and demand. Even if the regulator makes forecasts based on the best information at hand, these decisions will sometimes lead to conditions of under or over supply. In these conditions the risk associated with these forecasting errors are carried entirely by the end customer, who has no choice but to fund all approved investments.

In addition to limitations in knowledge, the regulator can also generally intervene reasonably easily in key decisions of the utility, which makes it easier to pursue other public policy goals. Regulators are also susceptible to influence or pressure from groups that stand to benefit or suffer loses based on their decisions, even when theoretically regulators are independent. Also, when regulating monopolies, regulators frequently know less about features of demand and supply than the companies they regulate, which creates further opportunities for their decisions to be influenced to benefit one section of society instead of consumers as a whole.

Lastly, in a market where one entity is directed to deliver a service, incentives for innovation are generally considered to be weak, unless governments are particularly and effectively involved in supporting complementary research and development activities.

Competitive model

Introducing competition in generation and marketing means allowing multiple parties to compete to provide electricity to customers in a given area. A wholesale market platform, organised or over the counter, is established whereby generators can offer their supply at a given price. The cheapest power is procured first and this allows for a price to be set reflecting the conditions of supply and demand at that time. The electricity market prices allow investors in supply to assess the profitability of investing in infrastructure required to supply customers with power. Although many may invest, none is guaranteed that it will be called upon to generate.

When a party decides to invest in generation infrastructure, it makes projections about future demand similar to those of the regulator in the monopoly model. However, the investor is unable to pass all the risk of inappropriate projections on to the customer in the same way.

In addition to parties that own infrastructure, there are other parties that enter the market merely as marketers of electricity. This involves procuring electricity on wholesale markets, bundling underlying electricity with network services, and billing end customers. (Some parties both generate and market electricity.) Marketers seek to acquire more customers based on lower prices and superior levels of service.

Because supply and demand must be constantly matched in real time and customers have for the time being very little opportunity to ration their use when wholesale prices are high, prices on wholesale markets can increase rapidly when supply is short. In response to this volatility in prices, a complex array of financial instruments has developed in competitive markets to allow marketers to reduce their exposure to volatile movements in wholesale prices.

Benefits

The benefits of a competitive market are generally considered to be that it addresses the shortcomings of the monopoly model in terms of poor efficiency, lack of innovation and too high prices.

Where providers must compete to provide generation and marketing services they carry the risk that their investments will be ill-conceived or that they will run their assets inefficiently. In this instance, they have strong incentives to make investments that anticipate the future needs of consumers, as well as to minimise costs, as this approach offers the best chance of a commercial return. In this context, customer choice can help to reveal the least cost alternative, as well as to deliver an evolution in products and services.

As a result of competition between multiple providers, customers generally see a more responsive service as well as a less costly means of supply. It is important to note in these circumstances that introducing competition does not automatically mean that prices for electricity will fall, for a range of reasons. But we must consider the baseline for energy prices, which may be increasing, for example because the cost of inputs (such as fuel) is increasing. In this instance, prices for electricity are likely to grow regardless of the supply model adopted, and may rise less under a competitive model than they would have under a regulated model.

Challenges

The challenges associated with designing competitive wholesale electricity markets are generally associated with some type of 'market failure', or an instance where competitive markets fail to provide efficiently for the supply of a good or service, or are unable to fully value the cost of goods and services. Market failures are frequently defined in terms of public goods[2] or negative externalities[3] and natural monopolies.

Among the various types of market failure that exist in relation to competitive electricity markets, some are long established, while others relate to more recent environmental challenges. In addition to market failure arising in relation to electricity networks, which are assets with monopoly characteristics, market failures associated with power generation include air pollution and carbon emissions flowing from, and technological innovation where the market does not adequately promote the development and diffusion of energy technologies such as renewable energy.

Approaches to internalising the cost of pollution long predate concerns about anthropogenic climate change. These approaches generally involve various forms of tax that look to introduce the cost of environmental damage to the cost of goods and services (Pigou, 1952). Estimating the cost of a negative externality and intervening in market frameworks can be done in a variety of ways.

Reliability, carbon emissions and technology spillovers

Reliability

In the category of market failures which have long been common to competitive power markets the question of reliability[4] is a pertinent example. The system frequency is common for all network users over a synchronous area (50 Hertz or 60 Hertz) and actions taken by one user can affect the frequency and therefore the quality of power supply for all the others. Because energy cannot be stored massively at low cost, the generator used to provide supply in rare moments of peak demand will only rarely operate. Customers value reliability differently depending on their circumstances. But unlike with markets for traditional goods, there are limited means to charge according to each customer's willingness to pay for reliability (or willingness to ration their use of power at times of peak demand). Consequently, all parties benefit somewhat from a system with adequate supply, but it is difficult to determine the value that the community as a whole puts on uninterrupted electrical supply.

In principle, a price level should exist above which a limited outage becomes an acceptable alternative to the average user. However, this price level is likely to vary as a function of many variables, such as the duration and timing of interruption, whether customers are generally prepared for interruptions, whether customers are notified in advance notice, and the type of customer.

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[2] A 'pure public good' can be defined as goods and services which once made available to one party are then available to all parties. One example is the atmosphere, which is used by all but traditionally was maintained by none. Problems arise in relation to public goods because it is difficult to exclude parties from the benefits of the good or service, and so it can be difficult to apportion the costs of providing the good or service to all parties that benefit.

[3] A 'negative externality' arises when the actions of an individual negatively affect the utility of another individual, but the full cost of this is not captured in the costs of the first individual. An example is a coal power station that emits CO_2 in to the atmosphere, while the negative cost of this pollution on the atmosphere is not factored into the costs of the power station. The problem of carbon emissions represents a classic problem of negative externality.

[4]Reliability here refers to reliability of supply rather than network reliability. Network reliability typically also presents challenges associated with public goods, since all parties using the network rely on network stability but have a strong private incentive to minimise their contribution to maintaining it.

Box 1 • The cost of ensuring security of supply

For a given construction cost, it is possible to calculate the associated reliability criteria in terms of expected lost load duration, a metric that governments often use in order to set the reliability criteria. To take a simplified numerical example, the annual cost of a peak power plant is 60 000 USD/MW/yr, with a variable cost of 100 USD/MWh. Building one MW of capacity to operate it only one hour would cost 60 100 USD/MWh, which is higher than the value of lost load (20 000 in this example). Therefore it is less costly not to serve this MWh and rely on load curtailment. For 2 hours, the cost would be (60 000+2*100)/2 = 30100 USD/MWh, which is again too costly. With a value of lost load equals to 20 000 USD/MWh, the optimal expected curtailment duration would be c. 3 hours.[5]

A number of different indicators are used by governments or regulators to define an acceptable level of reliability in energy markets (Table 1). These include measures that target a number of hours in a year where demand will not be fully met, and a threshold volume of unserved energy that should not be breached. These mechanisms all relate in some way to the cost of marginal supply, and indirectly to the value that customers place on reliability. In this way, considerations about the value of lost load are inherent in features of market design such as market price caps.

Table 1 • Examples of reliability thresholds in wholesale electricity markets[6]

Mechanism	Market	Implications for wholesale prices
Time-based No more than 30 hours of expected curtailment duration over 10 years	France	Implies that a marginal generator with fixed costs of USD 60/kW needs to earn USD 20 000/MWh for three hours on average in order to remain profitable.
Time based 1 day in ten years when capacity is insufficient	PJM (Northeast USA)	Translate to approximately 15 to 20 percent planning reserve margins above expected peak demand. PJM relies on a capacity market to ensure adequate capacity targets are met.
Volume based No more than 0.002% of energy unserved per year	Australia (eastern)	Price cap of AUD 12 900/MWh is designed not based on estimate of value customer ascribes to reliability, but to provide for generation that meets threshold of 0.002%.
Time and volume based 8 hours in a year or 34.5 energy units per million unserved	Ireland	Value of lost load calculated at EUR 10 520, based on average cost of a best new entrant peaking plant running for 8 hours in a year only.

Note: Unless otherwise cited, all material for figures and tables derives from IEA data and analysis.

Despite the complexity inherent in intervening in the power market to estimate an appropriate level of reliability, it should not be concluded that this is not feasible. A number of wholesale power markets have set price caps at high levels, and these markets have consistently delivered adequate (but not excessive) spare capacity, in the absence of other market interventions. Examples include the Australian National Electricity Market (NEM) and the Texas electricity market (run by the Electric Reliability Council of Texas, ERCOT); for an outline of the Australian situation, see Box 2.

[5] It is duration d* such as 60 000+d*×100=20 000 ×d* which yields d* = 3.015 hours.

[6] For France, see *Décret 2006-1170 du 20 septembre 2006 relatif aux bilans prévisionnels pluriannuels d'équilibre entre l'offre et la demande d'électricité*; for PJM, see FERC order 747 (www.ferc.gov/whats-new/comm-meet/2011/031711/E-7.pdf) and North American Electric Reliability Corporation Reliability First Corporation Standard BAL-502-RFC-02; for New Zealand, Single Electricity Market Committee Policy parameters 2012 Decision paper, SEM-11-073; for Australia: standard set by AEMC Reliability Panel.

While regulators can theoretically allow prices for wholesale energy to be bid up without limit, yet in practice they rarely do so. This is because customers are poorly placed to respond dynamically to changes in prices, so it is unclear whether extreme prices paid in peak periods genuinely reflect the value customers place on reliability. A further complication is that when supply is tight and ownership in peak generation is limited to small number of parties, these parties can enjoy market power whereby they can increase the price beyond competitive levels. As a result, system operators attempt to estimate the value of reliable supply to the community as a whole and frequently intervene to reduce consumption when prices exceed that level. The implications of such interventions are discussed in more detail in Chapter 4.

Box 2 • Incentives for investment in spare capacity in Australia

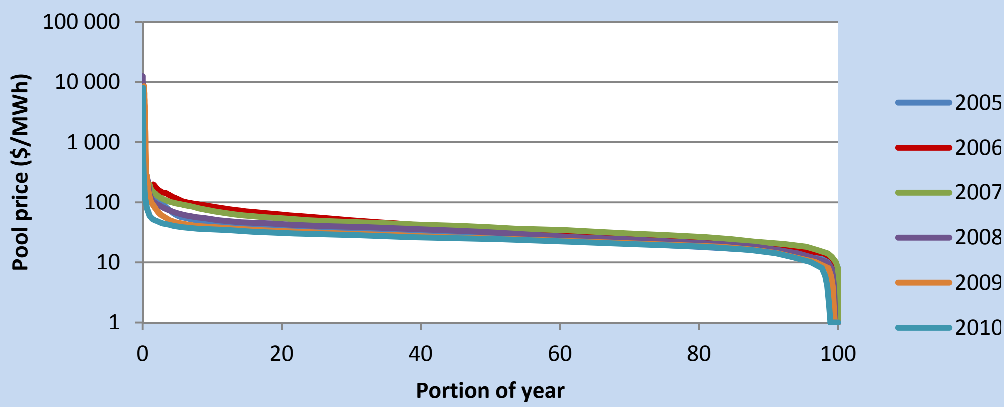
The Australian National Electricity Market (NEM) is a wholesale market through which generators sell electricity in eastern and southern Australia. The main customers are energy retailers, which bundle electricity with regulated network services for sale to residential, commercial and industrial energy users.

Electricity produced by large electricity generators in the NEM jurisdictions is sold through a central dispatch process that the Australian Energy Market Operator (AEMO) manages. The Australian NEM is an energy only design. This means that all capacity in the market is remunerated through market clearing prices. No other payments are made in the spot market except those arising from specifically designed reliability safety nets and specific purpose ancillary services. (Financial hedges also occur outside the market between market participants.)

The dispatch price for a 5-minute interval is the offer price of the highest (marginal) priced energy source that must be dispatched to meet demand. A wholesale spot price is then determined for each half hour (trading interval) from the average of the 5 minute dispatch prices. The pool price is the price that all generators receive for their supply during the half hour, and the price that wholesale customers pay for the electricity they use in that period. Spot prices may not exceed a cap of AUD 12 900 per MWh.

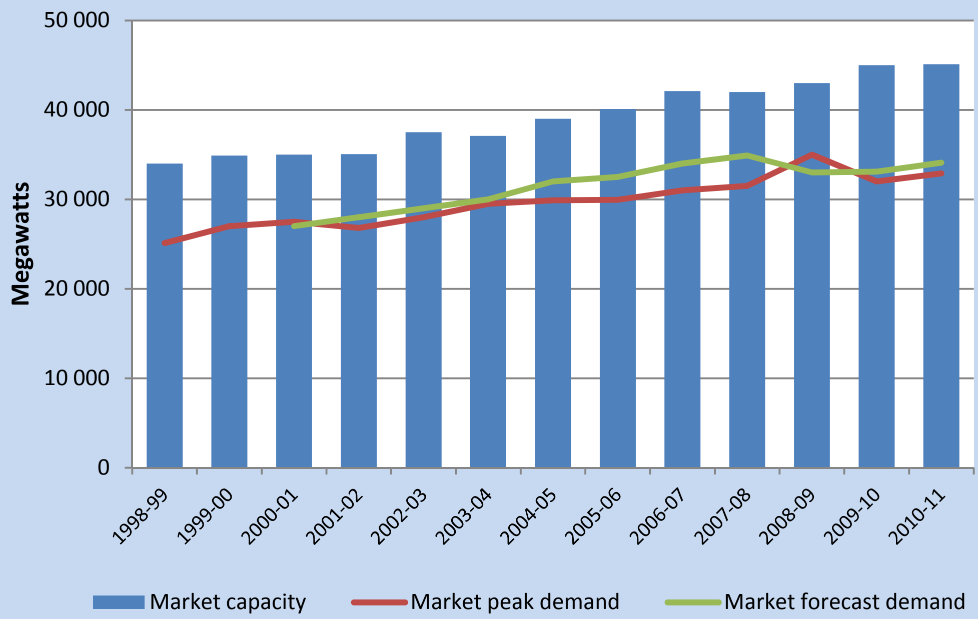
Figure 1 below shows a price duration curve for one of the Australian zones. As can be seen, very high prices are rare, with prices sitting within the range of AUD 0-40 for around 90% of the time.

Figure 1 • South Australian price duration curve, various years (logarithmic scale)



As shown in Figure 2, the NEM has consistently delivered capacity additions ahead of demand.

Figure 2 • Australian electricity market peak demand and generation capacity, 1998/99-2010/11



The Australian example illustrates adequate capacity in a robust competitive energy-only market. However, views differ on the adequacy of high but capped wholesales prices as a sufficient incentive to invest in marginal supply.

Reducing carbon emissions in a competitive framework

In contrast to traditional questions about market failure in relation to energy markets, the threat of anthropogenic climate change has created a new set of externalities. Reducing carbon emissions associated with power generation is a central challenge in the project to reduce overall emissions from human activity. This is the case not only because stationary energy currently accounts for 40% of global energy-related CO_2 emissions, but also because reducing emissions from sources such as the transport sector will involve further electrification – since many of the most promising low-carbon energy technologies are those that produce electricity (wind and solar being two examples).

Different analysis sought to estimate the value for carbon that would deliver the required reduction in emissions According to the IEA Energy Technology Perspectives scenarios (IEA, 2012a), “marginal abatement costs represent the cost of the last tone of CO_2 eliminated via abatement measures. They are often used as a reference for what carbon price is needed to trigger this abatement”. In the Two Degrees scenario provided by the IEA’s ETP, the carbon price should increase from 30-50 USD/tCO_2 (in real 2010 USD) by 2020 to 80-100 by 2030 and 130-160 by 2050.

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Table 2 • Global marginal abatement costs and example marginal abatement options in the 2-degree scenario

	2020	2030	2040	2050
Marginal cost (USD/tCO_2)	30-50	80-100	110-130	130-160
Energy conversion	Onshore wind Rooftop PV Coal with CCS	Utility scale PV Offshore wind Solar CSP Natural gas w CCS Enhanced geothermal systems	Same as for 2030, but scaled up deployment in broader markets	Biomass with CCS Ocean energy
Industry	Application of BAT in all sectors Top-gas recycling blast furnace Improve catalytic process performance CCS in ammonia and HVC	Bio-based chemicals and plastics Black liquor gasification	Novel membrane separation technologies Inert anodes and carbothermic reduction CCS in cement	Hydrogen smelting and molten oxide electrolysis in iron and steel New cement types CCS in aluminium
Transport	Diesel ICE HEV PHEV	HEV PHEV BEV Advanced biofuels	Same as for 2030, but wider deployment and to all modes	FCEV New aircraft concepts
Buildings	Solar thermal space and water heating Improved building shells	Stability of organic LED System integration and optimisation with geothermal heat-pumps	Solar thermal space cooling	Novel buildings materials; development of "smart buildings" Fuel cells co-generation

Source: IEA, Energy Technology Perspectives, 2012.

In the case of carbon emissions, a further complication arises, in that no low cost alternative or set of alternatives currently exist to replace fossil fuels entirely. As a result, markets (and market interventions such as permit systems) must deliver technological solutions as well as allowing for the least cost adoption of these. Furthermore, this means that mandating a dramatic reduction of emissions in the short term can imply very high (and in some cases not well-known) costs.

Estimating the cost of a negative externality and intervening in market frameworks to correct for market failure can be done in a variety of ways.

Trading systems in carbon permits have been established in number of economies in the world, notably in the European Union, and recently in Australia. Permit trading systems are designed to bring the cost of carbon emissions into the cost of producing goods and services, and thereby to improve efficiency in the economy by reducing investment in more carbon intensive activities. Trading systems are likely to be most efficient when there is significant variation in costs of reducing pollution among different parties and sectors, so that trading of surplus permits can take place and the least cost solutions can be adopted.

A wide variety of analyses have been carried out to assess the costs of limiting carbon emissions through permit systems. The European Emissions Trading System demonstrates some of the complexity involved in estimating the correct number of permits that should be made available in order to create sufficient scarcity such that permit prices will be high enough.

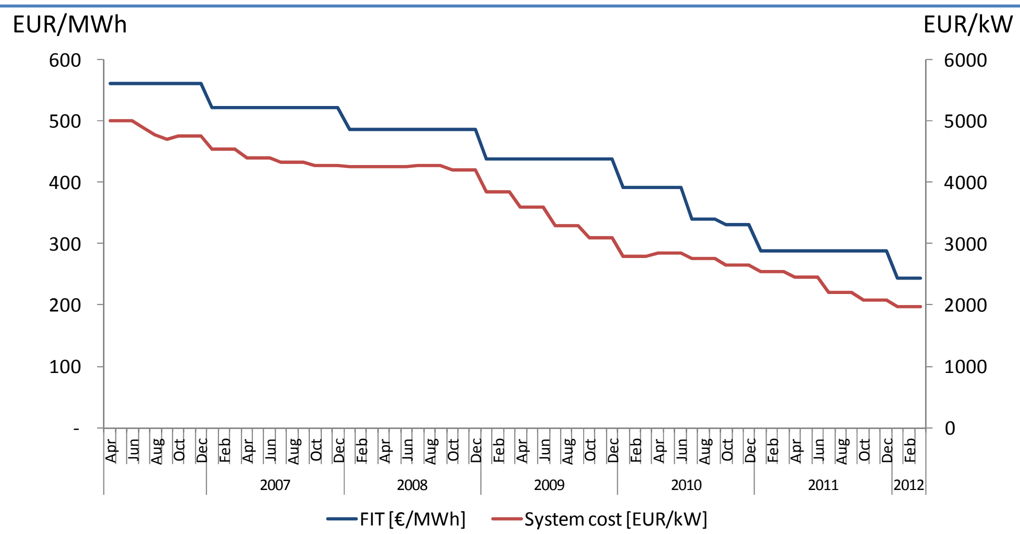
Promoting the inception of low-carbon technologies

Since the Industrial Revolution competitive markets have played a crucial role in delivering technological outcomes, comparable to that of the contribution from pure scientific research. Where a technological solution to a pressing environmental concern is not yet available, or is available only at high cost, governments look to intervene in markets to promote this outcome. The objective is not only to incentivise economic actors to address the problem to the extent possible, given existing technologies, but also to promote further technological development.

Economic theory suggests that significant cost reductions can accrue when commercial parties apply technologies that are still in their inception phase. These effects are sometimes referred to as "learning by doing", and "spillover" effects.[7] Considerable evidence suggests that such benefits genuinely occur (IEA, 2003). The extent of this externality relates primarily to the appropriate level of public subsidy that should be directed towards a technology, since public funds are justified to the extent that society as a whole will benefit.

In the case of climate change, mechanisms used to promote technological development in the market include subsidies and quotas for renewable energy – both mechanisms that direct expenditure towards emerging technologies. The objective of these programmes is not simply to foster the adoption of the technologies in question, but also to promote development that will lower their cost, as others copy the technological advances achieved. An example can be drawn from the cost of solar PV systems in Germany, which has fallen considerably. In response, subsidies for solar PV in Germany have been consistently reduced (Figure 3).

Figure 3 • Solar PV system cost and feed-in tariff, medium-scale systems (up to 100 kW), Germany 2006-12



Setting subsidies to support technological development presents challenges, particularly in estimating the appropriate value for a given technology in a given context. If subsidies are too generous, investment will exceed optimal levels. Eventually, the benefits from subsidising the production of a particular technology will present declining returns to scale, as the technology matures and production is adopted more broadly.

Can electricity markets deliver the carbon emission targets by 2050?

If the levels of reductions in emissions targeted in a number of IEA member countries are to be realised this implies significant growth in low-carbon energy generation such as CCS, renewable energy and nuclear. Electricity markets have been introduced in systems with large consolidated sources of energy such as gas, coal and nuclear, with relatively high marginal costs and few

[7] Spillovers can be considered a market failure driven by a positive externality: the party that carries out the initial research does not capture the benefits of technological diffusion, yet society as a whole stands to benefit if spillovers occur. See IEA (2008b) and IEA (2011a) for a discussion.

network constraints. As a result, the ambitious targets by 2050 for low-carbon energy in general, and renewable energy on a large scale, have considerable implications for competitive energy markets.

When variable renewable energy make-up less than five percent of output, it is treated within existing market frameworks. When penetration of renewable resources moves to between 20 and 40% of output, these electricity market frameworks need to be modified to allow a greater coherence in the operation of conventional and renewable energy sources. The optimal mix of conventional generation to support increased variable renewable generation and ensure security of electricity supply will be different from the most economic mix prior to the introduction of large amounts of variable energy resources.

In the long term, market design should not only ensure adequate investment but it should also incentivise investments in low-carbon generation. As renewable energy targets are set higher – and even as direct economic support for these sources is reduced – many questions arise concerning the functioning of electricity markets: what would be the level of low-carbon, including renewable generation, nuclear and CCS, with an electricity market with a high carbon price? Would this be enough to deliver the almost complete decarbonisation of the electricity sector by 2050? If not, how to design electricity markets?

Further work is required to fully understand how to design wholesale electricity markets and carbon dioxide regulations capable to deliver the policy targets in terms of carbon dioxide emission reduction.

The following chapters examine the suite of methods and approaches available to policy makers to intervene in competitive power markets during the next 10 to 20 years of the transition to a low-carbon electricity sector, where the penetration of variable renewables moves to, say, above 20 to 40% of output.

2. Policy context: transition towards a low-carbon electricity generation

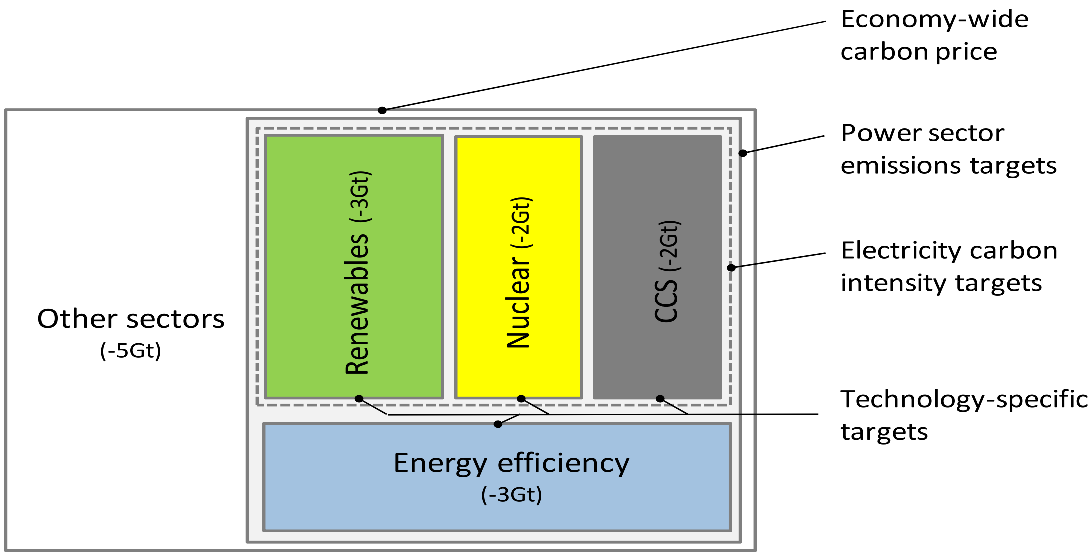
If governments want to achieve the global goal of limiting temperature rise to 2°C, they will have to introduce policies that will have the effect to reduce power demand, increase energy efficiency, promote investments in renewable technologies, nuclear and carbon capture and storage. Compared to the *World Energy Outlook's* (IEA, 2011c) New Policies Scenario, which is a central case, reaching the 2-degree scenario would require reducing energy-related carbon emissions by 15 $GtCO_2$ per annum in 2035, out of which, two-thirds would be from electricity, or 10 $GtCO_2$/year. Out of this total, lower electricity demand would contribute to a reduction of 3 Gt, renewable energy, 3 Gt, and nuclear and CCS about 2 Gt each (Figure 4).

To make this happen, OECD countries will have to lead the way and their relative contribution to the decarbonisation effort will need to be even greater. The 2-degree objective will require decarbonising the power sector almost entirely by 2050. Obviously, the current short-term macroeconomic issues do not help and long-term climate policies tend to shift away from governments' agendas. This uncertain commitment to climate policies is a major deterrent to investment.

What instruments are used to deliver low-carbon electricity and what is their influence on the functioning of electricity markets?

The previous chapter described the high level objectives of what we can call the "target electricity market arrangement", where a proper carbon price is the cornerstone of climate policy. Notwithstanding, current climate policies are from many aspects a trial and error process and in practice, governments use a broad range of policies to complement a carbon price (IEA, 2011b). This section reviews the existing or foreseen regulatory instruments which contribute to promoting low-carbon electricity and discusses their merits and impacts from the perspective of electricity markets and investment decisions.

Figure 4 • Reduction in world energy-related CO2 emissions in the 450 Scenario compared with the New Policies Scenario and scope of different regulatory instruments (Gt CO_2)



Source: IEA (2011c).

Level playing fields for low-carbon generation investments

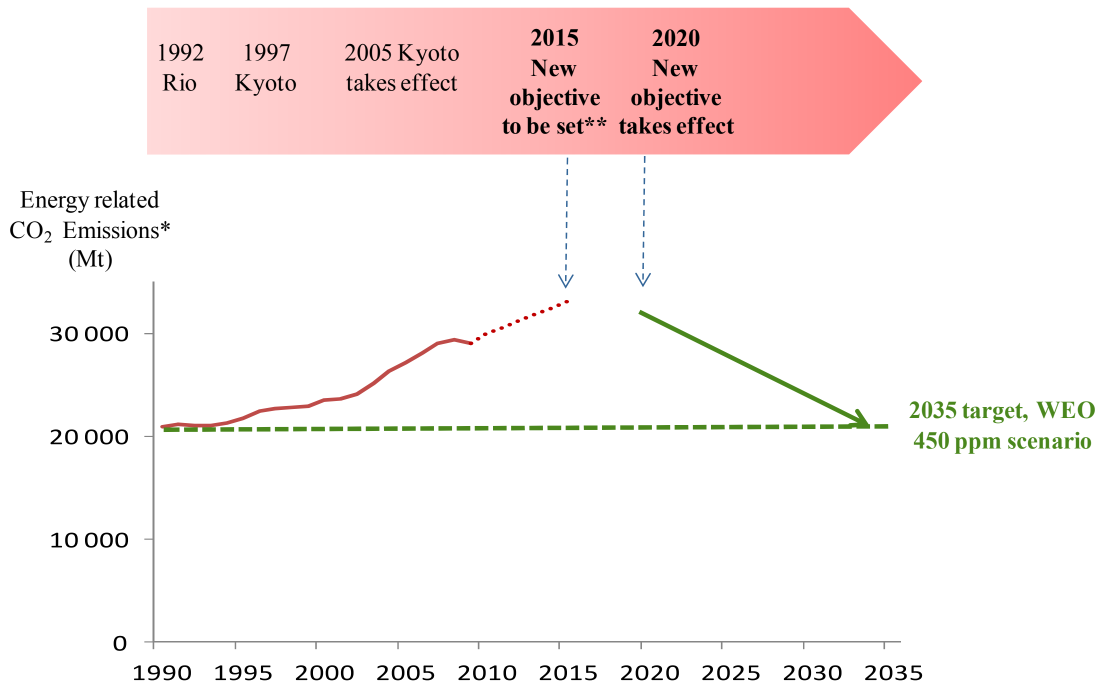
The price assigned to CO_2 will play an important role in directing investments away from traditional fossil-fuelled plants. In this perspective, the long-term credibility of governments to have a high carbon price will be important. But both the last summit dedicated to global climate negotiations and recent carbon market experiences suggest that this is far from being the case. Other electricity-specific policy instruments have been proposed to overcome these difficulties.

Global climate policy will remain uncertain

International climate negotiations are a key element in the long-term credibility of regional climate policy initiatives: ambitious but isolated regional policy initiatives may not be sustainable. Virtuous regions may well be constrained sooner or later to reduce their ambitions, due to concerns that carbon leakage could distort their competitiveness and reduce their economic growth. Even if current governments are committed to these policies, such anticipation by the business community may be sufficient to undermine the investments incentives.

From this perspective, the current outcomes of the United Nation Framework Convention on Climate Change, and in particular, the Conference of Parties in Durban in December 2011, do not bring much immediate clarification for investors. Since the beginning of climate discussions, global energy-related carbon emissions have increased by 50% and electricity sector emissions have increased by 65%. The Durban Conference decided to work toward a new global agreement by 2015, which will come into force in 2020. Meanwhile, IEA analysis suggests that if investment patterns do not shift toward low-carbon by 2017, the lock-in of high emissions plants will mean that the 2°C target will be much costlier and more difficult to achieve. In the short term, the absence of a global agreement on climate inevitably weakens the ability of governments to implement the carbon price high enough and above all, credible enough in the long run to trigger low-carbon investments.

Figure 5 • Timeline of global climate negotiations and evolution of carbon emissions, 1992-2020



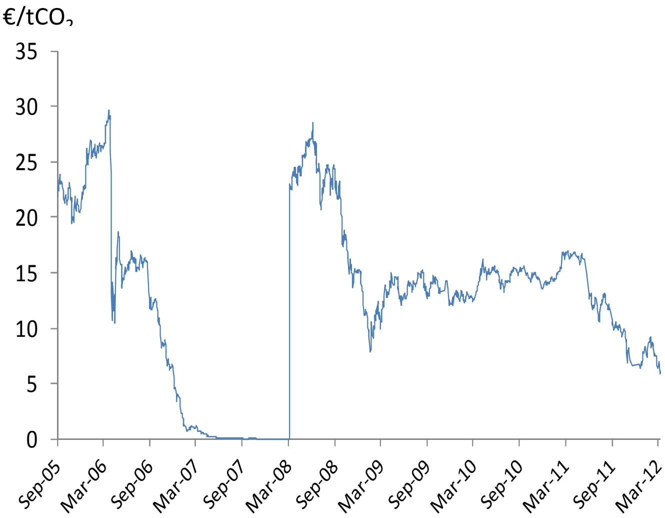
*Sectoral approach
** The goal is to have a global agreement for all UNFCCC parties

Regional carbon markets are failing to trigger low-carbon investments

Several countries or regions have introduced carbon markets in order to control carbon dioxide emissions, including the European Emissions Trading Scheme (ETS), New Zealand, Australia, California, ten northeastern states of the United States (Regional Greenhouse Gas Initiative, RGGI), and Alberta, Canada. Other countries are considering or developing such markets: Mexico, Brazil, Chile, South Korea and China.

The EU European Trading Scheme, the largest one, started operating in 2005 and was established with the EU Climate Package of 2008 as a permanent mechanism for Europe. While the European carbon price played a role in the coal-to-gas shift in power plant dispatch decisions, until recently, its role in promoting for low-carbon investment was showing mixed results. Specifically, *"…uncertainty about future carbon price may complicate decision-making particularly for financing projects"* (Neuhoff, 2011). The current prices are too low to have any influence on investment decisions. The economic crisis, the changing economic structure and the development of renewable energy all contribute to this situation. Options are under discussion to increase carbon prices, such as setting aside emissions allowances and possibly modifying the 2020 emission target. However, there is a trade-off between increasing the price through market interventions and doing this in a way that maintains the long-term credibility of the trading scheme. Indeed, the long-term credibility of the carbon price after the current phase ending in 2020 will be crucial for long-lived, low-carbon equipment such as nuclear power plants, CCS or off shore wind-farms.

Figure 6 • European carbon prices (EU allowances), 2005-2012



Source: Bloomberg and IEA data.

To supplement the EU emissions trading system, the United Kingdom unilaterally decided in 2011 to introduce a carbon price floor (HM Treasury, 2010). The floor price will start in 2013 at GBP 16 per tonne and will reach GBP 30 per tonne in 2020. But it is argued that even such a floor may not provide enough certainty to investors; as it takes the legal form of a tax, it will have to be voted each year by the parliament. Interestingly, the UK government itself is at the same time in the process of introducing long-term power purchase contracts (the so-called contract for difference, or CfD), to provide more certainty for investors.

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Australia has introduced a carbon pricing mechanism. There is a two-stage approach for the carbon price in Australia.

- A fixed price period: The price starts at AUD 23 per tonne on 1 July 2012 and will rise at 2.5% each year in real terms.
- Emissions trading scheme: On 1 July 2015, the carbon price will transition to a fully flexible price under and emissions trading scheme, with the price determined by the market. In a recent decision, this system will be linked with the European ETS after 2018.[8]

Power sector emissions or carbon intensity targets

Faced with the political difficulty of introducing economy-wide carbon prices, policy makers may consider mechanisms at the sectoral level, which could still exploit a large portion of the emission reduction potential in OECD countries. These approaches are second-best approaches as they may be more complex, and can introduce a bias in the emission reduction costs across sectors of the economy. However, unlike a carbon pricing arrangement, they can avoid − at least initially − large increases in energy prices and windfall profits, which are a hurdle for emissions pricing policies.

For the power sector, a first possibility would be to limit the scope of emissions trading to this sector, setting power sector emission targets in $MtCO_2$, encompassing generation and power demand in order to preserve the incentives to reduce electricity demand and seek gains in energy efficiency. An argument for adopting such a measure is to reduce to some extent the carbon price uncertainty associated with industrial demand.

But a second possibility proposed recently in the United States consists of restricting the scope of the carbon constraint to the generation side even further, by setting a standard for the emissions intensity of the generation mix. The arguments for adopting such measure are that this creates a level playing field for all low-carbon generation technologies (renewables, nuclear, CCS), leaving to the market the responsibility to select the most promising technologies and handle changes in future costs of different generation technologies and fuels. Thereby, it creates more certainty while avoiding picking technology “winners”. Furthermore, such a standard for emissions can avoid a large increase in electricity prices in the early stage of its introduction, which would otherwise be necessary to trigger low carbon investments. The associated argument against this approach is that, it may be less effective at reducing electricity demand than a carbon price.

Although it is not clear whether this proposal would create a more stable investment framework and will be applied in the United States (see Box 3), electricity sector mechanisms may be an interesting instrument. They can address the price uncertainty associated with industrial demand of quotas in an economy-wide cap and trade mechanism. They can also address the bias introduced by technology-specific policies, an issue that is discussed in the next section.

8 For further information please see the factsheet on Linking and Australian liable entities which may be accessed at: http://www.cleanenergyfuture.gov.au/wp-content/uploads/2012/08/CEF-FS43-Linking-liable-entities.pdf.

Box 3 • Proposal for a United States Clean Energy Standard Act

Following the failure in 2010 to pass a comprehensive cap and trade bill to reduce carbon, the Obama Administration proposed a Clean Energy Standard. Under this approach, electricity generators would be required to meet a rising fraction of their generation using zero carbon sources or sources with lower carbon intensity (RFF, 2012).

"A Clean Energy Standard is a policy that requires covered electricity retailers to supply a specified share of their electricity sales from qualifying energy resources. The impact of a CES can vary substantially based on the specifications of policy details. The specifications of the bill, Clean Energy Standard Act of 2012 are the following (EIA, 2012):

- *All generation from existing and new wind, geothermal, biomass, municipal solid waste, and landfill gas plants earns full credits; Hydroelectric and nuclear generation from capacity and uprates placed in service after 1991 earn full credits;*
- *Generation from nuclear and hydroelectric capacity placed in service prior to 1992 does not receive any credit, but the total generation from these two sources is deducted from the overall requirement for credits and deducted from the sales baseline of those owning them and purchasing power; and*
- *Partial credits are earned for generation using specific technologies fueled by natural gas or coal based on a calculated crediting factor that reflects the carbon intensity of each technology. (…)*

The Bill Clean Energy Standard Act of 2012 target for the share of retail electricity sales from clean energy sources starts at 24% in 2015 and ultimately reached 84% in 2035. (…) It is assumed that the target remains constant after 2035 and that the policy does not expire."

Source: EIA (2012).

Policies to supplement a carbon price are technology specific

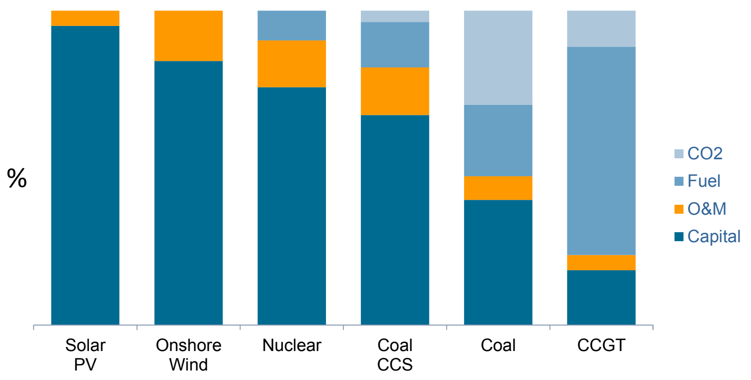
In parallel with climate policies such as carbon prices, policy makers introduced low-carbon generation support measures, combining efforts in research, development and demonstration, as well as technology learning resulting from marketplace deployment. Some low-carbon energy technologies are already competitive or close to becoming commercial and should be the first to be deployed on a massive scale. This is the case of nuclear energy, on shore wind and solar PV in certain regions. Many off-shore wind farms have already been built and some governments are actively pursuing the large-scale deployment of this technology. Other low-carbon technologies such as CCS, which has a huge potential, are less mature and require a longer-term vision.

The initial argument for adopting marketplace deployment measures is that low-carbon technologies will be needed to deliver timely CO_2 emissions cuts. Even where carbon pricing has been introduced, these technology policies have been kept or even accelerated. Indeed, in addition to their environmental benefits, deployment policies may be justified to reduce dependence on imported fuels, create local "green jobs" to stimulate economic growth and pursue industrial policy objectives to favour the emergence of global industrial leaders able to export the technology and create competitive jobs in the long run.

Many low-carbon generation technologies are generally not yet cost-competitive with gas and coal power plants, given the current level of fossil fuel and emissions prices. Furthermore, there is a wide range of costs of different technologies, so policies to create a level playing field between all low-carbon technologies would lead to investments in the least costly ones, depending on resources, probably large hydro, onshore wind and nuclear. With the goal of advancing a range of technologies, governments have therefore introduced technology specific measures to deliver investments in a portfolio of technologies and not only the most mature technologies at a given point in time.

The design of specific instruments to support these technologies must tackle the fact that the initial upfront investment cost typically represents 80% or more of the cost of production. This implies that the main question for policy makers is to provide appropriate risk/returns to investors.

Figure 7 • Breakdown of levelised cost of electricity of power generation technologies (%)

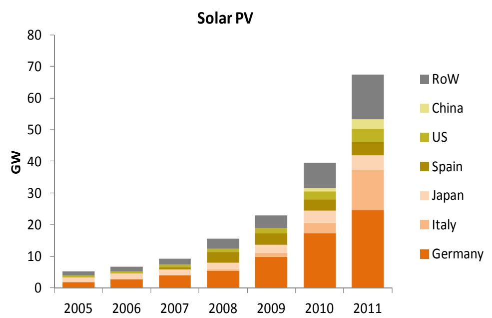


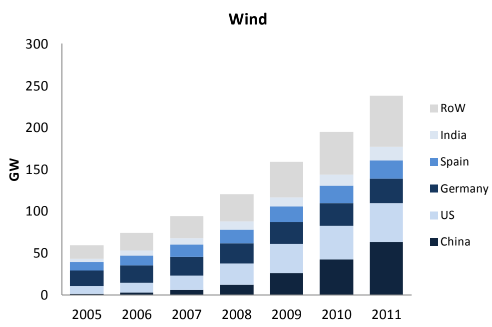
Source: IEA, NEA (2010).

Renewable support policies have been effective

Over the last five years, the installed capacity of wind and solar PV increased dramatically, by more than 10% for solar PV and by more than 20% per annum for on-shore wind. In Europe, these developments have been driven by the 2020 renewable targets. In the United States, tax incentives and renewable portfolio standards played a role.

Figure 8 • Installed capacity of solar PV and onshore wind worldwide, GW (1992-2020)





Renewable energy deployment has been extensively analysed (IEA, 2011a and 2012b), including the renewable support mechanisms best suited to attract the capital needed to finance renewables. With regard to the comparison of different support mechanisms, it appears that feed-in tariffs, where governments pay a guaranteed price and renewables benefit from priority dispatch, have been the most effective tool (IEA, 2011a). In some cases, a tendering process can be used to define feed-in tariffs for specific projects. While remaining higher than on-shore wind and conventional power generation technologies, solar PV costs have decreased dramatically in the last few years. In combination with effective renewable support policies, this has recently bolstered renewables in a way that had not been anticipated. However, for a number of reasons, including the financing of renewable support policies, RE deployment shows signs of slowing down, in particular in countries facing hard economic times. This might increase both the uncertainty concerning the deployment in the long run and the risk of forecast errors in residual demand addressed to conventional generation.

The experience in many countries like Spain, Germany and Italy makes it fairly clear that successful deployment of renewable energy have come with a cost. For instance, in Germany, the renewable support costs already reach 3.5 cents EUR/kWh compared to a wholesale market price of c. 5 cents EUR/kWh and a retail price of c. 24 cents EUR/kWh for domestic consumers. In Spain the renewable support costs amount to EUR 7 billion per year above the market price, c. 0.7% of the gross domestic product, while the country is struggling to reduce its budget deficit.

In some OECD countries, deployment of renewables now shows signs of slowing down. In certain countries, in 2009-2011, some governments failed to adjust feed-in tariffs according to cost decreases, which triggered rapid and very high solar PV installation. This solar bubble has been very profitable for project developers but very costly for electricity consumers. Adjustments had to be made and governments cut too generous feed-in tariffs for solar PV. These adjustments also reflect that renewables targets in percentage of generation will be more easily achieved as demand stalls, due to the economic crisis in certain countries.

Another reason explaining a growing uncertainty over renewable deployment is that solar equipment manufacturers have experienced significant competition from emerging countries, most notably China. The solar industry in Europe and the United States was severely hit in 2010 and 2011 by China's leading position on the solar PV industry, somewhat weakening the economic case for expensive feed-in tariffs in OECD countries.

This is very important for the deployment of renewables until 2020, as they will, in general, continue to be subsidized or mandated. Hopefully, some renewable technologies might reach competitiveness with conventional technologies soon, which will allow them to escape from the threat of political backlash. This future of renewables may now dramatically depend on the capacity of technologies to deliver the promised learning rates.

Nuclear

Nuclear power produces bulk low-carbon electricity, and unlike most of renewable energy technologies, it is dispatchable and it is already competitive, provided that the cost of capital used to finance the technology is not too high. However, nuclear energy experienced significant cost overruns and delays in IEA countries, and the capacity of the nuclear industry to build on time and on cost is a key element to keeping the cost of financing low and ensuring competitiveness. Besides costs, nuclear energy is also exposed to market price risks under the current liberalised market arrangement where electricity prices are set according to gas or coal prices. Based upon the experience in recent nuclear project developments, it is possible to say that no new merchant nuclear plants have been decided in liberalised markets recently. Nuclear power plants currently under construction do not face long-run market price risks and benefit either from long-term power purchase agreements or their inclusion in the regulatory asset base.

The accident of Fukushima did not obliterate the nuclear industry, although some countries decided to phase out nuclear power, most notably Germany and Switzerland. Japan will also have to decide of the role of nuclear energy in the coming years, given that the seismic/tsunami risk faced by the archipelago had not been sufficiently addressed at Fukushima. On the contrary, other large nuclear countries (China, Russia, Korea, the United States and the United Kingdom) have reaffirmed their support to nuclear energy and are actively continuing to create the proper regulatory frameworks to build new nuclear plants. With regard to nuclear waste, several OECD countries still need to find long-term storage solutions, and this legacy will continue to require much effort in the coming years, whether nuclear countries build new reactors or not.

From the perspective of security of supply, nuclear contributes to diversifying the electricity generation mix, and while uranium is generally imported, the production is widely distributed around the world and notably in OECD countries (Australia and Canada). In addition, large quantities of uranium can be easily stored and the stockpiles accumulated for military purposes represent several years of consumption, *de facto* eliminating any risk of fuel supply disruption. The main risks for security of supply could be a backlash from the population or a political risk of forced closure, which could lead to shutting down reactors rapidly. Another risk might come from finding of some type of fault on a series of reactors such as the cracks on reactor pressure vessels recently found in Belgium.

For countries where new nuclear capacity will be high, it may also be necessary to define strategies to mitigate the risk that delays of nuclear could cause for generation adequacy. In practice, this would require maintaining mothballed power plants or delaying the retirement of older units.

Table 3 • Status of nuclear projects in OECD countries and type of regulatory intervention

Country	Nuclear projects in OECD countries (as of 2012)	Regulatory intervention
United States	Continued support to nuclear Two reactors under construction at the Vogtle plant	Regulatory approval of investments Federal loan guarantee (Energy Policy Act of 2005)
United Kingdom	Active plan to build 4 to 8 GW of new nuclear	Long-term contracts with a contract for difference, with a counterparty backed by government
Finland	One reactor under construction and two in project	Long-term contracts with industry and electricity suppliers
France	One reactor under construction	Reactor financed by EDF on its balance sheet as part of its long-term nuclear strategy
Eastern Europe	Several projects under consideration	No regulatory intervention but financing issues tend to delay progress of these projects

Energy efficiency policies

Energy efficiency is one of the pillars of climate policies. According to the 2011 *World Energy Outlook*, reducing electricity end-use demand alone accounts for one-third of reduced greenhouse gas emissions over the next 10 to 15 years in the 450 ppm scenario. The potential for end-use efficiency improvements is enormous. National studies of economic energy efficiency improvements routinely estimate an economic energy savings potential of 20 to 25 percent over the next decade (McKinsey, 2009). Based on such projections, some governments have set ambitious targets of 10 to 15 percent for networked energy sales (gas and electricity) over the next decade (The State and Local Energy Efficiency Action Network, 2011).

Seen from an electricity security viewpoint, such projections beg the question of whether networked energy providers should plan based on historical demand growth trends or demand reductions to be achieved in response to energy savings targets. The answer is mixed. In the EU, progress towards the 20/20 energy savings target set in 2006 has fallen well short through 2012. Recognizing this, the European Parliament and Council of Ministers recently enacted a new Energy Efficiency Directive containing binding measures, not least of which are annual energy savings targets for energy providers.[9] If EU Member States enact these targets and energy providers meet them, the result would be a 9% reduction on final energy sales over the period 2014 to 2020. In other jurisdictions with extensive energy efficiency programmes – Australia, the Pacific Northwest and New England – electricity sales are on a downward trend. In Australia, according to the AEMO's 2012 Electricity Statement of Opportunities,[10]

> "the reduction in growth in electricity demand in Australia may be attributable to changes in the economic outlook, including a short-term moderation in gross domestic surplus (GDP), reduced manufacturing consumption and consumer response to rising electricity prices and energy efficiency measures".

Uncertainty in demand forecasts, however, is nothing new. Power planners, load forecasters and regulators have long experience in techniques to hedge for uncertainty and maintain electricity security.

Carbon capture and storage progress

Carbon capture and storage (CCS) is a promising technology to reduce carbon dioxide (CO_2) emissions from electricity generation. In the IEA publication *Energy Technology Perspectives 2012* (*IEA, 2012a*), CCS contributes slightly more than one-fifth of energy-related emissions reductions between 2015 and 2050 in the 2°C Scenario (2DS). Approximately half of emissions reductions resulting from the application of CCS under the 2DS are from power generation, with 63% of coal-fired generation, 18% of gas and 9% of biomass generation equipped with CCS by 2050.[11]

Despite the majority of support for CCS demonstration being focused on power generation applications (Global Carbon Capture and Storage Institute, 2011), none of the four currently-operating large-scale integrated projects (LSIPs) that carry out sufficient monitoring to demonstrate permanent storage of CCS are related to power generation. Of the seven LSIPs under construction, only two involve capture of CO_2 from power generation.[12]

All of necessary technologies exist today for CCS to be applied to power generation, but require demonstration at large scale before they can be considered commercially viable. Capture technologies for power generation (*i.e.* pre-combustion, post-combustion and oxy-combustion) are at different stages of readiness, but are generally in pilot-testing stages for coal and gas-fired generation (IEA, 2012a, p. 339). However, CCS deployment rates are currently woefully off pace to reach the approximately 16 GW of CCS equipped power generation in 2020 in the 2DS, and both government and industry need to redouble efforts to demonstrate CCS at commercial scale (*i.e.* hundreds of megawatts and up) for CCS to get back on track to meeting its emissions reduction potential.

The cost of electricity from power plants fitted with CCS is expected to become generally competitive with that of other low-carbon technologies such as wind or solar power. However, widespread CCS deployment will not occur without strong and credible emissions reduction policies from governments, additional funding for CCS demonstration and deployment, and clear deployment strategies and policies for CCS technologies. Significant work remains to be done across these areas.

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[9] Article 6 requires EU Member States to oblige energy providers to achieve cumulative end-use energy savings by 2020 equivalent to 1.5% of annual energy sales over the period 2014 to 2020. Member States can pursue alternative ways to achieve equivalent energy savings.

[10] See http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities.

[11] The remaining reductions result from industrial applications of CCS.

[12] See www.globalccsinstitute.com/projects.

How does the transition affect security of electricity supply?

Thanks to recent renewable policies, compounded with declining costs of wind on shore and solar PV, renewables represented about half of the capacity installed in the United States and the European Union in 2011 (Figures 9 and 10). IEA 450 ppm scenario indicates that further decarbonisation of the power sector is necessary to achieve the global goal of stabilising temperature to 2 degrees Celsius. In this scenario, investment in low-carbon generating capacity comprises 55% of total new capacity from now until 2020, and 91% from 2020 to 2035. Recent EU 2050 scenarios indicate similar trends, place great emphasis on the role of renewables, with scenarios with very high shares of renewables.

Figure 9 • Investment in the United States by technology group, 2002-2009

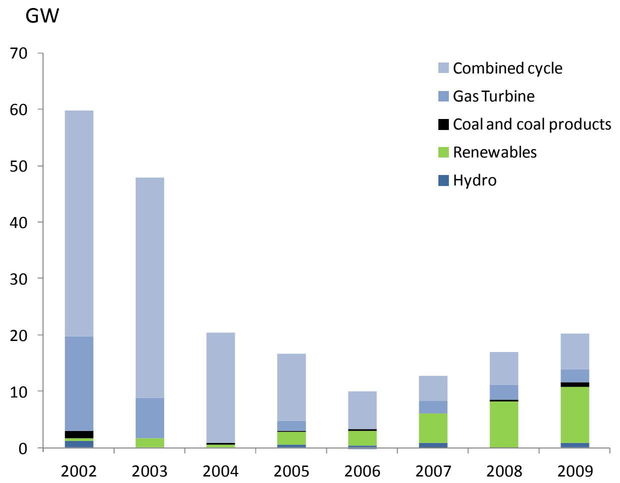
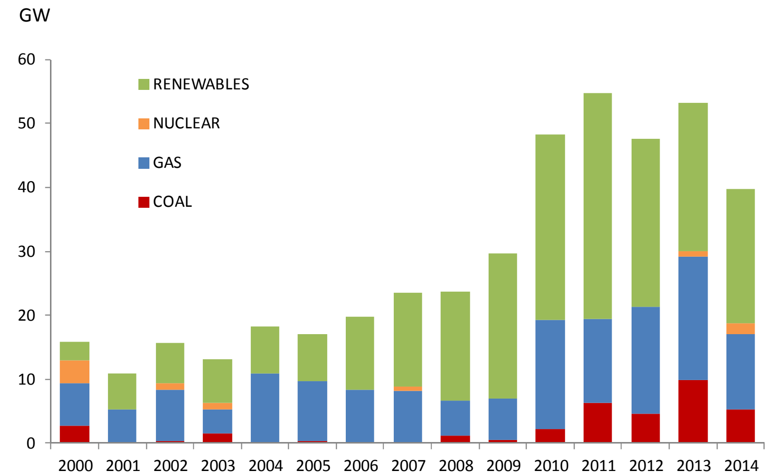


Figure 10 • Investment in Europe by technology group, 2000-2011 Europe



These developments take place in a context in which electricity demand is sluggish in most OECD countries, mainly due to the economic crisis following a period to high growth. The bad news is that most of the countries have excess capacity and therefore market prices are relatively low which leads to a low profitability of existing assets. The good news is that these countries do not face serious security of supply issues before at least the end of the decade. As a result, most governments and policy makers are not very concerned with electricity security of supply, except in a few countries. They have time in front of them to prepare well in advance possible evolutions of market arrangements, if and where needed.

Conventional power plants will also be needed to make up for variations in renewable generation and ensure electricity security of supply, which is the key issue addressed in this paper. This raises another related set of questions: are the current market arrangements capable to deliver enough capacity during peak periods in order to ensure generation adequacy? Does this change the capability of the market arrangements to deliver the investments needed? How the market arrangements should be changed in order to ensure market based investments in capacity necessary to maintain electricity security of supply?

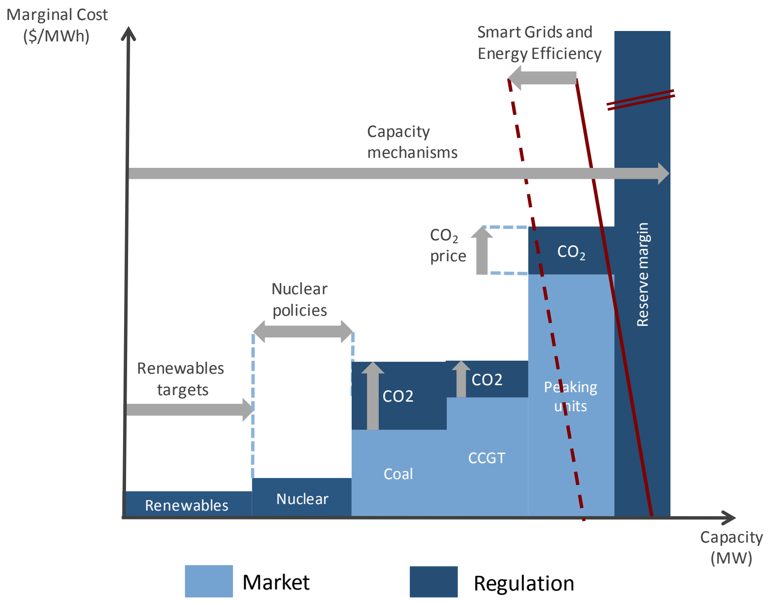
Figure 11 summarizes the impact of the different energy policies on the functioning of the price setting mechanism on electricity markets:

1. The carbon price increases the marginal cost of fossil fuel-fired power plants, pushing the electricity price-up.
2. Most renewable capacity has a null marginal cost and policy-induced investments displace the merit order to the right hand side, reducing prices as well as the load factor of existing dispatchable plants.
3. Nuclear capacity remains a matter of public policy. Germany nuclear phase-out (or conversely, UK nuclear policy) will displace the merit order, and tend to increase (resp. decrease) market prices.
4. Energy efficiency policies aim at decreasing demand, which would have the effect to lower electricity prices.
5. Capacity mechanisms, where they exist, aim at ensuring adequate capacity to meet peak demand, thereby avoiding hours of scarcity and the associated high prices.

Overall, the combined effects of these policies will depend on the installed capacity and the age of power plants. For instance, countries like the United Kingdom, where a large fraction of the generation capacity will be shut down in the coming years, may face more urgent problems.

Policy makers are now quartered between the urgency to accelerate climate action imperative and its potential costs for the economy in the coming years, in a context of slow international climate negotiations and economic crisis. Uncertain climate policies will magnify the challenges faced by the power industry to deliver reliable and secure market-based investments.

Figure 11 • The impact of energy policies on the functioning of electricity markets



3. Operating challenges

At significant penetration levels, generation using variable renewable energy presents challenges to system operations on account of the uncertain and variable output of renewable sources. These challenges are emerging in several leading countries and have been analysed in several recent publications, including Smith *et al* (2010), DENA (2010), Neuhoff, K *et al.* (2011) and the IEA (2006 and 2011), Eirgrid and Soni (2011) and NREL (2011).

This section examines the challenges associated with the integration of increasing shares of variable renewable energy (VRE) for system operations. These challenges are not new, since it has always been necessary to handle variable demand and uncertainty regarding possible contingencies. However, at high penetration levels of variable renewables, *i.e.* above 20% of annual generation, the increase of variability and uncertainty leads to new challenges. The four challenges are summarized in the following table.

Table 4 • Overview of operating challenges of renewable integration

Peak load adequacy	Minimum Load balancing	Ramp rates of residual demand	Predictability of renewables
▪ During hours with high demand and low renewable input ▪ Contribution of variable renewables to peak demand can be low ▪ Enough dispatchable capacity is needed to meet peak demand, including generation capacity, storage and demand response	▪ During hours with low demand and high renewable input ▪ Some power plants have to be operated for security reasons (providing ancillary services) ▪ Renewable resources may have to be curtailled to balance generation and load	▪ When renewable output decreases and demand increases simultanously ▪ Ramps can be steeper and longer or their direction change rapidely ▪ Capacity must be available to meet ramping requirements, including fossil capacity, nuclear, storage, demand response and renewable	▪ Uncertainty in forecasts of VRE output ▪ Supply/demand must be balanced closer to real time ▪ Capacity must be available to compensate forecast errors

Peak load generation adequacy

Generation adequacy is the ability of the electricity system to meet electricity demand with a reasonably high probability during periods of high load. The system operator needs to have enough capacity available during the hours where electricity demand is the highest, plus a reserve margin to cope with contingencies. Adequacy is generally assessed using indicators such as the probability of lost load or the expected duration of load curtailment.

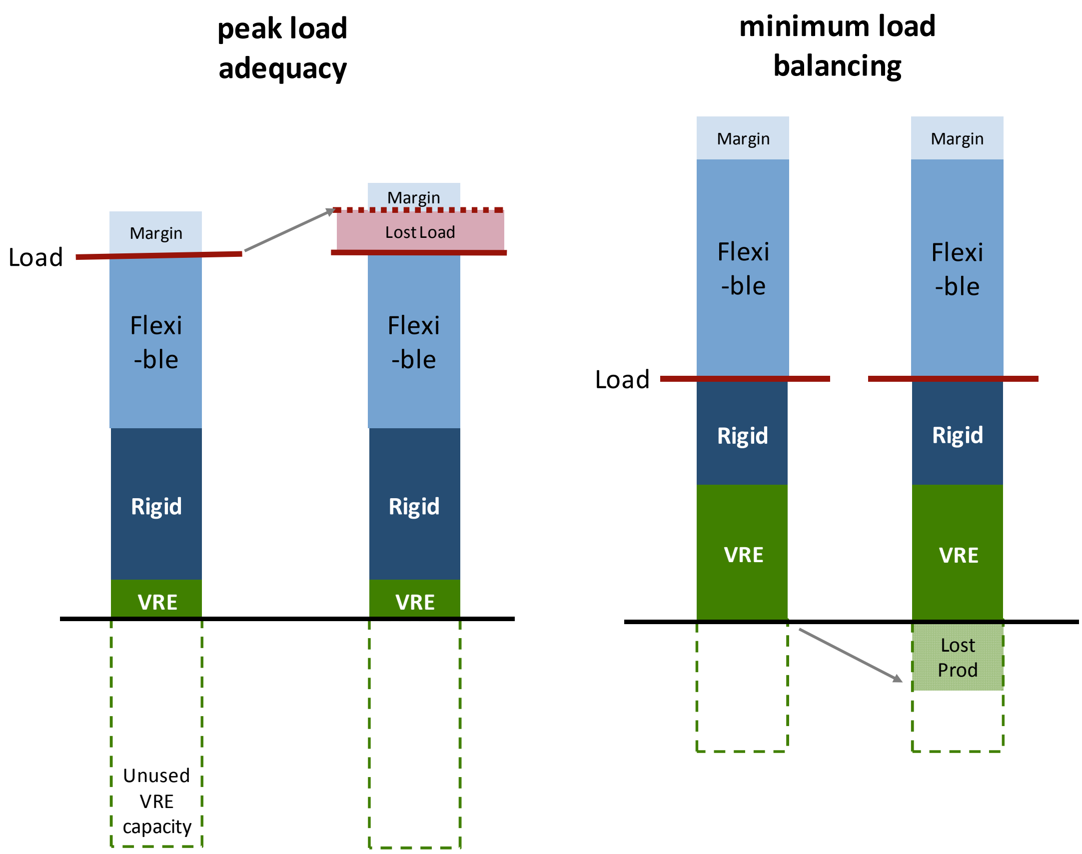
The maximum output of wind and solar generation vary according to weather conditions and time of day. Consequently, assessing the amount of power they can be expected to produce with a reasonable degree of confidence when demand is the highest is challenging. This “capacity credit” of renewables depends on the correlation between wind, sun and demand. (If solar generation correlates with peak demand due to air conditioning, as is the case in California, then the capacity credit may be high.) According to recent IEA estimates, capacity credits of solar and wind range from 0% to 20% of their installed nominal capacity in different regions (IEA, 2011a and IEA, 2011c). Other studies indicate higher capacity credit of 38% for solar (PJM, 2010). However, we are still in the early stage of development of variable renewables and the contribution of variable renewable capacity to meet peak demand decreases with increasing penetration.

Low capacity credits imply that dispatchable capacity must still be available to balance variability of some renewables and ensure adequacy. Despite investments in variable renewable generation capacity, other resources such as the conventional plants, demand response and storage will be needed to ensure adequacy. In the medium term, conventional generation is bound to take the bulk of this function. These conventional plants run less frequently and produce less energy, which changes their economics and therefore tend to favour less capital-intensive technologies, such as open-cycle gas turbines, instead of combined-cycle gas turbines.

Minimum load balancing

The opposite of peak load, minimum load balancing refers to the need to maintain generation equal to the load during periods of low consumption, generally on Sundays or during the summer period of cold climate countries. These situations of minimum residual load do not necessarily occur during periods of low demand and they have implications for all markets, including the day-ahead market, intra-day or balancing and ancillary services markets. Little consideration has been given to these situations of low load, as it is usually sufficient to shut down plants during a few days or at night time when they are not needed.

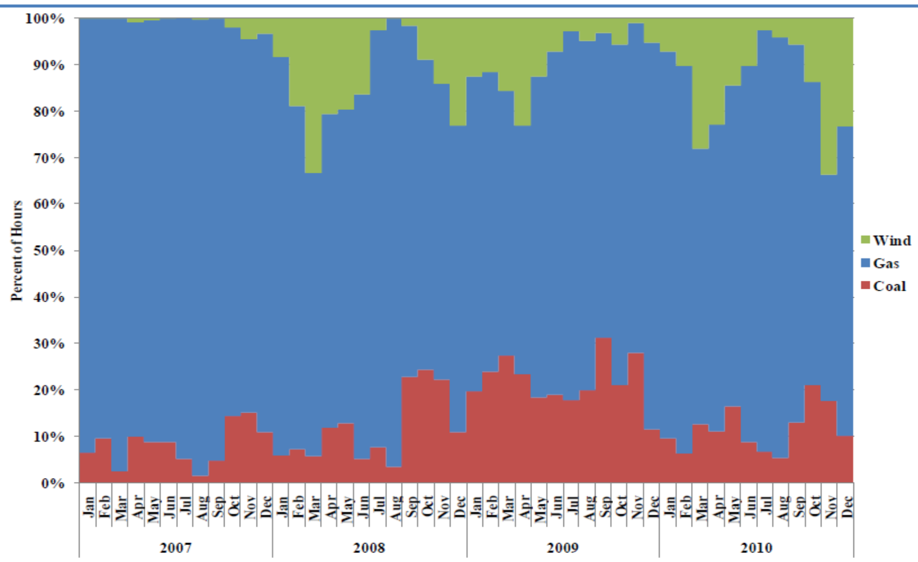
Figure 12 • Peak load adequacy and minimum load balancing



To date, while wind and solar do not exceed 20% in Germany Ireland and Texas, there is already enough to see the first signs of operating tensions during low load hours:

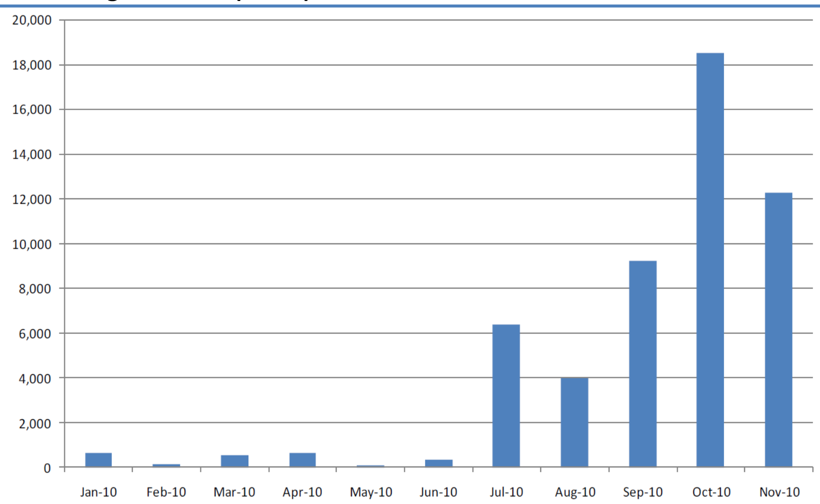
1. Wind can be the marginal fuel when wind generation exceeds load, as it is the case in the West Zone of Texas (Figure 13);
2. Wind generation has to be curtailed in Ireland by about 1% of total wind output and up to 7.5% of wind output for certain wind farms (Eirgrid and Soni, 2011), in order to maintain electricity security given current operation practices;[13]
3. Negative prices can occur if wind has to be dispatched and conventional load are running at their minimal technical level and want to avoid shut down for economic reasons or must be kept online for system security reason (Figure 15).

Figure 13 • Marginal fuel frequency, ERCOT, West Zone



Source: Potomac Economics, 2010 State of the Market Report for ERCOT.

Figure 14 • Unused wind generation (MWh) Jan-Nov 2010

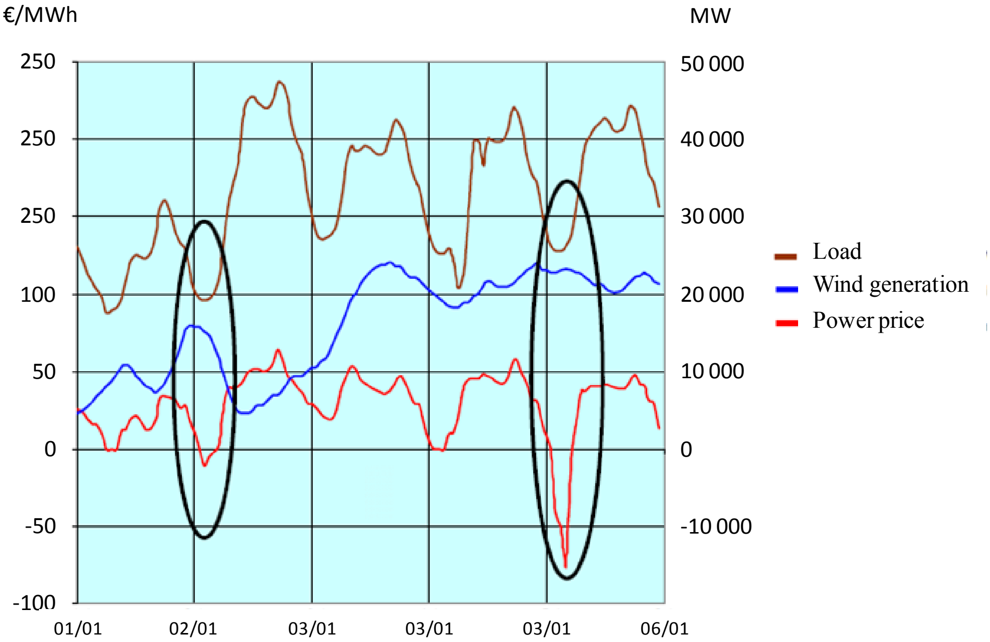


Source: Eirgrid and Soni (2011).

[13] Curtailment of wind generation on the high voltage level occurs mainly during line maintenance, according to the Spanish TSO Red Eléctrica d'Espana.

Negative prices can result when there are high levels of renewable energy, because the primary energy source of fuel is costless and renewable energy is frequently subsidised through feed-in tariffs paid if electricity is generated. Frequent and sustained negative prices will lead to depressed revenues for units at the margin and this is likely to have an impact on the viability of existing conventional generation. As variable renewable generation becomes a significant source of energy across many IEA member countries there are arguments that the policies designed to favour renewable energy may need to adapt so that there is more coherence across fuels.

Figure 15 • Negative prices in Germany (2012)



Source: RWE Innogy.

Spain has successfully adapted its electricity system to accommodate a very significant share of variable renewable energy (in 2011, wind and solar generated 18.3% of energy), a paucity of interconnections of the Spanish peninsular system. New legislation (Royal Decree 1565/2010) entered into force and the system operator Red Eléctrica de España (REE) has taken several actions, notably developing the first national Control Centre for Renewable Energies (CECRE), the introduction of a new grid code, the increased participation of wind generation to voltage control, and the increase of demand-side management (REE, 2012). Looking forward, the development of storage technologies and the development of international interconnections are foreseen to further facilitate the integration of wind and solar power.

As variable renewables reach 20% to 30% of electricity generated, there will be a multiplication of situations of "excess" renewable generation, which indicates that balancing areas have become saturated. In these situations, balancing the power system during periods of low load will necessitate further adaptations to maintain the physical parameters of the network. An ongoing IEA work within the Grid Integration of Variable Renewables project (GIVAR) analyses these options in more detail. This includes the following:

- Consuming more power during periods of low load, either by final consumers or by electricity storage facilities such as pumped-hydro;
- Exporting more through interconnection capacity. However, if neighbouring systems have also reached high penetration levels, this interconnection is only a viable option to the extent

that high output periods or peak demand do not typically coincide between regions; and

- Reducing the minimum output required from conventional generation plants to maintain network stability.

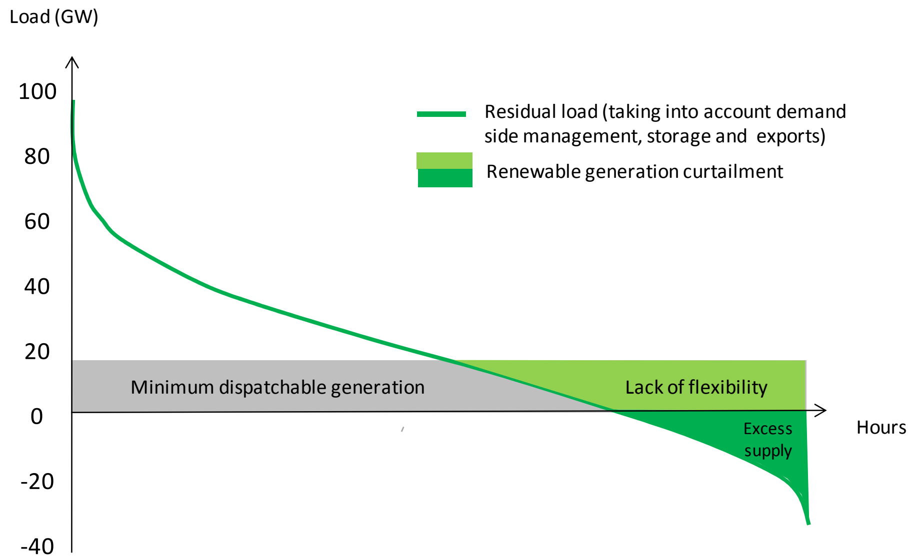
The technical and economic potential to increase demand may be limited, interconnections are slow to develop and provide only a partial solution. Hence, it will be necessary in the next 20 years to keep some conventional power plants online to provide ancillary services and ramp-up capabilities. Consequently, renewables also will have to play an increasing role to balance the network during low load situations. Figure 16 shows this issue with a modelled load duration curve corresponding to 80% of renewables in an isolated balancing area. During periods with low load or excess generation, wind and solar will probably have to reduce their output to maintain network security.

Minimum load balancing constraints have important implications for the design of both renewable support mechanisms and the design of electricity markets. As more wind and more solar power plants are coming on line, granting them priority dispatch only constrained by security of supply reasons may become highly uneconomical. Instead, renewable plants could participate in the market by providing a dollar per MWh bid below which they are no longer willing to generate. These bids should reflect the marginal cost of production of the plants (which is close to zero).

Renewable curtailment on economic grounds immediately yields another question: which renewable plants should be dispatched? To that end, a locational marginal pricing framework would be helpful to attain the least cost dispatch and curtailment decisions should reflect the impact of different renewable generators on losses and congestions on the network.

From a technical standpoint, steps are also being taken by wind plant designers to enable greater flexibility in operation of the plant themselves (Smith *et al*, 2010). Active power control algorithms can limit wind plant output during curtailment events. Reactive power control is also available to enable voltage control of the plant output, even at no load in some cases.

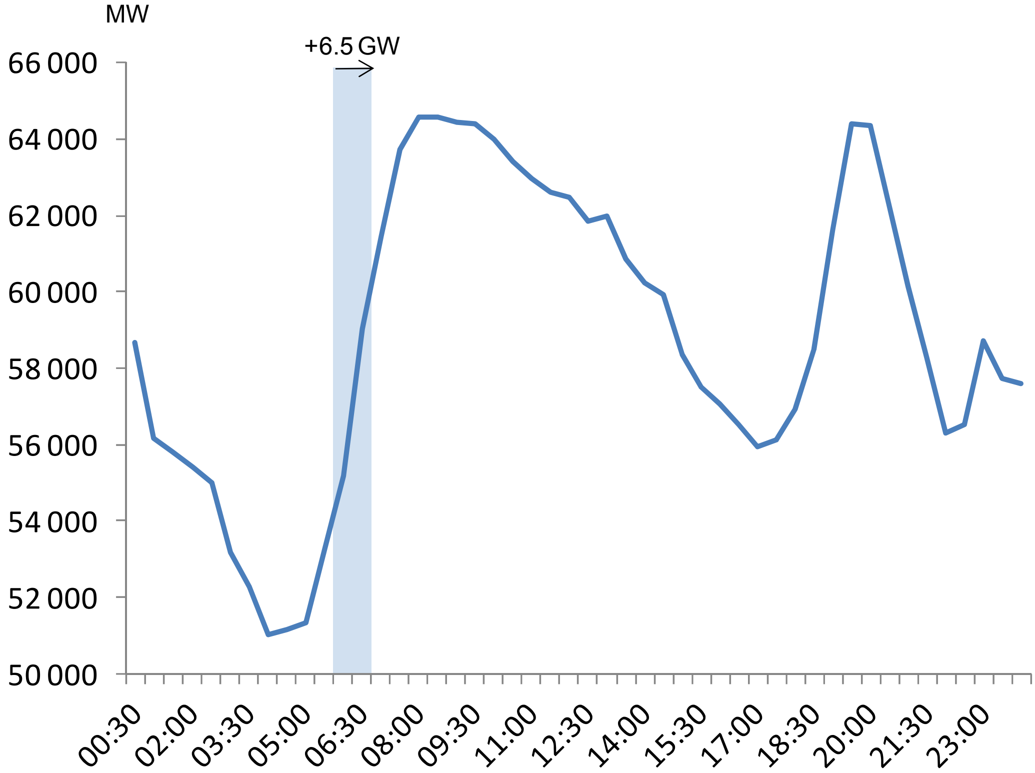
Figure 16 • Illustrative residual load duration curve and renewable curtailments



Ramps and start-ups

Reliable operation of the power system requires real time matching of supply and demand, which implies ramping the aggregated output up and down. The graph below shows that traditional variability of consumption in France can typically increase by 6.5 to 7.5 GW in one hour between 6:00 and 7:00 for a typical winter day, during which generation has to be ramped up accordingly. Different generation technologies can contribute to meet ramp-up needs; nuclear reactors must be already operating in a part load mode, below their available output, so as to be able to ramp up during the morning hours. Other generation plants such as hydro and gas turbines can technically provide high ramp rates and can be made available to follow load.

Figure 17 • Electricity consumption in France on 22 March 2012



Increased penetration of wind and solar will change the shape of the residual demand curve that needs to be followed by conventional generation plants. Flexibility of conventional plants (ramp-up/down, startup/shutdown, reserve capabilities, etc.) might be more frequently and intensively called upon. Modelling results (Figure 18) for the United Kingdom with a very high share of renewables (80%) and a wind-heavy portfolio shows many hours of excess VRE output (negative residual load). The hourly variation in residual load could exceed 10 GW/hour and can reach 40 GW/hour during windy hours (about half of the system peak load), should wind benefit from priority dispatch run at available output.

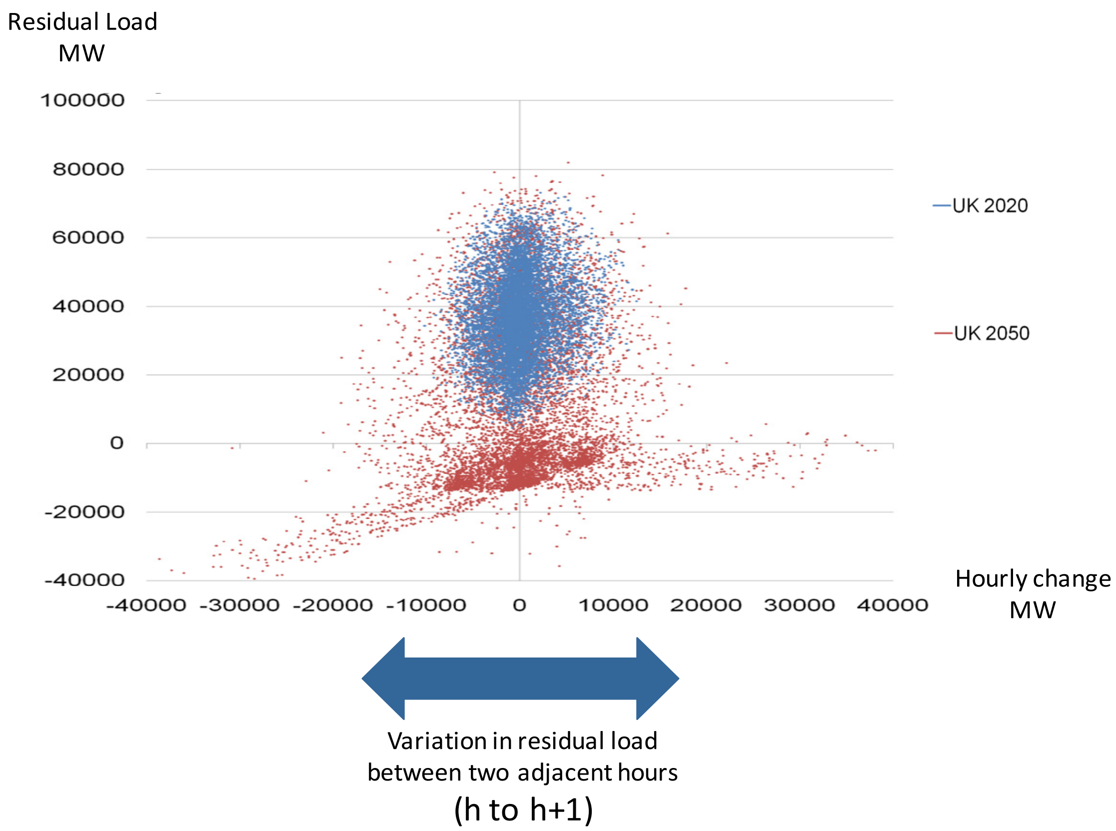
Ensuring network reliability under such conditions will require a series of actions, including relying on storage and demand response. Interconnections will be particularly valuable for the aggregation of loads in different countries and to smooth wind output variations when a weather front passes through wind plants distributed over hundred of kilometres.

However, the ramping capability is not generally perceived as a major barrier for the deployment of renewables in the foreseeable future for several reasons:

spinning reserve and "up ramp" service. The extent to which this will take place will depend on the relative economic merits compared to other options. Similarly, the ability to enable a limit in the "up" ramp of renewables can be technically possible during normal operations and has proven to be very helpful in maintaining reliable operations (Smith *et al.*, 2010). Conversely, when large "down" ramp of renewables are forecasted, renewable output may be reduced in advance so as to control the ramp rates, if this is the most economic choice for the system.

At present, in many electricity markets, wind and solar generally do not participate in the supply of ramping needs. Exposing variable renewables to the electricity and balancing markets risks can change this behaviour, as undistorted markets could provide for a level playing field of a sufficient quality and quantity of flexible reserves. Where organised markets are mandatory, it may be required to define new products, for instance standardized flexibility products that could reveal a price for flexibility. Renewables should also be able to participate in these markets.

Figure 18 • Hourly variability of residual load with high shares of renewables (United Kingdom with 80% of renewables)



The number of cycling and start-ups of power plants is also expected to increase with high shares of variable renewables. Typically, a gas power plant will need to operate during morning peak demand, then stops generating when the sun is shining during the day and then resumes operations for the evening peak, before stopping it at night when demand is lower. This will add start-up costs, and reducing the expected technical life time of some assets. While state-of-the-art CCGTs are capable of start and stop operations, most of the installed capacity has not been designed to be operated in such an intermittent mode. In addition, existing market design does not necessarily provide an adequate remuneration of these start-up and cycling costs.

Predictability

In addition to being variable, wind and solar generation are also uncertain. Whereas demand uncertainty on a day-ahead time-scale is typically in the range of 1-2% of load, the mean absolute error for wind is 15%, 24 hours before real time. Commercial providers of forecasting solutions claim that they can reach a forecast error to 5%, 24 hours before real time.[14] Centralisation of information concerning weather forecasts and improvements of forecasting models will reduce this uncertainty. On the other hand, higher penetration of wind and solar will add to the uncertainty of day-ahead scheduling, day-ahead transmission analysis and security-constrained, unit commitment program.

There is also a risk that large off-shore wind farms are set out during storms (storm protection shut-down typically happens at wind speeds above 25 metre/second). In that case, a high expected output from off-shore wind is not delivered.

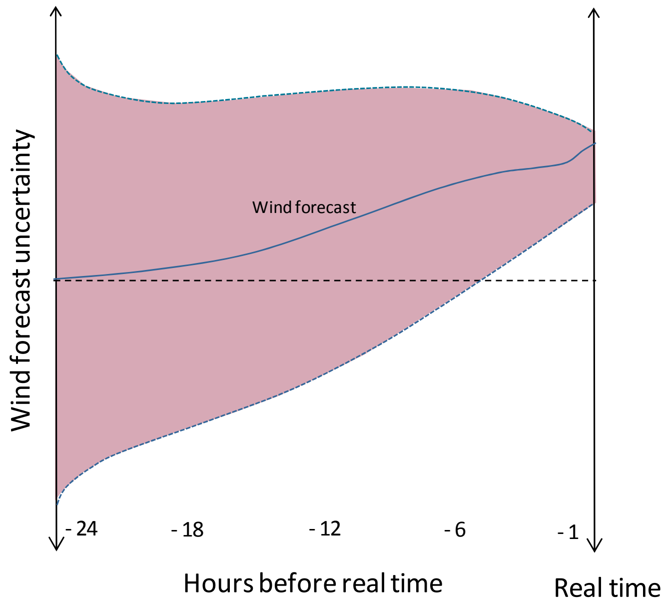
Uncertain wind and solar generation forecasts increase the need for flexibility closer to real time. As a result, wind uncertainty may yield a need to redefine the amount of reserves required to maintain the standard of power system security. In Spain, REE estimated that +0.5 GW of additional reserves are needed for 10 GW of wind. In Germany, DENA (2010) forecasts + 3 GW of additional reserves for 36 GW of VRE by 2015.

To provide this type of flexibility, demand response can be a competitive solution. Low-cost demand responses already exist in many markets, such as Denmark, where district heating providers have installed boilers. The existing potential of low-cost demand response for large users running capital intensive factories or industrial facilities must be assessed and the pace of development of smart grids remains uncertain.

Other strategies can be developed to control balancing costs. Large balancing areas and geographic diversity of wind resources can help to optimise the balancing costs. Improving the design of electricity markets is another important lever to control these costs. In several US markets and in Australia, sub-hourly energy markets are integrated and co-optimised with ancillary services markets. In Europe, where balancing services are traded on separate markets than energy, balancing prices are correlated to energy prices but tend to be more expensive. As a result, utilities prefer to reschedule their unit commitment program of their own portfolio of power plants rather than being exposed to the balancing market. In that case, allowing intra-day trade and rescheduling until one hour before real time could reduce the exposure to the balancing market risk and lower the balancing costs for market participants (IEA, 2011d).

[14] http://www.windprognose.de/english/Leistungen/prognose.php.

Figure 19 • The evolution of wind forecast uncertainty 24 hours before real time (illustrative)



Source: Adapted from Borggrefe and Neuhoff (2011).

4. Investment issues

> "The unprecedented combination of the global financial crisis, tough environmental targets, increasing gas import dependency and the closure of ageing power stations has combined to cast reasonable doubt over whether the current energy arrangements will deliver secure and sustainable energy supplies." Ofgem (2010).

As Joskow (2007) already pointed out,

> "These policy concerns have not disappeared. On the contrary, they are now exacerbated by the consequences of increasing shares of policy-driven variable renewables, which can further undermine the functioning of electricity markets and may distort incentives to invest."

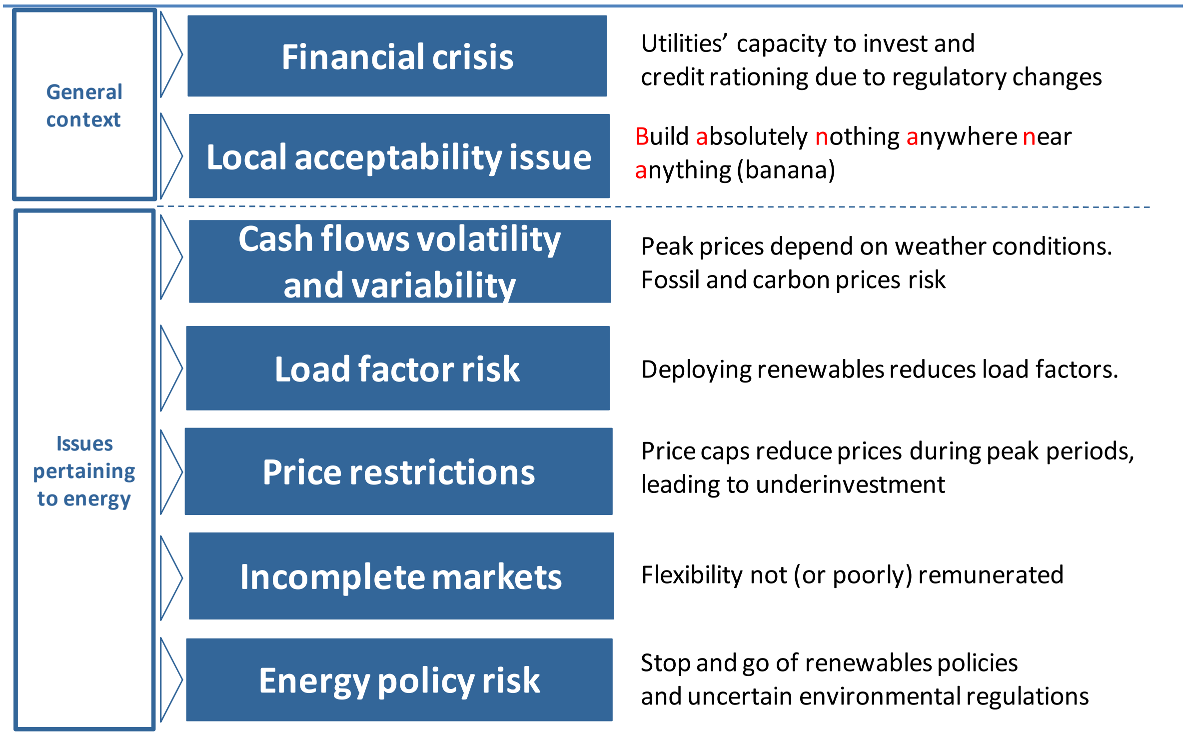
The market and regulatory frameworks are keys to electricity security of supply, also expressed in terms of reliability and generation adequacy. In most cases, these concerns have been raised because policy makers have observed a reduction of profitability of existing assets, with some generators planning to mothball power plants that may be necessary to meet system load at times of low variable RE generation. In some markets, most notably continental Europe, the absence of investments does not necessarily put generation adequacy at risk. On the contrary, in a situation of economic crisis, slow electricity demand growth and excess capacity, stopping investments is exactly what we expect from well-functioning electricity markets. Several countries, including Denmark, the Netherlands, Ireland, Greece and Spain enjoy comfortable reserve margins and enough flexible gas-fired capacity to accommodate high shares of variable renewables and do not need investments in the next ten years.

However, ageing and polluting power plants built in the 1970s will be retired in the coming years in many OECD countries. In some cases, policy makers forecast shrinking reserve margins but little evidence of adequate investments in new generating capacity. This is the case of Ercot in Texas, California and the United Kingdom. This new investment cycle will constitute a major test for competitive markets and one of the last opportunities to decarbonise the electricity mix by 2050.

Many economists, as well as the IEA (2007), recommend well-functioning electricity markets as the efficient solution, provided that prices can rise high enough during periods of scarcity, and that there is a stable regulatory framework. Yet a growing number of countries have recently adopted new rules mandating system operators to contract for generation capacity (New Zealand, Ontario, California, Norway and Sweden) or have introduced explicit margin or capacity targets (PJM, Italy, Australia's eastern states and Latin America). Many other countries are actively introducing new regulatory arrangements to ensure that enough capacity will be available in the future to ensure reliable system operations (the United Kingdom, France, Germany and Belgium).

In this section we find that, based on the analysis of the experience in several OECD countries, there are a number of imperfections in market design and uncertainties about energy policy that substantially increase the risk associated with new investments in generation capacity. These factors are tending to delay investment decisions. If this situation is allowed to persist, it will lead to underinvestment in generating capacity, and to higher prices or involuntary rolling blackouts. These problems are currently exacerbated by the ongoing economic and financial crisis in Europe, which reduces the appetite for high risk investment, and by issues with local acceptance that can increase the lead time of new projects.

Figure 20 • Overview of investment issues



Most of the issues associated with investment in new generating capacity pertain to the energy industry itself and reflect real or expected problems with the design of wholesale electricity markets and the impact that energy and climate policies have on electricity markets.

It is often argued that electricity markets do not provide sufficient certainty of revenues to attract investment, either for peaking units, mid-merit power plants or for low-carbon investments. In addition, high shares of variable renewables increase the price and load factor risks. In other words, expected prices may be quite high, but too unpredictable and too volatile to ensure a proper remuneration of the cost of capital (risk-adjusted) used by investors to evaluate investments in new generation capacity in liberalised markets. Even if prices can be very high during a few hours, these peak price episodes are too rare and provide irregular/intermittent revenues that may fail to attract enough investment in new generation to meet reliability criteria.

The argument is similar for low-carbon investments. According to this view, long-lived and high fixed cost, low-carbon investments are exposed to the electricity market price risk, which depend not only on volatile and uncertain fossil fuel prices like coal and gas; but also on carbon price risk. In addition, some low-carbon investments such as nuclear and CCS could be exposed to the load factor risk associated with high deployment of variable renewables. If market players are usually well-equipped to handle fossil fuel price risk, they are less well placed to tackle the carbon price risk and renewable policy risk, in particular, the risk of a low-carbon price. These arguments then lead to conclude that liberalised electricity sectors can provide neither the low-carbon investment needed, nor the investments in conventional generation to ensure security of supply at reasonable cost.

It is often also argued that, in addition to being volatile, wholesale electricity prices and ancillary services cannot provide sufficient revenues to attract adequate investments. One reason is that prices can not go high enough to cover both operating costs and capital investment costs required to trigger investment in new capacity. These peak pricing restrictions are known in the economics literature as the missing money problem. Problems can also arise if markets for specific products are missing or products are not well defined, as might be the case for flexibility services which are increasingly needed to handle growing shares of renewables. We will refer to this problem as the missing market problem.

Market participants often state that energy policy risk may make the electricity industry difficult to invest ("uninvestable"). Market rules change too frequently. Government or regulators have opportunities to "hold-up" incumbents by imposing new regulatory constraints in the future or deploying policies affecting negatively the profitability of previous investments. Energy policies may be too costly and exposed to backlash from taxpayers or ratepayers. This creates an unstable investment environment and the lack of credibility of some policies acts as a deterrent to new investments. Furthermore, the lack of commitment towards liberalization and unceasing discussions concerning further market reforms tend to delay investment decisions, in order to wait for announced evolutions of the regulatory framework, as real option theory would suggest. The perspective to have regulatory intervention in case of generation adequacy problem may create a self-fulfilling prophecy.

In this section, we provide a comprehensive overview of these generation investment issues, with a particular focus to the implications of energy policies undertaken by governments.

The impact of the financial and economic crisis

In the wake of the financial crisis which started in 2008, the situation in the banking industry made it virtually impossible to finance any kind of conventional power plant on a project-finance basis. Previously in the 2000s, several merchant gas power plants in the United States filed for bankruptcy. Given the current financial context, securing financing is increasingly difficult for project developers to achieve.

The banking industry argues that investment is therefore likely to come mainly from utilities at the moment, and financed on balance sheet. But even this will be limited owing to the fact that most utilities, even large ones, have to face low profitability of existing assets, and issues in terms of equity and credit rating. Indeed, they suffer from the consequences of the economic crisis which has created excess generating capacity and low electricity prices, reducing their EBITDA and constraining their ability to invest. This is particularly a concern when it comes to financing large projects such as nuclear power plants or large off-shore wind farms, owing to the fact that only one of those multibillion investment projects is enough to have an impact on the credit rating of even the largest utilities. These factors tend to increase the weighted average cost of capital (WACC) used by utilities to finance new projects.

In addition, the sovereign debt crisis in Europe, the recession in some countries, financial regulatory changes (most notably Basel 3 tighter capital adequacy requirement) and the restructuring of financial institutions, all these elements create one of the most challenging environment for banks to finance any investment in general, and the more risky ones in particular. Bank credit rationing can lead to situations where investment projects with a positive net present value, are not built because of lack of financing.

It is often argued that the electricity sector will need to rely on new categories of investors (pension funds or sovereign investors); in order to find the trillion dollars needed to finance the new investments in the coming decades to replace ageing capacity and decarbonise the electricity mix. However, attracting these investors is not free lunch and would call for serving them an appropriate risk-return proposition. Moreover, these pure financial players are less familiar with the specificities and subtle market design issues of electricity markets. As such, they are less able to find proper risk mitigation strategies and thus will either not invest or add a risk premium on their cost of capital, increasing their expected returns on investment in the power generation industry. Indeed, the most important issue for investors to tackle seems to be the revenue risk of new power plants, as investors engage in a "flight to quality" in the current uncertain macroeconomic times.

Interestingly, financing is not an issue for all generation investments. Renewable projects continue to attract proper financing, even in period of tight financing conditions. Unlike the case of market-based investments, they benefit from feed-in tariffs, priority dispatch or alternatively, power purchase agreements (PPA). This suggests that revenue risk is a key topic in the electricity sector.

More basically, investments in some markets, in particular in Europe, do not happen just because they are not needed. With the notable exception of the United Kingdom, most European countries enjoy comfortable reserve margins, excess capacity and generation adequacy is not a concern for the next 10 years (ENTSO-E, 2010).

Local acceptability issues

IEA member countries are increasingly confronted with local acceptability issues in their day-to day activities. This effect is often referred to as "**b**uild **a**bsolutely **n**othing **a**nywhere **n**ear **a**nyone" (BANANA). While this is mainly a concern for transmission network development, because a transmission line has a significant impact on landscapes, finding new sites in some densely populated IEA countries is becoming an issue.

Nuclear power, gas and coal-fired power plants have also to face anti-nuclear groups or local opposition and new projects tend to be located on existing nuclear or industrial sites. Overall, acceptability issues increase the public consultation duration and administrative burden and carry the risk of delay of the projects. While this concern is not specific to the energy industry, its consequences can be particularly important in the electricity sector if a country faces a shortage of suitable sites. Failure to build new capacity on time may lead to situations where electricity security cannot be ensured on a national basis. If this is the case, interconnections can contribute to ensure security of electricity supply.

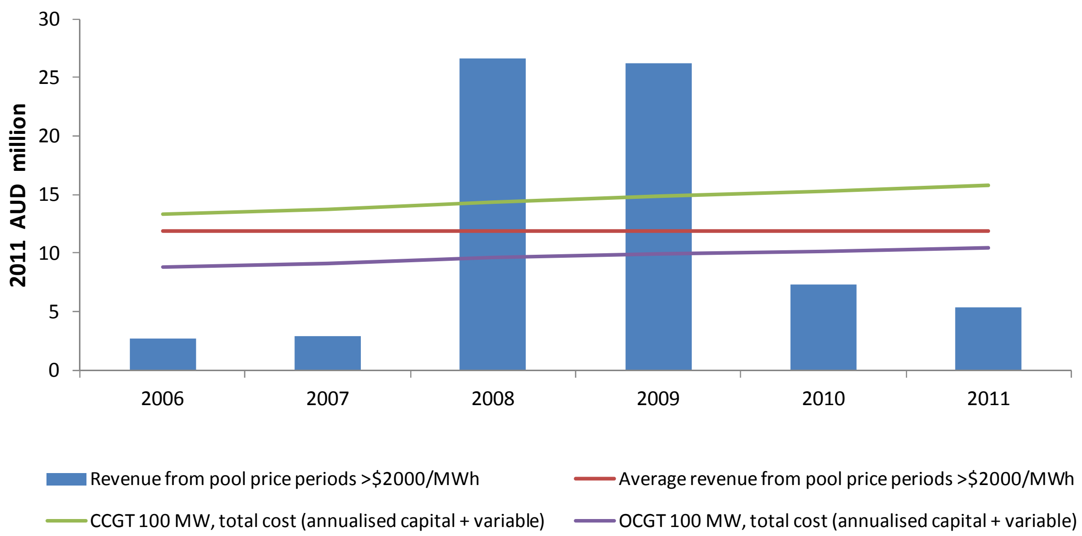
Cash flow volatility and variability

Uncertain revenues for peaking units

Electricity markets are characterized by high price volatility due to inelastic demand and volatile demand and supply. Potential investors in new generating capacity must expect to cover their variable operating and fuel costs, their operation and maintenance costs and their capital costs from sale of energy over the lifetime of the power plant. The profitability of generating units that are likely to operate only for a relatively small number of hours in each year (peaking capacity) is especially sensitive to the level of prices that are realized during the small number of high demand hours in which they provide energy or operating reserves.

Due to yearly variability on the demand and the supply side, these hours erratically fluctuate from year to year. Figure 21 shows the notional revenues calculated for a peak power plant in Australia. A gas fired power plant running only when prices are above 1000 AUS$/MWh would have earned revenues above annual costs only two years in the period 2006-2011, corresponding to two dry years. While average revenues are higher than the average annualized cost of OCGT, such a cash flow profile implies a long sequence of losses for investors.

Figure 21 • Cost and revenues of notional peaking gas-fired generators in the South Australian wholesale Market, 2006-2011



The price spikes due to scarcity events may be further magnified by other factors such as demand growth uncertainty, boom-bust investment cycles, market power, or regulatory or political interventions.

Policy-driven development of variable renewable generation can also increase variability on the supply side. The probability of having a heat wave or a cold spell is low. The probability that either will occur at the same time as a period of low wind and solar output is even lower, which could result in scarcity events becoming rarer.

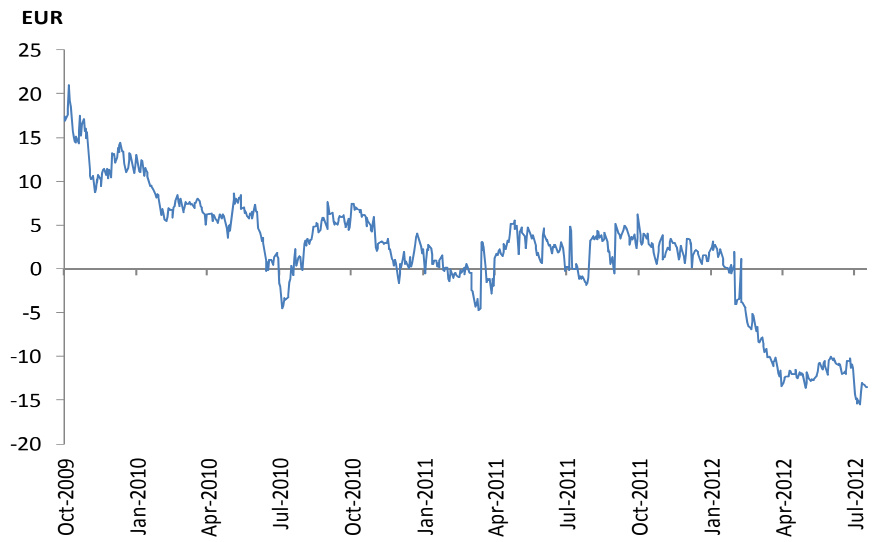
Do gas plants benefit from a natural hedge on electricity markets?

Under current market arrangements, wholesale electricity prices reflect the marginal cost of the marginal power plant and are thus driven primarily by fossil fuel prices (and where they exist, a carbon price). As a result, fossil generators thus benefit from a natural hedge: the difference between the electricity sales price and the cost of fuel (the spread) is reasonably stable. However, looking to it more carefully, coal and gas power plants have been competing with each other intensely, and as a result, one of them can get shifted off the marginal fuel. The key factors affecting their position on the merit order are relative coal and gas prices, carbon price and residual demand left for thermal generation after renewable plants are dispatched.

In Germany for example, high gas prices combined with a low-carbon price have led coal to become the dominant marginal fuel and set the clearing price. Gas plants are too expensive given the current price of gas. Similarly, in the Netherlands, reduction in coal prices in the last few years has resulted in much fewer run hours of even most efficient gas plants.

Looking forward, coal and gas prices are difficult to project. Assuming that the carbon price in Europe will rise significantly, this should give an advantage to gas-fired plants, let them set the marginal price and therefore become more “self-hedged”, as they used to be perceived until a few years ago. Although, the degree of the advantage the higher carbon price can give to gas generation will depend on the relativity of coal and gas prices.

Figure 22 • Clean spark spread, base-load month ahead, Germany (EUR/MWh)



Impact of VRE on revenues of mid-merit plants

High shares of wind and solar also increase the daily volatility as well as the quarterly and yearly variability of revenues for mid-merit plants such as CCGTs. These plants are running less hours and they have to recoup fixed costs during a reduced number of hours which vary from one year to the other, depending in particular on weather conditions.

While this was an issue mainly for peaking units, the deployment of variable renewable increases the variability of revenues for mid merit power plants. Having less predictable and more volatile cash flows, mid-merit power plants are more difficult to finance and this could ultimately lead to underinvestment if the proper incentives are not restored.

Long-term contracts and vertical integration

It is often proposed that long-term contracts reflect average spot market prices and could partly smooth revenues over time. However, these cash flows are very volatile and it may not be possible to find counterparties willing to enter into forward contracts of ten or more years' duration to allow investors to hedge such market risks. Furthermore, even if there are no price restrictions, price uncertainty will affect the cost of capital used by investors to evaluate projects. As Joskow (2007) pointed out, the example of other industries shows that investors finance oil refineries, cruise chips and other costly capital projects where there is considerable price uncertainty without the security of long term contracts.

In the electricity sector, retail suppliers of electricity are exposed to wholesale price risk. Partial vertical integration between retail supply and generation ownership is emerging in Europe and in the US. This can be analysed as an industry response that addresses the issue of financing investments and dealing with imperfections in wholesale spot markets.

Low-carbon investments

In Europe, the carbon price is foreseen to be the cornerstone of climate policies and to promote low-carbon investment in the power sector, replacing renewable support policies as these technologies reach maturity. In principle, this could work if, despite the risk associated with short-term volatility of electricity prices and long-term uncertainty over fossil fuel prices, low-carbon investments generate a sufficient expected return, in excess of the risk-adjusted cost of capital. Assuming low-carbon solutions are cost competitive, the optimal mix would lead to some low-carbon investment. The higher the carbon price, the more low-carbon investments are made.

However, the carbon price alone is currently too low in Europe to support nuclear and renewable power investment. Assuming a higher carbon price, investors may fear political intervention, which undermines the future credibility of the carbon price.

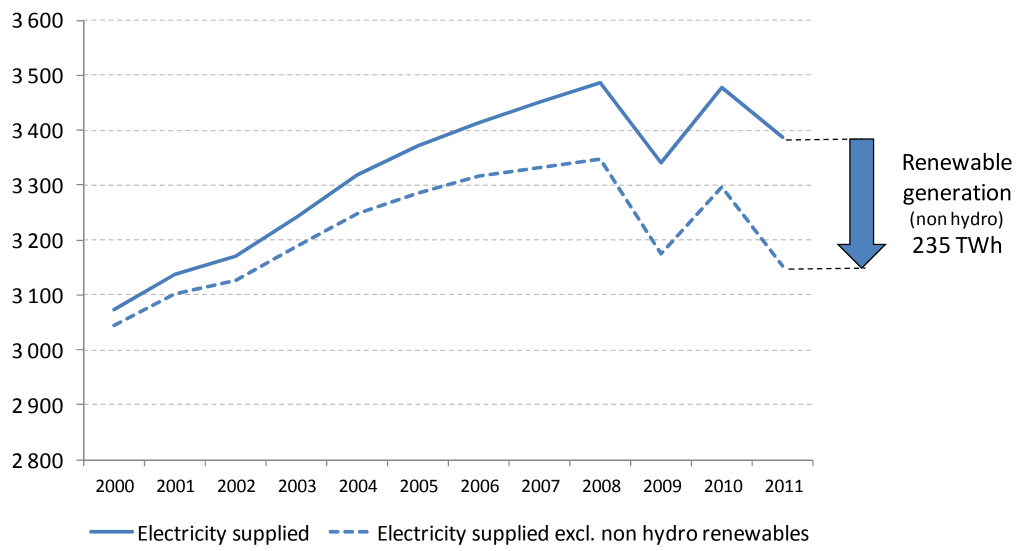
Confronted with this situation, the UK Administration's proposed solution has been to introduce long-term contracts that take away electricity market price risk from investors, and are legally enforceable and hence credible in a way that the carbon price – even a carbon price floor – is not. This proposal, where the government picks up the technologies and transfers part of the risk to taxpayers, is a quite noticeable change in the United Kingdom, which pioneered electricity liberalisation in the 1990s.

Another important question regarding low-carbon investment concerns the functioning of electricity markets when marginal costs are low and investment costs of each plant are high. One often mentioned issue is that market prices with high shares of renewables would reduce prices and undermine the incentives to invest, even with a high carbon price. According to this analysis, investments in low-carbon generation would stop once prices are too low, and may not deliver the investment needed in the nearly full decarbonisation scenarios foreseen in 2050. This issue calls for further research.

Load factor risk

Policy-induced renewable capacity development, like in Germany or Spain, relies on feed-in tariffs or other support mechanisms which are higher than the electricity price. As a result, there is no coordination between demand and investments. On the contrary, while electricity consumption has been slowing down, governments have accelerated renewable investments since 2008. The implication for Europe is that the residual demand to conventional generators in 2011 was equal to the level of 2002.

Figure 23 • Electricity supplied in Europe, OECD Europe (TWh)



In this context, a major economic effect of renewable deployment is that the residual demand (and thus the load factor of conventional power plants) decreases. In addition, the average price levels decrease, negative or zero prices can happen, and peaking units are running fewer hours. As depicted in the Figure 24 below, it is possible for the sake of the analysis to separate two effects: the load duration factor (or compression effect) and the price effect.

The load factor effect and price effects combine to reduce the profitability of the existing fleet of power plants in the short term. Solar generates power during the day, when consumption is generally higher. The rapid deployment of solar PV in several European countries has the effect of flattening the residual daily demand curve, which used to be served by mid-merit power plants.

From this perspective, it could be argued that rapid deployment of renewable energy “holds up” existing conventional power plant investment. The major risk here is that renewables push existing plants out the market, leading to mothballing. Note that if these mothballed plants are needed to meet peak demand for their ramp-up capability or to contribute to ancillary services, then the corresponding markets should remunerate properly (an issue which is discussed later).

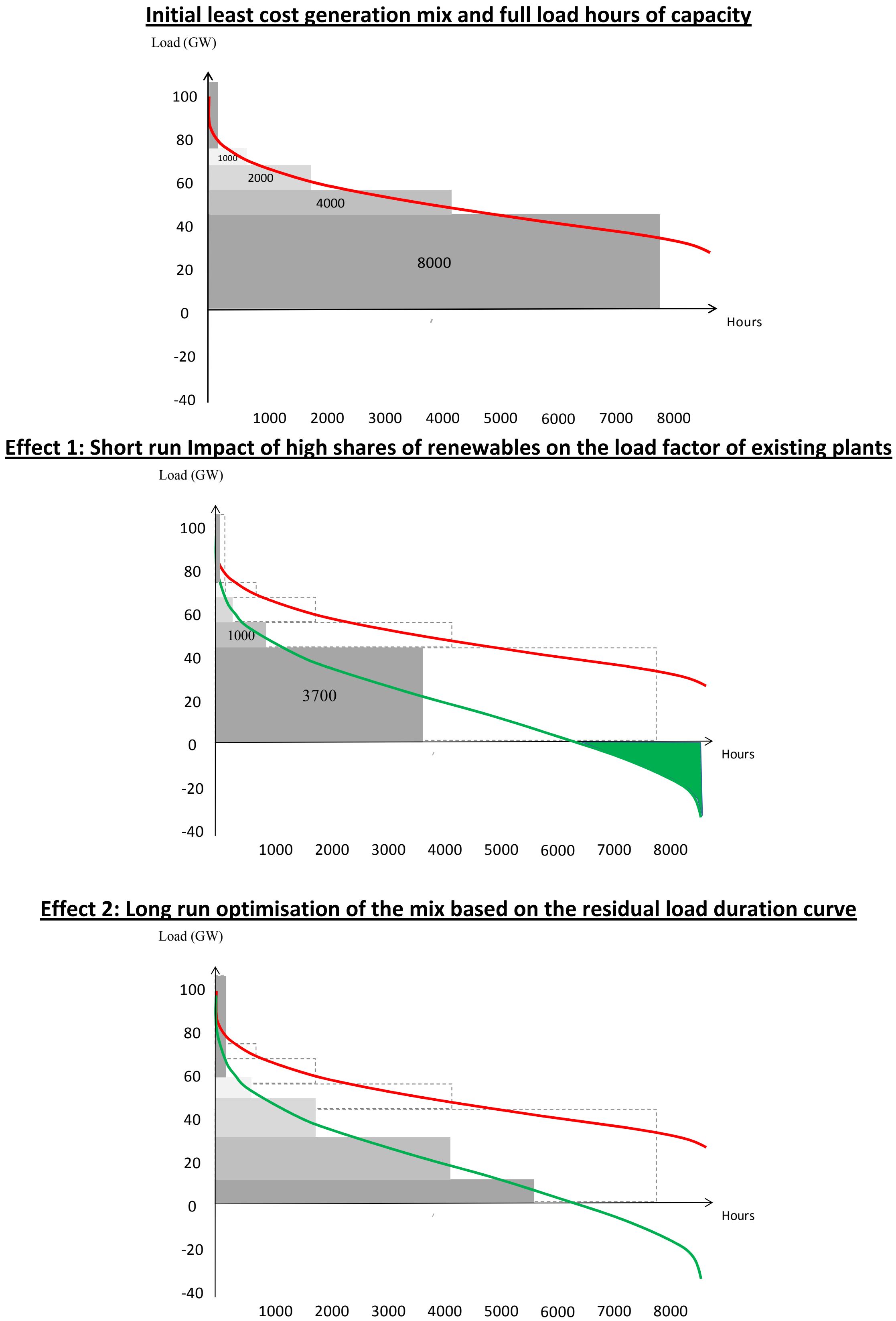
This analysis suggests that the impact of renewables on the generation capacity mix depends not only on the target, but also on the pace of deployment of renewables. Green and Vasilakos (2011) and NEA (2012) use a simplified model to compute the optimal equilibrium generating mix based on a residual load duration curve. In this optimal generation mix, the share of different technologies will evolve into less base load and more peak units. But it is remarkable that the effect on prices should remain limited in the long run once the system has reached a new equilibrium, assuming constant carbon and fuel prices. The reason is that the “equilibrium durations” between different technologies depend on the cost composition of different generation technologies but are independent from the shape of the residual load duration curve.

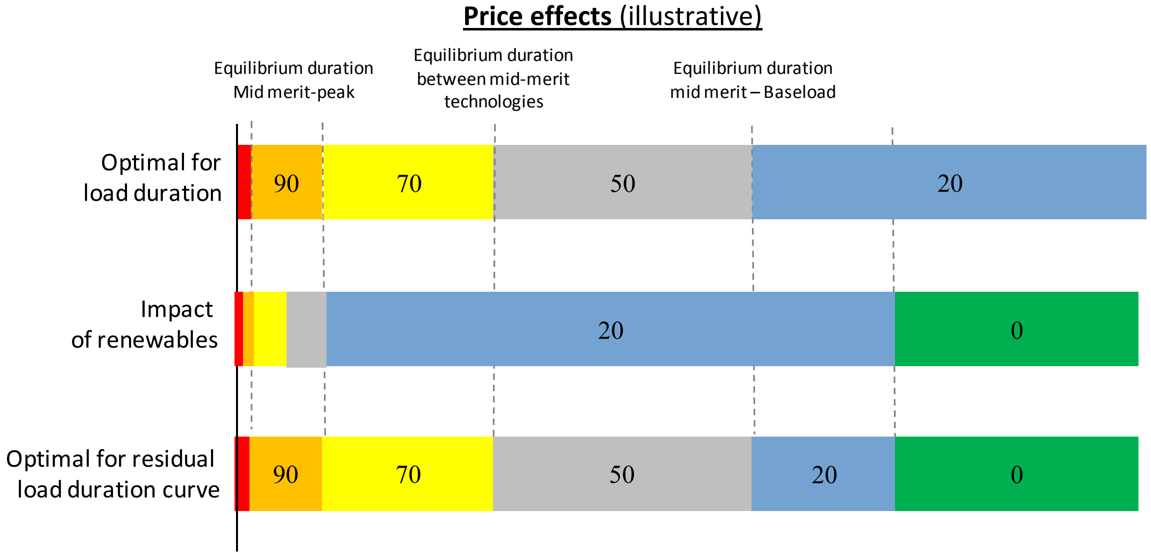
During the transition to low-carbon electricity, the rate of deployment of renewables may exceed the demand growth rate and the need to replace of ageing capacity. Taking a dynamic view, the load factor of conventional power plants will not be constant over time, but will be reduced as renewables are deployed. Consequently, it is possible to anticipate that a new power plant will initially be operated at a higher load factor, and then at a lower utilisation rate, selecting the right mix of technologies to serve such a declining market.

Another issue regarding load factors is their quarterly or yearly variability due to weather conditions. The number of hours with prices above variable costs may be difficult to predict, increasing the risk for potential investors. While already the case for peaking units, this will also become an issue for mid-merit units.

As a result, the load factor risk is an issue, but it may be limited mainly to the profitability of existing plants in the short run. Our analysis does not suggest that this will be a major issue for security of supply, as long as companies investing in new plants are able to anticipate carbon prices and levels of development of renewable energy; this will be discussed later in the section on regulatory risk. For new investments, the optimal generation mix may evolve over time towards less capital-intensive power plants and will depend on future carbon prices and expectations of load factors and of their variability.

Figure 24 • Schematic illustration of the impact of renewables on load factors, capacity and prices

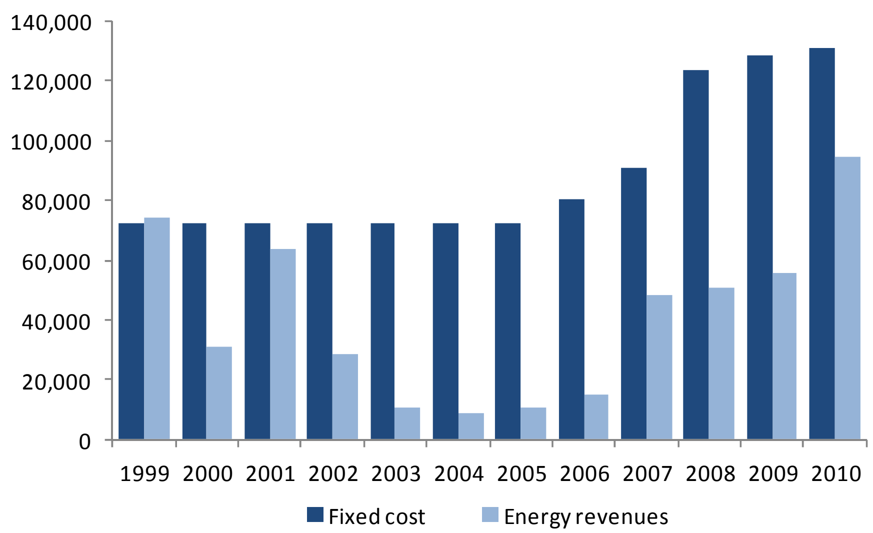




Peak pricing restrictions

There is a concern that competitive wholesale electricity markets for energy and operating reserves do not provide sufficient net revenues to attract adequate investment in generation capacity to meet conventional reliability criteria. More precisely, the spot wholesale electricity price may not be high enough to cover the operating and capital investment costs required to attract capacity. This problem is often referred to as the missing "money problem" in the academic literature. There is a lot of empirical evidence in the United States suggesting that revenues are lower than the cost of new entry in the market. Figure 25 shows that the gas power plant revenues from energy and ancillary services markets in the United States rarely exceed the cost of new entry (a rough estimate is 60 USD/kW per year), except in the congested New York area. Remuneration from capacity markets that have been introduced in PJM and NYISO represent a significant share of gas plants revenues.

Figure 25 • Twenty-five-year levelised, fixed cost and economic dispatch net revenues, 1999-2010 (USD per installed MW-year)



Source: Monitoring Analytics, 2010.

It is well established that prices during peak hours, when there are scarcity conditions, must be very high to cover the fixed cost of peaking units and also contribute to the fixed cost of other mid-merit and base-load power plants (Boiteux, 1949). In a market context, the price formation process during peak hours characterised by operating reserve shortage is critical for understanding whether the market is providing the right signals. However, there are a number of wholesale market imperfections and regulatory restrictions on prices, as well as procedures utilised by system operators to maintain network security (Joskow, 2007; Cramton and Stoft, 2005).

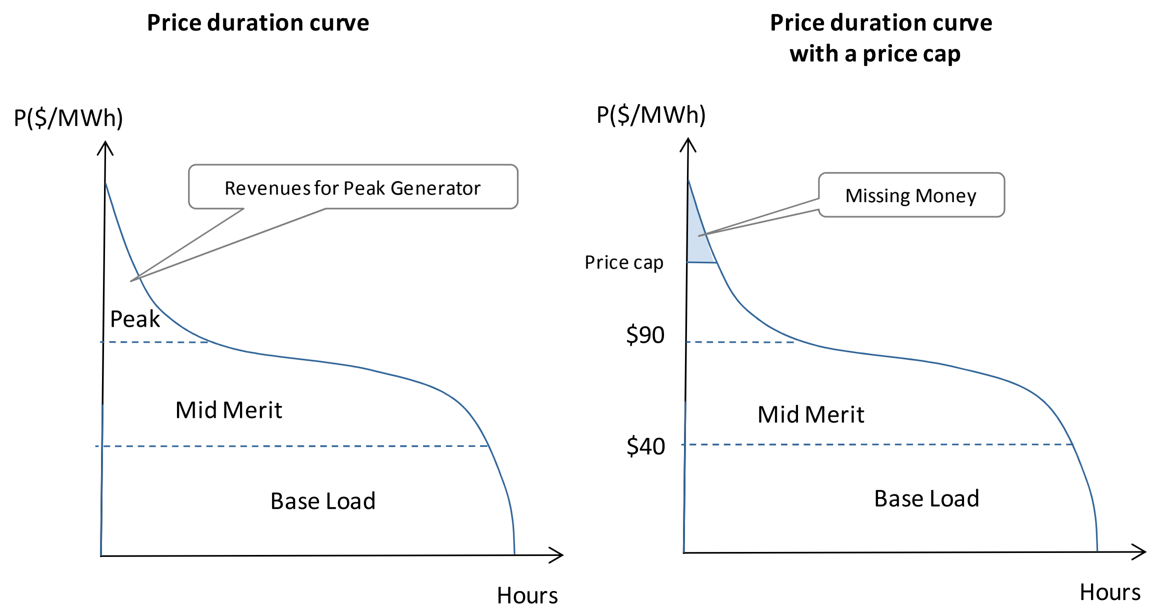
System operations during scarcity conditions

Only a small fraction of consumers are responding to real time prices (usually a few percent of the total load) and this situation will probably remain so at least until the development of smart grids, smart homes and smart appliances allow differentiation of usages of electricity according to customers' preferences. The consequence is that system operators rely on out-of-market operations to maintain reliable network operations and avoid non-price rationing of demand (rolling blackouts). The engineering procedures often rely on bilateral contracting with specific power plants for network reliability reasons, asking consumers to reduce consumption without compensation to maintain security of supply during tight hours, accepting capacity margins below their normal level or ultimately reducing voltage. All these actions have the effect of depressing peak prices during scarcity conditions and have been presented as the main explanation of the missing money problem (Joskow, 2007).

Market power

Periods of high demand are those when market power problems are likely to be most severe. If capacity is scarce, suppliers even with a small percentage of the market could exercise extreme market power. After these peak prices, regulators monitor markets carefully (*e.g.* energy regulators monitor peak prices in several countries, including France) and control bids. In some jurisdictions, regulators impose price caps to mitigate market power during peak hours.

Figure 26 • Peak pricing restrictions



Source: adapted from Hogan (2011).

Market power is a feature of most electricity markets and this can lead to underinvestment in generation capacity, maintaining prices higher than their efficient level (Léautier, 2012) and justifying price caps to mitigate market power. In markets which are not sufficiently competitive, it is argued that binding price caps are the cause − not the consequence − of under-investments (Léautier, 2012). In that case, removing price restrictions would not necessarily yield adequate generation capacity but would only increase monopoly profits. Similarly, capacity mechanisms would also probably increase monopoly profits.

Political interventions

There is also a risk of political intervention to avoid peak prices. In some countries, sensational peak power prices, exceeding 10 or even 100 times the cost of production, are making the headlines of newspapers, and these levels of prices are difficult to explain to the public. This carries the risk of political interventions to limit price spikes. Anticipation of such political interventions may act as a deterrent to investing in power plants that cover their costs through peak prices during a limited number of scarcity hours.

Figure 26 illustrates the consequence of restricting peak prices. Revenues are lower for all types of power plants, including peak plants, mid-merit or base-load plants that under well functioning electricity market conditions should also sell their output at the market price. The existence of peak price restrictions therefore distorts the market-based investment decisions, leading to a generation mix that is not the least cost-efficient one.

Restricting peak prices is one of the most common rationales for the introduction of further market reforms such as capacity markets in several countries. It is therefore crucial to analyse in detail the causes of peak price restrictions in order consider all possible solutions, such as improving the performance of existing markets, rather than introducing further complex regulations such as capacity markets.

Missing or incomplete flexibility markets

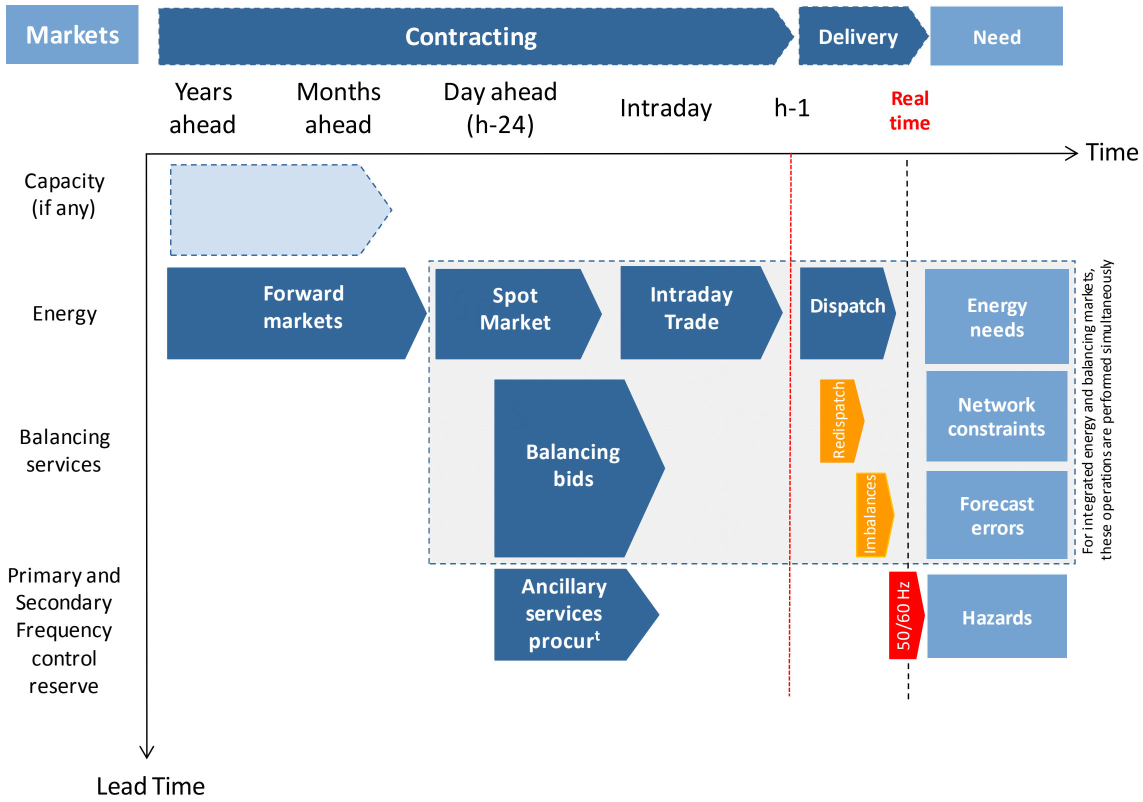
The supply of energy and various balancing or ancillary services are different possible usages of the same power plant. In general, power plants operating below their maximum output can provide ramp-up capability, but in that case, they lose some revenues as they do not sell all the power they could produce on the energy market. Arbitrage links energy market prices with balancing and ancillary services prices and this creates opportunities to change the operations of generating units according to price incentives delivered on these different interrelated power markets.

Markets for operating reserves and balancing services typically define the relevant products fairly crudely. The market for reserves or balancing services may not have any locational dimension. Generation services are much more differentiated than the basic underlying commodity with which they are associated. The system operator may, for example, need generating capacity responding in 10 minutes at a particular node of the network (Joskow, 2007). When supplies from generators with more specific characteristics are needed, the system operator may rely on bilateral out-of-market contracts to secure these supplies. These out-of-market operations can inefficiently depress prices received by other market participants for similar services and do not create a transparent price signal to operate efficiently and invest in flexible capacity.

For instance, if a system operator needs a “quick start” supply or demand response that can supply within 15 minutes rather than 30 minutes, it is better to define that as a separate product and to create a market for it that is fully integrated with related energy and ancillary service product markets, rather than relying on out-of-market bilateral arrangements and “must-run” scheduling (Joskow, 2007).

In addition to short-term balancing price signals, another issue is that market participants may not have the information to accurately forecast the balancing requirements over time, as variable renewables become more important on the network. Indeed, balancing services needs differ if the system experiences a shortage of quick-start capability or downward flexibility to handle a minimal load situation. However, in most power systems, balancing services tend to be procured close to real time, usually after the day-ahead market, and there are few market design with forward markets for balancing services. If system operators were able to anticipate operating challenges, forward demand for such balancing products could be created, in order to help market participants make the economic case for investments needed to enhance the flexibility of existing or new capacity and to contribute to secure power systems.

Figure 27 • Missing markets



Energy policy and regulatory risks

Investment decisions always involve a bet on future economic conditions. Even in a world of perfectly stable regulation, investors still face the macroeconomic "structural" risk of electricity demand forecasts errors as well as gas and coal price risk that can substantially affect the profitability of large and long lived power plant investments. It is widely acknowledged that this structural risk is an integral part of the market risk and it is usually factored in the risk-adjusted cost of capital used in the investment decision process. Furthermore, in competitive markets, investors have also to make investment decisions based on strategic interactions with others. Strategies may be good or not and may result in boom and bust cycles. But here again, it is widely recognized that the risk of poor strategic decisions is an integral part of the market risk.

With investments in the power industry being increasingly done through policy-driven measures, it becomes more difficult to draw the line between market risk and policy or regulatory risk. For instance, utilities complain about the impact of renewables on the load factor of conventional power plants, most notably, the recent gas-fired combined cycle. According to this view,

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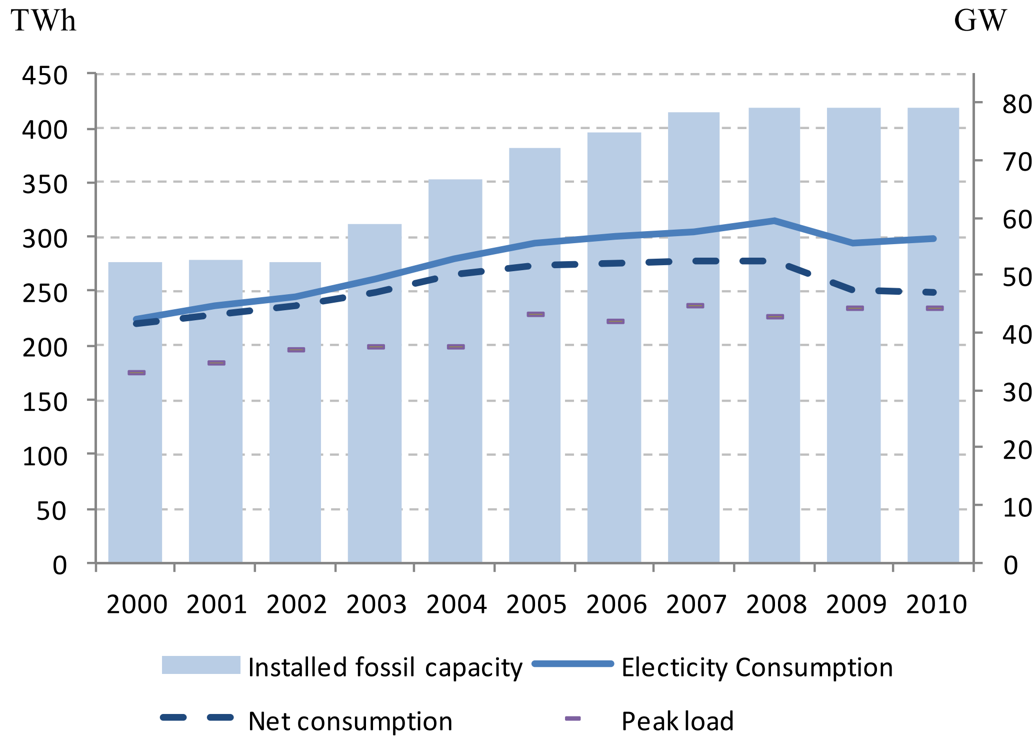
renewable deployment creates sunk costs that should be compensated for in one way or another. But looking more carefully, it might be difficult to determine *ex post* whether decreasing CCGTs' load factors result from lower than anticipated electricity demand since the economic crisis started in 2008, from renewable deployment faster than initially anticipated by utilities, or from strategic investment decisions that induced a peak of investments in some countries. Disentangling these different factors is impossible, in practice.

Figure 28 • Evolution of electricity consumption and non-renewable consumption in Spain



In Australia, the impact of carbon policy uncertainty on generation investment has been extensively analysed. A Deloitte report[15] found that policy uncertainty was detrimental to investment in baseload electricity, including combined cycle gas turbines, and as a result, OCGT was considered the lowest risk investment as it has lower capital costs. Deloitte calculated the cost of policy uncertainty, in terms of sub-optimality in investment, characterised by a preference for OCGT rather than OCGT. They estimated the cost of policy uncertainty by 2016 as AUD 4.73/MWh or AUD 1.2 billion/year (in real 2010 dollar). This increased to AUD 4.73/MWh in 2020 and in AUD 16/MWh 2024.

That is not to say that investors should be insulated from policy and regulatory risk. Industry participants usually develop their own views concerning the probability of success of energy policies, such as the share of renewables that can be reasonably achieved or the number of squared meters of buildings that will be successfully refurbished as a result of energy efficiency policies. In other sectors as well, investments in large oil or gas projects in some non-OECD countries also factor in an enhanced risk of expropriation (the expropriation of REPSOL in Argentina is a recent example), of legislative instability and other important dimensions of risk. Investment decisions are a question of risk/return and diversification of the portfolio of projects.

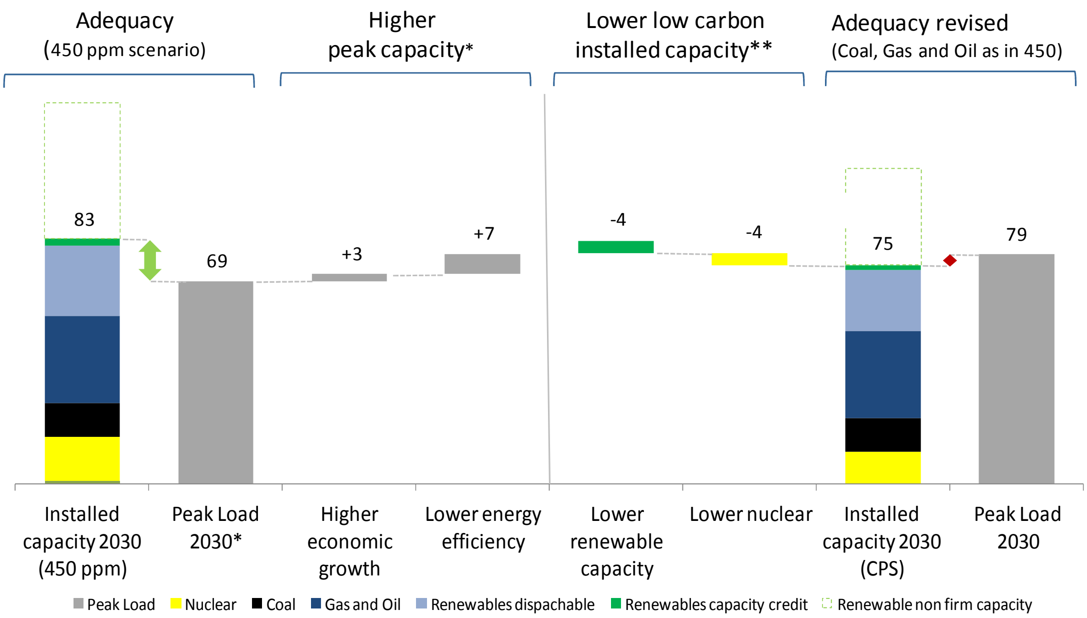
[15] http://www.ret.gov.au/energy/Documents/Energy-Security/Deloitte-Draft-Report-on-Electricity-Investment-01.pdf.

However, energy policies regarding electricity present some characteristics that have the potential to undermine investment decisions in new capacity, ultimately raising concerns about security of supply. Figure 29 provides an illustration of the possible impact of policy uncertainty on generation adequacy forecasts. First, policy-driven renewable energy introduces uncertainties, including the pace of deployment of renewables and the existence and ambitions of future renewable policies, in particular beyond 2020 in Europe.

Second, in the light of historical experience, ambitious energy efficiency policies may remain tainted with uncertainty, and this will exacerbate demand forecast errors. Aggressive smart metering roll outs approved by regulators may or may not deliver the demand response potential that can contribute to ensuring security of supply during periods of scarcity.

Finally, when governments take actions to address investment issues and wish to create the conditions for nuclear investments, these actions can also delay investment decisions. In the United Kingdom, the ongoing nuclear policy began in 2008 and the first new nuclear reactors are not expected before 2018, if the reform proceeds successfully. After two years of active consultations, several barriers must still be removed. Political processes are frequently delayed when the attention of governments shifts towards a more pressing topic or if a government changes.

Figure 29 • Possible impact of policy uncertainty on adequacy forecasts (*10 GW)



* higher growth (1%/annum instead of 0.8%) and CPS demand scenario
** CPS scenario for low carbon technology

Source: IEA (2011c), based on WEO CPS and 450 PPM Scenario, OECD Europe.

Confronted with such major uncertainties, the profitability of new capacity can be either positive or negative, depending on the outcome of the political process. That is, relying on fossil fuel capacity can be extremely profitable under one framework or they can be financially disastrous in another. Thinking in terms of real options, investors would wait until the policy framework is clarified, before committing to a make a final investment decision. But indefinitely delaying decisions carries the risk of tightening supply conditions and deterioration of security of supply.

Stakeholders complain about the uncertainty over the future path of regulation and changing and overlapping policies regarding renewables, carbon and energy efficiency risk. The associated political and regulatory risks could constitute one of the major deterrents for new investment in the liberalised electricity market. It is often argued that this can lead in the medium term to serious generation adequacy concern, higher prices and inefficient investment decisions made in emergency mode.

5. Policy options

Addressing the operating challenges and investment issues discussed in the previous sections will require an adaptation of regulatory and market frameworks. Even though countries face different supply and demand features, jeopardizing security of electricity supply is never an option. However, security of electricity supply in a country with large hydro reservoirs is not the same as for a country with a lot of variable wind or, to take another example, an ageing generation capacity. Each country will need to find the solution best suited to its situation.

This section provides an overview of the toolbox for policy makers concerned with electricity security aiming to rapidly reduce CO_2 emissions from power generation and at the same time to preserve or develop liberalised electricity markets. The perspective taken here is the market segment of generation, *i.e.* the segment that is fully exposed to market price risk. The time horizon considered is the next 10 to 20 years, corresponding to the period which is relevant for the business plans of power projects currently being considered by investors. Note that most of the instruments described here are not relevant in electricity systems where investment decisions are regulated, where the share of each technology is approved or tendered by a central body.

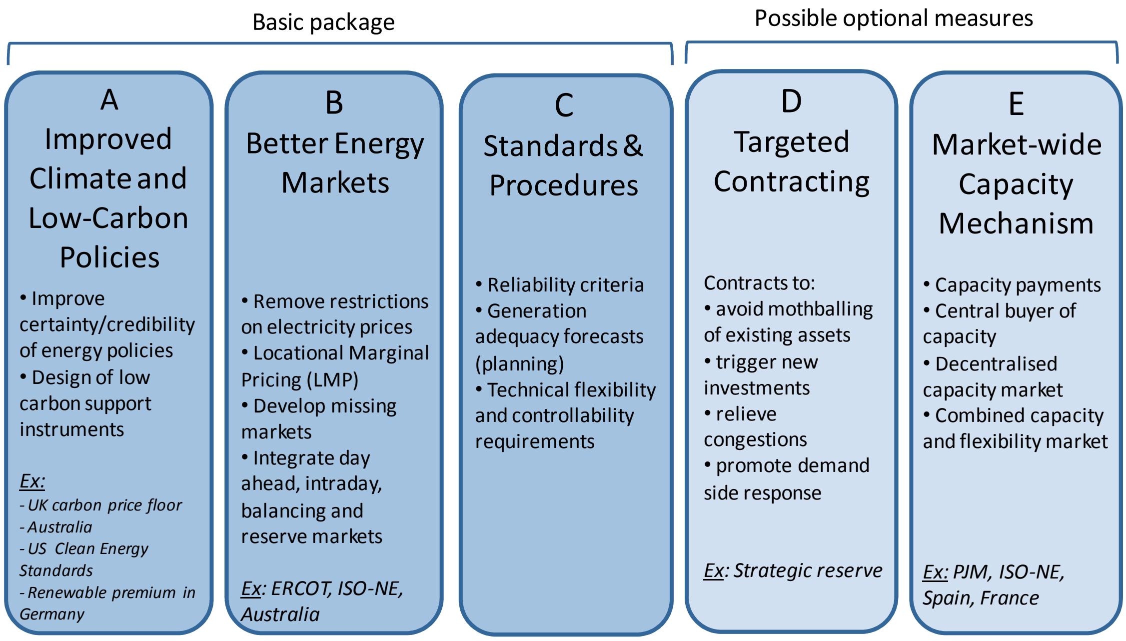
Five sets of policy measures can be identified that contribute directly or indirectly to enhance the security of electricity supply. Some of them should be pursued in any case to improve the functioning of electricity markets with high shares of renewables, including:

1. Improved climate and low-carbon energy policy instruments: an ongoing, long-term process;
2. Better electricity market design: a no regret solution; and
3. Engineering standards and norms: a valuable contribution.

The rationale and interest of a complementary capacity mechanism, on top of the basic package of policy measures, is also discussed.

4. Targeted contracting: a temporary fix; and
5. Market-wide capacity mechanism: a safety net.

Figure 30 • Policy measures



It is possible to define a basic package of policy measures that should be pursued as a priority. Specifically, improving climate policies and better energy-only markets (A, B and C) could bring benefits in terms of security of electricity supply. This may solve some of the issues associated with increasing shares of variable renewables. While financing peak plants and mid-merit power plants will still need to address the issues associated with cash flow volatility and variability, enhanced energy policies and better energy markets can significantly increase investment incentives to ensure generation adequacy at least cost. Furthermore, undertaking these measures has broader benefits and should therefore be regarded as no regret actions.

However, implementing the basic package of measures A to C will, at best, take time, and it is also possible that governments may fail to implement the appropriate measures. In particular, improving the certainty of climate policies for investors may be especially challenging in view of the inherent uncertainty associated with climate policies and future technology cost reductions. If this is the case, additional measures resulting in further modifications of market arrangements should be considered to maintain security of supply. The capacity mechanisms described in D and E lead to a significant departure from the market framework described in section 1. They are hybrid solutions between energy-only markets and more heavy-handed regulation where governments contract for all new generation capacity. Nevertheless, such capacity arrangements may well be necessary to ensure security of supply during the transition period to cope with some regulatory or market failure regarding energy policy uncertainty, the impossibility of preventing price restrictions and the lack of certainty of revenues of peak plants and mid merits power plants.

Improving climate and low-carbon energy policies instruments: an ongoing long-term process

The main purpose here is not to discuss the overall efficiency of climate and renewable policies. Nevertheless, a major risk faced by investors in electricity markets comes from the uncertainties associated with climate policies (see chapter 2), in that an unexpectedly rapid deployment of low-carbon energy would reduce the market of conventional plants. Conversely, a failure to deploy low-carbon energy would be a upside for conventional plants. Policy makers should take this into account when designing policies.

The basic measure is to design low-carbon policies that provide a more predictable framework for reliable electricity supply. This includes the design of climate policies, of carbon markets, and low carbon generation policies.

Definition of energy and climate policies

Findings

- Stable and predictable climate and low-carbon policies would have the potential to solve some of the problems associated with investment incentives, although technological developments and other investment issues are important. Improved climate and low-carbon policies include providing more certainty for carbon prices (or equivalent policies where a carbon price is not yet in place); supplementing it by setting targets that are backed with credible policies to ensure their delivery; predictable renewables and energy efficiency policies; and avoiding sudden reverses in the overall energy strategy.
- Governments should aim to provide more certainty and predictability, while it has to be acknowledged that policies will need to be reviewed and modified over time to reflect changing economic conditions, policy successes (or failures), and technology developments.

Carbon pricing policies

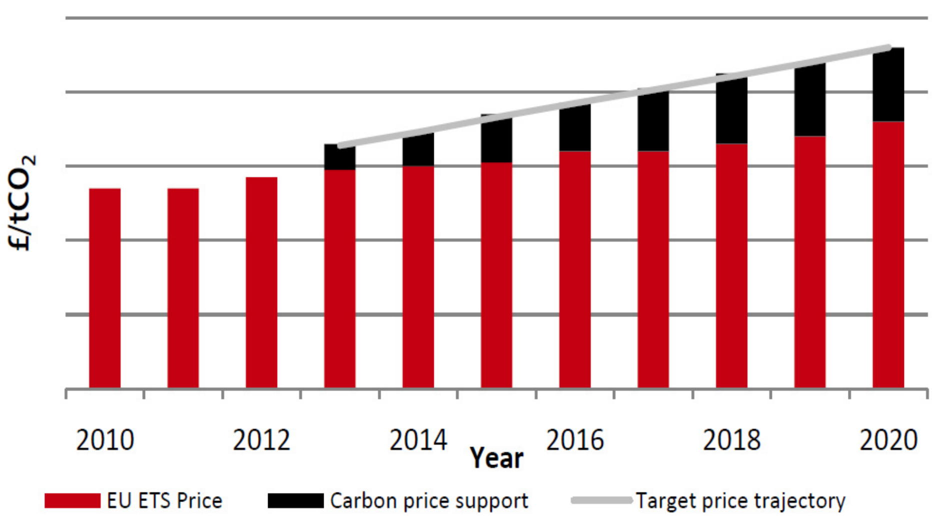
Uncertainty about global climate policy and regional or national climate policies can deter potential investors while they wait for the rules of the game to be more clearly spelled out.

At the global level, governments can seek to conclude climate negotiations on schedule by 2015 as agreed in Durban in 2011, to clarify the global framework and ambitions from 2020 onward. While security of electricity supply is not the driver of these global negotiations, negotiators from IEA member countries should be aware that failure to reach agreement affects investment in electricity markets.

However, global certainty will not be achieved quickly or easily, and governments face the challenge of ensuring that investment continues in the meantime. A stable, long-term domestic policy framework with wide political support helps provide investment certainty, although global uncertainties will still cause investors to question the probability of these policies being modified in the future. To provide this sort of certainty, the EU has already set targets for 2020 in its emissions trading system, and intends to set 2030 targets in the next few years.

The design of domestic climate policy instruments can build on lessons learned from policies already implemented. Emissions trading schemes (ETS) are currently regarded as the most politically feasible means of pricing greenhouse gas emissions, aiming at providing appropriate incentives for investment in low-carbon technologies and demand reduction. However, the detailed design of these schemes matters, particularly setting the overall cap on emissions at a level that requires emissions reductions from participants. Due to the financial crisis, the caps for Phase II (2008-2012) and Phase III (2013-2020) are now understood to have been set too high. Confronted with a carbon price too low to trigger low-carbon investments, the European Union considered setting-aside EU Allowances and changing the 2020 CO_2 emissions target. On the one hand, such actions would be consistent with the decarbonisation objective and one could argue that this signals the commitment of Europe to maintaining binding climate policy. But on the other hand, this needs to be done in a way that maintains trust in the scheme's settings and seeks to minimise perceptions of political risk; otherwise, it could undermine the long-term credibility of the trading scheme.

Figure 31 • Illustration of the carbon price support mechanism



Source: HM Treasury, 2010.

Alternative design features to improve investment certainty include carbon price floors, as long as these are credible (IEA, 2008a), or even specifying separate emissions targets (and associated policy measures) for the electricity sector. In general, economic efficiency and the cost of climate policy is minimised by wide sectoral coverage. However, setting a separate emissions target for the electricity sector could give a clearer signal to electricity investors, particularly if this is seen as a more sustainable policy. There will be a trade-off between overall economic efficiency and investment certainty that will need to be assessed. This takes time, but can restore confidence concerning the commitment of the global community to mitigate climate change despite the economic turmoil.

Energy Efficiency Policies

Reducing energy demand through cost-effective efficiency gains can be a key element of both managing energy demand growth and implementing low-carbon strategies. However, these gains are not always easy to deliver in practice, and they must be continuously monitored and verified. Some energy efficiency programmes in the Pacific Northwest, California and New England (such as the California initiative) have been very successful in reducing or eliminating the need for new supply-side resources, consistently delivering on targets. However, in other instances governments have announced ambitious energy efficiency goals but not backed these up with credible policies, institutions, and tracking systems, leading to disappointment. Fortunately, a significant evidence base now exists on "what works" in terms of energy efficiency policy design and implementation. This is highlighted in the IEA's *25 Energy Efficiency Recommendations*, and the "Policy Pathways" series of publications which provide guidance on implementation.[16]

Technology policies

Over the past 20 years, several layers of energy policies have been added to facilitate deployment of renewable technologies, improve energy efficiency or develop nuclear energy. These policies now determine an increasing portion of investment in the electricity sector.

As pointed out in Summing up the Parts, “the package of energy policies must be regularly reviewed and updated to maintain calibration over time” IEA (2011b). However, once introduced, project developers become used to them and these policies tend to be difficult to reform, which can lead to significant inconsistencies between them.

These risks can be minimised by getting policies right at the outset. Reforming policies can help staying in the comfort zone. Furthermore, well-designed technology policies must prevent possible side-effects on the electricity market functioning. This includes:

- Defining credible policy targets taking into account the maturity of different technologies and uncertainty on learning rates, with sensible objectives and milestones for renewables and energy efficiency;
- Provide a predictable and transparent renewable energy policy framework, integrating RE policy into an overall energy strategy, taking a portfolio approach by focusing on technologies

[16] One particular area that shows significant promise both for delivering efficiency gains cost-effectively, and also delivering them with certainty, is to place obligations for energy efficiency delivery with electricity providers such as utilities or retail companies. If these programmes are well designed, they can deliver consistent year-on-year savings, reducing the need for new supply in a predictable manner. The IEA’s work stream entitled Policies for Energy Provider Delivered Energy Efficiency (PEPDEE) is working to coalesce and disseminate proven practices in regulation and programme delivery through regional PEPDEE workshop reports and PEPDEE case studies.

that will best meet policy needs in the short and long term, and backing the policy package with ambitious and credible targets.

- Taking a dynamic approach to policy implementation, differentiating according to the current maturity of each individual renewable energy technology, while closely monitoring national and global market trends and adjusting policies accordingly;
- Choosing a time schedule of renewable deployment, reflecting these cost reductions but also taking into account needs to replace ageing capacity and demand growth; and
- Avoiding unexpected reversals of the overall energy strategy.

There is a trade-off between ensuring long-term stability of existing policies and adjusting them to changing economic, international and technological conditions.

When regulatory changes occur, it should be done in a planned and well communicated way. The example of the United Kingdom shows that reforming low-carbon support instruments can take time. The proposed electricity market reform, which goes through several reforms in parallel, mobilizes a lot of resources and staff.

However, in many countries, it must be acknowledged that reducing the causes of energy policy risk and regulatory opportunism will remain a challenge during the transition to a low-carbon economy. Governments should aim to provide more certainty and predictability, while evolutions of climate policies may be needed to reflect a rapidly changing new economic environment and rapidly declining costs of some low-carbon generation technologies.

Design of renewable support instruments

Findings

- Accurate forecasts of low carbon deployment are essential to be able to evaluate the size of both the market for low-carbon generation and the residual market. Support instruments for low-carbon generation which include some control over quantitative deployment of capacity provide more predictability.
- Efficient participation of renewables in the markets requires adaptation of some renewable support instruments. While instruments such as feed-in tariffs are effective during the inception phase, the benefits of market participation increase for high shares of variable renewable resources. For an efficient participation, renewables would have to provide a dollar-per-MWh bid, below which they are no longer willing to generate.

The first support policies for renewable energy were introduced without considering their possible impact on the functioning of electricity markets (IEA, 2011b). In the early stage this was not an issue, as the share of variable renewable energy was initially very low. But as these policies become effective, variable renewables now represent 20% to 30% of the electricity generated in some countries and they grow much more rapidly than electricity consumption. Support instruments and market frameworks must be designed to be mutually compatible with each other during the transition period toward market-based low-carbon investments; several simple measures would significantly reduce the risks faced by market-driven investments, without necessarily altering the effectiveness of renewable policies.

These include the following:

- Using predictable instruments to achieve the policy targets, and

- For high shares of variable renewable energy sources, avoiding incentives to renewable generators that hinder the system integration of renewables, such as fully decoupling remuneration from market price signals. For instance, decoupling subsidies from generated electricity would create the conditions to move toward participation of renewables on the day-ahead and balancing energy market.

Predictability of support instruments for renewables

Accurate forecasts of renewable deployment are essential to be able to evaluate the size of the residual electricity market for non-renewable generation. Even though the load factor may be decreasing over time, investors can anticipate this effect and they can choose the lower cost option to serve this declining market.

Nevertheless, the pace of renewable deployment introduces uncertainty over the load factor for conventional power plants (cf. Chapter 4). For instance, feed-in-tariffs for solar PV and wind in Europe led to an unanticipated increase in installed capacity in 2010 and 2011.

More predictable renewable policies would reduce the load factor risk. In practice, this means preventing the "stop and go" of renewable policies and controlling costs. Auctions or quantity-based approaches to subsidies can better control the quantity of new capacity (Cramton and Ockenfels, 2011). Such adaptations would greatly contribute to mitigating policy risk for owners of conventional power plants and also for the renewable industry itself.

Adapting renewable support instruments to ensure efficient participation in the energy, balancing and ancillary services markets

Wholesale electricity markets are based on marginal cost pricing in order to attain the least cost dispatch of installed capacity. Most of the hours, variable renewables with a zero marginal cost will be dispatched efficiently. But in case of very high renewable generation and low demand (see section above on minimum load balancing), renewable output may have to be curtailed to balance supply and demand or for reasons of system security (even if this increases the full lifecycle cost of renewable production).

Wholesale markets are efficient if generators bid their marginal costs on markets, but this may not be the case if some generators benefit from out-of market revenues such as priority dispatch and feed-in tariffs or tradable green certificate revenues. In particular, if TSOs sell renewable electricity into the spot market at high, negative prices to guarantee the dispatch of variable renewables, inefficient outcomes can occur – as has been the case in Germany, in particular in late 2009.

Instruments such as feed-in tariffs provide incentives to locate wind and solar capacity in good resource locations and to ensure that they are actually generating. This is effective during the inception and scale-up phase (IEA, 2011a) at relatively moderate shares of variable renewables. However, as these technologies reach maturity and their installed capacity increases, so do the benefits of market participation.

In order to restore efficient market signals, the participation of variable renewables in the energy and reserve markets has to be ensured. Exposing renewable generators to market price signals, providing incentives to generate according to the value associated with this generation. In practice, this means that renewable generators would have to provide a dollar per MWh bid, below which they are no longer willing to generate.

In that perspective, renewable support instruments might need to be adapted in order to change the marginal remuneration scheme when the system is in a state of excess supply. Germany and the United Kingdom are already considering adaptations of their support mechanisms. Germany recently introduced a market premium payment (see Box 4) and the United Kingdom is considering the introduction of Contracts for Difference for off-shore wind farms.

Designing renewable support instruments compatible with the market participation is an emerging topic. However, as the penetration of variable renewables in the system grows, they will need to become normal actors in the overall energy markets.

Box 4 • Market premium payments in Germany

The optional market premium model was introduced on 1st January 2012 (Erneuerbare Energien Gesetz - EEG). It opened the opportunity for renewable energy generators under the FIT scheme to opt for selling electricity directly into the market. This has been applied in particular for wind farms. Under the market premium model, a wind farm sells its produced output to a third party at the market price rather than selling it to the grid operator at the regulated feed-in-tariff.

The reference market price for the calculation of the market premium is determined as the monthly technology-weighted spot price at the EPEX spot energy exchange. The premium is then set as the difference in the average wind market price and the feed in tariff level. This represents an implicit floor price guarantee for the wind farm at the level of the regulated tariff. All wind generators that achieve a higher price on the market have an advantage; all who make a below average revenue get less.

In addition to the market price and the market premium, the wind farm is entitled to receive a management premium, intended to cover the administrative costs associated with the direct marketing of energy. The management premium is set at 12 EUR/MWh for 2012 and steps down gradually to 7 EUR/MWh in 2015, where it was scheduled to will remain. However, a reform of the premium is ongoing, as some stakeholders perceive it as being too high.

More than 15 000 MW of renewable energy have been transferred to new renewable market premium scheme in the first months of 2012.

Sources: Statkraft and Reuters websites.

Allowing renewables to participate to the provision of balancing services

Variable renewables generation is volatile and its output is less predictable than conventional power plants, requiring ramping-up and down to compensate for variations and imbalances of variable generation.

There is a growing debate concerning the economic interest to expose variable renewables to the balancing markets. One the one hand, exposing wind energy sellers to a balancing mechanism would reflect the costs and value associated with wind volatility and unpredictability.

In situations of imbalance, wind or solar generators can provide flexible services by themselves. For instance, a wind plant can operate at a fixed level below its available maximum output to enable a spinning reserve to be available and “up ramp” service to be provided. The extent to which this will take place will depend on the relative economic merits compared to other options. Provided that balancing markets are well designed and in countries where they are integrated with the energy market, it is efficient to expose variable renewables to the energy and balancing market.

On the other hand, in some countries balancing mechanisms are not perceived as being efficient or enough liquid (Newberry, 2012). In these countries, exposing variable renewables to the balancing risk could create inefficiencies, while the gains would be modest for small penetration of wind power. Possible market design improvements are further investigated in the next section.

Energy Market Design Improvements: a no-regret solution

Findings

- Removing undue restrictions on peak prices will be important to ensure well-functioning electricity markets. Wholesale peak prices are not intrinsically bad, since in periods of scarcity, high prices act to incentivise demand response and peak investments. However, monitoring that peak prices are not excessive in periods of relative scarcity will remain a challenge for regulators.
- Creating an efficient and transparent market platform for flexible services would allow all technologies to compete equally. Defining new flexibility products such as ramping up and down, fast response ramping, minimum load balancing, etc. would reveal a price for each flexibility service. All technologies should be able to participate in these markets, including variable renewable and conventional generation, demand response and storage. On this basis, forward markets for such services could provide longer-term signals to invest in the right technologies.
- Variable renewable resources will have to contribute to the balancing of the system during minimum load conditions. Above a certain level, the renewable output must be controlled during periods of oversupply in order to ensure secure and reliable system operations. This means that, in practice, some wind turbines or solar power plants must either operate below their maximum output, as is already the case in Spain, Texas and Ireland.
- The locational marginal pricing (LMP) framework could bring increasing benefits as higher shares of renewables have to be accommodated. LMP provides an efficient framework to attain the least cost dispatch and curtailment decisions in order to reflect the impact of thousands of renewable generators on losses and congestion on the network.

Improvements of energy market design can be implemented easily and at minimal administrative costs. Such incremental measures not only improve incentives to ensure generation adequacy, but also handle operating challenges of integration of increasing share of variable renewables. This includes:

- removing the causes of price restrictions that prevent electricity prices to rise high enough;
- defining and introducing new products (when and where necessary) (*i.e.* balancing, forward energy product for extreme peak conditions….);
- considering the adoption of locational marginal pricing; and
- ensuring an efficient and integrated design of energy, balancing and reserve markets.

Remove restriction on electricity prices

In principle, well functioning and non-distorted electricity prices should ensure prices high enough to cover the fixed costs of peaking units during tight supply conditions when reserve margins are too low. Figure 32 (below) shows the highest electricity prices in PJM. Even though they can exceed 700 USD/MWh during a limited number of hours, these prices may remain too low. Departing from this textbook market design is likely to lead to adequacy problems. The straightforward way to address the missing money problem is to remove economic price caps below the value of lost load and limit out-of-market operations.

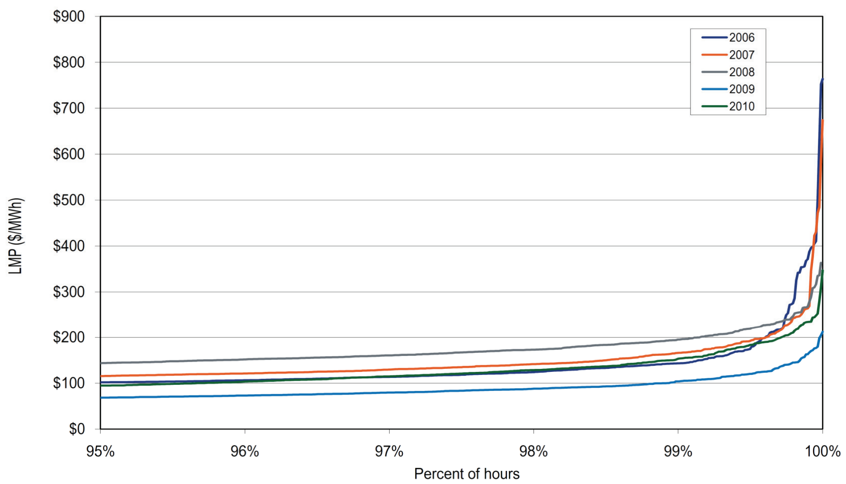
The causes of restrictions on electricity prices were discussed in chapter 4. One major question is whether governments and system operators can address these causes.

Explicit price caps below the value of lost load could technically be removed and replaced by other market power mitigation measures. Indeed, price caps have been introduced in some markets (PJM) to address market power issues during scarcity conditions. As these price caps have been used as justification for the introduction of complex and costly capacity markets, one could legitimately ask whether price caps are the best instrument to mitigate market power. This is all the more the case as market power on capacity markets also has to be monitored, meaning that price caps only mitigate but do not solve the problem. Other mitigation measures are available, including market monitoring during extreme peak prices, structural decisions to increase competition where there is local market power, entering into long-term contracts with generators facing a local market power or simply expanding the transmission network to increase competition.

The impact on price resulting from the behaviour of system operators could also be addressed. One possibility is to prevent out-of-market operations that restrict prices from increasing high enough during scarcity hours. This might be difficult to implement in practice because as system operators would be considered liable for not taking action in case of blackout, they usually prefer the certainty associated with bilateral contracts. Another (more realistic) possibility would then consist of setting the electricity price to the value of the lost load each time the system operator relies on out-of-market operations, such as voltage reduction, to maintain reserve margin in real time.

A trickier problem is the risk of political intervention when prices are peaking. In some countries, high prices raise political acceptability issues and, based on experience, generators may anticipate that governments will intervene. In other sectors, nobody hears or cares about the price of intermediate goods being very high, as these prices have a negligible impact on their average cost. Financial markets such as call options can help manage exposure of markets players to this volatility. But sometimes peak power prices do make the headlines and public opinion is sensitive to such events. Even in the absence of explicit price caps, just the threat of government intervention may have the effect of discouraging investment. Unless governments are credible in their commitment not to restrict prices, this can lead to expected missing money. And, as discussed later, this issue becomes even more challenging as the share of variable renewables increases.

Figure 32 • Price duration curve for PJM real-time market during hours above the 95th percentile, 2006-2010



Source: Monitoring Analytics (2011).

 © OECD/IEA 2012

Electricity product definition

While a megawatt-hour of electricity is often considered as a commodity, this does not capture the essential features of the product. Actually, electricity is an extremely differentiated product. Electricity available in hour h and location i is not substitutable with electricity in hour h' and location i' and should therefore be considered as two distinct products and markets. Furthermore, the sub-hourly variations of power over several consecutive time intervals also matters. Maintaining a supply and demand balance in real time requires satisfying both technical constraints and the economic capability to increase or reduce generation or load at different time horizons (i.e. instantaneously, within 15 minutes, one hour, several hours or days), at different speeds (ramp rates).

As the features of electricity systems change with increasing shares of renewables, so should the definition of electricity markets where substitutable products are traded. Introducing new products or services or even changing the definition of existing ones may be required. Such products would represent an opportunity to further develop ancillary services markets.

Indeed, as electricity markets developed, a set of power markets was created to put together similar electricity products and reflect the features of electricity systems. Forward and day-ahead energy markets, by far the largest one, intra-day, balancing and reserve markets (primary and secondary) followed. Some countries have distinct markets for technical constraints (voltage control and congestion management) while others co-optimise dispatching and balancing services. Some countries have developed sophisticated locational marginal pricing of electricity for thousands of different nodes of a network, while others try to have uniform electricity tariffs over a large geographic area.

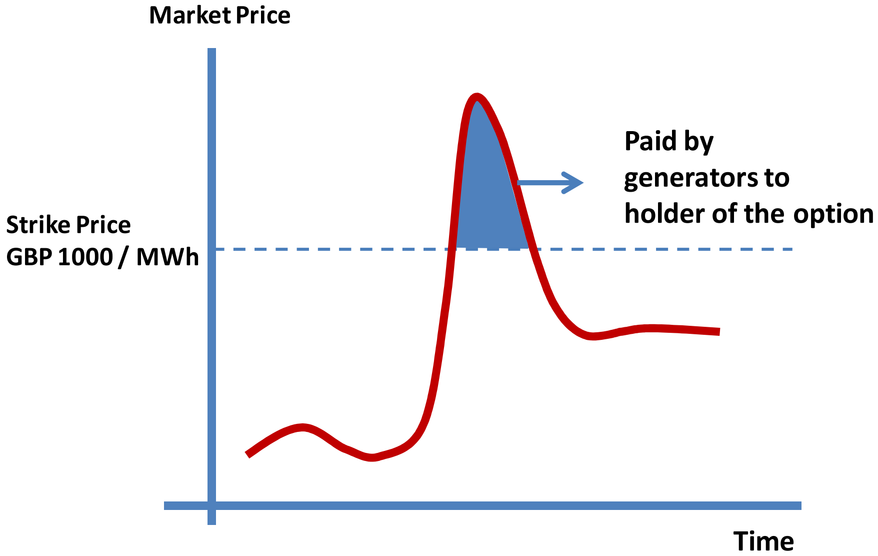
Call options (reliability options)

A reliability option (RO) is a call option that is both physical and financial. A generator that sells a reliability option must pay the system operator the difference between the spot price and the strike price whenever the spot price exceeds the strike price.

It is physical, in that it is associated with a specific plant that will be penalised if it is not available when the option is called (*i.e.* when the spot price exceeds the option's strike price). The RO is called when the spot price exceeds the strike price. The strike price can be set at a price that is slightly higher than the marginal cost of the most expensive unit on the system. (Cramton and Stoft, 2005).

These options can smooth revenues of peak plants over time and could also be used to hedge market players exposed to peak prices. Some proposals have been made to create options for balancing resources (Pöyry, 2011b). Another possibility is that these options could be procured by system operators. In that case the outcome is similar to capacity markets discussed later. In any case, such option products require well-functioning energy markets, in particular, that electricity prices can be high enough during scarcity conditions.

Figure 33 • Example of a reliability contract



Source: DECC, 2011.

Definition of flexible products

In some jurisdictions, there is no market platform for some specific products needed by the system operator in the short run. This may be the case for products to solve network congestion (counter trading), products to ramp-up or ramp-down capacity to follow demand and renewable output variations, or products for voltage control during certain hours. Some countries such as Spain are considering the creation of new short-term, flexible products markets, using existing electronic market platforms as the tertiary reserves market.

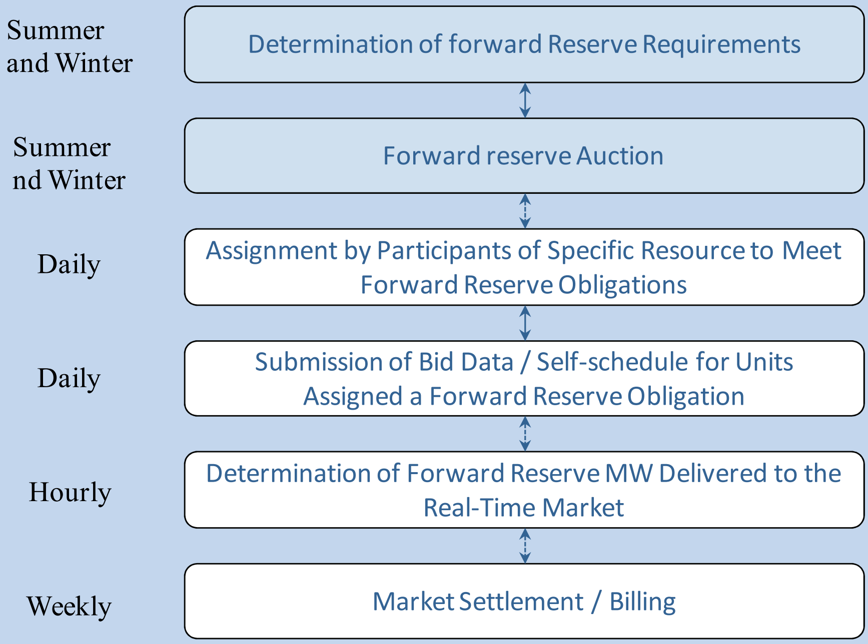
In the absence of such markets, system operators tend to rely on bilateral contracts with specific power plants that have the technical capability to supply the specific service. However, the financial settlement of these operations often lacks transparency. Defining open market platforms for new products would contribute to increasing the revenues of flexibility services. Such markets should be opened to power plants or demand response. They can provide a price signal to decide to mothball an old power plant, to invest in demand response capabilities or a new flexible plant. One caveat must be mentioned here: as products are defined more precisely, market liquidity and market power quickly become issues. Cutting the definition of flexibility products into too many small slices could reduce too much liquidity. Therefore, the number of products may have to remain limited. In addition, system operators are often the natural counterparty of such flexibility products and are the only ones that can create a forward demand curve.

Box 5 • ISO New England Forward Reserve Market

The ISO-NE determines locational reserve requirements for three ISO-NE zones (import-constrained) for each of the three following operating reserve products:

Function	Product	Characteristics
Primary frequency control response	No market	
Secondary Frequency control response:	Regulation Reserve	Nominated capacity must be delivered in less than five minutes, a minimum ramp rate of one MW/min and output must be maintained during a minimum duration of sixty minutes.
Tertiary Frequency control response:	Ten-Minute Spinning	Nominated capacity must be delivered in less than ten minutes and output must be maintained during a minimum duration of sixty minutes.
	Ten-Minute non-spinning	Nominated capacity must be synchronized at nominated capacity in less than ten minutes and output must be maintained during a minimum duration of sixty minutes.
	Thirty Minute Operating	Nominated capacity must be synchronized at nominated capacity in less than thirty minutes.

Twice a year, the ISO-NE manages a Forward Reserve Market. This Forward Reserve Market is unique to ISO-NE and includes Forward Reserve Auction to acquire in advance capability to supply required Operating Reserves to meet the reserve requirements in each Reserve Zone in real time, as depicted in the following figure (a detailed version can be found in Ellison *et al*, 2012).



Locational marginal pricing

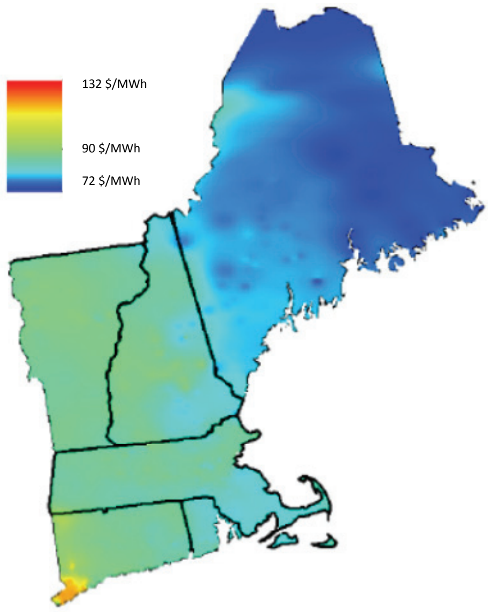
Locational Marginal Pricing (LMP), or nodal pricing, is the cutting edge market-design for economists. Defined very generally, LMP consists of centrally-computed electricity hourly prices, set node by node (there are several thousands in PJM) that reflect the marginal cost of producing and consuming electricity at each node of the network. A considerable literature lauds the merits of LMP currently being applied in the North West of the United States. This centralised approach factors in generation costs, losses and network constraints, so as to yield to the optimal dispatch of existing assets in a transparent way.

Currently limited to the United States and New-Zealand, many economists in other OECD countries advocate nodal pricing. In Europe, nodal pricing would reduce the generation cost by 1.1% to 3.6% (Neuhoff *et al,* 2011). PJM estimates the overall benefits of integrated operation of their system are USD 2.2 billion (approximately EUR 1.8 billion) annually (Ott, 2010, quoted by Neuhoff *et al*, 2011).

However, applying nodal pricing across multiple jurisdictions may be a complex and lengthy process. For the time being, market coupling in Europe is a much simpler procedure. Similar zonal pricing approach can also be found in Australia (NEM), in some U.S. RTOs and in Nordpool. It captures some of the benefits of LMP with a simpler definition based on the observation that most network congestion in Europe occurs mainly at the borders between different system operators' areas.

Looking forward, increasing shares of variable renewables located far from consumption centres may lead to new grid congestions and increase transmission losses, in particular if network investments lag behind renewable energy deployment. With higher shares of renewables, nodal pricing could bring more cost savings. Indeed, nodal pricing allows differentiating the value of different wind farms according to their impact on network congestion of network losses. LMP can also provide locational signals for investment in new renewable generation. In addition, in case of excess supply, LMP would lead to curtail first wind turbines located in nodes at the origin of congestion or higher network losses.

Figure 34 • Average nodal prices, real time, Q3 2005 (ISO New England)



Source: ISO NE.

Consistent and integrated day-ahead, intra-day, balancing and reserve markets

The juxtaposition of several electricity markets (forward, day-ahead, intra-day, balancing and reserve markets) reflects the complexity of system operations and of the engineering procedures to ensure the balance of generation and load in real time. This organization reflects practical computational restrictions with electrical grid management systems in the 90s. But this also induces some complexity for market participants having to decide to allocate and sell their output on these markets. Well designed and coordinated markets are essential to achieving efficient operations of the existing assets.

Progress has been made in the United States and Australia to integrate balancing and energy markets (Australia). This reduces complexity for market participants but usually require greater centralization of system operations which could limit its geographical scope.

In European countries, balancing markets are separate from energy markets. They are also asymmetric, penalizing market participants that increase system imbalances. Such asymmetries introduce distortions between balancing prices and energy prices. In the perspective of increased participation of renewables in the balancing markets, this would penalize renewable operators, who are less able to accurately predict their output before real time (for a more detailed description, see Newberry, 2012). With this kind of balancing market, market participants prefer to have gate closure closer to real time in order to adjust their generation plans and reduce their exposure to the imbalance risk. Moreover, regional integration of balancing markets and even other reserve markets over wider geographical areas could yield efficiency gains.

Standards and Procedures: a valuable contribution

Finding

- Governments also contribute to ensuring security of electricity supply by issuing standards and bringing transparency to the market. This includes the definition of reliability standards; the publication of adequacy projections or the definition of technical requirements, such as flexibility of power plants, controllability of wind and solar power plants or controllability of electrical appliances.

Technical standard and procedures will continue to play a role to ensure electricity security. Even where operations and investment decisions are market-based, governments and system operators will continue to define, in one way or another, the reliability criteria, some dispatching capabilities and requirements for new generation capacity and electrical appliances connected to the grid.

Two items have implications for electricity security in the context of decarbonisation: the definition of the reliability criteria and the technical standards for system resources.

Reliability criteria

Owing to the technical restrictions that constrain the possibility to price reliability according to the willingness to pay of different categories of consumers, governments will continue to have a role to play in setting the reliability standards. In theory, the criteria defined is the value of lost load (voll), with values in the range of 10 000 to 25 000 USD/MWh, and determines the cost of the last unit that must be built to meet peak demand. In practice, governments take a decision on the security of supply, in terms of acceptable unserved energy, corresponding to a reliability of c. 99.95%.

Adequacy forecasts

Another important procedure at the disposal of governments is to periodically publish adequacy forecasts, projecting the supply/demand balance and forecasted reserve margins during peak hours. Legislation mandating such projections is already in place in most OECD member countries. This simple tool brings transparency on market forecasts and also helps inform market-based investment decision making. Such adequacy forecasts remain subject to macroeconomic uncertainty but are becoming even more important in the context of uncertainty over renewable policies.

Technical flexibility and controllability requirements

Technical requirements can ensure that new-build or existing plants are flexible enough. Usually, these tend to be defined by the industry. For instance, in the EUR (European Utilities Requirements), the nuclear industry and utilities defined specifications in terms of flexibility for nuclear reactors (Pouret, and Nuttall, 2009). But governments can also play a role in promoting specifications that reinforce future system flexibility, in consultation with technical bodies.

Renewable plants should be equipped with devices to control their output in real time. In particular, decentralised solar PV plants should also technically be able to contribute to system stability, e.g. via dynamic control of active and reactive power output. This is particularly important for decentralized PV in order to maintain the voltage level in the local network. As already the case in many jurisdictions, technical norms published under the responsibility of governments could mandate this to all newly created facilities. This is a key requirement for the secure integration of increasing shares of renewables.

These technical specifications are contained in grid codes which define the parameters that a facility connected to a public electric network has to meet to ensure safe, secure and proper economic functioning of the electric system. The “facility” can be a generating plant, a consumer, or another network. The grid code is specified by an authority responsible for the system integrity and network operation. Its elaboration usually implicates network operators (distribution and/or transmission operators), representative of users and, to an extent, varying between countries, the regulating body.

Targeted Reliability Contracts: a temporary fix

Findings

- Targeted contracts period can help countries facing short-term and transitory adequacy or reliability issues.
- Such contracts are quick to implement and it is possible to stop to sign new contracts once the policy and regulatory uncertainty have been reduced and market design improved.
- Targeted contracts ensure security of supply without jeopardizing the objective to achieve the economic benefits of well-functioning energy only markets in the longer run.
- However, expectations of such contracts might lead to strategic behaviour as companies withhold investment and wait for their introduction, and experience in certain countries indicate that it could be difficult to stop them.

The policy measures described in the previous sections constitute the basic policy package (improved climate policies, better energy only markets and standard and procedures). If these policies were to be implemented successfully, they would lay the foundation of well-functioning, energy only markets.

However, some reforms may be difficult to implement successfully and may take time. This is the case, for example, of stable renewable policies and of building credibility of governments to let electricity prices rise high enough during periods of scarcity. In addition, even if implemented successfully, they have only an indirect effect on incentives to maintain or build adequate capacity to meet demand, and there is no absolute certainty that they will be effective in ensuring the right level of security of electricity supply in all circumstances. Furthermore, they may not address all the investment issues. In particular, variability and volatility of revenues for peak power plants, the load factor risk and peak prices may remain a concern.

The practical considerations also matter, and implementing the measures of the basic package takes time-- several years -- a lead time not compatible with urgent security of supply concerns. In this respect, IEA countries face different situations. Most states have already developed or improved energy markets and will continue to do so. While some regions face urgent generation adequacy constraints (the United Kingdom and Japan, for instance), most of other countries have enough excess-capacity, as a result of sluggish demand growth. In the latter case, reforming electricity market design is not seen as a pressing concern.

Targeted reliability contracts consist in signing a (generally multi-annual) - contract with few power plants or consumers, to maintain reserve margins or network stability and reliability. This includes measures such as strategic reserves, contracts to relieve congestion or maintain voltage stability in certain zones.

Targeted reliability contracts are easy and quick to implement. This feature is a major advantage in case of urgent concern over security of electricity supply. In addition, it is fairly easy to stop to sign new contracts once the policy and regulatory uncertainty have been reduced and market design improved. Thus, targeted contracts ensure security of supply without jeopardizing the objective to achieve the economic benefits of well-functioning energy only markets in the longer run.

Several sub-options can be distinguished, based on the nature of the service or asset contracted:

- A contract with existing assets to prevent mothballing and handle transmission constraints;
- A contract to trigger investments in new power plants; and
- Contracts to develop demand response or other innovative solutions.

Contract to prevent mothballing and handle transmission constraints

System operators often enter into bilateral contracts with specific power plants to solve network constraints or maintain network reliability. The advantages of such targeted contracts are their rapidity and simplicity, and that they can be transitory. In markets without locational signals but facing recurrent congestion or a voltage stability problem, system operators usually force the operation of plants, even when their cost is higher. In general, such actions are necessary with older plants that are less efficient.

A similar contracting approach to keep ageing plants from being mothballed has recently been used in several European countries:

- In 2003, authorities in Sweden and Finland asked their TSOs to procure “strategic reserves”, to be activated in times of scarcity. This measure was motivated mainly to meet the need for peak capacity during periods of drought, when the capacity of hydro would be reduced by 40-50% and by the perceived failure of the energy-only market to deliver enough capacity.
- In 2012, the regulator in Germany approved a contract to maintain gas capacity in southern Germany after the shutdown of 8 GW of nuclear power plants.
- In Denmark and Spain, the TSOs have contracted with thermal power plants needed to maintain voltage stability during periods of low load and high renewable generation.

In the United States, a federal regulation entitles system operators to sign so called Reliability must-run contracts (RMR) with units required to meet reliability criteria in constrained areas. These multi-year contracts are based on cost-of service agreement and have been used to maintain existing capacity on line in all US zones, including liberalised markets such as PJM and New England.

In markets where a locational marginal pricing framework is applied, bilateral contracts can also be signed to mitigate the locational market power issues when only one or two power plants can relieve congestion or supply reactive power. However, to handle a network constraint, there may be a lack of competition to provide these as only a few power plants are typically located in the right place. Regulators should therefore keep in mind that targeted contracting can be subject to lobbying or gaming. Generators may threaten to mothball a plant in order to extract some additional revenues and increase the profitability of their assets. As regulators and system operators tend to adopt a conservative approach towards electricity security, they prefer to keep power plants online to avoid being blamed in case of capacity shortage or a network problem. Maintaining effective System Operators incentives and transparency remains therefore important in this context.

The main drawback of targeted mechanisms is that they introduce market distortions. In particular, if the strategic reserve is bidding too low prices on the power market, this can result in depressing prices and discouraging investments in new peaking plants. In addition, as pointed out by the UK Department of Energy and Climate Change (DECC 2011, p. 36), *"…strategic reserve runs the risk of plants not selected choosing to close down if they do not receive a Strategic Reserve contract. If this happens this could lead to the 'slippery slope' effect, whereby more and more plants must form part of the Reserve to ensure it remains effective."*

Box 6 • The strategic reserve in Sweden and Finland

Sweden and Finland depend on hydro availability and after significant shortage in 2002/2003, the authorities decided that their TSOs should procure a peak load reserve that is activated in times of scarcity. Under the Act (2003:436) on peak load reserve, the Swedish TSO Svenska Kraftnät has the responsibility to ensure that up to 2 000 MW is available during the winter period (compared to an historic peak load of 27 000 MW). An Ordinance states the amount to be procured every winter (1750 MW for the period 16 March 2011 to 15 March 2013. Plants need to be able to be activated within 12 hours in Finland and 16 hours in Sweden. The Finnish TSO Fingrid procures up to 600 MW (compared to an historic peak load of 15 000 MW).

In Finland, Fingrid organised auctions to contract short lead time, indicating that the intention of the mechanism is to prevent existing plants from mothballing or decommissioning. Finland has old heavy oil and coal plants. In 2009 and 2010, provision costs amounted to 22 500 EUR/MW/yr and 2 500 EUR/MW/yr, respectively. Four plants participated in the May 2011 auction and three were selected.

In Sweden, the peak load reserve is procured annually and is composed of generation capacity and demand reduction capacity. The share of demand reduction capacity will increase from 25% in 2012 to 100% for the period 2017-2020. By 2020, the peak load reserve is to be completely phased out.

In Sweden, reserves can be activated on Nord Pool Elspot, if there is not enough capacity to clear the market, at a price equals to the last commercial bid plus 0.1 EUR/MWh (with a maximum price of 2 000 EUR/MWh). However this rarely happens (On December 17, 2009, the Swedish and Finnish peak load reserves were activated on Elspot). Usually, Svenska Kraftnät activates the strategic reserve after the closing of Elspot. In that case, the minimum price is specified in the contract. Svenska Kraftnät activated the reserves during 30 days during winter 2009/2010, and during 8 days during winter 2010/2011.

Source: Svenska Kraftnät *Frontier Economics* (2011).

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Contracts to bring in new investment in power plants

Another possibility to ensure generation adequacy consists in organising tenders to build new power plants. This is a straightforward, quick and effective means to bring in new capacity when supply adequacy forecasts show a lack of capacity a few years in advance and if old plants have to be closed.

In France in 2000, the legislature passed a measure which would permit organisation of a call for tenders to ensure adequate capacity or network constraints. This mechanism has been used to build a CCGT power plant in France in Brittany. Likewise, in Norway, the network operator also built and owns a gas-fired power plant to feed oil rigs in case of a dry year.

This approach clearly substitutes for the market. With strategic reserves, the government or the system operator, not the market participants, decides the type of capacity and chooses the technology and the timing of investments. There is a room for competition, but it is limited to the selection of the least cost provider of the capacity considered necessary.

Contracts to develop demand response

In order to correct the market failure associated with inelastic electricity demand, governments may wish to promote demand response. Large industrial customers are already able to reduce load. This potential can be increased but may remain limited. Moreover, demand response has to compete with peaking plants whose annual fixed cost is low, in c. 100 USD/kW/year and the availability of demand response potential is not guaranteed, unlike conventional generation. The economic case for large-scale deployment of demand response capability still must be made. This is the case in particular for small consumers for which savings on their electricity bill may be very low.

Targeted contracting can accelerate the deployment of demand response and reinforce the business model of smart grids. However, a centralised definition of the specifications of the service may be a barrier to the development of other innovative demand-side solutions. As these demand side solutions reach a sufficient degree of maturity and as the automation and remote control of electrical appliances develops, they will become competitive with other sources of capacity.

Market-wide capacity mechanism: a safety net

Findings

- Capacity markets can be effective to ensure adequate capacity and they can be used to promote flexibility, investment in capacity and, in particular, demand response.
- Capacity markets have the advantage to encourage competition between different technologies on a level playing field.
- However, capacity markets tend to have high transaction costs and put a burden on regulatory institutions.
- They might have unintended consequences in creating secondary incentives and, depending on their design, may create excess capacity and lower demand response during scarcity conditions.
- National capacity markets have a potential to introduce distortions between different countries or jurisdictions of a single electricity market. Before introducing capacity mechanisms, governments should consider their impact on incentives and define common rules on a market-wide basis.

Unlike targeted reliability contracting, capacity markets should be viewed as a likely permanent instrument. They are quite heavy-handed administrative interventions which may ultimately lead to re-regulating many parameters of electricity markets. Their introduction can be motivated by a lack of trust in energy-only markets or poorly designed electricity markets. However, capacity markets involve very technical discussions, still ongoing, about the incentives and their expected effects.

Our analysis suggests three reasons why governments may lose faith in the ability of energy-only markets to acquire enough investment to ensure security of electricity supply.

1. Price restrictions or regulatory opportunism: governments anticipate that they will not let electricity prices go high enough during periods of scarcity.
2. Climate and technology policy risk: governments give priority to climate and renewable policies which are not well-integrated with well functioning electricity markets. They may continue to define ambitious policy targets but lack certainty and to use renewable policies to pursue multiple objectives.
3. Revenue variability and volatility: given the current financial context, increasing yearly variability of revenues negatively impacts the availability and the cost of capital. This reflects concerns about liquidity of financial markets to hedge such risks and little appetite of financial counterparties for it. This is a particular concern as peaking units are increasingly needed with the development of renewables.

A market-wide capacity mechanism can be broadly defined as a regulatory instrument designed to create revenues for all capacity − generation or demand response − available during a specified period, generally when system operations are tight. These capacity mechanisms complement revenues from the sale of electricity, in order to assure that enough capacity is available to meet peak demand in restructured electricity systems. This is especially the case for fixed cost recovery of peak capacity rarely used and facing unduly capped prices.

As market-wide arrangements remunerate all capacity, this prevents negative bias that could appear with targeted mechanisms. No technology is favoured by the mechanism; this leads, in theory, to an efficient – least cost – portfolio of technologies.

There are several classes of capacity mechanisms: regulators can choose to set prices (capacity payments) or quantities (capacity markets), the time-horizon can be annual or several years in advance (forward capacity markets), capacity-obligations can be assigned on suppliers (decentralised capacity mechanism) or system operators can organise tenders (centralized capacity mechanism). This section briefly describes the main dimensions of market-wide capacity mechanisms.

Capacity payments[17]

In price-based capacity mechanisms, a central institution sets the price for capacity. Such capacity payments are supposed to compensate for the shortfall of revenues for all the capacity resulting from price restrictions. The capacity payment is supposed to determine the capacity provided, which is an outcome of the market.

Take a simple example. Assuming for simplicity that prices never exceed the short-run, marginal cost of peaking units, these plants never cover their fixed costs. The missing money is equal to the capital cost annuity for an efficient peaking unit, usually in the range of 50-100 000 USD/MW/year. These payments should be made for all capacity.

[17] This section is based on Frontier Economics, 2011.

The payments used in Spain are one example of such capacity payments (see Box 7).

It has been argued that in practice, capacity payments can be motivated in order to increase profitability of power plants and compensate generators for the reduction of load factors resulting from rapid deployment of renewables. However, it is important to keep in mind that the objective of such mechanisms is not to increase the profitability of existing assets hit by the economic crisis, but rather to provide certainty that there will be enough capacity available.

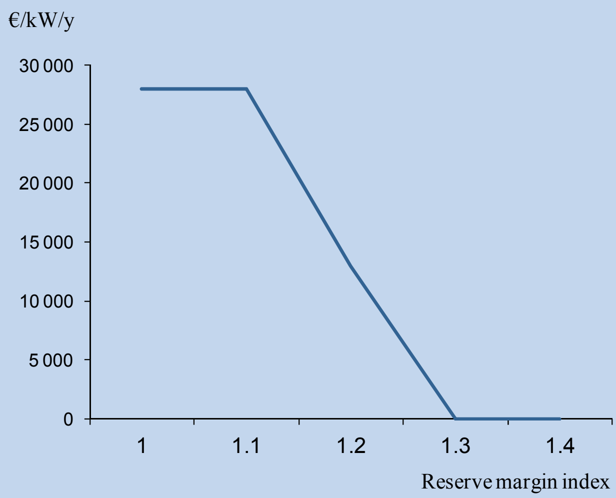
Box 7 • Capacity payments in Spain

Spain has had a capacity charge system since market liberalisation in 1996. The original price for capacity of 7.8 EUR/MWh was chosen as part of the stranded cost compensation that the government guaranteed to generators, which has decreased progressively to 4.8 EUR/MWh between the years 2000 and 2007.

In 2007, after investment increased rapidly, the government introduced a new capacity charge. It acts as a "long-term investment incentive" consisting of a payment for ten years, restricted to new plants with a capacity above 50 MW (existing plants are eligible in case of significant refurbishment investment).

The incentive payment is computed as a function of the reserve margin when the plant starts operations. The charge is capped to 28 000 EUR/MW/yr for a reserve margin index of 1.1 and declines to 0 EUR/MW/yr for a reserve margin index equal to 1.29.

Figure 35 Capacity payment (EUR/MW/yr) as a function of reserve margin index in Spain



Source: *Frontier Economics* (2011).

Capacity markets

A capacity market is a market designed by policy makers and regulators to meet capacity needs as defined by regulators. Unlike energy-only markets, it is a central body that defines which level of capacity is adequate and explicitly sets the quantity for reserve margin or capacity obligation. This constitutes a higher degree of regulatory intervention. The price determination and the choice of the type of capacity (demand response, old power plants or new investments) are left to the market.

So-called Reliability Options are similar to financial call-options to buy power at a predefined strike price when the spot market price is above the strike price (Cramton and Ockenfels, 2011). Such options hedge consumers and generators. With these options, system operators play a

Our understanding is that these reliability options are similar to capacity markets except that they are financial and physical. They have been presented above as a financial product derived from energy-only markets on account of the fact that they must be based on well-functioning energy markets during scarcity conditions.

Table 5 summarizes the different capacity markets according to two dimensions. Capacity obligations can defined either for the short term or forward-looking, and the price determination can be left either to decentralised trading or based on centralised auctions organised by the system operator.

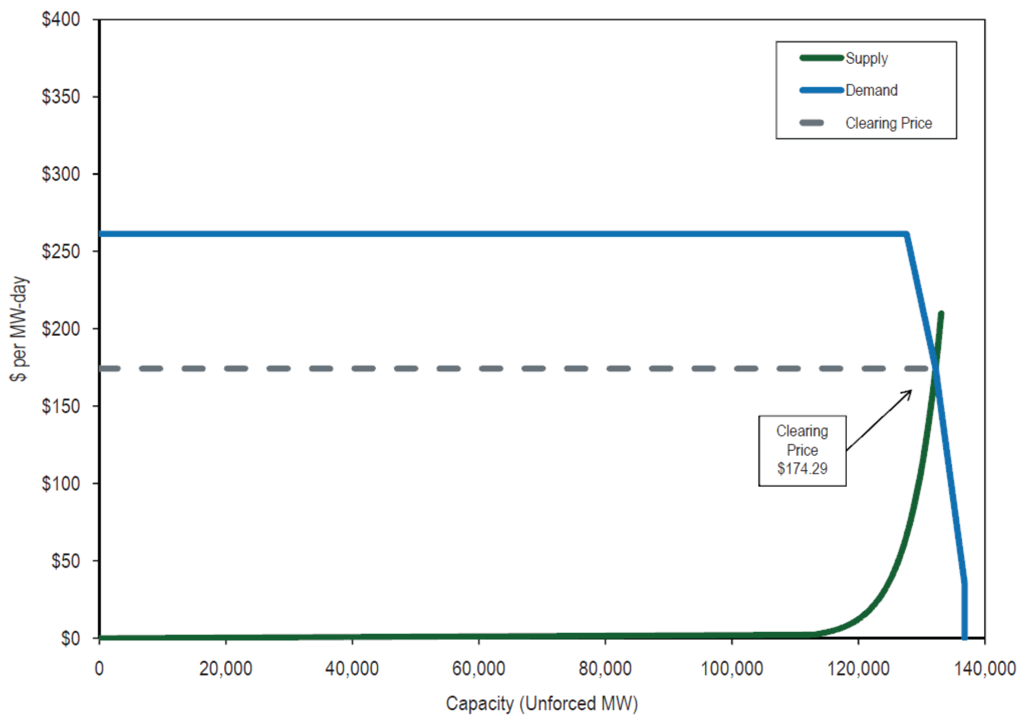
Table 5 • Different types of capacity markets

The system operator defines…	the capacity obligations for each supplier…	…and runs auctions to set the price.
short-term	short-term, decentralised capacity market	short-term, centralised capacity market
several years in advance	forward, decentralised capacity market	centralised, forward capacity market

Decentralised vs. centralised

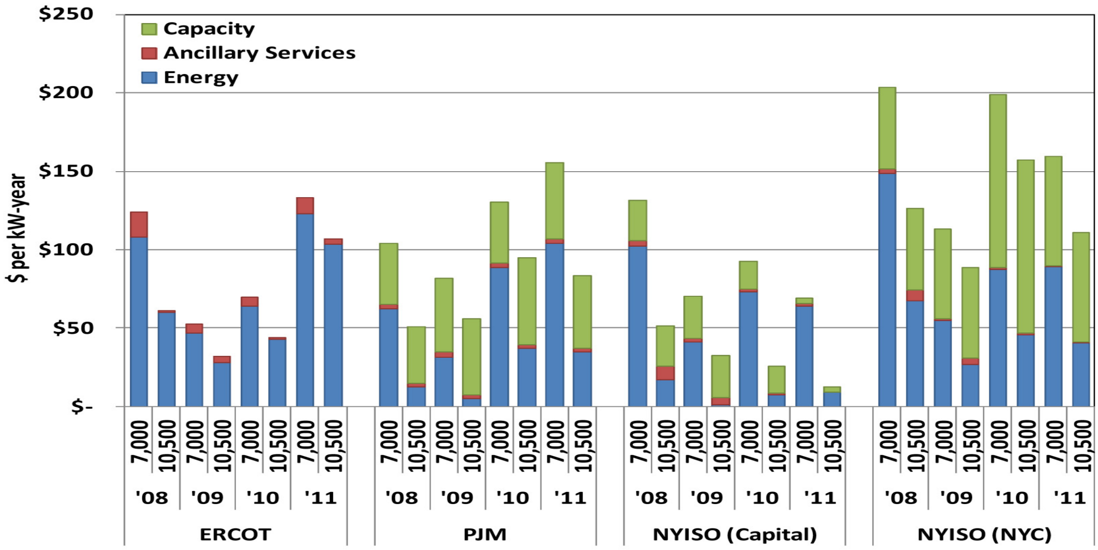
In decentralised capacity markets, such as the one discussed in France in 2011-2012, the system operator defines the capacity obligation for each supplier as a percentage above the load they expect to serve. These obligations can be either self supplied or bought on a market. The ISO certifies capacity and certificates can be traded on a secondary market which determines a price. Although capacity obligations are defined, adequacy still depends on the decentralised forecasts of market size and market shares of each competing supplier.

Figure 36 • Capacity supply and demand curve 2010-2011



Source: *Monitoring Analytics*, 2010 State of the Market report for PJM, October 2011, p. 392.

Figure 37 • Comparison of net revenues of gas-fired generation between markets

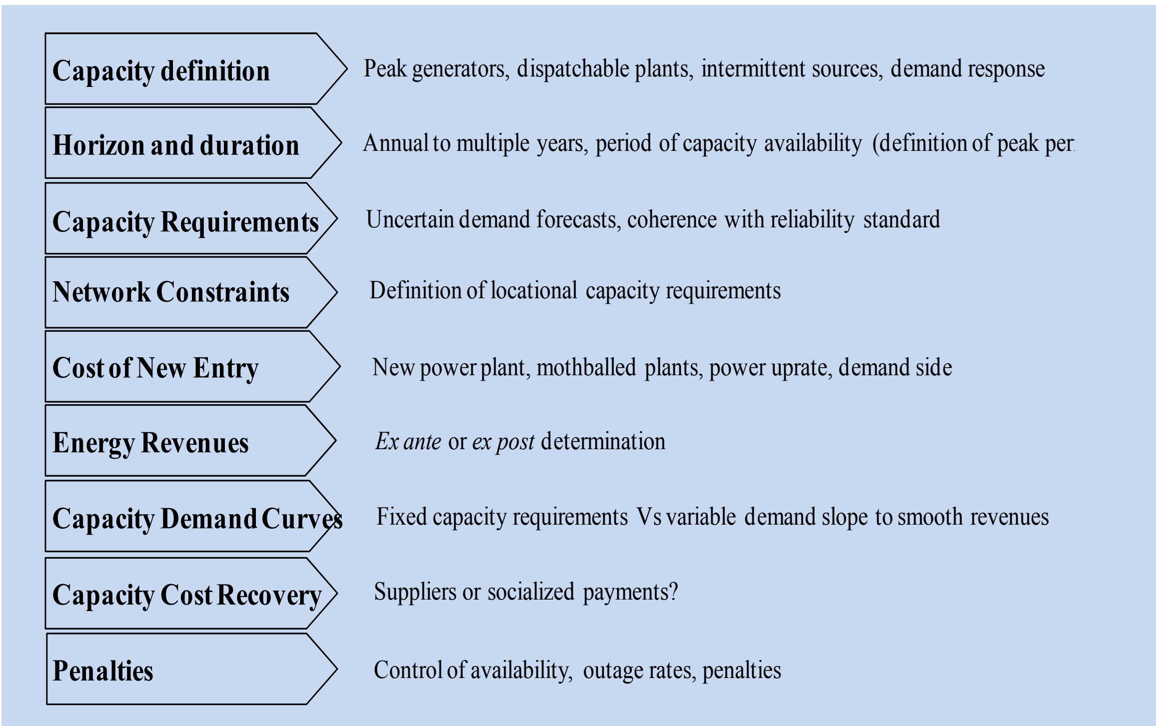


Source: Potomac Economics (2012a).

Short-term vs. forward markets

In short-term markets, capacity targets are typically defined one year in advance. Like many other markets in other sectors, short-term price signals can work, provided that there is enough certainty concerning the sustainability of the arrangement. Indeed, in many other industries (*e.g.* mining, car, chips manufacturers), long-term investments are rarely financed on the basis of long-term product sales.

Box 8 • Design details of capacity markets



Source: adapted from Hogan, 2011.

In forward and centralised capacity markets, capacity targets are established from three to five years in advance, to reflect the minimum lead time required for the construction and development of a new peaking plant or deployment for energy efficiency projects. It has been argued that this presents the advantage of allowing new entrants to bid, making the market more contestable.

Geographical scope of capacity markets

Electricity markets are interconnected and increasingly integrated in some regions. During periods of scarcity in one country or market, interconnections play a key role in ensuring system adequacy. Available capacity in a zone contributes to meeting peak demand in the other zone.

Introducing a capacity mechanism in a jurisdiction representing only one zone of an electricity market raises many questions. First, the contribution of other zones via the interconnection capacity has to be quantified by the system operator when defining the capacity requirement for the jurisdiction. Second, this contribution of interconnection can be remunerated or not, and if it is remunerated, this can be done to the owner of the transmission rights or to the generating capacity on the other side of the interconnection. Third, the implications of different mechanisms on the effectiveness in terms of generation adequacy and possible gaming of the capacity markets must be carefully analysed. For instance, a capacity market limited to one jurisdiction may lead to overinvestment in generation capacity if the contribution of interconnection is underestimated by conservative system operators.

Finally, the competitive effects must be carefully analysed. A single capacity market may introduce a distortion of competition within a single market. In Europe, there are some concerns that national capacity markets could attract investment in countries introducing them, distort competition and create a new barrier for regional market integration. There are also concerns about the treatment of interconnections and the lack of regional coordination regarding supply adequacy.

Where capacity markets are implemented, the treatment of interconnections will remain a key issue. For regions well interconnected and with coupled electricity prices, the target model should include a common definition of capacity credits and the possibility to exchange these credits with a proper treatment of network constraints.

Other dimensions

Designing the details of capacity markets necessitates solving many other technical questions.

- Interaction with peak prices: a capacity market ensures that there is always more than enough capacity and this tends to prevent episodes where market conditions are tight, thus reducing peak prices. This may reduce incentives to save energy or engage demand response actions during these hours, unless they can participate in the capacity market, which might not be possible for small players because of transaction costs.
- Local capacity markets: some small zones of the grid remain poorly interconnected and ensuring adequacy in these zones requires setting up local capacity markets. If a limited number of competing generating units are sufficient to serve it, market power can be an issue.
- Complexity and governance: it is often mentioned that capacity markets tend to be complex and costly. Indeed, the experience of PJM, where a new capacity market was introduced in 1997 to fix several problems, shows that fine-tuning capacity markets is a difficult and lengthy process.

Flexible capacity markets

It has been proposed that capacity markets can also play a role in ensuring that sufficient flexibility services will be available to accommodate increasing shares of variable renewables. Based on the experience of some existing capacity markets, there is a concern that the power plants triggered by capacity markets may not flexible enough. This could lead to restrict the dispatch of variable renewables in the future or require further investments to upgrade plants. Indeed, adding flexibility features to the definition of capacity obligation can contribute to ensuring that the ramp-up or minimum load requirements will be met.

However, restricting capacity markets to flexible products would not solve the generation adequacy issue, as all the capacity would not be factored in. In practice, flexible capacity markets would thus lead the regulator to define quantitative flexibility forward objectives in terms of ramp-up, ramp-down or minimum load. This would go a step further than the definition of flexibility products already discussed before and would constitute an additional market intervention.

Our study suggests that the opportunity of such flexible capacity markets needs further examination for several reasons. Indeed, the ramp-up capacity of conventional power plants is not a major concern until 2020 in most countries. Gas-fired power is the technology of choice for new investments and the recent CCGTs are flexible. As a result, flexibility can be seen as a by-product of adequacy, since generation capacity that will be built primarily to ensure adequacy is also flexible.

Minimum load balancing may be a more important operating challenge, as this leads to curtail renewable during hours of low load and high renewable generation. However, provided that renewable generation is controllable, this is not an issue for the security of electricity supply. While the value of lost load is extremely high in case of a generation adequacy problem (10 000 to 20 000 USD/MWh), the cost of lost renewable generation remains low (50 to 200 USD/MWh). This suggests that regulators could continue to be concerned with supply adequacy more than with flexibility. As discussed previously, creating a market platform for flexibility could be sufficient in order to bring together solutions such as flexibility from nuclear or coal plants, pumped storage, demand-side positive response (water heating) and curtailment of variable generation, as well as other technical solutions in order to develop least cost flexibility solutions.

Annex: Evaluating the policy options

Policy makers in several member countries are considering new measures to address security of electricity supply. There are many options and liberalisation is still a work in progress. Choosing the most promising measures and prioritising regulatory efforts will be a key challenge during the transition to a low-carbon economy.

The evaluation framework proposed here has been designed to help governments to select the options that best fit their specific situations. While pure economic analysis would probably lead to prescribing an ideal solution, the approach adopted here aims to reflect real life circumstances and to identify situations under which one option might be preferable.

The following criteria are proposed to help evaluate the range of measures:

1. Proportionality: Does the scope and form of the regulatory intervention match what is necessary to tackle the issue, given its social cost?
2. Effectiveness: Will the implemented option be effective in ensuring adequate security of supply?
3. Lead time: Is the duration necessary to set-up a regulation compatible with the potential electricity security of supply problem?
4. Simplicity: Has the incremental evolution of existing tools been taken into consideration in order to avoid unnecessarily complex market design?
5. Direct costs: What information and authority would a regulator need in order to set the capacity requirement and what would be the direct costs?
6. Indirect costs: What are the potential unintended effects, market distortion and resulting dynamic costs?
7. Adaptability: Can the arrangement be easily harmonised with neighbouring markets in order to prevent distortion of competition? Can it be easily abandoned when it no longer needed?

The qualitative evaluation framework has been applied to assess the strength and weaknesses of the different options. The results of this analysis are summarised in the figure below, followed by a detailed description of each criterion and the analysis of the options.

Figure 38 • Qualitative assessment of different policy options to ensure security of electricity supply during the transition

	A Improved climate and low carbon policies	B Better energy markets	C Standard & procedures	D Targeted contracting	E Market-wide capacity mechanism
Proportionate	Good	Good	Average	Weak	Weak
Effectiveness	Weak	Average	Weak	Good	Excellent
Lead time	Poor	Weak	Average	Excellent	Good
Simplicity	Weak	Average	Excellent	Good	Weak
Direct costs	Average	Excellent	Good	Average	Weak
Indirect costs	Excellent	Good	Poor	Poor	Good
Adaptability	Average	Average	Average	Good	Weak

Legend: Poor Weak Average Good Excellent

Proportionality

The options available to ensure adequate capacity and security of electricity supply can lead governments to reintroduce a significant degree of regulation of the generation market. A heavy-handed market intervention may undermine the liberalisation objective and the expected benefits in terms of least cost dispatch, efficient operation and market-based investments.

A proportional regulatory intervention is one whose scope and form does not exceed what is necessary to address the issue that needs to be fixed and its social costs. A proportional market design reform is one that neither under-regulates nor over-regulates. In general, the more social costs are at stake, the more effective the measures imposed should be: electricity rationing is not an option for IEA member countries' governments. Striving for proportionality can help to ensure that measures are appropriate for the issue, that they don't pursue distinct objectives and thus are more predictable. This notion is used in competition law in some jurisdictions, such as the EU, where competition statutes expressly require remedies to be proportionate to the infringement committed (OECD, 2008).

Options A (improved climate and low-carbon policies) and B (better energy only markets) addresses the roots of the problem and thus can be considered as proportionate measures. The analysis of option C (standards and procedure) is intermediate and depends on specific measures under consideration. Options D and E are interventions that significantly affect the functioning of energy markets. Indeed, even where there are price caps, the simple anticipation by market players of political intervention to cap power prices is one of the key issues. Assuming this is actually the case, incremental enhancement of energy-only market design can reinforce the credibility of governments or even didactic presentation for policy makers may be sufficient. Instead, a market-wide capacity mechanism may seem heavy-handed and complex.

Effectiveness

Electricity systems involve a significant degree of complexity and enhancing one specific measure does not necessarily produce the expected effect. Other events can occur and gaming effects can lead to unanticipated consequences, which can, in turn, erode the confidence in market-based solutions to ensure sufficient and timely investments.

An effective option to ensure generation adequacy has to guarantee enough certainty to have timely and sufficient investments. It is necessary to assess to what extent the issue will be reduced if the option is successfully implemented. Accordingly, policy makers may prefer quick fixes to eliminate the symptoms rather than addressing the roots of the problems: If you don't have enough capacity, just ask the system operator to add new capacity! This is simple to understand, has visible effects and keeps the lights on.

Among the options available, this is exactly what targeted contracts do and also what capacity markets do more indirectly, by defining directly reliability criteria not in terms of value of lost load (voll) but in terms of capacity requirements. However, the effect of more market-based options is more indirect, difficult to monitor and can be affected by financing conditions. But in case of a blackout, those responsible for system security will be blamed for having relied on dubious solutions.

Lead time

Designing and implementing proper policies takes time. The process involves asking experts to write reports, organising consultations of stakeholders, drafting legislation and bringing the bill to vote. Once the bills are approved, the administration must draft decrees and administrative orders. Overall, policy changes can be a slow process subject to shifts in governments and changes in political priorities or negative arbitrage, all of which have the potential to ruin several years of efforts.

The lead time can be defined as the duration between the initial policy proposal and the date by which it enters into force and begins to have effects. Moreover, even after it enters into force, it may take a few years to build a track record showing that a new market design produces the right signals and is sufficiently stable. For instance, a few years with peak prices not followed by regulatory intervention could be necessary to build trust in an energy-only market design.

This has two implications. First, when regulatory change occurs, it should be done well in advance and in a planned and well communicated way. An example is the current energy policy developed in the United Kingdom, which started in 2008 with a White Paper on nuclear and is expected to come into force in 2013-14 with the first Contracts for Difference (CfD). Second, when there is no time left, governments may be obliged to choose more rapid, though less efficient options.

The leads times for the various options presented above differ:

- Global climate policies (option A) will not be clarified until 2015 for an application after 2020, at best.
- Regional climate and renewable policies (option A) take a few years to be defined and may not produce effects before 2020. Moreover, changing an existing renewable support scheme may be a complex and quite long process.
- Incremental change of energy-only market design (option B) is a quicker option to implement – a few months or years – but a track record may be necessary before they deliver adequate capacity.
- Standards and norms (option C) can also be quickly introduced and applied.
- Targeted contracts (option D) is by far the most rapid option as contracts can always be signed in a few months in order to ensure system security in a hurry.
- Introducing capacity mechanisms (option E) may take two or three years. Unlike the case of market design evolutions, they produce effects as soon as they enter into force.

The slow pace of development of energy policies and the long time associated with energy investment and decisions is a matter of uncertainty. Energy policies can change with governments. New administrations can undo a law before it takes effect, or even after. Some degree of uncertainty seems inevitable: while stable regulation is of key importance for successful market functioning, governments cannot stick to unsuccessful or too costly regulatory reforms.

Simplicity

Several overlapping policies already influence the framework for electricity markets, encompassing. not only liberalisation but also carbon policy, renewable policies and energy efficiency policies. It appears that this increasingly complex market environment increases the perceived policy risk. While originally designed to be complementary and consistent policies, each one tends to become autonomous and live its own life. The typical approach has been to add new regulations to fix issues resulting from other regulations. Uncertainty over the future pace of these policies and continuous regulatory changes can push the attractiveness of the industry down.

A simple policy is a policy that is capable of avoiding unnecessarily complex policy or regulatory intervention. It must be easy to understand, as far as possible use existing procedures and IT tools; and should aim to replace old policies rather than adding a new layer of regulation.

Among the options considered here, forward capacity market (option E) is by far the most complex, as it requires setting-up an entirely new system. Climate policies (option A) also involve a certain degree of complexity, as they usually rely on a set of policy instruments such as carbon pricing, FiT, auctions for renewables, energy efficiency policies, and so on standards and procedures (option C) and targeted measures (option D) are relatively simple to understand and implement and can normally be abandoned easily. Improving energy-only markets can also be regarded as fairly simple, although the design details must be carefully defined.

Direct cost

Regulation is not free. Regulators need staff, information and consultancy to do their job. In addition, corporations also bear costs and establishing new trading electronic platforms entails expenditure. At first glance, these costs may appear relatively limited compared to the expected benefits of new measures. However, public spending is coming under increasing pressure and many member countries must streamline their administrative processes.

Given its complexity, creating capacity markets (option E) tends to be relatively more costly than other options. Improving existing market design and standards and procedures (options A and C) are incremental evolutions and their costs are easier to predict and lower.

Indirect cost

The costs of regulation must be viewed dynamically, taking into account the potential impact on the adoption of new technologies and practices. Indeed, these dynamic effects often represent a significant potential cost of regulations. Indirect dynamic costs can make market performance even worse than if we simply lived with the market imperfections. (Joskow, 2010)

Avoiding indirect costs is about preventing rules or distortions that can create barriers to new technology development. Solutions that create a level playing field, *e.g.* a comparable treatment for all technologies, are more likely to limit indirect costs. Appropriately designed solutions should focus on solving the causes of issues, such as policy risk or better designed markets. On the contrary, options that pick up technologies such as targeted contracts, and in certain cases, standards and norms, carry the risk of significant indirect costs.

Adaptability

By many aspects, liberalisation in still a work in progress in many countries, and integration of renewables is expected to require future changes of market design. Market integration over large geographical areas will bring benefits. It reduces dispatching and balancing costs and facilitates the accommodation of increasing shares of variable renewables. As these developments are foreseen, policy makers need to anticipate that further harmonisation will be required.

The two fundamental principles which ensure the adaptability of a regulatory arrangement are:

- reversibility, in order to remove the new regulation if it is not needed anymore, and
- ability to be harmonised, so that the regulatory option can converge rapidly with other systems.

Market-wide capacity mechanisms tend to be less adaptable than targeted contracts. The possibility to adapt other options would depend on design details.

Acronyms, abbreviations and units of measure

Acronyms and abbreviations

2DS	2-degree Celsius scenario of *Energy Technology Perspectives*
AEMO	Australian Energy Market Operator
BANANA	build absolutely nothing near anyone
BEV	battery electric vehicle
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CfD	contracts for difference
CHP	combined heat and power
CO_2	carbon dioxide
EEG	Erneuerbare Energien Gesetz
ESAP	Electricity Security Action Plan
ETS	European Emissions Trading Scheme
EUR	European Utilities Requirements
FCEV	fuel-cell electric vehicle
FiT	feed-in tariffs
GIVAR	Grid Integration of Variable Renewables
HEV	hybrid electric vehicle
HVC	high value chemical
ICE	internal combustion engine
LED	light emitting diode
LMP	locational marginal pricing
LSIP	large-scale integrated project
NEM	Australian National Electricity Market
PHEV	plug-in hybrid electric vehicle
PPA	power purchase agreements
PV	photovoltaic
RGGI	Regional Greenhouse Gas Initiative
RO	reliability option
RMR	reliability must-run contracts
VRE	variable renewable energy
WACC	weighted average cost of capital

Units of measure

GW	gigawatt
MWh	megawatt hours
TWh	terawatt hours

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