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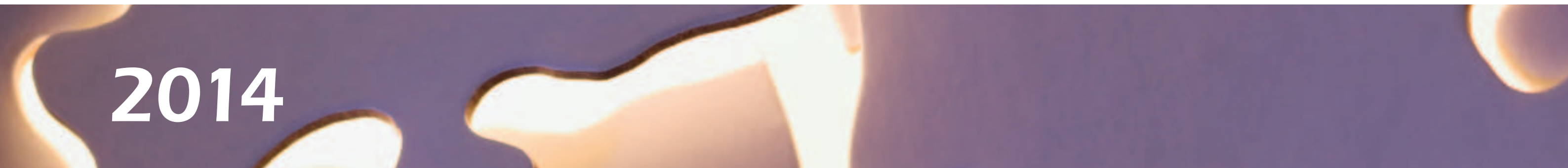
SEAMLESS POWER MARKETS

Regional Integration of Electricity Markets in IEA Member Countries

FEATURED INSIGHT

Manuel Baritaud and Dennis Volk



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2014

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The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 29 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

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Foreword

At the October 2011 Governing Board Meeting at Ministerial Level, International Energy Agency (IEA) member countries endorsed the IEA Electricity Security Action Plan (ESAP). The electricity security work programme reflects the challenge of maintaining electricity security while seeking to quickly reduce power systems' CO_2 emissions. 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, creating new challenges to maintain electricity security.

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

ESAP 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 renewables 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, as well as from regional market development experience in IEA 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 key peer review programmes of the IEA – 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 strengthening power system security and emergency preparedness.

"Seamless Power Markets" is one of the ESAP work streams. It sheds light on key issues to be considered for successful market integration. It draws upon two Insights Papers, "Securing Power during the Transition" (IEA, 2012) and "Electricity Networks: Infrastructure and Operations" (IEA, 2013). This report adds a further dimension to the analysis, namely regional integration, a key feature in the recent development of electricity markets.

Acknowledgements

The principal authors of this paper are Manuel Baritaud and Dennis Volk of the Gas, Coal and Power Markets Division, working under the direction of Laszlo Varro, Head of Division.

This paper has benefitted greatly from discussions and suggestions by Doug Cooke, from the IEA. The authors want to thank for their contributions and comments the following staff from the IEA: Christelle Verstraeten, Matthew Wittenstein, Sylvia Beyer, Christina Hood, Kieran McNamara and Katrin Schaber.

In addition, the IEA and the authors are grateful to the following IEA member country administrations for their participation in the review process:

- Luis Hilario Alonso Mijares (Spain)
- Johann Duvigneau (Germany)
- Espen A. Hauge (Norway)
- Lenka Kovačovská (Czech Republic)
- Adam Normark (Poland)
- Geoff Whelan (Australia)

This work has been reviewed by

- Richard Baron (OECD)
- Jacqueline Boucher (GDF SUEZ)
- Pieter Boot (PBL, Netherlands)
- Silvano Domergue (Réseau de transport d'électricité, RTE)
- Christophe Gence-Creux (Agency for the Cooperation of Energy Regulators, ACER)
- Anne-Malorie Geron (Eurelectric)
- Jean-Michel Glachant (European University Institute and Florence School of Regulation)
- Bernd Goedde (Vattenfall Energy Trading GmbH)
- Annegret Groebel (Bundesnetzagentur)
- David Halldearn (Office of Gas and Electricity Markets, Ofgem)
- Jan Horst Keppler (OECD Nuclear Energy Agency, NEA)
- Steven Macmillan (Origin Energy Australia)
- Richard McMahon (Edison Electric Institute)
- Leornardo Meeus (Vlerick Business School and Florence School of Regulation)
- Scott Miller (Federal Energy Regulatory Commission, FERC)
- John Moura (North American Electricity Reliability Corporation, NERC)
- Faisal Naru (OECD)
- Susanne Nies (Eurelectric)
- Richard O'Neill (FERC)

- Davide Puglielli (ENEL)
- Konrad Purchała (Polskie Sieci Elektroenergetyczne)
- Matthew Ramsden (Ofgem)
- Ulrik Stridbæk (Dong Energy)
- Peter Styles (EFET)
- Matti Supponen (European Commission)
- Miguel de la Torre Rodriguez (Red Electrica de Espana, REE)
- Jonas Tornquist (Electricité de France, EDF)
- Fabienne Salaun (EDF)
- Charles Verhaeghe (Commission de régulation de l'énergie, CRE)
- Daniel Wragge (European Energy Exchange)
- Stephen Woodhouse (Pöyry)

This work also benefitted from the input of many other people met at various conferences and meetings, in particular during the review team visit of the In-Depth Review of the Energy Policy of the United States that took place in June 2013.

Janet Pape and Romy de Courtay provided essential support in terms of editing and design of this paper.

Executive summary

Electricity markets covering large geographic areas are needed to accommodate the deployment of wind and solar power at least cost. Renewables need to be harvested and transported via wire over vast territories. Their output does not follow consumption. It depends on variable wind, sun and exogenous conditions that are difficult to predict. Given the limited and relatively expensive options for storing electricity, it is less costly to integrate variable renewables when tapping into the flexibility of electricity systems over wide areas.

Electricity markets in some regions are under strain. Perhaps the most salient phenomenon in Europe is that gas-fired power plants in markets with overcapacity are not competitive, despite the fact that they will be needed to complement renewables and replace ageing capacity. Another issue is the use of state-level renewable energy support schemes. Not only do these not use power markets to drive investments, they also undermine their functioning. The cost of renewables support can seem very high compared with the cost of measures to support conventional generation and ensure supply security. Yet falling back on some form of fragmented state regulation should not be seen as a reasonable solution to decarbonisation.

Reaping the benefits of market integration is vital to enable renewables deployment and control costs. The cost of renewable energy policies is a growing concern. Hence, decarbonising at least cost requires tapping renewable and flexible resources over large geographic areas. Large markets are essential to efficiently co-ordinate the growing number of generators and consumers. Recent studies have quantified the potential benefits of market integration in Europe at EUR 12.5 billion to EUR 40 billion per year, or a medium value of EUR 6.8/megawatt-hour (MWh) of consumed electricity (Booz, 2013). Similarly, PJM Interconnection LLC (PJM) claims that more efficient operations save USD 2 billion annually, or USD 2.7/MWh.

The question, therefore, is where and how governments can work together to reap the full benefits of power market integration.

Renewables deployment calls for more efficient integration of real-time markets. Currently, the rapid deployment of wind and solar power creates bottlenecks in networks and unscheduled loop flows among adjacent grids. This tends to limit the network transfer capacity (NTC) available for cross-border trade. Looking ahead, managing variability of renewable energy, for instance between the sunny Mediterranean Sea and windy North Sea regions, will become necessary. A successful integrated electricity market should not only cover wide geographic areas, but also be flexible, demonstrating its ability to cope with changing weather conditions and unpredictable power flows while ensuring electricity security.

Cross-border electricity trade continues to be perceived as potentially risky to electricity security. Indeed, it must be acknowledged that all the recent blackouts – Italy and New York in 2003, Western Europe in 2006 and India in 2012 – were due to a lack of co-ordination among system operators. System operators are inherently conservative – which is legitimate when deploying wind and solar power in electricity systems designed for conventional power generation technologies such as gas, coal and nuclear power plants. Furthermore, growing imports tend to be seen as risky in some jurisdictions where governments' first priority is not market integration, but "keeping the lights on".

Based on the experience of International Energy Agency (IEA) member countries, this paper can identify two ways to integrate markets over wider geographic areas:

- First, **consolidate** markets and system operations. The most direct way is to merge system operators, ensuring that the same rules for electricity system security apply across all consolidated control areas. The National Electricity Market (NEM) in Australia and PJM and MISO in the

United States illustrate the higher efficiency of this approach. To date, consolidation has created large control areas spanning several states within a country (intra-country), but not among countries (inter-country).

- Second, **co-ordinate** markets and system operations. When consolidation is not possible, co-ordination remains necessary between adjacent system operators. This approach requires defining cross-border transmission capacity and ensuring efficient price formation at the border. It also requires a co-ordinated adequacy assessment and management of emergency situations. The more efficient the co-ordination, the more likely the outcome of a consolidated system and market operations.

The consolidation approach is more suited to real-time market integration in highly meshed networks. In principle, this can ensure more efficient, dynamic and flexible use of existing assets for real-time markets. Consolidated system operators can better avail themselves of physical transmission capacity and handle network congestions. This is particularly relevant in highly meshed networks. In electric islands or peninsulas with limited physical cross-border lines/interties, separate system operators with different price zones may remain the best practical solution.

A key finding of this report is the need for strong co-ordination of electricity security regulatory frameworks. Electricity security lags behind market integration. The lack of co-ordination of reliability standards is limiting further progress. Without a clear, common and sound regulatory framework on electricity security, markets cannot deliver the right price signals during scarcity conditions or provision the necessary flexible resources to complement variable renewable energy (VRE) or signal where investments should be made. Hence, the electricity security regulatory framework needs to be harmonised − or better yet, standardised − over the relevant geographic area of an integrated market.

Several barriers hinder the efficient integration of electricity markets. The physical explanation is the lack of transmission lines to interconnect markets in some areas. Even where transmission lines do exist, they are not always used efficiently. Other barriers are institutional. Electricity security remains a concern, and local government and regulator mandates are set at the national (e.g. in Europe) or state level. Finally, the distributive impacts of market integration should be addressed, as they will otherwise remain a barrier.

Addressing barriers to integration of electricity markets requires actions at the three levels of policies, regulation and markets. Governments have an important role to play, along with regulators and system operators. Federal or international organisations can overcome some barriers, while bilateral or multilateral governmental frameworks can address others with bottom-up initiatives. Regulators and system operators can also play a decisive role (e.g. with market coupling in Europe).

Policies

Power markets do not integrate by themselves. A policy commitment is needed to create efficient markets over large geographic areas. Governments must work together – and with international organisations – to ensure reliable, affordable and clean electricity in the relevant geographic area. The mandates of independent regulators and system operators should also be aligned with these policy objectives. Integrating markets requires functional, liquid and competitive wholesale markets, which in turn calls for a strong commitment towards electricity market liberalisation at the political level.

Policies pertaining to the security of the electricity supply are either national (in Europe) or the responsibility of states or provinces (in North America and Australia). They include many dimensions, such as defining reliability targets (in terms of loss of load expectations [LOLE]) and attaching value to reliability in the cost-benefit analysis of investment decisions. Their more technical aspects include devising binding security standards for network construction, as well as protocols for use in scarcity conditions and load curtailment procedures across jurisdictions. Efforts to harmonise the regulatory frameworks for electricity security lag behind efforts aiming at market integration. To a certain extent, policy integration implies transferring competence for supply security, which might explain the slow progress to date.

Low-carbon generation and renewables are now an integral part of many electricity systems and are probably the most promising field for further integration. An integrated approach can bring significant benefits over renewables policies for countries or individual regional governments. Evidence shows that despite its effectiveness, today's patchwork of policies across borders has a high cost and is visibly impacting on end-user prices. As renewable technologies mature, low-carbon policies need to be included in the scope of the market integration project.

Interconnectors

Interconnector services constitute the backbone of electricity market integration. Yet the interface between system operators very often constitutes a barrier to cross-border trade. The major issues found at this "seam" between the control areas of adjacent system operators include planning, construction and cost allocation of new transmission lines, the reliability implications of cross-border power flows of adjacent system operators and practical difficulties in making the best use of existing interconnection capacity.

Transmission lines that connect markets can already be well developed within synchronous frequency areas. Cross-border lines amount to 11% of installed generation capacity in Europe – ranging widely from only 3% in Spain and the United Kingdom to 48% in Switzerland (a key European country whose electricity flows are influenced by international trade). In the United States, the Western and Eastern Interconnections are poorly linked, with only 2 gigawatts (GW) of capacity for an installed system capacity exceeding 900 GW.

Reliability is the first preoccupation of governments, regulators and system operators. Recent security events in synchronous areas remind us of the fundamental physical reality of electricity grids. With the deployment of renewables, power flows will become more volatile from one hour to the next, or over even shorter timeframes, creating electricity flows that cannot always be correctly anticipated. Some system operators have created embryonic common control rooms to improve co-ordination in real time. Deeper market integration, including wind and solar power, would require more exchange of information in real time and better co-ordination of network operations.

Interconnectors are not always the least-cost solution. Ensuring system adequacy can result in a mix of solutions blending capacity generation, demand response, storage and new transmission and distribution infrastructures.

Building new interconnectors requires co-ordinated planning, regulation and siting on a comparable cross-border area. The long and burdensome licensing and siting procedures are further compounded by the challenges to creating a co-ordinated investment framework, leading to concerns about the slow development of interconnectors. Should the licensing process be streamlined, new interconnectors would still encounter local opposition and costs that could constrain interconnector capacity. It is vital to create an open network development framework to take advantage of competing market and technological solutions.

The cost allocation of new transmission lines must reflect the benefits. The lack of agreed cost-allocation methodologies can hinder investment, since greater interconnection normally creates both winners and losers by lowering prices in one area while raising them in another.

While identifying and allocating the available interconnector capacity of existing assets can prove effective, this exercise is often neglected. Its main tasks include: (i) applying dynamic and close to real-time capacity assessments that accurately reflect the physical network and system reality with high spatial resolution; (ii) removing any cross-border access charging of infrastructure costs that do not represent costs of network use across the integrated market; and (iii) allocating the transfer capacity over different time horizons (i.e. long-term, forward, intraday, balancing and system services timeframes). Transmission rights should be allocated dynamically and competitively, especially in regions with growing dynamics from variable renewables generation. But trading closer to real time reinforces the need to closely monitor system security.

Governments and regulators play a very important role, as they establish and amend sound policies, regulatory frameworks and institutions. These dimensions influence electricity reliability, as well as market participants' use of existing assets for different services at different times and locations and the efficiency of renewables integration. Stronger dedication to inter-regional approaches and sufficient responsible staff at all institutions will facilitate reliable and efficient regional market integration.

Markets

There is clear empirical evidence that consolidating system operations over wide geographic areas can lead to significant changes in power flows – an indication of a more efficient dispatch, in particular in areas with locational marginal pricing. The most famous examples are the establishment of the NEM on Australia's east coast in 1998 and the expansion of the PJM footprint since 2000 to a large portion of the Northeast Interconnection. Other opportunities to merge system operators and their balancing areas may exist in Europe, North America and Japan.

In any event, co-ordinating energy markets at the interconnection seam is a necessary step. Poor co-ordination sometimes leads to energy trades in the wrong direction, i.e. from higher-price zones to lower-price zones. Among the solutions available to co-optimise networks and generation, day-ahead market coupling – already implemented in parts of Europe – ensures efficient use of interconnector capacity and has proven successful at eliminating such inefficient trades on the day-ahead timeframe. These trades are, however, more difficult to eliminate for intraday and close-to-real-time pricing, as witness the cases where real-time prices diverge significantly from day-ahead prices. Inefficient trades usually result from administrative time lags between system operators that schedule cross-border transactions before knowing the real-time prices.

Balancing energy and ancillary services will likely grow to compensate for the variability and uncertainty of wind and solar power. These services are traditionally subject to regulation and operated by system operators within their control area. Two leaders in renewables deployment, Germany and California, have recently procured balancing services in adjacent control areas. Several plans are under way to extend them, including the Agency for Cooperation of Energy Regulators (ACER) Framework Guidelines, the European Network of Transmission System Operators for Electricity (ENTSO-E) Network Codes on Balancing and Ancillary Services and the Energy Imbalance Market proposed by the California Independent System Operator (CAISO) in the Western Interconnection of the United States. The key question here is, will each balancing area retains control over real-time dispatch instructions or will a single system operator control the integrated system?

Forward and financial markets also need further development to provide a hedge against cross-border electricity trades. Selling electricity across borders may expose traders to hard-to-predict volatile price differences when interconnector capacities become scarce. Financial products such as financial transmission rights (FTRs) or contracts for difference (CfDs) offer more opportunities to trade long-term contracts across borders, thereby increasing competition. When physical contracts do exist, they should contain provisions such as "use it or sell it" to ensure they match financial contracts in terms of efficiency of capacity use. Independent service operators (ISOs)/regional trade organisations (RTOs) and power exchanges may need to play a more active role in establishing and maintaining enough liquidity for FTRs.

Burgeoning capacity mechanisms raise many co-ordination problems. Fragmented and inconsistent capacity constructs as varied as capacity payments, strategic reserves or capacity markets risk undermining the functioning of integrated energy markets. While allowing cross-border capacity trade would improve the situation, it faces many obstacles, mainly stemming from the absence of integrated electricity security policies and regulations. The proposed principles for ensuring co-ordination of capacity markets are:

- integrated generation adequacy forecasts;
- harmonised capacity product definition;
- joint determination of cross-border capacity transfer capability; and
- adaptability of capacity markets to future harmonisation efforts.

Differences in low-carbon policies, including different CO_2 taxation and national carbon prices, distort integrated wholesale electricity markets. For instance, carbon prices applicable in one jurisdiction but not in another can lead to carbon leakage and imports of electricity with a higher carbon content. In the absence of a comprehensive energy policy, the patchwork of local clean policies inevitably reduces the efficiency of integrated electricity markets.

Building on the positive experience of integrated pools and coupled markets, the next step in achieving integration requires common intraday, balancing and capacity markets and harmonised carbon policies to cope with new challenges and enhance the efficiency of energy transitions and renewables integration.

Introduction

Creating continental-scale electricity markets is a historical industry trend. The rapid deployment of VRE is reinforcing the case for further market integration. Indeed, while it is possible to transport primary fuels at cheap cost from the pit to the power stations, wind and solar power must be transported via wire. The physical properties of electricity entail balancing this weather-induced variability in real time over wider geographic areas.

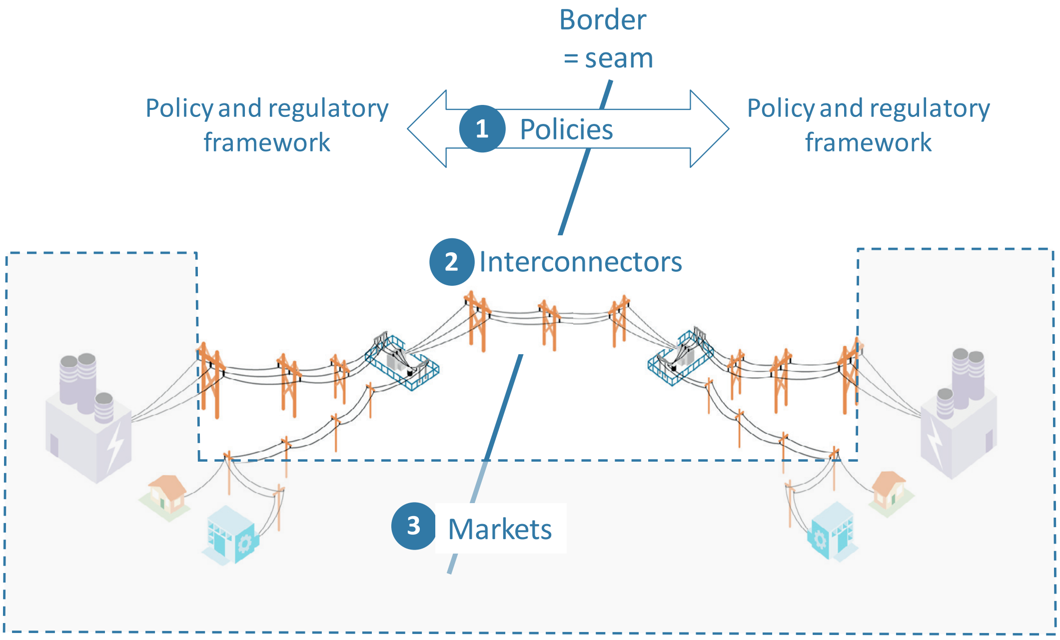
Many studies focus on the technical feasibility of the regional electricity system required to accommodate high shares of wind and solar power. This report focuses on the market and regulatory frameworks needed to achieve these visions. It draws on the experience of IEA member countries in consolidating and co-ordinating markets and system operations and sheds new light on the role of system operators.

The report identifies possible priorities for governments in terms of market integration and aims to:

- provide an overview of different models of integration of market over wide geographic areas;
- identify market integration's contribution to increasing electricity security and supply, as well as identify barriers towards more co-ordinated approaches to reliability regulations;
- assess the implications of differences in low-carbon and technology-specific policies;
- identify barriers to physical market integration;
- provide balanced advice on developing bulk power exchanges between areas; and
- identify best practices in terms of integrating different capacity markets.

The report is structured as follows (Figure 1): Chapter 1 provides an overview of the benefits of market integration. Chapter 2 discusses high-level policies towards integration of electricity markets. Chapter 3 focuses on the regulatory framework of network interconnectors. Finally, Chapter 4 analyses the integration of real-time, wholesale, financial and capacity markets.

Figure 1 • Market integration



Source: Unless otherwise indicated, all material in figures, tables and maps is derived from IEA data and analysis.

Benefits of regional market integration

Regional integration of electricity markets is a persistent historical trend in the electricity industry. Whereas the drivers of electricity market integration are the same in different Organisation for Economic Co-operation and Development (OECD) regions, the current degree of market integration differs widely, reflecting largely different institutional and regulatory frameworks (Annex 1).

Electricity market integration rests on reliability and efficiency considerations. This section reviews the drivers, benefits of and barriers to market integration (Figure 2). First, it discusses how integrating electric systems improves reliability for all participants – historically one of the first reasons for constructing electric transmission lines across borders. Second, it identifies how integration reduces overall costs through demand aggregation and complementarities of the mixes of generation capacity. Wind and solar power deployment increases these benefits. Third, it presents quantitative estimates of the benefits associated with large-scale market integration. This section concludes with a review of the main barriers to the "seamless market" creation that need to be addressed by policies, regulations and market integration.

Figure 2 • Drivers, benefits and barriers to market integration

Electricity security of supply

Different dimensions of electricity security are already crossing borders. Most countries or states import the primary fuels (such as gas and coal) used to generate electricity. Annex B discusses the contribution of market integration to fuel security. System security requires strong co-ordination among system operators across synchronous frequency zones. Further, benefitting from available capacity in adjacent areas reduces LOLE.

System security: synchronous frequency areas are interdependent

Electricity systems have been developed in all IEA regions in a co-ordinated fashion around technical standards and norms (all electrical equipment is designed for a 50 hertz (Hz) frequency in Europe and 60 Hz in the North America). Strong co-ordination among system operators is required to maintain system security over such large synchronous-frequency areas[1]. Any frequency deviation (e.g. caused by an unscheduled generator loss in a control area) can damage the power system equipment, possibly leading to cascading blackouts.

Experience shows that the lack of co-ordination among system operators is at the root of almost all major blackouts in IEA systems (Table 1). For instance, the Italian blackout in 2003 involved co-ordination problems between Italy and Switzerland. The Great Northeast Blackout in 1965 led

[1] The term "frequency area" refers to the physical reality where electric utilities are electrically tied together during normal system conditions and operate at one synchronised frequency of 50 Hz (in Europe, Australia and parts of Japan) or 60 Hz (in North America). This report will use the term "frequency area" (also known as "interconnection" in the North American context) throughout.
Electric ties can cross control areas, state borders and/or interconnections. Transmission lines constitute these electric ties and wherever they do so, this report refers to them as "interconnectors". Thus, an interconnector can support trades between control areas operated by one or several system operators, across states and their systems and also across interconnections.

to the creation of the North American Electric Reliability Corporation (NERC) in 1968 to ensure the reliability of the North American bulk power system.

In Continental Europe, co-ordination among adjacent control areas started with the creation of the Union for the Co-ordination of Production and Transmission of Electricity (UCPTE) in 1951, which is now included in ENTSO-E. More recently, CooRdination of Electricity System Operators (CORESO) in 2006 and Transmission system operator Security Cooperation (TSC) in 2008 were created to support several national transmission system operators (TSOs) with wider and often closer to real-time (every 15 minutes for CORESO) awareness of the physical status of transmission grids across borders.

Table 1 • Large-scale blackouts involving several power system areas

Date	Region	Population affected (indicative)	Affected power system areas	Cause
1965, 9 November	US Northeast	30 million	5 (Ontario Hydro System, St Lawrence-Oswego, Upstate New York, New England, Maine)	Relay with faulty trips, setting off power line overloads
2003, 14 August	US Northeast, central Canada	50 million	5 (Ontario, MISO, PJM, New York ISO, ISO New England)	Plant outage, line failure led to a chain reaction
2003, 28 September	Italy	56 million	3 (France, Switzerland, Italy)	Failure of a transmission line in Switzerland, lack of communication
2006, 4 November	Western Europe	15 million	7 (France, Germany, Netherlands, Belgium, Italy, Spain, Portugal) – the entire Continental Europe system was affected	Human error in a substation

Source: IEA, 2013.

Despite some challenges associated with system security, electricity market integration presents substantial benefits in terms of diversified supply sources and decreased costs of maintaining adequate generation capacity.

Adequacy

Market integration over large geographic areas helps pool the expensive capacity resources required to maintain reserve margins. Ensuring access to a broader portfolio of power plants makes it easier to find the capacity needed to replace a power plant when it becomes unavailable due to a planned maintenance, unscheduled outage or safety concern. This, in turn, reduces the cost of maintaining adequate capacity, thereby increasing the reliability of the electric system.

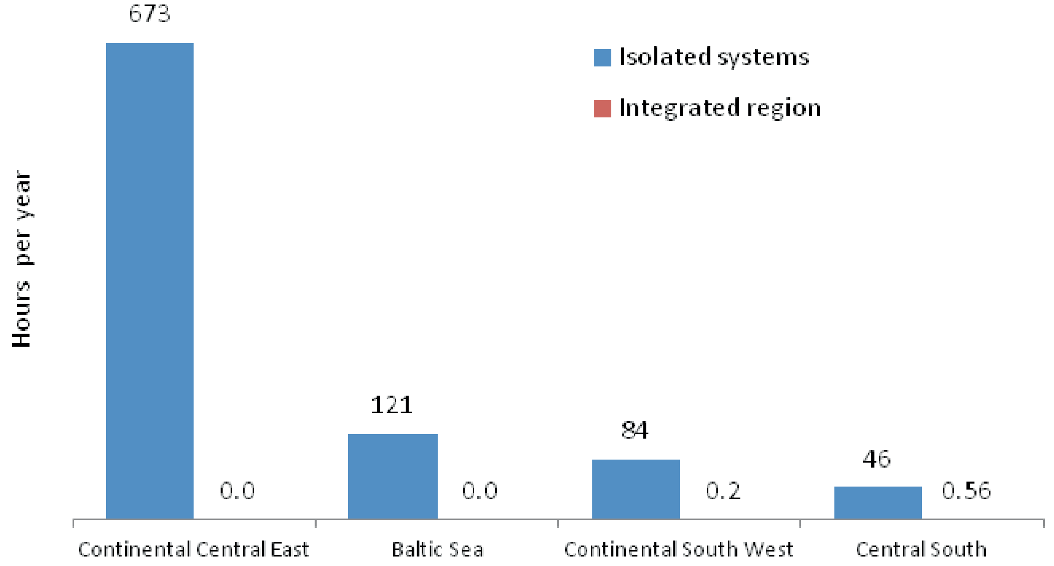
In Europe, ENTSO-E assesses the benefits of market integration to supply security. The association of TSOs performs a probabilistic assessment of generation adequacy for different regions based on probabilistic analysis of load uncertainty, availability of thermal generating sources, hydro uncertainties and wind and solar uncertainty. These stochastic models calculate a LOLE adequacy metric representing the expected number of hours per year where the available supply is smaller than the load.

As Figure 3 below depicts:

- The aggregated LOLE calculated for isolated electricity systems in 2020 would be very high, corresponding to several days per year of capacity shortage. Such poor quality clearly exceeds the acceptable level in many IEA member countries.
- The results of the Monte Carlo analysis for integrated systems are much more positive. The LOLE never exceed one hour by 2020, reflecting an adequate infrastructure. Such an analysis

leads to the conclusion that electricity market integration improves electricity supply security in all the integrated markets.

Figure 3 • LOLE in 2020 for isolated systems and integrated regions



Note: Scenario B of ENTSO-E.
Continental Central East region: Austria, Czech Republic, Germany, Hungary, Croatia, Poland, Romania, Slovenia and Slovak Republic;
Baltic Sea region: Denmark, Estonia, Finland, Lithuania, Latvia, Norway and Sweden;
Continental South West: Austria, Switzerland, Germany, France, Italy and Slovenia;
Central South: France, Spain and Portugal.
Source: IEA graph, based on ENTSOE calculations.

The adequacy analysis should reflect the stochastic nature of electricity demand and wind and solar power generation. The specific results of such probabilistic simulations depend on many assumptions about the exact shape of probability distribution. It is important to note that adequacy is not a deterministic notion. It would be too costly to build enough capacity to cope with all possible situations. Rather, optimal adequacy depends on the value societies attach to reliability and the risk of occasionally having to cut load (see IEA, 2012).

Efficiency

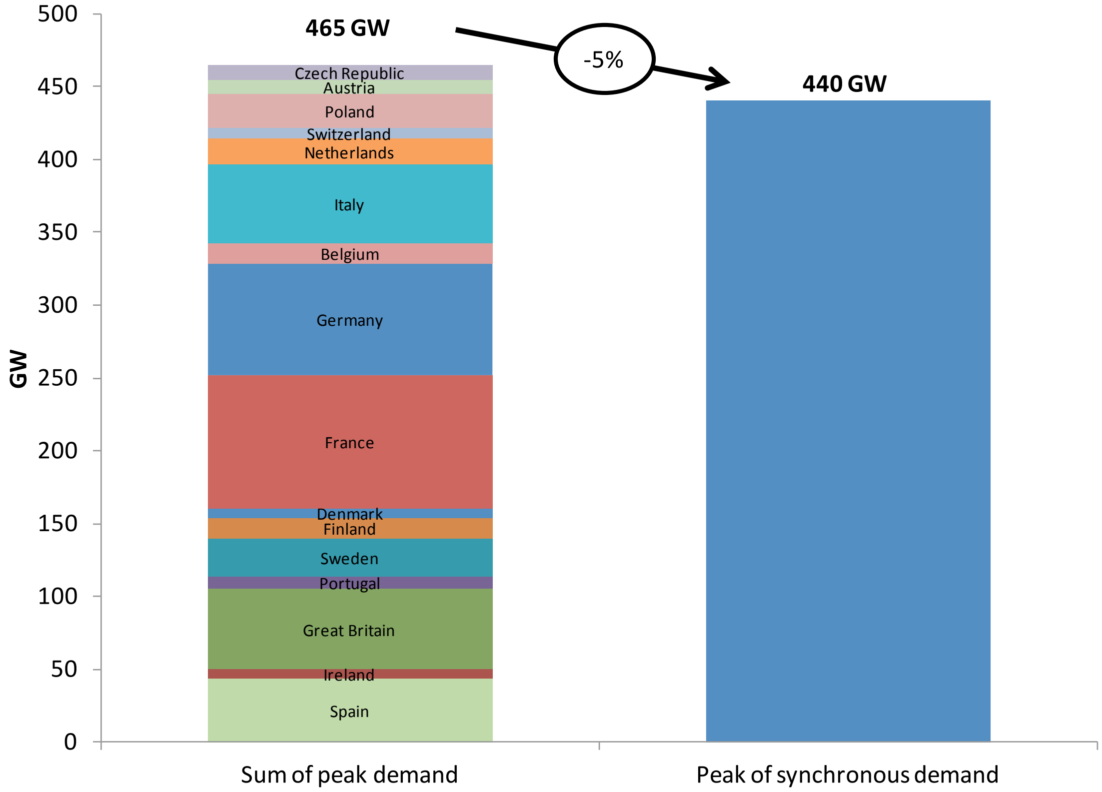
Integrated electricity markets and the associated development of cross-border electricity trade are already ingrained in all IEA markets, albeit to different degrees (see Annex 1 on the state of play of market integration). Cross-border trades contribute to reducing the overall cost of the electricity system by exploiting the complementarities between demand patterns and cost differences between electricity systems. Countries with wind and solar power tend to deploy it more rapidly in windy and sunny locations. These recent developments increase the benefits of market integration over larger geographic areas.

Aggregation of demand across regions

Maximum electricity demand usually occurs at different times in neighbouring regions. Northern Europe and Canada experience peak demand in winter thanks to electric heating, whereas Southern Europe and the United States experience summer peaks due to air conditioning. This seasonal variation in electricity demand means the regions can share resources. Instead of building up capacity that would sit idle for many months of the year, sharing resources reduces the need for expensive facilities on both sides of the border (Energy Information Administration (EIA), 2012).

In European countries, synchronous peak demand was 5% lower in 2011 than peak demand of each country taken separately (Figure 4). This gives an order of magnitude of possible gains from a regional approach towards generation adequacy.

Figure 4 • Peak demand in 16 European countries, 2011



Another attraction of market integration across large areas is that it smoothes demand variations. Aggregate demand increases the proportion to baseload demand and reduces the share of peak demand (Figure 5). This effect increases the average load factor of the power plant fleet needed to meet demand, driving down costs.

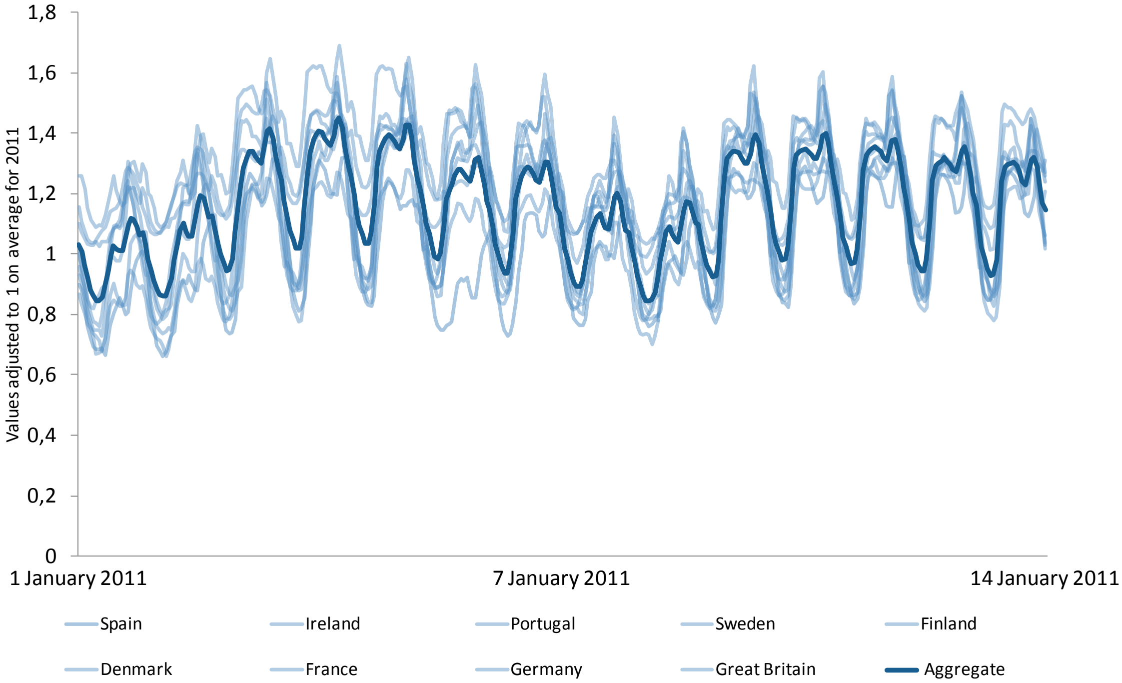
Synergies between generation-capacity mixes

There is also little debate that market integration offers benefits in terms of overall dispatching costs. The least-cost solution to meet demand during a certain hour is to start with the cheapest generating sources (wind, solar power, run-of-river hydro and nuclear) and then call on other units by order of increasing marginal cost. The overall generation cost is lower if dispatching over a broader and more diversified portfolio of plants.

As Figure 6 below shows, technology mixes differ substantially in Europe. In Poland, the United Kingdom, the Netherlands and Denmark, more than 75% of installed capacity is fossil fuel-fired. At the other extreme, Norway, Switzerland and Austria have considerable hydro capacity. France, Belgium, Sweden, Germany, Spain and the United Kingdom concentrate nuclear capacity. Germany, Denmark, Spain and Italy account for most wind and solar power. Such heterogeneity creates many trade opportunities between these countries.

The diverse generation capacity results from differences both in the countries' energy policies and natural endowments. Renewable resources depend on wind or sun conditions and the existence of suitable locations to site reservoirs. While energy policies in different countries often pursue similar objectives, the actual technology mix tends to diverge. Some regions develop plentiful nuclear power, while others favour wind and solar power.

Figure 5 • Variability of demand in nine European countries, first two weeks of January 2011



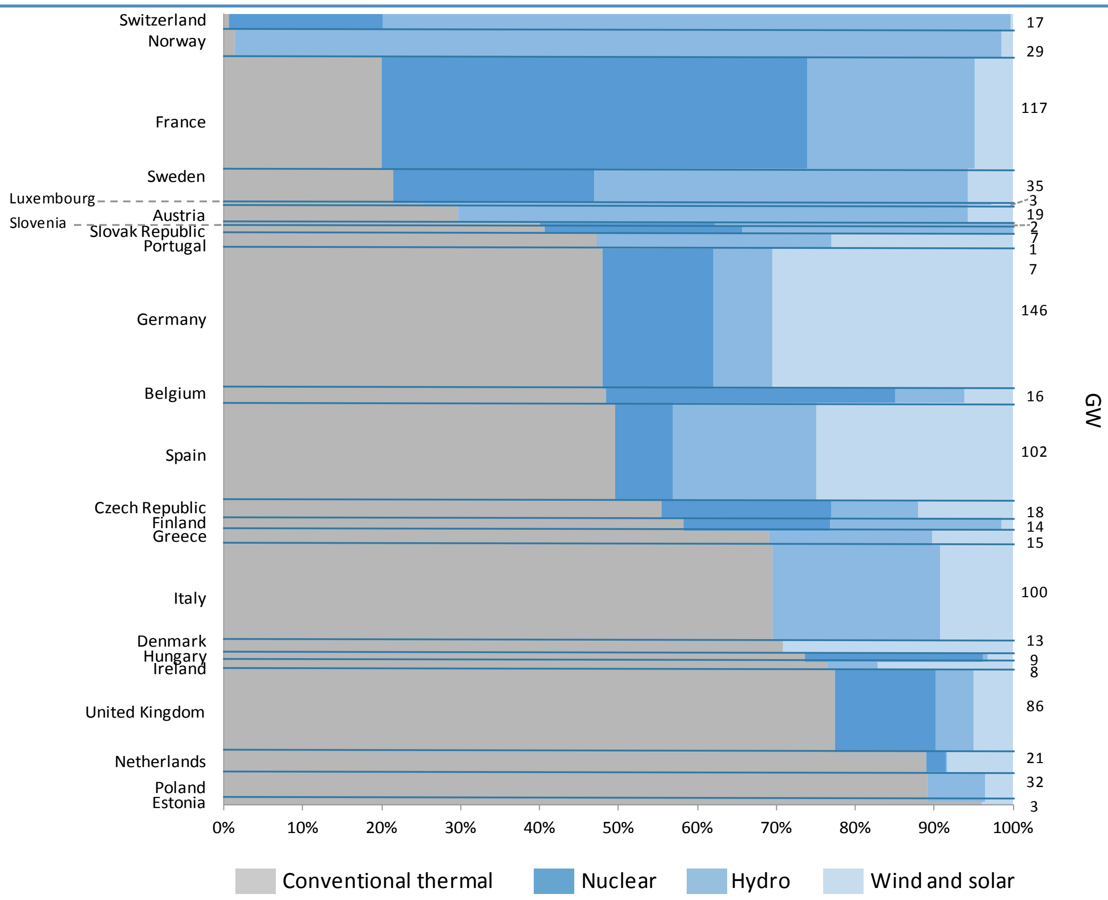
Once installed, generating capacities are rarely optimal, even though they will last for decades. Increasing electricity trade to factor in differences in fuel costs is therefore generally beneficial. Low-cost generators seek to sell as much power as possible, while high-cost gas or coal plants can save fuel costs, resulting in considerable efficiency gains. To give an order of magnitude, if most of the 350 terawatt hours (TWh) worth of European electricity trades substituted high-cost gas power at EUR 50/MWh with low-cost (low carbon) power at 20 EUR/MWh marginal cost, the associated economic benefit would exceed EUR 10 billion per year – and that is considering only the variable part.

Looking at the diversity of power sources in North America, Canada has substantial hydro capacity. In the United States, the Powder River Basin in the centre has cheap coal, while the East Coast has mostly nuclear energy. The Midwest, for its part, has better wind resources and the desert zones of Arizona and New Mexico are the best locations for solar power.

But the development of shale gas is rapidly changing this picture. Ubiquitous shale gas plays in North America, together with massive investment in the federal pipeline network, have removed bottlenecks and led to a convergence of US gas prices. As a result, the different electricity markets are choosing gas to generate electricity at similarly low prices. Since transporting gas through pipelines can be less costly than “gas by wire”, this again raises the issue of properly co-ordinating the gas and electricity infrastructure.

Moreover, many markets that are liberalising their electricity industry are still dominated by an incumbent operator inherited from the vertically integrated regulated monopoly. Whereas some countries (such as the United Kingdom and Italy) have separated the industry horizontally into several competing generation companies, others have not. Increased regional market integration helps alleviate the situation by heightening the competitive pressure and mitigating market power (see the section on competition policy).

Figure 6 • Installed generating capacity in Europe by country, 2010 (GW)



Variable Renewable Energy (VRE)

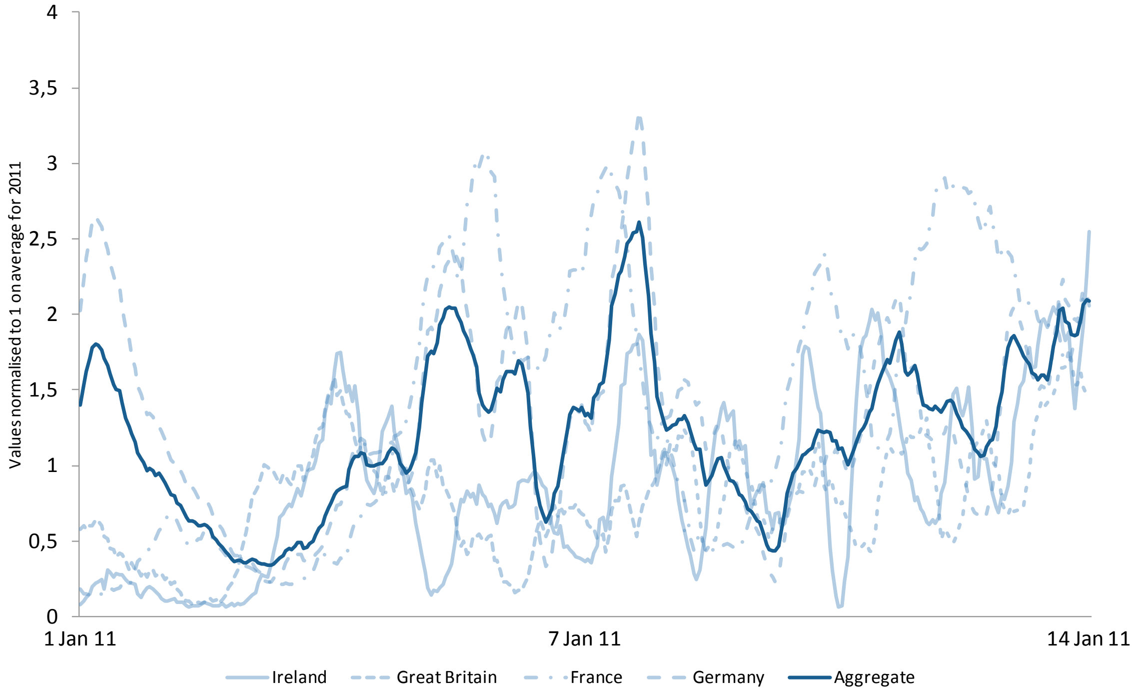
Several studies of the grid integration of variable renewables make the case for further geographic market integration. They argue that further market integration is required to leverage the spatial diversity of VRE sources, a topic that has received considerable attention (see e.g. European Climate Foundation (ECF), 2010; National Renewable Energy Laboratory (NREL), 2013; IEA, 2014).

To begin with, regions with good wind and solar resources are often located far from consumption centres. In the United States, the best wind resources are in the Midwest and solar potential is highest in the southern states of Arizona and New Mexico, while consumption is higher on the East and West Coasts. Similarly, the best solar resources are located in North Africa and Southern Europe, while electricity consumption is highest in Northern Europe.

Not surprisingly, many projects envision the construction of continental-scale networks crossing the Mediterranean Sea, North America and even several continents (e.g. Desertec and Medgrid). This is indeed feasible from a purely technical perspective, as demonstrated by existing networks in Brazil or Australia extending up to 5 000 kilometres – equivalent to the distance between Lisbon and Moscow. However, the electricity intensity per square kilometre in these countries usually remains much lower than in the United States or European Union.

Furthermore, wind and solar generation profiles can be complementary. Wind power can spread over large areas, covering different regions with different wind regimes. This enhances the geographic smoothing effect, which is generally larger for wind than solar power. In some cases, the negative correlation between wind and sun can be beneficial. As a result, integrating markets over large distances has the potential both to smooth output variability (Figure 7) and reduce the forecasting errors associated with wind and solar power. A recent NREL wind integration study (2011) provides another long-term analysis of the transmission needed in extreme renewables deployment scenarios by 2050.

Figure 7 • Variability of wind output in four European countries, first two weeks of January 2011



Absent a sufficient transmission capacity over thousands of kilometres, the smoothing effect remains modest. Further, benefits are much more limited during extreme weather conditions. Many neighbouring countries or zones tend to have similar (especially extreme) weather conditions. A typical example is a cold snap caused by an anticyclone in Western Europe affecting simultaneously the United Kingdom, France and Germany. Poÿry (2011) calculated that under such circumstances, wind is low all over the region, limiting the benefits of market integration in compensating for the absence of wind in a specific location.

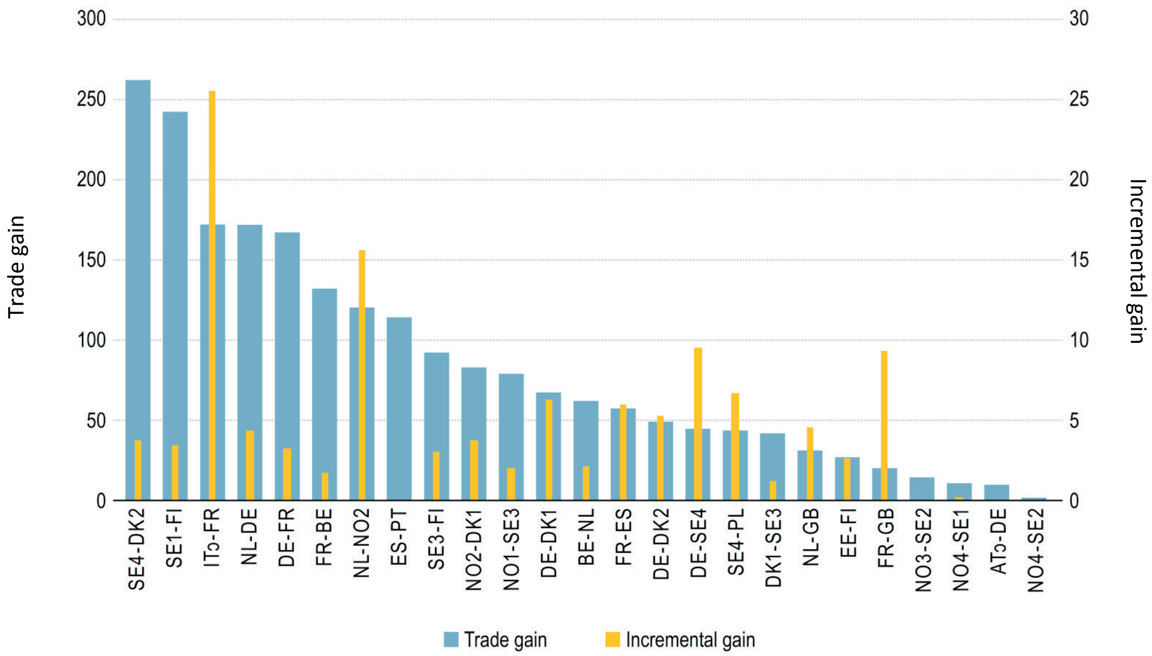
Quantifying the benefits of market integration

While there is little debate that integrating electricity markets offers benefits, very few studies quantifying these benefits are available. Roughly speaking, the "benefits from improved integration lie broadly in the range of 1% to 10 % of system costs (the cost of electricity system)" (Booz & Co, 2013).

European national regulatory agencies provide a quantitative analysis of the gains of cross-border electricity trade (e.g. Commission de régulation de l'énergie [CRE], 2013). At the European level, ACER quantified the benefits associated with cross-border flows at several hundred million euros per year (Figure 8). Other recent studies in the European context comparing fragmented market situations with a perfectly integrated market indicate potentially high benefits. This does not, however, reflect the reality that some electricity trades occur on a bilateral basis even in the absence of perfectly integrated markets.

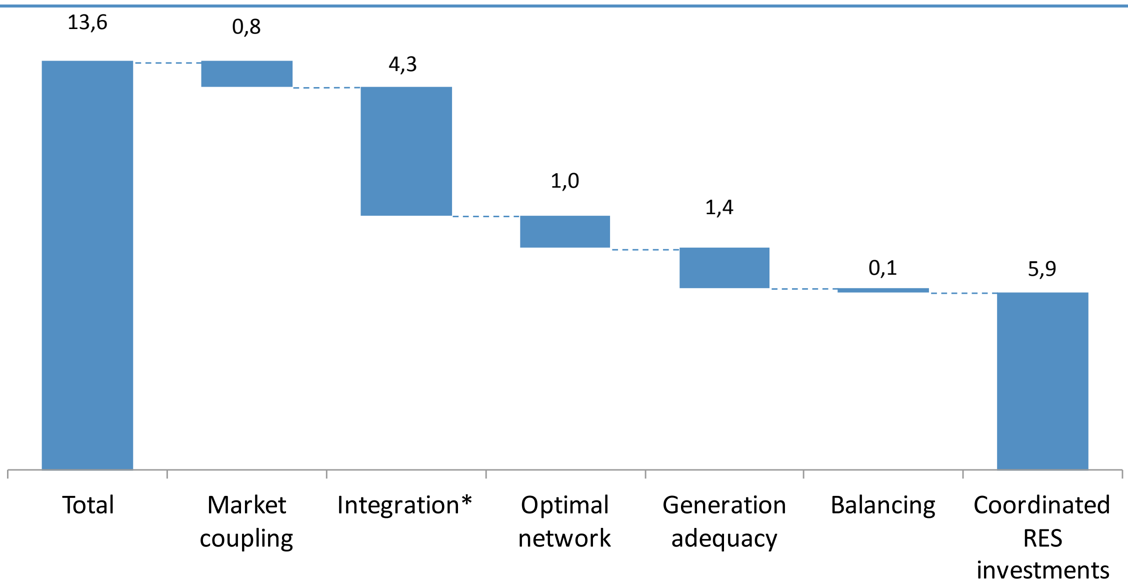
Figure 9 illustrates the order of magnitude of the potential benefits of market integration in OECD Europe, based on a report by Booz & Co. (2013) prepared for the European Commission's Directorate-General for Energy (DG Energy). By 2030, the estimated benefits of full electricity market integration are expected to reach between EUR 12.5 billion and EUR 40 billion per year, representing on average EUR 6.7/MWh). Similarly, the benefits of integrated renewable energy policies and better co-ordinated renewable energy investments could reach EUR 15 billion to EUR 30 billion per year, representing on average EUR 5.9/MWh.[2]

Figure 8 • Gross welfare benefits from cross-border trade and incremental gain per border (2011, million EUR per year)



Source: ACER and Council of European Energy Regulators (CEER), 2013.

Figure 9 • Summary of the potential net benefits of European market integration in 2030 (EUR/MWh)



* with 50% of the optimal additional transmission capacity
Source: Based on Booz & Co, 2013.

[2] For the sake of simplicity, this paper considers average values of benefits of market integration by 2030 and expresses them in EUR/MWh. It also assumes that it is possible to add and subtract the results of different scenarios. While this is not mathematically correct, it simplifies the presentation and is not the strongest assumption made in this work. The original report presents ranges varying from a factor of 3 for markets and 2 for investments in renewable energy sources, illustrating the uncertainty associated with those estimates. The report provides detailed assumptions and a description of methodology.

The estimated gains of fully implemented market coupling are EUR 2.5 billion to EUR 4 billion per year, representing less than EUR 1/MWh (second bar on Figure 9).

In addition to market coupling, this study brings to light the following benefits:

- Generation costs (including capital and operating expenditures) could further drop by EUR 6 billion to EUR 27 billion (EUR 4.3/MWh on average). This is due to better use of low-cost generation assets such as nuclear and coal (although since the report does not specify the optimal generation mix, these results are difficult to interpret) and occurs despite a limited expansion of the transmission network.
- An optimal transmission network would need to double investments in new transmission capacity, with associated net gains of EUR 3 billion to EUR 5 billion per year (EUR 1/MWh on average).
- If generation adequacy objective was shared across boundaries – e.g. thanks to integrated capacity markets – the estimated cost savings would be EUR 3 billion to EUR 7.5 billion per year (EUR 1.4/MWh). (See the self-security scenario of Booz, 2013.)
- Integrating balancing markets only present modest gains (EUR 0.1/MWh).

Other studies estimate higher benefits to integrating balancing markets. In a report for DG Energy, Mott Mac Donald estimated that "Integration of Balancing Markets and the exchanging and sharing of reserves could achieve operational cost savings in the order of € 3bn/year and reduced (up to 40% less) requirements for reserve capacity" (Mott Mac Donald, 2013). Thus, for a total electricity consumption of around 3 800 TWh per year by 2030, the potential benefits represent nearly EUR 1/MWh.

Barriers to market integration

Lack of interconnector capacity

It is common knowledge that the key barrier to market integration is the lack of interconnector[3] capacity. In their 2012 annual report on the internal electricity market, CEER and ACER placed great emphasis on the transmission network, stating that:

"…the lack of market integration mainly results from two key areas:

- Inefficient use of existing transmission networks stemming from inefficiencies in cross-zonal capacity allocation, cross-zonal capacity calculation and the assumed definition of possible bidding zones for long- term, day-ahead, intraday and balancing timeframes and
- Lack of investments in electricity network infrastructure that would enable more cross-zonal capacities and more cross-zonal trade between areas with excess supply and areas with excess demand." (ACER/CEER, 2012)

Europe and the United States have adopted different sets of policies on interconnections. Integrating electricity markets is very high on the political agenda of the European Commission. By contrast, the Federal Energy Regulatory Commission (FERC) in the United States does not appear to have a very proactive policy to improve the efficiency of cross-border trades. While Europe is working

[3] This report uses the term "interconnector" to designate cross-border transmission lines. This term is used in the United Kingdom and Australia, and more generally in radial systems or undersea cables. In the United States, cross-border transmission lines are called "interties". In Continental Europe, the notion of interconnection between countries is used in the context of a well-meshed grid.

hard to design better market rules, the United States tends to rely on bilateral contracting and bilateral co-operation between adjacent system operators.

While the lack of cross-border transmission lines often reflects regions' physical geography, it can also result from existing institutional barriers.

Institutional barriers

One of the major difficulties in integrating markets consists in overcoming institutional differences (Glachant, Saguan, 2007). Market integration within the same country – e.g. the United States and Australia – is often quite challenging because of differences in state-level institutional settings and regulations. Market integration spanning several countries – e.g. in Europe – comes up against even more challenging institutional barriers.

Governments and regulators have a national mandate or a mandate restricted to an individual state or province. Some regulators state that implementing measures optimising social welfare at both the domestic and international level is the key challenge to integrating (for example) European markets. The legacy of divergent and inconsistent rules that are difficult to harmonise is an expression of this challenge. Its two most important manifestations are electricity security of supply and distributive impacts.

Electricity security of supply remains the competence of local governments

Governments place great emphasis on ensuring a secure and reliable electricity supply throughout their jurisdictions. This is a legitimate concern, given the importance of electricity in modern economies controlled by computers and electronic communications. Electricity cannot yet be stored at a reasonable cost. It requires an expensive physical infrastructure, for which governments are still accountable, by contrast with security of supply for other energies (such as oil and gas), for which governments must rely on global markets.

Although in many aspects electricity security is already a regional issue involving neighbouring jurisdictions, policy makers continue to approach it in an insulated manner, as if electrons stopped at borders. For instance, several governments prefer to generate electricity locally rather than import it, even if importing is less expensive. Similarly, system operators are often organised on a national basis, irrespective of the network topology or size of the electricity systems.

Local governments are unwilling to abandon this energy-related competence. Indeed, should anything go wrong, government officials will always be held responsible. Nevertheless, this institutional framework must be modernised to reflect the physical and market realities.

Distributive impacts of market integration

Market integration can increase prices in exporting countries, possibly erecting barriers to market integration. While increasing interconnector capacity removes congestion, it also triggers wholesale price convergence, thus reducing the overall dispatching cost. While these trades do improve total welfare, price adjustments also lead to important distributive impacts for consumers and producers in different locations.

There is strong empirical evidence that jurisdictions benefitting from cheap coal, nuclear or hydro power are reluctant to engage in electricity market integration or even liberalisation. For example, certain US states benefitting from cheap coal generation do not wish to liberalise their markets (in fact, only East Coast states with expensive power have decided to liberalise). The province of Quebec in Canada has cheap hydropower and has not liberalised its electricity market, although it exports electricity to the United States. Similarly, France has introduced a regulated wholesale electricity price for nuclear energy below market price.

Electricity prices remain a politically sensitive issue. Governments do not have as their objective to act in the interest of neighbouring countries, but rather to protect the interests of domestic consumers. They tend to neglect the distributive impacts of regional market integration, even though these are perhaps the major barrier to further market integration in many jurisdictions. While in theory, economists advocate increasing overall efficiency first and then tackling redistribution, governments rarely do so in practice.

Conclusion

Despite some challenges associated with system security, electricity market integration presents benefits in terms of increased fuel diversity, diversified supply sources and decreased costs of maintaining reliability. A quantification of the potential benefits of further market integration indicates benefits in the range of USD 4.5/MWh to USD 15/MWh. But physical and institutional barriers to market integration need to be overcome to reap these benefits.

Improving electricity market integration requires taking action at different levels. Section 2 reviews the policies and regulatory frameworks needing to be co-ordinated across market seams. Section 3 analyses how interconnectors can be developed and used with the utmost efficiency and the regulation required. Finally, Section 4 examines the key features of electricity markets enabling their efficient integration.

Policies towards seamless power markets

Regional electric markets can offer benefits in terms of security of supply, efficient use of existing assets and renewables integration. Hence, it should be a central policy objective of policy makers aiming to ensure reliable, affordable and clean electric energy.

Most IEA member countries have started to integrate their electricity markets and liberalise their electricity sector in the past 20 years. The creation of the Australian Energy Market Operator (AEMO) in Australia, the expansion of PJM or MISO in the United States, the optimisation of the seams between the ISOs in the United States and Canada, and advances in the internal energy market and regional initiatives in Europe are examples of this process offering a wealth of experience in regional integration. In many aspects, however, these instances of integration are still in progress.

This section discusses the main issues facing policy makers wishing to develop electricity markets over several jurisdictions. It follows the order of the energy policy trilemma, i.e. ensuring reliable, affordable and clean energy (Figure 10).

Figure 10 • Policies towards electricity market integration contribute to energy policy objectives

Reliable	Affordable	Clean
• Right regulatory framework needed for electricity systems that are already interdependent across borders	• Efficient use of available assets (least-cost dispatch) • Pooling of expensive capacity resources	• Efficient location of wind and solar power plants

First, it is necessary to better integrate security of supply policies, which are currently lagging behind electricity market integration. Second, deploying renewables may entail redefining the entire market integration project. Third, since renewables are now an important part of electricity systems, integrating renewables policies becomes a necessity. Finally, establishing integration policies requires re-examining institutional competition policy and distributive dimensions, briefly mentioned in this section.

Electricity security of supply policies

Ever since the 1970s oil crisis, national energy policies have focused on oil and gas security. Over the past decade, however, electricity security has become a growing concern. This may seem paradoxical, since electricity supply is usually less exposed to the risks of international commodity markets and production trends. Yet the current lack of profitability of some of the plants that will probably be used to complement wind and solar power is hotly debated in Europe.

Generation mix

Supply security was one of the key drivers of electricity market integration in Europe. Indeed, the first interconnections to neighbouring countries were built to cover emergency situations. In this context, increasing interdependency among jurisdictions constitutes a paradigm shift.

Integrating electricity markets diversifies the generation mix and gives access to generation capacity in case of a shortage in any one country. Empirical evidence of the benefits associated with market integration abounds. For instance, Norway imports power from Sweden during dry years. In 2012, France imported up to 10% of the power needed to meet peak demand during cold spells. In 2013, Belgium imported power to compensate the temporary shutdown of its nuclear reactors.

The Treaty of Lisbon ratified in 2007 introduced a chapter on energy in European primary law, but left the choice of energy mix to EU member states[4]. The same goes for North America, where each US state and Canadian province can choose its energy supply.

Not surprisingly, neighbouring countries choose different generation mixes. This is, of course, partly due to differences in their initial resource (e.g. hydropower) endowment. But other energy policy factors also play a role. Nuclear energy is the perfect example of policy-driven divergences among countries. So is renewable energy – which develops much faster in some countries than in others – and to a certain extent gas, since some countries are reluctant to expose consumers to international gas/oil price volatility and high import bills.

The lack of integrated policies regarding fuel security and fuel mix can create problems for supply security. Take gas: in North America, low prices from shale gas are increasing gas-fired generation and a new wave of investment is expected in every US state, as well as Canada. In Europe, reliance on gas-generated power created unexpected high demand during the February 2012 cold spells, raising gas prices and nearly causing supply disruption.

The lack of a co-ordinated deployment of renewable energy can have consequences on electricity security. During periods devoid of wind and sun, it is not just the national markets that respond, but also the integrated electricity market. Rapid development by a jurisdiction (e.g. California) of variable renewable energies impacts on neighbouring electricity systems. Hence, governments should pay more attention to the security of supply implications of the fuels (including renewables) they use to generate electricity.

Harmonising regulatory frameworks pertaining to electricity security

Electricity security lags behind markets in terms of integration. While electricity market integration has progressed over the last 20 years, electricity security regulation remains fragmented. Yet reliability rules are critical to ensuring peak wholesale price formation and investment incentives. Moreover, the procedures market and system operators apply in scarcity and emergency situations often lack transparency. This makes it difficult to predict the behaviour of neighbouring system operators – a prerequisite to ensure reliable operations and reap the full benefits of market integration.

To take an analogy, integrating electricity markets without reliability criteria is like creating a unique currency without proper economic governance. It makes it difficult to predict what system operators in neighbouring areas will do in case of a problem. This lack of co-ordination and visibility leads to very conservative approaches to cross-border trade that hinder market integration.

European legislation explicitly stipulates that member states are responsible for electricity supply security (Box 1). It therefore comes as no surprise that some national governments are taking measures within the existing integrated framework for reliability regulation.

The situation is more advanced in the United States. The Energy Policy Act (EPAct) of 2005 granted FERC the authority to oversee mandatory reliability standards governing the nation's electricity grid. EPAct created NERC, a federal electric reliability organisation that also oversees reliability in Canada. However, its powers remain limited. In practice, operational responsibility is

[4] In the Treaty on the Functioning of the European Union (TFEU or "Lisbon Treaty"), Articles 194(2) and (3) stipulate that measures in the field of energy taxation and member states' rights in deciding on the conditions for exploiting their energy resources, choices amongst different energy sources and the general structure of their energy supply are subject to unanimity. The treaty of Lisbon sets four main aims for the EU Energy policy: (i) ensure the functioning of the energy market; (ii) ensure the security of supply in the Union: (iii) promote energy efficiency; and (iv) develop new and renewable forms of energy and promote the interconnection of energy networks (EPIN, 2011).

largely in the hands of system operators, whose reliability criteria can differ from NERC targets. Further, system operators are responsible for their own footprint and lack an integrated vision.

Box 1 • The EU Security of Supply Directive

Directive 2005/89/EC establishes measures aimed at safeguarding security of electricity supply so as to ensure the proper functioning of the EU internal market for electricity. This includes an adequate level of interconnection between member states, an adequate level of generation capacity and balance between supply and demand.

The Directive states the general principle that member states must define general, transparent and non-discriminatory policies on security of electricity supply compatible with the requirements of a competitive single market for electricity.

However, in practice, European member states retain full control over electricity security in the most critical areas, as suggested by the following provisions:

"Member states shall take appropriate measures to maintain a balance between the demand for electricity and the availability of generation capacity.

Member states may also take additional measures, including but not limited to the following:

Provisions facilitating new generation capacity and the entry of new generation companies to the market (…)."

Source: Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment.

To be fair, system operators have been proactive on many topics. Given the high physical interdependence of operations in interconnected and synchronous systems, they have no choice but to ensure the day-to-day reliability of the interconnected network.

Regulators and system operators have significantly improved the situation in Europe in recent years. At the regional level, CORESO and Transmission system operator-Security-Cooperation (TSC) have emerged as co-ordination centres of TSOs on system security. They have reinforced exchange of data among TSOs and harmonised security procedures. While this is now one of the core missions of ENTSO-E, its focus remains system security rather than market functioning, as each TSO is responsible for ensuring reliability within its boundaries.

As a result, further regional integration of system security policies, regulations and governance is necessary in many OECD regions. This might require the following actions:

- amend substantially existing supranational or federal legislation, such as the Directive on electricity security of supply;
- clarify and harmonise reliability standards, such as loss of load expectation, used in jurisdictions taking part in the same integrated electricity market; and
- clarify and improve the transparency of emergency protocols used by system operators in scarcity conditions, including contract prioritisation within and with adjacent control areas, load curtailment procedures between different areas, and other technical operating protocols that can impact on market prices.

The European Union is currently developing network codes on security and reliability to harmonise some aspects of system security. However, harmonising 28 countries with very different histories will be a protracted and difficult task, as experience shows. Not only is defining such procedures the core competency of the various system operators, but institutional barriers to change also exist.

Further harmonising security is a prerequisite for addressing major challenges to electricity market integration. Failure to do so would hinder efficient market integration, likely leading to less efficient utilisation of available infrastructure.

Efficiency and competitiveness

There is no doubt regional integration of electricity markets can increase efficiency. The creation of a market operator for the NEM in Australia in 1998/99, and of the European Internal Electricity Market (IEM) and the expansion of ISO footprints in the United States illustrate massive progress in achieving better integration. Several policy questions nevertheless need attention.

Many regions have already picked the low-hanging fruits of market integration. Even before liberalisation, utilities started to exchange bulk power – usually in the form of baseload power with long-term contracts between vertically integrated utilities. In Europe, market liberalisation accelerated and expanded these exchanges, which now amount to 10% on average of European consumption (Annex A).

Box 2 • Framework guidelines and network codes

In 2007, the European Commission launched the Third Legislative Package, paving the way for the development of an internal EU gas and electricity market. Regulation (EC) 714/2009 specifically identified the need to put in place common rules for these markets to operate effectively.

These common rules are known as network codes. When they become law, the network codes will have the same status as any other European regulation and will govern all electricity market transactions with a cross-border impact.

ACER and ENTSO-E were assigned the task of developing framework guidelines and network codes (which will define a set of common rules for all regional or national networks. As set out in Article 8 of Regulation 714/2009/EC, the network codes shall cover 12 areas of network operations, most importantly network security and reliability rules, network connection, data exchange, interoperability and operational procedures in an emergency.

ENTSO-E is currently working on ten network codes covering three inter-related areas:

- **Connection codes**. TSOs operate the electricity transmission grid. Two types of users connect to and use these grids: generators (who produce electricity) and large customers (who use electricity themselves or sell it on to smaller customers). The connection codes cover the rules for these users to connect to the transmission grids.
- **Operational codes**. To keep an electricity system reliable, sustainable and stable, each TSO prepares, plans and schedules to operate a system in real time. This involves analysing whether there will be enough electricity generation to meet demand and whether the system can handle the resulting flows securely. The operational codes provide a set of rules and regulations governing how these systems are operated in the context of increasing interconnection among TSOs.
- **Market codes**. The design of a pan-European electricity market will see both electricity and capacity (the available capacity of transmission networks to transport electricity) traded across Europe. The market codes will foster greater competition, generator diversification and optimisation of existing infrastructure.

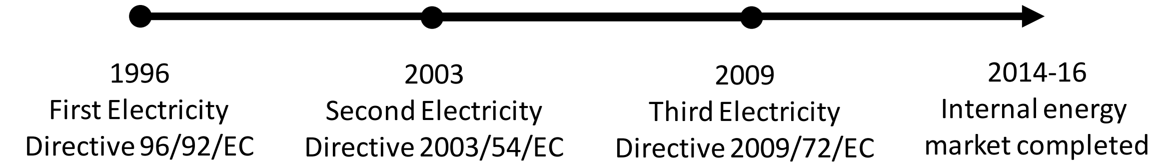
The completion of these network codes, their introduction into law and their implementation will form a coherent set of rules to underpin a reliable, sustainable and connected internal energy market.

Source: ENTSO-E, http://networkcodes.entsoe.eu/category/introducing-network-codes/?p=what-are-network-codes-data.

In Europe, the market integration process of the past 20 years has mobilised legislative and regulatory activity (Figure 11 and Box 2). Governments have opened access to networks, enabling competition and allowing consumers to choose among generators. They have also unbundled network operations from electricity generation. This period has seen the emergence of independent regulators, market coupling and wholesale electricity trading platforms.

Other routes have also opened up. Regional initiatives enable a smaller group of countries to integrate their markets further and faster, as illustrated by the success and progressive expansion of market coupling. More recently, two groups of TSOs created CORESO and TSC to improve real-time co-operation on system security. On the downside, progress in some regions has created very specific solutions that cannot be applied or expanded to other areas.

Figure 11 • European electricity liberalisation: Step-by-step approach



In the United States, market integration has taken a different route. The footprint of PJM and MISO expanded progressively on the basis of a voluntary opt-in. In 2002/03 FERC proposed a set of common rules, "Standard Market Design", which may have prompted the emergence of five or six large ISOs. But politics forced FERC to adopt a more incremental approach. Since then, all ISOs have voluntarily adopted key features (such as locational marginal pricing) of the Standard Market Design. Little progress, however, has been made in some of the regulated states.

Renewables deployment strengthens the case for a much more dynamic market integration to cope with the variability and uncertainty of wind and solar power. From a policy perspective, grid integration of variable renewables overtook liberalisation as the most popular justification for regional integration of electricity markets.

Updating the market integration project

To further integrate (renewables) markets, intraday and real-time market rules must also be compatible. While integrating intraday and balancing markets is important to accommodate increasing shares of renewables, the associated benefits could be lower than when trading bulk power. Strong co-operation among TSOs and moderation of the process by policy makers will be essential.

This close-to-real-time integration entails a significant harmonisation of market and system operation rules. Since these are the core competences of system operators, harmonisation will likely encounter more resistance than the first phase of integration.

Hence, redefining a project to integrate electricity markets based on lessons learnt over the past two decades might become necessary. Australia's NEM and PJM, MISO and Southwest Power Pool (SPP) in the United States have successfully consolidated small regional electricity systems.

The deployment of variable energy sources is prompting some utilities that had until now resisted it to consider market integration. For instance, the proposed creation of an Energy Imbalance Market by CAISO in the US Western Interconnection is an innovative way of integrating markets to cope with the challenge of wind and solar power.

Integrated electricity markets heighten competition among generators. Competitors can choose the fuel and technology they use to generate power, seek new capacity in the most favourable locations and decide on the timing of their investment. As a result, some jurisdictions participating in the market integration effort believe that market-driven investment decisions could jeopardise electricity security.

Competition policies

There is a clear interaction between market integration policies and competition policies. Any movement to integrate electricity markets can be restricted by heterogeneous competition policies. For instance, market integration in an area or country with a dominant incumbent generator may offer significant benefits in the form of increased competition. But weaker competition policy in one jurisdiction can undermine some of the benefits of market integration.

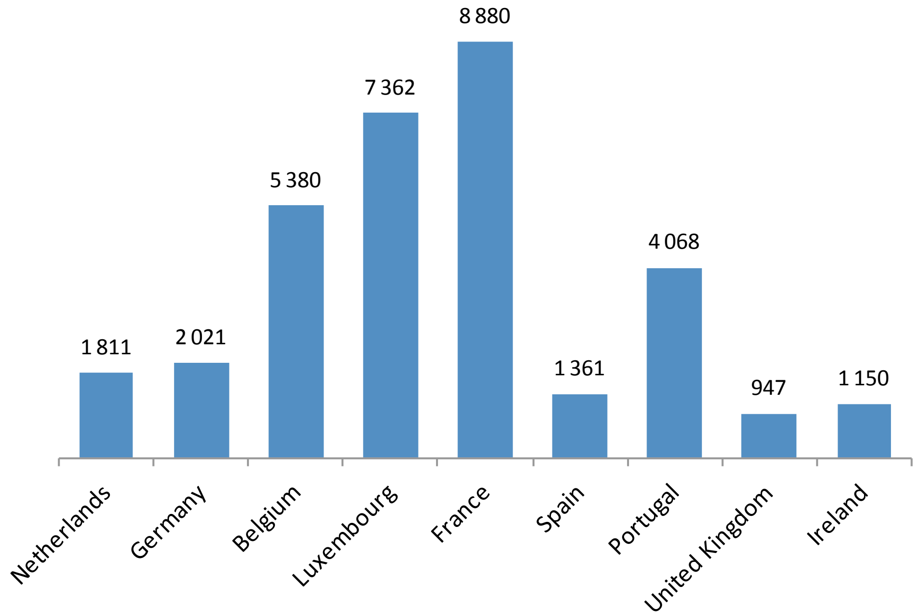
In 2007, the European Commission enquiry found that:

- Sales in electricity markets generally reflect the significant level of concentration in generation. Analysis of trading on power exchanges shows that, in a number of them, generators have scope to exercise market power by raising prices…
- Cross-border sales do not currently impose any significant competitive constraints. …integration is hampered by insufficient capacity and a lack of adequate incentives to invest in additional capacity…. (European Commission, 2007).

Based on this analysis, the European Commission uses the Herfindahl-Hirschman Index (HHI)[5] for each national market (Figure 12). Although this metric does not capture important features of market power in the power industry, it indicates that market concentration is high in all – and very high in some – European countries.

Since the 2007 European Commission enquiry, the competitive landscape has significantly changed in Europe. Weak demand conditions and rapid renewables deployment result in excess capacity which limits power to set wholesale market prices above the marginal cost of generating electricity. But in the absence of deeper market integration, this market power can return for specific markets segments, such as system and balancing services.

Figure 12 • HHI of market concentration in European countries (2011)



Source: European Commission (2011), Country reports.

[5] The HHI is a commonly accepted measure of market concentration. It is calculated by squaring the market share of each firm competing in a market and summing the resulting numbers. The HHI number can range from close to zero (perfect competition) to 10 000 (monopoly). The closer a market is to a monopoly, the higher the market concentration (and the lower the competition). A market with a result of less than 1 000 can be considered a competitive marketplace; a result of 1 000 to 1 800 constitutes a moderately concentrated marketplace; and a result of 1 800 or greater is a highly concentrated marketplace.

An analysis of market concentration in electricity markets should include the local, national, state and inter-regional levels. It should also cover the relevant time scale, distinguishing between extreme peak hours, peak hours and off-peak hours, as well as situations with and without congestion between neighbouring markets.

Development of the interconnected transmission network can help address market concentration in larger markets. In theory, transmission expansion can increase competition among wholesale electricity suppliers (Borenstein, Bushnell and Stoft, 2000). In a recent academic study, Wolak (2012) provides an empirical analysis of the Alberta Wholesale Electricity Market from 2009 to 2011. Using a sophisticated econometric model, he calculates the impact of network congestion on supplier bidding behaviour. He finds that in the absence of perceived congestion by suppliers, wholesale cost savings for consumers could exceed USD 2 billion for the sample period. He therefore argues that the transmission planning process should factor in the competitiveness benefits of transmission expansion.

While increased regional market integration can enhance the competitiveness of electricity markets, this alone may not mitigate market power. Several measures designed to obtain market clearing prices close to short-run marginal costs might become necessary. Market structures need to be competitive. Structural remedies, such as horizontal separation of incumbent operators into several competing generation companies, reduce market power. When a transmission constraint creates a local market power issue, the large size of conventional power plants does not always make it possible to create strong enough competition. In this case, local market power mitigation methods can include introducing tests (Box 3) and minimum offer prices or bid caps, as well as increasing transparency of market information.

Box 3 • Market concentration metrics: HHI and the three pivotal supplier (TPS) test

In the United States, independent market monitors for different RTOs also analyse market concentration according to hourly HHI calculations for the control area of each RTO.

- The HHI indicates a moderately concentrated 2012 PJM Energy Market by FERC standards. Based on the hourly Energy Market measure, the average HHI was 1 240, with a minimum of 931 and a maximum of 1 657 in 2012 (Monitoring Analytics, 2013).
- The HHI is low for MISO, but considerably higher in individual regions – and nearly 2 500 in the eastern region (i.e. "highly concentrated"). Regional HHIs are higher than in comparable zones of other RTOs because vertically integrated utilities in MISO have not divested generation and tend to have a substantial market (Potomac Economics, 2012).

However, the HHI metric does have some limitations as an indicator of overall competitiveness. In particular, it does not capture the unique characteristics of electricity and local market power issues caused by network constraints. Another indicator of potential market power used in the United States is the notion of a "pivotal supplier". A supplier is pivotal when its power plants are necessary to satisfy load or manage a network constraint.

Independent US market monitors consider the TPS test as the most relevant measure of market structure when demand is totally inelastic. The test uses actual market conditions reflecting both temporal and geographic granularity and indicates the existence of market power in local markets created by transmission constraints. According to Monitoring Analytics, the application by PJM of the TPS test has mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints (Monitoring Analytics, 2013).

Where markets span multiple jurisdictions, competition policies and institutions need to reflect the geographic scope of integrated markets. First, market integration poses new competition problems involving several jurisdictions. One feature of the power generation business is that diversified utilities operate in several states or countries. Europe numbers several big players holding assets in many countries. In the United States, diversified utilities also usually operate in several markets. This market structure may create opportunities for cross-border collusion between generation companies exchanging market shares in different countries. Such behaviours do not necessarily involve cross-border trading and escape the scrutiny of cross-border trade monitoring bodies.

Second, as markets are increasingly integrated, behaviour in one control area can impact on pricing in an adjacent market. For instance, expanding market coupling in Europe leads to converging prices, with the corollary that the relevant electricity market is usually itself the coupled market. However, there is no guarantee that market monitoring rules are applied consistently among jurisdictions in charge of different markets (Table 2).

Table 2 • Comparison of entities with market abuse mandates

Market regulated	United States	European Union
Physical electricity	FERC, state regulators, RTOs, independent market monitors	EU DG Competition, ACER, national regulators
Financial products	CFTC and/or FERC	EMSA, Competent financial authorities

Source: Adapted from Lederwood, Shaun and Dan Harris, 2013.

In practice, a patchwork of competition laws spans different jurisdictions, with different entities in charge of competition policies. Mergers and acquisitions generally remain in the hands of competition authorities. While specialised entities can manipulate physical electricity markets, competition laws are usually enforced by competition authorities. Co-operation among competition authorities across control or market areas is particularly important when markets are increasingly integrated.

Both the United States and Europe have taken steps toward greater harmonisation of competition policies and practice for the wholesale electricity market. The European Commission DG Competition has pan-European authority. With greater market integration as an objective, this authority should not be limited to monitoring cross-border electricity trades.

Environmental policy

Environmental (e.g. renewables) policies pursue several objectives, first and foremost to reduce CO_2 emissions. Many governments aim to create business and employment, often in line with the interests of the renewables industry. The aim is to create “local jobs” and “local industry champions” thanks to the deployment of renewable energy sources financed by local taxpayers or local consumers. Since each government aims to create jobs and develop industry in its own jurisdiction, the result is a series of fragmented policies.

In Europe, each country has defined its own renewable energy objectives for 2020. According to the European Commission, 20 member states achieved or exceeded their 2010 renewable energy shares featured in the National Renewable Energy Action Plans and are on track for their 2020 goals. But fragmented environmental policies increase their overall costs. Not only do they use sub-optimal wind and solar resources, but their localisation cannot benefit from cheaper construction costs in certain countries. A study by the Institute of Energy Economics at the University of Cologne (EWI, 2010) estimated that the cost of policy support for renewables projects in Europe could drop by about 10% (EUR 4 billion per year on average) thanks to regional integration of renewables policies. Booz & Company and al. (2013) estimates the potential gain from co-ordinated renewables investment at EUR 15.5 billion to EUR 30 billion per year by 2030. In other words, the potential benefits from regional integration of renewables policies alone are as high as the benefits of integrated electricity markets!

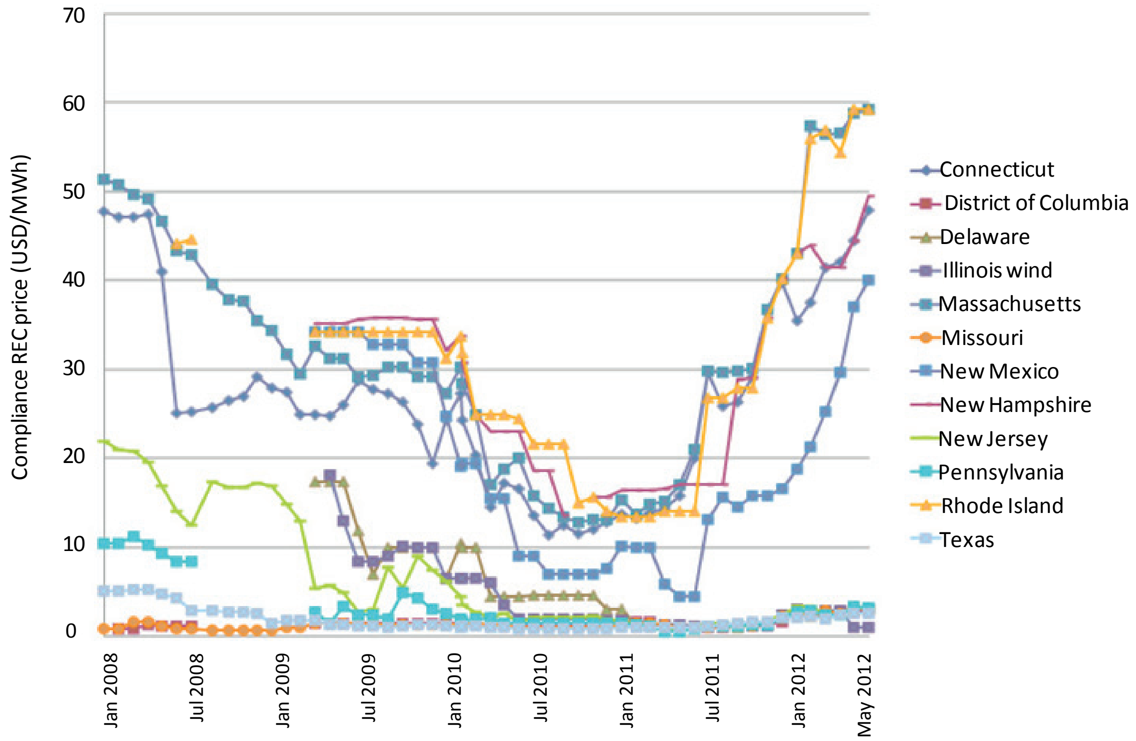
The European Union should therefore encourage co-operation across states. The European Renewables Directive allows renewable energy trade to contribute to the national renewables target. Three cross-border mechanisms exist – statistical transfer, joint projects and joint support schemes. However, the creation by Sweden and Norway of a common market for renewable energy certificates (Box 4) remains the exception rather than the rule. Few countries have used these mechanisms to date. First, member states have no financial incentives to purchase external renewable energy. Second, inconsistent support schemes in EU member states does not facilitate cross-national co-operation.

To better integrate renewables policies on a regional basis, the European Commission wishes to design and reform national renewables support schemes. In its communication "Delivering the internal electricity market and making the most of public intervention" (2013), the DG Energy states that:

> The Commission specifically as regards renewables envisages exploring options for such "Europeanisation" of support schemes for the future EU legal framework on renewables. The Renewables Directive does not prohibit member states from limiting their support schemes to nationally generated renewables production. Already today member states can use cross-border support within co-operation mechanisms to introduce cross-border support. The Commission strongly encourages member states to use these opportunities and progressively open up their nationally oriented support schemes to producers from other Member States. (European Union, 2013)

In the United States, 29 states have adopted "Renewables Portfolio Standards" (RPS) programmes setting mandatory targets for the share of renewables in the energy mix. In some states, RPS programmes can be fulfilled with certificates originating in other states. But the markets for renewable energy certificates remains fragmented, with prices in the range of just a few US dollars to USD 60 (Figure 13). Even in the absence of a national renewables portfolio standard, this gives a sense of the benefits of integrating renewable the energy certificate markets across the United States.

Figure 13 • US compliance market (primary tier) Renewable Energy Certificate prices, January 2008 to June 2012



Source: Spectron Group (2012), quoted by US Department of Energy (DoE) Energy Efficiency and Renewable Energy (EERE).

In some states, the RPS programme features a clause imposing an in-state production location or certain delivery requirements as a condition for eligibility. The debate on the location clause has taken a more legal angle in that RPS programmes favouring in-state renewable energy projects could be unconstitutional under the US Federal Commerce Clause.[6]

The solar photovoltaic (PV) trade case with China also illustrates the importance of industrial objectives in environmental policies. It is difficult to envision European countries subsidising the construction of expensive solar farms without expecting economic returns. This is why the European Union and China agreed in August 2013 to set a 7 GW per year cap on solar PV trade until 2015 (PV Magazine, 2013).

As renewable energies become more competitive and no longer require subsidies, their deployment could become more market-driven, facilitating efficient location of renewables and development of better-integrated policies.

Box 4 • Common Swedish-Norwegian certificate market for renewable electricity

The Nordic countries provide an interesting example of co-operation on renewables. Sweden and Norway decided to launch a common market of tradable renewable energy certificates. The two countries set the goal of increasing their production from renewable sources by 26.4 TWh by 2020, equally divided into two national objectives, i.e. 13.2 TWh per country. This market-driven approach also ensured technology neutrality.

On paper, this mechanism is an excellent implementation of new opportunities encouraged by the European Renewable Directive. In practice however, Sweden and Norway do not have the same tax system. Despite very good wind resources in Norway, investors identified Sweden as the most favourable location for two-thirds of new investments, leading to imbalanced investments in new-capacity generation and grid extension, with a large increase in export flows from Sweden to Norway. This example illustrates the importance of factoring in the whole regulatory framework – including taxation and the supply chain, which represent a significant share of the total cost of renewable energy production.

Implementation and governance

Markets and system operators do not spontaneously integrate. Unlike in the generation business, system operators have few incentives to expand their geographic footprint through mergers and acquisitions. The nature of regulated industry means that system operators hardly increase their profitability by increasing their footprint, even when such a move is efficient. In all the regions where market integration has progressed satisfactorily, governments, federal or supranational institutions have been crucial in pushing for heightened competition and cross-border trade. Implementing market integration policies requires both focusing on institutional design and addressing distributive concerns.

Institutional design

Integrated markets require integrated institutions. Institutional design remains fundamental to developing and sustaining competitive electricity markets as the resulting neutrality and transparency supports economic decision making across the integrated market.

[6] Indeed, the Commerce Clause contains a dormant dimension that prohibits economic protectionism – regulatory measures designed to benefit in-state economic interests by burdening out-of-state competitors – where they are not justified. See http://media.ca7.uscourts.gov/cgi-bin/rssExec.pl?Submit=Display&Path=Y2013/D06-07/C:11-3421:J:Posner:aut:T:fnOp:N:1148803:S:0, accessed on 7 February 2014.

Good governance requires **clear allocation of roles and responsibilities** among governments, regulators, reliability organisations, system operators and/or power exchanges and system planners in neighbouring areas. Governments and ministries are responsible for policy making and market rule making. Regulators are in charge of regulating markets and approving network investments.

Regulators

Almost all IEA member countries have independent regulatory agencies active at the national or state level. Legally, EU national regulatory agencies (NRAs) are national entities created by national laws. Regulators usually have the mandate to protect consumer interests. From their perspective, the key challenge to integrating European markets is implementing an arrangement that optimises social welfare at both the domestic and EU levels. Despite the high-level principles set by supranational (e.g. the European Commission) and national bodies, the national, state or regional approaches to regulatory institutions vary, reflecting different political traditions. In Europe, the co-operation agency ACER has limited executive power. Its website states that "[T]he overall mission of ACER as stated in its founding regulation is to complement and co-ordinate the work of national energy regulators at EU level."

Various approaches to creating overarching regulatory authorities exist, largely depending on the institutions in place.

- In Australia, the Australian Energy Regulator has taken over responsibility from 13 state-level regulators for serving the needs of all market participants, independently of the side of the border where they are located and active. According to the Energy Reform Implementation Group (2007), the horizontal regulatory harmonisation achieved by establishing a single responsible regulator for the NEM has avoided any jurisdictional bias across the various states, favouring jurisdictional decisions over market-wide decisions.
- In the United States, the Constitution and laws give the responsibility for wholesale sales and interstate commerce to FERC. Retail, distribution and intrastate transactions are the responsibility of public service commissions in the 50 individual states.
- In the Nordic countries, the organisation of Nordic energy regulators NordReg actively promotes the legal and institutional framework and conditions necessary to develop the Nordic electricity markets. This fostered the emergence and expansion of Nordpool, now covering Finland, Sweden, Norway and the Denmark.
- In the European Union, EU legislation gives the authority for wholesale, retail and internal transactions to regulatory authorities in member states. European directives transposed into national laws ensure a certain degree of harmonisation and consistency to promote cross-border trade. ACER was created in 2009 primarily to co-ordinate national regulatory agencies.

A comparison of FERC and ACER highlights the following tasks required to integrate electricity markets:

- **Monitoring electricity markets.** In the United States, FERC created market monitors and a Market Monitoring Center. In Europe, Regulation of Energy Market Integrity and Transparency (REMIT) charges ACER with collecting data, monitoring and investigating market abuse at both the national and cross-border levels.
- **Establishing network codes and standards.** In close consultation with all stakeholders, ACER develops the Framework Guidelines of the network codes, and provides opinions and recommendations on the draft network codes.
- **Playing an advisory role.** For instance, ACER advises the European Commission on adoption of the network codes.

In addition, regulators can have other activities, e.g. focusing on unbundling vertically integrated utilities or regulating a fully unbundled monopoly. Their mission can also evolve. For example, the 2005 EPAct expanded the authority of FERC to impose mandatory reliability standards and higher penalties on entities manipulating the electricity markets (EPAct, 2005; FERC, 2006). Agency sizes vary considerably, reflecting the scope of their activities. FERC (which regulates gas and oil pipelines and hydroelectric projects) numbers 1 500 professional staff, while ACER has approximately 50.

Regulators should focus on economic policy decisions, preserving independence throughout their decision making to maintain trust and prevent undue government and private sector influence. Accountability, transparency, engagement and performance evaluation are further core components influence the performance and perception of regulatory decision making, with the goal of achieving governments' social, economic and environmental policy objectives. The OECD (2013) has drawn up comprehensive guidelines on regulatory governance.

Siting agencies

As a result of enhanced transparency within electricity markets, standards for determining new interconnector investments are subject to scrutiny by a growing number of stakeholders. This also applies to siting agencies, which deal with the social and environmental impacts of new network infrastructure with a clear mandate to minimise them in relation to system needs. This also holds true for increasingly informed and active electricity consumers, who may be driven by economic, social or environmental reasons to assess the need for new interconnector investment. The siting process should include their interests and views from the onset, as this improves accuracy and early recognition of pathways with least environmental and social costs. Any cost-benefit analysis needs to have a wide cross-border market scope in integrated electricity markets.

Further, siting agencies and consumers must be convinced of a proposed project's drivers and superiority over other solutions. According to the IEA (2013), open planning procedures must include these stakeholders from the onset (see also the section on co-ordinated planning and cost allocation below). Only a transparent and inclusive process can determine the most suitable project and its systemic, social and environmental dimensions and implications. This open approach helps identify stakeholder views and requirements, increasing initial co-ordination and reducing lengthy negotiation procedures later in the process. Obviously, siting authorities – as well as consumers – will need to develop a holistic view of all the possible benefits arising in multiple jurisdictions. The Australian Regulatory Investment Test for Transmission (RIT-T), described in more detail in Box 4, provides a good example of public engagement in investment planning and siting processes.

Many transmission projects including interconnectors face significant delays due to the siting process. Based on a survey of 24 European transmission developers (Roland Berger, 2011), the European Commission acknowledged that lengthy and ineffective siting procedures and public opposition are two major obstacles to timely development of electricity overhead lines, including interconnectors (EC, 2011a; EC, 2011b). As siting processes usually occur at an intrastate level, investment barriers can arise even within a single operating area if it spans multiple jurisdictions.

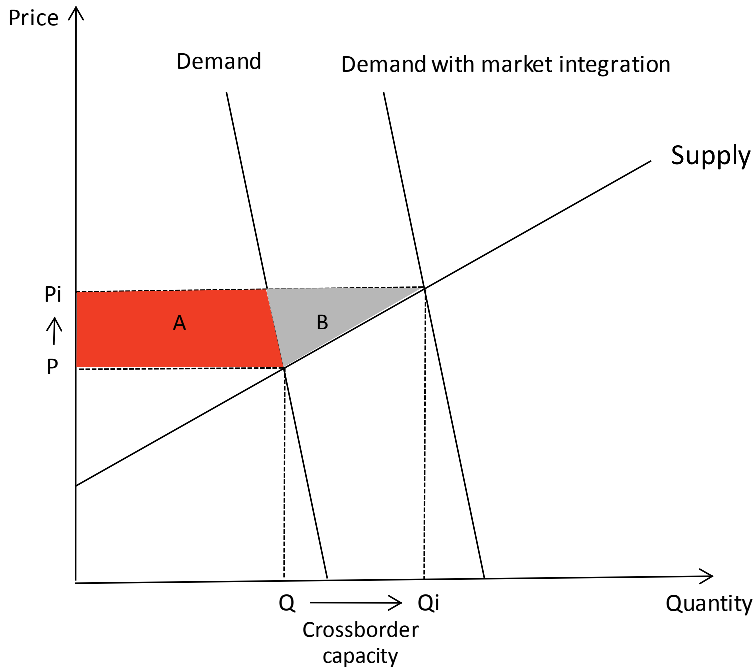
Further, public opposition can delay transmission investments even beyond the frequently observed timeframe of ten years from start to final commissioning. For this reason, the European Commission recently submitted a priority proposal to streamline cross-border siting procedures (EC, 2011a) to cut back on the duration of project implementation and increase public participation and acceptance. Such streamlined siting procedures (the "one-stop-shop" concept) would give responsibility to a single agency within each country, while attempting to reduce agency-specific siting variations to an acceptable level. The aim would be to create an efficient environmental review process with sufficient communication, common understanding of information needs and regulatory requirements to avoid duplicating applications, scoping and permit review meetings among all cross-border stakeholders. According to the Regulatory Assistance Project (2001), which observed the US electricity market, agencies will need to focus on the significance of the rule change to divest power from state-level agencies. They should also focus on the inherent need for local information and consultation, which can lead to delayed or poor decision making, especially if other urgent matters arise simultaneously.

Further, whether the responsible authority in one jurisdiction would allow a higher authority to decide on the right procedure within its territory is questionable. Hence, establishing interagency staff groups to work jointly on reviewing interconnector plans could be beneficial. This process could be supported either by a memorandum of understanding among all participating agencies, or by a permanent inter-regional body with clear frameworks and responsibilities bringing together jurisdictional knowledge and decision makers when required. When possible, all approaches should be combined with backstop authority by a higher siting authority should state authorities fail to do so within a specified timeframe.

Distributive impacts also need attention

While extensive evidence shows that liberalisation has brought many benefits, the public still believes current market liberalisation and integration yield mixed results. The most popular explanation is that liberalisation does not translate into lower prices for end consumers. Furthermore, policy makers now favour environmental policies that rely relying on support schemes, such as feed-in tariffs, which have proven effective. Altogether, the costs of national renewables deployment can be very high compared with the potential benefits of market integration.

Figure 14 • Welfare impacts of market integration in the low-cost exporting zone



Market integration policies tend to overlook distributive impacts on consumers. Despite clear advantages (such as lower generation costs), market integration triggers price convergence, increasing electricity wholesale prices in low-cost exporting areas. This distributive effect creates barriers to market integration. As Figure 14 shows, increasing cross-border capacity by Qi-Q leads to a price increase in the exporting zone (P to Pi), boosting producer welfare (areas A + B) but reducing consumer welfare (area A) in the exporting country. Conversely, electricity prices decrease in the importing zone, reducing producer welfare but increasing consumer welfare.

Anticipating these results, jurisdictions with cheap coal or hydro power are often reluctant to liberalise and integrate markets. (Further, where markets are integrated, several countries have adopted measures designed to insulate some consumer categories from high prices.) In areas (such as Quebec) with cheap hydro, markets are not liberalised. Similarly, most US states not actively liberalising their markets enjoy cheap power from coal. While the French government did transpose the EU Directive on market liberalisation, it decided to maintain regulated tariffs for residential customers until 2025 which are based on the production cost of the existing fleet of nuclear reactors.

Conclusion

Policies promoting electricity market integration developed in parallel with electricity sector liberalisation and created independent regulators that play a vital role in promoting market integration. Given these policies' institutional and regulatory implications, integrated markets were rarely implemented overnight. In Europe and North America, market integration has proceeded incrementally.

IEA member countries already reap some of the benefits of market integration policies in terms of lower dispatch costs and increased security of supply. Integrated electricity markets contribute to ensuring adequacy and system security during periods of extreme weather conditions and unscheduled unavailability of power plants. Market integration is also helping accommodate renewable energy sources, which calls for updating the market integration project in many regions.

Yet security of supply policies need to catch up with market integration, particularly to ensure adequate capacity over the integrating markets. Failure to do so has led to the development of uncoordinated local policies. These, in turn, can lead to partial re-fragmentation, further hindering market integration and free trade.

Despite the growing importance of environmental objectives, a strong commitment to liberalised electricity markets, competition and market integration remains an important dimension of energy policies. Executing these policies requires a tremendous effort to set up the appropriate regulatory and market frameworks. This topic is examined in the next section.

Interconnectors as the backbone of integrated electricity markets

Interconnectors are the physical link enabling physical integration of electricity markets. Interconnectors form the infrastructural backbone of any activities pertaining to cross-border electricity systems. They are therefore are an essential – and sometimes even inevitable – tool in the power system, provided they serve the goal of ensuring reliability, affordability and sustainability. Conversely, the absence of sufficient available or usable interconnector capacity can endanger these goals. This section presents the state of play in various OECD regions and recounts experiences in developing new interconnections. It concludes by stressing the importance of using existing interconnectors with the utmost efficiency.

State of play

The initial development of interconnectors in OECD member countries was largely driven by inter-regional and transnational government investment programmes after World War II (Union for the Co-ordination of Transmission of Electricity (UCTE), 2009). Early developments of interconnectors trace back to the 1920s. In Europe, the objective was primarily to harness valuable hydro resources in Switzerland. In the United Sates, the first interconnector supported the development of an early power pool among Pennsylvania, New Jersey and Maryland (UCTE, 2009; IEEE, 1967). These interconnectors were built under bilateral or multilateral arrangements and long-term contracts between integrated utilities and governments.

The development of these transmission lines created increasingly large interconnected electricity systems with a synchronous frequency (50 Hz or 60 Hz). Within a single frequency area, disturbances or contingencies are felt almost instantaneously throughout the power system. When various entities operate the system, co-ordination of emergency preparedness and remedial reactions over a wide area is indispensable.

North America: Limited interconnector capacity among the five interconnections

Five frequency areas currently exist in North America: the Western Interconnection, Eastern Interconnection, Texas Interconnection, Alaska Interconnection and Quebec Interconnection. The different interconnections[7] are not synchronised, precluding the use of alternative current interconnectors and limiting the level of physical interconnector capacity to direct current (DC) lines. To date, a few DC lines with roughly 2 GW in interconnector capacities exist between the Western and Eastern Interconnections and another interconnector with 2.6 GW capacity between the Eastern Interconnection and Texas Interconnection. There is no interconnector between the Texas Interconnection and the Western Interconnection (PSERC, 2012). Compared with the overall installed generation capacities within each interconnection – 235 GW in the Western Interconnection, 825 GW in the Eastern Interconnection and 80 GW in Texas – the interconnector capacities are almost negligible.

Furthermore, most interconnections (except for Texas) in the United States and Canada are further broken down into smaller areas (balancing or operating regions) where a single authority

[7] In North America, "interconnection" means a synchronous frequency area, while in a European context, interconnection refers to cross-border transmission lines. The notion of interconnector that is used in this report is consistent with Australia and the United Kingdom for undersea cables. Another term used in North America to designate transmission lines between adjacent control areas or interconnections is "interties".

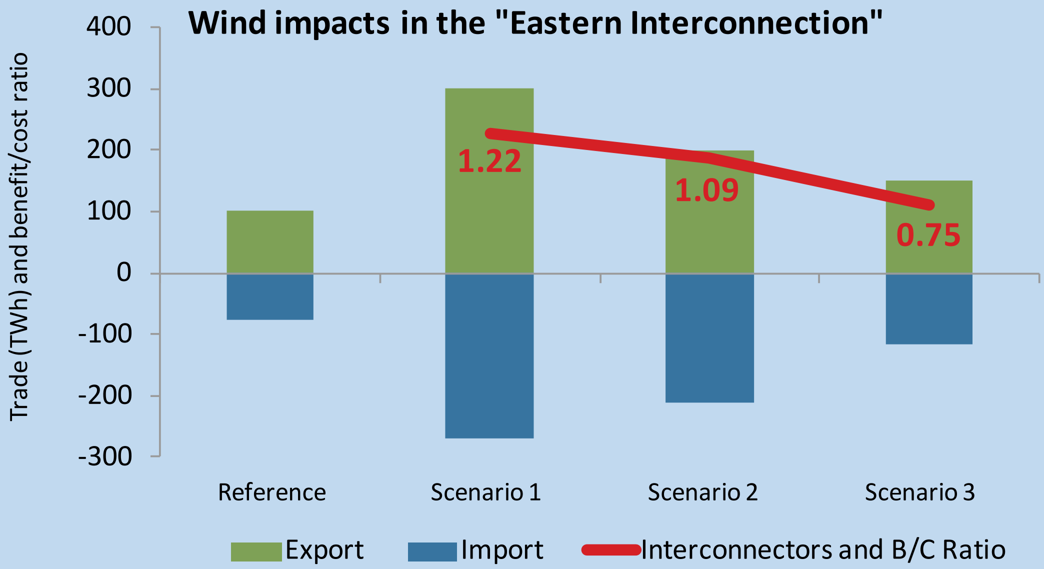
is responsible for independent system operation and transmission planning. The largest areas are operated by ISOs or RTOs, often spanning multiple states (footprint) that apply and continue to develop market-based measures to supply roughly two-thirds of US and one-third of Canadian electricity demand. Transmission lines between these regions have the same role and face the same issues as interconnectors (also known as interties), as they exceed a single system planning jurisdiction and sometimes even span several states and power system policies.

Box 5 • Reinforcing the Eastern Interconnection

On behalf of the DoE, the NREL assessed transmission needs across the footprint of various system operators within the Eastern Interconnection. The "Eastern Wind Integration and Transmission Study" (NREL, 2011) analyses the required transmission and interconnector developments and the operational impact of 20% to 30% wind energy penetration on the power system by 2024. The study was the first of its kind for the United States, identifying required interconnector developments resulting from a scenario of different wind resource developments.

The study used three scenarios and varying wind location and technology to assess the interconnection requirements for integrating wind with curtailment between 7% and 1%. Scenario 1 produced the biggest interconnector needs crossing multiple jurisdictions, as it largely aimed to capture the best onshore wind resources in the remotely located Great Plains. Scenario 3 looked at the other end, which aimed to harness mostly offshore wind, only filling residual wind requirements with onshore wind development close to demand centres. Scenario 3 is as a hybrid scenario, using wind located closer onshore and offshore.

The study indicates the lowest power system costs in the first scenario, favouring multijurisdictional interconnection, transmission upgrades and increased trade flows over local scenarios and/or strong offshore wind scenarios. Calculated network economics favour an overlay grid as opposed to incremental build-out of the existing system, comprising alternating current circuits of up to 765 kilovolt (kV) in combination with 400 kV and 800 kV DC architecture. However, only the first two scenarios indicated positive net benefits, expressed in "benefit/cost ratios" (B/C ratio) of 1.22 for Scenario 1 and 1.09 for Scenario 2, whereas in Scenario 3, the production costs savings did not exceed the added transmission costs.

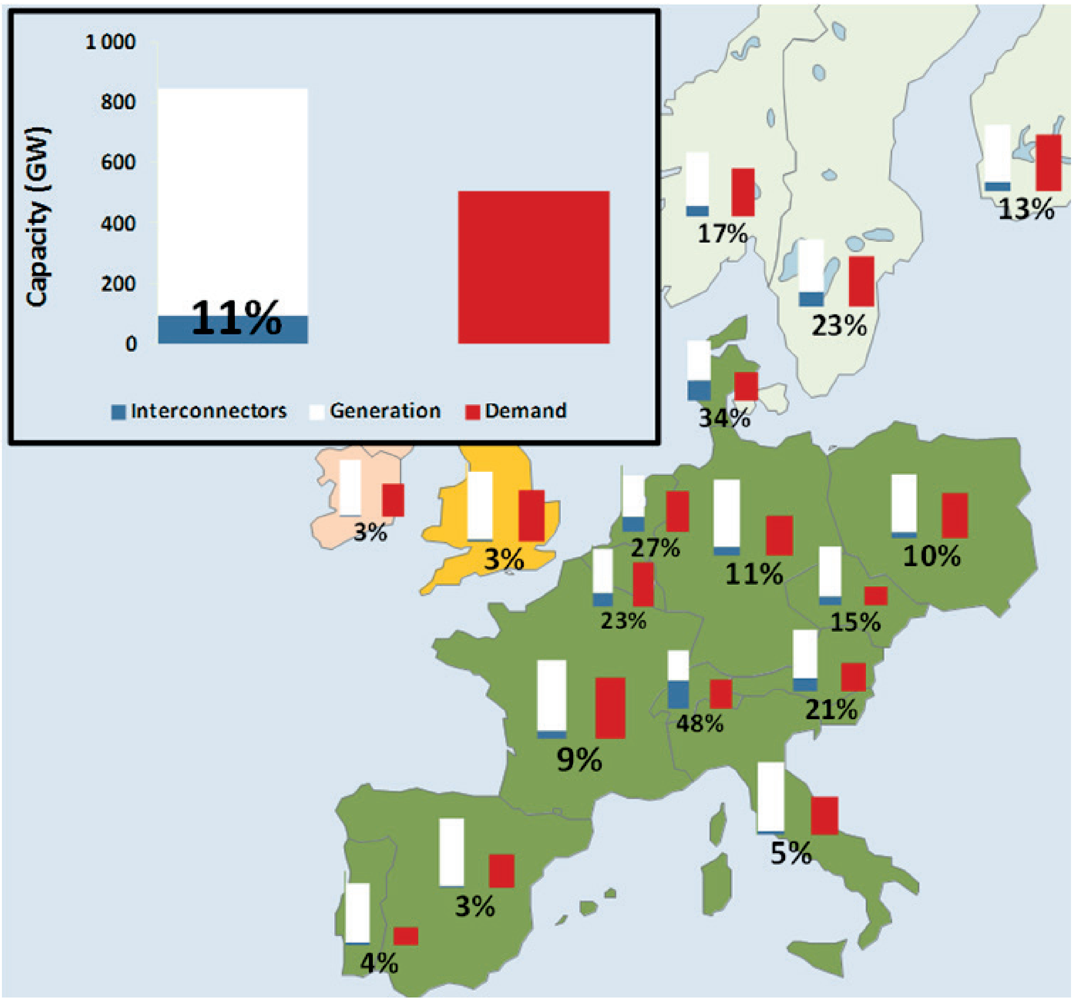


Source: IEA, with data from NREL, 2011.

Europe

In Europe, interconnectors between countries have created a large synchronous frequency area extending deep into the eastern parts of Continental Europe at a frequency of 50 Hz. Interconnectors amount to 11% of installed generation capacities across European countries (Figure 15). However, a European Union-wide view would not suffice to determine the efficiency of these interconnectors, since regional differences exist.

Figure 15 • Interconnections, generation and demand in selected European Union countries



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

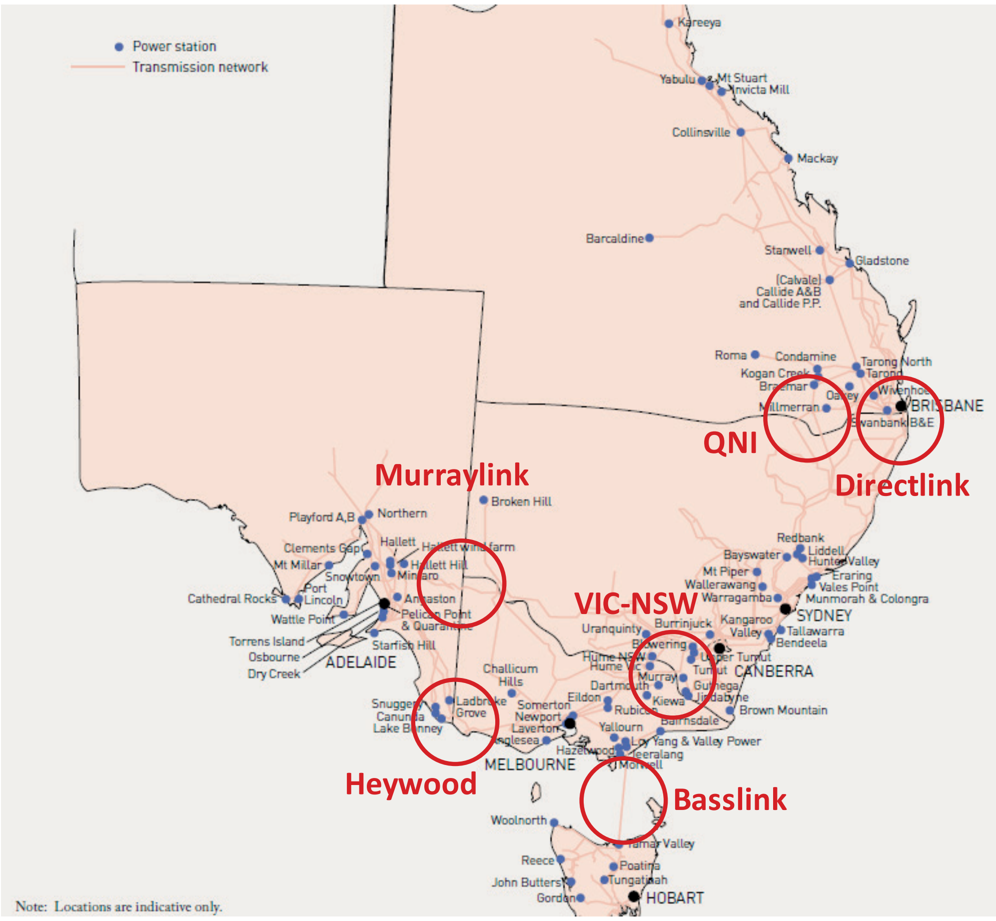
Source: IEA graph based on data from ENTSO-E, 2013b.

Australia: Interconnectors are recent

In Australia, six jurisdictions (Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania) agreed to establish the competitive NEM, enacted through the National Electricity Law. The NEM, which began operating on 13 December 1998, subsequently led to the development of new interconnectors. Queensland became physically interconnected with the NEM in 2000/01, thanks to two transmission lines (Directlink and the Queensland-to-New South Wales interconnector). Tasmania joined the NEM in 2005. In April 2006, a high voltage DC submarine interconnector cable (Basslink) from Tasmania to Victoria was completed as a merchant investment project. These jurisdictions are now all physically linked by at least one interconnector.

In terms of geographic span, the NEM is one of the longest AC interconnections in the world (Australian Energy Regulator (AER), 2009).

Figure 16 • Interconnectors across states serving the Australian wholesale market (NEM)



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: Amended graph from AER, 2009.

Investments in new interconnectors

Investments in new interconnectors face the same barriers as other transmission lines, including policies and regulations, institutions, planning, utilisation rights and cost allocation (IEA, 2013). The inter-regional dimension adds some complexity and calls for improved co-operation, co-ordination and even consolidation (where applicable) among all stakeholders.

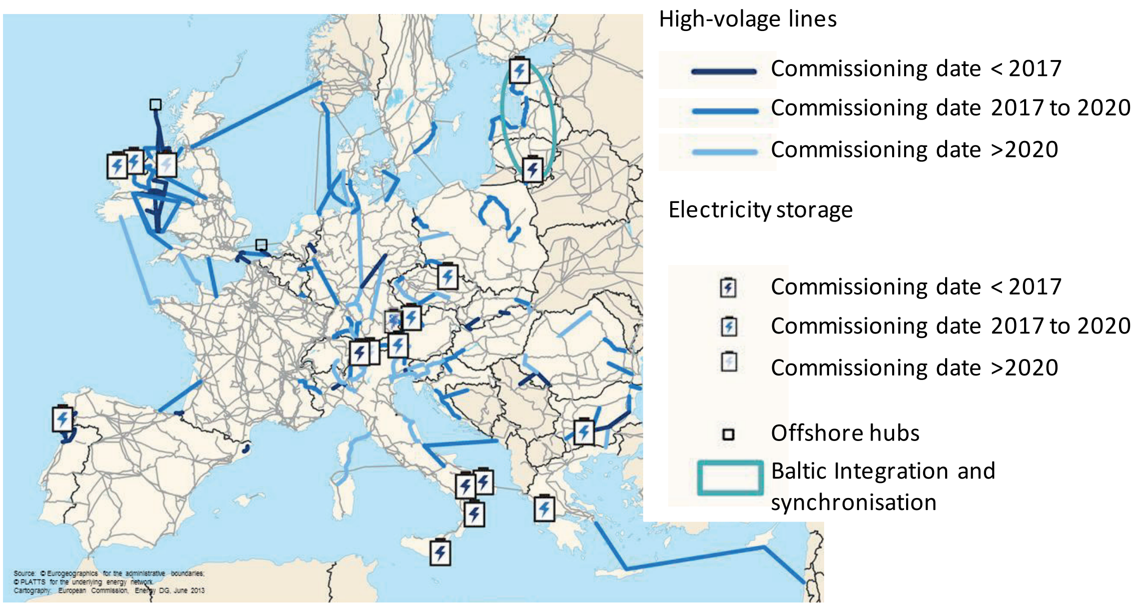
Co-ordinated planning

Co-ordinated planning of interconnectors is already underway at an inter-regional scale in Europe (with the Ten-Year Network Development Plan (TYNDP)) and North America (with bilateral protocols and committees). Many of these initiatives did not emerge spontaneously. Rather, they were responses to binding policy mandates from the European Commission or FERC.

Almost 60 interconnector projects are in various stages of development in the ENTSO-E power operating region (ENTSO-E, 2013a). These interconnectors are part of the TYNDP, a co-ordinated planning initiative to deliver a pan-European transmission plan within the ENTSO-E region (ENTSO-E, 2012). However, only eight of these interconnector projects are currently under construction. The others are in various stages of development – 20 in design and permitting, 10 in the planning stages and 21 under long-term consideration. They may undergo further evaluations, decisions changes, funding difficulties, deferrals or cancellations.

In 2013, Europe adopted EU-wide guidelines for priority cross-border energy infrastructure projects – known as projects of common interest (PCIs) – as part of the Energy Infrastructure Package (Regulation EU 347/2013). The European Union released the list of PCIs for electricity infrastructure in October 2013 (Figure 17).

Figure 17 • Transmission Line of Common Interest (PCI), as of October 2013



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: European Commission, 2013.

Several US regions plan interconnectors in a co-ordinated manner as part of – or in addition to – single operating region plans. These co-ordinated planning initiatives rest on joint agreements and planning committees, including the:

- Inter-regional Planning Stakeholder Advisory Committee of PJM and MISO (PJM, 2013a) based on the Joint Operating Agreement (PJM, 2008); and
- Northeast ISO/RTO Planning Co-ordination Protocol (InterISO, 2004) among ISO New England (ISO-NE), the New York Independent System Operator (NYISO) and PJM.

These initiatives, developed by requirement of FERC, have produced a variety of interconnector plans (ISO-NE, NYISO, PJM, 2012). Further, in 2010 the Department of Energy (DoE) funded the Eastern Interconnection Planning Collaborative (EIPC) to analyse possible transmission additions under various policy scenarios (that may or may not be implemented). The map below (Figure 18) illustrates the assumptions created for the low-carbon ("really combined policy") scenario in the year 2030.

Co-ordinated interconnector planning is also proceeding in Australia under the aegis of AEMO as national transmission planner (AEMO, 2012). ElectraNet Pty Ltd and AEMO conducted a joint feasibility study to increase interconnector transfer capability between South Australia and other NEM load centres (AEMO, 2011). The study's goal was to identify the technical option(s) delivering the highest NEM-wide net benefits stemming from reduced supply (including wind) costs.

Figure 18 • Combined Policies – New/Upgraded Transmission in the EIPC study[8]

Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: EIPC, 2013.

The five options initially identified ranged from incrementally upgrading the transformer on the Victorian side of the interconnector to increasing throughput while maintaining reliability on the construction of new long-distance (>1 000 kilometres) DC greenfield interconnectors. Additional options, including demand response programmes and better controllability of planned wind generators, came to light during extensive stakeholder consultation and scenario assessments. The investment test concluded that net market benefits are highest for an incremental transformer upgrade, while equally expensive or more expensive greenfield new-build options would deliver lower net benefits (AEMO, 2013).

The existence of multiple neighbouring system planners requires strong co-ordination of the planning process. Many jurisdictions have made progress in implementing integrated planning frameworks. The aspects needing to be co-ordinated and harmonised to support an efficient cross-border planning procedure include:

- using consistent data sets
- converging the different planning models
- harmonising reliability requirements.

In Europe, the regulation on access conditions (EC, Regulation 714/2009 2009) seeks to harmonise the relevant rules for developing the network and interconnectors. The objective is to ensure co-ordinated and sufficiently forward-looking planning and sound technical evolution of the transmission system (including interconnectors) in the European Community.

A few neighbouring countries have also made progress on a regional basis. For instance, the Nordic region interconnector planning process improved many aspects (including creating a

[8] Note from the original map; "It should be noted that the Stakeholder Specified Infrastructure (SSI)I was prepared solely for the purpose of the analysis to be performed under the DOE project. The SSI differs in many respects from the additional resources that were included in the Toll-up case prepared by the Planning Authorities in accordance with their respective Order 890 planning processes. The planning Authorities have made no attempt to reconcile or compare the two, nor do they intend to modify their respective regional plans cased upon the SSI. DOE Project DE-0E0000343 Stakeholder Specified Infrastructure – S1S2S3 Constraints + Solutions 20121121, MISO using Ventyx Velocity Suite C 2012"

multijurisdictional planning view across the Nordic region) and rendered cost-benefit assessments comparable among Nordic countries (NordReg, 2010a).

Box 6 • RIT-T in Australia

AER has been using RIT-T since 2010. It builds on and replaces a similar regulatory test in place since 1998, when NEM started operations. The purpose of RIT-T is to identify the transmission investment option that maximises net economic benefits and – where applicable – meets the relevant reliability standards. RIT-T provides a single framework for all transmission investments, removing the distinction between projects driven by reliability concerns and by market benefits. RIT-T is a transparent process, with published RIT-T application guidelines (AER, 2010b).

The test specifies the methods permitted for estimating market benefits that may occur outside the region in which the investment is located. Market benefits generally derive from more cost-efficient generator dispatch options, changes in generator investment costs and enhanced system reliability. Similarly, the application guidelines include guidance and examples on acceptable methodologies for valuing market benefits accruing across regions.

The test does not account for externalities, benefits and costs that do not accrue to parties other than those producing, consuming and transporting electricity in the market. The RIT-T process starts with a network owner identifying a need, assessing available options and engaging in a public consultation. The network owner then prepares a project specification consultation report and provides a summary to AEMO. Based on submissions throughout the consultation process, the network owner assesses credible options and classifies market benefits it deems material to the case. It then presents the preferred option (and all others) to AEMO, where a subsequent consultation period leads to a final project assessment. The AER is responsible for resolving any conflict.

According to PCGov (2013) and AEMC (2012), the application of RIT-T and other surrounding planning arrangements delivers an appropriate level of interconnector investment among the Australian states.

Box 7 • Differences in economic regulation in the Nordic region

Frameworks for economic regulation can vary significantly between countries. Some differences result from the application of different methodologies to assess and value assets or operational costs. Among other initiatives, NordReg introduced transparency about the detailed rules in 2012, leading to deeper understanding of the way economic network regulation takes place in the different Nordic countries. This transparency provides interconnector investors with the various conditions applying to the investment, which can also be used by all involved stakeholders to identify best approaches for regulating planned interconnector investments. For example, Denmark approves *ex post* transmission tariffs, whereas the other countries' regulators set an *ex ante* annual revenue cap. Furthermore, parts of the operational costs in Norway are subject to periodical benchmarking, whereas in Finland and Sweden these costs are deemed non-controllable and passed through directly into the revenue cap. These regulatory regimes also treat new investments differently, using different numbers for calculating the weighted average cost of capital (WACC), as well as different inflation, risk premiums and betas, capital structures, tax rates and debt premiums. Finland and Sweden apply a real cost of capital, whereas Norway uses nominal WACC.

In the United States, FERC Order 1000 set new requirements across regional planning authorities. These included exchanging data at least annually, engaging in joint efforts to harmonise model assumptions and models, and harmonising inter-regional project and cost-benefit assessments (FERC, 2011). Most regional planners have already complied and amended their planning frameworks (FERC, 2013a). While this has triggered significant changes in the regional authorities' planning approaches, it is too early to judge the long-term effects of FERC Order 1000.

Co-ordinating infrastructure planning and regulatory approval in a timely and consistent manner requires extensive harmonisation of cost-benefit analyses, e.g. through the development by ENTSO-E of a single cross-border assessment methodology (ENTSO-E, 2013c) required by the European guidelines for the implementation of European energy infrastructure priorities (European Union, 2013). In Australia, a single regulatory investment test is performed (AER, 2010a) (Box 6).

Furthermore, since interstate projects present higher risks and are more difficult to license, some regulators try to incentivise them by offering a higher return on capital. For instance, FERC allows a substantially higher return on investment (ROI) than the typical remuneration of regulated investments served by state public utility regulatory commissions. In the European Union, Italy provides for higher rate of return on investments (premiums) to signal investment priority for interconnectors.

Cost allocation

Cost allocation for interconnectors can stumble against missing incentives for network investors and a lack of consumer or regional acceptance. FERC (2011) notes that inaccurate cost allocation represents a significant cross-border investment barrier. In some cases, interconnectors or electricity flows cross a jurisdiction without offering it any benefits. A correct allocation would not allocate any cost to countries or states that do not benefit. However, the jurisdiction might have to bear the licensing, siting and environmental costs.

Note that investments that do not cross administrative boundaries still have an impact on cross-border capacity. For example, increasing the cross-border interconnection between Spain and France is useless if the French network is too weak to transport electricity to its northern borders. Accordingly, cost allocation principles can also extend to these investments. Likewise, AEMC found that approximately two-thirds of all internal transmission constraints contain an inter-regional term (AEMC, 2011).

As already argued in a previous paper (IEA, 2013), costs should be allocated to the beneficiaries. One of the advantages of this approach is to avoid overinvesting if the combined jurisdictions do not provide enough cumulated benefits. Another advantage of the “beneficiary pays” principle is informing each group of stakeholders during the planning and assessment process to gain acceptance for new interconnector investments. These cost allocation approaches are already applied in Australia and are being developed in the United States and Europe.

In early 2013, the AEMC published its final determination and rule on inter-regional transmission charging (AEMC, 2013). While the new arrangements will better reflect the benefits of transmission in supporting energy flows between regions, they will not affect the total revenues from each transmission business. The major expected benefits will derive from enhanced incentives for businesses to pursue transmission investments whose costs fall predominantly in their own regions but whose benefits fall in neighbouring regions, since they can recover some of the investment costs from consumers in those regions. Further, the prices consumers pay for transmission services will better reflect the actual costs of providing those services. Finally, regulatory arrangements will be more credible – and inspire more confidence – as the cost of transmission capacity for conveying electricity among regions is allocated to the regions benefitting from this capacity.

Merchant investments

The construction of new network infrastructure is mostly supported by regulation, which can usually eliminate barriers to market-based network infrastructure investments (merchant investments). Investment planning and regulatory revenue calculation and allocation seek to reduce uncertainty and potential revenue shortfall. Beyond the lack of transparency and certainty, further barriers to merchant investments may include continuous market power-induced price spreads, rising transaction costs or incumbent rights to refuse third-party investment proposals (Joskow, 2005; Littlechild, 2011; IEA, 2013).

However, each of these barriers seems to be country- or even project-specific. The academic debate is still ongoing about the experiences of existing real-life projects and their resulting policy implications. Single observations with real-life projects have identified imperfect market information as a major hurdle to merchant transmission investments where expected price spreads between interconnected nodes proved to be lower in practice (Littlechild, 2011). In Australia, two interconnectors, Murraylink and Directlink, that initially started as merchant projects (see Figure 21) were transferred under regulatory regimes when the required price spreads between regions ceased to exist. Basslink remains a merchant interconnector in the Australian NEM.

Nevertheless, it seems worthwhile to continue identifying – and possibly eliminating – barriers to merchant-based transmission investments. The resulting potential increase in these investments will reduce the need for regulatory tasks to assist the process. This can mitigate some of the potential failures inherent in all regulatory processes and produce enhanced economic efficiency, innovation, technological neutrality, delivery and financial resources (Joskow, 2010).

As remote renewable generators are connected, these now-rare merchant investments are expected to grow – which might also help solve the "chicken-and-egg" problem associated with developing remotely located renewable generators (e.g. offshore wind) (IEA, 2013). Hence, FERC has started reducing entry barriers to merchant investors by lifting the so-called "right of first refusal" for incumbent transmission owners (FERC, 2011).

In the European context, merchant investments are decided on a case-by-case basis, granting access regulation exemptions for interconnectors for a set period (see EC, 2009). The exemptions can only be granted if the investment: i) enhances competition and does not negatively influence the functioning of the internal market; ii) would face an overburdening risk without exemption; ii) is owned by a person legally separate from the TSOs; iv) recovers revenues from use of the specific investment only; and v) is not cross-financed by revenues from other activities.

Using interconnectors

A seamless power market needs to eliminate these barriers to cross-border trade, mainly through the regulatory framework. The next section reviews the major barriers associated with using existing interconnection infrastructure: (i) calculating the networks transfer capacity; and (ii) allocating it to manage congestions at borders.

Network transfer capacity

System operators determine cross-border transfer capacity in a co-ordinated manner by taking into account the physical thermal limits of transmission lines and security requirements, such as the need to cope with unplanned outage of a line or large power station ("n-1 rule"). For example, the four interconnectors between France and Spain have a nominal thermal capacity of 4 120 MW in winter, but the NTC is "only" 1 400 MW (34% of nominal capacity) from France to Spain and 1 100 MW since 2011 from Spain to France (Booz & Co, 2011). In this specific case, the loss of a nuclear power unit located in Spain would increase the flow from France to Spain by 1 200 MW, reflecting the shared activation of primary reserves all over Europe until the secondary regulation in Spain increases its output. This is the main reason for the difference between the nominal thermal capacity and the NTC available for trade.

NTC assessment rests on defining the meshed network's topology and pattern of injections, which depends on both market conditions and wind and solar conditions. Thus, calculating the NTC ahead of real time requires considering several probable scenarios featuring different wind and solar conditions, thermal generation changes and resulting cross-border flows. This is why

TSOs can only allocate a fraction of the NTC ahead of real time. If they allocate too much firm capacity too early, they expose themselves to commercial risk.

One important issue is the priority of wind and solar dispatch when it impacts on cross-border flows. A period of high wind output can reduce the long-term interconnector capacity made available to conventional generators. TSOs are likely to hesitate to expose themselves to the potentially large risks engendered by reduced NTC. As a result, they will likely reduce the NTC allocated to allow forward contracting. They might also allocate this capacity over shorter periods, thereby failing to meet the needs of generators and customers willing to contract over longer periods.

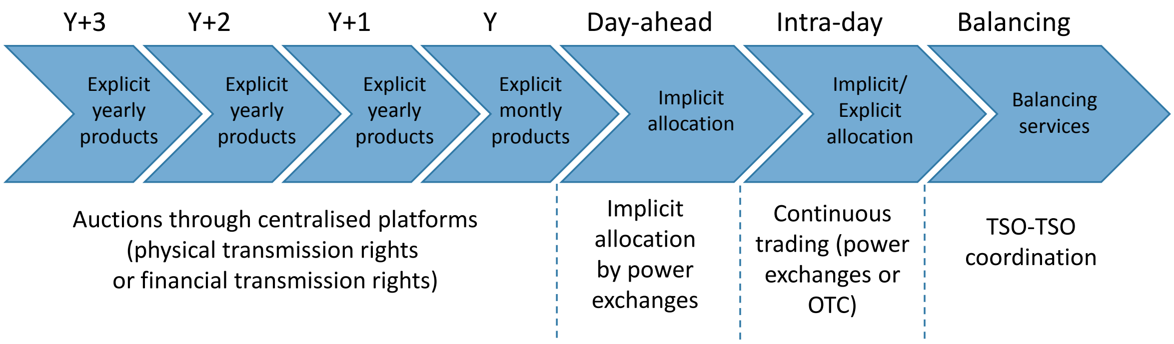
Proper market integration of VRE presents other practical difficulties. Due to unpredictability of wind and solar power, system operators have to block capacity in all directions, i.e. imports and exports. It is difficult, however, to demand that renewables buyers pay (i.e. by compensating for re-dispatching costs to buy long-term transmission rights) for cross-border flows associated with wind and solar power. While installing phase shifters to control power flows at borders provides a temporary technical fix, it does not solve the problem.

Allocating interconnector capacity

To co-ordinate adjacent markets closer to real time, interconnector capacity must be allocated to different users. In Europe, this is mainly achieved through physical transmission rights allocated on a forward basis, years or months before the day-ahead market (Figure 19). These forward transmission rights are nominated a few hours before the day-ahead market. Once nominated, the TSOs can net out the rights nominated in the opposite direction and calculate the resulting available transfer capacity for the day-ahead time frame. The market coupling of neighbouring markets then ensures optimal use of this available transfer capacity.

It is also possible to use cross-border trades for intraday and balancing timeframes. At present, most European network capacity is supposed to be used for day-ahead market coupling. In case of congestion, there is no capacity left to export power on the balancing and reserve markets. As intraday and balancing timeframes become more important with the deployment of wind and solar power, the market and network capacity allocation frameworks will need to be adapted accordingly.

Figure 19 • Allocation of interconnector capacity and sequence of electricity markets in Europe



Interconnectors can find a significant source of revenue in cross-border from cross-border trading of intraday, balancing and reserve energy. The interconnections between Norway and Denmark are a good example. On the fourth interconnector, Skagerrak 4, 100 MW (one-seventh of capacity) was allocated to trade reserves for a period of five years. The remaining capacity was allocated to day-ahead trade. Finding the optimal allocation between day-ahead trade, intraday and reserve trade is challenging and depends on fluctuating market conditions. The possibility to trade reserve was an important element in the investment decision. Even though only one-seventh of total capacity has been allocated to reserve trade, it accounted for 33% of revenues.

In the United States, ISOs must also co-ordinate on an inter-regional basis for the day-ahead and real-time markets timeframe. But as the next section illustrates, efficient co-ordination of adjacent real-time markets is not easy, given the regulatory and administrative time lags for gate closure between markets. While improvement is possible, some dispatching inefficiencies seem inevitable in the absence of a centralised entity in charge of calculating security-constrained and economic dispatch for adjacent control areas.

The firmness of allocated transmission rights is an essential issue with implications on the static and dynamic efficiency of power systems. Non-firm allocation of transmission rights is a relatively simple procedure, whereby competitive generators are only dispatched in the absence of binding transmission constraints. Under this approach, generators will not pay to use interconnector services. However, it will only produce efficient outcomes and minimal system costs if the transmission planner is required to adequately forecast all relevant system developments. For this, generators would need to foresee medium- to long-term network conditions with perfect accuracy.

By contrast, an optional firm-access approach would enable generators to choose between "firm" and "non-firm" access to interconnector capacities. Firm generators buy a hedge against transmission constraints; the cost of the hedge functions as a revenue stream for network investors. Thus, interconnector investment would be partially driven by generators choosing and paying for firm access, rather than by planners anticipating generator market development and customers paying for all transmission. This enhanced firmness can also increase energy contract liquidity. Further, transmission cost differences for firm access at varying locations would influence generators' locational decisions.

Loop flows

Loop flows are a growing problem stemming from the deployment of wind and solar power. They result from the differences between the physically metered flows and scheduled flows at an interface over a defined period. They exist because the generation scenarios designed to predict network flows differ from real-time generation as a result of wind and solar prediction errors or conventional unit outages. The lack of accurate locational pricing in some markets can also cause loop flows.

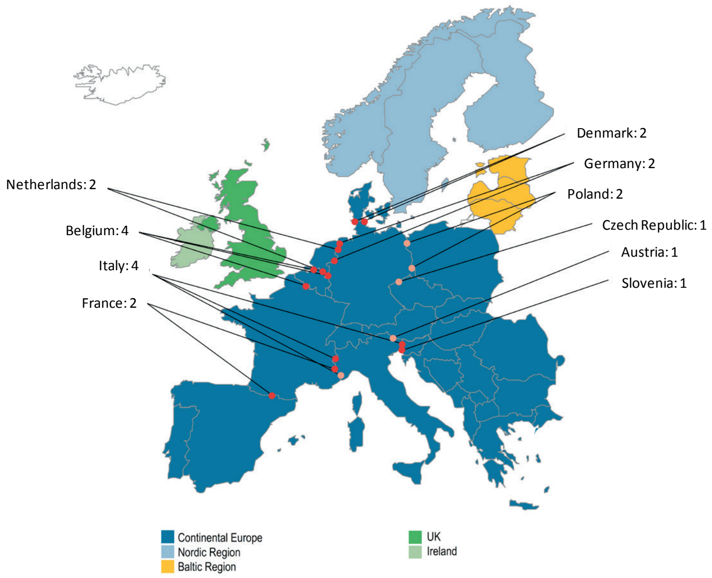
A recent study for the European Commission (Thema Consulting, 2013) concluded that bottlenecks within Germany are not reflected in the prices, as Germany does not apply bidding zone delimitation. The observations indicate that prices in northern Germany are higher than they should be – triggering higher generation in northern Germany, but also higher generation in Poland destined for market exports to Germany. In the south of Germany, prices seem to be too low; triggering lower generation than what is optimal from a cross-border and local balance point of view.

Developing wind without proper co-ordination can pose a real problem to system security. High wind generation can create loop flows that conflict with existing rules for calculating and allocating transmission capacity between adjacent control areas. For instance, wind generation in northern Germany changes power flows across Poland and reduces the formerly available transfer capacity at the border between Germany, Poland and Slovakia. These modified power flows can also lead to new internal constraints in the Polish network. For instance, Polskich Sieci Elektroenergetycznych PSE have seen situations where generation in northern Germany needed to be reduced, but increasing generation in Poland was impossible due to congestion at the border between Poland and the Czech Republic.

The fast deployment of wind in northern Germany has had a huge impact on co-ordination with neighbouring TSOs. It is perceived as a risk to security of supply – so much so that many TSOs have installed phase shifters to better control power flows. This inefficient move is probably the least desirable event in integrated markets as it ultimately leads to physical fragmentation (Figure 20).

To address these issues, Germany has proposed to increase the financial compensation included in the inter-TSO compensation mechanism.

Figure 20 • Phase-shifting transformers installed and planned in the European Union at a selection of borders (as of June 2012)



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.
Source: ACER/CEER, 2012.

Loop flows can occupy a considerable share of scheduled trade between regions. In 2012, PJM experienced loop flows amounting to 226 GWh, representing an additional 34% of the scheduled flows (PJM, 2013b).

Loop flows pose a significant challenge to security of electricity supply. One physical solution is to prohibit transactions that would result in loop flows. Another solution is to control flows through phase angle regulator (PAR) deployment, co-ordinated operation of power control devices or circuit-path prohibitions. However, the experience of the Lake Erie loop flow (NYISO, 2010) shows that PARs have many drawbacks. They are relatively costly and can be challenged by inaccurate cost allocation to beneficiaries in the absence of accurate data and modelling approaches. They require detailed operating protocols between operators and present some operating limitations, such as insufficient locational outreach and flexibility to adapt to changing conditions.

Another issue is that loop flows can lead system operators to reduce NTC allocated during different timeframes. This occurs on a forward basis – reducing opportunities to use interconnectors to sign long-term energy contract across borders – as well as with day-ahead and intraday time frames because NTC at the border is usually calculated before the day ahead, e.g. two days before real time in Europe.

A more dynamic intraday recalculation of NTC could use better wind and solar power forecasts that improve considerably a few hours before real time. However, such calculations – and the necessary co-ordination between adjacent system operators to agree on the NTC value – take time. Absent a single entity in charge of real-time security constraint dispatch, the time needed for proper co-ordination is one of the fundamental reasons for the superiority of consolidated system operations in integrating markets with high shares of wind and solar power.

Better inter-regional co-ordination to prevent loop flows is therefore essential to achieve market integration. A recent analysis of the Lake Erie loop flow estimated annual savings throughout the region at USD 362 million. This amount includes enhanced inter-regional transaction co-ordination, interface pricing, market-to-market co-ordination and congestion buy-through (FERC, 2011).

Box 8 • Following the laws of physics and not regulations: Loop flows in North America

Problems with the Lake Erie loop flows first came to light in 2007. The scheduled path of counter-clockwise electricity flows around the lake suddenly started to change. This caused congestion within the NYISO operating region and imposed additional costs and uncertainty on the day-ahead and intraday markets. Energy traders, who saw arbitrage opportunities between non-aligned interface prices between operating regions, were a significant cause of these loop flows (DPS, 2008). It was further assessed that loop flows affected multiple operating regions, including MISO, NYISO, PJM and IESO (PJM-MISO, 2008).

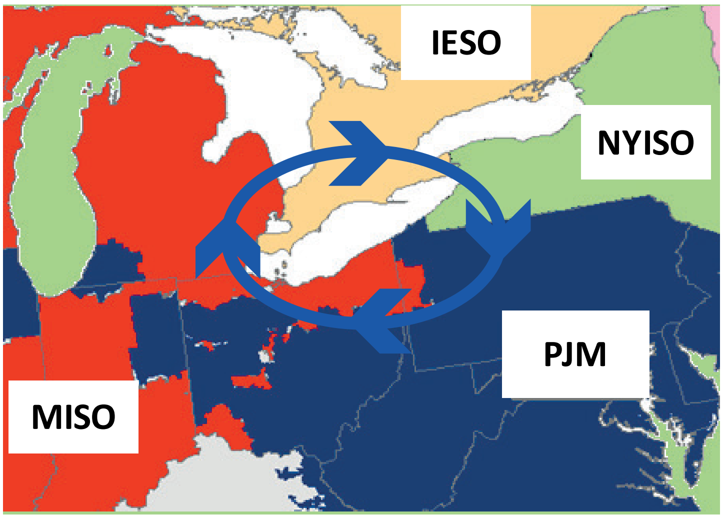
On 21 July 2008, NYISO filed tariff amendments to prohibit transactions exploiting differences in pricing and settlement rules among operating regions. As a long-term solution, NYISO further proposed deploying PRAs to ensure close alignment of actual and scheduled flows. FERC regarded the tariff amendments as a temporary response and demanded a longer-term solution to tackle the loop flow problem through a collaborative process across all affected regions (FERC, 2008).

While the implementation of pricing rules and technical measures has reduced the loop flows, they have not completely resolved the issue. Further, these measures are seen as a second-best solution as they failed to address the initial cause of the loop flows.

Based on this demand, NYISO, together with PJM, MISO and IESO, has worked to develop and implement a mutual interface pricing initiative, approved by FERC in 2013. Under the approved filing, NYISO has utilised new software to better identify occurrences of unscheduled power flows triggering the application of specific interface pricing methodologies on all relevant physical interface nodes between the operating regions. This methodology is expected to be compatible with adjacent operating regions' pricing methodologies intended to deliver the same market prices.

The effects of the permanent rule change on the loop flows have not been fully assessed yet, particularly with regard to using historical – rather than real-time – flow conditions in day-ahead market assessments. Some stakeholders, such as the PJM Independent Market Monitor, have stated that a more dynamic approach could address parts of the remaining loop flows.

Figure 21 • The Lake Erie loop flow



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: ISO NE, 2011a.

In Europe, TSOs have begun to better co-ordinate their operations. CORESO (2006) and STC (2008) were inaugurated into the European frequency area to support several national TSOs with wider and often close-to-real-time (every 15 minutes for CORESO) situational awareness on a voluntary basis. Just like NERC in the North American frequency areas, these organisations frequently develop reliable market and operation procedures under changing system conditions, e.g. making progress on variable generation integration (CORESO, 2013).

Conclusion

Insufficient interconnector capacities among markets, system operators or countries can create a bottleneck, limiting efficient integration of electricity markets. Overcoming this physical barrier to market integration should be a priority. Building more infrastructure may present many benefits in terms of increased competition and simplification of network operations that are otherwise difficult to handle without proper locational marginal pricing.

A transmission grid may not seem very expensive compared with the cost of low-carbon generation and renewable support schemes. This does not mean, however, that it is necessary to have a "copperplate", i.e. a grid free of network congestions. On the contrary, optimal grid investment will likely also imply a degree of congestion at the interconnection. Further, local acceptability problems may constrain the number of lines that can actually be built.

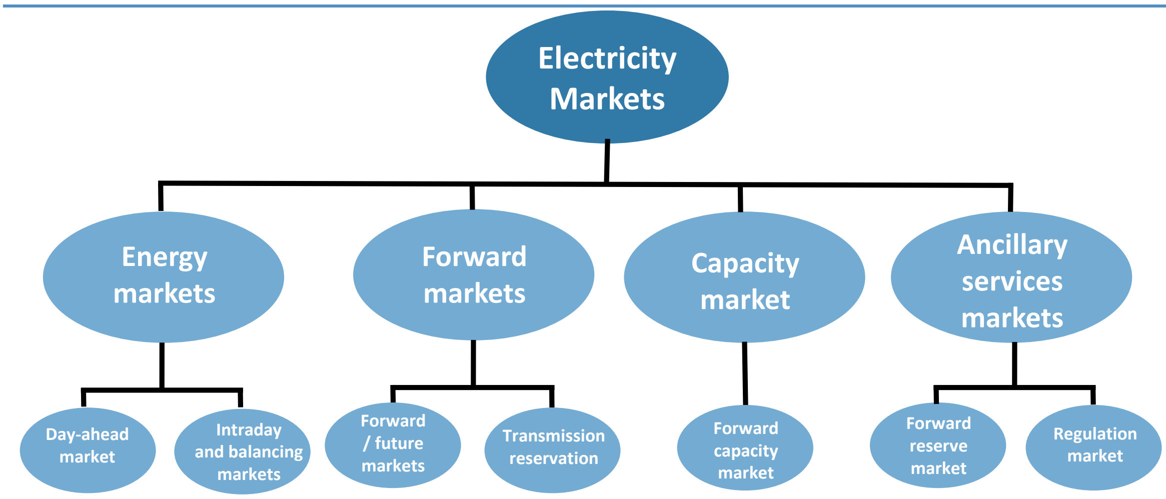
High shares of wind and solar power call for using existing interconnectors with the utmost efficiency. Renewables are blamed for creating unscheduled loop flows, leading system operators to reduce cross-border capacity available to market participants. Such inefficiencies generally result from practices inherited from the past. Better use of existing infrastructure requires more dynamic and closer co-ordination between adjacent system operators.

Market integration

Any design of integrated markets needs to account for the impact of high shares of wind and solar power on adjacent electricity markets. Renewable energy sources may be situated far from consumption centres, leading to more volatile real-time power flows, sometimes spanning the footprints of several system operators or balancing areas. This strengthens the case for close integration of markets over wider geographic areas. However, the variability and uncertainty of wind and solar power also raise new challenges and could threaten inter-regional market integration in the event of poor co-ordination among system operators.

Yet most studies on grid integration of wind and solar power ignore how to turn engineering vision into market reality. Based on the ten-year experience of market integration in IEA member countries, this report discusses two broad and complementary pathways to market integration: consolidation of control areas – as applied in several countries – and co-ordination of adjacent system operators.

Figure 22 • Overview of electricity markets



In practice, integration over wider areas of liberalised electricity systems requires integrating and co-ordinating a suite of electricity markets (Figure 22).

- Regional co-ordination of energy markets is important to accommodate variable and uncertain wind and solar power – but ensuring proper co-ordination closer to real time can be a complex task involving core system security issues.
- Forward and financial market integration needs further development, providing the hedging tools needed to tackle the increased variability associated with high shares of variable renewables.
- Regional integration of capacity markets between adjacent control areas will help reduce the costs of maintaining sufficient generation capacity and avoid creating distortions.
- Ancillary services markets are also a candidate for further market integration.

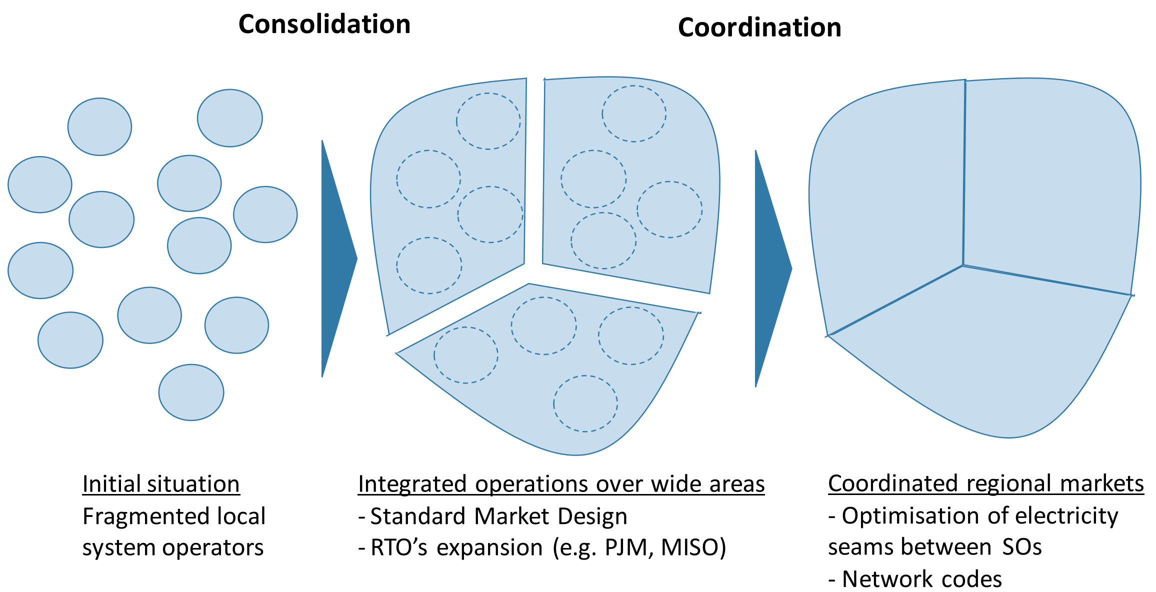
This section also provides an overview of the impacts of fragmented environmental policies related to electricity markets.

Two ways to integrate markets: Consolidation and co-ordination

Creating a well-functioning integrated market can take a variety of forms. In the United States, the typical approach has been to harmonise market design for jurisdictions wishing to liberalise their electricity systems. This has led to a dual system. Some states have liberalised their market, adopting the RTO approach; for example, PJM and MISO regularly expand their geographic footprint, integrating new control areas on their perimeters. The rest of the country is still under a regulated framework and market integration remains extremely limited (Annex A).

By contrast, Europe has adopted a comprehensive and mandatory policy requiring each EU member state to liberalise its electricity market. At least in terms of system operations, no consolidation has taken place, except to a certain extent in Nordpool. Germany still numbers four transmission network operators. Due to its institutional barriers, Europe has relied on co-ordinating rather than consolidating system operators. European countries have different reliability regulations and are reluctant to transfer responsibility for electricity security of supply.

Figure 23 • Consolidation and co-ordinated approaches to regional market integration



Based on the experiences of the United States and the European Union, two models of market integration – i.e. consolidation and co-ordination – have been identified (Figure 23).

- **Consolidation of markets and system operators:** consolidation refers to the merging of system operations. Note that ownership of the grid can remain separated, as can asset maintenance management (which requires a local field organisation). But operations have to be unified under the responsibility of a single entity controlling power plants over a control area. Consolidating market and system operations has proven a very powerful approach to optimise use of scarce transmission infrastructure, particularly under a nodal pricing system.

- **Co-ordination of system operators:** even if consolidation is impossible or geographically limited, neighbouring system operators must nevertheless be co-ordinated. This involves optimising and perhaps harmonising cross-border flows. However, given the need to prevent system security events or blackouts, co-ordination usually leads to lower utilisation of cross-border capacity, complicating new network investments.

The two models described above are not mutually exclusive. It is possible to consolidate (such as with the PJM expansion) and co-ordinate in parallel with neighbours (such as in the United States) to optimise the seam, i.e. the border between system operators' areas. Conversely, the European Union started TSO co-operation and power exchanges without taking significant steps to merge system operations.

To be clear, full market integration does not mean having a single electricity wholesale price for the entire integrated market at all times. In some regions, the target is to apply a single price over the entire market area spanning several countries or states. This would require getting rid of network congestions and investing heavily in the transmission network infrastructure. Such a "copperplate" network – i.e. a congestion-free grid – is increasingly unlikely. It should be acknowledged that transmission capacity will most probably remain scarce and will not suffice to achieve this perfect vision of the electricity market.

There are several reasons for this.

First, while transmission network needs to be expanded, the goal should never be to eliminate all congestion. This would not be economical. Efficient transmission investment would lead to an optimal level of congestion between zones, meaning that some transmission lines would be congested for at least some hours of the year.

Second, with the development of variable renewables, power flows will become more dynamic. It is less costly to accept a certain degree of optimal congestion, which will occasionally lead to differences in electricity prices.

Finally, owing to local acceptance issues and distributive effects, it might not be possible to build all the efficient lines in a timely manner (another reason is that network losses also lead to price differences among network locations).

As a result of unavoidable transmission constraints, the benchmark market design should efficiently handle transmission constraints and network losses. Instead of a single electricity price, a locational marginal pricing framework will ensure better use of scarce transmission capacity. Where market integration is concerned, this means that co-operation between system operators should aim to ensure converging real-time electricity prices at each node of interconnection between two system operators.

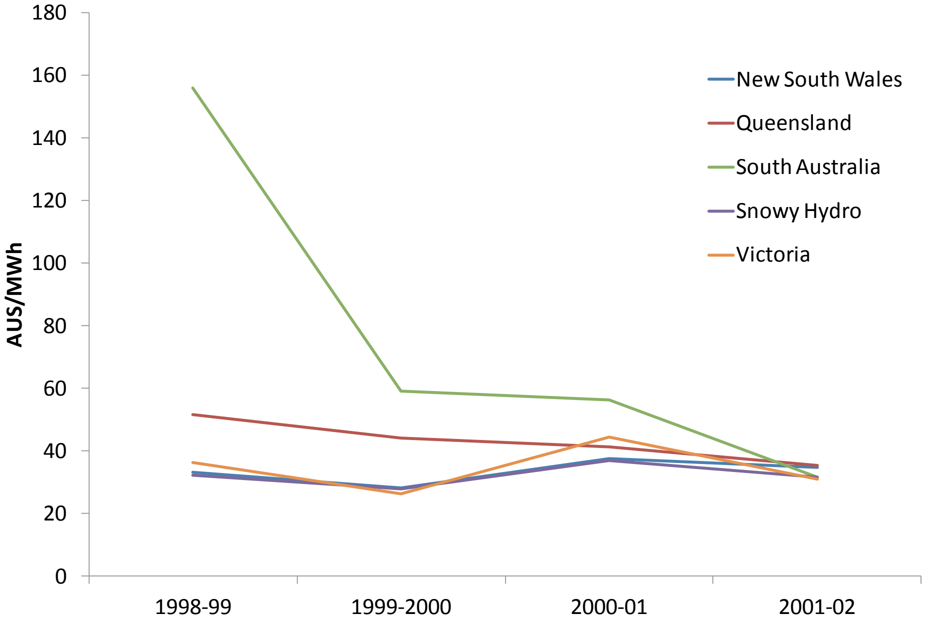
Examples of consolidation: NEM, PJM, MISO

Mergers of system operators and electricity markets over wider geographic areas increase overall efficiency. With this process, a single entity in charge of managing the system over a wider geographic area controls system operations. Consolidation of system operators may ensure the most efficient use of existing assets and should be regarded as the benchmark of market integration.

In Australia, AEMO came into operation in 1999, superseding about five state organisations. Under this top-down approach, the Australian government decided to centralise the National Energy Market's system operations. AEMO initially calculated market clearing prices for five zones that are part of a radial electricity system along Australia's east and south coasts. As a result of better utilisation of existing network capacity, market prices began moving much more closely together after market integration (Figure 29).

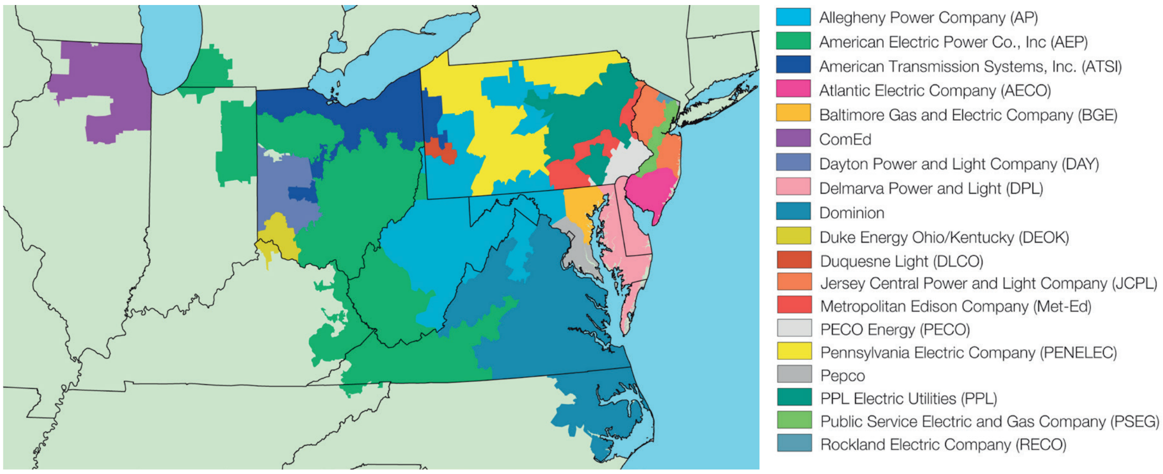
In the eastern United States, the PJM interconnection gradually expanded its footprint to become the largest interconnection in the world in terms of peak demand. In 2001, FERC designated PJM as an RTO. Allegheny Power joined PJM in 2002, followed two years later by Commonwealth Edison, American Electric Power and Dayton Power and Light. In 2005, Duquesne Light Co. and Dominion Virginia Power merged operations with PJM. More recently, First Energy and Duke Energy Ohio and Kentucky merged. PJM now serves peak demand amounting to approximately 150 GW (Figure 25).

Figure 24 • Convergence of regional market prices in Australia, yearly average prices, 1998-2002



Source: Australian Energy Market Commission

Figure 25 • PJM footprint

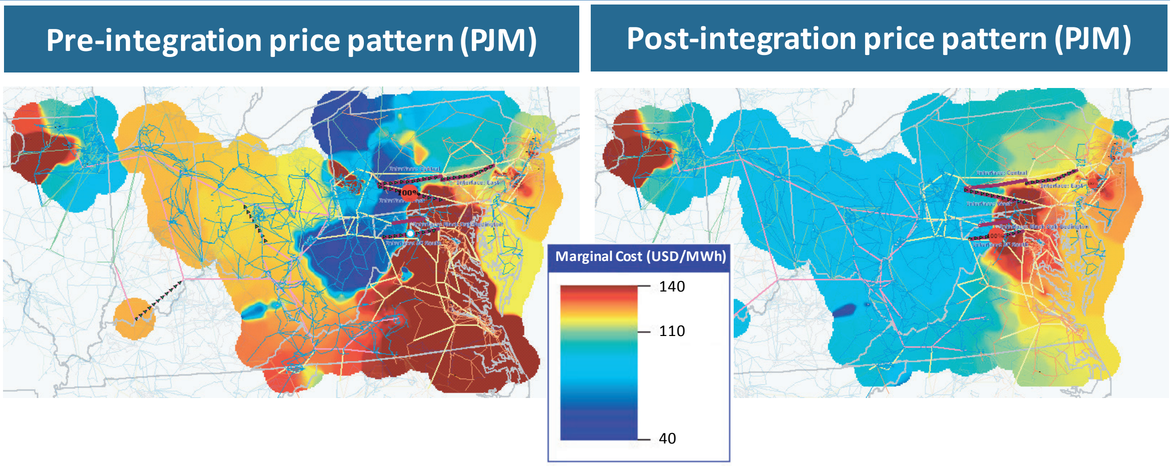


Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: Monitoring Analytics, 2013.

The consolidation of market and system operations by PJM has led to a more efficient dispatch of power plants. A 2006 simulation (Figure 26) clearly illustrates that pre-integration locational marginal prices derive from the use more expensive power plants. Post-integration prices tend to converge across the consolidated area, although consolidation does not suppress congestions. From a purely technical perspective, there are no technical or computational limitations to implementing locational marginal pricing (LMP) over a wider area.

Figure 26 • LMP patterns before and after integration



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: PJM, 2013d.

Significant institutional barriers hinder consolidation of system operators

Despite the existence of NERC, more than half of the US electricity system has not been reformed. It is still regulated and fragmented, with over 100 different balancing authorities. Liberalisation stalled ten years ago, after the California electricity crisis of 2000 and 2001.

In Europe, around 30 system operators remain stuck within the boundaries of their national or regional countries. Yet opportunities for efficient consolidation of system operators exist. For instance, cross-border acquisitions by Dutch system operator Tennet and Belgian operator Elia signals that consolidation could happen. The German TSOs they purchased have not consolidated from an operational perspective and still operate with different control rooms and under different regulatory frameworks.

Indeed, the regulatory framework regarding electricity security of supply remains fragmented, since governments retain responsibility over their jurisdiction. This case illustrates that institutional barriers can hinder the consolidation of companies in charge of system operations in different jurisdictions. Arguably, consolidation of system operators across the European continent is extremely unlikely.

Inter-regional co-ordination

Improving co-ordination among system operators remains essential to ensuring efficient integration of electricity markets despite institutional constraints. This is especially important when the generation capacity of adjacent TSOs is strongly complementary and to accommodate high shares of wind and solar power. In North America, inter-regional co-ordination includes co-ordinating electricity seams among MISO, PJM, New York ISO and ISO New England, as well as with multiple balancing authorities.

However, inefficiencies resulting from poor co-ordination remain at the outer limits of system operators. They mainly stem from the network charging rules, trades in the wrong direction – i.e. against price differentials – and inefficient use of existing NTC (see previous section on regulation).

Essential framework details that guide system operations and development need to undergo systemic harmonisation. The implementation of the European Union's "Third Energy Package" in 2009 initiated the binding development and implementation of network codes. The overarching objective was to create a secure, competitive and low-carbon energy sector, as well as to support the integration of renewable generation, the activation of often passive consumers and cross-border trades.

Energy markets co-ordination

Market coupling

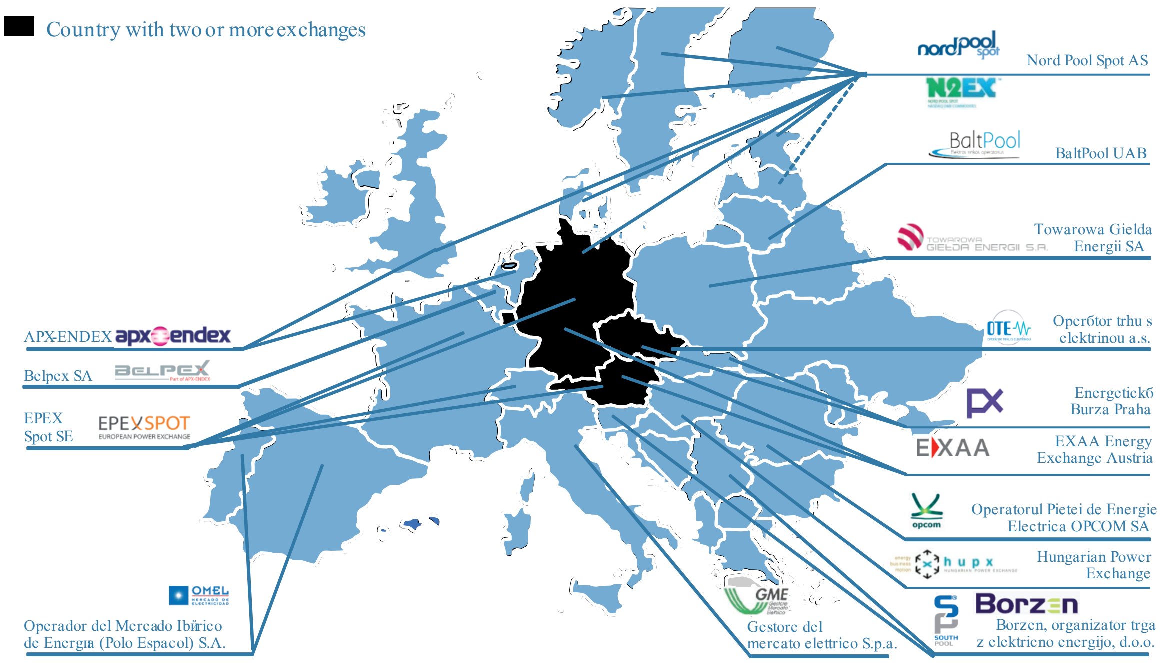
The European Commission has long considered addressing inefficient electricity trades a priority. The current solution is to rely on power exchanges to ensure full use of available NTC in the day-ahead market. This "coupling" of day-ahead markets involves TSOs and power exchanges (Figure 27). TSOs calculate the available transfer capacity, while power exchanges calculate residual offer curves and demand curves that are not activated by national market clearing. A market coupling algorithm then activates bids to fill up the network capacity, ensuring efficient use of interconnector capacity (this process is also known as "implicit auctions"). Expanded market coupling led to higher electricity price convergence (Table 3). The fact that day-ahead market coupling will be extended to 27 national markets should be regarded as a major achievement.

Table 3 • Percentage of hours in a year when hourly day-ahead prices were equal in a selection of European regions, 2003-11

Area	2003	2004	2005	2006	2007	2008	2009	2010	2011
FR=DE	0%	0%	0%	0%	0%	0%	0%	8%	68%
FR=DE=NL	NA	NA	NA	0%	0%	0%	0%	8%	63%
FR=NL	NA	NA	NA	4%	60%	66%	54%	58%	67%
NL=DE	NA	NA	NA	0%	0%	0%	0%	12%	87%
NORDIC	27%	26%	30%	33%	28%	9%	25%	19%	26%
ES=PT					19%	38%	75%	79%	92%

Source: Data provided by the Swedish Energy Markets Inspectorate (EI) and a selection of power exchanges, 2012.

Figure 27 • Power exchanges in Europe



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: Adapted from European Energy Exchange (EEX).

Box 9 • Market coupling in Western Europe

The Netherlands has been a strong advocate of market integration in Central West Europe (CWE) since the start of the trilateral market coupling among the Netherlands, Belgium and France in 2007, continuing with its extension to Luxembourg, Germany/Austria in 2010 and to Norway and the United Kingdom in 2014. The primary aim of the mechanism is to improve market liquidity and consequently induce lower and more stable electricity prices by integrating a number of energy markets into a single area for energy exchanges.

This overall integration process received support at the political level from the Pentalateral Energy Forum, together with Austria, Belgium, France, Germany, Luxembourg, the Netherlands and Switzerland (an observer since 2011). Further liquidity and depth was added to the CWE market by so-called interim tight volume market coupling (ITVC) with the Nordic region via four DC cables (including NorNed) and day-ahead coupling with the British market (via the BritNed cable).

The day-ahead market coupling applied to CWE allows hourly transactions between buyers and sellers on the exchanges independently of their physical location. Cross-border capacity is used to eliminate price spreads between the markets, as long as capacity remains available. The cross-border capacity allocation is carried out together with the financial energy settlement in a single operation, rendering prior reservation of cross-border capacity unnecessary.

In cases of sufficient cross-border capacity, this implicit auctioning process delivers a single market price across borders. In cases of cross-border capacity constraints, optimal trades are restricted and lead to price spreads.

Along with market coupling, another emerging trend is to merge national power exchanges across several price zones in the CWE regions.

Market coupling has also led to more efficient utilisation of cross-border interconnector capacity, as transmission capacity use has supported the most beneficial financial arrangements in a flexible manner. However, it does not reflect the cost of transmission network use (e.g. losses) that would promote even more cost-efficient trades across regions.

Intraday capacity auctions and long-term (month or year-ahead) auctions remain covered under the explicit capacity allocation methodology. Explicit auctioning requires *ex ante* reservation of cross-border capacities to cover single financial transactions between supply and demand.

In 2009, the CWE region harmonised its auction rules. Since then, a single auction operator (CASC.EU) explicitly allocates cross-border capacity on the basis of a harmonised set of auction rules across CWE, Italy, Slovenia and Scandinavia.

Explicit auctioning tends to maintain inefficient utilisation of interconnectors and creates opportunities for incumbents to distort the market by withholding network capacity. Introducing a functioning liquid secondary trading market for physical cross-border capacity rights can provide greater transparency in valuating these rights.

Market coupling is operational in the day-ahead market of the CWE region and will be rolled out across the European Union through the upcoming price coupling of North West Europe (NWE). The NWE day-ahead market coupling will link Nordpool (including the Baltic States, Poland and Sweden), Great Britain and CWE in February 2014. Flow-based market coupling (for implicit auctions) is also introduced across the European Union internal energy market. In the medium term, it will include Central Eastern Europe and Southern Europe to cope with growing loop flows. Flow-based market coupling is meant to enhance network integrity and price convergence. It is expected to add greater accuracy to the market coupling method thanks to more detailed description and modelling of the underlying physical network, allowing more precise evaluation of feasible financial trading contracts.

Flow-based allocation is expected to deliver welfare benefits from increased price convergence (58% to 90% of the time), trade and reliability in the range of EUR 136 000 per day across all regions, with clear benefits for the Netherlands (APX, 2011). However, the flow-based algorithm is only one means of ensuring efficient grid integration of renewable energies. This will also require fully integrated renewable sources in the wholesale markets and merit-order dispatch in the regions.

Box 9 • Market coupling in Western Europe *(continued)*

The European Union is also considering introducing smaller price zones defined by congestion rather than national borders to better deal with network congestion at the national and cross-border levels.

Market coupling largely focuses on the day-ahead markets, while intraday and balancing markets organised by TSOs are essentially national or bilateral. To date, the Dutch intraday market remains small in both scope and liquidity. Intraday trading across the Nordic and CWE markets is still low. It has been implemented at a bilateral/regional level, as follows:

- Dutch-German border (December 2008) - first-come-first served
- Dutch-Belgium border (May 2009) - implicit auctions
- Nordpool Elbas platform (February 2011) – continuous trading
- Dutch-Norwegian NorNed interconnector (March 2012) – continuous trading
- United Kingdom on BritNed (May 2012) – explicit auctions.

With the rising shares of variable renewables and more dynamic power flows in the NWE market, integrated intraday markets will play a strong role in providing flexibility and strengthening cross-border trade. The creation of a harmonised platform for continuous implicit cross-border intraday trading in CWE region is currently under development.

Source: IEA, 2014.

Co-ordination of intraday and balancing markets

Co-ordination becomes more complex when it comes to integrating European markets closer to real time. The variability and uncertainty of wind and solar output increase the potential benefits of market co-ordination close to real time. Continuous adaptation of power plant scheduling can reflect improved wind and solar forecasts over the last 24 hours. It is less costly and more efficient than activating expensive resources on short notice just before real time.

Jurisdictions with rapid renewables deployment can tap the flexibility potential located beyond borders, provided that sufficient interconnector capacity is available. For instance, solar and wind power integration in Germany benefits from flexible hydropower in Switzerland and France, as well as from the possibility of exporting power to Southern Europe.

However, day-ahead market coupling alone does not suffice to reap the benefits of market integration with high shares of wind and solar power. Many stakeholders complain that uncoordinated approaches could soon become unmanageable and are focusing increasingly on cross-border trading of flexibility. Some European countries (e.g. France, Germany and Switzerland since 2013) have developed trade in the intraday or even balancing timeframe (e.g. BALIT between France and Great Britain).

But co-ordinating close-to-real-time markets requires overcoming institutional and technical barriers. In some markets – especially Europe – day-ahead, intraday and balancing time frames are not integrated. Each constitutes a separate market, with different platforms and different products. While the markets are inter-related, there is no compulsory power exchange, in line with the bilateral models ruling EU electricity market designs.

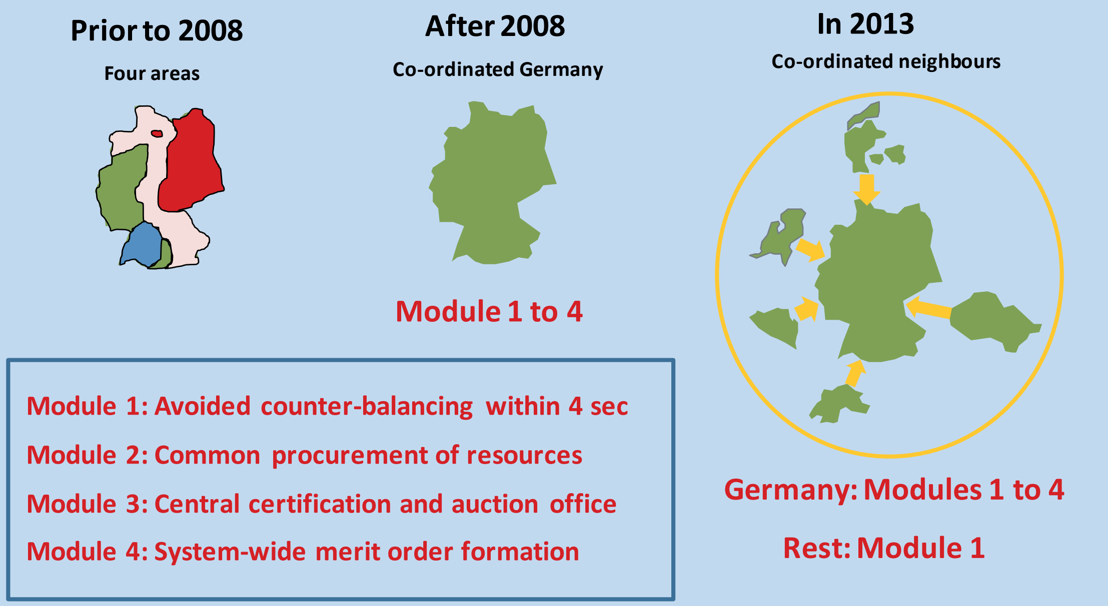
As a result, Europe is now developing network codes to optimise interfaces between countries (see Chapter 2). One objective is to better integrate the intraday and balancing markets, as well as some system services. This top-down harmonisation process faces a number of issues, such as defining the traded products to be harmonised and overcoming the lack of liquidity in many marketplaces. The European Commission will provide a general framework, which will enter into force after a long process of European legislation (comitology). Once adopted, network codes may not be very precise and will not be easily modified. Many items covered by the codes may continue to rely on either the subsidiarity principle or bilateral/multilateral co-operation to fine-tune the details.

Box 10 • The creation of multijurisdictional balancing services within Europe

In 2002, Nordic countries started harmonising reserves with longer (15-minute) activation timeframes ("tertiary reserves"). They are also considering secondary reserve products. In 2009, with the support of Nordic ministers, Nordic system operators agreed to further integrate the existing balancing arrangements. They harmonised common gate closures to 45 minutes before deployment and devised a common model for determining prices under a merit order approach and settling imbalances (NordReg, 2010b).

Prior to 2008, four operators balanced the German electricity system without significant co-ordination. Counter-balancing situations in which a balancing region had to deploy upward balancing resources, while other regions had to use downward resources, occurred frequently. Common procurement of balancing resources reduced overall resource requirements, while central provider entry points reduced technical entry barriers and a system-wide merit order created additional benefits through competition. These inefficiencies between balancing areas were tackled by the introduction of four modules, which together were expected to reduce balancing costs by over EUR 260 million per year (BNetzA, 2009). Because of the multijurisdictional involvement, the introduced model was designed so that individual balancing authorities maintained responsibility over final dispatch within their individual control areas, but identified the dispatch on a multijurisdictional basis. This model is capable of reducing counter-balancing by netting area control error every four seconds and delivers the benefits of the other modules.

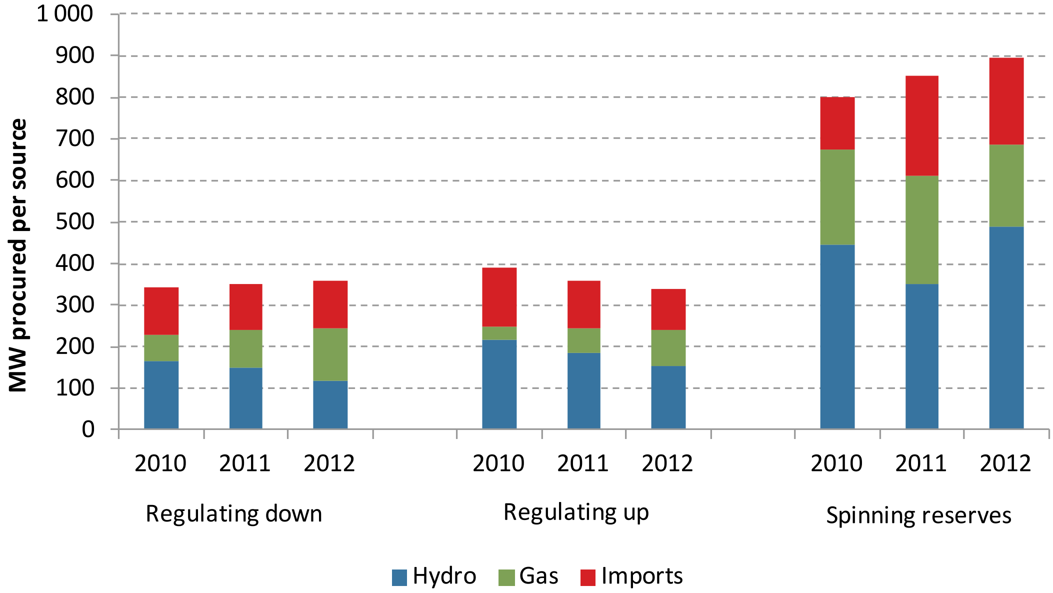
This grid control co-operation among balancing authorities has now expanded beyond Germany's borders. As of today, balancing authorities in Denmark, Czech Republic, Switzerland, the Netherlands and Belgium have joined the first module (avoiding counter-balancing).



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

It should also be stressed that close-to-real-time harmonisation can affect security of supply. System operators are responsible for ensuring security of supply over their footprint. As described previously, most recent major blackouts have involved several system operators. Not surprisingly, adjacent operators co-ordinate on the basis of conservative assessments.

Figure 28 • Resources for providing ancillary services in the CAISO operating region



Source: IEA, using data from CAISO, 2012a.

Interconnectors already provide various balancing services. In 2012, CAISO used 23% to 30% of imports to provide the most flexible balancing services (CAISO, 2012a). Procurement of these reserves follows clearly established minimum operating and control performance rules and standards by NERC and CAISO import standards (CAISO, 2012b). Procurement of most of the resources is undertaken on capacity, bidding on the day-ahead markets, and dispatch is fully managed by CAISO. In 2013, CAISO also proposed to create an energy imbalance market to further develop regional integration in the Western Interconnection.

Cross-border optimisation with nodal pricing

Co-optimisation of generation and networks by a central entity is already in place in several US regions (through CAISO, PJM, NYISO, MISO, ISO-NE and ERCOT), as well as in New Zealand. Poland is also considering implementing the LMP approach. One advantage of this approach is that it delivers higher economic performance by supporting congestion management, particularly when combined with tradable rights for transmission use.[9]

However, when adjacent RTOs in the United States apply nodal pricing separately, they still co-ordinate poorly at the electricity seam. In 2012, power flow directions at the borders between PJM and MISO were not consistent with real-time energy market price differences for 53.3% of the hours. A similar situation at the seams between PJM and NY ISO and NY ISO and ISO NE (Figure 29) would disappear if the interface were entirely internal to one of the markets. These inefficiencies derive from administrative time lags between system operators and the need to schedule cross-border transactions in advance, based on possibly erroneous expectations of real-time prices.

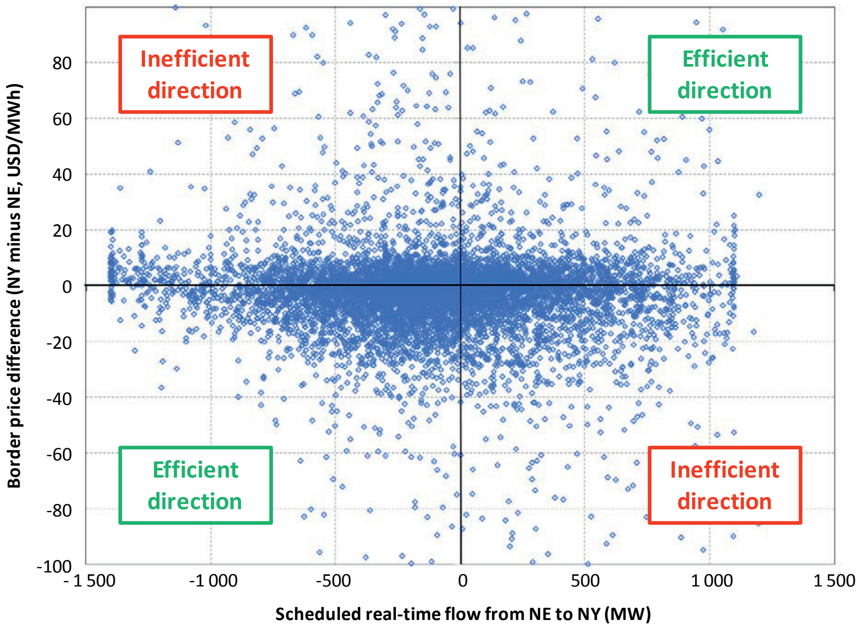
According to MISO (2013), inefficient trades have frequently occurred at the seams between RTOs:

- 32% of all hours with its neighbouring IESO[10] operating region
- 49% of all hours with its neighbouring PJM operating region.

[9] See IEA (2013a) for a further description of the LMP and other network use, pricing, hedging and congestion management approaches.

[10] Ontario Independent Electricity System Operator.

Figure 29 • **Efficiency of Inter-Market Scheduling Over Primary Interface from New England to New York in 2011**



Source: Potomac Economics, 2012.

Optimising electricity flows across the seams between RTOs implementing LMP implies converging real-time prices for each seam node. This requires close-to-real-time exchange of data between these operators and harmonising modelling approaches to estimate total service requirements at the right location. To summarise, "getting the prices right" when engaging in cross-border trades can be challenging.

Market integration for ancillary services

Efficient co-ordination of ancillary services across interconnectors includes integrating the market for (spinning and non-spinning) operating reserves and (in a European context) secondary reserves. Large procurement areas can enhance economics for providing ancillary services for the same reason that trade enhances electricity or balancing markets. Demand for ancillary services is expected to rise with the wider integration of variable renewables and expanded trade between jurisdictions. In the absence of sufficient service resources, situations of high renewables output may leave system operators with no other solution than to curtail renewables generation to maintain reliability (ENTSO-E, 2010). These potential developments call for enhanced provision of ancillary services across markets and interconnectors.

Since ancillary service providers are often generators, this situation also has implications for electricity prices. For this reason, the Australian electricity market is co-optimising balancing services and electricity services. Comparable forms of co-optimisation could also be expanded to other ancillary services (such as reactive power provision) to achieve significant savings (FERC, 2005; IEA, 2013).

Conclusion: actions to improve inter-regional co-ordination are needed

Inter-regional integration of electricity markets consists in optimising the seams between areas controlled by different system operators to achieve efficient, security-constrained economic dispatch. When possible, system operations should be consolidated over wider geographic areas. Given the current computing power and reliability of telecommunications systems, this is not technically difficult. Some opportunities might exist, even though many institutional and regulatory barriers (including transferring competencies for security of electricity supply) will need to be overcome. To the extent that system operators are non-profit or regulated organisations, market forces will not lead them to merge spontaneously. Governments will have a role to play.

Since institutional barriers will likely impede consolidation of market and system operations, the alternative solution is inter-regional market co-ordination. Strong co-ordination close to real time is necessary to accommodate the hourly variability of wind and solar power and uncertainty of day-ahead weather forecasts. But system security concerns increase as real time approaches. Security of supply remains to a large extent the prerogative of local governments. It is therefore likely that inter-regional co-ordination will continue to be based on conservative assumptions, leading to less efficient use of existing infrastructure.

Forward and financial market integration

Most electricity is not exposed to the daily and real-time price volatility of spot electricity markets,[11] but is exchanged across markets in the form of long-term trades at a price set in advance. A generator can currently make a contract for several months or years with a buyer in another control area and secure physical access to cross-border network capacity in that country. This form of physical hedge could become more difficult with high shares of VRE, hence the need to develop financial instruments to hedge cross-border trades.

The following section on forward and financial market integration starts by explaining why long-term contracts and hedging are both important and desirable. It then presents the physical and financial products allowing cross-border trade of electricity to be hedged. It discusses their relative merits in the context of increasing shares of VRE. It concludes with some issues surrounding implementation.

Reasons to hedge

Generators and suppliers typically sell to final consumers at a fixed price over a certain period. Consumers use this price information to set the price of their own products, without having to speculate on extremely volatile electricity spot prices. Generators also enjoy more stable profits, thus reducing the risks and costs of financing their activity. In liberalised electricity markets, forward and financial contracts serve to hedge against electricity price volatility. They range from weekly to monthly and yearly baseload products that can be contracted up to four years in advance.

High wind and solar deployment could further increase the need to hedge against price volatility. Some gas generators do not know whether they will operate (if there is no wind) or not (if wind is blowing) and may find it difficult to enter into long-term contracts backed by physical generation. While these generators can sell baseload power in advance and procuring electricity on markets should they not produce, they will need the capacity to hedge these contracts. Future products will also need to be defined to reflect the need to complement VRE output, while product definitions should remain harmonised to ensure market liquidity.

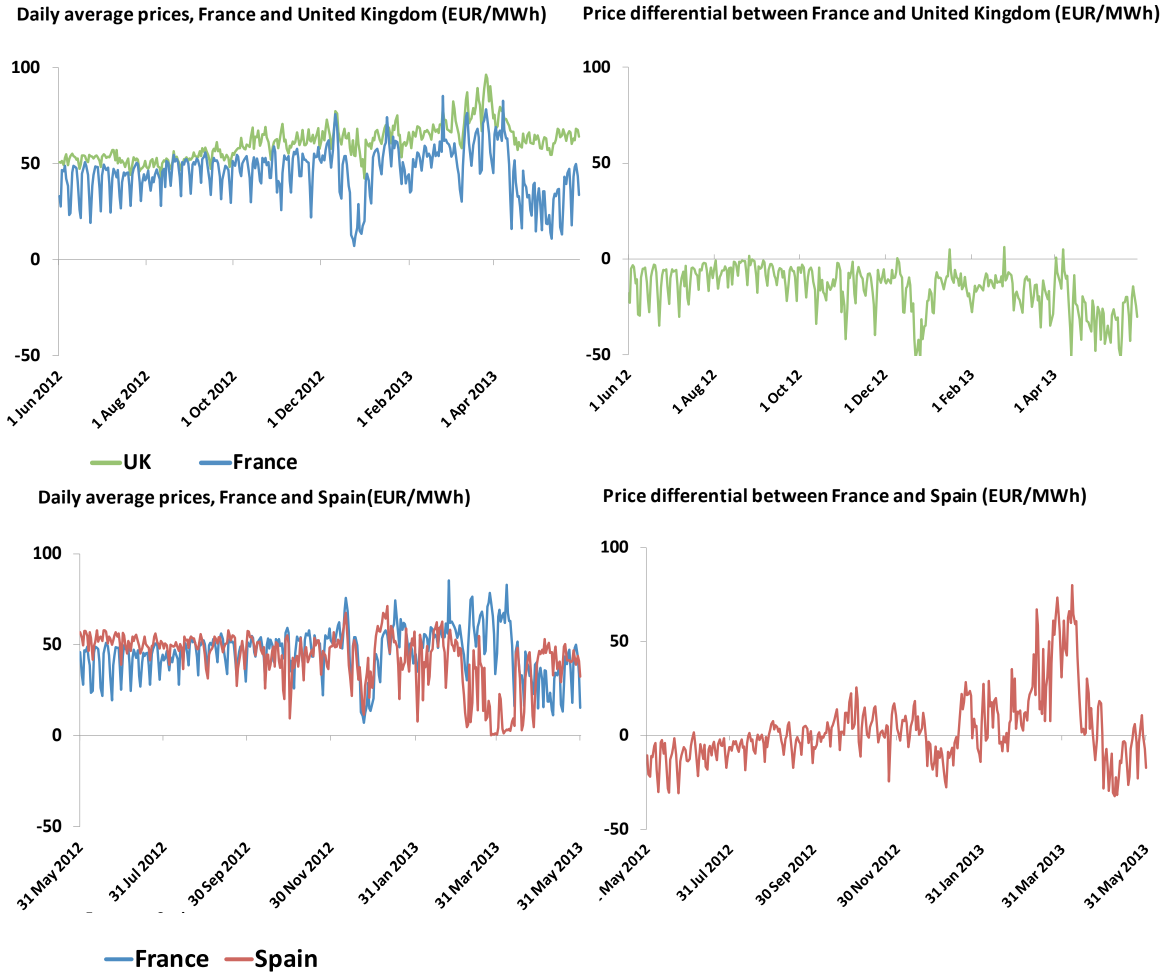
Hedging is especially important to cross-border trade of electricity. Network congestion at borders is frequent and the spread between electricity prices on either side of a border is extremely volatile (Figure 30). Moreover, price differentials are increasingly difficult to predict due to variable wind and solar power.

One advantage of long-term cross-border trade contracts is that they promote cross-border competition among generators. When consumers buy electricity to cover their needs for a given

[11] This section is based on Booz et al (2011).

period, they can choose among a larger number of suppliers. The ability to offer long-term contracts across borders improves market transparency and leads to fiercer competition between generators in different countries. This competitiveness benefit is particularly important in the European context, where national markets are generally dominated by historical utilities.

Figure 30 • Wholesale prices and price differences at a selected border (May 2012-May 2013)



Source: Bloomberg and IEA.

Several prominent studies have recently highlighted the role of cross-border hedging products in mitigating market power (Booz et al*.,* 2011). The manner in which these products are designed and traded is important to ensure sufficient liquidity.

How to hedge cross-border trade of electricity

Evaluating the relative merits of different hedging products requires understanding the basics of cross-border electricity trade. Notions such as PTRs, CfDs, FTRs, options or obligations are not always well understood outside the financial trading arena. The following paragraphs enumerate the advantages and disadvantages of the different hedging instruments.

There is considerable academic and empirical literature lauding the merits of FTRs over PTRs. One advantage of FTRs[12] is that they offer more opportunities to trade long-term contracts across borders,

[12] Consider here are only FTR obligations, i.e. where the holder of the right receives a payment in case of positive price difference and has to pay the electricity price difference in case of a negative price difference. With FTRs as options – where the holder receives a positive price difference but does not have to pay a negative price difference – netting is not possible.

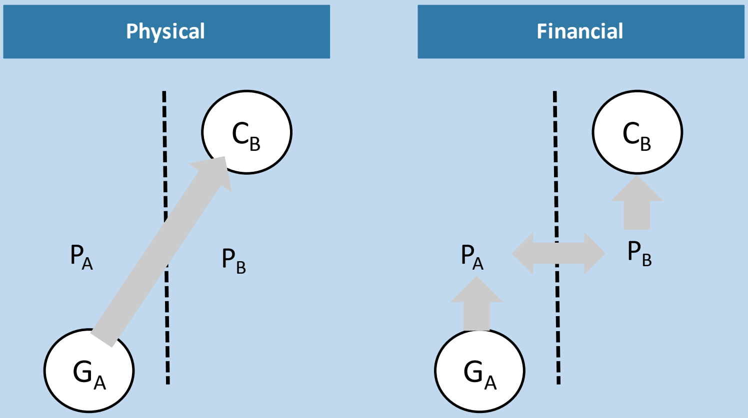
fostering competition between generators across borders. The reason is that if a generator sells power from zone A to zone B and another generator sells from zone B to zone A, FTRs can be netted, thus creating new trading opportunities and intensifying competition.[13]

Moreover, it is not necessary to nominate cross-border trades, thus preventing arbitrage errors from construction and nomination of electricity flows in the wrong direction.

Box 11 • Physical transmission rights and FTRs

Consider a generator or trader in country A (G_A) selling electricity to a consumer in country B (C_B) at a fixed price over a period of time.

The simplest way to secure such a trade is to secure physical access to the NTC between country A and country B and cover the cost in the selling/sale price. The right to use transmission capacity is called "physical transmission right" (PTR) in Europe or "firm transmission services" in the United States. The total quantity of rights must not exceed the NTC determined by system operators. A fraction of these rights is allocated by system operators several years or months in advance, with the remainder allocated closer to real time. Generator G_A, which holds such rights, needs to nominate the capacity it intends to use the day before operations.



A more financial approach has been developed in markets where generators are obliged to sell the output to the local pool. In that case, G_A sells electricity in the pool and receives the market clearing price P_A). In order to serve consumer CB, generator G_A has to buy electricity in country B at price P_B and is therefore exposed to the price difference P_B-P_A. In order to hedge its positions, the generator needs to be reimbursed the price difference between country A and country B.

- A first possibility for G_A is to sign a contract with a financial entity (e.g. a bank) that will reimburse the difference in market prices: Nordpool uses such CfDs. Of course, these contracts are not free.
- Another possibility is to sign a contract with the system operator, which will also reimburse the difference between market prices. Such contracts are called FTRs and are auctioned by system operators.

System operators are the natural counterparty of such contracts. Indeed, they optimise the use of interconnectors. System operators can ensure the financial settlement of power at price P_A in country A, transmit it over the network to country B and resell it at price P_B. They receive a congestion rent of P_B minus P_A when they clear the markets in country A and country B, which is exactly what they have to reimburse to generator G_A. This FTR approach is implemented within the several RTOs in the United States.

More generally, comparing FTRs with PTRs depends on the many contract provisions. For instance, the use-it-or-sell-it clause for PTRs means they can be used as financial hedgers. However, if the option to use the right has to be nominated the day ahead, this prevents netting before the

[13] Note that this is true for FTR-obligations. The network code on Forward Capacity Allocation also allows for financial transmission rights options that cannot be netted before nominating the option.

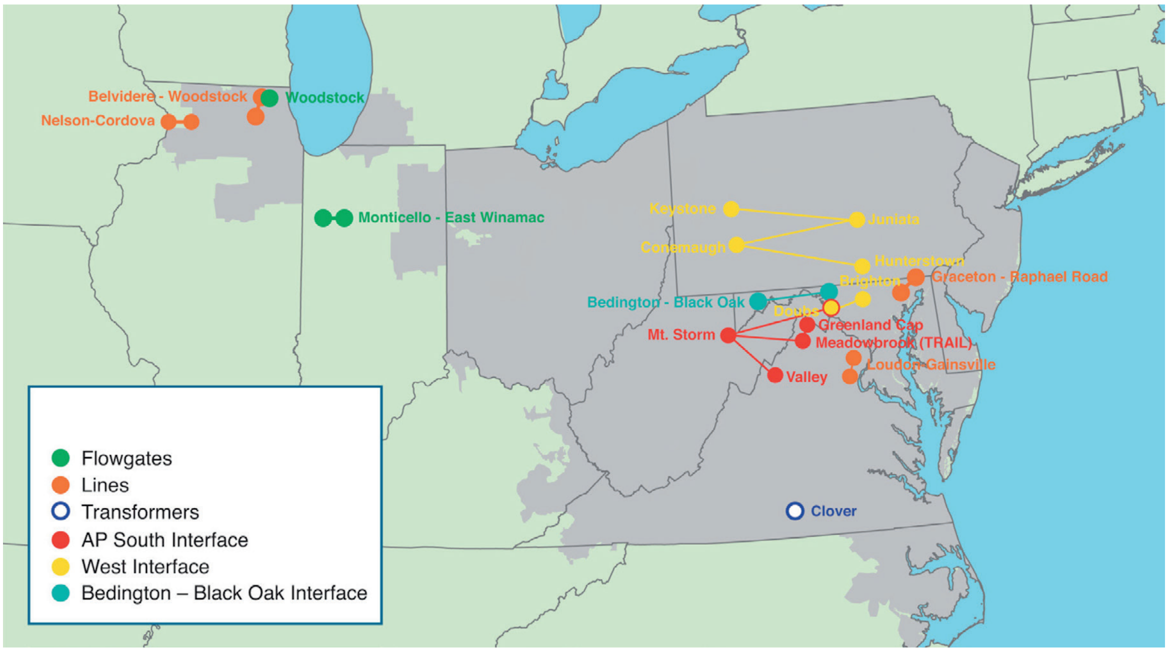
timeframe, thereby reducing choices for consumers seeking long-term contracts. Note, however, that netting is also possible with PTRs when nominations are made before the day-ahead timeframe, as the long-term contracts are signed.

The difficulties in implementing FTRs should not be overlooked.

- They have never been applied to cross-zonal trade of electricity (except in Nordpool, but in the form of CfD) and are applicable only when market coupling is actually functioning.
- They require robust prices and sufficient liquidity of the market in each zone.
- They may imply significant adaptation of cross-border trades as all cross-border trade orders must be done on power exchanges, entailing costs and fees for using the platforms.

A detailed discussion of the issues of FTRs versus PTRs is far beyond the scope of this report. Further complications will need to be addressed to implement FTRs, including minimising revenue risks for TSOs, allocating revenue associated with congestion and designing secondary markets for FTRs. Furthermore, the firmness of FTRs can become more difficult to ensure with the deployment of wind and solar power. This issue is analysed in the next section.

Figure 31 • Location of the top 10 constraints affecting PJM congestion costs: 2012



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: Monitoring Analytics, 2013.

Implementation issues

Implementing FTRs requires cross-border transactions to use power exchanges. These market platforms must be coupled to ensure optimal use of existing NTC. One advantage of trading through power exchanges is that it reduces the counterparty risk, as transactions are anonymous and done with a clearing house. One disadvantage is that traders have to pay a power exchange fee, incurred in both countries and zones.

Moreover, liquidity of wholesale electricity markets is important to ensure strong price formation on either side of the border and, hence, a credible market price difference. The liquidity of power exchanges remains limited in some countries (Figure 32), reflecting the European choice to favour bilateral trades and the high degree of integration between generation and supply. Implementing the efficient financial hedging products required with the increasing shares of renewables in Europe will entail actions to improve the liquidity of power exchanges.

Figure 32 • Traded volumes at power exchanges on day-ahead markets as a percentage of national demand, 2011

Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

* 2010 data.

Source: ACER/CEER, 2012.

Integrating capacity mechanisms

A number of jurisdictions have introduced capacity mechanisms to create a new revenue stream for generation capacity on top of revenues from selling electric energy on the markets. Governments introducing capacity markets state as their primary objective the creation of incentives for adequate generation capacity to meet peak demand and ensure electricity of security supply. The IEA report "Securing Power during the Transition" (IEA, 2012) discusses the rationale for such capacity mechanisms.

Fragmented and uncoordinated capacity mechanisms in adjacent markets are increasingly perceived as creating inefficiencies and increasing the overall costs of the electricity system. Most capacity markets are introduced over a specific territory and fail to acknowledge that generation adequacy is an inter-regional dimension of integrated electricity markets. While progress has been made in Europe in terms of integrating the market for electricity energy, the totally uncoordinated capacity mechanisms may seem paradoxical. Capacity payments in Spain and Ireland and strategic reserves in Sweden and Finland were introduced before 2010. France and Great Britain decided to introduce capacity markets after 2010, while other countries are still discussing this option.

The limitations of such local capacity markets will become even more apparent with high wind and solar power. Indeed, when considered over large geographic areas, at least some VRE sources are likely to generate power during scarce conditions. Thanks to the geographic differences of weather conditions, it should be possible for wind generation in Germany or Spain to contribute to peak demand in France, even if there is no wind in France. But how is it possible to factor in the potential contribution of Spanish renewables to the French capacity market?

This section recognises that several jurisdictions have added capacity mechanisms to their market design. After reviewing the rationale (which can differ among jurisdictions) for capacity markets, it discusses inefficiencies resulting from poor co-ordination. It then presents relevant experiences of co-ordinating adjacent capacity markets in the United States. It concludes with a few principles that might enable stepwise integration of capacity markets.

Reasons for introducing capacity mechanisms

The debate over the need for some remuneration of capacity has raged since the beginning of power sector liberalisation. Economists do not agree and have never provided an overriding answer to this problem. Not surprisingly, policy makers use shortcuts to justify their capacity market initiatives *ex ante* or *ex post*.

In the United States, Eastern Interconnection RTOs operate capacity markets such as the Reliability Pricing Model (PJM), UCAP Requirements (NY ISO) or voluntary capacity auction (MISO). Several of these markets were introduced in 2002-04, replacing bilateral contracts under FERC regulations designed to maintain availability of unprofitable old units in case of a reliability issue ("Reliability Must-Run (RMR) Contracts"). At the time, a growing number of generating units benefitted from these RMR contracts. These units were unprofitable after massive investments in combined-cycle gas turbines during the dash for natural gas in the late 1990s and early 2000s. Many merchant power plants filed for bankruptcy in 2002-04.

Interestingly, these mechanisms were introduced during a period of excess capacity. Economists provided a theoretical justification for introducing capacity markets, devising the concept of "missing money". In a nutshell, this means that prices of electric energy are not allowed to climb high enough during periods of scarcity, creating a revenue shortfall and preventing generators from covering fixed costs (IEA, 2012).

Several capacity remuneration mechanisms have been introduced in Europe – strategic reserves in Sweden and Finland in 2002, capacity payment in Spain and Ireland (2006), capacity markets in France and the United Kingdom (2011) – with other countries now considering this possibility. The most recent mechanisms were considered at a time of low profitability of gas turbines due to several factors (slowing demand, low carbon prices, competition from coal and massive deployment of variable renewables). Interestingly, these mechanisms were introduced during a period of excess capacity, with many gas power plants mothballed in 2012/13.

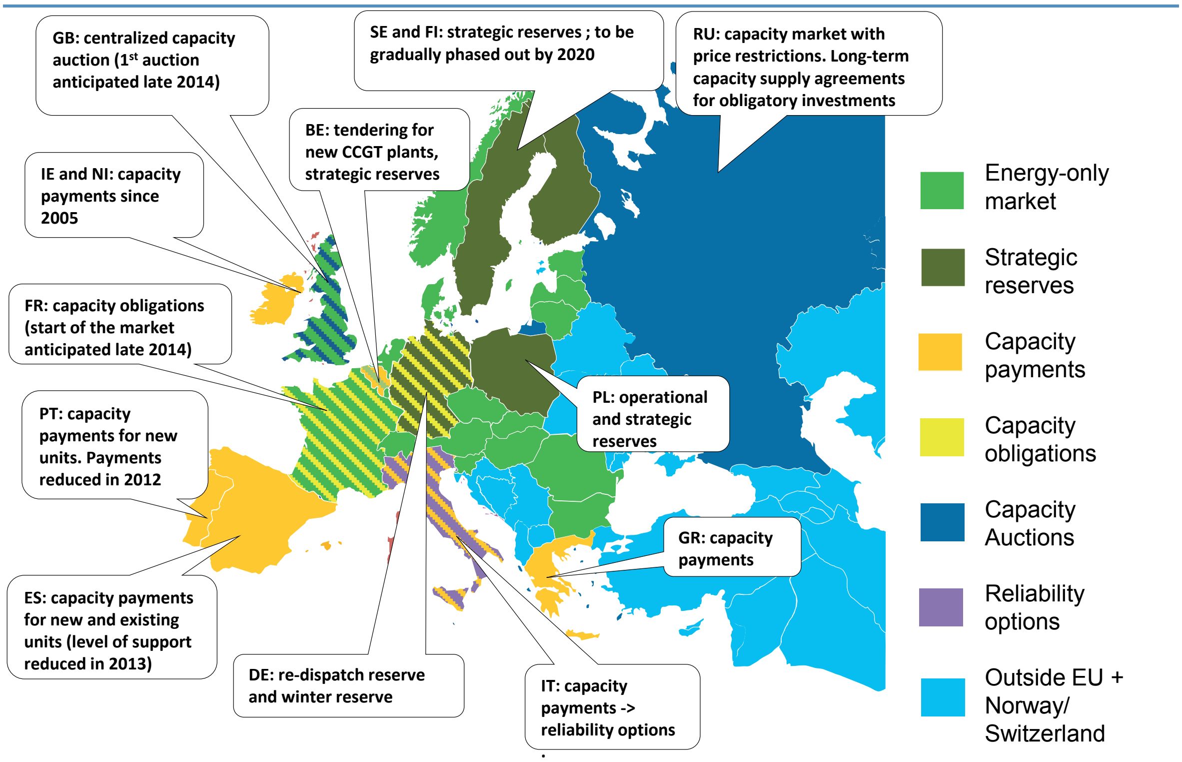
By contrast, several other markets have reaffirmed their intention to rely on "energy-only" markets without major government intervention on the capacity side. In this perspective, prices must be allowed to reach very high levels at times of scarcity for low-utilisation plants to recover their fixed costs. In practice, implementing efficient scarcity pricing remains difficult due to the discrepancy between reliability standards and the lost load value, the lack of demand response in case of scarcity prices, the market power issues during extreme peak hours and the risk of political intervention in case of high spot prices.

Faced with a capacity shortage in 2003/04, the Netherlands considered introducing a capacity mechanism in 2004, but finally rejected this option. Similarly, Ercot in Texas faces fast-growing peak demand caused by air conditioning during heat waves, raising concerns about generation adequacy. While it is considering capacity markets, Ercot has so far decided to rely on other measures.

The European developments are very paradoxical. Despite the fact that the "internal energy market" is slated for completion by 2014/15, administrations address generation adequacy on a purely national basis. Many explanations for this have been advanced. First, the European Directive on security of supply (2005) explicitly recognises energy security as a matter of national policy under the subsidiarity principle. Second, European construction has focused on markets and overlooked issues of electricity security and reliability regulation.

Nevertheless, these national initiatives have led to uncoordinated market designs co-existing in adjacent jurisdictions – some without capacity mechanisms, some with capacity markets and yet others with strategic reserves or capacity payments (Figure 33). Some of these national markets are already relatively well integrated for electric energy. However, introducing capacity mechanisms could distort competition, lead to overinvestment and ultimately increase costs for European consumers.

Figure 33 • Capacity mechanisms introduced in Europe



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

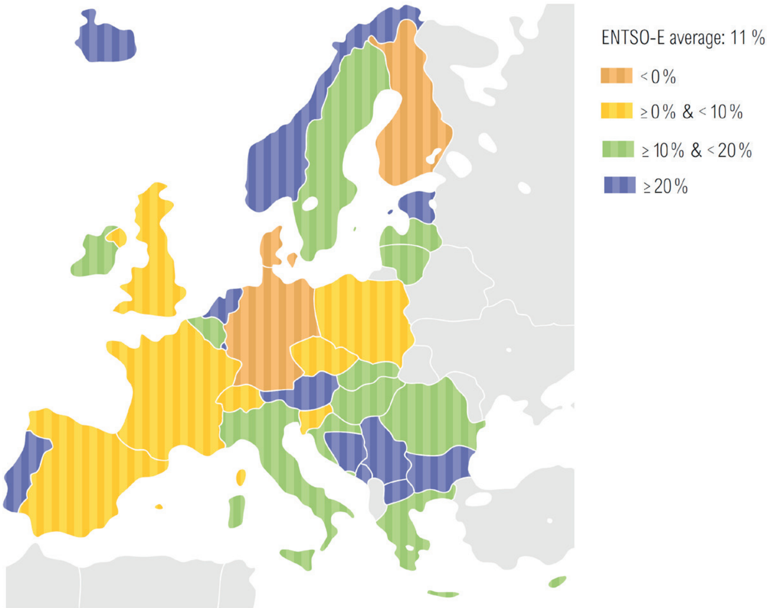
Source: Eurelectric, 2013.

Issues with uncoordinated capacity mechanisms

Inconsistent market designs within a single energy market introduce several kinds of distortions: (i) for utilisation of existing installed capacity; (ii) calculation of wind and solar power capacity credit; (iii) exercise of market power on capacity markets; and (iv) for location of a new generation of investments.

To begin with, some countries will enjoy comfortable margins at least during the next decade, while others will have to close down ageing power plants or face growing demand. Generation adequacy forecasts by ENTSO-E for EU member states show that the Netherlands, Austria, Norway and Italy should continue to have sufficient capacity until 2020 (Figure 34). This excess capacity could benefit countries that anticipate capacity shortage by 2020, provided capacity markets are compatible and integrated.

Figure 34 • Remaining capacity by 2020, best estimate scenario



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.
Source: ENTSO-E, 2013f.

Second, capacity market integration can better value the capacity credit of wind and solar power in terms of their contribution to meeting peak demand. Considered in isolation, a wind turbine is intermittent – it does not produce during certain hours. Considered over larger areas, wind is still variable, but output aggregation smoothes the intermittency. Similarly, during scarcity hours, VRE sources are more likely to produce over a large geographic area. For instance, wind generation in Germany or Spain can help meet peak demand in France, even if there is no wind in France. On the other hand, it is possible to have periods without wind all over Western Europe. The frequency of such events has to be assessed against government objectives regarding reliability criteria, i.e. the expected duration of such events over 10 or 20 years. Factoring in the aggregation effect of variable renewables across borders probably represents one of the major challenges to integrated capacity market design.

Third, generators can have market power in capacity markets, particularly when these markets are limited to a zone or country. Inter-regional integration also promotes competition for capacity markets. In a European context, the HHI index of generation capacity provides a good metric of concentration in the absence of cross-border capacity trade.

In the longer run, uncoordinated capacity markets may also introduce differences in generators' revenue streams, creating distortions in both the timing and location of new investments. All things being equal, an investor will choose to invest earlier if offered extra remuneration for capacity. EU member states believe that utilities will not invest anymore in their own jurisdiction if an adjacent jurisdiction introduces capacity markets. This perception acts as a powerful driver for introducing capacity markets throughout the European Union.

Long-run distortion of investment decisions deserves more careful analysis. A capacity market in country A designed to ensure generation adequacy in country A will not trigger the investments needed to ensure adequacy in country B *without a capacity market* (if too much capacity is built in A, then the capacity price should fall). Moreover, in case of congestion between A and B, scarcity prices in B can be very high and investments will be based on an energy-only market design. In this view, there is neither distortion nor incompatibility between market design with and without capacity markets. Still, the details of the design and timing of capacity markets are also essential to a full understanding of the interactions among different mechanisms.

Taking into account interconnector capacity

Arranging for and managing capacity located outside a system operator's control area is vital. From a physical perspective, capacity helps ensure generation adequacy. For instance, when France hit a consumption record of 102 GW at 19h00 on 8 February 2012, the country imported no less than 8 260 MW at that particular hour. Regional market integration is clearly important to ensure secure electricity supply. One key challenge lies in translating this physical reality into proper capacity market arrangement.

Uncoordinated system operators can unilaterally assess the statistical contribution of interconnectors during scarcity hours. In the above example, if Réseau de transport d'électricité expects a contribution of, say, 7-10 GW from interconnectors, this could reduce demand for capacity located in France by 7-10 GW. Generators located across the border are excluded from the capacity market, but their contribution to generation adequacy is factored in.

The alternative is to accept bids from generation capacity (or demand response operators) located beyond the borders. In the French example, this would imply contracting forward capacity in Spain, Italy, Switzerland, Germany, Belgium, the United Kingdom and possibly the Netherlands, as well as other European countries. While resolving the institutional barriers to cross-border capacity trades is difficult, the experience between PJM and MISO (Box 12) suggests that such trades could yield significant economic benefits.

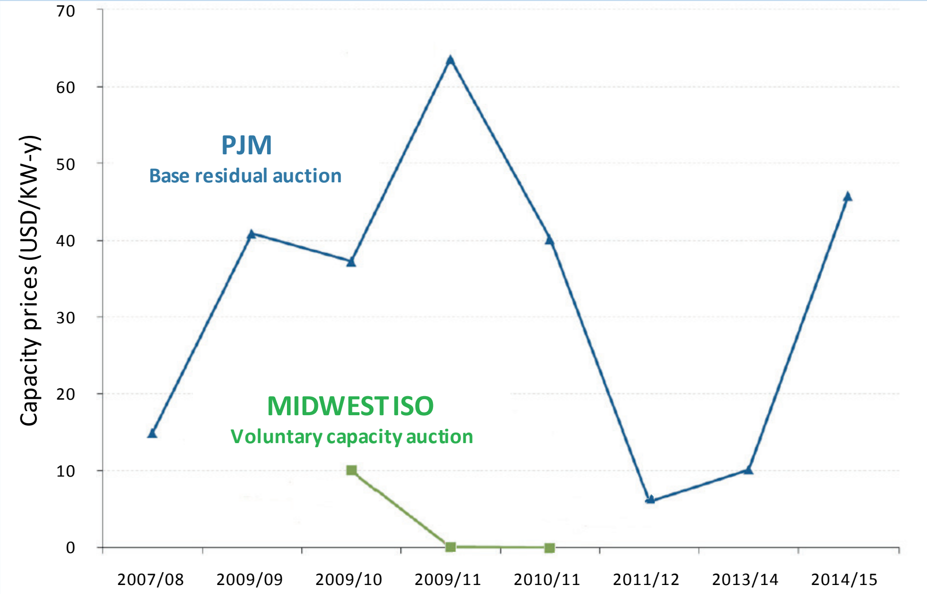
It should be noted that the perceived degree of certainty of "external" capacity is lower than internal capacity. The duty of system operators is to ensure system reliability in their control area. In scarcity conditions, curtailment procedures (where they exist) do not necessarily fulfil contract arrangements. In the French example, it is difficult to predict how France's neighbours might behave if they had to curtail load in their own country by 1 GW to 2 GW to execute a contract to sell capacity on the French capacity market. Thus, defining curtailment procedures across borders is essential in order to ensure trust among system operators and create the proper conditions for cross-border capacity trade.

The inherent complexity of capacity markets (IEA, 2012) entails a significant risk of unintended consequences and gaming opportunities.[14] Consider a generator in country A receiving a capacity payment in that country. The generator could participate in auctions for strategic reserve in country B and also receive a capacity certificate that can be traded in country C. When the scarcity materialises, what could happen? This generator could sell electricity on the energy market with the highest price – for instance in country D, where the price cap is equal to the value of lost load (voll). Inconsistencies and differences in defining the product attached to electricity can undermine the ability to trade.

This gaming problem is already recognised and solutions to it exist. In the United States, external capacity participating in PJM capacity market must sign a "letter of non-recallability" assuring PJM that a unit's energy and capacity cannot be recalled to any other control area (PJM, 2013c). But cross-border enforcement could be difficult.

[14] Booz & Co (2012) define gaming as follows: "Gaming means the use of apparently perverse strategic choices by market participants (e.g. withholding generation capacity that would in itself be profitable to run, or nominating generation that will be constrained off and receive compensation for not operating) that take advantage of the operation of the rules to make a profit, or disadvantage competitors, and which reduces the efficiency of the wider outcome."

Box 12 • Cross-border trading of capacity between PJM and MISO



Cross-border capacity trade is possible between PJM and MISO based on price differences between regional capacity products. The figure compares PJM capacity clearing prices with MISO capacity prices. The capacity price differential across the seam is around USD 30/kilowatts per year on average, creating strong incentives for MISO suppliers to sell capacity to PJM. MISO experts indicate a strong enough transmission system, capable of reliably transferring 5 300 MW to 6 300 MW of capacity in 2014/15. Actual capacity sales for that year are only around 400 MW net (900 MW gross). The gap between possible and realised capacity sales across the border has large economic and reliability implications and results in higher than required supply costs of up to USD 1.5 billion per year. The barriers created by the difficulties in obtaining long-term firm interconnector services seem to explain the missing trades. Many long-term firm reservations are held by market participants who do not use them for capacity sales or other energy trades. In some cases, market participants simply hold capacities to keep the option of selling energy. A further barrier to efficient use is the lack of a mechanism for netting out capacity commitments in the opposite direction.

NTC for external capacity

The ability of interconnectors to transfer capacity between areas covered by different capacity mechanisms is equally important. When contracting forward power capacity (usually three to five years in advance to ensure generation adequacy) it is useful to know whether NTC will be available.

What matters from a physical perspective is dispatching during scarcity conditions, when the system is tight. Hence, the interconnector transfer capability for external capacity depends on network topology and market conditions during scarcity hours, when demand is high yet there is neither wind nor sun. A first approximation is to take the NTC used for trading energy. In some instances, the cross-border flows could increase during hours of tight market conditions. While these considerations warrant further analysis, the important point here is to ensure that interconnector transfer capability is fully used during situations of system stress. This reinforces the case for efficient optimisation of real-time markets.

From the perspective of interconnector capacity reservation, external generators with capacity commitments may need to hold and nominate firm transmission rights. Under this approach, electricity producers would be required to nominate and use these rights to bid on the energy market in order to execute their capacity contract. While this could be effective during periods of scarcity, it could also lead to inefficient use of network capacity should the bid not clear in the market.

Well-designed cross-border capacity schemes should seek to increase competition in capacity markets and prevent inefficient use of transfer capacity. In Europe, Eurelectric has already proposed preliminary ideas to co-ordinate capacity markets (Eurelectric, 2013). Among these ideas, netting capacity commitments in the opposite direction should be feasible. As with the forward energy market, this also strengthens the case for using FTRs in cross-border trade.

Monitoring generation adequacy in integrated markets

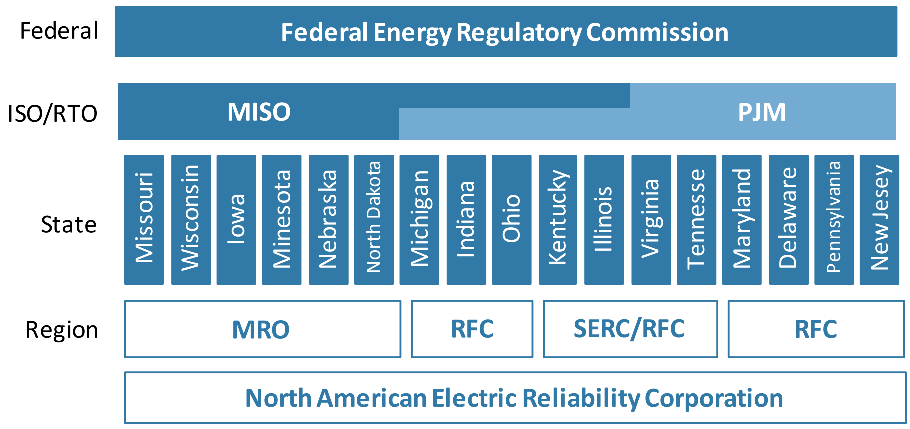
The purpose of capacity markets is to ensure generation adequacy over a given geographic area. Thus, integrating capacity markets also implies considering generation adequacy over the integrated area.

The institutional framework needs to evolve in parallel with the market footprint. Yet the mandate of institutions in charge of generation adequacy is limited to country or state borders, failing to adapt to new market developments.

The European integration process focused on the market without paying much attention to reliability regulations, apart from restating that security of supply falls under the subsidiarity principle (Directive 2005/89/EC on electricity security of supply). There are, of course, limits to using European laws resulting from the European Treaty. Hence, governments have a responsibility to act collaboratively on a regional basis.

In the United States, while NERC regions were defined almost 50 years ago after the 1966 blackout, they do not match the footprint of RTOs created 10 years ago (Figure 35). While arguably, performing and comparing several generation adequacy forecasts could help provide more robust overall assessments, consistent institutional organisation could do a better job. The correct solution would be to monitor generation adequacy for each electric region across jurisdictions and covering several states or countries.

Figure 35 • The footprint of states, NERC regions and RTOs



The discrepancy between market developments and electricity security of supply regulation makes it equally important to align the market and reliability regulation footprints. To achieve this, generation adequacy forecasting and integrated resource planning should occur at the relevant geographic scale.

Certain jurisdictions may also have different reliability criteria. Some criteria are binding, while others are not. Criteria can be time-based or quantity-based and expressed in terms of lost load duration or lost load frequency. In North America, NERC uses this criteria to define a planning the reserve margin (the norm is 15% above peak demand). Other jurisdictions simply do not have any explicit reliability criteria or margin objectives.

Defining clear emergency procedures across borders is also essential. The market coupling rules in Europe specifies that in case of scarcity, the curtailment is proportional to loads in all the coupled markets. This approach overlooks actual electricity flows and actual responsibility for the problem.

The lack of clarity in defining protocols to manage scarcity undermines trust among system operators. As a result, they rely on conservative assessments, thereby erecting barriers to market integration and creating inefficiencies in existing electricity infrastructure use. As previously stressed, barring a clear and fair protocol to manage scarcity conditions, system operators will likely maintain an extremely conservative approach to cross-border integration.

Principles ensuring proper co-ordination of capacity markets

Proper inter-regional integration of capacity markets will be difficult. Governments have made opposing choices on key structural parameters – such as the decision to have centralised or decentralised obligations and the treatment of existing and new capacity. In addition, capacity markets affect electricity security of supply, which remains in the hands of states and countries.

Several measures could be taken to lay the groundwork for integrating capacity markets and ensure:

- **Integrated generation adequacy forecasts** and integrated resource planning, to be consistent with the energy market footprint. (This includes the contribution of wind and solar power to generation adequacy.)
- **Harmonised capacity product definition,** if and where capacity markets are introduced, to enable cross-border trade of capacity.
- **Joint determination of interconnector transfer capability**, not on average, but during hours that matter for generation adequacy, to ensure efficient use of the networks and tap the complementarities of electricity systems in terms of generation adequacy.
- **Adaptability,** to fix unanticipated issues and ease subsequent convergence of market designs in adjacent control areas.

Impact of environmental policies on integrated power markets

Some environmental policies do not actually match the footprint of electricity markets (Figure 36). This is especially true of renewable support schemes, but also of carbon price floor and carbon emission standards in certain countries. Such environmental policies could distort prices and create inefficiencies. This section provides an overview of the problems arising from fragmented environmental policies from the perspective of electricity market functioning and integration (Figure 36).

Figure 36 • Match and mismatch between environmental policies and electricity market footprints

	Match	Mismatch
Carbon pricing	EU Emission Trading Scheme	European Union: Carbon price floor (UK) United States: Regional initiative (RGGI, California)
Renewable policies		European Union: National targets and support schemes United States: Renewable Portfolio Standards (RPS)
Emission standards	United States: - SO_X/NO_X - Emission standards	European Union: National carbon emission standards (UK and the Netherlands)

Carbon pricing

Differing carbon prices in different jurisdictions have the potential to distort competition in electricity markets. The objective here is not to discuss the merits of carbon pricing in general, but rather to draw the attention of policy makers on the impact of applying different carbon prices in adjacent jurisdictions that are also part of an integrated electricity market.

Two major carbon pricing schemes – one on the East Coast (the Regional Greenhouse Gas Initiative - RGGI) and the other in California – have been introduced in the United States.

- RGGI covers the entire area of ISO NE (Connecticut, Maine, Massachusetts, New Hampshire, Vermont and Rhode Island) and New York ISO. But RGGI is only part of the PJM footprint (Delaware and Maryland are part of PJM). Pennsylvania acts as an observer, along with several Canadian provinces.[15] New Jersey (which is part of PJM) formerly participated, but withdrew from RGGI in 2011. Other PJM states (Virginia, West Virginia, Ohio, Indiana, Illinois and Michigan) are not part of RGGI. Comparing this footprint with the PJM ISO footprint clearly shows that some areas of PJM are exposed to a carbon price, while other areas are not. Uneven carbon pricing policies create differences in the marginal cost of producing electricity. They also impact on the dispatching of power plants if a more polluting plant gets dispatched because it is not "taxed", while its more efficient competitor is charging a CO_2 price.
- California introduced a cap-and-trade mechanism for CO_2 emissions. But imports represent about 25% to 30% of the state's consumption, some of which is generated by coal. This has led California to implement a complex set of rules to take into account these carbon emissions associated with imported electricity.[16]

Clearly, the first best solution would be to have a uniform carbon price for all jurisdictions. As electricity generation is a major source of CO_2 emissions, a uniform carbon price is essential in order to create a level playing field for electricity market integration. However, the first Obama Administration's attempt to pass legislation in the United States failed and it is widely recognised that a unique carbon price is not expected in the foreseeable future in either the United States or the rest of the world.

In Europe, the introduction of a continental-scale cap-and-trade of carbon emission should be regarded as a major achievement. The EU Emission Trading Scheme is an integrated system covering the entire European Union. A single carbon price applies to all generators of the IEM, ensuring that there is no internal EU distortion. Looking forward, the development of distributed generation (such as micro combined heat and power) could alter this situation if the fuel used is not submitted to a carbon price.

However, some countries participating in the EU ETS have introduced carbon prices on a national basis. The United Kingdom decided to have a carbon price floor gradually increasing to EUR 30/tonne of CO_2 by 2018, while the EU ETS forward carbon price is lower than EUR 5/tonne of CO_2 over 2013-16 (Figure 37). A higher carbon price in the United Kingdom could provide a

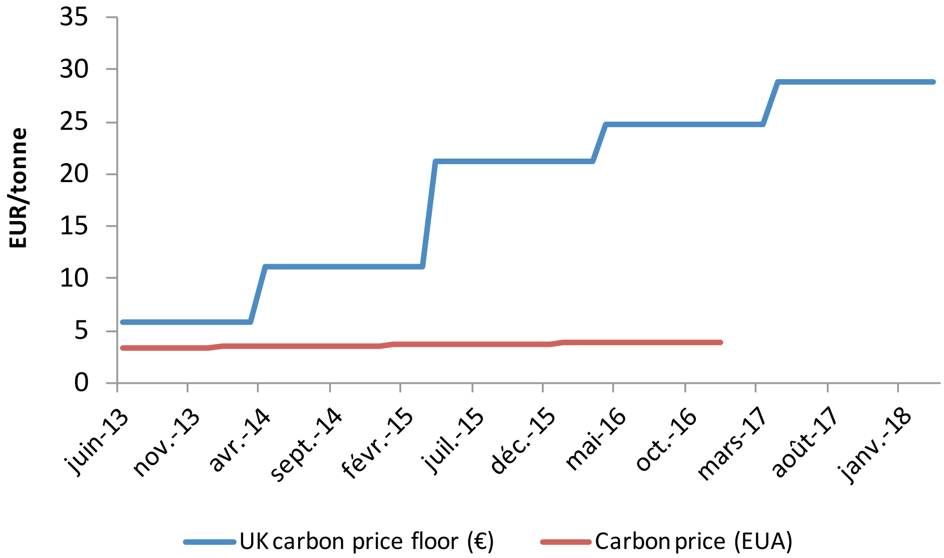
[15] http://en.wikipedia.org/wiki/Regional_Greenhouse_Gas_Initiative - cite_note-participating-states-1

[16] "California imports much of its electricity from other US states, with the level of imported electricity standing at about 30% in 2011 according to state government statistics. Consequently, Carb crafted the cap-and-trade programme to account for the emissions of out-of-state generators in an attempt to ensure it doesn't lead to greater emissions from power plants elsewhere. That led to a complex set of rules applying to "first deliverers of electricity" – companies in California that receive power from sources outside the state. Under those rules, first deliverers must account for the greenhouse gas emissions of power sources located outside California and comply with the cap-and-trade scheme accordingly. They are also prohibited from resource shuffling – or making changes that reduce the emissions reportable to Carb, but do not actually lower the total level of emissions they produce. This could involve modifying power purchase agreements so that electricity from a wind farm is routed into California, for example, while electricity from a coal-fired power plant is redirected into Nevada instead." (Source: Risk Net, www.risk.net/energy-risk/feature/2232003/california-carbon-market-faces-challenges).

stronger incentive to invest in low-carbon investments and reduce emissions in the country, but will mechanically increase emissions in other countries subject to the same overall cap. This discrepancy between the two prices will also increase electricity price in the United Kingdom relative to the continent and increase imports.

The distortions introduced by different carbon prices are generally not perceived as a major problem with respect to the functioning of electricity markets. To date, carbon prices remain relatively low in absolute terms (around USD 3.5 per short tonne in RGGI, USD 15 per metric tonne for the California carbon allowance and EUR 4 per metric tonne for the EU Allowance (Point Carbon, 2013). These prices have a small impact on generation costs lower than USD 2/MWh. In coming years, electricity markets will integrate better and carbon prices are expected to increase substantially. Should this occur, all generation plants will need to be exposed to the same carbon price.

Figure 37 • Carbon price floor in the United Kingdom and EU Allowance (EUA) price, 2013-18, as of May 2013



Note: Exchange rate 1 EUR = 0.855 GBP
Source: HM Revenue & Customs, 2013.

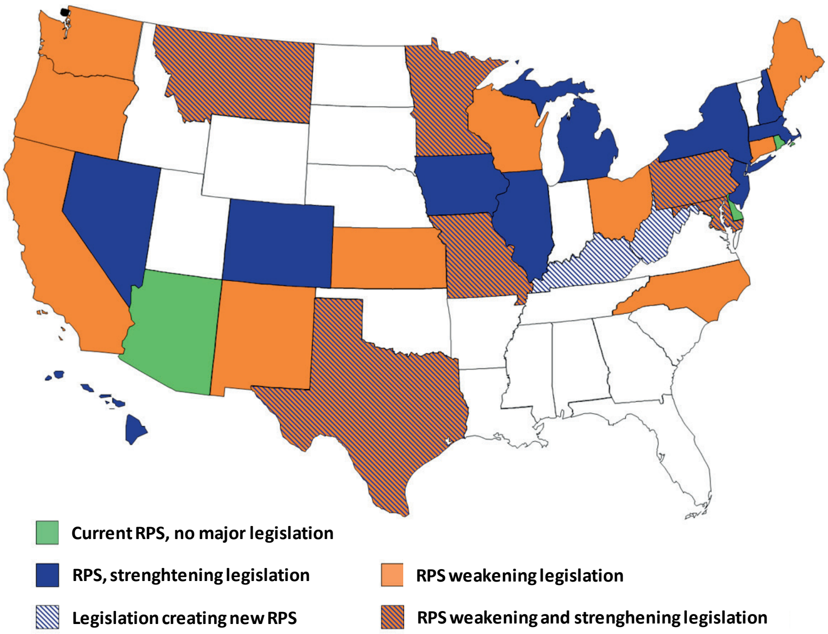
Renewables policies

The best wind and solar locations are often situated far from consumption centres. Given the heterogeneity of wind and solar resource endowments, it is easy to understand the interest in building solar power where the sun shines and installing windmills where the wind blows. Yet this is not happening. Fragmented renewable energy policies can result in inefficient location of wind and solar power generation (Figure 38).

VRE deployment can create challenges to electricity market integration. Besides their impact on renewables deployment itself, uncoordinated renewables policies can affect the functioning of electricity markets not only where they are deployed, but also in adjacent markets. In addition to the impact on loop flows already discussed in section 3, these effects are already visible at three levels: (i) wholesale electricity prices; (ii) flexibility requirements.

High shares of wind and solar power depress wholesale electricity prices in all adjacent markets. For instance, when the wind blows and the sun shines in Germany, low prices in Germany also reduce prices in France (Figure 40). Similarly, Spain and Ireland are keen to develop an interconnection to export their excess renewables generation. Such trades can have important distributive effects, in that lower prices in importing countries increase their consumer surplus thanks to subsidies paid by consumers in the exporting country. However, depressed prices also reduce generator surplus in the importing country, resulting in price distortions and lower investment incentives.

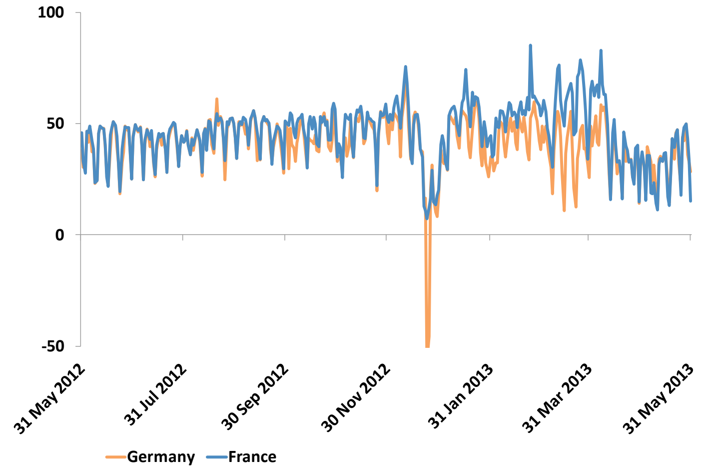
Figure 38 • Renewables policy continues to evolve



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: Clean Energy States, quoted by National Grid, 2013.

Figure 39 • Daily average prices, France and Germany, May 2012-May 2013



Source: Bloomberg and IEA.

State regulators tend to regard interconnectors between neighbouring markets as a source of flexibility. A few zones, such as Germany and Spain in Europe and California and the Midwest in the United States, concentrate massive wind and solar power deployment. These regions export the variability of wind and solar power or – put differently – tap the flexibility potential of adjacent markets. Germany already exports through interconnectors when its renewable output increases. Germany and the United Kingdom are also pursuing simultaneous projects to increase interconnector capacity with Norway and benefit from the flexibility of its hydro system. Similarly, California is currently considering introducing a regional imbalance market to access the flexibility resources of the Western Interconnection.

This, however, raises the question of the remuneration of flexibility services provided by adjacent markets. Flexibility services include ramping down or up to compensate for renewables variability, supplying reserve power to cope with forecast errors, or reducing the minimum output of power plants to maintain network stability in case of over-generation. If there is no market for such services or if the associated costs are socialised, system operators could perceive the cross-border flows as a threat to system security and an extra cost created by neighbours. As renewables deployment will increasingly impact on cross-border flows, market constructs must be created to align incentives for system operators and generators across borders.

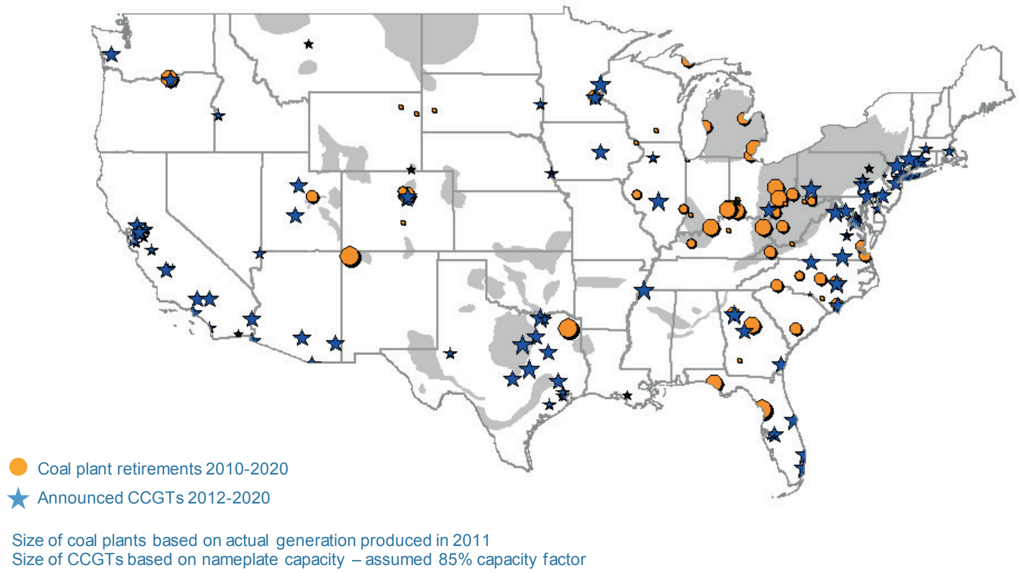
Emission standards

In principle, emission standards introduced in certain jurisdictions for pollutants such as nitrogen oxide and sulphur dioxide could affect the pattern of cross-border electricity trade. In Europe, the Large Combustion Plant Directive (LCPD) of 2001 limits emissions. Hence, some installations must shut down completely by 2015.

CO_2 emission standards are currently proposed for new European power plants and are being discussed for existing power plants in the United States. The Environmental Protection Agency (EPA) can introduce these standards without the approval of Congress. While this was not the best first option, the Obama Administration has relied on such standards to bypass the difficulty of introducing a cap-and-trade mechanism in Congress.

The United Kingdom has also introduced carbon emission performance standards for new-build plants. While these can be effective and simple tools to control emissions, producers in integrated markets can build a coal plant in another country and export power to the Netherlands or the United Kingdom.

Figure 40 • Announced coal retirements and new natural gas combined-cycle units in the United States



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: EEt DoE, EIA, Ventyx Inc., the Velocity Suite.

While a market-wide standard does not create bias between different locations in the electricity market, it can lead to substantial relocation of generation capacity. The introduction of greenhouse gas standards in the United States might lead to closing down 40 GW to 50 GW of coal capacity which will be replaced by gas power plants in different locations (Figure 40).

Conclusion

Does VRE represent a threat or an opportunity for market integration? The deployment of VRE is one major driver of further inter-regional integration. The best renewable resources tend to be located far from consumption centres, and differences in renewables policies lead to uneven deployment and complementary generation mix. Market integration is essential to accommodate renewable energy at minimum cost and to ensure that the cost of decarbonisation remains affordable.

Recent experience in Europe and the United States also suggests that rapid deployment of VRE can threaten market integration. The existing co-ordination procedures and protocols between control areas took decades to develop. They are not well suited for capturing the impact of VRE variability and uncertainty on cross-border flows. The result is multiplied co-ordination problems such as loop flows, reduced forward NTC for cross-border trade and inadequate congestion revenues. Inherently conservative system operators choose to reduce their capability to exchange power at their borders and ultimately install phase shifters to control flows, which represents steps towards the physical fragmentation of electricity systems.

The most efficient technical solution would be to consolidate system operations and markets over larger geographic areas. When institutional barriers are too high for consolidation, better co-ordination of real-time markets is necessary. Further progress in this regard may require a deep harmonisation of reliability and security of electricity supply policy and regulatory frameworks. Governments, regulators and system operators wishing to integrate their markets need to overhaul and revamp the regulatory framework for electricity security of supply.

General conclusion: consolidation or co-ordination

Electricity markets covering large geographic areas are necessary to deploy wind and solar power at least cost. The integration process must cover the right set of electricity markets. Integration needs to be efficient at close-to-real-time timeframes and reflect the variable and unpredictable nature of wind and solar power. Given existing cross-border trade arrangements, high shares of wind and solar power often continue to be perceived as a potential risk to electricity security, prompting local governments to develop inefficient local solutions.

While failure to better integrate markets and system operations would not necessarily result in lower security of supply, governments would need to take costly actions and overinvest to maintain security of supply. This would increase the costs of decarbonising the electricity system and hamper decarbonisation's competitiveness.

Consolidating system operators and markets is the most straightforward approach to ensure efficient real-time market integration in highly meshed networks. While this is technically feasible, institutional constraints in a number of areas will be difficult to overcome in the foreseeable future. Where consolidation remains blocked, accurately co-ordinating the various services provided across borders becomes inevitable.

A key finding is that strong co-ordination of electricity security regulatory frameworks is required to achieve this. Electricity security lags behind market integration and the lack of co-ordination of reliability standards is limiting further progress. Without a clear, common and sound regulatory framework on electricity security, markets cannot deliver the right price signals during scarcity conditions or provision flexible resources to complement VRE.

Governments have an opportunity to clarify, formalise, revamp and modernise these regulatory frameworks to enable efficient trade of electrical products required for electricity security of supply. This involves taking action at the level of policies, regulations and market design.

ANNEX A – Cross-border trade of electricity in North America, Europe and Japan

Cross-border trade of electricity can have slightly different meanings in different IEA member countries. In Europe, cross-border trade refers to international trade of electricity. In Japan, it means trade of electricity between regional companies. In North America, depending on the context, it can mean either interstate trade of electricity, exchange of power between RTO/ISOs or utilities, or international trade of electricity among Canada, the United States and Mexico.

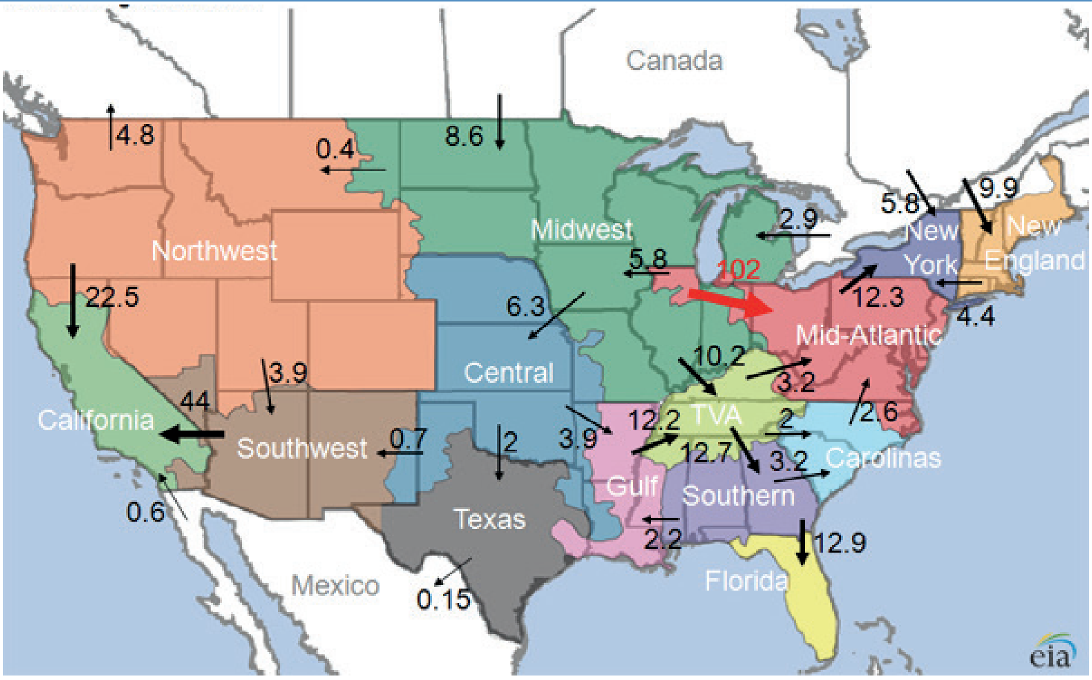
North America

In the United States, the Public Utility Holding Company Act (1935) limited the operations of utility companies geographically and introduced regulation. Since 1990, regional market integration has progressed more rapidly with the liberalisation of electricity markets. ISOs, and RTOs in liberalised markets now operate over larger geographic areas in Texas and the Northeast.

According to the DoE, net inter-regional trade accounted for less than 1% of delivered power in 2010 (Figure 42).[17] Some electricity trades are significant:

- **Canada** exports excess low-cost power, primarily from hydroelectric generators in British Columbia, Manitoba and Quebec.
- California imports 25% of its electricity from neighbouring states.

Figure 41 • Annual net power flows among regions in North America, 2010 (TWh)



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: Energy Information Administration.

[17] Gross power flows would be a better indicator of market integration, but data are not available.

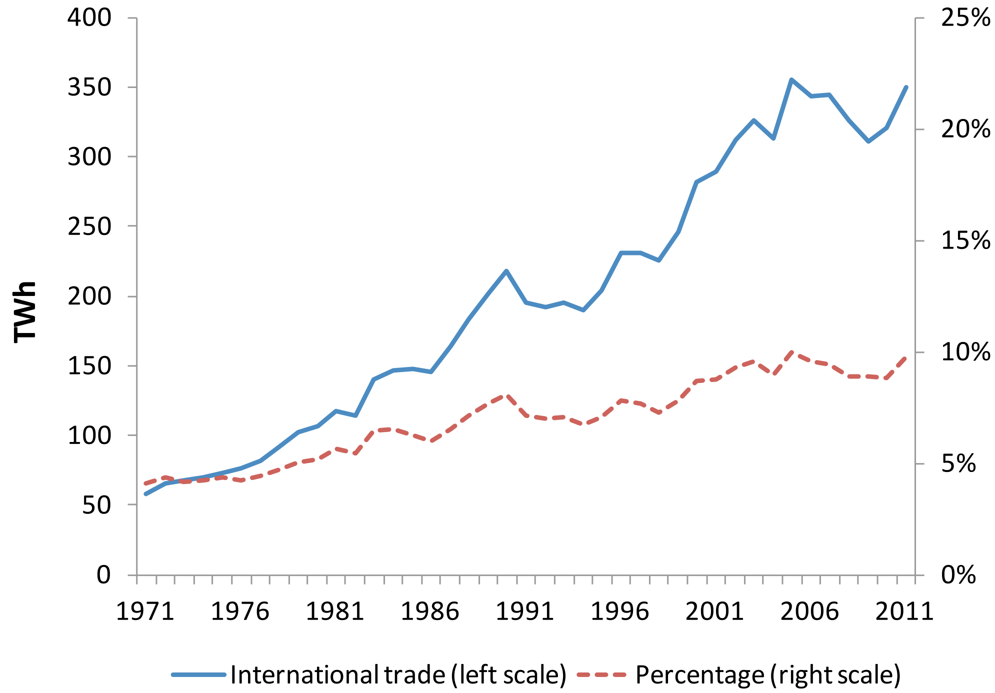
In general, a clear trend has emerged over the years towards increasing electricity trades between countries, states, RTOs or regional electric companies. These developments initially took place on a mostly bilateral basis. However, there is good empirical evidence that more integrated electricity markets can lead to significant changes in power flows and more efficient dispatch of power plants (Joskow, 2008). Perhaps the best example is the expansion of the boundaries of PJM to its far western part, dramatically increasing the electricity flows from west to east. About 100 TWh of electricity flows from the far western part of the PJM interconnection, corresponding to low-cost electricity generated with nuclear and coal.

Europe

In Europe, the first international interconnections were developed to improve the reliability of zones operating at a synchronised frequency and share the costs of frequency control reserves. Some bulk electricity trades took place prior to 1990, mainly from countries (France and Norway) with low-cost generation to countries with expensive gas and oil-fired power plants. Europe has 29 system operators and several power exchanges. The ongoing development of network codes is an important step in creating a well-functioning European Electricity Market.

Cross-border electricity trade is vital to successfully implementing the EU Internal Energy Market. Figure 42 shows the evolution of international trade of electricity in OECD Europe over the last 30 years. International trade of electricity was already occurring in the 1970s and 1980s, but liberalisation in the 1990s bolstered international trade, representing 350 TWh or around 10% of gross production in 2011. The degree of market integration is higher in Europe than in North America.

Figure 42 • International trade of electricity in OECD Europe, 1971-2011 (TWh and % of gross production)



Following are some of the major electricity trades in Europe:

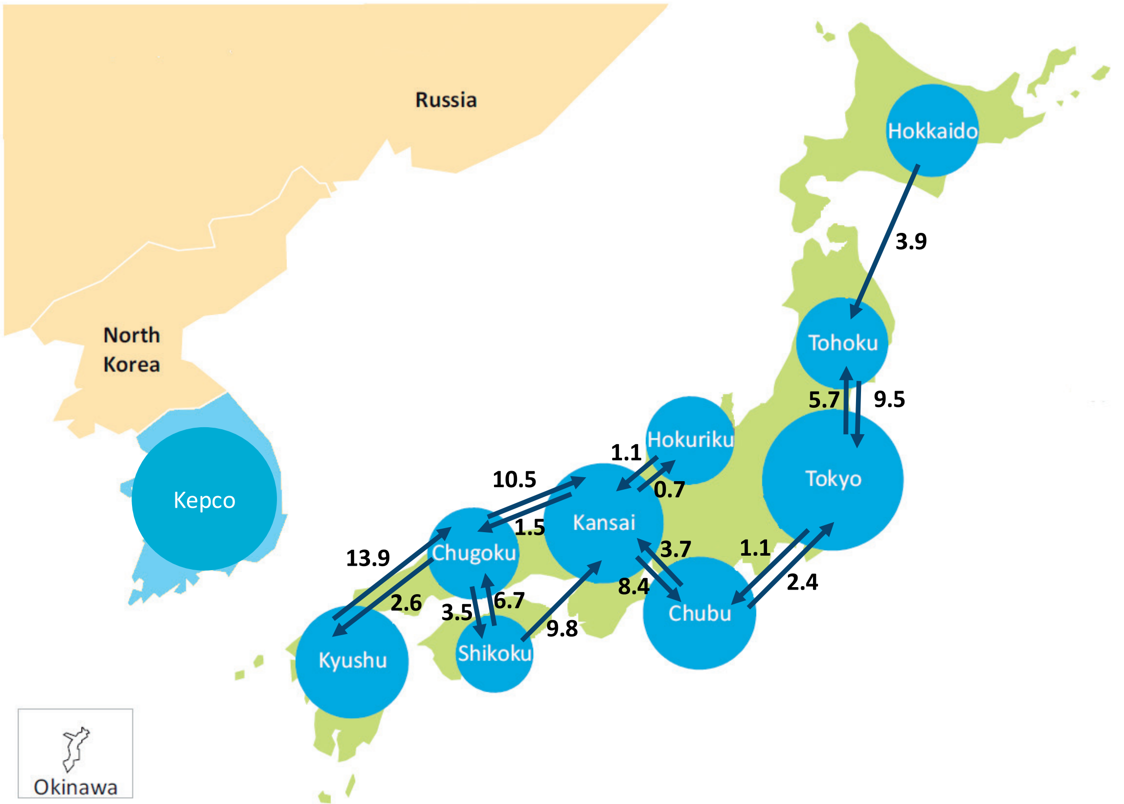
- Germany, Europe's biggest power market with 513 TWh, imported some 43.8 TWh of electricity and exported 66.6 TWh, resulting in a surplus of 22.8 TWh in 2012, despite the close-down of nuclear power plants in 2011.

- France remained Western Europe's leading energy exporter in 2012 with 44 TWh, although this figure was down by 21% from 2011.
- Norway, Sweden, Austria and Switzerland have a strong hydroelectric installed base and also export electricity to other countries.

Japan

The electricity sector in Japan is dominated by ten regional vertically integrated utilities, each operating over a specific island or area. The country is split into two different frequency zones (50 Hz and 60 Hz). Despite this traditional organisation and an unfavourable geography, electricity flows among Japanese electric companies amount to around 10% of electricity consumed in the archipelago – a degree of integration similar to Europe, albeit for a smaller electricity system (Figure 43).

Figure 43 • Annual power flows among electric companies in Japan, April 2011 - March 2012 (TWh)



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

ANNEX B – Electricity security of supply and market integration

Integrating electricity systems improves reliability for all participants. Historically, this was the initial motivation for building interconnectors, allowing the pooling of expensive resources needed to maintain frequency. This triggered the emergence of large synchronous frequency areas, thereby lowering the cost of managing load and capacity deviations.

Based on the definition of power system reliability featured in Box 13, it can be said that the different dimensions of electricity security are already crossing borders. First, most countries or state import the primary fuels (such as gas and coal) they use to generate electricity. Second, system security requires strong co-ordination among system operators across synchronous frequency zones.

Primary fuels used to generate electricity are crossing borders

The dominant fuels used to generate electricity in IEA member countries are coal (50% of electricity generated) and nuclear energy (27%). Coal can be stockpiled. It is an abundant fossil energy source in the United States, as well as in some European countries such as Germany, Poland and the United Kingdom. Imports of coal come from such diverse origins as Australia, Indonesia, the United States, Colombia and South Africa.

Similarly, while much of the uranium used in nuclear power plants is imported, the supply sources are diverse (Canada, Australia, Kazakhstan, Niger). Many reactors burn the Russian stocks of highly enriched uranium and uranium can be easily stockpiled (Joskow, 2008).

Interestingly, nuclear power programmes were developed and accelerated after the first oil shock in 1973 to reduce dependence on imported oil in IEA member countries. France stepped up its civilian nuclear programme after the 1973 and 1979 oil shocks, increasing its energy independence from 20% in 1972 to 50% in 2010. At present, the share of electricity generated from oil in IEA member countries is almost nil, down from 25% in 1973 to 2.4% in 2010.

Almost all IEA member countries are developing renewable energy – including biofuels, hydropower and VRE, such as wind and solar power – in a continued effort to increase energy independence while reducing CO_2 emissions. These generators can be built using local engineering resources and local fuels, further reducing the reliance on imported fuels.

A naturally recurring issue with VRE is the need to complement these sources in the absence of wind and sun. While storage and demand response can complement wind and solar power, one of the most competitive solutions in practice is still to install gas-fired power stations – which raises the issue of security of gas supply.

Increased reliance on gas to complement VRE requires sufficient installed capacity, but decreases the total volume of gas needed. However, the changing nature of fossil-fuel-fired generation could increase the volatility pattern of gas flows and the associated imports. Unlike nuclear or coal, gas must be injected into the pipeline system to keep the pressure stable. Gas flows between countries or states will become less predictable and more erratic, increasing the need for deep and liquid gas markets, gas storage and (more generally) a flexible gas infrastructure. A well-functioning and integrated gas market is key for security of gas supply in Europe (Lévêque F., Glachant J.-M., Barquín, J., von Hirschhausen, C., Holz, F., and Nuttall, W., 2009).

Essentially all the natural gas used in North America to generate electricity is produced in the United States and Canada. While the development of shale gas has enabled a massive switch from coal to gas, the increased reliance on gas raises new issues for the power sector in terms of gas availability. Unlike the still-fragmented electricity system, the gas pipeline system is relatively well integrated. Massive investment in gas pipeline infrastructure and the development of shale gas have removed bottlenecks and reduced gas price differentials between zones (Figure 44).

Box 13 • Defining electricity security

Power system reliability is a very broad notion built around loads, generation and networks. Its simplest definition means "keeping the lights on", which provides little insight into its multifaceted nature. The concept of reliability needs to be "unbundled" if it is to be better understood and managed. In this context, reliability encompasses the ability of the value chain to deliver electricity to all connected users within acceptable standards and in the amounts desired. It has three fundamental requirements:

- **Adequacy,** which refers to the capability of the power system using existing and new resources to meet changes in aggregate power requirements in the present and over time, through timely and flexible investment, operational and end-use responses;
- **System security,** which refers to the capability of the power system using existing resources to maintain reliable power supplies in the face of unexpected shocks and sudden disruptions in real time, such as the unanticipated loss of key generation or network components or rapid changes in demand;
- **Fuel security,** which focuses on issues associated with maintaining access to reliable fuel supplies for power generation in the context of changing international commodity markets, upstream developments and security of existing and new supply routes.

These dimensions are inter-related. For instance, system security policies and practices help establish the effective adequacy envelope of existing generation and network infrastructure in the present, while efficient, timely and well-located investment is needed to maintain power system adequacy and provide the resources needed to maintain system security into the future. At the same time, access to reliable fuel supplies and efficient use of those supplies is required to ensure that generation equipment operates reliably and predictably from a short-term power system security perspective and that generation infrastructure is able to meet demand – and hence adequacy requirements – in the present and the future.

The convergence of gas prices between zones implies that the cost of generating electricity from gas should also converge in different parts of the United States, reducing the benefits of electricity market integration over wider areas. Electricity and gas infrastructure co-ordination is an emerging feature of electricity markets in North America closely monitored by RTOs and FERC.

Electricity and gas markets are becoming increasingly inter-related. For instance, building new gas-fired power plants near liquid natural gas import stations can create local excess generation capacity, which would then have to be exported. Such exports require well-integrated power markets and neighbouring countries that are willing to rely on this capacity to ensure domestic security of electricity supply.

There are currently few integrated policies aiming at defining and implementing regional approaches to fuel security and fuel mix for electricity generation. At the heart of the mission of the IEA are measures for collective action in case of a disruption of oil supply. The IEA also reviews and assesses administrations' oil and gas emergency policies and has recently expanded these activities to include electricity.

Indigenous resources are considered a pillar of national energy security and many countries have focused on developing crucial national natural resources. Little progress has been made in terms of regional integration of security policies for the fuels used to generate power. In practice, however, geological conditions are such that gas storages and hydro facilities are commonly used across several constituencies. The electrification of the economy and development of renewables are also driven by the wish to improve security of electricity supply. Clearly, a key dimension of fuel security is gas security. Coal is less of a concern and arguably contributes to fuel security in many IEA member countries.

Besides the security of supply of each fuel, a diverse electricity infrastructure is also key to ensuring flexibility in type of fuel use. The shutdown in 2011 of all the nuclear reactors in Japan illustrates the importance for a country of being able to switch to other fuels in case of a shock. Japan had the infrastructure necessary to burn coal, oil and gas, helping to compensate for the missing nuclear capacity.

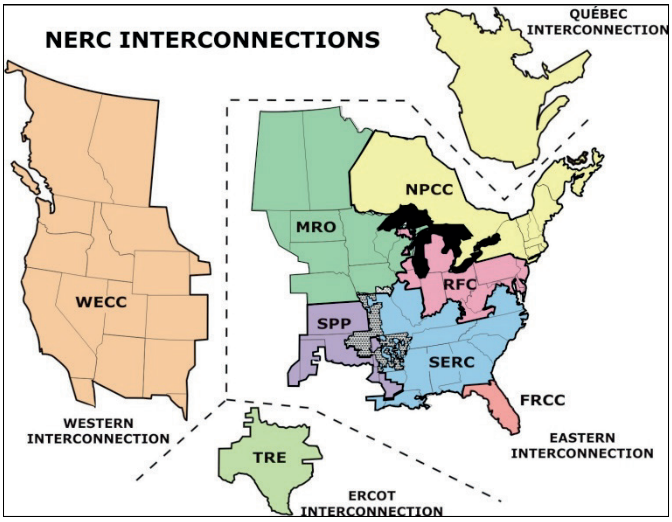
Synchronous frequency areas are already interdependent

The speed of the synchronous generators within one interconnection determines the frequency, which is 60 Hz[18] in North America. In these areas, demand must equal supply to maintain a steady system frequency, thus avoiding damages to power system equipment – particularly steam turbine generators and some loads – and cascading blackouts. Frequency is easy to measure. Any frequency deviation, for example caused by the unscheduled loss of a generator in one control area, can be observed and used to deploy countermeasures. As an immediate reaction, for example to a lost generator in one control area, an interconnection's automated generation control can provide an initial response by modifying the output of individual generators to meet constantly changing demand.

In all IEA regions, electricity systems have been developed in co-ordinated fashion around technical standards and norms (all electrical equipment is designed for a 50 Hz frequency in Europe and 60 Hz in North America). The creation of large synchronous frequency areas (Figure 45) has helped pool the expensive resources needed to ensure real-time frequency control (Figure 45). In Japan, two frequencies (50 Hz and 60 Hz) co-exist. The existence of regional utilities and unfavourable insular geography also represent a constraint for market integration.

[18] Frequency is measured in rotation cycles per second or Hertz (Hz).

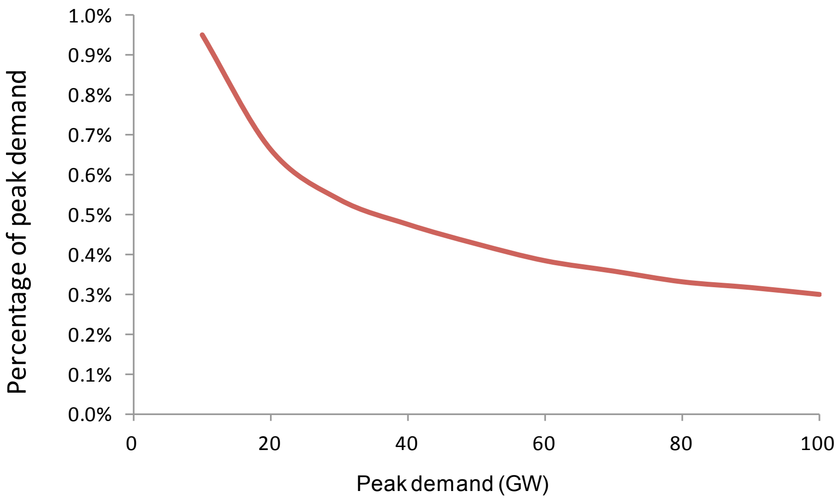
Figure 44 • North American synchronous frequency areas span multiple jurisdictions



Note: this map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: EIA, based on Energy Velocity.

Figure 45 • Indicative regulating requirements for a balancing authority as a function of peak demand (%)



Source: NREL, 2011.

Acronyms and abbreviations

ACER	Agency for the Cooperation of Energy Regulators
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ATC	Available transfer capacity
BALIT	BALancing Inter TSO
BNetzA	Bundesnetzagentur
CAISO	California Independent System Operator
CASC	Capacity allocating service company
CCGT	Combined-cycle gas turbine
CEER	Council of European Energy Regulators
CfD	Contract for Difference
CORESO	COoRdination of Electricity System Operators
CRE	Commission de régulation de l'énergie
CWE	Central Western Europe
DC	Direct current
DE	Germany
DLCO	Duquesne Light Company
DoE	Department of Energy
DSIREUSA	Database of State Incentives for Renewables & Efficiency
EC	European Commission
ECF	European Climate Foundation
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
ENTSO-E	European Network of Transmission System Operators for Electricity
EPA	Environmental Protection Agency
EPAct	Energy Policy Act
ERIG	Energy Reform Implementation Group
ES	Spain
ESA	Environmental Science Associates
ESAP	Electricity Security Action Plan
ESB	Electricity Supply Board
ETS	Emissions trading scheme
FBMC	Flow-based market coupling
FERC	Federal Energy Regulatory Commission
FR	France
FTR	Financial transmission right
HHI	Herfindahl–Hirschman Index
IEEE	Institute of Electrical and Electronics Engineers
IEM	Internal energy market
IESO	Independent Electricity System Operator
IESO	Ontario Independent Electricity System Operator
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
LCPD	Large Combustion Plant Directive
LMP	Locational marginal pricing
LOLE	Loss of load expectation

MISO	Midcontinent Independent System Operator, Inc.
NC	Network code
NEM	National Electricity Market
NERC	North American Electric Reliability Corporation
NordREG	Organisation for the Nordic energy regulators
NREL	National Renewable Energy Laboratory
NTC	Network transfer capacity
NYISO	New York Independent System Operator
OECD	Organisation for Economic Co-operation and Development
OTC	Over the counter
PAR	Phase angle regulators
PCI	Project of common interest
PJM	PJM Interconnection LLC
PSERC	Power Systems Engineering Research Center
PT	Portugal
PTC	Production tax credit
PTR	Physical transmission right
PX	Power eXchange
REC	Renewable energy certificates
REMIT	wholesale energy market integrity and transparency
RGGI	Regional Greenhouse Gas Initiative
RIT-T	Regulatory Investment Test for Transmission
RMR	Reliability-must-run
RPS	Renewable portfolio standard
RTO	Regional Transmission Organisation
SCER	Standing Council on Energy and Resources
SO	System operator
SPP	Southwest Power Pool
TPS	Three pivotal supplier
TSC	Transmission system operator-security-cooperation
TSO	Transmission system operator
TYNDP	Ten-Year Network Development Plan
UCAP	Unforced capacity
UCPTE	Union for the Co-ordination of Production and Transmission of Electricity
UCTE	Union for the Co-ordination of Transmission of Electricity
VRE	Variable renewable energy
WACC	Weighted average cost of capital

Units of measure

Hz	hertz
Gt	gigatonne
GW	gigawatt
MWh	megawatt hour
TWh	terawatt hour
EUR/MWh	Euro per megawatt hour
USD/MWh	Dollar per megawatt hour

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9, rue de la Fédération, 75739 Paris cedex 15

Printed in France by IEA, September 2014

International Energy Agency 1974•2014

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