Chapter XX
Electricity Market Integration

Introduction

The benefits of market deregulation and subsequent market integration have been long advocated (Markusen, 1981; e.g. Joskow and Schmalensee, 1983). On the one hand, deregulation encourages competition which may lead to more efficient allocation of scarce resources, reduction in production costs, lower wholesale prices and, ultimately, lower prices for final consumers. On the other hand, market integration results in joint operations and economies of scale which, at least in theory, make markets more efficient and improve social welfare. In the specific case of energy markets, greater competition should reduce market concentration and lead to lower wholesale prices, as expensive generation can be replaced by cheaper alternatives (Emerson *et al.*, 1988; Turvey, 2006; e.g. Battle, 2013). From a policy maker's perspective, electricity market integration is a path to jointly address the objectives of higher security of supply and affordability (Boffa and Scarpa, 2009; Creti, Fumagalli and Fumagalli, 2010; de Menezes and Houllier, 2016), especially in a context of increasing generation from intermittent renewable sources. Electricity market integration would benefit consumers in high-cost energy markets and increase the profitability of lower-cost generation (Finon and Romano, 2009), since wholesale prices in integrated markets are expected to converge to the common marginal generation cost, which should fall between the lowest and the highest prices of generation in the individual coupled markets.

Market integration can decrease system operational costs because it allows for the possibility of dispatching modern and more efficient generation in a connected area rather than older local inefficient generation. Regional markets can take advantage of weather variations and diversity in hydro-regimes across the region, as well as of differences in electricity demand patterns that are due to distinct calendars and time-zones. Most importantly, the system operational difficulties that can result from the uneven distribution of renewable generation sources across a region may be mitigated within the region. A larger market can accommodate expensive base-load and flexible backup generation that otherwise would not be profitable. By sharing resources, including reserves, the risk of shortages and price spikes can be minimised and electricity prices are therefore expected to be more stable, which should increase market liquidity, facilitate planning and investment decisions. Not surprisingly, the last two decades have seen the creation of regional and supranational electricity markets, which comprise several states or countries.

In the European Union, the liberalisation of energy markets has been strongly tied to the general principles of a single internal market rather than separate national markets for goods and services, and was introduced to the electricity sector with the Single Electricity Act of 1986 (Gebhardt and Höffler, 2007). Since then, a series of directives (e.g. 96/92/EC; 2003/54/EC; 2009/72/EC) have addressed not only how to improve competition in electricity markets, but have also specified paths to the common objectives of decarbonisation and energy security. The most important step of electricity market integration in Europe took place on 4 February 2014, with the day-ahead price coupling in North Western Europe (NEW). Since then, the coupled area has been extended and now encompasses 19 countries and 85% of electricity consumption in the EU. Nevertheless, recent empirical studies suggest that the degree of electricity market integration remains uneven across the region which faces several challenges, such as the lack of coordination between national policies and increasing decarbonisation targets. The latter are laid out in the EU Renewable Energy Directive (2009), which sets the target of increasing renewable electricity generation to 20% (10% for transport fuels) and reducing carbon emission by 20% (in comparison to 1992) by 2020. On 30 November 2016, the EU Commission published a proposal for a revised Renewable Energy Directive (EC COM (2016) 860, European Commission, 2016), which raises the target of renewable energy sources (RES) to 30% by 2030, to be achieved in a cost-effective way across the three sectors of: electricity (RES-E), heating and cooling (RES-H&C), and transport (RES-T). It also targets a minimum of 40% cut in CO_2 emissions by 2030 and includes a set of measures to make sure the new targets are met. Among these measures are the easy access to consumption data that would enable individual consumers to change their demand pattern, the removal of obstacles to self-generation and a new regulatory framework to ensure that renewables can fully participate in the electricity market, thus underlining the evolving process of electricity market integration. In the next sections, this chapter reviews studies of electricity market integration, with a special focus on the liberalised European markets, reflects on policy implications and ends by drawing conclusions for the future research agenda.

Studies on the Integration of Electricity Markets

Most literature that addresses electricity market integration refer to the Law of One Price as the theoretical foundation to justify their assessment of price convergence. This law states that prices of a commodity offered in two markets should never differ by more than its transportation costs between the markets (after adjusting for the exchange rate, if the prices are denominated in different currencies). Violations of the law of one price are therefore indicative of barriers to trade (Marshall, 2000). In this context, several methodologies have been used to examine the extent of price convergence across regional markets, ranging from: correlation analysis that presumes co-movement in prices; cointegration and fractional cointegration tests for long-run association; multivariate generalised autoregressive conditional heteroscedasticity (GARCH) models that estimate the conditional correlation; vector error correction model (VECM) focusing on price differentials; Granger causality; impulse response functions; supply-demand models; and simulation and system dynamics, among others. Although interconnected electricity markets and the process of market integration are not unique to Europe, most studies have tended to focus on the EU or groups of neighbouring countries within it, possibly due to the number of nations involved and the EU's aim to achieve an Energy Union.

On the American Markets

Market integration has been addressed in different regional contexts outside Europe where there is some degree of interconnection between neighbouring electricity markets, mostly in the Americas and Asia Pacific. One of the earliest works on the performance of decentralised electricity markets in North America is by De Vany and Walls (1999), who looked for evidence of electricity market integration in the western United States. Their work covered eleven regional sub-markets during 1994-96 and used cointegration analysis and a VECM on daily spot electricity prices for both peak and off-peak periods. They found that all off-peak market pairs were cointegrated, with two-thirds of them being strongly integrated and half being perfectly integrated. Nearly 90% of peak market pairs were cointegrated, with one-third of them strongly integrated and just a few perfectly integrated. Overall, they concluded that deregulated western US markets priced power and transmission efficiently.

Park, Mjelde and Bessler (2006) considered firm peak spot prices for day-ahead trades between 1998-2002, for eleven spot markets and 23 different cities across the United States, including ERCOT in Texas, PJM in the Northeast and MAIN in the Midwest. The authors used a combination of VAR modelling, directed acyclic graphs and impulse response functions to investigate the relationships among the eleven markets. In most VAR equations, four or five markets had significant coefficients, i.e. they were integrated. While analysing contemporaneous structures among markets, the authors found evidence that the US was effectively split in three large areas, parallel to the three main power grids, or "interconnections": Western, which covers most of western United States from the Rocky Mountains to the Pacific coast; Eastern, which covers most of eastern United States and extends to the Atlantic coast all the way from Maine to Florida; and Texas. Their analysis suggested that: the Western interconnection had very few contemporaneous price information flows with the other two areas; Texas (ERCOT) had relatively little influence on any of the other two markets, possibly because at the time it used mostly gas as a generation fuel; and that PJM was dominant among other regional markets in the Eastern interconnection, most probably due to the fact that PJM real-time data provided a price discovery function not only to the Eastern Seaboard, but also to markets further west due to the time zone difference.

Moving one step further, Mjelde and Bessler (2009) examined the interrelationships between wholesale electricity (base and peak) prices and four major fuel sources (natural gas, crude oil, coal and uranium) in two regional US markets (PJM and mid-Columbia). The authors used cointegration and VECM methodology to model the long-run relationships between electricity and fuel prices in the two regions. Their study concluded that all price series examined were cointegrated in the long-run, but not all series were fully integrated. They noted that "peak electricity prices move natural gas prices in contemporaneous time, which in turn influence oil prices. At longer horizons, fuel sources prices move electricity prices."

In South America, Ochoa, Dyner and Franco (2013) looked at the integration of the electricity markets of Panama, Colombia, Ecuador and Peru and developed a system dynamics (SD) model to assess the likely effects of system expansion and security of supply. Their SD model outputs, such as generation capacities by technology and transmission capacities, were used as inputs in a dispatch algorithm which operated under market coupling conditions. The authors ran their simulations under several scenarios, such as a base case of self-sufficiency and a free market scenario, where security of supply relied on interconnections and the generation capacity of neighbouring countries. Their analysis concluded that a free market would bring more benefits in terms of supply costs, as it would allow a more efficient use of resources across all countries. These benefits, however, were conditional on the absence of technical problems, political instability or any other issue that could interrupt cross-border electricity flows.

Following the same line of thought and methodology, Ochoa and van Ackere questioned the purported benefits of electricity market integration and developed a system dynamics model to examine the potential benefits and risks of market coupling. In Ochoa and van Ackere (2015a), Colombia and Ecuador were used as an example of countries with reliable interconnection and active cross-border electricity trading. Their model simulated how electricity prices would develop in the two countries under four different scenarios, three of which assumed capacity payments to incentivise investment in new electricity systems. Their simulation results showed that electricity market integration can bring benefits in terms of lower supply costs and better uses of resources, although these benefits are highly dependent on the degree of interconnection and the relative size of the countries. In some cases, there was a trade-off between lower prices and independence from the neighbouring country, which highlighted the sensitivity to political relationships between the countries.

The issue of renewables integration into the electricity mix is increasingly drawing more attention, especially in the US, where capacity expansion for both solar and wind generation have increased exponentially since 2000. The National Renewable Energy Laboratory has provided an impetus with their large-scale Renewable Electricity Futures (RE Futures) Study (Hand *et al.*, 2012). The study provides an analysis of grid integration opportunities, challenges, and implications of high levels of renewable electricity generation for the US electric system. The focus is on the technical issues related to the operability of the US electricity grid and the integration of high penetrations of renewable electricity technologies. Building on this, Mai *et al.* (2014) revisited some of the analysis conducted in the RE Futures Study and modelled four scenarios where 80% of all electricity generation in 2050 is sourced from renewables, including wind, solar, geothermal, biomass, and hydropower. Their scenarios included: a base scenario; a high-demand scenario; a constrained scenario, where RE capacity, transmission and interconnection expansion is challenged; and an advanced-technology-improvement (ATI) scenario, which assumes greater future renewable technology improvement. Although the analysis remained focused on technical issues, the authors estimated the retail electricity price trajectory under the various scenarios. Of these trajectories, the highest (30% higher prices than the low-demand base scenario, by 2050) is associated with the 'constrained' scenario, while the lowest (3% higher prices) is achieved by the ATI scenario. Among the authors' conclusions is the conviction that high renewables penetration is technically feasible, but would be more efficient with new transmission capacity, flexible conventional generation, grid storage and changes in power system operations. Although this suggests a brave new future world with a high penetration of renewables in the electricity mix, the share of renewables in US electricity generation was actually 14.9% of approximately 4,000 TWh generated in 2016 (EIA, 2017), with hydro at 6.5%, wind at 5.6% and solar at 0.9%. As renewable market shares are likely to increase in the coming years, so is the interest in assessing their impact on market prices.

Woo, Horowitz *et al.* (2011) used 15-min price data from Texas' ERCOT and showed that rising wind generation is indeed likely to reduce spot prices, but it is also likely to enlarge the spot-price volatility. In a further analysis of ERCOT data for the wind-rich West Texas, Woo, Zarnikau *et al.* (2011) found that high wind generation and low demand in the West ERCOT zone led to congestion and zonal price differences. Gil and Lin (2013) analysed the impact of wind generation on day-ahead PJM prices and concluded that even for low wind power penetration levels, the quantified expected benefit to wholesale market participants may be substantial. Hence, they advocated a benefit allocation mechanism to further encourage the development of wind power. A question that follows is whether these benefits remain substantial when a region already has alternative renewable generation. Woo *et al.* (2013) investigated this question in the context of the hydro-rich electricity system of the Pacific Northwest, and found that increased wind generation decreased wholesale prices by a small, but statistically significant amount. They also observed that a hydro-rich system can integrate wind generation at a lower cost than a thermal-dominated, but the direct economic benefits to end-users from greater investment in wind power may be negligible.

Woo *et al.* (2016) examined the possible merit-order effects of renewables on California electricity prices and the price divergence between day-ahead and real-time prices. Their study used hourly observations of CAISO (California ISO) market prices between December 2012 and April 2015 and applied a regression-based approach to evaluate: (a) merit-order effects, i.e. displacement of conventional generation by renewables; and (b) why there is a divergence between day-ahead and real-time electricity prices. The authors used as explanatory variables: fuel prices (Henry Hub natural gas); nuclear capacity availability; hydropower availability; and solar and wind generation. Their findings imply that merit-order effects for solar and wind generation are present in California's electricity markets, while the divergence between day-ahead and real-time prices was attributed to CAISO's renewable energy forecasting errors. The authors also concluded that while electricity prices may increase with nuclear capacity retirement and a reversal of low natural gas prices, this effect can be mitigated with higher renewables portfolio standards (higher renewables penetration), combined with increased energy efficiency and demand side management policies.

On the Asia-Pacific Markets

The degree of interconnection among Asia-Pacific countries is not at the level seen in either the Americas or Europe. Except for the more developed Australian market, research tends to focus on the pre-conditions for a future integrated electricity market, such as investment in the necessary infrastructure, co-ordination among TSOs, increased renewable generation and concomitant policy implications.

Some of the earlier thinking of energy trade and energy market integration in the East Asia Summit Region (EAS)[1] were by Krishnaswamy (2007) and Bannister *et al.* (2008). Building on these, Wu (2013) reviewed electricity market integration in the EAS area and noted the heterogeneity of the various national markets. There are the more mature and integrated, Australia, New Zealand and Singapore, where generation, transmission, distribution and retailing are unbundled and partly privatised. At the other end of the spectrum lies Brunei, whose electricity sector is vertically integrated and state-owned. In between are all other EAS countries, some of which have allowed unbundling of, and private participation in, generation, while others have also extended the process to transmission. The author suggests several progressive steps that need to be taken towards an integrated electricity market in the EAS region, or at least in its sub-regions. These include: investment in infrastructure, especially in countries which have very low levels of electrification and need to move faster towards universal access to electricity; even before national markets are fully developed, it is important to increase bilateral and multilateral interconnections, sub-regional cooperation and cross-border electricity trading, so that the foundation is laid for future market integration; EAS countries should work on harmonizing regulations and technical standards and follow best practice in preparation for market integration; and, finally, the aspiration of market integration should be reflected in national policies and planning in power sector investment and development.

[1] The East Asian Summit (EAS) is a forum of 18 nations in the East Asian, Southeast Asian and South Asian regions. They are: Australia, Brunei, Cambodia, China, India, Indonesia, Japan, Laos, Malaysia, Myanmar, New Zealand, Philippines, Russia, Singapore, South Korea, Thailand, United States, Vietnam.

The Association of Southeast Asian Nations (ASEAN), a subset of EAS which consists of 10 member countries[2], is integrating its power transmission infrastructure via the ASEAN power grid as part of the ASEAN Vision 2020. In this context, Ahmet *et al.* (2017) reviewed energy resources, their current utilization, and future projections. Given the potential for growth in renewables, export-import scenarios and renewable-generation-based transmission expansion, planning practices in ASEAN were analysed. Major challenges for the establishment of an ASEAN grid that will require information sharing and coordination between different TSOs were identified. These included voltage and frequency deviation due to non-dispatchable production (intermittent power located in remote regions), congestion, blackouts as well as demand-supply management for long distance power transmission network. They concluded that methods for efficiently allocating costs and revenues between different TSOs and inter-TSO compensation mechanisms will be needed, as well as coordinated investments in generation in order to avoid over estimation of reserve margins. Finally, they stressed that a lack of coordinated transmission and generation planning could limit the development and utilization of the interconnected transmission system, increase costs and send negative signals to investors.

Considering Australia, Nepal and Foster (2016) argued that although its National Electricity Market (NEM) was established in 1998, the effects of integration had not been systematically examined. Thus, they analysed daily electricity spot prices, which were obtained by averaging the publicly available real-time original and official half-hourly spot prices for electricity. The period from January 2000 to November 2013 was considered, except for Tasmania that joined NEM in May 2005, for which the sample was from 1 January 2006 to 1 November 2013. Pairwise unit root tests on the log-price differences indicated that an integrated market for electricity had not been universally achieved, price convergence seemed to be mainly driven by bilateral regional interconnections between separate markets. Cointegration analysis led to contradictory findings, and the authors concluded that they could not reject the existence of significant persistence in price differences (or the lack of long-run price equilibrium). Finally, a time-varying coefficient model that measured the strength of the relationship between prices in different markets, which was estimated using a Kalman Filter, suggested price convergence in the two markets that had fully privatised generation. Overall, their results suggest that full market integration had not been achieved in NEM. More generally, they concluded that convergence in generation and network ownership plus a common regulatory approach would facilitate improvements in wholesale market integration, especially as these markets experience increasing shares of renewable energy.

Apergis *et al.* (2017) questioned the appropriateness of cointegration analysis that is common to many studies, and used a different method to assess market integration of the Australian regional markets. They argued that Phillips and Sul's (2007, 2009) methodology is better suited to test for convergence in wholesale electricity prices, because it has three advantages over cointegration analysis. First, it allows for econometric testing of 'convergence clubs' and estimation of convergence paths relative to identified common trends. Second, it can be implemented on multivariate data comprising prices in the different markets, rather than focusing on pairs of markets. Third, the methodology does not need to rely on assumptions of a presence of a trend or stationarity in the time series. Two types of price convergence were hypothesised. In the short-run, price convergence is expected to be driven by arbitrage, for

[2] Brunei, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand and Vietnam.

which opportunities reduce as markets become efficient. While, in the long-run, price convergence should follow the exploitation of profits under free entry and exit conditions, and thus should be dependent on the structure and evolution of the power markets. Thus, the authors hypothesised that the more electricity markets are homogeneous with regard to technology and design, the more likely price convergence occurs, even with limited or absent interconnection capacity, and vice versa. Accordingly, “long-run price convergence is affected, by energy policies targeted at reducing externalities, and in particular, power production from carbon-intensive fuels” (Apergis, Fontini and Inchauspe, 2017, p. 412). Their data excluded the Northern Territories and consisted of weekly wholesale electricity prices for the remaining six states, spanning the period January 1999 to July 2014.[3] Three distinctive growth patterns in wholesale electricity prices across the six Australian States were identified. In all, their results confirmed that markets with limited physical interconnection can achieve price convergence over the long run, if there is some homogeneity in market structures. Tasmania and Western Australia, which have less competitive markets in which a major role is played by state-owned companies, were found to share a separate, non-competitive convergence pattern, despite differences in how capacity is remunerated. In addition, the introduction of a carbon tax did not alter the price convergence process in the identified clubs of states, except South Australia, which would have converged to the club formed by the other NEM States (except Tasmania) had the carbon tax not been in place. The study highlighted that although interconnection is important, there is need to identify the features of market design that can foster integration.

In line with other electricity markets, the role of renewables and their impact on wholesale electricity prices and market integration is gaining momentum in the research agenda. In Australia, the government put in place a mandatory renewable energy target (MRET) in 2001, with the initial aim to source 2% of the nation’s electricity generation from renewable sources. In 2009, the scheme was renamed renewable energy target (RET) and that target was raised to 20% of renewable electricity generation by 2020.[4] MacGill (2010) made a first attempt to evaluate the prospects of wind power integration in the Australian NEM by reviewing its decision-making framework in terms of governance, security, commercial and technical regimes. The author concluded that Australia’s National Electricity Market and renewable policy support arrangements both incorporate significant roles for commercial, competitively driven, decision making. He recommended that wind generation should be formally incorporated into the NEM’s operational decision making mechanism, by requiring greater participation in data provision, scheduling, ancillary services and security projection arrangements.

[3] Data for Eastern Australian States (New South Wales, Victoria, Queensland, South Australia and Tasmania) were obtained from the Australian Energy Regulator (AER, www.aer.gov.au). Data for Western Australia's SWIS market were obtained from the Independent Market Operator of Western Australia (IMOWA, www.imowa.com.au). For SWIS, they averaged half-hourly clearing prices of the short-term energy market.

[4] In 2011, RET was further refined into a ‘large-scale’ section (looking at utility-scale renewables, such solar farms, wind farms and hydropower plants) and a small-scale section (focussing on financial incentives for the installation of solar panels, wind, hydro systems, solar water heaters and air source heat pumps) (Australian Government Clean Energy Regulator, 2016)

Cutler *et al.* (2011) explored wind power integration in the South Australian region, which has the highest wind penetration in NEM. They assessed the interaction of regional wind generation, electricity demand and half-hourly spot prices over a 2-year period from September 2008 to August 2010. They found that electricity demand was dominant in determining spot prices, with wind power having a significant secondary influence. There was a clear inverse relationship between wind generation and prices, but no clear relationship between wind generation and electricity demand. There were also several extreme events where prices were either very high or, conversely, negative. These were attributed to the relatively limited interconnection between South Australia and the other NEM regions. Bell *et al.* (2015) picked on the issue of wind speed and electricity demand correlation, in an effort to determine the ability of wind generation to meet peak-load electricity demand on the Australian NEM without the need for energy storage. The authors used correlation analysis on half-hourly wind speed and electricity demand data, for the three calendar years 2010-2012 and for 50 regional nodes. Their analysis found low wind speed correlations in the peripheral states of Queensland, South Australia and Tasmania, which could assist system balancing if adequate interconnection capacity is installed between these regions, via New South Wales and Victoria. They also found notable positive correlation between wind speed and electricity demand in Queensland, New South Wales and South Australia which pointed to the ability of wind generation to cover peak-load demand, once again under the proviso that interconnection capacity increases among the regions.

Worthington and Higgs (2017) studied the impact of generation mix, including fossil fuels (coal and gas) and renewables (hydropower and wind) on daily spot electricity prices across five regions of the Australian NEM. They used daily electricity prices between January 2006 and September 2012, alongside data on daily generation by type, available capacity for each generator and interconnection flows between regions. Their results indicated that electricity prices were lower with the use of coal and higher with the use of natural gas and renewables, suggesting the likelihood of higher wholesale prices as the electricity industry moves towards the announced RETs. The authors also concluded that the effect of price increases due to the introduction of renewables were mitigated in certain regions which had a comparative advantage: South Australia and Tasmania for wind; and Victoria and Tasmania for hydropower.

Turning their focus on southeast Asia, Chang and Li (2015) used a linear dynamic programming model to assess the impact of energy market integration in the ASEAN region, taking into account renewable energy, feed-in-tariffs (FITs) and carbon pricing. Their study covered the ten ASEAN countries, included power generation from both conventional and renewable sources (coal, diesel, natural gas, hydro, small hydro, geothermal, wind, solar PV and biomass), and covered the period 2012-2035. Based on the simulation results, the authors concluded that energy market integration in the ASEAN region would significantly promote the adoption of renewable energy. They also recommended the co-ordinated adoption of either renewable energy portfolio standards, i.e. renewable energy targets, or FITs. They concluded that energy market integration with policy coordination among the ten ASEAN countries would speed up the expansion of renewables and achieve carbon reduction targets, while incurring only negligible increases in the total cost of electricity.

Not much has been written on the progress of energy market integration in other regions, especially developing ones. Before moving onto the European market, it is worth mentioning a comparison of three developing region power pools (SAPP, WAPP and MER[5]) with Nord Pool by Oseni and Pollitt (2016). The authors initially embarked on a review of the benefits and disadvantages of opening electricity trade among countries in a region, including security of supply issues, price adjustments in low-cost and high-cost generators, impact on retail consumers and possible reaction of large-scale industrial consumers. They then carried out a descriptive comparison of the four pools, in terms of the nature of the trading platform used, the institutions developed to support it, the governance of those institutions, the practical steps to implementation and the concrete evidence on the benefits of trade. Subsequently, they compared the extent of cross-border trading in the regions as a proportion of their respective total electricity consumption and interconnection capacity. The authors highlighted several common themes and lessons to be learned in electricity market integration, such as: countries must be committed to free trade and have adequate transmission capacity for this trade to occur; there is a need for strong, independent institutions as well as appropriate market design, which make use of day-ahead and real-time markets; timely development of regional power pools requires a timetable for reform, should start with a small number of countries, expanding over time, and can be facilitated by international organisations. Many of these conclusions emanated from the experiences of building a well-functioning Nord Pool, which brings us conveniently to focus on the European market.

On the European Market

The prospect of a European single market for energy has led to a series of studies. The first stream of literature is focused on assessments of price convergence and the progress towards a pan-European market. These have identified enablers and deterrents of electricity market integration and led to at least three subsets of studies. Several authors have analysed the role of inputs to electricity generation, while others focused on interconnection and market coupling. More recently, as observed in other markets, a growing body of research addresses the impact of increasing renewable generation on interconnected electricity markets.

Studies of Price Convergence

One of the earliest attempts to assess European electricity market integration was by Bower (2002). His sample included mean daily prices, in 2001, for day-ahead trading in 15 different locations in eight countries: Norway, Sweden, Finland, Denmark, England & Wales, Spain, Germany and Netherlands. After an initial inspection of correlation coefficients, he proceeded to use cointegration analysis to assess the level of integration between markets. His results indicated that there were robust long-run equilibrium relationships between all pairs of locational spot prices within Nord Pool and between many Nord Pool locations and locations outside Scandinavia. Cointegration relationships between pairs of locations outside Nord Pool were weaker, but still statistically significant. The results of correlations and cointegration between pairs of locations were used as evidence of price convergence (or lack of it). There was no effective arbitrage process connecting Spain and the rest of locations, while the remaining European locations exhibited strong price cointegration, but weak price change correlation. The latter was attributed to transmission constraints which prevented enough trade to occur in order to equilibrate prices between locations. Overall, the author concluded that, despite price co-movement and arbitrage trading between locations, the market was inefficient because generating firms exercised market power at some locations and mechanisms to allocate capacity on congested transmission lines were weak. From a policy perspective, he recommended that the European Commission should increase

[5] SAPP: South African Power Pool; WAPP: West African Power Pool; MER: Central American Power Market.

competition by breaking up dominant generating firms, rather than subsidising new transmission capacity.

Building on the analyses by Bower (2002) , Galli and Armstrong (2003), and Boisseleau (2004), Zachmann (2008) performed a principal component analysis (PCA) of wholesale electricity prices between 2002-2006 for ten European countries: Austria, France, Germany, Netherlands, UK, Poland, Czech Republic, Denmark (East and West) and Sweden. His results provided general evidence that a common European price pattern was increasingly able to explain national price developments. The author then tested for pairwise convergence of daily average electricity prices. Results were mixed, with convergence mostly occurring between directly linked markets. Further analysis confirmed the mixed results in terms of market integration, with nearly 60% of hourly pairs of national wholesale electricity prices converging. This convergence was evident primarily in off-peak prices, while three quarters of peak prices were diverging. The author concluded that at the time the efforts for the creation of a single EU electricity market were only partially successful. In a subsequent study, Zachmann (2009) investigated the integration of the new member states, and observed that the trade of electricity across the German-Polish-Czech border did not lead to a convergence in wholesale prices. He concluded that buying electricity in the Polish and Czech markets was subject to high price uncertainty due to low levels of liquidity, market concentration, and difficulties in estimating the available transmission capacities. His observations highlighted a need for a common balancing market, which could manage transmission capacity and thus reduce transaction costs (improve liquidity).

Von Hirschhausen and Zachmann (2009) examined further the integration of new member states to the EU electricity market. They observed that the Eastern countries had implemented some reforms, but most market objectives were still to be achieved (e.g. competitive national markets, a functioning wholesale market and efficient cross-border trade). For example, Poland had the largest power exchange among the new entrants, but market liquidity was insufficient to enable competitive wholesale prices. Slovenia was characterized by an unbundled electricity sector, which was state-controlled. Croatia had vertically integrated the state-owned electricity sector that was in place. Romania and Bulgaria had a small share of independent power producers in the almost completely state-owned generation and distribution sectors. While the Baltic countries, Lithuania, Latvia, Estonia were still part of the North-West Russian electricity system. In all, long-term power purchase agreements were in place and the new member states lagged considerably behind, with only Hungary and the Slovak Republic having achieved standards that were comparable to the remaining EU member states.

In the same spirit, Bunn and Gianfreda (2010) addressed the integration of the French, German, British, Dutch and Spanish electricity markets at day-ahead, week-ahead, one month-ahead and two month-ahead lead times. They tested several hypotheses on market integration, with regard to factors such as: interconnection capacity, geographical proximity, level of cross-border electricity exports, demand seasonality, base versus peak price, and forward versus spot prices. They used diverse methods, including causality tests, cointegration and impulse-response techniques for both price levels and volatilities. In general, the authors found evidence of market integration, increasing over time, despite an underlying inefficiency in each market with respect to the forward and spot price convergence. More specifically: integration was higher as the interconnection capacity of a market increased; integration was not a simple function of market proximity, with evidence that Germany was integrated with both the British and the Spanish markets; a large exporter, such as France, did not always create price shock transmissions to the markets it exports to, possibly because its nuclear generation is normally low-cost. Finally, the authors did not find enough evidence that there is high integration between seasonal demand and peak periods and, surprisingly, neither did they find higher integration in the forward than in the spot market.

Moving away from cointegration studies, Autran (2012) developed a jump-diffusion model with time-varying estimates and concluded that, despite signs of regional convergence of electricity prices, market integration of the Belgian, Dutch, French and German electricity spot and future markets had not been achieved in the period between 2006 and 2011. Differently from most of the literature thus far, the author noted that the convergence of electricity prices followed a *stepwise process*, which could be due to the implementation of market coupling.

Huisman and Kiliç (2013) examined the development of day-ahead prices in the Belgian, Dutch, French, German and Nordic markets, over the period from 2003 to 2010 which saw both increased liberalisation in, and increased connectivity of, European electricity markets. Rather than looking at classic price convergence models, as in Bunn and Gianfreda (2010) above, the authors used a two-regime switching model to ascertain whether there were changes in the spike behaviour of electricity prices. They defined two regimes: one where prices were normal; and one where prices were abnormal, i.e. more 'spiky'. Their results for the first four markets indicated that the mean log price level in the normal regime increased, while the opposite happened in the abnormal regime. In the Belgian, Dutch and French markets the probability of price spikes decreased, while the same probability increased in the German and Nordic markets. The authors also noted a reduction in the speed of mean-reversion, implying more randomness in prices, which was interpreted as a sign of progressively more efficient electricity markets. Finally, they observed that the estimated parameters for the five markets converged over time, which could be explained by increased connectivity and market liquidity.

In contrast to studies that tested the integration of European electricity markets and assumed electricity prices to follow a trend, de Menezes and Houllier (2016) adopted a time-varying fractional cointegration analysis. Daily spot prices from February 2000 to March 2013 of nine European electricity spot markets (APX-UK, APX-NL, Belpex, EPEX-FR, EPEX-DE, IPEX, Nord Pool, Omel and OTE) and month-ahead prices in four markets (French, British, German and Dutch) from November 2007 to December 2012 were investigated. Their results showed that unit root tests are inadequate for assessing electricity spot market convergence, because spot prices were found to be fractionally integrated and mean-reverting time series. Geographically close or well-connected electricity spot markets were found to have longer periods of price convergence, and the authors concluded that market coupling initiatives were delivering a more robust electric system. However, overall electricity spot prices were not increasingly converging, and spot price dispersion could not be linked to market integration. Spot price behaviour and their association with different markets were observed to change over time, reflecting changes in the EU electrical system. Their findings highlighted the relevance of extreme weather conditions, public holidays, reduced plant availability and fuel price developments for changes in the speed of mean reversion and convergence of electricity spot prices. One-month-ahead prices, by contrast, were found to have become more resilient to shocks and to follow more stable trends.

Studies of Interconnection and Market Integration

With several studies indicating only partial price convergence among EU countries, attention was given to the potentially detrimental effect of explicit auctions of interconnector capacity. Weber *et al.* (2010) discussed the merits of utilising implicit auctions to allocate transmission capacity on European cross-border interconnectors. The authors observed that the prevailing explicit auctions of such capacity often led to 'adverse flows', i.e. flows of electricity from a high-price to a low-price area, which highlighted market inefficiencies where the parties involved were not able to predict properly prices in the connected regions. The authors then juxtaposed the use of implicit auctions in coupled markets, where interconnector capacity simply forms part of the day-ahead auctioning of electricity in connected markets. They went on to show how market coupling results in 'normal' flows of electricity from low-price to high-price markets, leading to prices converging (where interconnector capacity is restricted and may be congested) or even equalising (where interconnector capacity is unrestricted) between these markets.

In the same spirit, Pellini (2012) evaluated the impact of replacing explicit auctions of interconnector capacity with market coupling, by looking at the case of Italy and its neighbours France, Switzerland, Austria, Slovenia and Greece, with which it has interconnections. Using data from deterministic simulations of the Italian day-ahead market for 2012, which took account of all domestic generation sources, the author built two scenarios - a reference and a high scenario, with the latter assuming higher demand and fuel prices. She then proceeded to construct four alternative cases: (a) the baseline case of perfect competition, whereby generators are price-takers and offer their power output at marginal cost; (b) a business-as-usual case where generators compete and offer their power at above marginal cost prices; (c) case [b] with market coupling; and (d) case [a] with market coupling. After comparing the welfare results of cases [b-d] to the baseline case, the author concluded that welfare increases with market coupling and the welfare gain is maximised when market coupling is accompanied by perfect competition (case d).

Kiesel and Kusterman (2016) modelled the dynamics of neighbouring European electricity markets which are implicitly or explicitly coupled. They focused on the NEW market coupling, which includes: the 13 countries and TSOs involved in the power exchanges APX, Belpex, EPEX SPOT and Nord Pool Spot; Spain and Portugal, since May 2014; and Italy, France, Austria and Slovenia, since February 2015. They analysed the effects of implicit market coupling on typical products traded on energy exchanges such as futures, options on futures, hourly power forward curves, and virtual power plants. They did this by constructing a supply-demand model for coupled electricity markets, where demand is inelastic (horizontal) and has to be satisfied at all times, supply is determined by the summation of capacity usage of the various generators according to their input fuel prices and the markets are interconnected. They used their model to investigate the effects of market coupling for France and Germany. Although prices generated by the model followed the pattern of historical prices, the latter demonstrated higher variation, which highlights the challenges in modelling interconnected markets. The authors made two interesting conclusions: first, introducing market coupling might lead to lower futures prices in all affected markets, with increasing interconnector capacity finally leading to price convergence; and second, introducing market coupling might lead to volatility spillover effects, with the low-volatility market likely to experience increased volatility. The latter is in line with observations by Zareipour *et al.* (2007) concerning interconnected North American electricity markets, as the authors showed volatility progressing in the direction of the smaller Canadian markets. Other studies of connected continental markets have also noted the role of the larger and more liquid German market in transmitting its price volatility in the region (e.g. de Menezes and Houllier, 2015).

The limitation of interconnection capacity between EU countries and its role in obstructing market integration is a recurring consideration in the literature. Gebhardt and Hoffler (2013), for example, acknowledged that the integration of European electricity markets was still work in progress, and examined the question of whether price differences were caused by limited interconnector capacities or also by lack of cross-border competition. Their approach aimed to assess the extent to which price differences stem from limited participation in cross-border trade. Using the concept of a rational expectations equilibrium, they derived a theoretical integration benchmark, which they compared to data from European electricity markets. The market integration hypothesis was rejected and their findings indicate that well-informed traders were not engaging in cross-border trade.

Expanding their work on the benefits of electricity market integration in Latin American markets, Ochoa and van Ackere (2015b), used their system-dynamics model on the UK-France interconnection and found considerable differences from the Colombia-Ecuador case that they had studied earlier. They attributed these to differences in generation mix (nuclear and hydro in France, coal and gas in the UK, hydro predominant in both Colombia and Ecuador). In addition, UK and France are more mature markets, with slow demand growth and adequate capacity margins. Since then, of course, the UK energy mix has changed considerably, with nuclear, gas, wind and even solar having displaced coal as a source of baseload generation, but with coal being maintained as a backup option with the help of capacity payments.

Regional interconnection was also at the centre of work by Ciarreta and Zarraga (2015) who assessed electricity market integration between spot markets in Spain, Portugal, Austria, Germany, Switzerland and France between 2007 and 2012. They used GARCH models to estimate spillovers and price convergence, which were then used as indicators of market integration. They concluded that the target of achieving a single electricity market depends largely on increasing interconnections and efficient rules of market operation, since they found evidence of increasing price convergence and stronger price correlation between the market pairs of Spain-Portugal, Germany-Austria and Switzerland-Austria.

Studies of Common Price Dynamics with Input Fuels

Since it has been argued that in European electricity markets, common long-run price dynamics might reflect the cost of generation in the region, several authors assessed the association between fuel sources and electricity prices (Serletis and Herbert, 1999; Gjølberg and Johnsen, 2001; Emery and Liu, 2002; e.g. Asche, Osmundsen and Sandsmark, 2006; Bosco *et al.*, 2006, 2010; Sensfuß, Ragwitz and Genoese, 2008; Roques, Newbery and Nuttall, 2008; Mjelde and Bessler, 2009; Mohammadi, 2009; Kalantzis and Milonas, 2010; Bollino, Ciferri and Polinori, 2013). In this spirit, a more recent study, Castagneto-Gissey (2014), analysed electricity and carbon prices in the year-ahead energy markets during ETS Phase II. He observed that electricity prices in the EU can be driven by coal prices, but also that generators may excessively charge for the cost of carbon. According to his analysis, prices in the German market and Nord Pool increased 35% above the competitive threshold, given a unit increase in costs. Although prices could have reflected generation with greater emissions, he argued that generators might have pushed for higher electricity prices. Market power may, therefore, moderate the associations between fuel and electricity prices in European markets.

De Menezes, Houllier and Tamvakis (2016) also considered the potential impact of fuel inputs on the integration of European electricity markets. Using daily peak and base-load electricity spot prices from December 2005 to October 2013 from the British, French and Nord Pool markets, the associations between electricity spot prices with neighbouring electricity spot markets and fuel input prices were examined. The authors argued that the time-varying nature of the electricity price series were such that there were periods of mean reversion as well as periods of non-stationarity. Hence, the method to analyse co-movements should reflect these characteristics of the data. Indeed, estimates of localized autocorrelation functions confirmed that EU electricity spot prices were characterized by local non-stationarity, and illustrated that such periods could be linked with inputs to electricity generation. Moreover, British electricity spot prices were found to move with fuel prices and thus the British electricity market was mostly decoupled from the continental European markets, while in the French and Nord Pool day-ahead markets price movements were correlated with interconnected electricity markets. Overall, the electricity mix was shown to be linked to spot price behaviour and, in turn, can impact market integration.

On the Implications of Renewables

As Renewable Energy Directives increased the pressure on EU nations to increase their renewable generation, the challenge to incorporate these new, often non-continuous, energy sources increased as well. Several scholars turned their attention to the impact of RES-E on social welfare, price dynamics and market integration. As Cochran *et al.* (2012) argued in their report on best practices based on the history of different countries on integration of renewables, there is no universal approach. Yet, critical factors for success could be identified, for example: public engagement, particularly new transmission; coordinated planning; the development of market rules that support system flexibility and access to diverse resources; and improvements in system operation. For example, Oggioni *et al.* (2014) and Neuhoff et al. (2013) investigated different wind integration policies, by using simulation models of policies for dispatch and transmission capacity. Together, their findings suggest that, with high wind power penetration, priority dispatch is in detriment of electricity market integration. Although nodal pricing could make better use of existing transmission capacities, it was argued that this was unlikely to be sustainable under priority dispatch. Hence, their findings highlighted a need for wind power and solar generation to be subject to market signals.

A side-effect of increasing intermittent RES-E on wholesale electricity markets is an increase in day-ahead and intra-day price volatility, since the merit-order curve changes significantly between high- and- low wind scenarios. Different studies have therefore stressed the need for secure reserve capacity (e.g. Henriot and Glachant, 2013), especially since more expensive generators are more likely to face lower load factors (Cludius *et al.*, 2014). As observed by de Menezes and Houllier (2015), Aatola *et al.* (2013) might have been the first authors to consider RES-E policies in their assessment of electricity market convergence in Europe. Based on daily electricity and carbon forward price data from 2003 to 2011, they concluded that electricity market integration in Europe was increasing over time, and that carbon prices might have had a positive but uneven effect on integration.

Anaya and Pollitt (2014) explored trends in distributed generation across Germany, Denmark and Sweden. They focused on the regulation of renewable energy generation, grid access and connection mechanisms, and attributed the spread of distributed generation in these countries to the early support given to the expansion of renewable energy generation within their respective national policies. Germany and Denmark were countries with the most sophisticated and evolving support schemes, with Germany having the most favourable connection regime that prioritised connection and dispatch. Sweden, by contrast, treated equally different technologies. High connection costs were observed and, as network upgrade costs were shared across customers, policies that avoided unnecessary costs in expanding the distributed generation were needed. Accordingly, smart technologies, combined with new business models, should be considered in the context of interconnected markets in order to enable efficient use of the distribution infrastructure.

Tangerås (2015) developed a theoretical model of a multinational electricity market with transmission investment in order to analyse the effect of RES-E policies on market integration and national policy makers' incentives for implementing renewable policies. He concluded that goals of increased RES-E production and market integration can oppose one another when implementation is decentralised. He argued that, if national policy makers choose RES-E support schemes to maximize domestic welfare, a trade policy incentive operates independently of any direct benefit of renewable electricity. His model predicts electricity importing (exporting) countries to choose policies which reduce (increase) electricity prices, thus the pursuit of domestic objectives is inefficient as it distorts transmission investments and market integration. The added social benefit of additional transmission capacity may not be achieved. This inefficiency cannot be corrected by having national renewable targets, centralised subsidies to transmission investment as well as fewer and harmonised policy instruments, as for example an integrated certificates market for RES-E, are required to increase the efficiency in electricity markets and reduce the scope for local trade policy interference.

De Menezes and Houllier (2015) investigated electricity market integration before and after the closures of eight nuclear power plants that occurred within a period of a few months in Germany during 2011. Interrelationships of daily electricity spot prices, from November 2009 to October 2012, in APX-ENDEX, Belpex, EPEX-DE, EPEX-FR, Nord Pool, OMEL and Swissix and wind power in the German system were examined with the use of MGARCH models with dynamic correlations and fractional cointegration analysis. Changes in short and long run behaviours were analysed. Their results showed positive time-varying correlations between spot prices in markets with significant proportions of shared interconnector capacity and negative association between wind power penetration in Germany and electricity spot prices not only in the German market, but also in its neighbouring markets. In addition, in most markets, a decreasing speed in mean reversion of spot prices was observed, which led the authors to conclude that electricity market integration in the EU might have been affected by an isolated national policy that changed its electricity mix.

Horst Keppler *et al.* (2016) assessed the impact of renewable production and market coupling on the spread between French and German electricity prices, with the use of panel data regression models. They observed that, since renewable electricity production is concentrated on periods with favourable meteorological conditions and interconnection capacity between France and Germany is limited, increases in production of wind and solar PV in Germany resulted in increasing price-spreads between the two countries. Their estimates, based on a sample of French and German day-ahead hourly prices from November 2009 to June 2013, showed that RES-E production in Germany increased price divergence between the two markets, which however was mitigated by market coupling which has been in effect since 10

November 2010. Their findings, therefore, call for research on the optimal level of interconnection as well as further analysis that would include a larger number of countries.

Friesenbichler (2016) started from the principle that a single EU market for electricity does not exist and uses the fragmentation of the European electricity market as the background in order to examine cross-country variance in policy making. Germany showcases the promotion and diffusion of RES-E, which led to its exports increasingly causing difficulties in grid stability, i.e. imbalances between demand and supply and greater risk of outages. The author explored why other EU countries have not experienced such difficulties, by comparing German, Spanish and Danish policies and institutional arrangements and then linking the observed differences to differences in sectoral outcomes. These three countries were chosen because they financially promoted the diffusion of renewable technologies effectively leading to significant increases of RES-E in their electricity mix. His analysis underscores three cross-country differences. First, country size matters: Denmark successfully integrated volatile RES-E by compensating imbalances via the Nordic wholesale market, which is possible due to its size and open economy; by contrast, Germany and Spain have been less flexible in securing supply internationally. Secondly, the different designs of promotion instruments for RES-E: in Spain, the premium option required RES-E operators to meet pre-defined targets that mandated the management of systemic risks via balancing loads to RES-E generators, thus the system operator was exposed to less complexity which facilitated grid stability. Thirdly, differences in institutional architectures might have contributed to a reduction in coordination problems and thereby led to different outcomes; while Spain implicitly imposed the prioritisation of security of supply over other policy targets via its control agency, German policies are less coordinated and their flexibility can lead to conflicting priorities. Hence, the author concluded that his findings indicate the relevance of energy policy coordination and a common hierarchy in objectives at EU and national levels.

Karanfil and Li (2017) used hourly data covering the period from January 2012 to May 2014, to investigate the causal relationships among the price differences between the intraday and day-ahead markets, the deviations of wind generation, conventional generation, and total demand from their committed day-ahead levels, as well as cross-border electricity trades in the Nordic electricity market.. Their results, from VAR models and generalized impulse response (GIR) simulations, show that the wind and conventional generation forecast errors explain the price differentials between the two markets, and that the relative intraday price decreases with the unexpected amount of wind generation. Zonal differences were also detected. The authors noted that the Nordic intraday electricity market can be regarded as effective because causality between the intraday price signals and the market fundamentals could be established. They noted that although their analysis highlighted the practicality of an intraday market, they could not conclude that the market is optimal, since balancing costs and other data would be needed in a more comprehensive analysis. Nonetheless, their study showed that cross-border exchanges are important in handling wind power forecast errors, as in the case of Denmark intermittent production deviations are effectively reduced, because the forecast errors are jointly handled through the responses from demand, conventional generation, and intraday international electricity trade. This management of forecast errors is important since wind power forecasts, rather than the actual levels of wind power, have been shown to be positively correlated with electricity spot price volatility (de Menezes and Houllier, 2015). Indeed, their conclusions underline observations by Woo *et al.* (2016) concerning the potentially positive impact of improvements in wind power forecasting on electricity markets.

As EU markets are looking for cost-efficient ways to maintain system reliability and price competitiveness, interconnection and market coupling will need to accommodate innovations to manage demand response. Feuerrigel and Neumann (2016) argued that when integrated into electricity markets, demand response can be used for load shifting and as a replacement for both control reserve and balancing energy. They compared these three usage scenarios using historic German data from 2011 and observed that load shifting provides the highest benefit: its annual financial savings was estimated to be 3.1 billion euros for the household and the service sectors, and corresponded to savings of 2.83% compared to a scenario without load shifting. They concluded that reductions in bid sizes, delivery periods and the time-lag between transactions and delivery dates are needed to facilitate demand response, thus highlighting some design challenges and trade-offs that are faced by coupled EU electricity markets.

On the Current Status of Market Integration in Europe

The different streams of literature imply that full market integration is still work in progress. In fact, TenneT's Market Review 2016 (TenneT, 2016) reported that during the first month of the year, the CWE region had convergent prices, but subsequently prices diverged into two zones: a price region containing Germany and the Netherlands, and another including Belgium and France. According to the monthly average of day-ahead prices, in the first eight months of 2016, price differences between market areas in the CWE region were small, however in the last four months of 2016 the average price was approximately 54 €/MWh in Belgium and France, and 37 €/MWh in the Netherlands and Germany. Nevertheless, the report also underscored increases in hours of price convergence between many market areas in Europe from 2015 to 2016, which can be seen as a positive development for the integration of national electricity markets. In addition, the report shows that day-ahead electricity price volatilities in 2016 was on average comparable to 2015, which may suggest improvements in the management of renewable electricity generation. It is noteworthy that quarter-hourly products are traded in the intraday market and enable a better approximation of the real demand ramps and generation variability (e.g. from solar or wind power generation) than the hourly products at the more liquid day-ahead market. These products are especially important because imbalance settlement periods are on a quarter-hourly basis.

Comparatively higher electricity price volatility was observed in Great Britain. Possible explanations provided are a combination of heavy infrastructure maintenance, security of supply concerns following unplanned power plant closures, and the political turmoil of Brexit that devalued the British pound. The latter underscores the potential impact of isolated policies and the ongoing need for cooperation in connected markets, especially since the second and third highest volatilities were observed in the neighbouring Belgian and French day-ahead markets. These observations reinforce the conclusions of many studies that relate to the need of coordinated policies in EU electricity markets.

Summary of Findings and Implications

Overall, studies of electricity market integration imply that transmission capacity, interconnection and coordination between regions or countries can drive price convergence. However, price convergence is not always present, even within individual countries, such as Australia or the United States where there is one, or a small number of ISOs. In Europe, legislation, a common approach to regulation, and market coupling have achieved some level of price convergence. Nonetheless, most studies imply that full market integration is yet to be achieved and that the extent of convergence is time-varying. Several studies highlighted the shortfalls of explicit auctions of interconnection capacity and strongly recommended implicit auctions, eventually leading to market coupling, as well increased connectivity. Electricity prices appear to be responding to market coupling initiatives and increasing interconnector capacity, but studies also emphasise that short run dynamics can be very volatile and generation fuel prices may be responsible for the mixed findings on market integration.

Government targets for energy efficiency, carbon reduction and renewable generation have generated research interest into the various aspects of integrating increasing amounts of renewable sources, which are often interruptible and more difficult to predict. Although there seems to be consensus that renewables are the right pathway to controlling carbon emissions, high renewables penetration brings its own challenges. While the level of wholesale prices may be lower, volatility seems to increase. Increased interconnection is one way of dealing with the need to redirect increased amounts of renewable generation to neighbouring regions or countries. Interconnection, however, is only one of the building blocks of a reliable electricity system. Given the increasing penetration of renewable energy, system flexibility is paramount. For example, Nord Pool Spot operates both the Elspot day-ahead and the Elbas intraday markets mainly in the Nordic (Denmark, Finland, Norway, and Sweden) and Baltic (Estonia, Latvia and Lithuania) regions. In contrast to Elspot, where prices are settled through an hourly uniform-price auction after the day-ahead gate closure at 12:00 CET, Elbas is a continuous market where trading takes place from 14:00 CET on the day before the day of operation, and up to one hour before physical delivery. The intraday prices are set on a first-come, first-served basis, that is buyers and sellers choose directly the bids to be accepted in the market. A similar conclusion was reached for US regional markets, especially those which have set high renewable energy targets, such as California, or have high renewable generation, such as Texas. As a result, all US RTOs operate both day-ahead and real-time markets.

Even with increased interconnection capacity, market coupling and competitive electricity trading, large-scale penetration of renewables still brings challenges to system operability, reliability and security. Researchers increasingly point to the need for demand side management (or demand response) as a way of mitigating the weak predictability of renewable generation. Demand side response is also challenging, as much of the knowledge that has been acquired by system operators in forecasting load profiles that have led to very precise estimates of short-term aggregate demand may become less useful, especially in the context of interconnected markets.

While the jury may still be out on giving a verdict on the efficiency, effectiveness and social benefits of the various electricity market structures, operations and markets, we are faced with overhanging taxing issues and emerging fresh challenges. Of utmost urgency is the decarbonisation of the energy and electricity supply chain, while at the same time maintaining security of supply. There is no panacea on how this can be achieved and most countries are pragmatic about future technology pathways. For some countries switching away from imported fossil fuels to domestic or regional renewables may be a no-brainer, assuming investment in generation capacity, transmission and distribution is cost-efficient. Other countries will find it more difficult to adapt; existing thermal capacity offers reliability and security of supply, employment and the opportunity to generate profit (often from heavily depreciated assets) both in the domestic and cross-border markets.

Some countries have taken more definitive steps than others to tackle the issue of decarbonisation. Great Britain has committed to a combination of increased wind and solar, switch towards natural gas and away from coal (albeit with capacity payment made for backup generation during peak-load periods and winter months), and continuous commitment to nuclear generation with investment in new plants that may become too expensive given the decreasing costs of solar and even offshore wind power. Germany is continuing its path to energy transition (Energiewende), which has been expensive, but embraced by society and has led to local technological development. To do this, the country has had to rely on the rather odd combination of lignite, hard coal and renewables, but in more recent months it seems committed to a switch to natural gas, despite the political ramification this may have in terms of security of supply. At the same time, the country has also reformed its Renewable Energy Act (EEG), initially in 2014 and again in 2017. EEG 2014 cast aside the FIT system and sought to control how much renewable capacity is installed every year, while at the same time it introduced auctions for solar PV. Voss and Madlener (2017) looked at bidding strategies for the pilot auction scheme and concluded that it was possible to successfully award funding authorizations for renewable energy plants via an auction process. EEG 2017 goes a step further with the extension of renewable capacity auctions to wind (both onshore and offshore) and biomass, in addition to solar.

Denmark is a good example of a country with very ambitious targets of 100% renewables in heat and power by 2035 and 100% in all sectors by 2050. Denmark currently has the highest wind penetration in the world and has benefited from monetising its generation technology by selling it around the world. It relies, however, on its access to the interconnected Nordic market for its security of supply. Also, it is a relatively small market, approximately a tenth of the British electricity market and a twentieth of the German one.

As noted earlier, there is increased interest, and need, to harness a flexible demand side within the electricity system to match the uncertainty and, at the same time, inflexibility of renewables. In their discussion on how to integrate wind through changing the design of balancing and intraday market design, Borggrefe and Neuhoff (2011) suggest the use of six criteria: (a) facilitate system-wide intraday adjustments to respond to improving wind forecasts; (b) allow for the joint provision and adjustment of energy and balancing services; (c) manage the joint provision of power across multiple hours; (d) capture benefits from international integration of the power system; (e) integrate the demand side into intraday and balancing markets; and (f) effectively monitor market power. The authors point to the example of the market design for PJM (as well as the other US RTOs), where the system operator uses locational marginal pricing (LMP), centrally adjusts intraday dispatch close to real time, integrates demand side response and effectively monitors market power.

The dilution of market power could be one of the additional benefits brought by a higher participation of renewables in the energy mix. Renewables are to a large extend smaller scale projects, in comparison to conventional thermal generation assets. They, therefore, lend themselves to a more decentralised ownership by smaller financial units. For example, in Germany and Denmark distributed generation by smaller renewable units, such as wind, solar and biomass CHP, are positively encouraged. With an expanded portfolio of smaller renewable generation assets and a grid which is smart enough to handle both distributed and large-scale supply, demand response and interconnections, new business models and entrepreneurial opportunities may arise. Examples include: aggregators who can pool small-scale generation; demand response managers who can act on behalf of both large and small consumers, generate savings and be remunerated for balancing services; energy storage managers who can absorb excess supply from poorly-forecast renewables generation; electric vehicle (EV) fleet operators who not only offer transport services, but are effective managing 'moving' batteries which could be used for small-scale demand response; and IT-based companies offering managerial and system-operation services.

The above examples of new business models and opportunities increased competition in electricity markets requires the implicit assumption of increased market liquidity, lower transaction costs, and the reduction of market power exercised by incumbent large-scale generators. In their study of the effects of the diversification of energy portfolios on the merit order effect in an oligopolistic energy market, Acemoglu *et al.* (2017) showed that when thermal generators have a diverse energy portfolio, which includes some or all of the renewable supplies, they offset the price declines due to the merit order effect because they strategically reduce their conventional energy supplies when renewable supply is high. In Great Britain, decreasing wholesale market liquidity alarmed the regulator (Ofgem), who instituted a system of licence obligations, intended to help improve independent suppliers' access to the wholesale markets, and who also undertakes an annual review to assess the impact of the reforms and compliance of market participants (e.g. Ofgem, 2016). In Germany, the electricity market is also deemed to be liquid, but is this the case with other EU countries? The same could be said for many of the US RTOs, but is this the case for entire US electricity grid, given the limitations in interconnections? As for Asia-Pacific markets, liquidity is for the time being an aspiration, linked to future plans for increased interconnection, renewable generation and more active cross-border trading.

Ultimately, electricity markets are an integral part of the broader energy markets and the lines separating the two are increasingly blurred with technological advance. For example, transportation has remained largely separate to electricity markets, as all modes have traditionally relied on some form of liquid fossil fuels, whether gasoline, diesel, fuel oil or jet kerosene. Only electrified railways linked transportation with electricity. As car manufacturers are competing to bring more and more EVs to the average consumer, electricity (and how it is generated) is increasingly linked to transportation and this has already started to have implications for generation, distribution through specialised battery-charging infrastructure, randomness of demand and the possibility that EVs could also be used for energy storage purposes.

The issues highlighted offer a glimpse to the complexity of integrating electricity markets, in the face of rapidly changing energy markets, technologies which are likely to create disruption and the unabated pursuit of energy which is secure, affordable and sustainable. As some scholars have observed "there is no 'one-size-fits-all' recipe for all markets and all countries" (Bollino *et al.*, 2017, p. 2). With developments like the ones discussed above, common sense and good practice should point towards minimising complexity of market design to reduce transaction costs, improve liquidity, ensure market depth to reduce investment risk and keep attracting investment. At the same time, continuous intra-day trading provides the right environment for maximising the benefits from renewables integration, greater energy efficiency, and the resultant decarbonisation of the world economy.

References

Aatola, P., Ollikainen, M. and Toppinen, A. (2013) 'Impact of the carbon price on the integrating European electricity market', *Energy Policy*, 61, pp. 1236–1251. doi: 10.1016/j.enpol.2013.06.036.

Acemoglu, D., Kakhbod, A. and Ozdaglar, A. (2017) 'Competition in Electricity Markets with Renewable Energy Sources', *The Energy Journal*, 38(1). doi: 10.5547/01956574.38.SI1.dace.

Ahmed, T. *et al.* (2017) 'ASEAN power grid: A secure transmission infrastructure for clean and sustainable energy for South-East Asia', *Renewable and Sustainable Energy Reviews*, 67, pp. 1420–1435. doi: 10.1016/j.rser.2016.09.055.

Anaya, K. L. and Pollitt, M. (2014) *Integrating Distributed Generation: Regulation and Trends in Three Leading Countries*. 1423.

Apergis, N., Fontini, F. and Inchauspe, J. (2017) 'Integration of regional electricity markets in Australia: A price convergence assessment', *Energy Economics*, 62, pp. 411–418. doi: 10.1016/j.eneco.2016.06.022.

Asche, F., Osmundsen, P. and Sandsmark, M. (2006) 'The UK Market for Natural Gas, Oil and Electricity: Are the Prices Decoupled?.', *Energy Journal*, 27(2), pp. 27–40. Available at: http://0-search.ebscohost.com.wam.city.ac.uk/login.aspx?direct=true&db=bth&AN=20533606&site=ehost-live.

Australian Government Clean Energy Regulator (2016) *About the Renewable Energy Target*. Available at: http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target (Accessed: 11 July 2017).

Autran, L. (2012) *Convergence of day-ahead and futures prices in the context of European power market coupling*. KTH.

Bannister, H. *et al.* (2008) *Energy Market Integration in the East Asia Summit Region*. REPSF II Project No. 07/005. Jakarta: ASEAN Secretariat.

Battle, C. (2013) 'Towards a Better Integration of the EU Electricity Market (Conference Presentation Online)', in *Berlin Conference on Electricity Economics: Modelling and Policy in Energy Transformation - Germany, Europe, and Beyond*. Berlin: DIW - https://youtu.be/Hrr8kqeC_Bs.

Bell, W. P. *et al.* (2015) 'Wind speed and electricity demand correlation analysis in the Australian National Electricity Market: Determining wind turbine generators' ability to meet electricity demand without energy storage', *Economic Analysis and Policy*, 48, pp. 182–191. doi: 10.1016/j.eap.2015.11.009.

Boffa, F. and Scarpa, C. (2009) 'An Anticompetitive Effect of Eliminating Transport Barriers in Network Markets', *Review of Industrial Organization*. Springer US, 34(2), pp. 115–133. doi: 10.1007/s11151-008-9198-4.

Boisseleau, F. (2004) *The role of power exchanges for the creation of a single European electricity market : market design and market regulation*. Delft University Press. Available at: https://inis.iaea.org/search/search.aspx?orig_q=RN:35039055 (Accessed: 3 July 2017).

Bollino, C. A. *et al.* (2017) 'Forward to the Special Issue on Renewables and Diversification in Heavily Energy Subsidized Economies', *The Energy Journal*. International Association for Energy Economics, 38(1). doi: 10.5547/01956574.38.SI1.cbol.

Bollino, C. A., Ciferri, D. and Polinori, P. (2013) *Integration and convergence in European electricity markets*. Università di Perugia, Dipartimento Economia. doi: DOI:

Borggrefe, F. and Neuhoff, K. (2011) *Balancing and Intraday Market Design: Options for Wind Integration*. 1162. Berlin: DIW. Available at: https://www.diw.de/documents/publikationen/73/diw_01.c.387225.de/dp1162.pdf.

Bosco, B. *et al.* (2006) *Deregulated Wholesale Electricity Prices in Europe*. Università degli Studi di Milano-Bicocca, Dipartimento di Statistica. doi: DOI:

Bosco, B. *et al.* (2010) 'Long-run relations in European electricity prices', *Journal of Applied Econometrics*. John Wiley & Sons, Ltd., 25(5), pp. 805–832. doi: 10.1002/jae.1095.

Bower, J. (2002) *Seeking the single European electricity market : evidence from an empirical analysis of wholesale market prices*. Oxford. Available at: https://ora.ox.ac.uk/objects/uuid:b3aa59b6-4c86-4aef-8b0a-db4bb66173ae (Accessed: 3 July 2017).

Bunn, D. W. and Gianfreda, A. (2010) 'Integration and shock transmissions across European electricity forward markets', *Energy Economics*, 32(2), pp. 278–291. doi: 10.1016/j.eneco.2009.09.005.

Castagneto-Gissey, G. (2014) 'How competitive are EU electricity markets? An assessment of ETS Phase II', *Energy Policy*, 73, pp. 278–297. doi: 10.1016/j.enpol.2014.06.015.

Chang, Y. and Li, Y. (2015) 'Renewable energy and policy options in an integrated ASEAN electricity market: Quantitative assessments and policy implications', *Energy Policy*, 85, pp. 39–49. doi: 10.1016/j.enpol.2015.05.011.

Ciarreta, A. and Zarraga, A. (2015) 'Analysis of mean and volatility price transmissions in the MIBEL and EPEX electricity spot markets', *Energy Journal*, 36(4), pp. 41–60. doi: 10.5547/01956574.36.4.acia.

Cludius, J. *et al.* (2014) 'The merit order effect of wind and photovoltaic electricity generation in Germany 2008–2016: Estimation and distributional implications', *Energy Economics*, 44, pp. 302–313. doi: 10.1016/j.eneco.2014.04.020.

Cochran, J. *et al.* (2012) *Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience*.

Creti, A., Fumagalli, E. and Fumagalli, E. (2010) 'Integration of electricity markets in Europe: Relevant issues for Italy', *Energy Policy*, 38(11), pp. 6966–6976. doi: 10.1016/j.enpol.2010.07.013.

Cutler, N. J. *et al.* (2011) 'High penetration wind generation impacts on spot prices in the Australian national electricity market', *Energy Policy*, 39(10), pp. 5939–5949. doi: 10.1016/j.enpol.2011.06.053.

EIA (2017) *What is US electricity generation by energy source?* Available at: https://www.eia.gov/tools/faqs/faq.php?id=427&t=3 (Accessed: 11 July 2017).

Emerson, M. *et al.* (1988) *The economics of 1992: The EC Commission's assessment of the economic effects of completing the internal market*. Available at: http://ec.europa.eu/economy_finance/publications/pages/publication7412_en.pdf (Accessed: 10 July 2017).

Emery, G. W. and Liu, Q. (Wilson) (2002) 'An analysis of the relationship between electricity and natural-gas futures prices', *Journal of Futures Markets*. John Wiley & Sons, Inc., 22(2), p. 95. doi: 10.1002/fut.2209.

European Commission (2016) *Communication from the Commission to the European Parliament, the Council, The European Economic and Social Committee, the Committee of the Regions and the European Investment Bank: Clean Energy for All Europeans*. COM(2016) 860 Final. European Union: European Commission. Available at: http://eur-lex.europa.eu/resource.html?uri=cellar:fa6ea15b-b7b0-11e6-9e3c-01aa75ed71a1.0001.02/DOC_1&format=PDF (Accessed: 10 July 2017).

Feuerriegel, S. and Neumann, D. (2016) 'Integration scenarios of Demand Response into electricity markets: Load shifting, financial savings and policy implications', *Energy Policy*, 96, pp. 231–240. doi: 10.1016/j.enpol.2016.05.050.

Finon, D. and Romano, E. (2009) 'Electricity market integration: Redistribution effect versus resource reallocation', *Energy Policy*, 37(8), pp. 2977–2985. doi: 10.1016/j.enpol.2009.03.045.

Friesenbichler, K. S. (2016) 'Policy interaction and the integration of volatile renewable energy', *Environmental Economics and Policy Studies*, 18(2), pp. 193–211. doi: 10.1007/s10018-015-0130-5.

Galli, A. and Armstrong, M. (2003) *Comparing the spot prices from Powernext and EEX*. Available at: https://inis.iaea.org/search/search.aspx?orig_q=RN:37095431 (Accessed: 4 July 2017).

Gebhardt, G. and Höffler, F. (2007) 'How to Determine Whether Regional Markets are Integrated? Theory and Evidence from European Electricity Markets', *SSRN Electronic Journal*. doi: 10.2139/ssrn.1074983.

Gebhardt, G. and Höffler, F. (2013) 'How Competitive is Cross-border Trade of Electricity? Theory and Evidence from European Electricity Markets', *The Energy Journal*, 34(1). doi: 10.5547/01956574.34.1.6.

Gil, H. A. and Lin, J. (2013) 'Wind Power and Electricity Prices at the PJM Market', *IEEE Transactions on Power Systems*, 28(4), pp. 3945–3953. doi: 10.1109/TPWRS.2013.2260773.

Gjølberg, O. and Johnsen, T. (2001) *Electricity futures: Inventories and price relationships at Nord Pool*.

Hand, M. M. *et al.* (eds) (2012) *Renewable Electricity Futures Study*. NREL/TP-6A. Golden, CO: National Renewable Energy Laboratory. Available at: http://www.nrel.gov/analysis/re_futures/.

Henriot, A. and Glachant, J.-M. (2013) 'Melting-pots and salad bowls: The current debate on electricity market design for integration of intermittent RES', *Utilities Policy*, 27, pp. 57–64. doi: 10.1016/j.jup.2013.09.001.

Von Hirchhausen, C. and Zachmann, G. (2009) 'Ensuring EU Enlargement to New Member States', in Glachant, J.-M. and Lévêque, F. (eds) *Electricity Reform in Europe: Towards a Single Energy Market*. Cheltenham, UK & Northampton, USA: Edward Elgar Publishing Ltd, pp. 105–141.

Horst Keppler, J., Phan, S. and Le Pen, Y. (2016) 'The Impacts of Variable Renewable Production and Market Coupling on the Convergence of French and German Electricity Prices', *The Energy Journal*. International Association for Energy Economics, 37(3). doi:

10.5547/01956574.37.3.jkep.

Huisman, R. and Kiliç, M. (2013) 'A history of European electricity day-ahead prices', *Applied Economics*. Routledge, 45(18), pp. 2683–2693. doi: 10.1080/00036846.2012.665601.

Joskow, P. L. and Schmalensee, R. (1983) *Markets for Power: An Analysis of Electric Utility Deregulation*. Cambridge, Mass.: MIT Press.

Kalantzis, F. and Milonas, N. T. (2010) 'Market integration and price dispersion in the European electricity market', in *Energy Market (EEM), 2010 7th International Conference on the European IEEE*, pp. 1–6.

Karanfil, F. and Li, Y. (2017) 'The Role of Continuous Intraday Electricity Markets: The Integration of Large-Share Wind Power Generation in Denmark', *The Energy Journal*, 38(2). doi: 10.5547/01956574.38.2.fkar.

Kiesel, R. and Kusterman, M. (2016) 'Structural models for coupled electricity markets', *Journal of Commodity Markets*, 3(1), pp. 16–38. doi: 10.1016/j.jcomm.2016.07.007.

Krishnaswamy, V. (2007) *Potential and prospects for regional energy trade in the South Asia Region*. Washington, DC: World Bank. Available at: http://documents.worldbank.org/curated/en/985241468170700557/Potential-and-prospects-for-regional-energy-trade-in-the-South-Asia-Region (Accessed: 6 July 2017).

MacGill, I. (2010) 'Electricity market design for facilitating the integration of wind energy: Experience and prospects with the Australian National Electricity Market', *Energy Policy*, 38(7), pp. 3180–3191. doi: 10.1016/j.enpol.2009.07.047.

Mai, T. *et al.* (2014) 'Envisioning a renewable electricity future for the United States', *Energy*, 65, pp. 374–386. doi: 10.1016/j.energy.2013.11.029.

Markusen, J. R. (1981) 'Trade and the gains from trade with imperfect competition', *Journal of International Economics*, 11(4), pp. 531–551. doi: 10.1016/0022-1996(81)90033-7.

Marshall, J. F. (2000) *Dictionary of financial engineering*. Wiley.

de Menezes, L. M. and Houllier, M. A. (2015) 'Germany's nuclear power plant closures and the integration of electricity markets in Europe', *Energy Policy*, 85, pp. 357–368. doi: 10.1016/j.enpol.2015.05.023.

de Menezes, L. M. and Houllier, M. A. (2016) 'Reassessing the integration of European electricity markets: A fractional cointegration analysis', *Energy Economics*, 53, pp. 132–150. doi: 10.1016/j.eneco.2014.10.021.

de Menezes, L. M., Houllier, M. A. and Tamvakis, M. (2016) 'Time-varying convergence in European electricity spot markets and their association with carbon and fuel prices', *Energy Policy*, 88, pp. 613–627. doi: 10.1016/j.enpol.2015.09.008.

Mjelde, J. W. and Bessler, D. A. (2009) 'Market integration among electricity markets and their major fuel source markets', *Energy Economics*, 31(3), pp. 482–491. doi: 10.1016/j.eneco.2009.02.002.

Mohammadi, H. (2009) 'Electricity prices and fuel costs: Long-run relations and short-run dynamics', *Energy Economics*, 31(3), pp. 503–509. doi: 10.1016/j.eneco.2009.02.001.

Nepal, R. and Foster, J. (2016) 'Testing for Market Integration in the Australian National Electricity Market', *Energy Journal*. Charles Darwin U, 37(4), pp. 215–237. Available at: http://www.iaee.org/en/publications/journal.aspx.

Neuhoff, K. *et al.* (2013) 'Renewable electric energy integration: Quantifying the value of design of markets for international transmission capacity', *Energy Economics*, 40, pp. 760–772. doi: 10.1016/j.eneco.2013.09.004.

Ochoa, C. and van Ackere, A. (2015a) 'Does size matter? Simulating electricity market coupling between Colombia and Ecuador', *Renewable and Sustainable Energy Reviews*, 50, pp. 1108–1124. doi: 10.1016/j.rser.2015.05.054.

Ochoa, C. and van Ackere, A. (2015b) 'Winners and losers of market coupling', *Energy*, 80, pp. 522–534. doi: 10.1016/j.energy.2014.11.088.

Ochoa, C., Dyner, I. and Franco, C. J. (2013) 'Simulating power integration in Latin America to assess challenges, opportunities, and threats', *Energy Policy*, 61, pp. 267–273. doi: 10.1016/j.enpol.2013.07.029.

Ofgem (2016) *Wholesale Power Market Liquidity: Annual Report 2016*. Available at: https://www.ofgem.gov.uk/system/files/docs/2016/08/wholesale_power_market_liquidity_annual_report_2016.pdf.

Oggioni, G., Murphy, F. H. and Smeers, Y. (2014) 'Evaluating the impacts of priority dispatch in the European electricity market', *Energy Economics*, 42, pp. 183–200. doi: 10.1016/j.eneco.2013.12.009.

Oseni, M. O. and Pollitt, M. (2016) 'The promotion of regional integration of electricity markets: Lessons for developing countries', *Energy Policy*, 88, pp. 628–638. doi: 10.1016/j.enpol.2015.09.007.

Park, H., Mjelde, J. W. and Bessler, D. A. (2006) 'Price dynamics among U.S. electricity spot markets', *Energy Economics*, 28(1), pp. 81–101. doi: 10.1016/j.eneco.2005.09.009.

Pellini, E. (2012) 'Measuring the impact of market coupling on the Italian electricity market', *Energy Policy*, 48, pp. 322–333. doi: 10.1016/j.enpol.2012.05.029.

Phillips, P. C. B. and Sul, D. (2007) 'Transition Modeling and Econometric Convergence Tests', *Econometrica*. Blackwell Publishing Ltd, 75(6), pp. 1771–1855. doi: 10.1111/j.1468-0262.2007.00811.x.

Phillips, P. C. B. and Sul, D. (2009) 'Economic transition and growth', *Journal of Applied Econometrics*. John Wiley & Sons, Ltd., 24(7), pp. 1153–1185. doi: 10.1002/jae.1080.

Roques, F. A., Newbery, D. M. and Nuttall, W. J. (2008) 'Fuel mix diversification incentives in liberalized electricity markets: A Mean–Variance Portfolio theory approach', *Energy Economics*, 30(4), pp. 1831–1849. doi: 10.1016/j.eneco.2007.11.008.

Sensfuß, F., Ragwitz, M. and Genoese, M. (2008) 'The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany', *Energy Policy*, 36(8), pp. 3086–3094. doi: 10.1016/j.enpol.2008.03.035.

Serletis, A. and Herbert, J. (1999) 'The message in North American energy prices', *Energy Economics*, 21(5), pp. 471–483. doi: 10.1016/S0140-9883(99)00015-8.

Tangerås, T. P. (2015) 'Renewable Electricity Policy and Market Integration', *The Energy Journal*, 36(4), pp. 331–353. doi: 10.5547/01956574.36.4.ttan.

TenneT (2016) *Market Review 2016: Electricity Market Insights*. Available at: https://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/Dutch/2016_Market_Review_TenneT.pdf.

Turvey, R. (2006) 'Interconnector economics', *Energy Policy*, 34(13), pp. 1457–1472. doi: 10.1016/j.enpol.2004.11.009.

De Vany, A. S. and Walls, W. D. (1999) ‘Cointegration analysis of spot electricity prices: insights on transmission efficiency in the western US’, *Energy Economics*, 21(5), pp. 435–448. doi: 10.1016/S0140-9883(99)00019-5.

Voss, A. and Madlener, R. (2017) ‘Auction Schemes, Bidding Strategies and the Cost-Optimal Level of Promoting Renewable Electricity in Germany’, *The Energy Journal*, 38(1). doi: 10.5547/01956574.38.SI1.avos.

Weber, A., Graeber, D. and Semmig, A. (2010) ‘Market Coupling and the CWE Project’, *Zeitschrift für Energiewirtschaft*. Vieweg Verlag, 34(4), pp. 303–309. doi: 10.1007/s12398-010-0033-x.

Woo, C. K., Horowitz, I., *et al.* (2011) ‘The impact of wind generation on the electricity spot-market price level and variance: The Texas experience’, *Energy Policy*, 39(7), pp. 3939–3944. doi: 10.1016/j.enpol.2011.03.084.

Woo, C. K., Zarnikau, J., *et al.* (2011) ‘Wind generation and zonal-market price divergence: Evidence from Texas’, *Energy Policy*, 39(7), pp. 3928–3938. doi: 10.1016/j.enpol.2010.11.046.

Woo, C. K. *et al.* (2013) ‘The Impact of Wind Generation on Wholesale Electricity Prices in the Hydro-Rich Pacific Northwest’, *IEEE Transactions on Power Systems*, 28(4), pp. 4245–4253. doi: 10.1109/TPWRS.2013.2265238.

Woo, C. K. *et al.* (2016) ‘Merit-order effects of renewable energy and price divergence in California’s day-ahead and real-time electricity markets’, *Energy Policy*, 92, pp. 299–312. doi: 10.1016/j.enpol.2016.02.023.

Worthington, A. C. and Higgs, H. (2017) ‘The impact of generation mix on Australian wholesale electricity prices’, *Energy Sources, Part B: Economics, Planning, and Policy*. Taylor & Francis, 12(3), pp. 223–230. doi: 10.1080/15567249.2015.1060548.

Wu, Y. (2013) ‘Electricity market integration: Global trends and implications for the EAS region’, *Energy Strategy Reviews*, 2(2), pp. 138–145. doi: 10.1016/j.esr.2012.12.002.

Zachmann, G. (2008) ‘Electricity wholesale market prices in Europe: Convergence?’, *Energy Economics*, 30(4), pp. 1659–1671. doi: 10.1016/j.eneco.2007.07.002.

Zachmann, G. (2009) ‘The EU Integration of the New Member States’ Electricity Markets – Testing for Wholesale Price Convergence Using the Kalman Filter’, in Glachant, J.-M. and Lévêque, F. (eds) *Electricity Reform in Europe: Towards a Single Energy Market*. Cheltenham, UK & Northampton, USA: Edward Elgar Publishing Ltd, pp. 269–288.

Zareipour, H., Bhattacharya, K. and Cañizares, C. A. (2007) ‘Electricity market price volatility: The case of Ontario’, *Energy Policy*, 35(9), pp. 4739–4748. doi: 10.1016/j.enpol.2007.04.006.