Chapter 3

Business Model and Market Design for ASEAN Electricity Market Integration: Principles, Practicalities, and Conditions for Success

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Chapter 3

Business Model and Market Design for ASEAN Electricity Market Integration: Principles, Practicalities, and Conditions for Success

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Since the announced construction of an integrated ASEAN Power Grid (APG) almost 2 decades ago, progress in this ambitious project has been slow. Coincidentally, a similar programme in the European Union (EU) has been fully embraced and has moved well ahead that of the Association of Southeast Asian Nations (ASEAN). As the EU has the most integrated electricity market at present, its experience and lessons on electricity market integration have important implications for ASEAN. This chapter aims to investigate the barriers, especially institutional and political barriers, to electricity market integration in ASEAN. It also discusses practical policy options to accelerate market integration in the ASEAN power sector and the most significant aspects of design, including market coupling arrangements and algorithms, congestion management and capacity auction methods, coordination mechanism and relevant network code among transmission system operators (TSOs) for grid balancing, and auxiliary services and compensation for such services. This chapter discusses these issues by referencing the Nordic and European experiences. Major standing problems and challenges of the European electricity market model are also briefly discussed.

1. Background

At present, the European electricity market liberalisation represents the world's most extensive cross-jurisdiction reform of the electricity sector, involving integration of distinct state-level or national electricity markets (Jamasb and Pollitt, 2005). The energy market liberalisation process in Europe has always focused on electricity market integration and related cross-border issues. The vision of the European Union (EU) was based on an aspiration to create an integrated energy market that ensures cost-effective, secure, and affordable electricity supplies to EU citizens. Over the last two decades, Europe's energy policy has consistently been geared toward producing affordable and competitively priced, environmentally sustainable, and secure energy for everybody in the EU. In 2011, the heads of European states or governments recognised the importance of an internal energy market and set a clear deadline for its completion by 2014, underlining the endeavour that no EU member state should remain isolated from the European gas and electricity networks after 2015 (European Commission, 2012).

It is not difficult to visualise how the intended integrated electricity market would make it possible to produce energy in one EU country and deliver it to consumers in another through common energy market rules and cross-border infrastructure. Additionally, this process intends to keep electricity prices in check by creating competition and giving consumers choices of their energy supplier.

2. History of Development

Europe took the very early steps of market liberalisation more than two decades ago when nine of its member states signed The Single European Act on 17 February 1986, with an aim of creating a single European market (internal) by 1992. The actual liberalisation process, however, started in 1997 with the adoption of Directive 96/92/EC, which defined common rules for the gradual liberalisation of the electricity industry within the scope of the concept of a unique European market as later defined in 1985 (Boisseleau, 2004).

In a nutshell, the ultimate objective of the directive was to create one common European electricity market and increase transmission capacity between regional electricity grids. Previous studies have argued about an understandable consensus of the highest priority to 'encourage cross-border trade' and 'eliminate discriminatory practices' without going much further in details of market design (Boisseleau, 2004). However, the lack of common guidelines on market design, arrangement, and institutions needed to create an integrated market led to a wide range of trading arrangements in each member state.

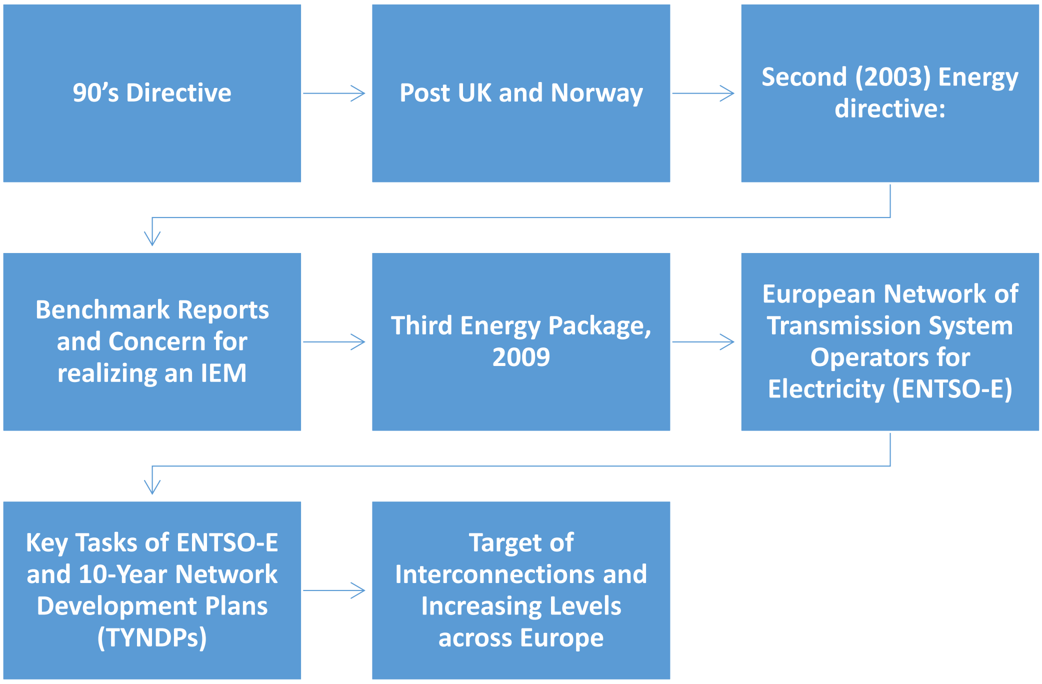
To this end, the liberalisation of electricity market in Europe started with the UK in 1998 when it stepwise opened an electricity market aimed at giving consumers full choice of suppliers. The two kinds of market that emerged were power pools and exchanges. Power pools were public or government initiative for electricity trading that required mandatory participation by all members. Exchanges, on the other hand, were created with an organised market of generators, distributors, and traders as voluntary participants.

Thus, during the liberalisation process in the UK, power pools were expected to stimulate competition in the wholesale market by defining clearing prices on the basis of supply bids and demand forecasts by the National Grid[1]. Replacing the old pool model, the New Electricity Trading Arrangements was established in 2001 and consisted of four voluntary markets: a bilateral market for long-term transactions, a forward market for standardised products, a

[1] The National Grid was owned by twelve regional electricity companies created as a result of reorganisation of area boards.

spot market, and a reserve market. The establishment of this system contributed to a fall in electricity prices for consumers from 2001 to 2004, although prices started rising again in 2005 due to other certain reasons. With the trading arrangements extended to include the Scottish market in 2005 and the British Electricity Trading and Transmission Arrangements recently, the entire UK is now coordinated by one wholesale market (Weight, 2009).

Figure 3.1: Chronology of Events – History of Market Development



IEM = Internal Energy Market, UK = United Kingdom.
Source: Authors.

The Norwegian market was the second to be fully liberalised in Europe (Weight, 2009) in a process that included both reforms and restructuring. While the core element of reform was a decentralised free trade approach, the restructuring included the transfer of the transmission system from a state-owned company (Statkraft) to a new state-owned company (Statnett) while the remaining generation facilities were reorganised to stay with the former. Other substantial reforms included the introduction of a common carrier approach and grid access for third parties, retail liberalisation, and the establishment of voluntary wholesale markets. What made the Norwegian market liberalisation process different from the UK's was the presence of a spot market even before liberalisation. This market was established to facilitate better management of the occasional source of the country's large hydro-generation capacities. In addition, the post-liberalisation spot market Nordpool was opened to allow long-term transactions for market participants.

Again, unlike in the UK, the liberalisation process in the Norwegian market focused on creating market competitions through structural reforms, ownership being a petty concern under the strategy adopted: public ownership of generation facilities remained and generation and supply were not separated. A common Nordic market was formed when other Nordic countries integrated their electricity sectors into one. Sweden joined in 1996, Finland in 1998, Western Denmark in 1999, and Eastern Denmark in 2000. Nordpool was jointly owned by the transmission system operators (TSOs) of the participating Nordic countries: Energinet (Denmark), Fingrid (Finland), Statnett (Norway), and Svenska Kraftnät (Sweden).

The Nordic market was the first to introduce a combination of energy and transmission capacity auctioning. Elspot, a day-ahead cornerstone market in Nordpool, takes care of auctions on a daily basis. Hourly supply and demand bids for the next day are aggregated and matched, generating a market clearing price or system price. If there is no transmission congestion, electricity is traded at system price (Fridolfsson and Tangerås, 2008).

In case of a cross-border congestion signal by a TSO, the bids in the market are allocated to several congestion areas predefined by country borders (in the case of Norway, up to four congestion areas or zones). A different price, called zonal price, is defined for each area or zone although it differs in countries. In the case of Sweden, prices are not allowed to differ in different regions, and holdups are handled by countertrading and/or re-dispatching of power plants). Transmission from one area to another is priced with the difference of the area prices. Congestion within one area is managed through countertrading and re-dispatching of power plants. The resulting congestion rent is split between TSOs.

As evident in both cases, early reforms in the electricity market of Europe in the 1990s included liberalisation, privatisation, and restructuring of the energy supply and distribution industry. The EU has since then been actively engaged in developing a strategic policy for the development of a truly competitive, single, and integrated European electricity and gas market that is expected to open competition among Europe-wide companies. The EU's reform process was mostly dependent on the driving force of the European Commission (EC).

Reform after the directive of the 1990s ran on two parallel tracks. First, under the EU Electricity Market Directives, member countries were required to take at least a minimum set of steps by certain key dates to liberalise their national markets, e.g. determine TSOs and distribution system operators (DSOs) responsible for operating, ensuring the maintenance of, and developing the transmission system in a given area and its interconnection with other systems to guarantee security of supply. Second, EC promoted efforts to improve interfaces between national markets by improving rules on cross-border trading and expanding cross-border transmission links (Tooraj and Pollitt, 2005).

It is important to note that the EU Electricity Market Directives of 1996 and 2003 were focused on unbundling the industry and gradually opening national markets. Over the years, several energy market laws have been adopted and efforts have gradually been shifted from energy market liberalisation to energy market integration.

A particular concern among policy makers related to the realisation of an integrated internal energy market (IEM) was regarding insufficient cross-border capacity and partly inefficient allocation mechanism. The Trans-European Energy Networks Program (TEN-E) started the liberalisation process. As the first directive did not address the issue of cross-border trade, Regulation 1228/2003 and Directive 2003/54/EC were issued to provide a framework for cross-border trade and establish more consistent trading.

While the common rules introduced by the first directive were clearly not effective enough to realise a single IEM, the second EU directive sought to further stimulate competition by fortifying regulation of access to networks and requiring the participation of independent regulators. Regulation of cross-border trade was aimed at facilitating market integration. The second directive's major objectives were (i) the unbundling of TSOs and DSOs from the rest of the industry, (ii) free entry to generation, (iii) monitoring of supply competition, (iv) full market opening, (v) promotion of renewable sources, (vi) strengthening the role of regulators, and (vii) a single European market (Tooraj and Pollitt, 2005).

TEN-E and Regulation 1228/2003 somehow built a framework for cross-border development. Considering interconnection, inter-operability, and development of trans-European networks for transporting energy (electricity and gas) as essential for effective operation of the internal energy market, TEN-E enumerated bottlenecks in need of clearing, provided co-financing of feasibility studies (around 50 percent of budget) (Meuss et al., 2005), and, to some extent, co-financed actual grid investment. The list was revised in 1997, 1999, and 2003. As required by Regulation 1228/2003, revenues from interconnections capacity allocations, called congestion revenues, were to be used for (1) guaranteeing the availability of capacity, (2) network investments, or (3) reducing network tariffs (Weigt, 2009).

Additionally, Directive 2003/54/EC required the member states to open their electricity markets and guarantee non-discriminatory network access to third parties while Directive 2009/72/EC put wider emphasis on cross-border interconnections and the need to mitigate barriers to cross-border trade. As a result, electricity markets across Europe experienced liberalisation, privatisation, and price deregulation in a bid to meet the energy policy goals and targets of sustainability, affordability, and security of supply.

The fourth benchmark report of EC in 2005 concluded that although states were moving in the right direction, some were rather slow in doing so, and eight of them received a warning from the commission. The 2005 report also found that although the market-based allocation of cross-border capacities should have been in place in 2004, 13 of the 25 most-congested connections had none of it (Meuss et al., 2005).

The benchmark report of EC in 2007 concluded that despite encouraging improvements, particularly in cross-border coordination, major barriers to achieving a single IEM still existed, including implementation of European legislation (which was insufficient), empowerment of national regulators, harmonisation of regulatory practices, and regulation of energy prices.

The latest in a row of EU energy market legislation, known as the third package, has been enacted to improve the functioning of IEM and resolve structural problems. The EU's Third Energy Package was proposed by the European Commission in September 2007, adopted by the European Parliament and the Council of the European Union in July 2009, and entered into force in September 2009.

To date, one of the biggest achievements in establishing an IEM has been the founding of the European Network of Transmission System Operators for Electricity (ENTSO-E). ENTSO-E, established and given legal mandates by the EU's Third Legislative Package, represents 41 electricity TSOs from 34 countries across Europe (Table 3.1).

With the key objective of supporting the implementation of the EU's energy policy by promoting closer cooperation across Europe's TSOs, ENTSO-E focuses in the areas of security of supply, standardised market integration, and sustainability. It pursues coordinated, reliable, and secure operations of the interconnected electricity transmission network and is tasked to promote completion of IEM in electricity and cross-border trade by providing standardised market integration frameworks that could be useful in facilitating competitive and integrated central wholesale and retail markets. Furthermore, the secure integration of renewable energy sources such as wind and solar power into the power system to reduce the EU's greenhouse gas emissions is one of the major tasks it pursues under the area of sustainability.

ENTSO-E contributes to the achievement of said objectives primarily through drafting of network codes, development of ten-year network development plans, technical cooperation between TSOs, publication of summer and winter outlook reports for electricity generation, and coordination of R&D plans.

Considering that interconnections play an important role in establishing IEM and for every country benefitting from such connections, it is essential to maintain a high level of exchange capacity (maximum instantaneous electrical power that can be imported or exported between two electricity systems while maintaining the security criteria of each of the systems). In this respect, the EU recommends that the minimum interconnection capacity between countries should represent at least 10 percent of the installed generation capacity in each one of them.[2]

The European Union Package 2015 again cited the urgency of achieving interconnection level target (Energy Union Package, 2015), recognising security of supply, affordable prices in the internal market, sustainable development, and decarbonised energy mix as benefits of an interconnected energy system.

[2] In 2002, the European Council agreed on the 'target for Member States of a level of electricity interconnections equivalent to at least 10 percent of their installed production capacity by 2005'. The target was reiterated by the European Council in October 2014 for 'all Member States to achieve interconnection of at least 10 percent of their installed electricity production capacity by 2020' (Barcelona European Council, 2002; European Commission, 2015)

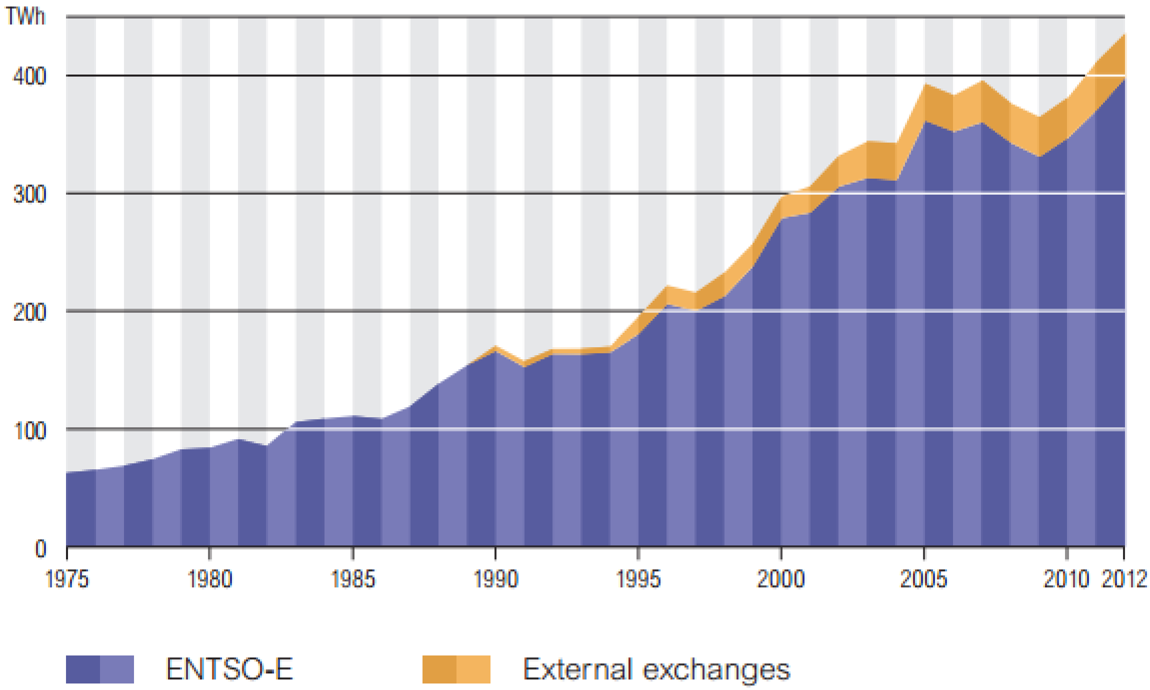
Table 3.1. TSOs Across the European Network of 34 Countries

Country	Company
Austria (AT)	Austrian Power Grid AG Vorarlberger Übertragungsnetz GmbH
Bosnia and Herzegovina (BA)	Nezavisni operator sustava u Bosni i Hercegovini
Belgium (BE)	Elia System Operator SA
Bulgaria (BG)	Electroenergien Sistemen Operator EAD
Switzerland (CH)	Swissgrid ag
Cyprus (CY)	Cyprus Transmission System Operator
Czech Republic (CZ)	ČEPS a.s
Germany (DE)	TransnetBW GmbH, TenneT TSO GmbH, Amprion GmbH and 50Hertz Transmission GmbH
Denmark (DK)	Energinet.dk
Estonia (EE)	Elering AS
Spain (ES)	Red Eléctrica de España S.A.
Finland (FI)	Fingrid OyJ
France (FR)	Réseau de Transport d'Electricité
United Kingdom (GB)	National Grid Electricity Transmission plc, System Operator for Northern Ireland Ltd, Scottish Hydro Electric Transmission Limited and Scottish Power Transmission plc
Greece (GR)	Independent Power Transmission Operator S.A.
Croatia (HR)	Croatian Transmission System Operator Ltd.
Hungary (HU)	MAVIR Magyar Villamosenergia-ipari Átviteli Rendszerirányító Zártkörűen Működő Részvénytársaság
Ireland (IE)	EirGrid plc
Iceland (IS)	Landsnet hf
Italy (IT)	Terna - Rete Elettrica Nazionale SpA
Lithuania (LT)	Litgrid AB
Luxembourg (LU)	Creos Luxembourg S.A.
Latvia (LV)	AS Augstsprieguma tīkls
Montenegro (ME)	Crnogorski elektroprenosni sistem AD
FYR of Macedonia (MK)	Macedonian Transmission System Operator AD
Netherlands (NL)	TenneT TSO B.V.
Norway (NO)	Statnett SF
Poland (PL)	PSE S.A.
Portugal (PT)	Rede Eléctrica Nacional, S.A
Romania (RO)	C.N. Transelectrica S.A
Serbia (RS)	JP Elektromreža Srbije
Sweden (SE)	Svenska Kraftnät
Slovenia (SI)	Elektro Slovenija, d.o.o.
Slovak Republic (SK)	Slovenska elektrizacna prenosova sustava, a.s.
Observer Member	
Turkey (TK)	TEIAS

Source: ENTSO-E.

It is important to note that cross-border exchanges have increased prominently since the end of the 1990s with the start of the market opening process (Figure 3.2). Since the establishment of ENTSO-E, however, a substantial growth of around 23 percent has been achieved in five years (2010–2014) as compared to the 16 percent rise in the previous decade (2000–2010) (Figure 3.3).

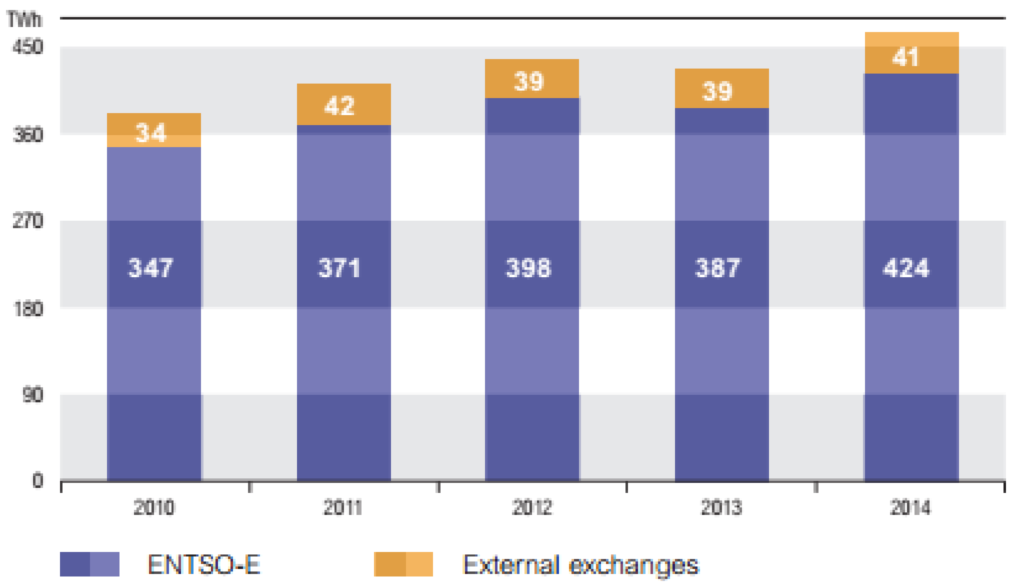
Figure 3.1. Development of Overall Cross-border Exchanges of ENTSO-E Member Countries Since 1975



Source: ENTSO-E, Memo 2012.

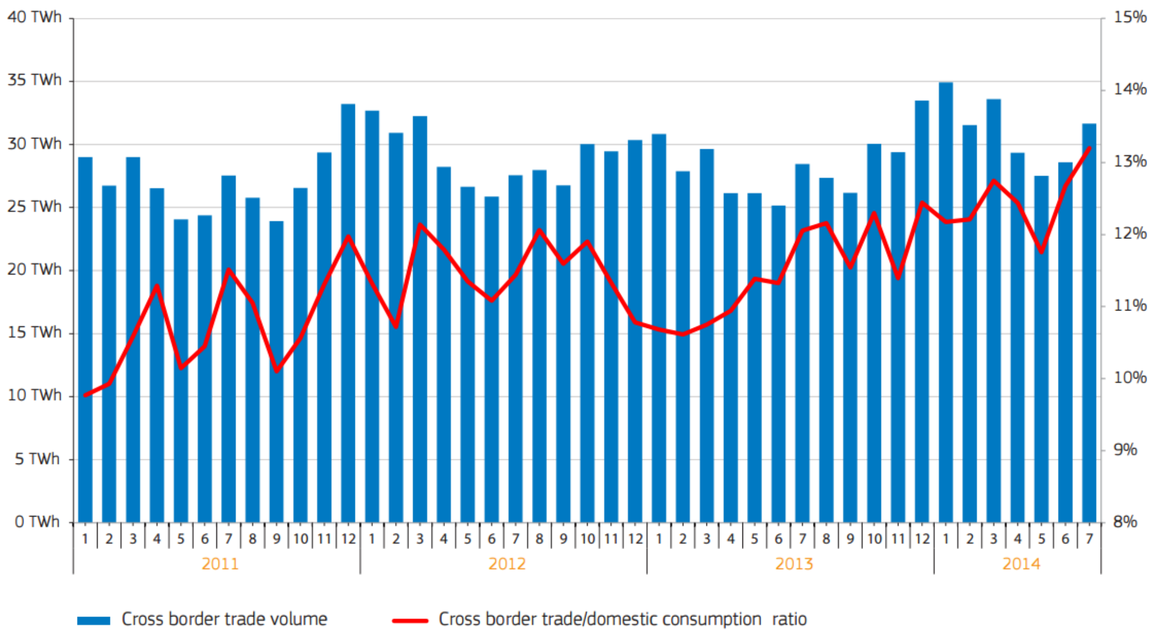
Monthly cross-border physical power flows across the EU in May–July 2014 reached an average 29.3 TWh, 10 percent higher than in the same period of 2013. Electricity consumption only slightly increased (by 1.6 percent) in May–July 2014 compared to the same months of 2013, while the combined traded volume of power increased by 3.3 percent on the major electricity trading platforms in the EU (ENTSO-E, 2014). In 2014, 10 countries within the ENTSO-E perimeter exported more than 10 percent of their annual national generated power to neighbouring countries. Thirteen other countries of ENTSO-E imported more than 10 percent of their annual internal electricity consumption from other ENTSO-E countries. The ratio of cross-border physical flows and electricity consumption in the EU reached 13.2 percent in July 2014, the highest in the last four years (Figure 3.4). The increase in cross-border physical flows outnumbered both the increase in electricity consumption and traded volume of power, pointing to improving liquidity, growing interdependency, and further integration of electricity markets in the EU.

Figure 3.3. Development of Overall Cross-border Exchanges of ENTSO-E Member Countries



As in 2013, exports from countries along the North–East to South–West axis increased and were related to an energy mix based on hydropower, coal, and renewables.

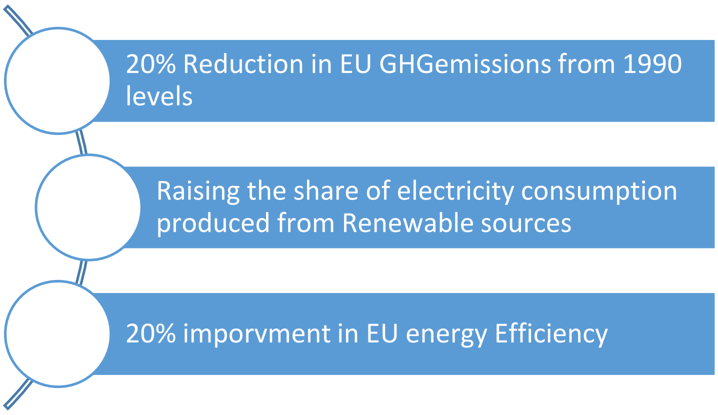
Figure 3.4. Monthly Volume of Cross-Border Trade of Electricity and its Ration with Consumption



3. Legislative and Regulatory Framework

In March 2007, a commitment by EU leaders to the 2020 energy objectives came as a turning point for the European power systems and all market participants. As closer cooperation of transmission grid operators was needed to ensure security of supply, the completion of IEM, and significant increase in power generation from renewable energy sources (Figure 3.5), a set of new directives and regulations, called the Third Energy Package, was adopted in 2009. This package, was created the ENTSOs for gas and electricity (i.e. ENTSO-E and ENTSO-G) and the Agency for the Cooperation of Energy Regulators (ACER).

Figure 3.5. EU Energy Objectives 2020



Source: Authors.

3.1 The Third Energy Package 2009

The Third Energy Package, ratified to improve the functioning of IEM and resolve structural problems, is a set of two European directives and three regulations:

- Common Rules for the Internal Market in Electricity Directive (2009/72/EC)
- Common Rules for the Internal Market in Natural Gas Directive (2009/73/EC)
- Regulation Establishing an Agency for the Cooperation of Energy Regulators (713/2009/EC)
- Regulation on Conditions for Access to the Network for Cross-Border Exchanges in Electricity (714/2009/EC)
- Regulation on Conditions for Access to the Natural Gas Transmission Networks (715/2009/EC).

These regulations set out ENTSO-E's responsibilities in enhancing the cooperation between its 41 member TSOs across the EU to assist in the development of a pan-European electricity transmission network in line with the EU's energy policy goals. The Third Energy Package covers five main areas:

Table 3.2. Three Recommended Options of Unbundling

Ownership unbundling	No majority stake of production/supply company in TSO
Independent system operator	Can formally own electricity transmission networks in cases where entire operation, maintenance, and investment in the grid are being done by an independent company
Independent transmission system operator	An independent transmission system operator in cases where energy supply company still owns and operates gas or electricity networks

Source: Compiled from various public domains

Unbundling: unbundling aims to separate energy supply and generation from the operation of transmission networks to facilitate fair competition in the market (Table 3.2).

Strengthening the independence of regulators: The Third Energy Package requires regulators to be free from both industry and government interests. Regulators hold the power to impose penalties upon non-compliant companies. Electricity generators, gas network operators, and energy suppliers are required to provide precise data to regulators, while regulators have a mandate to cooperate with each other across all EU countries.

Establishment of ACER: Tasked to ensure a smooth functioning of internal energy market, ACER is involved in (1) drafting guidelines for the operation of cross-border electricity networks, (2) reviewing the implementation of EU-wide network development plans, (3) coordinating with national regulators, and (4) monitoring internal market functioning.

Cross-border cooperation: The Third Energy Package ensures a smooth transportation of electricity across borders and optimal management of EU networks through ENTSO-E and the European Network for Transmission System Operators for Gas (ENTSO-G).

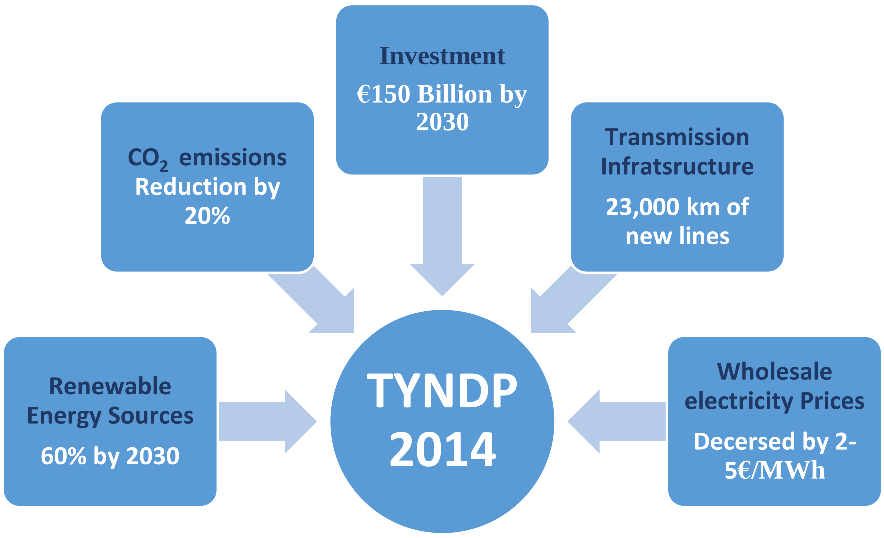
Transparency in retail markets to benefit consumers: The Third Energy Package empowers European energy consumers to choose or change suppliers without extra charges, receive information on energy consumption, and quickly and cheaply resolve disputes.

3.2 Ten-Year Network Development Plan (TYNDP)

The prime objective of TYNDP is to ensure transparency with regards to the electricity transmission network and support decision-making processes at regional and European levels. To this end, TYNDP aims to ensure electricity transmission infrastructure investments across 34 European countries. TYNDP is a non-binding plan, meant to be updated every 2 years. The pilot TYNDP was published in 2010, followed by successive versions in 2012 and 2014.

TYNDP 2014 (Figure 3.6) proposes the integration of up to 60 percent of renewable energy by 2030 by strengthening Europe's electricity power grid. This integration aims to achieve cost efficiency and energy security under certain broad categories:

Figure 3.6. TYNDP 2014 and its Major Aim



Source: Compiled information from various public domains.

Renewable energy sources. Major driver for grid development until 2030:

A major shift in power generation is expected by 2030, starting from likely replacement of obsolete fleet of conventional generating units with modern ones, which are located distantly from load centres and with higher share of renewable energy sources.

Interconnection capacity enhancement. Need for stronger market integration with mainland Europe of the four main electric peninsulas[3] in Europe:

TYNDP has identified interconnection bottlenecks that are in dire need of reinforcement and is working to double interconnection capacity (on average across Europe) by 2030.

Massive investment and wholesale electricity prices. The total investment cost for pan-European significance projects under TYNDP is €150 billion, of which €50 billion relates to subsea cables. Although said investment represents only two percent of the bulk power prices or approximately one percent of the total electricity bill, the consequent increased market integration has led to a significant lowering of average electricity prices across Europe.

[3] Targeted is the interconnection of the Iberian Peninsula, the Italian peninsula, the Baltic states, Ireland, and Great Britain to mainland Europe.

Emissions mitigation, technical leadership, and future energy policies: By directly connecting renewable energy sources, avoiding spillage, or running more environment-friendly power generation units, TYNDP 2014's project portfolio aims to directly contribute to reducing CO_2 emissions by approximately 20 percent by 2030. Also, investment projects requiring appropriate grid reinforcement solutions have led to adoption of cutting-edge technologies. As various market situations simulated for project portfolio under TYNDP 2014 are required to be analysed for different policy visions, TYNDP is considered to be contributing to the implementation of 2050 energy goals. Moreover, as TYNDP aims for network development up to 2030, this serves as energy policy to bridge the gap between EU's energy targets from 2020 to 2050.

3.3 Trans-European Energy Network (TEN-E)

With building and financing important energy infrastructure as purpose, TEN-E lists and ranks projects eligible for community assistance in line with a series of guidelines adopted under Decision No. 1229/2003/EC of the European Parliament and of the European Council of 26 June 2003. TEN-E identifies and gives push to corridors that require urgent infrastructure development to connect EU countries currently isolated from European energy markets. Thus, such infrastructure strategy has potential to strengthen existing cross-border interconnections and help integrate renewable energy sources. More details regarding TEN-E are included in Section 4 below.

4. Infrastructure Development

With the need to upgrade current European grid infrastructure, EC has estimated €200 billion as the required investment for transmission grids and gas pipelines. A major part of infrastructure upgrade includes urgent infrastructure to connect EU countries currently isolated from European energy markets, strengthen existing cross-border interconnections, and help integrate renewable energy.

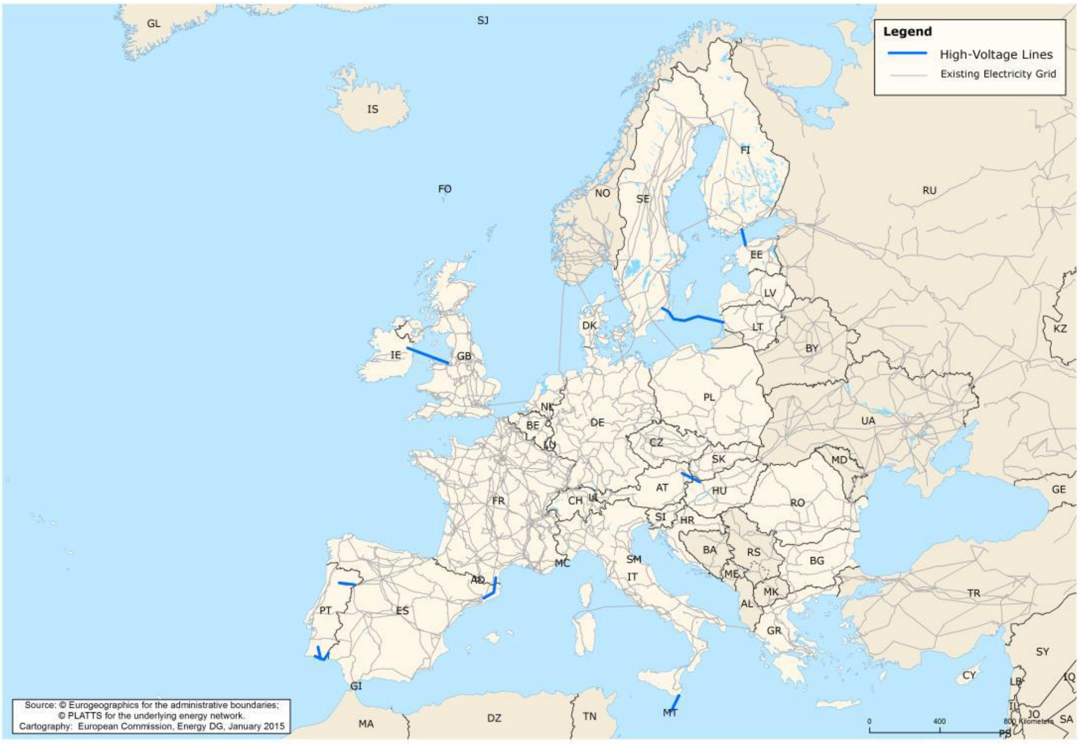
Although a significant increase in interconnection capacities was seen in the last decade, 12 member states, mainly in the periphery of the EU, still fall below the 10 percent electricity interconnection target and are thus isolated from IEM (Table 3.3).

Table 3.3. Electricity Interconnection Level, 2014

Member State	Interconnection Level (%)
Member states with above 10% interconnections target	
Austria (AT)	29
Belgium (BE)	17
Bulgaria (BG)	11
Czech Republic (CZ)	17
Germany (DE)	10
Denmark (DK)	44
Finland (FI)	30
France (FR)	10
Greece (GR)	11
Croatia (HR)	69
Hungary HU	29
Luxemburg (LU)	245
The Netherlands (NL)	17
Slovenia (SI)	65
Sweden (SE)	26
Slovak Republic (SK)	61
Member states with below 10% interconnection target	
Ireland (IE)	9
Italy (IT)	7
Romania (RO)	7
Portugal (PT)	7
Estonia (EE)	4
Luthuania (LT)	4
Latvia (LV)	4
United Kingdom (UK)	6
Spain (ES)	3
Poland (PL)	2
Cyprus (CY)	0
Montenegro (MT)	0

Source: Energy Union

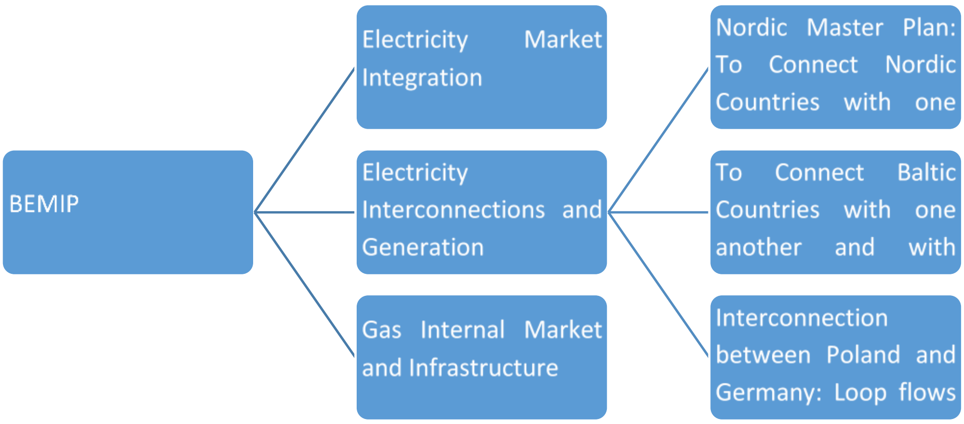
Figure 3.7. Interconnections Supported by EEPR



Source: Energy Union Package.

To this end, the EU has been working on infrastructure upgrade for a long time now, with interconnection networks at the forefront. The regulations of EEPR and TEN-E are among the most prominent policies for enhanced interconnections of member states.

Figure 3.8. BEMIP and Related Major Interconnection Projects



Source: Compiled information from various public domains.

EEPR, which focuses on identifying interconnection projects across the EU, spent around €650 million on electricity interconnections. Thus, the programme has made some significant interconnections that previously could not have been made due to lack of funds. One of the major interconnections backed by EEPR is the Baltic Energy Market Interconnection Plan (Figure 3.8). As shown in Table 3.2, Estonia, Latvia, and Lithuania still lack adequate electricity connections. The Baltic Energy Market Interconnection Plan intends to integrate the energy market of the Baltic States by building more infrastructure/interconnections. Some of the more prominent interconnections being made under the plan include linking Finland and Sweden (Fenno–Skan II) under the Nordic Master Plan, the Great Belt project in Denmark, linking Sweden and Lithuania (NordBalt), linking Poland and Lithuania (LitPol), and linking Poland and Germany to deal with loop flows caused by increased wind electricity in northern Germany (See Figure 3.9).

Figure 3.9. Interconnections Under BEMIP

Source: European Commission, Energy.

With the broad objective of interconnection, interoperability, and development of trans-European networks for transporting electricity and gas, the TEN-E Regulation sets out guidelines for streamlining the permitting processes for major energy infrastructure projects that contribute to European energy networks.

Under the TEN-E regulations, EC has drawn up energy infrastructure projects, known as projects of common interest (PCIs), that can benefit from accelerated permit granting, improved regulatory conditions, and access to financial support totalling €5.35 billion from the Connecting Europe Facility. The funding is intended to speed-up project implementation and attract private investors. Energy infrastructure projects requiring community assistance have been categorised as:

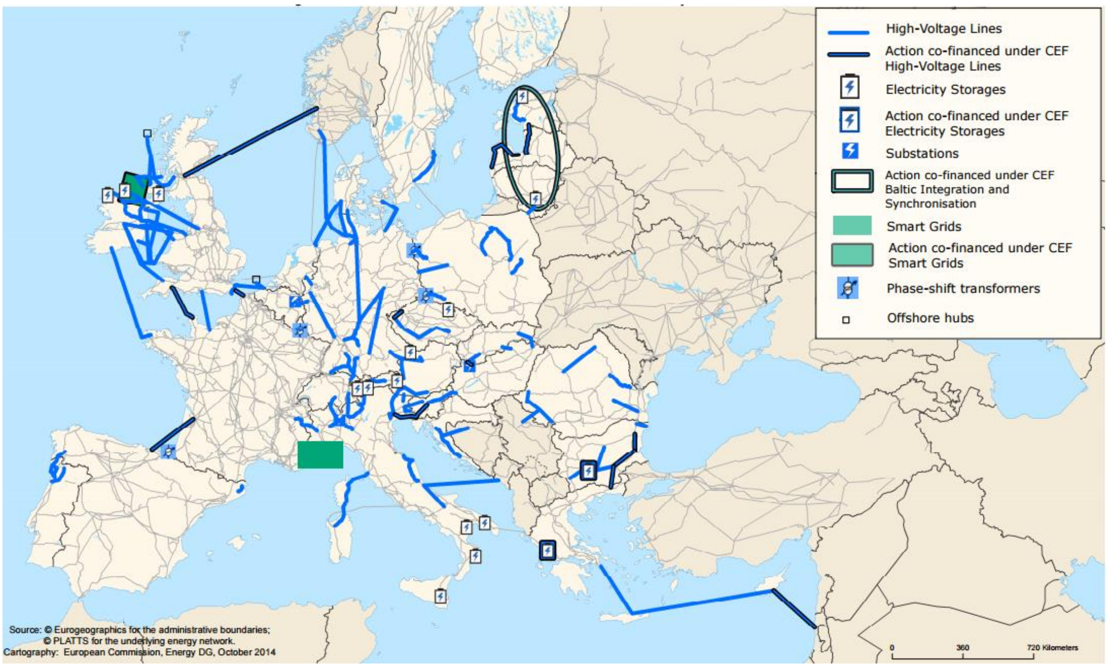
Projects of common interest. Economically viable electricity and gas networks projects.

Priority projects. Projects of common interest with significant impact on the proper functioning of the internal market, security of supply, and/or use of renewable energy sources. Priority projects get community financial assistance.

Projects of European interest. Certain priority projects of cross-border nature or having significant impact on cross-border transmission capacity.

Of the 248 PCIs on the 2013 list, 137 are related to electricity, including 52 electricity interconnections and one project with anticipatory investments to enable future interconnections (Figure 3.10). Of these, 37 projects involve member states whose current interconnection level is below 10 percent. Around 6 percent of PCIs on the 2013 list were supposed to be completed by 2015 while some 75 percent are planned to be completed by 2020.

Figure 3.10. Projects of Common Interest on the 2013 List



Source: European Commission.

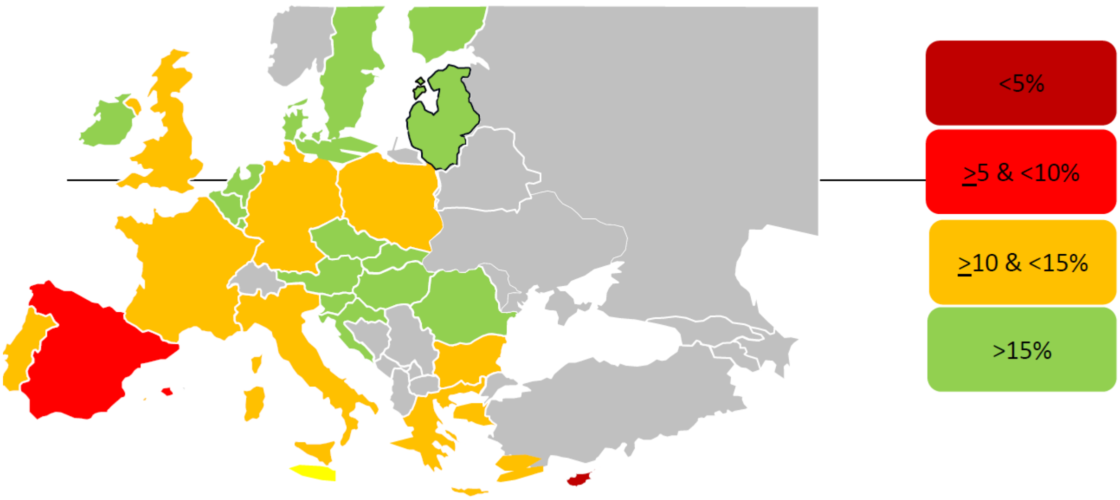
Table 3.4. Interconnection Projects under PCI and EEPR

Interconnection Project	Related Policy	Status	Intended Outcome
Interconnection between Baixas (France) and Santa Llogaia (Spain)	EEPR	Inaugurated in February 2015	Double electricity interconnection capacity between France and the Iberian Peninsula
Interconnection between Aquitaine (France) and the Basque country	PCI	Currently under detailed studies, financed by EC grants	Double electricity interconnection capacity, reaching the interconnection target of 10%
Interconnection between Vila Fria– Vila do Conde-Recarei (Portugal) and Beariz-Fontefría (Spain)	PCI	Underway	Increased interconnection capacity between Portugal and Spain (of current 7%) and above 10% by 2016
Interconnection between Nybro (Sweden) and Klaipeda (Lithuania)	EEPR	Project Nordbalt under process	Improved integration of the future power market between the Baltic member states and Nord Pool Spot from mid-2016
Interconnection between Lithuania and Poland	PCI	Underway	Double interconnection level of Poland to 4% by the end of 2015
Interconnection between Vierraden (Germany) and Krajnik (Poland)	PCI	Underway	Increased interconnectivity of Poland above 10% by 2020
Interconnection between the United Kingdom and Belgium, France, and Ireland	PCI	Underway	Ten percent target reached by the UK; less congested interconnections
Extension of existing interconnection between Ireland, the United Kingdom, and France	PCI	Underway	Above 15% percent increase in interconnection capacity of Ireland by 2020
Interconnection between Romania and Serbia	PCI	Underway	Above 9% increase in interconnection capacity of Romania by 2017 in comparison to the current 7% level.
Cyprus Euroasia Interconnector	PCI	Prefeasibility phase, to be completed in 2023	Over 100% interconnection level for Cyprus when completed in 2023
High-voltage interconnection between Malta and Sicily (Italy)	EEPR	Underway	Increased interconnection level for Malta, from the present 0% to approximately 35%

Source: Energy Union Package, 2015.

The PCI list is updated every 2 years to include newly needed projects and remove obsolete ones. The next PCI list is under process and will be released in 2017. Priority will be given to projects capable of significantly increasing the current interconnection capacity from below the established 10 percent objective. It is worth mentioning that numerous interconnects projects are underway that, when completed, would help member states reach the 10 percent target (Table 3.4).

Figure 3.11. Interconnection levels in 2020 as planned under current PCI



Source: European Union Package.

As mentioned in the 'Energy Union Package Communication from the Commission to the European Parliament and the Council', the implementation of PCIs is expected to bring Europe closer to achieving the 10 percent electricity interconnection target between member states once the projects are completed in 2020 (Figure 3.11).

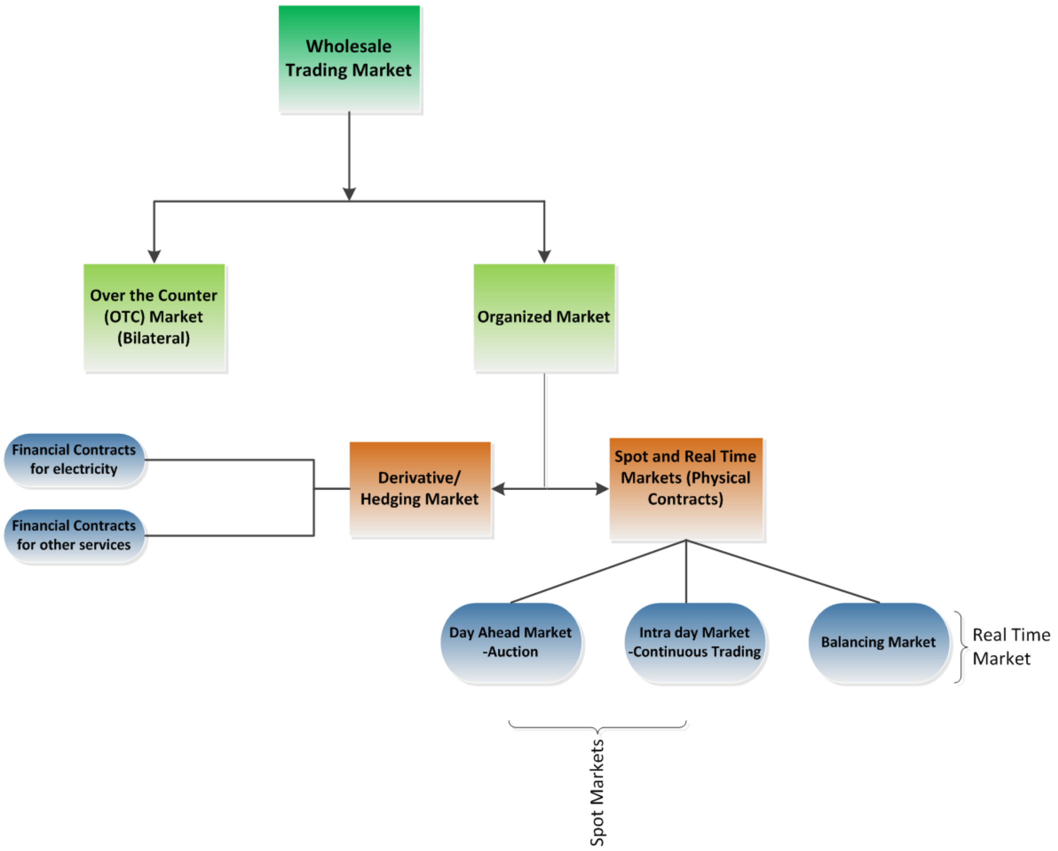
5. Market Design

Over a period of time, Europe was able to liberalise a major share of its electricity market that ultimately created a need for organised markets for wholesale trade of electricity. Initially, organised markets started developing under two concepts: power pool and power exchange. However, in contrast to power exchanges that emerged as voluntary marketplace as a result of private sector initiatives, power pools were public initiatives mandating the participation of member countries or parties. Power exchanges are now the obvious favourite of market players[4] as power pools are not being practiced by many European countries these days.

[4] Market players refer to generators, distribution companies, traders, and large consumers.

Before the establishment of the New Electricity Trading Arrangements, the pool of England and Wales was a typical example of power pool concept. After consecutive directives by the EU from the 1990s to 2003, power exchanges have emerged as competitive wholesale (energy only) trading facility/market for spot electricity trading. In this market, once trading results – which disclose traded volume of electricity and corresponding market clearing price – have been announced, independent system operators[5] take the responsibility of facilitating the physical delivery of electricity (transmission) to dedicated hubs. Thus, the power exchange can be defined as a voluntary marketplace in contrast to the classic bilateral over-the-counter market. Figure 3.12 shows a typical structure of power trading market.

Figure 3.12. Typical Structure of Wholesale Market



Source: Authors.

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[5] As mandated by the second EU directive (2003), most member states have to create independent TSOs, although their levels of independence can be differentiated by ownership, legal, and management categories. For instance, UK, Finland, Sweden, and other member states have chosen to appoint a separate legal entity (different from other entities under supply chain of electricity production) as TSOs while Belgium, Germany, and France have opted for TSOs that are independent in terms of management (Boisseleau, 2004).

Day-ahead Market

Across Europe[6], over-the-counter or bilateral markets are still the dominant market in terms of volume of trade, while day-ahead markets are the main arena for electricity trading under organised markets (through power exchanges). Day-ahead markets (e.g. Elspot of Nordpool) are short-term (spot) markets where contracts are made between seller and buyer for delivery of power the following day. In general, a day-ahead market is composed of four stages. In stage 1, both seller and buyer submit bids for electricity trade for a chosen period within a day[7]. In stage 2, price and volume information are fed in an advanced computing system of exchanges where market clearing price (MCP) is computed using specific algorithms. In general, MCP and market clearing volume (MCV) are computed at the equilibrium point of the supply and demand curve (Figure 3.13). In stage 3, all transactions are settled on the basis of MCP and MCV. In stage 4, once the transactions are settled, the information is transferred to system operator to ensure physical delivery of electricity. NordPool, the largest market for electricity trading in Europe, has almost 360 buyers and sellers in their day-ahead market, placing around 2,000 power trading orders daily. Deadline for submitting bids (for power to be delivered the following day) is 12:00 CTE, and hourly prices (or MCP) are typically announced to the market at 12:42 CET or later (Nord Pool, 2015).

Intraday market (e.g. Elbas of Nordpool) compliments the day-ahead market and provides flexibility through continuous trading. Although majority of trading volume across Europe is traded on the day-ahead market, the intraday market plays a key role by providing a platform for balance between supply and demand to account for any sudden changes in power supply (generation) or demand (e.g. a fossil fuel or nuclear power plant may suddenly stop working due to some technical snag or renewable energy sources such as wind power plants, for instance, may start generating more than the predicted volume the day before. Continuous trading (24 hours a day, 7 days a week, 52 weeks a year) and price formation take place in intraday market. In some major intraday markets, like those in the Netherlands, trading can take place even five minutes before final delivery. Intraday markets are becoming more important as the share of renewable energy is going up in total power-generation capacity across Europe. Table 3.5 shows a snapshot of major organised markets across Europe.

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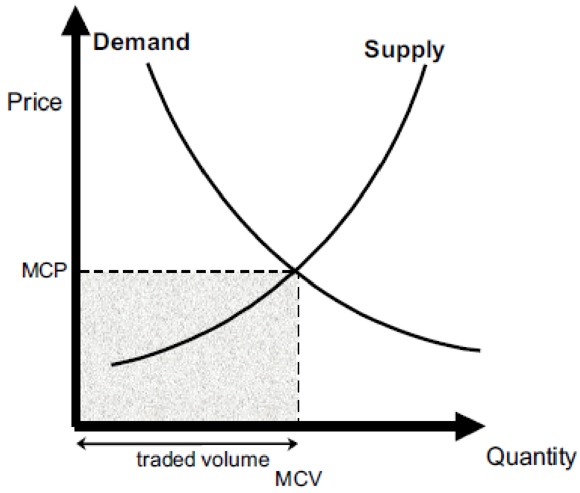
[6] Over-the-counter trade represents more than 90 percent of total electricity consumption in the Netherlands, Germany, and France. Nordic countries also trade more than 75 percent consumed electricity in over-the-counter market (Boisseleau, 2004).

[7] Duration is usually one hour. However, it goes up to two hours depending upon the protocols of different exchanges.

Figure 3.13. Auction Model under Day-Ahead Market



Source: Boisseleau.

Table 3.5. Major Organised Markets Across Europe

Market	Country
Nordpool	Norway, Finland, Sweden, Denmark
Operadora del Mercado Espanol de Electricidad (OMEL)	Iberian Peninsula (Spain, Portugal)
APX	The Netherlands, United Kingdom, Belgium
EPEX SPOT[8]	France, Germany, Austria, Switzerland
Leipzig Power exchange (LPX)	Germany
European Energy Exchange (EEX)	
EXAA	Austria
United Kingdom Power exchange (UKPX)	UK
Gestore Mercato Electricco (GME)	Italy
The French Power Exchange (Powernext)	France

Source: Compiled information from various public domains.

[8] EPEX SPOT is 100 percent owner of APX Group.

Derivatives/Hedging Market

Derivatives or hedging market is a financial/commercial market where price-securing contracts are traded to manage future risks. Financial markets trade futures power and other derivatives that are settled against future spot prices. Future contracts ensure liquidity by targeting system spot price[9] (Bang et al., 2012).

Balancing Market

Day-ahead market creates preliminary round of balance in the power system. However, balance markets or real-time markets are responsible for keeping the real time physical balance in the power system. Imbalances are typically caused by deviation between day-ahead planning/forecasting and actual consumption/generation. This is managed by ordering regulating power from regulating power market.

Regulating power is a manual reserve, defined as increased or decreased generation that can be fully activated within 15 minutes, or demand that is increased or decreased. Activation can start any time and duration can vary. Regulating markets are operated by TSOs and share many designs and functions similar to day-ahead market such as:

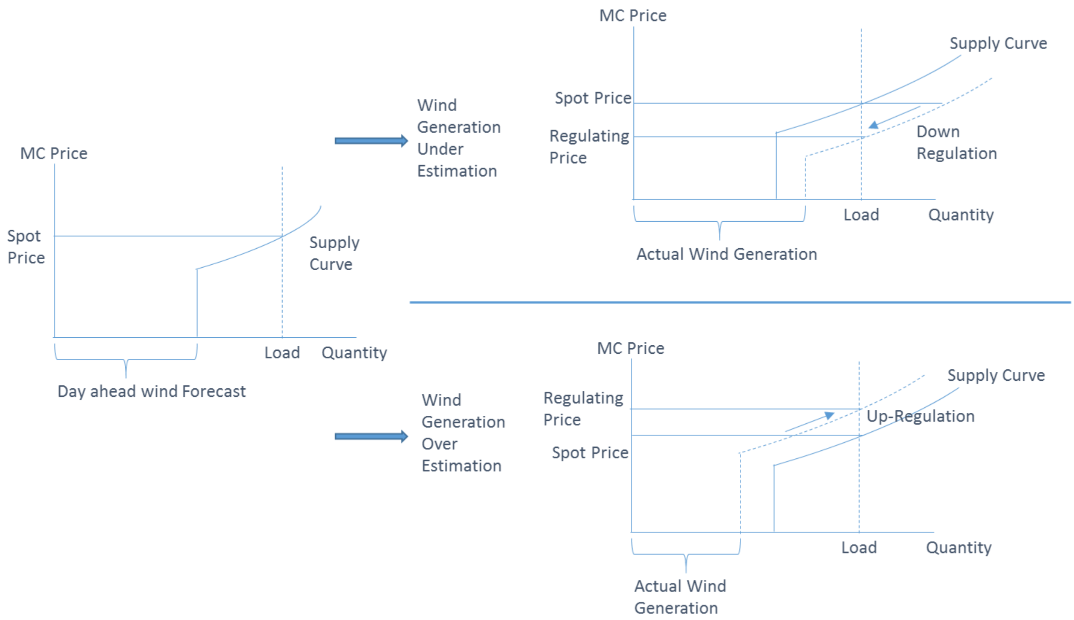
- Merit order supply curve based on bids submitted by market players
- and the bids and offers of all players participating in the same bidding zone are settle at a single price.

All bids for delivering regulating power are sorted on a list of increasing prices for up-regulation[10] (above spot price) and decreasing prices for down-regulation[11] (below spot price) (Figure 3.14). The day-ahead market (spot) price represents the minimum price for up-regulating power bids and the maximum price for down-regulating power bids. Imbalance settlement cost is settled with all market players in line with certain market rules.

It is worth noting that although the initial features of regional organised markets included only price and quantity of power market, Europe is actively working on IEM agenda and cross-border cooperation to ensure a smooth transport of electricity across borders. Transmission constraints during electricity trading are additional features that the market needs to consider. ENTSO-E ensures closer cooperation of Europe's independent TSOs by acting on standardised market integration frameworks.

[9] MCP when there is no congestion.
[10] More generation- less demand.
[11] Less generation-more demand.

Figure 3.14. Pricing in Regulating Market



Source: Interviews with EnergiNet DK.

As mentioned, European markets are moving toward greater physical integration. Although quite a few regulations and energy programmes are actively working to enhance interconnection capacities among European countries (Refer to Section 4: Infrastructure development), having IEM is still challenged by limited transmission capacity between countries. Thus, taking into account transmission capacity during cross-border trade among European countries and adopting a relevant market design are two of the most complex, albeit most important, design features of the European electricity market.

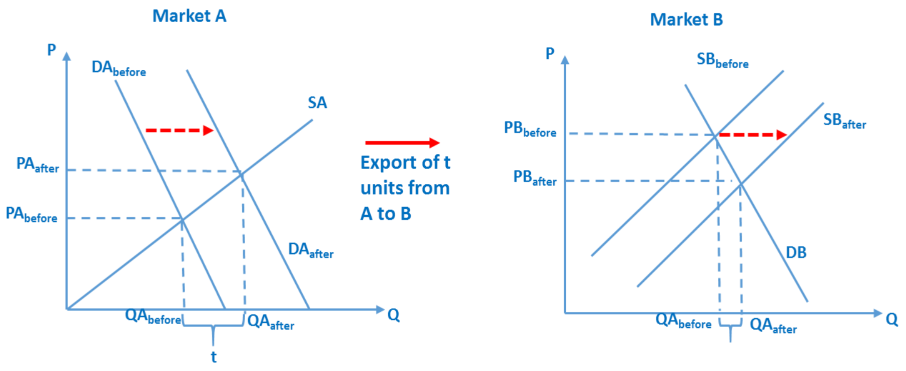
There are typically two market-based options to combine cross-border trade and cross-border transmission capacities: explicit and implicit capacity auctions (market coupling). Under the target model[12] for completing IEM, regional market coupling is the market design being implemented by ENTSO-E in close cooperation with member TSOs, power exchanges, and other stakeholders.

[12] 'The target model for the European electricity market is the vision shared by stakeholders on the future market design. The model is the blueprint with top-down guidance for regional market integration projects and is being implemented bottom-up through regional market coupling projects and top-down through the network codes that ACER, EC, and ENTSO-E develop.' (ENTSOE, 2014).

5.1 Market Coupling and Congestion Management

Market coupling is a method for integrating electricity markets in different areas. It is a congestion-management method where allocation of cross-border transmission capacity is determined according to demand on respective energy markets (Moffatt Associates, 2007). Market coupling is basically an implicit auction approach used in day-ahead market to facilitate flow of power toward the high-price area.

Figure 3.15. Principle of Market



DA	Demand Market A	SA	Supply Market A	PA	Price Market A
DB	Demand Market B	SB	Supply Market B	PB	Price Market B
QA	Quantity Market A	Before		Before Market Coupling	
QB	Quantity Market B	After		Before Market Coupling	

Source: Böckers et al.

Figure 3.15 illustrates a simplified example of market integration through market coupling and related auction method.

Market coupling is considered to be a way to integrate different energy markets into one coupled market. With market coupling, the daily cross-border transmission capacity between various areas is not explicitly auctioned among market parties but is implicitly made available through energy transactions on the power exchanges on either side of the border (hence the term 'implicit auction'). Thus, energy transactions can involve sellers and buyers from different areas, restricted only by electricity network constraints. It means that buyers and sellers on a power exchange benefit automatically from cross-border exchanges without the need to explicitly acquire the corresponding transmission capacity (Belpex, 2016). The efficiency of the mechanism is further revealed by an increasing price convergence between market areas.

5.2 Market Splitting

Under market splitting, one power exchange operates across several price zones. To understand it more clearly, market splitting defines relevant local submarkets according to congestion. If there is no congestion at a specific point in time between two areas, then both are treated as a single area. For instance, Sweden, Denmark, Norway, and Finland are linked via market splitting. Sweden has no single area but fragments, defined by transmission capacities and potential congestion. Thus, power prices may vary even in Sweden while the remaining markets may have same prices.

Box 1. Capacity Auction Mechanisms

Explicit Capacity Auction

An explicit auction is when the transmission capacity on an interconnector is auctioned to the market separately and independently from the marketplace where electricity is auctioned.

An explicit auction is a relatively simple method of handling cross-border capacity and was previously widely used in Europe. The capacity is normally auctioned in portions, through annual, monthly, and daily auctions (Moffatt Associates, 2007).

Implicit Capacity Auction

In implicit auction, the capacity between bidding areas is made available to the spot price mechanism operated by the power exchanges in addition to bid/offers per area. Thus, the resulting prices per area reflect both the cost of energy in each internal bid area (price area) and the cost of congestion.

In case of sufficient capacity availability, market becomes one: bids in the high-price market can be matched against offers in the low-price market. However, if sufficient capacity is not available, prices congregate but remain different, and the gap represents the cost of congestion (Moffatt Associates, 2007).

Two main inefficiencies are associated with the explicit auction concept and that have mostly been resolved in implicit auctions as described below:

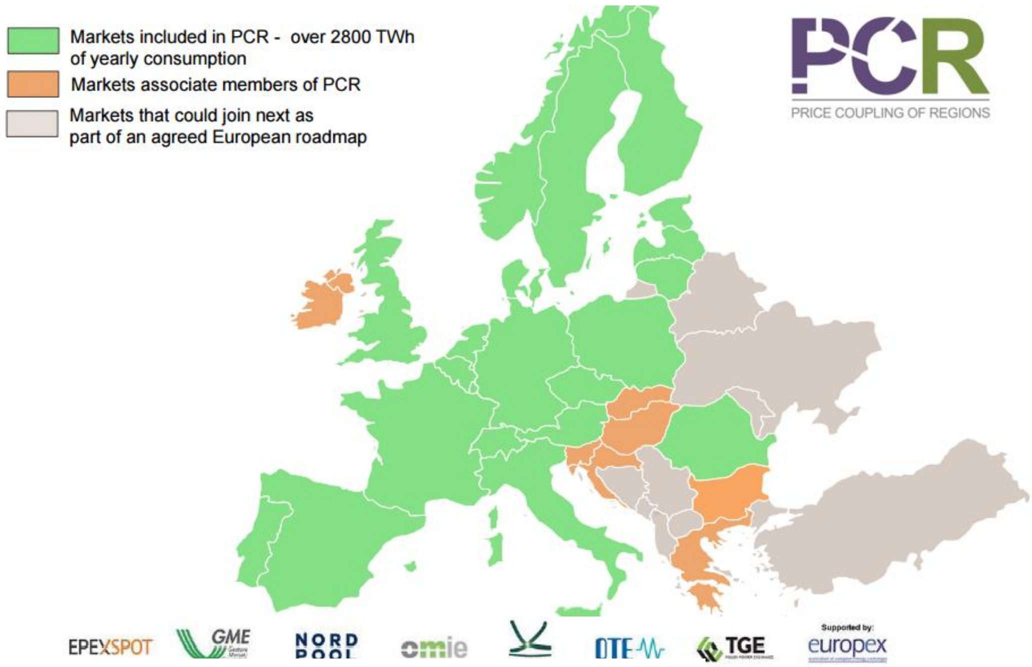
Explicit Auction	Implicit Auction
Flow on interconnector is not taken into account. Instead, transmission capacities are booked for both directions. Hence, the possibility of getting capacities booked for wrong directions.	Flow on interconnector is taken into account based on market data from the market place in the connected markets.
Cross-border transmission capacities are booked prior to the actual day-ahead market. Thus, auctions are based on predicted day-ahead prices. **Therefore, the booked transmission capacity is not necessarily equal to the power units finally sold.**	Usually, information on availability of transmission capacities is required to be gathered from various transmission system operators and incorporated in the algorithm that optimises respective power auctions in both markets.
Higher transaction cost	Implicit auction takes place in a single auction office, thus, leading to decreased transaction cost. However, a single auction office being a monopoly, it is crucial that the auctioneer remains independent from other market participants and does not discriminate among different generators and/or traders.

5.3 Single Price Coupling of Regions: Multi-Regional Coupling Project

With a vision to acquire a single price market coupling[13] for day-ahead market with implicit allocation of cross-border capacities, the multi-regional coupling project of ENTSOE-E aims to achieve full price coupling of major regional day-ahead markets, e.g. North-West Europe.

The North-West European price coupling project encompasses fully coupled day-ahead market enforcing same coupling approach in all involved countries and covers Central-West Europe (Belgium, France, Germany, Luxembourg, and The Netherlands), the Nordic-Baltic region (Denmark, Sweden, Finland, Norway, Latvia, Lithuania, and Estonia) and Great Britain, as well as the Swepol link between Sweden with Poland (ENTSOE, 2014). The North-West European project was launched on 4 February 2014 while the full price coupling of the South-West Europe and North-West Europe day-ahead electricity markets was achieved on 13 May 2014. Parallel to the multi-regional coupling project, the '4M' market coupling project aims to extend the day-ahead market coupling of the Czech Republic, the Slovak Republic, and Hungary to Romania and Poland.

Figure 3.16. Geographical Spread of PCR and Involved Power Exchanges



Source: Price Coupling of Regions.

[13] Under single-price market coupling mechanism, market prices and traded volumes of power are calculated by a single centralised system on the basis of all relevant information, e.g. cross-border capacity, order book of individually involved power exchanges, etc.

Similarly, price coupling of regions is the single-price coupling solution initiated by seven European power exchanges (EPEX SPOT, GME, Nord Pool, OMIE, OPCOM, OTE, and TGE) to calculate electricity prices across Europe[14] and allocate cross-border capacity in a day-ahead market. Price coupling of regions is implemented in both the multi-regional coupling region and 4M MC as shown in Figure 3.16.

Price coupling of regions is generally based on three main principles: single algorithm, decentralised operation, and decentralised governance.

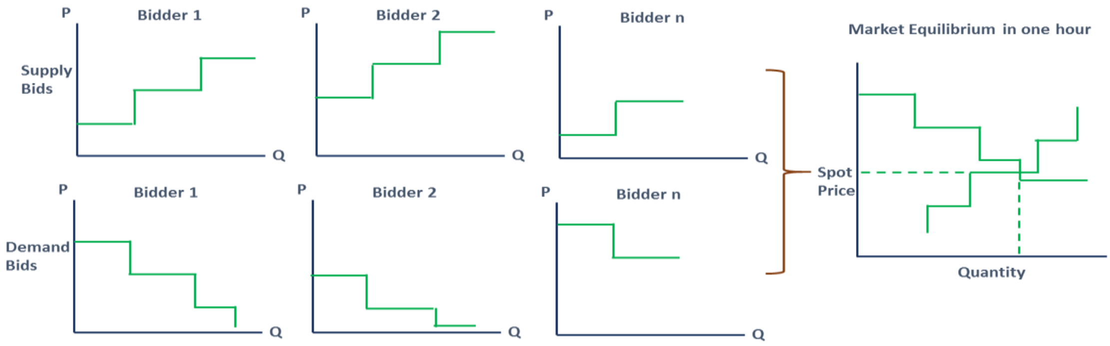
Under the old scenario of separate national markets and power exchanges, different power exchanges used to use different algorithms, such as COSMOS, SESAM, SIOM, and UPPO, to arrive on various electricity price and volume,. Nonetheless, the concept of single-price market coupling seeks a single-price coupling algorithm that can compute energy allocation and relevant prices for participating markets with a high degree of transparency.

Accordingly, the Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA) is a single-price coupling algorithm used in price coupling of regions to cover all the requirements of pricing and capacity allocations in coupled day-ahead markets.

Bidding Areas: Taking into account the constraints in transmission systems and regional market conditions in terms of price, a coupled day-ahead market is divided into different bidding areas based on information provided by TSOs as input to the algorithm (EUPHEMIA in the case under consideration). Bidding areas may vary according to the change in interconnections. In general, what first determines bidding areas is congestion on national boarders, although congestion within a country is also considered as a separate zone. For instance, the Nordic Part of North-West Europe is divided into 15 bidding areas; the Norwegian internal market, five bidding areas; Eastern Denmark and Western Denmark, two separate bidding areas; Finland, Estonia, Lithuania, and Latvia, one bidding area each; and Sweden, four bidding areas.

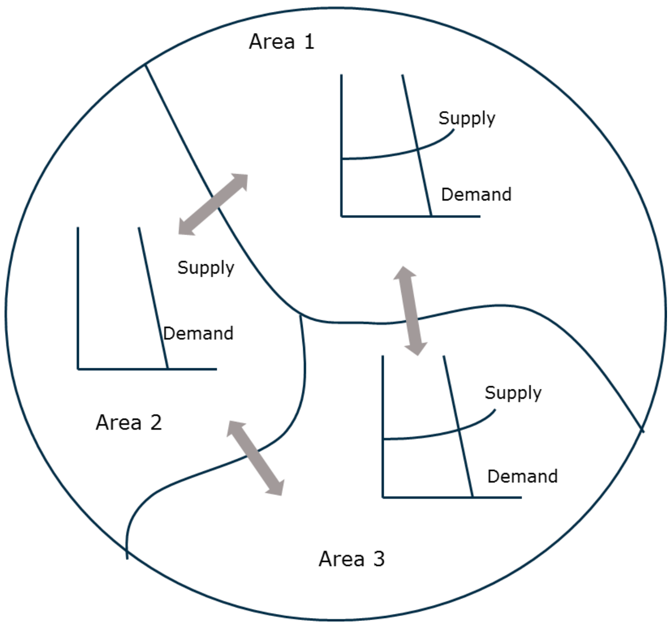
[14] It covers Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Hungary, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, and the UK.

Figure 3.17. MCP-System Price



In the case of regional markets connected through market splitting (Nordpool, for instance), once the TSO declares the bidding areas, buyers and sellers submit their bids to market operator or exchange (e.g. Nordpool Spot) for each bidding area. Using applicable algorithm, market operator groups all submitted marginal cost supply and demand bids on a supply and demand curve and computes MCP, a single price across all exchange areas (Figure 3.17). MCP computed in such a way is called system price and does not take into account transmission constraints.

Figure 3.18. Congestion Management and Least-cost Option



Source: Interviews with EnergiNet.

Thus, if bidding areas are not congested between them, entire bidding area is considered one and system price becomes its area price. However, cross-border or internal congestion between bidding areas has to take into account the interconnection capacity and can lead to separate area prices. For instance, if congestion occurs between three bidding areas (Figure 3.18), the whole market is divided into three separate areas and prices are computed accordingly. To reach the least cost option in such situation, power exchanges facilitate the flow of power from low-price area to high-price area until prices in both areas are the same (increased demand in low-price area raises price while increased available supply in high-price area pushes down price, and/or interconnector capacity is fully utilised (or congested)

The difference between area prices of two bidding areas represents the congestion rent. Such amount is collected by exchange and divided between relevant TSOs (Figure 3.19). Congestion rent is used to develop and enhance the capacity of cross-border interconnections. To summarise the process, power exchange collects generation and consumption bids and determines the optimal market outcome, i.e., the market outcome with maximum social benefit (consumer surplus, producer surplus, and congestion rent or revenue).

5.4 Capacity Allocation Mechanism

On 29 July 2011, ACER adopted the Framework Guidelines on Capacity Allocation and Congestion Management (CACM) for Electricity[15], the core elements of which include regular review and updates of bidding zones to maintain overall market efficiency, maximum possible trade between bidding areas or flow-based capacity calculation (Please see Box 2) in meshed networks, efficient allocation of cross-zonal capacity in forward markets (explicit auctions in day-ahead market, implicit auctions in intra-day market), and financially and physically firm explicit and implicit auctions, respectively.[16]

In line with the Commission Regulation (EU) 2015/1222 issued on 24 July 2015 and establishing guidelines on capacity allocation and congestion management, TSOs are required to reckon the available cross-border capacity by establishing a common grid model,[17] including estimates on generation, load, and network status for each hour. Available capacity computation should be in accordance with flow-based capacity model[18]. The available cross-border capacity is one of the inputs to further calculations. Under the distinctive feature of

[15] http://www.acer.europa.eu/en/electricity/FG_and_network_codes/CACM/Pages/default.aspx

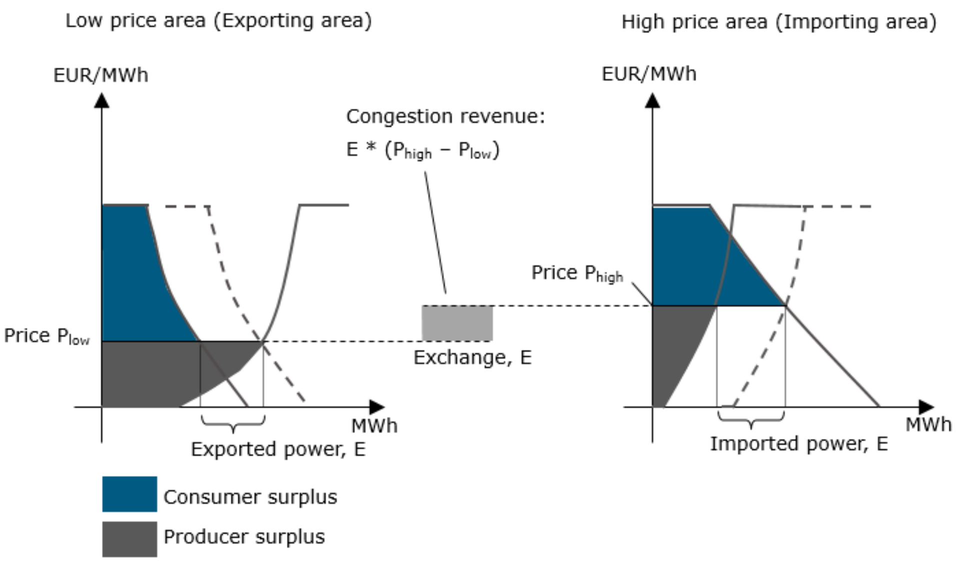
[16] Based on guidelines for CACM, 'firmness' means a guarantee that cross-zonal capacity rights will remain unchanged and that compensation will be paid if they nevertheless changed.

[17] The common grid model includes a model of the transmission system, location of generation units, and loads relevant to calculating cross-zonal capacity. Accurate and timely information by TSOs is key to creating a common grid model. Each TSO generates its single individual grid model that can be merged later with grid models of other TSOs to create a common grid model.

[18] The flow-based capacity model takes into account that electricity can flow via different paths and optimise the available capacity in highly interdependent grids.

PCR of decentralised operation and governance, the market coupling operator is tasked to use a specific algorithm to optimally match bids and offers and make the results available to all member power exchanges. Accordingly, power exchanges have to publish result of successful bids and offers before energy is transferred across the network. The capacity allocation process for single day-ahead and intraday coupling is similar, with their trading rules (continuous process throughout the day in intraday coupling and one single calculation in day-ahead coupling) as the only exception.

Figure 3.19. Congestion Revenue and Consumer/Producer Surplus



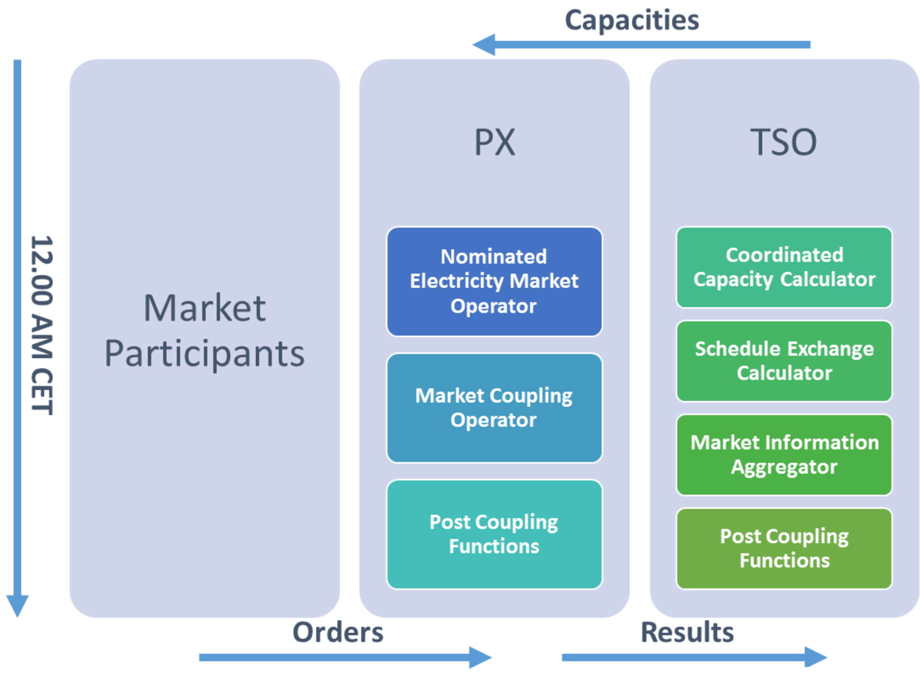
Source: EnergiNet DK.

ACER is responsible in appointing a single regulated entity, called nominated electricity market operator (NEMO), to perform common functions of market coupling operator relating to the market operation of single day-ahead and intraday coupling. As of the time of interview with the European power exchanges during the development of this report, the appointment of market coupling operators was a function developed and operated jointly by NEMOs. There is always one NEMO in charge as coordinator on a rotational basis.[19] (A broad snapshot of the role of each entity in CACM framework and market coupling task is shown in Figure 3.20;

[19] The Commission Regulation (EU) 2015/1222 states that 'each Member State electrically connected to a bidding zone in another Member State shall ensure that one or more NEMOs are designated by latest 4 months after the entry into force of this Regulation to perform the single day ahead and/or intraday coupling'.

further terms are explained in footnote[20].). Thus, power exchanges act as market operators in national or regional markets in cooperation with TSOs in single day-ahead and intraday coupling. Their major tasks involve receiving orders from market participants, taking overall responsibility for matching and allocating orders in accordance with the single day-ahead and intraday coupling results, publishing prices, and settling and clearing the contracts from the trades according to relevant agreements and regulations of participants.

Figure 3.20. Day-ahead Market: Market Coupling and CACM



PX = power exchange, TSO = transmission system operator.

Source: ENTSO-E.

[20] According to the Commission Regulation on Capacity Allocation and Capacity Allocation and Congestion Management, scheduled exchange means the transfer scheduled between geographic areas for each market unit and for a given direction. Schedule exchange calculator does such calculations. Post coupling functions involve scheduling and nominating cross-border flows, settling exports and imports on relevant exchange, distributing congestion revenue to TSOs, and so on. In addition, TSOs work as market information aggregators, required to publish, as soon as matched, at a minimum, the execution status of orders and prices and ensure that this market information is published and made publicly available in an accessible format for a period of not less than 5 years (where such historical data exists).

Under the Commission Regulation, the two permissible models for cross-border capacity calculation are the flow-based model and the available transmission capacity (ATC) model. However, the flow-based market coupling model (FBMC) is the best recommended model, while ATC is suggested when cross-zonal capacity is not depended on each other (Refer to Box 1.2).

In addition to calculating remaining available margin (RAM) and power transfer distribution factors of critical lines (or transmission constraints) under FBMC (Refer to Box 1.2 for further details on FBMC model), calculation of the inputs to capacity calculations includes operational security limits or contingencies relevant to capacity calculation and allocation constraints, and generation shift keys[21] and remedial actions.

Also, all TSOs in each capacity calculation region shall, as far as possible, use harmonised capacity calculation inputs by 31 December 2020.

[21] Generation shift key represents forecast of the relation of a change in the net position (net position is the net sum of electricity exports and imports for each market time period for a given bidding zone) of a bidding zone to a specific change of generation or load in the common grid model.

Box 1.2. Evaluation of Cross-Border Allocation Methods

The initial day-ahead market coupling in Europe (trilateral market coupling of the Belgian, Dutch, and French day-ahead markets in 2006; South-West and North-West Europe market coupling in 2014) was based on available transfer capacity (ATC) method for cross-border allocation still being practiced by most market zones in market coupling.

However, in line with the Commission Regulation (EU) 2015/1222, FBMC is used for cross-border capacity allocation in Central West European day-ahead markets now (Belgium, the Netherlands, Luxembourg, France, and Germany/Austria), replacing the ATC method (Bergh et al., 2015).

Power exchange collects generation and consumption bids and determines the optimal market outcome or the maximum social welfare (sum of consumer surplus, producer surplus, and congestion revenue). Accordingly, algorithm for optimal market outcome is subject to market clearing conditions (net exchange or net clearing position on the basis of net generation, consumption, import, and export) and constraints by available transmission capacity.

Therefore, the problem of cross-border capacity allocation consists of two sub-problems: transmission capacity available to the market and relationship between the net exchange positions and flows through the grid.

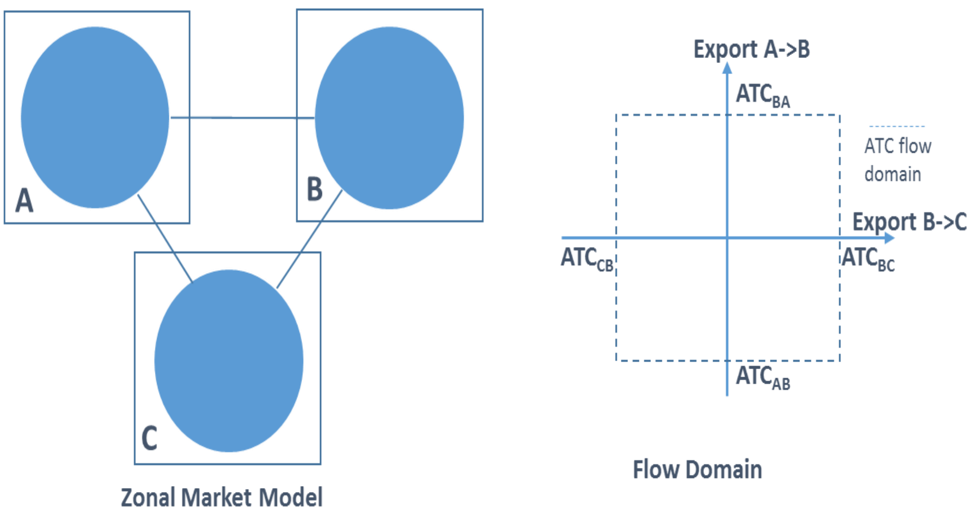
Considering that electricity does not flow directly from generator to consumer but spreads out over parallel paths in the network according to Kirchhoff's laws, there is a fundamental difference between commercial flows (i.e. the shortest path in the network between generator and consumer) and physical flows through the grid. Consequently, the transmission capacity between two market zones cannot be fully allocated to commercial trade between these market zones since some of the capacity will be used by parallel flows resulting from trade between or within other market zones. These two permissible approaches (ATC and FBMC) for calculating cross-border capacity under Regulation on CACM are further described below:

Available Transfer Capacity

ATC is calculated as the maximum commercial exchange between two market areas, compatible with the physical transmission constraint. A cross-border link's ATC is independent of the flow on other cross-border links. To calculate ATC, TSOs estimate parallel flow due to market outcome or on the basis of a base case (ex-ante to the market clearing) and ATC value is determined for each cross-border link and depends on the flow direction of the line, e.g. minimum ATC and maximum ATC representing negative and positive direction, respectively, in algorithm. An incidence matrix is also included in computation algorithm to provide information whether a cross-border link is starting at a market zone (with value of incidence = 1), or ending at a market zone (with value of incidence = -1) or not connected to a market zone at all (with value of incidence = 0).

As shown in Figure 3.21 (Bergh et al., 2015), only one equivalent node per zone is considered, with one cross-border link connecting the market zones, thus a simple grid in ATC method considers a zonal network of three nodes and three cross-border links. The ATC flow domain (shown by dotted line in Figure 3.21) is a rectangle, characterised by the ATC values.

Figure 3.21. ATC Model

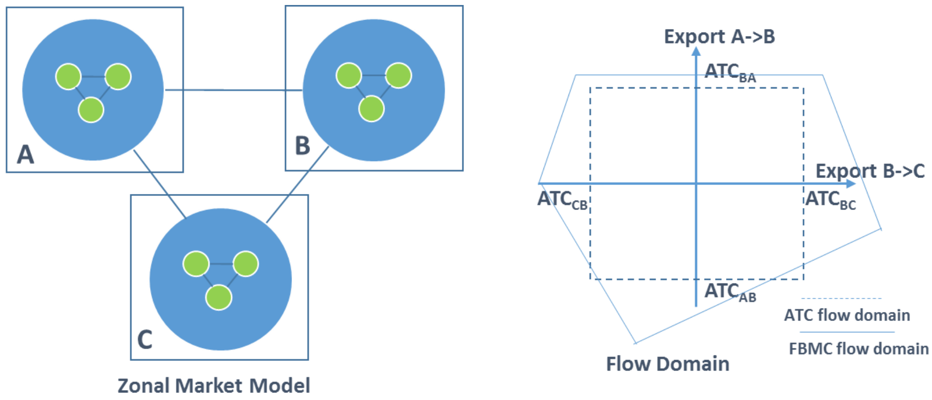


Source: Drawn on the basis of information available in Bergh et al.

Flow-based Market Coupling

Capacity allocation in FBMC takes place partly ex-ante with the market clearing and partly simultaneously with the market clearing. Although FBMC works on the zonal approach as in ATC, it takes into account the physical transmission constraint as well. Unlike ATC, the allowable commercial export/import between two market zones in FBMC is no longer independent from the allowable commercial export/import between other market zones. As a result, the FBMC flow domain is likely larger than the ATC flow domain, as shown in Figure 3.22 (Bergh et al., 2015). The transmission constraints in market clearing algorithm of FBMC depends upon the remaining available margin and PTDF of critical lines (or transmission constraints).

Figure 3.22: FBMC Method



PDTF represents the approximation of the real physical characteristics of the grid and can be derived from generation shifts key. These keys give the nodal contribution to a change in zonal balance, e.g. GSKn,z = 0.3 indicates that the generation at node n increases with 0.3 MW if the zonal balance of zone z increases with 1 MW.

The remaining available margin is the line capacity that can be used by the day-ahead market and depends upon two key components: critical branches (transmission element, e.g. cross-border line, internal transmission line or transformer) and critical outages. Like ATC, a base case is needed in FBMC and for calculating remaining available margin and PDTF. In general, the calculation of remaining available margin and PDTF starts two days before the delivery date (i.e. D-2) and finishes before the morning day-ahead so that they can be used in the day-ahead market clearing.

Base Case (Day-2 Congestion Forecast)

The base case, also referred to as day-2 congestion forecast, is a forecast, made two days before the delivery day, of the state of electricity system at moment of delivery. The base case is needed for (certain) methods of generation shift keys and to determine the reference flows in calculation of remaining available margin.

Every TSO estimates the local base case for its own control area and then different local base cases are merged into one common base case. Base case is estimated on the basis of a reference day, i.e. a day in the past with the similar conditions, e.g. winter, summer, etc.
The reference day outcome is then updated with D-2CF-renewable generation forecasts, load forecasts and outage schedules for generation units, and grid elements. Ultimately, TSOs coordinate the net exchange positions of the reference day to have a balanced CWE (Central Western Europe) system and to update it even if each TSO applies a slightly different methodology.

All TSOs are also required to develop robust fall-back procedures to ensure efficient, transparent, and non-discriminatory capacity allocation in the event that the single day-ahead coupling process is unable to produce results.

Any costs incurred to provide firm capacities and to set up entire processes are supposed to be recovered in a timely manner through network tariffs or appropriate mechanisms. NEMOs are entitled to recover their incurred costs if they are efficiently incurred, reasonable, and proportionate. (For further details, see ITC mechanism in a separate box).

TSOs and NEMOs are required to jointly organise the day-to-day management of the single day-ahead and intraday coupling by meeting regularly to discuss/decide on day-to-day operational issues. TSOs and NEMOs invite ACER and the European Commission as observers to these meetings and publish summary minutes of the meetings.

Under the CACM regulation, NEMOs are required to develop, maintain, and operate a price coupling algorithm and a continuous trading matching algorithm.

Box 1.3. Inter-TSO Compensation Mechanism

Inter-transmission system operator compensation is a mechanism designed to compensate TSOs for (i) costs associated with losses resulting from hosting transmission flows on networks and for (ii) costs of making infrastructure available to host cross-border flows of electricity. ENTSO-E is responsible for establishing an ITC fund to provide such compensation to TSOs.

According to Articles 4.2 and 4.3 of the Annex, Part A, of Commission Regulation (EU) No 838/2010 ENTSO-E, the amount of losses incurred on national transmission systems is computed on the basis of difference between '(1) the amount of losses actually incurred on the transmission system during the relevant period; and (2) the estimated amount of losses on the transmission system which would have been incurred on the system during the relevant period if no transits of electricity had occurred'.

Compensation for transmission losses is required to be calculated separately from compensation for costs incurred associated with making infrastructure available to host cross-border flows of electricity.

ENTSO-E is responsible for computation of transmission losses while ACER verifies the same to ensure a fair and non-discriminatory computation.

The costs of facilitating infrastructure have to be calculated on the basis of forward-looking long-run average incremental costs, taking into account losses, investment in new infrastructure, and an appropriate proportion of the cost of existing infrastructure.

A separate mechanism has been established for inter-TSO compensation for countries sharing a common border with at least one third country.

Regarding contribution to compensation fund, TSOs contribute to the system in proportion to the absolute value of net flows onto and from their transmission system, relative to the total of this measure across the EU. Net flow of electricity means the absolute value of the difference between total exports of electricity from a given national transmission system to countries where TSOs participate in the ITC mechanism and total imports of electricity from countries where TSOs participate in the ITC mechanism to the same transmission system.

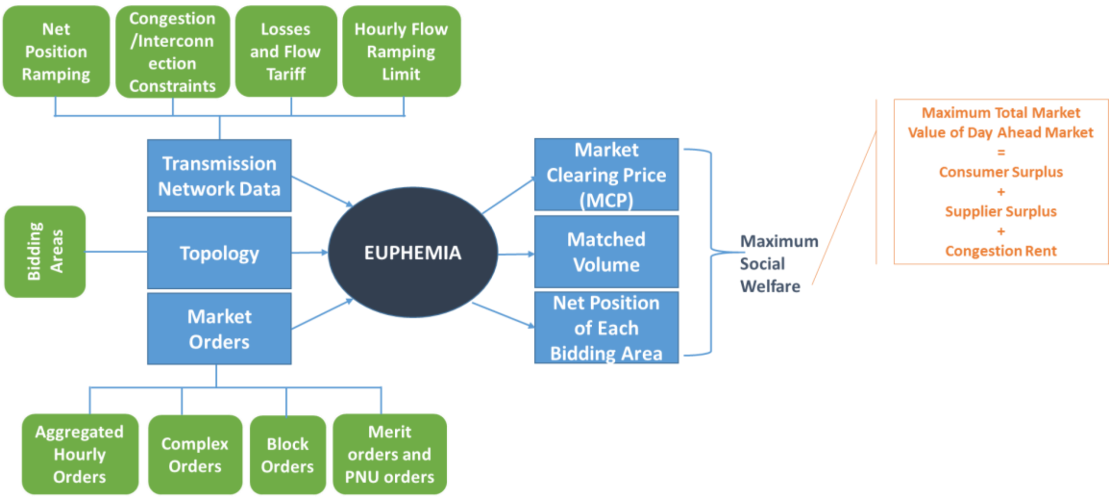
The annual cross-border infrastructure compensation shall be distributed among participating TSOs on the basis of transit and load factor with weightage of 75 percent and 25 percent, respectively.

Transit factor is a proportion of transits on a particular national transmission system state to total transits on all national transmission systems while load factor is the square of transits of electricity in proportion to load plus transits on that national transmission system relative to the square of transits of electricity in proportion to load plus transit for all national transmission systems.

In the case of coupled markets in PCR, EUPHEMIA has evolved a new and precise algorithm for single price coupling and congestion management. Under this mechanism, market participants from each bidding area submit their bids to respective power exchanges. These bids are collected and submitted to EUPHEMIA that then computes an MCP for each bidding area and each period along with a corresponding net position[22]. This algorithm decides on acceptance of orders to maximise social welfare[23] and keep net position[24] of each bidding area below the interconnection capacity.

In general, EUPHEMIA receives a large set of input data containing information for bidding areas, interconnection constraints, net position ramping, losses, flow tariff, and a complex set or market orders, and process it with a sole objective of maximising social welfare or total market value of day-ahead market (function of consumer surplus, supplier surplus, and congestion rent) and ultimately providing with market clearing price, matched volume, net position of each biding areas, and flow in interconnectors (Figure 3.23).

Figure 3.23. Input and Output Data Flow in EUPHEMIA



Source: Price Coupling of Regions, 2016; visit and interaction of study team with various power exchanges across Europe.

EUPHEMIA handles more sophisticated order types (e.g. aggregated hourly orders, complex orders, block orders, merit orders, and PUN [Prezzo Unico Nazionale] orders; see Box 1.4 for further description) and equally treats orders submitted by participants. It matches all bidding areas at the same time to find initial good solution. It keeps computing, however, to increase

[22] Difference between matched demand and supply.
[23] Social welfare = consumer surplus + producer surplus + congestion rent across the regions.
[24] Net position is the difference between the matched supply and the matched demand quantities.

overall welfare. General rule for accepting orders in reference to MCP applies as described below. However, there are specific conditions of acceptance for each order type:

Price of demand order > MCP Price of supply order < MCP	In-the-Money Orders	Must be fully accepted
Price of demand order = MCP Price of supply order = MCP	At-the-Money Orders	Can be either accepted (fully or partially) or rejected Exception applies to regular block orders: That cannot be accepted partially, totally rejected or accepted (condition of fill or kill)
Price of demand order < MCP Price of supply order > MCP	Out-of- the-Money Orders	Must be rejected

Box 1.4. Various Order Types Under EUPHEMIA

Various order types per local market rule at the same time as below (Price Coupling of Regions, 2016)

Aggregated Hourly Orders (Major Regional Markets: OMIE, APX, Belpex, GME, OTE, NORDPOOL and EPEX)	• All demand and supply orders are aggregated on a curve computing aggregated demand and respective supply (for each period of the day) • Sorting of demand orders: highest to lowest prices • Sorting of supply orders: lowest to highest prices • Aggregated hourly orders can be of linear piecewise curve containing interpolated orders or stepwise curve in which two consecutive points will always have same quantity or same price. • Moreover, hybrid curves can contain property of both piecewise and stepwise curves.
Complex Orders	• **Complex minimum income condition (MIC) orders:** Complex MIC is a set of simple supply stepwise hourly orders bound by a constraint to cover supply production cost, which is the sum of fix and operating cost of power plant (Euros/MWh). • **Complex load gradient orders:** In such orders, the amount of energy matched at certain period is constrained by a maximum increment and decrement condition to the energy matched in previous period of the same day. • Complex order can combine properties of both MIC and load gradient orders
Block Orders	• The key elements of block orders are sense (supply or demand), price limit, number of periods, different volumes for different periods, and minimum acceptance ratio. • **Regular block order:** May consist a consecutive set of periods with the same volume and minimum acceptance ratio of 1. • However, in more diverse cases, volume might be different for different periods. Having consecutive periods is not necessary; acceptance ratio might be less than 1. • **Linked block order:** Acceptance of two block orders can be linked to each other by a particular set of rules. • **Exclusive groups of block order:** Combined various block orders with cumulative acceptance ratio of 1 or less. • **Flexible hourly block order:** Regular block order with flexible period of an hour; hour of supply is determined by EUPHEMIA using optimisation criteria.
Merit Orders and PUN Orders	• **Merit order:** Individual stepwise order for a given period in a bidding area ranked according to merit order (taking into account the most crucial congestion in particular bidding areas). • The lowest the merit order, the highest the chance of acceptance • Works as a mechanism in choosing between different orders in an uncongested adjacent bidding areas offering same price (that is equal to MCP). • **PUN Order:** Merit order (in GME-Italy) cleared on PUN price rather than on MCP. • PUN stands for ‘Prezzo Unico Nazionale’, Italian for single national price.

To manage transmission constraint better, cross-border flow between bidding areas is allowed under the ATC model, the flow-based model, and the hybrid of both as described below:

Available transfer capacity model: In the ATC model, lines interconnect bidding areas and are limited by available capacity of such lines. Bidding areas are divided into source and sink bidding areas on the basis of direction of possible flow of power. Thus, nomination of the lines or interconnectors is based on its ATC.

EUPHEMIA also takes into account line losses between bidding areas during physical flow of power. Moreover, levy (cost/MWh) to line operator is considered as flow tariff and included in algorithm as loss with regards to congestion rent with a condition:

- If (MCP of Bidding Area A- MCP of Bidding Area B)<Flow Tariff, No Flow
- If (MCP of Bidding Area A- MCP of Bidding Area B)=Flow Tariff, Flow of Power Until Congestion
- If (MCP of Bidding Area A- MCP of Bidding Area B)>Flow Tariff, Positive Congestion Rent

EUPHEMIA puts a constraint on hourly flow ramping limit on individual lines and set of lines as well.

Flow-based model[25]: Under this model, modelling of physical power flow is based on RAM and PTDF. With all bidding areas connected in a meshed network, this model expresses the constraints arising from Kirchhoff's laws and physical elements of network in different contingency scenarios considered by TSOs. It translates into linear constraints on the net positions of different bidding areas.

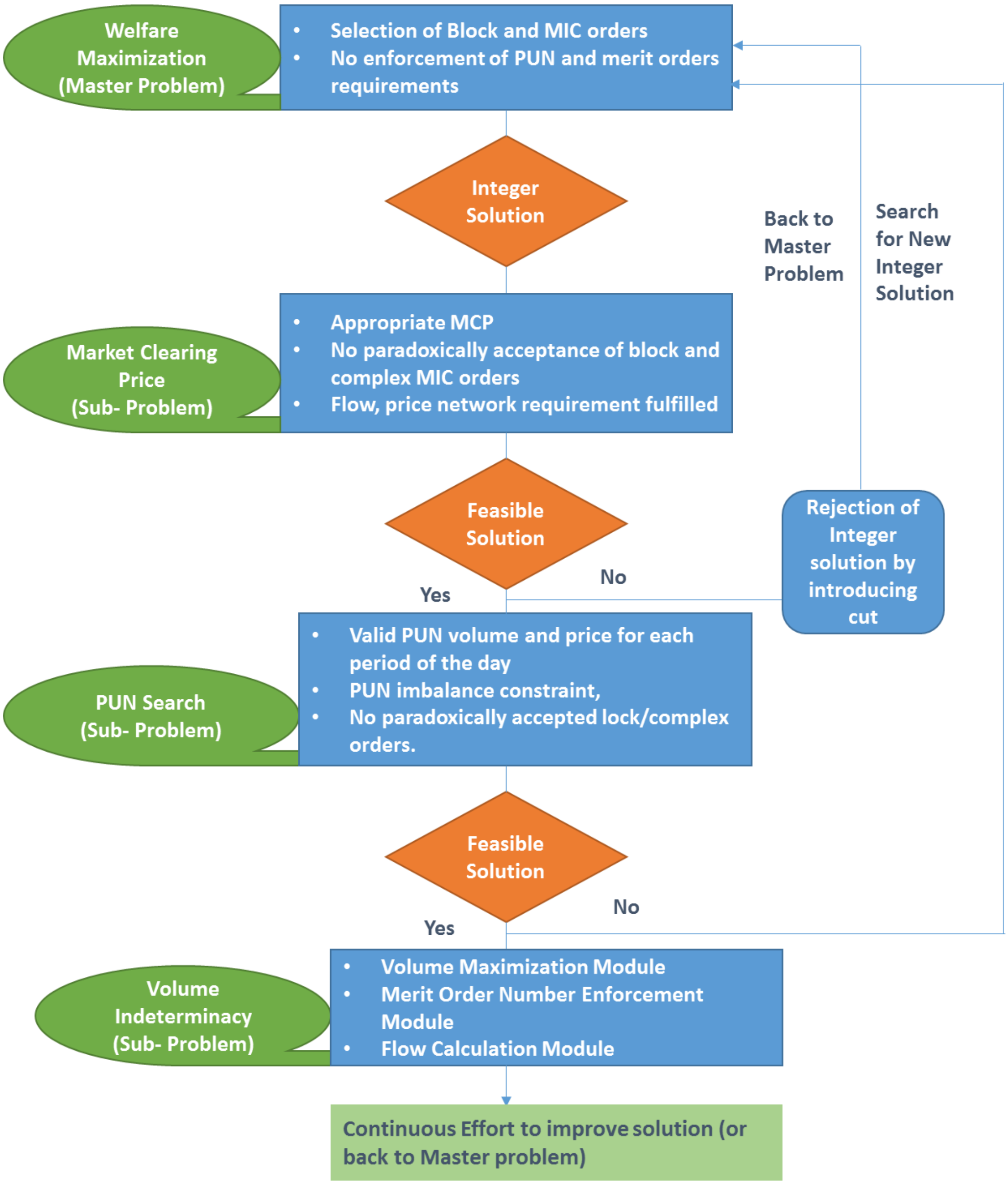
The net position of a bidding area is subject to hourly and daily ramping[26] to add the necessary reserve capacities recurrently.

How the algorithm works: To solve a complex market coupling problem, EUPHEMIA breaks it into simpler problem and models it as quadratic programme. It runs a combinatorial optimisation process aimed to solve a master problem of welfare maximisation and three interdependent sub-problems: price determination, PUN search, and volume indeterminacy (Figure 3.24).

[25] The feasibility of using flow-based model for market coupling is being analysed by several projects and regions across Europe.

[26] Hourly net position ramping refers to a limit on the variation of the net position of a bidding area from one hour to the next. Daily net position ramping is a limit on the amount of reserve capacity that can be used during the day.

Figure 3.24. Algorithm Working Process



MCP = market clearing price, MIC = minimum income condition, PUN = Prezzo Unico Nazionale.
Source: Price Coupling of Regions, 2016; Visit and interaction of study team with various power exchanges across Europe.

Consequently, once completed, the algorithm provides price per bidding area, net position per bidding area, flows per interconnection, matched energy for each block, and MIC and PUN orders. EUPHEMIA produces feasible solutions and chooses the best in line with welfare-maximisation criteria. The chosen results are explainable to market participants and published solution represents the ones with the largest market value while respecting all market rules.

6. Problems and Challenges

The key problems and challenges of the EU target model and PCR for IEM involve:

- **No exclusive provision for integration of renewable energy (specifically wind power) into integrated electricity market:** In addition to achieving an IEM soon, Europe has been working keenly to achieve its targets for reduction of GHG emissions and certain percentage of electricity from renewables under the 2020 and 2030 Climate and Energy Framework. Accordingly, in addition to being a blueprint for market integration, the EU target model for IEM could be the best model to house the guidance rules for renewable energy integration as well and unlock the benefits for electricity market by large-scale deployment of renewable energy technologies. This might also help, under the PCR, to maximise overall welfare by lowering market risks, reducing cost of balancing services, and, ultimately, for generators by lowering market risks in a truly competitive market, for system operators by reducing operation costs of balancing and reserves, and for customers by lowering electricity prices while reducing exposure to fuel and carbon price risk. However, as concluded in Baritaud and Volk (2014), since various renewable energy sources are potential risk for market integration, better coordination and integration of real time markets and harmonisation of integration policy and regulatory frameworks are the recommended approach as adopted under the EU target model.

- **Framework for integrated intraday and balancing markets:** At present, PCR only targets integrated day-ahead market. However, cost-effective and efficient integration of electricity market and closer cooperation between member states might require rolling out a plan to integrate intraday and balancing market (or entire market for ancillary services) as well.
  The resultant large procurement area due to market integration of ancillary services can also help improve the market economy for balancing market and ease the integration of renewable energy systems into the market as widely available resources would take out the pressure from system operator to cut down on renewable energy generators to keep the grid balanced.
- **Demand response management:** As demand response management becomes need for the future as an essential part of smart grids and developed communication solutions, it is unclear how integrated day-ahead market fits well with the concept of demand response bids.

7. Key Findings and Linking with Southeast Asian Region

As concluded in Chang and Li (2012), rapidly increasing energy demand in Southeast Asia and uneven endowment of natural resources make it a perfect case for considering integrated electricity market.

To link the European model to the circumstances in Southeast Asia, the key issues to be discussed include the target model, coordination in network planning and capacity development, developing common algorithms, common business models for generation and transmission, open competition, and sharing infrastructure on the basis of fair compensation.

Looking at the situation of liberalisation and deregulation of electricity markets across Southeast Asia, Singapore was the first country to launch a competitive, liberalised, and deregulated electricity market. The Philippines and Viet Nam have followed the trend by establishing competitive wholesale electricity market. Thailand has yet to introduce whole competition in its electricity market although the state-owned Electricity Generating Authority of Thailand has the sole right to purchase power from private producers including neighbouring countries (Wu, 2012). Similarly, Indonesia has made some efforts toward liberalisation but none has succeeded so far. Malaysia enjoys partial liberalisation. Given this situation, Southeast Asian countries have a long way to go to be able to liberalise, deregulate, and introduce reforms and restructure their electricity markets.

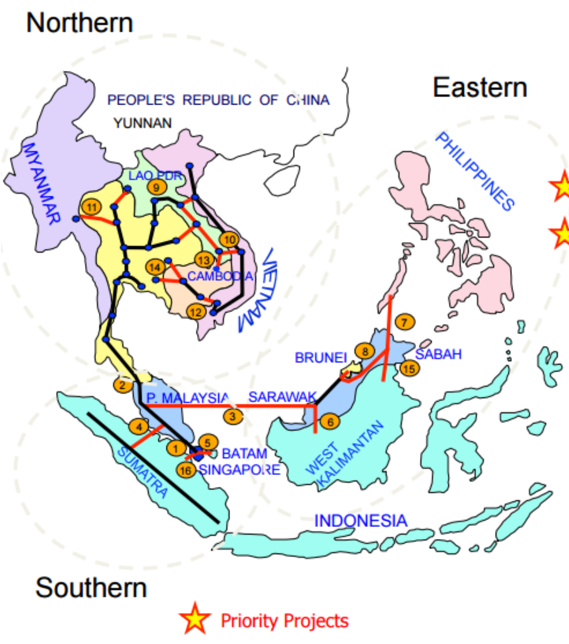
As far as bilateral trade is concerned, significant progress can be seen in terms of a few interconnection projects being promoted by HAPUA under APG (Figure 3.25). However, the cluster 1 and 2 research study aims to highlight the most feasible interconnections across the region and develop optimal power planning and supply reliability evaluation model by using BIMP interconnection.

The policy implications suggested here are deregulation and unbundling, domestic reforms, and subsequent harmonisation of regulation standards.

Considering the findings (Section 2), the European Commission, under the EU's successive energy packages, has put things together by issuing directives and regulations for needed liberalisation, unbundling of TSOs and DSOs, strengthening independence of energy regulators, transparency in the market, and cross-border cooperation.

The Southeast Asian counterpart HAPUA that has been around since 1981 and has recently made efforts toward APG and GMS can potentially play a role similar to that of the European Commission to expedite the efforts to achieve integrated electricity market in Southeast Asia by coming out with directives and regulations.

Figure 3.25. Interconnection Projects, APG



		Earliest COD
1)	P.Malaysia - Singapore (New)	Post 2020
2)	Thailand - P.Malaysia	
•	Sadao - Bukit Keteri	Existing
•	Khlong Ngae - Gurun	Existing
•	Su Ngai Kolok - Rantau Panjang	2016
•	Khlong Ngae – Gurun (2nd Phase, 300MW)	2016
3)	Sarawak - P. Malaysia	2025
4)	P.Malaysia - Sumatra	2019
5)	Batam - Singapore	2020
6)	Sarawak - West Kalimantan	2015
7)	Philippines - Sabah	2020
8)	Sarawak - Sabah – Brunei	
•	Sarawak –Sabah	2020
•	Sabah – Brunei	Not Selected
•	Sarawak – Brunei	2016
9)	Thailand - Lao PDR	
•	Roi Et 2 - Nam Theun 2	Existing
•	Sakon Nakhon 2 – Thakhek – Then Hinboun (Exp.)	Existing
•	Mae Moh 3 - Nan - Hong Sa	2015
•	Udon Thani 3- Nabong (converted to 500KV)	2019
•	Ubon Ratchathani 3 – Pakse – Xe Pian Xe Namnoy	2018
•	Khon Kaen 4 – Loei 2 – Xayaburi	2019
•	Thailand – Lao PDR (New)	2015-2023
10)	Lao PDR - Vietnam	2016-2020
11)	Thailand - Myanmar	2018-2026
12)	Vietnam - Cambodia (New)	2020
13)	Lao PDR - Cambodia	2016
14)	Thailand - Cambodia (New)	Post 2020
15)	East Sabah - East Kalimantan	Post 2020
16)	Singapore – Sumatra	Post 2020

Source: ASEAN Power Grid.

Some of the initiatives that worked as a foundation of integrated electricity market in Europe and could be followed by Southeast Asia include:

- ➢ Unbundling of TSOs and DSOs from other players of supply chain;
- ➢ Establishment of network of transmission system operators across various countries;
- ➢ A short-term plan/network to build a framework for cross-border development, including interconnection and interoperability for a trans-ASEAN power grid network;
- ➢ Non-discriminatory network access to third-parties;
- ➢ A periodic review of progress by a governance body, e.g. HAPUA, and subsequent feedback and suggestions for way forward to each member country;
- ➢ Strengthening the independence of energy regulators; and
- ➢ Viable funding mechanisms to support interconnections and other infrastructure to support cross-border trading

As far as infrastructure development is concerned, as recommended in Wu (2012), infrastructure should be at the core of integrated electricity market in Southeast Asia. Europe worked strategically to mandate a minimum x% of interconnections (of their total production capacity) for each country to connect previously isolated countries with European electricity market. Similarly, should Southeast Asia choose to work on a similar theme, a minimum interconnection level for each country is required? As it is, with construction and planned interconnection across Southeast Asia (Figure 3.24) and potential regional integration between CLMV (Cambodia–Lao PDR–Myanmar–Viet Nam) and BIMP (Brunei–Indonesia–Malaysia–the Philippines), a minimum level of interconnection is not being followed so far. For instance, with East Timor intent on joining ASEAN soon, targeting a minimum level of interconnection might help this country in a big way as it is planning to achieve mere eight percent electrification rate in the country.

Prioritising infrastructure projects in general and interconnections in particular could be developed on the basis of Europe's 'project of common interest' mechanism or economically viable projects on interconnections and renewable energy.

Regarding market design and harmonisation of technicalities, standards, and principles, the potential integrated market in Southeast Asia should aim for integrated organised market with provision for real time and spot market.

Balance market and financial markets are necessary for wholesale market to function properly.

Southeast Asia could focus on gradual price coupling of day-ahead regional markets. As Southeast Asia has just embarked on a journey to achieve an integrated market and as some of the countries are still working to achieve liberalisation in national markets, it is not possible to follow Europe's footsteps in each and every aspect of market coupling. However, the recommended steps as of now are gradual price coupling of day-ahead markets, e.g. price coupling of BIPM region, and exploring the option to adopt implicit auction mechanism so capacity and energy could be auctioned together in a day-ahead market.

As price coupling of day-ahead market uses a single algorithm to find market clearing price and matched volume, allocates efficiently cross-border capacities, and focuses on optimum social welfare, it would require comprehensive efforts from authorities (e.g. HAPUA) to develop a similar algorithm and work closely with TSOs in each region to identify and bifurcate considered regions into different bidding areas.

As to technical details of cross-border capacity allocation, ATC and FBMC are the latest mechanisms used in Europe. Considering the present limited interconnections in Southeast Asia, FBMC could be used to interconnect more efficiently and take into account the congestion in critical lines.

The major challenges we see regarding market coupling of spot markets across Southeast Asia are the need for comprehensive and precise institutional mechanism and overall governance to actively work on harmonisation of standards, codes, roles, and responsibilities of all parties involved; close coordination among TSOs and with market operators; fair selection of nominated market operators; and various other related aspects.

To conclude, on the basis of all the problems and challenges identified in Section 6 and 7, the key findings of the Europe study model, and linking the countries in the region under consideration, a preliminary model of integrated electricity market across Southeast Asia will be developed under research work of cluster 3 in year 2.

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