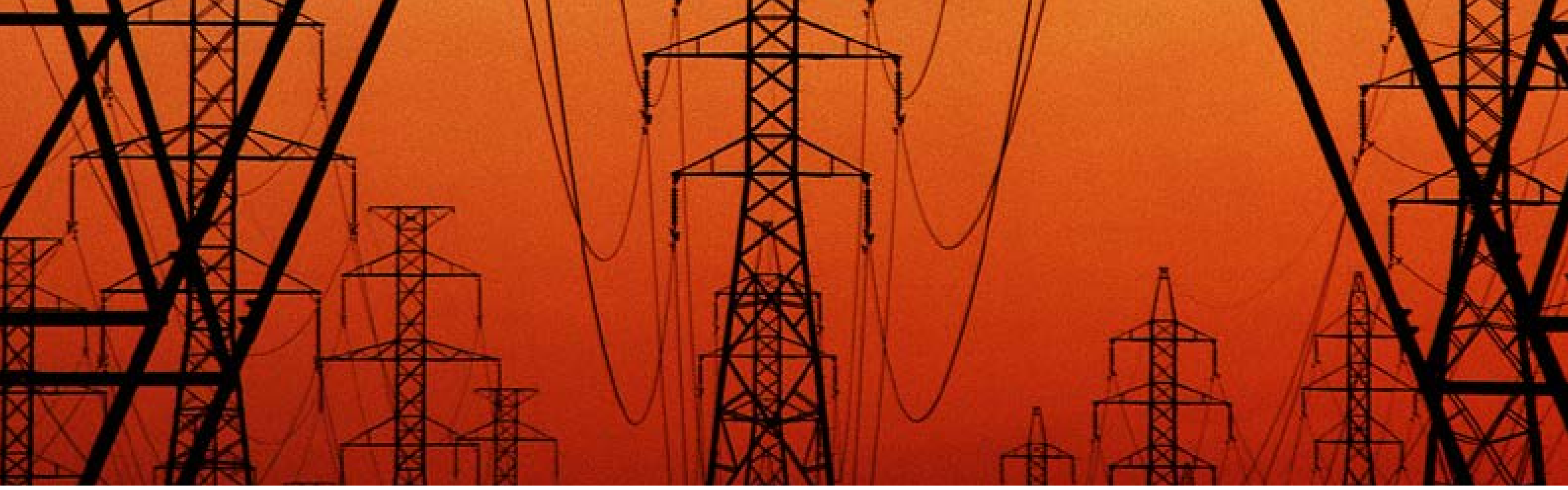
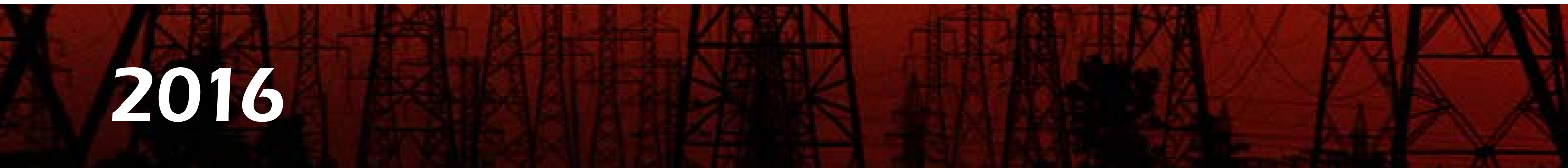


LARGE-SCALE ELECTRICITY INTERCONNECTION

Technology and prospects for cross-regional networks



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

Large-Scale Electricity Interconnection: Technology and Prospects for Cross-regional Power Networks, to be launched in April 2017, aims to deliver policy recommendations for power sector interconnection consistent with an integrated vision for future power systems, from end use to distribution and transmission. In keeping with International Energy Agency (IEA) scenarios, the publication will assess the short- and medium-term technical, market, regulatory and policy measures, benefits, costs and investments required to accelerate regional interconnection. As the publication is centred around regional opportunities for interconnection, the IEA is partnering with State Grid Corporation of China, Global Energy Interconnection Development and Cooperation Organization (GEIDCO), Nordic Energy Research, the Commission for Regional Energy Integration (CIER), and the Inter-American Development Bank to provide a world-spanning analysis of technological prospects for interconnection, the current levels of deployment and mid-term investment potential, and the market and regulatory frameworks necessary for linking national power systems at much higher scales.

Electricity transmission is a key enabler of a clean energy system. Given the versatile and efficient nature of electricity for end-user applications, electricity demand has been growing more rapidly than overall energy consumption. Decarbonisation is expected to strongly reinforce this trend: most of the low-carbon technologies that are applied at the largest scale (such as hydro, nuclear, wind and solar) are electricity-generating technologies. On the end-user side, the electrification of transport and of end-use consumption in buildings will strongly increase the share of electricity in final energy consumption.

Electricity networks have been built for over a century. Electrification started in major cities, which have become progressively interconnected to improve security of supply. This trend still continues today and leads to vast interconnections spanning the border of states and now reaching a continental scale. For most of this time, the network was built and optimised for a high-carbon power system relying on a small number of large, centralised power plants and feeding a transmission grid located reasonably near to load centres. While continental-scale interconnected and frequency harmonised systems have existed for decades, large-scale long-distance power flows have been limited, and interconnections primarily served system security purposes. In addition, traditionally the distribution system has been unidirectional, distributing electricity flowing from the transmission system down to end users whose demand was generally regarded as rigid and exogenous.

Such electricity networks are not well suited to serve a low-carbon energy system, which will tend towards greater decentralisation as highlighted in IEA decarbonisation scenarios. Significant reinforcement of long-distance transmission capacity within systems and enhanced interconnection between systems will be necessary to achieve the climate, security and affordability objectives of delivering electricity in the 21st century. Where cost-effective, interconnection at much larger scales than today could deliver a range of benefits:

Balancing mismatches in supply and demand and peak capacity savings. Demand patterns exhibit considerable variability due to differences in behaviour, economic structure and climate across various regions. Linking winter peak-demand regions with summer peak-demand regions, for example, or regions in different time zones, yields large benefits by smoothing seasonal and daily peak-load variability. Similarly, there is a regional disparity between renewable production patterns and resource endowment. As a result, strong transmission interconnections can increase the flexibility of the power system and achieve measurable savings in peak capacity needs.

Integration of variable renewable energy. Transmission interconnection is proving to be a valuable flexibility tool to facilitate the integration of variable renewable resources. While technological progress in wind and solar photovoltaic (PV) is opening new deployment possibilities in less favourable resource areas, transmission expansion is often the only possible way to integrate the most attractive resources. The increasing maturity of high- and ultra-high voltage (UHV)[1] transmission technology – with over 250 gigawatts (GW) commissioned globally and 200 GW in the pipeline – potentially opens up entirely new interconnection possibilities and transportation corridors.

Accessing remote energy resources. Electricity consumption is heavily concentrated in major cities, most of which will not be able to rely solely on local renewable resources due to the density of their energy demand. The three most important renewable energy sources – hydro, wind and solar – are highly location-specific, and the sites with the best resources are often located in remote regions far from the major demand centres.

[1] High voltage refers to voltage levels above the lower limit of transmission networks, generally above 35 kilovolts (kV). UHV generally refers to voltage levels above 800 kV.

Technology for interconnection: Status and prospects

The global power sector spent around USD 700 billion in 2015 to maintain, upgrade or expand power system assets from generation to end consumers (IEA, 2016). Despite the increased focus on renewables and new generation capacity, electricity networks accounted for nearly 40% of this investment. The global electricity grid is a complex and vast system encompassing 75 million kilometres (km) of networks. Under the baseline scenario in the IEA *World Energy Outloo 2015k*, the New Policies Scenario,[2] an additional 25 million km would be required. The total length of electricity networks under this scenario would be sufficient to cover the distance from Earth to Mars and back.

More importantly, the way in which the investment is directed will progressively change, with a greater emphasis on flexibility and interconnection. Investment in transmission will need to be increased to keep pace with policy developments, both in absolute terms (an increase by a third), and as a share of power sector investments.

Figure 1 • Historic and projected investments in transmission and distribution, IEA 2DS scenario

Source: IEA (2016, World Energy Investment; IEA (2016), *World Energy Outlook (2016)*.

Currently, around 250 GW of interconnectors and high-voltage transmission links globally, equivalent to the full generation capacity of France and Italy combined. This number is expected to grow by nearly a third before 2020.

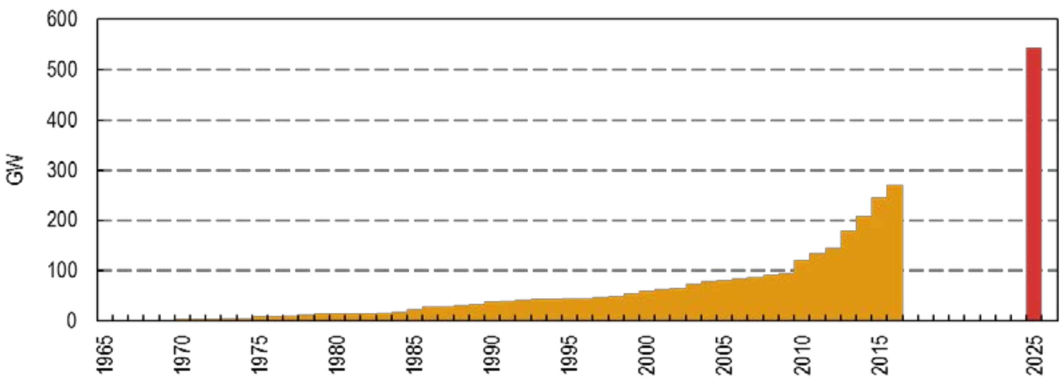
Technology needs for future interconnection

Alternating current (AC) has been the preferred global platform for electrical transmission to homes and businesses for the past 100 years. And yet high-voltage AC transmission has some limitations, starting with transmission capacity and distance constraints, as well as the impossibility of directly connecting two AC power networks of different frequencies. With the rapid growth of variable renewables; the growth in access to electricity; the electrification of new services in transport, industry and buildings; and the need to build a smarter grid, new technologies for transmitting power over long distances and between

[2] The New Policies Scenario takes account of broad policy commitments and plans that have been announced by countries, including national pledges to reduce greenhouse gas emissions and plans to phase out fossil energy subsidies, even if the measures to implement these commitments have yet to be identified or announced.

power systems are expected to grow far beyond their current levels of deployment. The needs of future power systems determine what role interconnection and large-scale transmission technology will play; and how various technologies could perform in these roles. *Large-Scale Electricity Interconnection: Technology and Prospects for Cross-regional Power Networks* will assess these future prospects in depth.

Figure 2 • Growth in high-voltage transmission capacity



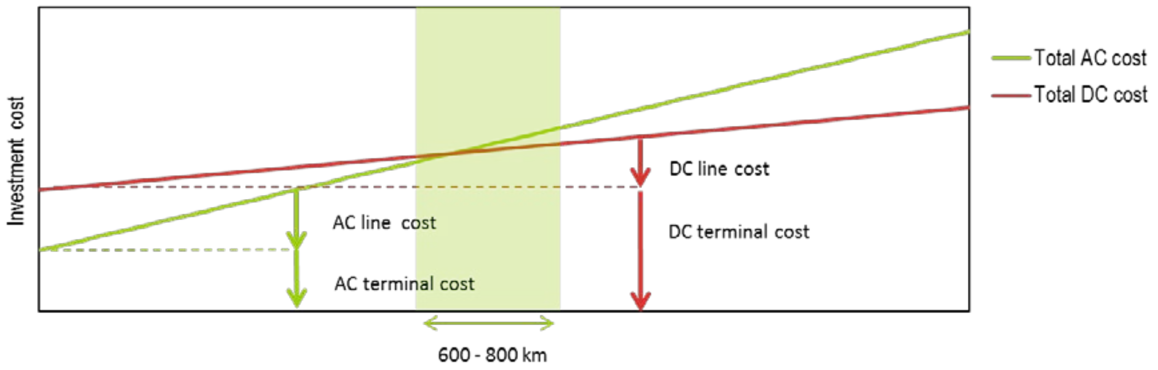
Source: BNEF (2016), *Global HVDC Interconnector Database*; IEA (2016), *Energy Technology Perspectives 2016*.

Role #1 Low-cost interconnection over large distances. While the fixed costs of terminals at both ends of high-voltage direct current (HVDC) links are more expensive than AC, the cost per unit length of the line itself is lower – meaning, all other things being equal, the longer the distance of the link, the lower the relative cost of the link per unit of energy. Over a certain distance, the so-called "break-even distance" (approximately 600-800 km for current technologies), HVDC becomes the lowest cost option. In addition, there are no technical limits to the potential length of a HVDC cable. In a long AC cable transmission, the reactive power flow due to the large cable capacitance will limit the maximum possible transmission distance. With HVDC there is no such limitation.

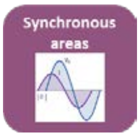
Current performance: At present, nearly 10 000 km of interconnectors have been built, with each interconnection measuring an average of 250 km. The longest interconnection is the undersea NorNed link between Norway and the Netherlands, spanning nearly 600 km and delivering 700 MW of high voltge direct current power.

Future prospects: With the increase in demand for long-distance interconnection, a number of projects have been envisioned that would greatly improve upon the current status. Projects in the pipeline include the undersea North Sea Network (NSN) link between the Nordic zone and the United Kingdom, which will deliver up to 1.4 GW of power through an undersea cable 730 km in length.

Figure 3 • Relative economics of HVAC vs HVDC for interconnecting power systems



Note: HVAC = high voltage alternating current; DC = direct current.



Role #2 Connecting asynchronous grids. When AC systems are to be connected, they must be synchronised. This means that they should operate at the same voltage and frequency, which can be difficult to achieve. Since HVDC is asynchronous it can adapt to any rated voltage and frequency it receives. Hence, HVDC is used to connect large AC systems in many parts of the world.

Current performance: Nearly 13 GW of links currently interconnect asynchronous grids around the world. These systems can be pinch points in power systems, as is the case of Japan where 1 200 MW connect the East and West regions. On the voltage side, the highest voltages for this functionality are seen in the 500kV China-Russia power interconnection.

Future prospects: Despite positive examples such as the NordBalt link, connecting the Baltic with the Nordic which began trial operations in 2016, projects linking asynchronous grids are greatly needed to advance interconnection in the short-term. Examples include links between the asynchronous grids of South America in Brazil, Uruguay and Argentina. Plans are also in place to increase the power exchange capacity between East and West Japan to 2 500 MW.

Role #3 Connecting remote energy resources and loads. Increasing voltage allows for more remote resources to become economical. The current race for increasing voltages and transmission distance is delivering entire systems transmitting power at 800 kV and 1000 kV, which greatly reduce losses over long distances. Examples of key resources that are particularly far from loads around the world include distant hydro resources in the Chilean Patagonia or in Brazil, wind and hydro power in Western China, or solar power in the Rajasthan desert in India.

Current performance: The world's longest transmission line is the Rio Madeira HVDC link in Brazil, which brings hydro resources from the Amazon basin to the densely populated Sao Paulo area, 2 800 km away.

Future prospects: UHV technologies above 800 kV are seeing increased deployment and could technically connect vast amounts of extremely distant resources. The Chinese ± 1 100 kV Xinjiang-Anhui line planned for 2017 will deliver 12 GW of power over 3 300 km, achieving historic highs for capacity, distance and voltage.

<u>Role #4</u> <u>Accommodating variable renewable electricity</u>. Variable renewable energy (VRE) deployment requires flexible transmission links. One of the key drivers behind HVDC lines and interconnectors is the ability to shift intermittent renewables to areas of high demand when conditions would otherwise lead to curtailment. This is an important part of the build out for intermittent renewables. A range of transmission technologies can be deployed to increase the capacity, including flexible alternating current transmission systems (FACTS) in HVAC lines, and in particular flexible high-voltage direct current (HVDC). A key component of flexible HVDC is a voltage-source converter – a way of converting DC to AC electricity with much greater freedom and flexibility

Current performance: Nearly 80% of new interconnection and high-voltage transmission lines rely on flexible technologies. Voltage source converter (VSC) is a leading option – costs for insulated-gate bipolar transistors (IGBT), a key component of flexible HVDC-VSC lines, have decreased by 2/3 over the past eight years. The new interconnector in Denmark, Skagerrak 4, is particularly designed for flexibility to accommodate high shares of wind power in the country, with the full transmission capacity rated at 1.4 GW.

Future prospects: Flexible HVDC systems can operate at voltages of 500 kV. In the medium term, as more flexible links are deployed, voltages and capacities are expected to increase. Multi-terminal VSC systems are expected to grow significantly, particularly in emerging economies, with high profile examples including multi-terminal links in India (the first multi-terminal 800 kV project), and the first five-terminal VSC-HVDC link in Zhoushan, China.

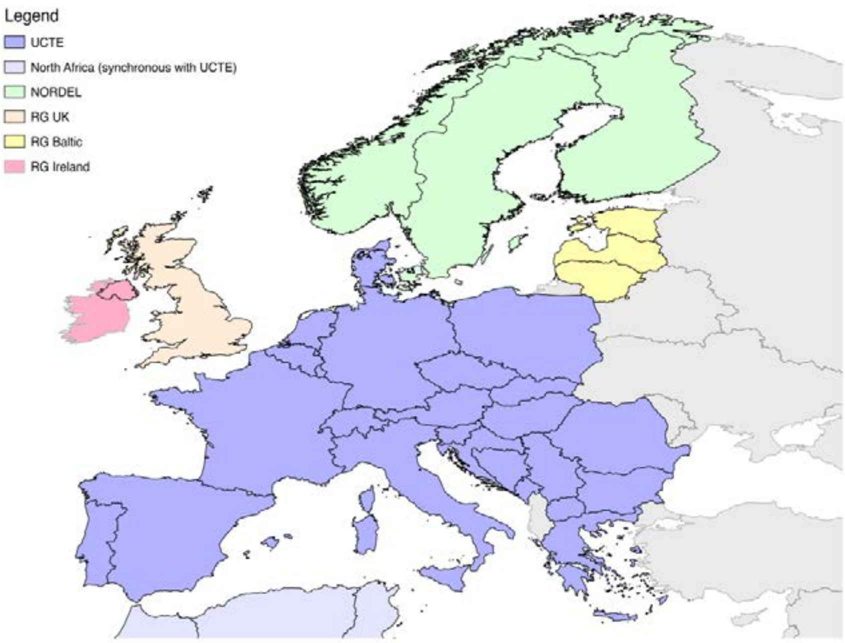
Case studies of regional energy interconnection

The degree future power systems will be interconnected will not be determined by technology - while some key technical developments could accelerate deployment, it is the market, regulatory, financial and political context in which interconnections are deployed that makes or breaks individual projects and that will determine future growth. *Large-Scale Electricity Interconnection: Technology and Prospects for Cross-regional Power Networks* will examine individual cases with significant potential for interconnection, present a long-term vision for them and assess the key levers to activate to increase links between these countries and regions. The case studies presented here will be expanded to present modelling of potential interconnections in the mid-term, complemented with Northeast Asia and African cases.

Case study #1: Interconnecting the European continent

A synchronous grid is an electrical grid operating at a synchronized frequency, physically connected during normal system conditions. Currently, the synchronous grid of Continental Europe (also called UCTE grid[3]) is the largest interconnected grid in the world in terms of hosted power capacity, with more than 1 TW installed by 2015.

Figure 4 • The synchronous grids of Europe



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

Source: Wikimedia commons.

[3] The Union for the Co-ordination of Transmission of Electricity (UCTE) was an entity which coordinated the operation and development of the electricity transmission grid for synchronous grid of Continental Europe since 1951. The UCTE was wound up in 2009 and all its operations have been transferred to ENTSO-E.

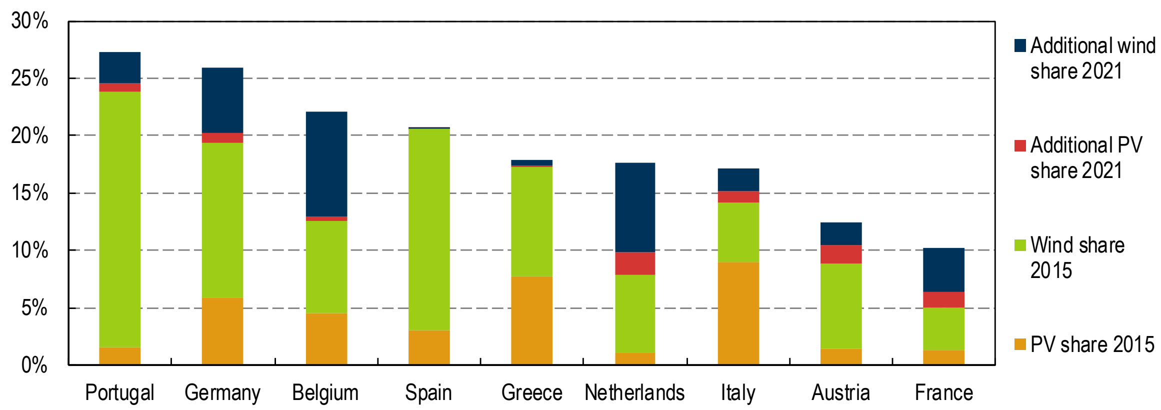
The synchronous grid of Continental Europe encompasses the 24 countries of the Continental Europe Regional Group of the European Network of Transmission System Operators (ENTSO-E) and neighbouring countries (Albania, Ukraine, Morocco, Algeria and Tunisia), synchronously connected but not involved in the ENTSO-E. The Continental Europe Regional Group of ENTSO-E addresses technical and operational aspects specific to the UCTE grid's system operations.

European power markets are characterised by the liberalisation of the electricity generation sector: the European Commission has strongly pushed in this direction since mid-90s, aiming to increase competition in the generation sector as well as the level of interconnection of European power systems. Currently, all European countries have liberalised their gas and power sectors to various degrees.

Over the last 6 years, electricity demand in the UCTE grid has slowly decreased, from 2 600 to 2 500 terawatt hours (TWh). In the same time period, wind and solar PV production increased by 79% and 338% respectively, reaching 226 TWh and 94 TWh in 2015. This development led to variable renewable energy (VRE) accounting 12.8% of total electricity production in 2015 (ENTSO-E, 2016). The large deployment of VRE technologies occurred primarily as a result of governments' commitment towards renewable energy, in combination with a rapid VRE cost decrease.

For the near future, the IEA *Medium term renewable energy market report 2016* projects a continuous deployment of VRE technologies in the UCTE grid (see figure 5).

Figure 5 • Share of VRE generation in 2015 and 2021 for selected UCTE countries



Source: Adapted from IEA (2016a), Medium Term Renewable Energy Market Report.

Key point • Double-digit shares of VRE in annual generation are becoming increasingly common in UCTE countries

VRE installed capacity has ramped up in recent years, and the mobilisation of flexible resources to balance the power systems has become more relevant to integrate higher levels of VRE penetration. Transmission and interconnector capacity are a valuable resource for cost-effective system operation, particularly at high shares of VRE.

Where an area has a high potential to interconnect with adjacent areas, it has the opportunity to make use of the flexible resources of its neighbours. Interconnection capacity may be used to jointly optimise use of power generation in two neighbouring markets, or to balance it. Very large areas will have proportionately less potential for interconnection, but small areas embedded in continental size systems have a large potential.

The European Commission emphasises the importance of sufficient interconnection capacity for boosting Europe's integrated electricity market, security of electricity supply and ability to integrate more renewable energy. The Commission has set a target of 10% electricity interconnection by 2020. In 2014, in its European Energy Security Strategy, the Commission suggested extending its 10% electricity interconnection target by 2020 to 15% by 2030.

In this case study, the interconnections of two borders of the UCTE grid are considered:

- **The Southern border**: The Iberian peninsula currently has low interconnection capacity with both France and with Morocco. Increasing the connectivity between Europe and the Maghreb could assist achieving energy policy objectives, including the VRE deployment in the regions.
- **The Northern border**: East Denmark, Sweden, Norway and Finland form the Nordic synchronous grid. The interconnections with the UCTE grid allow both systems to reap benefits (energy and flexibility) from each other.

The southern border

Background

Table 1 • Transmission System Operators (TSOs) in the 'southern border' case study countries

	Country	TSO
South Europe	Spain	Red Eléctrica de España (REE)
	Portugal	Redes Energéticas Nacionais (REN)
	Italy	Terna Rete Italia (TRI)
	France	Réseau de transport d'électricité (RTE)
North Africa	Morocco	Office National de l'Electricité et de l'Eau Potable (ONEE)
	Algeria	Sociètè Nationale de l'Electricité et du Gaz (Sonelgaz)
	Tunisia	Societe Tunisienne d'Electricite et du Gaz (STEG)

ENTSO-E represents 42 TSOs from 35 countries across Europe. ENTSO-E was established and given legal mandates by the EU's Third Legislative Package for the Internal Energy Market in 2009, which aims at further liberalising the gas and electricity markets in the EU. ENTSO-E members share the objective of setting up the internal energy market and ensuring its optimal functioning, and of supporting the ambitious European energy and climate agenda. One of the important issues on today's agenda is the integration of a high degree of VRE in Europe's energy system, the development of consecutive flexibility, and a much more customer centric approach than in the past.

In Morocco, the electricity market is structured around a national utility, the ONEE, placed under the administrative and technical control of the Ministry of Energy, Mines, Water and the Environment. This vertically integrated utility operates throughout Morocco's electricity value chain, including generation, transmission, and distribution, calling forward capacity and balancing the grid. ONEE is therefore responsible for generating and delivering electricity in all Morocco. As the sole buyer, ONEE supplies the market through its own plants, those of independent power producers (IPPs), imports and a number of private industrial producers.

Sonelgaz has since 1969 the monopoly on the distribution and sale of natural gas in Algeria, and for the production, distribution, import and export of electricity. In 2002, the field of electric power generation has been open to competition, ending Sonelgaz's monopoly.

The Tunisian government nationalised the generation, transmission, distribution, import and export of electricity and gas in 1962, entrusting these activities to STEG (*Société Tunisienne de l'Electricité et du Gaz*). STEG is a public institution with financial autonomy placed under the Ministry of Industry.

The Maghreb Electricity Committee was entrusted with the responsibility of co-ordinating the integration of the Maghreb electricity grid, following the signing of the Marrakesh Treaty by the Heads of State of the Arab Maghreb Union.[4] The Treaty of Athens (2003) signed with the European Commission further underscores the political will to integrate the Maghreb's electricity markets. Even if electricity trade among countries of the Maghreb is low, the construction of physical interconnections and the creation of political institutions demonstrate that a real Maghreb grid could emerge.

European policy framework favours the exchange of renewable energy from North Africa: Article 9 of the European directive on the promotion of the use of energy from renewable sources (Directive 2009/28/EC, 23 April 2009) permits the selling of electricity from renewable sources from third countries on the European market and allows Member Countries to import and include the energy in their quotas of electricity from renewable sources to be achieved by 2020. But as the 2008 financial crisis affected European power consumption, the need to buy renewable energy from other countries decreased.

Different organisations have been established to promote the co-operation of the European and African power systems, including RES4MED, MedGrid, Med-TSO and others.

Current physical infrastructure

The Iberian Peninsula is weakly interconnected with the rest of Europe. Interconnection capacity between Spain and France was expanded from 1.4 GW to 2.8 GW in February 2016 when a new interconnector came online. Iberian and French TSOs have advanced in the assessment of relevant projects in order to raise the capacity of electricity exchanges between Spain and France to 8 GW in the medium-term (EC, 2015)

At the end of 1997, the grids of Spain and Morocco were interconnected by a single 400 kV circuit in alternating current (AC) through a submarine cable line that links the substations of Tarifa in Spain and Ferdioua in Morocco. In July 2006, a second submarine 400 kV line became operational. The maximum transfer capacity is 600 MW from Morocco to Spain and 900 MW from Spain to Morocco, with a thermal limit of 1 400 MW. The interconnector is currently owned 50/50 by REE and ONEE. Morocco amended its energy legislation to be able to purchase electricity from Spain on the liberalised market. A 400 kV line then continues from Morocco to Algeria and Tunisia (REE, 2016).

Electricity trade

North African countries are experiencing a growing electricity demand, in particular Tunisia and Morocco. Almost all of the Morocco's imported electricity comes from Spain.

On the Iberian Peninsula, VRE generation accounted for 21% of total generation in 2015 (18% from wind and 3% from solar PV). This number is estimated to increase by 1% over the next five years (see figure 5). In Morocco, wind generation accounted for 8% of total generation in 2015. It is expected that the share of VRE generation will reach 15% by the end of 2021 (IEA, 2016a).

[4] The Arab Maghreb Union comprises Algeria, Libya, Mauritania, Morocco and Tunisia.

Mid-term opportunities for interconnection

Interconnections are a viable option to ease the burden of North Africa's increasing demand: compared to investment in additional generation and operational costs, grid infrastructure is a low-cost solution. The structural overcapacity in Europe can help meet the North Africa's increasing need for energy.

Also the high share of VRE in Spain and Morocco calls for investments to increase the flexibility in both European and North-African countries. Improved grid connections could play an important role in this regard. Looking further into the future, stronger interconnections could help net out different seasonal-demand profiles (peak demand for electricity in Europe is in winter, while in North Africa it is in summer) (Daly, 2015).

The connection between Spain and Morocco remains the only link between Europe and Northern Africa. There are currently plans to interconnect Tunisia and Italy. The planned line consists of a submarine 400-kV DC line, more than 200 km long, with a rated capacity of 600 MW. The line will connect the substation of Partanna (in Sicily) and Haouaria (Daly, 2015).

In June 2016, the Moroccan Minister of Energy and the Portuguese Minister of Economy signed an agreement to conduct a feasibility study for the electric interconnection project between Morocco and Portugal, with a capacity of 1 GW (MEM, 2016). Other projects for new transmission lines between Europe and Africa are at earlier, different stages.

Box 1 • Challenges and opportunities for increasing interconnection with Europe

Higher interconnection and transmission capacity in Europe and North Africa could enable the optimal use of VRE generation; alleviate the issue of daily and seasonal demand peaks; and reduce the need for new generation capacity to meet growing energy demand in Maghreb.

Clear regulations, agreements and grid codes are necessary to enable different power systems to operate together efficiently, catching all the potential that a shared power system may introduce.

Different organisations have been established to promote clean energy solution for North Africa countries and the co-operation of the European and African power systems, including RES4MED, MedGrid, Med-TSO and others. These knowledge networks may offer viable solutions to conform regulations and grid codes.

The northern border

Background

Various TSOs manage the national grids of the case study's countries. For historical reasons, there are four TSOs in Germany. Interconnection with the Nordic countries is managed by 50Hertz and TenneT. Currently the Nordic grid is linked via several HVDC cables with the UCTE grid (see table 3). The main drivers for interconnection development between the grids are the expected increase in renewable generation and the aim of securing a dynamic internal electricity market across Europe.

Table 2 • Transmission System Operators (TSOs) in 'northern border' case study countries

	Country	TSO
UCTE countries	Germany	50Hertz Amprion TenneT TransnetBW
	Poland	Polskie Sieci Elektroenergetyczne (PSE)
	Netherland	TenneT
Nordic grid countries	Denmark	Energinet.dk
	Sweden	Svenska Kraftnät
	Norway	Statnett SF

Current physical infrastructure

Denmark's grid is separated into the two asynchronous subsystems, interconnected by the Great Belt Power Link between the islands of Funen and Zealand. The Western Danish power system is synchronous with continental Europe; the Eastern Danish power system is synchronous with the Nordic power system (see figure 4).

Nordic countries are connected to UCTE countries with a number of submarine HVDC lines.

Table 3 • Interconnections between Nordic countries and central Europe

Name	Countries	Voltage	Capacity
NorNed	Norway–Netherlands	450 kV	700 MW
Skagerrak	Norway – West DK	250-500 kV*	1 700 MW
Konti–Skan	Sweden – West DK	300 KV	300 MW
Baltic Cable	Sweden – Germany	450 kV	600 MW
SwePol Link	Sweden – Poland	450 kV	600 MW
Kontek	East DK – Germany	400 kV	600 MW
Great Belt Power Link	East DK – West DK	400 kV	600 MW

Note: Skagerrak interconnections is formed by four different lines with different voltage levels

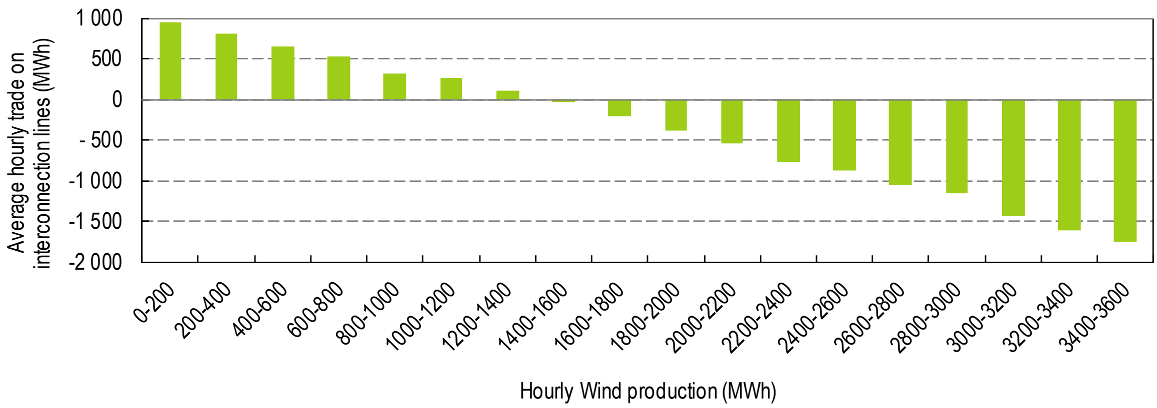
Electricity trade

Norway produced 144 TWh and consumed 129 TWh in 2015. As a comparison, in the same year Germany produced 616 TWh and consumed 567 TWh. Thanks to good resources, hydropower is the main source of electricity in Norway, accounting almost 96% of domestic energy production. Norway exports large amounts of its electricity production (net exports accounted by 10% of total energy production in 2015).

Sweden's energy system produced 158 TWh in 2015. Sweden's energy production depends on hydro (46.7% in 2015) and nuclear (34.1%) power. As Norway, Sweden exports large part of its energy production: in 2015, the net exports accounted by almost 15% of the domestic production. In 2015, almost 5 TWh were exported trough the HVDC interconnections, mainly to Poland.

Denmark is a net importer of electricity, importing from Norway and Sweden (8.8 TWh in 2015) and exporting to Germany (2.2 TWh). Exports happen mainly through the Kontek HVDC connections (IEA, 2016b; NPS, 2016). Interconnections in Western Denmark are already used to balance the system, selling energy when wind production is high and importing energy when wind production is low.

Figure 6 • Average trade on interconnection lines by wind generation levels, western Denmark, 2015



Source: Adapted from Energinet.dk (2016), Market data

Key point • Wind generation and interconnection capacity act in a complementary way.

Mid-term opportunities

In a detailed analysis of VRE integration potential for Northern Europe (IEA/NER, 2016), transmission capacity emerged as one of the most promising means of increasing energy system flexibility. A scenario in the analysis (the Nordic Carbon-Neutral Scenario) sees the VRE share of generation in Northern Europe grow from 7% in 2013 to 30% in 2050.

This scenario exemplifies the potential for regional smoothing through interconnection, illustrating the changing role of transmission grids under high shares of VRE. The majority of electricity trade today is unidirectional, flowing from an exporting country to an importing country. Under high shares of VRE, greater bidirectional utilization of interconnectors sees the majority of trade activity used for balancing, resulting in regional smoothing.

Additional HVDC links from Germany to Norway (NorGer, 1 400 MW, and Nord.Link, 1 400 MW) are currently planned and are expected to be operational in 2020.

Energinet.dk, 50Hertz and Svenska Kraftnät are involved in the so-called “Combined Grid Solution”, a unique offshore electricity grid in the southern part of the Baltic Sea. It will be the first international offshore power grid, utilising the planned Kriegers Flak wind farm to connect the national grids of Denmark, Germany and, potentially, Sweden. Completion of grid connection work is expected by the end of 2018, with first power exchanges by 2020.

The North Seas Countries Offshore Grid Initiative is a collaboration framework between European Union and Norway: the objective is to create an integrated offshore energy grid, linking offshore wind farms.

Box 2 • Challenges and opportunities for increasing interconnection with Europe

Sharing of costs and benefits and the required domestic grid-reinforcements can act as a non-economic barrier to expanding interconnections.

Increased interconnection between the UCTE and the Nordic systems allows benefitting from synergies in the generation portfolio, including the integration of variable generation and enhancing energy security in hydro reliant countries during periods of drought.

Increased interconnection capacity may unlock wind potential in Nordic countries beyond domestic demand in response to higher electricity prices on the continent.

Case study #2: Linking the Americas through SIEPAC

Central American countries, comprising Mexico, Nicaragua, etc., represented just under a tenth of final electricity demand in the continent. Over the last ten years, demand has increased by 200%. The IEA Energy Technology Perspectives 2016 projects a large-scale deployment of photovoltaic (PV) and wind power in the region, amounting to 110 GW - and nearly 15% of all generation by 2050, up from around 1% today. Meanwhile, countries in the region are undergoing dramatic shifts towards deregulation and good practice market design. It is in this context that the possibility of achieving higher levels of interconnection in the region is articulated, the initial stepping stones of which have been laid out by SIEPAC – the Central American Interconnection System (Sistema de Interconexión Eléctrica de los Países de América Central).

Background

SIEPAC is the supranational initiative developed by six Central American nations (Panama, Costa Rica, Honduras, Nicaragua, El Salvador and Guatemala) that resulted in the development of a regional electricity market (MER) and the construction of nearly 1 800 km of transmission infrastructure to increase transfer capacity at all borders in the region.

By means of the Framework Agreement of the Electrical Integration of Central American and its first protocol, ratified by the six Central American governments between 1997 and 1998, SIEPAC was provided with a legal foundation and two regional organisations for the regulation (Comisión Regional de Interconexión Eléctrica [CRIE]) and operation (Ente Operador Regional [EOR]) of the electricity market were created.

The Framework Agreement also provided for the establishment of an international transmission line company (Empresa Propietaria de la Red S.A. [EPR]) incorporated in 1999. EPR was mandated by the governments of Central America with the design, financing, construction and maintenance of the physical transFgiruemission infrastructure for the interconnection of the electricity systems in the region.

The public-private partnership model nature of EPR constitutes an international co-operation reference and is comprised of six regional state-owned utilities and three extra-regional shareholders (see Table 4), each with an 11.1% holding in the parent company. Rationale to develop the project under a purchasing power parity (PPP) model lies mainly in the natural monopoly nature of the transmission assets as well as the risk bare by the project developers that could potentially jeopardise returns and therefore interest of private sector.

Table 4 • EPR shareholders

Organisation		Country
Central American shareholders	Instituto Nacional de Electrificación (INDE)	Guatemala
	Comisión Ejecutiva Hidroeléctrica del Río Lempa (CEL)	El Salvador
	Empresa Nacional de Energía Eléctrica (ENNE)	Honduras
	Empresa Nacional de Transmisión Eléctrica (ENATREL)	Nicaragua
	Instituto Costarricense de Electricidad (ICE)	Costa Rica
	Empresa de Transmisión Eléctrica S.A. (ETESA)	Panama
Extra-regional shareholders	Interconexión Eléctrica S.A. (ISA)	Colombia
	Empresa Energética Española S.A. (ENDESA)	España
	Comisión Federal de Electricidad (CFE)	México

SIEPAC was conceived to stimulate the creation and consolidation of a regional electricity market (MER), throughout the promotion and establishment of legal, institutional and technical mechanisms to facilitate the participation of the private sector in the build-up of capacity generation in the region. A second target for the initiative was putting in place the appropriate transmission infrastructure that allowed energy trading between the different agents in the regional electricity market.

The SIEPAC interconnection has the potential to enhance the local underdeveloped hydro resources and to improve the efficiency in the operations of the thermal power plants in the region. Additionally, thanks to the strengthened Mexico–Guatemala interconnection (in operation since 2010) the SIEPAC transmission line enables trading with the Mexican market. Trading with Colombia will follow the commission of the Panama–Colombia interconnection project currently under development and expected to be operational by 2018.

Construction of SIEPAC's transmission line was finalised after ICE commissioned the last pending segment in Costa Rica (Palmar Norte–Parrita) in October 2014 and was officially inaugurated during the ministerial meeting "Celebración del SIEPAC: Impulsando la Integración energética Mesoamericana" in December 2014 in Panama City.

Current physical infrastructure

The development of SIEPAC's physical infrastructure was mandated to EPR under a build, own and operate basis (BOO), as provided in the 30-year concession granted by the governments to the company though the Framework Agreement. The project consisted mainly in the design, engineering and construction of nearly 1 800 km of single circuit 230 kV transmission lines (see Figure 7), designed to accommodate a future expansion to a second circuit, connected throughout 15 substations in the region and 28 access bays.

Together with the reinforcement of the national transmission systems, the construction of the SIEPAC's line provides 300 MW (equivalent to 20-60% of peak demands in the six geographies) of transfer capacity across its length, which could potentially be doubled once the second circuit.

Additionally, the construction of SIEPAC's transmission line allowed for the deployment of the telecommunication infrastructure needed for the integration of Central American, México and Colombia systems through the installation of an optical ground wire (OPGW) conductor with 36 fibre-optic cables.

Figure 7 • SIEPAC's transmission line route

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

Total cost of the line amounted USD 505 million covered by the six Central American countries and the three external shareholders. Financing for the project was mainly provided by the Inter-American Development Bank (IADB) with a key role through 12 credit contracts that totalled over USD 250 million (a portion of the IADB loans was provided by the Spanish Quincentennial Fund). Additional debt financing was secured with Central American Bank for Economic Integration (BCIE), Banco de Desarrollo de América Latina (formerly Corporación Andina de Fomento [CAF]), Bancomext and Banco Davivienda.

Nearly USD 20 million were deployed for the implementation of MER. IADB provided over 90% of the funding and the remainder assumed by the six member countries.

Table 5 • Key financing terms

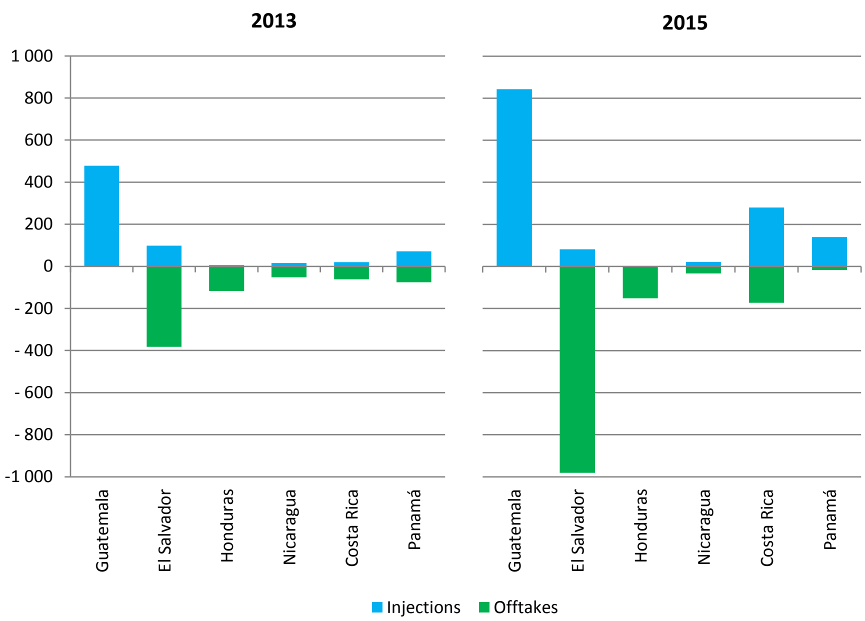
Institution	USD million	%	Key terms
IADB	253.5	50.2	Fund for special operations (40 years, five-year grace period, 1% interest) Ordinary loans (25 years, five-year grace period, 6% interest) Spanish Fund loan (35 years, five-year grace period, 2% interest)
BCIE (BEI)	109	21.6	Ordinary loans at 20 years, five-year grace period, 6.5% interest rate
CAF	15	3.0	n.a.
Bancomext	44.5	8.8	n.a.
Banco Davivienda	11	2.2	n.a
Other	13.5	2.7	n.a.
Equity providers	58.5	11.6	
Total	505.0	100	

Electricity trade

The electricity sector and market structure of the six countries involved varies significantly, from models based on fully competitive wholesale markets to vertically integrated utilities acting as single buyers. MER was conceived and operates as a separate market from the individual country markets, mainly seeking to accommodate the different stages of development of local individual markets.

MER was design to use a nodal pricing system with auctioned capacity rights (firm transmission rights and financial transmission rights to hedge in case of network constraints) in a day-ahead dispatch scheme with real-time balancing market.

Figure 8 • Energy transactions in MER, 2013-15



Traditionally, electricity trade flows from the northern and southern countries (mainly Guatemala, Costa Rica and Panama) towards off-takers in the centre (mainly El Salvador). Total trade has increased notably in the region since June 2013 when both the regional electricity market code (Reglamento del Mercado Eléctrico Regional [RMER]), and its detailed proceeding (Procedimiento Detallado [PDC]) entered into force. Energy injections in the MER doubled from 688 gigawatt hours (GWh) in 2013 to 1 363 GWh in 2015. During the last year, 58% of the transactions were contracted (Mercado de Contratos Regional [MCR]), while 42% were short-term energy trades (under Mercado de Oportunidad Regional [MOR]). The main exporting country in MCR was Guatemala with 662 GWh, while Costa Rica took the lead in MOR with 246 GWh. El Salvador was the main importer in both markets in 2015.

Box 3 • Challenges and opportunities for increasing interconnection in SIEPAC

Despite a well-structured regulation and clear protocols and codes, the process to harmonise national codes with regional codes may be delayed due to political factors driven by the different stages and economic situations of the countries involved. A consistent commitment to execution across the different countries and aligned investment needs are essential to benefit from a regional project that seeks to increase quality of service and the reliability of the electricity system.

The electricity system could emerge as a common point to further develop integration of regional economies, but local requirements in terms of an ageing generation fleet and transmission infrastructure have to be accommodated in the development of a regional market and future infrastructure.

Public institutions play a crucial role in the procurement of financing resources that ultimately benefit the region: low-cost, long-term and low equity commitments.

Going forward, the SIEPAC project will face several challenges and opportunities for a full capitalisation of its inner value. Among those, the countries must:

- Enable the use of SIEPAC's future second circuit as required to improve transmission capacity reducing national flows in the first circuit to improve reliability and safety of the regional transmission network.
- Timely execute the Colombia–Panama transmission interconnection project, which is crucial for the consolidation of the regional integration.
- Capitalise on the potential of the transmission line and MER to attract investment into regional energy projects that may potentially be at risk given the lack of regulatory harmonisation. Therefore, it is crucial for the institutions involved to jointly develop an expansion plan for the regional generation and transmission systems.

Case study #3: Towards an ASEAN Power Grid

Background

The Association of Southeast Asian Nations (ASEAN) heads of states first agreed to the concept of an ASEAN Power Grid (APG) in 1997. Central to this concept was the objective to enhance energy security in Southeast Asia by developing and investing in regional power interconnections. The APG was envisioned to connect countries that possessed surplus power generation capacity with those who faced a deficit, and, ultimately, to help all ASEAN countries meet rising energy demand by improving access to electricity and collectively economising on the development of interconnected energy infrastructure.

Following the establishment of the ASEAN Economic Community (AEC) in 2015, the AEC Blueprint for 2016-2025 identified the energy sector as a focal area for regional co-operation. The ASEAN Plan of Action for Energy Cooperation (APAEC) 2016-2025 highlighted the APG as a priority Programme Area for “enhancing energy connectivity and market integration in ASEAN to achieve energy security, accessibility, affordability and sustainability for all.”[5]

Today, the APG remains a work-in-progress. Power trade in the region is, at present, limited to a series of bilateral electricity exchanges between neighbouring countries. A number of challenges to regional integration persist, including underdeveloped domestic transmission grids in several ASEAN countries – particularly in lower-income Cambodia, Lao People’s Democratic Republic (hereafter “Lao PDR”), Myanmar, Viet Nam and the rural eastern provinces of archipelagic Indonesia – and diverse electricity market structures.

The prospects for an integrated ASEAN power sector remain promising, but achieving the full potential of a regional power grid will require significant investments and well-co-ordinated governance (for more, see the 2015 IEA study, entitled Development Prospects of the ASEAN Power Sector).

The cost of implementing the APG has been estimated at around USD 20 billion (HAPUA, 2015), requiring large financial support from both public and private sectors. Some interconnections are more economically and physically viable than others, thereby attracting priority investment from development banks, bilateral agencies and private developers. Other interconnections lack, at present, economic viability, but help strengthen regional grid stability, and can therefore be valuable as a public good.

Ultimately, building reliable and efficient interconnections between geographically dispersed energy sources and demand centres will benefit both electricity producers and consumers by optimising power generation for sale at increasingly competitive prices. Forward-looking infrastructure planning that prioritises greater integration of renewables and higher voltage transmission lines will not only help future-proof regional power systems as the penetration of clean energy resources grows, but also support the AEC targets of reducing overall energy intensity by 20% and increasing the share of renewables in power generation to 30% by 2020.

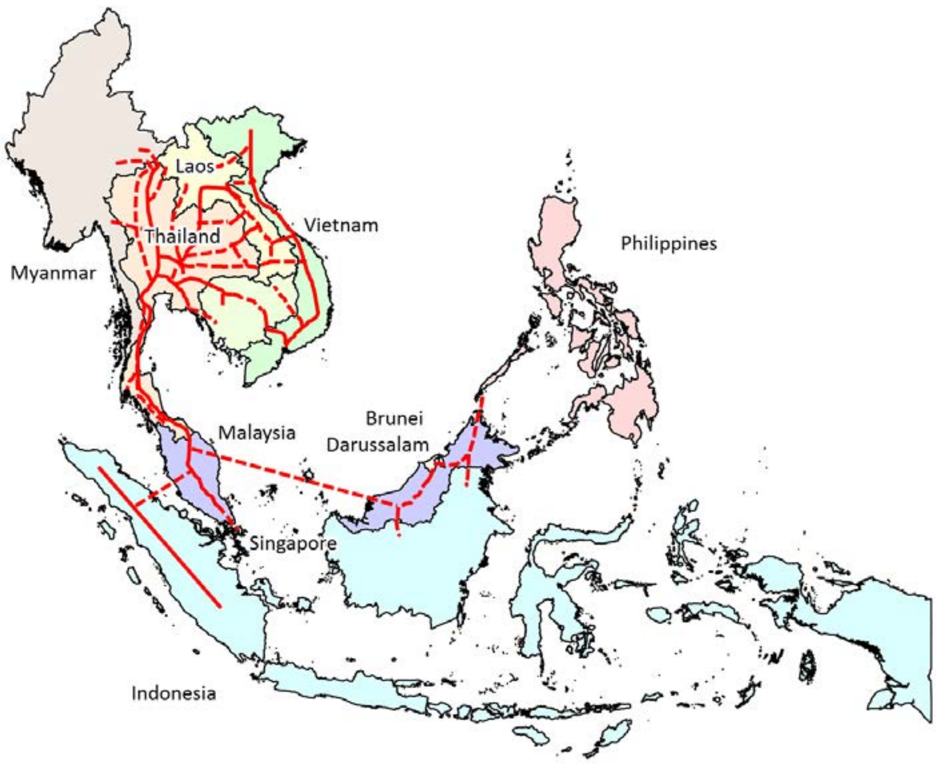
[5] The seven Programme Areas of APAEC 2016-2025 are: APG; Trans-ASEAN Gas Pipeline; Coal and Clean Coal Technology; Energy Efficiency and Conservation; Renewable Energy; Regional Energy Policy and Planning; Civilian Nuclear Energy.

While building interconnections is a matter of technical and financial mobilisation, operationalising interconnected power systems is a matter of policy co-ordination. Transparent, rules-based regulatory frameworks are crucial to facilitate and govern cross-border electricity exchanges. The establishment of an effective regional co-ordinator to work with national governments on developing rules for cross-border infrastructure development and power trade can support the harmonisation of national power markets regardless of market structure (IEA, 2015).

Current and planned physical infrastructure

At present, nine separate cross-border interconnections with a combined capacity of 5 200 megawatts (MW) connect: Malaysia–Singapore; Malaysia-Thailand; Malaysia–Indonesia; Lao PDR–Thailand; Lao PDR–Viet Nam; and Viet Nam–Cambodia (Hermawanto, 2016). Figure 9 below depicts three subregions for interconnections in Southeast Asia as defined by the Heads of the ASEAN Power Utilities and Authorities (HAPUA). The northern subregion includes Viet Nam, Lao PDR, Myanmar and Thailand. The southern subregion comprises Peninsular Malaysia and Sumatra (Indonesia). The eastern sub-region covers the Philippines, Borneo Island including Brunei Darussalam and Sulawesi (Indonesia). As of January 2016, Sarawak (Malaysia) has also begun exporting electricity to West Kalimantan (Indonesia).

Figure 9 • APG projects as of April 2016 (dashed lines denotes proposed/under construction)



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

Another six cross-border interconnections providing an additional 3 300 MW of capacity are planned by 2021 (Hermawanto, 2016). In the foreseeable future, interconnections between land-linked Thailand, Cambodia, Laos PDR and Viet Nam in the northern subregion of the APG are considered to be more feasible than long-distance submarine interconnections between Borneo Island and the Philippines. After that, it is envisioned that there will eventually be 16 cross-border interconnections across Southeast Asia, with total capacity reaching 23 200 MW (Hermawanto, 2016).

Another region relevant to the Southeast Asian context is the Greater Mekong Subregion (GMS). The GMS regional power integration program began in 1992 and presently includes five ASEAN countries (Thailand, Myanmar, Cambodia, Lao PDR and Viet Nam) and two southern Chinese provinces (Yunnan and Guangxi). As of 2016, the GMS has eight cross-border interconnections with a capacity of more than 3 215 MW (Nai, 2015).

Electricity trade

Power trade among ASEAN countries is conducted only under bilateral arrangements; multilateral trading agreements do not yet exist but are planned. In order to transition from bilateral to multilateral electricity exchange, several conditions should be met: 1) effective co-ordination or harmonisation of national reliability standards and grid codes across power systems; 2) sufficient cross-border and domestic electricity transmission to allow for unrestricted power flows across multiple borders; 3) establishment of commonly agreed-upon wheeling tariffs that adequately reflect the cost of transiting power flows; 4) a permanent, independent regional co-ordinator that can work with national utilities and other responsible parties to ensure open access to third parties and oversee that cross-border transmission is governed by inclusive, transparent, and rules-based regulatory systems.

There are two particularly notable models for bilateral electricity trade in Southeast Asia. The first is the Thailand–Lao PDR model, whereby Thailand imports approximately 2 293 MW of electricity from Lao PDR. While most of this power is consumed within Thailand, a portion is often re-exported back into Lao PDR to remote border towns that are not reached by domestic transmission networks. This electricity exchange encourages strong bilateral commercial interests in both Thailand's and Lao PDR's energy development, and Thailand has also acted as a developer of both power generation and transmission and distribution (T&D) projects in Lao PDR. Lao PDR is also developing hydropower projects to export some 1 410 MW of power to Viet Nam between 2015 and 2020 under a similar exchange model.

Another notable bilateral electricity trade model is the Singapore–Malaysia rolling zero net-energy exchange. Under this trading scheme, 100 to 200 MW of electricity is exchanged between Singapore and southern Peninsular Malaysia primarily to maintain grid stability and provide emergency power. Power exchanges are netted to zero to avoid pricing issues between the two jurisdictions since Singapore and Malaysia have very different power markets (Singapore's power sector is fully unbundled whereas Malaysia has a single buyer model). In 2011, however, when Malaysia's power sector experienced a shortage of gas feedstock, the Malaysian utility Tenaga Nasional Berhad (TNB) signed a short-term commercial exchange deal with Singapore PowerSeraya to import electricity for about two months. Malaysia continues to have the option to purchase power from utilities in Singapore via this commercial agreement at the agreed upon price plus an infrastructure cost determined by the Singapore market operator.

Mid-term opportunities for regional power market integration

At the 32nd ASEAN Ministers of Energy Meeting (AMEM) in September 2014, a group of ASEAN countries agreed to pilot a multilateral electricity trade initiative to transmit 100 MW of electricity via existing interconnections from Lao PDR through Thailand and Malaysia to Singapore. In September 2016, Laos, Thailand and Malaysia signed a memorandum of understanding (MoU) under which Malaysia will import 100 MW of hydro power from Lao PDR by 2018; it is expected that Singapore will join at a later date (Tan, 2016).

Given the limitations of national power sector structures, regulations and physical infrastructures, this effort is effectively an exercise to explore commercial and institutional arrangements to wheel electricity across multiple national jurisdictions. It represents the first concrete multilateral electricity trading project in ASEAN, and it is expected to lay a pathway towards realising a broader regional power grid.

Simultaneously, HAPUA is commencing a feasibility study on the potential of setting up an ASEAN Electricity Exchange (AEE), drawing from the experiences of Nord Pool and the Southern African Power Pool (SAPP).[6] ASEAN stakeholders, though supportive of the effort, have clearly expressed a concern that any such effort does not interfere with the sovereignty of individual ASEAN countries to govern their power sectors according to national interest. This means, for example, that the AEE should not oblige ASEAN countries to liberalise electricity tariffs, reduce subsidies, unbundle vertically integrated utilities or privatise national utility companies – unless such reforms are in line with national interests. The AEE feasibility study will last six months, followed by a design phase, with the ultimate objective of defining a pathway to operationalise the APG on a multilateral basis by 2018.

Box 4 • Challenges and opportunities for increasing interconnections in Southeast Asia

Making efficient use of the abundant renewables resources across Southeast Asian countries could be achieved by developing regional renewable resource and resource adequacy assessments, and integrating these assessments into national power development plans.

Concerns that increased regional power system integration may undermine national sovereignty or require reforms that conflict with national interests can impede progress on cross-border interconnections. Integration can be better supported through the creation of a regional institution that works with ASEAN member countries to harmonise national regulations while respecting national sovereignty.

ASEAN countries are characterised by diverse levels of economic growth and high levels of expected growth. Lower-income countries that are abundant in untapped energy resources can benefit from regional investment planning to lower the cost of financing and support more sustainable development, increasing exports while simultaneously meeting domestic needs.

Considering the potential of long-term growth in the APG, investing in higher rated (e.g. 500 kilo-volt amps [kVA]) transmission lines would accommodate future electricity demand growth more cost-effectively than building lower voltage lines that would inevitably have to be upgraded.

[6] For more information and presentations, see forum papers from the ASEAN Energy Market Integration Initiative (AEMI 2016).

Regulatory and market frameworks for interconnection

Interconnectors, by definition, connect distinct jurisdictions. Any power traded over interconnectors must therefore involve some degree of co-ordination between the relevant utilities or other responsible parties. *Large-Scale Electricity Interconnection: Technology and Prospects for Cross-regional Power Networks will examine*, for each of the key case study regions around the world with significant potential for greater interconnection, the market and regulatory frameworks necessary to accommodate for such investments. Previous work by the IEA has identified various models for cross-border trading of electricity (IEA, 2015), which are summarised here:

- unidirectional trades based on cost differences or IPP imports
- bidirectional or multinational power trades between national utilities
- multi-buyer, multi-seller market.

These models may be viewed as progressing from simple to complex, or in the direction of increasing market orientation. In any case, it is possible for a mix of models to be applied across different jurisdictional boundaries, depending on the different market frameworks or degree of restructuring. The more crucial aspect is that country-level regulations and legal arrangements allow for cross-border power trade, and that cross-border power trade be considered on an as equal footing as possible with domestic generation.

Market frameworks matter for two, broad reasons. First, they determine how new interconnectors are developed and paid for. Second, they determine how interconnectors are utilised.

Investing in new interconnectors

In terms of technology choices and cost structure, cross-border interconnectors do not differ from the development of transmission infrastructure within a single jurisdiction. In each case, developers face a set of hurdles that must be overcome in order to proceed with the investment, including working with relevant institutions, meeting policy and regulatory requirements (both technical and environmental), getting stakeholder buy-in, and appropriately allocating costs. The fact that interconnector development involves multiple jurisdictions, however, adds to the complexity of development and requires the additional layer of cross-border collaboration.

As power systems grow in size and complexity, and as consumers and market participants become more sophisticated with regard to the economic, social, or environmental implications of new transmission line development, transmission projects are undergoing a larger degree of public scrutiny and consultation. Open, inclusive, and transparent processes for transmission line development can put an additional burden on transmission developers, but can also lead to projects that better reflect the interests and views of all relevant parties.

These more complex siting procedures can, and often do, lead to project delays (Roland, 2011). The complexity of the process only increases when projects extend across multiple jurisdictions. In Europe, the European Commission has proposed creating a “one-stop-shop” for transmission development within each member country (EC, 2011). This can also support cross-border project development, especially if such projects are supported either by MoUs among all relevant agencies or through the establishment of a permanent, supranational body that is given clear levels and limits of responsibility.

There are numerous examples of co-ordinated planning. The most prominent ones, however, have generally been the result of top-down pressure or mandates from an institution with cross-border authorities. The Ten-Year Network Development Plan (TYNDP) process in Europe, for example, emerged from a mandate by the European Commission. In the absence of some overriding authority, cross-border planning exercises tend to be limited to one-off, bilateral exercises.

Truly integrated cross-border planning requires a large degree of harmonisation, which can act as an obstacle to regional collaboration. Topics of collaboration include (IEA, 2014):

- developing and using consistent and comprehensive data sets
- unifying (or at least making compatible) all relevant planning models
- harmonising reliability requirements
- agreeing to a common cost-benefit analysis (CBA) test.

Developing a cost-benefit test in particular can be a difficult challenge to overcome, as cross-border benefits can be difficult to quantify. For that reason, many regions have subsidised such projects by offering grants or higher rates of return to regulated entities.

Cost allocation

The most recommended methodology for cost allocation is the "beneficiary pays" principle, which states simply that costs should be allocated in proportion to the benefits the transmission line provides. Properly applied, the "beneficiary pays" principle can help overcome stakeholder resistance by demonstrating clear net benefits while also helping to reduce the potential for overinvestment.

There are, however, some inherent challenges. First, developing a common (or at least a harmonised) CBA test can be a challenge, given that all parties must agree to a common methodology for identifying and quantifying beneficiaries. There must also be clearly defined boundaries for cost allocation. In large, interconnected systems, developing new interconnectors can have wide-ranging impacts. It can also be difficult to identify all relevant stakeholders without clear geographical limits.

In addition, investments within a single jurisdiction can have cross-border impacts. For example, investing in domestic network capacity to reduce internal congestion can allow for better use of interconnectors, either by allowing electricity from the interconnector to reach more consumers, or by allowing more domestic generation to make use of the interconnector. Such projects should also be eligible for cross-border cost allocation.

Merchant investments

Most investments in transmission are made by regulated entities, which recover the cost of the investment through regulated rates charged to consumers. An alternative to regulated investment is merchant investment, where the transmission line is funded by a private investor.

As the cost of merchant lines are not recovered via the rate base, merchant investors need an alternative revenue source. The most common model is to take advantage of price differences, allowing low-cost generators to reach higher-priced regions, with the merchant investor charging a fee for access. An alternative model is to sell exclusive access to the line to some third party.

Merchant investors face a number of obstacles, including lack of transparency in regulated planning (making it difficult to judge the long-term viability of merchant investments), the right of incumbents to block third-party investments, an inability to agree on how to share the cost of supporting network investments, and divergent market frameworks (for example, connecting restructured markets to regulated markets).

As a result, merchant investments make up only a small portion of overall transmission investments globally. When the merchant model has been used, it has generally been to develop DC interconnectors (IEA, 2016). It could, therefore, serve as model for investment in large-scale, intra- or inter-regional interconnectors. Experiences remain limited, however, and so more work needs to be done to distinguish general obstacles to development from country- or jurisdiction-specific obstacles.

Using interconnectors

Proper use of interconnectors can allow for power markets that function seamlessly across borders. Doing so, however, requires harmonised regulatory frameworks and, in particular, co-operation on two key issues: determining network transfer capacity, and allocating capacity to market participants.

Network transfer capacity

Calculating the available transmission capacity within a jurisdiction is generally the responsibility of the system operator. This may be a vertically-integrated utility, a TSO, or some equivalent entity. Calculating the transfer capacity of interconnectors requires the involvement of two or more responsible parties. It is therefore another area where cross-border collaboration is of crucial importance.

Network transmission capacity is defined by the thermal limits of the transmission line in question and security requirements, which may be system specific. Unco-ordinated network capacity calculations can lead to mismatched estimates, which can in turn lead to inefficient use of interconnectors or, in extreme circumstances, security problems.

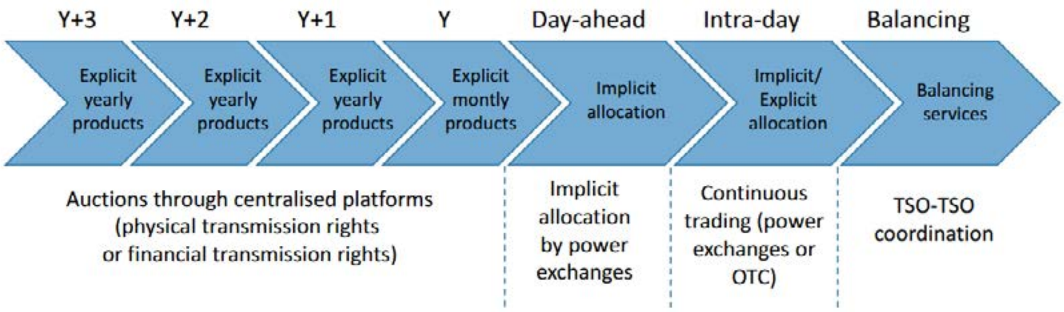
The amount of transmission capacity available is heavily dependent on system conditions such as the level of congestion or outages (both planned and unplanned). Therefore, simply harmonising the capacity calculation is not sufficient. Proper calculation of network capacity requires the sharing of data as well.

This becomes even more crucial in systems with high penetrations of variable renewables. The level network capacity can depend on the amount of wind and solar generation, as well as the real-time performance of thermal and other generation. This reduces the amount of network capacity that can reasonably be allocated ahead of real time. If interconnectors are built with the explicit intent of delivering variable renewable power into a different jurisdiction, the importing system must have sufficient visibility into the exporting system to plan its own system operations accordingly.

Allocating interconnector capacity

Allowing for commercial trading across interconnectors requires the allocation of interconnector capacity in advance of real-time. How interconnector capacity is allocated may vary depending on how far in advance market decisions are being taken. For example, in Europe transmission capacity may be allocated months or even years in advance through centralised auctions (Figure 10). When the day-ahead period is reached, the remaining available transmission capacity is determined net of any transmission capacity previously allocated via the explicit auction process. The remaining network capacity is then allocated via an implicit allocation process, taking into account bids and offers made in the day-ahead time frame.

Figure 10 • Allocation of interconnector capacity and sequence of electricity markets in Europe



Source: IEA (2014), Seamless Power Markets.

In many cases, the amount of transmission capacity available for the market may be completely allocated by the time day-ahead trading is closed. Increasing penetrations of wind and solar, however, make the intraday and balancing timeframes more critical. If interconnectors are to play a larger role in the delivery of variable renewable power, market frameworks will need to allow for greater allocation of transmission capacity in both the intraday and balancing markets.

The growing challenge of loop flows

In some regions, the increasing deployment of wind and solar PV is leading to increasing instances of so-called “loop flows” across AC power systems. Loop flows are the result of unscheduled power flows across interconnectors. They are only a problem, however, in synchronised power systems that extend across multiple jurisdictions.

Loop flow can have significant negative impacts on both commercial operations and system security. They can unexpectedly reduce available transmission capacity and can often only be managed by re-dispatch of local generation. The presence of loop flows also lowers transmission capacity available for forward allocation because the system operator must keep more transmission capacity in reserve.

Loop flows can be dealt with through both market reforms and investment in infrastructure. In wholesale market environments, for example, moving from zonal to locational marginal pricing (LMP) can reduce or eliminate loop flows by providing proper price signals to market participants. Loop flows can also be addressed through more dynamic calculations of cross-border interconnector capacity. In terms of infrastructure, investing in transmission capacity to lower internal network constraints or installing phase shifters at the jurisdictional boundaries, allowing for more dynamic control over transmission capacity, can both also address the issue.

Another alternative is to rely in DC interconnectors, which allow for a greater degree of control over power flows. The fact that DC lines can be controlled dynamically should, in theory, prevent any DC flows from creating loop flows in the importing jurisdiction. This does not, however, eliminate the need for both exporting and importing jurisdictions to manage flows to and from the interconnector (Thema Consulting, 2013).

What to look out for in 2017

This flyer serves as an advance insight into *Large-Scale Electricity Interconnection: Technology and Prospects for Cross-regional Power Networks.* Following the case study structure in this report, the publication will examine in depth the opportunities for increasing interconnection in key regions around the world, along the pathway towards global climate change stabilisation goals.

The publication will provide objectives based on IEA scenarios for interconnection needs, and assess opportunities to scale up trans-national power networks in five key areas of the world where such transmission links would yield great benefits: Europe and North Africa; South Asia and ASEAN countries; Central and South America; the North-East Asia region including China, Korea, and Russia; and Sub-Saharan Africa.

Finally, the publication will provide an analysis of the market, policy and regulatory environment in these regions and identify what barriers need to be addressed to achieve greater levels of interconnection commensurate with the ambition of a sustainable power system aligned with global low carbon objectives.

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Acronyms and abbreviations

AC	alternating current
AEC	ASEAN Economic Community
AEE	ASEAN Electricity Exchange
AMEM	ASEAN Ministers of Energy Meeting
APG	ASEAN Power Grid
ASEAN	Association of Southeast Asian Nations
BOO	build, own and operate
CBA	cost-benefit analysis
CIER	Commission for Regional Energy Integration
DC	direct current
ENTSO-E	European Network of Transmission System Operators
GMS	Greater Mekong Subregion
HAPUA	Heads of the ASEAN Power Utilities and Authorities
HVAC	heating, ventilation and air conditioning
HVDC	high-voltage direct current
IADB	Inter-American Development Bank
ICE	*Instituto Costarricense de Electricidad*
IEA	International Energy Agency
IGBT	Insulated-gate bipolar transistor
INDE	*Instituto Nacional de Electrificación*
IPP	independent power producers
LMP	locational marginal pricing
MCR	*Mercado de Contratos Regional*
MOR	Mercado de Oportunidad Regional
MoU	memorandum of understanding
NSN	North Sea Network link
ONEE	National Electricity and Water Agency-Electricity Branch ONEE
PV	photovoltaic
REE	*Red Eléctrica de España*
RMER	Reglamento del Mercado Eléctrico Regional
SAPP	Southern African Power Pool
STEG	*Societe Tunisienne d'Electricite et du Gaz*
T&D	transmission and distribution
TNB	*Tenaga Nasional Berhad*
TSO	transmission system operator
TYNDP	Ten-Year Network Development Plan
UHV	ultra-high voltage
UHVDC	ultra-high voltage direct current
VRE	variable renewable energy
WEO	*World Energy Outlook*


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