Integrating Power Systems across Borders

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Executive summary

Drivers and challenges of cross-border power system integration

Since the earliest days of their development, power systems have run up against, and then across, jurisdictional boundaries. A primary driver of this expansion has been economics, in particular a desire to lower the overall investment and operating costs of the power systems in question. At the same time, cross-border power system integration can bring with it a number of security benefits. More recently, a third driver of cross-border system integration has become more relevant: the integration of increasing shares of variable renewable energy (VRE) sources.

As a starting point, though, it is important to note that there is no single model for cross-border power system integration. However, it is possible to categorise cross-border integration efforts according to the mode and degree of integration.

Multiple modes of power system integration exist

The International Energy Agency (IEA) has identified three main modes of cross-border integration: bilateral, multilateral and unified.

Within these modes, multiple categories may be defined. For example, bilateral trades may be unidirectional, may involve intermediaries or may be bidirectional in nature.

Multilateral models are generally supported by regional institutions, but individual jurisdictions may still organise their own local markets and retain full control over system operations. This model may involve differentiated (i.e. mixed) market structures, or might only include jurisdictions with harmonised market structures. Finally, unified models centralise market organisation, and possibly system operations as well, across jurisdictions in a regional institution.

Integration has economic, security and environmental implications

Cross-border integration has implications for the economics, security and environmental impact of power systems. In many cases the implications are positive, lowering costs, increasing security and lowering the environmental impact of operations. However, integration also brings with it economic and security challenges, some of which relate directly to the environmental benefits.

Benefits of integration

From an economic perspective, expanding power systems across borders allows developers and market participants to take advantage of economies of scale on both the supply and demand sides, enabling the development of larger resources and access to cheaper supply sources.

The security benefits derive primarily from the fact that larger power systems are more diverse in terms of both supply and demand. They therefore require relatively fewer resources to meet peak demand needs, allow for the sharing of reserves between jurisdictions and increase overall system security by increasing the diversity of available resources.

Finally, the environmental benefits of cross-border integration derive primarily from the fact that larger power systems are able to integrate higher shares of variable renewables. This is because with larger balancing areas there is a natural smoothing of the underlying resource (e.g. the wind blows and the sun shines with different levels of intensity across large geographic areas). Cross-border power system integration can also increase access to flexible resources, including from the interconnectors themselves.

Challenges of integration

Though the net benefits of integration have generally been found to be positive, for individual market participants, integration can be challenging. As in any trading arrangement, some groups will benefit more than others, and in some cases the net impact may be negative.

The broader economic challenge for integration, therefore, is how to allocate benefits across market participants. This is the case for both investment costs (in particular, cross-border transmission infrastructure or local infrastructure investments that have cross-border implications) and operational costs.

With regard to security, there are three primary issues that must be addressed. First, individual jurisdictions tend to have an expectation that they should remain self-sufficient – that is, they should not rely on power from neighbouring regions to keep the lights on. The second issue is the fact that the tight coupling of power systems across borders increases the risk of a major blackout, one that starts in one jurisdiction but spills over into interconnected jurisdictions. Finally, interconnected, synchronised systems must deal with unexpected cross-border power flows (often called "loop" or "transit" flows). This is in particular a growing issue in regions with higher shares of variable renewables, which tend to vary significantly as weather patterns shift.

Finally, and related to the above, in interconnected systems local policies have cross-border implications. For example, policies to support local investment in renewables can result in increasing uncoordinated cross-border power flows. Local capacity mechanisms can result in a relative oversupply of capacity in one jurisdiction relative to total system needs. Or phase-out policies can result in a rapidly changing regional resource mix.

Supporting integration: What policy makers need to know

This report lays out the key aspects of cross-border power system integration that policy makers and other relevant stakeholders should be aware of. In particular, it focuses on three primary areas to consider: system security, resource adequacy and governance.

Keeping the lights on

System security, simply put, means keeping the lights on. For integrated power systems, this means increased co-ordination of real-time operations, establishing reliability frameworks, and developing mechanisms for cross-border energy trading.

Real-time operations is the most critical piece. Increased co-ordination of dispatch across borders can improve the economics of system operations while also improving the overall security of operations. Similarly, co-ordination on planning and operations is a key way of addressing loop and transit flows. Without such co-ordination the alternative is to invest in technological solutions such as phase shifters, which limit cross-border power flows, or increased investment in transmission. Here, however, misaligned economic incentives can potentially lead to underinvestment in some regions, and therefore the shifting of investment costs to other regions.

Many integrated jurisdictions have also found benefits to developing harmonised reliability frameworks, including reliability standards and grid codes. Of critical importance in this case are regional co-ordination and the inclusion of all relevant stakeholders in the development process.

Planning for the long term

Cross-border power system integration starts with the development of cross-border interconnectors. As with any transmission project, interconnector development can take many years and will involve multiple stakeholders. The involvement of multiple jurisdictions complicates things further by necessitating some degree of regional planning and agreements on how to share investment costs. Ideally, regional planning should look at overall regional resource adequacy, while cost sharing should be done according to a "beneficiary pays" principle, where the costs are shared in proportion to each party's received benefits.

Once interconnectors are in place, it is important to agree on how to measure and allocate interconnector capacity. Ideally, all parties should agree on a common calculation methodology, and interconnector capacity should be allocated across multiple time frames to ensure reliable access over time, but also to enable the optimal utilisation of interconnector capacity in real time. Effective allocation of interconnector capacity is also critical for jurisdictions that wish to trade capacity products (as opposed to energy products) across borders.

Governance

Looking across all of the elements highlighted above, a common element emerges: the need for increased cross-border co-ordination. This co-ordination is best enabled through governing institutions and regional market frameworks.

As a starting point it is important to note that in inter-jurisdictional integration, political institutions have a key role to play, both in enabling integration in the first place and supporting overall co-ordination. Regulatory institutions are also key, as they determine the rules for operations to ensure reliability and to allow local market participants to benefit fully from the gains of trade. Finally, market frameworks are necessary to enable trade. How these market frameworks look in practice, however, depends significantly on the underlying market structures of the interconnected jurisdictions.

If there is a single key lesson for the governance of cross-border power system integration, though, it is this: regional integration is best enabled by the presence of regional institutions. The role and level of authority of these institutions may vary, but all of the examples highlighted in this report have some form of regional institution in place.

Conclusion

Efforts at cross-border integration exist across the globe. Therefore, the primary question is not whether jurisdictions should integrate their power systems across borders, but how they should. To enable the secure and economic integration of power systems, policy makers should support inter-jurisdictional collaboration across a wide range of areas. In particular, the areas of system operations, long-term planning and governance require collaboration. In all cases, the role of regional institutions is critical. Importantly, it is possible to integrate power systems across borders without sacrificing local autonomy, though some balance between regional and local priorities is necessary to realise the full benefits of cross-border integration.

Key findings

Drivers and challenges of cross-border power system integration

Since the earliest days of their development, power systems have run up against, and then across, jurisdictional boundaries. A primary driver of this expansion has been economics, in particular a desire to lower the overall investment and operating costs of the power systems in question. At the same time, cross-border power system integration can bring with it a number of security benefits. More recently, a third driver of cross-border system integration has become more relevant: the integration of increasing shares of variable renewable energy sources.

The act of cross-border power system integration can involve a wide range of elements, including, but not necessarily limited to: co-operation on system planning; grid synchronisation; co-ordination of system operations; integration of electricity markets; and harmonisation (or consolidation) of policies and regulation. Broadly speaking, these elements fall into three categories: **system operations,** or managing integrated power systems in real time; **resource adequacy**, or ensuring sufficient long-term investment in transmission and generation; and **governance**, which includes policies, regulations and institutions.

What does "across borders" mean?

The primary focus of this study is on **jurisdictional** borders. This means the boundaries of decision making. This includes borders across which decision-making authorities are clearly defined, such as between countries, and borders for which the division of responsibilities between decision-making authorities is at times less clear. In practice, different jurisdictional borders may overlap with one another. The presence of, and interactions across, these jurisdictional boundaries are the key elements that differentiate cross-border power system integration from other power sector activities.

Multiple modes of power system integration exist

There is no single model for cross-border power system integration. However, it is possible to categorise cross-border integration efforts according to the mode and degree of integration.

There are two main ways to look at cross-border integration. One is as existing across a spectrum from limited integration to complete integration. The second is temporarily, along a spectrum ranging from long-term to short-term.

Figure 1 shows examples of cross-border integration that extend from limited (bilateral, unidirectional power trades) to complete (unified market and operations). Taken together, they can be considered a kind of hierarchy. The greater the degree of integration, the greater the potential benefits – but also the greater the complexity of organisation.

Figure 1. A hierarchy of integration: From limited to complete

Bilateral, unidirectional power trade	• Thailand imports from Lao PDR
Bilateral, bidirectional power trade	• California, USA ↔ Baja California, Mexico
Multilateral, multidirectional trade among differentiated markets	• Southern African Power Pool
Mulitlateral, multidirectional trade among harmonised markets	• EU Internal Energy Market
Unified market structure, differentiated operations	• Nord Pool
Unified market and operations	• PJM

Note: Lao PDR = Lao People's Democratic Republic, EU = European Union

Source: IEA.

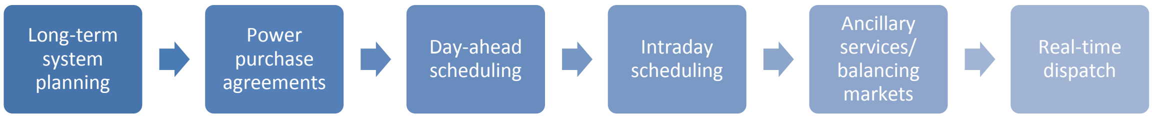
This hierarchy of integration can be subdivided into three main groups: bilateral, multilateral, and unified. Under **bilateral** integration, trades occur between only two jurisdictions. In some cases these trades may be unidirectional, and in other cases there may be intermediary transit (or wheeling) jurisdictions that transfer flows of power, but are otherwise uninvolved in the transaction.

Multilateral modes of integration involve three or more jurisdictions that can trade among one another. Underlying market structures within the jurisdictions can vary. In all cases, however, integration is supported through the development of regional institutions that help co-ordinate or manage, but do not replace, local institutions.

Finally, under **unified** models of integration, regional institutions take on some or all of the responsibilities for managing the power system across multiple jurisdictions, including at least market organisation, and possibly even system operations.

From a temporal perspective, cross-border integration can involve collaboration that occurs over long time horizons, such as long-term system planning or power purchase agreements, or short time horizons, such as ancillary services and real-time dispatch. Between those two extremes are areas that may be governed by market arrangements or inter-regional operating agreements, such as the sharing of short-term forecasts or information on day-ahead scheduling. This spectrum of integration is outlined in Figure 2.

Figure 2. A spectrum of integration: From long-term to short-term



Source: IEA.

As with the hierarchy of limited to completed integration, the hierarchy of long-term to short-term integration does not imply a natural evolution. In practice, many cross-border integration efforts do start with increased collaboration of long-term system planning, and these may lead to collaboration on, for example, the development of regional day-ahead markets. It is also possible, however, to find examples of integration that start with a focus on short-term markets. More importantly, these types of integration are not mutually exclusive. In fact, typically multiple modes of integration exist simultaneously.

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With regard to security, three primary issues must be addressed. First, individual jurisdictions tend to have an expectation that they should remain self-sufficient – that is, they should not rely on power from neighbouring regions to keep the lights on. The second issue is the fact that the tight coupling of power systems across borders increases the risk of a major blackout, one that starts in one jurisdiction but spills over into interconnected jurisdictions. Finally, interconnected, synchronised systems must deal with unexpected cross-border power flows (often called "loop" or "transit" flows). This is in particular a growing issue in regions with higher shares of variable renewables, which tend to vary significantly as weather patterns shift.

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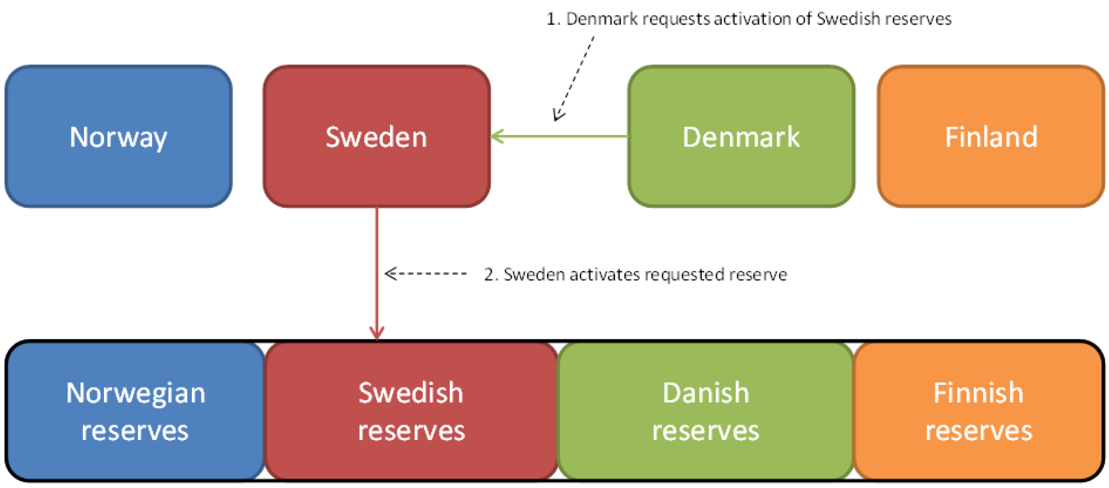
System security: Keeping the lights on

System security, simply put, means keeping the lights on. For integrated power systems, this means increased co-ordination of real-time operations, establishing reliability frameworks and developing mechanisms for cross-border energy trading.

Real-time operations is the most critical piece. Increased co-ordination of dispatch across borders can improve the economics of system operations while also improving the overall security of operations. Figure 3, for example, shows how the transmission system operators (TSOs) in the Nordic countries collaborate to utilise reserve generation in real time.

Figure 3. Example reserve activation between two Nordic TSOs



Source: IEA. All rights reserved.

Two key elements to this interaction are important to highlight. First, each of the TSOs retains full control over its power system. If, for example, Denmark wishes to activate a reserve resource in Sweden, it must make the request to the Swedish TSO, which then makes the actual operation decision. Second, this works only because there the TSOs share information with one another ahead of time (in particular, information on the cost and availability of their reserve resources) and because they have a communication plan in place that allows the request to be made.

Co-ordination on planning and operations is a key way of addressing loop and transit flows, or unscheduled flows of electricity across borders. Without such co-ordination, the alternative is to invest in technological solutions such as phase shifters, which limit cross-border power flows, or increased investment in transmission. Here, however, misaligned economic incentives can potentially lead to underinvestment in some regions, and therefore the shifting of investment costs to other regions.

Many integrated jurisdictions have also found benefits to developing harmonised reliability frameworks, including reliability standards and grid codes. Of critical importance in this case are regional co-ordination and the inclusion of all relevant stakeholders in the development process.

Resource adequacy: Planning for the long-term

Cross-border power system integration starts with the development of cross-border interconnectors. As with any transmission project, interconnector development can take many years and will involve multiple stakeholders.

The involvement of multiple jurisdictions complicates things further by necessitating some degree of regional planning and agreements on how to share investment costs. Ideally, regional planning should look at overall regional resource adequacy. This requires the aggregation of local power system development plans into regional plans, which in turn requires agreements over underlying assumptions, time frames of analysis and potential future scenarios.

Here again, having some regional institution take responsibility for these efforts can be helpful. In Europe, the European Network of Transmission System Operators for Electricity (ENTSO-E) has been assigned the responsibility for developing Europe-wide ten-year network development plans, which it does on a regular basis with the involvement of all relevant TSOs. In the United States, by contrast, there is no single entity with responsibility for developing regional plans. As a result, regional planning exercises tend to be done on a more ad-hoc basis.

Cost sharing of cross-border transmission lines should ideally be done according to a "beneficiary pays" principle, where the costs are shared in proportion to each party's received benefits. Modelling (supported by a common and agreed-upon set of assumptions) is again critical. In practice, however, the identification and sharing of benefits can be challenging. In such cases, it may make more sense to divide costs along lines that are based more on political agreement than economic efficiency. It may also be the case that the benefits are real but too diffuse to fully capture. In that case, regional institutions may step in to support their development through grants or other financial incentives.

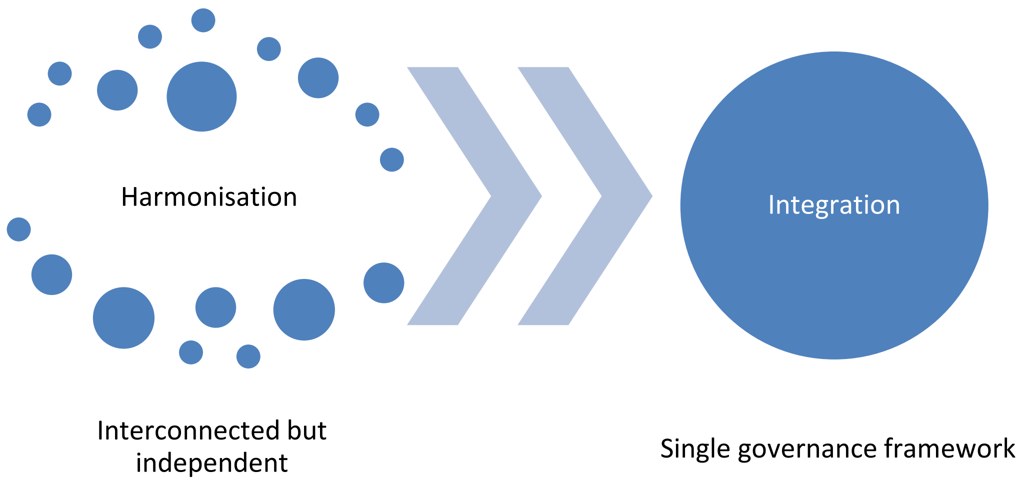
Once interconnectors are in place, it is important to agree on how to measure and allocate interconnector capacity. Ideally, all parties should agree on a common calculation methodology, and interconnector capacity should be allocated across multiple time frames to ensure reliable access over time, but also to enable the optimal utilisation of interconnector capacity in real time. Effective allocation of interconnector capacity is also critical for jurisdictions that wish to trade capacity products (as opposed to energy products) across borders.

Governance: Institutions and frameworks

Looking across all of the elements highlighted above, a common element emerges: the need for increased cross-border co-ordination. This co-ordination is best enabled through governing institutions and regional market frameworks.

There are many models of inter-jurisdictional governance arrangements, which may be thought of as existing across a spectrum. At one end, jurisdictions remain independent, and cross-border integration is managed through a set of harmonised bi- or multilateral institutional and policy arrangements (Figure 4). This enables trade without sacrificing local independence over key policies. At the other end, a single governance framework is developed that encompasses all relevant jurisdictions. Independence is sacrificed in order to increase overall efficiency of trading and system operations.

Figure 4. Models of cross-border integration: From harmonisation to unification



Regardless of the model of governance, political institutions have a key role to play, both in enabling integration in the first place and supporting overall co-ordination. Without political support, cross-border integration is unlikely to occur.

Regulatory institutions are also key, as they determine the rules for operations to ensure reliability and to allow local market participants to benefit fully from the gains of trade. In many cases, cross-border integration is best supported by the development of regional regulatory institutions, which work with, or, in the extreme case, replace local regulatory institutions.

Finally, market frameworks are necessary to enable trade. How these market frameworks look in practice, however, depends significantly on the underlying market structures of the interconnected jurisdictions. Market frameworks can be simple, for example bilateral contracts for imported power. Alternatively, frameworks can be complex, including the development of regional power markets that allow for multilateral trading. The first option allows for simple, predictable power trading, but lacks flexibility. The second option allows for more flexibility and more optimal use of regional resources, but it can also expose local resources to increased competition.

If there is a single key lesson for the governance of cross-border power system integration, though, it is this: regional integration is best enabled by the presence of regional institutions. The role and level authority of these institutions may vary, but all of the examples highlighted in this report have some form of regional institution in place.

Conclusion

Efforts at cross-border integration exist across the globe. Examples can be found among Organisation of Economic Co-operation and Development (OECD) and non-OECD economies, and range from ones that involve deep integration of power systems across borders to ones that involve only simple exchanges of power without an exchange of money.

The primary question, therefore, is not whether jurisdictions should integrate their power systems across borders, but how they should. To enable the secure and economic integration of power systems, policy makers should support inter-jurisdictional collaboration across a wide range of areas. In particular, the areas of system operations, long-term planning and governance require collaboration.

Notably, these areas of collaboration are linked. System operations requires the utilisation of infrastructure built under long-term plans. All forms of collaboration, whether long-term planning or short-term operations, require some form of enabling governance framework to function properly.

If one key element has emerged from the cross-border integration efforts examined in this study, it is that regional institutions have a critical role to play. They enable collaboration and communication, and can step in to provide important services or play key roles when necessary. Importantly, it is possible to integrate power systems across borders without sacrificing local autonomy. It is necessary, however, to strike a balance between regional and local priorities to realise the full benefits of cross-border integration.

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Cross-border power system integration: Drivers and challenges

In 1895, the first large-scale alternating current (AC) generator – the Adams power station, built by the Niagara Falls Power Company – was commissioned on the US side of the border with Canada, on a river that flows between both countries. Seeing an opportunity, Ontario's Niagara Parks Commission began to award leases to power companies seeking the right to generate electricity for sale across the border to the United States. These leases quickly became the commission's largest source of revenue.

The history of power system development is one driven by expansion. Economies of scale favoured the development of expansive power systems – ones that could take advantage of larger generators to serve a larger number of consumers. As power systems grew, they ran up against, and then leapt across, jurisdictional boundaries to take advantage of these economic benefits.

Another primary driver of integration is electricity security. Interconnecting power systems allowed system planners and operators to tap into a larger and more diverse set of resources, decreasing the need to build local reserve generation and helping to mitigate the potential impact of local generator outages.

The third primary driver is becoming increasingly more relevant in a number of jurisdictions around the world: renewables integration. Larger power systems can be more flexible by taking advantage of natural variations in resource and demand patterns, as well as a greater set of flexible generation and demand-side technologies, and thus make it easier to integrate variable renewable resources such as wind and solar photovoltaic (PV).

Regional integration also, however, brings with it a number of challenges. For example, while there are economic benefits to extending power systems across borders, these benefits are rarely distributed equally across all affected parties. Furthermore, these benefits can be hard to measure, especially *a priori*, and so it is often difficult for interconnecting jurisdictions to agree on how to share the costs of interconnector development.

The security benefits of regional integration are offset to some degree by increased exposure to external risks, which are, by definition, outside of one's own control. This is particularly true for interconnected AC systems, where a major disruption in one part of the grid can ripple across the entire integrated region (IEA, 2005).

Similarly, the uncoordinated deployment of variable renewables, particularly when not accompanied by grid investments, can lead to spillover effects like loop and transit flows which, if not managed properly, can increase the cost of system operations and potentially lead to outages.

When planned and managed effectively, however, it is possible to integrate power systems across borders in such a way as to maximise benefits while minimising potential risks. The act of power system integration can involve a wide range of elements, including but not necessarily limited to: co-operation on system planning, grid synchronisation, co-ordination of system operations, integration of electricity markets, and harmonisation (or consolidation) of policies and regulation. This publication will address each of these issues by focusing on areas of **governance** (which includes policies, regulations and institutions), **resource adequacy** (planning and investment) and **system operations** (managing integrated power systems in real time).

Box 1. What does "across borders" mean?

In discussing cross-border power system integration, a key question must be addressed: which borders? In fact, there are a number of borders that are potentially relevant.

National, state and local borders, for example, define the limits of political intervention in power systems. They may also, though not always, coincide with technical borders.

Technical borders may refer to the limits of physical grid, or, more relevant in this context, to the limits of control over the elements of the grid. For example, in Europe the technical borders are the service territories of the various TSOs. For most of Europe, national borders and TSO borders are the same, as most countries have a single TSO. There are, however, exceptions – most notably Germany, which has four TSOs. In at least one case (TenneT), a TSO operates in two different countries.

All of these borders, and many others not mentioned, are relevant to the topic at hand. The primary focus of this study, however, will be on jurisdictional borders. This means the boundaries of decision making. This includes both borders across which decision-making authorities are clearly defined and borders for which the decision-making authority is at times less clear. In practice, different kinds of jurisdictional borders may overlap with one another. For example, in the United States there are many different overlapping jurisdictional boundaries, such as the regions defined by the North American Electric Reliability Corporation (NERC) versus the various state regulators versus the borders of the regional transmission operator (RTO) regions. Focusing on jurisdictional boundaries allows for the examination of many different types of borders through a common lens.

Modes of cross-border integration

Cross-border power system integration is fundamentally the act of linking two or more power systems together. This linkage, however, can come in many forms. In particular they exist across a spectrum from limited integration to complete integration. They also involve cross-border collaboration across various time scales, from long-term to short-term.

Figure 5 shows examples of cross-border integration that extend from limited (bilateral, unidirectional power trades) to complete (unified market and operations). Taken together, they can be considered a kind of hierarchy. The greater the degree of integration, the greater the potential benefits – but also the greater the complexity of organisation.

Figure 5. A hierarchy of integration: From limited to complete

Bilateral, unidirectional power trade	•Thailand imports from Lao PDR
Bilateral, bidirectional power trade	•California, USA ↔ Baja California, Mexico
Multilateral, multidirectional trade among differentiated markets	•Southern African Power Pool
Mulitlateral, multidirectional trade among harmonised markets	•EU Internal Energy Market
Unified market structure, differentiated operations	•Nord Pool
Unified market and operations	•PJM

Note: Lao PDR = Lao People's Democratic Republic, EU = European Union.
Source: IEA.

This hierarchy of integration can be subdivided into three main groups: bilateral, multilateral and unified.

Under **bilateral** integration, trades occur between only two jurisdictions. In some cases these trades may be unidirectional. Thailand, for example, imports power from hydroelectric plants in the Lao People's Democratic Republic (Lao PDR), but does not export its own power to Lao PDR. In other cases, trades may be bilateral but may involve an intermediary country. Lao PDR, for example, also sells power to Malaysia, with Thailand involved only as a transit country. In most regions, however, when there is bilateral trade, it tends to also be bidirectional, such as the cases of California (United States) and Baja California, Mexico, and the United States and Canada.

Multilateral modes of integration involve three or more countries, all trading among one another. In some cases, such as with the Southern African Power Pool or the Central American Electrical Interconnection System (SIEPAC, the Sistema de Interconexión Eléctrica de los Países de América Central), trade occurs between jurisdictions that differ in terms of market structure, while in other cases, such as with Europe's Internal Energy Market, market structure and relevant regulations are harmonised. In either case, integration is supported through the development of regional institutions that help co-ordinate or manage, but do not replace, local institutions.

Finally, under **unified** models of integration, regional institutions take on some or all of the responsibilities for managing the power system across multiple jurisdictions. Nord Pool, for example, is a regional power market that functions across multiple countries, each of which maintains full control over system operations. In PJM, the largest regional electricity system in the United States, both market and system operations are contained within a single institution.

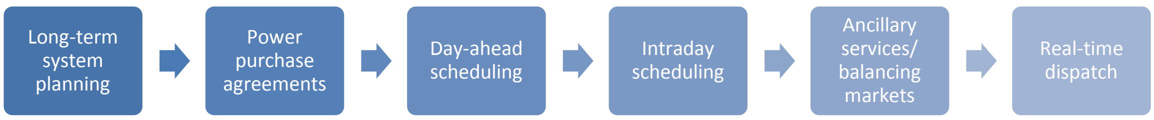
This hierarchy, it should be noted, is not meant to suggest a direction of travel for power market integration. That is to say, there is no natural tendency for power markets to increase the level of integration. In some cases, such as Nord Pool, integration has increased significantly over time, while in others (such as the examples from the Association of Southeast Asian Nations [ASEAN]), trade has functioned on an entirely bilateral basis for decades.

The reason is that increased integration requires increased harmonisation of market structures and regulations, increased cross-border collaboration, and, at the extreme, a willingness to relinquish control to a regional institution or institutions. This can be a limiting factor at any level of integration, but it is a particularly acute issue as the level of integration increases.

The above examples all focused on the degree of integration, but it is also possible to have degrees of integration that differ across time.

What does this mean? Cross-border integration can involve collaboration that occurs over long time horizons, such as long-term system planning or PPAs, or short time horizons, such as ancillary services and real-time dispatch. Between those two extremes are areas that may be governed by market arrangements or inter-regional operating agreements, such as the sharing of short-term forecasts or information on day-ahead scheduling. This hierarchy of integration, defined by temporal boundaries, is outlined in Figure 6.

Figure 6. A hierarchy of integration: From long-term to short-term



Source: IEA.

The simplest mode of integration is one that allows for a long time horizon for collaboration. For example, it is easier to share long-term power development plans than it is to share day-ahead scheduling information, easier to share day-ahead scheduling information than intraday, easier to share intraday schedules than to co-ordinate ancillary services, and easier to co-ordinate ancillary services than to share information on real-time dispatch. This is because with shorter time horizons communication happens closer to real time. Communication must therefore be rapid and robust (as the tolerance for errors is lower), and the time available for a response is by definition short.

As with the hierarchy of limited to completed integration, the hierarchy of long-term to short-term integration does not imply a natural evolution. In practice, many cross-border integration efforts do start with increased collaboration of long-term system planning, and these may lead to collaboration on, for example, the development of regional day-ahead markets. This is the model that has been employed in the European Union (EU), for example, which has historically focused on efforts to harmonise system planning and day-ahead markets across the member countries, and which has only recently begun work on the development of harmonised balancing markets.

On the other hand, in the United States' Western Interconnection, long-term power trading is often handled via PPAs, while at the same time the Western Energy Imbalance Market (EIM) functions as a regional real-time market. There is, however, no regional market that organises day-ahead or intraday transactions.

There is, therefore, no single path for cross-border power system integration. As many models exist, it is difficult to identify a single set of principles that can guide integration efforts globally. However, based on a review of international experiences, a number of best practices and lessons learned have been identified that should offer relevant lessons to all interested parties. These fall into three categories: resource adequacy (or ensuring long-term power system needs are met), system security (or managing real-time operations) and governance. These topics are described in more detail in the following sections.

Economic implications of cross-border integration

The economic benefits of regional integration derive from two primary areas: lower overall investment or development costs due to increased economies of scale, and lower total operating costs that result from increased system efficiency.

Many studies have already sought to quantify the benefits of increased integration. These have been well summarised in other publications (e.g. Zachmann, 2013) but it is worth noting some of the key findings here.

Gerbaulet et al. (2012) found that moving to a single, unified TSO for Germany, Switzerland and Austria (as compared with the six separate TSOs that exist today: four in Germany, one in Switzerland and one in Austria) could reduce system costs by 10%, and yields higher potential savings than what could be achieved through a combination of optimal bilateral agreements. Similarly, Haucap, Heimeshoff and Jovanovic (2012) found that increased co-ordination of the four TSOs within Germany had led to a more than EUR 3.3 billion reduction in five-minute reserve power costs over four years.

Abbasy, van de veen and Hakvoort (2009) found that integrating the Dutch, Nordic and German balancing areas would reduce balancing costs from a theoretical high of EUR 180 million per year (assuming no interconnector capacity, and therefore no ability to co-ordinate balancing) to less than EUR 100 million per year (assuming 10% interconnector capacity), a savings of EUR 80 million. Zachmann (2013) extrapolates this result to cover 27 EU member states and finds balancing savings for the entire European Union could be around EUR 289 million per year.[1]

Mansur and White (2012), focusing on the PJM interconnection in the United States, found that while the costs of moving to a centralised market are significant (estimated as a one-time cost of USD 40 million) the efficiency gains compensate for those costs many times over (USD 160 million annually).

Zachmann also notes that congestion rents may be used as a proxy for the value of interconnection. According to Supponen (2012), between 2006 and 2009, European TSOs collected EUR 1.6 billion in congestion rents. In principle, some level of congestion is likely to be optimal, so the actual value of interconnection would almost certainly be less than this amount.

Another proxy for estimating the benefits of integration is the cost to reserve transmission capacity. In Europe, a Joint Allocation Office (JAO) organises auctions for transmission rights (though, in addition, day-ahead and intraday capacity is allocated on an implicit basis via the market coupling process). Table 1 summarises the results of annual allocation auctions for a select set of borders from 2016 to 2018. Notably, while the auction price varies from year to year and border to border, one consistent element is that demand for capacity always exceeds supply.

[1] The analysis excludes Croatia, which became a member of the European Union on 1 July 2013.

Table 1. Transmission capacity auction results for select EU borders, 2015-18

Border	2017			2018		
	Requested (MW)	Allocated (MW)	Price (EUR/MWh)	Requested (MW)	Allocated (MW)	Price (EUR/MWh)
Belgium–France	3 477	200	1.25	2 963	200	2.16
Germany–France	4 741	600	6.25	6 431	600	6.91
Austria–Switzerland	1 712	159	8.76	1 223	140	7.77
France–Italy (1)*	3 967	620	10.16	5 923	620	6.09
France–Italy (2)*	3 448	310	11.59	4 686	310	8.19
France–Spain	3 287	700	12.78	8 350	699	8.10

Notes: MW = megawatt; MWh = megawatt-hour.
* Interconnector capacity between France and Italy is allocated in two separate annual auctions.
Source: JAO (2019).

The benefits of regional integration and increased cross-border power system co-ordination are not limited to regions with liberalised power markets. For example, the ASEAN Energy Market Integration study, which examined the benefits of full energy market integration (i.e. beyond just power system integration) found that integrating the ASEAN energy market would decrease total system costs by between 3% and 3.9%, and increase real gross domestic product (GDP) by 1-3% (AEMI Group, 2013).

Implications for investment

Investment costs that relate to cross-border integration can be divided into two main categories: generating capacity and grids. Generation costs are generally borne by investors in the generation itself, and are typically not shared in a formal fashion across borders. The exceptions to this rule are cases where the generator is built on land that straddles a jurisdictional boundary (in which case costs either are shared or are agreed in advance to be borne entirely by one party) or potentially in cases where an investment has direct or indirect cross-border impacts (e.g. development of an upstream hydroelectric plant).

By contrast, the costs of cross-border transmission lines (or interconnectors) are generally shared between the relevant parties. Optimally, these costs should be shared according to a "beneficiary pays" principle (Volk, 2013), where costs are allocated among relevant parties in proportion to the benefits they accrue. In practice, however, the beneficiary-pays principle is difficult to implement, as it relies on a precise estimate of the benefits of transmission development for each party, which can itself be challenging to determine. Moreover, even when the benefits are determinable, they can be so diffuse that it can be difficult to gain consumer acceptance.

Implications for operations

The impacts of cross-border power system integration on operating costs can be grouped into two categories: system balancing costs, which are directly recovered from consumers; and the impact on load factor, or operating hours, which affects particular generators.

In interconnected, synchronised power systems, supply and demand must be balanced at all times across the entire grid. As grids grow larger, the moment-to-moment operations of any individual generator are influenced by the operations of an increasing number of other generators.

Synchronised grids are often divided into separate control areas, within which a single, centralised system operator optimises balancing operations. For example, in Europe, balancing responsibility lies with the various TSOs. However, if two generators are in two interconnected and synchronised grids, the operating patterns of a generator in one system will by definition be affected by the operations of generators outside of the system operator's control area. That is, external generators impose a balancing cost on the local system, and local generators impose a balancing cost on external systems.

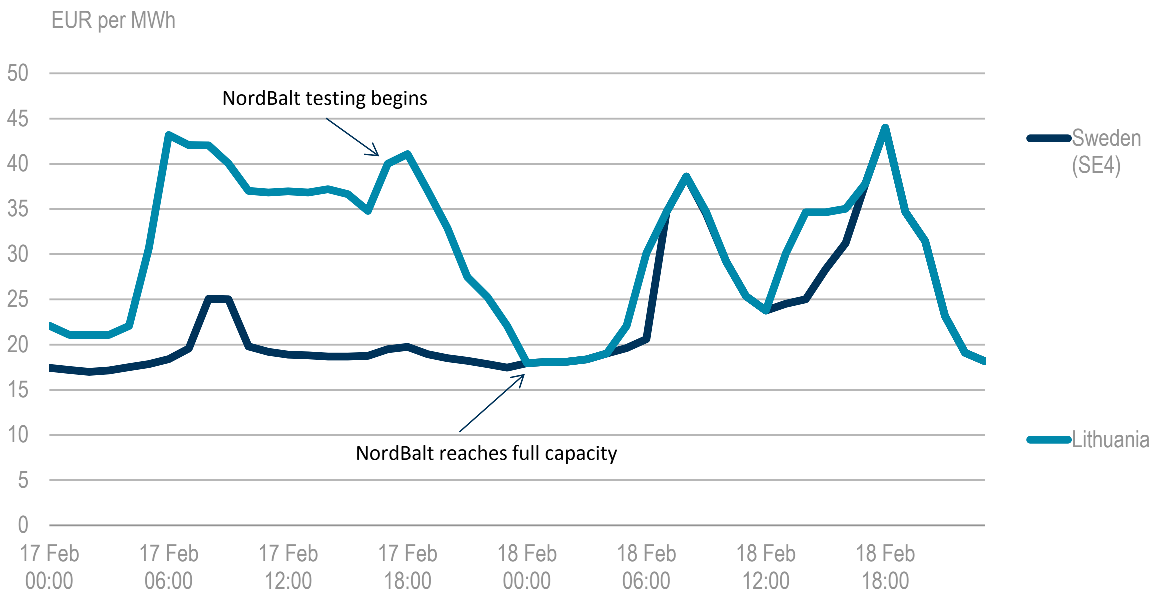
A number of interconnected jurisdictions have recognised the existence of these costs and have developed, or are developing, mechanisms to address them. Existing efforts include the shared reserves supply curve implemented by the Nordic TSOs, and the Western EIM in the United States. More nascent efforts include those by the European Union and Japan to develop common, regional balancing markets.

The impact on generator load factors can also be thought of as the impact of increased economic competition. Assuming that dispatch is managed according to least cost, increased integration will lead to a reduction in dispatch for relatively higher-cost resources. Depending on the prospects for demand growth and other factors, this can lead relatively expensive resources to close. This can also impact investment decisions, as cost recovery can depend on expected operating hours.

The impact of regional competition on load factors can be significant. For example, between 2010 and 2012 the three Baltic countries – Estonia, Latvia and Lithuania – joined the Nord Pool wholesale market. This was enabled by the development of the Estlink 1 and 2 High-Voltage Direct Current (HVDC) lines connecting Estonia and Finland (combined capacity, 1 000 MW), and NordBalt, a 700 MW HVDC line between Lithuania and Sweden. Estlink 1 was commissioned in 2007 and so it predates the integration of the Baltics into the Nord Pool market. Estlink 2, however, was commissioned in 2014, and NordBalt in 2016.

The impact of NordBalt on the Baltic market is illustrative. In terms of size, the NordBalt line is equivalent to approximately 20% of Lithuania's installed capacity. Testing on the NordBalt line began on 17 February 2016 and the line reached full capacity in the early morning of 18 February 2016. Immediately after reaching full capacity, wholesale electricity prices in Lithuania converged to the same level as in Sweden (Figure 7).

Figure 7. Impact of NordBalt on wholesale electricity prices, Sweden and Lithuania



Note: SE4 = Swedish bidding area 4.
Source: IEA analysis based on data from Nord Pool Spot.

Power system integration can have significant impacts on prices, which has implications for both producers and consumers.

In such cases generation owners may find themselves in a situation where significant capacity suddenly becomes uneconomic to operate. For example, in Denmark, natural gas generation declined from a 20.6% share of total generation in 2006 to 7.3% in 2016 due to increasing production from domestic renewable energy sources and competition from relatively low-cost imports (IEA, 2017a). Over time this could lead to exits from the power system.

While such exits may be economically justified, if systems see a net decline in capacity as a result of increased competition, system operators or policy makers may become concerned about increasing reliance on external capacity to meet peak load. This can drive the development of market reforms (for example, removing caps on wholesale electricity prices), new market mechanisms (such as capacity mechanisms), or policy interventions (such as direct subsidies) to keep the total capacity in the local system at or above some minimum threshold.

The above discussion focused on power systems that operate under least-cost dispatch. It is worth highlighting, however, that many power systems have constraints that prevent optimal cost-based dispatching. These may be self-imposed, such as the quota system that has historically been used in the People's Republic of China (Hernández Alva and Xiang, 2018), or may be the result of inflexible "take-or-pay" contracts (IEA, 2018). In either case, the benefits of increased power system integration are diminished or can be eliminated entirely.

It is also important to consider the financial implications of regional integration when energy prices are subsidised. A recent study focusing on the Gulf Cooperation Council (GCC) countries found that without subsidy reform, Saudi Arabia would essentially export USD 2.2 billion of subsidies to its neighbours in the form of lower electricity prices (KAPSARC, 2018).

Security implications

Though cross-border integration brings a number of benefits, it also raises a number of challenges that deserve equal consideration. For example, though the economic benefits of integration are real, these benefits are rarely shared equally across all interconnected jurisdictions, raising concerns over equity.

Cross-border integration is also difficult from an institutional perspective. Even when there is a will to integrate power systems across borders, the act of integration can run into political obstacles, or be limited in scope because of economic or security concerns.

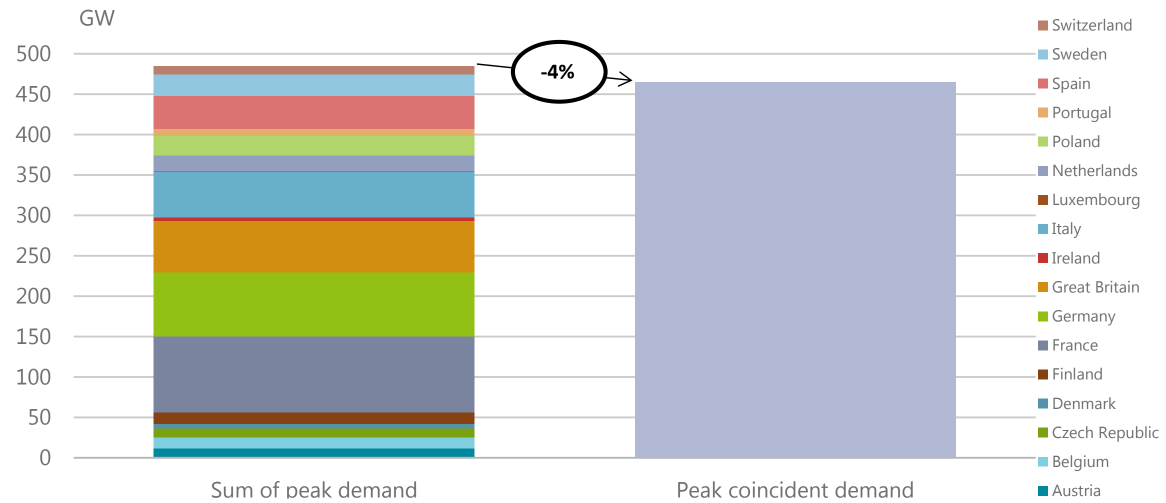
A critical area, however, relates to the security implications of cross-border integration. There are many security benefits to cross-border integration, including making it easier to meet peak demand, the ability to share reserves and increased diversity of supply. At the same time, however, interconnected power systems are exposed to external risks. As a result, when outages do occur the impact can be much wider and the recovery time longer. The critical point here is that when power systems are coupled, the reliability of one system is dependent on the reliability of all systems. Reliability therefore ceases to be a local concern, and instead becomes a regional one.

Meeting peak demand

Different regions – even ones that are geographically close – will tend to have different demand patterns. These differences may arise for a number of reasons, including differing economies or levels of development, differing weather patterns and different time zones, among other things.

The larger the balancing area, therefore, the greater variation one would expect to find in demand patterns. For example, peak demand across Europe varies significantly. In 2011, total peak demand (that is, the peak demand of each country simply summed together) for 17 Western European countries was 465 gigawatts (GW), while the synchronous, or coincident, peak demand (that is, the highest total demand in Europe at the peak hour of the year) was only 440 GW, or 5% lower (Figure 8). In an interconnected power system, therefore, the total capacity required to meet demand needs is lower than in isolated systems (Baritaud and Volk, 2014).

Figure 8. Total and coincident peak demand in 17 Western European countries, 2017



Source: IEA analysis based on ENSTO-E data.

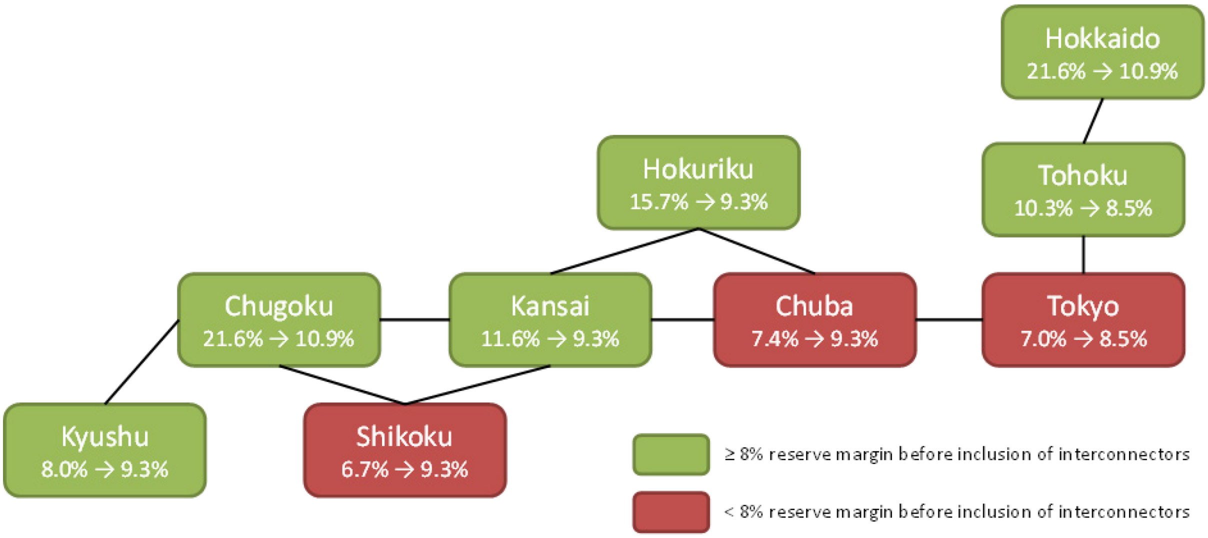
If fully integrated, total peak demand needs for these 17 European countries declines by 20 GW.

Sharing reserves

Increased interconnection reduces the total required reserves by leveraging a greater number of generating units. The required amount of reserves for a thermal-based power system increases in proportion to the square root of the total amount of capacity in the system (Zachmann, 2013). Therefore, larger power systems require proportionally less reserves than smaller power systems.

A recent reserve margin assessment of Japan provides a useful example. According to the most recent resource adequacy assessment, if there were no interconnectors between the various electric power companies (EPCOs), by 2019 three out of ten balancing areas would be unable to meet the minimum reserve margin requirement of 8%. Allowing for the use of interconnectors brings all ten service areas above the minimum threshold (Figure 9).

Figure 9. Reserve margin in Japan by EPCO with and without interconnectors (2019 fiscal year)



Note: Excludes Okinawa area.
Source: OCCTO (2018).

Without interconnectors, three out of ten EPCOs would be unable to meet their minimum reserve margin requirement.

Of course, the use of interconnectors in and of itself does not guarantee that all reserve margin requirements will be met. Note that in some cases – for example, Tohoku – the sharing of reserves leads to a net decline in reserves, bringing the region close to its 8% minimum. Long-term resource adequacy may still require the development of new generating capacity. Through the sharing of reserves, however, the marginal benefit of an additional generator can increase. Rather than just serving the reserve needs of a single region, new capacity can provide a benefit to multiple regions simultaneously.

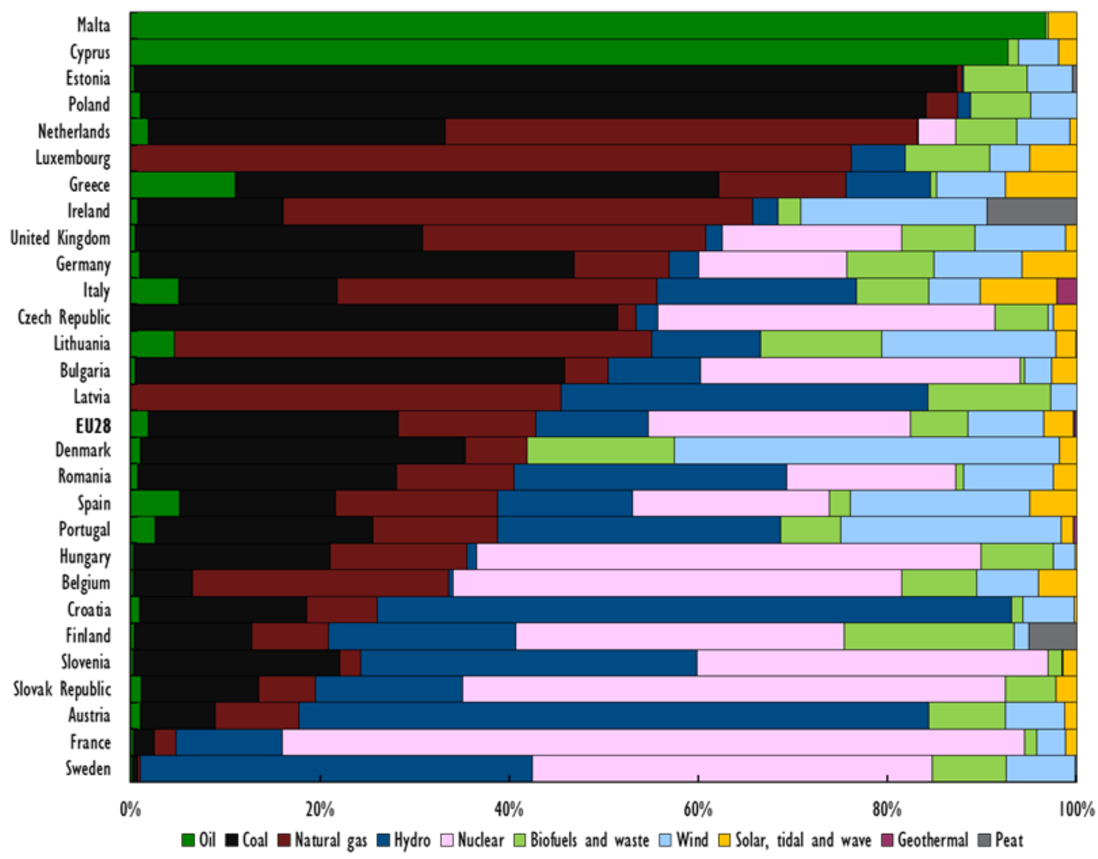
Diversity of supply

The mix of generation varies from jurisdiction to jurisdiction because of a combination of geographic differences and heterodox preferences. Geographic differences refer primarily to differences in resource endowment. For example, countries such as Canada, the Democratic Republic of the Congo, Lao PDR, and Norway all have significant hydro potential – more potential, in fact, than they can reasonably exploit with local demand alone. Cross-border integration allows these countries to export excess hydropower to their neighbours.

Other countries may be rich in fossil fuel deposits – most notably, coal and natural gas. South Africa, for example, has extensive coal reserves, while Myanmar has significant untapped natural gas reserves. South African coal can act as a good balance to the more seasonal hydro resources of Congo, and natural gas from Myanmar can do the same for Lao PDR.

Government policies with regard to the generation mix certainly do differ, both between jurisdictions and over time. Take, for example, the European Union as a whole. While the geographic diversity of the 28 countries (EU28) has certainly played a key role in determining the generation mix, it is hardly the entire story. In Germany, for example, coal plays a significant role because of the large domestic resource base (Figure 10). Nuclear, on the other hand, is being phased out – the result of a significant change in the overall preference of the country away from that technology as the low-carbon generator of choice in favour of wind, solar PV and biofuels. By contrast, France generates most of its electricity from nuclear energy and will phase out coal generation by 2021.

Figure 10. Supply mix, EU28, 2016



Sources: IEA (2016), *Electricity Information*; IEA (2016), *Energy Balances of OECD Countries*; IEA (2016), *Energy Statistics of Non-OECD Countries*.

Interconnecting the EU28 allows the region as a whole to benefit from both naturally occurring and preference-driven diversity of the various generating fleets.

Exposure to external risks

When two or more power systems are integrated into a single, synchronous frequency area, the operations of each individual jurisdiction are affected by the operations of all other jurisdictions.

This means that individual system operators must respond to unexpected events that occur both within their service territories and outside of them.

Managing unexpected events is part and parcel of the system operator's job, and so under normal circumstances the fact that events may be happening outside of their sphere of control is of limited consequence. However, some degree of co-ordination is necessary to ensure that system operators respond properly to unexpected events. If a given system operator misinterprets a system change, its response may turn a minor problem into a major one.

In fact, lack of or ineffective co-ordination among system operators has been a key cause of major, multi-jurisdiction power outages in a wide range of countries (Table 2).

Table 2. Select power outages in interconnected regions since 1965

Year	Affected power systems (number and regions)	Population affected (indicative)	Proximate cause
1965	Four (United States and Canada): Ontario Hydro System, St Lawrence-Oswego, Upstate New York, New England	30 million	Relay with faulty trips, setting off power line overload
2001	Seven (Indian states)	230 million	Failure of a substation in Uttar Pradesh
2003	Five (United States and Canada): Ontario, MISO, PJM, NYISO, ISO-NE)	50 million	Plant outage, line failure in Ohio
2003	Three (Western Europe): France, Italy, Switzerland	56 million	Transmission line failure in Switzerland
2006	Seven (Western Europe): France, Germany, Netherlands, Belgium, Italy, Spain, Portugal	15 million	Human error at a substation
2009	Two (Brazil and Paraguay)	87 million	Loss of key high-voltage transmission lines in Brazil
2012	Nine (Indian states):	620 million	Circuit breaker trip, line failure and relay problem

Notes: MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; ISO-NE = ISO New England.
Source: IEA.

Exposure to external risks can also extend beyond the power system to the underlying resource base that power systems rely on, in particular fuel and natural resources such as water for hydroelectric dams.

Cross-border power system integration can allow resource-poor countries to access energy sources in neighbouring countries, but this involves a trade-off. Either a country ties its power grids to a neighbouring country, or it imports the raw fuel and produces power domestically. In both cases, the country in question is import dependent. However, as already noted, increased interconnection means increased exposure to external risks. If a jurisdiction is dependent on another for most or all of its power needs, then it is also exposed to potentially having its power supply cut off for reasons entirely outside of its control. More critically, the loss of power from external sources can happen rapidly. The energy security implications of cross-border power system integration therefore differ from those of fossil fuel imports, which are easier to store locally.

For this reason, many jurisdictions see access to global markets for fuel as being more secure than relying on power imports from a single neighbour or a few. This security also comes from diversity: a diversity of global suppliers. Japan and Singapore, for example, are both heavily dependent on imports to meet their power needs. Both, however, choose to rely primarily on imported fuels instead of increased interconnection.

Put more concretely, though Singapore is interconnected to neighbouring Malaysia, the interconnector is limited in size and only used to help maintain system stability – there is, at least at present, no financially based energy trading between the two countries. As for Japan, it is completely isolated from neighbouring countries. A recent proposal has been put forward to interconnect Japan to China, the Russian Federation and South Korea – the so-called "Northeast Asia Supergrid". It is notable, however, that the Japanese signatory to the memorandum of understanding supporting the exploration of this grid is not a TSO, unlike the other countries.

It is possible to create an environment where dependence on electricity imports is not seen as potentially destabilising. Doing so, however, requires transparency, trust, and enforceable rules. Often all of these are best supported by the creation of regional institutions, in particular ones that focus on reliability and security.

Renewables integration

As the penetration of VRE resources such as wind and solar PV increases, their relative impact on power systems increases as well. The IEA has defined a number of phases of VRE deployment, the first four of which are as follows (IEA, 2017b):

- Phase 1: the impact of VRE on the power system is small enough that it does not noticeably impact system operations.
- Phase 2: the share of VRE increases to the point where it impacts the generating patterns of the existing generation fleet, but not significantly enough to require significant operational changes or system upgrades.
- Phase 3: generation patterns change significantly enough and on a short enough timescale as to require increased system flexibility.
- Phase 4: the variability of generation is high enough as to create stability problems for the system operator, requiring both significant technical investments and operational changes.

The phases relate directly to the share of VRE in the power system, but it is important to note that there is no clear delineation between one phase and the next. Many aspects of how increasing shares of VRE impact a system are specific to the system itself. As a result, two systems that have identical shares of VRE in percentage terms may nevertheless be in different phases.

Nevertheless, it can be said that moving up from lower phases to higher phases is directly related to the share of VRE in the system, in the sense that systems move from one phase to the next as the share of VRE increases. This fact is important because it points to the one reason cross-border power system integration is a useful tool in supporting the integration of higher shares of VRE.

In particular, the relative share of VRE in large, interconnected systems may be lower than the absolute share in isolated systems, in particular if some jurisdictions have deployed significantly more VRE than their neighbours. Denmark is perhaps the most obvious example of this type of country. In 2016, wind generation in Denmark reached 12.8 terawatt-hours, or 42% of total generation (IEA, 2017a). However, relative to Europe as a whole, Denmark's share of wind in total generation is relatively small. Compared with just total generation in Nord Pool, for example, wind in Denmark made up only 3% of total generation in 2017.

More generally, cross-border power system integration helps with VRE integration in two primary ways.

First, increasing the size of the total balancing area allows system operators to take advantage of the natural diversity of weather patterns across larger geographies.

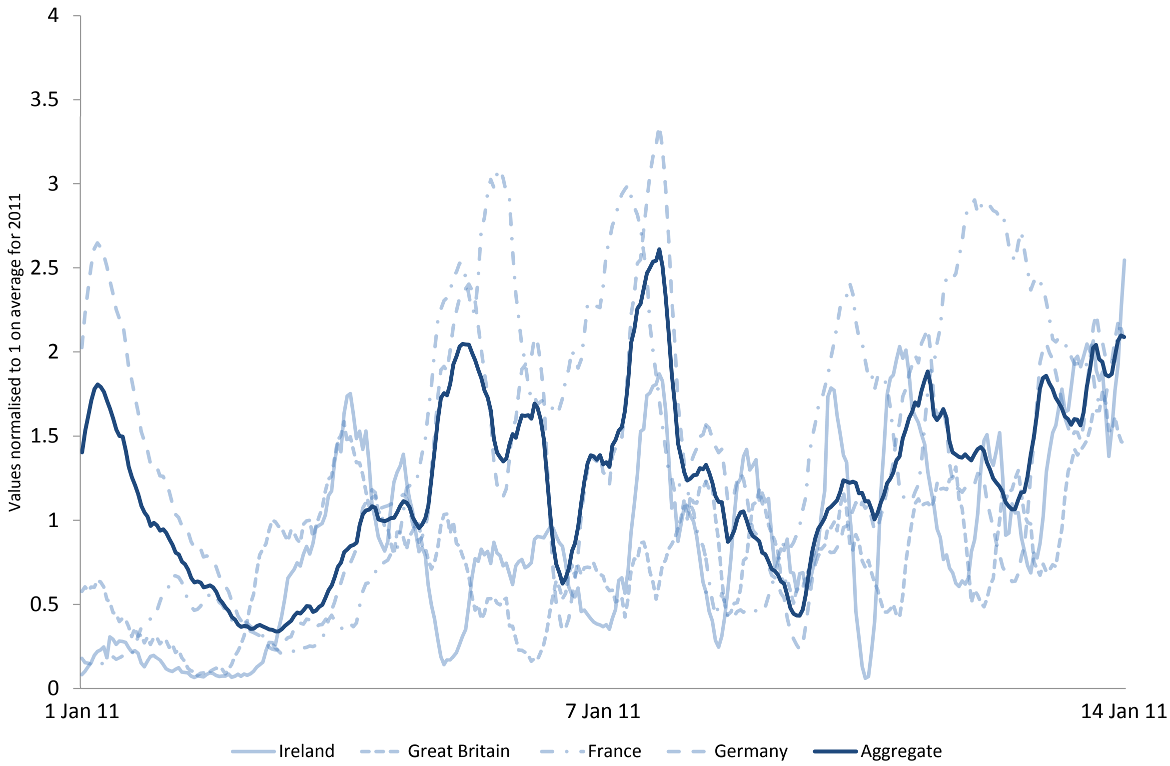
Second, interconnections give system operators access to a greater diversity of resources as well as additional pools of demand, making it easier to balance local VRE generation.

Balancing area size and resource smoothing

Weather patterns vary across space as well as across time. For example, at the start of the day it may be raining in France and sunny in Germany, and by the afternoon it may be raining in Germany but sunny in France. This is an intuitively obvious but important point, as these differences are a key reason that increasing the geographical size of power systems helps with VRE integration.

The key challenge for system operators in integrating increasing shares of VRE is managing their variability. The output of any given wind turbine, for example, may vary significantly over the course of a day or week. The output of all wind turbines in Ireland, though, has on average less variance than any individual turbine because when one stops spinning another one somewhere else on the island may start. For similar reasons, taking the average of all wind turbines across multiple countries gives a much smoother output than any individual turbine in the region (Figure 11).

Figure 11. Variability of wind output for four European countries, 1 January to 14 January 2011



Source: Baritaud and Volk (2014), *Seamless Power Markets*.

Therefore, it is possible to reduce the variability and associated uncertainty of VRE production by increasing the size of the total balancing area through the use of interconnectors.

It should be noted, though, that increasing the size of the balancing area is not a panacea for all variability issues. For example, solar irradiance at any given moment of the day varies from east to west, but not from north to south. There may be some benefits to increased north-south interconnections that relate to weather patterns (in particular, cloud cover) but there are natural limits to how far these benefits extend. At some point, in other words, system operators will need additional sources of flexibility.

Interconnectors as a source of flexibility

As already noted, the critical need for power systems with increasing shares of VRE is flexibility. Though increasing the size of balancing areas is important, it is not sufficient to simply build more transmission lines. To fully benefit from regional integration, system operators must also co-ordinate scheduling and dispatch, and share available reserves (IEA, 2017a). Regional market arrangements can also help, especially when countries with liberalised markets are involved.

As a starting point, the interconnectors themselves can provide flexibility by, for example, contributing to frequency response or, between synchronised grids, providing system inertia (IEA, 2017b).

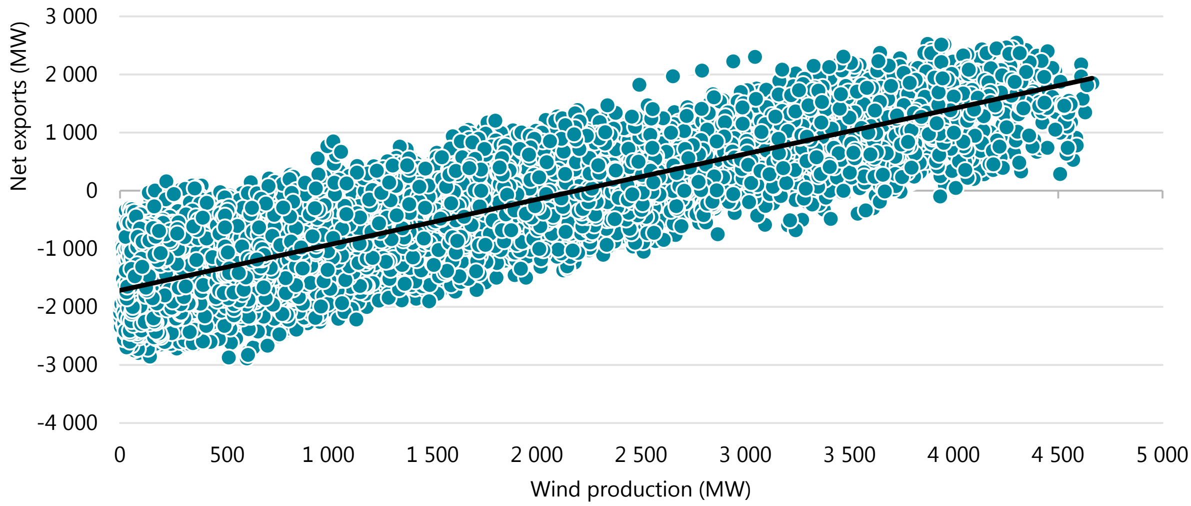
A more significant benefit to increased interconnections, though, is the fact that they give system operators access to a greater quantity and variety of flexibility resources than they would have otherwise (IEA, 2011).

Denmark offers a concrete example of the benefit interconnectors can provide for flexibility. As already noted, wind resources (both onshore and offshore) produced nearly half of Denmark's generation in 2016. Denmark also has a significant amounts of natural gas-fired capacity – 1 701 MW as of 2016 – which could potentially provide a great deal of system flexibility. However, the natural gas plants contribute only a relatively small amount to total generation: 7.3% in 2016, a significant decline from the 20.6% share they had in 2006.

A key reason for the decline in the share of natural gas generation is Denmark's significant levels of interconnection with its neighbours and its participation in the Nord Pool spot market.

Denmark has six interconnections with neighbouring countries, which in total provide around 6.4 GW of export capacity and 5.7 GW of import capacity – more than enough to meet Denmark's peak load of 5.6 GW. Participation in the Nord Pool market, meanwhile, allows Denmark to take better advantage of relatively less expensive flexibility resources in other countries, in particular hydropower in Norway. As a result, interconnectors provide most of the flexibility needed to balance Denmark's domestic wind power. In 2016, nearly 80% of wind generation was balanced by either exports to the region, or imports from the region (Figure 12).

Figure 12. Net exports in Denmark compared with wind production, 2016



Source: IEA (2017a), *Energy Policies of IEA Countries: Denmark 2017*.

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System security: Keeping the lights on

At its core, power system security means ensuring stable system operations in real time. In interconnected environments, the decisions made by individual jurisdictional authorities have unavoidable spillover effects which must be managed. This is most critical in real time, when there is no ability to provide advance warning on system changes. To a large extent, however, real-time issues can be managed through co-ordinated preparation, including the implementation of harmonised reliability standards, and the increased integration of day-ahead and intraday energy markets.

Real-time operations

In interconnected, synchronised power systems, the real-time operations of any given jurisdiction are affected by the real-time operations of all other jurisdictions in the synchronised region. Under normal circumstances, the security implications of these interactions are negligible. Uncertainty in real-time operations is a fact of life even in fully isolated systems, and power system operators have developed a number of tools and methods for managing it. For example, grid codes define the ways in which generators should respond to system changes, and power systems are designed with sufficient redundancies and resource diversity to manage at least some level of unexpected changes, such as generator or transmission line outages.

When operational responsibilities are divided among multiple system operators, however, some degree of co-ordination is necessary to ensure reliable operations in real time. Two aspects of this co-ordination are of particular importance.

First it is important for system operators to agree to some form of co-ordinated dispatch. This could involve simply sharing dispatch plans ahead of real time, or it could involve agreements that allow for co-ordinated changes closer to real time.

Second, system operators must have some way of managing unexpected cross-border power flows – that is, loop and transit flows. This is an issue in all interconnected power systems, but it is of increasing importance in environments where the penetration of variable renewables is increasing.

Co-ordinating dispatch

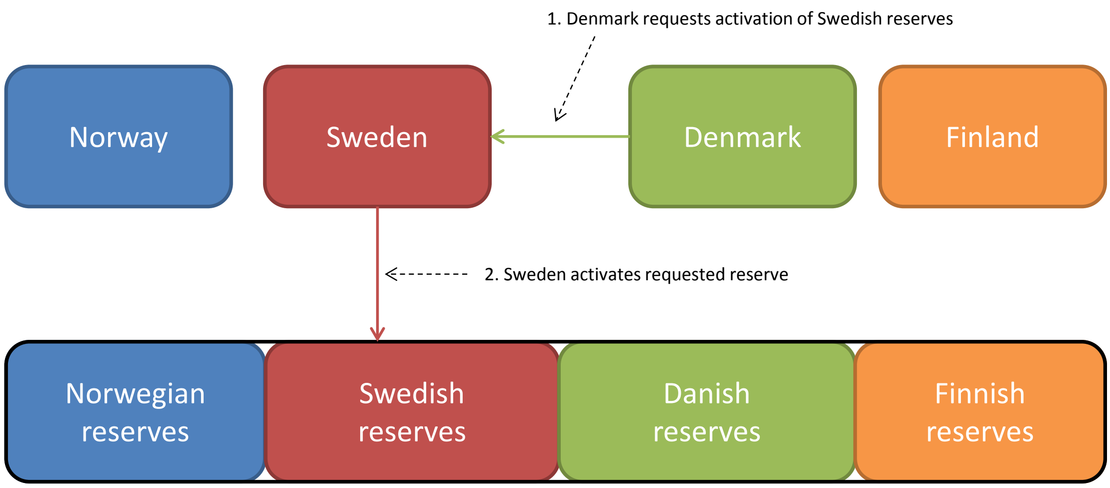
Many interconnected systems manage without a high level of co-ordination on real-time dispatch. Often it is sufficient to merely indicate ahead of real-time planned dispatch, as under normal system conditions real-time operations do not vary that significantly from planned dispatch. More importantly and as already noted above, power systems are already designed to manage some level of operational uncertainty, making them resilient to changes regardless of whether they originate from within or from outside their own territory.

Nevertheless, there are notable advantages to increased co-ordination on dispatch decisions. Some of these, as discussed in the section on economic implications of cross-border power system integration, are economic. Increased co-ordination of dispatch can reduce system costs by increasing operational efficiency. There are also, however, security benefits to increased co-ordination. In particular, while it is true that systems can deal with some level of uncertainty, there are nevertheless benefits to keeping that uncertainty to a minimum.

A notable example of dispatch co-ordination can be found among the Nordic TSOs. The Nordic (and Baltic) countries all participate in a common, regional wholesale market, Nord Pool. System operation decisions, however, remain the responsibility of the various national TSOs.

To improve system efficiency and system security, the four Nordic TSOs co-ordinate the operation of their balancing reserves. This is done through a common resource list and merit order curve. Though the information is distributed among all of the TSOs, the use of any particular balancing resource remains completely under the control of the TSO for the country where the resource is located. For example, if Denmark realises that a generator in neighbouring Sweden is better placed to help address a balancing need than any local generator, Denmark's TSO contacts Sweden's TSO, which then activates the resource in question (Figure 13). The Nordic method is therefore an improvement over each TSO relying solely on local resources to meet balancing needs, but it is still well short of a common balancing market for the region.

Figure 13. Example reserve activation between two Nordic TSOs



Source: IEA.

To call a reserve resource into service in a different service territory, the first TSO (here, Denmark) must contact the second TSO (Sweden), which then activates the resource in question.

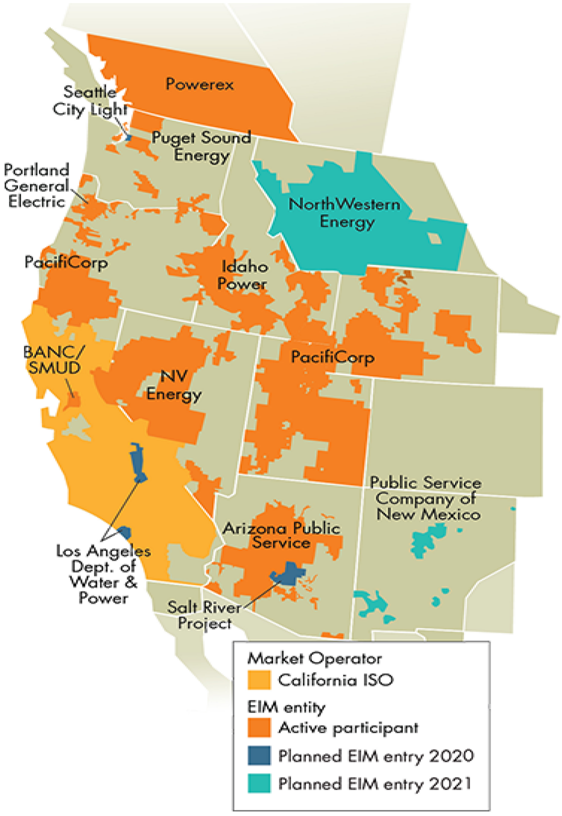
Another model for improving real-time dispatch co-ordination is the development of a regional real-time energy market.

The Western EIM is one of the more innovative approaches to regional collaboration on real-time dispatch. As a starting point, it is worth noting that it is the only regional market in the Western Interconnection. Among the states that make up the WECC, only California has introduced an independent system operator (ISO) – CAISO – meaning it is the only wholesale market environment in the region, and even there the utilities remain vertically integrated.

The development of the EIM, therefore, stands out from similar efforts elsewhere. In Europe, for example, efforts to develop regional balancing markets have followed the development of regional wholesale markets (e.g. Nord Pool) and wholesale market harmonisation more generally. The EIM, in contrast, starts from the balancing side first.

The EIM is, in essence, a regional real-time market that is managed by CAISO. There are currently seven utilities participating in this market (not including CAISO itself), and four more are planning to join by 2020 (Figure 14).

Figure 14. Western EIM participants



Note: BANC/SMUD = Balancing Authority of Northern California/Sacramento Municipal Utility District.
Source: CAISO (2019), "Western Energy Imbalance Market", www.westerneim.com/Pages/About/default.aspx.

The Western EIM is able to function despite the fact that only a subset of potential utilities participates.

As Figure 14 shows, the EIM is not a physically contiguous market. This is because participation in the EIM is voluntary, and a number of utilities in the region have not joined. However, as all of the utilities in the WECC are interconnected, developments within the EIM affect those utilities as well. Moreover, the transmission assets those utilities own and manage are critical elements of the EIM.

In some respects, the EIM model is closer in nature to the European model for market and system operations than it is to the traditional ISO/RTO model used in the United States. Unlike, for example, the RTOs of the Eastern Interconnection, which both organise the wholesale markets and take responsibility for system operations, the EIM is functionally distinct from system operations in the WECC. CAISO, as the EIM operator, collects real-time information on generators within the participating balancing areas, determines the optimal resource allocation for the region and then delivers dispatch plans back to the participating system operators. These system operators retain full responsibility for dispatch decisions.

In order to develop the EIM, it was necessary to create a governance structure that could allow for a diverse set of utilities to participate in a common market without giving up jurisdictional sovereignty. One initial stumbling block to the development of the EIM was a general concern among utilities outside of California that participating in the CAISO market would eventually lead to them becoming full CAISO members – extending CAISO's reach outside its state borders.

A few elements were implemented to address these concerns. First, as already noted, participation is fully voluntary. This means, in part, that participants can leave at any time without having to pay an exit fee. A more critical development, though, was the establishment of the EIM governing board. This governing board is made up of participating members in the EIM and is entirely separate from CAISO's governing board. CAISO's governing board is partially composed of people appointed by the governor of California. This led to a concern that if CAISO's board had full oversight of the EIM, California's political priorities could potentially impact its development.

The EIM board is responsible for oversight of the EIM market and for proposing market rule changes. However, it is important to note that the EIM board cannot actually approve these changes. The implementation of rule changes remains the responsibility of the CAISO board. So the EIM board's independence is, in theory, somewhat limited. In practice, if the EIM board proposes a rule change by consensus, the CAISO board has accepted that change without debate or modification.

Managing loop and transit flows

All AC power systems must deal with the possibility of physical power flows differing from expected flows. Dispatch scheduling relies on a forecast of system needs that will inevitably differ from actual real-time conditions – hence the need for balancing and other ancillary services.

In an isolated balancing area, these divergences must by definition be addressed with local resources under the direct control of the system operator. When two or more balancing areas are interconnected, however, real-time differences in one system can have an impact on interconnected systems as well. The phenomena of unscheduled power flows spilling over borders are generally referred to as transit or loop flows. Transit and loop flows differ only in the termination point. Transit flows terminate in a power system that differs from the power system of origin, and tend to be more prevalent in radial power systems. Loop flows, on the other hand, circle back to and terminate in the system of origin. These types of flows are only possible in meshed networks or grids where each jurisdiction has multiple exit and entry points. Both loop and transit flows are pure cross-border issues.

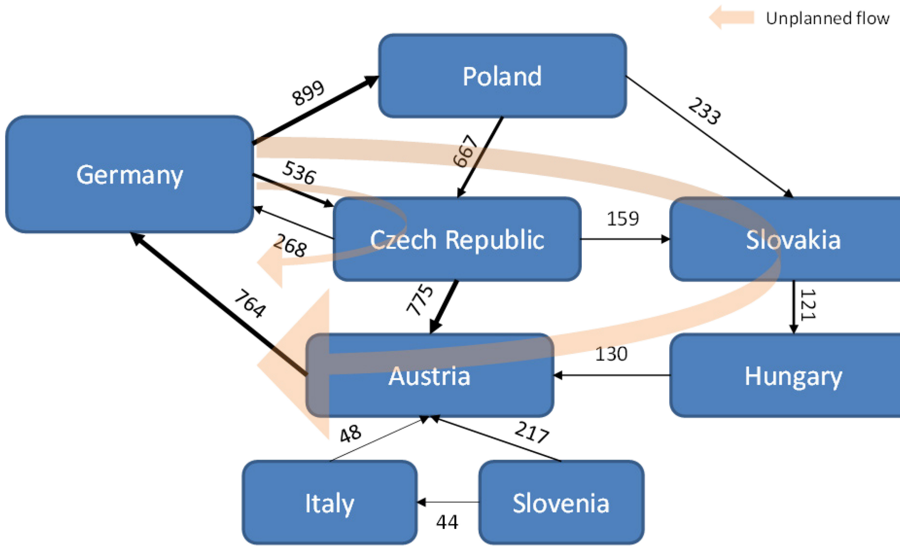
Loop and transit flows present a potentially vexing problem for system operators. By definition, they involve power flows that originate outside a system operator's area of control. Without some form of cross-border co-ordination, however, the operator can respond these flows only with their own, local, resources.

Though the phenomena of loop and transit flows are not new – in fact, they exist in all synchronised, zone-based power systems – the rapid increase in VRE penetration in some jurisdictions is raising the prominence of the issue. In Europe, for example, the issue of loop and transit flows has become implicitly tied to the issue of faster-than-average VRE deployment in some countries. In these countries, the increase in VRE deployment has not been met by an equivalent increase in local network infrastructure. As a result, during periods when VRE generation is relatively high compared with local demand, the excess power flows have been diverted across borders.

The country in Europe that gets the most attention on this particular issue is Germany, with the issue of excess wind generation. The best wind resources in Germany are in the north, while the load centres tend to be in the south. A relative lack of transmission capacity between north and south, however, limits the amount that can be transferred from north to south within Germany.

However, actual system conditions may turn out rather different from the scheduled flows. It is important to note that the shortest electrical path is determined by the physics of the power system, and that it may have little or no relationship between the shortest physical path between generation and load. In this case, the power flows tend to go east, to Poland, where they are often re-exported south, to the Czech Republic, and the west, back to Germany (Figure 15).

Figure 15. Loop and transit flows in Central and Eastern Europe (MW, 2011-12)



Source: IEA analysis based on ČEPS, MAVIR, PSE and SEPS (2013).

The shortest electrical path between generation and load may be very different from the shortest physical path.

Loop and transit flows can be addressed unilaterally, either by the system of origin or by the impacted systems. The system of origin, though, often has little incentive to take steps to address the issue. All of the various options for dealing with loop and transit flows locally – e.g. redispatching generation, or increasing internal network capacity – come with an associated cost, one that must be borne by some combination of local generators and ratepayers. By not addressing the problem locally, though, the system operator essentially outsources the problem to its neighbours.

If the neighbours are forced to respond, they have the same set of options available to them as the originating TSO, plus one extra. When the quantity of loop of transit flows is relatively small, redispatching of local generation is the most straightforward option to adopt. Under this option, local generation is curtailed to reduce network constraints and allow for the flow of the unscheduled imported generation. But this means local generation will run less often than it would otherwise, meaning it loses the opportunity to earn revenues, for which it may demand compensation from local customers.

Another option is to increase local transmission capacity. This allows for the continued dispatch of local generation and the absorption of loop and transit flows, but is relatively expensive and takes time. Moreover, this essentially shifts the transmission investment burden away from the source country to the recipient country. The source country therefore receives the benefit but pays none of the cost.

This leaves a third option: physically limiting the cross-border flows through the installation of phase shifters. A phase shifter allows the system operator to dynamically restrict or allow the flow of power across a given interconnector. By doing so, the loop and transit flow problem is essentially pushed back onto the system of origin, requiring the operator to take action to balance its own system. This is the option that has been adopted by Poland and the Czech Republic, for example, in response to loop and transit flows from Germany.

Both constructing new transmission lines and installing phase shifters impose a cost on transit system. Moreover, *a priori* it is not obvious whether this option is optimal from an overall system perspective. While in theory a more optimal solution can be found via multilateral negotiations, in practice the presence of misaligned incentives and the practical complexities makes such negotiations difficult.

Finding optimal solutions – whether it is improving real-time dispatch, investing in phase shifters or new transmission, or better aligning the market structure and zone configuration to actual grid constraints – may require a higher level of governance. In this example, this could occur at the EU level, though at present these decisions are all made nationally.

The European Union sees the presence of loop and transit flows as problematic, as they undermine the development of the internal energy market by reducing the reliability of imports from neighbouring countries or bidding zones. In doing so, they limit the ability of countries to rely on their neighbours for capacity adequacy and overall security of supply, raising overall system costs. The ability of the European Union to intervene, however, is limited. It lacks the authority to get involved directly in the energy decisions of each individual member state. It cannot, for example, require the redispatch of a particular generator, or demand the development of new transmission lines.

The European Union does, however, have a few useful tools in its toolbox. One is requiring the harmonisation of market rules. A second is supporting interconnector development through financial incentives. A third is the development of regional institutions such as the Regional Security Coordinators (RSCs), which co-ordinate security analysis across multiple countries

Interconnector development is described in more detail in the chapter on resource adequacy, and RSCs are described in the chapter on governance. On market harmonisation, the capacity allocation and congestion management (CACM) network code is perhaps most relevant. The CACM is a set of harmonised rules to support market coupling, including methodologies to match bids and offers and for the calculation of interconnector capacity, and, when necessary, methods for co-ordinating redispatch across borders (EC, 2015).

Dealing with system stress

All systems will, at some point, come under some level of stress that is beyond normal operating conditions. In some cases, periods of stress can last for an extended period of time, such as the unexpected loss of a large amount of generating capacity. In other cases, periods of stress can be significant in magnitude but short in duration, such as an extreme but brief heatwave. In either case, inter-regional co-ordination is essential for ensuring stable system operations during periods of stress. In some cases, direct intervention may be required.

Short duration periods of stress

A recent example from Japan shows how central institutions can play a critical role in ensuring system stability during times of stress.

Though day-to-day system balancing remains the responsibility of the various EPCOs, during an emergency, the Organization for Cross-regional Coordination of Transmission Operators (OCCTO) has the authority to step in to co-ordinate system operations across the interconnected balancing areas. Though OCCTO was only created in 2015, it has performed this role on a number of occasions. One intervention on 22 January 2018 is particularly instructive.

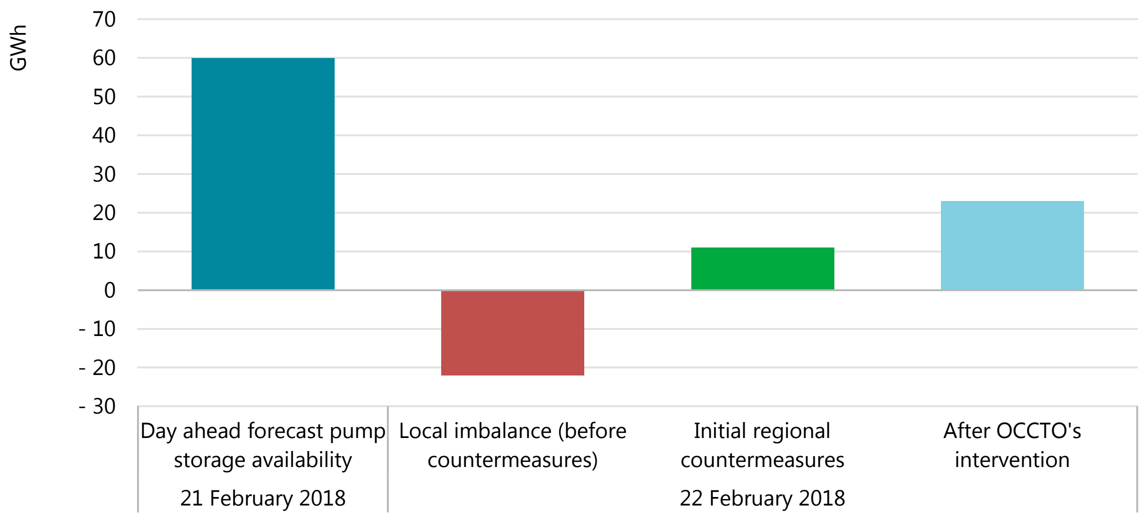
Earlier in the week, parts of Japan (and in particular, the Tokyo Electric Power Company [TEPCO] service area) experienced heavy snowfall. One impact of this snow was to cover the solar PV panels, removing 1.7 GW of generating capacity (the equivalent of around 15 gigawatt-hours [GWh] on a normal day) from the grid.

The weather forecast for 22 January predicted temperatures well above freezing, and so the assumption was the snow would clear and demand would remain in its normal range. Instead, however, temperatures dropped to near freezing and, related, demand increased by around 56 GWh above normal operating conditions.

The confluence of these two events led to a supply-demand imbalance over the day of around 22 GWh. TEPCO activated its available reserves and made use of approximately 10 GWh of available resources in neighbouring jurisdictions, but this nevertheless proved to be insufficient to fill the gap.

OCCTO was, at this point, already involved, having co-ordinated the 10 GWh transfer. When this proved insufficient, OCCTO intervened directly to deliver an additional 12 GWh, bringing the total amount of imports to 23 GWh (Figure 16).

Figure 16. Change in generation, 22 January 2018



Source: IEA based on data provided by OCCTO.

Extended periods of stress

Regional integration can provide significant benefits when there is an unexpected loss of generating capacity. This is particularly true when the loss lasts an extended period of time.

To give one example, over the winter of 2014/15, three out of Belgium's seven nuclear units were shut down in rapid succession. This happened during a period when Belgium already had resource adequacy concerns because of the retirement of 900 MW of local capacity, and the announced retirement of 800 MW more.

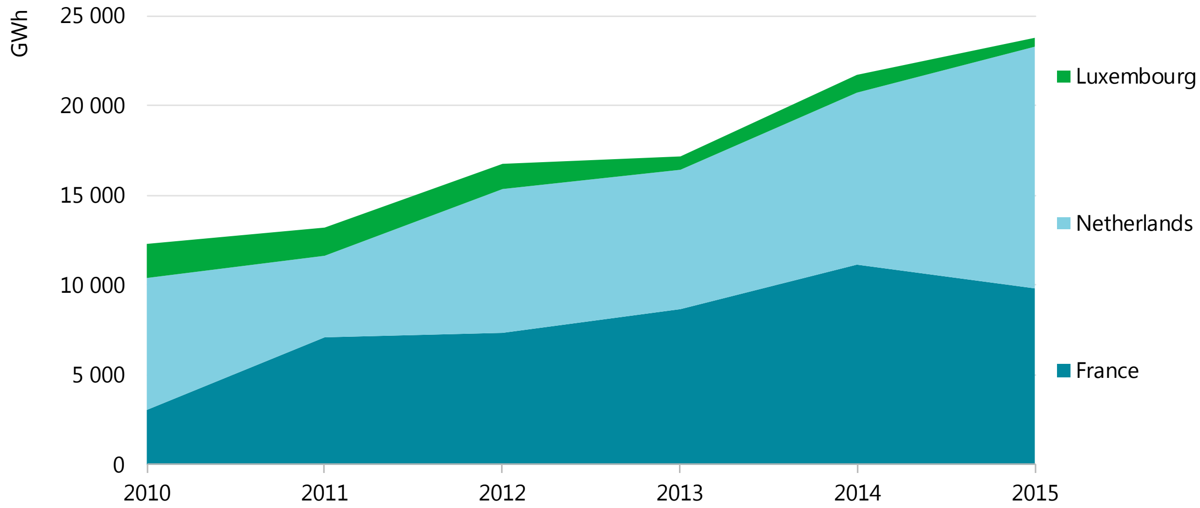
Because of the recent loss of capacity, Belgium had already planned to implement a strategic reserve of 800 MW. After the nuclear shutdown, the size was expanded to 1 200 MW. In effect, this meant entering into contracts with nearly all available mothballed generating capacity in the country.

Notably, however, Belgium did not include any available interconnector capacity when determining the size of the strategic reserve. The Belgian TSO, Elia, had estimated total available net transfer capacity (NTC) among itself, France and the Netherlands to be 3 500 MW – well above estimates for what was needed to meet local resource adequacy needs. But, as the Belgian regulator, the Commission for Electricity and Gas Regulation (CREG), noted, available NTC is not the same as secure and reliable NTC (CREG, 2014). Moreover, all of this was happening in an environment where imports from neighbouring countries had, in the previous years, been steadily increasing (Figure 17). Belgium already felt that it was increasingly reliant on neighbouring countries to meet domestic energy needs.

In other words, while Belgium knew in theory there was sufficient available capacity in the region to meet system needs, it was unwilling in practice to rely on the availability of this generating capacity.

The presence of loop flows in Belgium's power system is one reason it is reluctant to see interconnector capacity as a security resource. According to calculations performed by Elia, in 2017 Belgium experienced an average of 840 MW of loop flows (ENTSO-E, 2018).

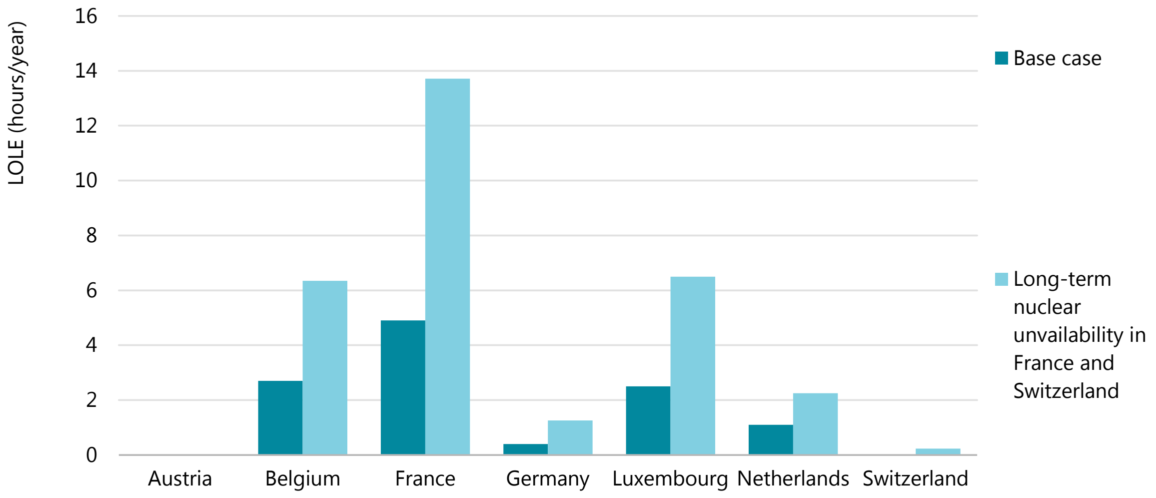
Figure 17. Belgian imports from France, Luxembourg and the Netherlands, 2010-15



Source: IEA (2016), *Energy Balances of OECD Countries*, www.iea.org/statistics.

Concerns over the potential impact of extended nuclear outages continue to this day. In the most recent regional resource adequacy assessment performed by the Pentalateral Energy Forum (PLEF), for example, modelled nuclear outages in France and Switzerland resulted in a significant increase in loss-of-load expectation (LOLE) for all countries in the region (Figure 18).

Figure 18. Impact of long-term nuclear unavailability in France and Switzerland



Source: IEA analysis based on PLEF Support Group 2 (2018).

Reliability frameworks

While having common reliability standards across interconnected regions is not a fundamental requirement of cross-border integration, experience demonstrates the value of at least having harmonised standards in synchronised regions. Also important is making standards mandatory or at least having a common understanding of how and to what extent voluntary standards have been implemented by all relevant parties.

To understand why this is the case, the North American experience is instructive.

In the United States and Canada, a major cross-border blackout in 1965 led to the development of an industry-based reliability organisation, the North American Electric Reliability Council. The council, among other activities, developed a set of reliability standards for member utilities to implement. Implementation of these standards, however, was voluntary and there was no compliance or enforcement mechanism. Though the United States suffered a number of notable, multiregional blackouts in the following decades, it was not until the 2003 blackout (which affected 50 million people across the northeastern United States and part of Canada) that the efficacy of voluntary standards was revisited.

Many changes were made in the aftermath of that blackout. Most critical was the adoption of legislation in the United States requiring the creation of an electric reliability organisation, NERC, whose standards were mandatory and enforceable. NERC is therefore responsible for both developing the reliability standards and for enforcing their implementation.

A lack of good data on outages prior to 2003 makes it difficult to quantify the impact of making reliability standards mandatory. Anecdotally, however, it does seem that the number and frequency of interregional outages has declined (NERC, 2018).

Developing harmonised grid codes

The European Union, in contrast to the United States, does not have harmonised reliability standards across all member states (IRENA, 2018). However, Europe has implemented a process for developing harmonised grid codes (or, more precisely, network codes) across all member states that is worth discussing because it offers a useful model for regions that wish to increase their level of integration, but that do not have an interregional body with the authority to impose standards across all participating jurisdictions.

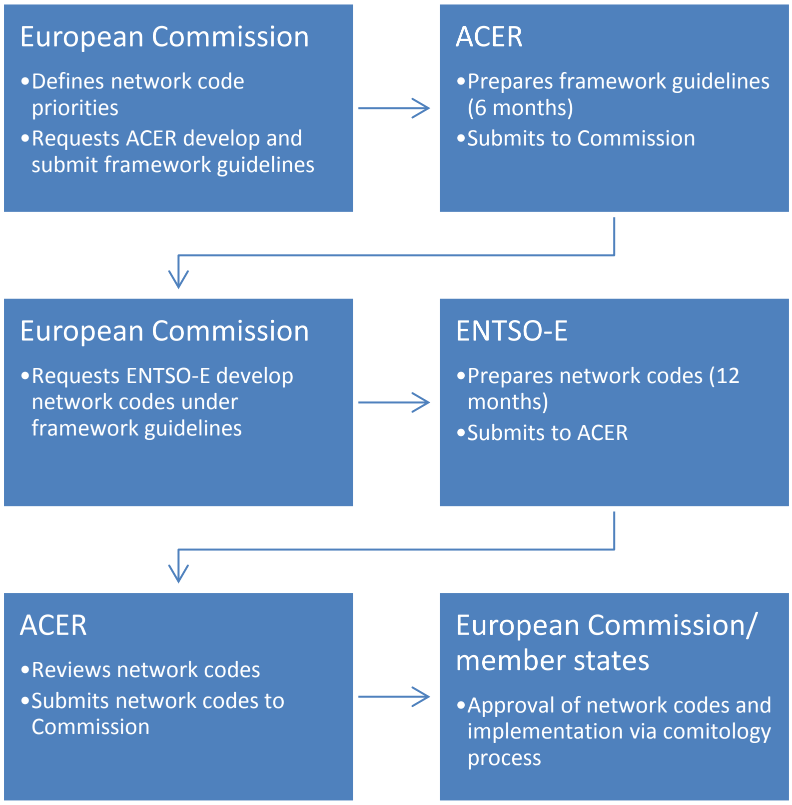
The network codes aim to harmonise the technical and commercial rules governing access to energy networks, with the overarching goals of ensuring fair access to all participants and removing barriers to trade between member states. These codes cover a wide range of areas that extends far beyond issues of reliability. Most importantly, many of these codes are directly relevant to the topic of cross-border power system integration. In particular, there are network codes for:

- Forward capacity allocation, which describes how to allocate interconnector capacity in the annual and monthly time frames.
- CACM, which focuses on the allocation of day-ahead and intraday interconnector capacity.
- System operations, including the development of RSCs.
- Balancing, which, among other things, aims to encourage the use of regional balancing resources whenever possible.
- Inter-transmission system operator compensation.
- HVDC network codes which relate specifically to the integration of HVDC lines into local grids.

Responsibility for developing the network codes is divided across a number of different entities. Ultimate responsibility for ensuring their development and implementation rests with the European Commission. However, the European Commission does not have the technical capacity to develop the details of the rules, so it allocates responsibility to two entities: the Agency for the Cooperation of Energy Regulators (ACER) and ENTSO-E.

Draft codes are prepared through an iterative process that involves the European Commission, ACER and ENTSO-E (Figure 19), as well as public consultation. The European Commission sets overall priorities, which ACER then develops into a set of framework guidelines. The framework guidelines set the overall scope and direction of each of the network codes. ENTSO-E (which is a consortium of TSOs) then develops detailed network codes that follow the framework guidelines while also respecting local (i.e. national) technical constraints.

Figure 19. Process for developing the EU network codes



Source: Wittenstein, Scott and Razali (2016), *Case Studies on Cross-Border Electricity Security in Europe*.

Energy trading

After power systems have been interconnected, some arrangement is necessary to guide the flow of power between the relevant jurisdictions. Such arrangements are important as they allow for optimisation of resources across the region in the day or hours ahead of real time, improving the overall efficiency of power system operations, and also increasing security by improving visibility of operations across the interconnected system.

Trading arrangements can be quite simple, non-financially based agreements where the relevant parties merely agree to account for the quantity of power exchanged, or they can involve complex regional market arrangements that allow multiple participants in all interconnected jurisdictions to buy and sell power on an as-needed or as-wanted basis.

How these arrangements are structured depends significantly on the market structures of the jurisdictions in question. When market structures are very different, it may be easiest to engage in non-financially driven forms of trade. For example, Malaysia (in particular, Peninsular Malaysia) and Singapore, which are interconnected by a 450 MW AC transmission line, have very different internal market arrangements. Peninsular Malaysia has a single, vertically integrated and government-owned utility, Tenaga Nasional Berhad (TNB). Singapore, on the other hand, is fully restructured, with liberalised wholesale and retail markets. While this is not a fundamental obstacle to the two countries engaging in financial (i.e. price-based) trade, in practice the interconnector is used only in emergency circumstances, in particular to help meet peak demand needs or to ensure the stability of the power grid. To avoid the need for financial compensation, power traded is netted out to zero over time.

For jurisdictions to trade power on a financial basis, some form of bilateral or market-based agreement is necessary. Previous work by the IEA has identified three primary models for cross-border power trade (IEA, 2015):

- unidirectional trades based on a bilateral agreement, such as a PPA
- bidirectional or multilateral power trades between utilities
- multi-buyer, multi-seller markets.

Another way to think of this, as described above, is moving from limited modes of trade to complete modes of trade.

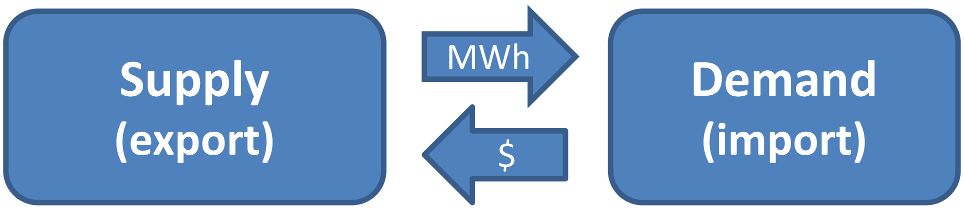
For limited modes of trade like a unidirectional PPA, it is not necessary to have a formal market in place, though having at least some type of market framework can be helpful in determining the cost of the imported power.

Going beyond a simple unidirectional trade requires the development of market models of increasing sophistication. Importantly, however, it is quite possible for multiple transaction models to exist simultaneously. For example, it is possible to have unidirectional, bilateral trades even in environments with full regional markets in pace.

Unidirectional trades

Unidirectional trades involve one jurisdiction importing power from (or exporting power to) a second jurisdiction without a corresponding agreement to export (or import) power in return. In the simplest case these can be structured as a typical PPA, which is either negotiated bilaterally between the purchaser and the seller, or procured through some kind of open tender process (such as an auction). The structures of these PPAs vary, but they will typically include some set price and possibly even a take-or-pay commitment tied to some minimum quantity of power.

Figure 20. Example of bilateral, unidirectional trade



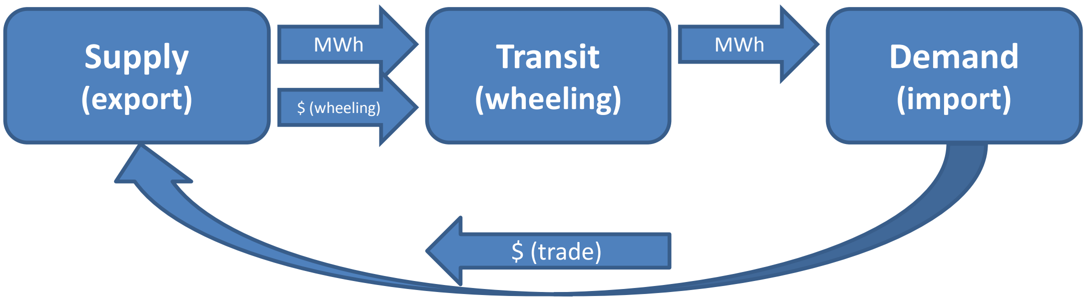
Source: IEA.

The fact that this transaction occurs between jurisdictions means that the importing party must consider the possibility of events occurring that are outside of its control. For example, a transmission line could trip, or the host jurisdiction's system operator could redispatch the generator in question unexpectedly. For this reason, many jurisdictions treat external generation differently in terms of their contribution to local resource adequacy.

To get around this issue, in some cases the importing party invests directly in the generating asset in question and perhaps in the transmission infrastructure as well. This is the case, for example, for existing transactions between Thailand and Lao PDR, where Thailand imports hydropower from plants that it has dispatch control over via transmission lines that it has developed (IEA, 2016). The ideal way to manage this situation, however, is through agreements between system operators that set specific rules for outage response and redispatch, and that also establish lines of communication between relevant parties. Because there are multiple jurisdictions involved, policy makers and regulators may also be involved in the development of such agreements.

There is one additional type of bilateral trade that should be highlighted, namely trades between two jurisdictions that require the transfer of power through the grid of a third jurisdiction. In this case, although the third party (the transit or wheeling jurisdiction) is not directly involved in the trade, it is nevertheless indirectly affected by the transaction. In particular, the flow of power across its grid potentially affects local system operations by creating additional congestion and requiring, for example, redispatch of generation. To address this issue, it is best to enter into some form of wheeling agreement with the transit jurisdiction. Under one simple model, for example, the supply country enters into a bilateral wheeling agreement with the transit country, and then pays the transit country a wheeling charge, which it (ideally) would recover from the transaction revenues (Figure 21).

Figure 21. Example bilateral, unidirectional trade with transit (wheeling) jurisdiction



Source: IEA.

Bi- and multidirectional trades

While bilateral, unidirectional trades are fairly straightforward to establish, they potentially limit the efficiency gains that come from trade. This is because one of the primary advantages of cross-border trade is to take advantage of interregional diversity, whether in terms of supply or demand. For example, if two neighbouring jurisdictions have very different peak periods (either daily peaks, seasonal peaks or both) it could make sense for one jurisdiction to import during its peak hours (or season) and export during its off-peak hours (or season).

To do so, the respective jurisdictions must enter into some form of bilateral or multilateral agreement that governs the rules of the trade. This could look come in the form of two separate PPA agreements, but ideally it would involve a more general agreement that allows for more flexible modes of trade. Some issues that should be addressed in such an agreement include the cost of power (which could perhaps depend on the time of the transaction), an agreed-upon methodology for measuring transmission capacity, and some way of sharing dispatch schedules or at least available generating capacity.

It is possible for these sorts of agreements to be multilateral in nature, but arriving at a common methodology for trade among multiple jurisdictions can be difficult without the presence of some form of inter-jurisdictional institution. As a result, in many regions trading arrangements are often bilateral and bidirectional. When this is the case it can be a challenge to move from bidirectional trades to a more harmonised multilateral environment, because the various existing bilateral agreements may not be compatible with one other. In such cases it is often easiest to leave existing agreements in place, and to create an additional, separate multilateral market arrangement.

Multi-buyer, multi-seller market

In a multi-buyer, multi-seller market environment, market participants from any jurisdiction can enter into a transaction with participants from any other interconnected jurisdiction. In some cases, market participants may be limited to vertically integrated utilities and perhaps some independent power producers (IPPs). This is the case, for example, in the Southern African Power Pool (SAPP). At the other end of the spectrum, regional markets may be fully open to any qualified participants, including financial participants that may not directly own generation access or be responsible for serving load. This is the case, for example, in the Nord Pool market.

It is possible to break these market arrangements up into two primary models: **primary** trading arrangements and **secondary** trading arrangements.

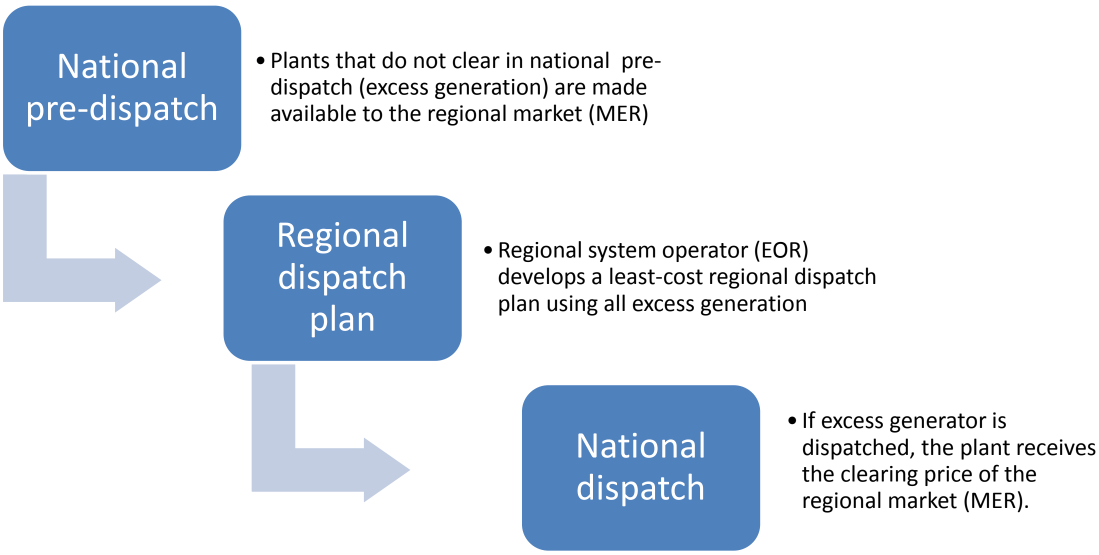
Primary trading arrangements are ones where the default mode of trade is multilateral. That is, by default all resources are pooled together in a single market, including transactions organised directly through the market and any bilateral trading agreements. Nord Pool is one example of a primary trading arrangement. PJM in the United States is another.

Secondary trading arrangements are ones where multilateral trading exists in addition to, or alongside, other (typically intra-jurisdictional) trading arrangements. In these environments, regional multilateral markets are used as a secondary option to either fill gaps in times of scarcity or sell power in times of excess. The SAPP is one example of a secondary market, as is SIEPAC in Central America.

To understand how such a secondary trading model works, an example from SIEPAC is illustrative.

SIEPAC is a regional market that covers six countries in Central America (Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua and Panama). Its primary purpose is to improve regional power system efficiency by making excess generation available to all interconnected countries. The process works as follows. First, the various national system operators perform a pre-dispatch optimisation where they determine least-cost dispatch using only domestically located generation. Excess generation (that is, generation that is not needed to meet local demand at least cost) is made available to the regional market, the Mercado Eléctrico Regional (MER, "Regional Electricity Market") (Figure 22).

Figure 22. Example trade in the SIEPAC market



Source: IEA diagram based on analysis by Delphos International.

The regional system operator, Ente Operador Regional (EOR, the Regional Operating Entity), develops a least-cost regional dispatch plan, using the available excess generation. If a generator is dispatched under this regional plan, it receives the regional clearing price. Other generators, which cleared in the national markets, receive their local clearing price.

Secondary markets can also be technology-focused. For example, to help improve the integration of variable renewables in its domestic grid, China has developed a spot market for excess renewable generation. Launched in August 2017, this regional market allows for the trading of excess renewable generation among a number of provinces (primarily Gansu, Xinjiang, Ningxia, Qinghai and Sichuan) where there is an excess of renewable generation relative to local demand.

As this excess generation tends to be low cost, purchasers (which might be grid operators, retailers or large consumers) benefit by gaining access to relatively cheaper resources in neighbouring provinces. Though volumes of trade are significant (with 6 billion kilowatt-hours traded by the end of 2017) the overall efficacy of the market is limited somewhat because of transmission constraints. In particular, a number of provinces have put in place import/export quotas that limit the amount of excess renewable power that could otherwise be traded.

Primary markets, as already noted, are functionally different in that they account for all available resources in the system. In some cases, market organisation is separated from system operations. For example, Nord Pool organises day-ahead and intraday markets for all participating countries, but system operations remain the responsibility of the various national TSOs. This is in contrast to the PJM model, which organises a regional power market covering multiple US states, and which is also responsible for system operations across the region.

There are advantages and disadvantages to both models. The Nord Pool model is more distributed, with system operation functions in the hands of organisations that are closer (both physically but also in terms of relationships) with local resources, policy makers and other stakeholders. There is also, however, a strong link between the TSOs and the regional market, as Nord Pool is entirely owned by its member TSOs. In theory, however, it is possible for other market organisers to operate in the Nord Pool region, either in competition with the Nord Pool market, or in addition to (for example, by offering different services).

The PJM model, on the other hand, is much more centralised, meaning there is a stronger alignment between market organisation and system operations.

To give a specific example of how this difference affects the respective markets, in Nord Pool the various price zones are determined at the national (TSO) level. So, for example, Norway has five price zones and Sweden has four, but Finland has only one price zone. In contrast, PJM determines the appropriate size and number of price zones based on a holistic assessment of transmission constraints across its service territory.

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Resource adequacy: Planning for the long term

Responsibility for ensuring long-term resource adequacy – that is, ensuring sufficient investment in generation and transmission capacity to meet long-term system needs – typically remains at the jurisdictional level even in highly integrated systems.

In the European Union, for example, each member state retains control over policies that relate to domestic energy supply. Domestic policies may be shaped by regional ones (for example, the EU 2020 targets for share of renewables in the power system are developed regionally and then allocated to the respective member countries; this is not the case for the 2030 targets, which are only binding for the European Union as a whole) but control remains local (for example, EU countries choose which policies to implement to meet these targets).

As in the case of system security, however, policies that relate to long-term resource adequacy can have spillover effects. For example, as noted in the discussion on managing loop and transit flows, cross-border power flows are heavily influenced by the level of domestic transmission system development or the share of variable renewables. Similarly, the presence of relatively inflexible generation technologies, such as co-generation[2], and policies that impact investment, such as a capacity mechanism, can influence power systems in neighbouring jurisdictions.

Managing these impacts requires some degree of cross-border collaboration or co-ordination. In some cases, in particular the development of interconnectors, cross-border collaboration is a fundamental necessity. In many other cases, however, the cross-border impacts of long-term power system development can be managed through increased transparency (for example, by sharing power system development plans) and increased co-ordination on real-time system operations. That said, many jurisdictions are finding that active collaboration on longer-term issues such as regional planning and power system development can help prevent long-term issues before they occur.

Developing cross-border interconnectors

The presence of cross-border interconnectors is a fundamental necessity for cross-border power trade. Whether and how they are developed, however, depends on a confluence of political, technical and economic decisions.

Interconnectors developed across borders must meet the same basic criteria as other kinds of transmission development, including:

- meeting some kind of economic test
- obeying regulatory requirements
- gaining stakeholder support.

[2] *Co-generation* refers to the combined production of heat and power.

In addition, however, there is the complicating element of cross-border co-ordination across multiple organisations. This may include policy makers, regulatory institutions and utilities, each of which may, in their own jurisdiction, face differing sets of interests, policies and regulations.

Regional planning

One key element to ensuring the long-term success of cross-border power system integration is to have robust regional collaboration on power system planning. There are many examples of these kinds of collaborative exercises, from ad-hoc and voluntary to formal and mandated. One clear lesson from these various experiences is the deeper the level of collaboration, the greater the likelihood of success.

At one end of the spectrum – ad-hoc and voluntary – is the Greater Mekong Subregion (GMS) Regional Power Grid Consultative Committee (RPGCC). Membership includes five of the ASEAN member states and Southern China. Supported by the Asian Development Bank (ADB), the GMS RPGCC has for a number of years sought to enhance regional power system integration among the GMS countries. Some of the plans are fairly ambitious, including the establishment of a regional control centre. The various meetings of the RPGCC, though, have tended to focus primarily on the sharing of power system development plans (in particular, transmission development).

It is almost certainly the case that these meetings have been beneficial to regional planning among the participating countries. The planning information presented, though, tended to be relatively high level. Moreover, the plans are not presented in any kind of harmonised format, and there is no process in place for aggregating the plans and/or incorporating them back into the various domestic plans.

Though there is significant collaboration among the GMS countries, the absence of a regional power market means there is little incentive for collaborative planning on a multilateral basis. In parts of the world that have developed regional markets, regional planning is typically done through a more formal process.

For example, the SAPP is responsible for collecting and aggregating national power development plans. From these plans it develops a list of recommended "priority projects", which it then submits to the Southern African Development Community (SADC) Secretariat (Mangwengwende, 2013). The SADC develops its own Regional Infrastructure Development Master Plan, which takes these projects into account. According to the most recent Master Plan, released in 2012, the total cost for all priority interconnector and transmission projects under consideration amounted to USD 3 billion (SADC, 2012).

Regional planning in other regions follows a similar bottom-up approach, although mixed models are also possible. For example, the Northwest Power and Conservation Council has had the authority since 1980 to develop a regional plan for the four US states in its service territory. However, of these four states, three still require the development of local, utility-level integrated resource plans (IRPs) first, which are then consolidated into a single regional IRP (IRENA, 2018).

The United States in general is a mix of TSOs covering multiple or single states (the so-called RTOs and ISOs), and vertically integrated utilities that may serve part or all of a single state. There is no process, however, for developing a formal, national power system plan. Instead, regional planning, when it does happen, tends to be done on a voluntary basis.

The US Federal Energy Regulatory Commission (FERC) has issued a number of orders to encourage increased regional collaboration on transmission planning issues. Perhaps the most relevant is FERC Order 1000, which is explicitly focused on improving interstate transmission planning. Among other things, Order 1000 defined a number of transmission planning regions and mandated that utilities within these regions establish joint planning exercises. The order also required utilities at the edge of each transmission planning region co-ordinate across the planning region border.

These requirements led, for example, to the launch of the Eastern Interconnection Planning Collaborative (EIPC), which involved a wide range of utilities, ISOs and RTOs from the eastern portion of the United States. The EIPC operates under what it refers to as a "roll-up" model, which takes utility-developed plans and aggregates them in such a way as to verify that individual plans are not in conflict with one another, and to identify potential system constraints that may emerge if the plans are fully developed. The EIPC also models various future scenarios for the region, such as a "heatwave and drought" scenario (EIPC, 2018).

FERC 1000 does not mandate any specific outcome from these planning exercises. As a result, outputs have been irregular. Europe and Japan, on the other hand, have a much more formalised regional planning process that:

- uses harmonised data and other information
- mandates participation
- is centrally managed through a regional institution or institutions.

In Europe, responsibility for developing regional plans rests with ENTSO-E, which does so through its Ten-Year Network Development Plan (TYNDP) process. The TYNDP is another example of a bottom-up development process, though in this case the process if quite formal and regular. Participating countries are required to submit national plans to ENTSO-E, which then aggregates those plans and develops a single model.

As with the EIPC process, the TYNDP includes various scenarios. The most recent TYNDP, for example, includes a variety of scenarios focused on the transition to a low-carbon power system, including a Sustainable Transition scenario (which assumed EU climate targets are met using national regulations, emissions trading schemes and subsidies, and which maximised the use of existing power infrastructure), a Distributed Generation scenario (which assumes a significant increase in behind-the-metre deployment of renewables and storage) and a Global Climate Action scenario (which assumed more ambitious global efforts on climate change and energy transition) (ENTSO-E, 2018).

One of the TYNDP's more critical functions, however, is the identification of Projects of Common Interest (PCIs). Developed on a biannual basis, PCIs are eligible to receive additional financial support from the European Commission, among other benefits. Most of these PCIs are transmission projects, though non-transmission alternatives can also qualify, including, historically, some phase-shifter projects (EC, 2017).

Japan follows a similar model to Europe's, though it takes it one step further. As with the TYNDP, utility plans in Japan are aggregated and consolidated by OCCTO. In addition, OCCTO can require the development of transmission lines if it finds that they are necessary for system security.

Regional resource adequacy assessments

Though regional planning is important for supporting and, hopefully, improving regional integration, from a resource adequacy perspective one piece is still missing. The regional planning exercises described above are, as already noted, bottom-up exercises. This means, among other things, that the level of generator capacity is taken as given. Regional planning in this context, therefore, tends to focus on implications for grid development.

One of the key benefits of regional integration, however, is the ability to rely on neighbours to help meet resource adequacy needs. For example, it was already noted above that regional integration can help reduce investment costs by allowing for the sharing of reserves.

To gain the full benefits of regional integration, regional planning must move beyond simply aggregating jurisdictional plans to the development of full regional resource adequacy assessments. Some regions have already started to do exactly this.

In Europe, for example, a regional generation adequacy assessment is developed for nine TSOs by the PLEF. The PLEF is a voluntary collaborative body that works towards increased electricity market integration and security of supply among its seven member countries.[3] Notably, a number of important advancements in regional market and power system integration have emerged from the PLEF, including the development of flow-based market coupling (which improves day-ahead market coupling by taking into account a more detailed picture of the grid) and the development of regional resource adequacy assessments.

To date the PLEF has released two regional resource adequacy assessments, in 2015 and in 2018. The 2015 assessment introduced a probabilistic methodology for adequacy assessment, something that will be increasingly critical as the share of renewables (which operate in more volatile, "probabilistic" manner than traditional dispatchable generation) increases. The second effort included a number of assessment innovations that go beyond what is included in a typical resource adequacy assessment, including the incorporation of demand-side flexibility and, more relevant in this context, a flow-based assessment approach (PLEF, 2018). Under the most recent "recast" of the EU Electricity Regulation, a new, European Union-wide adequacy assessment is being introduced, which will include development of a more state-of-the-art assessment methodology (EC, 2016).

The flow-based approach includes a number of relevant advances over the more typical, static approach, including replacing constant values for NTC with dynamic values that reflect actual interconnector availability under (modelled) real-world system conditions. Using this methodology allows for a more accurate assessment of potential resource availability on a regional basis, which should in turn allow for more accurate assessments of local resource adequacy needs.

Cost-benefit tests and cost sharing

Ideally, all interconnectors should be evaluated according to some form of cost-benefit analysis. When multiple jurisdictions are involved, however, a critical first step is to define a common cost-benefit test. It can often be difficult, however, to come to an agreement on a common methodology. Costs are usually fairly straightforward to evaluate, but quantifying benefits is much more challenging.

First, it can be difficult to identify clear boundaries for evaluating these benefits. The impacts of new interconnectors in large, synchronised systems can extend well beyond the local geography, suggesting that a large geographic scope may be appropriate. Here a delicate balance must be struck. If geographic limits are defined too narrowly, some consumers will end up bearing an unfair share of the costs. If, on the other hand, the area is defined too broadly, the benefits may be too diffuse to make a clear case for investment.

The European Commission has noted the difficulty in making the economic case for some projects in a large, interconnected system. This is a key reason it has introduced the PCI process, so that projects with regional benefits can receive additional support.

[3] Austria, Belgium, France, Germany, Luxembourg, the Netherlands and Switzerland.

Once the decision is made to develop an interconnector, the next is how to share the costs of development.

In Europe, despite the use of cost-benefit tests, the costs for most interconnector projects are shared evenly between the two relevant TSOs (Wittenstein, Scott and Rizali, 2016). This is because it can be more politically expedient to simply agree to share costs evenly than to go through the trouble of a cost-benefit test.

In cases where countries are unable to agree on a cost-sharing arrangement, the respective countries may choose to ask ACER to intervene and impose an arrangement. ACER can also, under some limited circumstances, choose to step in without having first been invited.

The role of ACER in this process highlights a key factor in the successful development of interconnectors: having a central institution play a role in cost allocation can help move interconnector development forward.

To provide another example, in Japan, new interconnectors have historically been developed by the individual EPCOs. Their tendency to prefer to develop local generation, however, led to a relatively low level of overall interconnection. Now, however, various institutions can suggest new interconnectors, including private enterprises, the Japanese government and, most relevant, OCCTO.

If OCCTO deems there to be sufficient benefits (including security benefits such as reduced potential for outages, and economic benefits such as reduced curtailment), it can require the development of new interconnectors. As part of this process, OCCTO can also impose a cost-benefit calculation and cost allocation methodology on the relevant parties.

Within the United States, despite the presence of a strong federal regulator, there is no common methodology for allocating costs. Instead, FERC Order 1000 indicates a strong preference for relevant parties to adopt a "beneficiary pays" approach, following a set of six principles, namely (FERC, 2011):

- Costs should be allocated in rough proportion to benefits.
- Costs should not be involuntarily passed on to non-beneficiaries.
- If a benefit-to-cost threshold is set, it cannot exceed 1.25 without permission from FERC.
- The cost allocation should be solely within the affected transmission planning region or regions, unless outside parties voluntarily agree to pay some portion of the costs.
- Benefits should be measured, and beneficiaries identified, in a transparent manner.
- A transmission planner may use different cost allocation methods for different types of transmission facilities, including differing types of interregional interconnectors.

Interconnector development between the United States and Canada offers another example of how costs may be allocated between responsible parties. Canada differs from the United States in that regulation of the transmission system is done entirely at the provincial (i.e. subnational) level. It is therefore the provinces themselves that negotiate the appropriate cost allocation and that are responsible for permitting and construction (in both cases, their responsibility ends at the border; on the US side both FERC and the local authority play a role).

Estimating and allocating interconnector capacity

Ensuring the efficient and equitable allocation of interconnector capacity is critical to enabling cross-border power trade. Ideally, available interconnector capacity should be calculated in a harmonised fashion on both sides of an interconnected border. In cases where it is not possible to agree on a common methodology, the best (and most conservative) approach is for both sides to take whichever calculated amount is smaller.

Globally, the most common method for measuring available interconnector capacity is to calculate the NTC. This is a static method that assumes a given amount of capacity is available, taking into account whatever portion of transmission capacity has already been allocated (for example, through long-term bilateral agreements) or which for whatever reason is not available for trading (for example, some amount may be kept on reserve in case of emergencies). This method does not, however, take into account actual system conditions.

The actual amount of transmission capacity available in real time, though, depends heavily on actual system conditions. It is for this reason that some regions are moving to a flow-based methodology. Flow-based calculations take into account actual (potential or modelled) system conditions when estimating the amount of capacity available, including the topology of the grid on both sides of the interconnector.

The difference between the NTC and flow-based methodology can be significant. For example, the most recent PLEF regional resource adequacy assessment found that the LOLE for some countries in the assessment region was significantly higher when estimated using the flow-based method, because the actual available interconnector capacity was less than what had been assumed under the NTC calculation, due in no small part to the presence of loop flows (PLEF, 2018). In theory, with the introduction of the CACM and other tools to limit loop flows, flow-based calculation methods should lead to less conservative estimates for available capacity.

Once the amount of capacity available is determined, the allocation of capacity itself can fall into two categories: non-firm and firm. If capacity is allocated on a non-firm basis, transmission access is not guaranteed, whereas on a firm basis, access is assured up to the allocated amount.

If access is provided on a non-firm basis, cross-border energy trading becomes riskier, as access to the neighbouring market is entirely dependent on there being sufficient transmission capacity available in real time. Generators may choose to minimise their risks by trading during off-peak hours, when interconnector capacity is less likely to be constrained, but also when prices are relatively low and the value of additional generation may be diminished. Moreover, without firm capacity, cross-border capacity trading is effectively impossible.

Firm capacity provides certainty in delivery, lowering the risk of energy trading and enabling the possibility of capacity trading. However, how capacity is allocated still plays a significant role in determining whether and how cross-border trade occurs.

For example, in Japan, interconnector capacity has historically been allocated on a first come, first served basis. Incumbent EPCOs were able to reserve transmission capacity for up to ten years, effectively locking third parties out of the market for cross-border trade. Without access to firm transmission rights, non-incumbent retailers were forced to procure sufficient local capacity to meet their balancing needs. At the same time, EPCOs tended to rely on local capacity to meet their own needs, leading to underutilisation of interconnector capacity and a general oversupply of capacity in many of the balancing areas.

To enable third-party access and to encourage more cross-border trading, interconnector allocation in Japan is being moved to an implicit auction system. This move follows the European example, which has moved to an implicit allocation process for at least a portion of interconnection allocation.

There are two market-based models for allocating transmission capacity: explicit and implicit auctions. Under the explicit model, transmission rights are auctioned off on a per-megawatt basis at some point ahead of real-time delivery. Typically explicit auctions are done well in advance, in the monthly or annual time frame. Explicit auctions are a useful tool for ensuring long-term access to transmission capacity, but they can also create inflexibility in the system, in particular by tying up transmission capacity that could potentially be more efficiently utilised in the real-time market.

Under the implicit auction process, transmission capacity is allocated consistently with least-cost dispatching. That is, parties are granted transmission capacity in the order in which they clear in the spot market (typically day-ahead and, if available, intraday), up to the available amount of capacity. Implicit auctions, therefore, require the presence of a wholesale market.

Box 2. Allocating direct current interconnector capacity

When two systems are connected via direct current (DC) transmission lines, the process for allocating interconnector capacity is slightly different. Unlike AC interconnectors, DC interconnectors provide a stable (i.e. highly predictable) level of capacity. However, the capacity of the AC grids connected by the DC interconnector is not as easily predictable. When allocating DC interconnector capacity, therefore, the focus must shift away from the interconnector itself to the capacity of the grids on either side of the interconnection.

In such circumstances, grid allocation is typically done in serial fashion. For example, for a DC interconnector that is expected to deliver power from Country A to Country B, first the capacity is measured from Country A to the interconnector, and then it is measured from the interconnector to Country B. The amount of capacity available for allocation is determined by whichever is smaller: the DC interconnector capacity, or the capacity to or from the AC grids.

Capacity trading

For cross-border power system integration to contribute to local (jurisdictional) resource adequacy needs, there must be some way to ensure the reliable contribution of cross-border generation assets on a long-term basis. Typically this is referred to as the trading of generating capacity across borders, as opposed to cross-border energy trading.

The definition of energy in the context of cross-border trade is fairly straightforward. It merely refers to the quantity of kilowatt-hours delivered in real time. For capacity, on the other hand, there is no standard definition. For example, capacity could refer merely to the total quantity of energy that could potentially be delivered – that is, kilowatts as opposed to kilowatt-hours. Or it could refer to the total quantity of energy that could actually be delivered under a given set of circumstances.

For the purposes of this discussion, the following definition of capacity is assumed: a quantity of energy, in kilowatt terms, that is physically deliverable to the point of need, at the time of need. That is, it should not be from generating capacity that is curtailable without advance warning, and it should not come from a physical location that is electrically isolated in some way from the purchaser.

Within a given control area, these criteria are relatively easily met. The dispatcher has control over the generating asset in question (within reason, i.e. accounting for the possibility of unexpected outages, or for the fact that a given resource may not be dispatchable), and it can take into account known or potential transmission constraints.

For assets located outside of a given control area, however, the availability or deliverability of capacity is complicated by two factors: a lack of visibility and a lack of control.

In some cases these issues can be overcome through the use of long-term bilateral contracts combined with the allocation of firm transmission capacity, or the direct control over cross-border transmission lines. For example, Thailand's imports of hydroelectric power from Lao PDR are typically done under long-term PPAs, with power transmitted via transmission lines owned and operated by Thailand's vertically integrated utility, the Electricity Generating Authority of Thailand (EGAT).

This model of capacity trading – where a local system operator effectively gives up control over a local asset so that it can provide capacity to a neighbouring system – exists in other environments as well. It is, for example, not dissimilar from the model PJM in the United States uses for capacity imports.

Under the PJM model, if an external generator wishes to sell capacity to PJM, it must meet the following criteria (PJM, 2018):

- The generator must be able to demonstrate that it has firm network capacity in its home jurisdiction, to the border with PJM.
- The generator must meet all of PJM's tests for capacity, including seasonal capability testing.
- The generator must have a "letter of non-recallability" (i.e. an agreement that it will not be curtailed) from its host system operator.
- The generator must be treated as having electronically moved to PJM's service territory.

The last two points are perhaps the most critical ones. Taken together, these elements mean the generator effectively removes itself from the control of its local system operator and gives operational control over to PJM.

From the perspective of PJM, therefore, this unit now looks and functions like a local generator. From the perspective of the host jurisdiction, however, the unit is now effectively islanded within its own territory. This means, for example, that the host system operator loses visibility into the real-time dispatch decisions of the unit in question.

This model works in the United States in part because PJM is responsible for both market organisation and system operations. It is harder to implement in an environment like the European Union's, where market organisation and system operations are functionally separated. In the European Union, cross-border trade has historically been limited to energy, a product that is harmonised across the respective countries.

Capacity products and market arrangements, however, differ from country to country. Moreover, there is no possibility for a generator in one country to electronically "remove" itself from its host country so that it may give control over to another – final decisions regarding dispatch remain firmly in the hands of the host TSO. For capacity trading to work in an EU context, there is a need to harmonise capacity products and markets along similar lines as energy trading. The recast electricity regulations require the participation of external resources in domestic capacity mechanisms (EC, 2016). Going forward, this will be facilitated by ENTSO-E, ACER, the national regulatory authorities (NRAs), and other relevant organisations.

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Governance: Institutions and frameworks

Cross-border system integration, by definition, involves multiple jurisdictions working together. Integration therefore requires both a political decision to proceed and a governance framework to manage the process. Both political decisions and governance frameworks are influenced by a number of concerns, including:

- The implications of increased dependence on neighbouring jurisdictions for electricity imports.
- Whether the export of local resources (in the form of electricity production) could come at the expense of local economic development.
- A desire to develop new resources (for example, renewable generation) locally in order to capture as much of the value (both economic and political) as possible.

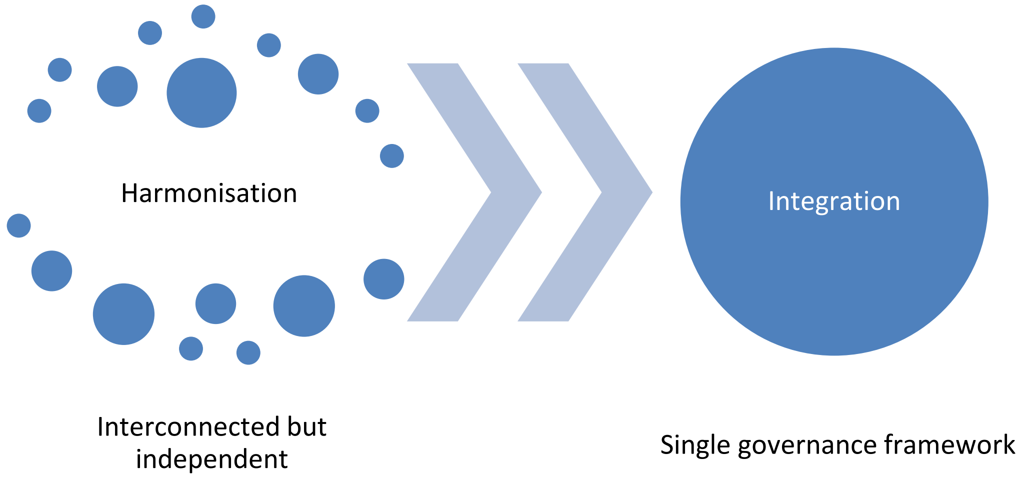
Once the political decision has been made to integrate power systems across borders, it is the governance framework that determines whether and how these and other concerns are addressed. Even where the political will exists to create an integrated system between two jurisdictions, effective governance is needed to ensure the intent is achieved in practice. The issue of governance is therefore of critical importance. In fact, it is the issue of governance that, more than any other factor, sets cross-border integration apart from local efforts to develop power systems.

As the examples below will show, there are many models of inter-jurisdictional governance arrangements. If one were to think of these models as existing across a spectrum, though, then it may be useful to describe the two possible extremes.

At one end of the spectrum, the relevant jurisdictions remain independent, and cross-border integration is managed through a set of bi- or multilateral institutional and policy arrangements (Figure 23). Under this model, the focus is on harmonisation of relevant market designs and regulations, so as to enable as much trade as possible without relinquishing local independence over key policies.

At the other end, a single governance framework is developed that encompasses all relevant jurisdictions. Under this model, the multi-jurisdictional system becomes, in essence, a single jurisdiction – albeit one with a large and diverse set of stakeholders.

Figure 23. Models of cross-border integration: From harmonisation to unification



In practice, most regional integration efforts fall somewhere between these two extremes. For example, in the United States, the various multi-state RTOs – in particular, ISO-NE, PJM and MISO – would fall somewhere on the spectrum close to full integration. Each of these acts as the market organisers and system operators for power systems that extend across multiple states. Each, however, is also under the jurisdiction of the federal government – in particular, the regulator FERC – and all cover states that have their own regulators and policy makers. As a result, they fall somewhat short of a true single governance framework model.

On the other end of the spectrum one could put the ASEAN Power Grid (APG). Though the APG has been technically under development for going on two decades, in practice it remains a somewhat piecemeal collection of interconnectors developed and operated on a bilateral basis. There are, as of yet, no overarching governance frameworks or institutions, and so each interconnector is developed under a different set of agreements – ones that, to varying degrees, enable trade, but without sacrificing the autonomy of the national power systems.

Regardless of the degree of integration, in all cases the roles of both political and regulatory institutions are of critical importance. As already noted, political institutional support is necessary for integration to happen in the first place. Assuming there are no political obstacles to integration, then the regulatory institutions become the most important link, as it is the regulators that will set the rules for exchange and that will enforce the rules once power trade begins.

Political institutions

The role of political institutions in enabling cross-border integration must be examined across two different dimensions. First, there is the role of political institutions in supporting integration efforts with external jurisdictions. Second, there is the role they play in supporting integration efforts within their own territories of authority.

Integration efforts will often, though not always, require explicit approval from a political institution to move forward.

Take, for example, interconnectors that cross the US and Canadian border.[4] From a US perspective, the US Department of Energy (DOE) has a few specifically defined roles to play.

The US DOE issues presidential permits for the construction, operation, maintenance or connection of electric transmission facilities at the United States international borders. The DOE may issue such a permit if it determines that issuance of the permit is in the public interest and after obtaining favourable recommendations from the US Departments of State and Defense. In determining whether issuance of a presidential permit is in the public interest, the DOE assesses the potential impact of the proposed project on electric reliability, the potential environmental impacts of the proposed project and any other factors that the DOE considers relevant to the public interest. The Departments of State and Defense must also concur, although the US DOE leads the effort. In total, 142 presidential permits have been granted, including 100 for lines between the United States and Canada, and 42 for lines between the United States and Mexico (DOE, 2019).

Second, the DOE also issues authorisations to export electric energy over US international borders. According to the Federal Power Act, exports of electric energy should be allowed unless the proposed export would impair the sufficiency of electric power supply within the United States or would impede or tend to impede the co-ordinated use of the US power supply network.

On the Canadian side, the National Energy Board (NEB, a federal agency) plays a similar role as the US DOE, granting permits for international transmission lines and regulating the export of electricity. Similar to the United States, in practice the NEB rarely intervenes to prevent international interconnection efforts.

Control versus influence

The US-Canada example highlighted above is one of political control: political intervention is required for integration to move forward. In some regions this control extends to supranational entities. In Europe, for example, the European Commission has the authority to enforce market harmonisation across EU member states. When it comes to interconnector development, however, the European Union's authority is more limited. Here it can only influence the development of interconnectors through incentives, such as highlighting infrastructure investments that have regional benefits by declaring them to be PCIs and by the supporting the development of these PCIs through financial grants.

This type of political influence can also be seen within the United States. Here the federal government has less of an ability to require, for example, planning collaboration between utilities. Instead it has encouraged collaboration by supporting, through financial grants, regional planning exercises such as the EIPC. The various national laboratories are also a tool for supporting integration efforts, though primarily at a technical level, through their research and development and analytical efforts. Finally, the US DOE has the power of the bully pulpit. In its first *Quadrennial Energy Review*, the DOE included recommendations for reforming FERC Order 1000, and in the second it included a full chapter on "Enhancing electricity integration in North America" (DOE, 2017).

Among the ASEAN countries, the proposed APG can also be seen as an exercise in "soft power". There is no ASEAN institution with the authority to develop transmission lines, demand market and regulatory harmonisation, or otherwise require increased cross-border collaboration. But ASEAN member states can collectively set aspirational targets and can support analytical work to demonstrate the benefit of integration. Two ASEAN Interconnection Masterplan Studies (AIMS I

[4] The United States also has interconnections with Mexico, where the same set of authorities and principles applies.

and II) have been developed, and ASEAN has organised the ASEAN Power Grid Consultative Committee to help move development of the APG forward.

As a final example, take the three Baltic countries, which are already relatively well interconnected with the Nordic countries via three HVDC transmission lines, allowing them to participate actively in the Nord Pool power market. The Baltic system itself, however, remains synchronised with the Russian Federation and Belarus. While there is no technical reason this situation cannot continue, the Baltic countries have indicated that they would prefer to desynchronise from Russia and resynchronise with Europe, most likely though Poland (EC, 2018).

The logic of politics can also at times limit the extent of cross-border power system integration. Thailand, for example, imports electricity from hydroelectric dams in Lao PDR. The structure of these imports, however, differs significantly from, say, US imports of electricity from Canada. The relevant dams in Lao PDR were built by Thailand and are treated as IPPs under the full control of Thailand’s utility, EGAT. Though Lao PDR earns revenues from these plants, it receives only a limited amount of power domestically from them, and it has no ability to influence how they are operated.

From Thailand’s perspective, this arrangement is attractive because it offers an additional degree of security. Thailand does not have to worry about power not being delivered as promised, because it controls the assets in question. Moreover, as EGAT (Thailand’s national utility) is fully owned by the government, the actions it takes when it comes to cross-border integration efforts can be seen as reflecting Thailand’s political preferences.

From Lao PDR’s perspective, this arrangement is suboptimal, because there are generating assets within its territory that use its local (water) resource but that it only derives a partial benefit from. More recently, the politics of this issue have begun to change, with Lao PDR beginning to assert a right to control assets developed on its territory. Now, rather than discuss new hydro plants being built under an IPP model, the discussion is more focused on moving to a grid-to-grid or utility-to-utility trading model.

Moreover, Thailand is beginning to change the way it sees the role of imported power. Driven by a desire to increase the diversity of its generation sources, the most recent Power Development Plan, released in 2015, includes a planned increase in imports from 10% of its current generating mix to between 15% and 20% (EGAT, 2015).

A more historical example demonstrates how the progress of integration is not always forward. The most significant development of cross-border interconnections in Southern Africa started after the formation in 1980 of the Southern African Development Coordination Conference, the predecessor to the SADC (ECA, 2009). These lines would eventually become the underlying infrastructure of the SAPP, but the initial driver of integration was resource diversity. South Africa was rich in thermal generation, while countries such as the Democratic Republic of Congo had excess hydroelectric resources. By interconnecting, South Africa gained access to lower-cost hydropower, while the rest of the region gained access to generating resources that were not seasonal in nature.

Regulatory institutions

Regulators play a key role at all points in the process of cross-border power system integration. They set rules for cost sharing and cost recovery of infrastructure assets, define and regulate the market frameworks of the various relevant jurisdictions, and monitor market participants to prevent anti-competitive behaviour.

The role of the regulator differs depending on whether the power system integration effort occurs within the regulator's own jurisdiction or involves multiple regulated jurisdictions. In the latter case, the best examples of regional integration efforts are ones where the work of jurisdictional regulators (state or national) are supported by an overarching regulatory body of some kind (national or supranational).

Here again, a comparison between the United States and the European Union is instructive.

In the United States, there are regulators at the state level and a single federal regulator, FERC. FERC's regulatory authority is limited to the transmission system and wholesale power trade in states where there is sufficient interconnection to other states. As a consequence, Alaska, Hawaii and Texas are excluded from FERC regulation. State regulators oversee distribution systems and retail markets.

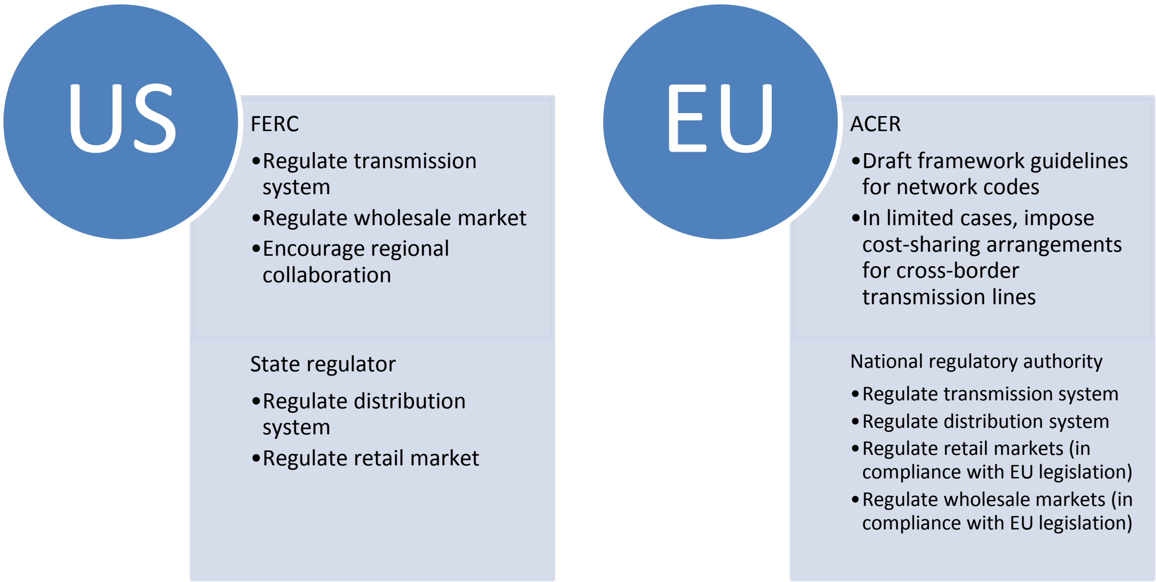
In Europe, the balance between regional and local regulation is shifted more in the favour of the local jurisdiction – in this case, the NRA. Unlike the United States, where FERC has the exclusive authority to regulate the transmission system, in EU member states each respective NRA retains that responsibility. The NRAs also regulate the wholesale markets (in addition to the retail markets), though regulations must comply with EU legislation. For example, power systems in all EU countries must be unbundled. In the United States, the decision on whether and how to unbundle is left entirely to the states.

The European Union does have a regional regulatory body. The difference between it and FERC can be found right in the name: the Agency for the Cooperation of Energy Regulators. ACER is an independent EU agency, but it is not a formal EU regulator. ACER's primary purpose is to encourage and support co-operation among the various NRAs, in particular in areas that fall under EU legislation. ACER can also step in to make decisions if and when NRAs cannot agree.

On electricity, ACER works on four key areas:

- preparation and implementation of framework guidelines and network codes
- electricity regional initiatives
- infrastructure and network development
- implementation and monitoring of the Regulation on Wholesale Energy Market Integrity and Transparency (REMIT).

Figure 24. Division of regulatory authorities in the United States and European Union



Source: IEA.

For the most part, ACER simply makes non-binding recommendations to the NRAs, TSOs and other relevant EU institutions. ACER does, however, have an authority directly relevant to the topic of cross-border power system integration. When an interconnector is being developed, if the respective NRAs are unable to come to a cost-sharing agreement within six months, ACER may step in to impose a cost-sharing arrangement. ACER also, at the request of the Commission, leads the drafting of framework guidelines for network codes.

In other regions, regulatory collaboration may have a formal structure, but it rarely has formal authorities. In some regions with regional power markets that are distinct from national markets, such as the SAPP and SIEPAC, there are regional regulators who are responsible for regulating the regional market. In the SAPP this is the Regional Electricity Regulators Association of Southern Africa (RERA). RERA is primarily focused on further developing the regional market, but it also encourages regulatory harmonisation and supports capacity building in participating countries. In SIEPAC, the Comisión Regional de Interconexión Eléctrica (CRIE) regulates the market to ensure fair competition. It has limited authority to intervene in the market to prevent abuse, but only for power trades made through the SIEPAC market.

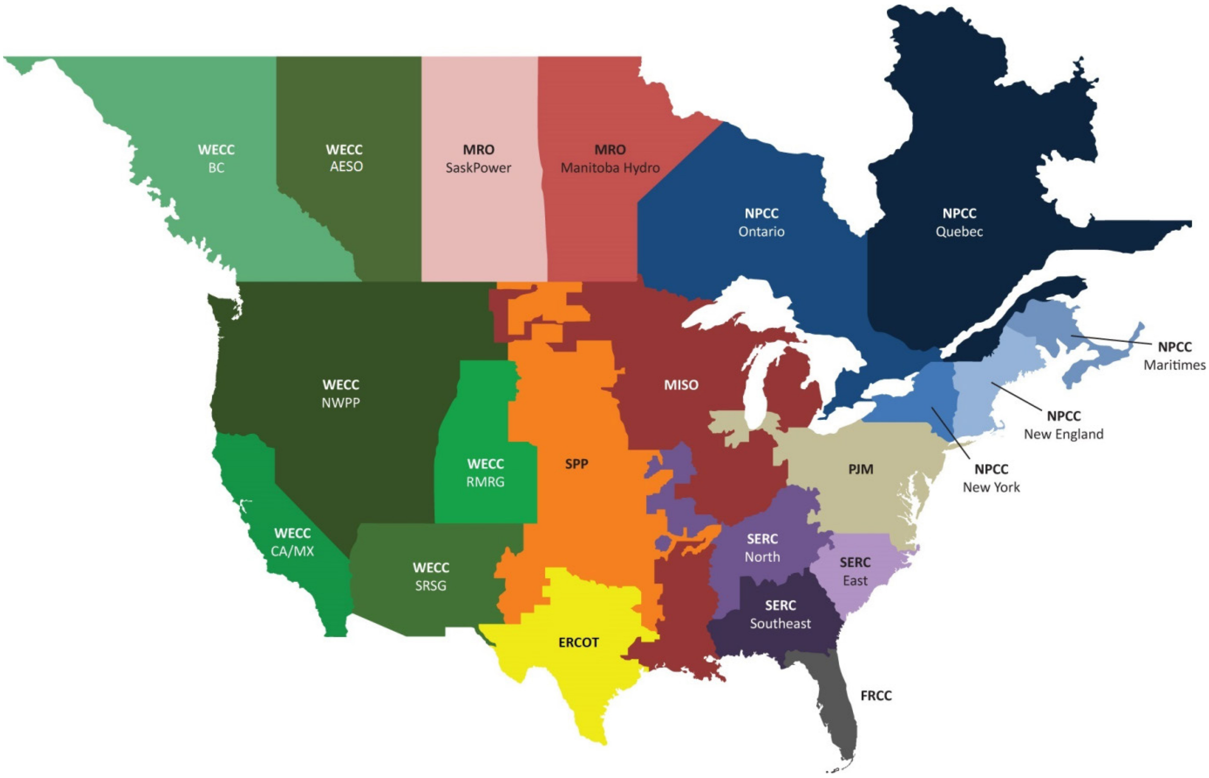
Reliability institutions

In most jurisdictions, the regulator plays the key role in ensuring the security and reliability of the power system. However, many of the roles and responsibilities necessary to support reliable cross-border integration fall outside of the normal day-to-day work of the regulator. Moreover, in most cases cross-border integration occurs between jurisdictions with different regulatory bodies.

As a result, a number of regions have introduced institutions that play a more direct role in enabling system security than either policy or regulatory institutions. These "reliability institutions", or reliability organisations, play a complementary role by introducing and monitoring the implementation of reliability standards, and assessing overall reliability needs for the power system in question. In many markets this may take on a regional or international component.

In North America the development and enforcement of reliability standards is the responsibility of NERC. NERC sets standards for the United States, Canada and a part of Mexico (specifically, Baja California, which is the only part of Mexico synchronised with the rest of North America). Initially, compliance with NERC standards was voluntary, but following the blackout of 2003, the United States passed legislation requiring that reliability standards be made mandatory and subject to FERC approval. In contrast, in Canada the federal government does not have the authority to mandate compliance with NERC standards. Instead, compliance is left to the individual provinces.

Figure 25. NERC assessment areas



Notes: BC = British Columbia; AESO = Alberta Electric System Operator; MRO = Midwest Reliability Organization; NPCC = Northeastern Power Coordinating Council; NWPP = Northwest Power Pool; CA/MX= California/Mexico; RMRG = Rocky Mountain Reserve Group; SRSG = Southwest Reserve Sharing Group; SPP = Southwest Power Pool; ERCOT = Electric Reliability Council of Texas; SERC = Southeastern Electric Reliability Council; FRCC = Florida Reliability Coordinating Council.

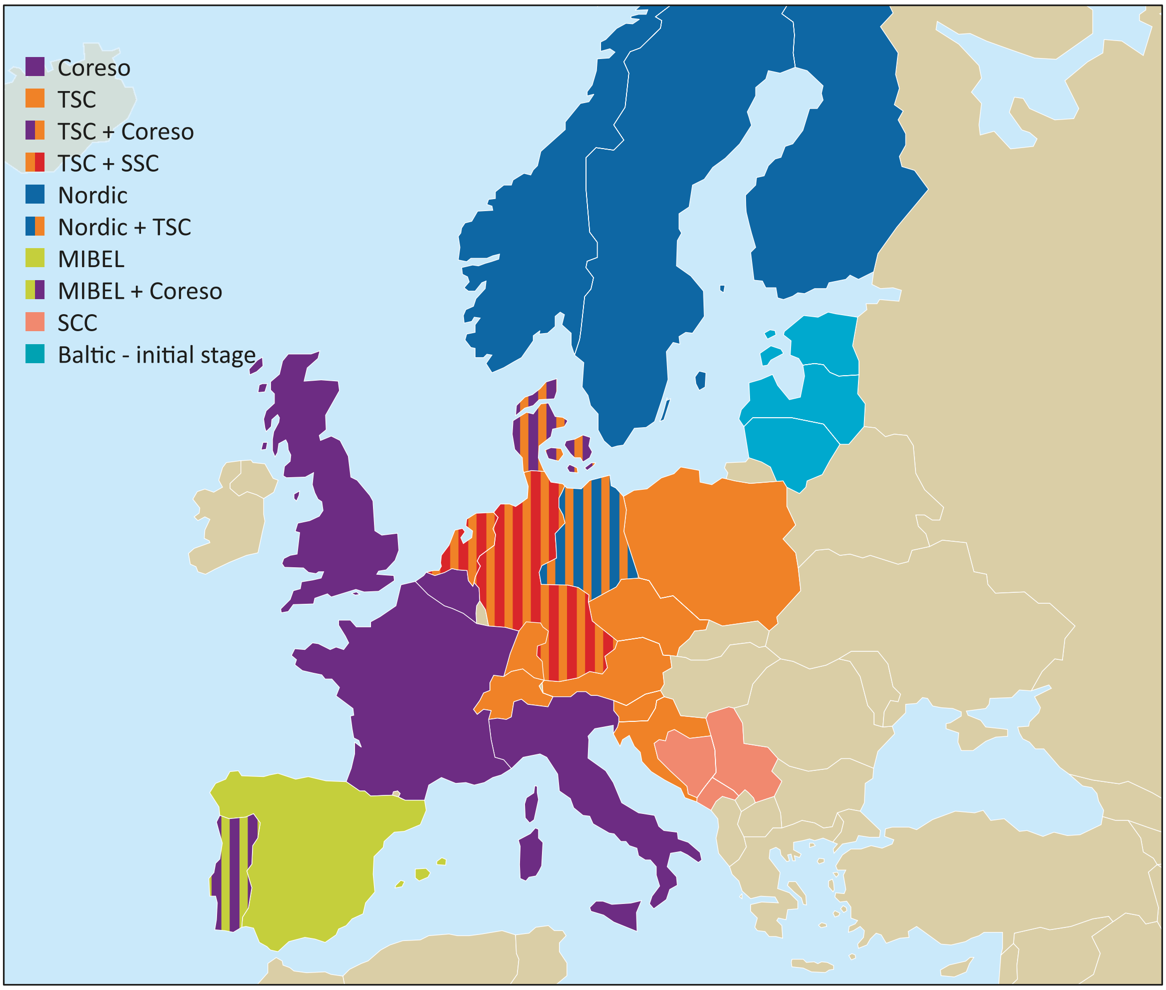
Source: NERC (2016)[5]

In Europe, responsibility for assessing the reliability of the regional power system rests with ENTSO-E. As part of its mandate, ENTSO-E performs regular resource adequacy assessments (which, under the recast Electricity Regulation, are in the process of being revised to improve the underlying methodology and overall prominence), and it develops the various network codes.

[5] This information from the North American Electric Reliability Corporation's website is the property of the North American Electric Reliability Corporation and is available at https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC_Assessment_Areas_2016.jpg. This content may not be reproduced in whole or any part without the prior express written permission of the North American Electric Reliability Corporation.

Collaboration on security issues is also managed through various RSCs. The RSCs are primarily responsible for collecting, processing and sharing data among member TSOs. Under the system operation guidelines, TSOs are required to join at least one RSC.

Figure 26. RSCs in 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.

Notes: TSC = Transmission System Operator Security Corporation; SSC = Security Coordination Centre; MIBEL = Mercado Ibérico de Electricidade (Iberian Electricity Market). Map reflects status of system as of 2016.

Source: IEA based on data from ENTSO-E.

Over time the role of the RSCs will evolve. Under the most recent EU legislation, the RSCs will change to Regional Coordination Centres, with their responsibilities increasing to cover a broader range of optimisation and reliability tasks ahead of real time.

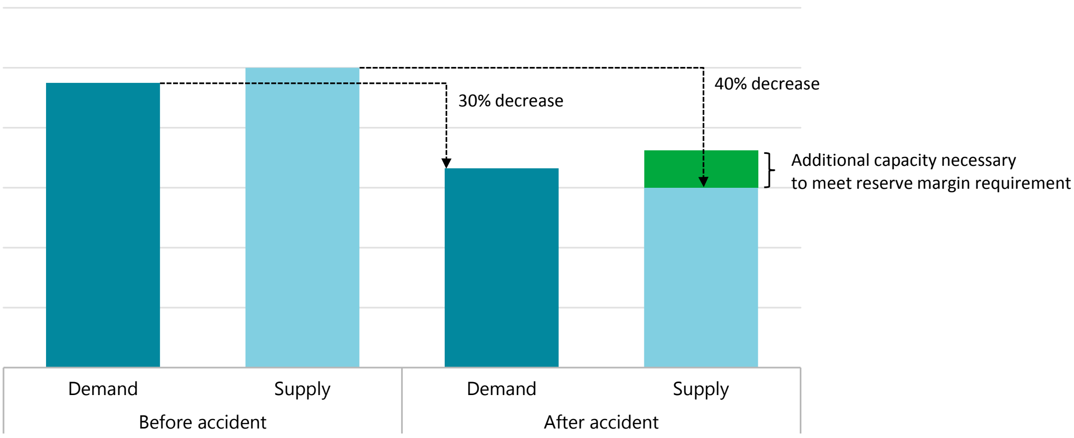
A third example of a regional reliability institution can be found in Japan. OCCTO develops reliability standards and monitors the status of the power system, similar, at least at a high level, to NERC. OCCTO also, though, has the authority to organise markets to ensure resource adequacy needs are met (in particular through the development of a capacity market) and can intervene directly in the market in time of system stress (for example, by mandating redispatch of generation to increase exports from one region to another).

OCCTO's authorities are therefore more expansive, and its ability to intervene in the power system more direct, than examples in other regions. As OCCTO has only recently been established, however, it is worth spending time describing its origins, as it may point in the direction of institutional development in other regions.

OCCTO was created in 2015 in direct response to the Fukushima Daiichi accident. Before the accident, the closest equivalent to OCCTO was the Electric Power System Council of Japan (ESCJ). The ESCJ was responsible for the development and management of the inter-regional interconnectors. However, it had no formal authority with which to exercise this responsibility. The ESCJ supported integration efforts, but it had limited visibility into the system development plans of the various EPCOs, it could not require the development of interconnectors, and it could not intervene to ensure sufficient cross-border power flows during times of system stress.

None of this was thought to be an issue until the Fukushima Daiichi accident. After the 2011 earthquake and ensuing tsunami, the TEPCO service area lost 40% of its installed capacity. Though demand also declined by 30%, the net result was a system that was unable to meet its needs with local resources alone. There was sufficient generating capacity in the neighbouring regions to offset this loss. What was lacking, however, was sufficient interconnector capacity and an efficient way of managing trade between the regions (Figure 27).

Figure 27. Change in supply and demand after the Fukushima Daiichi nuclear accident



Source: IEA analysis based on data provided by OCCTO.

As a result of the Fukushima Daiichi accident, supply dropped by 40% but demand dropped by only 30%, raising questions about how best to ensure security of supply.

OCCTO was established specifically to address this gap. Organised as a corporation under the authority of the Ministry of Economy, Trade and Industry (METI), OCCTO is tasked with ensuring the stable supply of electricity across Japan. Its membership is composed of all electricity companies in Japan (at present, around 1 100). It has a board of directors composed of two representatives each from the retail, generation, and transmission and distribution sectors, plus a seventh member (the president) who is required to be independent from any relevant business interests. There is also a board of councillors made up of 17 independent experts, and a general meeting, where all members are required to participate, and which decides upon the introduction of or changes to rules and regulations.

The overall intent of this structure is to ensure that OCCTO is representative of, but still independent of, the power system as a whole.

Maintaining the right balance between independence and representation is difficult but crucial, as OCCTO's wide range of authority gives it a unique position from which to influence Japan's power system.

This authority includes:

- Collecting and aggregating the long-term supply plans of the various EPCOs.
- Setting reliability (reserve margin) targets for the various EPCOs.
- Implementing a long-term policy for interconnector development.
- Establishing a cross-regional network development plan.
- If necessary, mandating the development of new interconnectors and determining the appropriate cost allocation method.
- Monitoring real-time supply-demand conditions.
- Intervening as necessary during supply shortage conditions to ensure power system stability.
- Organising and managing markets necessary to ensure long-term and short-term system security, i.e. the balancing and capacity markets.
- Managing the implicit auction process, used to allocate transmission capacity.

OCCTO is therefore something of a hybrid between NERC in North America, ENTSO-E and ACER in Europe, and the various TSOs and ISOs in both regions. It organises long-term and short-term markets, monitors real-time conditions, and can require redispatching to ensure regional supply-demand balance, making it more than an RSC but less than a system operator. It is involved in the development of interconnectors, including decisions related to cost allocation, but it is not a regulator.

The aim in centralising this authority is to ensure that the allocation of responsibilities is clear. The concern in separating the responsibilities is that it may lead to situations where it is unclear who is actually in charge. At the same time, putting such a large degree of responsibility in a single institution could lead to mission creep, where the response to future crisis is to give more responsibilities to OCCTO until, in the extreme case, OCCTO (or an organisation like it) is fully responsible for the entire power system, from supply down to demand.

Market frameworks

While it is possible for regions to trade power without the development of markets (for example, through long-term bilateral agreements such as PPAs, or by simply ignoring economics completely and exchanging only electricity), power trade is best enabled through some sort of market framework. How these market frameworks are formed and the role they play depends on the underlying market structure of the participating jurisdictions – specifically, are they restructured or are they fully regulated?

Restructured markets

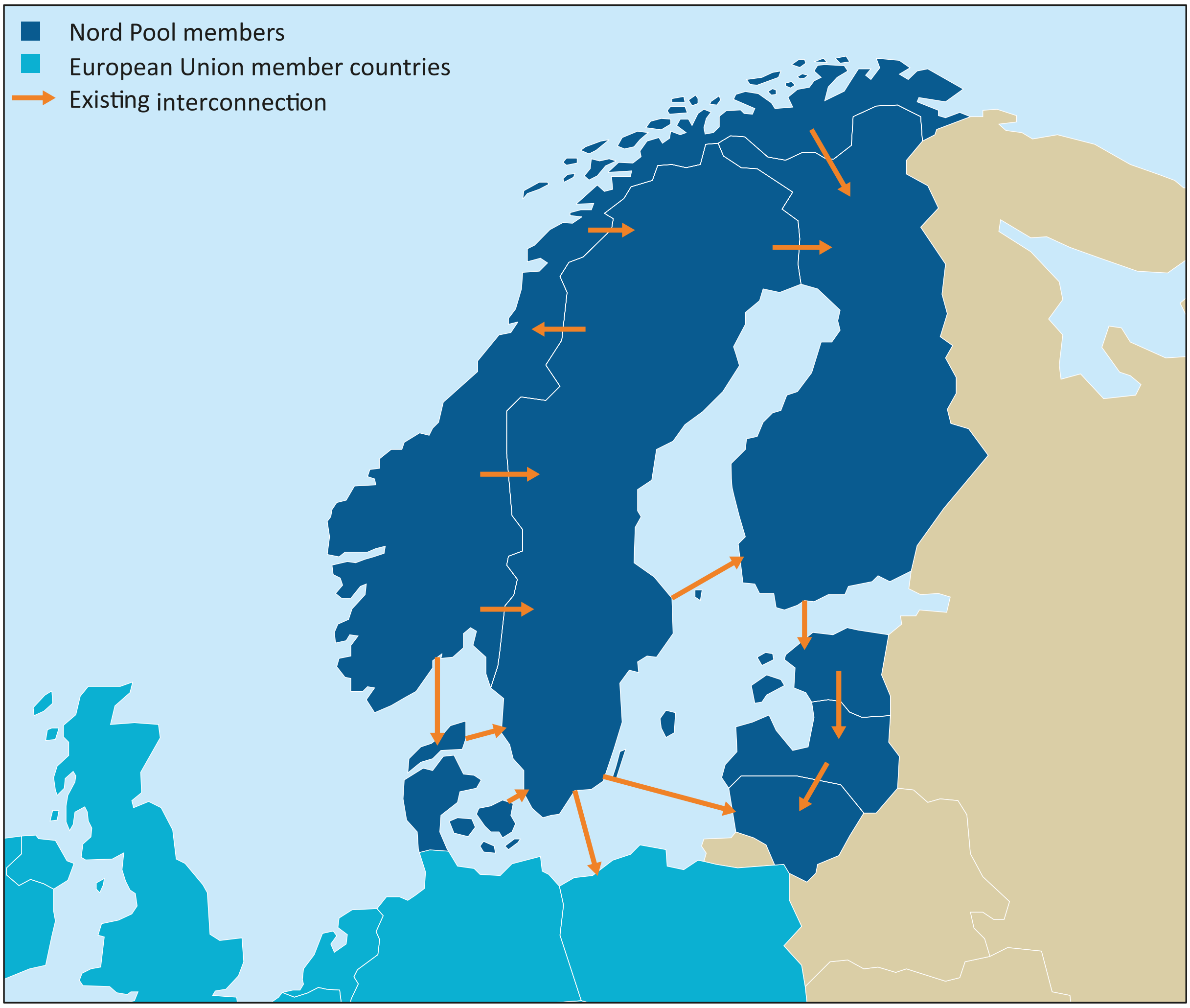
In restructured markets, the critical question is whether (and how) to allow external generators to participate in local (jurisdictional) markets, or whether to develop regional markets.

In **Europe**, the evolution has been to start with market restructuring at a national level and to increase market harmonisation and regionalisation over time. For example, as a result of the implementation of the various EU legislative packages, all EU member states have liberalised their power markets in some form. As part of this process, various power exchanges have formed which organise wholesale electricity markets in each country. In many cases the power exchange operates in multiple countries, but the markets are typically formed at the national level. For example, the power exchange company EpexSpot organises markets in Austria, Belgium, France, Germany, the Netherlands, the United Kingdom and Switzerland.

Though these power exchanges remain separated by country, over time they have become increasingly harmonised through a process known as market coupling. As a result, though they are functionally distinct, the power exchanges are in effect aggregated into a common wholesale market.

The process of market coupling is based on the development of the Nord Pool market, which is the first wholesale power market in Europe to cover multiple countries. Formed in 1996 as a joint venture between Norway and Sweden, the Nord Pool market has since expanded to cover seven countries (the four Nordic countries of Denmark, Finland, Sweden and Norway, and the three Baltic countries of Estonia, Latvia and Lithuania – see Figure 28).

Figure 28. Nord Pool member countries and interconnections



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: IEA.

Nord Pool organises a common day-ahead and intraday wholesale market for the entire region. System operations, however, remain the responsibility of the national TSOs. That means that while generators from each country bid into the same regional market, real-time operational decisions are disaggregated down to the country level.

The European Union is an example of how to develop advanced multinational power market frameworks. There are also, however, many countries that have differing internal power market structures.

Japan, for example, has a common energy policy (set at the federal level) but a fragmented utility structure. A number of market reforms, however, are underway that, when completed, will create a common market framework for the entire country.

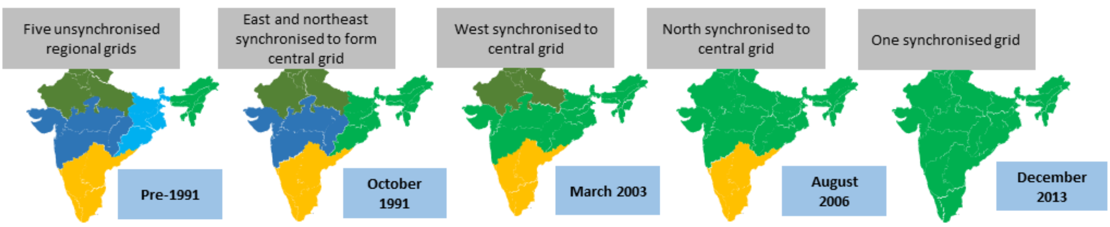
Japan's retail market is already open at a national level, and there is also the Japan Electric Power Exchange (JEPX). Volumes of trade on JEPX have historically been low because trade has essentially been limited to the various utilities. For example, in September 2017 the share of trading as a portion of total demand was only 6.8% (Shinkawa, 2018). As reforms move forward, however, and new participants enter the market, utilisation of the power exchange will likely increase.

From the perspective of cross-border power system integration, however, the two most relevant markets are still under development. In particular, Japan will soon launch a balancing market and a capacity market. Notably, both of these will be organised by OCCTO, which, as noted above, has significant responsibilities in promoting increased regional integration among the Japanese EPCOs, as well as ensuring security of supply for the entire Japanese power system.

Giving OCCTO the responsibility for organising these markets is not an accidental choice. Improving regional co-operation on both balancing and resource adequacy procurement is fundamental to the goals of these market reforms. The balancing market, for example, will allow the various EPCOs to procure ancillary (or balancing) services from neighbouring service territories. And while the capacity market will focus on ensuring that local resource adequacy needs are met, it will do so through a national capacity mechanism that will include locational pricing (reflecting the transmission constraints between EPCOs) and that will allow for the cross-border trading of capacity.

India has, over the past few decades, developed its national power system from a single-buyer model with five separate, unsynchronised grids, to a fully synchronised, fully harmonised national power market (Figure 29). This evolution took more than two decades, in no small part because of the strong federal-state divide.

Figure 29. Evolution of India's power system



Source: Delphos International.

There are, at present, two power exchanges in India: the India Energy Exchange (IEX) and the Power Exchange India Limited (PEX). These are competing exchanges, both of which are national and are regulated at the federal level. Through these exchanges it is possible to trade day-ahead and forward contracts (though forward contracts, called term-ahead market contracts, are limited to 11 days ahead of delivery), as well as renewable energy certificates and energy savings certificates, nationally.

Finally, the **United States**, despite hosting some of the largest and most sophisticated power markets in the world, is heavily fragmented when it comes to market structure.

Market structure in the United States is determined at the state level. Though FERC did at one point attempt to develop a common market framework for the entire country (the so-called Standard Market Design), FERC ended this effort in 2005 and has since then focused on encouraging the development of voluntary ISOs and RTOs. At present there are seven ISOs and RTOs (henceforth referred to only as RTOs) in the United States, four of which cover multiple states.

These RTOs form wholesale electricity markets and manage transmission system operations, and so they are regulated by FERC. How utilities participate depends on the state, as it is the state that determines the overall level of restructuring. For example, most of the states in the ISO-NE are restructured, meaning in those states all generators participate in the regional wholesale market.

In states that are not restructured, the utility chooses whether or not to participate in the organised market (hence the voluntary nature of these markets). In PJM, the largest RTO in terms of number of customers and installed capacity, some states are restructured and some remain fully regulated. Moreover, some of the vertically integrated states have multiple utilities, only some of which have chosen to join in the RTO. Voluntary participation also means there are large portions of the country (notably the Southeast and most of the West) that have no organised wholesale market whatsoever.

Regulated markets

In regulated, vertically integrated environments, the question is how to utilise market frameworks to enable trading among the various utilities, and also whether to allow IPPs to participate separately, or only through the various utilities.

The SAPP offers an instructive example of how to develop regional power markets among countries with vertically integrated utilities.

The SAPP is physically large (extending from the Democratic Republic of the Congo to South Africa) but relatively small in terms of participating, with only 16 members in total. Of the 16 members, 12 are government-owned, vertically integrated utilities, 2 are IPPs, and 2 are independent transmission companies. There are also 3 "non-operating members", meaning they participate as observers.

The SAPP is a **secondary** market, meaning the regional power market is organised in addition to (instead of as a replacement for) the organisation of jurisdictional (i.e. national) power markets. That is, each country retains full control of its domestic power system and can determine both its local market structure and the extent to which it wishes to utilise the regional grid. The two IPPs, it should be noted, are both located in countries with independent transmission companies (organised as single buyers), namely Mozambique and Zambia.

Members of the SAPP co-operate on a wide range of topics beyond just market organisation, including co-ordination of power system planning, development and system operations. All of this is structured through a co-operative agreement signed among the relevant energy ministries. A committee structure has also been created where the different topics of concern are discussed.

Under the SAPP market framework, only excess generation is traded. In other words, member states first ensure that they are able to cover their own demand before offering generation capacity to the SAPP regional market. In addition, power can also be traded through the SAPP on an emergency basis, to help meet unexpected shortfalls.

The SAPP consists of several different markets that target different system needs: a forward physical market, which allows for the trading of monthly and weekly products; a day-ahead market, which allows for the trading of hourly products for delivery the next day; and an intraday market, which is a continuous market that allows participants to update offers closer to real time on an hourly basis. All three markets are physical markets, meaning trades must result in the actual delivery of electricity at the agreed time and in the agreed quantity. Of the three markets, the day-ahead market is the most critical, as it provides the reference price for other markets.

From an institutional perspective, however, one of the most relevant aspects of the SAPP is the co-ordination centre. The co-ordination centre began with primarily secretariat responsibilities, co-ordinating working group and committee activities. Over time, though, its role has expanded to a number of key areas, including (SAPP, 2019):

- Market monitoring (including both transactions and operations).
- Track inadvertent or unexpected cross-border power flows.
- Monitor and advise on the implementation of the SAPP operating guidelines.
- Provide information and give technical advice to SAPP members on relevant issues.
- Develop operational studies to identify and highlight possible operating problems, and advise on how to address these problems.
- Measure interconnector transfer capacities and monitor use to ensure capacity limits are not exceeded.
- Advise on the feasibility of wheeling transactions.
- Collect and securely store relevant data.
- Facilitate trading in the day-ahead market.

This wide-ranging (and non-exhaustive) list of roles points to a critical aspect of the development of regional power market frameworks: there is a need even in secondary market arrangements for significant regional co-ordination. As cross-border integration moves beyond bilateral arrangements, there is significant value in having an institution which can play a co-ordinating role.

As a final point, however, it is worth noting that there is no fundamental need to incorporate all of the necessary functions into a single institution. In fact, there may be advantages in dividing responsibilities across a few institutions. In particular, doing so allows more than one participating jurisdiction to take on some ownership of the regional market. SIEPAC, for example, divides responsibilities for organising and monitoring the market into three organisations: the CRIE (the market regulator, located in Guatemala); the EOR (which operates the market, and which is located in El Salvador); and the Empresa Propietaria de la Red (EPR, or "Company that Owns the Network") (which, located in Costa Rica, owns SIEPAC's physical infrastructure).

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General annex

Abbreviations and acronyms

AC	alternating current
ACER	Agency for the Cooperation of Energy Regulators (European Union)
ADB	Asian Development Bank
AESO	Alberta Electric System Operator
APG	ASEAN Power Grid
ASEAN	Association of Southeast Asian Nations
BANC/SMUD	Balancing Authority of Northern California/Sacramento Municipal Utility District
BC	British Columbia
CACM	capacity allocation and congestion management
CA/MX	California/Mexico
CAISO	California Independent System Operator
CREG	Commission for Electricity and Gas Regulation (Belgium)
CRIE	Comisión Regional de Interconexión Eléctrica (Central America)
DC	direct current
DOE	Department of Energy (United States)
EGAT	Electricity Generating Authority of Thailand
EIM	Energy Imbalance Market
EIPC	Eastern Interconnection Planning Collaborative (United States)
ENTSO-E	European Network of Transmission System Operators for Electricity
EOR	Ente Operador Regional (Regional Operating Entity) (Central America)
EPCO	electric power companies
EPR	Empresa Propietaria de la Red (Company that Owns the Network) (Central America)
ERCOT	Electric Reliability Council of Texas
ESCJ	Electric Power System Council of Japan
EU	European Union
FERC	Federal Energy Regulatory Commission (United States)

FRCC	Florida Reliability Coordinating Council
GCC	Gulf Cooperation Council
GDP	gross domestic product
GMS	Greater Mekong Subregion
HVDC	high-voltage direct current
IEA	International Energy Agency
IEX	India Energy Exchange
IPP	independent power producers
IRP	integrated resource plan
ISO	independent system operators
JEPX	Japan Electric Power Exchange
Lao PDR	Lao People's Democratic Republic
LOLE	loss-of-load expectation
MER	Mercado Eléctrico Regional (Regional Electricity Market) (Central America)
METI	Ministry of Economy, Trade and Industry (Japan)
MIBEL	Mercado Ibérico de Electricidade (Iberian Electricity Market)
MISO	Midcontinent Independent System Operator (North America)
MRO	Midwest Reliability Organization
NEB	National Energy Board (Canada)
NERC	North American Electric Reliability Corporation
NPCC	Northeaster Power Coordinating Council
NRA	national regulatory authorities
NTC	net transfer capacity
NWPP	Northwest Power Pool
NYISO	New York Independent System Operator
OCCTO	Organization for Cross-regional Coordination of Transmission Operators
OECD	Organisation for Economic Co-operation and Development
PCI	Project of Common Interest
PEX	Power Exchange India Ltd
PLEF	Pentalateral Energy Forum
PPA	power purchase agreement
PV	photovoltaic
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency

RERA	Regional Electricity Regulators Association of Southern Africa
RMRG	Rocky Mountain Reserve Group
RPGCC	Regional Power Grid Consultative Committee (Greater Mekong Subregion)
RSC	Regional Security Coordinators
RTO	regional transmission operator
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SCC	Security Coordination Centre
SERC	Southeastern Electric Reliability Council
SIEPAC	Sistema de Interconexión Eléctrica de los Países de América Central (Central American Electrical Interconnection System)
SPP	Southwest Power Pool
SRSG	Southwest Reserve Sharing Group
TEPCO	Tokyo Electric Power Company
TNB	Tenaga Nasional Berhad (Malaysia)
TSC	Transmission System Operator Security Corporation
TSO	transmission system operators
TYNDP	Ten-Year Network Development Plan
US	United States
VRE	variable renewable energy
WECC	Western Electricity Coordinating Council (North America)

Units of measurement

GW	gigawatt
GWh	gigawatt-hour
MW	megawatt
MWh	megawatt-hour

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