AFRICAN SCHOOL OF REGULATION

POSITION PAPER

Guidelines on Transmission Pricing and Cost Allocation for Regional Power Trade

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April 2024

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Executive summary

Regional transmission infrastructure, connecting different jurisdictions, is the cornerstone of cross-border power exchanges. This infrastructure plays a pivotal role in decarbonisation, by integrating diverse low-carbon energy sources, allowing regions with abundant renewable resources to export clean energy to areas with higher demand, and enhancing the overall flexibility, resilience and reliability of the power system. This document provides guidelines for allocating transmission costs in the context of regional power trading; it is intended to support regulators in the implementation of such an allocation.

Transmission costs include the costs associated with investment planning, construction, maintenance planning, maintenance and operation of the transmission network.

"Common sense" has led policymakers and regulators in many parts of the world to allocate the costs of cross-border electricity transmission lines (and related infrastructure):

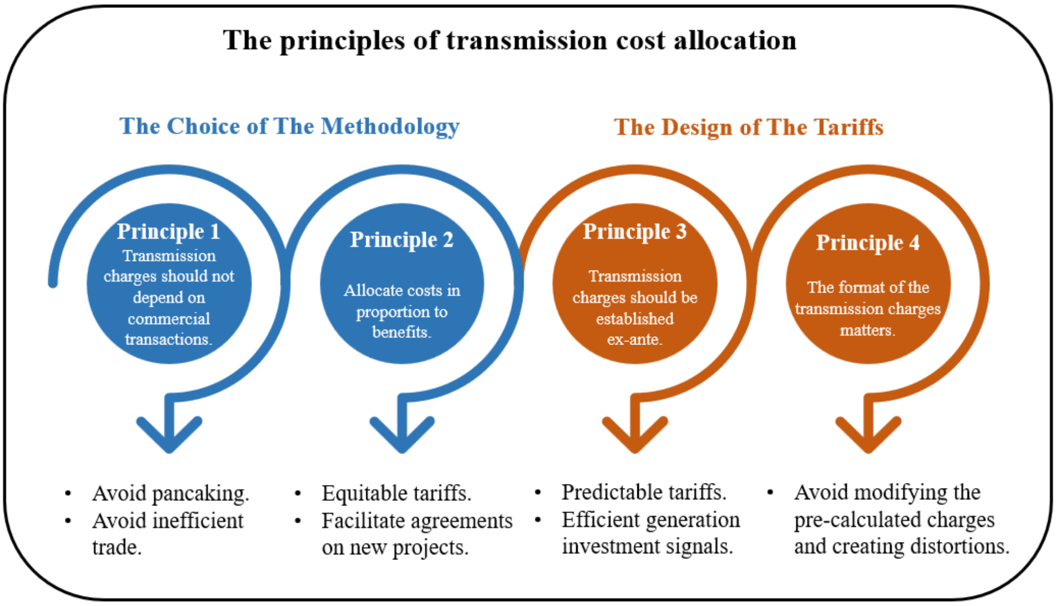
- among the countries involved in electricity exchanges, in proportion to the length of the lines in their respective territories (the so-called 'territorial principle');
- among electricity sector agents, only to individual generators, utilities, distribution companies or large consumers that engage in cross-border transactions.

The consequences of this common-sense approach have been unduly to distort and stifle cross-border trade and to discourage investment in cross-border infrastructure.

A prerequisite to attract private investment in transmission is a sound regulatory framework, covering the institutions, criteria, procedures and enforcement processes of regional transmission planning, the determination of transmission costs and the equitable allocation of these costs to the different agents in the region.

Therefore, in these Guidelines we propose an approach for allocating transmission costs and setting transmission tariffs for cross-border exchanges which overcomes the drawbacks of the common-sense approach and is based on:

- the 'single system paradigm', which requires that the guiding principle for the design of regulation for regional power trade should be to consider all trade in the region as if it happened within a single jurisdiction; and
- four principles for transmission pricing, which are equally valid within a jurisdiction and for cross-border exchanges under the single-system paradigm:
    - ***Principle 1: Transmission charges independent of commercial transactions*** – to avoid allocations that ignore the physics of electricity transmission, possibly resulting in incorrect economic signals. When applied to cross-border exchanges, this principle:
        - requires that the primary allocation of costs is to countries and not to individual agents;
        - avoids tariff pancaking (the accumulation of tariffs for transactions notionally crossing many borders).
    - ***Principle 2: Allocation of costs in proportion to benefits*** – to ensure an equitable cost allocation and to facilitate agreements on new transmission projects. Benefits are often difficult to be quantified and can be proxied by usage. Of all the many possible approaches to the allocation of costs based on usage, the 'average participation' method has proved to be the most robust one.
    - ***Principle 3: Transmission charges established*** **ex-ante** – to provide stable and predictable tariffs to facilitate new generation investments.
    - ***Principle 4: Non-distortionary transmission charges structure -*** to avoid operation and investment distortions. The best application of this principle means charging transmission costs as an annual lump sum.



It is the standard regulatory test that an investment in a new transmission asset is justified when the value of the aggregated net benefits that the asset delivers over its estimated lifetime to all the players, producers and consumers, is greater than the overall cost of the asset. If a project is expected to deliver positive net benefits, i.e., benefits that exceed costs, there is an allocation of costs that makes all affected parties better off, i.e., enjoying positive net benefits.

In allocating the costs of transmission network elements with cross-border/regional relevance, i.e. those supporting cross-border/regional power exchanges, and setting transmission tariffs for cross-border exchanges, we recommend a process which proceeds in the following way:

1) ***Establishment of a regional regulatory authority*** or of a dispute-resolution mechanism to deal with disagreements among national regulatory authorities in the region.
2) ***Identification of the transmission network elements with cross-border relevance*** to be considered. They are those which are needed to establish physical transfers of electric power between countries. It is the costs of these elements that should be allocated across borders. There is no clear separation to distinguish these elements from those with only local/national relevance and some criteria must be established in regulation.
3) ***Definition of a common approach to allocate the costs of the transmission network elements with cross-border/regional relevance*** among the agents of the regional power system.
    a. For some important cross-border transmission projects, especially those with a high political profile, an *ad-hoc* cost identification and allocation might be proposed by the project promoters and/or agreed upon among the countries involved. Any such *ad-hoc* allocation should be to the countries and not to individual agents. Otherwise, the following default procedure will apply.
    b. For the remaining transmission network elements, an allocation method that is compatible with the four principles of transmission cost allocation outlined above shall be defined, at least at the regional level, possibly following the following sequence:
        - The revenue requirement for each transmission network element with cross-border/regional relevance is determined by the relevant national regulatory authority. In case of dispute among such authorities regarding the approach to be implemented to define the revenue requirements for transmission network elements with cross-border relevance located in the different countries, the regional regulatory authority or the dispute-resolution mechanism should be activated;

- The allocation of the charges to recover the revenue requirement for the transmission network elements with cross-border/regional relevance is performed at the country level.
- In a first instance, the national regulatory authorities of the involved countries shall try to decide how to allocate the overall revenue requirement among these countries. If the national regulators do not manage to reach an agreement, the decision will be taken by the regional regulatory authority or through the dispute-resolution mechanism[1], using the following regional transmission cost allocation method consistent with the four principles defined above and in which:
    - the average participation method is applied to determine the contribution of each importing and exporting country to the usage of each transmission network element with cross-border/regional relevance;
    - the cost of each transmission network element with cross-border/regional relevance is allocated to the different countries on the basis of their contribution to the usage of the network element;
    - the allocation of the cost of the transmission network with cross-border/regional relevance to each country is determined as the sum of the contribution of the country to the costs of all transmission network elements with cross-border/regional relevance.
    - Once the allocation to the countries of the costs of the regional transmission network is defined, the national regulatory authority of each country shall determine the modified transmission revenue requirement to be used in the computation of the regulated transmission charges in the country.

[11] A similar approach is implemented in the EU for new Projects of Common Interest, projects having cross-border relevance and essential for connecting the different regions in the EU. The relevant national regulatory authorities are called to agree on a cost allocation among the benefitting countries. If no agreement can be reached, or upon request of the national regulatory authorities, the cross-border cost allocation (CBCA) decision is taken by the EU Agency for the Cooperation of Energy Regulators, in this case acting as dispute-resolution entity.

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List of Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
AfDB	African Development Bank
AP	Average Participations
CRNP	Cost-Reflective Network Pricing
DF	Dominant Flow
EOR	*Ente Operador Regional*
EU	European Union
EPR	*Entidad Propietaria de la Red*
FACTS	Flexible AC Transmission System
FERC	Federal Energy Regulatory Commission
FSR	Florence School of Regulation
ICRP	Investment Cost-Related Pricing
IRENA	International Renewable Energy Agency
ISO	Independent System Operator
ITC	Inter-TSO Compensation
MP	Marginal Participations
MW	Megawatt
OFGEM	Office of Gas and Electricity Markets
RTO	Regional Transmission Organization
RTR	*Red de Transporte Regional*
SAPP	Southern African Power Pool
SIEPAC	Central American Electrical Interconnection System
SO	System Operator
SPV	Special Purpose Vehicle
TSO	Transmission System Operator
UK	United Kingdom
US	United States
WAPP	West African Power Pool

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1. Introduction

Cross-border power exchanges can be arranged under unregulated bilateral agreements, coordinated operation of different power systems or market conditions. Power pools, as a mechanism for electricity exchanges between different vertically integrated utilities (therefore without the existence of local wholesale markets[1]) already existed in the 1970s in several regions in the US. The common feature of those power pools was the least-cost centralised dispatch of electricity production resources, i.e. the most efficient available generation units were dispatched to meet the aggregated power pool demand at all times (subject to transmission constraints). The participants in some power pools also developed joint capacity expansion plans of transmission and, sometimes, of generation as well. Other cross-border regulatory arrangements are being developed among neighbouring emerging economies in different parts of the world at bulk power system level, generally without competitive markets at national level. Given the existing diversity of situations, this document avoids using the term "market" when referring to these situations and uses the term "power system organisational structures" or "power pools" in short, instead, as recently recommended by IRENA[2].

Developing regional transmission infrastructure, connecting the different jurisdictions, is the cornerstone of cross-border power exchanges. A robust and interconnected transmission network enables the optimisation of resource utilisation by balancing supply and demand across borders. This infrastructure plays a pivotal role in decarbonisation by integrating diverse low-carbon energy sources, allowing regions with abundant renewable resources to export clean energy to areas with higher demand. Furthermore, a well-developed transmission network enhances the overall flexibility, resilience and reliability of the power system, enabling higher renewable energy penetration and ensuring a stable and continuous power supply. Thus, addressing the different issues of regional transmission infrastructure, such as cost allocation and network expansion, should be a high priority for any cross-border regulatory arrangement in the energy transition and decarbonisation process.

Common sense has led policymakers and regulators in many parts of the world to allocate the costs of cross-border electricity transmission lines among the countries involved in electricity exchanges in proportion to the length of the lines in their respective territories (the so-called 'territorial principle'). The advent of wholesale competition demanded a reflection on who should bear the transmission costs, and in particular the cost of cross-border transmission lines. At the individual-country level, the immediate common-sense solution has been to allocate the costs of interconnection lines only to those agents – such as individual generators, national utilities, distribution companies or large consumers – that engage in cross-border transactions. The paths of the physical power flows of these transactions were determined by more or less sophisticated engineering methods.

This approach to allocating the costs of cross-border transmission infrastructure dominated the early stages of the implementation of electricity trading between different jurisdictions – countries, or states and utilities within countries – in most regions of the world. However, this method might not necessarily allocate transmission costs to those actually benefitting from trading, or responsible for the related transmission costs. Moreover, it usually results in over charging cross-border trade, as commercial transactions rarely have any impact on the physical flows in the regional network, and therefore in its utilisation[3]. The consequences of this approach have been unduly to stifle cross-border trade and discourage investment in cross-border infrastructure.

This document presents the fundamental principles sustaining the allocation of transmission costs and their implementation through actionable rules with a focus on cross-border trade, but without ignoring its necessary coexistence with national regulation. The following section provides a brief illustration of the transmission

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[1] Wholesale markets only emerged in Chile in the early eighties and later in Great Britain in 1990 and in most countries in the European Union between 1995 and 2005.

[2] The term power system organisational structures can be used to refer to the systems, institutions, procedures and social relations through which electricity services are exchanged and rewarded. It encompasses all systems, from liberalised power systems (based primarily on market mechanisms) to vertically integrated systems. For a liberalised power system, the term power market is equivalent to power system organisational structure. See (IRENA 2022).

[3] Actually, no impact at all, if it is assumed that the agents behave with economic rationality and there is a regional economic dispatch of generation resources and demand. Only under exceptional conditions of a generalised blackout involving multiple countries, physical bilateral contracts with the necessary transmission rights would have to be respected, with a potential impact on the physical flows.

activity, its nature and the need for regulation in the transmission business. Section 3 presents and elaborates on the four regulatory principles of sound transmission cost allocation. In light of these principles, section 4 provides general recommendations on the implementation of these principles in sound cost allocation rules and on the way in which transmission costs should be recovered from grid users. Such recommendations are applicable to regional and national contexts. Section 5 applies the four regulatory principles presented in section 3 and the recommendations formulated in section 4 to propose Guidelines for transmission cost allocation at regional level, which are the central objective of this document. Finally, section 6 gives recommendations on the allocation of transmission losses.

2. Regulatory characterisation of the transmission activity

The design of proper regulation cannot be addressed without first identifying the features that characterise electric power transmission. In fact, such features, as well as the role electricity transmission plays in a liberalised electricity sector prevailing in many jurisdictions, are key aspects in defining the way in which such an activity should be regulated.

2.1 The function of transmission infrastructure

> *The transmission of electricity is not similar to the transmission of any other product.*
>
> *The electricity flows on the transmission network depend on the location of electricity injections and withdrawals –by generators and consumers, respectively – and the topology of the network, but not on the commercial arrangements between market actors.*

Transmission services may be generically defined as activities with economic value provided by the transmission network to the benefit of grid users. The primary transmission service is the transportation of electricity from production to consumers. Transmission assets can also contribute to some system operation activities, such as voltage control. Transmission activities include investment planning, construction, maintenance planning, maintenance and operation of the transmission network. System Operators can provide services that make use of the transmission network, as well as of generators and demand, such as voltage control, loss reduction or recovery from a blackout. These are not transmission services.

The transport of electric power is not transport in the usual meaning of the term, which generally implies the physical shipment of a product from a manufacturing plant to consumers. The transportation of electricity is a very complex phenomenon and there is no unambiguous way of attributing grid flows to system agents, despite the many attempts that can be found in the technical literature. Contrary to the situation in the vast majority of other network infrastructures, electricity cannot be steered at will through any one or any set of paths[4]. Adding new electric lines to an existing network modifies the way the flow of electric current is distributed across the remaining lines. Thus, no consumer or generator can choose to use a new line or otherwise.

[4] Thanks to the progress in power electronics, Flexible Alternating Current Transmission System (FACTS) hardware – a family of power electronic-based devices designed to improve and control power flows in an alternating-current system – is now available that provides for some control over the distribution of flows, although their use continues to be marginal because of the very high cost of such facilities.

The technical characteristics of the electricity system play a decisive role when designing transmission regulation. Energy flows and the use of electric lines do not depend on commercial relationships between market actors (generators, retailers, consumers), but only on the pattern of injections into and withdrawals from the network and the prevailing physical parameters of the grid. In well-functioning markets, the subset of generators that produce to supply the load[5] at any given time corresponds to the least-cost dispatch. Therefore, the tariffs charged to agents for using the transmission grid should depend on their physical location in the network in relation with the overall production and consumption patterns, but not on any notional contract path defined based on their (often private) commercial commitments, as shown in **Error! Reference source not found.**. The left panel in this Figure shows a likely commercial path which the generator and the load highlighted in the figure might consider reasonable. However, such a path does not correspond to how electricity flows from the

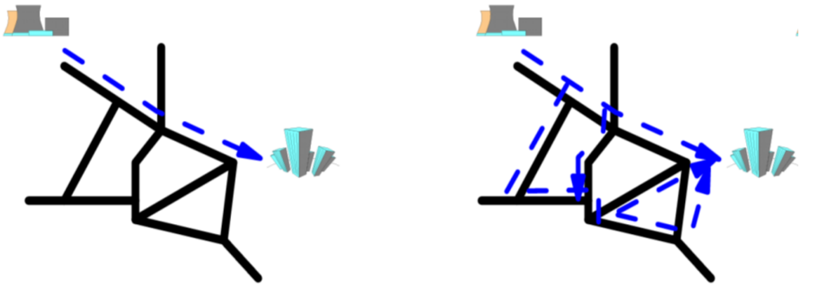

Figure 1: Assets used in a contract path versus assets used in a physical flow path. Adopted from (Hogan, William W, 2016).

generator to load, as shown in the right panel of the Figure. Therefore, only tariffs which are independent from any notional commercial path equitably allocate costs to those who benefit from the transmission network, provide the correct signals to network users, reveal the need for network reinforcements and incentivise generation investment where it is most needed.

2.2 Transmission costs, economies of scale and the natural monopoly nature of transmission

> *Transmission is a monopoly activity and, therefore, needs to be regulated.*
>
> *Transmission costs do not generally depend on the volumes of flows on the network.*

Transmission costs are those related to transmission activities. Since grid operation and maintenance costs are roughly proportional to the volume of grid assets (approximately 2-3% of the investment cost (Zhang et al., (2021)), total transmission costs can be considered to be driven by investment costs.

The share of transmission network costs in the total costs involved in the supply of electricity varies widely depending on a country's size and the geographical dispersion of its production and consumption centres. It is significantly lower than the share of generation and distribution costs, and it typically contributes about 5% to 10% to the total cost of the electricity delivered to consumers.

Electricity transmission is a natural monopoly.. This is because transmission costs exhibit significant economies of scale; it is hardly rational for several smaller networks to compete against one another when power can be transmitted over a single larger line much more cheaply. Therefore, transmission remuneration must be regulated based on the cost incurred in efficiently providing the service[6].

[5] Here for simplicity, and without loss of generality in the context of our considerations, we assume that the load at any one time is fixed, both in its level and in its geographical distribution.

[6] When the responsibility for providing the transmission service or for constructing a new line are allocated through a tendering process, the result of the tender could be used to define the level of remuneration for the transmission activity.

2.3 Congestion and transmission losses

> *Congestion and transmission losses occur on the transmission network, but, strictly speaking, they are not part of the transmission activity.*

Electricity transmission lines have thermal capacity that restrains the amount of energy that can be transported and might lead to network congestion if the demand for transmission services exceeds this capacity. Other capacity limitations exist due to voltage constraints. Moreover, some of the transported energy will inevitably be lost in the process due to the physical characteristics of the lines and other transmission system components, leading to network losses.

On the one hand, transmission network losses result in additional system costs because more energy has to be produced than the energy delivered to consumers. They are not network costs *per se,* although they happen in transmission facilities, but their cost is independent of the cost of building and maintaining the transmission infrastructure. Transmission losses are impacted by the design of the transmission network, the pattern of production and demand at any given time and the System Operator's decisions. Regulatory instruments should, therefore, be sought to incentivise the reduction of the volume and cost of losses, for instance, by making them part of the System Operator incentive-based regulatory scheme[7].

On the other hand, network congestion mainly impacts system operation by having transmission lines unable to transport more power due to reaching their maximum load-carrying capacity while maintaining specified security levels. Congestion costs, like the cost of transmission losses, constitute additional generation costs occasioned by grid characteristics, but are not grid costs *per se*. Note that in a regional context, when congestion occurs, prices in different jurisdictions linked by congested network elements might diverge, resulting in congestion income being collected, as shown in Figure 2.

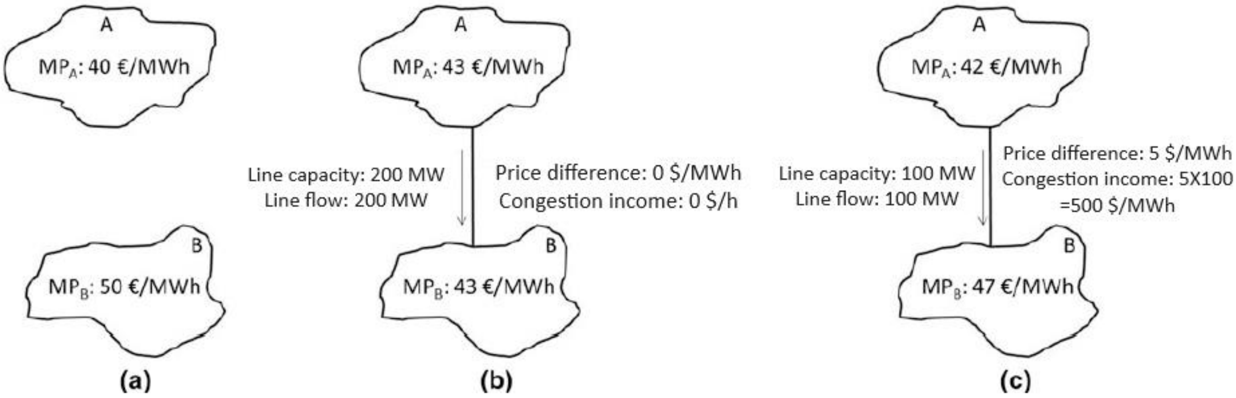

Figure 2: Market prices, line flows and congestion income for two systems, A and B, when they are separate (a), connected with sufficient interconnection capacity (b) and connected with insufficient interconnection capacity (c). Congestion happens in (c) due to the limited capacity and congestion income can, thus, be collected. Note that the cost of this congestion is received by the consumer in region B by means of higher prices in (c) compared to (b).

[7] Care must be exercised when designing incentive schemes for the System Operator to reduce the cost of losses and congestions. Losses and congestions largely depend on the location of generation and demand and the configuration of the transmission network, and are dictated by the economic dispatch of system, and very little by the actions of the System Operator. Strong economic incentives might lead the System Operator to deviate from the optimal economic dispatch or from a secure operation of the power system.

2.4 Transmission regulation at a glance

> *Transmission regulation should cover many diverse activities, from planning to the operation of the transmission system.*

The growing interconnectivity of different countries and the trend towards the establishment of regional organisations to support electricity trading across national borders are creating new challenges for electric power network regulation. The anticipated enormous growth of generation from renewable sources –wind and solar, in particular – frequently located far away from load centres and with highly variable production patterns, requires an increasing level of sophistication in transmission regulation, which should provide satisfactory answers to the following questions:

- Who should be responsible for deciding and executing the expansion and reinforcement of the network when needed?
- Who can connect to the network? And what happens when the network becomes congested?
- How should the network costs be allocated?
- Who pays for the power losses that take place in the network?

An integrated perspective of the major regulatory topics in electricity transmission network regulation is depicted in Figure 3. Transmission planning seeks to identify the most suitable expansion and/or reinforcements of the network, according to some pre-defined criteria. The cost of this expansion and of these reinforcements must be borne by those for whom, or because of whom, they are carried out. Therefore, there is a close relationship between network planning and network cost allocation. One or more business models could be available for investors to decide to finance projects for the expansion of the grid. The mechanisms for cost recovery are an essential part of these business models and they are directly related to regulation and the cost allocation method.

Siting is typically a difficult problem, because of the generalised opposition to the presence of transmission lines, and it is more of a social, environmental and political nature. However, it is made easier if the allocation of transmission costs is perceived as fair and the benefits derived from a new investment are clearly higher than the associated charges for all the countries and the local populations involved. The operation of the network can be considered a separate topic, with the management of access to the necessarily limited capacity of the grid being the major regulatory issue.

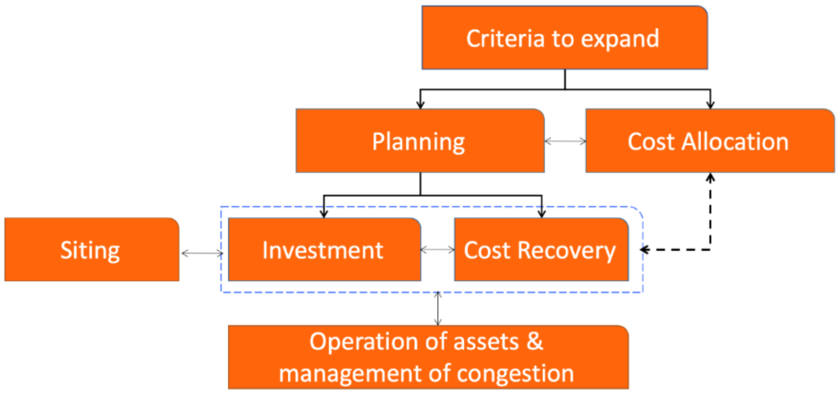

Figure 3: The regulatory framework for electricity transmission.

3. The key principles for transmission cost allocation

The combination of microeconomic theory, power systems engineering and sound regulatory practice suggests that the allocation of the cost of a transmission network among its users obey some basic principles. In fact, after much trial and error in several power systems, the following high-level principles have emerged as sufficient to define efficient transmission pricing (Rivier, Pérez-Arriaga, and Olmos 2013; MIT 2011).

3.1 Principle 1: Transmission charges should not depend on commercial transactions.

As indicated in section 2.1, the flows created in the network by each user and, consequently, the transmission network elements it uses depend on the location of the user in the network, the topology of the network and the temporal patterns of power injection (for generators) and withdrawal (for loads), but not on any commercial transaction. Therefore, transmission charges:

- should depend on the locations of the users and their temporal patterns of power injection and withdrawal, given the topology of the network;
- should not depend on commercial transactions that occur between users (that is, who trades with whom), as these transactions are irrelevant for the network flow.

For example, a generator located in a region – region A – that trades with a load-serving entity in another region – region B –, using the physical network connection that exists between regions A and B, should pay the same transmission charge as if, instead, it were contracted to supply a neighbouring load sited within its own region A. And conversely for the load in region B, which could purchase electricity from a generator in region B or a generator in region A. The application of this principle should not be affected by the existence of any contracts voluntarily signed by any agents, since they should modify neither the physical real-time dispatch of generation, nor the demand.

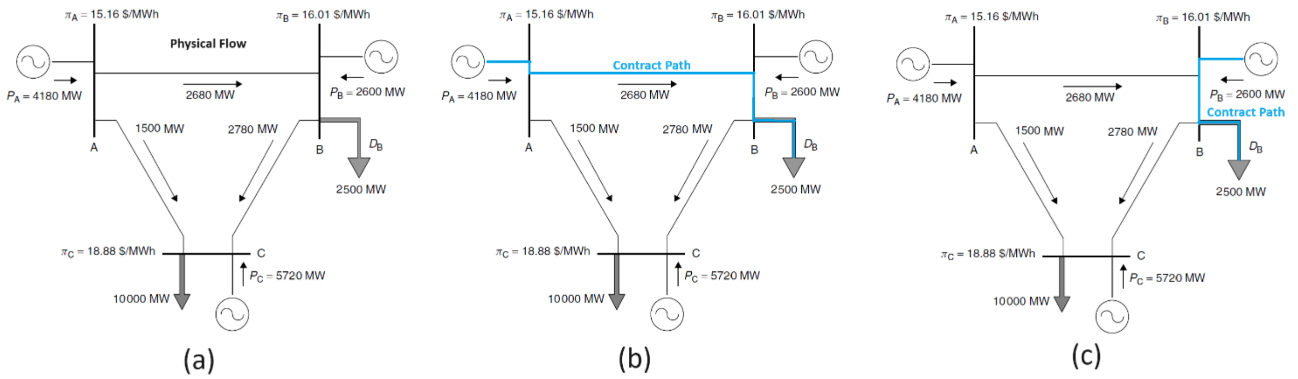

Figure 4: Power flow and transactions between demand and generators in three regions. (a) shows the physical flows resulting from the optimal dispatch upon which transmission tariff should be calculated. (b) and (c) shows the different contract paths that demand D_B could have if engaged in a commercial transaction with an exporting generator in region A and a local generator in region B, respectively. Note that violating principle 1 will lead to discriminating regional trade because D_B would prefer situation (c) in which it pays only for its local assets (the shorter contract path).

When applied to cross-border exchanges, this principle:

- allows that, in the first instance, the allocation of costs is to countries and not to individual agents;
- avoids tariff pancaking, a situation in which network users are required to pay accumulating entry-exit fees at every control area border their power is deemed by contract to cross, regardless of actual power flows. In this way, transmission charges end up depending on the number of control-area borders between the buyer and the seller. Such pricing tends to stifle trade and prevent buyers from accessing low-cost sellers.

In the European Internal Electricity Market, in the Central America Regional Electricity Market and within the Regional Transmission Operators' areas in the U.S. (but not between these areas) transmission charges are generally independent of commercial transactions.

3.2 Principle 2: Allocate costs in proportion to benefits.

Allocating network costs among network users in proportion to the benefits they receive strikes to most people as equitable. If a project is expected to deliver positive net benefits, i.e., benefits that exceed costs, there is an allocation of costs that makes all affected parties better off, i.e., enjoying positive net benefits. These parties are therefore less likely to oppose moving forward with the project[8]. Conversely, if a project's costs exceed its benefits, it will be impossible to allocate costs in such a way as to make all entities better off, but such a project should not go ahead anyway.

A beneficiaries-pay solution for allocating costs of a project delivering overall positive net benefits might be achieved through bargaining among the different entities involved. However, bargaining might not always be the most efficient cost-allocation approach, as it might imply high transaction costs, and a regulatory framework is needed. In this respect, the implementation of the regulatory test[9] for approving a project at the planning stage, to check that its overall benefits exceed its total costs, might also help in allocating costs, if the cost-benefit analysis performed as part of the regulatory test, in identifying benefits, also identifies beneficiaries[10]. It is however to be noted that the regulatory test only needs to assess if overall benefits exceed total costs and not necessarily the exact level of the benefits delivered by the project and by how much they, overall, exceed costs[11]. Instead, the allocation of costs based on benefits requires a more precise determination of the latter, if they are to be used as drivers in the cost allocation[12].

While the beneficiaries-pay approach has been used in a few jurisdictions[13], the difficulties of accurately assessing benefits[14] have led to the utilisation of the transmission assets being used as a proxy for such benefits, although there is not a clear nexus between them that can be proven.

The issue then becomes the identification of a reasonable method to measure network utilisation. Unfortunately, computing the electrical utilisation of lines by agents is not a simple task either, since there is no indisputable method to do it, as already indicated in section 2.1. Among the different methods which have been proposed, the one based on 'average participation' seems to be the most robust one. It is important to keep in mind that the final objective is not the impossible task of computing the use of the network by each agent, but of producing a reasonable estimate of the benefits accruing to each agent by the use of the transmission facilities.

3.3 Principle 3: Transmission charges established *ex-ante*.

Transmission network charges for network users should be determined *ex-ante* and not updated, or at least not for a reasonably long time. This is the only way to send predictable –although not necessarily constant in time – economic locational signals to investors that need to choose the most convenient sites with a low financial risk. This is of particular interest for wind and solar generators, which usually have many potential sites.

The locational impact of transmission charges is mostly meant to incentivise potential new generators to establish themselves at convenient places from the transmission network viewpoint, i.e., where the presence of the new generator will reduce (or, at least, not increase) congestion and the need for network reinforcements. Transmission charges may also have some impact on the retirement decisions for old plants with scant operation

[8] In principle, if the project has positive net benefits, it is possible to compensate losers for their losses and make all affected entities better off. In practice this is complicated and seldom if ever done. One could argue that compensation is not deserved for the loss of economic benefits (high prices to generators, low prices to loads) that exist only because of network congestion, but major environmental impacts may raise more serious issues in the future. Such impacts might be claimed, for instance, if a proposed line were to cross a particular area, but confer no benefits on its residents.

[9] The "regulatory test" is the set of rules that must be applied to determine whether the construction of a particular network investment or reinforcement, or a set of them, is justified.

[10] More information on the list of benefits and CBA guidelines in: https://consultations.entsoe.eu/system-development/methodology-for-a-energy-system-wide-cost-benefit/

[11] If there are financing constraints, projects might need to be ranked on the basis of the net benefits that they deliver and, in this case, a more accurate estimation of benefits is needed.

[12] It has also been attempted to allocate the costs of existing lines on the basis of the long-run marginal cost of transmission investment, i.e., the cost of expanding the transmission network, which requires adjustment as it over- or under-recovers the investment.

[13] The beneficiaries-pay approach to transmission pricing was adopted for the first time in 1992 in the development of the regulatory compact associated with the liberalisation and restructuring of the Argentinean power sector. The same approach also inspired, in the early 1990's, the allocation of the cost of a transmission line – the SIEPAC project – that connects six Central American countries, bringing major benefits to the region. Since then, it has been largely adopted as the guiding principle to allocate the cost of new transmission projects

[14] All benefits accruing to the network users should be included in the analysis, both the ones which can be monetised and those whose monetisation is more difficult.

profit margins. No significant impact is instead expected on the siting decisions of consumers, since transmission charges are typically a minor component of the total electricity payment, which normally does not attract a major share of the consumers' budget (with the exception of energy-intensive industry).

The importance of the stability of transmission charges over time reflects the fact that, once a new generator is into the construction period or in operation, no relocation is possible and investors should have confidence that the locational structure of transmission charges (or their trajectory over time) on which they based their siting decision will also apply at least in the initial period of operation of the new plant.

What is proposed here is that, when a new generator requests connection to a certain point of the grid, the System Operator provides an indication of the transmission charges to be levied to this generator for the next 10 years (or a similar period). For typical monetary discount rates, and given the uncertainty surrounding most of the major factors that affect the profitability of a power plant, 10 years should be enough for the new generator to decide whether and where to invest. The trajectories of transmission charges for potential new generators applying for connection in a specific year should not be changed during the following 10 years for these generators. However, in the presence of additional information during the year, the trajectory of network charges that will be announced at the beginning of the following year and applied to any new entrants requesting connection during that year could well be a different one. Once the 10 years have passed, these generators will be treated as any other one.

To the best of our knowledge, this principle is not applied anywhere. While the methods for calculating transmission tariffs in many countries have been established for many years, most countries update the exact values of their transmission tariffs annually for all network users to account for the evolution of costs, changes in the configuration of the power system, inflation and other factors.

3.4 Principle 4: Non-distortionary transmission charges structure

In the design of transmission charges, one must clearly differentiate the determination of *how much* each network user has to pay from the specific structure of the charge, i.e., as a volumetric charge ($/MWh), as a capacity charge ($/MW), as a lump sum ($) or as a combination of them. The choice of format for the transmission charges has implications on the short- and long-term behaviour of the agents in the market.

The key point to be realised is that procedures to allocate transmission costs based on scenarios and the estimated benefits or responsibilities for utilisation by generators and demands in each node, allow the computation of annual charges for each network user. Once the annual amount to be paid by each network user is known, it could be charged as a single lump sum, or conveniently broken down into monthly instalments or, perhaps for structural reasons, as a $/MW charge appropriately tailored to each generator or demand so that it results in the previously computed annual amount, but never as a volumetric charge applied to the actual energy generated or consumed[15].

Figure 5 shows the four principles and their intended objectives.

[15] If transmission tariffs are applied in the form of energy charges ($/MWh), i.e., a charge that depends on the amount of energy injected into or withdrawn from the network by the grid user, they effectively introduce a new short-term cost (for accessing the grid), therefore causing a change in the value used in the bids or the economic dispatch (for generators) as well as in the response of consumers to energy prices. Therefore, regardless of the logic used in the short-term economic operation of the power system, a volumetric transmission charge will cause a distortion. This is of particular relevance for generators in power systems with wholesale markets, because generators determine the market price with their bids or declared costs. An annual capacity charge ($/MW) also runs into problems, distorting the decisions of the agents in different ways. If the annual amount to be allocated to each agent has been already computed based on a sound method, why to create an unnecessary complication by applying it as a capacity charge? This would be particularly problematic for new generators whose capital investment cost would be impacted. Typically, the allocated cost for a certain location is divided by the rated or maximum declared capacity. If multiple generating units are located in the same location, this runs into the problem of discriminating between generators who use the network frequently (base load) and those who operate during peak hours (peak load).

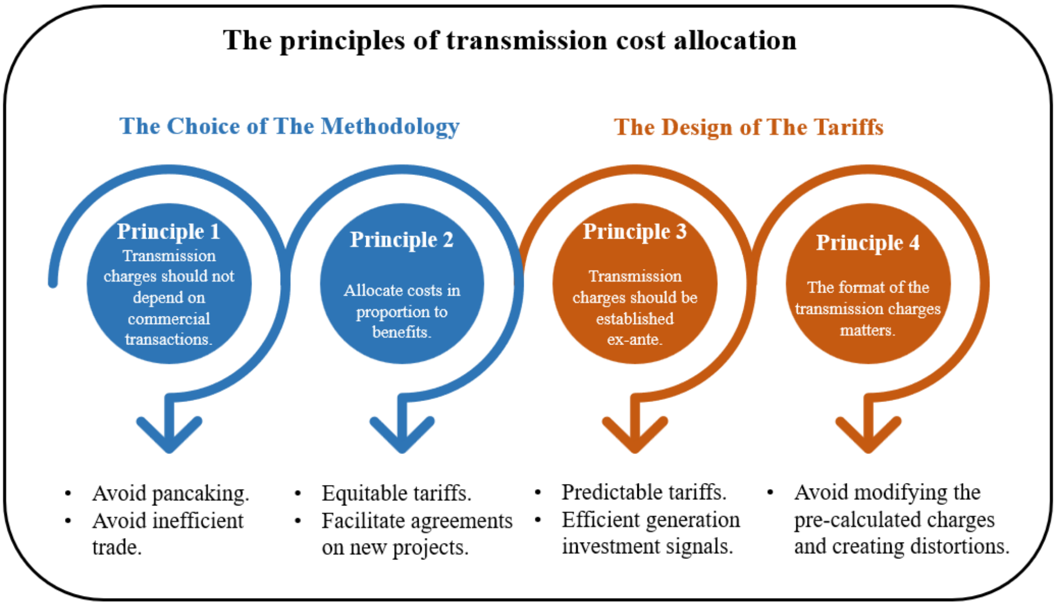

Figure 5: The principles of transmission cost allocation.

Building more transmission lines and upgrading transmission capacity, including across borders, are an essential part of the electricity sector strategy for developing countries, to electrify their economies. In most emerging economies this can only be done by attracting massive private investment[16]. A prerequisite to attract private investment is a sound regulatory framework, covering the institutions, criteria, procedure and enforcement of regional transmission planning, the determination of transmission costs and the equitable allocation of these costs to the different agents in the market.

The next section presents general recommendations and implementation strategies for transmission cost allocation that emerge from the four principles and which are applicable both within jurisdictions and at cross-border/regional level.

4. General recommendations and implementation strategies for transmission cost allocation

The recommendations and implementation strategies provided in this section apply to regulated transmission assets. They can also be used as reference for merchant lines[17], even though in this case the allocation of costs will be typically negotiated among their promoters and the transmission asset users.

Successful design and implementation of regulated transmission projects require abiding by cost recovery and allocation rules, as well as open access mandatory requirements[18]. The following are the general cost recovery and allocation rules we recommend for transmission projects at all levels:

i) Transmission cost recovery – It is a fundamental regulatory principle that the cost allocation method and the transmission charges to be levied on the users/beneficiaries of the transmission activity must cover the recognised cost of this activity – the regulated transmission revenue requirement. In particular, the total amount of transmission charges for a given year (the annual revenue requirement) shall be

[16] For instance, presently, almost all transmission investment in Africa is financed by state-owned enterprises. The estimates of annual investments required for transmission in Africa until 2040, range from US$3.2 billion to US$4.3 billion, which will not be possible to raise with only public funds (AfDB 2019).

[17] Merchant transmission lines are those lines built by investors who keep the revenue risk related to the utilisation of these lines onto themselves.

[18] As already indicated, transmission costs must only include the costs of investment and the cost of operating and maintaining the equipment. None of these costs depends on the level of utilisation of the transmission facilities. Operation and maintenance costs can be roughly estimated as percentages of the investment costs, with different percentage values for each type of facility. Losses and congestion happen in the transmission facilities, but, as already mentioned, they are not transmission costs *per se*. The allocation of the cost of losses is addressed in section 6.

determined by using accounting methods so that, over the economic (or regulatory) lifetime of the assets, the present value of the stream of annual revenue requirements equals the present value of the (efficiently) incurred costs. Besides covering the incurred costs, this amount must include a reasonable remuneration of the invested (equity and debt) capital, and perhaps also some efficiency or performance incentives. Alternatively, if a tendering process to determine the developer of the transmission asset is used, the outcome of the process will determine the regulated amount to be recovered. The annual revenue requirements should not change much from one year to the next, so that the trajectory of the transmission charges follows a smooth and predictable path over time.

ii) Minimisation of the cost-recovery risk – The regulation applicable to a new transmission asset must be designed so that the way in which transmission charges are defined and levied does not introduce unnecessary risks in the mechanism of recovery of the transmission revenue requirement. For example:

- Replacement-cost methodologies should not be used. Once the investment in a transmission project has been made using the technologies and the catalogue of components available at that time, the calculation of the revenue requirement for that project in subsequent years should not be based on the cost of the new technologies available in those years, since this creates an unmanageable risk for the transmission investor[19], resulting in a higher cost of capital and higher charges for the users/beneficiaries.
- Transmission revenues should not depend on the volume of energy flows over the transmission asset/network, because this unnecessarily introduces uncertainty in the remuneration of transmission, which must be a fixed annuity paid as a lump sum and recovered via fixed charges to generators and consumers. However, current end-consumer tariffs often recover part of the transmission costs via a volumetric component and errors in the estimation of the annual demand will result in a surplus or deficit in the collection of the transmission revenue requirement. This has to be accepted, as such errors cannot be avoided. However, until the design of end consumer tariffs is improved, this should not result in any uncertainty in the revenues of the transmission company, as the actual difference – positive or negative – can be easily compensated through the determination of the revenue requirement of transmission for the following year(s).

iii) Treatment of existing and new assets – It is also important to distinguish between existing and new (planned) transmission assets. While proper cost allocation should be aimed for both for existing and new assets, a proper cost allocation procedure is more important for new assets, at least to the extent that it can assist in dealing with the potential opposition to a technically and economically sound transmission project by agents who fear that they may end up paying more than the benefit obtained from the project. Obviously, the consequences of this potential opposition are only important for new investments.

iv) The specific transmission cost allocation method – The users/beneficiaries of the transmission asset/network shall pay transmission charges determined by a cost allocation method, which should reflect the benefits that these agents receive from such use or, as a practical proxy, some measure of the use of the transmission asset/network, thus respecting the principles outlined in Section 3. Within each jurisdiction, such an allocation should be applied at the individual agent or transmission network node level. At cross-border or regional level, the allocation should be first done at jurisdictional level, leaving each jurisdiction to pass on the allocated costs in line with national practice. In this latter case, however, as already indicated, costs of the cross-border transmission assets should not be allocated only to those who trade across border, but more widely to all those who benefits from cross-border exchanges. Box 1 and the Appendix review the best-known allocation methods that have been implemented or proposed. Most of them seriously violate one or more of the four fundamental principles presented in section 3.

[19] In case, for example, that more efficient, less expensive technologies become available in those years.

The international practice of transmission cost allocation at the national or system operator level is very diverse. Transmission tariffs in most countries do not contain any locational signal. They disregard the need to allocate line costs efficiently (see, for instance (ETSO 2009), (Fink et al. 2011) and (Lusztig et al. 2006)). Regulators have frequently settled for simple transmission charges that socialise the cost of the network to its users. However, in our view, as time passes and new types of generation, like renewables, compete for access, sending clear locational signals –including through transmission tariffs – will become more relevant.

The most common transmission charging scheme is the plain postage stamp method, whereby every load pays a flat charge per kWh of consumed energy at any time, or at most by time band, or per contracted kW of capacity. In some instances, generators also pay on a per-kW or per-kWh basis. As discussed in section 3.4, the latter charging method distorts the efficient outcome of wholesale power trade. A few systems have introduced some sort of locational transmission charges, and more systems are now considering doing the same because of the anticipated large penetration of wind and solar plants that could unnecessarily stress the transmission grid in the absence of any locational signal. In the EU, the term 'locational signals' is commonly referred to in regulatory documents as a desirable feature. However, no progress has been made in this regard at the European level, with the exception of the UK, Ireland and, up to a certain point, Sweden, which have all implemented it at the country level

The principle beneficiary pays is commonly accepted in official documents in the US, see (FERC 2012) for instance, although its practical implementation is so far very rudimentary, to say the least. In the EU, this principle has also been adopted.

With respect to cross-border/regional trade, both the U.S. and the European Union have abolished pancaking. The Federal Energy Regulatory Commission (FERC) issued Order No. 888, prohibiting discriminatory transmission tariffs for cross-border trade within each Regional Transmission Organisation (RTO). Nonetheless, no serious attempts have been made so far to extend intra-regional (RTO) cost allocation methods to the inter-regional level.

Moreover, the EU explicitly forbid, in its regulations, that transmission charges depend on commercial transactions and developed a standardised mechanism for accessing and paying for the transmission system. As part of this approach, an inter-Transmission System Operators (TSO) compensation mechanism (ITC) mechanism has been in place since 2002 with the following characteristics (Olmos Camacho and Pérez-Arriaga 2007). Countries – represented typically by one TSO, sometimes more than one – compensate one another for the utilisation of each other's network by referring to some metrics that are based on network usage. The net balance of compensations and charges for each country – either positive or negative – is added to its total network cost from which the transmission tariffs are computed. Every country is free to design its internal network tariffs. Payment of the national transmission tariff gives every agent the right to access the entire EU transmission network without any additional charge. Although some computational aspects of this method could be much improved, this overall hierarchical approach has been a major contributor to facilitating electricity trade in the EU and, despite its simplicity, has a solid conceptual basis. Note that this method implicitly and automatically allocates the cost of any new transmission investment in the EU territory, although the total amount to cover infrastructure costs at the EU level has been capped. However, since 2013, a new cross-border cost allocation (CBCA) mechanism is available for the main transmission investment projects with cross-border relevance (the so-called Projects of Common Interest), whereby national regulators agree on how the cost of these projects should be allocated to the different countries involved. If national regulators fail to agree, the cost allocation is decided by the EU Agency for the Cooperation of Energy Regulators (see ACER (2023)).

Box 1: International practices in transmission cost allocation.

v) Locational differentiation of transmission charges – It is desirable that transmission charges have some locational component, i.e., different charges for agents connected at different nodes of the transmission network. All other things being equal, those agents whose activities as producers or consumers make it necessary to add new transmission facilities or expand existing facilities should pay more than those that do not cause any stress or need for new reinforcements of the network. This is particularly important for large generators (or large concentrations of medium size or even small generators) because they typically have more siting freedom. Locational signals may guide new investors in generation to choose sites that avoid costly transmission investments or even relieve congestion in the system. When cost allocation is applied within a country, the regulator may choose to socialise – i.e., make uniform – the charges to consumers in the country, since, in their case, a transmission locational signal is not going to make much difference in their siting, except possibly for the largest consumers.

vi) Allocation to generators or consumers – According to the second principle of transmission pricing outlined in section 3, transmission charges must be levied on the beneficiaries of a transmission project, which, in general, are both consumers and producers. Therefore, *a priori*, radical decisions such as only consumers shall pay for transmission or all transmission charges must be levied on producers are not justified[20].

vii) Legal certainty – The cost allocation rules must not be modified if possible, and, if they are, this should happen only for a very good reason and with sufficient advance notice. However, the numerical results of the application of these rules will typically change, for instance when a new agent enters the system. Note that this is different from the remuneration of transmission assets that should be as stable as possible.

viii) Congestion income – Congestion happens frequently in transmission networks. Depending on the transaction rules at bulk power system level, many power systems collect congestion income under these circumstances[21]. The collecting entity is usually the System Operator, either at the national or regional level. Given that the transmission revenue requirement is determined based on transmission costs, and that congestion does not modify the cost of transmission, the best use of the congestion income is to decrease the transmission revenue requirement to be charged to the network users/beneficiaries[22]. Under no circumstance the congestion income should augment the remuneration of transmission or of the System Operators.

ix) Lumpiness in transmission investments – Transmission investments are lumpy, and they last many years (i.e., 40 or more; actually, they are refurbished or replaced, but never removed). When they enter into service, their load carrying capacity typically exceeds what is needed at that moment, i.e., there is a lot of idle capacity during the initial years. It does not seem cost-reflective to charge the total cost of a transmission investment to its users/beneficiaries when they are using/benefiting from only a fraction of the transmission capacity. Different approaches have been proposed to allocate these residual costs (see (MIT 2016)). In the context of transmission cost allocation, any simple method of socialisation of the cost to demand could be considered acceptable.

5. Guidelines for transmission cost allocation at regional level

In the previous section we presented the general recommendations and implementation strategies for transmission cost allocation, that apply both at the national and regional levels. In this section we shall make use of this knowledge to propose the Guidelines to deal with transmission cost allocation at regional level.

These Guidelines are based on the single system paradigm, which, as already indicated, requires that regional power trade function as close as possible – in its operation and planning decisions, transmission regulation and governance – to the way in which a single jurisdiction of the corresponding regional dimension would function.

5.1 The institutional framework

The implementation of a transmission cost allocation approach in the context of cross-border/regional trading - which respects the fundamental principles presented in section 3, equitably allocates costs to those who benefit from the transmission network, provides the correct signals to network users, reveals the need for network

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[20] It is however expected that transmission charges giving correct economic signals – i.e. based on the forward-looking marginal cost of investment in transmission infrastructures because of the use of the system by different agents - do not typically recover the full regulated revenue requirement. In this case, a least-distortive way of collecting the remaining part of the regulated revenue requirement could be based on allocating costs inversely to the price elasticity of grid access. Under this criterion, consumers, typically showing a much lower elasticity than generators, may end up bearing a larger proportion of transmission costs. However, this may not be always the case. Generation plants – both existing or new projects – with large margins of benefit may absorb residual transmission charges without incurring in financial distress. See also the Appendix.

[21] As already mentioned in section 2.3, congestion income arises where electricity market exists and congestion results in different market areas expressing different prices. Congestion income may also arise when the physical capacity over a congested interconnector is allocated at a fee.

[22] However, as congestion income may vary substantially from year to year, given that it depends, *inter alia*, on the price differentials between market areas, care should be taken that its use to reduce the regulated revenue requirement to be collected through transmission charges does not lead to such charges varying significantly from year to year, thus violating principle 3 outlined in section 3.3 above.

reinforcements and incentivises generation investment where it is most needed - requires the establishment of a specialised framework (a regional regulatory authority or an effective dispute-resolution and enforcing entity) responsible for the definition, implementation and possible modifications of cross-border/regional cost allocations for electricity transmission investment with cross-border/regional relevance, or at least to mediate and adjudicate in case of disagreement among national regulators on these decisions. A regional regulatory authority might also adopt a reference methodology for the cost allocation of electricity transmission investment with cross-border/regional relevance, according to the principles outlined in section 3. Such a methodology might be applied by the regional regulatory entity if it has to intervene in case of disagreement among the national regulatory authority, or be used as a reference and starting point for the cooperation among these authorities.

5.2 The Guidelines

Once the necessary institutional framework is in place, we recommend that the transmission cost allocation at regional level proceeds along the following steps:

Definition of the transmission network elements with cross-border relevance

The transmission network elements with cross-border/regional relevance are those which are needed to establish physical transfers of electric power between countries. It is their costs which should be allocated to beneficiaries across borders. These transmission network elements should be distinguished from those with only local/national relevance. There is no clear separation between the two categories and some threshold or criterion must be established by agreement among the involved regulators or by the regional regulatory authority, based on engineering estimates and actual power flow patterns. Transmission lines that cross country borders are obvious candidates as network elements with cross-border/regional relevance. Note, however, that many transmission lines that are purely internal to a country can have much relevance in regional power exchanges, for instance allowing the wheeling of power between the interconnectors with other countries.

Definition of a common approach to allocate the costs of the transmission network elements with cross-border/regional relevance

In this context, it is possible that some important cross-border transmission projects might be proposed, authorised and even deployed using some *ad hoc* cost allocation rules. Such rules might or might not follow the guidelines presented in this document, which could possibly serve as a starting point in the negotiations between the project promoters and the project users. Irrespective of which approach is chosen, we recommend that it allocates costs only at the country level, i.e. among the countries which benefit/use the transmission network elements developed by the project, and not to the individual agents in these countries.

For the remaining components of the transmission network with cross-border/regional relevance, we recommend a method for the determination and allocation of costs of transmission network elements with cross-border/regional relevance along the following steps.

i) The revenue requirement for each transmission network element with cross-border/regional relevance is determined by the national regulators (separately for the part of the elements on their respective territories or jointly). If national regulators act separately, any dispute on the method applied to determine the revenue requirement for the different parts of the transmission network element should be adjudicated by the regional regulator or through the dispute-resolution mechanism.

ii) The charges to recover the revenue requirement for each transmission network element with cross-border/regional relevance are applied at the country level[23].

[23] More granular locational differentiation might be applied within each country by the national regulator when setting domestic tariffs.

iii) In a first instance, the national regulators[24] of the involved countries shall try to agree on a cost allocation approach, possibly using the Average Participation method as a reference[25]. Such an approach would need fully to allocate the overall revenue requirements of all the transmission network elements with cross-border/regional relevance, but only allocate costs at the country level, leaving each national regulator to determine the charges applicable to the different agents within its jurisdiction.

iv) If the national regulators do not manage to reach an agreement on how to allocate among them the costs of the transmission network elements with cross-border/regional relevance within a pre-specified period of time, the decision will be taken by the regional regulator using the Average Participation method.

v) Once the allocation of the costs of the transmission network elements with cross-border/regional relevance is defined, the national regulator of each country shall determine the modified transmission revenue requirement to be used in the computation of the regulated transmission charges in the country. The regulator shall start from the costs of the transmission network within the country, then subtract the charges that have been allocated to other countries for the use of the transmission network elements with cross-border/regional relevance in the country, and finally add the charges allocated to this country because of its use of the transmission network elements with cross-border/regional relevance in other countries. Once this modified transmission network revenue requirement is obtained, the regulator can proceed to determine its internal transmission charges, with a method compatible with the recommendations presented in section 4.

The cross-border compensations between countries and the payments to transmission projects promoters, which are not the incumbent public transmission companies and System Operators of the countries involved, must be guaranteed by an entity in each involved country. At least a couple of reasonable options exist, with the choice between them depending on the specific circumstances of the involved utilities and the independence and executive power of the national regulators:

- the national regulators mandate the ring-fencing of these compensations and payments corresponding to each country from the revenues collected in the country from the electricity tariffs.
- the System Operator of each country, which collects the compensations and payments corresponding to its country is the national counterparty for the compensation resulting from the application of the allocation method described above. In many countries, the System Operator is part of a vertically integrated utility; in this case it will be effectively the latter which guarantees the compensations and payments[26].

5.2.1 Entities involved in setting the transmission charges for cross-border/regional transmission assets

As a general rule, the entities involved in the determination of the revenue requirements for transmission network elements with cross-border/regional relevance and for the allocations of such requirements among the users/beneficiaries of such transmission elements include:

- The project promoter(s)[27], which should plan, finance and develop the transmission network elements with cross-border/regional relevance, and propose the costs to be recovered in relation to such network

[24] Where a regulator has not been established, the task should be performed by the national government.

[25] The fact that, as indicated in the next bullet point, in case of disagreement the regional regulatory authority would use the Average Participation method to allocate the costs of the transmission network elements with cross-border/regional relevance makes this method a strong candidate to provide the reference for the agreement among national regulators.

[26] In fact, project promoters might have a preference that the payments are made by a utility, if they believe that this provides stronger guarantee of cost recovery than passing the recovery of transmission costs to national tariffs, when the regulatory framework and the governance supporting it (e.g. the regulatory authority or the central administration) are not considered sufficiently credible by project promoters to ensure the fulfilment of the compensations and payments. This is a general aspect which needs urgent attention

[27] In many cases, the project promoter is the transmission system operator or a group of transmission system operators of the control areas/countries involved in the project.

elements. The promoter(s) might also choose the regulatory regime under which the transmission asset will operate[28].

- The national regulatory authority(ies), which, separately for the part of the assets on their respective territories or jointly, should determine, upon the proposal of the project promoter(s), the cost of the transmission assets to be recovered through the revenue requirement. Such costs should be the ones prudently incurred and economically justified, and might include incentivising elements.
- A regional regulator or the national regulatory authorities acting jointly, which should determine the allocation of costs among the different countries or users/beneficiaries. If a regional regulator is not established, a dispute resolution mechanism should be put in place to solve situations in which the national regulatory authorities are unable to agree, e.g. on the allocation of costs.
- The government of the countries involved in the case in which an inter-governmental agreement is needed to establish the rules for cooperation of national regulatory authorities, for the establishment of a regional regulator or a dispute resolution mechanism and/or, possibly, for the definition of the cost allocation principles.

The System Operators and the grid users in the different countries involved also play a role in enabling and paying for new transmission network elements with cross-border/regional relevance.

Figure 6 illustrates the recommended process for determining the revenue requirement of a (new) transmission asset with cross-border/regional relevance and allocating it to the countries involved, as outlined above.

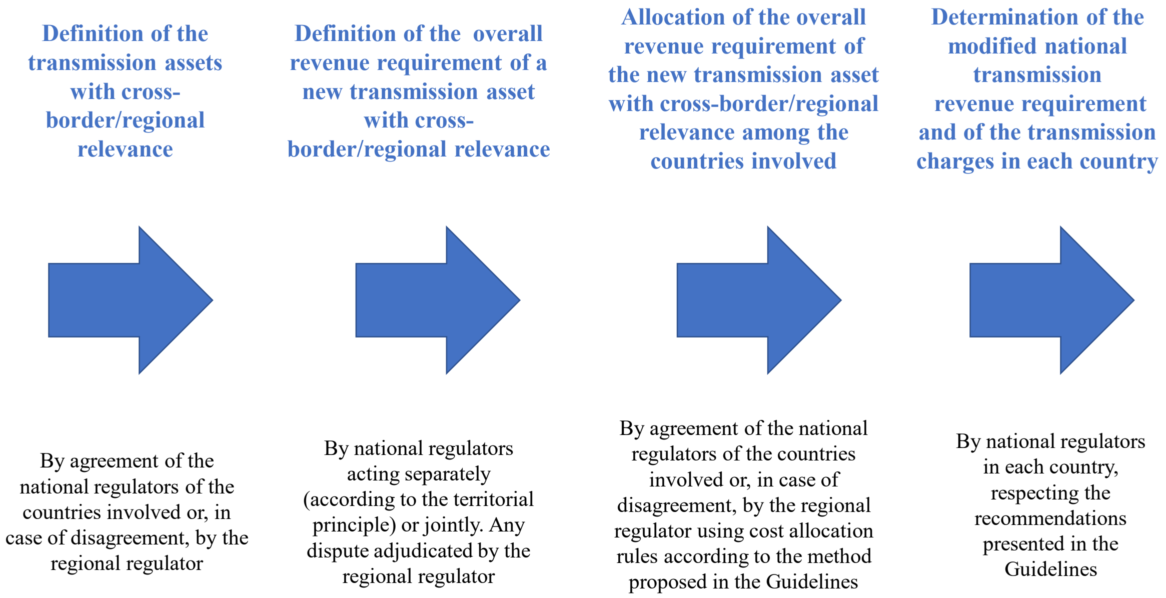

Figure 6: Regional transmission cost allocation recommended process and entities involved.

5.2.2 Proposal for the adoption of a quantitative method to allocate the cost of transmission network elements with cross-border/regional relevance

Once the transmission network elements with cross-border/regional relevance developed as regulated assets have been identified, a method to allocate their costs to the countries benefitting from or using them is needed. Here we focus on the design of the uniform regional method, which, if well-conceived, could also serve as a reference model for the cost allocation method to be agreed by national regulators or to be applied to any new

[28] For merchant lines, the allocation of costs will be agreed between the project promoter(s) and the line's users.

large transmission project. Note that such a method should allocate the revenue requirement among the involved countries, but such a requirement does not include the cost of losses that happen in the transmission facilities.

Two methods are presented in what follows: the "first best" method, allocating costs to beneficiaries, and a "second best" method, allocating costs to users.

5.2.2.1 The "first best" method: Allocation to beneficiaries

The "first best" method to allocate the cost of transmission network elements with cross-border/regional relevance is to charge the beneficiaries of such an element in proportion to the estimated benefits delivered to each one of them. As indicated previously, the allocation will be performed at country level, and therefore the benefits accruing to each country because of the considered transmission investment will have to be estimated. Since the project is expected to have a long useful life, the benefits must be estimated during a long-term period.

But what are these benefits? In principle, reference should be made to the net socio-economic welfare benefits accruing to the different countries, which should include, but not be limited to, the economic benefits of a higher net surplus from trading (higher surplus for generators in exporting countries and for consumers in importing countries net of any reduction of surplus for generators in importing countries and consumers in exporting countries). However, other benefits, possibly not directly monetisable, should also be included[29]. If the investment in the transmission project has been found to be well justified, the aggregated benefits for all countries must clearly exceed the cost of the project over its lifetime and the allocation of costs in proportion to the benefits must leave every country satisfied. The potential difficulties of implementing the beneficiaries-pay method have been discussed already. If those situations where these difficulties are considered to be excessive, the "second best" method can always be applied.

5.2.2.2 A "second best" method

Several engineering-based methods to assess the use of transmission assets by different network users have been proposed and some have been implemented, see the Appendix: Cost Allocation Methods. All these methods are based on some approach to quantify the level of utilisation of the considered transmission network element by each agent (country, in this case). The level of utilisation can be seen as a proxy for the amount of benefit delivered by the project. And the starting point can be the physical flows of energy that can be measured at any given moment exiting the generators, feeding the loads and being associated with each individual transmission network element.

The only engineering method that seems to make sense in this context is the Average Participations method. All others have been tried and discarded, as they can be found to produce inconsistent results (Olmos Camacho and Pérez-Arriaga 2007). Average Participations tracks the actual flows in each network component upstream and downstream to find its source and sink[30]. It has been frequently used in transmission cost allocation procedures.

The implementation of this method requires:

- a network representation, either the full one – i.e., with all lines and nodes, either regional or not – or just the regional network, with all the generators and loads being aggregated in the regional network nodes, and including the technical and economic characteristics of each transmission network element included in the representation.

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[29] For example, a transmission project can make possible the utilisation of energy resources that otherwise would have remained idle, or it can increase the size or the liquidity in a regional wholesale market, or it can mitigate market power by making the competitive utilisation of more generation resources possible. And these benefits will have to be approved and somehow quantified to arrive at a final agreement among the countries regarding the allocation of the cost of the transmission project.

[30] This does not correspond to the physical reality of how the electric energy actually moves from one point to another, but it seems the best feasible approach. The fundamental problem with the engineering approach, as explained in section 1, is that it can be stated, based on sound physical knowledge, that it is impossible to assign responsibility to any specific agent – generator or load – in the transfer of energy from generators to loads. The transfer is a collective phenomenon where all the generators and loads take part, and it happens guided by the ensemble of transmission lines.

- a suitable set of representative scenarios of the injections and withdrawals in the different nodes of the network representation.

The System Operators can typically provide a suitable regional network representation, as well as the estimated injections and withdrawals of power at each node for a number of representative scenarios for the year for which the cost allocation can be performed.

For each generator and each load in each scenario, average participations will determine how much it uses the capacity of each element in the regional transmission network, both in its own country and in the other ones. A simple mathematical procedure can be used to allocate the allowed revenues of each element in the regional transmission network to the different countries and thus obtain a list of values per country, indicating how much the country has to pay for each individual transmission asset. From this list, the method can provide a table of figures, with the number in each cell indicating how much one country shall pay another country for the use of all the transmission facilities located in the territory of the latter.

Once the cost of the regional transmission network has been allocated to each country, the regulatory authorities know the total transmission revenue requirement for their respective countries for the year under consideration. Then the regulators can proceed to take such (outgoing and incoming) payments into account in defining charges to producers and tariffs to end consumers.

For those transmission projects where the allocation of the cost has been agreed among the promoters, it will be easy to add the results obtained with their individual cost allocation methods to the ones obtained as outlined above.

In Central America, there is a procedure to identify the regional network, named the RTR (‘*Red de Transporte Regional*’ in Spanish). Part of the RTR is owned by the regional system owner, the EPR (for ‘*Entidad Propietaria de la Red*’ in Spanish), which also owns the SIEPAC line that connects all the countries in the region. National TSOs also own part of the lines of the RTR and private investors (mainly grid users) build and own lines in order to access other areas of the region and get the corresponding transmission rights. These are the so-called investments at risk. Thus, the operation and planning of the system and the ownership of transmission assets are independent of one another. The definition of the RTR is very relevant since regional and national lines are subject to different regulatory schemes (see “EOR, *Reglamento del Mercado Eléctrico Regional* (RMER)”). The costs of existing and new lines of the RTR are allocated using the same method.

The regional cost allocation method was defined by the regional regulator in 2009 but was implemented later, around 2018. The method is a combination of two usage-based methods: the Dominant Flow (DF) method and the Average Participation (AP) method. The DF method divides the flow over each line, using the superposition principle, into two parts: one associated with the national transactions, jointly called national super-transaction, taking place within the country where the line is located, and one corresponding to regional transactions, jointly called regional super-transaction. Each one of the national super-transactions comprises all the power injections and withdrawals accepted in the corresponding national market. Apart from them, there is one regional super transaction that comprises all the injections and withdrawals accepted in the regional market (modifications to national dispatches). Then, both components of the line flow are tracked separately using the AP method to compute how much each group of agents involved in this super-transaction are using each line. Transmission charges are obtained by applying the two methods to historical pre-dispatch data of the previous year. The method is, therefore, not transaction-based but usage-based. The term super-transaction is used to identify the total impact each country is making on the RTR since the national market is kept isolated and a regional nodal dispatch is performed on top of their outcomes. In addition, the fraction of the cost of a new line belonging to the RTR that is recovered through the application of regional transmission tariffs depends on whether this reinforcement was planned by the regional system operator, the EOR, or the national transmission systems. Transmission charges resulting from the application of this hybrid method discriminate between agents trading their energy regionally and those that trade it locally.

Between 2009 and 2018, a simple transitional method was applied to allocate the cost of the regional grid. It involved allocating the cost of those regional network elements that are entirely located within a country to the demand in that country, and the cost of cross-border regional network elements to all the countries in the region proportionally to the demand in each country.

Both the transitional and the currently applied methods are applied to allocate only the fraction of the cost of regional assets not recovered from congestion income resulting from the application of nodal prices at the regional level.

Box 2: Transmission cost allocation in the Central American Electricity Market.

5.2.3 The international practice

The territorial principle, associated with entry and exit charges based on some notional commercial path is still widely used in many parts of the world. This results in power flows being charged every time they cross a border along their notional commercial path, resulting in tariff pancaking.

Approaches consistent with the 'single-system paradigm', in which charges for the use of the entire regional transmission network are imposed only on injections into and withdrawals from such a network, are currently applied in the European Union, in the Regional Electricity Market in Central America and within the areas controlled by each Regional Transmission Organisation (RTO) in the US (but not across different RTO areas).

In other parts of the world, attempts have been made better to estimate the way in which cross-border/regional trade impacts on the use of the regional transmission network.

However, any method that is based on charging transmission costs to the commercial bilateral transactions, making use of some engineering calculation of the impact that the transaction has on the network, is conceptually flawed and, more importantly, will typically result in transmission charges for cross-border transactions several times higher than they should be, therefore seriously deterring power trade.

A more elaborate method may simply consist in using a load flow calculation method to determine the flows associated with every bilateral transaction in the transmission components of the regional network. This will be repeated for every considered scenario. Then the two agents involved in the transaction will have to pay an annual transmission charge according to the fraction of the network that they have used during the considered year. The typical example of such a method is the MW-km that is used in some parts of the world (see the African experience in Box 3).

These methods are in flagrant contradiction with one of the firmest principles of transmission pricing, which is to ignore commercial transactions when determining transmission charges. The obvious undesirable consequence of these approaches is to overcharge the commercial cross-border transactions – therefore disincentivising regional trade – ignoring that the benefit of the interconnections is more widely shared among

Among the African power pools, so far, only the Southern African Power Pool (SAPP) and the West African Power Pool (WAPP) have a defined methodology for transmission cost allocation. Both power pools currently have the same methodology, which is a variant of the MW-km method (based on DC load flow simulation and applicable to demands only). The method primarily computes the charges for bilateral transactions in the region by defining the injection and withdrawal nodes (typically, the injection node is a specific generator node or a node to which a group of generators is connected, while the withdrawal node is the border node of the buyer, i.e., not the exact demand node(s)) and forcing a load flow equal to the transacted capacity. The charges are then calculated based on the increase of flow in the assets compared to a chosen base scenario. In SAPP, transmission charges for the competitive markets are the average of the computed bilateral transaction charges and are shared evenly between the buyer and the seller. Originally, the SAPP used the Postage Stamp method that charges all users a flat rate of 7.5% of the total amount of energy injected or withdrawn from the network, but this was abandoned in 2003 (initially, it was not unanimously accepted by all utilities) in favour of a MW-km method after it was recommended by the wheeling rates study commissioned to the UK consultant Power Planning Associates LTD.

Currently, both power pools are in the process of revising the MW-km methodology to a non-transaction-based method. SAPP commissioned the consulting company Ricardo to propose an alternative method after it was reported that the current method was no longer suitable for competitive trade and calculating *ex-ante* charges. The proposed methodology considers a hybrid of Average Participations (AP) and Marginal Participations (MP) similar to the method presently applied in India. AP is applied first to determine the corresponding demands for each generator and the corresponding generators for each demand. Then, for each agent, MP is applied by simulating an incremental unit (1 MW) of power injected or withdrawn to calculate the change in the assets' flow (an approximation is used in which the Power Transmission Distribution Factors (PTDF) are used instead of a full load flow simulation). The final charges take into account the direction of flow in comparison to a base scenario. Such a hybrid method avoids the need for the arbitrary selection of a slack node, but arguably results in additional complexity. Additionally, the final charges are applied as capacity charges based on the rating capacity without taking into account the capacity factor for renewables and, hence, do not allocate costs based on their actual use of the grid.

Box 3: Transmission cost allocation in African Power Pools.

the agents (remember: the cost of transmission must be allocated to its beneficiaries). These methods are contrary to what is being tried to achieve, which is to facilitate regional trade.

5.2.4 Going further: Locational signals[31]

We now consider how some locational component could be included in the transmission charges that result from the "second best" approach recommended above. This can be accomplished in two stages: with the regional network charges and with the national charges that remunerate the purely national (i.e., not regional) component of the transmission network of each country.

The regional transmission charges computed according to the Average Participation method will charge more to predominantly exporting countries located far from predominantly importing countries, and also to predominantly importing countries located far from predominantly exporting countries, than to countries that do not import or export much. Therefore, the national regulators should charge the regional component mostly to generators in those far and predominantly exporting countries and mostly to demand in those far and predominantly importing countries.

Figure 7 summarises the recommendations presented for regional transmission cost allocation.

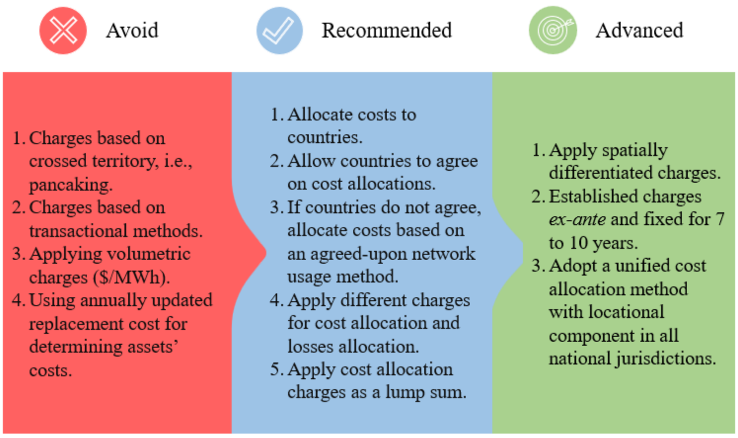

Figure 7: Summary of regional transmission cost allocation do's and don'ts.

6. Recommendations for the allocation of the cost of transmission losses in a regional network

As indicated in section 2.3 above, transmission network losses do not represent transmission (infrastructure) costs; however, they emerge from the transmission of power over the network and their cost might need to be properly allocated in the context of cross-border/regional exchanges of power.

There are typically two ways in which System Operators recover the losses or their costs in a single-system setting:

- Physically, by requiring generators to inject more power than what they have commercially sold and/or consumers to withdraw less power than what they have commercially bought, by the application of predefined loss factors.
- Economically, by charging generators and/or consumers for the cost of losses, which the System Operator procures on the market.

[31] This section can be ignored if there are already difficulties in implementing what has been proposed so far. However, it must be considered that solar and wind power plants can be deployed in many sites. Locational transmission cost signals can guide towards the deployment of these plants in places where the incurred costs of transmission expansion are lower or even negative, leading also to relieving network congestion as a result.

In both cases, it is necessary to determine the responsibility of each network user (generator or consumer) or set of users for the losses on the system. As the level of losses directly depends on the current flowing over a specific network element (losses increase with the square of the current), losses could be allocated to the different network users by performing a “with and without” analysis, i.e., by computing the flows on the network elements, and therefore the losses, with and without the injection or the withdrawal of power by each network user based in each country. Note that, in defining the two scenarios (with and without the injection or the withdrawal of power by each network user) an optimal power flow – economic dispatch – analysis needs to be performed to determine the optimal pattern of injections in these scenarios. Note moreover that, in the case of transmission losses, the users-pay principle is not a second-best to the first-best beneficiaries-pay principle, but represent the most appropriate way of allocating losses to different network users.

In the case of the economic allocation of losses, a value of losses would also need to be determined, but this is not a major problem if losses are, in this case, procured through a competitive procedure (e.g. through an auction).

A similar approach could be used in the context of regional power exchanges, to determine the responsibility of each country in creating losses in other countries’ networks through the exchange of power between them (and other countries). Also in this case, a “with and without” analysis could be performed, where the analysis compares the flows of power, and therefore the losses for each network element and for the network of a country as a whole, with and without the exchange of power with other countries. Also in this case, an optimal power flow analysis should be performed to determine the pattern of injections in the two scenarios.

Moreover, also in this case, the losses could be recovered physically – i.e., by requiring the other countries to transfer more power into the local system or less power out of the local system, again based on some pre-defined loss factors – or ecumenically – i.e., by payments between countries.

Note that cross-border exchanges of power do not necessarily increase the level of losses in a country, if such exchanges reduce the loading of transmission assets in the country, i.e., generate flows on the network which move in the opposite direction to the flows generated by internal exchanges in that country. Whether such a situation should lead to the country compensating the other countries for reducing losses on its own network is debatable and it is a matter of agreement.

Appendix: Cost Allocation Methods

This appendix contains a brief description of some of the best-known methods for allocating transmission grid costs. All these methods have been or could be applied for the allocation of transmission costs at country level. Most of them (all, except for Ramsey Pricing), or modified versions of them, have been used or proposed to be used also at regional level. The fact that they are described here does not mean that they are necessarily recommended. Figure 8 shows these methods and their adherence to the first and second principles presented in section 3.

A.1 Economically-based methods

The methods that are based on the second principle of transmission pricing – beneficiaries pay and its symmetrical responsibility for investment - have been already discussed. Only a brief account will be provided here. Even if their application is difficult in some cases, they should be the conceptual reference or guide for any other cost allocation schemes.

A.1.1 Beneficiaries pay

It is the standard regulatory test that an investment in a new transmission asset is justified when the value of the aggregated net benefits that the asset delivers over its estimated lifetime to all the players, producers and consumers, is greater than the overall cost of the asset. Therefore, conceptually speaking, the transmission charging procedure would consist in allocating the additional grid cost in proportion with the benefits that the grid affords to each of its users.

The beneficiary-pays method entails assessing the total benefits – including the non-monetisable ones - that each grid user obtains from the existence of each individual transmission facility and allocating the cost of that facility among the players in proportion to the benefit obtained.

As noted above, when investment in a facility is justified, the accumulated benefits exceed its cost. Therefore, if the charges are applied in proportion to the obtained benefits, users do not pay additional charges greater than the benefits deriving from the line. One of the primary virtues of this method, then, is that it is based on a fully justified economic principle, guaranteeing that the economic efficiency of long-term users' decisions is not distorted.

The main problem in implementing this method is the difficulty in accurately estimating the benefits accruing to each network users. The computation of the benefits depends, in any case, on multiple assumptions and information. Furthermore, some of the benefits might not be directly monetisable.

The application of the beneficiaries pay principle involves further challenges when applied to network lines that have existed for some time. Two typical situations have been found in practice. In the first one, eliminating the considered line means chaos in the power system, resulting in some permanent unmet demand. Obviously, this would never happen in an actual power system and the without-the-line counterfactual is nonsensical, as other measures would have been taken, in the absence of the line, to supply the entire demand. In the second situation, the removal of a line has basically no economic impact on the network users when the power system has enough built-in redundancy, and only sophisticated reliability analysis could detect any differences. Most cases lie in between these two extremes.

Despite the above difficulties, the beneficiary pays concept inspired the regulatory approaches adopted in Argentina (1992) and California (1998). Presently it is considered the guiding principle that should inspire any grid charging schemes, either implemented or under consideration.

A.1.2 Responsibility for investment

This method seeks to allocate transmission costs on the basis of the responsibility for investment, which is consistent with the economic principles set out above. It involves evaluating the additional grid investment costs induced by each user (known as deep connection costs[32]), in addition to the strict connection costs (known as shallow connection costs). In other words, transmission charges are calculated in proportion to the extra investment cost that some algorithm estimates that is occasioned by each user. The method has been in use in the UK (ICRP, investment cost-related pricing) and Colombia. Its implementation difficulties have been widely recognised (refer to (Hogan 2018)).

A.2 Network utilisation methods

As indicated previously, there is no unquestioned way of quantifying unambiguously the utilisation of a transmission network by its users. As the results obtained may depend largely on the method adopted, the choice of one or another method is not immaterial. The technical literature contains a plethora of approaches that have been proposed or actually applied. Here a selection has been made that contains some of the most popular ones: contract path, MW-km or MW-mile, marginal participations and average participations. Just a few of them seem to be able reasonably to approximate the second principle of cost allocation, while it is easy to find case examples indicating flagrant flaws in most of the others. Detailed critical evaluations can be found in (Pérez Arriaga, Olmos Camacho, and Rubio Odériz 2002).

A.2.1 Contract path

This is the most rudimentary of the network utilisation methods, and one that has been widely used in the past. It clearly violates the first principle of cost allocation presented in section **Error! Reference source not found.** above. In the contract path method, the cost of a given transmission grid service is calculated from the path that the energy is deemed to follow from the point of injection to the point of withdrawal (contract path). The route taken by electric power between these two points is determined by mutual agreement among the parties. In other words, buyer, seller and the transmission company agree to the most logical path that energy should follow over the grid for the intents and purposes of establishing grid charges. Such charges are then determined as a fraction of the cost of the lines where the transaction flows.

This method was developed in the context of the use of the transmission network for bilateral trading –known as wheeling– that preceded the creation of organised wholesale markets, an arrangement where two typically vertically integrated utilities agreed upon a transaction that crossed a third company's grid.

When applied in a multi-system context, this method also consists of determining the group of transmission systems that every transaction is deemed to cross to reach its destination. This usually leads to payment of a toll for each system crossed. The result is known as pancaking, i.e., the toll paid is the result of summing or piling up the tolls stipulated by each of the crossed systems. The fact that the result depends on how the boundaries between systems are defined is an indication that this approach, which obviously discourages energy trading, is fundamentally flawed.

A.2.2 MW-km

The MW-km (obviously, also MW-mile) is one of the earliest methods that attempted to provide a more precise measure of grid usage, taking not only the MW transmitted, but also the length of each line used, into consideration. The underlying principle is that it should not cost the same to transmit 10 MW over 100 km as it does over 10 km: grid use is not the same and this should be factored into the transmission charge. Again, this is a violation of the first principle of cost allocation presented in section **Error! Reference source not found.** above.

The method first defines a baseline case with a load flow regarded as representative of system operation and including all the transactions to be analysed. The resulting transmission flow in MW in each line is multiplied by the length of the line in km, and all the resulting products are summed. This gives the total MW-km associated with the baseline case. One of the transactions is then eliminated and a new load flow is computed. The total MW-km is then found for the new situation. The difference between the two sums is the amount of MW-km attributable to the transaction eliminated from the second calculation. The sum to be paid for the transaction is

[32] The terms shallow or deep applied to grid costs or charges are used to differentiate the grid investments required physically to connect a new agent to the system (i.e., a line or transformer exclusively for that agent) from grid reinforcements of existing grid required to evacuate the power produced by the new agent.

found by multiplying grid costs in the baseline case times the fraction, in MW-km, that the transaction represents of the total in the baseline case. This is repeated for all transactions.

This method has been and continues to be widely used. However, it is based on an incorrect assumption, since transmission charges should not be made to depend upon commercial transactions.

A.2.3 Marginal participations

The marginal participations (MP) method distributes line use, and consequently cost, on the basis of the marginal effect that each consumer or generator has on the flows over each line. The effect on the grid is obtained by calculating the variation in all flows when a user's consumption or production is increased by 1 MW. This is repeated for each network user and for each one of the representative scenarios that are considered. The variation in the flow obtained for each line, player and scenario considered serves as a basis for calculating a value that provides a measure of electricity system use. This value is the sum of the products of the variation in flow in each scenario times the power consumed or generated by the user in question, times the duration in hours of the scenario. The sum of the effects found for a given player on all the grid facilities is divided by the sum of the impact of all users on those facilities to find the proportion of the grid cost to be paid by the player.

All this seems very reasonable, but there is an underlying assumption that, in the opinion of the authors of this document, renders the method useless. In order to calculate the marginal effect caused by each user, a slack bus or balance node that responds to the increases in generation or demand must be defined, since the balance of generation and demand in the grid has to be maintained at all times. The choice of the location of the slack bus in the system conditions the absolute results obtained for each player, although not the relative differences among the absolute values, which remain constant regardless of the slack bus chosen (Vazquez, Pérez-Arriaga, and Olmos 2002). Therefore, all the allocation factors obtained with any choice of slack node or combination of slack nodes are fatally flawed since the main underlying assumption is totally arbitrary. Thus, it is very questionable that these figures should be used as a measure of the use of the line. The arbitrariness in the choice of the slack node would become even less acceptable when computing network charges in a multiple power system context, i.e., in regional or multinational systems, such as the EU's Internal Electricity Market, the Central American Electricity Market or any of the U.S. Interconnections.

Variations of this method with additional features that try to counteract up to a point the fatal flaw of the MP method are used in the Argentinean and Chilean electricity systems, where it is known as the areas of influence ("*areas de influencia*") scheme[33]. A similar method, known as CRNP (cost-reflective network pricing) is in place in Australia. A more sophisticated version of this method is used in the Single Electricity Market of Ireland, whereby the incremental flows created by a network user only count towards its network charges when these flows coincide in direction with the existing flows in the baseline or reference case. We have been magnanimous with the MP method in Figure 8, accepting that it satisfies principle 2. Unless it is conveniently tweaked, it does not.

A.2.4 Average participations

The average participations (AP) method is based on the actual pattern of grid flows. Application of a simple heuristic rule allows to trace upstream each flow withdrawn from the grid and to trace downstream each flow injected into the grid, in order to determine the fraction of the flow of each line that can be attributed to each generator and demand at any given instant of time. The heuristic rule that is used by the algorithm is very simple: At any branching point in the network (a node), any injected or withdrawn flow in a transmission line divides exactly in proportion to the values of the existing total flows. This rule makes much intuitive sense, but it cannot be proved to be accurate since: as indicated in section 2.1 above, electricity does not propagate as water in a pipe and it cannot be traced or ascribed to any specific line.

[33] As an explanation of the choice of this method in Chile or Argentina, it may be argued that the slack bus has been placed in the very dominant load centre (Santiago and Buenos Aires, respectively). In this way most of the demand does not pay (in Argentina demand does not pay transmission charges at all, anyway) and the charges to generators grow with the distance to the main load centre, as one should reasonably expect.

The main advantages of this method are its simplicity and clarity of use, and the absence of the problems involved in marginal methods since no slack bus is involved. In the extensive experience with the AP method of the authors of this document, no case examples that question its soundness have been found.

This method has been applied by New Zealand's Trans Power[34], by the Polish grid company and, more recently and with additional features, in the Central American electricity market and in India (see Box 4 below). The cost allocation method that the Southern Africa Power Pool is presently considering adopting is largely based on AP.

The AP method is not the only network utilisation method that appears to yield reasonable results. A very different but sensible approach is the Aumann-Shapley approach (Junqueira et al. 2007). Both methods have given very similar numerical results when applied to the same case examples. However, the Aumann-Shapley approach can be seen as more complex.

A.3 Methods without locational components

Current approaches to transmission cost allocation in most countries do not include any locational components. This is not desirable in general, particularly with the current trend towards deployment of wind and solar generation in a multiplicity of locations and with the integration of power systems into larger regional or multinational grids.

A.3.1 Postage stamp

This very popular method consists of covering the total transmission costs by applying a uniform rate to all network users based on some simple measure of transmission utilisation. In practice, this results in a uniform charge per MW connected or per MWh injected into or withdrawn from the network to recover the allowed revenue requirement. This is the method used in most European countries, by many U.S. electric utilities and many countries in the world. The charge is frequently applied only to consumers. Sometimes different charges are computed for consumers and generators, based on a priori breakdown of the total transmission cost into two –more or less arbitrary– fractions.

The name postage stamp refers to the fact that the transmission charge is wholly unrelated to the place where power is injected or withdrawn. These charges entail no geographic differentiation that can convey suitable locational signals to steer the siting of new production or consumption installations towards the locations where they cause the least stress to the system as a whole. This simple method may only be recommended when grid characteristics require no further sophistication, i.e., densely meshed grids with low demand and generation growth and requiring no major reinforcements.

A.3.2 Ramsey pricing

Some electricity systems have well-developed grids that would not benefit greatly from locational signals and do not need additional grid investments that could potentially benefit some users much more than others. In such systems, providing that short-term loss and congestion signals are conveyed in one way or another, the primary aim of grid cost allocation should be to interfere as little as possible with the market and investment decisions that players would take if there were nothing to allocate. Under these circumstances, the second-best or Ramsey approach may provide a valid justification for some cost allocation decisions. Ramsey pricing aims to allocate most of the grid costs to users that are the least elastic to the resulting charge. Under conditions of perfect competition (which rarely occur in real markets), generator elasticity to additional charges is very high, and any network charges to generators would ultimately fall on the consumers. Therefore, in a sufficiently competitive market, transmission network costs should be allocated primarily to consumers, charging the least

[34] A first reference to this method was found by the authors of this document in a paper of Trans Power by the professor of the University of Canterbury, Grant Read: Pricing and Operation of Transmission Services: Long Run Aspects in Turner, A. Principles for Pricing Electricity Transmission, Trans Power August 1989. More recent references are (Bialek 1996) and (Kirschen, Allan, and Strbac 1997).

elastic demand (typically domestic consumers, in more developed countries, at least) more than the most elastic demand (typically large industrial consumers).

In India, the States are responsible for managing and regulating state transmission networks through state load dispatch centers (SLDCs) and the state electricity regulatory commissions (SERCs), while the Inter-State Transmission System (ISTS) is managed by regional load dispatch centers (RLDCs) and the National Load Dispatch Centre (NLDC), and regulated by the Central Electricity Regulatory Commission (CERC). All the regions are synchronously connected. In June 2010, the CERC issued the Sharing of Transmission Charges and Losses Regulations for the ISTS. The Sharing Regulations introduced a comprehensive overhaul of the ISTS's cost allocation framework. At the heart of the framework is the shift from a regional postage stamp methodology to a usage-based hybrid method, called the Point of Connection charging method (the PoC method), which allocates the cost of transmission to ISTS customers (generators and distribution companies, charged 50:50) based on their geographical location on the ISTS. The method was implemented to eliminate the pancaking charges and encourage customers to make decisions that reduce congestion.

The PoC method consists of three calculation stages: In the first stage, the cost of the ISTS is allocated to the network users, who create the flows in this network using a combination of the Average Participations and the Marginal Participations methods. In the second stage, an India-wide uniform charge is added. Lastly, in the third stage, the charges computed that far are grouped into one of three slab rates. The second and third stages involve the application of national rules to add a "socialized" component to the final transmission charges applied and, hence, are irrelevant in a regional context. Stage 1 of PoC consists of five implementation steps:

Step 1 Development of full grid data for each seasonal period: The NLDC gathers information about the basic network for five seasonal periods throughout the year, and two times of day: peak, and "other-than-peak". Considering seasonal differentiation is essential for greater accuracy in estimating the overall annual network usage since different seasons see different flow patterns.

Step 2. Network truncation: Several load flow analyses are conducted to identify the ISTS network and model the actual use made of it. The overall grid is truncated by removing the intra-state networks from it. Truncation is performed according to the flow and the voltage level of each line (which differ across regions). In a regional context, this step is equivalent to identifying those assets belonging to the regional network.

Step 3 Defining slack buses: Slack buses are the nodes on the grid that are deemed to balance the injections and withdrawals in these and other buses. The slack buses are identified using AP method to determine which generators supply power to each demand. According to AP method, the generators in power-deficit regions tend to supply largely the demand in the states where they are located, while the generators in power-surplus regions serve demand in other regions as well as in their own. The flow patterns considered in this step and the next step are based on a forecast for next year.

Step 4. Applying MP to determine the flows created by each generator and load entity at each node considering the slack buses for these determined in Step 3: The NLDC runs an AC load flow for the projected nodal injections and withdrawals. The model calculates how much the flow in each network branch increases when the injection or withdrawal at a bus is increased by 1 MW, and the slack buses computed for this in Step 3 are considered. This yields the marginal participation factor and loss allocation factor on each line for each customer.

Step 5. Grouping nodal charges into zones: Geographically and electrically contiguous nodes whose charges are in the same range are grouped into zones and assigned a PoC zonal charge. For withdrawal charges, which distribution entities pay, the zones are generally made to coincide with the State boundaries, whereas, for injection charges, which generators pay, the zones are groupings of electrically close generators or even individual generators. Losses are also allocated by zone. They are attributed to the demand entities in this zone. Then, the amount of energy scheduled for each entity includes the one it is consuming and the losses allocated to it.

Box 4: Transmission cost allocation between the different states in India.

Some countries apply Ramsey pricing, more or less explicitly, in the design of their slightly more complex postage stamp transmission network tariffs.

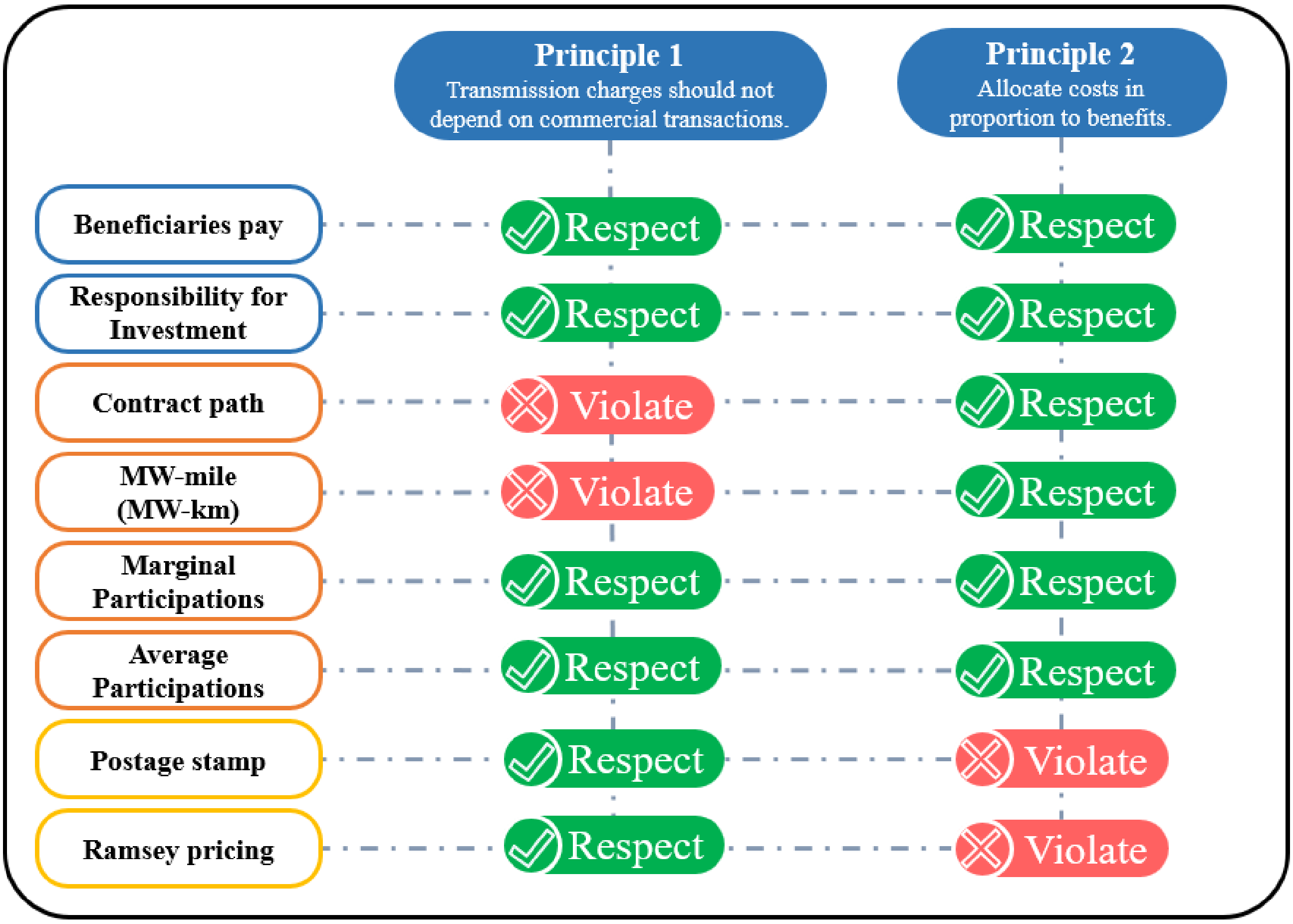

Figure 8: Cost allocation methods and their adherence to principles 1 and 2.

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