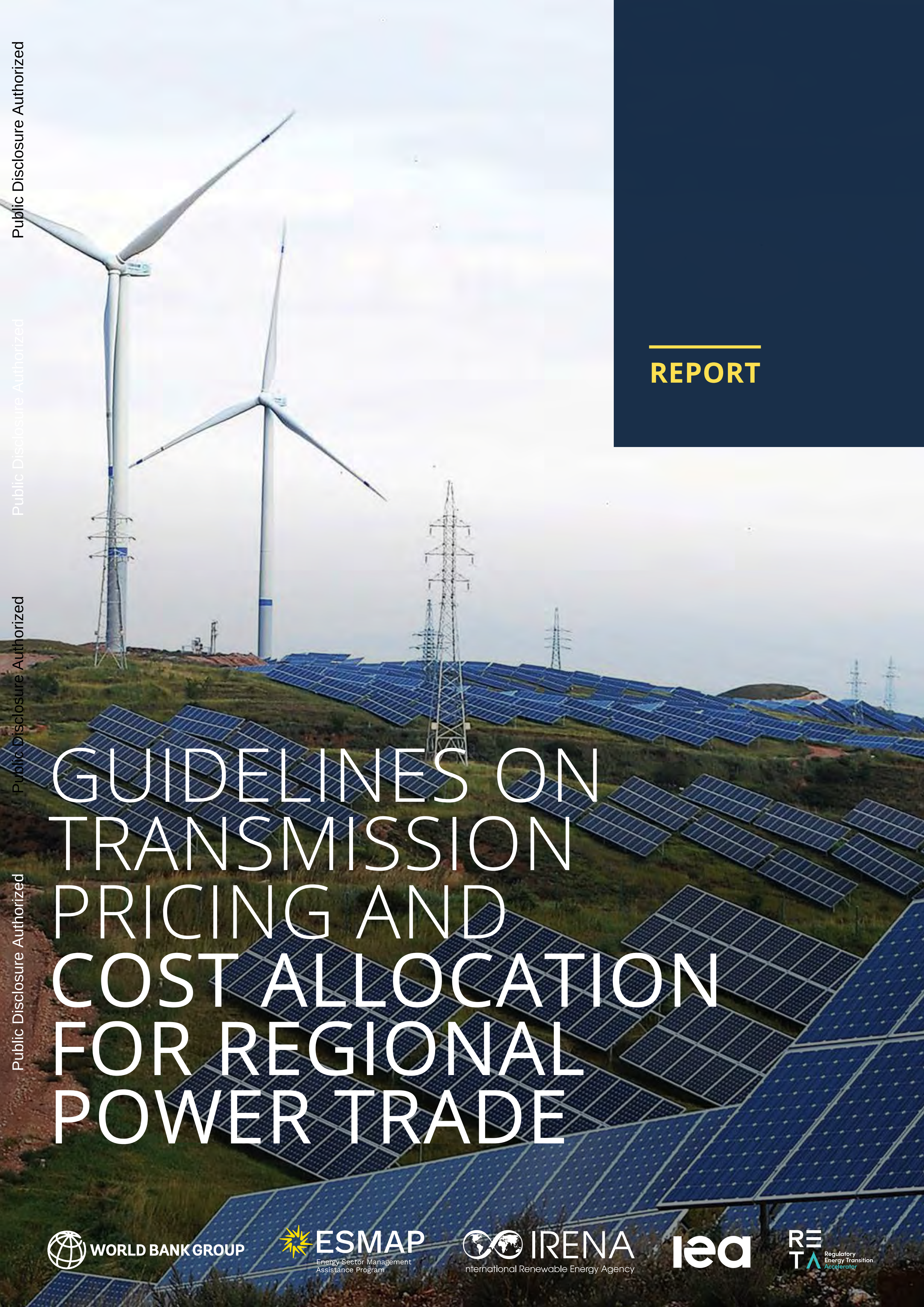

REPORT

GUIDELINES ON TRANSMISSION PRICING AND COST ALLOCATION FOR REGIONAL POWER TRADE

WORLD BANK GROUP
ESMAP
Energy Sector Management Assistance Program
IRENA
International Renewable Energy Agency
iea
RETA
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Acknowledgments

This paper was developed by the team from the Energy Markets, Connectivity, and Regional Trade (MARCOT) program, part of the World Bank-administered Energy Sector Management Assistance Program (ESMAP). The core material was prepared by Professor Ignacio Pérez-Arriaga,[1] Dr. Alberto Pototschnig,[2] and Mr. Mohamed A. Eltahir Elabbas.[3] The paper was reviewed by the MARCOT team members including Pedro E. Sanchez, Naoki Fujioka, and Debabrata Chattopadhyay.

The paper also benefited from a review and inputs from Waleed Saleh I. Alsuraih, Bipul Singh, Mohamed Zakaria Kamh, Tatyana Kramskaya, and Tom Remy, as well as from the team of Delivery Partners of the Regulatory Energy Transition Accelerator (RETA), which includes the International Energy Agency (IEA) and the International Renewable Energy Agency (IRENA).

Overall guidance was provided by Fanny Missfeldt-Ringius and Chandrasekar Govindarajalu, ESMAP Practice Managers.

Endnotes

1. Interim Director of the African School of Regulation (ASR), Professor at the Institute for Research in Technology (IIT), Comillas Pontifical University; Research Affiliate, MIT. ipa@mit.edu
2. Part-time Professor and Deputy Director (World of Practice) of the Florence School of Regulation, European University Institute and Director, DFC-Economics. alberto.pototschnug@dfc-economics.com
3. Research Assistant at the Institute for Research in Technology (IIT), Comillas Pontifical University. Mohamed.a.eltahir@hotmail.com

Abbreviations

CERC	Central Electricity Regulatory Commission
DC	Direct Current
EU	European Union
FERC	Federal Energy Regulatory Commission
ICRP	Investment Cost-Related Pricing
IRENA	International Renewable Energy Agency
ISTS	Inter-State Transmission System
MARCOT	Energy Markets, Connectivity, and Regional Trade (ESMAP initiative)
NLDC	National Load Dispatch Centre
O&M	Operation and Maintenance
PoC	Point of Connection
RTO	Regional Transmission Organization
RTR	Red de Transporte Regional
SAPP	Southern African Power Pool
SIEPAC	Central American Electrical Interconnection System
TSO	Transmission System Operator
UK	United Kingdom
US	United States

All dollar amounts ($) are US dollars unless otherwise indicated. The word “cents” refers to US cents, unless otherwise indicated.

Executive Summary

Regional transmission infrastructure, connecting different jurisdictions, is a fundamental component of cross-border power exchanges. It plays a pivotal role in decarbonization efforts by facilitating the integration of diverse low carbon energy sources, enabling countries with abundant renewable resources to export clean energy to areas with higher demand. It also contributes to enhancing the overall flexibility, resilience, and reliability of the power system.

Ensuring open and non-discriminatory access to the regional transmission system and electricity market is essential for fostering regional electricity trade and maximizing its benefits. An effective regulatory framework for regional electricity trading should encompass market rules, grid codes, and transmission tariffs, as well as a regional mechanism for enforcing these rules and resolving disputes. This document focuses on transmission cost allocation and pricing.

Approaches that policymakers and regulators around the world have traditionally employed to allocate the costs of cross-border electricity transmission lines and associated infrastructure typically involve:

- Dividing the costs among the countries involved in electricity exchanges in proportion to the length of the lines within their respective territories, known as the 'territorial principle'; and
- Selectively allocating costs among electricity sector agents, namely, individual generators, utilities, distribution companies, or large consumers engaged in cross-border power transactions.

However, such conventional approaches have inadvertently led to distortions in cross-border electricity trade and have discouraged investments in cross-border infrastructure.

The guidelines presented here advocate for an approach to allocating transmission costs and setting transmission tariffs for cross-border electricity trade that overcomes the drawbacks of the conventional approach. The proposed approach is based on the 'single system paradigm,' which requires that regulation for regional power trade should treat all trade in the region as if it happened within a single jurisdiction. A well-designed transmission tariff must balance cost recovery, economic efficiency, fairness, and predictability. Given these objectives, the allocation of transmission network costs among users should adhere to the following fundamental principles.

- **Principle 1: Transmission charges must cover the recognized costs of transmission activities** to reflect the cost imposed on the transmission network and returns on investment.

- **Principle 2: Transmission charges are independent of individual commercial transactions** since commercial transactions have no influence on the physical network flows. For cross-border power exchanges, this principle requires that costs are primarily allocated to countries rather than individual agents, thereby preventing tariff pancaking.
- **Principle 3: Allocation of costs in proportion to benefits** to ensure equitable cost allocations and to facilitate agreements on new transmission projects. Benefits are often difficult to quantify because they occur over a long period of time and are driven by factors many of which are intrinsically uncertain, and therefore may need to be proxied by usage. The ‘average participation’ method has proved to be the most robust approach for cost allocation based on usage.
- **Principle 4: Cost allocation rules should remain stable for a reasonably long time** to provide stable and predictable tariffs and avoid introducing uncertainty that could raise capital costs for transmission projects.
- **Principle 5: Non-distortionary transmission charges structure** to avoid operation and investment distortions. Ideally, transmission costs should be charged as an annual lump sum.

When implementing a transmission cost allocation approach at the regional level, it is desirable to have a specialized framework, such as a regional regulatory authority or an entity capable of effective dispute resolution and enforcement.

In allocating the costs of transmission network elements with regional relevance, i.e., those that support cross-border power exchanges, and setting transmission tariffs for cross-border electricity trade, the following process is recommended:

1. **Identify transmission network elements with cross-border relevance:** Transmission elements with cross-border relevance are crucial for enabling physical transfers of electricity among countries, and their costs should be allocated across borders to all beneficiaries. These elements include not only inter-country lines but also internal domestic lines that support power wheeling between interconnectors.
2. **Define revenue requirement for cross-border transmission assets:** National regulators must determine the overall revenue requirement for cross-border transmission infrastructure assets. A standardized methodology for valuing these assets and calculating capital and operation and maintenance (O&M) costs should be agreed upon.
3. **Allocate the overall revenue requirement for the transmission assets with cross-border relevance to involved countries:** The allocation of costs for cross-border transmission projects can sometimes be done using ad hoc rules, which may, or may not, follow established guidelines. Regardless of the approach, costs should be allocated at a country level among the nations benefiting from the asset, rather than directly to individual agents within those countries. The recommended option is as follows:
    a. Apply the average participation method to determine each importing and exporting country’s contribution to the usage of each transmission network element with cross-border relevance.
    b. Allocate the cost of each transmission network element with cross-border relevance to the different countries based on their usage contribution; and

   c. Determine the cost allocation of the transmission network with cross-border relevance to each country as the sum of the country’s contribution to the costs of all regional network elements.
4. **Finally, determine national transmission charges:** After the overall revenue requirement for cross-border relevance assets is defined, the national regulatory authority of each country determines the modified transmission revenue requirement for computing the regulated transmission charges in their own country.

ONE

DEVELOPING POWER POOLS

Cross-border power exchanges can be arranged under unregulated bilateral agreements, coordinated operations of different power systems, or through wholesale electricity markets. Power pools, as a mechanism for electricity exchanges among vertically integrated utilities (therefore, in the absence of local wholesale markets[1]) already existed in the 1970s in several United States (US) regions. These power pools were characterized by a least-cost centralized dispatch, namely, the most efficient generation units available were utilized to meet the aggregated demand of the power pool at all times (subject to transmission constraints). The participants in some power pools even developed joint plans for expanding transmission capacity and, sometimes, generation capacity. In different parts of the world, especially among neighboring emerging economies, other cross-border regulatory arrangements are evolving at the bulk power system level, typically without competitive markets at the national level. Given the diverse range of situations, these guidelines avoids the term “market” when referring to these situations and uses the term “power system organizational structures” or simply “power pools,” as recently suggested by the International Renewable Energy Agency (IRENA).[2]

Developing regional transmission infrastructure which connects different jurisdictions, is the cornerstone of cross-border power exchanges. A robust and interconnected transmission network enables the optimization of resource utilization by balancing supply and demand across borders. Such infrastructure plays a pivotal role in decarbonization, as it integrates 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 power system’s flexibility, resilience, and reliability, facilitating greater renewable energy penetration and ensuring a stable, uninterrupted power supply. Thus, addressing issues related to regional transmission infrastructure should be a high priority for any cross-border regulatory arrangement in the energy transition.

Ensuring open and non-discriminatory access to the regional transmission system and electricity market is crucial for promoting regional electricity trade and maximizing its benefits. This creates a level playing field where all market participants can compete fairly. A robust regulatory framework for efficient regional electricity trading should include commercial rules (market rules), technical rules (grid code), and pricing rules (transmission pricing), along with a regional mechanism for enforcing these rules and resolving disputes. Market rules provide clear and consistent guidelines for participation, trading processes, and settlement mechanisms, ensuring fairness. The grid code defines operational standards and requirements for maintaining system reliability and stability, preventing discriminatory practices. Transmission pricing establishes transparent and equitable methods for charging access to the network, avoiding practices that could hinder market entry or distort competition. Together, these elements create a comprehensive framework that supports efficient regional power exchanges.

When it comes to transmission pricing, it has been a common practice for 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 has prompted a reevaluation of who should bear the transmission costs, particularly those of cross-border transmission lines. At the national level, the intuitive solution has been to allocate the costs of interconnection lines only to the agents that engage in cross-border transactions – such as individual generators, national utilities, distribution companies, or large consumers. The paths of these transaction's physical power flows are typically determined by sophisticated engineering methods such as load flow models.

This approach to allocating the costs of cross-border transmission infrastructure was prevalent in the early stages of electricity trading among different jurisdictions – countries, or states and utilities within countries – in most regions of the world. However, this approach might not always allocate transmission costs to those who actually benefit from the trading or are responsible for the related costs. Moreover, it often results in excessive charges for cross-border trade, as commercial transactions rarely affect the physical flows in the regional network and its utilization.[3] The consequences of this approach have been an undue suppression of cross-border trade and a disincentive for investment in cross-border infrastructure.

This report presents the fundamental principles underpinning the allocation of transmission costs and offers guidelines to assist energy regulators in translating them into actionable rules, with a focus on cross-border electricity trade, while also considering the necessary coexistence with national regulation. Although there is a rich literature on transmission regulation and pricing, there are certain idiosyncrasies for cross-border transmission infrastructure that requires special attention for cost allocation. However, these cross-border transmission-specific issues are often not spelled out clearly, and navigating through multiple ad-hoc arrangements around different jurisdictions is difficult. This report is intended to provide a simple summary of the core principles that should guide cost allocation and pricing, present the popular regulatory models, and recommend a set of practical guidelines to implement them.

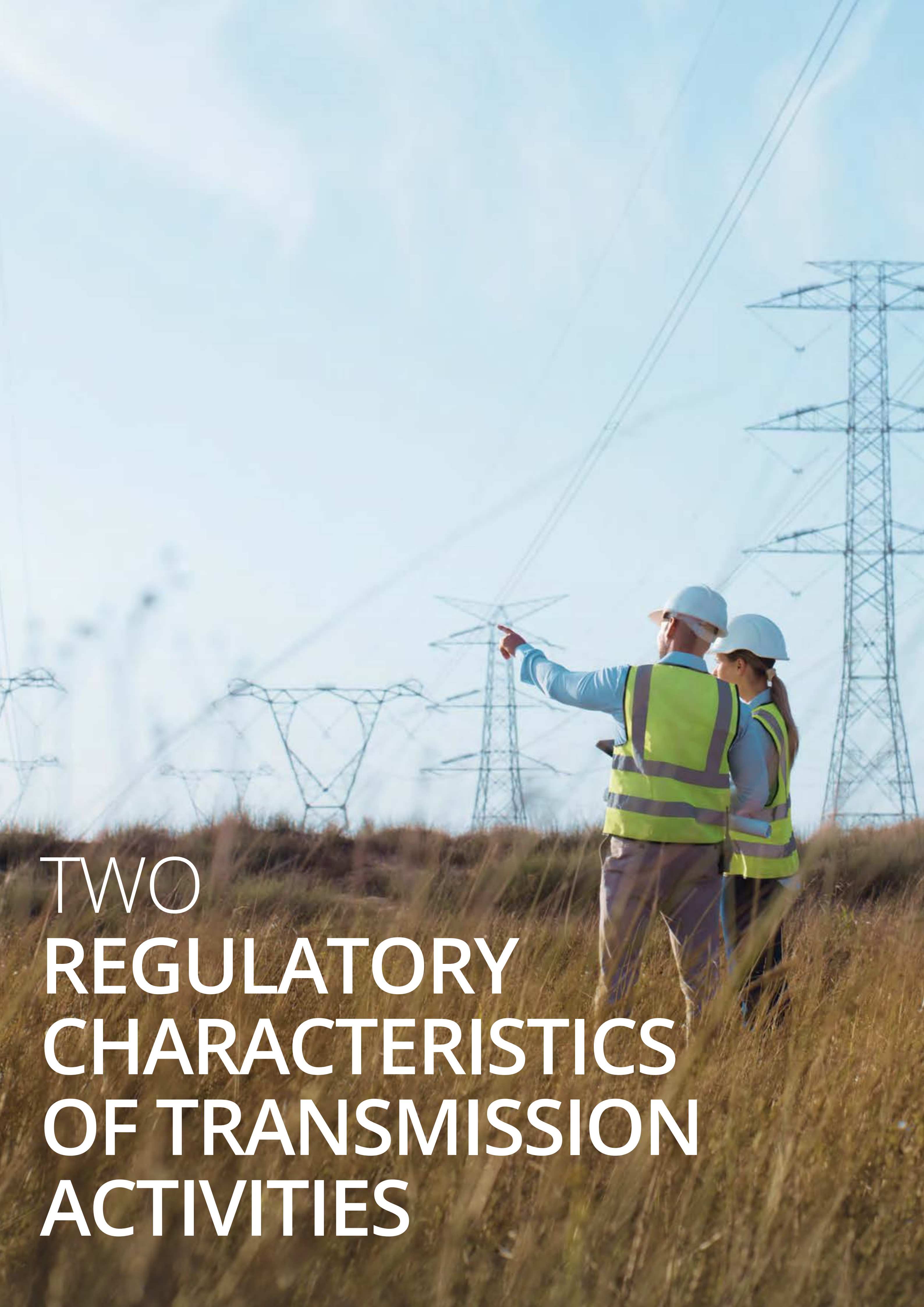
The report is structured into four sections. Section 2 provides a brief illustration of transmission activities, their nature, and the regulatory needs within the transmission business. Section 3 delves into the objectives and key regulatory principles of sound transmission cost allocation. Building on these, Section 4 applies the five regulatory principles presented in Section 3 to propose guidelines for transmission cost allocation at the regional level for cross-border transmission infrastructure.

Endnotes

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 organizational 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 liberalized power systems (based primarily on market mechanisms) to vertically integrated systems. For a liberalized

power system, the term power market is equivalent to a power system organizational 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 generalized 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.



TWO

REGULATORY CHARACTERISTICS OF TRANSMISSION ACTIVITIES

The design of appropriate regulation hinges on understanding the characteristics of the power sector. These characteristics, along with the role of electricity transmission in liberalized electricity sectors prevalent in many jurisdictions, are crucial in shaping the regulatory framework.

2.1 The Function and Nature of Transmission Infrastructure

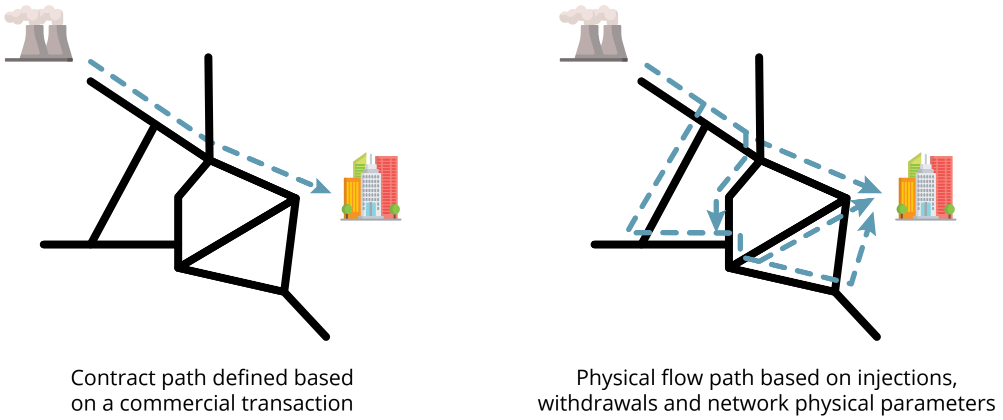
The transport of electric power differs fundamentally from the usual meaning of the term, which generally involves the physical movement of goods from a manufacturing plant to consumers. The transportation of electricity is a very complex phenomenon, and there is no straightforward way of attributing grid flows to individual system agents, despite numerous attempts that can be found in the technical literature. Unlike the vast majority of other network infrastructures, electricity cannot be directed through specific paths at will.[1] Adding new electric lines to an existing network alters the distribution of electric current across all lines, meaning that neither consumers nor generators can choose to use a particular line exclusively.

The technical characteristics of the electricity system play a critical role when designing transmission regulations. Energy flows and the use of electric lines are determined by the physical injections into and withdrawals from the network and the grid’s physical parameters, not by commercial relationships between market actors such as generators, retailers, and consumers. In well-functioning markets, the subset of generators that produce to supply the load[2] at any given time is chosen based on the least-cost dispatch. Therefore, the tariffs for using the transmission grid should reflect the physical location of agents in the network in relation to overall production and consumption patterns, rather than any notional contract path defined based on their (often private) commercial commitments, as shown in Figure 2.1. The left panel in this figure shows a likely commercial path that the generator and the consumer might consider reasonable. Yet, this path does not reflect the actual path of electricity flowing from the generator to the load, as depicted in the right panel. Hence, only tariffs that are detached from any hypothetical commercial path can justify allocating costs to the beneficiaries of the network. Such tariffs send accurate signals to network users, reveal the need for network reinforcements, and incentivize generation investment where it is most needed.

Additionally, electricity transmission is a natural monopoly due to significant economies of scale; a single, larger network is more cost-efficient than multiple smaller ones to compete against one another. Therefore, transmission remuneration must be regulated to reflect the costs incurred in efficiently providing the service.[3]

FIGURE 2.1

Assets Used in a Contract Path Versus Assets Used in a Physical Flow Path


Contract path defined based on a commercial transaction

Physical flow path based on injections, withdrawals and network physical parameters

Source: Adopted from (Hogan 2016)

2.2 Transmission Costs

Transmission services encompass a range of cost components that are reflected in the transmission tariffs levied on grid users. These tariffs are designed to recover costs and foster efficiency and reliability in the transmission network operation. The share of transmission costs in the total costs of electricity supply varies widely depending on a country’s size and the geographical dispersion of its production and consumption centers. However, it is significantly lower than the share of generation and distribution costs, accounting for about 5 to 10 percent of the total cost of electricity delivered to consumers.

Typically, the cost components of transmission services include capital costs and operation and maintenance (O&M) costs. These are often collectively referred to as infrastructure costs, directly associated with the transmission infrastructure used for the primary function of transporting electricity from producers to consumers. Capital costs include the construction of infrastructure, equipment procurement, land and right-of-way acquisitions, and expenses for engineering, design, and legal services, as well as financing costs. They also encompass the costs for upgrading and expanding existing infrastructure to meet demand or replace aging components. O&M costs entail the ongoing expenses necessary to ensure the transmission system operates efficiently and reliably, including routine inspections, repairs, vegetation management, and administrative costs. Since O&M costs are roughly proportional to the volume of grid assets (approximately 2-3 percent of the investment cost; Zhang et al. 2021), total infrastructure costs can be considered to be driven primarily by capital costs.

There are also costs associated with system services that help maintain the stability and reliability of system operation. These include voltage control, frequency control, and blackout recovery services, which are normally classified as ancillary services. These costs are charged separately from the transmission tariff. In many electricity markets, the costs associated with these system services are typically borne by the system operator and then passed on to market participants (such as generators and consumers) through specific service tariffs, which may be separate from the transmission charges.

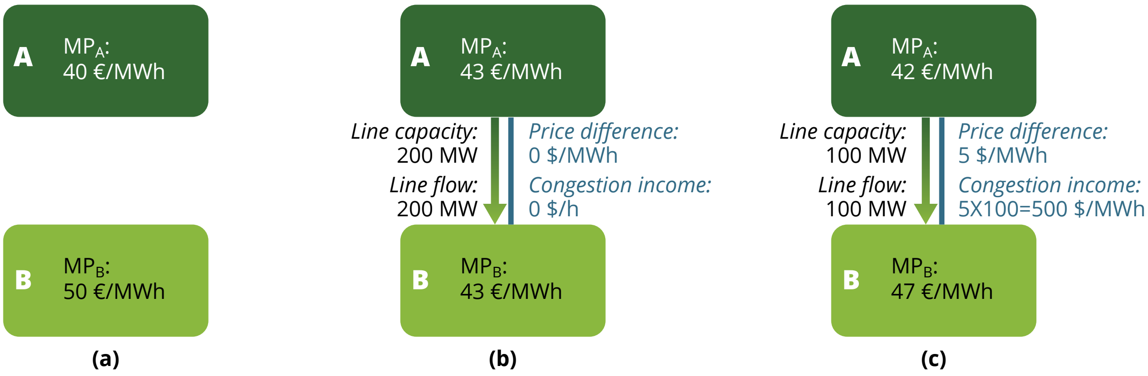
2.3 Congestion and Transmission Costs

There are additional costs associated with the use of the transmission system stemming from network congestion and losses. Transmission lines have a thermal capacity that restricts the amount of energy that can be transported, potentially leading to network congestion if demand exceeds this capacity. Other capacity limitations may arise from voltage constraints. Moreover, some energy is inevitably lost during transmission due to the physical characteristics of the lines and other system components, resulting in losses. It should be noted that these costs are independent of the cost of building and maintaining the transmission infrastructure.

On one hand, network congestion affects system operation when transmission lines reach their maximum load-carrying capacity while maintaining specified security levels. Congestion costs constitute additional generation costs occasioned by grid characteristics. In a regional context, congestion can lead to price divergence in different jurisdictions linked by congested network elements, resulting in the collection of congestion income, as shown in Figure 2.2. The two systems, A and B, are described in three scenarios: (a) separate; (b) connected with sufficient interconnection capacity; and (c) connected with insufficient interconnection capacity. Congestion happens in (c) due to the limited capacity, which allows for the collection of congestion income. It is important to note that the cost of this congestion is borne by the consumer in Region B, who faces higher prices in (c) compared to (b).

FIGURE 2.2

Market Prices, Line Flows, and Congestion Income for Two Systems (A and B)



On the other hand, network losses lead to additional system costs, like the cost of transmission congestion, because more energy has to be produced than is delivered to consumers. 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 aim to incentivize the reduction of the volume and cost of losses, for instance, by incorporating them into the system operator's incentive-based regulatory scheme.[4]

Transmission costs should include infrastructure costs associated with investing in and operating and maintaining transmission facilities. These costs are not influenced by the degree of utilization of the facilities. While congestion and losses occur within the transmission facilities, they are not, *per se*, considered transmission costs. The allocation of the costs associated with losses is discussed in Section 4.6.

2.4 Transmission Regulation at a Glance

The growing interconnectivity of countries and the trend towards the establishment of regional organizations to facilitate electricity trading across national borders pose new challenges for electricity network regulation. The anticipated surge in generation from renewable energy sources, particularly wind and solar, which are often located far away from load centers and have variable production patterns, requires an increasing level of sophistication in transmission regulation. This regulation must address key questions, such as:

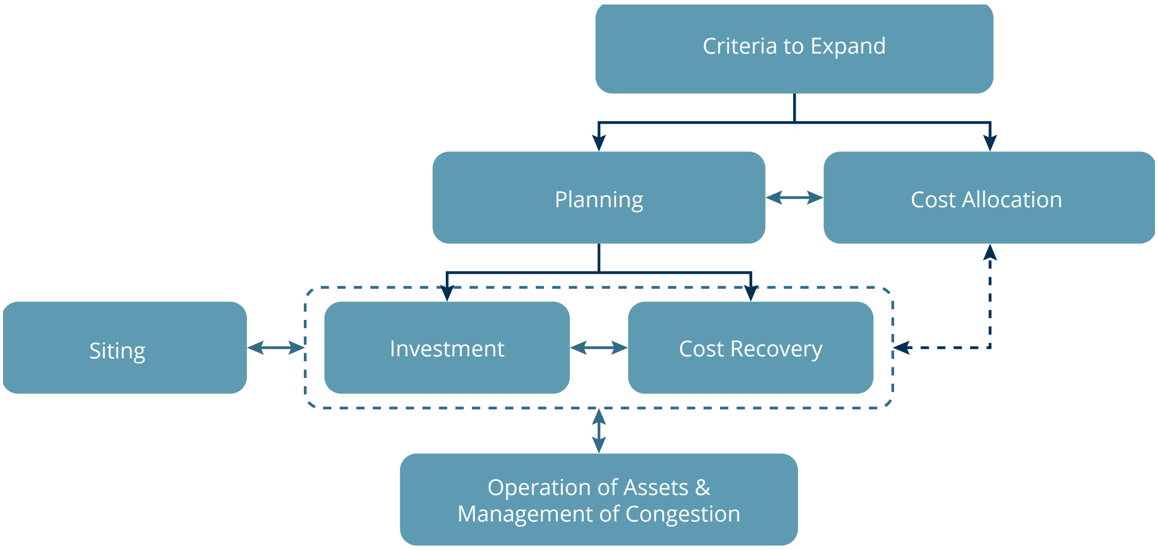
- Who should decide and execute network expansion and reinforcement when needed?
- Who is allowed to connect to the network, and what happens when it becomes congested?
- How should network costs be allocated?
- Who pays for the power losses in the network?

An integrated perspective of the major regulatory topics in transmission network regulation is depicted in Figure 2.3. Transmission planning involves identifying the most suitable network expansions and/or reinforcements based on predefined criteria. The costs of these expansions and reinforcements must be covered by those who require these assets ("causer") and/or benefit from them, linking network planning closely with cost allocation. Various business models may be available for investors to finance grid expansion projects, with cost recovery mechanisms being a key part of these models and directly related to regulation and cost allocation methods.

Siting is typically a difficult problem, because of the widespread opposition to the presence of transmission lines, and it is more of a social, environmental, and political nature. However, it can be facilitated if the cost allocation is perceived as fair and the benefits of new investments clearly outweigh the associated charges for all countries and local populations involved. Network operation is a separate topic, with the management of access to the grid's limited capacity being a major regulatory issue.

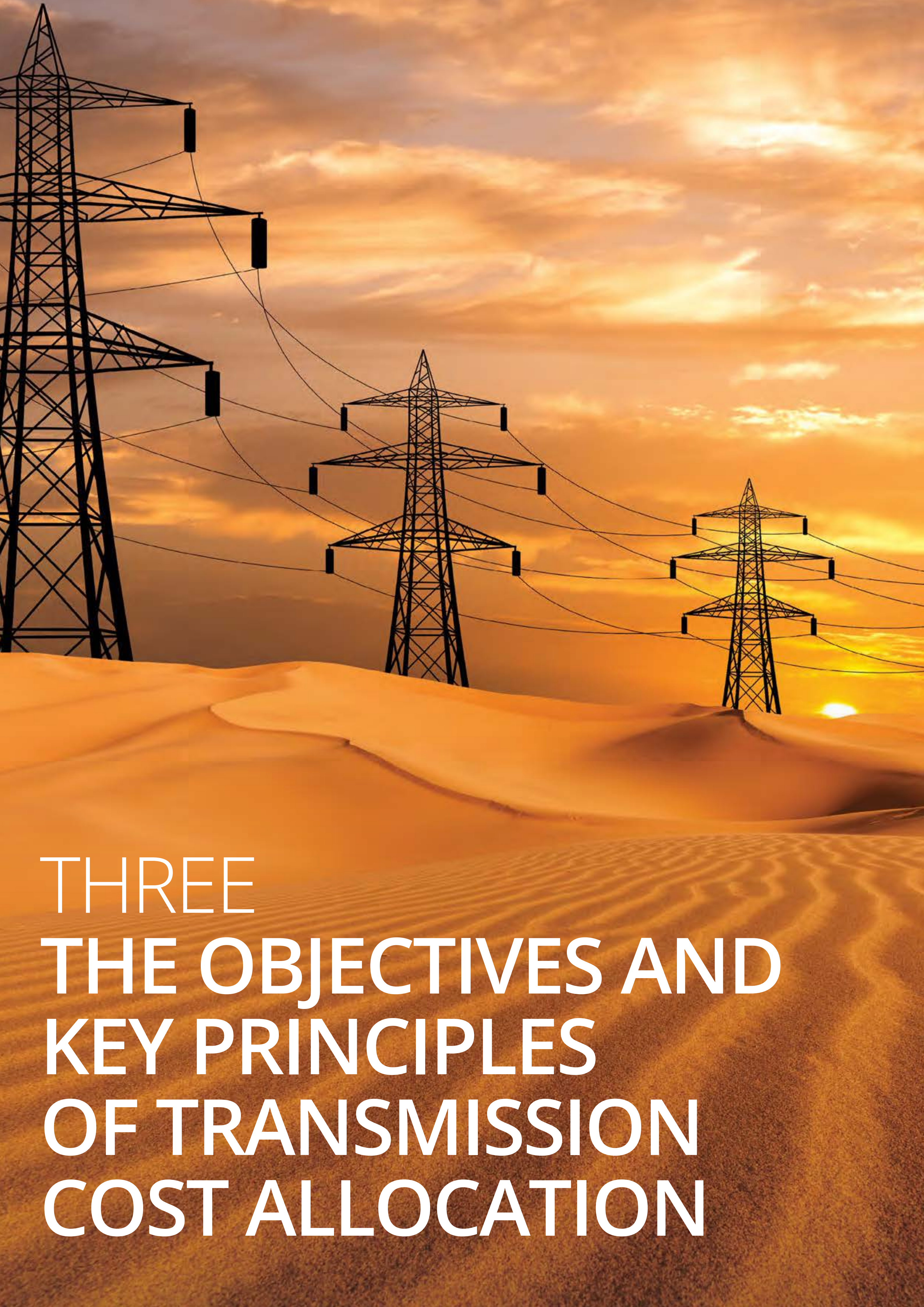
FIGURE 2.3

Regulatory Framework for Transmission



Endnotes

1. 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.
2. 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.
3. When the responsibility for providing the transmission service or for constructing a new line is allocated through a tendering process, the result of the tender could be used to define the level of remuneration for the transmission activity.
4. Care must be exercised when designing incentive schemes for the system operator to reduce the cost of losses and congestion. Losses and congestion largely depend on the location of generation and demand and the configuration of the transmission network and are dictated by the economic dispatch of the 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.



THREE

THE OBJECTIVES AND KEY PRINCIPLES OF TRANSMISSION COST ALLOCATION

In most emerging economies, building more transmission lines and upgrading transmission capacity, including across borders, is feasible primarily through massive private investment.[1,2] A prerequisite to attracting private investment is a sound regulatory framework, including the efficient allocation of transmission costs among market participants. A well-designed transmission tariff design must balance cost recovery, economic efficiency, fairness, and predictability. These objectives, along with the combination of microeconomic theory, power systems engineering, and sound regulatory practice, suggests that the allocation of transmission network costs among its users should adhere to some fundamental principles. In fact, after much trial and error in several power systems, these high-level principles have been recognized as sufficient to define efficient transmission pricing (Rivier et al. 2013; MIT 2011). They pertain to regulated transmission assets and may serve as a reference for merchant lines,[3] where cost allocation is typically a matter of negotiation between project promoters and asset users.

3.1 Objectives of Transmission Pricing Design

Efficient transmission tariffs have several key objectives that guide regulators in choosing methods for transmission cost allocation and in designing transmission tariffs:

- **Cost recovery:** Tariffs must recover the full cost of building, maintaining, and operating the transmission infrastructure, as long as the costs are prudently incurred. This ensures the financial sustainability of the transmission system operator.
- **Economic efficiency:** Tariffs should reflect the cost of providing transmission services and guide users towards efficient use of the network. This includes promoting efficient location decisions by generators and consumers and minimizing congestion and losses.
- **Fairness:** Costs should be allocated in a fair and non-discriminatory manner among all users of the transmission network. Typically, this means that users pay in proportion to their network usage or the benefits they receive from it, as well as the costs they impose on the system.
- **Transparency and predictability:** Tariffs should be transparent and predictable, allowing grid users to estimate the costs of using the transmission service and facilitating investment.

3.2 Principles of Transmission Cost Allocation

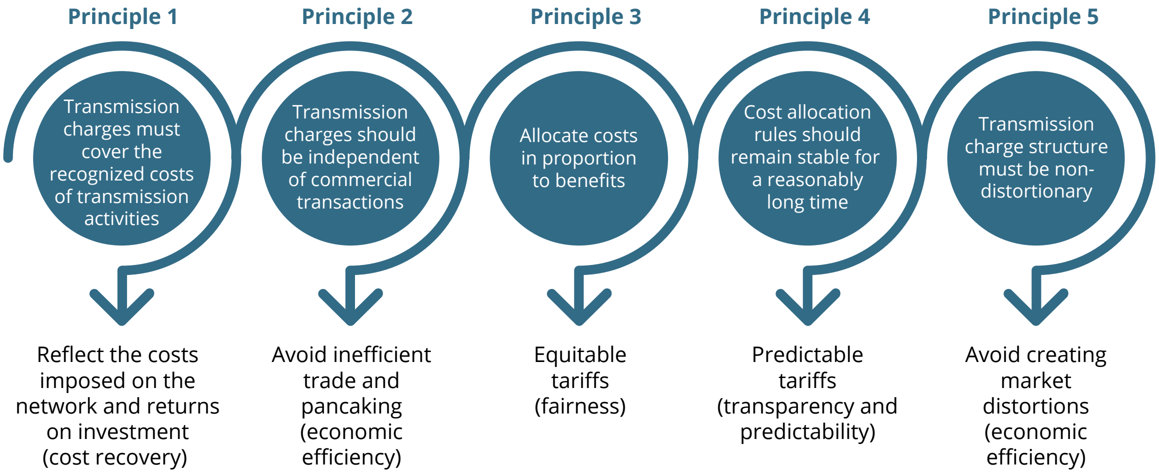
These primary objectives lead to the following fundamental principles that regulators should adhere to when determining the allocation of transmission network costs:

- **Principle 1:** Transmission charges must cover the recognized costs of transmission activities

- **Principle 2:** Transmission charges should be independent of commercial transactions
- **Principle 3:** Allocate costs in proportion to benefits
- **Principle 4:** Cost allocation rules should remain stable for a reasonably long time
- **Principle 5:** Transmission charge structure must be non-distortionary

FIGURE 3.1

Key Principles of Transmission Cost Allocation and Their Relevance to Primary Objectives



Principle 1: Transmission Charges Must Cover the Recognized Costs of Transmission Activities

The transmission cost allocation method and the transmission charges to be levied on the grid users/ beneficiaries of transmission activities must cover their recognized costs – the regulated transmission revenue requirement.[4] In particular, the total amount of transmission charges for a given year (the annual revenue requirement) should be determined using accounting methods that ensure the present value of the stream of annual revenue requirements over the economic or regulatory lifetime of the assets equals the present value of the efficiently incurred costs. This amount must not only cover the incurred costs but also include a reasonable remuneration of the invested capital (equity and debt), and potentially, efficiency or performance incentives. If a tendering process is employed to select the developer of the transmission asset, the outcome will determine the regulated amount to be recovered. Ideally, the annual revenue requirements would remain stable year over year, allowing for a smooth and predictable trajectory of transmission charges.

Transmission investments are lumpy and long-lasting, often exceeding 40 years – in practice, they are refurbished or replaced, but in many cases not completely removed. When they enter into service, their load-carrying capacity typically exceeds what is immediately required, resulting in idle capacity in the early years. It does not seem cost-reflective to charge the full cost of a transmission investment to its current users/ beneficiaries, who only utilize 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 approach to socializing the cost across demand could be deemed acceptable.

Minimization of cost-recovery risk is crucial when regulating a new transmission asset. The design of the regulation should ensure that the definition and imposition of transmission charges do not introduce unnecessary risks in the recovery mechanism of the transmission revenue requirement. For example, the use of replacement-cost methodologies is discouraged. Once a transmission investment is made with the technologies and components available at the time, the subsequent year's revenue requirements should not be reduced based on the costs of new technologies available in those years, since this poses an unmanageable risk for the investor.[5]

Principle 2: Transmission Charges Should be Independent of Commercial Transactions

As indicated in Section 2, the flows within the transmission network by each user and, consequently the network elements used, are determined by the user's location in the network, the network's topology, and the temporal patterns of power injection for generators and withdrawal for loads. These factors do not depend on commercial transactions. Therefore, transmission charges:

- should be based on the users' locations and their temporal patterns of power injection and withdrawal, given the network's topology; and
- should not depend on commercial transactions between users (i.e., who trades with whom), as these are often not directly relevant to the network flow.

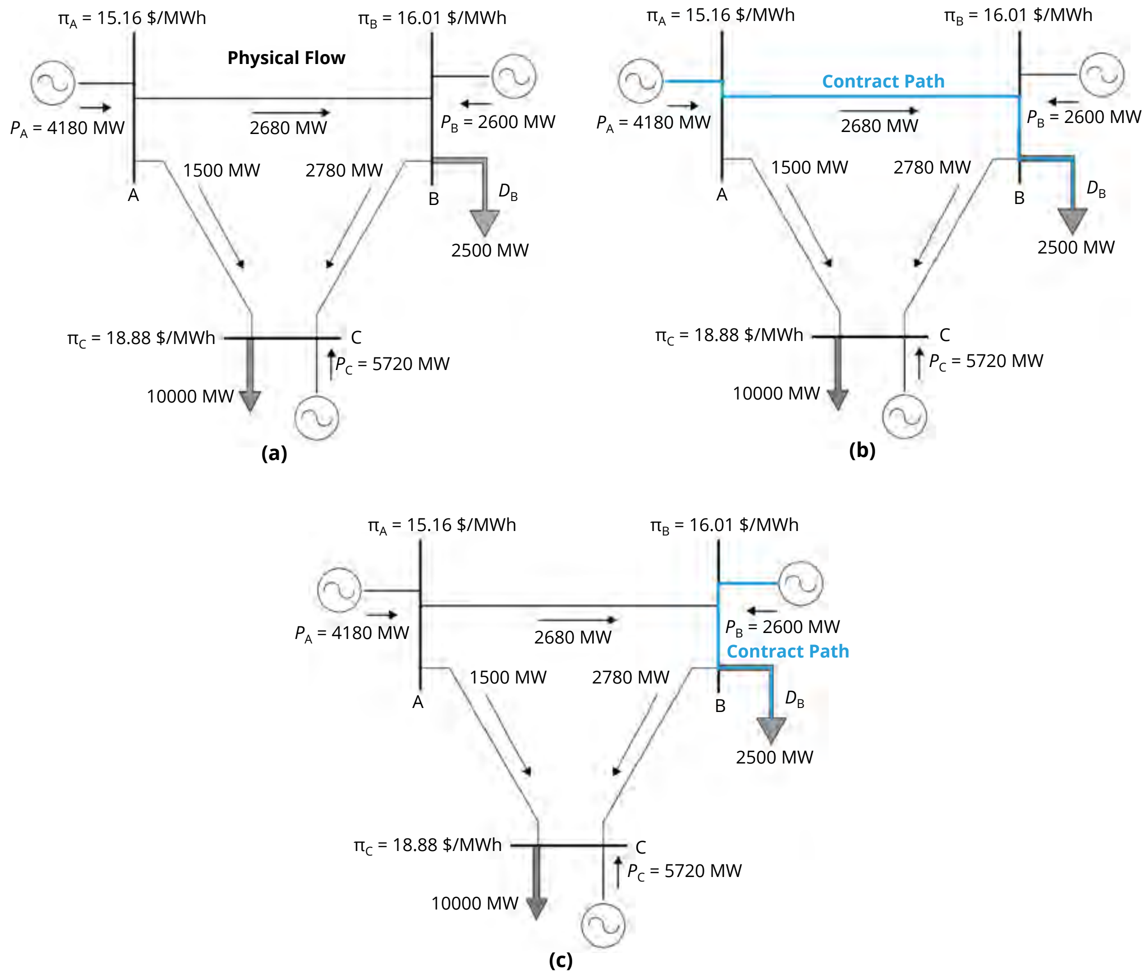
For example, a generator located in Region A that trades with a load-serving entity in Region B, using the physical network connection between the two regions, should pay the same transmission charge as if it were supplying power to a local load in its own Region A. Similarly, the load in Region B should face the same charges whether it purchases electricity from a generator within its own region or one in Region A. The application of this principle should not be affected by any contracts that parties may voluntarily enter into, since they should not alter the physical real-time dispatch of generation or demand.

In Figure 3.2, (a) shows the physical flows resulting from the optimal dispatch, upon which the transmission tariff should be calculated. (b) and (c) illustrate 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 this principle will lead to discriminatory 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 power exchanges, this principle ensures that the cost allocation is initially to countries, not to individual agents, leaving each jurisdiction to pass on the allocated costs in line with national practice. It also avoids tariff pancaking, where

FIGURE 3.2

Power Flow and Transactions Between Generators and Loads in Three Regions



(a) (b) (c)

network users incur cumulative 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, which can hinder trade and limit access to low-cost power sellers. In the European Internal Electricity Market, the Central America Regional Electricity Market, and within the Regional Transmission Operators' areas in the United States (but not between these areas), transmission charges generally do not depend on commercial transactions.

Principle 3: Allocate Costs in Proportion to Benefits

Most consider it fair to allocate network costs among grid users in proportion to the benefits they receive. These benefits are not limited to immediate financial gains, such as reduced electricity prices or surplus export revenue, but also include broader socio-economic benefits like CO_2 emission reduction, enhanced security of supply, and a reduction in necessary reserves. If a project is expected to deliver positive net benefits (i.e., benefits exceeding costs), there exists a cost allocation that can improve the welfare of all affected parties, making them less likely to oppose moving forward with the project.[6] Conversely, if a project's costs outweigh 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 proceed.

A "beneficiaries-pay" approach for a project with 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 due to potentially high transaction costs, and a regulatory framework is needed. In this respect, the regulatory test[7] for approving a project at the planning stage, to check that its overall benefits exceed its total costs, can aid in cost allocation, if the cost-benefit analysis is performed as part of the regulatory test, in identifying benefits and beneficiaries.[8] It is, however, important to note that the regulatory test is only required to confirm that benefits outweigh costs, not necessarily to determine the precise level of benefits or the extent to which they exceed costs.[9] The cost allocation based on benefits requires a more precise determination of the latter if they are to be used as drivers in the cost allocation.[10]

While the beneficiaries-pay approach has been used in a few jurisdictions,[11] the challenge of accurately assessing benefits[12] has led to the use of transmission asset utilization as a proxy, despite the lack of a clear, demonstrable link between the two. Identifying a reasonable method to measure network utilization is problematic. Computing the electrical utilization of lines by agents is not a simple task either, since there is no indisputable method to do it, as indicated in Section 2. Among the different proposed methods, the 'average participation' approach appears to be the most robust. The ultimate goal is not to calculate each agent's exact network usage but to reasonably estimate the benefits each agent gains from using the transmission facilities.

The cost allocation method should ensure that all users/beneficiaries of the transmission asset/network pay charges. The beneficiaries typically include both consumers and producers. Therefore, *a priori*, radical decisions such as charging only consumers or solely producers are not justifiable.[13] Within each jurisdiction, the allocation of transmission costs should be applied at the individual agent or network node level. At the cross-border or regional level, costs should be allocated at the jurisdictional level first. In the latter case, however, the costs of cross-border transmission assets should not be allocated only to those who actually trade electricity across borders, but more widely to all those who benefit from cross-border power exchanges.

Principle 4: Cost Allocation Rules Should Remain Stable for a Reasonably Long Time

The rules for determining transmission cost allocation should be predictable, and stable to the extent possible, while transmission charges can change over time. Any changes should occur only for compelling reasons and with sufficient advance notice. In an ideal and extreme case, though, transmission tariffs for network users should be set *ex-ante* and remain stable for a reasonable duration. This is to send predictable economic locational signals to investors who need to choose sites with minimal financial risk. This is of particularly applicable to wind and solar generators, which often have many potential sites.

The locational impact of transmission charges is, as discussed above, mostly meant to incentivize potential new generators to choose sites that do not necessitate network reinforcements and that reduce congestion. While transmission charges may influence the retirement decisions for old plants with low operation profit margins, they are unlikely to affect consumers' siting decisions. The stability of transmission charges over time is crucial because once a new generator is in the construction phase or in operation, relocation is not feasible, and investors should have confidence that the locational structure of transmission charges (or their trajectory over time) will remain consistent, at least during the initial period of operation.

The proposal is that when a new generator requests grid connection, the system operator should provide an indication of the transmission charges to be levied to this generator for the next ten years (or a similar period). Given typical monetary discount rates and the uncertainty surrounding major factors affecting a power plant's profitability, a ten-year period should be enough for a new generator to make investment decisions. The transmission charge trajectories for new generators applying for connection in a given year should not change for the next decade. 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. After the ten-year period, these generators will be treated like any other. To our knowledge, this approach is not practiced anywhere. While the methods for calculating transmission tariffs in many countries have been established for many years, the exact values of their transmission tariffs are typically updated annually for all network users to account for cost evolution, inflation, system configuration changes, and other factors.

Principle 5: Transmission Charge Structure Must be Non-Distortionary

In designing transmission charges, it is essential to clearly distinguish between determining how much each network user has to pay from the specific structure of the charge, namely as a volumetric charge (\$/MWh), a capacity charge (\$/MW), a lump sum (\$), or a combination of them. Regulators must carefully consider which charging structure(s) to adopt and how to allocate costs among these different structures, taking into account factors such as cost drivers,[14] implications on the short and long-term market behaviors, the stability and predictability of revenue for the transmission operator, as well as the regulatory and market framework.

The procedures to allocate transmission costs based on scenarios and estimated benefits or responsibilities for utilization 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 installments, for structural reasons, as a $/MW charge tailored to each generator or demand to result in the predetermined annual amount.

However, it should not be a volumetric charge based on the amount of energy injected into or withdrawn from the network by the grid user's actual energy generated or consumed. When transmission tariffs are levied as energy charges, they introduce a new short-term cost for grid access. This affects the valuation in bids or economic dispatch decisions for generators, as well as consumer responses to energy prices. Consequently, a volumetric transmission charge, regardless of the logic used in the power system's short-term economic operations, will lead to market distortions. This is especially significant for generators in power systems with wholesale markets, as their bids or declared costs influence market prices. Additionally, transmission revenues solely contingent on the volume of energy flows across the transmission asset add uncertainty to the remuneration of transmission activities.[15]

Similarly, an annual capacity charge ($/MW) can also distort market participants' decisions. If the annual amount to be allocated to each agent has already been computed using a sound method, there is no need to introduce unnecessary complexity by applying it as a capacity charge. This is particularly problematic for new generators who face increased capital investment costs. Typically, the allocated cost for a specific location is divided by the rated or maximum declared capacity. However, when multiple generating units share the same location, this approach can discriminate between generators that use the network consistently (base load) and those that operate primarily during peak hours (peak load).

BOX 3.1

INTERNATIONAL PRACTICES IN TRANSMISSION COST ALLOCATION

International practices for transmission cost allocation at the national or system operator level vary widely. In most countries, transmission tariffs lack any locational signal and fail to allocate line costs efficiently (see, for example, (ETSO 2009), (Fink et al. 2011), and (Lusztig et al. 2006)). Regulators often opt for straightforward transmission charges that distribute network costs among users. However, as new types of generation, such as renewables, vie for access, providing clear locational signals – through transmission tariffs, for instance – will become increasingly important.

BOX 3.1 (*Continued*)

The most common transmission charging scheme is the plain postage stamp method, where every load pays a flat fee per kWh of energy consumed, either at any time or, at most, by time band, or per contracted kW of capacity. In some cases, generators also pay based on a per-kW or per-kWh basis. This charging method can distort the efficient outcome of wholesale power trading. A few systems have introduced some form of locational transmission charges, and more are now considering this approach due to the anticipated large penetration of wind and solar plants, which could put undue stress on the transmission grid without locational signals. In the European Union (EU), ‘locational signals’ are frequently mentioned in regulatory documents as a desirable feature. However, progress at the European level has been limited, with notable exceptions including the United Kingdom (UK), Ireland, and, to a certain extent, Sweden, which have implemented such measures at the national level.

The principle of “the beneficiary pays” is widely accepted in official documents in the United States, such as (FERC 2012), though its practical implementation remains rudimentary. This principle has also been adopted in the EU. Regarding cross-border trade, both the United States and the EU have eliminated pancaking. The Federal Energy Regulatory Commission (FERC) issued Order No. 888, prohibiting discriminatory transmission tariffs for cross-border trade within each Regional Transmission Organization (RTO). However, no significant attempts have been made to extend intra-regional (RTO) cost allocation methods to the inter-regional level.

Furthermore, the EU regulations explicitly prohibit transmission charges from depending on commercial transactions and have developed a standardized mechanism for accessing and paying for the transmission system. Since 2002, an inter-Transmission System Operator (TSO) Compensation mechanism (ITC) has been in place (Olmos Camacho & Pérez-Arriaga 2007). This mechanism involves countries – typically represented by one or more TSOs – compensating each other based on network usage metrics. The net balance of compensations and charges for each country – whether positive or negative – is added to its total network cost from which transmission tariffs are calculated. Each country can design its internal network tariffs and payment of the national transmission tariff grants access to the entire EU transmission network without additional charges. Although there is room for improvement in the computational aspects of this method, this hierarchical approach has significantly facilitated electricity trade in the EU and has a robust conceptual foundation. This method also implicitly and

BOX 3.1 (*Continued*)

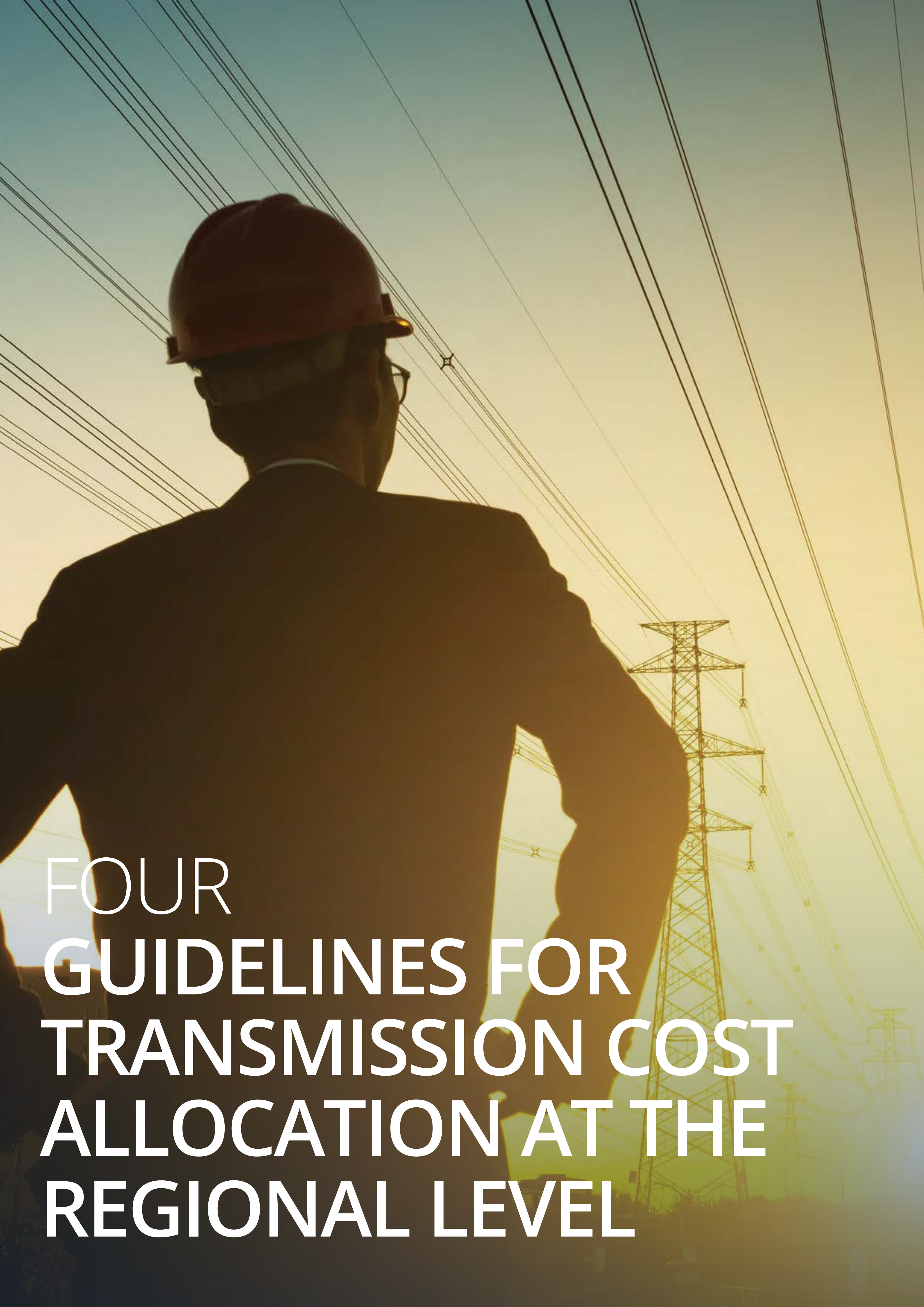
automatically allocates the cost of new transmission investments within the EU, though the total amount for infrastructure costs at the EU level is capped. Since 2013, a new cross-border cost allocation mechanism has been available for major transmission investment projects with cross-border relevance (known as Projects of Common Interest). National regulators negotiate how to allocate the costs of these projects among the involved countries. If they cannot reach an agreement, the EU Agency for the Cooperation of Energy Regulators decides the cost allocation (see ACER 2023).

Endnotes

1. 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).
2. World Bank Group (2017) "Linking up: Public-Private Partnerships in Power Transmission in Africa" examines private sector-led investments in transmission globally and how this approach is applicable in sub-Saharan Africa.
3. Merchant transmission lines are those built by investors who keep the revenue risk related to their utilization onto themselves.
4. The total costs that each transmission network owner is permitted to recover annually are referred to as the transmission revenue requirement. The most commonly employed approach for calculating these regulated earnings is the building block methodology, typically represented by the following mathematical equation: Regulated Revenue Requirement = Operating and Maintenance Expenditure + Depreciation + Tax + Weighted Average Cost of Capital * Regulatory Asset Base.
5. In case, for example, that more efficient, less expensive technologies become available in those years.
6. While generator and load losses are rarely compensated, significant environmental impacts may present more serious concerns and could potentially lead to claims. For instance, this could occur if a proposed line crosses and affects a particular area without providing any benefits to its residents.
7. 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.
8. More information on the list of benefits and CBA guidelines is available at https://consultations.entsoe.eu/system-development/methodology-for-a-energy-system-wide-cost-benefit/
9. If financing constraints exist, projects may need to be ranked based on their net benefits, requiring more accurate benefit estimations.
10. 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.
11. The beneficiaries-pay approach was first adopted in 1992 during the liberalization and restructuring of the Argentinean power sector. The same approach also inspired the cost allocation in the SIEPAC project that connects six Central American countries. Since then, it has been largely adopted as the guiding principle to allocate the cost of new transmission projects.
12. All benefits to network users should be included in the analysis, both those that can be monetized and those that are harder to quantify.
13. Transmission charges that provide correct economic signals, i.e., those based on the forward-looking marginal cost of investment in transmission due to system usage by different agents, often fail to recover the full regulated revenue requirement. In such

instances, a least-distortive way of collecting the remaining regulated revenue requirement could involve allocating costs inversely proportional to the price elasticity of grid access. Under this criterion, consumers, who typically shows much lower elasticity than generators, may bear a larger proportion of transmission costs. However, this is not always the case. Power plants, whether both existing or new, with large benefit margins may absorb the residual transmission charges without incurring financial distress.

14. Volumetric charges ($/MWh) are appropriate for recovering costs related to the actual amount of electricity transmitted, reflecting the wear and tear on the network due to electricity flow. Capacity charges ($/MW) are suitable for recovering costs related to the infrastructure needed to handle peak demand. They are often used to cover costs associated with maintaining sufficient transmission capacity. Lump sum charges ($) can be used to recover fixed costs that do not vary with capacity or volume, such as certain administrative or operational expenses.
15. While end-consumer tariffs may recover a portion of transmission costs through a volumetric component, and estimation errors of annual demand may lead to a surplus or deficit in the collection of the transmission revenue, such discrepancies should be expected and accepted. These errors are unavoidable, but they should not create revenue uncertainty for the transmission company. Any positive or negative variance can be adjusted for in the determination of the subsequent year’s transmission revenue requirement.



FOUR

GUIDELINES FOR TRANSMISSION COST ALLOCATION AT THE REGIONAL LEVEL

Building on the objectives and key principles outlined in Section 3, this section proposes guidelines for implementing a transmission cost allocation approach in the context of cross-border/regional electricity trading. These guidelines are based on the single system paradigm, which suggests that regional power trade should be planned, operated, regulated, and governed as similarly as possible to a single jurisdiction of corresponding regional scope.

FIGURE 4.1

Summary of Regional Transmission Cost Allocation Do's and Don'ts

✗ Avoid	✓ Recommended	◎ Advanced
1. Charges based crossed territory, i.e., pancaking. 2. Charges based on transactional methods. 3. Applying volumetric charges ($/MWh). 4. Using annually updated replacement cost for determining assets' costs.	1. Allocate costs to countries. 2. Allow countries to agree on cost allocations. 3. If countries do not agree, allocate costs based on an agreed-upon network usage method. 4. Apply different charges for cost allocation and losses allocation. 5. Apply cost allocation charges as a lump sum.	1. Apply spatially differentiated charges. 2. Established charges ex-ante and fixed for 7 to 10 years. 3. Adopt a unified cost allocation method with locational component in all national jurisdictions.

4.1 Institutional Framework

When implementing a transmission cost allocation approach at the regional level, it is desirable to have a specialized framework, such as a regional regulatory authority or an entity capable of effective dispute resolution and enforcement. This body would be tasked with defining, implementing, and modifying cross-border transmission cost allocations, or at least mediating and adjudicating disagreements among national regulators on these decisions. A regional regulatory authority might also adopt a reference methodology for cost allocation of electricity transmission with cross-border relevance, according to the principles outlined in Section 3. Such a methodology could be applied by the regional regulatory entity in case of disputes or serve as a starting point for cooperation among national authorities.

While establishing a regional regulatory authority is not always required, it is highly advisable, especially in regions where energy regulators often have limited capacity. A dedicated regional entity with the necessary expertise and resources can be more effective and efficient in developing and overseeing regional transmission cost allocation rules than if individual national regulators, who may themselves lack sufficient capacity, were to attempt collaboration on their own.[1]

In the absence of a regional regulator, there needs to be a structured mechanism for managing conflicts and maintaining the integrity of the cost allocation framework. This mechanism should facilitate the effective resolution of disagreements between countries (e.g., a dedicated dispute resolution body or a well-defined process for arbitration) and ensure the enforcement of agreed-upon cost allocation rules.[2]

4.2 Entities Involved in Setting the Transmission Charges for Cross-Border Transmission Assets

As a general rule, the entities involved in determining revenue requirements and allocating among users/beneficiaries include:

- **Project promoter**(s),[3] responsible for planning, financing, and developing transmission elements and proposing the costs to be recovered in relation to such elements. Promoter(s) might also choose the regulatory regime under which the transmission asset will operate.[4]
- **National regulatory authority**(ies), either separately for the assets within their respective territories or jointly, should determine the cost of the transmission assets to be recovered through the revenue requirement, based on the proposal of the project promoter(s). These costs should be prudently incurred, economically justified, and might include incentivizing elements.
- A regional **regulator** or joint national regulators should determine the cost allocation among different countries or users/beneficiaries. In the absence of a regional regulator, a dispute resolution mechanism should be put in place to resolve situations in which national regulatory authorities are unable to agree.
- **Governments** of the involved countries, in cases where an intergovernmental agreement is needed to establish the rules for the cooperation of national regulators, establishing a regional regulator or a dispute resolution mechanism, and/or defining cost allocation principles.
- **System operators and grid users** in the different countries involved also play a role in enabling and paying for new transmission network elements with cross-border relevance.

4.3 Steps of the Transmission Cost Allocation at the Regional Level

The following steps are recommended for the implementation of regional transmission cost allocation.

FIGURE 4.2

Recommended Process for Regional Transmission Cost Allocation and Entities Involved

IDENTIFICATION of the transmission assets with regional relevance	**DEFINITION** of the overall revenue requirement for transmission assets with regional relevance	**ALLOCATION** of the overall revenue requirement of the transmission assets with regional relevance among the countries involved	**DETERMINATION** of the modified national transmission revenue requirement and of the transmission charges in each country
By agreement of national regulators of the countries involved or, in case of disagreement, by the regional authority	By national regulators acting separately (according to the territorial principle) or jointly. Any dispute adjudicated by the regional authority	By agreement of the national regulators of the countries involved or, in case of disagreement, by the regional authority using cost allocation rules according to the method proposed in the Guidelines	By national regulators, respecting the recommendations presented in the Guidelines

Identifying the Transmission Network Elements with Cross-Border Relevance

The transmission network elements with cross-border/regional relevance are those that are needed to establish physical transfers of electric power between countries. Their costs should be allocated to beneficiaries across borders, distinguishing them from those with only local/national relevance. Transmission assets eligible for remuneration need to be clearly defined and agreed upon among countries. There is no clear separation between the two categories, and the involved regulators or the regional regulatory authority should establish a threshold or criterion for this distinction, based on engineering estimates and actual power flow patterns. While transmission lines crossing country borders are obvious candidates, many domestic transmission lines that are purely internal to a country can also have significant relevance in regional power exchanges, for instance, by allowing power wheeling between interconnectors.

Definition of the Overall Revenue Requirement for Transmission Assets with Cross-Border Relevance

National regulators determine the revenue requirement for each transmission network element with cross-border relevance,[5] either separately for their respective territory's portion or jointly. If national regulators act separately, any dispute over the revenue requirement determination methods for the different parts of the transmission network element should be adjudicated by the regional regulator or through a dispute resolution mechanism.

When determining the capital costs, two primary methodologies are commonly used: the historical cost method and the replacement cost method. The historical cost method calculates depreciation rates based on the original acquisition cost, adjusted over time for accumulated depreciation. While this approach reflects the actual investment made in the assets, it may not fully capture current market conditions or the real cost of asset replacement. In cases where the transmission service or construction of new lines is awarded through a tendering process, the tender result will be used to define the level of remuneration for those assets.

Similarly, the O&M costs associated with cross-border transmission assets must also be determined in a fair and transparent manner. The O&M costs can be structured similarly to the capital cost allocation, with historical cost methods reflecting the actual capturing of the expected costs under current market conditions. Agreement on these costs among participant countries is critical for preventing disputes and ensuring the long-term sustainability of the transmission system.

Allocation of the Overall Revenue Requirement for the Transmission Assets with Cross-Border Relevance to Involved Countries[6]

Some cross-border transmission projects might be proposed and even implemented using *ad hoc* cost allocation rules. Such rules might or might not follow the guidelines presented in this report, which could possibly serve as a starting point in the negotiations between the project promoters and users. Irrespective of the chosen approach, it should allocate costs only at the country level among the countries benefiting from or using the network elements developed by the project, rather than to the individual agents within these countries.
For other transmission components with cross-border relevance, a method should be established for determining and allocating the costs of transmission network elements:

- The charges to recover the revenue requirement for each transmission network element with cross-border relevance are applied at the country level.[7]
- Initially, national regulators[8] of the involved countries should attempt to agree on a cost allocation approach applying the Average Participation method to determine each importing and exporting country's contribution to the usage of each transmission network element with cross-border relevance.
- Such an approach would need to fully allocate the overall revenue requirements of all the transmission network elements with cross-border relevance on the basis of their usage contribution, but only at the country level, leaving each national regulator to determine charges applicable to different agents within its jurisdiction.
- If an agreement is not reached within a set timeframe, the regional regulator decides to use the Average Participation method.[9]

Determination of the Modified National Revenue and Transmission Charges in Each Country

After defining the allocation of the costs of the transmission network elements, each country's national regulator determines the modified transmission revenue requirement for computing regulated transmission charges in the country. The regulator should 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 country's transmission network elements, and finally add the charges allocated to this country because of its use of the network elements in other countries. Once this modified transmission revenue requirement is obtained, the regulator can proceed to determine its internal transmission charges.

Cross-border compensations between countries and payments to transmission project promoters, which are not the incumbent public transmission companies or system operators of the countries involved, must be guaranteed by an entity in each participating country. At least some reasonable options exist, with the choice depending on the specific circumstances of the involved utilities and the independence and executive power of the national regulators, namely:

- 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, acts as the national counterparty for the compensation resulting from the application of the allocation method described above. In many cases, the system operator is part of a vertically integrated utility, in which the utility will effectively guarantee the compensations and payments.[10]

4.4 Proposal for a Quantitative Method for Cost Allocation of Transmission Network Elements

A uniform regional method, which, if well-conceived, could serve as a reference for the cost allocation method to be agreed upon by national regulators, or to be applied to any new large transmission projects. It is crucial to note that this method should allocate the revenue requirement among the countries, excluding the cost of losses in the transmission facilities. Two methods are presented: the "first best" method, which allocates costs to beneficiaries, and the "second best" method, which allocates costs to users.

Allocation of Costs to Beneficiaries

The "first best" method for allocating the costs of transmission network elements involves charging the beneficiaries in proportion to the estimated benefits they receive. As indicated previously, allocations will be made at the country level, necessitating an estimation of the benefits each country derives from the transmission investment. Considering the project's expected long lifespan, these benefits must be estimated over a long-term period.

In principle, reference should be made to the net socio-economic welfare benefits for each country, including but not limited to, the economic benefits from increased trading surpluses (for generators in exporting countries and consumers in importing countries, offset by any surplus reductions for generators in importing countries and consumers in exporting countries). Other benefits, which may not be directly monetizable, should also be factored in. If the transmission investment is well-justified, the aggregated benefits for all countries must clearly exceed the project's lifetime costs, ensuring that the cost allocation proportional to benefits is satisfactory for every country.

The potential implementation challenges of the beneficiaries-pay approach have been discussed already. In situations where these challenges are considered to be excessive, the "second best" allocation of costs to users method can be applied.

Allocation of Costs to Users

Several engineering-based methods for assessing the use of transmission assets by different grid users have been proposed and implemented (see the Appendix: Cost Allocation Methods). These methods aim to quantify each agent's (or country's) level of utilization of a particular transmission network element, which can act as a proxy for the amount of benefits delivered by the project. The starting point is the measurable physical energy flow at any given moment from generators to loads, associated with each transmission element.

The Average Participation method is the only engineering approach that seems appropriate in this context. Other methods have been tested and discarded due to inconsistent results (Olmos Camacho & Pérez-Arriaga 2007). Average Participation tracks actual flows in each network component upstream and downstream to identify their source and sink.[11] It has been widely used in transmission cost allocation procedures. Implementing 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 network element in the representation. It also needs a set of representative scenarios of power injections and withdrawals in the different nodes of the network representation. System operators can typically provide a suitable regional network representation, along with estimated power injections and withdrawals at each node for various representative scenarios for the year the cost allocation can be performed.

For each generator and each load in each scenario, the Average Participation determines the usage of each regional network element's capacity, both in its own country and in the other ones. A simple mathematical procedure is used to allocate the allowed revenues of each network element to the respective countries, resulting in a per-country cost list for each transmission asset. This method also produces a table indicating the payments one country must make to another for the use of the latter's transmission facilities.

Once the regional transmission network's costs are allocated to each country, regulatory authorities will know their total transmission revenue requirements for the year under consideration. Regulators can then factor these (outgoing and incoming) payments into the calculation of charges for producers and tariffs for end consumers. For transmission projects with cost allocations agreed upon among the promoters, it should be easy to add the results from their individual cost allocation methods to the ones obtained as outlined above.

4.5 International Practices

The territorial principle, which involves entry and exit charges based on a notional commercial path, remains prevalent in many parts of the world. This practice leads to tariffs being applied each time power flows cross a border along this hypothetical commercial route, causing what is known as tariff pancaking. In contrast, under approaches consistent with the 'single-system paradigm,' charges for using the entire regional transmission network are levied solely on power injections into and withdrawals from the network. Such approaches are currently applied in the European Union, the Regional Electricity Market in Central America (See Box 4.1), and within the areas controlled by each Regional Transmission Organization (RTO) in the United States, although not between different RTO areas. There have been efforts elsewhere to estimate how cross-border electricity trade impacts regional transmission network usage.

BOX 4.1

TRANSMISSION COST ALLOCATION IN THE CENTRAL AMERICAN ELECTRICITY MARKET

In Central America, there is a procedure to identify the regional network, known as the RTR ('*Red de Transporte Regional*' in Spanish). The RTR includes segments owned by the regional system operator, the EPR ('*Entidad Propietaria de la Red*' in Spanish), which also owns the Central American Electrical Interconnection System (SIEPAC) connecting all the countries in the region. National TSOs own parts of the RTR lines, and private investors, mainly grid users, build and own lines to access other areas

(*continues*)

BOX 4.1 (*Continued*)

and obtain the corresponding transmission rights. These investments are referred to as "investments at risk." As a result, the operation and planning of the system and the ownership of transmission assets are independent of each other. The definition of the RTR is crucial, as regional and national lines are subject to different regulatory schemes (see "EOR, *Reglamento del Mercado Eléctrico Regional* (RMER)"). Costs for existing and new RTR lines are allocated using the same method.

The regional cost allocation method was defined by the regional regulator in 2009 but was implemented around 2018. This method combines two usage-based approaches: the Dominant Flow method and the Average Participation method. The Dominant Flow method divides the flow over each line, using the superposition principle, into two parts: one related to national transactions (termed the national super-transaction), which occur within the country where the line is located, and one related to regional transactions (termed the regional super-transaction). Each national super-transaction includes all power injections and withdrawals accepted in the corresponding national market. In addition, there is one regional super-transaction that encompasses all injections and withdrawals accepted in the regional market (including modifications to national dispatches). Both components of the line flow are tracked separately using the Average Participation method to determine the usage of each line by different groups of agents. Transmission charges are calculated by applying the two methods to historical pre-dispatch data from the previous year. Therefore, the method is usage-based rather than transaction-based. The term "super-transaction" is used to capture the total impact each country has on the RTR, as the national market remains isolated while a regional nodal dispatch is performed on top of the national outcomes. Furthermore, the fraction of the cost of a new RTR line covered by regional transmission tariffs depends on whether the reinforcement was planned by the regional system operator (EOR) or by the national transmission systems. The hybrid method discriminates between agents trading energy regionally and those trading locally.

Between 2009 and 2018, a simpler transitional method was used to allocate the cost of the regional grid. This method involved allocating the cost of regional network elements entirely within a country to that country's demand, while the cost of cross-border regional network elements was allocated proportionally to the demand in each country.

Both the transitional and current methods allocate only a portion of the cost of regional assets not covered by congestion income from regional nodal prices.

However, any method that charges transmission costs to commercial bilateral transactions, based on an engineering estimate of the transaction's impact on the network, is conceptually flawed. More importantly, it often results in transmission charges for cross-border transactions that are several times higher than they should be, thus significantly hindering power trade.

A more sophisticated method might involve a load flow calculation to identify the flows of each bilateral transaction within the regional transmission components. This process is repeated for every scenario considered. Subsequently, the two agents involved in the transaction have to pay an annual transmission charge according to the fraction of the network they have used during the considered year. An example of this method is the MW-km/mile approach, which is used in certain regions (see the African experience in Box 4.2).

BOX 4.2

TRANSMISSION COST ALLOCATION IN AFRICAN POWER POOLS

Among African power pools, only the Southern African Power Pool (SAPP) and the West African Power Pool (WAPP) currently have defined methodologies for transmission cost allocation. Both power pools use a variant of the MW-km method (based on direct current (DC) load flow simulation and applicable only to demands). This method calculates charges for bilateral transactions by defining injection and withdrawal nodes (typically, the injection node is a specific generator node or a node connected to a group of generators, while the withdrawal node is the border node of the buyer, not the exact demand node(s)) and enforcing a load flow equal to the transacted capacity. Charges are computed based on the increase in flow through the assets compared to a chosen base scenario.

In SAPP, transmission charges for competitive markets are the average of computed bilateral transaction charges and are shared equally between the buyer and the seller. Initially, SAPP used the Postage Stamp method, which charged all users a flat rate of 7.5% of the total energy injected or withdrawn from the network. However, this method was abandoned in 2003, following recommendations from a wheeling rates study by the UK consultancy Power Planning Associates LTD, in favor of the MW-km method. The Postage Stamp method had not been unanimously accepted by all utilities.

(*continues*)

BOX 4.2 (*Continued*)

Currently, both power pools are revising the MW-km methodology to adopt a non-transaction-based approach. SAPP has commissioned the consulting firm Ricardo to propose an alternative method, as the current method was found unsuitable for competitive trade and calculating ex-ante charges. The proposed methodology features a hybrid of Average Participation and Marginal Participation, similar to the approach used in India. Average Participation is applied first to determine the demands for each generator and the corresponding generators for each demand. Then, Marginal Participation is used for each agent by simulating an incremental unit (1 MW) of power injected or withdrawn to calculate changes in asset flow (using an approximation with Power Transmission Distribution Factors (PTDF) instead of a full load flow simulation). Final charges reflect the direction of flow compared to a base scenario. This hybrid method avoids the need for selecting a slack node arbitrarily but may add complexity. Additionally, final charges are applied as capacity charges based on rating capacity, without considering the capacity factor for renewables, thus not reflecting their actual use of the grid.

These methods starkly contradict one of the firmest principles of transmission pricing: commercial transactions should not influence transmission charges. A clearly undesirable consequence of these approaches is overcharging commercial cross-border transactions, which disincentivizes regional electricity trade by overlooking the broader distribution of interconnection benefits among various agents. It is important to revisit the core principle that transmission costs must be allocated to the beneficiaries. Such methods are contrary to the intended goal of facilitating regional power trade.

4.6 Recommendations for Dealing with Transmission Congestion and Loss Costs

As discussed in Section 3, costs associated with transmission congestion and losses are distinct from transmission infrastructure costs. However, they emerge from the activity of transmitting electric power over the network, and their costs need to be properly managed.

Congestion Management

Congestion happens frequently in transmission networks. Nodal pricing is often the method of choice in markets characterized by complex and congested networks, where detailed pricing and efficient congestion management are essential. This mechanism prices electricity at different nodes in the grid, reflecting the marginal cost of delivering an additional unit of electricity. The price at each node takes into account generation costs, transmission losses, and the losses incurred during the transmission of electricity. By establishing prices that accurately represent the cost of supply at each node, nodal pricing sends economic signals that promote the most efficient use of the transmission system and generation resources. As a result, it plays a pivotal role in alleviating congestion by encouraging electricity flows along the least costly paths in the overall system.

Congestion rent/income – the revenue generated from the price differentials between market areas – arises where an electricity market exists, and congestion results in different prices in different market areas. It may also be generated when the physical capacity over a congested interconnector is allocated for a fee. Depending on the transaction rules at the bulk power system level, many power systems collect congestion income typically through the system operator, either at the national or regional level. Since the transmission revenue requirement is determined based on transmission infrastructure costs, and congestion does not modify these costs, the best use of congestion income is to decrease the transmission revenue requirement charged to network users or beneficiaries.[12] Under no circumstance should congestion income augment the remuneration of transmission or system operators.

Allocation of Transmission Loss Costs

System operators typically recover network losses or their associated costs in one of two ways within a single-system setting:

- Physically, by requiring generators to inject more power than they have sold commercially, and/or consumers to withdraw less power than they have purchased commercially, in accordance with predefined loss factors.
- Economically, by charging generators and/or consumers for the cost of losses, which the system operator procures on the market.

In both cases, it is necessary to determine the responsibility of each network user (generator or consumer) or group of users for the system's losses. Since the level of losses directly depends on the current flowing over a particular network element (with losses increasing proportionally to the square of the current), these losses can be allocated to different network users by performing a "with and without" analysis. This involves computing the network element flows and, therefore, the losses, both with and without the power injected or withdrawn by each network user in their respective country. It is important to note that, in defining the two scenarios (with and without power injection or withdrawal by each user), an optimal power flow (i.e., economic dispatch) analysis is required to determine the optimal injection pattern for these scenarios. Furthermore, in the case of transmission losses, the "user pays" principle is the most appropriate way of allocating losses among different network users. When it comes to the economic allocation of losses, it is also necessary to determine the value of these losses, which is not a major issue if the losses are procured competitively (e.g., through an auction).

A similar approach could be applied to regional power exchanges to determine each country's responsibility for creating losses in other countries' networks through power transfers between them. Also in this case, a "with and without" analysis is performed, comparing the power flows and resultant losses for each network element and the network of a country as a whole, both with and without the power exchange with other countries. An optimal power flow analysis is also necessary in this case to determine the injection patterns for the two scenarios. Moreover, the recovery of losses can be physical (i.e., by requiring other countries to transfer more power into the local system or less power out of it) based on predefined loss factors, or economic (i.e., by payments between countries).

It is worth noting that cross-border power exchanges do not inherently increase the level of losses in a country. In fact, they may reduce the loading of transmission assets in the country by generating flows on the network that move in the opposite direction to those generated by internal exchanges in that country. Whether this situation should lead to a country compensating others for reducing losses on its own network is a matter for debate and agreement.

Endnotes

1. Agency for the Cooperation of Energy Regulators (ACER) is a good example of a regional regulatory authority overseeing energy markets. ACER has binding authority in the EU, harmonizing regulations, overseeing cross-border trade, and resolving disputes in a mature, integrated market.
2. NordREG, the cooperative body of Nordic energy regulators is a good example of a structured mechanism for managing conflicts in the absence of a regional regulator for the Nordic Energy Market, which operates without a formal, overarching regional regulator. This organization facilitates cooperation and ensures alignment across national regulators from Denmark, Finland, Iceland, Norway, and Sweden.
3. The project promoter is often the transmission system operator or a group of system operators of the control areas/countries involved.
4. For merchant lines, the allocation of costs will be agreed between the project promoter(s) and the line's users.
5. It is recommended to recalculate the regional revenue requirement at least every 3 to 5 years to reflect cost changes.
6. Different approaches for allocating transmission costs are discussed in Appendix: Cost Allocation Methods.
7. More granular locational differentiation might be applied within each country by the national regulator when setting domestic tariffs.

8. Where a regulator has not been established, the task should be performed by the national government.
9. 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 decision is taken by the EU Agency for the Cooperation of Energy Regulators, in this case acting as a dispute-resolution entity.
10. In fact, project promoters might preference that the payments are made by a utility, if they believe that this provides a 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 fulfillment of the compensations and payments. This is a general aspect that needs urgent attention.
11. This does not correspond to the physical reality of how electric energy moves from one point to another, but it is the best feasible approach. As explained in Section 1, the fundamental problem with the engineering approach is that, based on sound physical knowledge, it is impossible to assign responsibility to any specific agent (generator or load) in energy transfer. The transfer is a collective phenomenon involving all generators and loads, guided by the ensemble of transmission lines.
12. 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.

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APPENDIX
Cost Allocation Methods

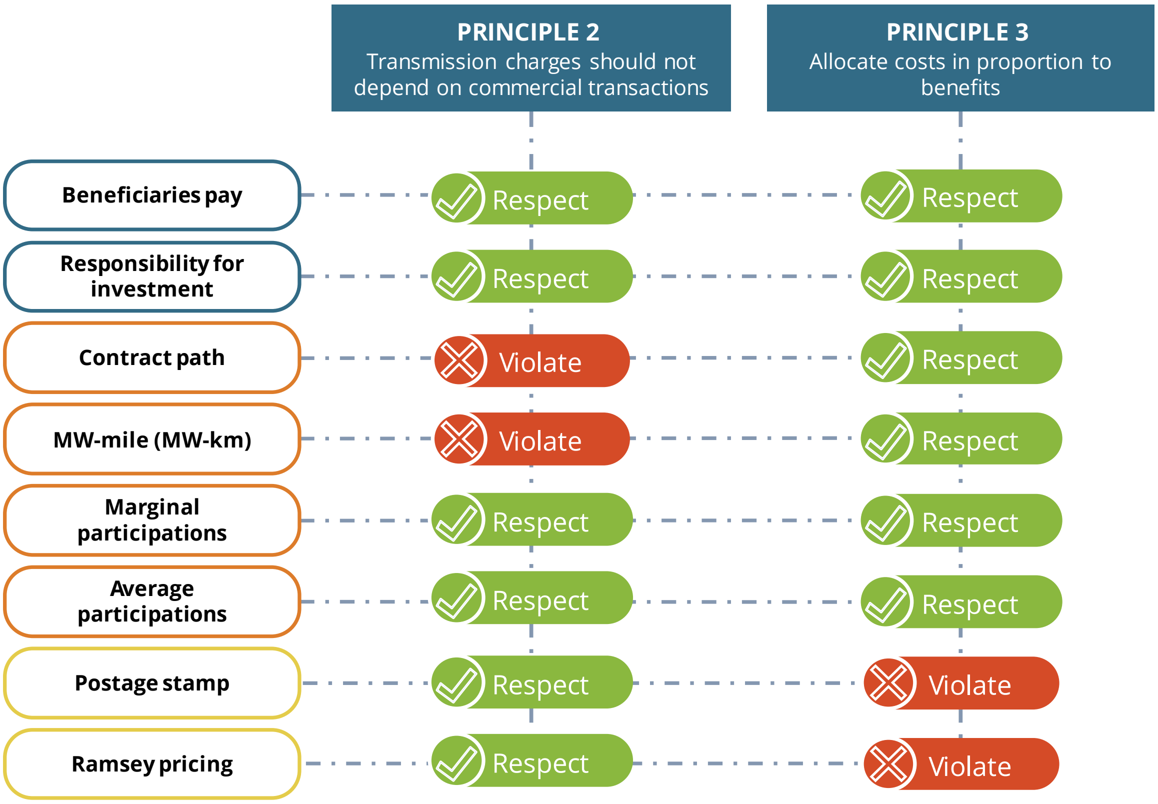
This appendix provides a brief overview and evaluation of some of the most well-known methods for allocating transmission grid costs[1] in the context of key principles: *Transmission charges should be independent of commercial transactions* (Principle 2) and *Allocate costs in proportion to benefits* (Principle 3), which are essential for a fair and efficient allocation of transmission costs.

Over time, various methods have been developed to assign these costs fairly and efficiently. These include Beneficiaries Pay, Responsibility for Investment, Marginal Participation, Average Participation, Contract Path, MW-km, Postage Stamp, and Ramsey Pricing methods. Most of these methods have been widely applied at both the national level and for cross-border projects except the last one.

Upon evaluating various cost allocation methods for transmission (See Figure A.1), methods such as Contract Path, MW-km, Postage Stamp, and Ramsey Pricing either fail to meet one or both principles. The Contract Path method, for instance, depends directly on bilateral commercial transactions, while the Postage Stamp and Ramsey Pricing approaches do not

FIGURE A.1

Cost Allocation Methods and their Adherence to Principles 2 and 3



	PRINCIPLE 2 Transmission charges should not depend on commercial transactions	**PRINCIPLE 3** Allocate costs in proportion to benefits
Beneficiaries pay	✓ Respect	✓ Respect
Responsibility for investment	✓ Respect	✓ Respect
Contract path	☒ Violate	✓ Respect
MW-mile (MW-km)	☒ Violate	✓ Respect
Marginal participations	✓ Respect	✓ Respect
Average participations	✓ Respect	✓ Respect
Postage stamp	✓ Respect	☒ Violate
Ramsey pricing	✓ Respect	☒ Violate

allocate costs in direct proportion to the actual benefits or use of the system. Similarly, the MW-km method, while grounded in the physical system, still does not entirely capture the proportionate benefit derived by each user. Therefore, while these methods may be practical for some specific applications, they do not fully align with the core principles of ensuring that costs are distributed according to the benefits received and independent of commercial arrangements.

Conversely, four approaches align with the two fundamental principles. The Beneficiaries Pay, Responsibility for Investment, Marginal Participation, and Average Participation methods adhere to these criteria. These methods ensure that the cost allocation reflects the actual use and benefits derived from the transmission system, and not the specific commercial transactions that may be driving electricity flows. By focusing on physical use and system benefit, these methods promote fairness and avoid distorting market operations. A summary (see Box A.1) and a description of these methods are explained below.

BOX A.1

SELECT METHODOLOGIES FOR CROSS-BORDER TRANSMISSION COST ALLOCATION

Beneficiaries Pay: The “beneficiaries pay” principle is widely regarded as one of the most equitable cost allocation methods because it directly links the costs of transmission investments to the parties benefiting from them. This method has been successfully implemented in multiple regional markets, such as in the European Union and the United States, where it ensures that those deriving the greatest benefit from new infrastructure contribute proportionally to its cost. The regulatory sophistication required for this approach is relatively high, as it demands a comprehensive and often complex analysis to quantify the benefits for each participant. However, once established, it can foster greater stakeholder support and ensure the long-term sustainability of investments.

Responsibility for Investment: The “responsibility for investment” method holds the entities or countries responsible for initiating the transmission investment accountable for the costs. This method has been used successfully in several countries where transmission investments are tightly linked to specific development objectives. It generally works best in regions where regulatory frameworks are relatively straightforward and transparent. However, this method requires careful

(*continues*)

BOX A.1 (*Continued*)

oversight to ensure that investments are justifiable and efficient. In more complex cross-border settings, assigning responsibility can be challenging due to differing regulatory standards and economic priorities, which can complicate the allocation process.

Marginal Participation: The "marginal participation" method, which allocates costs based on the marginal impact that each participant has on the transmission network, has found success in highly developed and mature electricity markets like those of Europe. Its regulatory sophistication is high, as it requires detailed and ongoing analysis of grid flows and the marginal impact of each user's electricity transactions. This method is effective in promoting cost-reflective pricing, where users are charged in proportion to the strain they place on the network. However, the administrative and technical requirements can be significant, requiring sophisticated grid modeling and real-time data to accurately assess the marginal impacts.

Average Participation: The "average participation" method, which allocates costs based on the average use of transmission assets by all participants, has been successfully implemented in less complex markets that aim for simplicity and fairness in cost allocation. It requires moderate regulatory sophistication, as it does not need the same level of data and analysis as the marginal participation method. This approach has been favored in regions where transmission flows are relatively stable and the aim is to avoid contentious debates over who benefits the most from each new transmission investment. While it may not be as precise as some other methods, its ease of application and transparency make it a reliable option in many contexts, particularly in markets with less sophisticated regulatory systems.

Beneficiaries Pay

The principle of "beneficiaries pay" is a standard regulatory test used to justify investments in new transmission assets. This principle asserts that investment is justified if the total net benefits it provides to all users (producers and consumers) over its lifetime exceed its overall cost. Conceptually, this method involves allocating the cost of a transmission facility in proportion to the benefits each user derives from it.

Under this method, the total benefits (including non-monetizable ones) each user gains from a transmission facility are assessed, and costs are allocated accordingly. When investment in a facility is justified, the benefits will outweigh the costs. Thus, users pay no more than the benefits they receive. This approach is grounded in sound economic principles, ensuring that long-term users' decisions are economically efficient.

However, implementing this method is challenging due to the difficulty in accurately estimating each user's benefits. Benefit calculations involve numerous assumptions and may include non-monetizable factors. Additionally, applying this principle to existing facilities can be problematic. For example, removing a line could lead to system chaos or have minimal impact if the network has sufficient redundancy. Despite these difficulties, the beneficiaries-pay concept inspired regulatory approaches in Argentina (1992) and California (1998) and remains a guiding principle for grid charging schemes.

BOX A.2

PUBLIC CONTEST METHOD IN ARGENTINA

In Argentina, in 1992, the Public Contest method was introduced for major transmission expansions for public use. This approach requires transmission users to propose, vote on, and finance significant transmission upgrades. Proponents must represent at least 30% of the beneficiaries in the expansion area. Once a proposal is made to the transmission company in the expansion area, the dispatch organization conducts a technical study using the Area of Influence method to identify the beneficiaries and determine the proportion of costs each beneficiary should cover. Costs are allocated among all identified beneficiaries based on their share, and these calculations are updated monthly throughout the amortization period of the Construct, Operate, and Maintain contract, ensuring that users pay in proportion to their actual benefits. (Littlechild & Skerk 2008)

Responsibility for Investment

The responsibility-for-investment method allocates transmission costs based on the investment responsibility of each user. This method evaluates the additional investment costs induced by each user (deep connection costs) in addition to the basic connection costs (shallow connection costs[2]). Transmission charges are thus proportional to the extra investment estimated for each user. This approach has been used in the UK (ICRP) and Colombia, though its implementation difficulties are widely recognized (see (Hogan 2018)).

BOX A.3

UK'S INVESTMENT COST RELATED PRICING METHODOLOGY

In the UK, transmission charges are determined using the Investment Cost Related Pricing (ICRP) methodology, which calculates costs based on the marginal investment needed to accommodate extra demand or generation. This approach utilizes a DC Load Flow transport model to evaluate the network enhancements required to support new demands or generators. The goal of ICRP is to strike a balance between the costs of network use and the benefits brought by new generators.

The methodology starts by assessing the costs of strengthening the network for the upcoming year. It then distributes these costs among network users according to their usage of the reinforced network. This distribution is carried out using a MW-Miles methodology, which involves analyzing how different circuits contribute to supporting the marginal increase in demand or generation at a specific node. This analysis is conducted through a DC load flow assessment, which identifies the most critical circuits in supporting the additional load and to what extent. (Wang & Li 2007)

Marginal Participation

The marginal participation method allocates line use and associated costs based on the marginal effect each consumer or generator has on the flows over each line. This effect is determined by calculating the change in all flows when a user's consumption or production is increased by 1 MW. This process is repeated for each network user and for each representative scenario considered. The variation in flow for each line, user, and scenario is used to calculate a value representing the use of the electricity system. This value is the sum of the products of the flow variation in each scenario, the power consumed or generated by the user, and the duration of the scenario. To determine the proportion of the grid cost to be paid by each player, the sum of the effects for a given player on all grid facilities is divided by the total impact of all users on those facilities.

While this method seems reasonable, it has an underlying assumption that, in the opinion of the authors, undermines its effectiveness. To calculate the marginal effect of each user, a slack bus or balance node must be defined to accommodate increases in generation or demand, as grid balance must be maintained. The choice of slack bus location affects the absolute results obtained for each player, though not the relative differences among these values, which remain constant regardless of the slack bus chosen (Vazquez at al. 2002). Thus, the allocation factors derived from any choice of slack node are fundamentally flawed, as the underlying assumption is arbitrary. This arbitrariness becomes even more problematic in multi-system contexts, such as regional or multinational systems like the EU's Internal Electricity Market, the Central American Electricity Market, or any of the United States interconnections.

Variations of this method with additional features that attempt to address the Marginal Participation method's flaws are used in the Argentinean and Chilean electricity systems, known as the "areas of influence" ("*areas de influencia*") scheme[3]. A similar method, known as CRNP (Cost-Reflective Network Pricing), is used in Australia. A more sophisticated version is employed in the Single Electricity Market of Ireland, where incremental flows created by a network user count towards network charges only if they align in direction with existing flows in the baseline or reference case. We have been somewhat lenient with the Marginal Participation method in Figure 8, accepting that it meets principle 3. However, unless it is properly adjusted, it does not.

Average Participation

The Average Participation method is based on the actual pattern of grid flows. It uses a straightforward heuristic rule to trace each flow withdrawn from the grid upstream and each flow injected into the grid downstream, determining the fraction of each line's flow attributable to each generator and demand at any given time. The heuristic rule applied by the algorithm is simple: at any network node, the flow in a transmission line is divided proportionally to the existing total flows. While this rule makes intuitive sense, it cannot be proven to be accurate since electricity does not propagate like water in a pipe and cannot be traced or ascribed to any specific line.

The Average Participation method's main advantages are its simplicity, clarity of use, and the absence of issues related to marginal methods since no slack bus is involved. In the extensive experience of the authors with the Average Participation method, no cases have been found that challenge its validity.

This method has been applied by New Zealand's Transpower[4], the Polish grid company, and, more recently with additional features, in the Central American electricity market and in India (see Box 7 below). The cost allocation method currently being considered by SAPP is largely based on Average Participation.

The Average Participation method is not the only network utilization method that appears to yield reasonable results. A different yet sensible approach is the Aumann-Shapley method[5] (Junqueira et al. 2007). Both methods have produced very similar numerical results when applied to the same case studies, although the Aumann-Shapley method is more complex.

BOX A.4

TRANSMISSION COST ALLOCATION BETWEEN THE DIFFERENT STATES IN INDIA

In India, state transmission networks are managed and regulated by state load dispatch centers (SLDCs) and state electricity regulatory commissions (SERCs), while the Inter-State Transmission System (ISTS) is overseen by regional load dispatch centers (RLDCs) and the National Load Dispatch Centre (NLDC), and regulated by the Central Electricity Regulatory Commission (CERC). All regions are synchronously connected.

In June 2010, the CERC introduced the Sharing of Transmission Charges and Losses Regulations for the ISTS, marking a significant overhaul of the cost allocation framework. Central to this framework is the transition from a regional postage stamp methodology to a usage-based hybrid approach known as the Point of Connection (PoC) charging method. This method allocates transmission costs to ISTS customers (generators and distribution companies, each bearing 50%) based on their geographical location within the ISTS. The PoC method was designed to eliminate pancaking charges and incentivize decisions that reduce congestion.

The PoC method involves three calculation stages:

- **First Stage:** The cost of the ISTS is allocated to network users based on their usage, employing a combination of the Average Participation and Marginal Participation methods.
- **Second Stage:** A uniform national charge is added.
- **Third Stage:** Charges are grouped into one of three slab rates.

BOX A.4 (*Continued*)

The second and third stages involve adding a “socialized” component to the final transmission charges, which is less relevant 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 collects data on the network for five seasonal periods throughout the year, as well as peak and off-peak times. Seasonal differentiation is crucial for accurately estimating annual network usage due to varying flow patterns.

Step 2. Network truncation: Multiple load flow analyses are performed to model actual network usage. The overall grid is truncated by removing intra-state networks based on the flow and voltage levels of each line, which vary by region. In a regional context, this step identifies assets belonging to the regional network.

Step 3. Defining slack buses: Slack buses are nodes on the grid that balance injections and withdrawals. The Average Participation method is used to identify these slack buses, determining which generators supply power to each demand. Generators in power-deficit regions primarily serve local demand, while those in power-surplus regions also supply other regions. The flow patterns considered are based on forecasts for the coming year.

Step 4. Applying Marginal Participation to determine flows: The NLDC conducts an altering current (AC) load flow analysis for projected nodal injections and withdrawals, considering the slack buses identified in Step 3. This analysis calculates how much the flow in each network branch increases when injection or withdrawal at a bus is increased by 1 MW, yielding the marginal participation factor and loss allocation factor for each customer.

Step 5. Grouping nodal charges into zones: Nodes that are geographically and electrically contiguous, with similar charge ranges, are grouped into zones and assigned a PoC zonal charge. For withdrawal charges (paid by distribution entities), zones typically align with state boundaries. For injection charges (paid by generators), zones group electrically close generators or even individual generators. Losses are allocated by zone, attributed to demand entities within the zone. The energy scheduled for each entity includes both its consumption and the allocated losses.

Endnotes

1. The World Bank Group (2024) report, "*Transmission Pricing Methodologies for Use in the Pan-Arab Electricity Market*," and the Asian Development Bank (2020) report, "*Harmonizing Power Systems in the Greater Mekong Subregion*," provide an overview of various transmission pricing approaches, including their advantages and disadvantages.
2. 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.
3. In Chile and Argentina, the choice of method can be explained by the placement of the slack bus in the dominant load centers (Santiago and Buenos Aires, respectively). This approach ensures that most of the demand does not incur transmission charges (in Argentina, demand does not pay transmission charges at all). Consequently, charges to generators increase with their distance from the main load center, which is a reasonable outcome.
4. The earliest reference to this method identified by the authors of this document is a paper by Professor Grant Read of the University of Canterbury, titled "*Pricing and Operation of Transmission Services: Long Run Aspects*," found in Turner, A. Principles for Pricing Electricity Transmission, Transpower, August 1989. More recent references include (Bialek 1996) and (Kirschen, Allan, and Strbac 1997).
5. The Aumann-Shapley method seeks to distribute the total cost of network infrastructure based on each user's impact on the system. The process involves calculating the marginal contribution of each user to the network's capacity and costs. To do this, the method evaluates how the presence or absence of each user affects the overall cost of providing transmission services. This approach ensures that the charges reflect both the user's share of the total capacity used and their contribution to any required system upgrades or expansions. While the method is praised for its fairness and efficiency since it takes into account the marginal impact of each user on the network's cost structure, its complexity arises from the detailed analysis and sophisticated mathematical framework required to implement it effectively.

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