Florence School of Regulation

A Study on the Inter-TSO Compensation Mechanism

October 2005

Robert Schuman Centre
for advanced studies

European
University
Institute

FLORENCE SCHOOL OF REGULATION

A Study on the Inter-TSO Compensation Mechanism

October 2005

The Florence School of Regulation (FSR) was commissioned by the Italian Independent System Operator GRTN to carry out an independent review of the current state of development on inter-TSO compensation mechanisms and to define a sound, transparent, cost-reflective and non-discriminatory method for assessing them. The FSR assembled a small independent expert group, chaired by Jacques de Jong (Clingendael International Energy Programme, The Hague) and including Ignacio Pérez Arriaga and Luis Olmos (Comillas University, Madrid) and Richard Green (Birmingham University). The authors of the report were helped by Heiko Neus and Daniel Schlecht of the IAEW (Institute of Power Systems and Power Economics, Aachen University) who provided relevant analysis and data on the issue of standardised costs. The authors also received advice and support from the FSR staff.

The publication of the study indicates that the FSR regards it as an authoritative contribution to the public debate and that for this reason it should be in the public domain. The FSR does not, however, hold opinions of its own; the views expressed in its publications are the responsibility of the authors.

Table of Contents

Part B: Implementation

List of Tables

List of Figures

Executive Summary

The Report focuses on the methodological approach to inter-TSO compensation (ITC). It also contains a numerical exemplification of the proposed methodology. The methodological assessment covers both the evaluation and the allocation of network costs. Different approaches for each of these aspects are considered and assessed with respect to a set of specific criteria. The assessment is designed to generate solutions for the longer-term mechanism which should replace the temporary mechanism which has been in operation since March 2002 among the majority of ETSO members in continental Europe (the ETSO mechanism).

The assessment used a set of specific criteria, covering *cost-reflectiveness* (compensations for actual costs incurred, independent of the location of political borders), *cost coverage* (costs attributable to cross-border flows, related to losses, new and existing infrastructure), *network cost evaluation* (i.e. forward-looking, long-run average incremental costs), *consistency with transmission regulation* (i.e. Regulation 1228/2003, including the overall framework of transmission regulation as required by the developing and integrating IEM), *suitability for the European network* (cross-border flows in the context of the highly-meshed European network), *technical soundness* (sound engineering principles without arbitrary assumptions or procedures), *implementation* (reasonably straightforward and cost effective to implement), and *transparency* (easy to understand and verify).

Methodology

ITC mechanisms may provide compensation for the costs incurred for hosting *all cross-border flows*, or compensation may be limited to costs related to transit flows. The introduction of an ITC mechanism was prompted by the abolition of transit fees and the current temporary ETSO mechanism provides compensation for transit-related costs only, whereas this Report proposes that the ITC mechanism be extended to provide compensation for all cross-border flows. The reasons are:

- consistency with the provision of Regulation 1228/2003 and its Article 3;
- equity in the treatment of generators and load, as the allocation of network costs should be related to network utilisation and each generator and load should contribute, directly or indirectly, to network costs irrespective of the nature of the flow produced by their injection or withdrawal;
- avoiding placing an excessive burden on the TSO of an exporting system in case network expansion is necessary to support electricity export, given that most of the transmission costs are recovered from load;
- avoiding the need to identify transits, which requires simplifying and arbitrary assumptions;
- consistency with the approaches used and developed under Regulation 1228/2003 regarding cross-border congestion management, which do not discriminate between the different types of international flows; and
- more generally, consistency with the paradigm of a single, integrated European electricity market.

The evaluation of network costs preliminarily requires the *definition of the Horizontal Network* (HN) (assumed to be affected by international flows). We propose a method for identifying the HN which is an extension of the one currently employed by ETSO in the transitional ITC mechanism. According to this method a network element belongs to the HN if a 100 MW increase in injection and withdrawal at all possible pairs of (injection and withdrawal) nodes located in different TSO areas results, in at least 5% of the representative operating conditions (snapshots), and for at least 5% of the node pairs, in a variation of the power flow over the element by more than 1 MW.

As regards network cost evaluation, the Regulation requires the concept of *forward-looking, long-run average incremental cost*. We propose applying LRAIC at the level of the individual network components and for cost calculations to be based on a relatively short list of standardised components. The appropriate increment in utilisation to be used should be equal to the level of flow over a network element under 'average' operating conditions, which would generally require a similar additional element to accommodate the increment. Peak-loading characteristics should be taken into account, by applying different weights to different scenarios (snapshots).

Standard procedures are required for calculating capital costs and the cost of operation and maintenance, including an assumption about their relative weights in regulated revenues.

Standardised costs for different types of HN elements should be used, avoiding distortions, perverse incentives and administrative cost burdens when different TSO cost levels are applied. These standard costs should only be used in the context of the ITC scheme. Topographical differences should be taken into account with typical standardised cost figures. The fact that the sizing of investments in network infrastructure was decided by the local TSO/Regulator and that the existing HN infrastructure was mainly developed to support electricity flows within each TSO area implies that the costs of these existing elements should only be allocated to external agents in relation to the actual level of utilisation. We recognise however that in some cases the benefit of a new infrastructure is clearly shared by several TSOs, to the extent that the decision on the investment may be taken jointly, or endorsed, by all the TSOs concerned. In these cases we propose that external agents should be allocated, through the ITC mechanism, a proportion of the cost of the entire capacity of the new infrastructure, equal to the share of the total flow on the element for which they are responsible, irrespective of the actual level of utilisation of such capacity. However, if instead these decisions are taken independently by the local TSO/Regulator, the same rule as for existing assets would apply, irrespective of the fact that the investment may also benefit other TSO areas.

The costs of losses are calculated by valuing the actual losses at the hourly prices on national electricity markets.

A number of alternative *approaches for network cost allocation* have been considered in the recent debate on ITC. These approaches are described and compared, classified into two categories, according to whether they identify responsibility for network costs of individual agents, or assess the overall responsibility of all external agents. These approaches are shown in the following table.

Network cost allocation level	Nature of flows for which compensation is provided	
	Transits	Cross-border flows
Individual agent/node	-	AP, SAP, MAP, MP, AS
External agents	WWT, ETSO, APT	WW

These approaches are described, discussed and assessed on the basis of the criteria outlined above. On the basis of this assessment, the *AP method* is recommended as the best available method, since it combines many of the characteristics considered desirable. In particular, the AP method:

- provides compensation with respect to all cross-border flows;
- allows responsibilities to be defined at the individual agent/node level;
- produces results which are independent of the location of political borders, and therefore is fully consistent with the 'single system paradigm';
- provides a coherent framework for defining entitlements and responsibilities for compensation;
- does not involve the creation of fictitious scenarios which may be characterised by power flows that have little to do with the physical reality of the actual power system;
- does not create particular problems when implemented in the highly-meshed European network;
- is transparent and easy to verify.

The main drawback of the AP method is the need for extensive data (as for some other methods). This is not, however, a particularly serious problem given that meaningful results can be obtained by restricting the analysis to a number of representative snapshots.

Implementation

The part of the Report dealing with implementation develops a classification and standard costing of transmission infrastructures, based on public literature and engineering judgements. Cost drivers are discussed and applied to overhead lines, transformers, and substations, being the relevant elements of the Horizontal Network to be taken into account. Furthermore, a numerical implementation has been made, using flow data for 72 scenarios, provided by ETSO. The AP method is applied, using the standardised cost figures as developed. Two cases are presented for the AP method, one where only the cost of the used fraction of each line is allocated, with a reliability margin of 30% of the thermal capacity, and one where the whole cost of each line used is allocated. Total amounts of net payments then vary between M€ 34,5 and M€ 104,2 respectively. This latter case can also be compared with the present ETSO mechanism, using the same data. The relevant amount is then M€ 266,3. Further discussing the comparisons, it is to be noted that Italy and France are always the main net payers, whereas Switzerland and Austria the main net recipients. Country payments under AP are largely restricted to neighbouring countries, whereas the ETSO mechanism requires almost every country to pay to almost all others. It should be stressed, however, that the only purpose of presenting numerical results is to demonstrate the possibility of effectively computing inter TSO-payments under the preferred methodology.

Final remarks

Discussions on ITC mechanism have been on the agenda since 1998 and have a largely symbolic value. The objective is to find an equitable and simple ITC mechanism, but to date all discussion and analysis have demonstrated that completely objective methodologies on flow calculations and on cost attribution have not yet been found, and arguably never will be. In the view of the authors, the AP method is however the best available, and produces reasonable and economically meaningful results in the liberalised internal European electricity market with its highly meshed, multi-TSO operated electricity network. We trust that the proposals in this study may contribute to a timely conclusion of the protracted and time-consuming decision-making process.

1 Introduction

From the outset cross-border transmission tariffs have been the main issue discussed in the Florence Forum process, a process established to discuss which further measures, over and above the 1996 Electricity Directive,[1] were required to ensure the development of the Internal Electricity Market (IEM). Existing cross-border or transit charges were seen as a major impediment to the development of cross-border trade, especially since they could lead to 'pancaking', whereby each Transmission System Operator (TSO) would levy a charge on transits for meeting its own system costs. The newly created Association of European Transmission System Operators (ETSO) was invited, and strongly encouraged, to propose a scheme for the cost allocation of cross-border loop flows and transfers and for their redistribution among TSOs. Such a scheme should then replace any border charges in the IEM.

However, the entire issue subsequently became highly symbolic and of political relevance, and dominated the Florence Forum agenda for quite some time. ETSO had to cope with very different positions amongst its members, especially when these positions were not counterbalanced by a national regulator or bound by the European Directive. National regulators were in the process of developing their own positions and their cooperation in the Council of European Energy Regulators (CEER), while the European Commission was acting carefully to maintain the balance in the voluntary Florence Forum process. There was no mandate to translate its conclusions into legally binding commitments.

The discussions in the Florence Forum process, and the inability to reach broadly accepted and implemented conclusions, resulted in the course of 2003 in a Regulation[2] on conditions for access to the network for cross-border exchanges in electricity. The Regulation requires guidelines, as defined for example in Article 3, which defines the way in which:

> '…*Transmission system operators shall receive compensation for costs incurred as a result of hosting cross-border flows of electricity on their networks* [and this] *compensation* […] *shall be paid by the operators of national transmission systems from which cross-border flows originate and the systems where those flows end'*.

Drafts of this guideline were discussed during 2004, but made little concrete progress. A voluntary 'transitional' inter-TSO compensation mechanism, defined within the framework of the Florence Forum and reluctantly accepted by the Commission and the CEER, has been in operation since March 2002. Initially intended to last only until the end of 2002, it has repeatedly been extended and modified. In late 2003, ETSO was finally able to agree on a compensation mechanism based on transparent and verifiable cost allocations and without any export charges. This system was more positively received by the Commission and the regulators, it was implemented in 2004 and is still in operation. The transitional mechanism is based on the Transit Key concept, which assumes a proportional allocation of responsibility in the utilisation of the network of each TSO between transit and local flows; a proportional allocation rule is also assumed in the allocation of the responsibility for transits to net imports and exports, irrespective of the geographical location of the countries concerned.

The mechanism is not in line with the Regulation, since it does not cover all cross-border flows and is not based on a standardised approach to the network costs to be covered.

---

[1] Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996, concerning common rules for the internal market in electricity.

[2] Regulation (EC) No. 1228/2003 of the European Parliament and Council of 26 June 2003.

The Florence School of Regulation (FSR) has been asked to conduct an independent review of the current state of development and to define a sound, transparent, cost-reflective and non-discriminatory method for the inter-TSO compensation mechanism which should promote the further development of the IEM and replace the transitional mechanism with effect from 1 January 2006. In defining the method for the inter-TSO compensation mechanism, the study should take into account:

- the need to identify those parts of the network affected by cross-border flows;
- the results of the implementation of the transitional mechanism for the years 2002–2005;
- the criteria specified in Article 3 of the Regulation, which indicate in particular that:
  - compensation payments shall be made on a regular basis with regard to a given period of time in the past. *Ex-post* adjustments of compensation paid shall be made where necessary to reflect costs actually incurred;
  - the magnitude of cross-border flows hosted and the magnitude of cross-border flows designated as originating and/or ending in national transmission systems shall be determined on the basis of the physical flows of electricity actually measured in a given period of time;
  - the costs incurred as a result of hosting cross-border flows shall be established on the basis of the forward-looking, long-run average incremental costs (LRAIC), taking into account losses, investment in new infrastructure, and an appropriate proportion of the cost of existing infrastructure, as far as infrastructure is used for the transmission of cross-border flows, in particular taking into account the need to guarantee security of supply. When establishing the costs incurred, recognised standard-costing methodologies shall be used. Benefits that a network incurs as a result of hosting cross-border flows shall be taken into account to reduce the compensation received.
- The treatment of perimeter countries, as well as the effect of reconnection of the two UCTE zones (ETSO and SETSO areas).

Therefore, in assessing the various methods for inter-TSO compensation (ITC) which have been proposed in the debate on this issue, and in defining the longer term method which is proposed for introduction from January 2006, a set of *specific criteria* will be used.

As a general remark, we should point out that the concept of the EU Internal Electricity Market (IEM) should be considered as a *sine qua non* for any ITC-mechanism. This political and legal concept is based on the idea of free trade in electricity throughout the EU, crossing political borders without any barriers. Ideally, this would require a single EU Transmission System Operator, without any cross border flows by definition. As this simple solution is not a realistic option for the time being, costs coming from cross border electrical flows must be allocated and re-allocated between the national TSOs. When assessing the various methodologies and methods for determining the allocations and re-allocations, the concept of the single EU electricity market should be considered as an essential element. We have therefore given this ‘single system paradigm’ a central place in our assessment criteria. That is, if two national markets were to be joined together as a single (sub-)system, bringing the IEM closer, this should not disrupt the operation, or affect the results, of the ITC-mechanism. In other words, the compensation obtained for the new sub-system should be equal to the sum of those computed for the two national markets.

The following set of criteria will therefore be used for the assessment:

1. *Cost-reflectiveness.* The ITC method should provide compensation for the standard costs incurred as a result of hosting cross-border flows of electricity on a TSO’s grid.

Cross-border flows should be assessed on the basis of actual measured flows of electricity. Benefits incurred by a network as a result of hosting cross-border flows should be taken into account to reduce the ITC received. The ITC method should define network cost allocation as independently as possible from the location of political borders ('single system paradigm'), and of commercial transactions ('non-transaction-based charges').[3]

2. *Cost coverage*. The ITC method should provide compensation for the costs attributable to cross-border flows and related to losses and investment in new infrastructure as well as existing infrastructure, taking into account the need to guarantee security of supply.
3. *Network cost evaluation*. Compensation should be based on the forward-looking long-run average incremental costs of network infrastructure.
4. *Consistency with transmission regulation*. The ITC method should be consistent with the provisions of Article 3 of Regulation 1228/2003. It should also allocate network cost in a way which is consistent with the overall framework of transmission regulation as required by the developing and integrating IEM, in particular in the areas of investment in new infrastructure, locational signals for operation and investment, congestion management and the process towards harmonisation of (the structure of) transmission tariffs.
5. *Suitability for the European network*. The ITC method should provide a sound approach to assigning responsibilities for the costs arising from cross-border flows to the TSOs of the grids in which these flows originate and end in the context of the highly-meshed European network.
6. *Technical soundness*. The ITC method should be based on sound engineering principles and should not rely on arbitrary assumptions or procedures.
7. *Implementation*. The ITC method should be reasonably straightforward and cost-effective to implement.
8. *Transparency*. The ITC method should be easy to understand and verify.

ITC mechanisms, by their very nature, should involve the following three steps:

- Determination/calculation of the compensation that each TSO is entitled to receive (from other TSOs) for the costs incurred for hosting cross-border flows on its network;
- Determination/calculation of the compensation that each TSO is required to pay for the costs incurred by other TSOs in relation to the cross-border flows arising from injections into and withdrawals from the TSO's grid; and
- Determination/calculation of the net position of each TSO as the difference between the level of the compensation the TSO is entitled to receive and the compensation payments it is required to make.

The determination of the compensation that each TSO is entitled to receive requires, in turn, the definition of which network is (assumed to be) affected by international flows, of the nature of

---

[3] It should be noted however that any ITC method involves a degree of aggregation of responsibilities at the TSO level and this inevitably requires reference to the boundary of control areas, which in many cases correspond to political border. The requirement in the criterion relates to the objective of having responsibilities for the utilisation of the HN identified in a way which is independent of political borders.

the flows on the network with respect to which compensation is provided, of the costs for which compensation is provided, of the methodology for evaluating these costs and of the methodology for determining which costs of the network in each TSO area are the responsibility of external agents. Furthermore, the determination of the compensation that each TSO is required to pay requires the definition of the methodology for assigning the costs of the network in each TSO area to the various agents/TSOs.

The remainder of the Report is structured into two parts, and a concluding chapter. Part A deals with the methodological issues which are relevant for the definition of the longer-term ITC mechanism. This part includes:

- Chapter 2, which addresses the two issues which determine the scope of the longer-term ITC mechanism: the nature of the flows on the network for which compensation is provided, and the definition of which network is (assumed to be) affected by international flows;
- Chapter 3, which discusses methodological approaches to LRAIC and proposes a solution which responds to the specific criteria outlined above, notably those on cost-reflectiveness, cost coverage and cost evaluation;
- Chapter 4, where the different approaches that have been proposed in the recent debate for assigning network costs to different agents (generators/load/TSOs) are reviewed and compared. All the approaches assume that the extent of utilisation of—elements of—a TSO's grid by the different agents is a suitable measure of the economic benefits that these agents obtain from using the network and therefore can be used as guidance for assigning responsibility for network costs. The different approaches, however, are characterised by the different ways in which they determine the degree of utilisation of the various elements of the network by different agents, as well as the nature of the flows for which compensation is provided. On the basis of the assessment of the different approaches with respect to the specific criteria outlined above—most notably those on cost-reflectiveness, on consistency with transmission regulation, on suitability for the European network, on technical soundness, on implementation and on transparency—Chapter 4 identifies the most appropriate approach to be included in the longer term ITC mechanism; and
- Chapter 5 which draws on the considerations presented in the previous chapters to characterise a methodology for a longer term ITC-mechanism.

Part B illustrates, with a numerical exemplification, how the methodological approach outlined in Part A can be implemented. This part contains:

- Chapter 6, which illustrates the grid cost assumptions which are used for the numerical exemplification; and
- Chapter 7, which describes the approach and presents the results of the numerical exemplification.

Chapter 8 concludes the Report with some final remarks.

Part A

Methodology

2 The scope of the longer-term ITC mechanism

This chapter addresses two aspects which are particularly important in defining the scope of the longer-term ITC mechanism:

- the nature of the international flows on the network with respect to which compensation is provided; and
- the network which is (assumed to be) affected by international (transit/cross-border) flows and the costs incurred which are therefore eligible for compensation, at least in part, through the ITC mechanism.

2.1 Transits versus cross-border flows

The different approaches to network cost allocation proposed in the recent debate differ as regards the type of international flows eligible for compensation. ITC mechanisms may provide compensation for the costs incurred for hosting cross-border flows, or compensation may be limited to costs related to transit flows. In this context:

- transit flows over a TSO's grid are defined as power flows which affect this grid but which both originate and end in the grid(s) of other TSO(s);
- cross-border flows over a TSO's grid are defined as power flows which cross at least one border.

Therefore, for each TSO, the notion of cross-border flows is more general, since it includes not only transit flows, but also import and export flows (i.e. cross-border flows which originate or end in the TSO's grid). This section considers the relative merits of limiting compensation to the costs related to transits or, alternatively, of extending it to the costs incurred for hosting all cross-border flows.

Various arguments have been put forward in favour of limiting compensation to the costs related to transit flows. One argument is based on the fact that the introduction of an ITC mechanism was prompted by the abolition of transit fees with a view to avoiding 'tariff pancaking'. Therefore, to the extent that the ITC mechanism is expected to provide economic compensation to TSOs that replaces the revenues from transit fees, the focus of the mechanism might be limited to compensating TSOs for costs related to transits hosted on their grid (and not extended to compensate for the costs incurred for hosting all cross-border flows). Furthermore, and in accordance with its historic background, the temporary ETSO mechanism in operation since March 2002 only provides compensation for transit-related costs.

Another argument notes that the Draft Guidelines published for consultation by the European Commission pursuant to Article 8 of Regulation 1228/2003, in the July 2004 and the September 2004 versions, limits compensation to costs associated with hosting transit flows. This approach was proposed in the Draft Guidelines even though the Commission itself admitted that it would have been conceptually sounder to relate compensation to all cross-border flows. The Commission approach on this specific aspect was criticised by the European Regulators Group for Electricity and Gas (ERGEG), which considers it essential that: '*the ITC mechanism* […] *take[s] into account as far as possible all cross-border flows, complying with Article 3 of the*

Regulation'.[4] Regulation 1228/2003 (Article 3, par.1), is quite explicit on this point, requiring that: *'Transmission system operators shall receive compensation for costs incurred as a result of hosting cross-border flows of electricity on their networks'.*[5]

There are other valid reasons for extending the ITC approach to provide compensation for all cross-border flows. For instance, while for electricity generated and consumed within the same TSO area the TSO receives use-of-system charges from both generators and load, for cross-border flows originating or ending in the area it only receives charges from either generators or load, respectively. Both types of flows (internal and cross-border) are caused by the concurrent action of generators injecting electricity into the grid and load withdrawing electricity from the grid. Both generators and load should therefore contribute, directly or indirectly (through the ITC mechanism), to cover the costs associated with the electrical utilisation of the network that these flows are responsible for, irrespective of whether such flows are internal or cross-border.[6] In this respect, the argument put forward by the European Commission, in the Draft Guidelines, that the extension of the ITC approach to all cross-border flows would have no material effect on the level of compensation entitlements and responsibilities—as *the impact on the networks of the importing country and the exporting country implies the same level of costs*—does not appear to be backed up by any logical substantiation, and it is generally contradicted by simulation results.

Furthermore, in most jurisdictions the cost of energy transmission is generally paid by load. The choice to levy most of these charges on load is justified on various grounds. For example, the fact that load is less price-elastic implies that recovering transmission costs mainly from load minimises distortions. Another justification rests on the fact that even if transmission costs were imposed on generators, this would increase total generation costs and, depending on the structure of transmission tariffs and the level of competition in the generation market, these higher costs might well feed through to the wholesale price of electricity, thus effectively transferring the burden to consumers.

If transmission costs are mainly charged to consumers, a jurisdiction which has to strengthen its grid to accommodate additional generating capacity mainly devoted to export, would face an increase in grid costs without a corresponding increase in the level of internal consumption on which these costs are recovered. Therefore, load in that jurisdiction would face higher transmission charges in order to pay for the grid expansion required to support exports of electricity from the jurisdiction. One can argue that the increased generation in the jurisdiction, even if mainly destined for exports, benefits local consumers, in terms of higher reserve margins and a wider choice of electricity sources. However, it can also be argued that it may be appropriate for the ITC mechanism to provide compensation for costs generated by exports, as well as transits.

Moreover, while it is relatively straightforward to identify cross-border flows (as those flows which cross at least one border) at the implementation stage, the identification of transits is more complex, and requires either some degree of simplification and somewhat arbitrary assumptions or reference to contractual paths.

For example, the approach used by the current temporary ETSO mechanism estimates transit flows over a TSO's grid in each hour as the minimum, in that hour, between the sum of the

---

[4] ERGEG, comments on the proposal for Guidelines on Inter-TSO Compensation (ITC) drafted by the European Commission, presented at the 11th meeting of the European Electricity Regulatory Forum, held in Rome on 16–17 September 2004.

[5] It is therefore surprising that the Draft Guidelines published by the European Commission and referred to above limit compensation to costs associated with transits.

[6] The principle of non-discrimination among the flows on the grid (and indirectly among the agents that cause these flows) is central to the creation of a truly integrated European electricity market.

cross-border flows in the import direction and the sum of the cross-border flows in the export direction. While actual transit flows can be measured in this way, not all the flows which are measured in this way necessarily represent transit flows, as shown in Annex 1.

Finally, treating transits and cross-border flows equally in the context of the ITC mechanism is consistent with the approach adopted for other regulatory aspects which are relevant for the development of the IEM. For example, in the context of congestion management, the framework being developed under Regulation 1228/2003 does not discriminate between different types of international flows. Therefore, despite the fact that the development of an ITC mechanism was prompted by the abolition of a fee on transits and the characteristics of the current ETSO temporary mechanism, the extension of compensation to the costs attributable to all cross-border flows:

- complies with the provisions of Regulation 1228/2003;
- is justified in economic terms, as the allocation of network costs should be related to network utilisation and each generator and load should contribute, directly or indirectly, to network costs irrespective of the nature of the flow produced by their injection or withdrawal;
- represents a more consistent approach, as it does not require the somewhat fictitious identification of transit flows;
- is consistent with the approaches used and developed under Regulation 1228/2003 for cross-border congestion management; and
- more generally, is consistent with the paradigm of a single, integrated European electricity market.

On the basis of the above considerations, *we propose to extend the compensation provided by the ITC mechanism to the costs associated with hosting all cross-border flows*.

2.2 Identifying the relevant network: the Horizontal Network

All the methods for network cost allocation considered in the recent debate are implemented using a suitable representation of the European electricity network. In fact, part of the analytical effort to date has been devoted to identifying which part of the grid in the various TSO areas is relevant for international flows. The result of this effort is the definition of the Horizontal Network (HN), which includes all those grid elements in the different TSO areas which are significantly affected by international flows.

As indicated in Section 4.1, some of the approaches to network cost allocation described provide indications as to whether, and to what extent, individual network elements are affected by international flows. If one of these approaches is selected for the longer-term ITC mechanism, a wider definition of the HN will not result in a higher ITC level. However, some other approaches described in Section 4.1, including the current ETSO mechanism, provide compensation with respect to the costs of all the elements included in the HN. In this case it is obvious that an appropriate definition of the HN is essential to avoid over-compensation. In general, we believe that the HN needs to be properly defined, to focus the analysis on that part of the network which is actually affected in a significant way by international flows.

We propose a method for identifying the HN which is similar to the one currently employed by ETSO in the transitional ITC mechanism. In the ETSO mechanism, the HN is the set of grid elements on which the power flow is significantly affected by purposely-defined elementary transits. For each TSO's network, these elements are identified by modelling the impact of all possible elementary transit flows. An element of the network is included in the HN if an additional 100 MW elementary transit flow changes the flow on the element by more than 1 MW.

The ETSO mechanism provides compensation for the costs associated with hosting transits and, correspondingly, focuses on ‘elementary transit flows’ in identifying the HN. As indicated in Section 2.1, we propose to extend the compensation provided by the ITC mechanism to the costs associated with hosting all cross-border flows. Coherently, the HN should include all those grid elements which are significantly affected by cross-border flows, and not just by transits.

Therefore, the approach we propose for identifying the HN considers, for each TSO area, not just all possible elementary transit flows, i.e. the flows between any pair of nodes at the borders of the area, but all the potential international flows which could affect the area, which also include the flows between any node located at the border of the TSO area and any node located inside the area. It is clear that there are many of these latter nodes in each TSO area, even more so if we consider the grid at all voltage levels. However, it can be argued that only the transmission grid—primarily the EHV grid and possibly some portion of the HV grid supports the transport of electricity over long distances, as it is the case with international flows, the remaining grid mainly serving a local distribution purpose. Therefore, in considering the flows between border nodes and internal nodes, we can focus on flows originating or ending at nodes on the EHV grid and at nodes on the portion of HV grid which performs transmission functions. Correspondingly, we can limit our assessment to the elements of the EHV grid and of the transmission portion of the HV grid.

Moreover, we want to avoid the inclusion of grid elements in the HN if they are significantly affected by international flows only under very infrequent operating conditions, or only when very specific (border-border or border-internal) node pairs are considered. For this purpose, we introduce some frequency thresholds in the method.

On the basis of these considerations we propose the following procedure to identify the HN. The starting point is a representation of the transmission network of the TSO areas included in the analysis, and a number of ‘representative snapshots’, describing the pattern of flows over this network at different times, generally meant to reflect different operating conditions.

For each TSO area we define all possible pairs of injection and withdrawal nodes which are relevant for the identification of the HN. These include any pair of nodes at the borders of the TSO area, as well as any pair of a border node and an internal node on the transmission grid.

We propose that, for each TSO area, a network element belongs to the HN if a 100 MW increase in injection and withdrawal at the defined pairs of (injection and withdrawal) nodes results, in at least 5% of the representative snapshots and for at least 5% of the node pairs, in a variation of the power flow over the element by more than 1 MW.

This approach for identifying the HN may appear cumbersome, but it is not excessively complex, and it would not have to be run every year.

Finally, as indicated in Section 4.1, some of the approaches described there assume a simplified representation of the HN, for example by collapsing several elements of the HN into a single node. However, even in these cases, the definition of the HN represents the starting point for the simplification characterising these approaches.

3 Methodological approaches to Long-run Average Incremental Cost (LRAIC)

For the ITC mechanism, Article 3, par. 6, of Regulation 1228/2003 states that:

> *The costs incurred as a result of hosting cross-border flows shall be established on the basis of forward-looking, long-run average incremental costs, taking into account losses, investment in new infrastructure, and an appropriate proportion of the cost of existing infrastructure, as far as infrastructure is used for the transmission of cross-border flows, in particular taking into account the need to guarantee security of supply. When establishing the costs incurred, recognised standard-costing methodologies shall be used. Benefits that a network incurs as a result of hosting cross-border flows shall be taken into account to reduce the compensation received.*

In addition to the above provisions in the Regulation, the explanatory notes to the Draft Guidelines on inter-TSO Compensation prepared by the European Commission in July and September 2004 suggest the following approach for determining network costs:

> *From 2005 the total network costs to be taken into account are to be based on the principle of forward-looking long-run average (incremental) costs, to be applied solely to the ITC. Regulators would be required to submit their estimates of forward-looking LRAIC, according to standard interpretation and methodology based on the estimated forward-looking investment requirements on the basis of current price levels and technology.*

The standardised methodology includes the following steps:

- country-specific assessments of projected future investment to be taken into account in LRAIC, excluding the cost of land purchase, access arrangements and permits; the existing network configuration is to be maintained (no optimisation) and the projected investment requirements would be discounted to present value using an appropriate discount rate;
- common financial and operating cost assumptions, such as a WACC of 6%, pre-tax, and a depreciation period of 40 years.

The July version explicitly states that the LRAIC principle is interpreted in the same way as for telecommunications, i.e. that the replacement or duplication costs of the existing assets on the basis of current price levels and technology would be a suitable approximation to forward-looking LRAIC. In addition, the Draft Guidelines and their explanatory notes stipulate a number of cost ranges for HN assets, from which regulators should not deviate when providing their LRAIC estimates under the scheme. These ranges have led to criticism from ETSO. Due to continuing difficulties in establishing a standardised approach for determining the costs to be covered under the ITC scheme, since 2003 ETSO has used the concept of 'regulated costs', whereby each TSO uses the cost of the HN that is accepted by its national regulator. This approach is still used and has been accepted for the time being by the European Commission and by national regulators, pending the adoption of the Guidelines under the Regulation.

The regulators (CEER, ERGEG) have never been very outspoken regarding their position on the LRAIC issue. Since their original proposal for a long-term scheme for ITC in September 2002, the CEER 'only' refers to costs to recommend that they should:

> *take into account energy losses and the costs of new and existing network assets* [and] *be based on standardised cost assessments, for the single purpose of this scheme only.*[7]

In its formal response to the September 2004 Draft Guidelines, ERGEG only notes that the draft is based on LRAIC, in accordance with provisions of Regulation 1228/2003. Recently, ERGEG has started a more detailed review of the September 2004 Draft Guidelines.

This chapter examines ways of calculating the long-run average incremental cost of transmission and is structured as follows. Section 3.1 discusses why the concept has been important for regulators. Section 3.2 sets out the way in which the LRAIC should be interpreted, taking each network element individually, using a definition of 'incremental' flow that would require another network element to be added. In Section 3.3, we argue that the use of standardised measures of cost may be preferable to country-specific measures, even though national regulators should clearly base their prices on the country's own costs. Section 3.4 discusses the possibility of treating new assets differently from existing assets in the horizontal network, effectively raising the amount to be recovered through the ITC mechanism if new investments have been approved by other system operators who are affected by their construction. Section 3.5 assesses the proposed implementation of LRAIC against the most relevant of the criteria developed in Chapter 1 of this Report.

3.1 Costs and regulation

Measuring costs is one of the most important tasks in regulation (or indeed in business), since almost everyone would agree that prices should normally be related to costs. This concept has two dimensions. First, the average level of prices should be sufficient to ensure that an efficient company can recover its costs (including an appropriate amount of profits). Second, the structure of prices should reflect the relative costs of producing the firm's different products or services. If a product is relatively expensive to produce, it should have a relatively high price. This should produce a 'fair' result in distributional terms, in that agents (firms or consumers) purchasing an expensive product have to pay a high share of the producing firm's costs. It will also encourage economic efficiency, in that the agents choose quantities such that their willingness to pay for their marginal purchase of a product equals its price. If this price equals the marginal cost of production, then the agents' valuation of the product will equal its cost, and we would not be able to improve welfare by producing more or less of it.

The problem for regulators is deciding how much of the costs of a multi-product firm to allocate to each of its products. At the outset, regulators tended to use average cost rules, such as the fully distributed cost principle. This required the firm to identify the direct costs of each of its products, and then to distribute all of the remaining costs across its products, according to an agreed rule. A typical rule would allocate the indirect costs in proportion to the direct costs, so that if half of the costs could not be directly allocated to products, each product's fully distributed cost would be double its direct cost.

The disadvantage of the fully distributed cost rule is that it may discourage some economic production. For example, in the case of rail regulation in the USA, some bulk freight customers may be willing to pay more than their direct costs for using the railway, but would not find it worthwhile to use the railway if their contribution to indirect costs was too great. Fully distributed cost pricing required these customers to make a large contribution to indirect costs, and so they preferred to use an alternative means of transport. This was bad for those customers, but it was also bad for the railway's other customers. Without any contribution from bulk freight customers, they had to pay all the indirect costs themselves. They may prefer the bulk

---

[7] *Inter-TSO Compensation Mechanism: A Model for the Longer-term,* CEER Position paper, 30 Sept. 2002.

freight customers pay a full share of the indirect costs, but if this is not possible, they are better off with a small contribution from bulk freight customers than with none at all. In the *Ingot Molds* case,[8] the railway's competitors persuaded regulators that fully distributed cost prices should still be used, ensuring that the bulk freight customers stayed away from the railway, thus (indirectly) raising charges for other customers.

The answer is to move away from the fully distributed cost rule and towards a set of prices that ensures that the price paid by each group of customers covers the direct costs of the products they buy and makes a contribution towards the company's indirect costs that reflects their willingness to pay for such products. This leads to the concept of subsidy-free prices—the minimum and maximum price for each group of customers (or product) that ensure that no group is made worse off because the company is offering its product to another group. Here the relevant principle is cost causality, i.e. consumers should be responsible for the costs that they cause the firm to incur in meeting their demand. Cost causality will not give a single number, however, because the costs imposed in meeting a customer's demand depend upon whether that customer is being served in isolation, or alongside many others. The maximum subsidy-free price is the stand-alone cost of providing the product to a single group of consumers. If a group of consumers is paying more than this, then they could get the product more cheaply by setting up a company that would only serve them, charging them the cost of doing so. In effect, consumers who pay more than the stand-alone price are subsidising another group.

The minimum subsidy-free price is given by the incremental cost of serving a group of consumers. If the consumers are paying this price, then the firm's costs and revenues will fall by exactly the same amount if it stops serving them. If they are paying any less than the incremental cost, they are subsidised by the other customers of the firm; the firm's costs will fall by more than its revenues if it stops serving them, and it would be able to use the surplus to reduce prices to other consumers. If consumers pay more than the incremental cost of serving them, then the firm's revenues will fall by more than its costs if it stopped selling to them, which would in turn create a deficit which would have to be made up by other consumers. Note that the concept of subsidy-free prices is not sufficient to define a firm's price structure exactly. Most firms have a lot of indirect costs, so that there is a wide band between the incremental cost and the stand-alone cost of each product. In this context, some other pricing rule is required. One popular rule among economists is Ramsey pricing, which sets mark-ups in inverse proportion to each consumer group's responsiveness to price. In popular language, this could be described as 'charging what the market will bear'.

The use of incremental cost is also important if there is entry into part of a formerly monopolised industry. Entry would be efficient (in a static sense) if the entrant's cost of providing the product or service to some customers is less than the cost of the monopolist doing so. Efficient entry can be encouraged with suitable charges for accessing the monopolist's network, which is often still needed to deliver the product to consumers. The efficient access charge is given by the Baumol-Willig rule, i.e. that the payment to use the network should equal the price charged by the monopolist for the product (including delivery), less the incremental cost of providing the product (excluding delivery). If an entrant has to make this payment for using the network, then it will only be able to undercut the monopolist (and hence find some consumers willing to buy from it) if its cost of producing the product is lower than the monopolist's incremental cost of doing so. In this case, however, entry will reduce the industry's overall costs and should be encouraged. Note that the Baumol-Willig rule explicitly does not consider the incremental cost of the network, and should not be taken as a model for inter-TSO compensation. It is only mentioned here as an example of the use of incremental costs in economic regulation.

---

[8] I. C. C. v. NEW YORK, N. H. & H. R. CO., 372 U.S. 744 (1963).

How should the incremental cost of serving each group of consumers be measured in order to apply a pricing rule? The concept most often applied in practice is the long-run average incremental cost (LRAIC). The long-run nature of the concept implies that the (annualised) cost of capital equipment should be included, even if there is currently some spare capacity. Including 'average' in the concept implies that we are not looking at really small increments in output, but at the cost of meeting reasonably large increases in demand, averaged over the size of the increment. Once again, this moves us away from the question of whether there is currently spare capacity (which would give a low short-run marginal cost) to look at the cost of producing additional output in a longer term 'steady state'.

This is the background against which the Commission has decided that the permanent scheme for inter-TSO compensation shall be based upon LRAIC. It is worth pointing out, however, that sending efficient price signals is hardly the aim of the ITC compensation mechanism. In the first place, the efficient price signal for many cross-border flows in electricity would be zero, discounting losses, if the flows did not affect a congested interconnector. Where flows affect such an interconnector, market-based congestion management schemes, such as those based on explicit or implicit auctions, are available and being implemented in many jurisdictions. If an auction sets an appropriate price for the use of an interconnector, then setting an additional charge will prove inefficient. However, such an additional charge is, in general, necessary to cover the total costs of transmission, and the allocation of this charge to the network users should not be arbitrary, as they have different levels of responsibility in the development of the network. Therefore, there is also some potential for efficiency when assigning what remains to cover the total network costs.

The aim of the ITC mechanism is in fact the other primary objective of an economic system, that of equity. The scheme is intended to ensure that transmission operators receive compensation for costs they incur in hosting flows from other countries, and to pay some of the costs that they impose upon others. The resulting net payments will be too small, relative to most TSOs' revenues, to act as meaningful signals, and as already argued, signals are not really necessary. The fact that equity, rather than efficiency, should be the objective (and the appropriate aim) of the ITC mechanism affects many of the recommendations presented in this Report. The LRAIC can be used as the basis of the mechanism, because even though the concept has been developed in the interests of efficient pricing, its use will not detract from the mechanism's equity. LRAIC may result, however, in a higher volume of monetary transactions than the regulated transmission costs that are currently used to compute inter-TSO payments. The question now is how to implement a system based on LRAIC.

3.2 The basis for calculating LRAIC

There are several issues which need to be addressed when defining an approach to calculating LRAIC and applying it in the context of the ITC mechanism. In particular:

- whether LRAIC should be applied at the level of the entire HN, or focusing on individual HN elements;
- which level of increment in utilisation to consider;
- to what extent peak-loading elements should be included;
- whether new HN elements should be treated in the same way as existing infrastructure;
- whether compensation should be provided for spare capacity on the HN.

This section addresses the first three issues. The last two issues, which are inter-related, are addressed in Section 3.4, after a discussion of the choice between the use of standard or national cost values in Section 3.3.

The first issue is whether to calculate LRAIC at the level of an entire network or looking at the specific individual components. If we were to work at the level of an entire network, the first question to be answered is the (almost philosophical) one of what constitutes an incremental use. Is it an additional flow over every single component? Or is it an incremental flow between two single points on the network? And if so, should two points be chosen at random, or should every possible permutation of points be considered and an average taken? Once this choice has been made, the details of each particular network need to be studied in order to determine how much investment is required to allow additional power flows on various routes. However, the relationship between LRAIC and the technical-economic aspects of electricity networks is not a straightforward one. Therefore, we propose to apply the LRAIC approach at the level of the individual network components. We note that many of the cost allocation methods discussed in Chapter 4 allow this allocation to be performed for each individual network component.

The next issue we focus on is the determination of the increment in the utilisation of individual network elements that is to be considered for the calculation of LRAIC. On the basis of the considerations presented in Section 3.1—where we noted that the reference to 'average' in the LRAIC concept implies that we should not consider really small increments in output, but rather the cost of meeting reasonably large increases in demand, averaged over the size of the increment—we argue that the appropriate increment in utilisation to be used for calculating LRAIC is equal to the amount of flow that would require a copy of the element to be added to the network.

In this case, we need cost estimates for the different components in order to perform the overall cost allocation calculations. Obtaining cost estimates for every network component would be a massive task. In this respect we are helped by the requirement to use forward-looking cost estimates which should even out any differences in asset types or ages that might result in different historic costs for otherwise similar components. This Report recommends that the cost calculations should be based on a relatively short list of standardised components. The advantages of simplicity and transparency should far outweigh any disadvantages from the loss of accuracy in the calculations. The costs for the lines on this list should of course be expressed in terms of euros per circuit-km, rather than per circuit, given the variety of lengths of transmission circuits.

A final issue is to what extent the approach to LRAIC should contain any peak-loading element. Clearly, if cross-border flows only used the 'spare' capacity of the HN in a TSO area—in the sense that this capacity would require to support local flows at other times—an argument could be made for cross-border flows to be allocated a less-than-proportional share of the HN costs in that TSO area. In the extreme, it could be argued that cross-border flows should not be allocated any of such costs, as their use of the HN does not require any additional capacity being made available, beyond the level required to support local flows. If, instead, cross-border flows were to use the HN capacity in a TSO area at peak times, when local flows also use this capacity heavily, the TSO would have to make additional capacity available to support cross-border flows and it seems only fair that these flows are allocated a share of the costs of this capacity, even if they do not use much of it at other times.

On the basis of these considerations, we propose that the ITC mechanism should have some peak-loading characteristics, even though we do not propose to take this to the extreme and allocate HN costs only on the basis of utilisation at peak times. Instead, we propose that, in calculating the share of costs of a HN element to be allocated to external agents, different weights are applied to the different scenarios (snapshots) representing different operating conditions, with higher weights applied to scenarios which correspond to the highest utilisation of the HN element. In particular, we propose that weights should be proportional to the level of flows on the HN element.

3.3 Standard versus national costs

Regulation 1228/2003 and the Draft Guidelines in particular, suggest that country-specific costs should be used in the ITC mechanism. We recommend that some differences in national circumstances should be taken into account, but that this should not lead to accepting national cost estimates without reservation. We recommend using standardised costs, but in a way that reflects national characteristics that can increase (or reduce) costs relative to the European average. This could involve calculating (different) standard figures for transmission lines built across different types of geographical terrain, and using the figure for the terrain that each line actually crosses.

The reason for proposing the use of (differentiated) standard costs is to avoid perverse incentives for the TSOs (and the Regulators) involved. In fact, each TSO's gross entitlement to compensation will be based upon the proportion of flows in its area defined as cross-border flows under the ITC mechanism and on the cost of the HN (elements) in that area. Raising the cost of the HN in a TSO area will increase the entitlement to compensation for the TSO. Since raising the cost of the HN in one TSO area will not affect the amount of compensation that the TSO is required to pay for using the HN in other TSO areas, the net effect will be to increase the net ITC entitlement, or reduce net ITC payments. This gives every TSO an incentive to raise the 'declared' cost of its own HN.

To deal with this (potential) problem, the European Commission would need to verify that no jurisdiction declares excessive costs, claiming that they reflect actual cost levels. This verification would be possible, perhaps using LRAIC standards, although it would add to the cost of administering the scheme. The practical impact of using national costs would be that countries with low costs per asset would tend to receive less from the ITC mechanism, while those with high costs would receive more. In most cases we are not talking about compensating countries for making new investments, but about reallocating the task of paying for existing assets, so that using standard costs for existing assets would avoid 'subsidies' from low-cost to high-cost countries. It would also respect the forward-looking nature of LRAIC, since new investments would be made using internationally-traded equipment, and so price variations between countries would be much lower than in the past, when national suppliers played a much more important role.

As already mentioned, a standardised approach does not mean that there should be no differences between countries. Topography can have significant effects on the cost of an electricity network, and countries differ greatly in their topography. We recommend that circuits (and perhaps other assets) should each be assigned to one of a small number of topographical types, and that each type should have its own cost figure. Chapter 6, for example, gives figures for the cost of lines built across flat land, medium mountains, and high mountains. For implementing such an approach in the ITC mechanism, clear definitions of topographical categories would be required. Then all HN elements would have to be surveyed and assigned to the different categories. A simple categorisation can be made on the basis of a line's height above sea-level. Lines could be unambiguously assigned on the basis of the average height above sea-level at the base of their towers, and a different standard cost used for each of the three categories. The problem with this simple categorisation is that it ignores the difference in cost between building lines across a mountain plateau (relatively cheap, despite the height above sea-level), and across rolling hills (arguably more expensive, despite the lower height). Clearly something more complicated is required. Furthermore, it might be necessary to consider other types of terrain, such as forests or urban areas. No simple classification will capture all the variations in cost, but we need a scheme that gives a general reflection of the fact that some TSOs will incur higher costs because of the terrain in which they have to operate. The task of assigning assets to topographical types could be large, but would only need to be performed once and would therefore seem to be worthwhile the effort.

Given the capital cost of the assets, we can calculate the equivalent annual cost, which includes the cost of writing down the asset's value over time (depreciation), and gives the owner a fair rate of return on the net asset value. We propose to use an annuity depreciation method, which ensures that the annual payment is equalised over the life of the asset—in the early years, most of this is the return *on* the asset, since little of its value has been written off at this stage. Towards the end of the period, the net asset value is low, as are the returns on the asset, and most of each annual payment consists of depreciation—the return *of* the asset.

Moreover, operating and maintenance costs must be considered alongside the capital costs of the transmission network. This Report recommends making the assumption that the ratio of operating costs to capital costs is the same for all transmission assets (and effectively to apportion any operation and maintenance costs across all assets in proportion to their capital costs). The share of allowed capital costs in total regulated revenues for transmission companies in Europe is, on average, around 60%.[9] Therefore, in order to include operating and maintenance costs the capital cost levels should be grossed-up by 5/3.

The final cost component is the cost of losses. It might be possible to use simplifying assumptions as to the level of losses over standard network components under standard conditions, but this is not actually necessary. The level of losses in each network component in each of our snapshots is known, and thus, depending on the allocation methods discussed in Chapter 4, we can apportion responsibility for each MWh of actual losses among the various users of the HN. We need to convert these values from MWh to money, however. Again, some simplifying assumption could be used, but the various European electricity markets give well-defined values in every hour, and so we should use these values. Some countries do not yet have an electricity market, and the price in a neighbouring market (or the average of two markets' prices) should be used instead. Similarly, the average of the neighbouring hours should be used on the rare occasions when a price is not set in one of the thinner markets.

To conclude, the proposal is to use standard costs in the context of the ITC mechanism. National transmission prices should continue to be regulated in whatever way the national regulator believes is most appropriate, in line with the principle of subsidiarity, and should be based on national cost levels. For the ITC mechanism, using standard costs is a way of simplifying the system, whereas for national regulators it would be more complicated to use standard, rather than national, costs.

3.4 New versus existing assets

Should new assets be treated differently from existing assets? Regulation 1228/2003 and the Commission's Guidelines mention both, but do not appear to require that they be treated differently.

We start from the consideration that the sizing of investment in network infrastructure has in the past, and generally still is, decided by the local TSO, sometimes in discussion with its Regulator. Therefore, other TSOs have very little to say on the dimension, and therefore cost, of this infrastructure. Moreover, the existing HN infrastructure was mainly developed to support electricity flows within each TSO area. For these reasons the costs of existing HN elements should be allocated to external agents only to the extent to which the flows for which these agents are responsible actually utilise those elements. In this way, any unused capacity will not attract compensation by external agents.

---

[9] See, for example, the calculations performed by Ofgem for the latest price control of the National Grid Company. Ofgem (2000) *The transmission price control review of the National Grid Company from 2001* (London, Office of Gas and Electricity Markets).

For example, consider a line with a thermal capacity of 130 MW and available capacity of 100 MW. At times when the flow over the line is only 50 MW, then only half of the cost of the line will be taken into account in the ITC mechanism and allocated to (internal or external) users. The remaining (half of the) cost will be left fully with the local TSO.

When considering new assets, we must take into account that investments can be made within one TSO area that will increase the capacity on its interconnectors with another TSO area, or even ease congestion within the latter area. If the TSO considering whether to invest is only concerned with flows inside its boundaries, it will have little incentive to undertake the investment. From the perspective of the European transmission system as a whole, this would be inefficient. Could the ITC mechanism provide a better incentive to make investments of this kind?

The case for treating new investments differently from existing assets implicitly depends on the fact that the approach proposed for these latter assets does not provide compensation for any unused portion of the capacity of the HN element. Therefore, the extent to which a new investment can recover its costs from the ITC mechanism will depend on how heavily it is used. If it is heavily used, then the compensation that the TSO receives for the external use of the asset should provide sufficient additional incentive to build the asset. This does not mean that the full cost would come from foreign TSOs, since there would generally be domestic usage of the asset as well, even if its primary purpose was to relieve congestion abroad or to facilitate external utilisation of the TSO’s network.

If the asset is not heavily utilised, however, the payments will be less than the cost of making the asset available, offering little incentive to the local TSO to build it. This does not mean, however, that it is not worth building the asset in the first place, as it may be more economic to ‘over-build’, thus anticipating higher future use, or else the asset may relieve congestion and allow other assets to be used more intensively or otherwise benefit other TSO areas. The question is whether the ITC mechanism should reflect this situation and include provision for a different treatment of new infrastructure, if these are clearly beneficial to cross-border flows (or to other TSO areas).

The ITC mechanism should not impede the development of the European network, but should instead promote it, even in those cases when benefits are spread over different TSO areas. One way to achieve this objective would be to allow TSOs freely to agree additional compensation for new investments. This approach is based on the Coase Theorem which argues that if property rights are well-defined, private negotiation should be able to reach an efficient outcome, without external intervention. The conditions for the theorem to apply also include a relatively small number of agents, each having sufficient information about the situation: conditions that apply in this case. Property rights are well-defined in this situation, for a TSO has no need to make an investment that will only benefit its neighbours. The ITC mechanism may provide some incentive to do so, but if the expected payments from this scheme, plus any benefits to the TSO’s own network, are insufficient to cover the cost of the investment, then the TSO would be ill-advised to make the investment. If the advantages to the neighbouring TSO are sufficiently great, however, it could generate benefit by paying for part of the cost of the investment, if this ensured that the investment would then take place. This side-payment would have to exceed the difference between the cost of the investment, the net domestic benefits to the TSO making it, and its net receipts from the ITC mechanism. If the benefits to the neighbouring TSO exceed the side-payment, this implies that the investment would be an efficient use of resources. If the benefits to the neighbouring TSO are not sufficient to offset the side-payment that would be required, it is likely that the overall benefits of the investment are less than its cost.

The move to a system of such side-payments—especially as regulators are not keen on side-payments—will not necessarily be an easy one. It will probably require a cultural change in the industry, and national regulators will have to be persuaded that these payments are a legitimate additional expense that should be included when calculating the appropriate level of national transmission tariffs. The approach suggested here is a second-best solution designed to replicate, at least qualitatively, the Coase Theorem approach within the framework of the ITC mechanism. It provides for a different treatment of new infrastructure, when the decision on the investment is taken jointly, or endorsed, by all the TSOs concerned. In particular, it is proposed that in this case external agents be allocated, through the ITC mechanism, a proportion of the cost of the entire capacity of the new HN element equal to the share of the total flow on the element for which they are responsible. In this way external agents would also be allocated a share of the costs of any unused capacity of the HN element. When calculating the payments the actual (agreed) cost of these HN elements could also be used, rather than the standardised costs used for existing assets, if this was also agreed by the TSOs concerned.

It is worth stressing that this treatment only applies when the decision to develop the new infrastructure is taken jointly, or endorsed, by all the TSOs concerned. These TSOs would be those which, on the basis of the ITC mechanism, will be responsible for contributing to the costs of the new HN element by a share greater than a predefined threshold (e.g. 3%). If instead, the decision to develop the new HN element is taken independently by the local TSO/Regulator, the same rule as for existing assets would apply, irrespective of the fact that the investment may benefit other TSO areas as well. In this way one can try to avoid the risk of TSOs facing an increase in the payments they are required to make under the ITC mechanism, as a result of investment decisions taken solely by other TSOs, which, if the costs of the additional unused capacity were included for compensation under the ITC mechanism could have an additional incentive to over-build.

One final aspect to consider is whether the proposed approach is able to promote the efficient development of the European network. To the extent that each TSO will be willing to endorse an investment decisions by another TSO if it can expect that the benefits to its area from the new infrastructure exceed the contribution it will be required to make, through the ITC mechanism, towards the costs of the infrastructure, the approach should result in the specific treatment for new infrastructure being applied in all those investments for which benefits to the different concerned TSOs are higher than the corresponding cost contributions. This is clearly only a subset of all the initiatives for which overall benefits would exceed costs, as the ITC mechanism may allocate costs differently from the way in which benefits accrue. However, we expect in most cases the two conditions to coincide, and the proposed approach should be able to promote the efficient development of the European network as required by Regulation 1228/2003.

3.5 Assessment of the proposed approach to implementing LRAIC

Finally, we assess the proposed approach for the implementation of LRAIC against the most relevant criteria set out in Chapter 1, which are cost-reflectiveness, cost coverage, and network cost evaluation.

- *Cost-reflectiveness*. The proposed approach uses standard cost values for the main network components, but with some degree of differentiation to reflect topographical conditions. The approach is therefore well suited to represent the different characteristics of the network in the various TSO areas, while it neglects variations in unit costs for similar components (in similar topographical conditions) between different TSO areas. This later characteristic is in line with the requirement to use forward-looking cost values. Moreover, the proposed approach generally provides compensation for the cost of an individual HN element only to the extent that cross-border flows actually utilise such an element (this is meant only for ITC calculations, and not for the complete cost recovery of the considered element).

- *Cost coverage*. The proposed approach provides compensation for the costs of losses and for the costs of existing and new infrastructure, with a different treatment for the latter if the decision is taken jointly, or endorsed by all the TSOs concerned.
- *Network cost evaluation*. The proposed approach ensures that compensation is based on the forward-looking, long-run, average incremental costs of network infrastructure.

On this basis, the proposed approach to long-run incremental cost meets the evaluation criteria of this Report, and provides a sound basis for the implementation of an ITC mechanism. Having decided which costs should be included in the ITC mechanism, we now have to decide how they should be allocated between participants, and this is the subject of the next chapter.

4 A review of existing approaches to cost allocation in inter-TSO compensation

This chapter examines the approaches to network cost allocation for the ITC mechanism proposed in the recent debate on this issue, together with the approach used in the ETSO mechanism currently implemented among the majority of ETSO members in continental Europe. The comparison of the approaches is based on the criteria presented in Chapter 1.

This chapter is organised as follows. Section 4.1 describes the different approaches to network cost allocation. Section 4.2 provides an assessment of these approaches based on the criteria outlined in Chapter 1. This assessment is carried out for each criterion individually and summarised with a score ranging from zero (minimum) to three (maximum). Not all eight criteria are used in this assessment, since the cost allocation approaches considered here are not specific with respect to the coverage of costs for which compensation is provided or the way in which these costs are evaluated. Section 4.3 presents an overall comparison of the various approaches and concludes with recommendations on method selection.

4.1 Methods of network cost allocation

In the recent debate a number of alternative ways to allocate network costs in the context of the ITC mechanism have been proposed. These approaches include:

- the Average Participations (AP) method, and two of its variants: the Simplified Average Participations (SAP) method and the Modified Average Participations (MAP) method;
- the Marginal Participations (MP) method;
- the Aumann-Shapley (AS) method, i.e. a method based on the Aumann-Shapley value;
- the With-and-Without (WW) method applied to all cross-border flows;
- the With-and-Without (WWT) method applied to transits;
- the Average Participations applied to Transits (APT) method;
- the current ETSO mechanism.

All these approaches assume that the degree of utilisation of network elements by any group of agents constitutes a suitable indicator of the share of the costs of these elements to be assigned to such agents (see Chapter 1). The approaches differ in the nature of the flows (all cross-border flows or only transits) for which compensation is provided, and in the level at which the allocation of network costs is performed. In particular, with respect to this latter aspect, the methods can be classified into two categories according to whether:

- they are designed to identify the responsibility of individual agents—or, more correctly, of agents located at each individual (injection or withdrawal) node—in the utilisation of the various elements of (some representation of) the HN; or
- are based on an assessment of the overall external utilisation of these elements.

Table 4.1 classifies these methods according to the nature of the flows for which compensation is provided and the level at which network costs are allocated.

Table 4.1: Classification of network cost allocation methods

Network cost allocation level	Nature of flows for which compensation is provided	
	Transits	Cross-border flows
Individual agent/node	-	AP, SAP, MAP, MP, AS
External agents	WWT, ETSO, APT	WW

Chapter 2 examined the nature of the international flows with respect to which compensation is provided and indicated that extending the ITC mechanism to provide compensation for the costs associated with all cross-border flows would be consistent with the provisions of Regulation 1228/2003, justified on economic grounds and conducive to the development of the IEM. Therefore, here we could have restricted our attention to those methods which consider all cross-border flows. However, notwithstanding the provisions in Regulation 1228/2003, the European Commission, in its 2003 Discussion Document on the ITC mechanism,[10] extended its attention to methods (such as WWT and APT) which limit compensation to the costs associated with transits. Therefore, in this chapter we describe all the methods listed above, whilst stressing that, in our view, only those methods which extend compensation to the costs associated with all cross-border flows comply with the provisions in Article 3 of Regulation 1228/2003.

4.1.1 Methods based on estimates of the responsibility of individual agents in network costs

These methods are based on an evaluation of the extent to which each agent, or rather, agents located at each node, use the grid. They then compute the participation of agents located on the network of each TSO in the utilisation of the grids of other TSOs by aggregating the participations of these agents in the utilisation of all the network elements in each of the grids of these latter TSOs. Therefore, methods included in this category are equally suitable to compute ITC payments and nodal transmission tariffs.

The main representatives of this category are the Average Participations (AP) method and the Marginal Participations (MP) method. Some variants of the AP method are also included in this category, as they retain the same underlying philosophy. An approach presented by the Belgian regulator (Commission for the Regulation of Electricity and Gas, CREG), and the Swiss Federal Office for Energy (SFOE) at the Florence Forum meeting in February 2002 is also included in this category, as it is broadly equivalent to the AP method. Finally, methods which apply cooperative game theory to allocate responsibility for network utilisation, such as those based on the Aumann-Shapley value, may also be considered in this category.

4.1.1.1 The Average Participations method

The Average Participations (AP) method assumes that it is possible to trace the flows of electricity over the various elements of the HN (lines, transformers) from the nodes where electricity is produced and injected into the network to the nodes where it is withdrawn from the network and consumed, and *vice versa*. In tracing power flows over the HN, the AP method employs a proportionality assumption about the way in which electricity flows into and out of individual nodes. In particular, it assumes that in each node of the network the *actual* inflows are allocated proportionally to the *actual* outflows, and *vice versa* (the 'proportionality branching rule'). We should emphasise that AP does not create or compute any artificial flows

---

[10] European Commission, Discussion Document, Inter-TSO Compensation, 23 June 2003. The Document was presented at the 10th meeting of the European Electricity Regulatory Forum in Florence on 8–9 July 2003.

by introducing any arbitrary assumption. AP only makes use of the *actual metered flows* in the network. The allocation rule in AP just assigns the *actual* inflows to the *actual outflows* and *vice versa*. The algorithm used by the AP method is illustrated in Annex 2.

By tracing power flows over the HN, it is possible to identify and measure the responsibility of each injection and withdrawal node for the power flows on each HN element. In particular, the responsibility of the agents located at each node for the power flow over a specific network element is assumed to be equal to the share of the flow over the element that can be traced backward or forward to the node. The responsibility of each TSO in the utilisation of a specific HN element is then determined as the aggregate responsibility of all injection/withdrawal nodes located on the grid of that TSO for the flow on the HN element in question. This responsibility can be expressed in monetary terms by allocating the cost of the HN element to each TSO in proportion to the TSO's responsibility in its utilisation.

The monetary compensation that one TSO is required to pay for the use of another TSO's grid is thus the sum of the compensations that the former must pay for the use of all the HN elements of the latter's grid. By appropriately aggregating these monetary compensations, it is possible to determine the total compensation that each TSO is required to pay (for the use of other TSOs' grids), and receive (for the use of its grid by generators and loads located on the networks of other TSOs). In particular, the monetary compensation that one TSO is entitled to receive (from the other TSOs) is calculated as the sum of the compensations that the TSO is owed by the other TSOs, while the monetary compensation that one TSO has to pay (other TSOs) is obtained as the sum of the compensations that the TSO in question owes the others.

4.1.1.2 Variants of the Average Participations method

The two variants of the AP method considered here are the Simplified Average Participations (SAP) and the Modified Average Participations (MAP) methods. These methods do not involve the definition of individual agents' responsibility in the utilisation of network elements and strictly speaking, do not belong to this category. However, their inclusion is justified as these methods are inspired by the same philosophy of the AP method, since they too trace power flows over some simplified representation of the HN using the actual pattern of flows as a reference. In particular, the SAP method applies the AP methodology to a simplified representation of the HN, which may be a useful temporary solution while detailed power flow data are not available. The MAP method aims to address the (apparent) problem which may arise when the AP method is applied to relatively small, well-balanced but heavily transited TSO areas. In this case, the AP method may result in a level of responsibility of the agents located in this TSO area for the utilisation of the network in other TSO areas which is higher than expected.

Simplified Average Participations

The SAP method is based on a simplified representation of the HN, in which each TSO area is collapsed into a single node and injections into, and withdrawals from, the grid of the TSO area are assumed to take place at this single node. The lines joining these nodes represent the interconnections between TSO areas. A procedure similar to the AP method is then used. Given the simplified representation of the HN which it employs, the SAP method only requires information on power flows across the borders between the different TSO areas. However, because of this simplified representation of the HN, the SAP method is unable to model explicitly the pattern of flows within each TSO area and, in particular, the degree to which each MW generated or consumed by external agents uses, on average, the TSO's grid in comparison to the average utilisation by each MW both generated and consumed within the TSO area.

Instead, the method uses TSO-specific coefficients which represent weighting factors for the utilisation of the TSO's network by external agents.

Modified Average Participations

The MAP method is based on the assumption that generators and loads in a TSO area primarily use the local grid, and that only the imbalance between generation and demand within a TSO area affects the flows on the grids of other TSOs. This assumption may be relevant in the case of relatively small, well-connected and heavily-transited TSO areas; in this case, the AP method may produce results that, although correct if assessed in the context of the single-system paradigm, may appear to assign generators and loads in the area a disproportionately high responsibility for the utilisation of the grids of other TSOs (the so-called 'small country issue').[11] The MAP method was developed to address this situation.

The MAP method considers each TSO area in turn. In order to determine the responsibility of agents located in the TSO area in the utilisation of other TSOs' grids, all HN elements in the TSO area are collapsed into a single node. This will be a generation or load node, depending on whether the TSO area is a net exporter to, or net importer from, other TSO areas. The representation of the HN in the other TSO areas is left unchanged. The AP method is then applied. If the TSO area is a net exporter the net power flow is traced downstream, while if the TSO area is a net importer the net power flow is traced upstream. In this way, only the net flows of each TSO area are considered when computing the responsibility of agents located in that area for the utilisation of the elements of other TSOs' networks.

4.1.1.3 The CREG/SFOE approach

At the Florence Forum meeting in February 2002, CREG and SFOE presented an alternative approach to the ETSO mechanism. If applied to the same HN representation the CREG/FSOE approach would be equivalent to the AP method and would involve:

- defining the (per MW) unit cost of each element of the HN;
- tracing the flows on the element forwards and backward to identify the withdrawal nodes and injection nodes that are responsible for such flows;
- assigning responsibility for the cost of each HN element to each injection and withdrawal node according to the proportion of the flow over the element which is caused by the power injections/withdrawals at the node.

The equivalence between the CREG/SFOE approach and the AP method rests on the fact that the rules used to trace electricity flows on the grid are the same in both cases. Both the CREG/SFOE approach and the AP method apply the proportionality branching rule to allocate the flows. The allocation of responsibility in the flow over each HN element to injection and withdrawal nodes is thus the same.[12]

Minor differences with respect to the AP method may arise from specific assumptions in the implementation of the CREG/SFOE approach. For example, when the approach was presented

---

[11] This criticism of the AP method derives from the aprioristic assumption that generation in a country is primarily devoted to meeting the local load. If political borders are ignored when determining responsibilities for network use, then this difficulty disappears.

[12] This holds true irrespective of whether the analysis is conducted by tracing flows from injection nodes towards withdrawal nodes, or *vice versa*, or by tracing the flow over the network element forwards (towards withdrawal nodes), and backwards (towards injection nodes).

at the Florence Forum meeting, it was assumed that flows would only be traced until they cross a political border (thus limiting compensations to neighbouring TSO areas). However, if the CREG/SFOE approach and the AP method are implemented using the same assumptions, they deliver identical results.

4.1.1.4 The Marginal Participations method

The Marginal Participations (MP) method (also known as the 'areas of influence' method) is based on an assessment of the extent to which a unit increase in the power injected into or withdrawn from the grid at each node affects the various HN elements. This assessment produces the 'marginal participation' of each node in the power flow over each HN element. The corresponding 'total participation' of the node is then obtained by multiplying its marginal participation by the net power injection/withdrawal at the node. The responsibility for the utilisation of an HN element—and the corresponding costs—are apportioned to the agents located at the various nodes proportionally to their total participation.[13] The algorithm used by the MP method is illustrated in Annex 3.

The MP method, like the AP method, computes individual responsibilities for market agents. Compensations at the TSO level are then calculated by aggregating these responsibilities for all agents in the TSO area.

However, as injection into, and withdrawal from, the grid should always be kept balanced, this method requires matching each increase in the power injection/withdrawal at a node of the HN with a corresponding increase/decrease in the power withdrawal/injection at one or more other nodes. The implementation of this approach, therefore, involves the choice of the node(s)—the 'slack' node(s)—which will balance/offset the marginal increase in the power injection/withdrawal simulated at each node. The slack node(s) must be the same for all injections into and withdrawals from the network. One option is to choose, as the slack node, a consumption node close to a large load centre. Alternatively, the balancing modification to the power injection/withdrawal in the system can be distributed to all injection/withdrawal nodes in proportion to the corresponding level of generation/load. The choice of slack node(s) is particularly important since the compensation responsibilities and entitlements vary very significantly with different slack node(s).[14]

4.1.1.5 The Aumann-Shapley method

The Aumann-Shapley (AS) method uses cooperative game theory to determine the allocation of responsibility in grid utilisation among different agents. Cooperative game theory may provide a sound approach for the allocation of sunk costs among a set of players. The technical literature

---

[13] Note that the aggregate total participation of all agents located at all the nodes in the power flow over a HN element may be higher (or lower) than the actual power flow over that element, as total participations are computed using a linearity assumption as to how marginal participations apply to total net injections/withdrawals. However, the distortion introduced by this assumption is likely to be limited.

[14] Several studies have concluded that changing the slack node in the MP method results in the unit transmission charges of all network users increasing by the same amount; see C. Vázquez, L. Olmos and J. I. Pérez-Arriaga, 'The Selection of Slack Bus in Mechanisms for Transmission Network Cost Allocation based on Network Utilization', paper presented to the 14th Power Systems Computing Conference (PSCC) Conference, Seville, 24–28 June 2002. Therefore, differences among nodal transmission charges are independent of the identity of the slack node chosen. However, compensations among countries, which most of the times are internally unbalanced, depend crucially on the decision on what node to choose as the slack.

contains several examples of the application of cooperative games to the allocation of the cost of the transmission grid among its users.[15] Some of these are based on the computation of the Aumann-Shapley value for each player (grid user), and the allocation of the cost of each line to the various users according to the corresponding value.[16] In order to describe the AS method it is essential to define the underlying game in terms of both the players that take part in it, and the rules that apply.

The objective of the game is to allocate the cost of each element of the HN among the grid users (generators and loads). The cost of each element is allocated on a separate basis. The players are the generators, which inject power into the grid, and loads, which withdraw power from the grid. A first decision regards the way that the total costs of the HN are split between these two sets of agents. The portions of costs to be recovered from generators and loads then need to be allocated; this allocation is carried out using symmetrical procedures.

The procedure to allocate the portion of costs to be recovered from generators considers all possible orderings of these generators. For each ordering, each generator is considered in turn and matched to a set of loads, according to the following criteria:

- the loads to be matched to the generator have not already been matched to other generators;
- total electricity consumption by the matching loads should equal total electricity production by the generator;
- the total impact of the corresponding (incremental) transaction on the power flows over the HN is minimised (in terms of utilisation cost).

The power flow on each HN element that the generator is held responsible for is considered to be equal to the impact on the flow over the element of the incremental transaction between the generator and the chosen set of loads. For each different ordering of generators, the fraction of the cost of each HN element to be recovered from generators is allocated among them, on the basis of their responsibility in the power flow over the element. The cost allocated to a generator is obtained as the average of the costs allocated to this generator over all the different possible orderings.

The procedure to allocate the portion of the cost of each HN element to be recovered from loads is based, symmetrically, on each load being matched to a set of responding generators.[17]

---

[15] See, for example, P. A. Kattuman, J.W. Bialek, and N. Abi-Samra, ‘Electricity Tracing and Cooperative Game Theory’, paper presented at the 13th Power Systems Computing Conference (PSCC) Trondheim, Norway, 1999; see also, X. Tan and T.T. Lie, ‘Application of the Shapley Value on transmission cost allocation in the competitive power market environment’, IEE Proceedings on Generation, Transmission and Distribution, 2002, Vol. 149 (No. 1), pp. 15–20. G. C. Stamtsis and I. Erlich, Use of cooperative game theory in power system fixed-cost allocation. IEE Proceedings Generation, Transmission and Distribution, 2004, Vol. 151 (No. 3), pp. 401–6. F. Evans, J.M. Zolezzi, and H. Rudnick, Cost Assignment Model for Electrical Transmission System Expansion: An Approach Through the Kernel Theory. IEEE Transactions on Power Systems, 2003, Vol. 18 (No. 2), pp. 625–32.

[16] Any cooperative game involves the formation of coalitions of players that cooperate in order to obtain a better payoff, i.e. in order to reduce the total grid payment each of them faces. The Aumann-Shapley value of a player (agent) is defined as the average incremental contribution of the player to the total payment to be made by the coalitions in which it can participate.

[17] For a more detailed description of this method see, Mercados Energeticos, *Plan Estratégico para Modernización del Marco Regulatorio*, Report for the Peruvian tariff regulator, OSINERG, May 2005, in particular Volume II, section 2.3.1, and section 2 of the Annex. The author of the report is currently working on an English version.

4.1.2 Methods based on estimates of the responsibility of external flows as a whole in network costs

All the methods in this category are designed to assess the overall external utilisation of the elements of a TSO's network. In all of these methods the compensation due to a TSO is based on the effect that international flows have on the internal flows in the TSO area. Given that identifying international flows through the grid of a TSO area, which often correspond to a country, requires reference to the political borders (of the country), all the methods in this category produce results for ITC that depend on the location of these borders. The most relevant methods in this category are: the With-and-Without method, applied both to cross-border flows (WW) and to transits (WWT), and the Average Participations method applied to transits (APT). The ETSO mechanism is also presented and commented in this section, as it can be interpreted as a simplified version of the WWT method.

4.1.2.1 The With-and-Without methods

The With-and-Without (WW) method and the With-and-Without applied to Transits (WWT) method, are based on a comparison of the flows on the HN of each TSO area between two different scenarios. The first corresponds to the actual system operation, and the second results from excluding either cross-border flows (in the WW method), or transit flows (in the WWT method). In this context, transits can be defined and allocated to the different interconnection lines in various ways. The approach adopted by ETSO for identifying transits in its current mechanism—which defines hourly transits as the minimum between the total hourly flow in the import direction and the total hourly flow in the export direction—is often used. Then, transits can be allocated to the different interconnection lines carrying flows in import and export directions in proportion to the measured cross-border flows on these lines in each direction. The flows over each of the HN elements in the two scenarios are computed using a load flow model. The resulting differential flow (between the two scenarios) over each HN element is attributed to cross-border flows/transits and therefore to external agents. The algorithm used by the WWT method is illustrated in Annex 4.

It should be noted that, in the WW method, when all cross-border flows are removed to produce the 'without' scenario, the generation and demand within the considered TSO area become isolated from the rest of the system and possibly unbalanced. In such cases internal generation and/or demand must be adjusted to keep the system balanced.

The compensation that a TSO is entitled to receive for hosting cross-border/transit flows can be computed in several ways. Compensation can be calculated for the external utilisation of each element of a TSO's network and then all these compensations can be summed to obtain the total compensation to which the TSO is entitled. The compensation for the external utilisation of an individual element of a TSO's network is, in this case, calculated as a proportion of the cost of that element, where the factor of proportionality is given by the ratio between the flows attributable to external flows (cross-border/transit flows) and the total flows on the specific element.

Alternatively, one can determine the total utilisation of the HN in both scenarios—and the differential utilisation attributed to external flows—and compute the compensation due to the TSO as a proportion of the total cost of the HN, in which case the factor of proportionality is represented by the ratio between the utilisation of the HN attributable to external flows and the total (actual) utilisation of the HN.

By summing all compensation entitlements of all TSOs, we obtain the monetary value of the total compensation fund. Responsibility for contributing to this fund is then allocated to the different TSOs on the basis of their responsibility in generating cross-border/transit flows. This responsibility can be determined in various ways. For example, net import/export from the grid of each TSO can be used as a proxy for the cross-border/transit flows generated by the injections into and withdrawals from that grid.

4.1.2.2 The ETSO mechanism

As of March 2002, an ITC mechanism has been in operation among the majority of ETSO members in continental Europe.[18] The mechanism has been slightly modified over time, and is presented here in its current (2005) version. The mechanism, which focuses on transits, can be interpreted as a simplified variant of the WWT method. However, this mechanism does not take into account the internal map of flows within each TSO area.

The ETSO mechanism includes four basic steps:

- identification of the HN;
- calculation of the fraction of the cost of the HN, in each TSO area and in the whole region, which is attributable to transits, and therefore the total compensation payable;
- definition of the responsibility of each TSO in generating transits and therefore its share of responsibility for the total compensation fund;
- determination of the net position of each TSO in the ITC mechanism.

In the ETSO mechanism, the HN is obtained as the set of grid elements on which the power flow is significantly affected by purposely-defined elementary transits. For each TSO network, these elements are identified by modelling the impact of all possible elementary transit flows. An element of the network is included in the HN if an additional 100 MW elementary transit flow changes the flow on the element by more than 1 MW.

Once the HN for each TSO has been defined, the share of transit flows in the total flow through this HN—and therefore the share of the HN cost attributable to transits—is established according to the so-called ‘transit key’. The transit key is TSO-specific and is defined as the ratio of the volume of transits through that TSO’s grid to the sum of these transits and the load within the TSO area, both on an annual basis. In this context, annual transits are assumed to be equal to the annual total of the minimum, for each hour, of imports into, and exports from, the TSO area. The transit key for the TSO is then applied to the regulated costs of the TSO’s HN to determine the level of compensation that the TSO is entitled to receive for hosting transits on its HN. The overall compensation fund is obtained by aggregating the compensation entitlements of all TSOs.

The compensation fund is financed in two ways:

- by ‘perimeter countries’,[19] which must pay a fee of €1 for each MWh exported into the grids of the TSOs participating in the mechanism;
- by participating TSOs, each of which is charged in proportion to the annual total of the hourly values of the net flow on the TSO’s grid; the hourly net flow is defined as the absolute value of the difference between imports to and exports from the TSO’s grid.

---

[18] The mechanism currently covers the TSOs of Austria, Belgium, Switzerland, Germany, Spain, France, Italy, the Netherlands, Portugal, Slovenia, the Czech Republic, Greece, Sweden, Denmark, Finland, Norway, Poland, Hungary and Slovakia.

[19] Perimeter countries currently include the UK, Morocco, Croatia, Albania, the Former Yugoslav Republic of Macedonia, Bulgaria, Romania, the Russian Federation, Ukraine, Byelorussia and Serbia and Montenegro.

The net position of each participating TSO is calculated as the difference between the compensation the TSO is entitled to—for hosting transits—and the charge assigned to the TSO.

4.1.2.3 The Average Participations applied to Transits method

The Average Participations applied to Transits (APT) method was devised as a modification of the AP method intended to deal with transits only. It uses the same definition of transits as the WWT method. Once the transit flows on each of the interconnections of a TSO area with the neighbouring ones are defined, the APT method tracks these flows both upstream and downstream. The APT method bases all computations on the existing record of physical flows employing the proportional branching rule to track transit flows on the grid. Therefore, it uses the same algorithm to calculate compensations and assign charges as the AP method.

In this way, the APT method determines, for each TSO's network:

- the extent of external use of the network by transit flows; and
- which agents in other TSO areas are responsible for these flows and to what extent, in order to allocate responsibilities.

By aggregating the responsibilities of agents located in a TSO area for the utilisation of the HN elements in another TSO area, it is possible to define the level of compensation that the latter TSO is entitled to receive from the former. As in the case of the AP method, by appropriately aggregating the compensation that each TSO is entitled to receive from each other TSO, it is possible to obtain the total compensation a TSO is entitled to receive, as well as the total compensation a TSO is responsible for paying.

4.2 Assessment of the proposed approaches

This section assesses the network cost allocation approaches described above, focusing on a subset of the criteria outlined in Chapter 1.[20] The different approaches do not provide specific indications on the coverage of the costs for which compensation is provided or on how these costs are evaluated, all of them can be applied to the forward-looking, long-run, average incremental costs of new and existing infrastructure, as well as to the cost of losses. The costs to be covered by the ITC mechanism and the evaluation methodology for these costs were considered in Chapter 3. Therefore, the cost allocation approaches are not assessed with respect to criteria 2 and 3 in Chapter 1.

4.2.1 Criterion 1: cost-reflectiveness

The ITC method should provide compensation for costs incurred as a result of hosting cross-border flows of electricity on a TSO's grid. Cross-border flows should be assessed on the basis of measured flows of electricity. Benefits that a network incurs as a result of hosting cross-border flows should be taken into account to reduce the ITC received. The ITC method should define network cost allocation as independently as possible from the location of political

---

[20] It should be noted that when it comes to using the criteria outlined in Chapter 1 to assess the methods for assigning responsibility for HN costs, some of these criteria may be conflicting. For example, methods which explicitly highlight the benefits of cross-border/transit flows—as required by criterion 1—may result in new lines reducing the compensation that the local TSO receives if cross-border/transit flows on the lines move in a direction opposite to the prevailing local power flows. This result, although possibly correct from an economic point of view, may discourage investment in such new infrastructure, potentially conflicting with criterion 4.

borders ('single system paradigm') and of commercial transactions ('non-transaction-based charges').

The AP and the MP methods both assign responsibilities for the utilisation of the various elements of the HN to agents located at individual nodes. In the case of the AP method, the assignment of responsibility is based on the actual pattern of flows. The MP method, on the other hand, uses a load flow model to calculate the effect on the use of HN elements of incremental injections into and withdrawals from the grid. These methods result in entitlements and responsibilities for compensation for the various TSOs which are derived consistently by appropriately aggregating the compensations that each TSO owes each of the other TSOs for the use of the elements in the network of the latter. Furthermore, the results obtained from these methods are independent of the location of political borders, making these methods fully consistent with the 'single system paradigm'.

The focus on incremental effects means that the MP method is able to detect those cross-border flows which reduce the overall flows on specific HN elements, and therefore have a beneficial effect on the utilisation of such elements. By contrast, the AP method, which is based on the physical flows for the allocation of responsibility among different injections and withdrawals, does not explicitly take into account the benefits that a TSO area may obtain from the existence of cross-border flows. However, the AP method is able to recognise these benefits implicitly; if cross-border flows on a TSO's grid move in the opposite direction to the prevailing local power flows, cross-border flows will not penetrate deeply into the TSO's grid and the AP method will record a limited external utilisation of this grid. This will result in a lower compensation entitlement for the TSO concerned. In general, therefore, the AP method tends to reduce the compensation entitlements for those TSOs for which cross-border flows have a beneficial effect in terms of grid utilisation.

The focus on incremental effects in the MP method may result in power flows, and therefore ITCs, which are inconsistent with the physical reality of the network. This may occur, for example, in the case of two TSO areas which are only weakly linked. The MP method may assign significant responsibility for the utilisation of the network in one TSO area to generators and loads in the other TSO area, if this would be the case when incremental injections and withdrawals are considered. This result, when applied to total injections and withdrawals, may be at odds with the physical capability of the networks, as the limited capacity of the interconnector may restrict the extent to which generators and loads in one TSO area can use the network in the other area.

While the SAP method is methodologically similar to the AP method, the fact that it reduces the network of each TSO to a single node implies that this method completely neglects the pattern of flows within each TSO area. Furthermore, the SAP method is inconsistent with the 'single system paradigm'. In fact, the results of the SAP method are clearly affected by the location of political borders, since the aggregation of grid elements is performed at the level of the TSO area—which generally corresponds to a country—and different configurations of these borders lead to different simplified representations of the HN.

The MAP method suffers from a similar drawback. In aiming to address the 'small country issue'[21] which may arise with the AP method, the MAP method employs a simplified representation of each TSO area in turn. Therefore, even in this case, the results depend on the location of political borders and the method is inconsistent with the 'single system paradigm'.

The AS method has many desirable qualities. It assumes an optimal economic behaviour by generators and loads. However, results may contradict the supposition that agents of the same type and with the same profile which are connected to the same grid node should be assigned the same responsibility for network costs, i.e. the same responsibility per unit of power injected

---

[21] See sub-section on 'Modified Average Participations' *supra*.

or withdrawn. Indeed, the AS method produces cost allocations which are not independent of the relative sizes of the agents. For example, the larger the generator, the greater the sensitivity of the cost responsibility assigned to it with respect to its position in the different orderings. This feature of the allocation resulting from the application of the AS method can be overcome by dividing each generator or load into elementary parts that are all of the same size (e.g. 1 MW). In this case, all the elementary power increments considered would attract the same average charge and the unit charge for each similar generator (load) located in the same node of the system would be the same. In the AS method, the incremental impact of the transactions considered on the flow over a HN element can be either positive or negative. Therefore, the AS method is able to identify those injections and withdrawals which reduce power flows over specific HN elements and thus have a beneficial impact on the use of such elements.

The WW and the WWT methods both require the definition of the 'without' scenarios. These scenarios are dependent on the location of political borders; therefore the methods in question are not consistent with the 'single system paradigm'.[22] The 'without' scenarios in the WW and WWT methods may result in larger flows over specific HN elements. These methods therefore allow us to identify those cross-border/transit flows that have a beneficial impact on the utilisation of such elements. However, in the WWT method these impacts may be affected by the specific definition of transits or, in the WW method, by the way in which generation or load is adjusted to keep the system balanced once the cross-border flows are removed.[23] A further drawback of the WW and WWT methods is that they do not assign responsibilities for the utilisation of the various elements of the HN to individual agents or TSOs. This means that the approach employed by these methods to determine the various TSOs' entitlement to compensation does not provide any indication regarding the allocation of responsibility for such compensation and *ad hoc* criteria need to be used.

The ETSO mechanism also suffers from the same drawback, as it computes the compensation entitlements of the different TSOs separately from the responsibility of each TSO in financing the overall compensation fund. Thus, in the ETSO mechanism and in the WW and WWT methods there is no intrinsic consistency in the way that compensation entitlements and responsibilities are computed. Each TSO is assumed to pay every TSO in the region the same fraction of the total compensation due to the latter, irrespective of the geographical or electrical proximity of the grids of the two TSOs and, therefore, of the effect that injections and withdrawals in the grid of one TSO may have on the flows over the other TSO's grid. Moreover, the ETSO mechanism does not take into account the internal pattern of flows within each TSO area when computing the compensation due to the TSO. Thus, counter-intuitive examples can be found where completely different patterns of utilisation of a TSO's grid by external agents result in the same level of compensation.[24] Finally, the ETSO mechanism does not distinguish between transits causing costs and transits producing benefits.

The APT method overcomes some of the drawbacks of the WWT method. First, it avoids creating the artificial 'without' transit operating condition, which may lack any physical sense. Second, the method provides a way to coherently allocate responsibilities for the external use of the grid of each TSO. In other respects, however, the APT method is characterised by shortcomings similar to those of the WWT method. In particular, as is the case with this latter method, the APT requires the identification of transit flows and the results depend critically on the location of political borders. Finally, due to the fact that it only considers the existing pattern of flows, the APT method does not explicitly take into account the beneficial effects that transit flows may have on the utilisation of specific HN elements, but addresses this issue in the same, indirect way as the AP method.

---

[22] See the example in Annex 3.

[23] See also criterion 6.

[24] See the example in Annex 1.

Table 4.2 provides a summary assessment of the various methods with respect to criterion 1, based on a score from 0 (minimum) to 3 (maximum).

Table 4.2: Assessment of cost allocation methods with respect to criterion 1 (cost-reflectiveness)

ITC approach ► **▼Criteria**	**AP**	**SAP**	**MAP**	**MP**	**AS**	**WW**	**WWT**	**ETSO**	**APT**
Cost-reflectiveness	3	1	2	2	3	1	1	1	1

4.2.2 Criterion 4: consistency with transmission regulation

The ITC method should be consistent with the provisions of Article 3 of Regulation 1228/2003. It should also allocate network cost in a way which is consistent with the overall framework of transmission regulation as required by the developing and integrating IEM, in particular in the areas of investment in new infrastructure, locational signals for operation and investment, congestion management and the process towards harmonisation of (the structure of) transmission tariffs.

Regulation 1228/2003 stipulates that compensation be paid for all cross-border flows. Therefore, all methods based on cross-border flows (AP, SAP, MAP, MP, AS and WW) comply with this aspect of the Regulation, while methods based on transits (the WWT and APT, as well as the ETSO mechanism) do not. Furthermore, the AP and the MP methods are consistent with other aspects of the IEM regulation, as they compute the responsibility of individual agents in network utilisation and therefore produce results which relate coherently with locationally-differentiated transmission tariffs. The aggregation of all nodes within a TSO area in a single node means that the SAP and MAP methods as well as the ETSO mechanism are unable to compute locational signals within each TSO area. Since both the APT and the WWT methods focus on transits, which are only a subset of all cross-border flows, they are unable to provide any guidance to locational signals at individual agent level.[25]

Table 4.3 provides a summary assessment of the various methods with respect to criterion 4, based on a score from 0 (minimum) to 3 (maximum).

Table 4.3: Assessment of cost allocation methods with respect to criterion 4 (consistency with transmission regulation)

ITC approach ► **▼Criteria**	**AP**	**SAP**	**MAP**	**MP**	**AS**	**WW**	**WWT**	**ETSO**	**APT**
Consistent with transmission regulation	3	1	1	3	3	1	1	0	1

4.2.3 Criterion 5: suitability for the European network

---

[25] The APT method focuses on transits, and therefore only on a fraction of the injections into and withdrawals from the grid. This fraction depends on the location of political borders. Therefore the APT method assigns responsibility for the utilisation of the grid only in relation to a fraction of the total flows on the network.

The ITC method should provide a sound approach to assigning responsibilities for the costs arising from cross-border flows to the TSOs of the grids from which these flows originate and where these flows end in the context of the highly-meshed European network.

As mentioned,[26] the WWT and WW methods, and the ETSO mechanism, provide a way to evaluate the compensation due to each TSO, which has to be paid globally by external agents, but *ad hoc* criteria are then needed in order to allocate responsibility for compensation to individual TSOs. Only the AP, SAP, MAP, MP, AS and APT methods use the same criteria to calculate compensation entitlements and allocate responsibilities. Furthermore, the MP method may provide meaningful results when applied to small, mostly radial systems of a single TSO, where congestion is not relevant. However, this method is much less suitable for large-scale, multi-TSO and highly meshed systems, like the European one, where congestion plays an important role. In fact, the MP method requires the identification of one or more slack nodes. While in small, radial, un-congested systems a node close to the central load centre may be suitably chosen as the slack node, when the system is highly meshed and is affected by congestions any choice of slack node(s) is likely to result in power flows which are either at odds with the flow pattern on the network or, when scaled up to correspond to total injections or withdrawals, are inconsistent with the physical capability of the network.

Table 4.4 provides a summary assessment of the various methods with respect to criterion 5, based on a score from 0 (minimum) to 3 (maximum).

Table 4.4: Assessment of cost allocation methods with respect to criterion 5 (suitability for the European network)

ITC approach ► **▼Criteria**	**AP**	**SAP**	**MAP**	**MP**	**AS**	**WW**	**WWT**	**ETSO**	**APT**
Suitability for the European network	3	3	3	1	3	0	0	0	2

4.2.4 Criterion 6: technical soundness

The ITC method should be based on sound engineering principles and should not rely on arbitrary assumptions or procedures.

The AP method assumes that flows through the HN can be traced and that consequently responsibility for the flow on each HN element can be assigned. The AP method does this using the ‘proportionality branching rule’, a simple heuristic rule which refers to the pattern of flows on the grid. Although this approach does not strictly reflect the laws of physics governing the distribution of electricity flows on the grid, it may represent a reasonable simplification to the extent that, in liberalised markets, electricity tends to flow from nodes where it is less expensive to nodes where it is more expensive. Therefore, using the network flow pattern to determine electrical usage may be a way to assign injection and withdrawal nodes to loads and generators respectively, in a reasonable and economically meaningful way.

The SAP disregards the pattern of flows within each TSO area. This problem is overcome, albeit crudely, by using TSO-specific coefficients which represent weighting factors for the utilisation of the TSO’s network by external agents. However, the value of these coefficients must be defined and the quality of the results of the implementation of this method clearly

---

[26] See criterion 1.

depends on the accuracy with which the chosen values of the coefficients represent the correct weighting of network utilisation by external agents. Moreover, we cannot guarantee that a single value for the coefficient corresponding to a TSO would be suitable for all the different operating conditions which may occur.

The MP method employs a load flow model to compute the impact on the system flows of power injection or withdrawal at each node. However, the advantage of this greater adherence to the laws of physics in tracing the flows over the HN is of little help since the method suffers from the requirement of having to select the slack node(s). The slack node(s) must be the same for all individual injections into and withdrawals from the network and different alternatives for the choice of the slack node(s) deliver different results. As indicated in the assessment of the MP method with respect to criterion 5, choosing a slack node that is suitable for a large system like the European one appears to be impossible, due to congestion on several interconnectors, which necessarily limits the use that agents in one part of the grid make of other parts of it.

The AS method uses a load flow model to determine the pattern of flows on the network. The choice of slack node is irrelevant here, since all the transactions that have to be modelled are strictly bilateral and balanced. Moreover, the slack node differs for the different injection/withdrawal nodes and for every possible ordering of these nodes, and is chosen on the basis of the assumed rational economic behaviour of the various agents.

The WWT and APT methods require an implementable definition of transits on the border of a TSO area/country. This definition is always arbitrary since there are infinite ways of deciding which, from all cross-border flows, should be considered as transit flows. The construction of the fictitious ‘without’ transit/cross-border flow scenarios, in the WWT and WW methods respectively, requires careful consideration. Applying a simple proportionality rule to adjusting flows on the borders may result in local flows that have little to do with the physical reality of the power system. Moreover, when all cross-border flows are removed in the WW method, the generation and demand within the TSO area in question become isolated from the rest of the system and may become unbalanced. The internal generation and/or demand must therefore be adjusted to keep the system balanced. Again, there are many ways of modifying the load or generation within a TSO area and no single way is free from potential criticism.

The ETSO mechanism relates the compensation payable to a TSO to the level of transits on the TSO’s network. As such it suffers, like the WWT and APT methods, from the need to identify transit flows. In this respect, the ETSO mechanism uses a very crude measure of transits, by referring to the transit key.

Table 4.5 provides a summary assessment of the various methods with respect to criterion 6, based on a score from 0 (minimum) to 3 (maximum).

Table 4.5: Assessment of cost allocation methods with respect to criterion 6 (technical soundness)

ITC approach ► **▼Criteria**	**AP**	**SAP**	**MAP**	**MP**	**AS**	**WW**	**WWT**	**ETSO**	**APT**
Technical soundness	2	1	1	2	2	1	1	1	1

4.2.5 Criterion 7: implementation

The ITC method should be reasonably straightforward and cost effective to implement.

From the point of view of implementation the main drawback of the AP, MAP and MP methods is their extensive data requirement (on energy flows over the full HN). This generally leads to the analysis being limited to a number of representative hourly snapshots. These snapshots may provide a valid simplification, provided that they are representative of annual flows. In contrast, the advantage of the SAP method rests on the fact that the data required for its implementation (import/export flows from each TSO area to each other TSO area) are usually available for each hour of a year and therefore the analysis does not have to be restricted to a limited number of snapshots.

One drawback of the AS method is its computational burden, as it requires computing the cost allocation for all possible orderings of generators and loads. The number of these orderings increases exponentially with the number of agents (or the number of megawatts, in the modified version of the method), making the AS method much more complex and difficult to apply than the others.[27]

Application of the WWT and WW methods also requires the consideration of the same number of snapshots as AP, MAP and MP. Besides, they require, for every selected scenario, the determination of transits or cross-border flows at the interconnectors together with the load and generation pattern within each TSO area or country. But, most importantly, the WWT and WW methods require the use of a load flow model to analyse power flows over the HN under both actual system conditions and the 'without' scenario.

The ETSO mechanism is easy to understand and to apply. It requires a very limited amount of input data and all the calculations involved in the process of computing ITCs are quite simple.

Table 4.6 provides a summary assessment of the various methods with respect to criterion 7, based on a score from 0 (minimum) to 3 (maximum).

Table 4.6: Assessment of cost allocation methods with respect to criterion 7 (implementation)

ITC approach ▶ **▼Criteria**	**AP**	**SAP**	**MAP**	**MP**	**AS**	**WW**	**WWT**	**ETSO**	**APT**
Implementation	2	3	2	2	0	2	2	3	2

4.2.6 Criterion 8: transparency

The ITC method should be easily understood and verified.

All methods are easy to understand with the exception of the AS method. The AP method, not requiring any arbitrary assumption, produces the same results irrespective of which user implements it, as long as the same specific set of input data is used. The same applies for the APT method. In addition, the AP method generally produces results in accordance with intuition since network flows tend to originate from, and end in, nearby nodes unless an area is transited by a prevalent flow pattern with distant sources and sinks. This generally avoids the dispersion problem of the participations produced by other methods (e.g. the MP method). However, the application of the AP method may mean that ITCs appear to assign excessive responsibilities in the utilisation of external networks to small and heavily-transited countries, even if load and generation in these countries are balanced.

---

[27] However, recent research suggests that the problem of computing responsibilities using the AS method could be formulated as a linear optimisation problem. This could make the implementation of the AS method more efficient in terms of the computational effort it requires. This new more efficient algorithm is still at the development stage and a cautious approach is required to its implementation.

The MP method requires the choice of one (or more) slack nodes and results can be replicated if the same choice of slack node(s) is used.

The WWT and WW methods rely on specific conventions for defining the 'without' scenarios and the results critically depend on the adopted conventions.

The ETSO mechanism is easy to understand and verify, as is the case for the SAP method.

The AS method does not rely on arbitrary assumptions, but because of its significant computational burden and the use of cooperative game theory, the results may be difficult to understand and may appear to be lacking in transparency.

Table 4.7 provides a summary assessment of the various methods with respect to criterion 8, based on a score from 0 (minimum) to 3 (maximum).

Table 4.7: Assessment of cost allocation methods with respect to criterion 8 (transparency)

ITC approach ▶ **▼Criteria**	**AP**	**SAP**	**MAP**	**MP**	**AS**	**WW**	**WWT**	**ETSO**	**APT**
Transparency	2	3	2	2	1	2	2	3	2

4.3 Summary

Of the methods analysed here[28] the AP method is the one which best combines many of the characteristics considered desirable in the light of the criteria outlined in Chapter 1. Other methods share some of these characteristics, but none of them appear to offer comparable levels of compliance with the outlined criteria. In particular, the AP method:[29]

- provides compensation with respect to all cross-border flows; this characteristic is shared by the MP, AS and WW methods, but not by the WWT and APT methods, or by the ETSO mechanism;
- allows responsibilities to be defined at the individual agent level; this characteristic is shared by the MP, AS and APT methods, but not by the WW and WWT methods, nor by the ETSO mechanism;
- produces results which are independent of the location of political borders, and therefore is fully consistent with the 'single system paradigm'; this characteristic is shared by the MP and AS methods, but not by the WW, WWT and APT methods, nor by the ETSO mechanism;
- provides a coherent framework for defining entitlements and responsibilities for compensation; this characteristic is shared by the MP, AS and APT methods, but not by the WW and WWT methods, nor by the ETSO mechanism;

---

[28] We did not assign explicit weights to the individual criteria to produce an overall score.

[29] In the comparison that follows, the SAP and MAP methods are not considered. In fact, the former method is a much inferior variant of the AP method the use of which is only justified if flow data are not available. As suitable flow data for the European network are now regularly collected, this method is unlikely to be a relevant candidate for the longer-term ITC mechanism. The MAP method is a variant of the AP which addresses the apparently inconsistent results produced by the AP method when applied to small, heavily transited, TSO areas. Therefore, it is not to be considered of general use for the longer-term ITC mechanism, but, at best, an alternative to the AP method in these specific situations.

- does not involve the creation of fictitious scenarios which may be characterised by power flows that have little to do with the physical reality of the power system; this characteristic is shared by the MP, AS and APT methods, as well as the ETSO mechanism, but not by the WW and WWT methods;
- does not create particular problems when implemented for the highly-meshed European network; this characteristic is shared by all the other methods, except the MP method;
- is transparent and easy to verify; this characteristic is shared by all the other methods, except for the AS method.

Table 4.8: Summary assessment of cost allocation methods

ITC approach ► **▼Criteria**	**AP**	**SAP**	**MAP**	**MP**	**AS**	**WW**	**WWT**	**ETSO**	**APT**
1. Cost-reflectiveness	3	1	2	1	3	1	1	1	1
4. Consistent with transmission regulation	3	1	1	3	3	1	1	0	1
5. Suitability for the European network	3	3	3	1	3	0	0	0	2
6. Technical soundness	2	1	1	2	2	1	1	1	1
7. Implementation	2	3	2	2	0	2	2	3	2
8. Transparency	2	3	2	2	1	2	2	3	2

The main drawback of the AP method—shared by other methods (e.g. MAP, MP, WW and WWT)—is its extensive data requirement. However, this is not considered a particularly serious problem here, as meaningful and reliable results can be obtained by restricting the analysis to a number of representative snapshots.

The implementation of all the methods examined in this chapter rely on specific assumptions and conventions. The AP method is no exception in this respect and uses the proportionality branching rule to determine how electricity flows into and out of individual nodes. This assumption may, however, constitute a reasonable/rational and economically-meaningful simplification in liberalised markets.

5 The methodological proposal for the longer-term ITC mechanism

The previous chapters examined different aspects which play a part in defining an approach to the longer-term ITC mechanism. Chapter 2 considered the nature of the flows for which compensation should be provided and developed arguments that suggest that extending the compensation to include all cross-border flows, and not just transits, is consistent with the provisions of Regulation 1228/2003 and with the development of the IEM.

Chapter 3 analysed the issue of long-run average incremental costs, both in the theoretical sense and in its practical implications. We concluded that the ITC mechanism should provide compensation for the costs associated with the replacement—or duplication—of the elements of the current HN. We also recommended that some element of peak-loading should be introduced in the ITC mechanism. Finally, we proposed to limit compensation for existing infrastructure to the actual level of utilisation of HN elements by external agents. However, a different treatment will be applied to new infrastructure which benefit more than one TSO area and for which the investment decisions are taken jointly, or endorsed, by all the TSOs concerned.

Chapter 4 focused on the way in which responsibility for the costs of the grid can be assigned to different agents—in particular to internal and external agents. A number of different methods proposed in the recent debate on this aspect were described. A common feature of all these methods is that they consider the degree of utilisation of network elements as an appropriate indicator on which to base the allocation of cost responsibility. The methods, which differ in many other respects, were then compared on the basis of some of the criteria outlined in Chapter 1. This assessment indicates that the Average Participation (AP) method is the best available method to determine the allocation of responsibility for network costs in the longer-term ITC mechanism.

On the basis of the analysis presented in this Report and the indications that have emerged, we can define a methodological approach to the longer-term ITC mechanism which best complies with the criteria outlined in Chapter 1, while meeting the specific requirements contained in Regulation1228/2003. This approach can be characterised in more detail as follows.

5.1 General aspects

a. The ITC mechanism provides compensation for the portion of ‘horizontal network’ (HN) costs that are attributable to cross-border flows;

b. the ITC mechanism is implemented using measured flows of electricity on the European network, with reference to a number of representative actual configurations and operating conditions (representative snapshots);

c. treatment of perimeter countries, as well as the effect of reconnection of the two UCTE zones (ETSO and SETSO areas) are to be approached on the basis of the same principles as characterised in this chapter;

5.2 Horizontal Network

d. the HN is defined as a network which includes all transmission grid elements (lines, transformers) which are significantly and persistently affected by cross-border flows;

e. in each TSO area, the transmission grid which is relevant for the identification of the HN is defined to include all nodes on the EHV grid and the nodes on the portion of the HV grid that fulfils a transmission function;

f. in defining the HN in each TSO area, any pair of nodes at the borders of the TSO area, as well as any pair of a border node and an internal node on the relevant transmission grid are considered;

g. a network element in a TSO area belongs to the HN if a 100 MW increase in injection and withdrawal at all identified pairs of (injection and withdrawal) nodes located in that TSO area results, in at least 5% of the representative snapshots and for at least 5% of the node pairs, in a variation of the power flow over the element by more than 1 MW;

5.3 Costs

h. the costs for which ITC is provided include the capital and operating costs of existing infrastructure, the capital and operating costs of new infrastructure and the cost of losses;

i. for capital and operating and maintenance costs, the implementation of the LRAIC approach implies considering the costs of duplicating the existing HN. No network optimisation is performed;

j. for costing purposes, HN elements are classified into a relatively small number of categories, defined by the type of elements included (overhead lines by voltage range, underground cables by voltage range, transformers); topographic features of the area on which the elements are located should also be taken into account;

k. standardised replacement cost values should be used for the capital and operating and maintenance costs of the HN elements in each category and should be expressed, for lines, in € per circuit km and, for transformers, in € per MVA;

l. the cost of losses should be evaluated, in each representative snapshot, on the basis of actual losses and the hourly electricity price on the relevant Power Exchange.

5.4 Allocation of cost responsibilities

m. responsibility for the costs of the HN will be allocated on the basis of the utilisation of HN elements. ITCs are based on responsibility for the utilisation of the different HN elements by different agents;

n. the analysis is conducted with respect to each of the different representative snapshots;

o. for each HN element, in each representative snapshot, responsibility for its utilisation is determined by tracing the power flow over the element backwards (to generation) and forwards (to load), according to the Average Participations (AP) method.

p. in tracing flows over the HN, reference is made to the actual pattern of flows on the HN. At each node of the HN, inflows are allocated proportionally to outflows and *vice versa;*

q. responsibility for the utilisation of each HN element is shared equally between the points of injection from which the flow over the element originates and the points of withdrawal where it ends;

r. in each representative snapshot, the costs of a HN element are assigned to the different injection and withdrawal nodes and therefore to the agents located at these nodes—on the basis of the portions of the flow over the element which, respectively, originate from the different injection nodes or end at the different withdrawal nodes;

s. for existing HN elements, the portions of the flow over the element used in assigning costs are computed as the ratio between the flow originating or ending at the different injection/withdrawal nodes in the representative snapshot, and the total available capacity of the element in the same snapshot, reduced by an adequate security margin. The same approach applies to new HN elements, unless the decision to develop the infrastructure is taken jointly, or endorsed, by all those TSOs which, on the basis of the ITC mechanism, are expected to be responsible for more than 3% of the total costs of the new infrastructure;

t. for new HN elements for which the decision to develop the infrastructure is taken jointly, or endorsed, by all those TSOs which, on the basis of the ITC mechanism, are expected to be responsible for more than 3% of the total costs of the infrastructure, the portions of the flows over the element used in assigning costs are equal to the ratio between the flows originating or ending at the different injection/withdrawal nodes in the representative snapshot, and the total of such flows;

u. for each representative snapshot and each HN element, the responsibility of each TSO in the cost of the element is computed as the total of the responsibilities for such costs of all the agents located in the TSO area;

v. for each HN element, the share of costs that each TSO is responsible for is determined as the weighted average of the corresponding responsibilities in the different representative snapshots, where the weights are proportional to the levels of flow over the element in the different snapshots;

5.5 Entitlement to, and responsibility for, compensation

w. the ITC which each TSO is entitled to receive from each other TSO is equal to the sum of the cost responsibilities of each other TSO for the costs of all the HN elements located in the area of the first TSO;

x. the total ITC which a TSO is entitled to receive is equal to the sum of the ITCs which the TSO is entitled to receive from all the other TSOs;

y. the total ITC which a TSO is required to pay is equal to the sum of the ITCs that all other TSOs are entitled to receive from the TSO concerned;

z. the net ITC position of each TSO is equal to the difference between the total ITC that the TSO is entitled to receive and the total ITC which the TSO is required to pay.

Part B

Implementation

6 Classification and standard costing of transmission infrastructures

This chapter describes the assumptions for the standard network costs used in the numerical exemplification of the proposed methodological approach to the longer-term ITC mechanism presented in Chapter 7. These assumptions have been developed for the sole purpose of providing inputs for the numerical exemplification; they are not intended to be applied to national tariff regulation, or as a first step towards a harmonised regulatory approach to transmission tariffication.

This chapter is organised as follows. Section 6.1 presents the types of network elements for which cost assumptions are provided, as well as the studies which have been used as reference sources in defining the standard cost assumptions. Section 6.2 focuses on the main drivers for network costs, while Sections 6.3, 6.4 and 6.5 provide cost estimates for lines, transformers and substations, respectively.

6.1 Horizontal Network structure and reference material

In the procedure for identifying the HN proposed in Chapter 2, the HN is composed of network elements at the EHV and HV levels. Chapter 3 proposed basing cost calculations on a relatively short list of standardised components. Here we focus on the main components of EHV and HV grids. In particular, standard cost estimates are provided for single and double circuits at 400 kV, 220 kV and 132 kV, 400 kV/220 kV, 400 kV/132 kV and 220 kV/132 kV, and substations at 400 kV, 220 kV and 132 kV transformers. Underground cables and multi-circuits (>2) are very rare, and no estimates are provided for these components. The cost of secondary equipment is relatively low, and this type of equipment is also not taken into account.

In formulating assumptions as to the level of standard costs for the different network elements considered here we have taken into account the results of a number of recent studies listed in Table 6.1.

Table 6.1: Reference sources for network standard cost data

↓ **Source**	**by**	**Countries**	**Date of publication**
Unit costs of constructing new transmission assets at 380 kV within the EU, Norway and Switzerland[a]	ICF	EU, N, CH	2002
Energiewirtschaftliche Planung für die Netzintegration von Windenergie in Deutschland an Land und Offshore bis zum Jahr 2020[b]	Dena-consortium	Germany	2005
Netzverstärkungs-Trassen zur Übertragung von Windenergie: Freileitung oder Kabel?[c]	Brakelmann	Germany	2004
Handbuch der Elektrizitätswirtschaft[d]	Müller	Germany	1998
IKARUS[e]	Haubrich	Germany	1993
Kabel und Freileitungen in überregionalen Versorgungsnetzen[f]	Palic	Germany	1992

Notes:

[a] ICF Consulting Ltd., *Unit Costs of constructing new transmission assets at 380 kV within the European Union, Norway and Switzerland*, prepared for DG TREN/European Commission, London, Oct. 2002.

[b] Konsortium DEWI/E.ON Netz/EWI/RWE Transportnetz Strom/VE Transmission, *Energiewirtschaftliche Planung für die Netzintegration von Windenergie in Deutschland an Land und Offshore bis zum Jahr 2020—Konzept für eine stufenweise Entwicklung des Stromnetzes in Deutschland zur Anbindung und Integration von Windkraftanlagen Onshore und Offshore unter Berücksichtigung der Erzeugungs- und Kraftwerksentwicklungen sowie der erforderlichen Regelleistung,* Studie im Auftrag der Deutschen Energie-Agentur GmbH (Dena), 2005.

[c] Heinrich Brakelmann, *Netzverstärkungs-Trassen zur Übertragung von Windenergie: Freileitung oder Kabel?*, Auftrag des Bundesverbandes WindEnergie e.V., Rheinberg, 2004.

[d] Leonhard Müller, *Handbuch der Elektrizitätswirtschaft—Technische, wirtschaftliche und rechtliche Grundlagen*, Berlin/Heidelberg, Springer, 1998.

[e] H.-J. Haubrich, *IKARUS—Instrumente für Klimagas-Reduktions-Strategien, Teilprojekt 4 'Daten: Umwandlungssektor', Bereich 'Verteilung und Speicherung elektrischer Energie', Forschungsvorhaben für das Bundesministerium für Forschung und Technik*, Aachen, March 1993.

[f] Markus Palic *et al.*, *Kabel und Freileitungen in überregionalen Versorgungsnetzen—Technik, Genehmigungsverfahren und Umweltverträglichkeit*, expert Verlag, Ehningen bei Böblingen, 1992.

These studies offer a wide range of cost estimates, and the results have been complemented by our own direct experience of network costs in order to obtain suitable standard cost assumptions. We stress however, that these assumptions should only be considered as appropriate for the purpose for which they are intended, i.e. supporting the numerical exemplification of the methodological approach to the longer-term ITC mechanism, and not as a definite norm for the cost of European transmission networks.

The sources listed in Table 6.1 provide cost estimates referring to different dates. To make these estimates comparable, we have used correction factors based on the consumer price index

(CPI).[30] Table 6.2 presents the CPI and the corresponding correction factors, to be applied to obtain cost estimates in 2004 prices, for EU 15 and Germany.

---

[30] In fact, other more relevant deflators could be used, such as the one related to capital goods.

Table 6.2: Consumer Price Index and correction factors for EU15 and Germany

↓ Year	**CPI for EU 15**[a]	**Correction factor relating to 2004**
2004	2.2%	100.0%
2003	2.2%	102.2%
2002	n.a.	104.4%
↓ Year	**CPI for Germany**[b]	**Correction factor relating to 2004**
2004	1.6%	100.0%
2003	1.1%	101.6%
2002	1.4%	102.7%
2001	2.0%	104.1%
2000	1.4%	106.2%
1999	0.6%	107.7%
1998	0.9%	108.4%
1997	1.9%	109.4%
1996	1.5%	111.4%
1995	1.7%	113.1%
1994	2.7%	115.1%
1993	4.4%	118.1%
1992	5.1%	123.3%

Notes:

[a] Organisation for Economic Co-operation and Development, http://www.oecd.org.
[b] Statistische Bundesamt Deutschland, http://www.destatis.de.

6.2 Cost drivers for network components

The costs for building overhead lines, more than those for transformers and substation bays, include not only the cost of material (conductors, towers etc.), but also, to a large extent, labour costs and other costs, such as those related to obtaining the required administrative permits or to acquiring the right-of-way. Table 6.3 presents the share of materials in the total costs for two types of overhead lines.

Table 6.3: Typical values for material costs

↓ Source	**Component →**	**Towers**	**Conductors**	**Insulators**	**Clamps**
ICF	sc 400 kV flat land	42[a]/17%[b]	48/19%	8/3%	12/5%
Müller	dc 132 kV	28%[b]	12%	8%	

Notes:
[a] absolute value in thousand €/km
[b] material costs as a percentage of total investment costs

As non-material costs tend to vary substantially between different countries, the costs for overhead lines show a wide range of variation across the EU. The ICF study lists a number of drivers which help explaining the differences in costs for building an overhead line in different Member States: topography, labour costs, population density, right-of-way costs and security standards (e.g. number of towers per km). In the following we consider each of these cost drivers in turn.

6.2.1 Topography

Topography has a large influence on the costs for building new transmission lines. Therefore ICF classifies overhead lines in the three different categories: flat land; medium mountains; and high mountain region.

Considering average values across the EU, building a single-circuit 400-kV overhead line in a medium mountain region is 20% more expensive than building the same line on flat land. In a high mountain region the cost mark-up may be as high as 52%. The strong influence of the topography is also reflected by the fact that the investment costs for a single circuit 400-kV overhead line are up to four times more expensive in the two alpine countries of Austria and Switzerland than in Finland and Sweden,[31] and the cost of building a double circuit 400-kV overhead line in Europe varies between €190,000 for flat land in Sweden and over €1,160,000 for high mountain regions in Switzerland.

---

[31] Different environmental standards may also explain some of the variation in investment costs for transmission lines.

6.2.2 Labour costs

The ICF report does not provide estimates of the impact of the other cost drivers on investment costs. On average, labour costs account for approximately 38% of total construction costs for a single circuit 400-kV overhead line built on flat land in Europe. The only indication that the ICF report provides about the impact of different labour costs on the construction of transmission line refers to the construction costs of a double circuit 400kV overhead line which are, on average, approximately 100,000 €/km higher in countries with high labour costs (Germany, France) than in countries with average labour costs (Belgium, the Netherlands, Italy).

6.2.3 Population density

The population density of a country also influences investment costs. According to the ICF report, costs for a double circuit 400kV overhead line across densely populated countries (Belgium, the Netherlands, Italy) are about 100,000 €/km higher than those across sparsely populated regions.

6.2.4 Right-of-way-costs and security standards

High right-of-way costs or high security standards—such as the requirement to use more towers—can lead to an increase in the investment costs for overhead lines. In this context, the UK is a typical example, since these two factors lead to approximately 200,000 €/km additional cost in comparison with countries such as Germany or France.

6.3 Cost of overhead lines

Table 6.4 presents cost estimates for overhead lines provided by different reference sources.

Table 6.4: Cost of overhead lines (in thousand €/ km)

↓ Source	Overhead line →	sc 400 kV	dc 400 kV	Sc 220 kV	Dc 220 kV	sc 132 kV	dc 132 kV
ICF - EU	Flat land	250	400	170	270	n.a.	n.a.
	Medium Mountain	300	480	200	320	n.a.	n.a.
	High Mountain	380	600	252	400	n.a.	n.a.
ICF – Germany	Flat land	450	600	280	450	n.a.	n.a.
	Medium Mountain	530	700	330	530	n.a.	n.a.
	High Mountain	680	890	430	680	n.a.	n.a.
Dena-study	Min.	n.a.	700	n.a.	445	n.a.	n.a.
	Max.	n.a.	850	n.a.	535	n.a.	n.a.
Brakelmann	Average	330	450	250	350	220	300
Müller	Min.	n.a.	560	n.a.	n.a.	n.a.	170
	Max.	n.a.	820	n.a.	n.a.	n.a.	
IKARUS	Min.	n.a.	510	n.a.	360	n.a.	150
	Max.	n.a.	610	n.a.	460	n.a.	260
Palic	Min.	n.a.	510	n.a.	410	n.a.	160
	Max.	n.a.	580	n.a.	470	n.a.	210

The ICF report provides both average data for the EU and data for individual Member States. The data for Germany in the ICF report appear to be consistent with estimates from other studies which focus on Germany.[32]

As indicated in Chapter 3, and discussed above in Section 6.2.1, topographical characteristics may have a significant impact on the cost of transmission lines. The ICF study provides estimates for these costs for lines built on flat land, medium mountain and high mountain, with the latter being approximately 50% more expensive than lines on flat land. However, given that information on the topographical characteristic of lines was not available for this study average cost values have been used. These values based on the ICF study, are presented in Table 6.5.

Table 6.5: Standard cost assumptions for overhead lines (in thousand €/km)

↓ Source	**Overhead line →**	**sc 400 kV**	**dc 400 kV**	**sc 220 kV**	**dc 220 kV**	**sc 132 kV**	**dc 132 kV**
This study	Average	310	475	225	340	160	225

6.4 Cost of transformers

Prices of transformers connecting different voltage levels, as provided in our reference sources, are presented in Table 6.6.

---

[32] With the only exception of the results in Brakelmann, who appear to come up with significantly lower values.

Table 6.6: Cost of transformers in Europe and Germany

↓ Source	**Transformer →**	**400/220 kV**	**400/132 kV**	**220/132 kV**
ICF	Min.	2 Million €/transformer		n.a.
	Max.	4 Million €/transformer		n.a.
	Belgium	1.8 Million €/transformer		
	Finland	3.5 Million €/transformer		2.5 Million € /transformer
Dena-study	Average	11,000 €/MVA	12,000 €/MVA	n.a.
Müller	Average	10,000 €/MVA	14,700 €/MVA	12,800 €/MVA
IKARUS	Min.	10,000 €/MVA	13,500 €/MVA	12,000 €/MVA
	Max.	13,500 €/MVA	17,000 €/MVA	15,000 €/MVA

For typical sizes of transformers—600 MVA for 400/220kV transformers, 300 MVA for 400/132kV transformers and 200 MVA for 220/132kV transformers—the estimates provided in the ICF report for Europe are similar to the values from German sources. Our cost assumptions for transformers, based on these values, are presented in Table 6.7.

Table 6.7: Standard cost assumptions for transformers

↓ Source	**Transformer →**	**400/220 kV**	**400/132 kV**	**220/132 kV**
This study	Average	7,500 €/MVA	10,000 €/MVA	10,000 €/MVA

6.5 Cost of substation bays

Standard costs of substation bays, as provided in our reference sources, are presented in Table 6.8.

Table 6.8: Cost of substation bays in Europe and Germany (in million €)

↓ **Source**	**Substation Bay →**	**400 kV**	**220 kV**	**132 kV**
ICF	Min.	1.5	n.a.	n.a.
	Max.	2.5	n.a.	n.a.
	Norway	1.55	n.a.	n.a.
Dena-study	Average	1.85	1.2	n.a.
Müller	Average	1.8	1.2	0.45
IKARUS	Min.	1.5	1.0	0.36
	Max.	2.1	1.5	0.51

All these sources provide very similar estimates. We base our cost assumptions for substation bays on these data. These assumptions are presented in Table 6.9.

Table 6.9: Standard cost assumptions for substation bays (in million €)

↓ **Source**	**Substation Bay →**	**400 kV**	**220 kV**	**132 kV**
This study	Average	2.0	1.25	0.5

7 Numerical implementation: an example

Chapter 5 presented a methodological approach to the longer-term ITC mechanism and this chapter illustrates how that approach could be implemented, using a numerical exemplification and based on the network cost assumptions presented in Chapter 6. We also provide results for the current ETSO mechanism, obtained using the same assumptions regarding network costs and power flows.

The results presented here are not designed to help select the most suitable methodology for the ITC mechanism, but are intended to illustrate the feasibility of applying the proposed approach to a reasonable number of scenarios that are representative of the real operation of the system over an entire year.

This chapter is structured as follows. Section 7.1 describes the data used for the analysis. Section 7.2 illustrates the main assumptions used for the numerical exemplification, Section 7.3 presents the numerical results for the AP method, while Section 7.4 presents the results for the current ETSO mechanism applied to the same input data. Finally, Section 7.5 provides a comparison of the results obtained with the two approaches.

7.1 Data used in the study

The data used to compute the numerical results presented in this chapter can be classified into two main categories: data provided by ETSO and data obtained from other sources.

7.1.1 Data provided by ETSO

ETSO provided a set of 72 power flow scenarios for 2003. The size and composition of this set was determined on the basis of a statistical analysis of hourly values of power flows on tie lines. The set includes six snapshots for each month of the year, recorded at 03:30h, 11:30h and 19:30h of the third Wednesdays and the preceding Sundays. The data comprise 15 countries: Austria, Belgium, Switzerland, the Czech Republic, Germany, Spain, France, Greece, Hungary, Italy, the Netherlands, Portugal, Poland, Slovenia and Slovakia, making a collection of 15 separate subsets of real network flow data for each hourly scenario. These subsets were made consistent before they were used for the analysis.[33]

---

[33] All scenarios have been received in ‘UCT’ format and a translator programme was used to obtain the PSS format data files required to run the algorithms. The following remarks apply to the 15 separate sets of data provided for each of the 72 scenarios:

- A perfect match cannot be expected due to the properties of State Estimation Procedures. This primarily relates to the comparison of recorded flows on tie lines between neighbouring transmission systems, which in some cases differ substantially.
- Data is provided applying the UCTE-Format including the ‘X-Node’ convention. In more detail, ‘X-Node’ convention fictitiously cuts each tie line between Countries/Control-Blocks at a border point and allows forcing the flow on each half of that line individually by inserting an artificial generator or load. Data were formatted applying the UCTE-Format.
- Representation of borders between transmission systems may be different. This is related to the fact that interconnections at lower voltage levels may not be part of regular recordings and

7.1.2 Other data used in the study

Standard network unit cost assumptions for lines, transformers and substations have been developed in this project, as presented in Chapter 6. The voltage level and number of circuits of the lines and other installations have been taken into account when obtaining these cost figures.

7.2 Assumptions and design options in the calculation process

Inter-TSO compensations and payments can be computed taking into account the whole cost of each HN element or just the cost of the used fraction of the capacity of the element. As indicated in Chapter 3, we propose the latter alternative for existing infrastructure. As all the elements currently included in the HN fall, by definition, into this category, only the used fraction of each element should be allocated among the different TSOs to compute ITCs.

In this chapter we also present the results obtained from the implementation of the AP method for network cost allocation taking into account the full cost of HN elements. In fact, only by allocating the whole cost of the HN it is possible to obtain results which are comparable to those from the implementation of the ETSO mechanism, which, by definition, takes into account the whole cost of the HN.

If only the used fraction of each line is allocated through the ITC mechanism, a reliability margin that represents the security criteria normally applied in the operation of the system should be used. In this numerical exemplification we have considered a reliability margin of 30% of the thermal capacity of each line. Neglecting the use of a reliability margin would contradict the common practice in the operation of real life systems.

Cost components examined in the analysis include both the cost of the HN and the cost of losses. In principle, the hourly energy price on the power exchange which is the most relevant for each TSO area should be used for valuing losses in each snapshot. Thus, the unit price of losses should vary from one country to another. However, in order to simplify the computation of ITCs we have opted for using the same price of energy for all the countries in the study and for all snapshots. This simplification should not affect the conclusions to be obtained here. A standard cost of losses of 40 €/MWh has been employed. We consider this value as representative of the average energy price in the European wholesale markets over the last year.

Standard cost figures for each type of grid asset have been used to value the HN in the different countries. Cost figures for the HN elements considered in the implementation of the long-term ITC mechanism should vary according to the topographical characteristic of the terrain where these elements are located. We have not distinguished between different types of terrain because

---

considered as negligible in a country and not in a neighbouring one. Either the representation of these interconnections is omitted completely or simplified by introducing fictitious elements into the model. The purpose of introducing these elements was to observe the interconnection but not to represent its electrical connection to the internal transmission system.

- Delimitation of transmission systems is not always coincident with political borders and reflects the structure of Control Blocks.
- Representation of borders is not stable because of structural changes. This is due to either putting a new interconnection into operation or putting an interconnection temporarily out of operation. Since a common rule on how to represent such changes does not exist, some tie lines have been omitted on one side of the border and represented as switched off on the other side.
- Models of transmission systems may be composed of two or more electrically non-connected parts, due to the outage of an internal line or the separation of bus bars for congestion management purposes. In these cases interconnection was forced by manual intervention.
- DC-Links in received data sets are represented by a ‘Load’ or ‘Generator’ connected to the node where the AC/DC converter is connected instead of X-Nodes.

the required topographic information was not available. The cost figures used are the average cost figures presented in Chapter 6.

The horizontal network taken into account in our computations is the one included in the 72 snapshots provided by ETSO. This HN is likely to be different from the one which would be obtained from the implementation of the procedure for HN identification proposed in Chapter 2. Again, no alternative data consistent with this latter definition of the HN was available.

Our methodology is based on a series of snapshots of the grid, which are used to calculate the compensations due in any given hour. In order to use these results to calculate the compensations due over the year as a whole, these snapshots should be weighted. In fact, the snapshots contain an equal number of hours in working and non-working days, while there are more than twice as many working days in the year. (The ratio would be of course five to two if we were to ignore public holidays). This means that we should give a greater weight to the results for working days when calculating the overall compensations. In our analysis we have ignored public holidays, due to the difficulty in deciding which days should be counted as such given that public holidays generally differ between countries, and we have given results for working days a relative weight of 2.5 compared to the results for non-working days.

A separate issue regards the weighting of snapshots to take account of the fact that they may be representative of a different number of hours within a day. For example, our data contains information on the flows at 3.3 a.m., 11.30 a.m., and 7.30 p.m. If these are representative of the flows in the eight-hour blocks between midnight and 8 a.m., 8 a.m. and 4 p.m., and between 4 p.m. and midnight, respectively, then we could weight them equally when aggregating the results. However, If the pattern of flows changes earlier in the morning, so that 7 a.m. would be a more appropriate dividing line between the ‘night’ and ‘morning’ patterns, then we should use weights of 7:9:8 when aggregating the results.

Patterns of flows in the network will clearly be subject to change at different times of day in different places, and in different months. It may be that the simple rule of equal weighting is in fact reasonable and we have used weights of one-third for each snapshot within a day. However, we believe that some further investigation should be conducted to assess which snapshot would be the most representative for the different operating conditions throughout the day and the relative weights to be assigned to these snapshots.

A final issue relates to the possibility of giving greater weight to snapshots close to peak times, in order to increase the proportion of payments made on the basis of flows when the network is most heavily loaded. Again, we do not make any adjustment for this in our calculations, but flag it as an issue that could be adopted in the final ITC mechanism.

7.3 Results obtained for the Average Participations method

This section presents the results obtained from the application of the proposed approach based on the AP method. Section 7.3.1 presents the results in the case in which only the cost of the used fraction of each line is allocated among agents (countries) in order to compute ITCs. Section 7.3.2 presents the results obtained when the whole cost of each line is considered. The results have been presented on a country-by-country basis, instead of by individual TSOs. The latter format, which neglects political borders, would have been more consistent with the single system paradigm. However we have chosen to present the results at country level, both to facilitate comparability and because the German TSO’s are participating in the scheme together, and not on an individual basis. In both cases, results are presented in two different formats:

- an inter-TSO compensation table where the results obtained for the 72 scenarios are summarised in a single matrix of compensations between countries; this is the main result from the implementation of the methodology; total compensations, charges and net inter-TSO payments are also included in this table;

- graphics showing the geographical distribution of compensations, charges and net payments for each one of the 72 scenarios; this provides information on the volatility, from scenario to scenario, of the compensations affecting each country.

7.3.1 Compensation based on the cost of the used fraction of each line

The results presented here have been computed on the basis that countries must only be compensated for the fraction of the capacity of their lines that agents in other countries are actually using. As indicated, a reliability margin equal to 30% of the thermal capacity of each line has been considered. This implies that, under normal operating conditions, 30% of the capacity of each line cannot be used, on system security grounds, and that using 70% of a line's capacity would mean that the whole cost of the line is allocated according to its electrical usage. Therefore, participations in the use of the line are scaled up using a factor of 1,43 (= 1 / 0.7).

The fact that a security margin is considered does not imply that a portion of the cost of the line is allocated according to security considerations. The cost of the fraction of each line deemed to be used—equal to the fraction actually used scaled up to reflect the security margin—is allocated among the different TSOs according to the electrical usage that the agents within each of these TSOs make of it. The non-used part of the line is assumed to be charged internally within each TSO.

Table 7.1 presents the average compensations among countries over the 72 scenarios considered, expressed in million €. To understand how the figures in the table should be read, consider first the numbers in any given column, for instance column FR for France:

- 18.1 means that the fraction of the French grid used by Italy is worth 18.1 M€.

If we now consider the numbers in row FR, again for France:

- 9.2 represents the cost of that part of the Swiss network used by France.

There are also other numbers of interest in column FR, for France:

- 39.4 is the sum of all external utilisations of the French network by others (4.3 by Belgium, 7.0 by Switzerland, 3.1 by Germany, 6.8 by Spain and 18.1 by Italy), excluding France's own use;
- similarly, the figure 41.4 in column FR is the sum of all the (external) utilisations that France makes of other networks, which are shown in row FR (5.5 for the utilisation by France of the Belgium grid, and 9.2, 10.5, 3.3, 12.7 and 0.1 of the Swiss, German, Spanish, Italian and Dutch grids respectively);
- the difference between the two previous numbers: 39.4 – 41.4 = -2.0, is the net inter-TSO payment for France. Since it is negative, it denotes a payment France would be required to make. This means that generators and consumers in France use other networks more than agents in other countries use the French network. This is the most important result of the analysis for France.

Table 7.1: Average inter-TSO compensations using the AP method for network cost allocation obtained when only the cost of the used fraction of each line is allocated and a reliability margin of 30% of the thermal capacity of each line is considered (in million €)

		OWNER														
		AT	**BE**	**CH**	**CZ**	**DE**	**ES**	**FR**	**GR**	**HU**	**IT**	**NL**	**PG**	**PL**	**SI**	**SK**
USER	**AT**	136.0	0.0	0.0	5.1	2.4	0.0	0.0	0.0	0.5	1.9	0.0	0.0	0.2	1.9	0.6
	BE	0.0	248.7	0.0	0.0	0.4	0.0	4.3	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0
	CH	0.4	0.0	202.4	0.0	8.7	0.0	7.0	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0
	CZ	8.2	0.0	0.0	171.6	7.3	0.0	0.0	0.0	0.9	0.2	0.0	0.0	3.1	0.3	1.4
	DE	4.8	0.9	9.1	5.0	1618.5	0.0	3.1	0.0	0.0	2.5	8.1	0.0	2.9	0.1	0.0
	ES	0.0	0.0	0.0	0.0	0.0	1008.0	6.8	0.0	0.0	0.0	0.0	6.2	0.0	0.0	0.0
	FR	0.0	5.5	9.2	0.0	10.5	3.3	1505.1	0.0	0.0	12.7	0.1	0.0	0.0	0.0	0.0
	GR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	303.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	HU	0.3	0.0	0.0	0.4	0.0	0.0	0.0	0.0	107.4	0.0	0.0	0.0	0.0	0.0	3.2
	IT	4.6	0.0	24.5	0.1	3.7	0.0	18.1	0.0	0.0	681.2	0.0	0.0	0.0	2.5	0.0
	NL	0.0	2.1	0.0	0.0	5.4	0.0	0.1	0.0	0.0	0.0	314.8	0.0	0.0	0.0	0.0
	PG	0.0	0.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	0.0	0.0	198.8	0.0	0.0	0.0
	PL	0.3	0.0	0.0	4.7	1.3	0.0	0.0	0.0	0.1	0.0	0.0	0.0	451.6	0.0	3.6
	SI	4.4	0.0	0.0	0.2	0.1	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0	29.7	0.0
	SK	0.6	0.0	0.0	2.1	0.0	0.0	0.0	0.0	4.3	0.0	0.0	0.0	4.2	0.0	95.5
Use by others		23.8	8.5	42.9	17.7	39.8	12.3	39.4	0.0	5.7	31.3	11.9	6.2	10.4	4.8	8.8
Use of others		12.5	8.4	29.6	21.4	36.5	12.9	41.4	0.0	4.0	53.6	7.6	9.0	10.0	5.3	11.3
Net use		11.3	0.1	13.2	-3.7	3.3	-0.7	-2.0	0.0	1.7	-22.2	4.4	-2.8	0.5	-0.5	-2.5

Numbers are expressed in Million €

The total amount to be paid, that is, the sum of the entitlements of the different countries equals 263.4 million €, while the total amount of net payments, which represents the sum of the amounts that change hands, equals 34.5 million € (this value can be obtained as the sum of all the positive values in the last row of Table 7.1 or, equivalently, as the absolute value of the sum of all the negative numbers in the same row).

Figures 7.1, 7.2 and 7.3 illustrate the geographical distribution of net compensations, compensations and payments for each of the 72 scenarios considered in the analysis. Each of the series in the figures is represented with a different marker and corresponds to a different snapshot. Each element in a series corresponds to a different country. Figure 7.1 represents the net compensations (compensations–payments) faced by the 15 countries for each of the 72 scenarios. Figure 7.2 represents the compensations countries are entitled to receive for the external use made of their grid, and Figure 7.3 represents the payments faced by countries for the use they make of the grid of the remaining ones.

From these figures it is evident that compensations produced by an ITC mechanism based on the AP method follow a fairly stable pattern. Italy is the most important payer and faces negative net compensations for almost all scenarios. On the other hand, Switzerland and Austria are the most important net recipients and obtain positive net compensations in almost all scenarios.

Compensations for the remaining countries are sometimes positive and sometimes negative. However, the range of variation of the results obtained for these countries is quite small in general, i.e. net compensations for most of these countries are small.

Figure 7.1: Geographical distribution of net compensations obtained using the AP method for network cost allocation when only the cost of the used fraction of each line is allocated and a reliability margin of 30% of the thermal capacity of each line is considered

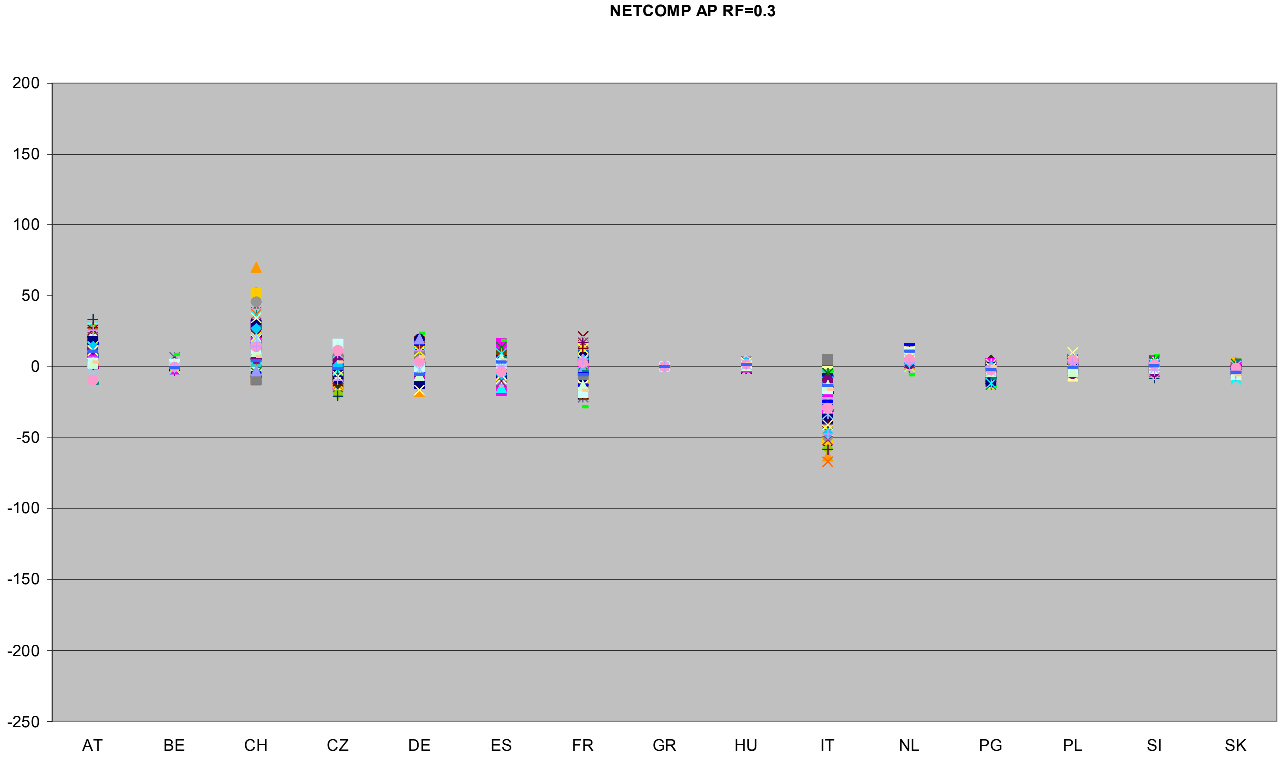


Figure 7.2: *Geographical distribution of compensations obtained using the AP method for network cost allocation when only the cost of the used fraction of each line is allocated and a reliability margin of 30% of the thermal capacity of each line is considered*

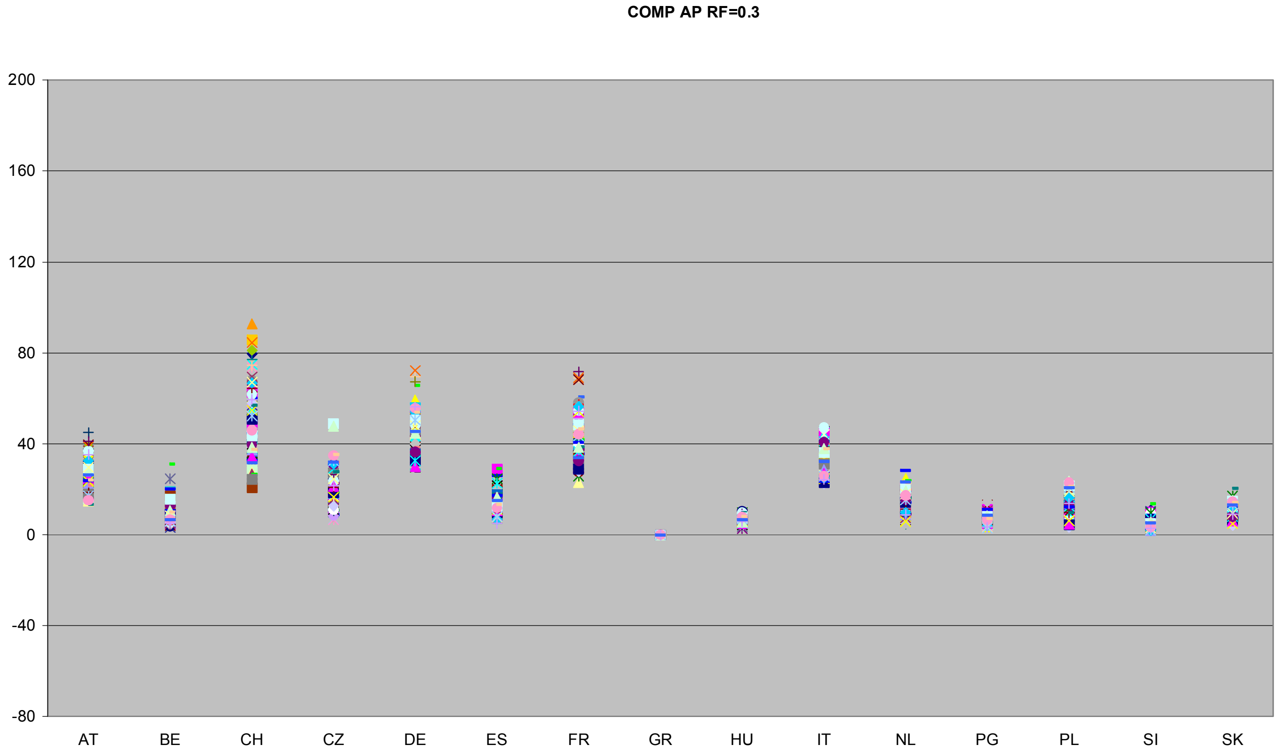
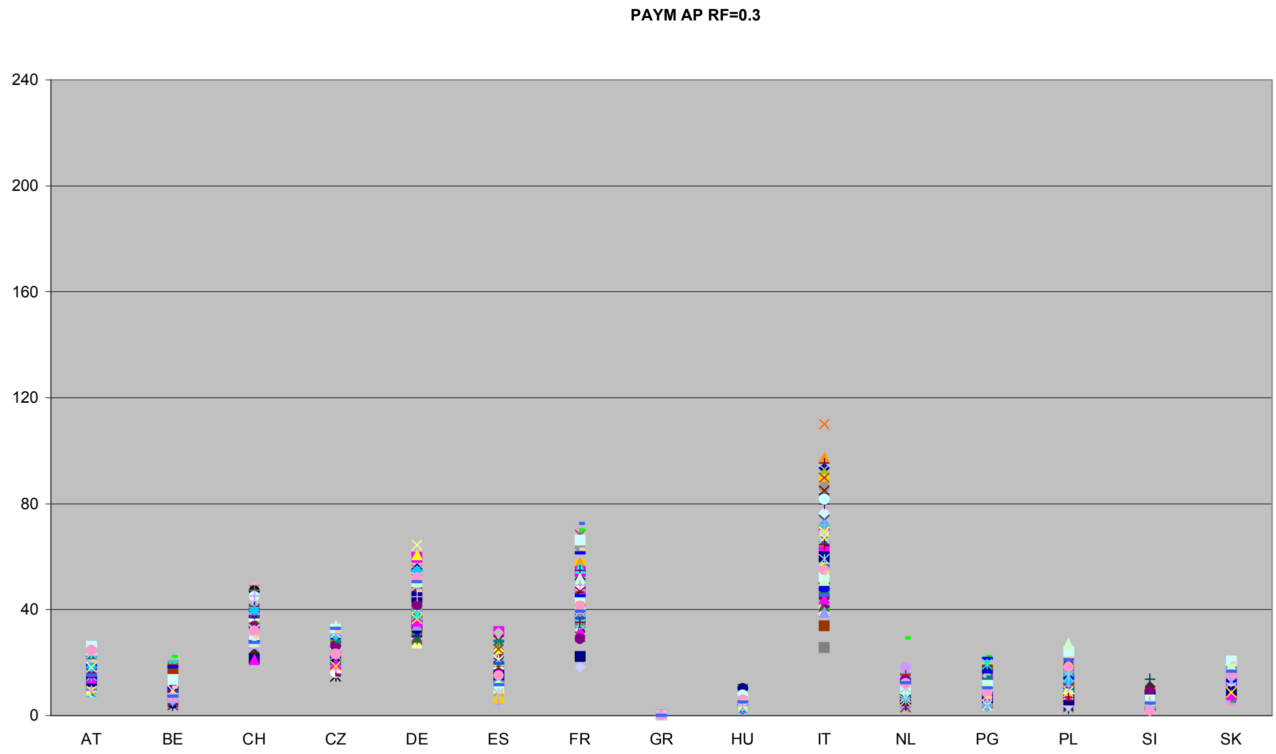


Figure 7.3: Geographical distribution of payments obtained using the AP method for network cost allocation when only the cost of the used fraction of each line is allocated and a reliability margin of 30% of the thermal capacity of each line is considered



7.3.2 Compensation based on the whole cost of each line

Results presented here have been computed assuming that compensation is based on the allocation of the full cost of each line, irrespective of its utilisation level. Results are presented in a similar format to those in section 7.3.1: Table 7.2 contains the average compensations among TSOs over the 72 considered snapshots, while Figures 7.4, 7.5 and 7.6 present the geographical distribution of net compensations, entitlements and payments for each one of the 72 scenarios. Each of the series in the figures is represented with a different marker and corresponds to a different snapshot.

Table 7.2: Average inter-TSO compensations for AP obtained when the whole cost of each line is considered (in million €)

		OWNER														
		AT	**BE**	**CH**	**CZ**	**DE**	**ES**	**FR**	**GR**	**HU**	**IT**	**NL**	**PG**	**PL**	**SI**	**SK**
USER	**AT**	92.2	0.0	0.1	11.5	7.4	0.0	0.0	0.0	2.7	4.0	0.0	0.0	0.3	4.8	1.3
	BE	0.0	232.3	0.0	0.0	1.0	0.0	8.7	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0
	CH	1.9	0.0	147.8	0.0	25.2	0.0	19.3	0.0	0.0	22.6	0.0	0.0	0.0	0.0	0.0
	CZ	21.3	0.0	0.0	144.1	21.8	0.0	0.0	0.0	2.4	0.4	0.0	0.0	7.4	0.8	4.9
	DE	17.2	2.2	24.8	11.6	1547.4	0.0	6.3	0.0	0.0	4.9	32.1	0.0	8.5	0.3	0.0
	ES	0.0	0.0	0.0	0.0	0.0	981.6	16.8	0.0	0.0	0.0	0.0	21.3	0.0	0.0	0.0
	FR	0.0	17.1	26.3	0.0	28.8	11.1	1457.0	0.0	0.0	28.9	0.4	0.0	0.0	0.0	0.0
	GR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	303.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	HU	1.6	0.0	0.0	1.6	0.0	0.0	0.0	0.0	96.1	0.0	0.0	0.0	0.1	0.0	7.3
	IT	11.0	0.0	46.3	0.3	9.8	0.0	36.3	0.0	0.0	649.7	0.0	0.0	0.0	7.0	0.0
	NL	0.0	5.5	0.0	0.0	11.6	0.0	0.1	0.0	0.0	0.0	282.2	0.0	0.0	0.0	0.0
	PG	0.0	0.0	0.0	0.0	0.0	27.5	0.0	0.0	0.0	0.0	0.0	183.7	0.0	0.0	0.0
	PL	0.7	0.0	0.0	13.2	4.9	0.0	0.0	0.0	0.2	0.0	0.0	0.0	434.2	0.0	15.6
	SI	12.0	0.0	0.0	0.6	0.2	0.0	0.0	0.0	0.0	2.0	0.0	0.0	0.0	21.5	0.1
	SK	1.9	0.0	0.0	6.5	0.0	0.0	0.0	0.0	11.7	0.0	0.0	0.0	11.5	0.1	75.2
Use by others		67.6	24.9	97.5	45.2	110.9	38.6	87.5	0.0	17.0	62.9	44.5	21.3	27.8	13.0	29.1
Use of others		32.2	21.8	69.1	59.1	107.8	38.0	112.6	0.0	10.6	110.6	17.3	27.5	34.5	15.0	31.7
Net use		35.4	3.1	28.4	-13.9	3.1	0.6	-25.1	0.0	6.4	-47.8	27.2	-6.2	-6.7	-2.0	-2.6

Numbers are expressed in Million €

According to figures presented in Table 7.2 the total amount to be paid, i.e. the sum of the entitlements for all the countries, equals 687.8 million € while the total amount of net payments (the total amount that changes hands) is 104.2 million €.

Figure 7.4: Geographical distribution of net compensations obtained using the AP method for network cost allocation when the whole cost of each line is considered

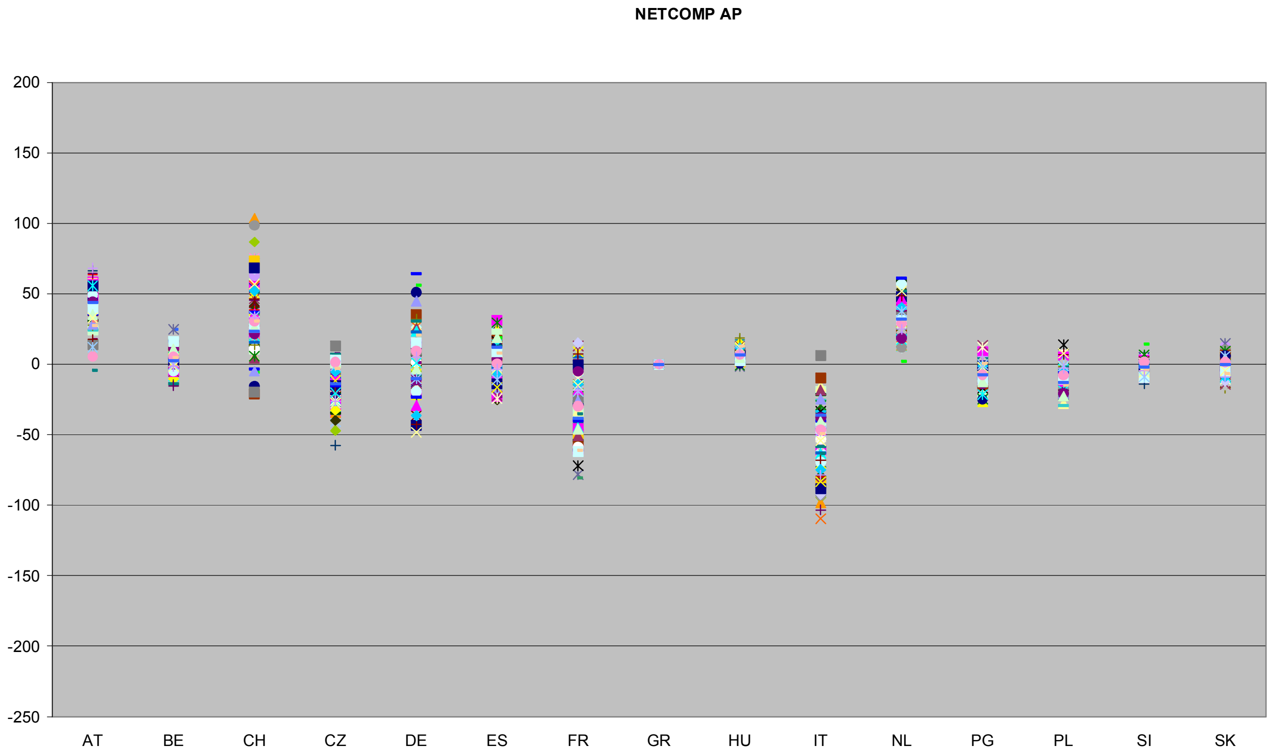


Figure 7.5: Geographical distribution of compensations obtained using the AP method for network cost allocation when the whole cost of each line is considered

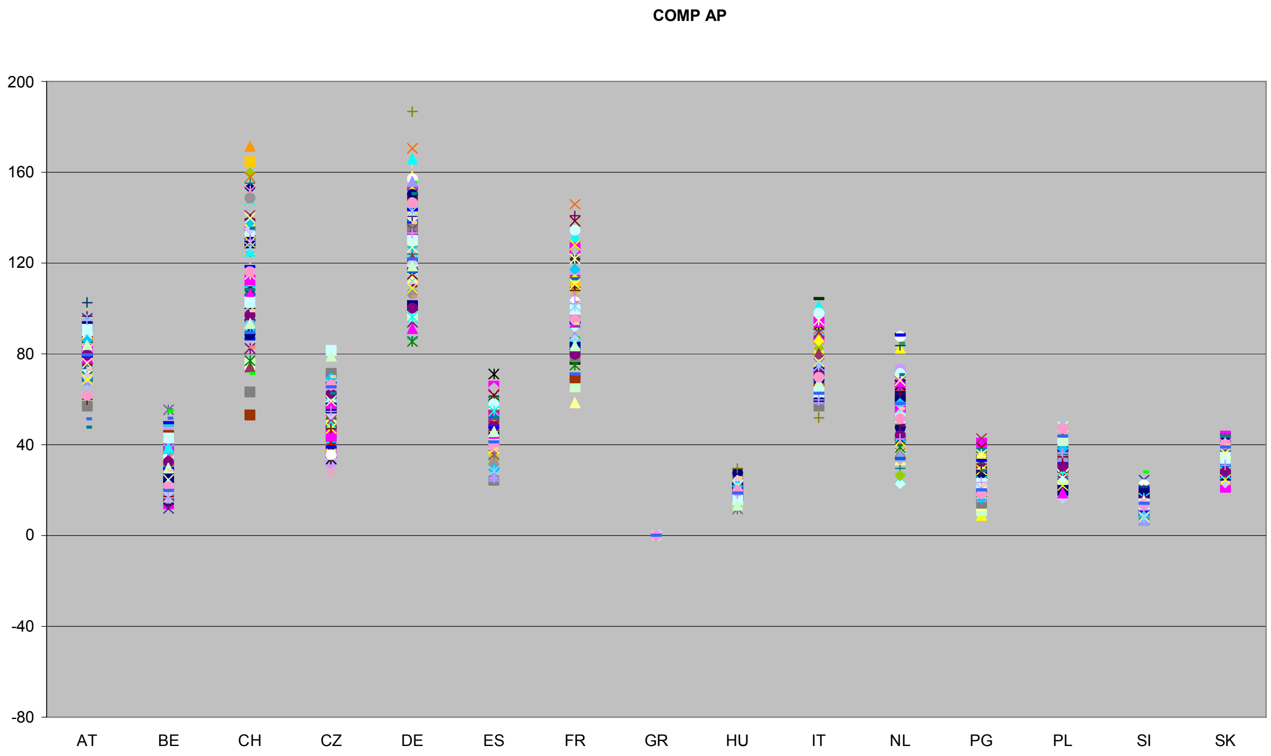
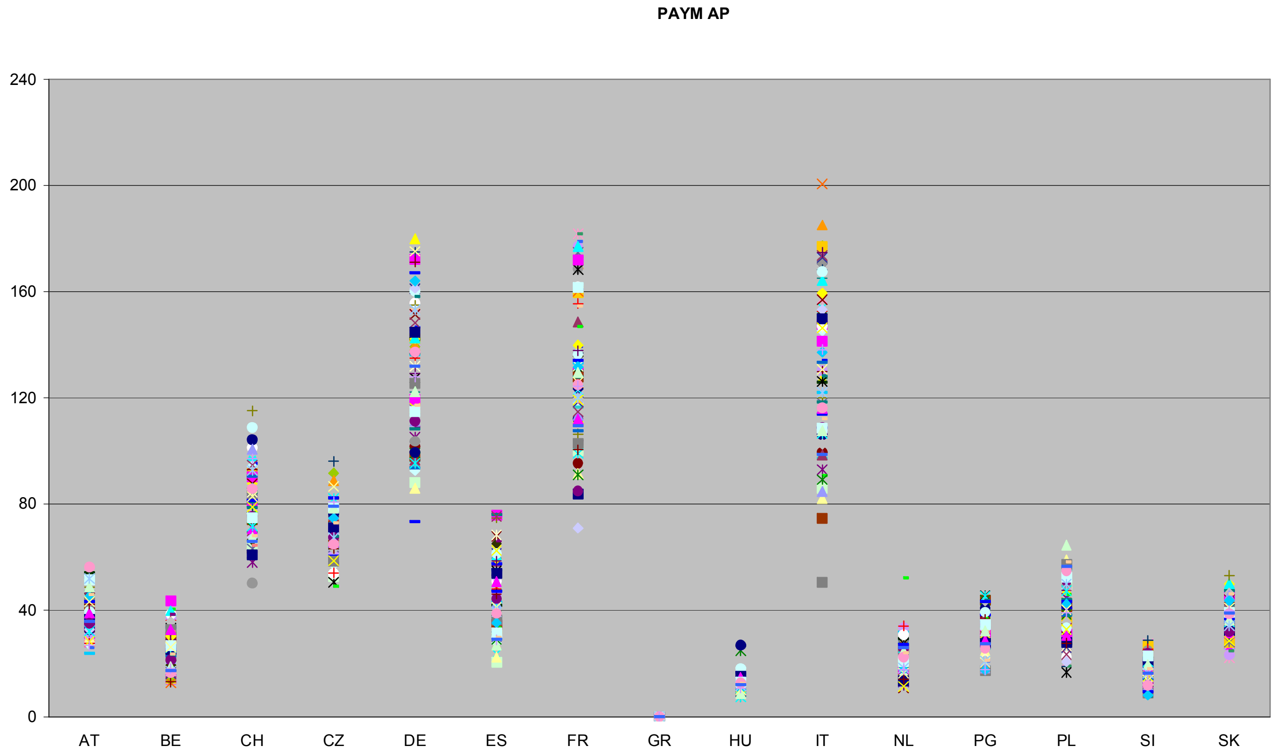


Figure 7.6: Geographical distribution of payments obtained using the AP method for network cost allocation when the whole cost of each line is considered



These results follow the same general pattern of those obtained when only the cost of the used fraction of each line is allocated. Here, the most important net receivers are Switzerland, Austria and the Netherlands while the most important net payers are Italy, France and the Czech Republic. Figures are generally larger when the whole cost of the HN is assigned through the ITC mechanism. Notable exceptions are Germany, for which net compensation is marginally higher when the ITC mechanism only considers the cost of the used fraction of each line, Spain is a net receiver if the whole cost of the lines is considered, but a net payer when only the cost of the used fraction of the lines is taken into account, Poland is in the opposite position. Italy, France and the Czech Republic are comparatively better off—their net payments are substantially reduced—when only the used fraction of each line is considered, whereas Austria, the Netherlands and Switzerland are, comparatively, worse off—their net receipts are substantially reduced. These different results may depend to a large extent in the different levels of line loading in different countries.

7.3.3 Comments on the results obtained using the AP method for network cost allocation

The AP method tracks the flows on the grid and allocates electrical usage according to where these flows originate and end. Hence, the compensations to be paid by countries depend on how deeply the cross-border flows for which they are responsible penetrate other countries' networks. Analogously, the compensation they receive depends on how deep cross-border flows on their borders penetrate their own grid. The larger the amount of cross-border flows that exist on the border of a country the more likely that both the compensation and payment faced by the country are larger. Hence, the net compensation faced by the country tends to be larger as well.

However, for some countries, such as Germany, this may not be true. Both the compensation and payment corresponding to Germany are among the highest in Europe. However, both are very similar in magnitude. Hence, their difference, i.e. the net compensation received by the country, is very small. Very important exporters and importers, such as Italy or France, tend to have large and negative net compensations (they have to pay overall). This is due to the fact that they create large power flows that end or originate (they are consumed or produced) far into the grid of other countries. Small heavily transited countries (internally balanced but importing and exporting large amounts of power), such as Switzerland or Austria, tend to receive large net compensations since an important part of the flows through their grid do not originate or end within their borders.

Some results, however, appear surprising at first sight. Thus, the AP method results in large payments for the Netherlands, despite the country being a heavy importer. This seems to be due to the fact that the use which Dutch agents make of the grid of neighbouring countries (such as Belgium and Germany) is relatively small with respect to the volume of imports from other countries. This is probably related to the existence of important generation centres in Belgium and, specially, in Germany that are very close to the Dutch border. Therefore, Dutch imports do not seem to result in a significant use of the grids deep into the neighbouring countries.

7.4 Results obtained for the current ETSO (temporary) mechanism

This section provides results from the application of the current ETSO mechanism to the same data described above in order to facilitate the comparison with the results obtained with the AP method. Results for the ETSO method must be compared to those obtained with the AP method when the whole cost of each line is considered in the ITC method. The comparison of the results for the ETSO mechanism with the results obtained with the AP method when only the cost of the used fraction of each line is allocated is somewhat more difficult since the ETSO mechanism, as it is applied now, allocates the whole cost of the HN. Table 7.3 presents the average figures of compensations among countries over the 72 scenarios examined.

Table 7.3: Average inter-TSO compensations for the ETSO method (in million €)

		OWNER														
		AT	**BE**	**CH**	**CZ**	**DE**	**ES**	**FR**	**GR**	**HU**	**IT**	**NL**	**PG**	**PL**	**SI**	**SK**
USER	**AT**	105.4	0.5	2.2	0.7	3.3	1.0	0.3	0.3	0.6	0.0	0.4	0.3	0.7	0.3	0.8
	BE	1.6	238.9	2.2	0.8	3.4	1.0	0.4	0.3	0.7	0.0	0.4	0.4	0.7	0.4	0.9
	CH	3.5	1.1	171.4	1.7	7.3	2.2	1.1	0.6	1.6	0.0	1.0	0.9	1.5	0.9	1.9
	CZ	4.6	1.5	6.6	164.6	10.1	3.1	1.2	1.0	2.0	0.0	1.2	1.1	1.9	1.1	2.4
	DE	4.6	1.5	6.1	2.2	1545.5	2.9	1.3	0.9	2.1	0.0	1.2	1.2	1.9	1.1	2.4
	ES	1.0	0.3	1.5	0.5	2.3	983.8	0.2	0.2	0.5	0.0	0.3	0.3	0.4	0.3	0.5
	FR	15.3	5.2	22.2	7.2	34.2	10.2	1533.0	3.1	7.0	0.1	3.9	3.8	6.5	3.8	8.2
	GR	0.6	0.2	0.9	0.3	1.4	0.4	0.2	292.1	0.3	0.0	0.2	0.1	0.3	0.2	0.4
	HU	1.8	0.6	2.5	0.9	4.0	1.2	0.6	0.4	88.9	0.0	0.4	0.4	0.7	0.4	1.0
	IT	13.0	4.3	18.4	6.1	28.3	8.7	3.6	2.6	5.8	712.3	3.4	3.3	5.4	3.3	6.9
	NL	4.1	1.6	5.5	2.1	8.9	2.8	1.2	0.8	1.7	0.0	313.1	1.0	1.6	1.0	2.2
	PG	0.8	0.3	1.3	0.4	2.0	0.6	0.2	0.2	0.4	0.0	0.2	191.2	0.4	0.2	0.5
	PL	2.4	0.8	3.1	1.4	5.1	1.5	0.8	0.4	1.0	0.0	0.6	0.6	439.5	0.6	1.4
	SI	0.3	0.1	0.4	0.1	0.7	0.2	0.1	0.1	0.1	0.0	0.1	0.1	0.1	20.8	0.2
	SK	0.8	0.2	1.1	0.3	1.8	0.5	0.2	0.2	0.4	0.0	0.2	0.2	0.4	0.2	74.7
Use by others		54.4	18.3	73.9	24.7	112.8	36.4	11.5	11.1	24.3	0.3	13.6	13.8	22.5	13.7	29.5
Use of others		11.4	13.2	25.3	37.9	29.4	8.2	130.7	5.4	15.0	113.1	34.6	7.4	19.9	2.6	6.6
Net use		43.0	5.0	48.6	-13.2	83.4	28.2	-119.2	5.7	9.3	-112.8	-21.0	6.4	2.6	11.1	23.0

Numbers are expressed in Million €

The sum of the entitlements of the different countries equals 460.7 million € while the total amount of net payments is 266.3 million €.

Figures 7.7, 7.8 and 7.9 present the geographical distribution of net compensations, entitlements and payments for each of the 72 scenarios. Each of the series in the figures is represented with a different marker and corresponds to a different snapshot.

Figure 7.7: Geographical distribution of net compensations obtained for the ETSO method

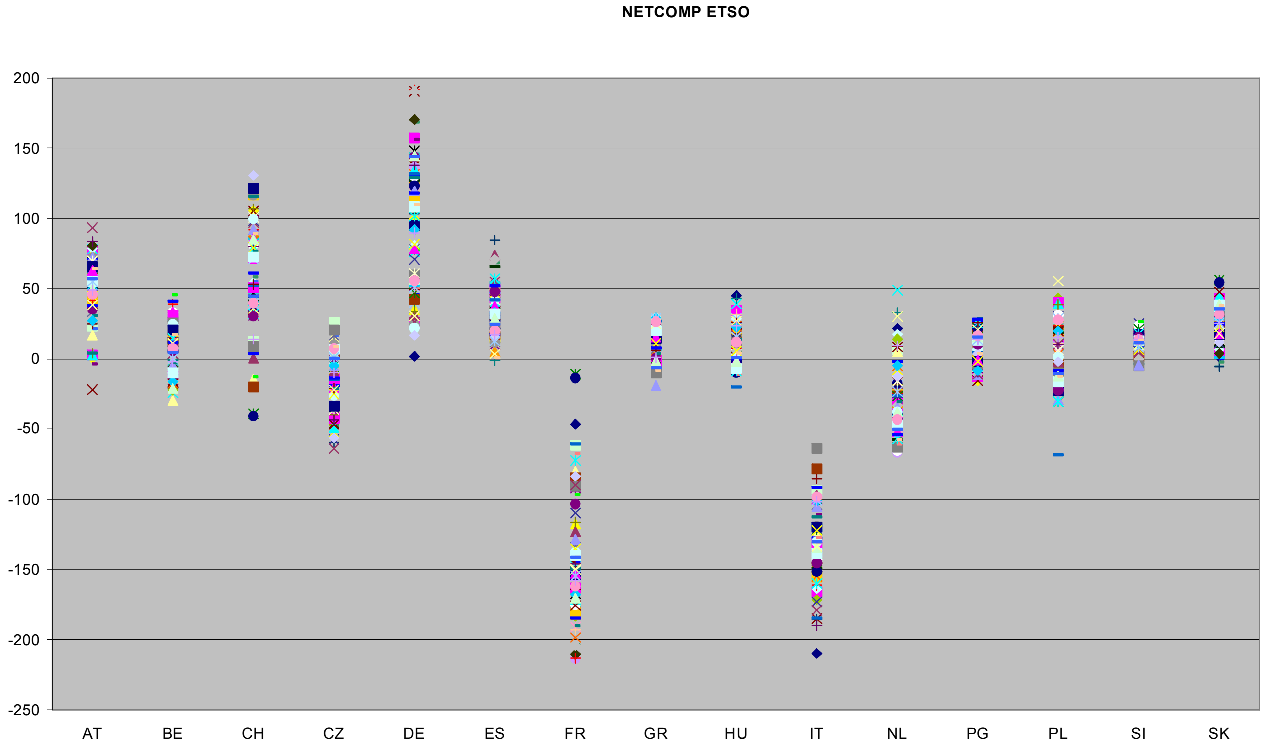


Figure 7.8: Geographical distribution of compensations obtained for the ETSO method

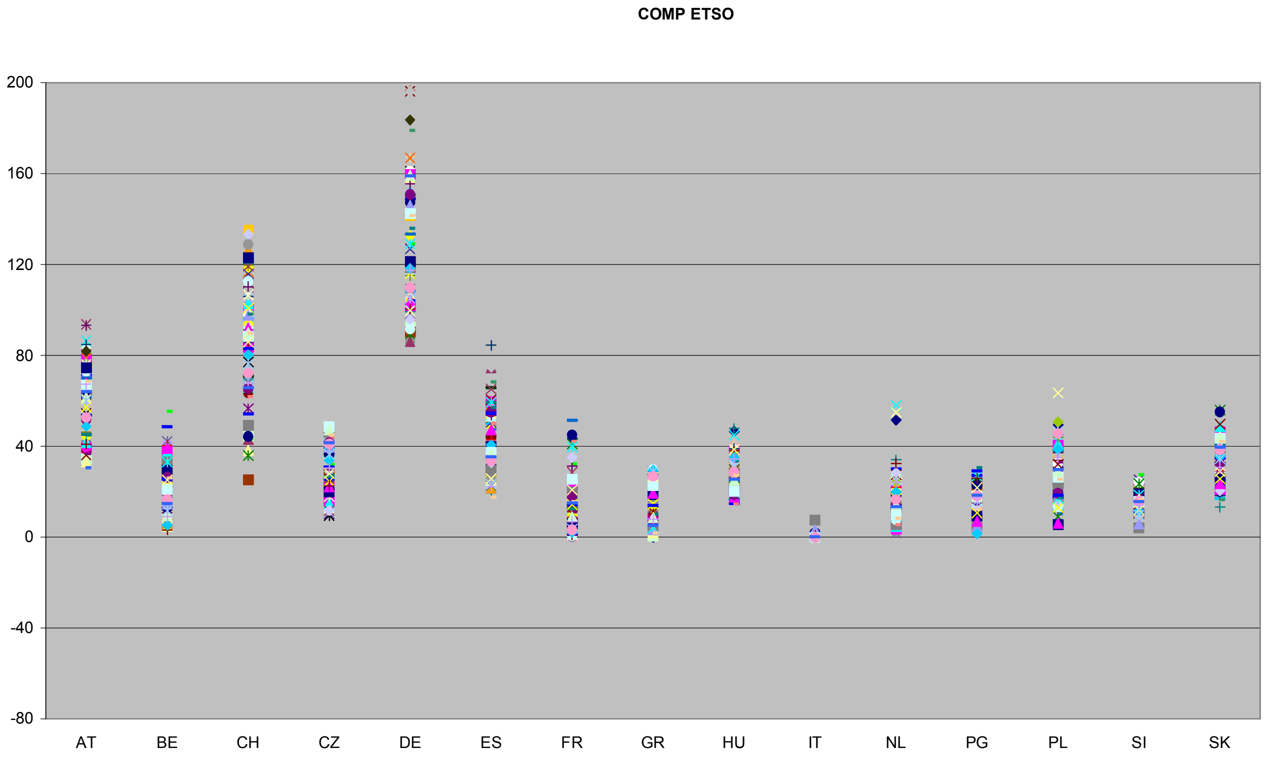
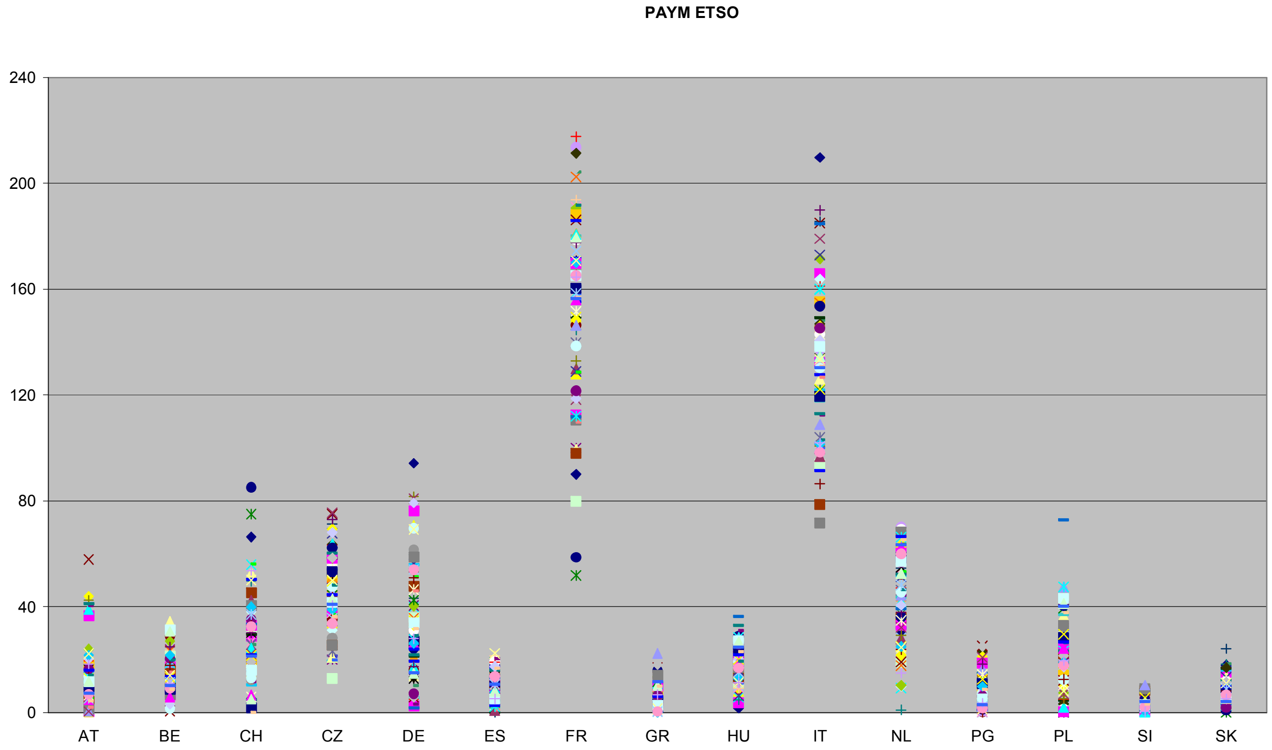


Figure 7.9: Geographical distribution of payments obtained for the ETSO method



7.4.1 Comments on the results obtained for the ETSO mechanism

The ETSO method is based on the concept of transit flows through, rather than the pattern of flows within, each country. This feature of the method may result in compensations and payments that are counter-intuitive.

Since compensations are linked to the existence of a transit through the grid of a country, countries that only export or import do not receive any compensation. Thus, this method favours mainly transited countries at the expense of the mainly exporting or importing ones. The most important receivers under the ETSO mechanism are countries for which computed transits are very large, such as Germany, Switzerland or Austria. On the other hand, the most important net payers are large exporters such as France and large importers such as Italy or the Netherlands.

When computing the compensations due to a country only the relative size of the transit with respect to the internal consumption is considered, and not the effect of the transit on the internal flows. Hence, transited countries secure an important compensation irrespective of whether the transit through their grid increases or decreases the total electrical use of their grid.

Finally, the determination of payments is not related to any sound engineering criterion for the allocation of responsibilities. Payments are determined according to the size of net exports or imports and irrespective of the pattern of flows in the region or the electrical distance between the countries. As a consequence of this a country must compensate every other country in the region (see compensations to be paid by each country in Table 7.3).

7.5 Comparison of results

The ETSO mechanism allocates he whole cost of the HN. Therefore, a meaningful comparison with the AP method can only be performed if the latter is applied to the whole cost of each line. Significant similarities and differences exist between compensations and payments obtained with the AP method and for the ETSO mechanism.

In both cases, Italy and France are amongst the most important net payers, while Switzerland and Austria are amongst the most important net receivers. However, similarities between both approaches end here. Transit-based approaches, such as the ETSO mechanism, favour heavily-transited countries at the expense of mainly exporting or importing countries. Thus, countries such as Italy, France or the Netherlands are better off under the AP method than under the ETSO mechanism. On the other hand, other countries, such as Germany, Switzerland, Austria or Slovakia, which are deemed to host important transits through their grids, are in a better financial position when the ETSO mechanism is applied. The ETSO mechanism does not take into account the actual pattern of flows within each country. Therefore, this method will produce large compensations for transited countries regardless of the impact of this transit on the use made of the grids involved.

As for the allocation of responsibilities, payments to be made by each country in the AP method are restricted, in general, to neighbouring countries whereas in the ETSO method every country must contribute to the compensation due to every other country in the same proportion. Additionally, we may note that the total volume of net compensations in the ETSO method is significantly larger (about twice) than in the AP method.

We conclude by stressing once again that the purpose of presenting numerical results is to show how the proposed methodology for the longer-term ITC mechanism can be implemented. The numerical exemplification is not intended to influence the decision on which network cost allocation approach is best suited for being used in the longer-term ITC mechanism. This is why results were provided for the AP method only—and the ETSO mechanism for comparison with the current situation—and not for the other methods described in Chapter 4.

By presenting numerical results obtained when applying the AP method to 72 real scale European snapshots we aim to prove that implementing this method in order to effectively compute ITC payments is entirely possible.

8 Concluding remarks

This Report presents the results of an assessment of the various components which contribute to the definition of an ITC mechanism which should replace the current temporary one and operates in the longer-term.

In particular, Part A focuses on:

- the scope of the mechanism, i.e. the definition of the relevant network and the nature of the flows in relation to which compensation is provided;
- the costs for which compensation is provided, and the way in which these costs is evaluated;
- the method for allocating network costs between users located in different TSO areas.

These aspects are assessed methodologically and a detailed proposal is presented in Chapter 5.

Part B illustrates how the proposed methodological approach could be implemented for the (continental) European network, providing some numerical examples.

In this concluding chapter we focus on the main methodological results of our analysis, especially where we depart substantially from the approach of the current ETSO mechanism.

Scope of the ITC mechanism. We propose that the ITC mechanism provide compensation for the costs related to all cross-border flows, and not just for costs associated with transit flows. Extending compensation to the costs associated with all cross-border flows complies with the provisions in Regulation 1228/2003, and is supported by sound economic arguments. The concept of a single EU market for electricity with the single system paradigm logically leads to the inclusion of all cross-border flows. The practical argument that using ‘just transits’ would be justified by the fact that for cross-border flows, other than transits, the mutual impact of neighbouring countries on each other would be identical, largely offsetting compensation payments on those flows, is not correct. Inclusion of all cross-border flows also avoids the need to identify transits, which requires either some simplifying and somewhat arbitrary assumptions or reference to contractual paths, a concept which was abandoned early in the development of the IEM. Moreover, extending the ITC mechanism to compensate for the costs related to all cross-border flows is more consistent with the regulatory framework of the IEM.

Costs to be compensated. Our proposal provides compensation for the cost of new infrastructure, for the cost of existing infrastructure, and for the cost of losses. We propose that the valuation of infrastructure is carried out by using standard replacement cost values, and not by using Member State-specific regulated costs. With this standardised approach, the diminishing regulatory and TSO burden would be combined with fairness, equity and simplicity. For the purpose of evaluation, HN elements should be classified in a small number of categories, according to their type and the topographical characteristic of the area in which they are located. Standard replacement cost values should be used for each category. This approach complies with the provisions in Regulation 1228/2003, which require that a forward-looking, long-run average incremental cost approach be used. We have argued that the LRAIC requirement, solely for the purpose of the ITC scheme, can be met in a practical and relatively burden-free way. For losses, we propose to use the actual valuation of electricity, which emerges from the hourly prices on the relevant Power Exchanges, and to apply these prices to the actual level of losses.

Network cost allocation. On the basis of a detailed assessment of the various network cost allocation methods which have been proposed in the recent debate, we conclude that the Average Participations method is the one best suited to be applied for the longer-term ITC mechanism.

The current ETSO mechanism is similar, in many respects, to the WWT method. Even though it does not comply with the provisions of Regulation 1228/2003—as it limits compensation to the costs associated with transits—the WWT method was, surprisingly, among those which the European Commission, in its Discussion Document of June 2003, indicated as candidates for use in the longer-term ITC mechanism. Consequently we can presume that there may be an inclination to adopt the WWT method for network cost allocation as the longer-term solution: by ETSO.

It is our view that the AP method is far superior to all the other methods which have been considered, including the WWT method, for implementation in the longer-term ITC mechanism. Adopting WWT would forego the opportunity to base such mechanism on a sound, cost-reflective methodology, best suited for the IEM. In fact:

- The AP method extends compensation to the costs associated with all cross-border flows, while the WWT method limits compensation to the costs associated with transits. As indicated above, we believe that extending compensation to cover the costs associated to all cross-border flows is an essential aspect of the longer-term ITC mechanism. And it does not appear to be the case, either logically, or in practice, that such extension has no material effect on the compensation between TSOs, as the European Commission, at least in the past, has claimed.
- The AP method allows network costs to be assigned to agents located at different nodes. In this way, compensation entitlements and compensation responsibilities can be derived in a consistent manner. The WWT method, instead, allows the computation of the level of compensation that each TSO is entitled to receive for the use of its grid by external agents, but does not provide any indication as to where these external agents are located and, therefore, which TSO(s) should be held responsible to pay such compensation. In the WWT method, typically, each TSO is required to contribute the same fraction towards the compensation entitlement of every other TSO in the region, irrespective of the geographical or electrical proximity of the grids of the two TSOs and, therefore, of the effect that injections and withdrawals in the grid of one TSO may have on the flows over the other TSO's grid.
- It should be noted that this shortcoming in the WWT method implies that the cost that corresponds to the external usage of a new built line belonging to the HN of any TSO will be automatically shared, through the ITC mechanism, by all TSOs with net flows, regardless of their electrical proximity to the line. It may even be the case that, when the 'without' situation reduces the flow in the line with respect to the 'with' situation, that the TSO where the line is located will have to compensate economically to all TSOs with net flows when the new line enters into operation. This is hard to accept, but it certain to occur.
- The AP method, being based on an allocation of costs at the individual node level, is as independent on the location of political border as possible. All network allocation methods aggregate entitlements and responsibilities at the TSO level, and therefore the ITC that they produce is inevitably affected by the location of the borders defining the various TSO areas, which often coincide with the political borders. However, in the WWT method, the location of political borders not only affects the aggregation of compensation entitlements and responsibilities, but also the definition of the 'without'

scenario, which is at the very heart of the method. This is not the case for the AP method. Therefore, the AP method is far superior to the WWT method in complying with the ‘single system paradigm’.

- The AP method is based on a sensible heuristic rule regarding the way in which power flows over the network. This rule may not strictly reflect the laws of physics, but is a reasonable simplification and ensures that power can be traced over the network in an economically sensible manner and in a way which reflects the actual pattern of flows over the grid. Instead, the WWT method relies on the fictitious ‘without’ scenario which may be characterised by power flows that have little to do with the physical reality of the actual power system.

We believe that the AP method is not computationally more onerous than the WWT method. It is true that compensation entitlements using the WWT method can be computed by each TSO independently. However we consider the latter characteristic of the method a drawback, as it does not ensure consistency of approach and, as already indicated, makes it impossible to identify the responsibilities of each individual TSO in a manner that reflects the actual utilisation of the other TSOs’ grids.

We also propose that, in general, infrastructure costs should be allocated to external agents, through the ITC mechanism, only to the extent that the flows for which these agents are responsible actually utilise those elements. Therefore the cost of any unused portion of the capacity of the infrastructure should not be considered for compensation. We believe that this approach is fully consistent with the fact that the decision to develop the network infrastructure was in the past, and often still is, taken by the local TSO, with no involvement of other TSOs which, if the full cost of the capacity were eligible for compensation, might be required to pay, through the ITC mechanism, some of the cost of such capacity even if unused.

In some cases, however, the benefit of a new infrastructure is clearly shared by several TSOs, to the extent that the decision on the investment may be taken jointly, or endorsed, by all the TSOs concerned. In these cases we propose that external agents should be allocated, through the ITC mechanism, a proportion of the cost of the entire capacity of the new infrastructure, equal to the share of the total flow on the element for which they are responsible, irrespective of the actual level of utilisation of such capacity. Therefore, external agents would also be allocated a share of the costs of any unused capacity of the infrastructure. In this way we ensure that the ITC mechanism promotes the development of the European network even in those cases when benefits are spread over different TSO areas.

The discussion on the ITC mechanism has been high on the agenda since the beginning of the Florence Forum process in 1998. From a technical and regulatory perspective, determining a fair and sound system for cost re-allocation between the TSOs in such a way as to avoid hampering cross-border trade has been a difficult task. Various methods and approaches have been discussed and proposed in the recent years. In this study we have compared them on the basis of a set of objective and specific criteria and defined a methodological proposal for the longer term ITC mechanism. We trust that the proposals in this study may contribute to a timely conclusion of the protracted and time-consuming decision-making process.

Annexes

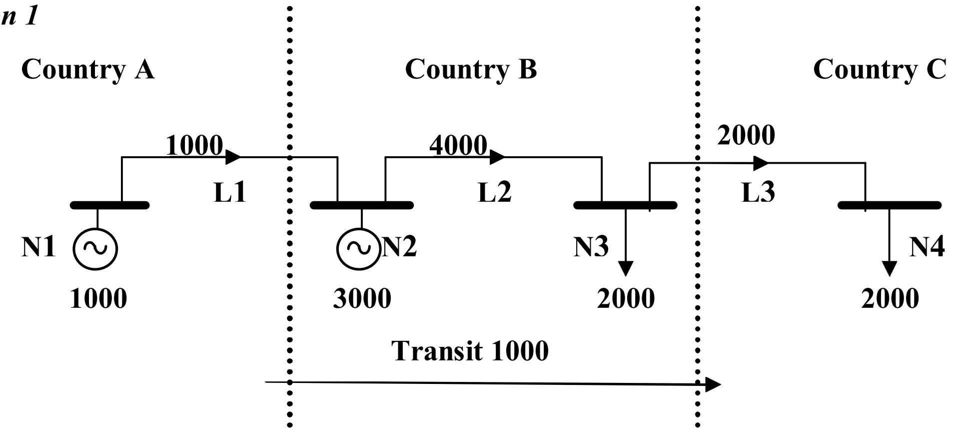
Annex 1: Specific issues related to network cost allocation using transit-based methods

Annex 1 focuses on the specific issue of the identification of the transit through a country or TSO area and the resulting implications for the compensation awarded by some transit-based methods (notably the ETSO mechanism).

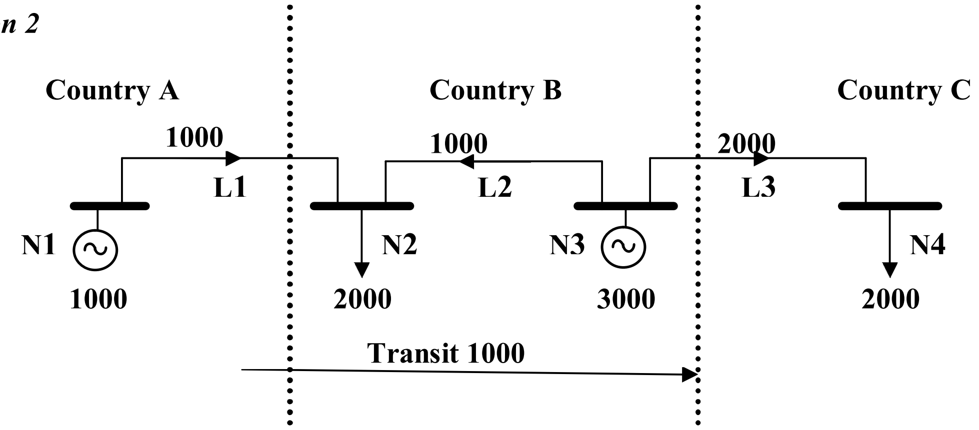
We consider the following two extremely simplified network topologies.

- Country A includes node N1 and the line L1;
- Country B includes node N2 and N3 and line L2;
- Country C includes node N4 and line L3.

Situation 1



Situation 2



The two situations are identical in all respects, except for the location of generation and load in country B, and the direction of the resulting flow on line L2. In situation 1, the generator in country B is located at node N2, closer to the border with country A. In this case, power on line L2 flows from N2 and N3. This flow includes both imports from country A and the production by the generator located at node N2. Part of this flow is consumed by the load located at node N3, with the remaining part being exported to country C (and consumed by the load located at node N4. In this situation, 1000 MW actually cross country B, from the interconnection with country A to the interconnector to country C, and therefore can safely be considered as a transit.

In situation 2, the load in country B is located at node N2. The electricity consumed at this node is partly imported from country A, and partly produced by the generator located at node N3. Power on line L2 therefore flows from N3 to N2. Country B still exports to country C, but only (part of) the electricity produced by the generator located at node N3. Therefore in this situation there is no power transiting through country B.

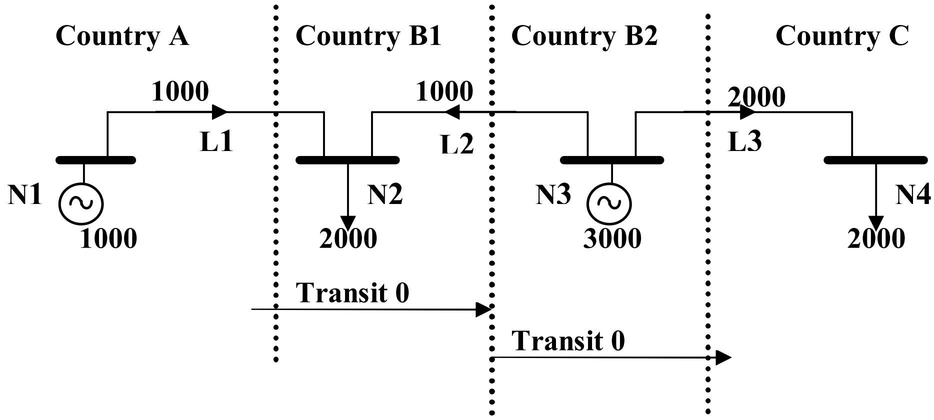
All the methods based on transits use a conventional definition of this concept. Both the WWT and the APT methods, as well as the current ETSO mechanism, generally define hourly transits as the minimum between the total import flows and the total export flows.

Despite the fact that country B is only affected by transits in situation 1, using the above definition would result in a 1000 MW transit through country B in both situations (this is the minimum between the 1000 MW import from country A and the 2000 MW export to country C).

In the current ETSO mechanism, the HN costs are allocated to internal and external users in proportion to domestic load and transits respectively. As domestic load and transits are the same—2000 MW and 1000 MW, respectively—in both situations, the proportion of country B's HN costs allocated to external users will also be the same, despite the fact that, as already indicated, no power actually transits through country B in situation 2. In fact, in this situation, the cross-border flows affecting country B reduce the utilisation of line L2.

We now consider the influence of the location of political borders in the identification of transits. We assume that a new border is introduced in situation 2 within the country B area, dividing it into two further areas, country B1 and country B2, as illustrated in situation 3.

Situation 3



No transits through country B1 or country B2 exist in situation 3. Hence, the outcome of transit-based methods in this case better reflects the physical reality and countries B1 and B2 would not receive any compensation using these methods.

The following conclusions can be drawn from the simple examples provided above:

- Compensations under the ETSO mechanism bear no relation to the flows within a country. Thus, the compensation due to a country may be the same in two very different cases: one where the transit increases the costs born by a country (situation 1) and the other where it actually decreases these costs (situation 2);
- Compensations may depend on the location of political borders. This directly follows from the comparison of the results provided by these methods in situations 2 and 3 above.

Annex 2: The algorithm of the Average Participations method

This Annex illustrates the algorithm used in the Average Participations (AP) method with the help of a simplified grid topology which includes 5 nodes connected by 5 lines. In every node, G indicates generation and L load and the flow is expressed in MW.

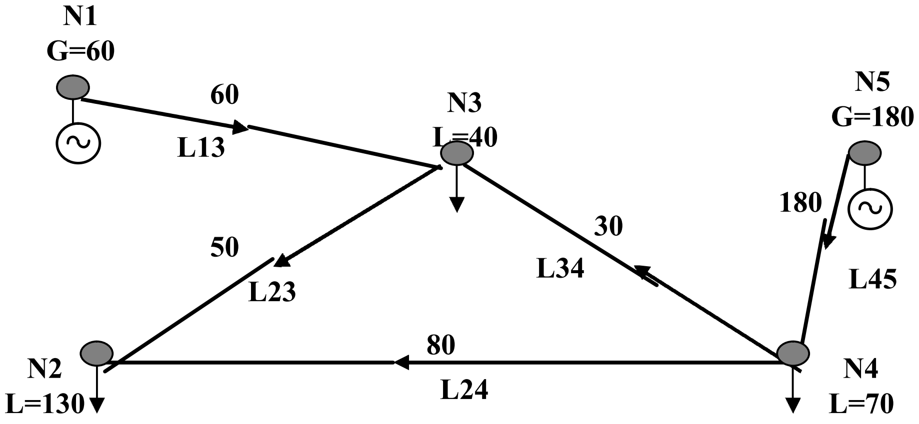
Node 1: G=100, L=40
Node 2: G=20, L=150
Node 3: G=40, L=80
Node 4: G=50, L=120
Node 5: G=200, L=20

Flows are obtained considering the following impedances:

X_{13}=0.2 Ω
X_{23}=0.1 Ω
X_{24}=0.1 Ω
X_{34}=0.1 Ω
X_{45}=0.2 Ω

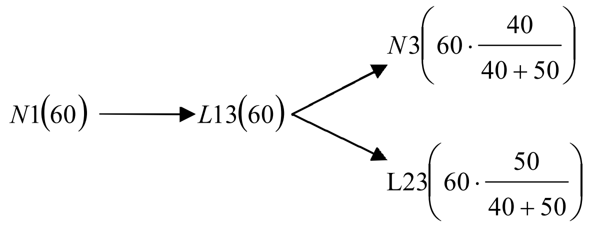
There are several possible implementations of the algorithm in the AP method. One first possibility involves computing the net amount of generation or demand at each node. If there is more generation than load (as it is the case for instance in node 1) the node injects power into the network: it is an injection node. On the other hand, if load is larger than generation (as in node 2) the node withdraws power from the network: it is a withdrawal node. Then, the net amount of power injected or withdrawn at every node is traced through the grid until it reaches the loads or generators where it is consumed or produced.

Alternatively, the method can trace separately the power injection or withdrawal by each market agent without previously netting generation and demand at each node. Results yielded by both versions of the algorithm differ significantly and one must decide whether to use one or the other. Here, results have been obtained for the first version, where generation and demand within each node are netted out.



Injection and withdrawal nodes are dealt with separately. Consider the allocation to the injection nodes first. These are the nodes 1 and 5 in the figure.

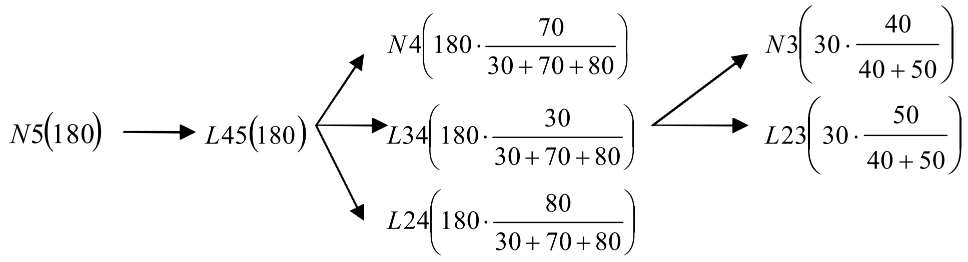
Let us start with node 1. When the net injection of 100 – 40 = 60 MW in node 1 reaches node 3, it is split between the net withdrawal (80 – 40 = 40 MW) in node 3 and the outgoing flow (50 MW) leading to node 2 in proportion to the size of these flows. Therefore, the flow of 60 MW entering node 3 is split into 60 x 40 / (40 + 50) = 27 MW[34] that are consumed in node 3 and 60 x 50 / (40 + 50) = 33 MW that flow into line L23. The flow in line L23 is not split further, since the flow on all the lines connected to node 2 goes towards this node.



In this way we have determined that the injection node 1 is responsible for 60 MW of flow in line L13 (out of 60) and for 34 MW of flow on line L23 (out of 80). Node 1 is not responsible for the flows on lines L24, L34 and L45.

The case of the net injection of 200 – 20 = 180 MW from node 5 is a bit more complex. The whole amount (180 MW) flows via line L45, but when it arrives at node 4 it branches in 3 directions:

- the net withdrawal of 120 – 50 = 70 MW in node 4;
- the outgoing flow of 80 MW towards node 2 where it is withdrawn;
- the outgoing flow of 30 MW towards node 3, where it continues further. This last flow of 30 MW is split between the net withdrawal of 80 – 40 = 40 MW in node 3 and the outgoing flow of 50 MW towards node 2, where it is withdrawn. The split in node 3 is computed in accordance with the proportionality rule: 13 MW remain in node 3 (30 x 40 / (40 + 50)) and 17 MW flow on line L23 (30 x 50 / (40 + 50)).



---

[34] All calculation results are rounded at the closest integer number.

The same procedure has been applied to the withdrawal nodes.

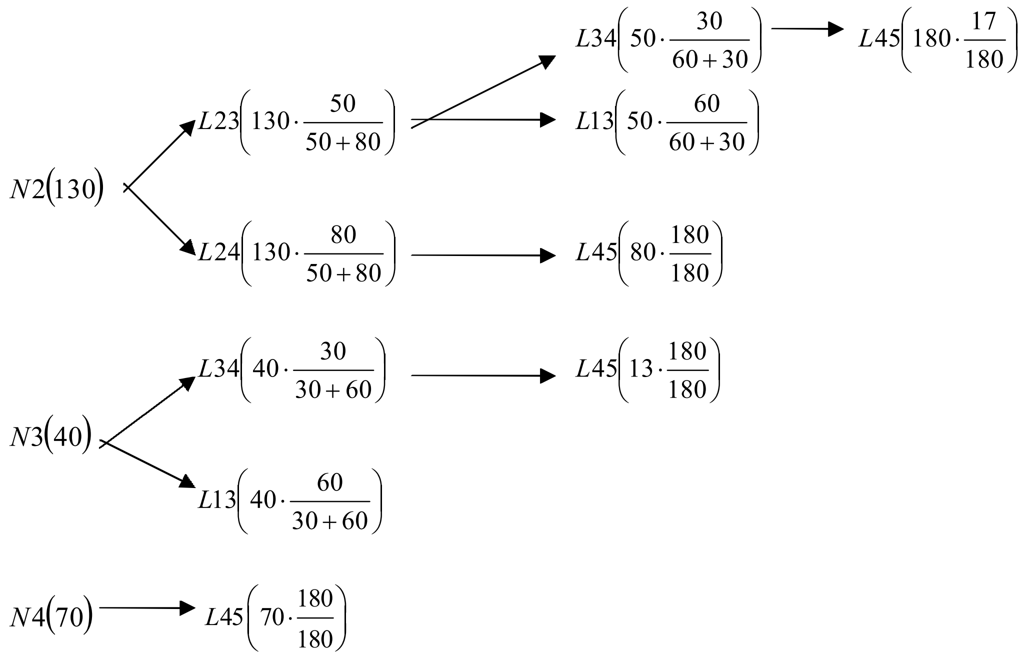


Table A1 shows the flows on each line that are the responsibility of (that is, whose origin can be attributed to) each one of the injection nodes and withdrawal nodes (separately).

In order to express these same responsibilities in per unit values (Table A2) we have divided the figures in each column of Table A1 by the total flow on the line corresponding to the column.[35] For instance, column 2 of Table A2 has been obtained by dividing the values in column 2 of Table A1 by 50.

Table A1

	LINE 13	LINE 23	LINE 24	LINE 34	LINE 45
NODE 1 (60)	60	33			
NODE 5 (180)		17	80	30	180
Total	60	50	80	30	180
NODE2 (130)	33	50	80	17	80+17
NODE 3 (40)	27			13	13
NODE 4 (70)					70
Total	60	50	80	30	180

---

[35] The per unit values have been obtained by dividing the flows attributed to each node in every line by the existing flow in that line. In a realistic example, when several scenarios have to be considered and the lines are not always loaded at full capacity, it is possible to weigh each scenario by the ratio: actual flow in the scenario/line capacity.

Table A2

	LINE 13	LINE 23	LINE 24	LINE 34	LINE 45
NODE 1 (60)	1	33/50			
NODE 5 (180)		17/50	1	1	1
NODE2 (130)	33/60	1	1	17/30	97/180
NODE 3 (40)	27/60			13/30	13/180
NODE 4 (70)					70/180

Before obtaining the final table, we have to decide which weight to assign globally to generators and loads in order to obtain the final allocation factors of lines to nodes. If it is decided that the weights should be the same, we just need to multiply all numbers in Table A.2 by 0.5. However, if the desired global weight is, for instance, 30% to generators and 70% to consumers, then all the per unit values in Table A2 corresponding to injection nodes have to be multiplied by 0.3 and the per unit values corresponding to withdrawal nodes by 0.7.

Assuming the same weight is assigned to load and generators, Table A3 shows the final allocation of line costs.

Table A3

	LINE 13	LINE 23	LINE 24	LINE 34	LINE 45
NODE 1 (60)	60/120	33/100			
NODE 5 (180)		17/100	1/2	30/60	180/360
NODE2 (130)	33/120	50/100	1/2	17/60	97/360
NODE 3 (40)	27/120			13/60	13/360
NODE 4 (70)					70/360

Annex 3: The algorithm of the Marginal Participations method

The method of marginal participations calculates how much would the flow in line j increase if the generation (or load) in node i increased by 1 MW: the method obtains the per unit measure of the marginal participation on line j for any agent located at node i. This calculation is performed for every node, for all the lines in the grid.

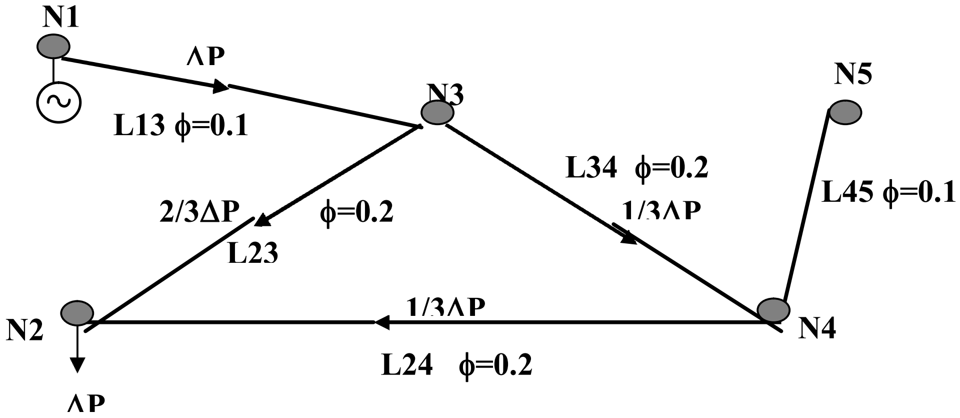
Due to Kirchhoff's laws, any 1 MW increase in generation (or load) at node i has to be compensated by a corresponding 1 MW (ignoring losses) increase in load (or generation) at some other node or nodes. Thus, the calculation of how much an injection at a certain node affects the flows in the network depends on the decision of which is the node that responds. Different choices are possible for the responding node ('slack node') and the final cost allocation will depend on the choice of the slack node.

Let us consider the same topography as in Annex 2.

Situation 1: N1 is chosen as the slack node

To calculate the participation of the agent located in node N2 of the network, we run the flow distribution model considering an increment in generation of ΔP in N1 and an increment in load of ΔP in N2.

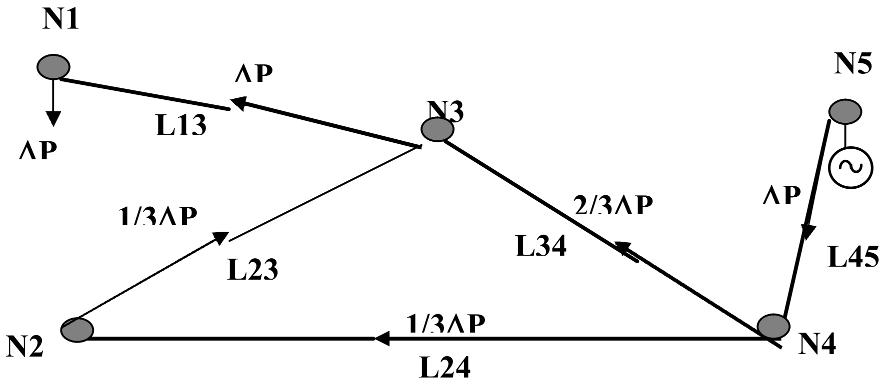
The participation of the load in N2 is given by the product of the amount of power consumed by this load and the portion of ΔP flowing through each line in the incremental transaction simulated, taking into account the flow direction.



Results are shown in the table below where P_{L13}^{N2} indicates the participation of the agent in node N2 in the use of the line L13:

P_{L13}^{N2}	P_{L23}^{N2}	P_{L43}^{N2}	P_{L24}^{N2}	P_{L45}^{N2}
$130 \cdot \frac{\Delta P}{\Delta P} = 130$	$130 \cdot \frac{\frac{2}{3}\Delta P}{\Delta P} = 87$	$130 \cdot \frac{-\frac{1}{3}\Delta P}{\Delta P} = -43$	$130 \cdot \frac{\frac{1}{3}\Delta P}{\Delta P} = 43$	$130 \frac{0}{\Delta P} = 0$

To calculate the participation of the agent located in node N5, we simulate an incremental transaction where the increment in generation ΔP is located in N5 (since it is an injection node) and the increment in load in located in the slack node N1:



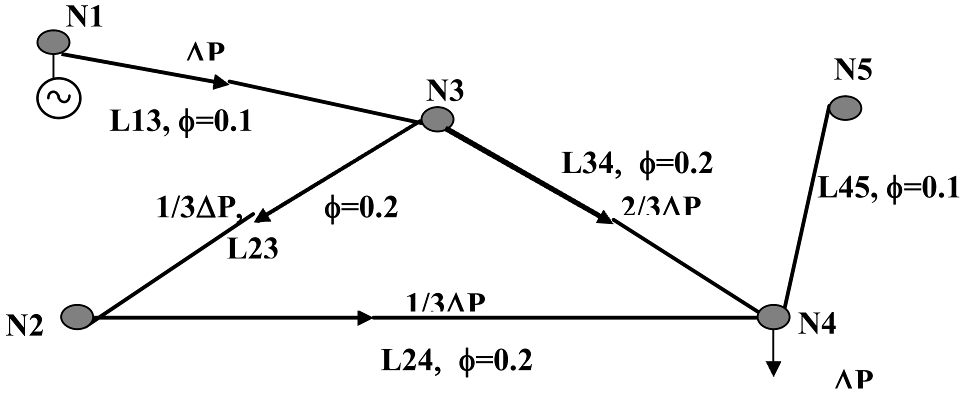
In this case, we obtain the following result:

P_{L13}^{N5}	P_{L23}^{N5}	P_{L43}^{N5}	P_{L24}^{N5}	P_{L45}^{N5}
$180\cdot\frac{-\Delta P}{\Delta P}=-180$	$180\cdot\frac{-\frac{1}{3}\Delta P}{\Delta P}=-60$	$180\cdot\frac{\frac{2}{3}\Delta P}{\Delta P}=120$	$180\cdot\frac{\frac{1}{3}\Delta P}{\Delta P}=60$	$180\cdot\frac{\Delta P}{\Delta P}=180$

Calculating the participation of the agent located in node N3 of the network grid, we obtain:

P_{L13}^{N3}	P_{L23}^{N3}	P_{L43}^{N3}	P_{L24}^{N3}	P_{L45}^{N3}
$40\cdot\frac{\Delta P}{\Delta P}=40$	$40\cdot\frac{0}{\Delta P}=0$	$40\cdot\frac{0}{\Delta P}=0$	$40\cdot\frac{0}{\Delta P}=0$	$40\cdot\frac{0}{\Delta P}=0$

Calculating the participation of the agent located in node N4 of the network grid, we obtain:

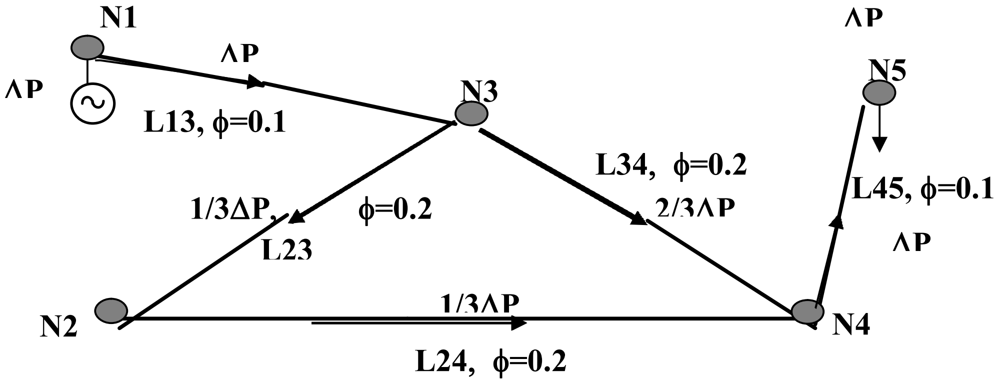


P_{L13}^{N4}	P_{L23}^{N4}	P_{L43}^{N4}	P_{L24}^{N4}	P_{L45}^{N4}
$70\cdot\frac{\Delta P}{\Delta P}=70$	$70\cdot\frac{\frac{1}{3}\Delta P}{\Delta P}=23$	$70\cdot\frac{-\frac{2}{3}\Delta P}{\Delta P}=-47$	$70\cdot\frac{-\frac{1}{3}\Delta P}{\Delta P}=-23$	$70\cdot\frac{0}{\Delta P}=0$

	LINE 13	LINE 23	LINE 34	LINE 24	LINE 45
NODE 1 (60)	0	0	0	0	0
NODE 5 (180)	-180	-60	120	60	180
Total	-180	-60	120	60	180
NODE2 (130)	130	87	-43	43	0
NODE 3 (40)	40	0	0	0	0
NODE 4 (70)	70	23	-47	-23	0
Total	240	110	-90	20	0
Total participation G + Total participation L	60	50	30	80	180

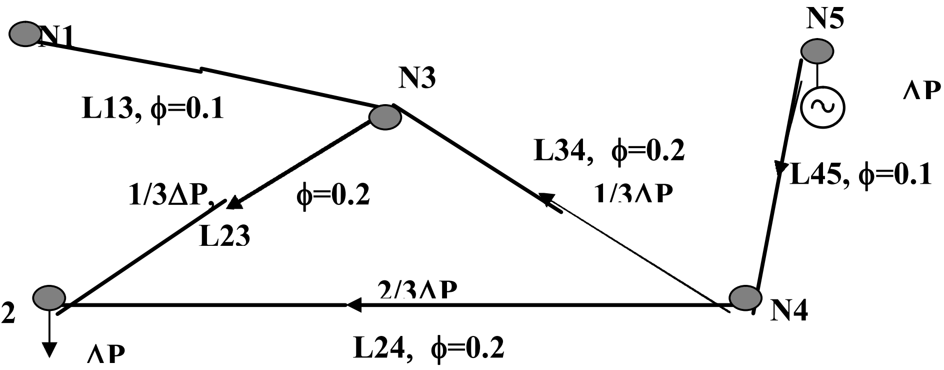
Situation 2: N5 is chosen as the slack node

In case N5 is selected as the slack node, we obtain a totally different result for the calculation of the responsibility of single agents in the network use, as shown in the following calculation. The participation of N1 in the network use is:



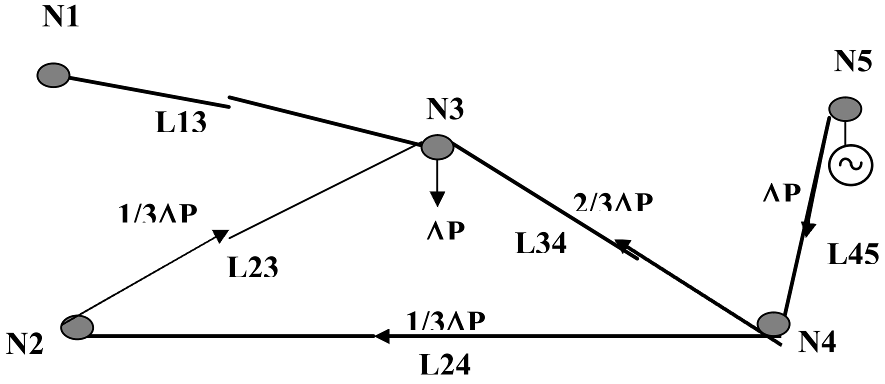
P_{L13}^{N1}	P_{L23}^{N1}	P_{L43}^{N1}	P_{L24}^{N1}	P_{L45}^{N1}
$60 \cdot \frac{\Delta P}{\Delta P} = 60$	$60 \cdot \frac{\frac{1}{3}\Delta P}{\Delta P} = 20$	$60 \cdot \frac{-\frac{2}{3}\Delta P}{\Delta P} = -40$	$60 \cdot \frac{-\frac{1}{3}\Delta P}{\Delta P} = -20$	$60 \cdot \frac{-\Delta P}{\Delta P} = -60$

In the case of N2:



P_{L13}^{N2}	P_{L23}^{N2}	P_{L43}^{N2}	P_{L24}^{N2}	P_{L45}^{N2}
$130\cdot\frac{0}{\Delta P}=0$	$130\cdot\frac{\frac{1}{3}\Delta P}{\Delta P}=43$	$130\cdot\frac{\frac{1}{3}\Delta P}{\Delta P}=43$	$130\cdot\frac{\frac{2}{3}\Delta P}{\Delta P}=87$	$130\cdot\frac{\Delta P}{\Delta P}=130$

The case of N3, is very similar and we obtain:



P_{L13}^{N3}	P_{L23}^{N3}	P_{L43}^{N3}	P_{L24}^{N3}	P_{L45}^{N3}
$40\cdot\frac{0}{\Delta P}=0$	$40\cdot\frac{\frac{1}{3}\Delta P}{\Delta P}=-13$	$40\cdot\frac{\frac{2}{3}\Delta P}{\Delta P}=27$	$40\cdot\frac{\frac{1}{3}\Delta P}{\Delta P}=13$	$40\cdot\frac{\Delta P}{\Delta P}=40$

In the case of N4:

P_{L13}^{N4}	P_{L23}^{N4}	P_{L43}^{N4}	P_{L24}^{N4}	P_{L45}^{N4}
$70\cdot\frac{0}{\Delta P}=0$	$70\cdot\frac{0}{\Delta P}=0$	$70\cdot\frac{0}{\Delta P}=0$	$70\cdot\frac{0}{\Delta P}=0$	$70\cdot\frac{\Delta P}{\Delta P}=70$

Therefore the final allocation distribution is:

	LINE 13	LINE 23	LINE 34	LINE 24	LINE 45
NODE 1 (60)	**60**	**20**	**-40**	**-20**	**-60**
NODE 5 (180)	**0**	**0**	**0**	**0**	**0**
Total	**60**	**-20**	**-40**	**-20**	**-60**
NODE 2 (130)	**0**	**43**	**43**	**87**	**130**
NODE 3 (40)	**0**	**-13**	**27**	**13**	**40**
NODE 4 (70)	**0**	**0**	**0**	**0**	**70**
Total	**0**	**30**	**70**	**100**	**24 0**
Total participation G+ Total participation L	**60**	**50**	**30**	**80**	**180**

Comparing the network allocation in the two examples, we can see that the result depends on the choice of the slack node:

	LINE 13		LINE 23		LINE 34		LINE 24		LINE 45	
	Slack node N1	Slack node N5	Slack node N1	Slack node N5	Slack node N1	Slack node N5	Slack node N1	Slack node N5	Slack node N1	Slack node N5
N1	0	60	0	20	0	-40	0	-20	0	-60
N2	130	0	87	43	-43	43	43	87	0	130
N3	40	0	0	-13	0	27	0	13	0	40
N4	70	0	23	0	-47	0	-23	0	0	70
N5	-180	0	-60	0	120	0	60	0	180	0

From the results one can immediately see that participations in the use of the lines may be much larger than the actual flow on the line (see for example the case of the line L13 when N1 is chosen as the slack node). This is true independently of whether the line may actually be able to carry these flows due to the limited transmission capacity of lines.

Annex 4: the algorithm of the With-and-Without Transits method

The algorithm of the With-and-Without Transits (WWT) method is explained in the present Annex with the help of a simplified topology of 6 nodes connected by 6 lines.

- Country A includes nodes 1, 2, 3 and the lines L12, L23, L31;
- Country B includes node 4 and line L14;
- Country C includes node 6 and line L62;
- Country D includes node 5 and line L35.

The WWT method is based on a comparison between the flows on the HN of each TSO area for two different scenarios. The first scenario corresponds to the actual system operation (situation 1). The second one results from excluding transit flows (situation 2).

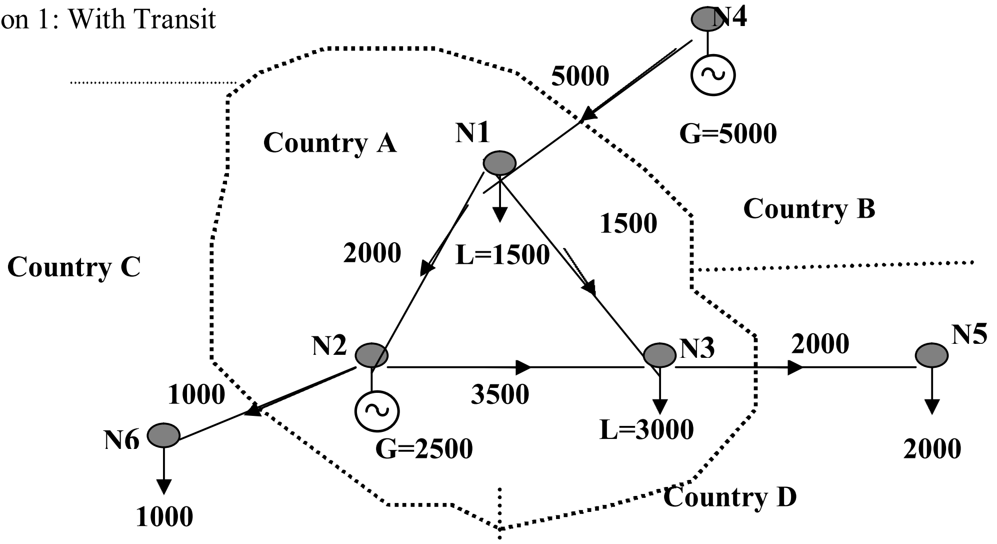
Using a standard definition, transits are calculated as the minimum between the total import flows and the total export flows; in the example below the transit through country A is 3000 MW, i.e. the minimum between 5000 MW (import) and 3000 MW (export).

There are several different ways to compute the compensation that a TSO is entitled to receive for hosting transit flows. One possibility is to determine the total utilisation of the HN in both scenarios—and the differential utilisation, attributed to external flows—and compute the compensation due to the TSO as a proportion of the total cost of the HN where the factor of proportionality is represented by the ratio between the utilisation of the HN attributable to external flows and the total (actual) utilisation of the HN. By adding up the compensation entitlements of all TSOs, the monetary value of the total compensation fund is obtained.

The usage of the network of a country could be calculated as the sum of the length of the lines multiplied by the flows over these lines. Thus, the network usage of country A corresponding to the actual operation of the system would be:

$$U = l_{12} \cdot I_{12} + l_{23} \cdot I_{23} + l_{13} \cdot I_{13} = l_{12} \cdot 2000 + l_{23} \cdot 3500 + l_{13} \cdot 1500$$

Situation 1: With Transit

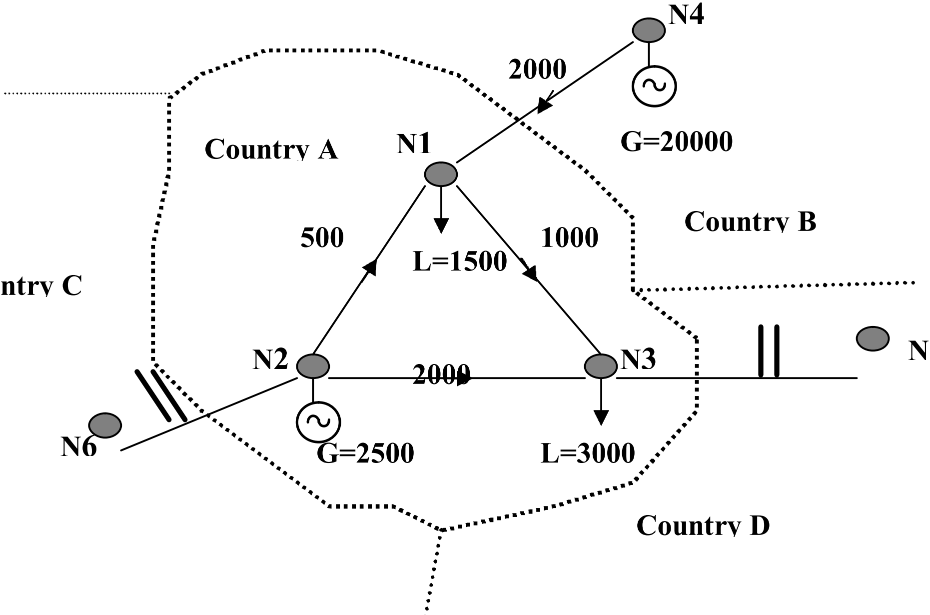


In order to calculate the compensation due to country A, we need now to create a fictional scenario where transit flows have been removed. Once the transit has been removed, export flows are zero and import flows amount to 2000 MW. First, we need to determine what the flow on each one of the cross-border lines will be. We distribute the transit among cross-border lines in proportion to the size of the original flow on each of these lines. Thus, flows on the cross-border lines in the without transit scenario are 0 for lines L26 and L35 and 2000 MW for line L41. Lastly, cross border flows are changed to these new values and a new load flow is run to determine the flows on the internal lines of the country in this fictitious scenario. See the picture corresponding to situation 2.

The usage of country A network in the scenario without transits can only be attributed to country A. This usage is computed as:

$$U^{wt} = l_{12} \cdot I_{12}^{wt} + l_{23} \cdot I_{23}^{wt} + l_{13} \cdot I_{13}^{wt} = l_{12} \cdot 500 + l_{23} \cdot 2000 + l_{13} \cdot 1000$$

Situation 2: Without transits



Compensation due to country A is obtained as the product of the fraction of total network usage for country A that is attributable to transits and the cost of the horizontal network of country A:

$$Compensation = Cost(HN_A) \cdot \frac{U - U^{wt}}{U}$$

Responsibility for contributing to this fund is then allocated to the different TSOs on the basis of their responsibility in generating transit flows. This responsibility can be determined in various ways. For example, the net import/export (net(I/E)) from the grid of each TSO can be used as a proxy to the transit flows generated by the injections into and withdrawals from that grid. In this way, the contribution of each of the countries in the system to the compensation due to country A (assuming there are no other countries) would be:

$$Payment_{AA} = Comp_A \cdot \frac{net(I/E)_A}{net(I/E)_A + net(I/E)_B + net(I/E)_C + net(I/E)_D} =$$

$$Comp_A \cdot \frac{2000}{2000 + 5000 + 1000 + 2000}$$

$$Payment_{BA} = Comp_A \cdot \frac{5000}{2000 + 5000 + 1000 + 2000}$$

$$Payment_{CA} = Comp_A \cdot \frac{1000}{2000 + 5000 + 1000 + 2000}$$

$$Payment_{DA} = Comp_A \cdot \frac{2000}{2000 + 5000 + 1000 + 2000}$$

Finally, note that the results presented in this annex confirm the relationship between the participations produces by the MP method by using different slack nodes, as indicated in footnote 15. In particular, changing the slack node affects the unit participation by the different nodes by the same amount. Consider for example the participation of the different nodes in the utilisation of line L13. Changing the slack node from N1 to N5 increases total participation of node N1 by 60, As node N1 is a (net) withdrawal node, the power withdrawn at this node is conventionally assigned the negative sign, and the corresponding change in the unit participation is -1. The change of slack node reduces the total participation of N2 in the utilisation of line L13 by 130. Even in this case, the change in the unit participation is equal to -1. It can easily be verified that this relationship holds for any change in slack node and for the participation of each node in the utilisation of each line.