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by
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Abstract

This paper presents a comprehensive design of electricity transmission charges that are meant to recover regulated network costs. In addition, these charges must be able to meet a set of inter-related objectives. Most importantly, they should encourage potential network users to internalize transmission costs in their location decisions, while interfering as least as possible with the short-term behaviour of the agents in the power system, since this should be left to regulatory instruments in the operation time range. The paper also addresses all those implementation issues that are essential for the sound design of a system of transmission network charges: stability and predictability of the charges; fair and efficient split between generation and demand charges; temporary measures to account for the low loading of most new lines; number and definition of the scenarios to be employed for the calculation and format of the final charges to be adopted: capacity, energy or per customer charges. The application of the proposed method is illustrated with a realistic numerical example that is based on a single scenario of the 2006 winter peak in the Spanish power system.

Keywords: transmission pricing, cost allocation, locational signals.

1 Introduction

Most of the approaches to transmission tariff design that are reported in the technical literature fail to address the full range of significant implementation

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issues that a comprehensive method should contemplate, see (Zolezzi, 2002; Strbac, 1998; Stamtsis, 2004; Rubio, 2000; Kirschen, 1997; Green, 1997; Galiana, 2003; Bjorndal, 2005; Bialek, 1996; Pan, 2000). This neglect is acceptable with vertically integrated utilities and in the absence of competition and even also in systems under advanced unbundling of activities and a competitive regime, when the transmission network is well developed and the applications for new grid connections are few and in well defined locations. Under these conditions, and given the typically low contribution of transmission charges to the total price of electricity in most systems, these charges could be socialized in almost any possible way without strong questioning. However, the situation has radically changed in a context where many potential investors –combined cycle gas turbines and large wind projects are the most frequent candidates in Europe and the US at least – are looking for suitable points of connection to the grid. Because of the large amount of new gas fired plants, as well as renewable and distributed generation capacity to be installed in most systems in the coming years, power flows in the grid are expected to increase in magnitude and their patterns may significantly change. Therefore, in these systems the cost of the estimated future transmission reinforcements will be significantly larger than it has traditionally been (the cases of the US where massive deployments of wind generation in the Midwest and solar in the Southwest are expected, or the ambitious programs in renewable generation in many EU countries are good examples). The costs of the reinforcements to the transmission network that will have to be constructed in the coming years will critically depend of the location decisions of new generation, and therefore efficient transmission charges that rightly allocate the responsibility for these network reinforcements have become of utmost importance. Where simplicity could be a reasonable recommendation years ago, a fair amount of sophistication is now required.

But, what most papers ignore is that the design of transmission charges is not finished with the specification of some algorithm that allocates the total network costs to the agents that are connected to the different nodes. Still other important implementation issues remain, which have to be addressed in a practical regulatory setting and that have been typically disregarded. These include avoiding interference of the transmission charges with the economic signals that guide the short-term behaviour of the agents in the power system; focusing on the responsibility of the potential new grid connections on the current and future costs of new network reinforcements; devising charges that are stable and predictable, which is essential for new investors; splitting total charges between generation and demand in a fair and efficient manner; using temporary measures to account for the low loading rate of most new lines; defining the number and nature of the scenarios to be employed for the calculation of charges and deciding which should be the format of the final charges to be adopted: capacity, energy or per customer charges. All these issues are relevant for a sound design of transmission locational signals.

This paper presents a comprehensive approach to jointly address all these issues, which has been built from the experience of many years of research on these topics and consultancy in many countries, and which has been finally put together by a team of professionals from the Spanish Energy Regulatory Commission (CNE), the Spanish System Operator (Red Eléctrica de España) and researchers from the Institute for Technological Research (IIT) at Comillas University. It must be stressed here that transmission charges computed according to the proposed approach are not meant to replace efficient operational signals sent through nodal prices (Locational Marginal Prices or LMPs) for energy. The purpose of the charges in this paper is to recover the regulated cost of the grid in a cost reflective manner, either by complementing any revenues that are obtained with LMPs (in systems that use nodal pricing) or just by themselves.

After this introduction, section 2 of the paper describes a plausible regulatory framework for transmission that is compatible with the proposed design of network charges. Section 3 presents a method for network cost allocation that is based on the responsibility of the network users in the incurred transmission costs. Section 4 provides answers to the remaining major implementation issues. A representative numerical case example is presented in section 5, corresponding to the application of the proposed methodology to a winter peak load scenario for the Spanish system in the year 2006. Lastly, section 6 concludes.

2 A plausible transmission regulatory framework

There is no universal consensus on the most adequate regulatory approach for transmission investment, access and pricing. Here a simple, but most sensible, regulatory framework will be presented schematically, with the only purpose to provide a reference scenario within which the proposed design of transmission charges would make sense. Certainly the same design of charges, as it is or with minor changes, would be also applicable to other situations. But it is convenient here to stress the point that one should not design the three major pieces of transmission regulation – investment, access and pricing - independently.

In the simplest –and most recommended – regulatory approach, a plan for transmission network expansion would be prepared by the System Operator, as the entity with the largest and most immediate expertise in the needs for new reinforcement, after receiving inputs and while maintaining good communication with all stakeholders. The plan should meet some prescribed “regulatory test” (set of conditions, either economic, technical or both, that justify the need for new investments) and, based on this same regulatory test, be approved by the regulatory authorities. The transmission facilities that are included in the plan will be built, either via a public auction scheme or by the incumbent transmission company – either a Transmission System Operator, an independent purely network company or some other scheme -, under some kind of cost-of-service remuneration. The incurred costs would be charged to the network users – typically both generators and consumers – under publicly established rules. Under this scheme investors should not have objections to invest in new transmission facilities (assuming the rate of return is attractive). The simple idea behind this simple scheme that is in use in several countries is just to make the business of transmission investment as “unexciting” (“boring” or “uneventful”) as possible. Sophistication and complexity in transmission planning – “leaving it to the market”, for instance - only cause indecision by investors, higher capital costs and – most frequently – lack of investment.

Access priorities during operation – i.e. congestion management and any associated charges – should not be mixed-up with transmission charges, which are related to longer term issues: cost recovery of transmission investments and locational signals for new network users. Any congestion rents that could be collected because of the application of nodal prices or any scheme of firm transmission rights should be deducted from the total annual transmission cost that has to be paid by transmission charges. If none of these schemes apply, transmission charges should cover the total amount.

The cost of the facilities that directly connect large consumers or generators to the transmission grid, with lines of at most a few kilometres, is usually recovered by dedicated transmission access charges. This paper is concerned with the design of transmission charges that are meant to recover the remaining network cost (the majority, by far). Therefore charges for short direct connection lines will be ignored here. Longer connection lines (the limit is somewhat arbitrary), therefore with a significant cost, must be treated under the general scheme that is presented here, since the cost may have an impact on the feasibility of the generation (typically) project and the existence of benefits of the project for the consumers should be then factored in.

2.1 Basic cost allocation guidelines

By now everybody should agree on some basic sound principles of transmission pricing, see (Pérez-Arriaga and Smeers, 2005): The charges should be independent on commercial transactions. They should rather be based on cost-causality principles, i.e. the cost of transmission investments should be charged to those network users who benefit from them (since any new transmission facility is built to increase the expected benefits that all network users will globally obtain from the operation of the system with this installed facility) or, equivalently, to those network users who have been responsible for incurring in the network investment costs (since the investments are made when they result in total benefits for the network users that exceed the additional transmission costs). In practice this has proven difficult to do in most cases and some proxy – such as network utilization – may have to be used instead.

Depending on the characteristics of the particular system (size, how well meshed is the network, fraction of the total electricity costs attributable to transmission, number and type of prospective new network users, regulatory history) the most adequate method of allocation may vary. In those cases of costly lines that only benefit a subset of the network users or that even hurt some others, in non-well-meshed networks, where the economic viability of an associated generation project may be at stake, it is recommended to base the allocation of costs in the a priori estimation of the benefits for each network user. This should preferably be done by using a one-shot computation, as explained in section 4.3 later, thus avoiding the difficulties of the future re-evaluation of the benefits.

Except for those extreme - but not unusual – cases, here it is recommended to resort to some measure of the electrical use of a line (or any other transmission facility) by the agents as a sensible proxy to the economic benefits that these agents will obtain from the existence of this line. Or, in other words, that the responsibility of each agent in the construction of a line is deemed to be proportional to the amount of use of the line by the agent.

Unfortunately, computing the electrical utilization of lines by agents is not a simple task, since there is no indisputable method to do it. Several methods to determine network use have been proposed and applied, with results that vary significantly from one another. It is important to keep in mind that the final objective is not computing network utilization per se, but determining the responsibility of agents in the construction of lines. Therefore, the method employed to compute network use should not deviate from the implicit purpose of identifying somehow the agents that are responsible for the development of the lines or, in other words, who benefit from them.

Current transmission tariffs in most countries do not contain any locational signals and they simply disregard the need for assigning the cost of each transmission line to those agents that cause the system to incur this cost, see for instance (ETSO, 2008) and (Lusztig et al., 2006). Whenever this is an acceptable simplification, regulators have settled for simple transmission charges that socialize the total cost of the network to its users, or frequently just to consumers. This is not the situation that is assumed in this paper, for the reasons explained above. It is the opinion of the authors that, as time passes and all kinds of new generation compete to enter into the system, clear locational signals – including transmission tariffs prominently – will be more and more necessary.

3 Transmission network cost allocation

3.1 A first pass in the allocation of network costs

The computation process consists of several stages, of which this is the first one. Some scheme must be used to determine in a first approximation how much of the power flow in each one of the lines can be attributed to each generator and load in the system. Subsequent refinements will be presented later in this section.

At this stage, the transmission tariff designer must select a specific cost allocation algorithm. General guidelines have been already provided. Here it will be assumed that a method that is based on some measure of network electrical utilization is adequate. Then it is recommended to resort to any of the very few sound available methods, such as Average Participations (AP), see (Bialek, 1996; Kirschen et al., 1997), or Aumann-Shapley, see (Junqueira et al., 2007). In this paper, AP will be used for the explanation that follows and also in the numerical case example. Except when otherwise indicated or obvious, the rest of this paper is applicable regardless of the specific adopted algorithm. Thus, it must be stressed here that, whether the AP method or any other electrical use-based algorithm is applied to allocate the costs of the grid, the overall tariff design that is proposed here remains valid.

The AP method will be now introduced for a single scenario of generation, demand and the corresponding actual flows. Later it will be explained how to account for multiple scenarios that are meant to represent a year or any other period of time. The basic idea behind the AP method, see (Bialek, 1996; Olmos and Pérez-Arriaga, 2007) for details, is that a simple and reasonable assumption (which cannot be proved or disproved) allows one to track the actual line flows in a given operation scenario, upstream and downstream to the generators and loads that can be associated plausibly to them. The basic assumption is that power inflows into a node contribute to the outflows from the node in proportion to the volume of the latter. The AP method reflects well the balance of generation and demand in the different areas for any given operation scenario and results in cost allocations that make general economic and physical sense.

The AP method only provides L and G utilization factors for those nodes where there are generation and load already. Therefore, just applying the AP method to a snapshot representing the real operation of the system does not allow one to compute the G and L use factors for many of the system nodes. In order to compute G and L factors for every node, one must modify the original scenarios slightly, by introducing in each of the nodes a small fictitious demand and generator of the same magnitude.

Once the participation factors of each one of the agents in the use of each one of the lines are known, in the following stages these factors will be conveniently modified to account for several additional considerations: the different ways in which the addition of a new generator or demand may affect the existing pattern of flows in a network; the treatment of the unused capacity of lines, in particular for underutilized recent lines; the share of total network costs between generators and consumers; and the influence that the time of entry in the system of a new generator or load may have on the responsibility over the incurred costs in every transmission facility.

3.2 Accounting for different patterns of modification of the network flows

The new concern that is addressed in this section is to associate the existence or the activity of the different network users and the preliminary evaluation of their contributions to the network flows with the corresponding need (or the lack of it) to reinforce the transmission grid. The guiding principle will be to try to find associations between the presence and the activity of a generator or load and the associated incremental changes in the network flows. This is only applicable to methods based on electrical utilization, such as AP.

If the electrical use of a line by an agent is defined as the impact of the power produced or consumed by the agent on the line flow, then one must conclude that agents can either make a positive or a negative use of a line. For instance, installing generation capacity in an importing area will probably reduce the amount of power flowing over the lines connecting this area to others, and should be considered as a "negative use" of the line.

Most grid reinforcements are needed to cope with incremental flows produced by new generators and loads[3]. Therefore, new network users should be held responsible for the cost of those lines that are built so that the grid can cope with the flows that they create. The identification of the responsibility in the creation of incremental flows by new generators and loads is far from obvious. New

[3] Investments are also made to extend the useful life of existing lines.

generation is built to replace inefficient generation or to serve new load. The changes in power flows result from the joint evolution of the global patterns of generation and load in the system[4].

If the distribution of generation and load in the system grid does not change significantly over time, i.e. if the load and generation growth in each area have been approximately proportional to the amount of generation or load that already existed in that area, then line flows have probably increased always with the passing of time, and these increments only have depended on the load growth rate and the existing global pattern of generation and load. The global pattern of generation and load, together with the topology of the grid, determines in this case the pattern of flows in the system. Therefore, in this situation, one could conclude that the existing pattern of flows in the system should be representative of the increments in line flows that are produced by the installation of new generation and load. Then, just by following the existing line flows, one could determine where the power produced by each new generator is consumed.

According to the reasoning above, new generation in each area A would only be devoted to physically supplying the load growth of those consumer centres already being served by the generation in area A. However, there is also the possibility that new generation in an area replaces the generation that already exists, or could be installed, in other areas. Therefore, the method employed to determine the location of the load served by each new generator should consider both possibilities. This is in accordance with the fact that the distribution of

[4] Given that investment decisions by generation companies (and maybe also those by consumers) can be conditioned by the decisions by the remaining agents on where to install new generation or load, one cannot claim that the location of the generator ‘responding’ to an increase in the power consumption by a load is not affected by the location of the latter. Hence, methods to compute the responsibility of network users in line flows cannot be based on this assumption. In general there is a stronger relationship between recent new network users and recent or near future network reinforcements than there is with network assets that were built a long time ago.

generation and load in the system gradually changes over time. Among other reasons for this, distribution of the natural resources used to produce energy may change or companies may be encouraged by energy prices or regulation to install a significant amount of new generation in importing areas. A totally symmetric reasoning can be made for new demand.

The proposed approach

The following discussion assumes that AP has been used for the preliminary cost allocation. The original AP method assumes that the agents either contribute positively to the flow over a line, thus reinforcing it, or do not use at all that line. Thus, AP does not consider the possibility that an agent might contribute to decreasing the flow over a line. However, as explained above, installing a new generator in a certain node may lead to one of the two following situations: a) the amount of power exported from this node to others may increase, or b) the amount of power imported by the node from others may decrease. Similar considerations can be made with respect to new loads.

This leads to simultaneously considering the new generator as an increase in the local generation (the one existing in a certain node N) and as a decrease in the local demand, i.e. as a negative load at N. Therefore, when computing the incremental utilization that a generator at node N makes of the grid, it is proposed here to take into account both the participation, according to the original version of AP, of the generation located in node N in the use made of the grid (utilization factor G_N), and the unit participation, also according to AP, of the demand in the same node n in the utilization of the grid (utilization factor L_N). The local generation charge shall be considered with positive sign, since installing a new power plant would increase the total amount of generation in the corresponding node, while the local load charge should be considered with a negative sign, since installing a new generator would reduce the net demand in the node.

It is proposed here to compute the per unit contribution of the generation in a node N to the incremental use of each line as the weighted average of the unit utilization factor computed with AP for the generation in node N (factor G) and the unit use factor, with a negative sign, computed with AP for the demand in the node (factor L). The weighing factors employed may vary. In any case, both weighing factors should add up to 1. Equation (1) provides the mathematical expression of the unit contribution by the generation in a node to the incremental use made of each line in particular (or the grid in general):

$$C_N = F_{G,N} \cdot C_{G,N}^{PM} - (1 - F_{G,N}) \cdot C_{D,N}^{PM} \qquad (1)$$

where C_N is the unit contribution to the incremental use made of the grid of the new generation located in node N, $C_{G,N}^{PM}$ is the network unit use factor for the generation in node N according to AP, $C_{D,N}^{PM}$ is the network unit use factor for the demand in that node provided by AP and $F_{G,N}$ represents the weight assigned to $C_{G,N}^{PM}$ (and, therefore, $1 - F_{G,N}$ is the weight assigned to $C_{D,N}^{PM}$).

The impact of increasing the generation in node N on the system line flows mainly depends on the pattern of inflows into the node and outflows from the node[5]. Therefore, the factors used to weigh the per unit L and G use factors produced by AP for a node N should be proportional to the total amount of power flowing into the area where node N is located and the total amount of power flowing from that area into others, respectively. Our objective is estimating the

[5] Consider, for example, a purely exporting node N where the amount of generation and load is similar (although there must be some more generation than load). It seems clear that, regardless of the generation/load balance in the node, most of the new generation installed locally would contribute to meet the increment in demand in the rest of the system, which would be much larger than that in the node.

impact that installing new generation in node N would have on the power balance in this area and, therefore, on the flows between this area and others. According to this, the mathematical expression of the weighing factor $F_{G,N}$ in (1) must be:

$$F_{G,N} = \frac{\phi_N^E}{\phi_N^E + \phi_N^I} \quad (2)$$

where ϕ_N^I and ϕ_N^E represent the total amount of power flowing into the area where node N is located and the total amount of power flowing from that area into others, respectively.

The criterion that has been followed to weigh the importance, or probability of occurrence, of situations 1 and 2 above, once new generation is installed in a node, is intimately linked to the current pattern of flows in the system and, therefore, to the generation and load patterns as well. Consequently, this criterion is more likely to successfully represent the effect that adding generation in each node is expected to have on the line flows. The same process can be followed in order to compute the contribution of the new load to be installed in each node to the system line flows.

3.3 Accounting for the loading rate of transmission facilities

Transmission lines have very long useful lives and the decision on their construction should consider the estimated future evolution of the power system. As a consequence, it is frequent that a line that has been recently built is loaded well below the average loading rate of more mature transmission lines in the same region.

Those generators or consumers that initially use these recent and underloaded lines should not pay their total annualised cost, since these individual agents can only be held responsible for the construction of a small fraction of their capacity. Agents are not benefiting from most of the capacity of these lines because this capacity cannot be expected to be used under any circumstance in the short term future.

In order to determine the fraction of the cost of each line to be assigned proportionally to the responsibility of agents in their construction (the so called cost of the 'used' fraction of each line), one may think of comparing the loading rate of this line with the average loading rate for this type of lines in the system. Line types should be defined according to the location of each line and its function. A fraction of the cost of each line equal to the ratio of the load rate of the line to the average load rate for lines of the same type could be allocated based on the application of the principle of cost causality that has been described in section 2.1. If the former ratio is greater or equal to 1 for a line, the whole cost of this line would be allocated taking only into account the responsibility of agents in the construction of the line. Otherwise, cost causality would be used to allocate a fraction of the total line cost equal to the above mentioned ratio. The remaining part of the cost of the line should probably be socialized to demand, since the short and long term decisions by consumers are less sensitive to the level of transmission charges than those made by generators, and there is no particular reason to use a different criterion.

3.4 Sharing the total network costs between generators and consumers

As explained in the previous section, the total cost of each line should be divided into two parts. The first one should, in principle, be allocated to the network users (both generators and loads) according to their responsibility in the construction of the line[6]. One can refer to this part as the cost of the ‘used’ fraction of the line. The remaining component of the cost of each line could be socialized to generators and/or loads, though probably it should be socialized only to demand since, in the absence of any logic of cost causality (mostly based on benefits or a proxy to them), consumers are the final recipients of the electricity service. This section discusses how to split the cost of the ‘used’ fraction of each line between generation and load in the system.

When examining the justification of transmission investments one will find that some lines are built to allow the export of generation from areas with excess of production, while others may be required to meet the demand of major load centres. In principle, the cost of the ‘used’ fraction of each line should be apportioned to generation and load in proportion to the aggregate economic benefits that each of the two groups of agents obtain from the existence of the line. However, in practice this may often prove impossible, due to the difficulties associated to determining the benefits that agents obtain now from a line that has been in operation for many years or to estimating the future benefits from a hypothetical line whose construction is presently being considered.

Here it is proposed to apportion the cost of the ‘used’ fraction of each line in proportion to the global incremental use of the line that can be attributed to the generation, on the one hand, and the load, on the other. However, even computing responsibility in network use may result in an ambiguous outcome, because of the assumptions that is necessary to make in basically any method, which in most cases actually predetermine the split between generation and demand.

[6] Sending locational signals to consumers may not be necessary in many systems, as discussed in section 2. In this case, the total fraction of the cost of each line to be paid by loads should be socialized among them.

In practice, it may be desirable to administratively determine from the outset the fraction of the cost of the grid to be paid by generators (and, therefore, the fraction to be recovered from loads). Taking into account the fact that the method (AP) that has been recommended here to track down the existing flows in each scenario allocates 50% of the use of each line to generators, and the remaining 50% to loads, the cost of the ‘used’ fraction of each line should also be allocated 50/50 to generation and demand in the system. However, this rule can be easily modified if, according to some reasonable criterion (such as a hypothetical rule to harmonize transmission charges within the region, as already decided for the EU Internal Electricity Market), competent authorities decide that generators as a whole should pay at most a certain fraction of the cost of the grid (either of the grid as a whole or line by line, depending also on the method), with the demand being charged the rest.

There is one major difference between generation and demand when it comes to the allocation of transmission network charges. Geographically differentiated network charges by nodes or areas are not compatible with the existence of a uniform transmission charge for all customers, which is a longstanding regulatory principle in many countries, see, for example (ITC, 2007). Besides, location-differentiated transmission charges are unlikely to affect the decisions by consumption agents on where to install new loads, since the transmission grid cost typically represents a small fraction of the total electricity supply cost. On the other hand, the level of the transmission charge may have a significant impact on the expected net profits of prospective generators, who therefore will be more likely to respond to these locational signals when choosing a site.

3.5 Accounting for the time of entry into the system

As explained before, most new lines are built in order to cope with the incremental power flows resulting from the installation of new generators and loads. Hence, new generators and loads are, to a large extent, responsible for the construction of new transmission lines. However, most methods to compute tariffs are unable to discriminate between existing and new generators and loads in order to identify those responsible for the installation of transmission reinforcements. These methods are only capable of determining the expected extent of use of each line by each generator or load for a given scenario of operation, regardless of the time when this generator or load was installed. However, computing efficient grid charges with locational content requires considering – besides the electrical utilization of lines by agents - also how long generators, loads and lines have been in operation. In broad terms, the relative contribution of *new or recent* generators and loads to the recovery of the cost of *new or recent* lines must be higher than their relative contribution to these lines' flows would indicate on the base of just electric use in current operation scenarios. The opposite can be said of network users that have existed for a long time with respect to new or recent lines: their actual contribution to the recovery of the incurred transmission costs should in general be smaller than the participation factors that result from the analysis of line utilization in present scenarios. As for the lines that were built a long time ago, there is no good reason to make any distinction between new generators or loads and the existing ones[7]. Remember that the entire purpose of this exercise is to design locational signals for new system agents, so that they can take into

[7] Transmission lines are never removed, in practice, when their useful economic lives end. They are typically refurbished with new wires, insulators and even towers, so that they can continue their operation without an end in sight. As this refurbishing process takes place continuously, it is very difficult to assign responsibility for it to generators or loads on the basis of vintage.

consideration, in their siting decisions, the costs they will make the transmission network incur.

As explained later in section 4 with more detail, when sending locational signals to each potential new generator or load, one must make the best estimate possible, at the time when the decision to invest is made by the corresponding agent, of the network costs that will be incurred because of the decision of the agent to install a new plant or load. The construction of those lines installed long before this agent decides to build a new generator or load could only be affected to a limited extent by the decision of the aforementioned agent, since this decision could barely be anticipated when these lines were built. Quite analogously, at the time this agent decides the construction of a new generator or load, there is strong uncertainty about, if not inability to predict, the construction of those lines that would be built long after. Thus, sitting signals aimed at generators or loads should not include the cost of lines built long before or after the installation of the former. In other words, the percentage of the cost of lines to be allocated to agents in order to provide siting signals should only be paid by those network users that have been installed shortly before or after the installation of these lines.

The percentage of the cost of lines to be recovered from siting signals may vary from one line to another and may well depend on the percentage of the capacity of each line that is expected to be used by new generators and loads. The determination of the span of time during which it is assumed to be a direct implication between network investments and the siting decisions of the network users is a regulatory decision that should be based on educated guesses and the perception of the need to send vigorous locational signals to future generators and loads.

The remaining percentage of the cost of the “used” fraction of existing lines (i.e., the one not recovered from sitting signals to new generators and loads), should be allocated on the basis of the incremental network usage made by generators and loads, regardless of the time when generators, loads and lines have been installed. All this taken together results in the cost of lines being paid mainly by network users installed around the time when these lines are built, though other users of these lines contribute also to the recovery of their cost.

Signals aimed at network users considering the possibility of exiting the system should probably be computed separately from those signals aimed at providing siting signals. Quite analogously to siting signals, exiting signals should include the cost of those lines that would be built short before or after the time when a network user is considering exiting the system and whose construction would be avoided if this user finally decides to exit. Exiting signals can probably be estimated based on the use that these agents are making of some already existing lines but, in the end, these signals should only refer to the cost of those lines still to be built when each network user decides to exit the system and whose construction partly depends on the exiting decision by this agent. Note that exiting signals so computed would not alter the network costs paid by agents until they decide to leave the system, which will typically occur many years after the installation. Given that network charges paid by agents leaving the system will be faced by them long time after their installation, these charges are highly unlikely to condition their investment decisions. Therefore, the investment decisions of these agents should only be affected by the (installation) network charges developed in this article, apart from the agents’ expectation of economic signals of a different nature from network charges, like LMPs of energy.

Because of the reasons provided in the previous paragraphs, it is proposed here to strengthen the charges to be assigned to new generators and loads for the use of new lines, with respect to the charges they would be allocated according to just their incremental contribution to the flows of these lines. Correspondingly, locational grid charges to be assigned to the existing generators and loads corresponding to the cost of new lines should be smaller than those resulting from the application of a cost allocation method exclusively based on network use. Regarding lines that have already been in operation for a number of years (e.g., more than 5 or 10 years), the fraction of the cost of these lines that is allocated to each agent should be directly derived from their electrical utilization factors.

Locational signals should be sent to any agent considering not only the installation of a new generator or load, but also an increase in the production or consumption capacity (that is to say, the contracted one) of an already existing network user. Thus, transmission charges to be paid by an agent if he finally decides to invest in new generation or load capacity (either as a new plant or load centre or within an already existing one) should reflect the increase in network costs that the system would incur in this case. Note that, as explained in section 4, once the agents have installed new capacity, their charges should not be affected by their actual use of the grid. Otherwise, siting signals would be weakened and operation decisions by agents would be conditioned by the recovery of the cost of existing lines, which does not depend on operation decisions by the agents.

3.6 The proposed approach

Figure 1 shows the process that is proposed here to compute locational transmission tariffs while taking into account temporal considerations. It must be stressed here that this process should be repeated every certain period of time (every year, for example). As a result of this process, transmission tariffs to be paid by all network users in the system would be computed. However, only the tariffs to be paid by generators or loads that apply for connection this year would be actually charged. As explained in section 4.1, transmission tariffs to be paid by network users must be computed at the time when they decide to enter the system and they should not be changed afterwards. Long term signals related to the cost of the network that are sent through transmission tariffs should go alongside time-varying operational signals. Transmission tariffs so computed will not be able to recover the whole cost of the grid. The fraction of the cost of the grid not recovered through these tariffs should be socialized, probably to demand.

First, one must specify the fraction of the cost of each line to be allocated based on cost causality principles. For those transmission lines that have been operating for longer than a prescribed number of years, this fraction should typically be 100%. As explained in section 3.3, for recently built transmission lines this fraction could be equal to the ratio of the loading rate of each line to the average load rate for the corresponding type of lines in the same area. The fraction of the line cost to be allocated based on each agent's responsibility in its construction is represented by α, while that allocated according to other criteria is represented by 1 - α. From now on, the fraction α of the cost of each line will be referred to as the cost of the 'used' fraction of the line. Parameter α may vary over the useful life of each line. For each considered year of operation, this parameter α refers to the fraction of the capacity of each line that will be used at least under some operating conditions, even when these are not likely to occur frequently. Therefore, the parameter $1-\alpha$ refers to the fraction of the transmission capacity of the line that is not expected to be used the corresponding year under any set of circumstances. Note that the fraction (1 - α) of the cost of each line, which is deemed not be allocated based on cost causality principles when computing tariffs to be paid by new network users each year, should not be mistaken for the fraction of the cost of each line that is finally not recovered from transmission tariffs presented in this article. However, in both cases the remaining part of the cost of the line is deemed to be socialized to demand.

Next, following the guidelines provided in section 3.4, the cost of the 'used' fraction of each line is divided into a fraction β to be paid by generators and the remaining fraction $1-\beta$ to be paid by demand. The parameter β should be determined according to the global responsibility of generation on the one hand, and demand, on the other, in the construction of each line. According to the methodology outlined in section 3.2, the responsibility of each group of agents, generators and loads, in the construction of a line, should be determined based on the aggregate incremental flows expected to be produced by agents of each type.

Thus, locational charges for consumers corresponding to each line l in the system would amount to $\alpha \cdot \beta \cdot CT_l$, where CT_l is the cost of line l, while locational charges for generators would amount to $\alpha \cdot (1-\beta) \cdot CT_l$. The contribution of each generator (respectively consumer) to the recovery of the fraction of the cost a line l that generators (respectively load) are deemed responsible for would be a function of the electrical use that the agent is expected to make of the grid, the time the line has been operating for and the time the generator (respectively load) has been operating for. Thus, we must define utilization factors representing the expected incremental use that each generator or load will make of the line. The method adopted along the guidelines set in section 3.2 must be used for this. Utilization factors of line l are represented as ${C_{G}}_{i}^{l}$ for each generator i and ${C_{D}}_{j}^{l}$

for each load j. We must also define factors representing how long each generator, load and line have been operating for at the considered point in time (the point in time that the considered scenario refers to). These are k_l for line l, k_{Gi} for generator i and k_{Dj} for demand j. The expression of the participation factor of generator i in the recovery of the fraction of the cost of line l to be paid by generators because of their responsibility in the construction of this line is:

$$CP_{Gi}{}^{l} = C_{Gi}{}^{l} \cdot (1 + k_l k_{Gi}) \tag{3}$$

An analogous expression can be obtained for loads, thus obtaining participation factors $CP_{Dj}{}^{l}$. The mathematical expression of factors k_l, k_{Gi} and k_{Dj} as a function of time must be defined a priori[8]. Lastly, participation factors $CP_{Gi}{}^{l}$ and $CP_{Dj}{}^{l}$ of generators and loads should be scaled up or down so that the aggregate contribution of each group of agents, based on their aggregate responsibility in the line cost, is the one computed in advance. Hence, the locational charge to be paid by generator i corresponding to its responsibility in the cost of line l can be computed as:

$$P_{Gi} = CT_l \cdot \alpha \cdot (1 - \beta) \cdot C_{Gi}{}^{l} \cdot (1 + k_l k_{Gi}) \cdot CS \tag{4}$$

where P_{Gi} is the locational transmission charge to be paid by generator i corresponding to line l and CS is the aforementioned scale factor for the same generator.

The mathematical expression of this scale factor is:

$$CS = \frac{1}{\sum_{i=1}^{ng} (1 + k_l k_{Gi}) C_{Gi}{}^{l}} \tag{5}$$

[8] One may think of implementing factors whose initial value is quite high (5, for example). These factors would decrease in value over time until they are zero after a certain number of years (for example, 10 years after the entry into service of the corresponding line or plant).

where ng is the number of generators in the system. Equations (3), (4) and (5) result in factors representing the relative responsibility of agents in the construction of lines using only a certain scenario. With the passing of time, these factors tend towards the incremental use factors of these lines by the aforementioned agents.

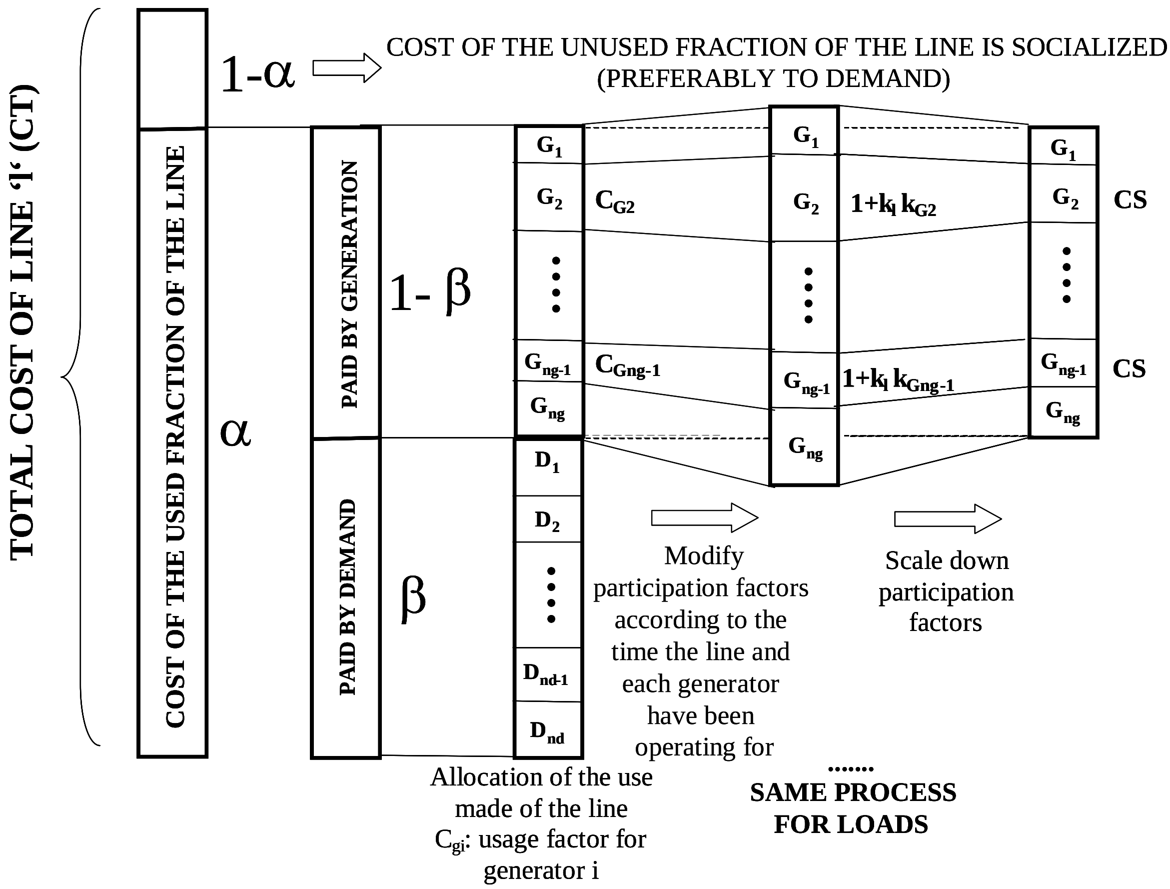

Figure 1: Process of computation of transmission charges

4 Other implementation aspects of the design of transmission charges

As mentioned before, designing transmission charges involves not only developing the methodology for computing the responsibility of agents in the cost of the transmission grid, but also providing adequate answers to many implementation issues that are seldom treated in the existing literature. This section discusses the most relevant aspects of the implementation of locational transmission grid charges that are not directly related to the cost allocation algorithm. These include the identification of the snapshots that should be taken into account for the computation of annual transmission charges and the way in which the results obtained for these snapshots about the use of lines by generators and loads should be combined to compute these charges; the format or structure of the transmission charges that network users will have to pay; the procedure to update the charges whenever it is necessary; and grandfathering issues that may arise in the transition time to a full application of a new transmission charges procedure.

4.1 The scenarios to be considered

The network agents benefit from the existence of a new line during many different operating conditions, only a few of which correspond to the system peak load. Therefore, the cost of the 'used' fraction of each line should be allocated taking into account a set of scenarios corresponding to a wide range of operating conditions that may take place in the system. Besides, and in order for the locational signals resulting from grid charges to influence the decision by market agents on where to install new generation or load, agents should know the value of these signals before the new power plant or load centre is built. The set of scenarios employed to compute the grid locational signal to be sent to a potential new power plant should correspond to the future expected operation of the system, where it is assumed that the new power plant or demand has been already installed. All in all, tariffs should be published a priori based on the expected future operation of the system over a set of scenarios that are representative of the different set of situations that may exist in the future, once the considered generator or load has entered into operation. Tariffs must be computed once and for all considering not only one scenario but a set of representative scenarios. These scenarios must reflect the incremental network utilization that this generator or load will make of transmission lines.

The construction of new lines is mainly aimed at reducing the operation costs of the system that are related to the existence of the transmission grid, namely: a) the cost of transmission losses; b) congestion costs, or costs due to the existence of congestion in the system. Given that transmission losses and congestion may, in principle, occur at any time during the year, the allocation of the cost of the 'used' fraction of each line should be based on a set of scenarios that are representative of all the different operating conditions that may take place. Before assigning the cost of the 'used' fraction of each line to agents, one must determine the weights to be given to the different scenarios that must be considered in this process. In other words, one must determine the part of the cost of the 'used' fraction of each line to be assigned according to the responsibility of agents in the total use made of the line in each one of the former scenarios.

First of all, one must estimate which fraction of new grid investments, in terms of cost, is aimed at reducing line losses and, therefore, which fraction is aimed at reducing grid congestion. A correct estimation of this split has to be made by the professionals in charge of transmission expansion in the considered power system. The final result will depend on the system's specific characteristics, but it will probably be in the realm of 50/50 (contrary to the common believe that peak load conditions are the only ones that matter). The cost of each line should be apportioned between the fraction aimed at reducing losses and the fraction aimed at reducing congestion proportionately to the expected reduction in the cost of losses and the expected reduction in the cost of congestion, over the whole useful life of the line, that the construction of the line would cause. If 50/50 is assumed, 50% of the cost of the 'used' fraction of each line should be allocated to the different scenarios in proportion to the level of losses in the line in each scenario. The remaining 50% of the cost should be allocated to agents taking only into account those scenarios where there is a significant level of congestion in the system, which will typically be the peak load scenarios. Each peak load scenario should be weighted according to the load rate of the line in it. As it has just been mentioned, once it has been determined which part of the cost of the 'used' fraction of a line must be assigned in each scenario, this part must be allocated to the generators and loads operating in this scenario in proportion to the responsibility of each one in the total use of the line.

4.2 The format (structure) of the transmission tariffs

The volume of the transmission charge that is assigned to each network user is not the only thing that matters. The format or structure of the tariff itself is important, since a poor design (as the one most frequently used[9]) can interfere seriously with an efficient behaviour of the network users in the electricity market.

To the extent possible, operation decisions by the network users, which are short term decisions, must be kept independent from the level of the transmission charge paid by these agents to recover the total network costs, which should be a long term signal. If one wants to send short-term locational signals, this can be conveniently done via nodal energy prices (locational marginal prices, LMP in the

[9] Most systems have traditionally adopted a two part transmission tariff. Tariffs are normally divided into a capacity charge, which is aimed at allocating the fraction of the cost of the grid that is needed to serve the peak load, and an energy charge, aimed at allocating the cost of those lines built in order to reduce congestion and losses. The capacity term is a uniform charge per unit of power contracted, in the case of loads, per unit of power installed, in the case of generators, or per unit of power injected into or retrieved from the grid in the peak load scenario. The energy term is a uniform charge per unit of energy produced or consumed. Unlike most tariff designs, the tariffs proposed in this paper aim not to distort the decisions by agents. Thus, these tariffs differ from the design that has just been described.

US terminology). By packaging transmission tariffs in the format of energy charges (€/MWh), i.e. a charge that depends on the amount of energy produced or consumed by the corresponding agent, the network users will have to internalize these charges in their energy bids to the Power Exchange or in their bilateral contracts, therefore causing an unwanted distortion in the original market behaviour of these agents and the outcome –both prices and quantities- of the wholesale market.

It is then concluded that the charge should have the format of a capacity charge (€/MW.year) or of just an annual charge (€/year). The first option runs into the problem of applying the same charge to a 300 MW base loaded plant and to a 300 MW peaking unit that only operates a few hundred hours per year (the same difficulty happens with demands with widely different utilization factors and the same contracted capacity). The transmission charge should therefore be an annual charge (€/year) that must be computed based on the expected network costs that each agent (or type of agent) will make the system incur. Note here that applying the same fixed charge to all network users, regardless of their characteristics, would be even more discriminatory than applying capacity charges. The proposed fixed charges could be conveniently split into equal monthly instalments.

Still there is one difficulty left, which is very much related to the material in the previous section 4.1. Two transmission charges, G_{ks} and L_{ks}, are computed at each node k and for each scenario s. But they should not be weighed and combined into a single value G_k and L_k without taking into consideration the production and demand patterns of the several generators or loads that might be connected at a given node k. The charge for the 300 MW base-loaded plant at k should not be equal to the charge for the 300 MW peaking unit connected at the same node.

Same considerations apply to demands with very different patterns. It would be possible (but not desirable) to compute tailor-made charges for each network user that take into account its actual production or demand (historical or expected) for all the considered scenarios. Apparently this is a good idea, since the resulting locational signals would be passed to the network users, who logically should internalize them in their short-term behaviour. However, this is undesirable, since nodal energy prices (or LMP) are already the complete efficient locational signals that should be sent in the short-term. Therefore, any additional locational signal would result in some distortion. For instance, when applied to generators, this would cause them to internalize transmission tariffs in their energy bids, distorting their short-term behaviour.

A method to decouple transmissions charges from the short-term behaviour of network users is to define “generic” per unit transmission charges for generators of different kinds and production profiles and also for a set of “characteristic” loads (perhaps only on the basis of their utilization factors), but without linking the value of the charges to the actual performance of generators or loads during any given year.

4.3 Updating scheme for transmission charges

The main objective of the proposed locational grid charges is to send a signal that can have an influence on the decisions of prospective investors on where to install new generation or load (locational signals for loads are of lesser interest, as discussed before). The locational signal that is given to a prospective network user must be the best possible estimate, at the time when the decision to invest is made, of the transmission grid costs that it will make the system incur. It has been shown that this signal must be independent of the actual use of the grid by the network user. In other words, in order to avoid distortions in the operational decisions of the agents, their utilization of the grid should not have any influence on the transmission charges that they will finally have to pay.

It logically follows that the total transmission charges to be paid by the new network user should be announced and committed before the decision to invest is made. Otherwise, if the given number is only an estimate and there is a history of large deviations between estimates and real charges, the locational signals become meaningless.

Therefore, the locational transmission charge to be paid by a generator that will be installed in a certain node should be computed and published before the generator is actually connected to the grid. Once the generator is in operation, this charge should be applied either as a one-shot payment or as a collection of payments that add up to the total amount previously computed. Transmission locational charges, to be levied on the new generators or loads that are installed in a year 'n', should be computed taking into account a set of scenarios that are deemed to be representative of the operation of the system throughout the M year period starting at year 'n' and ending in year 'n+M', where M should, in principle, be the length of the study horizon considered for the development of the expansion plan of the transmission grid. In practice, 'M' should not exceed 10 years. This is due to the effect of the discount rate and to the fact that the further one moves into the future, the less certain are the hypotheses that have been used to estimate the charges.

One drawback of this scheme of tariffs is the fact that, at least for some generators and loads, the locational charges they have to pay might significantly deviate from those who would have been computed a posteriori. Besides, as already acknowledged in section 3.5, transmission tariffs computed according to method proposed here will not recover the whole cost of the grid. As explained in section 3.6 when presenting the algorithm for the computation of tariffs, the difference between the cost of the grid and the amount recovered through the application of these tariffs should be socialized to demand. This is the same solution proposed in sections 3.3 and 3.6 to allocate the cost of the unused fraction of the capacity of each line when computing transmission tariffs to be paid by generators and loads whose construction is decided each year. However, the amount to be socialized to demand in one case and the other may differ.

4.4 Grandfathering issues

A drastic change in the design of transmission charges can make some network users unhappy, if they end up having to pay much more than with the original method. In order to mitigate this problem, some exceptions to the general rules could be allowed for the incumbent generators and loads. For instance, the new system of transmission charges may not be applied to the generators and demands that have participated in the system for a long time (e.g. more than 10 years), so they can continue with the existing regime. Alternatively, charges applied to these agents could gradually evolve from the current regime to the new one during a prescribed number of years. Once the new tariff regime is implemented, the difference between the current transmission charges that these senior network users pay and the ones they would have had under the new regime would have to be socialized to demand.

The loss of efficiency caused by this grandfathering scheme would probably be minimal from a siting viewpoint, since these agents have been located in the network for a long time and a change in transmission charges is unlikely to force them out of the system or to relocate. Efficiency losses from an operational viewpoint would also be minimal since, if the guidelines in section 4.2 are followed, the transmission tariffs should not have an impact on the short-term operation of generators or loads.

5 Numerical results

Figure 2 shows the distribution of the per unit locational transmission charges for new generators in the Spanish system that result from the application of the proposed methodology. These numbers correspond to just one scenario of operation: the 2006 winter peak load. The considered snapshot corresponds to January 18th 2006 at 19:30 hours. Total load in the Spanish system in this snapshot is around 29.600 MW while total power produced is around 30.000 MW. The transmission grid that has been modelled is comprised of 416 nodes and 692 lines. The geographical distribution of load and power production in the system for the considered snapshot is provided in Table I referring to 5 different areas that the Spanish system has been divided into: Northwest, North, East Central and South. Net exports to Portugal are close to 250 MW while net imports from France are about 280 MW. Charges have been computed for all the nodes of the 400 and 220 kV transmission grids.

Only one scenario has been used, because of the lack of data corresponding to other operating conditions. However, in real life, tariffs should take into account the expected operation of the system in a number of scenarios representative of the different operating conditions that may exist once the considered generator or load has entered into operation. This is explained in section 4.1.

Table 1: Geographical distribution of load and generation in the Spanish system for the snapshot corresponding to January 18th 2006 at 19:30

AREA	*GENERATION*	*DEMAND*
NORTHWEST	7017.0	2614.1
NORTH	4016.2	3121.2
EAST	6253.2	6778.8
CENTRE	6827.2	11404.9
SOUTH	5919.1	5686.0

For the sake of facilitating the presentation of the results and contrary to what has been proposed in section 5.2, the numerical values are expressed as an energy charge (€/MWh) so that they can be compared to other grid locational signals, such as those corresponding to transmission losses and congestion costs. Each dot in the figure refers to a different grid node. Its colour and size represents the level of the unit transmission charge that should be levied on the new generation that is installed in that node. For the sake of clarity, the coloured dots only portray values in the range of (-2 to +4.5 €/MWh). The colour of dots ranges from dark blue for the lowest transmission charges (-2€/MWh) to dark red for the highest ones (+4.5€/MWh). The size of dots increases with the level of the corresponding charges between -2€/MWh and 4€/MWh. Outliers, i.e. those values that are above or below this range, have been represented using square boxes, if they are positive charges, and crosses, if they are negative, so that typical values for charges can be represented more accurately. Transmission charges, including the outliers, range between -3€/MWh and 11€/MWh. Only 10% of the computed charges have been classified as outliers.

Numerical results presented here are not an estimation of the locational signals that should eventually be sent to new generators if the proposed mechanism were implemented, since only one scenario has been considered. The values appear to be very reasonable. Exporting areas (those located in the North Western part of the country, like Galicia and Asturias) exhibit the highest charges for new generators, while importing areas (those where demand is significantly larger than generation, like Catalonia in the North Eastern part of the country, or Madrid, in the centre) exhibit the lowest ones. The computational requirements are quite modest, and no practical problem is envisioned in extending the analysis to any desired number of scenarios.

Transmission charges should be long term economic signals that drive the decisions by agents on the location of new generation and load. Therefore, these charges should evolve gradually over time. In other words, they should be relatively stable charges. In order to evaluate the stability of charges, several 400 MW fictitious power plants were separately included in the original scenario in several areas of the system, with the objective of evaluating the impact that installing them or not would have on the locational signals for these areas. Hopefully they would not change much, and the signals would be sufficiently stable. Several new scenarios were created from the original one. In each of them, a new 400 MW power plant was included in a different 400 kV node of the transmission grid. Nodes chosen for considering the installation of a new plant were located in the North West (Galicia), the North-Western part of the central plateau, the North-East (Catalonia), the Eastern coast (Valencia), the country's centre (Madrid) and the South (Andalucía). As expected, transmission charges to new generators in the areas where a new plant had been included increased slightly with respect to the original ones. The average increase in transmission charges was slightly smaller than 1 €/MWh, while the maximum increase computed for the transmission charge in a node was of 2.26 €/MWh. Given the range of variation of the values of transmission charges in Figure 2, one may conclude that the locational signals that are provided by the proposed method are quite stable.

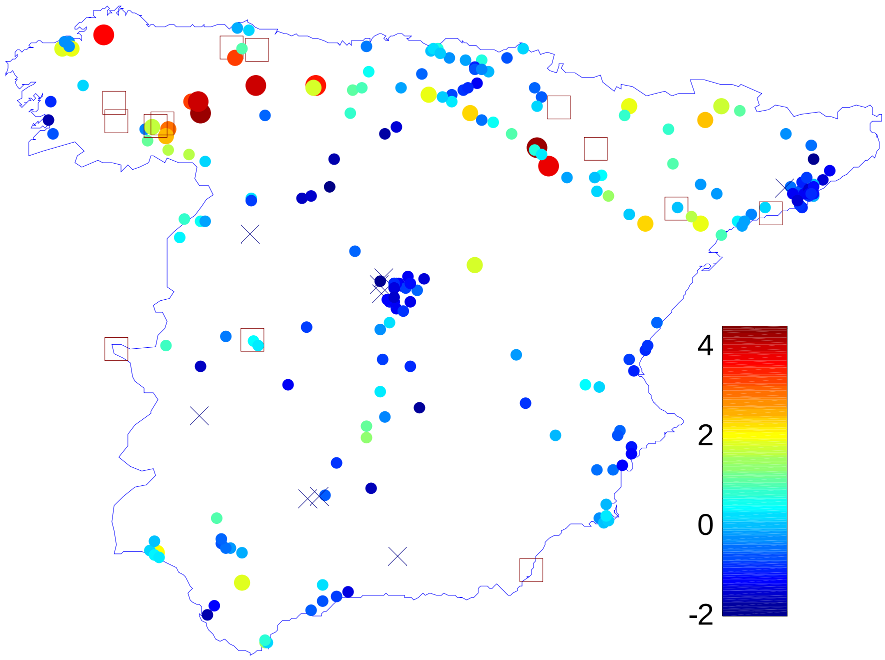

Figure 2: Distribution in the Spanish system of per unit locational transmission charges for new generators resulting from the application of the proposed methodology. Only one scenario corresponding to the 2006 winter peak load has been considered. Values are expressed in €/MWh.

6 Final Remarks

This paper has presented a comprehensive review of the many different issues that have to be considered in the design and implementation of transmission network charges with a locational content. It has also proposed specific responses to each one of these issues. As it is frequently the case in regulation, there is some amount of judgement involved in some of the choices, and other options are possible. Although the proposed approach is meant to be general, other choices could be more advisable under specific circumstances The resulting tariffs are meant to encourage potential network users to internalize the cost of any new grid reinforcements that may be associated to their siting decisions, when considering the installation of new generation or load. The numerical results that have been obtained confirm the advisability of implementing these charges. It must be stressed here that the proposed transmission charges have a different purpose than LMPs, and they are meant to be used besides LMPs, not instead of them. The objective of these transmission charges is to efficiently recover the regulated cost of the grid.

This study has only considered the locational signals that are associated to transmission network costs, that is, the costs of constructing, operating and maintaining transmission facilities. Obviously, other energy infrastructure-related costs with locational component should also be taken into account by agents when deciding where to install new power plants or loads, such as the costs of access to gas supply or any reduction of revenues due to network losses and constraints, in addition to the cost of the land, other local costs such as taxes, access to cooling water, roads or other facilities. Under the present conditions in many countries of scarcity of network capacity and abundance of applications for connection to the grid, locational signals derived from transmission charges should be an ingredient of the complete picture.

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