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Abstract
The present Report investigates the regulatory framework of the European TSOs remuneration policy with particular attention to the incentives schemes for developing transmission networks in the European electricity sector, and specifically cross-border interconnections.

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ACRONYMS AND DEFINITIONS

AC: Alternating Current

ACER: Agency for the Cooperation of Energy Regulators

Adequacy: ability of the electric system to supply the aggregate electrical demand and meet energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities (See also Reliability, Security).

AEEG: Autorità per l'Energia Elettrica e il Gas (Italian Electricity and Gas Regulator)

AP: Average Participation

CAPEX: Capital Expenditure

CBT: Cross-Border Trade

CCGT: Combined Cycle Gas Turbine

CEER: Council of European Energy Regulators

COS : Cost Of Service

DC: Direct Current

DSO: Distribution System Operator

EC: European Commission

EIB: European Investment Bank

ENTSO-E: European Network of Transmission System Operators for Electricity. New organization grouping 42 European Transmission System Operators established in late 2008 and operative from mid 2009. Previous associations such as ETSO, UCTE, NORDEL, BALTSO, UKTSOA and ATSOI have been dissolved and their tasks and functions moved to the new organization.

ERGEG: European Regulators' Group for Electricity and Gas

EU: European Union

FERC: Federal Energy Regulatory Commission

GME/IPEX: Gestore del Mercato Elettrico - Italian Power Exchange

GSE: Gestore dei Servizi Energetici (Italy)

HVDC: High Voltage Direct Current. An HVDC link consists of a cable or overhead line where current is transmitted in direct (instead of alternating) mode.

IEM: Internal Energy Market

Interconnection: This document adopts the term "interconnection" when referring to a transmission line connecting the competence zones of two TSOs

ISO: Independent System Operator. An ISO is responsible for the management of a transmission system, but does not own the transmission assets (See also TSO).

ITC: Inter-TSO Compensation mechanism

KPI: Key Performance Index

LMP: Local Marginal Price

NIMBY: Not In My Back Yard

NORDEL: previous association of Nordic transmission system operators of Denmark, Finland, Iceland, Norway and Sweden (See also ENTSO-E).

OFGEM: Office of Gas and Electricity Markets (UK)

OHL: Overhead Line

OPEX: Operational Expenditure

RAB: Regulatory Asset Base

Reliability: it describes the degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within acceptable standards and in the amount desired. Reliability on the transmission level may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply / transport / generation. Reliability is the sum of adequacy and security (See also Adequacy and Security).

RES: Renewable Energy Source

ROR: Rate Of Return

Security: ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components. Another aspect of security is system integrity, which is the ability to maintain interconnected operations (See also Security of Supply).

Security of supply: ability of the electric power system to provide electricity to end-users with a specified level of continuity and quality in a sustainable manner (See also Security).

Stability: the ability of an electrical system to withstand normal and abnormal system conditions or disturbances and to regain a state of equilibrium.

TAR: Transmission Access Review

TFEU: Treaty on the Functioning of the European Union

TSO: Transmission System Operator. It owns the transmission assets and is responsible for the management of the transmission system in its control area

TYNDP: ENTSO-E Ten-Year Network Development Plan

UCTE: Union for the Coordination of the Transport of Electricity. It was the former association of the transmission system operators of continental Europe before ENTSO-E was created.

1. EXECUTIVE SUMMARY

The progressive opening of electricity markets in Europe entails a redefinition of several parameters regarding incentive regulation, regulatory governance and market design assessment, in order to achieve the liberalization targets. New investments in cross-border electricity networks have emerged as a crucial need to better integrate the Internal Electricity Market (IEM), secure the electricity supply and facilitate the integration of renewable energy sources (RES) into the European grid. This is a process involving various stakeholders as Transmissions System Operators (TSOs), national regulators and European institutions, with the aim to harmonize national needs with the pan-European interest.

The present Report investigates the regulatory framework of the European TSOs remuneration policy with particular attention to the incentives schemes for developing transmission networks in the European electricity sector, and specifically cross-border interconnections.

The study focuses firstly on the regulatory context related to transmission incentive mechanisms that could stimulate the implementation of TSO's network investments, by presenting the main approaches used worldwide for regulating transmission network development which span from the traditional cost-plus model to the more performance-based schemes, as the "cap-regulation". A complement to the regulated transmission investment model is also explored by presenting the merchant transmission investment scheme, based on a private investment approach, where parties concerned are fully or partially exempted from the rules on third party access and/or the rules on the use of the congestion rents. However, this option remains a relatively minor issue in Europe. Projects having recently granted exemptions have to observe a stringent set of conditions concerning the impact of the project on competition, not forgetting network externalities and the risk to hamper regulated investments which remain the rule.

Despite there are both positive and negative aspects concerning interconnections investments at technical, economic, environmental and socio-political level, there is a common agreement on the advisability of optimizing regulation on investment incentives in Europe. TSOs, who are usually the main agent tasked with identifying and delivering additional transmission infrastructure, might not have sufficient incentives to fully consider the potential for investing in transmission capacity improvement, and while the need for substantial investment in more electrical interconnection capacity is widely recognized, the ways and means to promote such investments are more controversial. Potential interconnector investors are further discouraged by the existence of a "regulatory gap", due to the fact that each regulator only has authority within its national market and no authority decides on cross-border and regional issues. There is no supra-national authority responsible for the cost allocation of cross-border projects - for example deciding on a compensation for transit country - and investors face an important risk of project failure when the concerned national regulatory authorities are unable to agree on key cross-border regulatory provisions. Moreover, a lack of supra-national network planning may impede the identification of the most beneficial interconnector investments.

By comparing theory and current praxis, one of the main worries emerged is a lack of explicit incentivization for new efficient investments. Incentives are mostly set for short-term projects, and that represents a main concern especially in the case of long-term and lumpy investments, as cross-border networks are. In the view of the REALISEGRID project, a thorough cost-benefit analysis should be the correct foundation for a correct evaluation of investment efficiency, on the basis of which a an increase in the return of investments of the TSO could be calculated. Meanwhile, the Inter-TSOs compensation (ITC) mechanism, still too weak and not truly cost-reflective, should be reformed: an extension of the current scheme covering also investment costs could be the right solution to allow motivating the so-called "transited countries", i.e. those which contain neither the source nor the destination of the electricity transactions. An adequate harmonization of national revenue and incentivization schemes should emerge too, integrated with the new ITC-mechanism, in order to avoid distortion of the economic signals.

Cost-benefit analysis and new ITC-mechanism should be combined with a proactive behavior of the TSOs in their investment activity. The liberalization process, implying the separation between generation and transmission, caused an asymmetry of the investments coordination which generates bottlenecks and delays, particularly in an uncertain regulatory environment. Taking into account investors' interest for generation technologies with short lead construction time, the proactive behavior of the TSOs could facilitate the connection of these types of power plant and encourage market entry. The anticipation of the planning of some specific network investments, as the cross-border ones, avoids that congestion appears, with negative consequences on dispatching costs, while the new power plants are still in the building phase and new power lines are still in their administrative phase.

Finally, a kind of innovative approach is suggested as an example of a second best option for fostering cross-border investments. This alternative financing mechanism constitutes a hybrid model where the regulated framework is kept, with some integration permitting to involve private funds which may constitute a good opportunity in order to accelerate the investment process.

2. INTRODUCTION

2.1 Objectives of the deliverable

Bottlenecks and congestion problems on most important European cross-border lines push policy makers to implement corresponding legal and regulatory frameworks enabling a further development of the European electricity networks.

In 2010, ENTSO-E, the new association gathering all the European TSOs created as an implementation of the Third Energy Liberalization Package, has issued its first Ten-Year Network Development Plan to be updated every two years. (TYNDP 2010). This plan identifies the most urgent transmission investment projects in the upcoming years across Europe. In general, the TYNDP 2010 provides a detailed classification of the transmission investment needs according to the contribution to the different EU policy objectives: (i) improvement of security of supply; (ii) further development of the internal European electricity market; (iii) massive integration of RES-E generation necessary to meet the EU-2020 policy targets.

The lack of cross-border networks is a main concern and their development involves thinking over all the aspects concerning this particular kind of investment. Following this general need, the major objective of this report is to find the right formula to ensure an adequate remuneration for promoting European cross-border investments in electricity transmission, creating at the same time the right incentive mechanism for guaranteeing the most efficient grid planning, avoiding to jeopardize the operational network security and contributing to an efficient and effective integration of renewable energy sources into the European grid.

One of the major obstacles for developing new investments in new transmission cross border facilities is the uncertainty concerning an adequate remuneration scheme (CEER, 2003). For clearing this hurdle it would be necessary to establish a more comprehensive framework for regulatory control and financial reward, in order to promote infrastructure investments and thus, the achievement of an effectively competitive internal electricity market.

Delays and difficulties to obtain authorizations for building cross-border infrastructures represent another important barrier. The length of the authorization path related to the investments is a crucial issue that should be taken seriously into account, especially when the aim is to encourage transmission system operators (TSOs) to provide new facilities for improving the efficiency of generation capacity, resource allocation and RES development.

Therefore, this study aims at providing policy recommendations on TSOs remuneration and incentivization mechanisms for promoting cross-border transmission investments, highlighting also infrastructure needs and proposing regulatory solutions in order to guarantee a better social welfare on the long-run. The results concern different aspects of this delicate issue and different variables both endogenous and exogenous play a very crucial role. There is no only one solution, but many complementary approaches contributing to stimulate the development of cross-border grids in a more efficient way.

2.2 Expected outcome

The Work Package 3.6 of the project REALISEGRID aims at analyzing the impact of incentive and regulation mechanisms on transmission investments so as to improve transmission adequacy and contribute to the fulfillment of the three different EU policy targets: (improvement of security of supply, further development of the internal European electricity market and massive integration of RES-E generation).

The methodology applied in this deliverable to deal with the target of the study has followed a synthetic approach, taking on board all the inputs coming from the related deliverables (D3.6.2, D3.6.3, D3.7.1 and D3.3.1 mainly), so as to present some policy recommendations for incentivizing TSOs to invest in cross-border networks while guaranteeing a correct remuneration in the long-run.

After a brief overview of the regulatory background in Europe (Chapter 3), the study is articulated in three main parts:

- Chapter 4 illustrates the regulatory principles for investing in transmission infrastructures taking into account both regulated and market based options, with a focus on the implications regarding the RES integration into the grid.
- Chapter 5 presents the current debate concerning the impact of incentive mechanisms on cross-border transmission investments, highlighting the influence of some exogenous variables as authorization delays, public acceptance and loans availability on financial markets.
- Chapter 6 provides some suggestion to better deal with future transmission needs underlining the necessity of a previous cost-benefit analysis for cross-border investments, and proposing in addition a reassessment of the current ITC-mechanism, in order to implement a new cost-reflective scheme able to send the good economic signals. A case study concerning the "hybrid model" recently applied in Italy is also presented, as an example of second best option.

2.3 Approach

The approach followed started from the analysis of the national cases presented in the deliverable D3.6.2.

Then, a few interviews were led to important European Stakeholders (regulators, TSOs, Florence School of Regulation, ENTSO-E). Some of the elements collected within these interviews are explicitly quoted in this deliverable, others have been taken into account in different ways within the text.

A thorough revision of the scientific literature was carried out to get an overall picture of the analyzed problems of the proposed solutions. Additionally, the prospect of performing investments in sight of integrating an increasing amount of Renewable Energy Sources (RES) was considered too (see also REALISEGRID D3.6.3).

3. BACKGROUND

In order to allow the achievement of the European goals, in terms of security and interconnectivity of energy supply and solidarity, the Treaty on the Functioning of the European Union (TFEU – Consolidated Version)[1] at the article 194 (Title XXI) highlights some key drivers: "*ensure the functioning of the energy market; ensure security of energy supply in the Union; promote energy efficiency and energy saving and the development of new and renewable forms of energy; and* ***promote the interconnection of energy networks***".

As mentioned in the Treaty, a more intense interconnectivity of EU energy networks represents a crucial issue to guarantee a better functioning of the energy markets in a more secure and sustainable environment. The high need for infrastructure investments, especially for cross-border networks, is coupled with the necessity of both reducing congestion - involving benefits in terms of **security of supply** and **internal market integration** - and promoting measures for developing **renewable energies**, taking into account the need of transmission flexibility which is crucial to manage the intermittent renewable generation.

At the Barcelona European Council in 2002, a 10% interconnection benchmark has been promoted by the Heads of State, regardless of the level of congestion.[2] On most borders this benchmark has not been reached yet and the Commission's Sector Inquiry[3] revealed that today the relevant markets have mostly to be considered national. Meanwhile, the proposed 20% renewable energy target (leading to about 33% electricity generation from renewables) stresses the call for grid investments.[4] After more than 10 years since the beginning of the electricity sector liberalization process, there is still a lack of cross-border transmission investments, and a look at the TEN-Energy-Invest study[5] reveals that most bottlenecks identified at its start in 1996 still exist today.

In order to satisfy new needs concerning security of supply, system reliability, competitive markets development and renewable energies integration, the role of electricity interconnections becomes essential. Today, all the actors (European Institutions, National Regulators, TSOs, Private Companies, etc.) are involved in this challenge which concerns not only market design issues but also new financing mechanisms and regulatory reforms in order to realize new cross-border networks which are essential to achieve the European targets for the coming future (cf. Third Energy Package).[6]

Before the liberalization process, interconnections represented only a physical instrument to guarantee security of supply and solidarity among countries in case of accident. Today, as previously mentioned, interconnections represent the core of the market integration process, guarantying the development of competition by increasing transmission capacity and so contributing to the congestion attenuation. Also, as identified in the Third Energy Package,

[1] Official Journal of the European Union – C 115/47 (9.5.2008).
[2] European Council 2002, Presidency Conclusions, Barcelona European Council 15-16 March 2002.
[3] DG Competition Report on Energy Sector Inquiry – SEC(2006) 1724, 10 January 2007.
[4] Cf. EC - Third Energy Package.
[5] See: http://ec.europa.eu/energy/infrastructure/studies/doc/2005_10_ten_e_invest_summary.pdf
[6] Directive 2009/72/EC; Regulation (EC) No 713/2009; Regulation (EC) No 714/2009.

interconnections seem more and more important for an easier integration of renewable energy sources into the European grid, allowing a better exploitation of the installed generation capacity.

Following the European energy policy, the **security of supply** has to be continuously guaranteed and improved by strengthening interconnections - both at national and transnational level - for reinforcing system stability and reducing risks of blackout. For that reason, the European Commission strongly stresses the fact that the construction of network infrastructures, and in particular cross-border interconnections, is a crucial step for promoting a stable electricity supply.[7]

However, the reliability and security targets have to be fulfilled considering the new integrated and competitive dimension of the European **Internal Energy Market.** Transforming national markets into regional ones and ultimately into a single pan-European market is crucial for reducing market power and increasing competition. Nowadays, the lack of electricity interconnections represent a limitation to the commercial exchanges between Member States, reducing by consequence the community welfare as the least cost generation plant may not be able to provide all of its production to the market because of congestion. For these reasons, as the European Commission highlights: “The development of a true internal market in electricity, through a network connected across the Community, should be one of the main goals (…) and regulatory issues on cross-border interconnections and regional markets should, therefore, be one of the main tasks of the regulatory authorities, in close cooperation with the Agency where relevant”.[8]

Furthermore, as mentioned before, interconnections contribute to smoothen the impact on the system of the investments in renewable energies (mainly wind power and solar power), essential in order to reach 20% of total energy consumption by 2020, meaning about 33% of the European electricity generation mix. A strong impact on power systems design and operations is in fact expected in the coming years due to the unpredictability of the new variable power generation, highlighting as a more interconnected European grid is becoming a *conditio sine qua non* for achieving a **sustainable energy development**.

Therefore, strong interconnections appear to be essential both to promote the development of renewable energies, and to ensure security of supply when there is a high level of renewable generation. In the long term (2020-2030) both the wind power capacity, installed mainly in the North Sea, and the solar energy, coming principally from North Africa,[9] will need a significant enhancement of cross-border interconnections to facilitate a reliable integration of these new “green electrons” into the European grid: a power system is flexible if it can respond rapidly to large fluctuations in demand and supply. However, when grids become highly loaded, the tolerance to such variations decreases and this entails huge investments to improve system reliability, also by increasing the transmission interconnection capacity to adjacent power systems which should be carried out together by several TSOs. Moreover,

[7] Cf. Whereas (44) Directive 2009/72/EC.
[8] Whereas (59), Directive 2009/72/EC
[9] Cf. Art. 9, Directive 2009/28/EC.

with the increasing penetration of variable renewable generation the need for reserve becomes crucial and the possibility to share it on a pan-European basis could constitute a good framework for reducing the overall need and to rationalize its purchase. To do that, a robust transmission system in which most structural bottlenecks have been removed becomes essential.

On the other hand, the liberalization of the electricity sector, implying the unbundling of vertical integrated electricity companies, has modified the European panorama of the power sector, changing the structure of the industrial chain by opening the contestable segments (i.e. generation and supply)[10] which are gradually deregulated. The transmission segment, which presents natural monopoly characteristics, continues to be subject to price, network access, quality of services and entry regulations (Joskow, 2005).[11] The Transmission System Operators (TSOs) have emerged as new companies in a regulated environment where networks are considered essential facilities.[12] Some TSOs have been privatized and their stock company status, yet having to operate in a regulated regime fixed by regulators upon the hypothesis of natural monopoly, obliges them to make profits. Additionally, their planning activities have become more difficult because of the complexity to foresee the trans-national transits due to variable generation sources and to the uncertainties bound to the bidding behavior of the several independent market players.

In this new context, the regulator emerges as new actor, operating *ex-ante* to enforce a planning investment policy and favoring the social welfare achievement where the welfare consequences of these industry restructuring and deregulation initiatives depends on the performance of both, the competitive and the regulated segments of these industries. This fundamental task is extremely delicate in a context where national goals often prevail on pan-European investment logics, and at the Community level is emerging a sharp necessity to take into account the need of harmonizing regulatory frameworks. Moreover, cross-border flows will increase because of market integration targets and common rules will be necessary both to foster investments and to manage electricity trade.

An important component of the European agenda has included the introduction of "incentive regulation" mechanisms for the remaining regulated segments, in particular concerning the regulation of the TSOs, as an alternative to traditional "cost of service" or "rate of return" regulation. The expectation was that incentive regulation mechanisms would provide more powerful incentives for regulated firms to reduce costs, improving service quality in a cost effective way, stimulating the introduction of new products and services, and ecouraging efficient investment in and pricing of access to regulated infrastructure services. However, the long-term dimension of the aforementioned challenges impose that **a new regulatory framework is implemented providing TSOs with clear incentive schemes for fostering the pan-European transmission development.**

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[10] Cf. Baumol W.J., Panzar J.C., Willig R.D., (1982 and 1988), *Contestable Markets and the Theory of Industry Structure,* Harcourt Brace Jovanovich, New York.

[11] Cf. Joskow P.L., (2005), *Incentive Regulation in Theory and Practice : Electricity Distribution and Transmission Networks,* Working Papers 05-014, MIT – Center for Energy and Environmental Policy Research, Cambridge, MA.

[12] Cf. Posner R.A., (1969), *Natural Monopoly and Regulation,* « Stanford Law Review », vol. 21, 548-643;

4. REGULATORY PRINCIPLES FOR INVESTING IN ELECTRICITY TRANSMISSION INFRASTRUCTURES

4.1 The regulatory context

The liberalization of the European electricity markets, started in the mid 90ies upon the approval of the first EU Directive (1996/92/EC). It aims at reducing electricity costs and improving customer services quality by promoting entries of new market operators, and thus shrinking the market power of historical monopolies.

Most electricity sector reforms initially focused on the introduction of competition in the fields of generation and supply, while transmission and distribution have been less affected due to their natural monopoly nature. On the whole, the industrial organization of the electricity sector has progressively changed and investments are no more coordinated by the same mechanisms as in the past, when the investments decision was centralized by the same vertical integrated entity. The presence of new structures and the diversity of the many new players have fundamentally invalidated some assumptions and relationships of the traditional transmission planning process, bringing new challenges. So, despite some bottlenecks and delays, the restructuring in the competitive segments is going forward also by changing the reference frame of the investments planning, which today is more articulated, including also a series of decentralized decisions partially based on prices.

Following these recent changes, regulatory reforms of the non-competitive activities have become more and more necessary, considering also that the European electricity market integration is hampered by insufficient incentives for investing in additional cross-border capacity. The European Directive 2009/72/EC and the Regulation No. 714/2009 highlight, among others, that new investments in transmission infrastructure are crucial to reduce congestion and to consent the RES deployment, granting at the same time a better system reliability. Hence, regulatory reforms of public utilities should provide the right signals - often complemented by specific supplementary incentive schemes - for improving these long-term investments, taking into account that cross-border aspects complicate the issue, imposing the harmonization of rules and procedures among Member States in order to satisfy the common European interest.[13]

Transmission congestion can be radically removed only by investing in grid reinforcements/upgrades and construction of new transmission lines that imply a long-term approach. Most of the transmission capacity expansion projects are capital-intensive and time-consuming, with a considerable impact on the environment, implying some concern of social acceptance that risk to entail delays, jeopardizing the realization of the projects (see e.g. REALISEGRID Interim Report and report D3.7.1, comprehensively addressing several aspects of streamlining planning and approval procedures of electricity transmission infrastructures). Moreover, given the lumpiness and the irreversible nature of network investments, a correct risk assessment in the regulatory regime is of crucial importance for the financial viability of network companies.

[13] Cf. Artt. 5, 6, 12 & 13, (EC) Regulation 714/2009.

In Europe the investments in transmission networks are normally regulated. However, there exists also a commercial (“merchant”) alternative implying that the investment is not recovered through regulated tariffs, but from revenues coming from the future use of the asset (e.g. revenues that are induced by the price difference for power between two ends of the transmission line).

Therefore, three major approaches exist today to the investments in transmission infrastructures: the first two representing the main regulated mechanisms and the third one the “merchant option”.

The first approach refers to the action of the TSO in forecasting needs for new investments asking to the regulator to set the financial remuneration under some form of price control. Under such a scheme, the regulated firm is immunized against cost changes, which are actually transferred to the customers who finally bear the risk.

The second approach is more market oriented and implies that the identification of transmission needs is provided by the competitive interaction of market actors - as well the direct action of the regulator - that would provide useful price signals helping the TSO to set down the investments plan. In this case the regulator sets the prices or revenues that a TSO can earn over a certain period, partially or totally decoupled from the costs it incurs over this time.

The merchant approach is rather different because the actors involved in the investment are not the same. This approach concerns private parties which identify, construct and/or operate new transmission infrastructure and receive remuneration from congestion rents. In this case, TSOs are only involved for connecting these facilities - “merchant lines” - to the national network.

The first mechanism derives from the existing methods applied also in the past by the vertically integrated monopolies, whereas the second one is more oriented to an environment of competitive markets and unbundled players (CEER, 2004). Concerning the “merchant approach”, it is important to mention that under the existing EU Regulation, regulated investments are supposed to be the general rule, while merchant investments are judged as exceptional cases.[14]

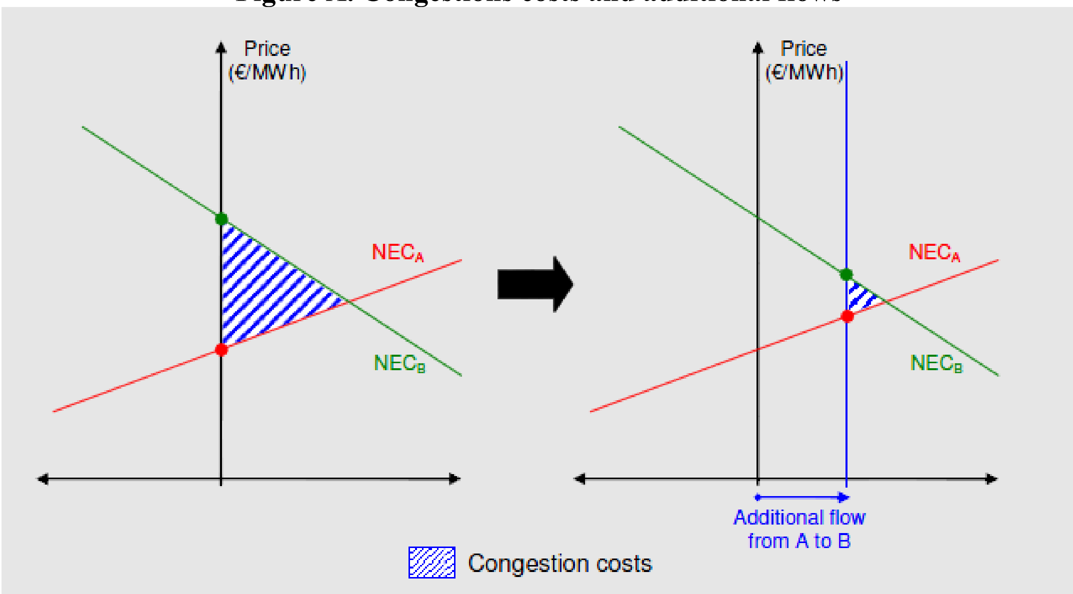
Congestion costs.[15]

Different prices in power markets generate costs for the society called *congestion costs.* These

[14] Cf. Artt. 16 & 17, Reg. EC/714/2009.
[15] Many textbooks define this quantity as *dead-weight loss* (see deliverable D3.3.1:“*Transmission congestion can lead to a reduction of the SW (small triangle area called dead-weight loss) which entails a loss of efficiency in the dispatching due to the effect of the system bottleneck. The loss comprises two components, one related to the loss of consumers surplus and another one related to the loss of producers’ surplus.*”
For a broader analysis, see: Lesieutre B.C. & Eto J.H. (2003), *Electricity Transmission Congestion Costs: A Review of Recent Reports,* University of Berkeley.

costs are the consequence of a scarcity of transmission capacity in a period of time when the demand can't be fully satisfied, and thus a loss in social welfare is produced (Fig. A). In other words, transmission congestion refers to requests for deliveries (transactions) that cannot be physically implemented as requested. The cost of transmission congestion, assuming that demand is fixed ("inelastic") and must be met, is thus the net cost of the replacement power that must be supplied by other means to make up for deliveries that cannot be executed as requested.

Figure A. Congestions costs and additional flows



Source: ERGEG 2009

Determining how these costs are calculated and how they can be accurately interpreted and used is an important issue, especially for making investment decisions. When congestion appears and its cost is estimated higher than the cost of the investment to reduce it, then the trade-off is between expanding/reinforcing the transmission system to increase its capability to deliver electricity, and pursuing non-transmission strategies by increasing generation capacity closer to the deficient load.

In liberalized electricity markets generators are owned by many different firms, while the transmission system is operated (sometimes owned) by a separate business entity. This market design implies that the "cost" of maintaining safe transmission operating margins can be defined in a variety of ways. A critical element is specifying how the costs of safe operating margins are recovered from or paid to customers receiving electricity service and/or are paid to or recovered from the generators. These costs are defined differently in different markets, and different calculations are used to determine their total amount.

Uplift Charges

Congestion costs are equal to the increased dispatch payments by the market to generators out of merit order. The dispatch payments are calculated using a uniform market clearing price for most generation. However, generators dispatched out of merit order because of congestion are paid at their offer prices. The uplift charge is shared equally among the consumers.

System Redispatch Payments
Congestion costs are equal to the difference in dispatch payments by the market to generators in the congested case relative to costs for the uncongested case. The dispatch payments are calculated using LMPs (Local Marginal Prices).

Congestion Revenues
In a market that uses LMPs, congestion revenues are the valuation of transmission of energy across a congested interface. Neglecting losses, these revenues equal the product of the energy flow and the price. Congestion revenues are also equal to the difference between what consumers pay for energy and what generators are paid for supply.

4.2 Remuneration policy and incentive mechanisms for regulated investments.

National regulations of transmission electricity networks are not the same in all the European countries, some differences and nuances exist, often hybrid models are preferred in order to both incentivizing and ensuring investments. However, two main approaches are mostly followed, considering that an incentive regulatory mechanism for a TSO should provide incentives to the regulated firm in order to make efficient investment decisions and permitting the regulated firm to earn enough revenues to cover capital and operating costs in an imperfect information environment about cost and demand functions (Rosellon, 2003).

The first approach is more "traditional", the TSO is in charge of the grid expansion plan by setting the investment needs which are then submitted to the approval of the regulator who sets tariffs for allowing the network operators to cover their capital and operating expenses. In this case the financial risk for the investor is very small, since is remunerated by a fair rate-of-return. To establish it there are two possibilities: i) certifying standard costs (investment, operation and maintenance costs); ii) launching a public tender for the realization of the expansion. In this second case the regulator may ask each potential builder to propose a tariff for the life of the project, awarding the project to the company that bids the lowest tariff. The tendering approach should thus reduce the danger concerning the potential risk of overinvestment that such cost-plus mechanism could produce implying an overcapitalization (i.e. Averch and Johnson effect, 1962).[16]

In other countries, on the contrary, another typical approach is followed. The regulator - which would not retain an explicit role to approve or oppose specific infrastructure project, but often only in assessing TSO's "baseline investment" forecasts of expected demand and supply - bases the asset remuneration on some form of performance measure, fixing *ex-ante* a price (or revenue) cap that represents the reference for the TSOs investment strategies within a given period. As a result, the TSO takes the risk of failure, the global reward being generally subject to RPI-X procedures, which are applied for a fixed control period. In this case, market signals have an important role helping to point out new investment needs.

[16] This effect, empirically proven by Stigler and Friedland (1962) and Courville (1974), occurs because of the relative favorable risk investment position that is guaranteed to the monopolistic networks operators.

Depending on the kind of regulatory approach, the incentive framework to promote network investments will be different. The first approach could be advantageous when the investments are particularly significant and/or in case of important economic uncertainties. The incentive to invest should be represented by the high level of remuneration certainty, which represents the major issue for network operators, but at the same time there are no real incentives to efficiently reduce costs. In this case there exist two main risks in terms of overcapitalization and technical inefficiency (i.e. x-inefficiency, Leibenstein, 1966), not forgetting that the inflation could worsen the situation.

The second approach certainly encourage to cut costs contributing to promote efficiency, but at the same time it risks to not stimulate adequately the long-term and lumpy investments, as cross-border interconnections are.

In both approaches, the economic incentive for the TSO to invest in a network facility may be deficient if the rate of return is too low, or the performance index used for setting remuneration parameters doesn't reflect real costs. Furthermore, the cross-border dimension of the investment often complicates things, imposing a regulatory harmonization. Thus, in order to set an appropriate and stimulating framework for promoting this kind of investments, it is important that incentive mechanisms encourage the coordination between TSOs, by harmonizing performance indicators and taking into account that the expected projects benefits for the consumers should be evaluated (Olmos and Pérez-Arriaga, 2009).[17] As a general rule, it can be affirmed that when regulatory differences exist, implying a lack of shared rules, trade opportunities drop.

4.2.1 Short-term and long-term issue: two sides of the same coin

Economic analyses on electricity markets usually focus on short term issues, such as spot markets, short-run congestion management, nodal pricing, day-ahead auction rules, and typically considers the transmission network capacity, as well as generation investments, as given. However, transmission capacity development depends on generation investments, which can be analyzed only from longer term perspective. Short and long-term imply different kinds of risk intrinsic in the nature of the cross-border transmission investments. If on one hand, the non-storability of electricity creates the necessity of short-term incentives, on the other hand, transmission is characterized by particular long life cycles, which imply specific risks and the necessity of incentives too.

Different types of investment may be affected differently by regulation and in particular by incentive regulation. Investment in cost reduction and replacement, let's say ordinary investments, may be positively affected by cap regulation (Borrmann and Brunekreeft, 2009). However, the lumpiness and "sunken" nature of innovative investments, as new cross-border infrastructures, entails augmented risks as well as highly uncertain costs. Thus, in this case incentive regulation is usually combined with rate-of-return regulation by creating a sort of hybrid model that should help to reduce risks, through the use of historic cost standards (Egert, 2009).

[17] *Ibidem*.

Regarding that, Vogelsang (2001, 2010) proposes a two-period framework distinguishing a *short period* and a *long period.* The short period typically coincides with the length of a regulatory lag, or of (RPI-X) type adjustments or adjustments from profit sharing. During a short period the firm makes and executes decisions on operations, repairs and maintenance costs: a full regulatory commitment and significant incentives for cost reductions in this short time are feasible. On the other hand, the long (commitment) period corresponds to the time for revisions of (RPI-X) adjustments and of incentive mechanisms at the end of each regulatory period.[18] In this way, short and long term needs are matched by diversifying both incentives and guarantees, in order to deliver the most efficient investment possible.

The literature on this topic is abundant and the debate is still open, implying different approaches to the problem. Léautier, who considers vertical separation alone insufficient to stimulate investments and so to reduce congestion, holds that specific incentives are required to stimulate TSOs to choose the transmission capacity that minimizes the sum of the expected congestion cost, the expected transmission losses and the expansion cost. For that reason, the author proposes a scheme by which the regulator offers a menu of contracts that would induce, according to the revelation principle, the transmission company to operate and expand the transmission system efficiently, while allowing its cost recovery. Under the proposed scheme, the costs of congestion and expansion are the responsibility of the transmission company, including a revenue sharing rule that trades off cost minimization against rent extraction, and an uplift management rule that induces optimal expansion of the transmission network (Léautier, 2000).

Some authors argue that efforts should be concentrated on the optimization of congestion management mechanisms rather than on building new interconnectors (Nies, 2010), considering that the main question is the inefficient use of existing interconnection capacities. The issue would concern for example explicit auctions which do not lead to an optimal use of scarce interconnector capacity, representing a significant barrier to efficient cross-border trade, implying anti-competitive behavior such as capacity withholding or inefficient arbitrage by dominant generators (i.e. trading from a high to a low price area to sustain market power). For that reason, implicit auctioning mechanisms are proposed to facilitate an optimal use of existing capacities, improving the operational efficiency of power commercial exchanges. However, this approach can’t solve one of the main causes of the problem that is the lack of cross-border transmission facilities, showing how important is for the achievement of the European internal electricity market both, an efficient congestion management and a sufficient interconnector investment.

[18] Cf. I. Vogelsang (2001), *Price Regulation for Independent Transmission Companies*, Journal of Regulatory Economics, 20, 141-165; I. Vogelsang (2010), *Incentive Regulation, Investments and Technological Change*, CESifo WP No. 2964. Vogelsang’s mechanism works as follows: in times of excess capacity, the variable charge of the two-part tariff decreases, causing an increase in consumption. The fixed charge, in turn, augments so that total income increases despite the diminishment of the variable charge. As a consequence, the TSO does not invest more in capacity expansion and net profits grow since costs do not augment. On the contrary, when there is congestion in capacity, the variable charge will be a pure congestion charge and, if congestion charges are in the margin greater than the marginal costs of expanding capacity, the TSO will have incentives to invest in new capacity.

Even if the risk of overinvesting in some case is real, an excess capacity may be considered as a cheap social insurance against the higher costs of congestion due to a lack of capacity. In any case, this complex issue should be tackled taking into account all the available solutions, being careful to respect market rules, and limiting too generous compensations, which could produce negative externalities perturbing market equilibrium and undermining the whole foundation of electricity restructuring (Hogan, 2003). Today, there is a trade-off between imperfect markets and imperfect regulation, but there is no first-best solution available for guaranteeing perfect economy efficiency in transmission investments. Theory and practice often diverge, and variables are not always manageable. However, cross-border issues should be tackled in a harmonized way, trying to find a shared approach between countries, not forgetting the pan-European interest that is on the top of this investments need.

4.3 Regulated investments and merchant lines: a question of financial reward, incentives and social welfare

Regulated and merchant transmission investments represent two different approaches to deal with the lack of cross-border networks. The latter, as an ample literature stated, could play a significant but not exclusive role in efficient transmission expansion by mitigating the problem of under-investment, especially in case of regulatory uncertainty. In general, a regulatory gap between national legislation and European policy is at the origin of this lack of regulated investments in interconnectors, as well as the lumpiness that regulation hard put to internalize.

Both regulated and merchant lines may coexist and they may complement each other in ways that will end up being useful for the global power system (CEER, 2004). However, under the existing EU Regulation, regulated investments are assumed to be the general rule in accordance with the European energy policy.

Merchant network investments are facilities that are not built under the initiative of regulators or TSOs but private parties, and whose remuneration is determined by the market and not by regulation (CEER, 2004). In this case, TSOs are only involved for connecting these facilities - "merchant lines" - to the national network and to upgrade national grids so as to allow their exploitation. These investments concern private parties which identify, construct and/or operate new transmission infrastructure fully or partially exempted from the rules on third party access and/or may get right to acquire the revenue created by the spot price differential across the line (congestion rents).[19] To manage the risk of congestion charge volatility, a transmission user may buy an hedging instrument called transmission right, which can be physical or financial.[20]

[19] Cf. Article 17 of EC Regulation 714/2009.

[20] Joskow and Tirole demonstrate the superiority of financial rights over physical ones in terms of economic efficiency. P. Joskow, J. Tirole (2000), *Transmission rights and market power on electric power networks*, Rand J Econ, 31, 450-487.

Nodal pricing, congestion rents and Financial Transmission Rights.[21]

Nodal pricing systems provide an energy price for each system node, indicating where it is preferable to generate or to consume one more megawatt taking into account both network losses and network limitations. Nodal prices differences generate a merchandise surplus for merchant line investors, also called **congestion rent**.

Nodal prices are very volatile and are a too dubious revenue source for the merchant line investors as well as for the merchant plants investors. Some financial tools complete the market for the market participants to hedge against the risk of locational price fluctuations. Hogan (1992) defines such hedging tools as point-to-point transmission rights between a sink node and a source node. These rights, the "**Financial Transmission Rights**" (FTR) are long term financial rights that allow their owners to hedge against nodal price volatility. FTRs are not physical rights. They do not give a right to flow energy between two nodes, but allow their owners to earn the differences in prices between a sink and a source node for the contracted quantity of FTR between these two nodes. As the nodal prices are for merchant line investors what energy prices represent for merchant plant investors, FTRs are for the merchant line investors what the forward contracts represent for merchant plant investors (Rious, 2006).

Depending from its aversion to the risk generated by locational price fluctuations, a merchant line investor chooses to earn money either by receiving the difference in nodal prices associated to its FTRs either by selling its FTRs to other market participants as hedging tools against these differences in nodal prices.

4.3.1 Merchant lines: an exceptional case

Merchant lines will never be an "alternative" to regulated investments, and they make sense only under exceptional circumstances. For example, a merchant approach could be suitable when the remuneration of the transmission activity in a Member State is not strictly based on some kind of cost-of-service schemes, but on other more performance-oriented criteria, which are less appropriate for certain types of investment, as the case of submarine interconnectors or cross-border networks in some particular conditions.

One typical case is when short-term reductions of the tariffs are envisaged by politicians, and hence TSOs are pushed to invest less in expensive long-term projects as this would raise the asset base on which most tariffs are calculated, even if these investments would yield greater benefits in the long-term (Buijs, Meeus, Belmans, 2008). Indeed, this asymmetry of incentives may produce negative externalities, hampering necessary investments which in this case would be subordinated to short-term interests.

Therefore, even if there is a general reluctance at the European level vis-à-vis this kind of financing approach - especially on letting dominant generators and suppliers undertake merchant investments (or obtain long-term priority access rights to interconnection through merchant investments promoted by a third party) - the merchant option should not totally excluded, but, indeed, strictly monitored. A stringent set of condition has to be observed

[21] For a broader analysis, V. Rious (2006), *What place for competition to develop the power transmission network?*

concerning, among others, the impact of the project on competitive equilibrium, network externalities[22] and the obligation of complying with the EU guidelines regarding on capacity reservation and market power issues.[23] The concerns regarding the potential risks in harming competition that exemption requests could generate in the markets served by the new infrastructure are concrete, and the potential negative externalities could be various, unpredictable, and expensive.

If a merchant investment represents a kind of derogation to the ordinary regulatory framework, it is also true that regulated investments may meet inefficiencies resulting from asymmetric information and political interference in planning and investment processes. Furthermore, regulated investments may be less effective than a merchant model in providing the high powered incentives that lead to the identification of innovative transmission options, costs minimization and efficient trade-off between generation and transmission investments (Joskow and Tirole, 2005).

Nevertheless, from an economic point of view, merchant transmission does not provide for optimal grid expansion, mostly due to misaligned incentives: a profit-driven transmission developer selects the expansion that maximizes the (*ex-post*) value of the asset, which does not generally coincide with the socially desirable expansion (Joskow and Tirole, 2005). Private and public incentives differ. A merchant developer increases the interconnection capacity between two markets expecting to increase his revenues (calculated in terms of price differential between markets times incremental capacity). However, the socially optimal network investment would reduce too much, from the point of view of investors, the remaining congestion rents. Thus, merchant investment either is not profitable (in which case it will not take place) or the capacity increase that is optimal for the investor is smaller than the one optimal for the system (Brunekreeft, 2003). Moreover, as Perez-Arriaga (1995) suggests, not more than 30% of total costs could be recovered by Local Marginal Price (LMP) differentials even with optimal capacity investments.

For that reason, it would be advisable to discourage investments in merchant lines by those suppliers who hold a dominant position: merchant investments should represent an *ad hoc* alternative instrument to foster new market entries for reducing market power of the historical incumbents.

On the other hand, from a regulatory perspective, there is a real concern regarding the coexistence of the two investment frames. The risk is that perverse incentives appear for either TSO or the owner of a merchant line. As a matter of fact, the construction of a regulated line could significantly impact the revenues collected by an existing merchant link, so it is crucial to establish a regulatory framework which deal with the risk that the existence of a merchant line could prevent the construction of a regulated one.[24]

[22] Constraints on grid operation, voltage control, congestion relief, impact of planned and unexpected outage on grid reliability analyses, etc.(CEER, 2004).

[23] Cf. Article 17 of EC Regulation 714/2009.

[24] Merchant lines seem to be limited to some very specific investments where the huge difference in zonal prices can be sustainable because of some constraints of energy isolation. The example of NYC is paradigmatic,

4.4 RES integration into the grid: cost allocation and incentives

When significant amounts of RES-E generation technologies have to be integrated into the existing electricity systems, the question regarding where the boundary of (financial) responsibilities between project developers (RES-E generators) and grid operators should be defined - in terms of grid connection/access aspects - is still controversial (see e.g. also REALISEGRID Report D3.1.1 comprehensively dealing with European practice of grid connection of wind power)[25]. Moreover, also grid reinforcement and extension measures caused by large-scale RES-E integration raise a set of new questions, as the extra costs allocation regarding remuneration and/or socialization of the different cost items.[26]

The core problem in this context is that any changes in a meshed grid infrastructure (e.g. the disconnection of a large industrial customer) will alter the load flows in the electricity system. Load flow changes depend, in turn, from a variety of factors: changes in the spatial distribution of generation and load centers in general, intensity and direction of commercial power trading activities, congested transmission lines in peaking periods, etc. Considering all these interactions, the choice of a methodology for the allocation of reinforcement costs appears at least questionable.[27]

In general, textbooks on economic theory of natural monopolies[28] would expect to socialize both RES-E grid connection costs[29] and grid reinforcement/extension costs through the transmission and distribution tariffs (and not to include either of these cost components to the

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showing the impossibility to build new generation capacities or to expand interconnectors trough classical terrestrial ways because of the urban density. Therefore, energy and capacity are expensive in this area. A merchant investor can benefit from this isolation to connect this isolated area to a close one thanks to non conventional means such as HVDC lines. Such a merchant line can than benefit from a high and sustainable difference in zonal prices (cf. Rious, 2006).

25 Cf. Fulli Gianluca, Ana Roxana Ciupuliga, Angelo L'Abbate, Madeleine Gibescu: "Review of existing methods for transmission planning and for grid connection of wind power plants", Project REALISEGRID, Final Report, D3.1.1, http://realisegrid.erse-web.it, 2010.

26 Whereas the extra cost for grid connection of RES-E generation technologies can be determined and allocated easier and more precisely, the allocation and quantification of extra measures and costs is much more complex. Even more, in a meshed network infrastructure it might be ambiguous to allocate extra measures and costs of grid reinforcements/extensions to the marginal net-effects of a new generation facility.

27 In general, there doesn't exist a grid integration discussion for conventional power plants having been built up to now and/or are built at present. As an illustrative example the nuclear power plant *Olkiluoto* – currently being built in Finland – can be quoted. This nuclear power plant also causes – besides grid connection costs – significant grid reinforcement/upgrading costs in the Nordic electricity system. Implementation of correct unbundling, however, allocates and remunerates the different cost components correctly; i.e. grid infrastructure cost components are not incorporated into the calculation methodology of the electricity generation costs of the nuclear power plant; they are incorporated into the corresponding grid tariffs directly.

28 Cf. Averch H., L. Johnson, *The Behavior of the Firm Under Regulatory Constraint*, American Economic Review, Vol. 52, p. 1053-1069, 1962; Baumol W. J., J.C. Panzar, R. D. Willig, *Contestable Markets And The Theory of Industry Structures*, Academic Press Ltd., Revised Edition, ISBN 0-15-513911-8, 1983; Baumol W.J., D.F. Bradford, *Optimal Departure from Marginal Cost Pricing*, American Economic Review, Vol. 60, p. 265-283, 1970.

29 However, signals for entry of entrepreneurs (e.g. locational signal cost component allocated to RES-E developer) are foreseen in economic theory. For a more comprehensive discussion in this context it is referred to the following section 3.2.2.

RES-E project costs).[30] As a matter of fact, a reinforcement that is carried out to the benefit of a newly connected generator can be then useful also for a second one that is subsequently connected to the network. If the whole reinforcement cost is charged to the former, the latter will unfairly use the infrastructure without contributing to its costs. However, in many European countries major parts of these grid-related cost components are still allocated to the project cost of a RES-E generation facility.[31]

In general, the following grid connection/access boundaries between the RES-E generation facilities and the grid infrastructure are possible (see Figure 4.1; compare also with the REALISEGRID Report D3.6.3):[32]

- "Deep" Charging: Based on this approach, costs for grid connection as well as grid reinforcement/extension are allocated to the RES-E developer and added to the overall long-run marginal costs of RES-E generation. So the RES-E developer has to cover also several grid-related costs upfront besides "actual" RES-E project cost.
- "Shallow" Charging: In the shallow grid integration approach, the RES-E developer usually bears the grid connection costs, whereas grid reinforcement/extension costs are attributed to the network operator (and, eventually, socialized via grid tariffs).
- "True Cost" Charging: Derived from shallow charging, sometimes also the term "true" connection cost charging is used, indicating that the costs paid by the RES-E developer for the new connection are equivalent to the cost of connecting the RES-E developer to the nearest point on the network with sufficient capacity on the network to accommodate RES-E generation without network reinforcements.
- "Super-Shallow" Charging: Following this approach, costs resulting from grid connection and reinforcement/extension are allocated to network operators (and socialized via grid tariffs). The term "super-shallow" has been introduced in the GreenNet-Europe projects,[33] referring to future requirements to connect centralized, large-scale RES-E generation technologies like offshore wind, marine technologies, concentrated solar power plants, etc. The coordinates of these kinds of – mainly offshore – sites are rather "planned". But note, this does not mean that the selection of the RES-E developer on a particular site is not based on competitive principles (e.g. like tenders etc.).

[30] In principle, there exist both options: (i) socialisation within the supply area of a grid operator or (ii) socialisation across the whole country/market/region.

[31] Weissensteiner L., C. Obersteiner, H. Auer, W. Prueggler, T. Faber, G. Resch, *Promoting Grid Related Incentives for Large-Scale RES-E Integration into the Different European Electrcity Systems*, Action Plan, Project GreenNet-Incentives, May 2009.

[32] In the last couple of years, in general, the same or at least similar "wording" has been used to describe the different connection charging boundaries. Most common are the terms "deep" and "shallow". Connection charging models in between these two approaches are called "hydrid", "shallowish" or "mixed".

[33] See e.g. project website www.greennet-europe.org

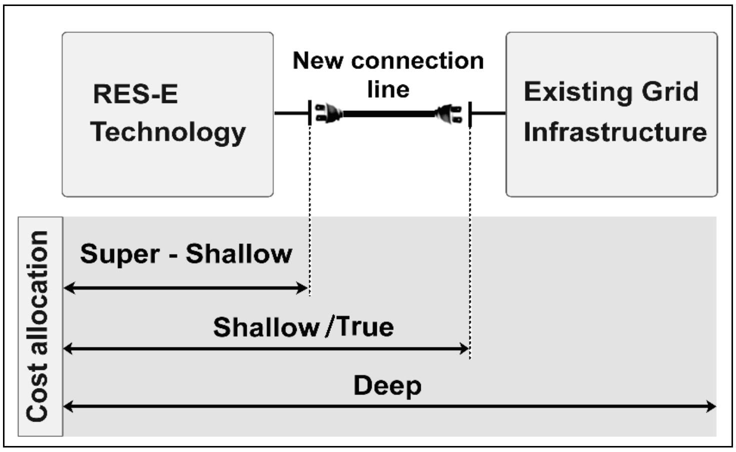

Fig. 4.1 Different connection boundaries between RES-E power plant and grid infrastructure.[34]

At present, in European practice rather hybrid/mixed approaches are implemented, mainly incorporating elements of both "deep" and "shallow" RES-E grid integration charging. This means in particular that some parts of grid reinforcement/extension costs are usually allocated to the newly connected RES-E generation facility and the remaining parts of deep costs are socialized in the grid tariffs.

In addition, the entire grid connection costs are borne by the RES-E developer and allocated to the long-run marginal generation costs of the RES-E generation facility in the hybrid model. However, in some EU Member States the existing pattern for allocating RES-E grid integration costs might change in the near future, not least due to the currently ongoing benchmarking and grid regulation implementations by national regulatory bodies.

4.4.1 The locational signal question of RES-E integration.

The overall objective of different cost allocation and RES-E integration charging policies is to guide efficient expansion and use of transmission and distribution grids, on the one hand, and efficient management of generation and load assets being connected to the grid infrastructure, on the other hand. Whereas economic theory presents clear approaches and procedures for optimal RES-E grid and market integration into existing electricity systems,[35] circumstances in practice are far more complex and accompanied by a variety of uncertainties, imperfections and problems. A selection of these critical issues of the different RES-E integration charging policies is discussed in the following.

[34] Source: Auer H, *The Relevance of Unbundling for Large-Scale RES-E Grid Integration in Europe*, Energy & Environment, Vol. 17, No. 6, p. 907-928, ISSN 0958-305X, 2006b.
[35] In economic theory, the general principle underlying efficient RES-E integration charging is that charges should reflect the different marginal costs and benefits to the electricity system at each node of RES-E connection. In practical discussions this is often called "marginal participation".

"Deep" integration charging: ideal versus real world

In general, deep RES-E integration charging approaches have the advantage of providing strong locational signals for new entrants. However, this approach – having been traditionally adopted by grid operators in the past – is far from uncritical. In practice there exist at least the following challenges:

- Although deep RES-E integration is characterized by favorable locational signals to new entrants, the computation of proper deep connection costs (and, subsequently, connection charges to RES-E generators) is very difficult because it is impossible to correctly foresee the future number of generators, the demanded connection capacity and choice of locations[36].
- Furthermore, assuming the case that the connection assets of a specific location are shared by more than one RES-E generator, the costs would also be shared, but as the assets would be quasi-public goods, efficient charges would not necessarily be the same for several new entrants at the same location if their willingness to pay is different.
- In almost all cases the situation described above is getting even more complex taking into account dynamics: RES-E connection applications are rather sequential in time than simultaneous. For sequential connection inquiries the first mover problem at a specific location is inherent, i.e. the critical question arises whether or not the first entrant shall be charged the full costs and encourage subsequent entrants to rebate some fraction (either by granting the right to the first entrant to charge successors, or calculating a charge for successors by the grid operator and rebating it to the first entrant).[37]
- Last but not least, there exists a strong concern about the deterrent effects on large-scale RES-E deployment in case of deep integration charging policies. Moreover, it also has to be taken care that this approach is not misused for non-eligible "cross-subsidies" flowing from the competitive generation segment to the regulated grid infrastructure part of the electricity supply chain. This would clearly violate the basic unbundling principle and, therefore, also undermine the legal framework of the EC-Directives trying to implement and establish a common internal European electricity market.

[36] Only in theory the grid operator can optimally plan the electricity grid and specify the location of each new entrant by setting corresponding location-specific and entrant-specific deep connection charges. In this ideal world the total collected connection charges from each entrant at each location would exactly add up to the total connection costs of several new RES-E generators.

[37] In general, RES-E generators and, therefore, also the first entrant are likely to be less well-informed than the grid operator about the connection capacity needed and corresponding costs. Moreover, the first entrant usually is not in a financial position to raise the capital to pay for more than its own grid connection. Therefore, from the first mover's point-of-view it is an advantage if grid operators charge for the cost of the connection in proportion to the use made of the different entrants. However, in this ideal case the grid operator faces the following risks: (i) subsequent entrants must arrive as predicted, (ii) the correct connection capacities must be chosen and (iii) the willingness to pay for connection of subsequent entrants must be similar.

"Shallow" integration charging: ideal versus real world

Although deep RES-E integration policies provide strong locational signals, recognition of the disadvantages of this approach has favored rather hybrid mechanism (incorporating elements of both deep and shallow charging) in the majority of EU Member States in recent years. Moreover, to fulfill the basic unbundling principles of the EC-Directives, further amendments towards shallow integration policies are expected in the context of RES-E integration in the near future, aiming to limit the connection assets attributed to the RES-E generator (e.g. up to the next voltage level). However, a shallow integration charge has to incorporate also location specific cost elements, otherwise a conflict of interests will arise between a RES-E generator wishing to connect a remote power plant - utilizing favorable resources - to the closest point of the existing grid infrastructure, on the one hand, and the respective grid operator favoring a connection point at which total network costs are minimized, on the other hand. This could lead the grid operator to delaying or obstructing connection in certain grid areas, which are regarded not to be cost-minimizing. The rejection of a RES-E connection/access inquiry can therefore be regarded as an extreme variant of setting locational signals in the shallow integration approach.

Compared to the deep integration charging approach, shallow integration charging has at least the following further advantages:

- Shallow RES-E integration costs and corresponding charges are presumably easier to define than those for the deep integration approach.
- The first mover problem disappears since the first entrant is expected to be charged only costs of the connection in proportion to the use made of it. Moreover, from the grid operator's point-of-view the risk of non-recoverable costs, which cannot be recovered from generators, in case of over-sizing connection capacity (e.g. for providing the basis for synergies for later RES-E connections at the same location) disappears since grid reinforcement and upgrading costs are socialized in the grid tariffs and, therefore, are directly borne by the network users.
- Previous arguments lead to the conclusion that barriers for entry are low in case of shallow integration policies, providing favorable framework conditions for large-scale RES-E deployment.
- Costs of capital are likely to be higher for RES-E developers than for regulated grid operators.[38] Subsequently, shallow integration policies can lead to lower overall integration costs: cost components for grid reinforcements and upgrades - being allocated to the grid operator and socialized in the grid tariffs of the network users in case of shallow integration - are not included in the financing costs of the RES-E power plant to be connected. This provides a strong argument against deep RES-E integration charging.

Finally, the shallow RES-E integration charging approach goes more in line with the unbundling principles of the EC-Directives than the deep approach.

[38] Mainly due to higher risk premiums and shorter depreciation periods the financing costs are likely to be higher for RES-E developers than for regulated grid operators. For example, RES-E generation facilities are depreciated in time horizons of 15-20 years whereas regulated grid operators depreciate their grid infrastructure assets in 30-40 years.

5. IMPACT OF EXOGENOUS VARIABLES ON TRANSMISSION INVESTMENTS: A CURRENT DEBATE

5.1 The exogenous variables: authorizations delays, public acceptance and financial markets confidence

5.1.1 Authorization procedures and public consensus

Europe is now following the path of liberalized electricity markets, leading to a single internal electricity market. The construction of overhead transmission lines and substations remains ultimately the responsibility of national electricity transmission companies. Their development has mainly been defined by the normal demand growth and the need to safeguard the security of supply to customers. Furthermore, the market liberalization process contributes to assign them additional importance as a fundamental instrument to facilitate electricity trade. Thus, the emerging single electricity market emphasizes the important role to be played by national authorities and regulatory bodies to promote new cross-border interconnection investments and deal with the public acceptance of the new projects, which often could have a non-negligible environmental impact.[39]

A general problem with any governmental assessment of proposed projects is that since network users pay for the regulated interconnector, it would however be fair that the most attractive (i.e., the most "welfare optimizing") alternative is selected. This does not only refer to the optimal site and capacity of a new link, but also relates to the broader evaluation regarding how society's money could be spent in the best way, including the estimation whether investments in other infrastructures could be preferred above new electricity transmission, as for example investments in gas transport or subsidies to stimulate market investments in renewable power generation (Hakvoort and De Jong, 2007).

Therefore, rising public objections to the building of overhead high voltage transmission lines and substations forces TSOs to adopt more sophisticated policies in seeking approval for new projects from national and local planning authorities and support from the affected publics. The dialogue with landowners, in particular, requires the presentation of detailed environmental studies, well-prepared public consultation meetings and face-to-face negotiations to identify acceptable compensations depending on the extent their property is affected by the new project: properly clarifying benefits and costs of new infrastructures is an essential must to create positive conditions in order to achieve the objective. **Therefore, the construction of a new transmission project could require a lot of time also due to unexpected authorization delays which could be tackled by setting procedural time-limits for unlocking delayed projects**.

In some cases it is possible to predict with some tolerance how long the permit process will last, including Environmental Impact Assessment (EIA) and appeals. However, the expected time span for licensing varies from country to country and from project to project (from 3 to

[39] Cf. Eurelectric (2003), *Public acceptance for new transmission overhead lines and substations*.

15 years) tending to increase as a result of public and political interest in projects. Objections to the construction of transmission lines can be managed effectively by developing the dialogue between the various stakeholders, and by a detailed environmental study confirming that the project satisfies the relevant international standards and EU Directives, but also showing benefits that such an investment could produce at the European level, in satisfying the European general interest of a better social welfare.

The current approach, mainly driven by the national regulators, delegates very few decisional powers at European level, contributing to generate delays and bottlenecks when tans-national investments are at stake. Indeed, national ministries, competition authorities and regulatory agencies frequently act without taking into account the common European interest, mainly because of this "regulatory gap" implying a certain degree of uncertainty that might significantly alter the return on investment and thus delay the project delivering (Kapff and Pelkmans, 2010).

The France-Spain interconnection represents a paradigmatic case study, showing the bottlenecks that investors may encounter and deal with: more than 15 year of delays, changes in planning, regulatory uncertainties and difficulties to obtain the public consensus. As far as the new line of the French-Spanish interconnection is concerned, the engineering project has been defined, but the works on site have suffered postponements. At present, it is expected that in 2014 there will be a gross capacity increase of around 2.000 MW. However, the capacity still remains under the target agreed by the European Council at the Barcelona summit of March 2002 (at least 10% of the production capacity installed in each Member State).[40]

One of the main sources of delays, as Eurelectric (2003) states, is the public acceptance which mainly depends to a great extent on the importance that the governing authorities ascribe to such needs. For this reason TSOs need detailed and exhaustive criteria on how developing the grid system, other than the national authorities support in getting approvals for the projects. These additional factors should contribute **in reducing delays which, as mentioned before, increase costs, creating negative incentive for generators to invest in new capacity**. Hence, changes in authorization procedures of new transmission infrastructures are suitable.

Today the problem is that the harmonization of authorization procedures cannot be reached at EU level, but only at national level first and then at cross-border level, between the involved countries. Moreover, a clear distinction between regulatory aspects (incentives) and planning problems should be made. From a planner point of view, existing regulation should be in charge of properly remunerating a specific priority project, either at internal or cross-border level. **The proposal of planning anticipation of transmission (respect to generation) could be taken into account (cf. par. 6.3)**.

The potential consequences of delaying or preventing needed investments in the transmission network are likely to be either the hindering of local, regional or national economic development or, in more severe cases, worsening the security of supply in specific areas,

[40] CNE (2010), *Spanish Energy Regulator's Annual Report to the EC*.

where the existing infrastructure becomes inadequate due to growing electricity demand or due to a new situation in the emerging liberalized electricity market.

Authorization procedures and timescales, while taking account fair concerns such as adequate time for the public or other stakeholders to register objections, should be balanced with a realistic appraisal of such impacts. Transmission system operators, national authorities including electricity regulators, relevant ministries and planning authorities at national, regional, and local level, are in charge of maintaining close interactions in order to ensure and foster the construction of new transmission projects.

5.1.2 TSOs and financial issues

Full harmonization of remuneration schemes for transmission is extremely difficult, as it requires changing high level regulation in most countries. Therefore, looking forward to a more harmonized regulatory environment, it should be necessary to operate by reducing the financial risk of transmission investment as much as possible, since uncertainty in investment cost recovery is presently a major deterrent to transmission expansion affecting directly the TSO credibility at the financial level, by reducing the financial market confidence.

TSOs are natural monopolies on the national level, but on the international financial markets they are like all the other actors, in competition to find loans and thus rely on the same financial market conditions. Equity and debt finance will only be available to utilities who agree to credit conditions posed to firms that operate in competitive industries and have a comparable credit ranking. Moreover, equity finance will only be available if profitability can be expected that covers the risk free rate of interest (i.e. yield of long term credible government bonds) and a risk premium.

Given the capital-intensive nature of electricity networks, the return on asset accounts a significant share of the allowed revenue and as relatively small changes to the rate of return can have a significant impact on the total revenue requirement and investment behavior of the companies, it is essential that the regulator sets the rate of return at a level that reflects an adequate commercial return for the regulated companies. As D. Dobbeni[41] stresses, regulatory uncertainties and low tariffs produce negative externalities on investments because they contribute to reduce the confidence of financial markets. The financial risk of transmission investment should be tackled as much as possible, since uncertainty in investment cost recovery is presently a major deterrent to transmission expansion.

The potential mismatch between the basis on which regulators determine allowed returns and the criteria used by financial markets in assessing alternative investment opportunities is perhaps the most important factor affecting future investments in utility infrastructure. So a key question is how regulators trade off the apparent short term “efficiency” in capital structures which results from gearing up against longer term robustness.

[41] President of ENTSO-E.

If on one hand, cross-border transmission investment incentives provided by Member States can take the form of direct subsidies, or indirectly of low-interest or interest-free loans; on the other hand, such selective aid measures risk being qualified as prohibited state aid. Regarding that, it is important to mention that aids for "important projects of common European interest" are compatible with the internal market in accordance with art. 107 (3-b) TFEU, showing thus that this derogation could be a way to follow. However, it is improbable that Member States will rely on such costly scheme because investments in interconnections typically generate positive cross-border externalities whose benefits are hardly collectable. For that reason, as the European Commission underlines, investment funding is better, but the existing gap in private financing should be bridged by making even more use of the EU budget than is currently the case today, by using innovative financial instruments, as European funds that could be used in partnership with the banking and private sectors, specifically through the European Investment Bank (EIB).[42] For projects of "European interest" which have no or poor commercial viability, innovative funding mechanisms should be proposed for maximum leverage of public support to improve the investment climate in order to cover the main risks or to speed up the projects implementation.[43]

What is possible is to establish that all lines/interconnections that are declared by ENTSO-E and/or ACER as priority lines have a guarantee of cost recovery and in some cases also economic incentives, such as an enhanced rate of return on investment as is presently done in the US following FERC rules.[44]A higher return on equity for projects of European interest could be matched with both the recovery of construction works in progress and of the abandonment costs, thereby facilitating proactive investments (Belmans, 2011).[45]

[42] COM (2010) 608 final, *Towards a Single Market Act. For a highly competitive social market economy.*
[43] COM (2010) 639 final, *Energy 2020: a strategy for competitive, sustainable and secure energy.*
[44] Cf. FERC, Order 679. Order 679 authorizes providers of transmission service to seek a range of non-exclusive incentives, including enhanced return on equity (ROE), inclusion of construction work in progress (CWIP) in rate base, hypothetical capital structures, accelerated depreciation, recovery of the costs of abandoned facilities, and deferred cost recovery. The Order also contains specific incentives for the formation of transmission-only companies ("Transcos") and RTO participation. Incentives are also available for projects using "advanced technologies."
[45] Cf. R. Belmans (2011), *Costs and benefits of interconnection Technical standards*, Workshop DG Energy-FRS: Identifying benefits and allocating costs for cross-border electricity and gas infrastructure projects.

6. POLICY RECOMMENDATIONS

Promoting investments in cross-border electricity networks, by incentivizing TSOs, represents a pan-European issue involving different actors at regional level. Today, the regulation still has a national dimension, and ACER, the role of which is to assist National Regulatory Authorities in exercising at Community level the regulatory tasks that they perform in the Member States and, where necessary, to coordinate their action, is not entitled to define new common rules. In this context, national interests often do not correspond with pan-European ones, creating a negative asymmetry which represents an important drawback against the development of a real European Internal Market, well interconnected and without an excessive amount of congestion.

A new regulatory approach balancing short-term and long-term interests is therefore necessary, to deal with the new important transmission investments that have to be urgently realized, in a context where vertical integrated firms do not exist anymore, and incentives as well as economic signals are radically changed.

In order to deal with these challenges, three main recommendations are presented here, aiming at providing a useful regulatory tool to better tackle the existing drawbacks and the well known inefficiencies. Since only what is measurable can be objectively taken into account by the regulation, a specific KPI comparing TSOs costs with system benefits is proposed, as well as a reform of the present Inter TSOs Compensation mechanism (ITC), and a radical change of TSOs' behavior by suggesting a proactive strategy in their investing activity. Finally, a kind of "hybrid model" is illustrated in order to promote some fundamental cross-border transmission investments.

6.1 Cost-benefit analysis and performance indicator for cross-border investments

In order to create the positive conditions for fostering cross-border network investments is essential that the TSO remuneration mechanism considers as a fundamental parameter the social surplus that will be created by the realization of the new projects. This estimation could be based on an *ex-ante* assessment of the social value generated by the capacity increase, but the problem is how calculating the social surplus and how establishing the optimal network expansion. In a meshed grid with difficulties due to the loop-flows - as the European one is - generation can be an alternative of network capacity expansion, and the "patchy" European market structure, which is still far from a homogeneous and harmonized design, could represent an additional drawback hard to overcome.

Furthermore, the new volatile generation and the expected "smart" demand will influence the electricity flows in a significant way, affecting the allocation of total network costs between generators and consumers. As Olmos and Pérez-Arriaga (2009) state *"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."*[46] For that reason, for promoting cross-border transmission investments, a cost-benefit analysis is essential in order to set an attractive incentives framework able to provide useful tools to identify the most efficient project.

This cost-benefit analysis (actually, one of the key topics of the project REALISEGRID, see D3.3.1 and D3.5.1), could constitute the basis for an incentivization factor that may contribute to highlight the transmission investment optimality. In fact, the optimal way to measure the economic viability of an investment, and consequently establish a "prize" for the entity that brought it, would be to estimate, on the basis of the actual market prices and transits on the new interconnector, what increase in the social welfare - and other benefits that can be translated into monetary terms - may actually be obtained over a certain period of time, following the entrance into service of the infrastructure.

This estimate could be derived from the costs of redispatching - or 'congestion uplift', as Léautier and Thelen (2009) call it - that would be avoided by the investment, even though the redispatching can be manipulated easily, as the involved generating companies typically have local market power.

However, all things considered, Léautier and Thelen (2009) consider reduction in congestion cost, when congestion is high, the best metric of the value of transmission expansion, despite there exist some weakness related to the fact that congestion may be impacted by factors others than grid expansion, as for example: possibly asymmetric load growth, fuel prices, availability of hydro-resources (when relevant), and generation capacity addition/withdrawal.

In fact, even congestion rents provide an indication of the marginal value of a link or path, the lumpiness of the investment does not contribute in signaling the full social value of a network upgrade that would require information regarding demand and supply curves. Moreover, the congested cross-border capacity is not always due to capacity limits on the interconnectors themselves: restrictions on import/exports may actually be motivated by capacity shortages within the connected national networks.

So, whereas import capacity auction revenues may signal a demand for more capacity, they do not necessarily signal where this capacity should be added. In addition, parallel explicit (flow-gate) auctions may distort price signals, as well as the existence of large parallel flows, which, in the current situation in Europe, do not increase congestion revenues but do contribute to the demand for network capacity. Finally, the hybrid structure of the European power market, with many vertically integrated firms combined with cross-border ownership of generation, creates a risk that incentive-based regulation of transmission be manipulated.[47]

Establishing the "optimal" network expansion is a very difficult task, and it appears to be even more complex for a large, meshed network where generation and network capacity expansion can be considered substitutes. Furthermore, the location of generation can change

[46] L. Olmos and I.J. Pérez-Arriaga (2009), p. 11.
[47] Cf. Léautier and Thelen (2009); De Vries, J. De Joode, R. Hakvoort (2009).

due to the fuel price differentials and to the development of renewables, showing how is difficult foreseeing the optimal network configuration over the life cycle of its assets: the upgrading of an existing transmission line takes several years and at least a decade is necessary for the construction of a new line.

Hence, transmission investment projects should be undertaken based on long-term that imply uncertain expectations of future demand. Otherwise, they may take place only after the demand for additional network capacity is manifest, but in this case demand will go unmet while the project is under development, which can be many years. Therefore, the only alternative to accepting a risk of excess investment appears to accept certain under investment.

Due to the significant amount of time elapsing between the decision of investing and the entrance in service of the infrastructure, tuning TSO incentives on the basis of "field measurements", possible only after the new infrastructure is put in service, would introduce a significant delay between the moment when the investment decision is taken and when the benefits are measured, with the risk to take into account a lot of non-foreseeable new elements that will become effective only after the investment decision was taken. Therefore, in our view it would be much fairer to calculate the advantages of the new infrastructure (in terms of difference between benefits and costs) at the time at which the investment decision is taken. This would be done by assessing, by means of two system simulations (one with the new infrastructure and one without), the impact of the new interconnector in terms of benefits minus costs. This indicator could constitute a KPI in percentage to which an increase in the return of investments of the TSO could be calculated.

Finally, ENTSO-E should enforce a pan-European tool to calculate costs and benefits in order to prioritize investments and replace a bottom-up collection of needed interventions from the single TSOs with a truly pan-European investments policy. This is in a long term period. By contrast, in the short period a direct financial involvement of ENTSO-E in single investments will stay out-of-scope (national TSOs will continue to carry out the investments autonomously). In fact, first of all national regulators should **recognize extra-territorial costs in their Regulatory Asset Base (RAB),** trying to fill up this regulatory gap. Then, such approach would contribute to minimize the TSOs' investment risk, promoting a wider regional framework. However, even if the coordination between national regulators represents an essential aspect to endorse cross-border investment, and the recognition of extra-territorial costs in the RAB could be an important step, a "proactive" European regulator seems to be the only way for better promoting pan-European interests. Looking forward to a positive evolution of the European regulation in a harmonized way, it is important to remark that there exist some tools that could be reformed (or better implemented) helping the incentivization of TSOs investing activity, as the ITC-mechanism.

6.2 ITC-mechanism and the European welfare: a new cost-reflective scheme for sending good incentives

The ITC (Inter-TSO Compensation) mechanism has been implemented in 2004 and, except some marginal adjustments, is still in operation. This system assumes a proportional allocation of responsibility in the utilization of the network of each TSO between transit and local flows. Besides, a proportional rule is assumed in the allocation of the responsibility for transits to net imports and exports, irrespective of the geographical location of the countries concerned. However, the mechanism does not cover all cross-border flows and is not based on a standardized approach to the network costs to be covered. Moreover, concerning new interconnections investments, the cross-border countries would draw no advantages as no generators/consumers would profit of the new infrastructure, but, by contrast, money has to be spent for it.

Currently, investments in grid expansion are not included in the ITC-mechanism and the fixed fund for infrastructure does not represent an incentive for new lines (as the contribution per line will be reduced by each new line) and by far too low to cover the real costs. This represents a market distortion as the additional cost for international power flows has to be paid by the national customers through tariffs, but **"transited" countries draw no benefit in paying for expanding their national transmission backbones in order to favor cross-border transactions for which they are neither the source nor the sink.** To correct this unequal treatment, the ITC-mechanism should cover actual infrastructure costs without cap. For these reasons, it could be envisaged a reform of the current mechanism - presently of marginal importance since it covers only operative costs and not infrastructure investment costs - **making ITC able to cover also investment costs, in order to allow the local TSOs of the crossed countries to retrieve money in proportion to the usage of the local networks.** These funds could be destined to reduce G and L tariff components, and, consequently to produce a local benefit for infrastructures that are otherwise only motivated at a pan-European level.

Such an approach would allow maintaining regional distinct cost allocation procedures, creating at the same time a standardized method for allocating costs between regions. Knowing that the construction of new interconnections aims at reducing losses costs (reducing network charges on overcrowded lines) and congestions costs, which represent the main grid operation costs, the investment charges should be shared, in principle, depending on the economic benefits that generators and loads would obtain from the existence of a new line. Regarding this, the **Average Participations (AP) method** - based on the assumption that electricity flows can be traced, or the responsibilities for causing them can be assigned - could be useful by supposing that, at any network node, the inflows are distributed proportionally between the outflows. This method contributes to identify, for each producer injecting power into the network, physical paths starting at the generator until they reach certain loads where they end. Symmetrically, the paths from the loads to the generators are also identified, and the cost of each line is allocated to different users according to how much the flows starting at a certain agent have circulated along the corresponding line.

However, because of the arbitrary allocation of total transmission charges between generators and demand customers, and the difficulties in estimating future benefits linked to the construction of a new network asset, the signals generated by the aforementioned charges are somehow arbitrary too. Besides, eventual succeeding generation or load asking to be connected will benefit of a network expansion that has been already paid, creating a cost asymmetry between market actors and thus, an alteration of the competitive equilibrium. In what measure the improvements to accommodate new generation have to be allocated to the generator itself or rather socialized is a well known regulatory issue (deep vs shallow cost allocation).[48]

For this reason, the present formulation of ITC, that significantly deviates from a truly cost-reflective scheme, doesn't send good incentives, and thus should be reformed by improving the mechanism with an *ex-ante* approach for the new infrastructures, based on a cost-benefit analysis, including both operative and long-term investments costs.

6.3 TSOs proactive behavior and its potential benefits on networks development

Before liberalization, transmission investments decisions were coordinated with generation capacity installation. Based on demand forecasts, governments chose to build plants of a certain fuel type or decided to contract long-term imports. Grid investments were selected in function of generation decisions, import needs and load locations.

In a liberalized market, transmission and generation investments are decoupled due to the unbundling, and grid investments are settled facing uncertain regulation and generation location. For that reason, the coordination between generation and transmission is more difficult today, considering also that investors are free to choose the generation technology. Furthermore, for developing cross-border interconnections, the regulation has to consider generation forecasts at the regional level, taking into account that reinforcements of an interface impact all the others, implying a significant change in the network investment approach: a foreigner TSO could be interested in promoting other TSOs investments abroad in order to avoid an internal one, and solving at the same time internal congestion problems.[49] Thus, regulation should take into account these new factors to avoid uncertainty in the network planning, and to evaluate if the generation capacity development should attract network investments or vice versa.

As previously highlighted (par. 5.1.1), delays and difficulties to obtain authorizations for building cross-border infrastructures represent a crucial issue. The length of the investment is an essential question that plays an important role in the definition of incentivization policies for fostering interconnections investments. The electricity market opening has prompted the

[48] Cf. D3.6.3 of Realisegrid Project and paragraph 4.4 of this Deliverable.
[49] For example, difficulties on the Belgian system often originate in French territory, and due to the weak North-South link in the German internal network Dutch and German TSOs reduce the available capacity on the Dutch-German in order to cope with any loop-flows.

generation investors to build mainly power plants needing short building time, such as the Combined Cycle Gas Turbine plants (Glachant, 2006), or wind farms (ETSO, 2007), which often require important network upgrading. In this way the time needed to build these reinforcements is much longer than the one needed for building the new power plants. Therefore, the regulation has to take into consideration this different investment time-span between networks construction and generation capacities installation. Regarding that, Rious, Glachant and Dessante (2010)[50] suggest a new TSOs strategy, proposing to anticipate the connections of these power plants in order to facilitate the development of the new installation capacities, minimizing at the same time the expected social costs, and contributing to the increase of market entries.

Therefore **the key issue is how regulation could stimulate a proactive behavior of TSOs**. The asymmetry of information between TSOs and regulators is still remaining a crucial point, and without adequate information, setting incentive criteria is a difficult task. Moreover, the interest of a TSO could be in maintaining congestion which represents an important temporary financial resource, in case the regulator is forced to set too low tariffs for satisfying political exigencies.[51] In order to avoid this eventuality it should be set a mechanism that valorizes the investment by ensuring the remuneration of the new enhanced asset base. However, two main challenges should be tackled:

- Reduction of the asymmetry of information between regulators and TSOs by improving transparency;
- Introduction of generation siting constraints considering that new RES power plants will be placed mostly far from the established fuel plants at the end of their life cycle, and typically far from loads. Moreover, today the generation capacities needs to satisfy the national load may be retrieved out of the national borders as well, making transmission planning more difficult.

To reduce time lost in authorization procedures and increase public consensus, the EC coordinators approach has proved successful and should be applied systematically. Fast tracks should be identified within the national legislations so that European priority projects could receive a preferential priority treatment.[52] As Rious, Glachant and Dessante (2010) state, a TSO should play in advance so as to reduce the gap between the time when new generation is installed and when the necessary infrastructure is operational. The evaluation of the probability that a new generator requesting the connection will really become operative is part of the TSO risk assessment, just like demand forecasting. Thus, the key issue is how evaluating the efficiency of the proactive behavior for a TSO from a social point of view, considering the cost of anticipation.

[50] V. Rious and J.M. Glachant (2010), *Transmission Network Investment as an Anticipation Problem*, EUI Working Papers – RSCAS 2010/04.
[51] Cf. (EC) Regulation 714/2009, art. 16 para. 6.
[52] Cf. COM (2010) 677/4, *Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network,* p. 14.

First of all, the connection of a generator to the grid is a probabilistic event because of market uncertainties and administrative delays and/or refusals.[53] Secondly, as mentioned before, the time interval between the generation (2 or 3 years for some technologies as CCGT and wind farms which stand for the biggest amount of generation investments in EU) and transmission (7 or even 10 years in Europe) investment can create congestion, implying costs affecting the social welfare. Therefore, a risk assessment is crucial, taking into account three essential parameters: the anticipating investment costs, the probability of connecting generators and the time difference for building such infrastructures; not neglecting that a proactive behavior could create a virtuous circle giving better information to market participants by signaling new opportunities to locate generation capacities.

This approach could be helpful to better deal with some uncertainties in an efficient and strategic way. However, the proactive behavior should be included in the regulatory framework through some incentive mechanisms encouraging TSOs to bear the risk. Again, to avoid inefficiencies or failures, the regulator has to mould the market design by a dynamic approach which implies to adapt regulation to the industrial development in a liberalized environment.

6.4 A hybrid solution to foster investments deployment

In order to preserve private capital financing to new big infrastructures, an alternative way to the merchant lines approach would be that big energy-consuming customers deliberately chose to financially support the investment of the TSO in new interconnectors with foreign countries. The new lines would actually be both built and operated by the TSO itself (thus not constituting a true example of "merchant investment") in exchange for a reduction of the obligations of possible interruption the big energy-consuming financers are subject to. In this way, the drawbacks coming from a possible lack of motivation in case of extraction of congestion rent or reduction of third party access due to capacity reservation are both avoided, while keeping the possibility to have the injection of private capital to finance new interconnectors.

This financing mechanism constitutes a kind of hybrid model where the regulated framework is kept, with some integration permitting to involve private funds. The private contribution to the investment may represent a good opportunity to accelerate the investment process, also by offering additional financial guarantees.

The Italian law 99/2009 constitutes a partial application of this scheme. However, in the Italian case, the third party exemption is retained too, additionally to the interruption-bound conditions for the energy consuming customers. Therefore, the scheme does not completely overcome the usual merchant investment approach.

[53] The duration of the administrative procedures required before the construction of a power line stands for almost three quarter of the construction time.

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