Network expansion by a proactive transmission system operator: A case study

Angelamaria Groppi[a], Elena Fumagalli[a,b,*]

[a] Politecnico di Milano, Department of Management, Economics and Industrial Engineering, Via Lambruschini 4B, 20156 Milano, Italy
[b] Centre for Research on Energy and Environmental Economics and Policy (IEFE), Department of Economics, Bocconi University, Milan, Italy

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1. Introduction

According to EC (2013) Green Paper, massive investments in transmission and distribution grids, which are necessary to complete the internal energy market, will also be crucial to accommodate the increasing share of renewable energy. ENTSO-E (2012a) in its Ten Year Network Development Plan (TYNDP) identifies the need to invest €104 billion in the refurbishment or construction of roughly 52,300 km of extra high voltage power lines clustered into 100 investment projects across Europe.

Transmission expansion has always been a complex task, also before liberalization, when the vertically integrated structure of the electricity sector favored a close coordination between generation and transmission planning. Under the current regime, as designed by Directive 2009/72/EC, a transmission system operator is responsible for operating and developing the transmission network while generation investment decisions are made by power producers (EC, 2009). Although this ensures that transmission upgrades take place in the interest of all network users, the lack of coordination between generation and transmission investments raises several problems.

First, transmission system operators are confronted with higher uncertainties in investment planning, as the de-integration of the traditional utility makes it difficult to obtain detailed information on the timing, magnitudes, and locations of new generating units, and of future load as well (Hirst and Kirby, 2001). Also, the future path of investments in generating capacity is difficult to predict on the basis of simple price signals (Benjamin, 2007; Rious et al., 2009). As a result, uncertainties affect network project assessments based on cost-benefit analyses and, indirectly, give an

* Corresponding author. Tel.: +39 02 2399 3968; fax: +39 02 2399 2710.
E-mail addresses: angelamaria.groppi@polimi.it (A. Groppi), elena.fumagalli@polimi.it (E. Fumagalli).

incentive to postpone transmission investments, until the risk of inaccurate planning is reduced (Buijs et al., 2011).[1]

Second, competition in generation pushes investors to faster planning, shorter deployment times and less sharing of sensitive information (Glachant, 2006). Instead, the regulated regime under which transmission companies operate, favors longer deployment times, capable to accommodate a "public" process (Hirst and Kirby, 2001). Indeed, developments in transmission networks in Europe appear to be severely hampered by long and complex administrative procedures (ENTSO-E, 2012b, 2010).

Uncertainties and delays are a common problem in the EU as well as in the USA. Comparing the projects identified in pilot TYNDP 2010, ENTSO-E's TYNDP 2012 finds that one in three European major planned investments are experiencing delays in implementation due to "longer than expected" permitting processes. Similar delays and siting difficulties are reported also for USA (see for instance The Brattle Group, 2009; Benjamin, 2007; Vajjhala and Fishbeck, 2007). According to several scholars and practitioners, one of the main reasons of the observed delays in transmission investments is related to local opposition phenomena (for instance, López-Rodríguez and Escribano-Bombín, 2013; ENTSO-E, 2012b, 2010; Buijs et al., 2011; Devine-Wright et al., 2010; Vajjhala and Fishbeck, 2007), and efforts have been made to enhance public acceptance (for instance, Ciupuliga and Cuppen, 2013; IEA, 2013; Cotton and Devine-Wright, 2012; Schneider and Sander, 2012; Sander, 2011). Nevertheless, the need to account for the environmental, social and economic impacts of transmission infrastructures unavoidably results in long investment processes (McLaren Loring, 2007).

In this context, Italy is no exception. Although the institutional setting provides solid incentives to network investments, the average time to complete a (major) transmission investment is 10 years, compared to the average five years necessary for a conventional generation investment. Indeed, this temporal mismatch appears associated with the complexity and the unpredictable duration of the public engagement process and of the administrative procedures.

The literature has proposed some solutions to ensure a higher coordination between transmission and generation investments. Among those, Rious et al. (2011) have suggested that a Transmission System Operator (TSO) adopts a so called "proactive" behavior.[2] A proactive TSO anticipates the planning process, before the generation connection becomes certain. On the one hand, anticipation exposes the TSO to the risk of sunk costs in case the new generation is not built. On the other hand, the system faces lower costs when the network is reinforced without a delay.

This paper contributes to this line of work. In particular, we test the efficiency of a proactive behavior on a real-life transmission project, the Trino–Lacchiarella power line (an ongoing network upgrade in the North of Italy). Using publicly available data, we construct a realistic, however simplified model of the area interested by the project. Then, we apply the methodology proposed by Rious et al. (2010, 2011), with some refinements and modifications. In particular, our model allows new generation capacity to be connected to the grid on an annual basis. This is a different, more realistic hypothesis than the one made in the original model, where a single generation unit was added in the first year and no further changes occurred on the supply side. In addition, we recall that Rious et al. (2010, 2011) tested the efficiency of anticipation for two fictitious cases (i.e., the connection of a Combined Cycle Gas Turbine – CCGT and of a wind farm), using a simple test grid with two nodes, while our model reproduces, albeit with some simplifications, a realistic network configuration. To the best of our knowledge, this is the first application of their methodology to an actual project, which could be easily replicated to other real investment projects as well.

Our results largely support the adoption of an anticipatory behavior and are consistent with those produced in previous studies. A proactive approach is more likely to be the efficient strategy when the delay between generation and transmission investments is expected to be significant (beyond six years) and/or when the cost of anticipation represents a modest portion (around 10%) of the total investment cost. They also highlight the effect on the efficiency of anticipation of additional parameters, besides those indicated in the literature (i.e., demand growth and the frequency of congestion).[3] Notably, the estimated social benefit of the proactive approach appears as large as the investment cost, for realistic transmission investment parameters.

Altogether, our results from the Trino–Lacchiarella case study support the implementation of a proactive behavior in case of complex transmission projects, as these normally present long and unpredictable planning processes. They also indicate that for a proactive TSO the quality of the public engagement process is crucial, as costs sustained in this activity significantly affect the efficiency of an anticipation strategy.

The rest of the paper is organized as follows. Section 2 analyzes the Italian institutional setting governing the process of transmission expansion. Section 3 reviews the relevant literature and introduces the methodology by Rious et al. (2011). Section 4 describes the model of the Trino–Lacchiarella project and Section 5 discusses the results of the case study. Concluding remarks and policy indications are presented in Section 6.

2. Transmission expansion and the case of Italy

Building on the work by Joskow (2006), Léautier and Thelen (2009) compared the level of grid expansion with the institutional arrangements of 16 different countries, i.e. with the degree of vertical separation and the steepness of the regulatory incentives for transmission investments.[4] They found that "vertical separation may be necessary, but it is not sufficient to induce grid expansion: a well-designed incentive scheme is also required" (Léautier and Thelen, 2009, p. 129). Incentives for expansion fall into two categories: financial incentives and contextual enablers. The former are reward and penalty mechanisms that link transmission revenues to an observable measure of congestion costs or to the level of investment.[5] The latter can play an important role in facilitating or delaying necessary transmission investments and are associated with the strength of the environmental constraints and/or with the structure of the planning process.

[1] In addition, generation expansion decisions may be affected by decisions on transmission expansion: a generation project may be initiated after the transmission project has commenced, potentially altering the financial assumptions used to justify the transmission project (Wu et al., 2006). Such interactions make the transmission expansion planning no longer a simple sequential process.

[2] Their proposal is grounded on previous, practical experience (e.g., Brattle Group, 2007; FERC, 2007).

[3] Congestion occurs on the transmission network when actual or scheduled power flows over a line or piece of equipment (e.g., voltage transformer) are constrained. These restrictions may be imposed by the physical characteristics of the individual line/transformer. More frequently, however, they are imposed by engineering reliability and contingency criteria that account for the entire electrical system (N-1, N-2, etc.).

[4] Vertical separation between generation and transmission creates superior incentives for socially optimal investments, with respect to the incentives found under vertical integration – in most regulatory regimes, increasing transmission capacity increases transmission profits, but it may also reduce generation profits (Léautier and Thelen, 2009).

[5] For a definition of congestion costs, see Section 3.

We interpret this as an indication that a well-designed planning process is required, together with vertical separation and financial incentives, to support socially optimal transmission investments. Following this line of thinking, we explore the institutional arrangements that, in Italy, govern transmission expansion.

2.1. The case of Italy: vertical separation and financial incentives

Italy introduced an ownership unbundling requirement ahead of the provision introduced by the Third Energy Legislative Package (EC, 2009). Since 2005, Terna is the owner and the operator of the national transmission network.[6] In this capacity, it is responsible for operating, maintaining and, if necessary, developing the transmission network.

In addition to ownership unbundling, in 2004 Italy adopted a regulatory regime where specific incentives directly promote investments in new transmission capacity (AEEG, 2012, 2008, 2005). This mechanism increases the allowed rate of return for investments in new transmission infrastructures, by means of an over-remuneration of the pre-tax Weighted Average Cost of Capital (WACC), with respect to the ordinary rate of return, for a period of 12 years. The over-remuneration is now subject to the compliance with intermediate milestones and a final deadline for the completion of the project. A set of indirect incentives also applies, by promoting Terna's performance in terms of expenditures on the Market for Ancillary Services, reduction of network constraints and increased quality of supply.

On the one hand, Terna seems to have positively responded to these regulatory interventions with a sharp increase in its investment rate: as illustrated in Fig. 1, it went from an average 7% before 2006 to 18% in 2010 (it was 14% in 2012).[7] This figure is well above the average investment rates measured across different transmission and distribution operators in Europe.[8]

On the other hand, the Network Development Plans (NDPs), annually elaborated by Terna, show that the expected delivery dates of several, relevant projects in new transmission capacity have been systematically postponed (Fumagalli and Groppi, 2011). In practice, a large temporal mismatch appears to exist between the identification of investment need and the delivery date of the necessary network reinforcement.

2.2. The case of Italy: the planning process

An investment process, in Italy as elsewhere, is composed of several steps.[9] As for Italy, when Terna identifies the need for additional transmission capacity, the new power line is included in the NDP, with only a general indication of its actual path and expected delivery date. At this point, several activities need to be completed, which can be divided in a concertation phase, an authorization phase and a building phase.[10]

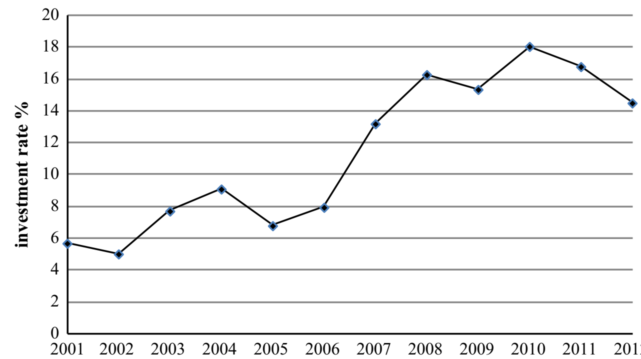

Fig. 1. Investment rate (capital expenditure in year N to total assets in year N-1), Terna SpA.
Source: own elaboration from Terna balance sheets

The objective of the concertation phase is to define the actual path of the power line. First, Terna characterizes the concerned territory using pre-defined criteria. Then, in cooperation with local authorities, the Italian TSO identifies a potential route corridor and a feasibility belt. Only at this point, the final design of the line is completed. The authorization procedure (ex Law 290/03) includes four relevant milestones: first, the Environmental Impact Assessment (EIA); second, a final and formal meeting with all the concerned public administrations (at national, regional and local level) which expresses a decision on the basis of a majority vote; third, the approval of the Regional authorities (which have veto power on the final decision); finally, the Ministerial decree of authorization. Only at this point the TSO can begin building the new power line.

After taking a sample of 15 major projects included in the NDPs in the last 10 years, we estimated in three years and a half the average duration of the concertation phase, in three years and a half the duration of the authorization process and in three years the time to build the power line. Altogether, the average time to complete a (major) project is about 10 years.

By contrast, a characteristic delivery time for a conventional generation investment in Italy (typically a CCGT) amounts to five years (Garrone and Groppi, 2010). In other words, the overall time needed to expand the transmission capacity is not only difficult to predict, but also typically greater than the time required by a generation investment to be completed.[11]

3. Transmission investments as an anticipation problem

The coordination problem that exists between generation and transmission investments in liberalized electricity markets has been explored in the literature using different approaches.

One stream of work focuses on possible solutions to the coordination problem itself. These include one-period problems where a decision criterion (e.g., present value of expected costs or social welfare) is used to select the best option for expansion, under a set of uncertainties (Roh et al., 2009). Real Option theory has also been advocated, in order to consider the possibility of either postponing or altering decisions in the future (van der Weijde and Hobbs, 2010). Finally, game theoretic approaches have been proposed, where the transmission investment decision accounts for the fact that network expansion will influence

[6] Terna's largest shareholder is the state-owned company Cassa Depositi e Prestiti (30%). The remaining shares are in the hands of institutional and retail investors.

[7] This indicator was calculated from Terna's balance sheets as the ratio of capital expenditure in year N to total assets in year $N-1$

[8] Cambini and Rondi (2010) estimated these values to be between 6% and 7%. They also found that investment rates of EU electric utilities are positively affected by the level of the regulatory WACC.

[9] For further details on Italy see Groppi and Pellini (2009) and Fumagalli and Groppi (2011). For other European countries we refer, for instance, to Schneider and Sander (2012).

[10] The term concertation refers to a dialog and co-decision process, involving all interested parties (or their representatives). It implies a mutual exchange of information and knowledge, an open discussion and confrontation, and the evaluation of different options, before finding a route of least impact for a necessary network upgrade (Ciupuliga and Cuppen, 2013).

[11] The Italian regulatory authority has also observed that, paradoxically, recent generation investments have often magnified the problem of transmission adequacy: several new power plants were located in areas where transmission capacity was already constrained (AEEG, 2009).

generation investments and market behavior (Sauma and Oren, 2006).

Another line of work has focused, more simply, on reducing the difference in times between generation and transmission investments. The solution indicated by this literature is that a TSO adopts a "proactive" approach, i.e. anticipates the connection of the new generator and takes a few actions even before such connection becomes certain.[12] As a result, the network is already upgraded when the new power plant is operative. In contrast, a "reactive" TSO would begin working on the network reinforcement only when the connection of the new power plant becomes certain. In this case, the delay between the generation and the transmission upgrade may create/increase congestion. Note that anticipation does not commit the TSO to invest if the network upgrade ceases to be necessary. In this case, anticipation represents a sunk cost.[13]

Under the implicit assumption that anticipation has no costs, Sauma and Oren (2006) showed that a proactive behavior is always more efficient, i.e. minimizes expected social costs. More realistically, Rious et al. (2011) considered that anticipation is costly and derive a methodology to assess, under this assumption, when a proactive behavior is more efficient.

3.1. *Assessing the efficiency of a proactive behavior*

The methodology developed by Rious et al. (2011) tests the efficiency of anticipation from a social perspective. It is based on the estimation of a social cost for the network upgrade, defined as the sum of network investment costs and congestion costs. Congestion costs are calculated as the difference between: (i) social welfare in the absence of any transmission constraints and (ii) social welfare in the presence of a given transmission constraint. Assuming, as we do in this paper, that the anticipated activities are part of a regulated company's costs, network users pay the cost of the investment via the network tariff, including the cost of anticipation. In turn, they will benefit from a welfare increase if congestion is reduced.

Rious et al. (2011) begun from the calculation of CW_y, the yearly congestion cost without the network upgrade (i.e., with more stringent transmission limits) and of CU_y, the yearly congestion cost with the network upgrade (i.e., with less stringent transmission limits). In their work they assumed that the inequality $CW_y \geq CU_y$ always holds.

Using these yearly values, the congestion cost for the period d (measured in years) prior to the upgrade, $CW(d)$, and the "residual" congestion cost for the period T, following the upgrade at year d, $CU(d, T)$, are estimated as follows:

$$CW(d) = \sum_{y=1}^{d} \frac{CW_y}{(1+a)^y} \text{ and } CU(d,T) = \sum_{y=d+1}^{d+T} \frac{CU_y}{(1+a)^y} \tag{1}$$

where T is fixed (and equal to 10 years) and a is the discount rate.[14] Note that Eq. (1) can be calculated for different values of d, to simulate different delays between the investment in generation and that in transmission. Also, it is assumed that costs saved by expanding the network as soon as the generator is connected are higher than the total investment cost, I

$$CW(T) - CU(0,T) \geq I \tag{2}$$

The expected social cost associated with a reactive behavior on the part of the TSO, $EC_R(p)$, is then

$$EC_R(p) = p\left(CW(d) + CU(d,T) + \frac{I}{(1+a)^d}\right) \tag{3}$$

where p is the probability of connection for the new generator. Also, Eq. (3) implies that when the generator does not connect, there are no network investment costs and congestion costs are null.

Similarly, the expected social cost for a proactive behavior, $EC_P(p)$, is

$$EC_p(p) = p(I + CU(0, d+T)) + (1-p)\alpha I \tag{4}$$

Eq. (4) implies that the network and the new power plant are ready to work at the same time ($d=0$). Note that the residual congestion cost after a network upgrade that occurs without delay, $CU(0,\ d+T)$, is calculated over the same period ($d+T$) as the congestion cost in Eq. (3). Moreover, the anticipation cost is expressed as αI (where α is a number between zero and one), i.e. the cost of anticipation is a share of the total investment cost.[15]

From Eqs. (3) and (4) and assuming a social cost perspective, it follows that a proactive behavior will be more efficient when: $EC_p(p) \leq EC_R(p)$. By considering the case of equality, Rious et al. (2011) defined a probability limit P_{lim} so that a proactive behavior is more efficient when the probability of connection p is greater than P_{lim} and vice versa. This has the following form:

$$P_{\text{lim}} = \frac{\alpha}{(1+a)^{-d} + \alpha - 1 + ((CW(d) + CU(d,T) - CU(0,T+d))/I)} \tag{5}$$

For a given anticipation cost αI, P_{lim} decreases with the delay d between generation and network upgrade (under easily verified assumptions). For a given delay d, P_{lim} increases with the anticipation cost.

Under the hypothesis of high congestion costs, Rious et al. (2011) showed that P_{lim} is expected to be low and favor a proactive behavior. Instead, under the hypothesis of low congestion costs, anticipation is not always the more efficient strategy.[16] Also in this case, however, anticipation is more efficient (i.e., a proactive behavior is efficient with a lower probability of connection) when anticipation costs are "low" and delays are "long".

In the next section we consider a specific, real-life project and apply the above described methodology to assess the efficiency of a proactive strategy.

4. Case study: the *Trino–Lacchiarella* power line

Our choice for an investment project is the 380 kV, 94 km long, overhead line Trino–Lacchiarella, connecting the transmission network node Trino, in Piedmont, to the node Lacchiarella, in Lombardy (hereinafter, TL line). The line was identified as necessary as early as in 2002 to reinforce the connection between the North West (NW, typically an exporting area) and

[12] These actions include engaging in a dialog with the concerned stakeholders and initiating the authorization procedures related to the investment project.

[13] In other words, the locational choices made by generators are assumed as given. This is consistent with empirical evidence on thermal power plants (Garrone and Groppi, 2012). The same is likely to apply to investments in renewable power plants, constrained in their location choices, by the availability of natural resources.

[14] The reference time for discounting is when the generation is connected (Rious et al., 2011).

[15] The cost of anticipation is assumed proportional to the investment cost because a power line which is longer and crosses a wider area will require more work in both the concertation and in the authorization phase. According to Rious et al. (2011), in assessing the efficiency the cost of anticipation might include also the cost born by the local authorities involved in the process.

[16] Their assumptions in this case are the following: there is no residual congestion after the investment, or $CU=0$; $CW(d)/I$ increases linearly with d; congestion costs before the investment are just high enough to justify the network upgrade.

Table 1
TL line: planning process.
Source: Terna NDPs

Milestone	*Time*
Evidence of the TL line in the NPD	2002
Concertation phase	2002–2008
Request for authorization (submission)	9 Dec. 2008
EIA (submission)	7 Apr. 2009
Positive EIA Decree	27 Jan. 2010
Final authorization	17 Nov. 2010
Expected delivery date	*2014*

the North East (NE, typically an importing area) of the North Zone.[17]

The TL line went through an unexpectedly long planning process (Table 1). Initiated in 2002, the concertation phase had initially been planned to be completed by 2006 and the delivery date for the project set for 2008 (Terna NDP, 2005).[18] However, the concerns raised by the communities affected by the new power line, as well as the local authorities involved in the process turned out to be particularly numerous. The latter included a total of 41 local authorities and institutional bodies: two Regions, three Provinces, 34 Municipalities and two Natural Parks. An agreement on the route corridor and on the feasibility belt was reached only in 2008 and the project delivery date was moved to 2011. A formal request for authorization was submitted to the competent Ministry at the end of 2008 and the delivery date moved forward, again, to 2012. After a positive outcome of the EIA in early 2010, the project was finally approved in November of the same year. Construction works started in 2011 and 2014 was set as, and it is still today, the expected delivery date. Should this expectation be confirmed, the whole project will have taken 12 years to be completed. Due to the plurality of administrations and technical bodies involved in the siting process, the TL line may be considered representative of similar complex projects planned to in the rest of Europe (ENTSO-E, 2012a).

In the following section, we build a simplified model of the portion of the electric system (i.e., network, load and generation) which has mostly been affected by the project, and we use this to calculate congestions costs. In Section 5 we employ these costs to test, in retrospective, the efficiency of a proactive behavior.

4.1. Network model

Our network model simplifies the actual grid configuration in the North Zone by considering a single interface between the NW and NE areas, as illustrated in Fig. 2. The winter Net Transfer Capacity (NTC) at the interface (in the direction NW to NE) is assumed equal to 4600 MW without the network upgrade and to 5100 MW with the network upgrade, where the additional 500 MW will result from building the TL line (Terna NDP, 2012).[19]

The analysis we plan to conduct requires the computation of congestion costs on the NW–NE interface for a period of 10 years after the network upgrade.[20] This means that, ideally, for both the NW and NE areas we would need data on load and generation patterns for each hour over the entire time span. Nevertheless, both areas belong to the same transmission Zone and neither supply nor demand data are currently available, in a separated form, from public sources. To limit the time devoted to data collection, each year in this case study is modeled against a single "reference" hour. Moreover, for the same reason, our analysis extends over a fixed period of time, from 2004 to 2013.

4.2. Load model

To estimate the load for the reference hour in each year, we relied on publicly available data, provided by the Italian Power Exchange (IPEX) and/or by Terna. Specifically, since IPEX provides historical data for each Zone and hour, we also needed a way to project these data over future years, as well as a methodology to separately estimate load in the NW and in NE areas.

In practice, as for the 2004–2008 period, we collected, from IPEX, hourly data for the third Wednesday of December, at 5 p.m. in each year (i.e., an expected congested hour, often coinciding with the winter peak). As for the years 2009–2013, we had two options: either to consider the load growth forecasted by Terna before 2008, or to look at actual data for 2009 and 2010 and then rely on forecasts from the same source. Because of the economic crisis, actual data for 2009 and 2010 differ significantly from historical projections (those available to a proactive TSO). In the end, we decided to consider two scenarios. Scenario 1, assumes a load growth of 2.4% per year, starting from 2008. Scenario 2 considers real consumption data for 2009 and 2010 and then assumes a revised growth rate of 1.9% per year for the period 2011–2013 (Terna NDP, 2011).

The load for the North Zone was then split between the NW area (20%) and the NE area (80%), in both scenarios. These percentages were derived using Terna statistics on yearly energy consumption per administrative Region for the years 2004–2010.[21]

Finally, demand was further modified by exports from neighboring countries and for exchanges with the Center-North Zone.[22]

As in Rious et al. (2010), demand is considered inelastic with respect to price, i.e. we only need its value in MW for each reference hour. These are the values illustrated in Table 2, for the NW and NE areas, over the whole time span, for both scenarios.

4.3. Generation model

Similarly, for generation data we relied on publicly available information, taken from either IPEX's website or Terna's NDPs. In this case, however, the collected data took a more complex form. Specifically, for each hour in a year, IPEX provides the supply bids (in price and quantity) submitted by all domestic production units on the Day-Ahead-Market (DAM), plus additional bids that represent exchanges with neighboring countries, bilateral contracts and offers from Renewable Energy Sources (RES).

We started from the reference hour in 2008 and (after a lengthy identification procedure) we were able to establish the zonal location

[17] The Italian electricity market employs a zonal model for the transmission network; the model currently includes seven national Zones, several "production-only" Zones and five Zones that represents neighboring countries.

[18] According to an earlier NDP, the estimated delivery time was 2005 (Terna NDP, 2003).

[19] In our simplified network structure France is fully interconnected to the NW, while Austria and Slovenia are fully interconnected to the NE. Exchanges with Switzerland are partially allocated to the NW (90%) and partially to the NE (10%). The NW and NE areas are also connected to the Center-North Zone.

[20] The costs avoided thanks to a transmission upgrade are generally calculated over a period of ten years. Beyond that, forecasts on load and generation behavior become highly uncertain.

[21] NW includes the Regions Piedmont, Val d'Aosta and Liguria; NE includes Lombardy, Veneto, Trentino Alto Adige, Friuli Venezia Giulia and Emilia Romagna.

[22] As for the latter, we made the assumption that when the North Zone imports from the Center-North Zone, then all the power flows in the NW area; vice versa, when the North Zone exports to the Center-North Zone, then all the power flows from the NE area. In a simple, yet realistic manner, this assumption accounts for the geographical location of all major production and consumption centers in both Zones. Accordingly, exports to the Center-North Zone were added to the load in the NE area.

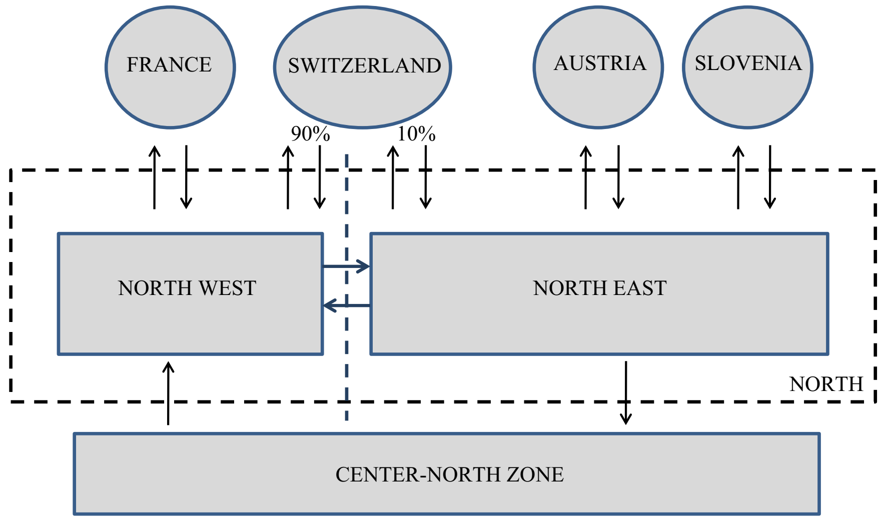

Fig. 2. Network model.

Table 2
Hourly load, 2004–2013, in MW.

Year	Scenario 1		Scenario 2	
	North West	*North East*	*North West*	*North East*
2004	5368	22,787	5368	22,787
2005	5383	23,091	5383	23,091
2006	5465	23,652	5465	23,652
2007	5443	24,034	5443	24,034
2008	5318	24,007	5318	24,007
2009	5447	24,588	4970	22,305
2010	5579	25,183	5186	23,215
2011	5714	25,792	5285	23,656
2012	5852	26,416	5385	24,106
2013	5994	27,056	5488	24,564

Table 3
Supply curve and demand for the reference hour in 2008.

Supply curve	*Price* (*€/MWh*)	*Quantity NW* (*MW*)	*Quantity NE* (*MW*)
	0	9909	10,214
	20	503	1819
	85	804	3168
	105	852	2056
	170	134	2701
	300	411	2517
Total supply[a]		*12,613*	*22,476*
Demand[b]		***5318***	***24,007***

[a] Total supply in the NW and NE zones.
[b] Demand for the same 2008 reference hour in the NW and NE zones.

Table 4
Total supply, 2004–2013, in MW.

Year	Scenario 1		Scenario 2	
	North West	*North East*	*North West*	*North East*
2004	11,868	22,209	11,868	22,209
2005	12,806	22,570	12,806	22,570
2006	12,518	22,529	12,518	22,529
2007	12,897	22,506	12,897	22,506
2008	12,613	22,476	12,613	22,476
2009	12,503	22,520	12,328	22,775
2010	12,411	22,565	12,140	22,881
2011	12,333	22,609	12,198	22,912
2012	12,301	22,654	12,578	22,943
2013	12,215	22,700	12,316	22,974

for all domestic bids.[23] From the bids belonging to the North Zone, we then built two separate supply curves for the NW and the NE areas, using additional geographic identifiers. Bids relative to bilateral contracts and production from RES were all aggregated in a zero price step of the supply curve and assigned to the NW or the NE, using a coefficient based on the generation distribution in the two areas. Imports from the Northern frontier were allocated to one of the two areas on the basis of the network model in Fig. 2 (and also priced at zero). Imports from the Center-North Zone were added to the supply curve in the NW area (always at zero price).

Finally, these two supply curves were simplified by aggregating bids in six price steps. Table 3 reports these values, together with the level of demand for the same hour, and shows a typical power flow from West to East.

Given the complexities encountered for 2008, supply curves for the previous and following years were more simply obtained by considering changes in installed capacity.

In Scenario 1 the growth of installed capacity reflects Terna's forecasts in 2008. In Scenario 2, quantities for the years 2009 and 2010 are actual values, while for 2011–2013 they are forecasts taken from Terna's NDP, 2011.

Table 4 provides a summary of total supply in each area and for both scenarios, accounting also for historical and projected modifications in imported quantities.

4.4. Congestion costs

For our case study, we started with the calculation of the congestion cost in the reference hour for each year (recall that we always selected a peak hour so that the interface was most likely congested). In line with Rious et al. (2011), this is the loss in social welfare due to the congestion. Accordingly, the hourly congestion cost, CC_h, was computed as the difference between the "unconstrained" social welfare, $W_{unc,h}$ (infinite NTC at the interface) and the "constrained" social welfare, $W_{c,h}$ (limited NTC at the interface)

[23] Assistance on this matter from the Energy Department (Politecnico di Milano) is gratefully acknowledged.

Table 5
Hourly congestion costs, 2004–2013, in €.

Year	Scenario 1		Scenario 2	
	No network upgrade	*With network upgrade*	*No network upgrade*	*With network upgrade*
2004	89,565	47,065	89,565	47,065
2005	162,063	81,185	162,063	81,185
2006	163,228	93,528	163,228	93,528
2007	221,189	141,701	221,189	141,701
2008	197,724	123,157	197,724	123,157
2009	158,927	102,502	73,245	20,187
2010	195,100	87,600	88,347	38,183
2011	250,007	142,507	110,866	63,952
2012	276,343	172,137	130,244	86,633
2013	229,806	129,918	125,409	82,909

for the reference hour, h, in each year. The hourly congestion cost is thus

$$CC_h = W_{unc,h} - W_{c,h} \tag{6}$$

where social welfare, W_h, is the sum of consumer surplus $S_{c,h}$, producer surplus $S_{p,h}$, and (when a congestion occurs) congestion rents, R_h, in the same hour

$$W_h = S_{c,h} + S_{p,h} + R_h \tag{7}$$

Social welfare W_h, was computed by finding the market equilibrium for the relevant hour, using the supply and demand curves previously described. For each hour, the constrained social welfare was calculated using the winter NTC, first without the network upgrade (4600 MW) and then with the network upgrade (5100 MW). As expected, for each hour, we obtained a higher congestion cost in absence of the network upgrade, and a lower congestion cost in presence of the network upgrade. Our results for all 10 reference hours in the 2004–2013 period are illustrated in Table 5, for the two scenarios.[24]

To estimate the annual values of the congestion cost we resorted to a simplified procedure. First, we estimated the number of hours that, in 2008, presented load and generation levels that were similar to those of the reference hour (i.e., those most likely to present congestion on the NW–NE interface). Then, we multiplied the hourly congestion cost in the reference hour by the estimated number of congested hours in 2008, NCH_{2008}.[25] For the remaining hours the congestion cost was assumed to be equal to zero ($W_{unc,h} = W_{c,h}$).[26]

As for all the other years in the observed period, we kept the number of congested hours fixed, i.e. we simply multiplied the hourly congestion costs in each year by NCH_{2008}.[27] To compensate for this simple assumption, in Section 5 we performed a sensitivity analysis on the number of congested hours.

Finally, we calculated the discounted, cumulative congestion costs over the observed period. In this regard, note that, for each value of d, congestion costs in both the reactive and the proactive approach must be calculated over the same time span ($d+T$). Calculating congestion costs on a different time frame for each TSO type (i.e., proactive and reactive) would introduce a bias in the results (Rious et al., 2011).

With regard to a reactive TSO, the cumulative congestion cost before the network upgrade, $CW(d)$, was calculated as in Eq. (1). Differently, in order to use Eq. (1) to calculate the residual congestion cost for the period T following the network upgrade, $CU(d,T)$, a modification was necessary to account for the availability of data. Instead of keeping T fixed and equal to 10 years as in Eq. (1), we kept $d+T$ fixed and equal to 10 years (our data cover only the period 2004–2013).

In case of a proactive TSO, there is no delay between the generation investment and the network upgrade ($d=0$). Also the residual congestion cost for the period T following the network upgrade, $CU(0,\ d+T)$, was calculated by making, in Eq. (4), the same modification as above. While in Eq. (4) $d+T$ increases as d increases (T is fixed and equal to 10 years), in our study $d+T$ is fixed and equal to 10 years.

For the same reason, we further assumed that a proactive TSO would have upgraded the network in the year 2004: this ensure that the residual congestion cost in the proactive approach, $CU(0,\ d+T)$, is always calculated over a period of 10 years. The year 2004 is also used as the reference time for discounting.[28]

Two last remarks regard the validation of additional hypotheses that are necessary in order to apply the methodology. First, it is true that the investment costs for the TL line justify the network upgrade (benefits associated with the network upgrade greater than related costs). In other terms, the inequality in Eq. (2) is verified. Second, we recall that Eq. (3) requires that, before the generator connects, congestion costs are null. To the best of our knowledge, this hypothesis holds also for our case study. Terna included the TL line in the 2002 NDP in view of the expected increase in generation capacity in the North Zone and not because congestion on the NW–NE interface was already a problem at that time. It follows that assuming 2004 as the optimal delivery time for the TL line, although not completely realistic (see Table 1), is nevertheless compatible with the absence of prior congestion costs.

5. Results for the case study

In this section we discuss the results of the case study. These are given in terms of the probability limit, P_{lim}, for the two load and generation scenarios described in Section 4. As indicated by Terna, the investment cost for the TL line is 315 million Euros. We assume a 2% discount rate and an anticipation cost of 10% of the overall investment.[29] The number of congested hours in 2008 is equal to 649 per year. Values of P_{lim} are derived using Eq. (5), for

[24] For the sake of clarity, in Appendix B we illustrate in detail the procedure for computing the hourly congestion cost in a generic year (2004 is taken as an example).

[25] To calculate the number of congested hour in 2008, NCH_{2008}, we estimated power flows on the relevant interface, for each hour in the year, using data from the DAM (this procedure is thoroughly explained in Appendix A).

[26] The same number of congested hours is used when calculating the congestion cost with the network upgrade, CU_y, and without the network upgrade, CW_y. Another possibility was to calculate the former using a lower number of congested hours per year. The assumption made is, however, conservative and avoids making uninformed conjectures.

[27] The reason behind this last simplification is that the NW–NE interface is located within a Zone. Differently from inter-zonal congestions, intra-zonal ones are resolved on the Market for Ancillary Services, where Terna purchases also capacity for reserve and balancing. For each hour and day, only the aggregated value of all Terna's transactions is available and no information can be extracted on the existence of an intra-zonal congestion.

[28] We recall that in Rious et al. (2011) the reference time for discounting coincides with the generator's connection. Differently, in our case study new generators connect to the grid over the entire period of observation.

[29] Two percent is the average market yield for 10-year Italian Government Bonds during the period under study. In other words, it is a measure of the risk-free rate. This choice reflects the idea that we are discounting future costs which are considered to be known ex-ante with certainty in our model. As such, the risk-free rate it's the appropriate discount rate to use. Nevertheless, since a variation in the discount rate can modify the results obtained for the probability limit, in Appendix C we report the values of the probability limit for two different discount rates (5% and 10%). For typical delays, we observe that the variation in the probability limit is relatively small. We thank an anonymous referee for suggesting this additional sensitivity analysis.

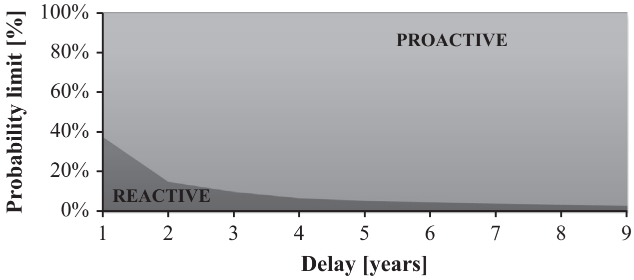

Fig. 3. Probability limit vs. delay – Scenario 1.

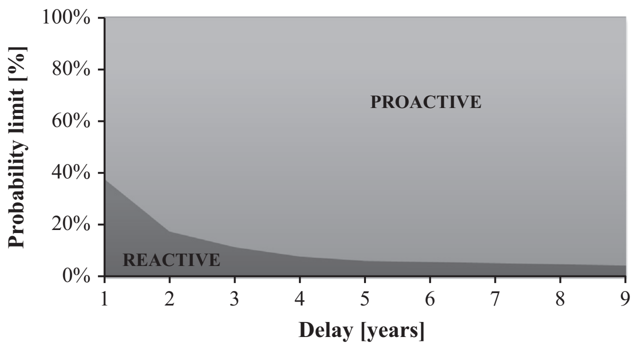

Fig. 4. Probability limit vs. delay –Scenario 2.

different delays in construction, d, with respect to the optimal delivery time for the network investment (2004). All estimated values for the probability limit are reported in Appendix C.[30]

In Figs. 3 and 4 the probability limit is plotted against different years of delay (from 1 to 9 years), respectively for Scenarios 1 and 2. Recall that when the probability of connection for new generation is above P_{lim}, a proactive behavior is more efficient than a reactive one and vice versa.

Our results are consistent with those obtained by Rious et al. (2010) for the connection of a CCGT power plant. As expected, P_{lim} decreases when d increases, indicating that a proactive approach is the most efficient strategy for lower probabilities of connection as the delay becomes larger. The probability limit is 38% for a one-year delay and it gradually decreases down to 3–4% for a nine-year delay. The two Scenarios lead to similar results, with Scenario 2 always producing slightly higher values of P_{lim}. This outcome is consistent with a proactive behavior being comparatively less efficient for a slower growth in load and generation patterns (and therefore lower congestion costs).

Note that most of the new generation capacity in the North Zone was connected to the network between 2006 and 2008: given the actual, expected delivery time for the TL line (2014), the average delay between generation and transmission upgrades will be six to eight years (Terna NDP, 2009). In this range of delays a connection probability greater than 6% would have made a proactive TSO more efficient in both scenarios. These values should be compared with an actual connection probability. Considering Terna's 2007 forecast for new thermal capacity over the period 2008–2011 (10,325 MW) and the actual capacity installed at the end of 2011 (8140 MW), we roughly estimate a 79% probability of connecting a new CCGT (Terna NDP, 2008–2012).[31] Thus, on the basis of the available data, we conclude that, despite the numerous simplifications introduced in the study, a proactive approach would have been certainly more efficient in the case of the TL line.

Table 6
Expected social benefit (EB), Scenario 2, delay 7 years, in €.

p (%)	**EB** (***p***) **[€]**	**EB/*I*** (%)[a]
0	−3,15E+07	−10,0
5	−1,42E+06	−0,5
6	4,59E+06	1,5
10	2,87E+07	9,1
25	1,19E+08	37,7
50	2,69E+08	85,5
75	4,20E+08	133,2
100	5,70E+08	181,0

[a] EB/I is the expected social benefit on investment cost ratio.

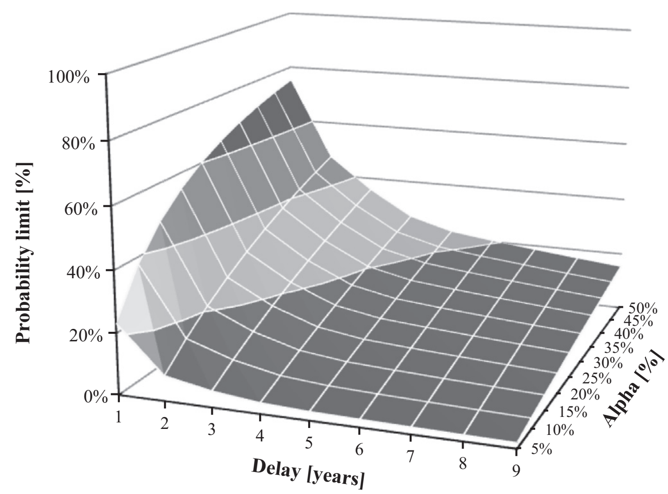

Fig. 5. Probability limit vs. delay vs. anticipation costs – Scenario 2.

In addition, we quantify the social benefit associated with the adoption of the proactive approach, as the difference between the expected social cost in the proactive and in the reactive case. Table 6 shows our results for different values of the probability of connection limit, given a delay of seven years, a typical time difference between transmission and generation investments (Rious et al., 2010; Buijs et al., 2011). Appendix D reports social benefits for two additional, extreme delay values (two and nine years). These benefits are compared with the investment cost (last column in Table 6). Notably, for a probability of connection greater than 50%, the social benefit of anticipation becomes higher than the investment cost. This outcome is not necessarily specific to the present case study: actually, it is expected to apply to transmission projects with similar benefit-cost ratios.[32]

To test the robustness of our results we performed a sensitivity analysis on two parameters: the anticipation cost share, α, and the number of congested hours in a year, *NCH*.

As for the anticipation cost, the analysis is motivated by the fact that information about this type of costs are difficult to find for real-life projects and the value of 10% of the investment costs was simply taken from the literature (Rious et al., 2010). Fig. 5 illustrates for Scenario 2 the change in P_{lim} with d, for an anticipation cost share that varies between 5% and 50% of the total investment costs.[33]

[30] They were estimated using the Microsoft Office Excel software package.

[31] Previous NPDs did not provide sufficient information to estimate the probability of connection on a longer time span.

[32] The TL line presents a benefit-cost ratio of 3.2 (Terna NDP, 2012). ENTSO-E has recently published a proposal on the adoption of a common methodology for performing Cost-Benefit Analyses of grid development projects (ENTSO-E, 2013).

[33] Christiner (2007) reported that anticipation costs can be as high as 40% of the investment cost.

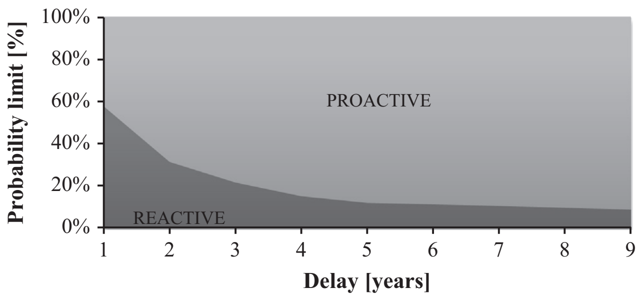

Fig. 6. Probability limit vs. delay, Case (a), 325 *NCH*, Scenario 2.

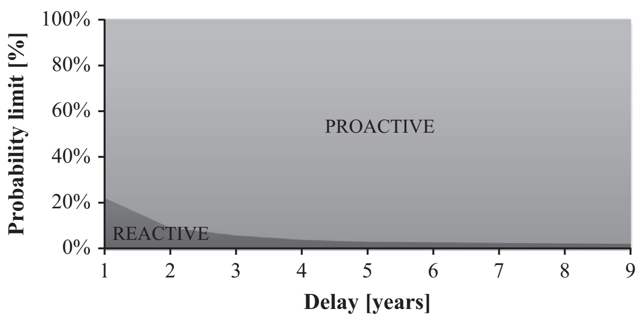

Fig. 7. Probability limit vs. delay, Case (b), 1298 *NCH*, Scenario 2.

Estimated values for P_{lim} always increase as α increases, especially when there are smaller delays (e.g. less than five years) between generation and transmission investments. Focusing on the worst case (Scenario 2) with a delay of seven years, the probability limit is 3% (α equal to 5%) and 22% (α equal to 50%). The efficiency of anticipation is thus confirmed also for higher anticipation costs. Note, however, that a variation in the anticipation costs has a significant effect on the value of the probability limit (as observed also in Rious et al., 2011).

To account for the uncertainty in the *NCH* in each year, we considered a Case (a) where *NCH* is half the 2008 value (325 h per year) and a Case (b) where *NCH* is double the 2008 value (1298 h per year). Results are illustrated in Figs. 6 and 7, only for Scenario 2 and for α equal to 10% (results for Scenario 1 are available in Appendix C).

As expected, in Case (a) the probability limit is always higher than in the base case, 11% for a realistic seven year delay. By contrast, in Case (b) the probability limit is lower with respect to the NCH_{2008} case and the probability limit decreases to 3% for a seven year delay. The efficiency of anticipation for the TL line is thus confirmed, for both a higher and a lower number of congested hours per year.

The effect of a change in the number of congested hours (which, in turn, affects the congestion costs) is consistent with previous observations regarding the effect of "high" and "low" congestion costs on the value assumed by the probability limit (Rious et al., 2011). In addition, our calculations provide a quantification of the actual changes that can be observed in practice and highlight the effect of the frequency of congestion on the costs of congestion (hence, on the value of the probability limit). Finally, from our results it appears that, at least for this case study (and delays of the order of six to eight years), the probability limit is highly sensitive to changes in the *NCH*, at least as much as it is to changes in anticipation costs.

6. Conclusions

Despite a well-designed institutional setting and a well-structured planning process, the average time to complete a (major) transmission project in Italy is not only difficult to predict, but also longer than the time necessary to complete a generation investment. This is a common problem for several, major transmission projects in Europe.

Among possible solutions to the coordination problem between generation and transmission investments, the proposal to anticipate the planning procedure seems particularly well suited to address the complexities that derive from the authorization procedures (in particular, the EIA) and the adoption of "collaborative planning" approaches.

This work tests the efficiency of a proactive planning behavior, using a real-life transmission project. We find that, given a typical delay of six to eight years, a connection probability above 6% would have made a proactive behavior the most efficient choice in the TL case. This is largely below the estimated connection probability for new CCGT capacity during the same period in Italy.

From a research perspective, our analysis adds to previous studies by assessing the role of an unpredictable change in forecasted demand growth and by testing the sensitivity of the results with respect to the number of congested hours in a year. While the unexpected variation in demand did not produce any major effect (thus providing robustness to the adoption of a proactive approach even in an uncertain context), a change in the number of congested hours was found to significantly influence the value of the probability limit. The latter is consistent with previous observations regarding the effect of higher and lower congestion costs on the value of the probability limit.

In terms of policy, the Trino–Lacchiarella case study is of general interest for several reasons. First, because the problems encountered in completing the transmission project are exemplary of the current difficulties faced by other European projects; in these cases, due to the complexity of the network upgrade, longer delays are to be expected between generation and transmission investments. Second, because results for the TL case indicate that also for a proactive TSO, the quality of the public engagement process is crucial, as costs sustained in this activity significantly affect the efficiency of an anticipation strategy. Third, because the case study highlights that social benefit associated with the adoption of a proactive approach can represent a significant portion of the whole investment cost, for realistic investment parameters. Finally, because it indicates that a realistic forecast of the frequency of congestion (hence, of the corresponding congestion costs) is crucial in the anticipation decision. In this regard, TSOs are in the best position (in terms of data, models and software) to provide the most accurate estimation.

Two last remarks regard open questions. First, in order to generalize our findings (in terms of efficiency and social benefit related to a proactive approach) similar, major projects should be tested. As of today, a growing number of demands for connection regard capacity from RES: further work should account for the typical connection probability of renewable plants. Second, we believe that, before anticipation is included in the regulated activities of a TSO, as assumed in this paper, specific rules and responsibilities should be worked out in further details. This is relevant to avoid bias in the allocation of cost and benefits arising from anticipation and to prevent opportunistic behaviors.

Acknowledgments

For helpful comments and discussions, we thank Pia Saraceno (ref – Ricerche per l'Economia e la Finanza), Matteo Di Castelnuovo and participants at the 34th IAEE International Conference (Stockholm, Sweden, 2011) and at the 4th Annual Conference on Competition and Regulation of Network Industries (Brussels, Belgium, 2011) where an earlier version of this paper was presented. For their valuable research assistance in the data elaboration we are grateful to A. Bonvini, A. Gabriele, F. Galluzzi, and C. Piazzese, students at the Department of

Energy (Politecnico di Milano). Two anonymous referees provided extremely valuable suggestions. The responsibility of any errors lies solely with the authors.

Appendix A

The approximate number of congested hours in 2008, NCH_{2008}, was calculated on the basis of a simplified network model with two areas, a North West (NW) and a North East (NE) area, each connected to its neighboring Zones, as in Fig. 2 in Section 4.

Information regarding hourly demand, supply as well as imports/exports for the relevant Zones was collected from the IPEX's website. Demand and supply in the North Zone were then allocated between the NW and NE areas, using the methodology described in Section 4. Similarly, imports/exports from/to neighboring countries and the Center-North Zone were assigned to each area using the same assumptions as in Section 4.

The flow on the NW–NE interface (in the direction West to East), $\Phi_{W\rightarrow E}$, was thus estimated from an energy balance equation for the NW area

$$F_{W\rightarrow E} = (G_{NW} + I_{CN} + I_{CB}) - (D_{NW} + E_{CB})$$

where

- G_{NW} is local production in the NW area;
- I_{CN} is import from the Center-North Zone to the NW area;
- I_{CB} is cross-border import to the NW area;
- D_{NW} is local demand in the NW area; and
- E_{CB} is cross-border export from the NW area.

Estimated flows for all hours in 2008 are illustrated in Fig. A.1. In particular, the flow from the NW to the NE in the reference hour (5 p.m. on the third Wednesday of December) results equal to 5687 MW. As expected, given an NTC of 4600 MW this is a congested hour.

Assuming, as in Section 4, the same hourly congestion cost for all congested hours in the year, we would underestimate the congestion cost for all hours with flows higher than 5687 MW and overestimate the congestion cost for all hours with flows above the NTC limit but below 5687 MW. Given the uncertainty on the estimation error, we made the conservative assumption (one that lowers congestion costs) to label as congested only the hours with a flow above 5687 MW in the NW to NE direction. With this assumption, NCH_{2008} results equal to 649 h per year.

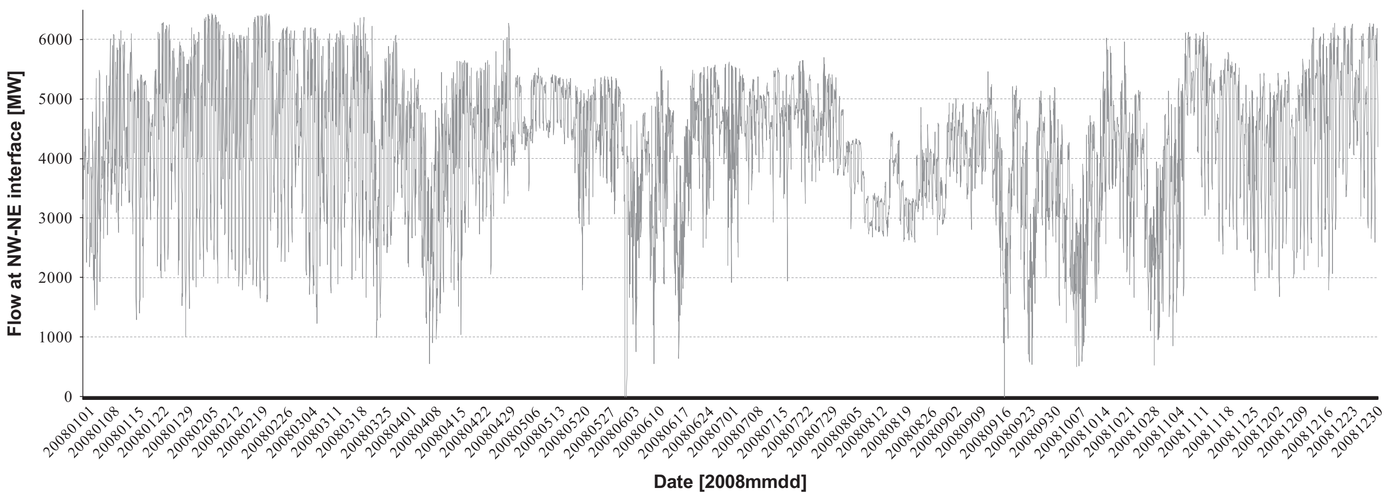

Fig. A.1. Estimated flows for each hour on the NW–NE interface, 2008.

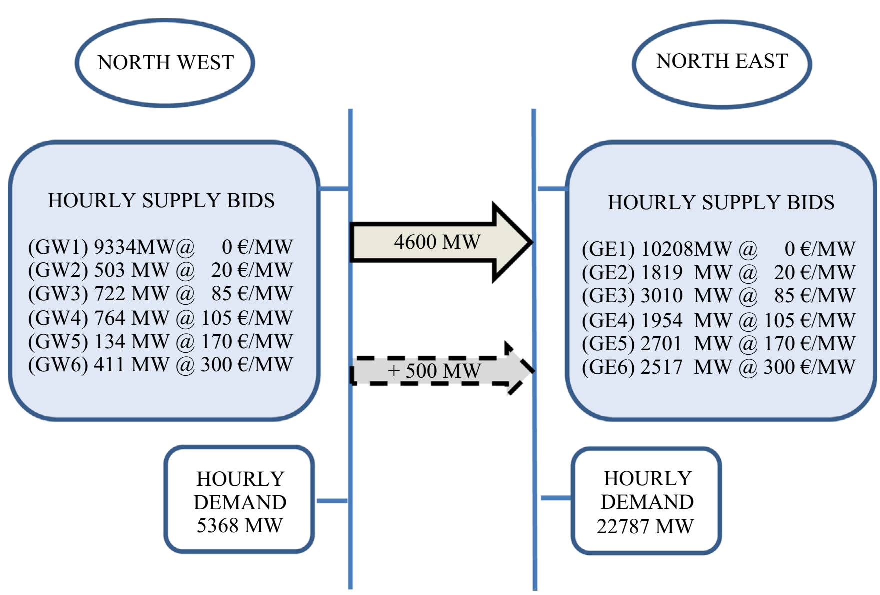

Fig. B.1. Market model, North zone, reference hour in 2004.

Appendix B

From an economic perspective, the common criterion for assessing the benefit of a transmission investment is its impacts on social welfare (for instance, Borenstein et al., 2000; Sauma and Oren, 2007). As for an electricity market, this is given by the sum of producer surplus, consumer surplus and congestion rents. Producer surplus is a measure of the utility that producers extract from selling a given quantity of electricity at the market price (revenues minus variable costs). Consumer surplus is a measure of the utility that consumers extract from purchasing a given quantity of electricity at the market price (the benefit that they extract from it minus the amount paid). In the case of a two-zone system (as the one considered in the paper), congestion rents (R) can be simply calculated as the price differential between the two zones times the power transferred across the congested interface. Clearly, congestion rents are different from zero only when the transmission limit is binding. Congested market equilibrium also presents a deadweight loss in social welfare with respect to an unconstrained equilibrium. This is the "congestion cost". Because congestion cost is normally reduced by a transmission upgrade, this reduction is often taken as a measure of the societal benefit of the transmission investment.

For illustration purposes, hereinafter we compute, step by step, the hourly congestion cost (CC_h) for the reference hour in the first year of our time span (2004). Fig. B.1 represents the market model for the North zone in the reference hour (hourly supply bids and inelastic hourly demand), along with the current net transfer capacity (in absence of the network upgrade) and the upgraded net transfer capacity, associated with the construction of the TL line.

Using the data reported in Fig. B.1 it is possible to calculate the market equilibrium in case of an infinite transfer capacity between the NW and the NE (the unconstrained case). As illustrated in Fig. B.2, the market clearing price is 105 €/MWh (see also Table B.1). The quantities produced by each generator in the reference hour (accepted hourly bids) are indicated in Table B.2. The power

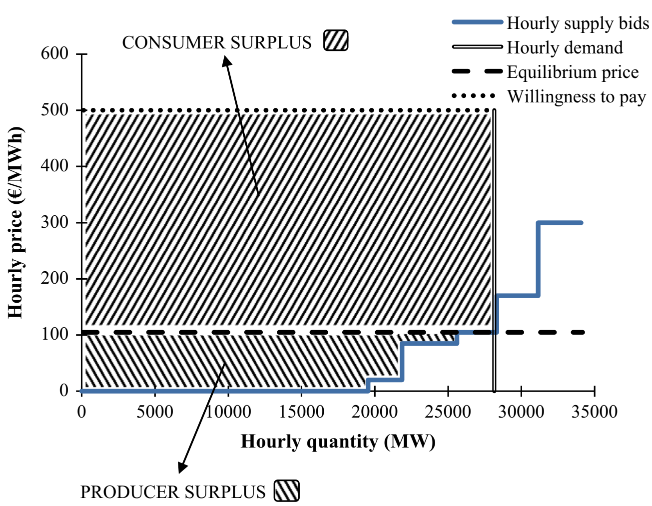

Fig. B.2. Unconstrained market equilibrium in the North zone, reference hour in 2004.

Table B.1
Market clearing price, in €/MWh.

	Equilibrium price	
	NW	NE
Unconstrained equilibrium	105	105
Constrained equilibrium – no transmission upgrade	85	170
Constrained equilibrium – with transmission upgrade	85	170

Table C.1
Probability limit for different delays and values of anticipation alpha, Scenario 1, *NCH* 649.

Delay (No. of years)	Alpha (%)									
	5	10	15	20	25	30	35	40	45	50
	Probability limit (%)									
1	23.3	37.7	47.6	54.8	60.3	64.5	68.0	70.8	73.2	75.2
2	8.2	15.1	21.1	26.2	30.8	34.8	38.4	41.6	44.5	47.1
3	5.3	10.0	14.3	18.2	21.7	25.0	28.0	30.8	33.3	35.7
4	3.5	6.8	9.9	12.7	15.4	18.0	20.3	22.6	24.7	26.7
5	2.8	5.5	8.0	10.4	12.6	14.8	16.8	18.8	20.7	22.4
6	2.4	4.7	7.0	9.1	11.1	13.0	14.8	16.6	18.3	19.9
7	2.1	4.1	6.0	7.9	9.6	11.3	13.0	14.6	16.1	17.6
8	1.8	3.5	5.1	6.7	8.3	9.7	11.2	12.6	13.9	15.2
9	1.5	3.0	4.4	5.8	7.1	8.5	9.7	11.0	12.2	13.3

Table C.2
Probability limit for different delays and values of alpha, Scenario 2, *NCH* 649.

Delay (No. of years)	Alpha (%)									
	5	10	15	20	25	30	35	40	45	50
	Probability limit (%)									
1	23.3	37.7	47.6	54.8	60.3	64.5	68.0	70.8	73.2	75.2
2	9.6	17.5	24.1	29.7	34.6	38.8	42.5	45.8	48.8	51.4
3	6.0	11.4	16.2	20.5	24.3	27.8	31.0	34.0	36.7	39.1
4	4.0	7.8	11.2	14.4	17.4	20.2	22.8	25.2	27.5	29.6
5	3.1	6.1	8.8	11.5	13.9	16.2	18.5	20.5	22.5	24.4
6	2.9	5.7	8.3	10.7	13.1	15.3	17.4	19.4	21.3	23.1
7	2.7	5.2	7.7	10.0	12.1	14.2	16.2	18.1	19.9	21.6
8	2.4	4.8	7.0	9.1	11.2	13.1	14.9	16.7	18.4	20.1
9	2.2	4.3	6.4	8.3	10.2	12.0	13.7	15.4	17.0	18.5

Table B.2
Accepted hourly supply bids, in MW.

	NW Generation[a]						NE Generation[a]					
	GW1	GW2	GW3	GW4	GW5	GW6	GE1	GE2	GE3	GE4	GE5	GE6
Unconstrained[b]	9334	503	722	685	0	0	10,208	1819	3010	1874	0	0
Constrained – no upgrade[c]	9334	503	131	0	0	0	10,208	1819	3010	1954	1196	0
Constrained – upgrade[c]	9334	503	631	0	0	0	10,208	1819	3010	1954	696	0

[a] Hourly supply bids accepted in North West and North East zones, respectively.
[b] Single one North market.
[c] North market split in two NW and NE markets.

Table C.3
Probability limit for different delays and values of alpha, Scenario 1, *Case (a)*: *NCH* 325.

Delay (No. of years)	Alpha (%)									
	5	10	15	20	25	30	35	40	45	50
	Probability limit (%)									
1	40.8	57.9	67.4	73.4	77.5	80.5	82.8	84.6	86.1	87.3
2	16.0	27.7	36.4	43.3	48.9	53.4	57.2	60.5	63.2	65.6
3	10.6	19.2	26.2	32.2	37.2	41.6	45.4	48.7	51.6	54.3
4	7.2	13.4	18.8	23.6	27.9	31.7	35.1	38.2	41.0	43.6
5	5.8	10.9	15.5	19.7	23.4	26.8	30.0	32.9	35.5	38.0
6	5.0	9.5	13.7	17.4	20.9	24.0	27.0	29.7	32.2	34.5
7	4.3	8.3	11.9	15.3	18.4	21.3	24.0	26.5	28.9	31.1
8	3.7	7.1	10.2	13.2	16.0	18.6	21.0	23.3	25.5	27.5
9	3.1	6.1	8.9	11.5	13.9	16.3	18.5	20.6	22.6	24.5

Table C.4
Probability limit for different delays and values of alpha, Scenario 2, *Case (a)*: *NCH* 325.

Delay (N. of years)	Alpha (%)									
	5	10	15	20	25	30	35	40	45	50
	Probability limit (%)									
1	40.8	57.9	67.4	73.4	77.5	80.5	82.8	84.6	86.1	87.3
2	18.7	31.5	40.9	47.9	53.5	58.0	61.7	64.8	67.5	69.7
3	12.2	21.7	29.4	35.7	41.0	45.5	49.3	52.6	55.6	58.1
4	8.2	15.2	21.2	26.5	31.0	35.0	38.6	41.8	44.7	47.3
5	6.4	12.1	17.1	21.6	25.6	29.2	32.5	35.5	38.3	40.8
6	6.0	11.4	16.2	20.5	24.3	27.9	31.1	34.0	36.7	39.2
7	5.6	10.6	15.1	19.2	22.9	26.3	29.4	32.3	34.9	37.3
8	5.1	9.8	14.0	17.8	21.3	24.5	27.5	30.2	32.8	35.1
9	4.7	8.9	12.8	16.4	19.7	22.7	25.5	28.2	30.6	32.9

Table C.5
Probability limit for different delays and values of alpha, Scenario 1, *Case (b)*: *NCH* 1298.

Delay (N. of years)	Alpha (%)									
	5	10	15	20	25	30	35	40	45	50
	Probability limit (%)									
1	12.5	22.2	30.0	36.4	41.7	46.2	50.0	53.4	56.3	58.9
2	4.1	7.9	11.4	14.7	17.7	20.5	23.1	25.6	27.9	30.1
3	2.6	5.1	7.5	9.7	11.9	13.9	15.8	17.7	19.5	21.2
4	1.7	3.4	5.1	6.6	8.1	9.6	11.0	12.4	13.8	15.1
5	1.4	2.7	4.1	5.3	6.6	7.8	9.0	10.1	11.2	12.3
6	1.2	2.4	3.5	4.6	5.7	6.8	7.8	8.8	9.8	10.8
7	1.0	2.0	3.0	4.0	4.9	5.9	6.8	7.7	8.5	9.4
8	0.9	1.7	2.6	3.4	4.2	5.0	5.8	6.6	7.3	8.1
9	0.7	1.5	2.2	2.9	3.6	4.3	5.0	5.7	6.3	7.0

transferred on the NW–NE interface is 5796 MW (demand in the NE minus accepted generation bids in the NE).

Social welfare is the shaded area in Fig. B.2, i.e., the sum of producer surplus ($S_{p,h}$) and consumer surplus ($S_{c,h}$); there are no congestion rents (R_h). Two observations are in order. First, we assume that supply bids for generators are representative of their marginal costs (as in a perfectly competitive market). Second, consumer surplus is computed using an arbitrary ceiling price of 500 €/MWh (demand is perfectly inelastic), which represents

Table C.6
Probability limit for different delays and values of alpha, Scenario 2, *Case (b)*: *NCH* 1298.

Delay (N. of years)	Alpha (%)									
	5	10	15	20	25	30	35	40	45	50
	Probability limit (%)									
1	12.5	22.2	30.0	36.4	41.7	46.2	50.0	53.4	56.3	58.9
2	4.8	9.2	13.2	16.9	20.2	23.3	26.2	28.9	31.4	33.7
3	3.0	5.8	8.5	11.0	13.4	15.7	17.8	19.9	21.8	23.7
4	2.0	3.9	5.8	7.5	9.2	10.9	12.5	14.0	15.5	16.9
5	1.5	3.0	4.5	5.9	7.3	8.6	9.9	11.1	12.4	13.6
6	1.4	2.8	4.2	5.5	6.8	8.0	9.2	10.4	11.6	12.7
7	1.3	2.6	3.8	5.1	6.3	7.4	8.5	9.6	10.7	11.8
8	1.2	2.4	3.5	4.6	5.7	6.8	7.8	8.8	9.8	10.8
9	1.1	2.1	3.2	4.2	5.2	6.2	7.1	8.0	9.0	9.9

Table C.7
Probability limit for different delays and discount rates, Scenario 1, *base Case* (*NCH 649*), *Case (a)* (*NCH 325*) and *Case (b)* (*NCH 1298*).

Delay (N. of years)	Discount rate (%)								
	NCH 649			NCH 1298			NCH 325		
	2	5	10	2	5	10	2	5	10
	Probability limit (%)								
0	100	100	100	100	100	100	100	100	100
1	38	42	52	22	24	26	58	69	99
2	15	17	20	8	8	9	28	33	47
3	10	11	14	5	6	6	19	23	34
4	7	8	10	3	4	4	13	16	24
5	5	6	8	3	3	4	11	14	20
6	5	6	7	2	3	3	10	12	19
7	4	5	6	2	2	3	8	11	17
8	3	4	6	2	2	2	7	9	15
9	3	4	5	1	2	2	6	8	13

consumers' willingness to pay. The choice is arbitrary because this value cancels out in the calculation of the congestion cost.

Accordingly, social welfare for the reference hour in the unconstrained case is as follows

$$W_{unc,h} = S_{p,h} + S_{c,h} = (2,323,920 + 11,121,225)€ = 13,445,145€$$

We consider now two constrained cases, respectively without and with the network upgrade, and proceed in the same way: first find the market equilibrium and then calculate producer surplus, consumer surplus and congestion rents (now different from zero). Equilibrium prices for the constrained cases are given in Table B.1. Table B.2 reports the hourly production for all generators (accepted hourly bids). The power transferred on the NW–NE interface is 4600 MW without the upgrade and 5100 MW with the upgrade.

In the absence of the network upgrade we obtain

$$W^{W}_{c,h} = S_{p,h} + S_{c,h} + R_h = (3,217,155 + 9,747,430 + 391,000)€ \\ = 13,355,585€$$

where $W^{W}_{c,h}$ is the constrained social welfare in absence of the network upgrade. Note that producer and consumer surpluses are computed separately for the two zones, using their respective zonal prices.

Similarly, in the case of the network upgrade, we obtain

$$W^{U}_{c,h} = S_{p,h} + S_{c,h} + R_h = (3,217,155 + 9,747,430 + 433,500)€ \\ = 13,398,085€$$

Table C.8
Probability limit for different delays and discount rates, Scenario 2, *base Case* (*NCH 649*), *Case (a)* (*NCH 325*) and *Case (b)* (*NCH 1298*)

Delay (N. of years)	Discount rate (%)								
	NCH 649			NCH 1298			NCH 325		
	2	5	10	2	5	10	2	5	10
	Probability limit (%)								
0	100	100	100	100	100	100	100	100	100
1	38	42	52	22	24	26	58	69	99
2	17	20	24	9	10	11	32	39	59
3	11	13	16	6	6	7	22	27	43
4	8	9	11	4	4	5	15	19	30
5	6	7	9	3	3	4	12	15	24
6	6	7	9	3	3	4	11	15	25
7	5	6	8	3	3	4	11	14	25
8	5	6	8	2	3	3	10	13	24
9	4	5	7	2	2	3	9	12	23

Table D.1
Expected social benefit (EB), Scenario 2, delay 2 years, in €.

p (%)	**EB (*p*) [€]**	**EB/*I* (%)**[a]
0	−3,15E+07	−10,0
5	−2,25E+07	−7,1
10	−1,34E+07	−4,3
20	4,60E+06	1,5
25	1,36E+07	4,3
50	5,88E+07	18,7
75	1,04E+08	33,0
100	1,49E+08	47,3

[a] EB/*I* is the expected social benefit on investment cost ratio.

Table D.2
Expected social benefit (EB), Scenario 2, delay 9 years, in €.

p (%)	**EB (*p*) [€]**	**EB/*I* (%)**[a]
0	−3,15E+07	−10,0
4	−2,47E+06	−0,8
5	4,79E+06	1,5
10	4,11E+07	13,0
15	7,74E+07	24,6
20	1,14E+08	36,1
25	1,50E+08	47,6
50	3,31E+08	105,2
75	5,13E+08	162,8
100	6,94E+08	220,4

[a] EB/*I* is the expected social benefit on investment cost ratio.

where $W^U_{c,h}$ is the constrained social welfare in case of the network upgrade.

Finally, the hourly congestion cost is derived as follows:

$$CC^W_h = W_{unc,h} - W^W_{c,h} = 89,560€(\text{without network upgrade})$$

$$CC^U_h = W_{unc,h} - W^U_{c,h} = 47,060€(\text{with network upgrade})$$

The same values are reported in Table 5 for the reference hour in 2004.[34]

[34] All numbers used in this example are rounded. This might create minor discrepancies with the figures given in Table 5.

Appendix C

See Tables C1–C8.

Appendix D

See Tables D1 and D2.

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