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Generation Capacity Expansion with CO_2 Emission and Transmission Constraints in an Oligopolistic Market

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Abstract: The European Union is committed to cut Greenhouse Gas emissions (GHGs) by 30% of 1990 levels by 2020; other countries are committed to make similar reductions under a global agreement. Some technical options are available on the supply side, to reduce GHG and other harmful emissions by the power sector. Therefore, it is important to analyze what type of power generation technologies will be chosen by companies under different CO_2 mitigation targets. Several models look into Generation Expansion Planning in oligopolistic markets; however, they do not consider the impact of CO_2 reduction targets and the transmission constraints together. This study presents a Generation Expansion planning model with transmission constraints for analyzing the implications of CO_2 emission mitigation constraints for investment decisions in oligopolistic electricity markets. The results of the model are presented with reference to the Italian power sector, responsible for 32% of national CO_2 emissions.

Keywords: CO_2 capture and storage, cournot model, generation expansion planning, GHG mitigation, oligopolistic market

INTRODUCTION

Recently, various methods have been developed to model the strategic behavior of participants in the electricity market; they are based on different factors such as price, quantity and supply functions. In Day *et al*. (2002), Song *et al*. (2003) and Zhang *et al*. (2008) modeling has been done using the Conjectured Supply Function (CSF) method, which tries to predict the behavior of competitors building price and conjectural values from the historical data. This method, like any other algorithm based on historical data, has the drawback of late adaption to the new changes occurring in the market. Papers (Green and Newbery, 1992; Green, 1996; Rudkevich, 1999; Baldick *et al*., 2004) apply a Supply Function Equilibrium (SFE), more capable of handling real cases; however, in this model, all reactions of rivals are predefined and there is the possibility that multiple equilibrium or even no solution at all occur. The Cournot strategy (Kreps and Schneikman, 1983; Younes and Ilic, 1999; Hobbs and Helman, 2004), although suffers from neglecting the supply function of competitors, still seems to be more flexible than its counterparts and has the ability to adapt itself to long-term competitions (Younes and Ilic, 1999).

However, the significant growth of Greenhouse Gas (GHG) emissions from the power sector has led policy makers to engage in a wide ranging debate over different GHG mitigation polices. Number of technical options exists for reducing GHG and other harmful emissions from the power sector. These can be divided into two groups: supply and demand-side options. Among these two options, the greatest potential for large-scale cuts is expected to come from supply-side options.

While there exist several models that look into Generation Expansion Planning (GEP) in oligopolistic markets (Murphy and Smeers, 2005; Pineau and Murto, 2003; Rudkevich, 1999; Chung *et al*., 2001; Lise and Kruseman, 2008; Abeygunawardana *et al*., 2010; Kaymaz *et al*., 2007; Nanduri *et al*., 2009; Linares *et al*., 2006), few models (Lise and Kruseman, 2008; Abeygunawardana *et al*., 2010; Linares *et al*., 2006) take into account environmental considerations, e.g., CO_2 prices. Most of these models assume that firms make their GEP decisions according to the Cournot model. On the contrary, Nanduri *et al*. (2009) adopts a parameterized supply function competition to represent power market bidding, but it has been applied for a very simple system and scalability of the model for larger systems has not been addressed.

In the present study, not only the last two issues-namely, price of carbon and large size of the system-are considered but also the proposed model deals with transmission system constraints (different from Abeygunawardana *et al*. (2010)), since they can dramatically impact on the GEP. As the generation

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expansion may lead to adding or relieving congestions in transmission lines, which consequently can affect the zonal prices, it is very important to include the transmission network representation in the GEP model. The main purpose of this study is therefore to develop an oligopolistic GEP model for analyzing generation investment decisions under different CO_2 reduction targets, taking into account both the transmission system constraints and the presence of bilateral contracts among some market players, in addition to the pool market mechanism.

The model proposed in this study can also be used to analyze the long-term implications of different GHG mitigation policies like emissions trading and carbon tax. An application to the Italian electricity market illustrates the capabilities of the model for analyzing the long-term implications of the European Union Emissions Trading Scheme (EU ETS). Although, there are number of supply-side options to mitigate GHG emissions from the power sector, the greatest potential for large-scale cuts is expected to come from deployment of CO_2 Capture and Storage (CCS). Therefore, in this study, we place special emphasis to analyze how the CO_2 prices that emerge from the EU ETS would help to promote Clean Coal Technologies.

GEP model with transmission and CO_2 emission constrains: The GEP problem goal is to define the generation technology options to meet the growing energy demand over a planning period, their location and the time they should be put in service. In centralized electricity markets, the GEP is typically studied as a least cost expansion plan. However, in the deregulated framework, some models have been proposed for studying the investment decisions by generating companies in oligopolistic electricity markets, taking into account either environmental constraints (particularly, CO_2 emissions) or physical transmission limits that impact on electricity prices and quantities. The Cournot game for representing oligopolistic electricity markets is often adopted (Murphy and Smeers, 2005; Pineau and Murto, 2003; Rudkevich, 1999; Chung *et al*., 2001; Lise and Kruseman, 2008; Abeygunawardana *et al*., 2010; Kaymaz *et al*., 2007).

The GEP model proposed in this study differs from the classic Cournot model in that it incorporates both CO_2 emission costs and transmission constraints, through the differentiated nodal prices; moreover, it is applied to a real electricity system and market, where also bilateral contracts are taken into account.

In this model, the equilibrium of the market is obtained by writing, for each market subject, its own objective function and constraints; all the optimality Karush-Kuhn-Tucker (KKT) conditions for all subjects and the market clearing conditions are solved simultaneously and result in the market equilibrium point. In the following subsections, the models adopted are presented and discussed. The main output of the model is the GEP for each firm, i.e., the amount of thermal new capacity installed x_{fn} and the year of installation vn_{fn}, given the current set of installed generators and the already-defined planning of some new generation units; this GEP gives also as a byproduct the expected behavior of the electricity market (nodal prices and quantities).

The model of generation firms: The market clearing mechanism here considered is the centralized bidding process supervised by an Independent Market Operator. The market is modeled for T years. Each year t can be divided into periods (e.g., seasons) and load levels (e.g., peak hours, off-peak hours, etc.). In general, LB_t load blocks during year t are assumed.

The price in each load block b of every node i is modeled as a linear function of the net quantity at that bus:

$$p_{itb} = p_{itb}^{0} - \varepsilon_{itb}(q_{itb} - q_{itb}^{0}), \quad \forall i,t,b \tag{1}$$

The goal of each generating firm f is to maximize its profit by strategically deciding both its production pattern in the short-run and its investments on new capacity in the long-run. The profit of firm f is given by sales minus costs for the following set of plants and for the time horizon T: existing thermal (PE_f), hydro (PH_f), pumped storage (PPM_f), already committed plants (i.e., not considered as variable for the GEP; PC_f), new thermal plants (defined by the GEP solution; PEN_f); capital costs (SC_f) and salvage (FS_f) are considered.

Among the costs, it is important to take into account the EU ETS mechanism to achieve the EU GHG emission reduction targets. Generating companies are exposed to the impacts of the EU ETS. It would be very hard to directly include the CO_2 market mechanism in the Cournot-based GEP model, because CO_2 prices:

- Are determined not only by electricity markets but, e.g., also by the flexible mechanisms set up within the Kyoto protocol (Clean Development Mechanism and Joint Implementation) that are international and inter-continental tools
- For what electricity markets are concerned, they are determined, of course, not only by the Italian electricity market, but also by the different national implementation of electricity markets in all the European Countries involved

This is because it would be very difficult to model the interactions among such different markets to include them in the GEP model. Therefore, we choose to give the CO_2 price Pc_t exogenous to the model.

For the generation firms, the optimization model is:

$$\max\left[PE_f + PH_f + PPM_f + PC_f + PEN_f - SC_f + FS_f\right]$$

where,

$$PE_f = \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} \sum_{e=1}^{E_f} B_{tb}(p_{fitb} - MCE_{fe} - Pc_t EE_{fe})\, qe_{fetb}$$

$$PH_f = \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} \sum_{h=1}^{H_f} B_{tb}(p_{fitb} - MCH_{fh})\, qh_{fhtb}$$

$$PPM_f = \sum_{t=1}^{T} D_t \sum_{b=1}^{LB_t} \sum_{p=1}^{PM_f} B_{tb}(p_{fitb} - MCPM_{fp})\, qpm_{fptb}$$

$$PC_f = \sum_{c=1}^{C_f} \sum_{t=VC_{fc}}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}(p_{fitb} - MCC_{fc} - Pc_t EC_{fc})\, qc_{fctb}$$

$$PEN_f = \sum_{n=1}^{EN_f} \sum_{t=vn_{fn}}^{T} D_t \sum_{b=1}^{LB_t} B_{tb}(p_{fitb} - MCEN_{fn} - Pc_t EE_{fn})\, qen_{fntb}$$

$$SC_f = \sum_{n=1}^{EN_f} D_t CC_{fn} x_{fn} \qquad for \quad t = vn_{fn}$$

$$FS_f = \sum_{n=1}^{EN_f} D_T SV_{fn} x_{fn} \tag{2}$$

In (1), the subscript i is relevant to the bus each considered power plant is connected to. Therefore, i is obtained from the matrix IE for thermal plants, IH for hydro plants, IPM for pumping storage plants, IC for committed plants, IEN for new thermal power plants, respectively. It is worth noticing that according to (2), the CO_2 prices emerging from the CO_2 market. The objective function in (2) is subject to the constraints described in the following (dual variables are shown in the brackets and can be used as byproduct of the optimization, see Appendix).

Locational marginal price constraints: Each firm f anticipates a price for node i; at the equilibrium, both the differences in node prices must equal transmission costs, referring to a hub node, h and p_{fitb} for the different firms must be equal to the actual price:

$$p_{fitb} = p_{fhtb} + w_{itb} \qquad \forall i \neq h, f, t, b \quad (\mu lmp_{fitb}) \tag{3}$$

As p_{fitb} must also fulfill (1), replacing q_{itb} in (1) with the net injection in the node i Eq. (15), gives:

$$p_{fitb} = p^0_{itb} - \varepsilon_{itb}\Big(\sum_{k=1}^{F}\sum_{e=1}^{E_k} qe_{ketb} + \sum_{k=1}^{F}\sum_{h=1}^{H_k} qh_{khtb} + \sum_{k=1}^{F}\sum_{p=1}^{PM_k} qpm_{kptb}$$
$$+ \sum_{k=1}^{F}\sum_{c=1}^{C_k} qc_{kctb} + \sum_{k=1}^{F}\sum_{n=1}^{EN_k} qn_{kntb} + a_{fitb} - q^0_{itb}\Big)$$

$$\begin{cases} qc_{kctb} = 0 & for\ t < VC_{kc} \\ qn_{kntb} = 0 & for\ t < VN_{kn} \end{cases}$$

In this study it has been assumed that, according to the Cournot approach, the suppliers will not change their sales in reaction to f's sales decision.

Capacity limits: The power generated by a plant cannot exceed the installed capacity:

$$qe_{fetb} \le GE_{fet}, \forall f, e, t, b \quad (\mu pe_{fetb}) \tag{4}$$

$$qh_{fhtb} \le HF_t\, GH_{fht}, \forall f, h, t, b \quad (\mu ph_{fhtb}) \tag{5}$$

$$qpm_{fptb} \le PMF_t\, GPM_{fpt}, \forall f, p, t, b \quad (\mu ppm_{fptb}) \tag{6}$$

$$qc_{fctb} \le GC_{fct}, \forall f, c, t \ge VC_{fc}, b \quad (\mu pc_{fctb}) \tag{7}$$

$$qen_{fntb} \le x_{fn}, \forall f, n, t \ge VN_{fn}, b \quad (\mu pn_{fntb}) \tag{8}$$

Maximum installed capacity limits of new plants: The total new capacity installed of the new plant n should satisfy the maximum level allowed for each firm f at each bus i the new plant n is connected to:

$$x_{fn} \le MAX_{fti}, \forall f, n, t \quad (\mu IC_{fnt}) \tag{9}$$

Arbitrage balance: The purchase and sale of power in order to profit from a difference in the price consist arbitrage function. Here, it is modeled by the power transfers from/to the hub node which is arranged by the TSO. Arbitragers are assumed to be neither producers nor consumers: hence, their energy balance must be zero:

$$\sum_{i=1}^{N} B_{tb} a_{fitb} = 0, \forall f, t, b \quad (\mu a_{ftb}) \tag{10}$$

Non negativity constraints: All the following variables must be non-negative:

$$qe_{fetb}, qh_{fhtb}, qpm_{fptb}, qc_{fctb}, qen_{fntb}, x_{fn} \ge 0 \tag{11}$$

The TSO model: The market model considered in this study is based on a nodal system. Like producers, the TSO goal is to maximize its profits. These come from providing transmission services, subject to transmission capacity constraints. The following assumptions are made to make computation of equilibrium feasible:

- The transmission system is linearized.
- All generating firms and arbitragers make decisions under the assumption that their actions will not affect the transmission fees received by the TSO.

- Pricing of transmission services is based on the nodal model.

The TSO optimization problem is therefore:

$$\max \sum_{t=1}^{T} \sum_{b=1}^{LB_t} \sum_{i=1}^{N} w_{itb} \, B_{tb} \, y_{itb} \tag{12}$$

subject to:

$$\sum_{i=1}^{N} PTDF_{ki} y_{itb} \le T_k, \quad \forall k,t,b \; (\mu tr_{ktb}) \tag{13}$$

Market clearing conditions: At the equilibrium, the following balance must hold between the transmission services provided by the grid and the services anticipated/demanded by the arbitragers:

$$a_{fitb} = y_{itb}, \quad \forall f, i \ne h, t, b \tag{14}$$

In addition, the market clearing conditions ensure, at each bus, the balance between power generation and demand, which is assumed price responsive:

$$q_{itb} = \sum_{f=1}^{F} Tot\_gen_{fitb} + a_{fitb}, \quad \forall t, i, b \tag{15}$$

$$Tot\_gen_{fitb} = (\sum_{e=1}^{E_f} ze_{fei} qe_{fetb} + \sum_{h=1}^{H_f} zh_{fhi} qh_{fhtb} + \sum_{p=1}^{PM_f} zp_{fpi} qpm_{fptb} + \sum_{c=1}^{C_f} z_{tfc} zc_{fci} qc_{fctb} + \sum_{n=1}^{EN_f} z_{tfn} zn_{fni} qn_{fntb}) \tag{16}$$

where the factors,

$z_{fxi} = 1$ if the power plant x (either thermal (e), hydro (h), pumping storage (p), committed (c) or new (n)), is connected to bus i

$z_{fxi} = 0$ otherwise

Solution of the GEP model: The first order KKT optimality conditions of the different optimization problems (generation firms, TSO) are written and solved together with all the constraints to define the equilibrium. The equilibrium problem can be defined as a Linear Complementarity Problem, which allows solving simultaneously the optimization problems of each generating company and the TSO, considering both transmission and emissions constraints. It has to be mentioned that if the market solution exists, it satisfies the optimal condition for each market players and market clearing condition; therefore, it has the property that no participants will want to change their decision unilaterally (as in Nash equilibrium). The model is implemented in GAMS Development Corporation (GDC) and General Algebraic Modeling Systems (GAMS) (2008) and solved using the MILES solver (GDC).

The Italian electricity and CO_2 markets:

The Italian electricity market: The Italian power system has gradually carried out its deregulation, ruled in Europe by the EC (1996b) (Directive 96/92/EC) and in Italy by the Decreto Legislativo 16 Marzo (1999, n. 79) (Decree 79/99 of 31/3/1999).

Competing generating companies have captured over 50% of the market, though ENEL (the former vertically integrated company) is still greatly dominating. The ENEL large share of mid-merit plants, hydropower and peak plants and its practically exclusive pumping storage capability provide it with price setting power in many internal market areas of the zonal market adopted (Terna SpA). Other few generating companies have price setting power in some internal market areas. The total efficient power installed in Italy in 2010 was 110 GW (71.7% thermal power plants, 28.3% RES and hydro power plants). The total energy production was 299 TWh by thermal (74%), hydro (17%) and other RES (9%) (Terna SpA).

The European Union emissions trading scheme: The EU is at the forefront of international efforts to face climate change and reduce GHG emissions. The EU ETS is one of the policies introduced to meet its GHG emission reduction target under the Kyoto Protocol. The implementation of the EU ETS began with Phase I (2005-2007) and it is currently in the Phase II (2008-2012), which coincides with the Kyoto commitment period. Phases I and II impose annual targets for CO_2 emissions on each EU Country and then in turn each Country allocates, according to its own criterion, its national allowance on the power plants covered by the scheme.

Companies that do not use all their allowances, that is, emit less than they are entitled to, can sell them. Companies which exceed their emission target must offset the excess emissions by buying allowances or paying a fine. Therefore the EU ETS puts a price on CO_2 emissions and creates a relevant market, which is influenced not only by the electricity sector. The EU-ETS impacts on the electricity sector come from two factors: the CO_2 prices emerging from the ETS and the methodology used to allocate allowances to firms. The proposed model focuses mainly on the CO_2 price impact. Since the CO_2 price is assumed exogenous to the model, it also assumes that any free allowances to the installations will give additional profit to the firms. Currently, companies do not need to buy all their emission allowances on the market but receive them largely for free, which makes them able to realize windfall profits thanks to the current regulation.

Table 1: Existing installed capacity of firms (MW)

GenCo	Oil	CCGT	Coal	Import	Pump	GT	Bilateral	Hydro	Total
Firm 1	3249	9249	4647	0	7073	3302	2395	6258	36173
Firm 2	1373	4749	1209	320	0	0	922	834	9407
Firm 3	362	4528	321	135	299	0	1888	377	7910
Firm 4	109	1466	0	0	0	47	540	1868	4030
Firm 5	1237	0	0	0	0	0	0	0	1237
Firm 6	0	7384	0	6983	0	0	8776	502	23645

RESULTS AND DISCUSSION

The case study: The presented model has been applied to the expansion of the Italian electricity system for the time horizon 2010-2024. As the Italian electricity market is a zonal market, the model has been simplified to be adopted for the zonal approach by assuming each zone as a node. The input data required are relevant to demand, supply, emission factors and investment costs. The five largest generating firms in the Italian electricity market are considered as strategic firms; the other firms are aggregated to one single price taker firm. This allows the solver to conveniently handle the problem. The generators with the same technology and fuel are represented with the same marginal production cost. To further reduce the size of the problem, all power plants belonging to each generating firm in a specific market zone have been merged into one group per technology. Table 1 shows the values adopted for the existing installed capacity by technology. It should be mentioned here that two coal power plants belonging to Firm 1 with the capacity of 1700, 1980 MW will be put in operation in 2012 and 2013 respectively. Firm 3 will start projects on CCGT and coal power plants with capacity of 410 and 780 MW respectively on 2012 and 2013.

The data on candidate expansion units considered are presented in Table 2. Currently, some coal power plants are in operation; for the expansion, however, only Super Critical Coal (SCC) plants are considered. In the tests, only the five largest companies are allowed to expand their capacity by building new power plants. Moreover, the maximum new capacity per technology that could be installed is assumed to be 4000 MW in each year in advance for each firm.

The discount rate Dt is set to 8%; in order to reduce the size of the problem, although the model allows the processing of many load blocks, the load of each year is represented by a single block. Moreover, a common demand elasticity $\varepsilon = 0.2$ €/MW^{2}h is assumed while the price and quantity pairs (p^0_{itb} and q^0_{itb}) that model the price dependence on quantity at each node are computed from historical data, updated taking into account an inflation rate (3%) and an yearly increase factor respectively.

Table 2: Data for candidate power plants

Technology	Capacity cost (€/kW)	Variable cost (€/MWh)	CO_2 emission rate (tCO_2/MWh)
CCGT	600	53.79	0.360
CCGT+CCS	900	65.00	0.040
SCC	1250	17.75	0.900
SCC+CCS	1900	45.00	0.098

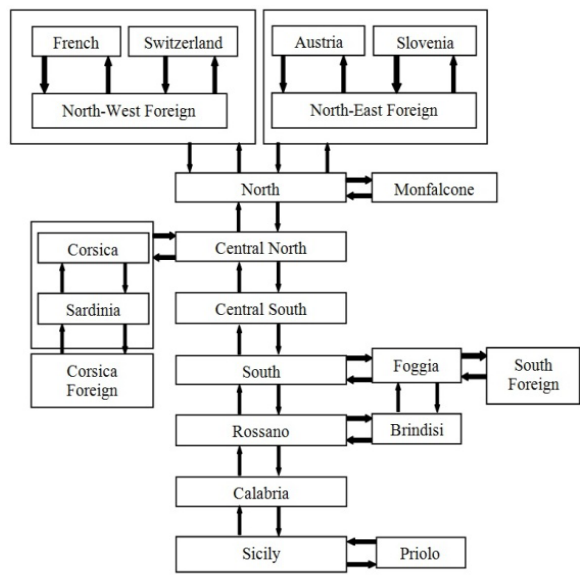

Fig. 1: Italian zonal market structure

The electricity sales through bilateral contracts by each firm are pre-dispatched and not considered as a part of the market clearing mechanism. However, they are not considered after 2014. The data on the volumes of transactions on both the spot market and the bilateral contracts adopted in the study are based on the historical data published by (GME).

Figure 1 represents the Italian zonal market structure; neighboring markets (Austria, France, etc.) are represented as foreign zones as well as some production poles (Brindisi, Foggia, etc.) that are limited by structural congestions.

Actually, some congestions between zones are observed only in few exceptional operating conditions; according to the practice from the Italian TSO, the system is finally reduced to six zones, four in continental Italy (North, Center-North, Center-South and South) and one each for Sardinia and Sicily

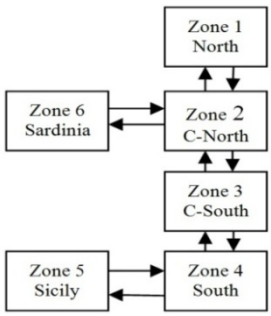

Fig. 2: Zonal structure implemented in the model

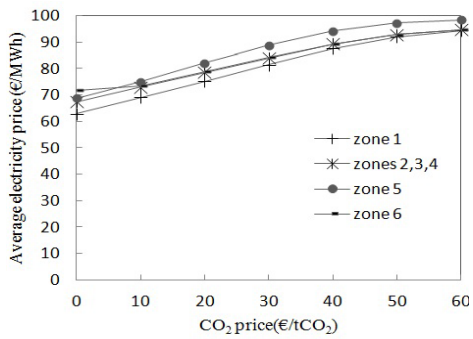

Fig. 3: Average electricity price during 2010-2024 at selected Pc in all zones

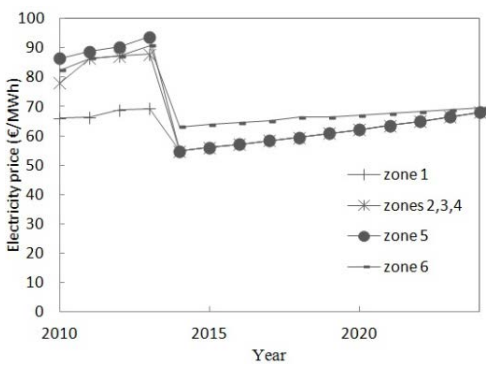

Fig. 4: Electricity price during 2010-2024 at Pc = 0 €/tCO_2 in all zones

(Fig. 2). According to these assumptions, the size of the equilibrium problem is such that the number of equations and variables is around 34000. In our study, network expansion has been considered negligible during the 15 years planning period.

The GEP model has been carried out for investigating the impacts of both EU ETS and transmission constraints on the Italian electricity sector in terms of changes in electricity prices, generation mix, investment decisions, profits and CO_2 emissions. Six different CO_2 prices are considered in this study,

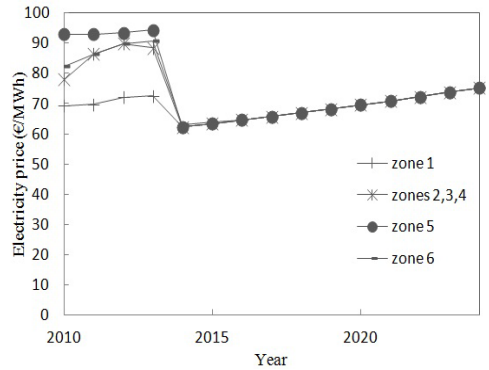

Fig. 5: Electricity price during 2010-2024 at Pc = 10 €/tCO_2 in all zones

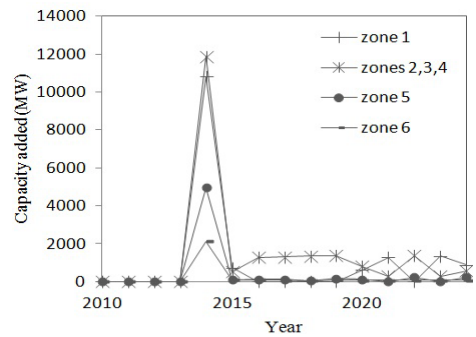

Fig. 6: Capacity added during 2010-2024 by zone

namely 10, 20, 30, 40, 50 and 60 €/t CO_2, respectively and compared with the base case characterized by a zero CO_2 price.

Electricity prices: The introduction of a CO_2 price changes the short-run marginal cost of power plants and hence the electricity prices. Figure 3 shows the average electricity prices during the planning period in each zone as Pc increases. Due to the Italian system structure, the average prices of the zones 2, 3 and 4 are the same, because no congestions are present. Figure 3 depicts the average electricity price on the time horizon considered: increasing Pc results in higher zonal prices, with a different impact depending on the share of the different generation technologies in each zone. The yearly prices for the base case and for Pc = 10 €/tCO_2 are shown in Fig. 4 and 5 respectively. Both figures show that in 2014 a significant change occurs, related to the change of the marginal technology that results in reduced prices. Moreover, it is worth noticing that for Pc = 10 €/tCO_2, after 2014 the electricity price is unique, showing that the locational price signals are strong enough to force producers to build capacity where necessary, thus reducing the occurrence of congestions. Actually, looking at Fig. 6, it is clear

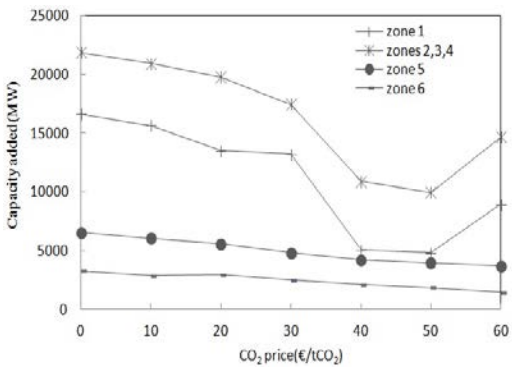

Fig. 7: Capacity additions during 2010-2024 (MW)

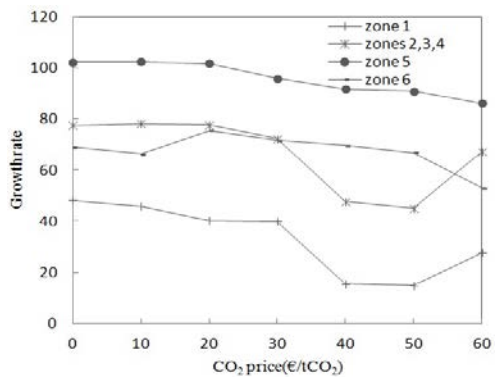

Fig. 8: Percent growth rate of capacity expansion

that, in 2014, generation companies are in the conditions to invest in new generation.

Effects of transmission capacity on investment decision: The capacity of transmission lines between zones plays an important role on investment decision due to its influence on prices. Figure 7 depicts the total cumulated capacity of each zone from 2010 to 2024, for different Pc. The technology of new power plants installed is not considered so far.

Figure 7 shows that, in all zones, the installed capacity (initially, SCC plants) decreases up to a Pc = 50 €/tCO_2, due to the increasing of costs associated to the CO_2 emissions. At this value, the SCC+CCS solution becomes attractive and this results in the capacity increase (new SCC+CCS power plants). This does not occur for zones 5 and 6, because of their initial low levels of generation, as also Fig. 8 depicts. In order to better understand which zone has more potential for investments in future years, Fig. 8 indicates the capacity expansion growth rate during 2010-2024 (related to the estimated demand in 2024), for different Pc.

Zone 5 and 6 show the larger percent growth rate: zone 5 does not have, in 2010, enough generation to supply the 2024 demand; moreover, the weak interconnection to the other zones makes it very difficult to import energy.

It is interesting to investigate some features of zones 2, 3 and 4 (combined in a single curve because there are not congestions among them) that are not apparent from Fig. 8. Zone 2 shows, at Pc = 20 €/tCO_2 and Pc = 30 €/tCO_2, a remarkable growth rate because it will compensate the low growth of zone 3 exploiting the transmission capability between zones 2 and 3. At Pc = 60 €/tCO_2, the growth rate of zone 4 actually increases because zone 4 exports to zones 2 and 3, thanks to the strong interconnections. Zone 1 shows the highest capacity expansion in absolute values during all the considered years, but it is offset by the high demand in 2024.

Power plant technology: Table 3 presents the capacity additions in each zone during 2010-2024 by technologies as a function of CO_2 prices. During the planning period, CCGT and CCGT with CCS power plants are not selected by the model, due to the lower variable cost of the SCC or SCC+CCS technologies.

Table 3: Capacity additions by technology during 2010-2024 (MW)

		Pc (€/tCO_2)						
Zone	Technology	0	10	20	30	40	50	60
1	SCC	16639	15637	13504	13209	5044	0	0
	scc+ccs	0	0	0	0	0	4814	8958
2	SCC	9224	4960	9296	8398	1225	0	0
	scc+ccs	0	0	0	0	0	1435	3915
3	SCC	5299	8632	3570	2564	4260	0	0
	scc+ccs	0	0	0	0	0	3512	4369
4	SCC	7369	7369	6934	6503	5423	0	0
	scc+ccs	0	0	0	0	0	4997	6409
5	SCC	6544	6061	5571	4826	4216	0	0
	scc+ccs	0	0	0	0	0	3938	3677
6	SCC	3265	2879	2942	2477	2104	0	0
	scc+ccs	0	0	0	0	0	1840	1427

Table 4: Generation mix (%) during 2010-2024 at selected CO_2 prices

	Pc (€/tCO_2)						
Technology	0	10	20	30	40	50	60
CCGT	4.13	4.10	4.24	4.95	22.04	23.17	8.29
Coal	15.19	15.74	16.40	16.83	16.56	14.63	2.91
Oil	0.55	0.46	0.26	0.06	0	0	0
Hydro	14.10	14.57	15.20	15.85	16.55	17.03	17.29
Pumping storage	0	0	0	0.03	0.74	0.76	10.38
Bilaterral	4.39	4.56	4.75	4.95	5.17	5.15	4.92
Import	12.32	12.77	13.31	13.89	14.50	14.92	15.15
SCC	49.32	47.80	45.84	43.44	24.44	0	0
SCC+CCS	0	0	0	0	0	24.34	41.06
Total (TWh)	7817.10	7543	7236.10	6935.60	6644.40	6458.50	6357.70

Table 5: Profit of firms during 2010-2024 at different Pc (10^{10}€)

Pc (€/tCO_2)	Firm 1	Firm 2	Firm 3	Firm 4	Firm 5	Firm 6
0	5.44	3.61	3.48	3.33	2.92	4.62
10	5.45	3.36	3.17	3.16	2.66	4.80
20	5.48	3.10	2.90	2.96	2.38	4.98
30	5.46	2.86	2.64	2.77	2.11	5.19
40	5.36	2.04	1.68	2.44	1.84	5.48
50	5.00	2.16	1.79	2.84	2.39	5.59
60	4.74	3.09	2.85	3.16	2.50	5.53

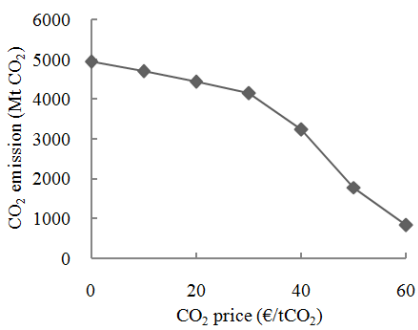

Fig. 9: Total cumulative CO_2 emission during 2010-2024 at selected CO_2 prices

Table 3 shows that, in the base case, the model defines the addition of a total amount of 48 GW of SCC technology, due to the low variable cost. Increasing Pc up to 40 €/tCO_2, the SCC additions in zones 1, 4, 5 and 6 decrease, due to the increased cost. The scenario seems to be different, but it is not, for zones 2 and 3, that actually are to be considered together because of the strong interconnection capability. Pc = 50 €/tCO_2 is the limit for the complete replacement of SCC additions by SCC+CCS.

Generation mix: CO_2 price will increase the variable cost for fossil fueled power plants. Therefore, the generation mix is likely to change to less CO_2 intensive technologies.

Table 4 shows the cumulated generation in the considered period (2010-2024) and percent shares of generation which is different for different Pc. As can be seen from Table 4, at Pc up to 30 €/tCO_2 there is no significant change in the generation mix. At Pc = 40 €/tCO_2, the generation of electricity from existing CCGT becomes cheaper than investing in new SCC. At Pc = 50 €/tCO_2, although the share of electricity generation from CCGT remains almost the same, there is a switch from generation from SCC to SCC+CCS. At Pc>60 €/tCO_2, it is cheaper for firms to invest more on SCC+CCS. Furthermore, the picture is complete observing that the generation from existing conventional coal plants is significantly reduced for Pc>50 €/tCO_2.

Profits of firms: Table 5 depicts the effect of Pc on the total profit of firms over 2010-2024. The capacity of Firm 1, which has the highest market share, is mainly based on CCGT, coal and hydro power plants; therefore, initially, it is not forced to invest in new capacity, also because it benefits in some price setting power thanks to transmission constraints. Therefore, its profit is almost constant up to Pc = 50 €/tCO_2 and then decreases. Firms 2, 3, 4 and 5 invest in new generation capacity. Their profits decrease for Pc up to 40 €/tCO_2 but they tend to increase at Pc = 50 €/tCO_2 and above as firms switch their capacity additions from SCC to SCC+CCS. The profit of the Firm 6, which owns only existing CCGT plants, increases with CO_2 prices up to Pc = 50 €/tCO_2.

CO_2 emissions: The purpose of the EU ETS is to reduce the EU GHG emissions. Therefore, it is of interest to check the change in CO_2 emissions at different CO_2 prices. Figure 9 shows the cumulative CO_2 emissions during the planning as a function of the CO_2 price. There is only a marginal decrease in CO_2 emissions up to Pc = 20 €/tCO_2, while at Pc = 30 €/tCO_2 a 16.2% mitigation in CO_2 emission occurs, with respect to the base scenario. This reduction

becomes more significant as Pc increases: at Pc = 60 €/tCO_2, the reduction is 83%. The large reduction in CO_2 emissions at higher CO_2 prices of 50 €/tCO_2 and above is due to replacement of high CO_2 intensive electricity generation of conventional coal and SCC plants by less CO_2 intensive technologies (SCC + CCS).

Conclusions and further research: The study presents an oligopolistic GEP model in the presence of transmission constraints for analyzing generating firms' investment decisions under different CO_2 reduction targets. The model proposed in this study can also be used to analyze the long-term implications on the electricity markets of different GHG mitigation policies, like EU ETS and carbon tax. The ability of the proposed procedure is demonstrated with reference to the transmission constrained Italian electricity market and to the EU ETS system, showing the possibility to model real markets and systems.

Further research will be carried out to investigate the sensitivity of the equilibria to changes in the system, both from the transmission system point of view (reinforcements, faults, etc.) and on the market point of view (changes in the demand models, which should imply stochastic models) in order to give information for risk managers of firms.

NOMENCLATURE

Sets and parameters:

T	:	Time horizon considered in the GEP (years)
D_t	:	Discount factor for year t
LB_t	:	Number of load blocks in year t
E_f	:	Number of existing thermal plants of firm f
B_{tb}	:	Duration of load block b in year t (h)
MCE_{fe}	:	Marginal cost of the e-th existing thermal plant of firm f (€/MWh)
Pc_t	:	CO_2 price in year t (€/tCO_2)
EE_{fe}	:	Emission factor of the existing e-th thermal plant of firm f (tCO_2/MWh)
H_f	:	Number of existing hydro plants of firm f
MCH_{fh}	:	Marginal cost of the h-th existing hydro plant of firm f (€/MWh)
PM_f	:	Number of existing hydro plants of firm f
$MCPM_{fp}$	:	Marginal cost of the p-th existing pumping storage plant of firm f (€/MWh)
C_f	:	Number of already committed thermal plants of firm f
VC_{fc}	:	Commissioning year of plant c of firm f
MCC_{fc}	:	Marginal cost of the c-th commissioned thermal plant of firm f (€/MWh)
EC_{fc}	:	Emission factor of commissioned c-th thermal plant of firm f (tCO_2/MWh)
EN_f	:	Number of new thermal plants of firm f
$MCEN_{fn}$	:	Marginal cost of the n-th new thermal plant of firm f (€/MWh)
EE_{fn}	:	Emission factor of the new n-th thermal plant of firm f (tCO_2/MWh)
CC_{fn}	:	Capital cost of the new thermal generator n of firm f (€/MW)
SV_{fn}	:	Salvage value of new thermal generator n of firm f (€/MW)
IE_{fe}	:	Bus number the e-th existing thermal plant of firm f is connected to
IH_{fh}	:	Bus number the h-th hydro plant of firm f is connected to
IPM_{fp}	:	Bus number the p-th pumping storage plant of firm f is connected to
IC_{fc}	:	Bus number the c-th already commissioned thermal plant of firm f is connected to
IEN_{fn}	:	Bus number the n-th new thermal plant of firm f is connected to
p^0_{itb}	:	Price assumed to describe the demand at bus i in load block b of year t (€/MWh)
ε_{itb}	:	Slope of the demand curve in load block b of year t (€/ (MW^2h)
F	:	Number of firms
q^0_{itb}	:	Quantity assumed to describe the demand at node i in load block b of year t (MW)
GE_{fet}	:	Maximum capacity of thermal plant e of firm f in year t (MW)
HF_t	:	Factor used to calculate the allowed power production from hydro plants in year t
GH_{fht}	:	Capacity of hydro plant h of firm f in year t (MW)
PMF_t	:	Factor used to calculate the allowed power production from pumping storage plants in year t
GPM_{fpt}	:	Maximum capacity of pumping storage plant p of firm f in year t (MW)
GC_{fct}	:	Maximum capacity of the c-th already commissioned thermal plant of firm f in year t (MW)
MAX_{fti}	:	Maximum capacity that can be installed by firm f in bus i during year t (MW)
N	:	Number of busses
$PTDF_{ki}$	:	Power transfer distribution factor of a unit power injection at an hub bus and unit withdrawal at bus i on the transmission interface k
T_k	:	Upper limit of interface k (MW)

Variables:

a_{fitb} : Net amount of power sold by arbitrages at bus i in load block b of year t, anticipated by firm f (MW)

qe_{fetb} : Power generated by the e-th existing thermal plant of firm f during the load block b of year t (MW)

qh_{fhtb} : Power generated by the h-th existing hydro plant of firm f during the load block b of year t (MW)

qpm_{fptb} : Generation from the p-th existing pumping storage plant of firm f during the load block b of year t (MW)

qc_{fctb} : Power generated by the c-th commissioned thermal plant of firm f during the load block b of year t (MW)

qen_{fntb} : Power generated by the n-th new thermal plant of firm f during the load block b of year t (MW)

x_{fn} : Installed capacity of new generator n of firm f (MW)

p_{itb}, q_{itb} : Price and quantity at bus i in load block b of year t (MW)

p_{fitb} : Price, anticipated by firm f, of electricity at node i in load block b of year t (€/MWh)

w_{itb} : Transmission charge to move power from hub to bus i in load block b of year t (€/MWh)

y_{itb} : Power delivered from the hub to bus i in load block b of year t (MW)

vn_{fn} : Commissioning year of new plant n of firm f

APPENDIX

The mathematical structure of market equilibrium problem is simultaneous optimization problem for each firm linked together through the price, resulting from the interaction of all of them. The mathematical model is shown in Fig. 10 (Ventosa *et al*., 2005).

In Fig. 10, π_f represents the profit of each firm $f \in \{1, \ldots \ldots, F\}$; qf are firm f's decision variables; $h_f(q_f)$ represent firm f's constraint; and λ_f is a dual variable of constraints h_f. The complete set of the KKT conditions for all the market participants and then adding equality conditions to represent clearing of the market defines a complementarity problem (MCP) as shown in Fig. 11 where L_f represents the Lagrangian function of firms f's optimization problem (Linares *et al*., 2006).

The direct solution of market equilibrium conditions by complementary methods has important computational advantages because large complementary problem can be solved.

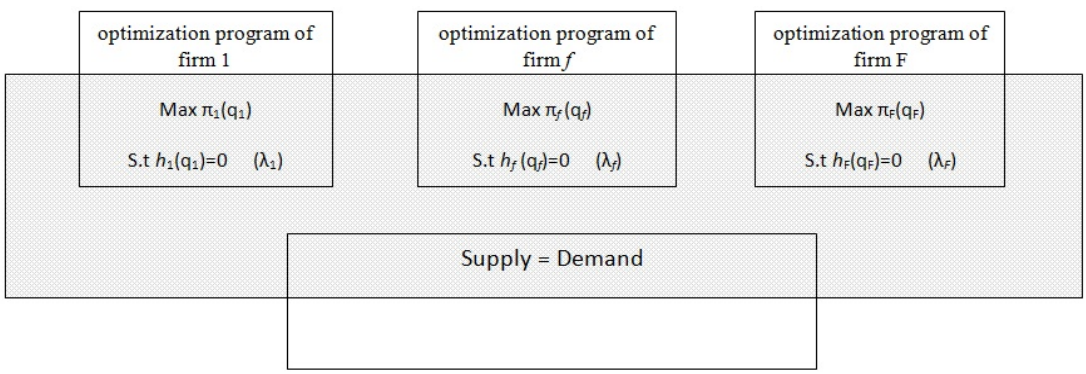

Fig. 10: Mathematical structure of equilibrium models

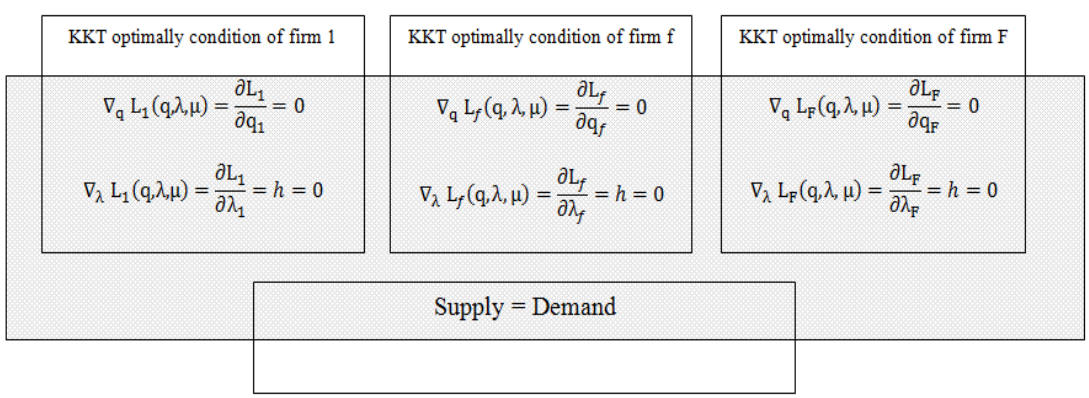

Fig. 11: Market equilibrium as a mixed complementary problem

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